THE DEEPWATER PIPELINE & RISER TECHNOLOGY

CONFERENCE & EXHIBITION

March 6-9, 2000
Marriott Westside Hotel • Houston

ORGANIZED BY

PIPES & PIPELINES INTERNATIONAL and CLARION TECHNICAL CONFERENCES

SUPPORTED BY

Pipeline & Gas Journal

Deepwater Pipeline & Riser Technology Conference
Houston, March 6-9, 2000

CONFERENCE PROGRAM

Monday, March 6
5:30pm Cocktail reception, exhibition opens

Tuesday, March 7 RISER TECHNOLOGY
7:30am Registration, coffee
8:30am-5:30pm Conference & exhibition

8.30	[1]	Getting the Risers Right for Deepwater Field Developments Brian McShane and Chris Keevill, INTEC Engineering, USA
9.05	[2]	Optimized Design Procedures for Deepwater Risers Dr. Kim Mørk and Nils Sødahl, Det Norske Veritas, Norway, and Tommy Bjørnsen Det Norske Veritas, USA
9.40	[3]	Experience and Advances in SCRs for Deepwater: Roncador Vincius Braga and Antonio Critsinelis, Petrobras, Brazil
10.15		*Coffee, Exhibition*
10.50	[4]	Strength and Fatigue of Deepwater Metallic Risers Gawain Langford, Jens Jensen, Per Damsleth, Ole Grytå, ABB Offshore Systems, Norway, and Prof. Yong Bai, American Bureau of Shipping, USA
11.30	[5]	The Application of Bundled Pipeline Installation to Drilling and Hybrid Risers R.J. Brown, Kværner RJ Brown, USA
12.10	[6]	Catenary Riser Interaction with the Seabed at the Touchdown Point Prof. Andrew Palmer, University of Cambridge, UK
12.45		*Lunch*
2.00	[7]	Ultra Deepwater Production Riser Design Christopher Wajnikonis and Richard Hill, JP Kenny, USA
2.35	[8]	The Combined Riser Mooring (CRM) System : An Innovative Concept for Deepwater Mooring and Riser Design Kieran Kavanagh, MCS International, USA, Fank Grealish and Adrian Connaire, MCS International, Ireland, and Paul Batty, MCS International, Norway

3.10 [9] Dynamic Analyis and Simulation of Risers: Review and Assessment of Current Methods
Dr. Saadat Mirza, Dr. Basim Mekha, and Slimane Bouabbane, INTEC Engineering, USA

3.45 *Coffee, Exhibition*

4.15 [10] Deepwater Riser VIV, Fatigue and Monitoring
Dr. Frank Lim, 2H Offshore Engineering, UK

4.50 [11] Fatigue Performance of Catenary Risers Installed by Reelship
Mike Bell, Coflexip Stena Offshore, UK

5:30 *Cocktail reception & Exhibition*

Wednesday, March 8 PIPELINE TECHNOLOGY

7:30am Registration, coffee
8:30am-5:30pm Conference & exhibition

8.30 [12] Deepwater Development and Cost Optimization – A New Approach
Richard Hill and John Pierce, JP Kenny, USA

9.05 [13] Recent Advances in Deepwater Pipeline Technology
Leif Collberg, Det Norske Veritas, Norway, and Tommy Bjørnsen, Det NorskeVeritas, USA

9.40 [14] The Royalty-in-Kind Program for Offshore Gas Production in the Gulf of Mexico
Bonn Macy, Minerals Management Service, USA

10.15 *Coffee, Exhibition*

10.45 [15] Burst Test Basis for the Internal Pressure Design Formulation in the Revised API Recommended Practice 1111for Offshore Pipelines
Dr. Carl Langner, Langner & Associates, USA

11.20 [16] Gulf of Mexico Pipeline Failures and Regulatory Issues
Alex Alvarado, U.S.Minerals Management Service, USA

11.55 [17] Material Test Methods and Data Requirements for Pipeline Design
Prof. Alastair Walker and Dr. Kahled Kamhawi, KW Ltd, and Bert Holt, Mitsui Babcock Energy Ltd, UK

12.30 *Lunch*

1.45 [18] Deepwater Pipeline Repair System
Tom Preli, Shell International Exploration & Production, USA, and Jeffrey McCalla, ROV Technologies, USA

2.20 [19] Forming a Deepwater Pipeline Repair Alliance
Dr. Ray Ayers, Stress Engineering Services, USA

2.55 [20] Dulcimer and Pluto Pipeline Repair Projects
Norb Gorman and Mike Ellis, Oceaneering International, USA

3.30 *Coffee, Exhibition*

4.00 [21] Review of the State of the Art of Pipeline Blockage Prevention and Remediation Methods
Dr. Doreen Chin and John Bomba, Kværner RJ Brown, USA

4.35 [22] Flow Assurance Techniques: Relative Costs vs. Effectiveness
Chuck Horn, Paragon Engineering, USA

5.10 [23] Underwater Joining to 8,200ft—An Alternative to Mechanical Connectors
Dr. P. Hart, Dr. I. M. Richardson, Prof. J. Billingham, P. Nosal and J. H. Nixon
Cranfield University, UK

5.45 *End of day*

Thursday, March 9 PIPELINE TECHNOLOGY (continued)

8:00am Registration, coffee
8:30am-12:30pm Conference & exhibition

8.30 [24] Subsea Structure Installation Technology
Naum Kershenbaum and Joseph John, Mentor Subsea Technology Services, USA

9.05 [25] Deepwater Pipeline Routing: the Unexpected Challenge
Kerry Campbell, Fugro GeoServices, USA

9.40 [26] Pipeline Routing Using 3D Seismic in West Seno (Indonesia) and Ladybug (GOM)
Chuck Hebert and Mike Reblin, Unocal, USA

10.15 *Coffee, Exhibition*

10.45 [27] Gel Pig Technology - An Evolving Flow Assurance Tool
Craig Tucker, Paragon Engineering, USA

11.20 [28] Analysis of Deepwater Debris Flows, Mud Flows and Turbidity Currents for Speeds and Recurrence Rates
Dr. C.W. Reed, A.W. Niedoroda, B.S. Parsons and J. Breza, URS Greiner Woodward Clyde, USA, and G.Z. Forristall, Shell E & P Technology, USA

11.55 [29] An Improved Formula for Calculating Pipe Hoop Stress
Jaeyoung Lee and Don Herring, Aker Engineering, USA

12:30pm *Light lunch & adjourn*

Deepwater Technology conference

March 6-9, 2000, Marriott Hotel Westside, Houston, TX

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Conference Evaluation Form

Deepwater Pipeline & Riser Technology Conference
Houston, March 6-9, 2000

We would be grateful if you will fill in and return this form to the Registration Desk before leaving the conference. Your response will help us plan future events for the greatest benefit to those interested in this and related subjects.

1. Your initial reaction to the conference *(in a few words, an overall comment)*:

Please indicate (where shown below) your evaluation on a scale of to 5, where 1=poor and 5=excellent.

2. Content:

General technical or professional relevance of the program	1-5:
Usefulness of documentation	1-5:
Presentation of documentation	1-5:
Value of presentations on	
Tuesday morning	1-5:
Tuesday afternoon	1-5:
Wednesday morning	1-5:
Wednesday afternoon	1-5:
Thursday morning	1-5:
Value of discussions during sessions	1-5:
Value of informal discussions during breaks, etc.	1-5:

Did you think the program was
- too long
- too short
- about right

Topics not covered that you would like to see addressed in a future conference on this subject:

3. Prior information and publicity:

Quality of publicity 1-5:
How/where did you hear about the conference?

Quality of information given to you before the event? 1-5:

4. Venue:

Suitability of Houston as a location 1-5:
Quality of your hotel room (if applicable) 1-5:
Conference room and facilities 1-5:

food and refreshments 1-5:
ability to see 1-5:
ability to hear 1-5:

5. General organization

How efficiently were you kept informed of details of the program during the conference? 1-5:

How efficiently were any questions relating to your stay at the hotel answered? 1-5:

Please rate the conference compared to other professional conferences you have attended 1-5:

Would you recommend a future conference organized by Clarion to your business colleagues?

Please rate the conference for value for money 1-5:

6. Exhibition

Were the displays of technical interest? 1-5:

Was the number of displays ❒ too few ❒ too many ❒ about right

What kinds of products, services or companies would you like to see represented at a future exhibition related to Pipeline Operator Qualification compliance?

Are you interested in exhibiting at a future conference? If so, check the box and attach your card or write the contact information below. ☐

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Do you see the need for a future conference on this subject?

Would you attend a future conference in 2000?

Where would you like such a conference to be held?

During which months should a future event NOT be held:

What other topics would you like to see covered in a future conference on this subject (if not already answered under section 4 above)?

On what other subjects would you like to see a conference held?

8. Which industry magazines or trade journals do you read most often:

9. To which industry or professional associations to you belong:

10. Other comments:

Name and address (optional):

May we quote your comments in our publicity for a future conference on this subject? yes/no

Many thanks for your time in completing this form. We value your comments and will act on them to the future benefit of all.

B.J. Lowe
Clarion Technical Conferences

John Tiratsoo
Pipes & Pipelines International

Getting the Risers Right for Deepwater Field Developments

Brian McShane and Chris Keevill
INTEC Engineering, Houston, USA

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

Getting the Risers Right for Deepwater Field Developments

1. ABSTRACT

As stand alone deepwater developments are one of the main focuses of the oil and gas industry, it is important to select the correct development concept at an early stage. Decisions made at the front end are the most important ones to get right as they are the most costly to change. This is true for all components of the system but in particular for the risers, as these are the key link between the subsea production systems and the floating facilities. It is imperative that these decisions are based on a realistic appreciation of the capabilities of each riser system, rather than pure intuition. This appreciation does not only include understanding the technology issues and each designs' functionality limits but also the associated reliability of each design, their interface requirements and their costs, to name but a few.

This paper presents a method to logically organization, prioritize and assess the key considerations associated with riser designs thus providing a complete basis for selecting the right riser solution at an early stage of a field development.

2.0 INTRODUCTION

The targeted water depths for oil and gas developments are increasing every year. This is reflected in figure 1 that summarizes the projected application of FPSOs by year. These developments tend to be self-sufficient and made up of a subsea well/manifold infrastructure, tied back through an array of flowlines and risers to a floating production host. The host processes the product which will then be exported either via tanker based offloading facilities or through pipelines. For these developments to be committed to or "sanctioned" by the investors it has to be demonstrated that:

A system can be developed that meets all the functionality requirements for the field (flowrate capacity, temperature limits etc.),

The development is economical (comparison of CAPEX and OPEX cost to the estimated reserves)

The confidence in the predictions of (1) and (2) are high.

This financial commitment or sanctioning of a project occurs relatively early in the project's life and so predictions of (1) and (2) are made typically based on a system definition that is limited to a conceptual level. This is acceptable, if several of these types of developments have already been installed, as these provide a basis for the confidence of the predictions. However, for deepwater developments the most suitable system solution often involves either an extension of technology (for example P18, an SCR to a semi-submersible[1]) or a completely new technology (for example Girassol's offset hybrid riser towers[2]). Selecting the most suitable solution, may result in accepting the system with the least associated experience or track record. This could be viewed as adding commercial and perhaps technical risk to the project. Commitment to the most suitable solution in these situations is not for the faint hearted. However, with a logical assessment of the various criteria and a sound estimate of each criterion's level of importance, it

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is possible to develop a firm basis for a solution's selection. The purpose of this paper is to outline a logical basis for the selection of a riser system for a deepwater field development.

3.0 BACKGROUND

The functionality of a particular riser solution is dependent upon many site-specific issues particular to the field development project. The following outlines what some of these might be for a riser system. This is by no means all encompassing but provides an initial basis for the assessment of the most suitable riser solution. Identifying all the issues that need to be considered not only provides a basis for determining the criteria to be met but also highlights how overwhelming making the correct riser selection may appear.

The following list and associated discussion outlines aspects of a field development that will impact the selection of the most appropriate riser solution. The questions to be answered are "What criteria need to be defined to address all of these issues? What should their relative importance be?"

Field development issues include:

- Location and water depth
- Field Architecture
- Future expansion
- Field Development Plan
- Host vessel type
- Host vessel dynamic response
- Host vessel mooring configuration
- Environmental Loadings
- Other facilities
- Flow assurance and operability
- Safety
- Economic viability
- Riser gas lift
- Geographic location

3.1 Location and Water Depth

The geographical location of a field development relates to riser selection or feasibility not only based upon the environmental conditions but also the knowledge or experience of riser systems installed to date and in operation in that area and environment.

Water depth is one of the major challenges for riser systems and one of the primary reasons is related to the hydrostatic loading imposed on the risers by deep water. It is therefore necessary to produce a design to prevent collapse and buckling of the risers. Extended water depths have also required the development of higher strength, light weight, materials which will withstand the hydrostatic loadings, but which do not require lay tensions that exceed the majority of vessel capabilities. Accordingly reducing the riser weight will reduce the reaction loads transferred through the riser porches on the host vessel. These deepwater hydrostatic loadings also effect secondary riser materials such as thermal insulation. Materials which work efficiently in shallow water applications often do not have sufficient mechanical strength to withstand the deep water external pressures. With deep water comes reduced ambient temperatures and hence multiphase production, and the risk of hydrate formation. Hydrate control and management can be a major driver in riser design. The other obvious effect of ever increasing water depth is the need to design for diverless installation, intervention, inspection and repair methods.

3.2 Field Architecture

The design of each system component (both floating and subsea) and their overall configuration relative to one another are affected by: installation limitations, construction sequencing, operability and maintenance /intervention requirements, environmental conditions and the reservoir depletion plan. It is critical that the overall field layout be defined early in the project development process and that all the interfaces are also clearly defined and managed throughout the project.

HSE requirements regarding the location of hydrocarbon lines and the flare in relation to predominant wind directions, living and working areas, life boat locations and life boat egress routes all impact the available riser porch locations. These locations and the riser configuration impact the locations where the risers can be installed.

For example, depending upon the relative positioning of the subsea components to the host and the available riser porch locations it may be impractical to route flowlines to the manifold from the touch down point of an SCR. A straight length of flowline at the base of the riser is required to anchor the SCR touchdown point. This situation can be improved by provision of a riser base to anchor the SCR, but this would still require more seabed real estate than either a flexible riser or hybrid riser tower option.

The riser configuration, touchdown point and their effect on the flowline routing must consider not only the mooring patterns of permanent facilities within the field, but also the potential interference with drilling and work over vessels.

Riser porch arrangements, configurations and flowline routing will need to ensure that suitable corridors and sufficient clearance are provided for future flowlines and risers.

The location of riser porches on the host, the riser configurations and flowline routing must ensure that there is still free access for supply boat /crew boat approach and loading/offloading operations.

3.3 Future Expansion

The field architecture of the overall field development should identify all future wells or fields which may be tied back to the host facility to ensure that flowline corridors and spare riser tie-in porches are identified. Similarly the construction schedule and installation methods proposed for initial installation of a riser may be quite different from that of a future riser installed once the field is operating and there is considerable local infrastructure to consider. Some riser systems are more flexible to accommodate expansion and changes to the field than others. For example, it is quite feasible to install a single SCR at a future date to a floating production host, however, a riser tower will need to be designed with future expansion capability built in from day one unless expansion is to be so significant to warrant another riser tower.

3.4 Field Development Plan

The field development plan defines the overall functional requirements for the field such as details of the reserves, type and location of reservoirs, reservoir depletion plan, number of wells, use of gas injection or water injection for reservoir pressure maintenance. It also defines the proposed field development concept or concepts to be evaluated, i.e. a ship shaped FPSO with subsea wells and offloading via a deep water SPM, or a TLP or a wellhead SPAR and FPSO combination. All of these factors obviously play a major part in the selection of the optimum riser solution or combination of riser types for a particular field development.

3.5 Host Vessel Type and Dynamic Response

The type of host vessel can impact the feasibility of the riser. Two examples are the track records of Top Tension Risers (TTR) and SCRs. TTRs have been used for TLPs and SPARs but they have not been employed in conjunction with ship shaped FPSOs. SCRs to date have been associated primarily with semi-subs, TLPs and more recently SPARs but not ship shaped monohull vessels. Track records, however, are a reflection of the technology of the time and severity of field environments. Currently some of these perceived capability limits are being challenged, for example the Bonga field development is considering using SCRs as their riser concept with a ship shaped monohull vessel. Bonga is considered to have a more benign environment, which enhances the feasibility of SCRs

3.6 Host Vessel Mooring Configuration

The vessel type and the mooring configuration of the host vessel will have a major effect on the overall field layout. For example, the tendon type mooring system of a TLP will provide far less restrictions on the seabed architecture than a spread moored FPSO where the mooring legs offer a potential clashing hazard in the water column under extreme vessel offsets. This creates routing restrictions for risers and flowlines to avoid interference with the moorings.

Predominant environmental loading directions also influence the type of mooring arrangement. For example, under conditions where the predominant environmental loading is in one direction and wind and current loading are co-linear, it is acceptable to use a spread moored ship shape host, where the vessel is headed into the direction of prominent weather. However, if there is no predominant direction, to still use a ship shaped host, the vessel must be able to weathervane about its moorings. This will have a significant effect on the riser system design as all risers will have to be terminated into a turret about which the vessel can rotate.

3.7 Environmental Loadings

The headings and combinations of environmental criteria can determine the host vessel type and mooring system requirements which in themselves effect the design of the riser system. However, it should also be remembered that vessel response and maximum offsets are not only a function of vessel type, but also of the environmental conditions. This can have a major effect on the feasibility of particular riser systems. For example, SCRs have been installed on host facilities such as TLPs and Semi-subs. These types of FPSs are normally recognized as having reduced offsets when compared to monohull type vessels. However, many of these applications are in relatively extreme environments. In a more benign environment a monohull type FPSO would experience similar offset ranges to TLPs and Semi-subs where SCRs are installed. It could therefore be argued that depending upon the environmental conditions in the field, installation of SCRs to a monohull FPSO would be a small extension of field proven technology.

3.8 Other Facilities

As previously discussed all temporary and permanent facilities in the field will affect the overall field layout. This includes the life of field facilities, future facilities, drilling vessels, workover vessels and construction vessels. The sequencing of operations and the mooring patterns of these vessels will impact the riser system configuration and installation methods. For example, if the field development includes an SPM offloading system, the offset distance and orientation with respect to the host vessel will be driven by:(1) operational safety, (2) predominant environmental loading directions (affects tanker approach and mooring operations), (3) SPM system mooring and loading line interference with host vessel moorings. All of this congestion will impose severe limits on the opportunities available for engineering riser solutions and under these circumstances it is important to determine what are the relative priorities in determining the key constraints for the field layout.

To avoid unnecessary criteria limits there is clear benefit in evaluating options at an early stage and define realistic constraints on field architecture, such as HSE concerns. All disciplines need to be involved in a pro-active system wide approach to concept definition.

3.9 Flow Assurance and Operability

Flow assurance and operability are often the key drivers in flowline and riser design for deepwater field development project. Issues such as wax and hydrate management dictate system requirements such as thermal insulation, chemical injection, heating and circulation, operational pigging access and intervention requirements. The functional requirements necessary to satisfy flow assurance and operability demands will often be the determining factor in the riser system design and may in fact preclude some riser systems from consideration.

3.10 Safety

HSE issues are top priority and risk / hazard assessments are becoming more and more an integral part of deepwater projects. It can sometimes be perceived that safety is directly opposed to technological advancement. While it is true that it is often safer to follow existing field proven technology, using well-understood methods and procedures, the risk of using new technology may be significantly reduced by the implementation of design reviews, risk assessments, testing programs (full scale and model tests), and constructability reviews.

The safety issues relating to a riser system design must be evaluated throughout all stages of fabrication, testing, installation, operation, maintenance and repair. In evaluating various riser systems on the basis of a set of criteria, it is important to apply a relative weighting to each criteria to ensure an accurate and valuable evaluation. Safety should always be weighted as one of the most significant criteria.

3.11 Economic Viability

Along with safety the other key focal point for any project is economics or commercial viability. That is not to say the lowest cost solution, but the solution that is the most suitable for all functional and safety criteria which also meets commercial objectives.

With the rapid advancement of some areas of riser technology for deep water fields, it is sometimes difficult to predict the actual cost of a riser system. To have confidence in the accuracy of the cost estimate it is ideal if data exists from previous projects to relate the estimated costs against actual installed costs, thereby benchmarking the estimate. The more novel the riser system, such as the hybrid riser tower, the fewer the number of similar installed systems and hence the fewer systems to benchmark against. This should be considered when comparing the relative costs of riser solutions. Some systems are well understood and field proven while others are essentially no more than best estimates based upon experience and judgement.

3.12 Riser Gas Lift

The need to provide gas lift at the base of a riser to improve flow characteristics, can lend itself to some riser systems more readily than others. If this is a determined to be a functional requirement, it will bias the evaluation towards riser systems that are reliant upon a riser base. For example, in the case of a hybrid riser tower, it is relatively straightforward to include gas lift lines within the riser bundle and accommodate the connections into the main production riser within the base structure. In contrast, this complicates the system design for a flexible riser or a steel catenary riser, which may have been designed without the need for a riser base.

3.13 Geographic Location

The geographical location of the field, the level of local development including onshore support facilities, ports and road systems, can affect fundamental project decisions on the feasibility of in-country fabrication. Similarly, political drivers such as the risk to personnel and materials in areas of political unrest, or conversely incentives for development of local capabilities and infrastructure can have a major effect on base philosophies. These, in turn, influence the potential application of a riser system to a particular field development. Such an example would be the fabrication of a hybrid riser tower. This activity is heavily dependent upon onshore fabrication at a site close to a sheltered location where the riser bundle can be launched and trimmed in preparation for tow into the field. Obtaining onshore fabrication and material transportation capabilities may require a large capital investment or be in an area where the political or environmental circumstances are unfavorable. Under these conditions other riser options that rely only on offshore construction may appear more attractive.

4.0 METHOD FOR DECISION MAKING

To make the best riser selection for a development an assessment method is required. The following summarizes one such method, Kepner and Tregoe's Decision Analysis method[3], and how it might be applied to the selection of the best riser solution for a development.

The Kepner Tregoe method is based on three key elements.

- the quality of the definition of the criteria that needs to be achieved,
- the accuracy of the evaluation of the alternatives, and
- the assessment of the potential consequences of the solution.

The Kepner Tregoe (KT) assessment method is a process by which the most suitable solution, that meets a set of prioritized criteria, can be determined from a range of possible alternatives. This method determines the relative 'quality of fit' of the various solutions to the prescribed criteria. The KT assessment is carried out in the following stages:

- State the decision to be made

- Make a list of 'musts' and 'wants' – where 'musts' are requirements that are mandatory and 'wants' are project preferences. Categorize these criteria into groups and allocate, by weightings, the relative level of importance of each group.
- Identify all possible solutions.
- Discard all solutions that do not meet the 'musts'.
- Assess the remaining solutions against the 'wants' by the KT scoring method. KT scoring provides a method of determining the relative performance of each solution.
- Tentatively select the solution with the highest score.
- Estimate the risk associated with the selected solution and assess what potential negative consequences that might be associated with each solution.
- Select the solution with the highest KT score which has an acceptable level of risk – 'The balanced choice'.

Decision Statement: The decision statement identifies the choice or dilemma that is to be resolved. In this instance it is the selection of the most suitable deepwater riser system for the development under consideration. This statement defines the focus for the process and limits the choice. For example, the deepwater riser decision statement eliminates the option of a long distance tie-back to a platform in shallower water.

The 'musts': The criteria that are defined as 'musts' have to be quantifiable in a manner that is not based on personal judgement. When solutions are reviewed against these criteria it needs to be absolutely clear as to whether or not these are achieved by the solution. The criteria also have to be 'reasonable'. Reasonableness is based on the response to "How reasonable is it to make the defined criteria mandatory?"

Weighting: Quantifying the importance of a 'want' is achieved by weighting factors, which are directly related to the level of importance of each 'want'. For example if the 'want' is something that would be nice to have but not very important, it would be assigned a weighting factor of say 2. However, if it is something that is very important to have, it would be assigned a weighting factor of say 10.

Scoring: Scoring each solution on its achievement of each 'want' is performed using a graded scale from 1 to 10. If a solution is very poor at achieving the 'want' then it would score a 1 whereas if the solution achieves the 'want' then it would score 10. For example, for the criterion of minimum field architecture congestion on the seabed a riser tower solution may score 9 whereas an SCR would probably only score 6.

Weighted Score: By multiplying each 'want' score with the associated weighting factor and summating each solution's score for all 'wants' will determine the KT score for that solution. The relative numeric scores of each solution can then be used to determine which is the preferred overall solution.

Verification: This method is directly related to the preferences of the assessor, as many of the criteria can only be judged subjectively. Therefore, there is a potential for the result to be biased by the assessor. To manage this issue two approaches can be adopted: (1) Utilize several assessors to independently score the solutions (2) Review the sensitivity of the KT score for each criterion and determine if there is concern with the criterion and associated weightings.

A logical assessment method of this type is a very useful tool to quantify the relative merits of various design solutions.

5.0 RISER ASSESSMENT

The following is a summary of the application of the KT method to getting the risers right for deepwater field developments.

5.1 Riser Assessment Criteria

One of the biggest issues associated with the development of the most suitable solution is the clear definition of the criteria and whether these are 'musts' or 'wants'. Quite often criteria definitions are not well thought out and so are initially considered to be 'musts' until it is realized that perhaps only one solution qualifies. On review it is realized that the criterion is actually a 'want' and so does not necessarily disqualify all solutions. A way of managing this issue is perhaps to think of each criterion as a 'must' and a 'want' where the 'must' is a minimum threshold to be achieved and the 'want' is a measure of how well the solution exceeds the threshold. An example of this would be the thermal performance. Maintenance of the temperature above the hydrate formation temperature for a period of time (say 12 hours) when the pipeline is shut in would be a minimum thermal performance – a 'must'. However, how far each solution exceeds these criteria would be a 'want'.

In determining whether a criterion is a 'must', the rationale for it being mandatory should be defined. By reviewing the benefit to the project, and whether this benefit can be achieved by some other method, helps to determine what criteria fall into this category. For example, requiring that the solution must have a track record for exactly the same configuration would provide confidence based on field proven experience. However, this benefit could be achieved by compiling information from test data and similar applications.

The issues discussed in section 3 need to be organized into 'musts' and 'wants'. Table 1 summarizes the 'must' issues.

TABLE 1 THE 'MUSTS' FOR A RISER SYSTEM

'Must' Criteria	Threshold
Water Depth	Risers must be able to function in the water depth range of the field development.
Number and size of Risers	Minimum required to produce the reservoir economically. These injection and production risers must have the capacity to meet the required flowrates and the number of well locations.
Tension capacity of Host facility to support the risers	Each host floating production system will have an upper limit on the tension support that can be provided to the riser systems. The tension limit is dependent upon the host, and may be limited by issues such as buoyancy capacity or hull interface loads.
Cooldown	Minimum acceptable cooldown duration of production lines where internal temperature is

	higher than those at which hydrates form under shut in conditions.
Weather vaning of vessel	May or may not be a requirement of the project. Dependent upon combined environment loading directionality.
Constructability	It must be possible to construct the riser system and demonstrate that it is feasible.
Diverless installation of subsea equipment	System constraint.
Operational safety	Must be demonstrated to be less than an acceptable level of risk.
Safe routing of risers	Minimum distances and relative locations of risers and: living quarters, supply boat loading areas, muster stations wind direction etc.
Economic Viability	The riser solution must be within defined budget constraints.

Before determining the order of importance, the 'wants' criteria are organized into groups. The main categories are:

Functionality – summarizes how the overall riser system performs relative to the design parameters includes such criterion as thermal performance, field architecture congestion, fatigue resistance.

Constructability – groups criteria related to the ability to install the riser system with existing techniques and includes criteria related to the complexity and feasibility of the fabrication and installation phases.

Operability –includes criteria related to ability to intervene; provide maintenance or repair the riser system.

Safety – includes criteria such as system reliability and each systems track record.

Commercial – includes both the CAPEX and OPEX estimates of each system as well as strategic commercial decisions such as commitments to local content participation.

Table 2 summarizes the 'want' criteria for the riser system assessment. Associated with each criterion is a list of considerations that should be reviewed when determining how a solution should be scored.

The categories are a little unbalanced in regard to the number of criteria in each category. However, this is not an unreasonable grouping as long as it is reasonable that all the criteria in each group merit the same weighting. If this is not the case then the groupings should be reviewed. For the groupings summarized in Table 2, it could be argued that perhaps Capacity for system expansion or Field Architecture Congestion would not have the same weighting as the other criteria in the Functionality group. However, for the purposes of this decision analysis example, they will be considered to have the same weighting.

TABLE 2 'WANT' CRITERIA SUMMARIZED BY GROUPS

Primary Criteria	Base Criteria	Considerations for each Criteria
Functionality	Product flowrate	Systems capacity to service the number of wells and the associated flowrates.
	Fluid loads	Temperature and Pressure.
	Vessel movements	Vessel movements that can be accommodated by the riser.
	Environmental loads	Ability to withstand environmental loading in the field for the design life.
	Tension requirements of host	Ability to react riser interface loads.
	Thermal Performance	Insulation characteristics over time.
	Fatigue	Ratio of fatigue damage to the risers capacity to absorb fatigue.
	Field architecture congestion	Relative space requirement for different riser configurations.
	Capacity for system expansion	Ability to post install system in remaining acreage around host.
	Feasible FPS Hosts	Ability of riser system to meet functional performance requirements of different FPS hosts.
	Interference with other systems	Likelihood of clashing with other systems and access limitations for installation and operation activities.
Constructability	Types of installation vessel required	Consider vessels required for initial installation or later expansion.
	Complexity of installation	Assessment of construction sequencing and associated risks and consequences.
	Fabrication techniques required and complexity of fabrication	Location and limitations of support bases or available construction vessels. Complexity of sequence and potential impacts on schedule.

Primary Criteria	Base Criteria	Considerations for each Criteria
Operability	Diverless intervention	A measure of the ability for intervention considering the tools available and their application to the riser system.
	Diverless inspection	A measure of the ability for inspection considering the tools available and their application to the riser system.
	Diverless Repair	A measure of the ability to repair, considering the tools available and their application to the riser system.
	Intervention ability to remediate a hydrate blockage	Access and options for managing hydrate blockages.
	Access for drilling/workover vessels	Interface with mooring patterns and risk potential to pipelines and flowline systems.
Safety	Track Record	Number of previous similar installations and their performance.
	System reliability	Assessment of the reliability of the component and the combined reliability of the overall riser system.
Cost	CAPEX	Capital costs of the system and their relative percentage of recoverable reserves.
	OPEX	Operational costs of the system and their relative percentage of recoverable reserves.
	Local Content	Percentage of investment that will involve local businesses and personnel.

5.2 Weighting Riser Criteria

The assessment criteria presented in this paper are based on a riser solution perspective and are weighted as such. Weightings are only applied to the main groupings. The applied weightings are based on the relative importance of the groupings to one another and are summarized in Table 3.

TABLE 3 WEIGHTINGS OF 'WANTS'

Group	Weighting
Functionality	8
Constructability	4
Operability	6
Safety	8
Commercial	6

Functionality is obviously the most important. The ability of the solution to meet the 'wants' of the functional performance criteria, for these types of developments, is the key component to: the solution being technically feasible, a low risk of failure, and achievement of the safety requirements. For example, how resistant is the solution to fatigue damage is a measure of how safe the design is for this criterion. Safety is also of prime importance. However, as mentioned before the safety of a solution is not only dependent upon items identified in this group but is also linked to many of the other criteria in the other groups. In particular, those relating to the solution's functional performance will impact the safety of the system. Operability and Commercial aspects of the solution have lower weightings than Safety and Functionality. However, they are still important as the ability to intervene or repair a system or the economics of the solution are still main considerations as to whether a project should proceed to implementation. Constructability has been given the lowest weighting. The 'musts' criteria have determined that the system can be installed. For the Constructability 'wants' this is a measure of the complexity which will impact issues such as the likelihood of a cost over-run due to installation taking longer than expected.

Care needs to be taken in selecting the weightings to identify the main criteria for success. Applying similar weightings to each group would result in the key success factors being hidden by less important criteria.

Once the evaluation process is completed for a set of solutions the question may arise as to what is the confidence in the assessment and selection of the preferred solution. A means of reviewing this would be to carry out a sensitivity analysis of the KT scoring by altering the group weightings to see if the preferred solution changes.

5.3 Risk and Consequence

Once the preferred solution is identified the final step is to assess the potential consequences associated with this solution and their likelihood of occurrence. This assessment must be carried out even if a solution is by far the 'best fit' with the criteria. If the consequence of a failure of this solution is large and its likelihood of occurrence is high, then it is not the right solution. This is a qualitative assessment[3,4] of potential downsides of a solution based on the likelihood of occurrence and the consequence if it occurred. Both consequence and likelihood can be assessed on a relative scale, consequence ranging from serious to not serious and likelihood ranging from probable to not probable. These can then be combined to a numeric score with a serious consequence, high likelihood scoring 10 and a non serious consequence, low likelihood scoring 2.

6.0 HYPOTHETICAL CASE STUDY

To demonstrate some of the key drivers and criteria associated with assessment of potential riser system solutions for a field development, the following has been generated as an outline model:

- Host Vessel - Spread Moored Ship Shaped FPSO
- Water Depth – 1000 m
- Location – West Africa
- Subsea Production Wells and Cluster Manifolds
- Reservoir pressure maintenance via water injection
- Re-injection of produced gas

Total number of wells - 30

For the purposes of demonstrating the decision analysis process the following three potential solutions were considered for the hypothetical case study:

- Riser Tower
- SCRs – Single pipe for the water injection and gas injection risers and pipe-in-pipe for the production risers
- Flexibles

Top tension risers have not be considered in this review as they are not considered to be a suitable solution for a ship shape FPSO host and subsea production cluster manifolds. Other solutions may be applicable, however, the purpose of this example is to demonstrate the decision analysis process rather than determining the optimum solution for this field development.

The following provides a general review of the riser solutions for the criteria groups summarized in section 5. These are lists of engineering judgements or engineering experience that summarizes, for each criteria group, some of the advantages or disadvantages of the different riser systems. These summaries do not include any quantified performance data that would normally be generated for a concept review but provides generalities as to the relative performance of the system. For example, the calculated thermal performance or the fatigue life of the system.

6.1 Riser Tower

Functionality

- Capacity is predetermined during design. Thus any future expansion must be planned in advance and built into the riser tower. Or space planned for future tower
- Key tower parameters are buoyancy capacity and soil foundation capacity to carry tension loads
- Riser Tower is not directly connected to the surface vessel and hence is independent of vessel motions other than interaction with the jumpers
- Excellent thermal insulation potential, opportunity for incorporation of heating lines. Water injection risers could be incorporated in the tower and may be used for remedial heating

Constructability

Fabrication

- Fabrication and testing performed onshore at lower average unit costs compared with offshore construction
- Fabrication and installation requires sheltered coastal site
- Political driver maybe to develop a construction base for offshore development and hence provide some local content
- There may be some risk / security issues associated with onshore fabrication in areas of political instability

Installation

- Field layout and construction sequence will affect the riser tower location relative to FPSO
- Requires subsea tie-in between riser base and either separate flowlines or bundle
- Flexible construction sequence
- Fabrication and testing performed onshore, installation can use low cost marine spreads (tugs)
- High risk operation during tow and upending. A single riser tower scenario offers no contingency

Operability

Operation

- Verification of analytical predictions
- Potential for heat input/circulation via dedicated lines or use of water injection lines for hydrate remediation
- Pigging of production risers round trip through, flowlines and manifolds
- Compact field layout with FPSO
- Low load transfer to the FPSO through the riser porches

Maintenance

- Monitor flex joint at the riser base
- Pigging of production risers round trip through flowlines and manifolds
- Difficult to inspect individual risers externally
- Difficult to maintain/repair a single riser within the tower. Can only be addressed by inclusion of spares

Safety

- The gas injection and production lines would be bundled together, which increases the operational risk

- Integrity of lower flex joint and anchor latch: (consequence of failure - large upward thrust on riser tower). The flexjoint loads should be designed to be well within the capability of the component. Consider use of catcher chain as a secondary restraint
- ESDV requirements and location of valves
- Solution potentially dependent upon a single component system. "All eggs in one basket."

Risks

- High risk operation during tow and upending. A single riser tower scenario offers no contingency
- There may be some risk / security issues associated with onshore fabrication in areas of political instability
- Reduced opportunity for future expansion / development not planned and built in to original field development
- If riser tower is the only thermally/operability acceptable solution for production risers, repair, replacement etc. is difficult without incorporation of spare lines

6.2 SCRs

Functionality

- PIP SCR installed on Shell Bullwinkle (fixed platform). Macaroni and Europa PIP SCR installations in the Gulf of Mexico will be completed by 2000
- SCR design more dependent on quality of met-ocean data for fatigue predictions. Heave motion of FPSO is the main design parameter
- High dependency on good water stop design
- Bulkhead design must be suitable for static loads, thermal expansion, fatigue and must minimize local heat loss (cold spot)
- High dependency on vessel motions for feasibility
- SCRs offer flexible field development, addition of spares or replacement of risers
- SCR Hang-off /interface requirements need to be identified early for vessel porch design
- Thermal performance may impact outer jacket pipe dimensions
- Touch down design requires accurate modeling of the soil interaction and requires anti-abrasion coatings
- Field layout and SCR configuration requirements impact the flowline routing
- Feasibility is improved where there is a longer offset distance and thus more pipe on seabed after touch down point

Constructability

Fabrication

- Onshore fabrication of multi-joint strings (up to 6 joints) allows minimization of offshore welding and NDT
- Onshore fabrication does not have to be in local country. Completed multiple pipe joints can be transported by pipe haul vessel for offshore transfer to installation spread. Similarly, if reeled with flowlines, the spoolbase need not necessarily be in country
- Fabrication as integral part of the flowline

Installation

- No subsea tie-in at riser base if installed with pipe-in-pipe flowlines.
- J-lay handover to host vessel or Riser recovery from pipeline laydown; both require extra equipment for handling. Cost driven by vessel type and lay-rate
- Field joint welding critical to layrate and fatigue life. Number of welds can be reduced with insulation systems that allow the inner pipe to move relative to the outer pipe
- J-Lay limited to single workstation for welding, NDT and field joint
- High J-lay tension loads, but within the capacity of the available systems
- The termination of the SCRs on the FPSO are likely to be flexjoints. To avoid clashing between neighboring SCRs, need to increase the spacing between SCRs. May result in congestion issues on FPSO
- Vessel used for installation of flowlines could be used to install SCRs
- Welding critical to fatigue life

Operability

Operation

- Difficulty in inclusion of heat input into PIP either fluid or electrical, due to complication at field joints. Though heat trace designs do exist
- Hydrate remediation will be dependent upon chemical or pressure control. Perhaps using coiled tubing. Potential for development of local injection points.
- Pigging of production risers round trip through flowlines and manifolds. Not required for water injection and gas injection flowlines
- Monitor fatigue damage and continually cross check with predictions

Maintenance

- Monitor SCR response to allow prediction of fatigue damage
- External Inspection with ROV, with focus on critical areas such as touch down location

Safety

- Gas injection riser is a separate entity and hence does not impact the safety of the production risers
- Potential for breach of carrier pipe into annulus and subsequent pressure build up

- No track record, but possible if vessel motion is not excessive, i.e. feasibility highly dependent upon environmental conditions
- High axial compression loads on the inner carrier pipe
- ESDV requirements and location of valves

Risks

- Insulation degradation from cyclic loading -potential enhanced heat loss
- Risk of water ingress into annulus damaging insulation performance
- PIP SCRs have been installed on a fixed facility and soon to a TLP. Conventional SCRs have been installed on floating facilities
- Offers opportunity for replacement of single risers
- Riser Congestion - Dynamics of a number of SCRs close together raises issues of clashing
- Single pipe SCRs to floating facilities is existing technology but limited to semi-subs, TLPs and Spars

6.3 Flexibles

Functionality

- Brazil experience; 10-inch flowlines have been used in 1900m of water depth
- Coflexip and Wellstream offer product designs suitable for the water depths and design pressures in the likely sizes required
- Significant track record with compliant systems for interface with floating facilities
- Optimization of configuration to minimize cost and interface loads, but provide flexibility to accommodate vessel motions
- CSO has developed a concept of an integrated production bundle flexible riser incorporating small bore water heating lines

Constructability

Fabrication

- Proprietary Design from limited number of vendors. At increased size and water depth the number of qualified vendors reduces
- Intermediate connections may be required for the longer lines due to manufacturing reel limitations

Installation

- May use a separate vessel from flowlines, i.e. DP DSV or MSV
- Relatively simple installation from hydraulically powered reel
- Will require subsea tie-in / pull-in with the flowline unless entire flowline and riser are flexible and installed in one operation

Operability

Operation

- Can only provide limited insulation which may not be capable of meeting operational criteria. However, positive insulation through an integrated production bundle type of system is possible

Maintenance

- Pigging not normally performed as riser is a composite structure
- External inspection with ROV, with focus on critical areas such as touch down location

Safety

- Gas egress through the membrane
- ESDV requirements and location of valves

Risks

- Commercial risk if size, pressure rating and water depth limitation create a sole sourcing situation
- Offers opportunity for replacement of single risers

6.4 Scoring of Risers

The above performance summary of the different riser solutions has been used as a basis to score each solution on the various criteria. Table 5 and 6 summarize the allocated scores and the compilation of weighted scores respectively. Figure 2 shows a plot of the scores of the alternative solutions on the selection criteria.

The 'quality of fit' with the criteria can be judged by reviewing the scores as a percentage of the maximum total score possible. For the solutions considered the range is from 58% to 71%. The performance of the solutions on the criteria is considered to be acceptable for all three solutions. If the solutions scored poorly either the criteria would need to be reassessed or a decision made to reject all solutions, concluding than none of these solutions are acceptable at this stage.

TABLE 5 SOLUTION SCORES ON CRITERIA

CRITERIA		SOLUTIONS		
Primary Criteria	Base Criteria	Riser Tower	Pipe-in-pipe SCR	Flexible
Functionality	Product flowrate	10	10	10
	Fluid loads	10	10	10
	Vessel movements	8	4	8
	Environmental Loads	7	5	8
	Tension requirements of host	8	4	5
	Thermal Performance	9	8	4
	Fatigue	7	4	8
	Field architecture congestion	9	4	6
	Capacity for system expansion	4	7	8
	Feasible FPS Hosts	8	5	9
	Interference with other systems	8	5	5
	TOTAL	88	66	81
Constructability	Types of installation vessel required	8	5	7
	Complexity of installation	4	6	9
	Fabrication techniques required and complexity of fabrication	4	5	7[1]
	TOTAL	16	16	23
Operability	Diverless intervention	5	7	7
	Diverless inspection	2	7	8
	Diverless Repair	2	5	7
	Intervention ability to remediate a hydrate blockage (assumes heating lines can be incorporated into the system)	8	6	7
	Access for drilling/workover vessels	8	5	6
	TOTAL	25	30	35
Safety	Track Record	1	5	9
	System reliability	5	4	8
	TOTAL	6	9	17

CRITERIA		SOLUTIONS		
Primary Criteria	Base Criteria	Riser Tower	Pipe-in-pipe SCR	Flexible
Commercial	CAPEX	3	8	4
	OPEX	4	5	7
	Local Content	9	6	2
	TOTAL	16	19	13

Notes: [1] Complex process, however, well proven/factory supplied product

TABLE 6 WEIGHTED SOLUTION SCORES BY GROUPS

CRITERIA		SOLUTIONS – Weighted Scores		
Primary Criteria	Weighting	Riser Tower	Pipe-in-pipe SCR	Flexible
Functionality	8	704	528	648
Constructability	4	64	64	92
Operability	6	150	180	210
Safety	8	48	72	136
Commercial	6	96	114	78
TOTAL		1062	958	1164

The ranking of the solutions, for this scenario, in order of preference are: flexibles, Riser Towers and SCRs. However, reviewing the scores determined by this assessment highlights that the scores are similar and in fact all three solutions are within 10% of each other. This is a good position to be in, as it implies that if the first solution does not pass the consequence review, the alternate solutions would also be acceptable solutions.

A point to note is that this assessment has only been carried out by the authors. To ensure confidence in the result, a complete assessment requires that several assessors score the solutions against the criteria. The objective of this additional assessments is to ensure that the conclusion is not biased toward a preferred solution.

6.5 The Balanced Riser Choice

Before selecting the solution with the highest KT score it is important to review the solution from a risk and consequence perspective. Some general comments on the risks associated with each system are summarized in the previous sections. For the consequence review of the flexibles, issues will include: limited suppliers, extension of technology to include heating tubes in the flexibles carcass, limited installation contractors, minimal local content, reliability of hardware connectors.

A review of the consequences is summarized in Figure 3. Of the consequences considered only three are in the high consequence category. These are identified as: a component failure, a fatigue failure or a thermal performance failure. However, only the thermal performance failure has a likelihood greater than low. If this occurred operational issues that may need to be managed are wax formation in the risers, slug flow, delivery temperature which may require intervention or replacement of the riser. For this case study it is assumed that all this aspects could be managed and so it is determined that the risks and consequences associated with a flexible solution are acceptable.

7.0 CONCLUSIONS

This paper presents a decision analysis method that can be applied to getting the risers right for deepwater developments. This method provides a thorough, logical basis for assessing the most suitable solution for a defined set of criteria. Based on this assessment a 'balanced decision' can be made that takes into account all aspects related to the decision, including: the data available at the time of the decision, the solution options and the potential consequences. This type of approach helps to document the decision process, and clearly summarize the key areas that impacted the final choice.

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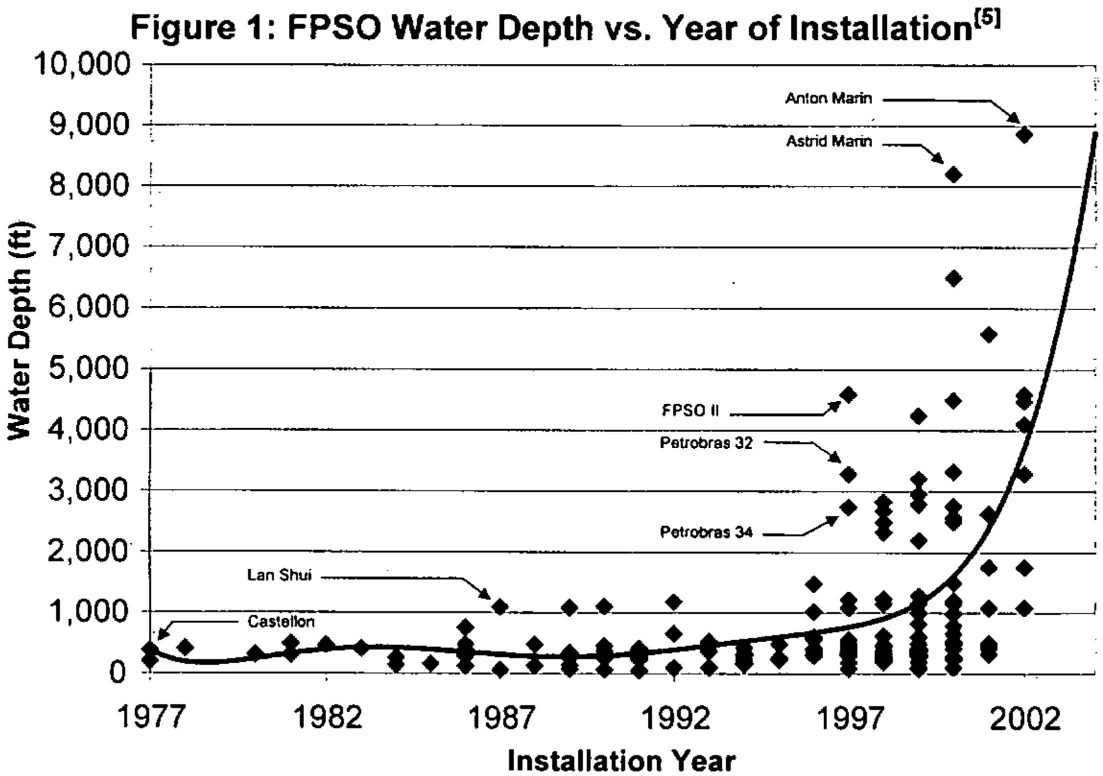
Figure 1: FPSO Water Depth vs. Year of Installation[5]
Water Depth (ft)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1977
1982
1987
1992
1997
2002
Installation Year
Anton Marin
Astrid Marin
FPSO II
Petrobras 32
Petrobras 34
Lan Shui
Castellon

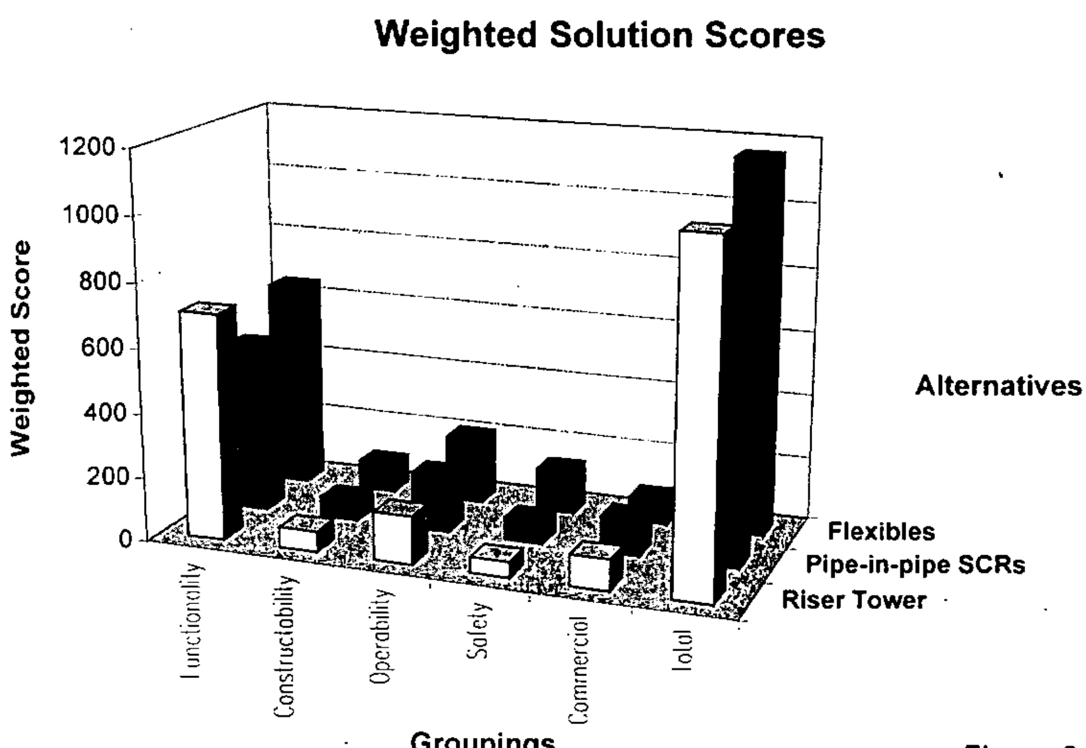
Weighted Solution Scores
Weighted Score
1200
1000
800
600
400
200
0
Functionality
Constructability
Operability
Safety
Commercial
Total
Groupings
Alternatives
Flexibles
Pipe-in-pipe SCRs
Riser Tower

Figure 2

Likelihood and Consequence Assessment of a Flexible riser solution

Consequence \ Likelihood	Low	Medium	High
High	Component Failure 8 Fatigue Failure	9 Thermal Performance failure	10
Medium	5	Schedule Delayed; Hydrate Blockage 6 Cost Overruns	Minimal Local Content; Slug Flow 7 Limited Fab and Inst contractors
Low	2	3	Shutin 4 Gas Egress through membrane

Figure 3

Optimized design procedures for deepwater Risers

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ABSTRACT

The paper gives an introduction to the acceptance criteria and design procedures in the new DNV Offshore Standard OS F201 for Metallic Risers. The design format adopted is based on a modern limit state design principles with safety classes linked to consequence of failure. The standard provides a consistent link between global analyses, failure modes, load conditions, characteristic load effects and design cases, which allows for cost effective design.

The focus of this paper is an introduction and discussion on recommended global analysis procedures and practical implementation of the design approach in design analyses.

The benefit and potential for optimised design solutions is illustrated in a few examples. Further, the performance of the limit states for combined loading versus standard industry practice is discussed.

KEY WORDS: Metallic risers, Limit state design, Global Analysis, Practical Implementation

INTRODUCTION

Background and Motivation:

For risers the term optimised may be interpreted as "a fit for purpose design solution in all anticipated scenarios with a minimal life cycle cost." This implies that all possible design conditions must be considered and designed for with an adequate level of safety. For conventional riser concepts, flexible and cost optimal solutions may be obtained by (conservative) standardised wall thickness sizing. For deepwater risers this is not the case since unduly conservatism imply added weight and may render some concepts unattractive or even un-feasible. Compared to shallow-water risers, deepwater risers are characterised by:

- Increased cost profile.
- Higher potential for use of metallic compliant configurations.
- Increased risk for Riser interference and Vortex Induced Vibrations.
- Increased attention to new potential failure modes such as local buckling (due to external overpressure and bending moment.)

An essential issue in cost optimisation is the ability to control the implicit conservatism in the design via rational design criteria and analyses procedures. Standard industry practice for riser design, e.g. reflected by API RP 2RD, apply the traditional working stress design (WSD) format where structural safety is taken care of by using a single usage (safety) factor. One of the limitations experienced by application of WSD is that a single safety factor leads to a varying safety level strongly dependent on the load conditions. For well-known concepts, this is considered acceptable, but an extension to new concepts and applications is neither optimal nor appropriate. In addition, recent design codes only provide limited guidance on how to establish relevant load effects to be used in the code checks. Hence, a clear need has been identified for safe and efficient design criteria and analysis procedures for risers in general and deepwater risers in particular.

The new DNV Offshore Standard OS F201 for Metallic Risers is considered a contribution towards optimal design. The basis for the standard was developed within the recently completed 4 year Joint Industry Project (JIP) "Design Procedures and Acceptance Criteria for Deepwater Risers". The JIP were performed by DNV, SINTEF and SeaFlex and supported by international oil- and manufacturing companies. The standard was issued for industry hearing January 2000.

Objective of the Standard:

The standard shall be applicable to all new riser systems and may be applied to modifications, operation and upgrading made to existing ones. It is intended to serve as a common reference for designers, manufacturers and end-users, thereby reducing the need for company specifications. The object is to assess and reflect the state-of-the-art and consensus on accepted industry practice.

The major benefits in using this standard comprise:

- Provision of riser solutions with consistent safety level based on flexible limit state design principles;
- Application of safety class methodology linking acceptance criteria to consequence of failure;
- Provision of state-of-the-art limit state functions in a Load and Resistance Factor Design (LRFD) format with reliability-based calibration of partial safety factors. As an alternative, a simple conservative Working Stress Design (WSD) format is also given;
- Guidance and requirements for efficient global analyses and the introduction of a consistent link between design checks (failure modes), load conditions and load effect assessment in the course of the global analyses;
- Allowance for the use of innovative techniques and procedures, such as reliability-based design methods.

What's new:

The basic design principles and functional requirements are not in conflict with current acceptable industry practice for well-known cases but provides an alternative approach to e.g. API RP 2RD (1998).

The most pronounced difference compared to recent industry practice is the adoption of a Limit State Design with explicit design checks rather than WSD (or Allowable Stress Design (ASD)) methods with implicit design checks where a simple stress based equation is assumed to cover a number of different failure modes. Implicit design checks are only relevant for well-known concepts and loading conditions within the original scope of application and often leads to design with varying (and even unknown) safety levels.

Using this modern design format with explicit design checks and associated reliability based safety factors will imply that risers are designed with a more uniform safety level compared to simple single-factored WSD format e.g. represented by API RP 2RD (1998). Such an approach complies with modern design standards, see e.g. ISO 13819-1 and pipeline codes, e.g. DNV'96.

Another difference is related to guidance and requirements for efficient global analyses introducing a consistent link between design checks (failure modes), load conditions and load effect assessment in the course of the global analyses.

ANALYSIS ASPECTS

The design objective is to keep the failure probability (i.e. probability of exceeding a limit state) below a certain value for all relevant failure modes for the riser. A design criterion is defined for each Limit State (or mode of failure) and failure is interpreted as synonymous to the design criterion no longer being satisfied. Limit states are divided into the following categories:

Serviceability Limit State (SLS) requires that the riser must be able to remain in service and operate properly. This limit state corresponds to criteria governing the normal operation (functional use) of the riser.

Ultimate Limit State (ULS) requires that the riser must remain intact and avoid rupture or fracture, but not necessarily be able to operate. This limit state generally corresponds to the maximum resistance to applied loads.

Fatigue Limit State (FLS) results from excessive fatigue crack growth or Miner damage under cyclic loading. The FLS can be regarded as an ULS caused by cyclic loads.

Accidental Limit State (ALS) corresponds to the ultimate failure of the riser due to accidental loads and/or local damage with loss of structural integrity and rupture. The ALS ensures that local damage or accidental loads do not lead to complete loss of integrity or performance of the riser.

The input to these acceptance criteria requires riser system response due to functional- and environmental loading predicted by an adequate global analysis approach.

The purpose of FLS capacity checks is to ensure the integrity of the system under long-term cyclic loading. It is normally required that the 'average' cycles with high probability of occurrence are well described. FLS will normally be fundamentally different from SLS, ULS and ALS with regard to choice of global analysis and may often be adequately performed using a simplified method of analysis such as frequency domain analysis. In addition it will be necessary to assess the fatigue due to vortex induced vibrations (VIV).

The purpose of SLS, ULS and ALS capacity checks are to ensure that the integrity of the system is maintained under normal in-service conditions as well as extreme loading conditions. These capacity checks for combined loading are given as explicit expressions of the cross-sectional utilisation as function of hydrostatic pressure and global load effects in terms of bending moment and effective tension. The cross-sectional utilisation may hence be regarded as a *generalised load effect*. The ultimate purpose is hence prediction of the extreme generalised load effect with adequate precision. In order to account for all relevant non-linear effects a time domain analyses is most likely required.

Herein, an implementation of the ULS capacity checks for combined loading in the global time domain analyses is demonstrated. Separation of load effects into components due to functional and environmental loading as required by the LRFD formulation for ULS, as well as consistent treatment of moment/tension correlation and two-axial bending are given special attention. These issues are crucial for the effective application of the new riser standard in practical design. A few examples are included to illustrate the basic principles.

Another important issue addressed in this work is methodologies for assessment of the extreme generalised load effect with a specified return period. In principle, two fundamentally different methods can be applied:

- Design based on long-term environmental statistics :
- Design based on long-term load effect statistics.

Design criteria based on environmental statistics where the design conditions are defined in terms of a set of stationary environmental conditions with a given return period have traditionally been applied to establish characteristic load effects. The extreme load effect identified by analyses of all design conditions (of typically 3-6 hours duration) is adopted as the characteristic load effect. The main problem with this approach is that the return period for the characteristic load effect is unknown due to the non-linear dynamic behaviour of most riser systems. This will in general lead to an inconsistent safety level for different design concepts and failure modes. Acceptable results can however be expected for quasi-static systems with moderate non-linearities.

Design based on long-term load effect statistics is the ultimate approach for consistent estimation of the extreme (generalised) load effect with a specified return period (e.g. 100 years). This approach should mainly be considered for benchmarking of design based environmental statistic on a case by case basis. A careful evaluation is recommended in the following situations:

- New concepts
- Systems with significant non-linear response characteristics
- Dynamically sensitive systems

DESIGN CHECKS FOR COMBINED LOADING

In the new standard, a comprehensive set of explicit design criteria has been defined in order to address the different failure modes. In this paper only the combined loading SLS, ULS and ALS design checks (i.e. pipe members subjected to differential pressure, effective tension and bending loads) are considered. For a more detailed discussion on safety philosophy, safety classes and limit state design, reference is made to Mork et al (2000).

Combined loading (internal overpressure)

Pipe members subjected to combined differential internal (over) pressure, effective tension and bending loads shall be designed to satisfy the following condition at all cross sections:

$$\gamma_{SC}\gamma_m \cdot \left(\frac{T_{e,d}}{\alpha_c T_k}\right)^2 + \gamma_{SC}\gamma_m \cdot \left(\frac{|M_d|}{\alpha_c M_k} \cdot \sqrt{1-\left(\frac{p_{i,d}}{\alpha_c p_b}\right)^2}\right) + \left(\frac{p_{i,d}}{\alpha_c p_b}\right)^2 \le 1$$

The design load effects are obtained by multiplying the characteristic load effect by the corresponding load effect factor:
Design bending moment:

$$M_d = \gamma_F \cdot M_F + \gamma_E \cdot M_E$$

Design effective tension:

$$T_{e,d} = \gamma_F \cdot T_{e,F} + \gamma_E \cdot T_{e,E}$$

Local design internal differential pressure (≥ 0):

$$p_{i,d} = \gamma_P \cdot p_{li}$$

M_F = Bending moment from functional loads
M_E = Bending moment from environmental loads
$T_{e,F}$ = Effective tension from functional loads
$T_{e,E}$ = Effective tension from environmental loads
p_{li} = Local internal differential pressure (≥ 0)

M_k is the (plastic) bending moment resistance given by:

$$M_k = f_k \cdot (D_o - t)^2 \cdot t$$

T_k is the (plastic) axial force resistance given by:

$$T_k = f_k \cdot \pi \cdot (D_o - t) \cdot t$$

p_b is the internal overpressure resistance given by:

$$p_b = \frac{4}{\sqrt{3}} \cdot f_k \cdot \frac{t}{D_o - t}$$

α_c is a factor explicitly accounting for strain hardening.

The failure modes controlled by this limit state comprise yielding, gross plastic deformation and wrinkling due to combined loading. It may be viewed as a Von Mises criterion in terms of cross sectional forces and plastic cross sectional resistance. It is equivalent to the plastic limit bending moment capacity (including the effect of strain hardening and wall thinning) for $(T_{e,sd}/T_k) << 1$. It reduces to the traditional wall thickness Von Mises criterion, see e.g. API RP 2RD, for pressure and effective tension load effects only.

The derivation is based upon an analytical limit-load solution for the pipe cross section modified to include strain hardening, see (Vitali *et al*, 1999). The present formulation is a linearized version.

Combined Loading (external overpressure)

To avoid local buckling and hoop buckling due to combined loading, the bending moment and net external pressure should be limited as follows:

$$\left(\gamma_{SC}\cdot\gamma_m\left(\frac{T_{e,d}}{\alpha_c T_k}\right)^2 + \gamma_{SC}\cdot\gamma_m\left(\frac{|M_d|}{\alpha_c M_k}\right)\right)^2 + \left(\gamma_{SC}\cdot\gamma_m\left(\frac{\gamma_p p_{\delta o}}{\alpha_c p_c}\right)\right)^2 \le 1$$

where p_c is the well-known hoop buckling resistance according to DNV'96 (or BS8010) and $p_{\delta 0}$ is the local external differential pressure (≥ 0).

The failure modes controlled by this semi-empirical limit state is yielding and combined local buckling and hoop buckling due to combined bending, tension and external over-pressure. For small effective axial force levels the limit state coincides with (DNV'96), (seamless pipe with α_{fab}=1.0).

In the above design criteria (γ_{SC}, γ_m) and (γ_F, γ_E, γ_p) denote the resistance factors and load effect factors, respectively. The safety class factor γ_{SC} (linked to the actual safety class) account for the failure consequence. γ_m is a resistance factor to account for material and resistance uncertainties. The resistance factors applicable to all limit states are specified in Table 1 and Table 2. The load effect factors are given in Table 3.

Table 1 - Safety class resistance factor, γ_{SC}

Low	Normal	High
1.04	1.14	1.26

Table 2 - General resistance factor, γ_m

ULS	SLS/ALS
1.15	1.0

Table 3 - Load effect factors

Limit state	P-load effect	F-load effect	E-load effect	A-load effect
	γ_P	γ_F [1)]	γ_E [2)]	γ_A
ULS	1.05	1.1	1.3	NA
SLS & ALS	1.0	1.0	1.0	1.0

1) If the functional load effect reduces the combined load effects, γ_F shall be taken as 1/1.1.
2) If the environmental load effect reduces the combined load effects, γ_E shall be taken as 1/1.3.

Several combinations may have to be checked when load effects from several load categories enter one design check. For ULS, the following combinations need to be checked in practical design analyses:

Table 4 – ULS combinations

Combination no.	γ_P	γ_F	γ_E
1	1.05	1.1	1.3
2	1.05	1.1	0.77
3	1.05	0.91	1.3

An overview of the design approach is shown in Figure 1.

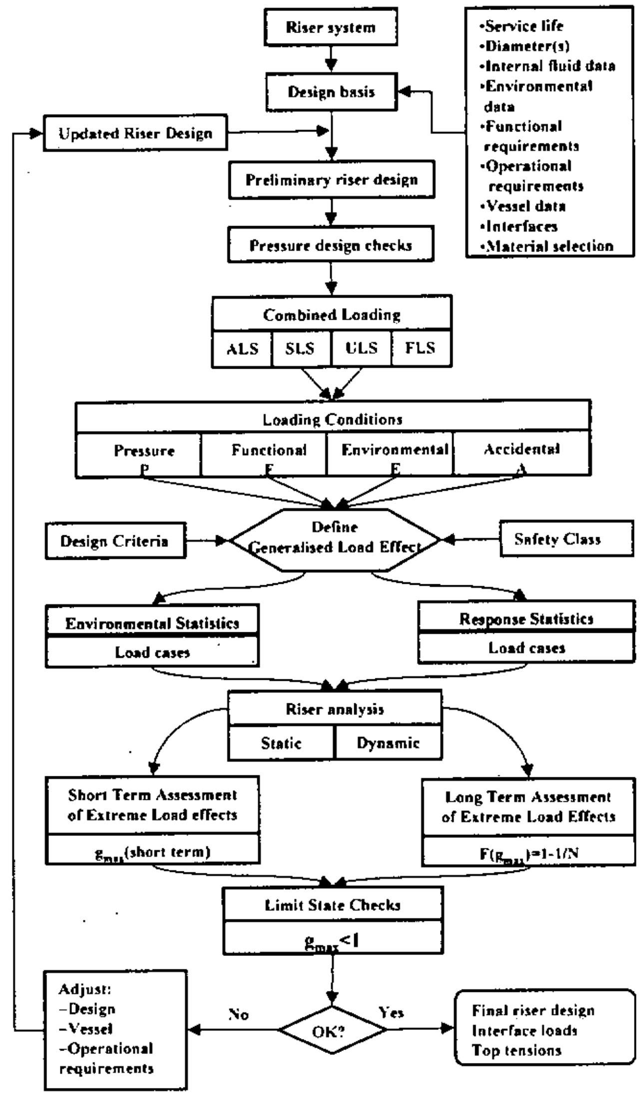

Figure 1 Design Approach according to OS-F201

The design approach may be summarised as:

- Identify all relevant design situations and limit states, e.g. by FMEA, HAZOP and design reviews.
- Consider all relevant loads
- Perform preliminary riser design and static pressure design checks (bursting, hoop buckling and propagating buckling)
- Establish loading conditions
- Define generalized load effect for combined design criteria
- Conduct riser analysis using appropriate analysis models and methods
- Establish extreme generalized load effect estimate based on response statistics or environmental statistics.
- Check that no relevant limit state is exceeded.

SHORT TERM ASSESSMENT OF EXTREME LOAD EFFECT

General

This section is devoted to (time domain) assessment of the extreme generalised load effect considering stationary designs environmental conditions. Extension to long term assessment of the extreme load effect is discussed in (Sødahl et al., 2000).

In has traditionally been common practice to adopt the most unfavourable load effect found by exposing the riser system to multiple stationary environmental conditions as the extreme load effect. Each design condition is described in terms of a limited number of environmental parameters (e.g. significant wave height, peak period etc) and a given duration (e.g. 3-6 hours). Different combinations of wind, waves and current yielding the same return period (e.g. 100 years) for the combined environmental condition are typically applied. Furthermore, the most severe directional combination of wind, waves and current consistent with the environmental conditions at the actual site is normally applied. This will typically lead to analysis of 'near', 'far' and 'transverse' conditions. A period variation covering a realistic variation range (e.g. 90% confidence interval) is also mandatory to identify the most critical design condition. This is of special importance for dynamically sensitive systems.

Generalized Load effect

Consistent treatment of the moment/tension correlation is essential for efficient capacity checks for combined loading. For that purpose it is convenient to consider the acceptance criteria for combined loading expressed by the following generic equation:

$$g(t) = g(M_d(t), T_{e,d}(t), p_d, C) \leq 1.$$

Where g(t) is the generalised load effect and M_d, T_d, and p_d denote design values for bending moment, effective tension and internal or external differential pressure, respectively. C is a vector of cross-sectional capacities. The importance of this formulation is that the combined time dependent action of bending moment and tension is transformed into a scalar process expressed by the generalised load effect. The code checks for combined loading is hence reduced to extreme value prediction of the generalised load effect, i.e.

$$g_{max} \leq 1$$

This approach will automatically account for the correlation between effective tension and bending moment components and is hence capable of optimal design (i.e. allow for maximum utilisation). The standard framework for response processing of results from time domain analyses can therefore be directly applied for code checks. This will typically include application of response envelopes in case of regular wave analysis and statistical extreme value prediction in case of irregular wave analysis. This is of particular importance for compliant riser systems with significant dynamic response all along the riser. The relative contribution from bending moment and effective tension may hence vary along the riser which calls for consistent treatment of correlation to allow for maximum cross-sectional utilisation. A typical example is touch down area of free hanging (catenary) risers.

It should however be noted that conservative estimates always could be obtained by separate estimation of design values for effective tension and resulting bending moment disregarding correlation effects, which formally may be expressed as:

$$g\left(M_d^{max}, T_{e,d}^{max}, p_d, C\right) \leq 1$$

where indices ^{max} indicate extreme values. This approach may yield acceptable result when the design is driven by one dominating dynamic component (typically bending moment for top tensioned risers with well functioning heave compensation system).

Separation of global response into components due to functional and environmental loading is an essential issue for ULS analyses, which require due consideration of analysis strategy as well as response post processing.

In the following, implementation of design equations for ULS analyses is discussed. Relevant simplifications in case of SLS and ALS conditions are also given. Note that the analysis procedures described in this section also form the basis for evaluation of acceptance criteria for combined loading by long-term.

ULS Analysis Procedure

The basic output from global time domain analyses is simultaneous time series of bending moments and effective tension. These response quantities contain contributions due to functional (F) as well as environmental (E) loading. Separation of bending moments and effective tension into F and E components requires that the static configuration due to functional loading is determined separately. The following analysis sequence can be applied:

1) Static analysis - functional loading

The purpose of the 1st step in the analysis sequence is to establish the static equilibrium configuration due to functional loading (i.e. effective weight and nominal floater position). The analysis is typically started from an initial stress free configuration with incremental application of functional loading to reach the final solution. The static force output is two axial bending moments and effective tension due to functional loading:

$$\bar{M}_F = \left[M_{y,F}, M_{z,F}\right]$$
$$T_{e,F}$$

2) Static analysis - environmental loading.

This analysis is restarted from 1) considering additional loading due to steady current and mean floater offset due to environmental actions.

3) Dynamic time domain analysis - environmental loading.

This analysis is restarted from 2) considering additional relevant dynamic environmental loading on the system (e.g. loading due to wave action and floater motions, possible slug flow etc). The force output is simultaneous time histories of two axial bending moment and effective tension:

$$\vec{M}(t) = [M_y(t), M_z(t)]$$
$$T_e(t)$$

These quantities are assumed to contain the total response, i.e. dynamic components from environmental loading as well as static components due to functional and environmental loading. This is in accordance with the storage and output conventions applied in the majority of tailor made computer codes for slender structure analysis

In fact, this analysis sequence is convenient for application of static and dynamic loading and is used in the vast majority of design analyses. The distinction between static and dynamic environmental loading is always an essential issue that must be evaluated carefully in view of the actual concept (e.g. static vs. dynamic current and LF floater motions). The only additional effort needed from the analyst is hence separate storage and treatment of the static response due to functional loading.

ULS Post processing procedure

The post processing to perform code check based on output from the ULS analysis procedure described in the previous section can be summarised in the following steps:

1) Establish response components due to environmental loading:

$$\vec{M}_E(t) = \vec{M}(t) - \vec{M}_F$$
$$T_{e,E}(t) = T_e(t) - T_{e,F}$$

2) Establish design values

$$M_d(t) = \left\| \gamma_F \vec{M}_F + \gamma_E \vec{M}_E(t) \right\| = \sqrt{(\gamma_F M_{y,F} + \gamma_E M_{y,E}(t))^2 + (\gamma_F M_{z,F} + \gamma_E M_{z,E}(t))^2}$$
$$T_{e,d}(t) = \gamma_F T_{e,F} + \gamma_E T_{e,E}(t)$$
$$p_d = \gamma_P \Delta p$$

3) Establish time history of the generalised load effect

$$g(t) = g(M_d(t), T_{e,d}(t), p_d, C)$$

4) Evaluate acceptance criteria

$$g_{max} \le 1$$

Where g_{max} is the expected extreme value for g(t) for the duration of the design condition (typically 3-6 hours) in case of irregular wave analysis and observed extreme value in case of regular wave analysis.

Statistical estimation of the expected extreme value is hence required in case of irregular analyses. It should however be noted that g(t) always will be a non-Gaussian response process. This is because the bending moment components and effective tension normally are non-Gaussian response processes and because the limit state function defines a non-linear transformation of these time series. Expected extremes of non-Gaussian time histories are in practical applications normally estimated from a parametric probabilistic model (e.g. Weibull) fitted to the simulated realisation of the individual response peaks (i.e. peaks of g(t)). The standard deviation of the extreme estimate provides a measure of the confidence of the estimated extreme estimates. For a further discussion of techniques for assessment of statistical confidence as well as simulation planning (i.e. estimation of the required simulation length required to obtain a specified confidence) reference is made to e.g. Sodahl and Larsen (1992).

SLS and ALS post processing procedure:

SLS and ALS capacity checks can be based directly on time series for resulting moment and effective tension given as output from the global analyses. Consistent treatment of correlation requires that steps 3) and 4) in the post processing procedure discussed in the previous section is considered.

Computer implementation:

The key to efficient capacity checks for combined loading is a computer implementation of the procedures described in the previous sections. The main technical features needed covered can be summarised as:

- Separate global load effects into E- and F- components
- Generate time series of the generalized load effect
- Processing results from regular/irregular dynamic analysis
- Analyze several P-E-,F- safety factor combinations
- Evaluate utilization by non-Gaussian extreme value statistics
- Evaluate statistical confidence in extremes
- Evaluate contribution from P-,F-,E- loads
- Derive key statistical information of samples
- Efficient communication with FE global analysis program
- Graphical presentation of results as a function of location along the riser

A computer code has been established for evaluation of the practical efforts needed to perform capacity checks for combined loading. The main experience from this study is that a computer program with the described functionality is capable of performing all relevant capacity checks for combined loading automatically with a minimum of input from the analyst. Two application examples are given in the following.

ULS APPLICATION EXAMPLES

Top tensioned TLP production riser

Non-linear irregular time domain analyses have been conducted for a top tensioned TLP production riser at 1500m water depth considering extreme North Sea environmental conditions. The data for the design are given in Table 5.

Table 5 – Key data for TLP top tensioned riser system

Riser top tension, overpull	40 %
Design pressure	34.5 MPa
Produced fluid density	800 kg/m3
Specified minimum yield strength	480Mpa
Nominal outer diameter	244.5mm
Nominal wall thickness	17.2mm
Internal corrosion allowance	2mm
External corrosion allowance (splash zone)	6mm

The governing failure mode is yielding in operational mode due to internal overpressure. Results are presented graphically as a function of vertical co-ordinate along the riser in Figures 2 and 3. The highest utilisation for the riser pipe was found in the splash zone for combination 1 of partial safety coefficients (ref. Table 4), see Figure 2.

Utilisation in terms of expected 3hour extreme based on a fitted Weibull distribution is presented in Figure 3. The standard deviation of the extreme estimate is also included to indicate the confidence of the predicted extreme value. The utilisation due to P loads and F+P loads clearly show that this design is dominated by functional loading due to the applied top tension.

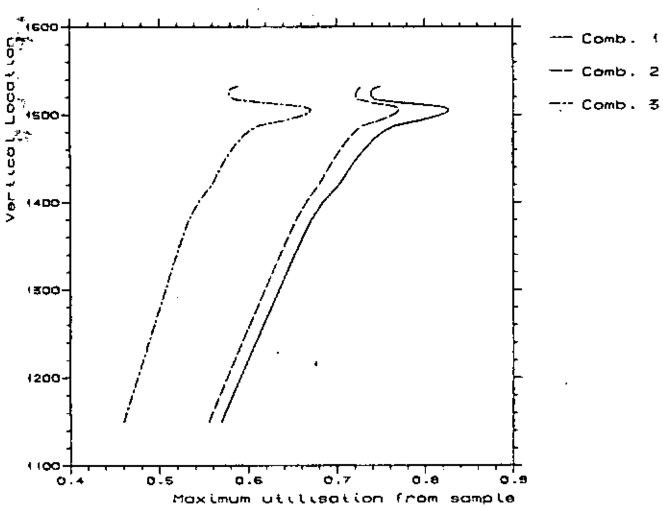

Figure 2 Maximum utilization at upper part of riser versus ULS combination.

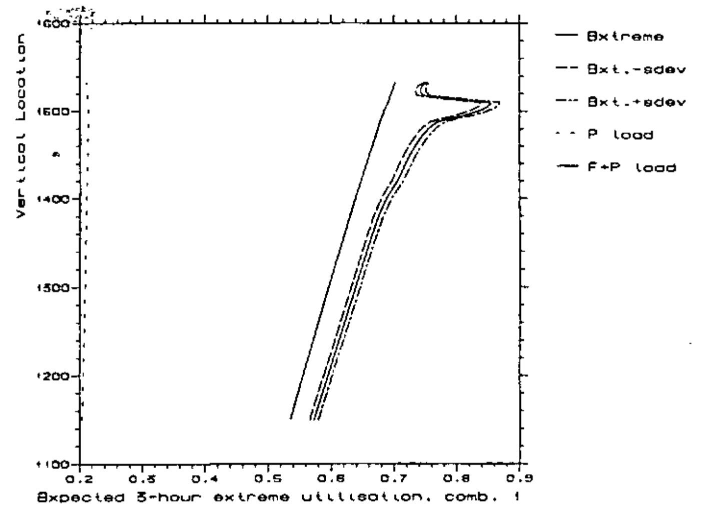

Figure 3 Expected 3-hour utilization for ULS combination 1

Steel catenary riser operated from semi-submersible

A steel catenary riser (SCR) operated from a semi-submersible platform at 1000m water depth exposed to Brazilian extreme environmental conditions has been analysed using a non-linear irregular time domain approach. The data for the design are given in Table 6.

Table 6 – Key data for SCR

Design pressure	34.5 MPa
Produced fluid density	300 kg/m3
Specified minimum yield strength	480Mpa
Nominal outer diameter	244.5mm
Nominal wall thickness	17.2mm
Internal corrosion allowance	2mm

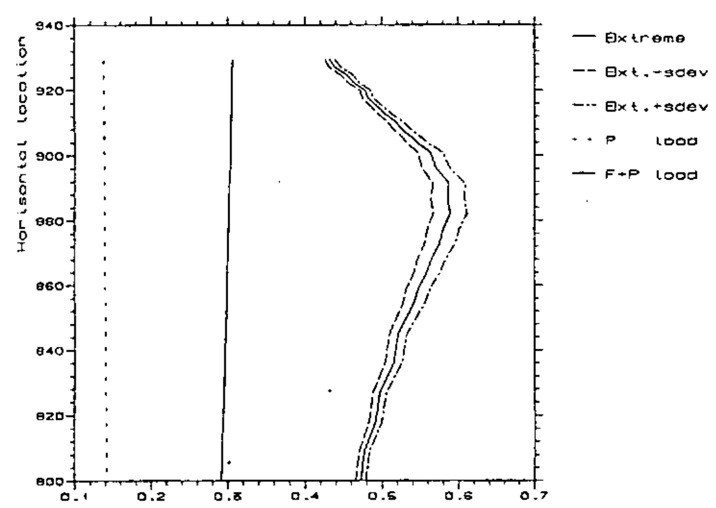

Figure 4 Expected 3-hour utilization for ULS combination 1

As for the previous example, yielding was found the governing Limit State in normal operational mode. Furthermore, the splash zone and touchdown areas were identified as critical locations. Results for the touchdown area are presented in Figure 4.

It is seen that the relative contribution from environmental loading is more pronounced than observed for the top tensioned riser.

COMPARISON WITH API RP 2RD

For comparison, the API 2RD von Mises stress based yield check can be rewritten as a yield Limit State function in terms of the differential pressure $p_{\delta i}$ between the internal and external pressure, the effective axial force T_e, and the bending moment M, as follows:

$$\left(\left(\frac{T_e}{T_k}\right)+\frac{4}{\pi}\left(\frac{M}{M_k}\right)\right)^2+\left(\left(\frac{p_{\delta i}}{p_b}\right)\right)^2 \le \eta_{vM}^2$$

The API proposed usage factors, η_{vM}, are 0.67, 0.8 and 1.0 for normal operating, extreme and survival condition. For load cases not governed by bending moment the present format (WSD) and API RP 2RD results in comparable design.

However, yielding strength checks based on the mean (membrane) wall thickness stress limit state for bending moments, as in API RP 2RD, have several limitations compared to a full cross section yielding which is applied herein. The pipe capacity to resist pure bending is a factor of 1.27 (i.e. $4/\pi$) larger when determined on the basis of full cross-section yielding vs. using mid-wall yielding as the criterion. Furthermore, there is in reality not a linear relationship between the ratio of effective axial force to plastic axial capacity ratio, and the ratio of bending moment to plastic bending capacity.

In the following a comparison versus industry practice reflected by API RP 2RD (1998) is performed. The comparison is made for the API RP 2RD extreme case with a usage factor equal to 0.8.

Combined loading – internal overpressure

The comparison in terms of the expected extreme utilisation for the top tensioned TLP production riser (see above) is illustrated in Figure 5. It is noted that the present design is not accepted by API RP2RD while it fulfils the safety objective in the new standard for safety class HIGH. The reason is that the API von Mises criterion is conservative for designs governed by functional loading.

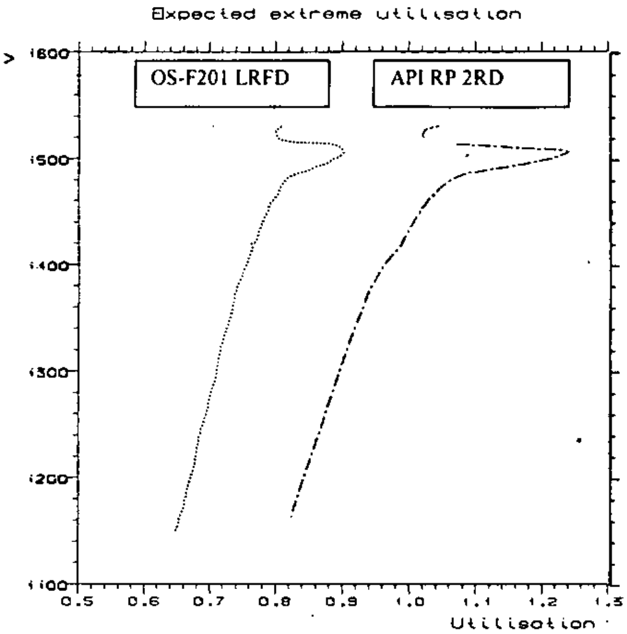

Figure 5 – Comparison against Industry Practice

Combined loading – external overpressure

In Figure 6 the comparative combined external overpressure and bending moment capacity is given for safety class Normal and High. (two parallel curves and lines). The horizontal axis is the normalised bending moment while the vertical axis is the external pressure normalised with respect to the collapse pressure.

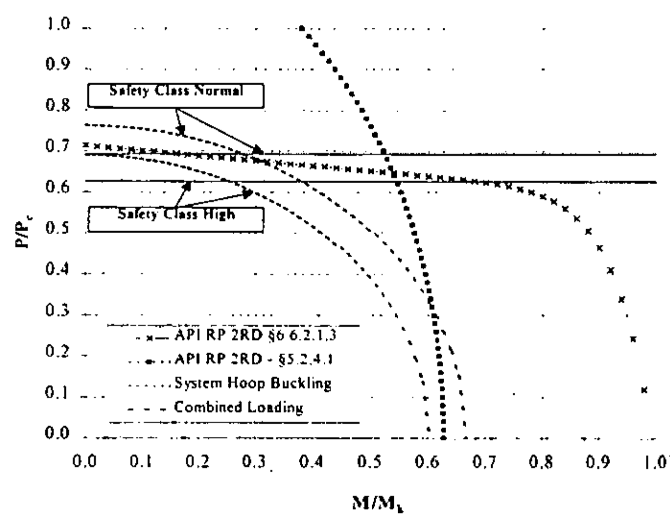

Figure 6 - Local buckling and hoop buckling comparison, (D_o/t=20, T_e/T_p≈0, α_{fab}=1.0).

The following comment apply:

- In the pressure-dominated region (minor bending) the design is controlled by the (system) hoop buckling criteria. The implicit safety level for API RP 2RD is in-between safety class Normal and High for both pressure- and bending dominated cases.

- In the bending dominated region the utilization is governed by the von Mises check according to API RP 2RD. From a failure mode/mechanism viewpoint this is only appropriate for low D_O/t ratios, but is considered conservative. The new standard allows for a similar or somewhat higher utilization.
- In the combined bending and pressure region API RP 2RD indicates a rather high utilization (dependent on D_O/t and other factors), not substantiated by tests or sound mechanical reasoning.

However, in most practical applications the new standard and API RP 2RD are not in gross conflict.

CONCLUSIONS

The objective of the new standard for Metallic Risers is to provide more refined design criteria compared to existing design practice. Accordingly, it may serve as a powerful tool for safe and cost effective design and analysis for metallic risers. For final optimisation of riser design solutions and for novel concepts the standard is particularly useful.

In compliance with the standard, a consistent framework for design checks based on an extreme value prediction for the generalised load effect has been outlined herein and the basic principles illustrated by a few examples.

The main experience from use of the associated computer tools is that all relevant capacity checks for combined loading can be automated with a minimum of input from the analyst. The LRFD capacity checks are hence found well suited for implementation in practical riser design using standard riser analysis methodology and modelling practice.

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Deepwater Steel Pipelines and SCRs Installation

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Deepwater Steel Pipelines and SCRs Installation

Abstract

Based on Petrobras experience in deepwater fields such Roncador (1300 m to 1800 m), this paper outlines, with real examples, the various aspects involved in the design and installation of steel pipelines and SCRs systems in large scope and scale development scenarios.

The work discusses how an effective project management may yield an enhanced system design and facilitate installation by adopting an integrated and iterative approach which starts at the conceptual stage of the field development. Several relevant factors are considered and their impact on the design and installation processes is assessed. These factors include contracting strategy, project schedule, field layout, geomorphology, design and installation constraints, production unit characteristics, installation vessel requirements etc.

Some trends are presented, involving new riser concepts and alternative installation methods. In addition, the tendency to employ insulated rigid pipes for oil production is focused and the soil effect is highlighted.

Notation

Q is the heat in joule
R is the radius of the layer in metres;
R_1 is the internal radius of the layer in metres;
R_2 is the external radius of the layer in metres;
T_1 is the internal temperature in K degree;
T_2 is the external temperature in K degree;
U is the overall heat transfer coefficient in watt / m K or watt / m^2 K;
K is the thermal conductivity of the material in the layer in watt / m K;
H_i is the internal total surface heat transfer coefficients;
h_o is the external total surface heat transfer coefficients.

Introduction

Significant discoveries have been made in offshore Brazil in water depth of 800 m and greater. These field developments have been calling for deep water export pipeline installation, in a timely and cost effective manner, using the available capability established in the market.

Flexible pipes have been extensively used, successfully, for smaller diameter flowlines, connecting wellheads, manifolds and platforms in deep water scenarios.

However, the higher initial cost of flexible pipes, specially for greater diameters, have given a considerable market for steel pipes, which have been used for the large diameter export

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network in Campos Basin. The hybrid solution, comprising steel pipelines with flexible jumpers and risers at both ends, have been the common practice. In addition SCRs have come into play as an alternative solution. Recent technological developments for SCRs and the possibility of application to gathering and injection lines have expanded the range of steel application.

The large scope, posed by the demanding concomitant multi-field development, requires efficient management. In order to cope with such a demanding need, recurring annual export pipeline installation campaigns have been organized, involving, each year, 110 km in average, of laid rigid export pipelines in ever-increasing water depths.

The purpose of this paper is to evaluate some key issues that must be addressed in steel pipelines and risers projects for deep water applications, highlighting potential problem areas and develop an overall understanding of the inter-dependence of the multi-disciplinary nature of this promising area. Different aspects are considered, based on recent experiences, involving management, design and installation problems, adopted solutions and learned lessons. Important trends are also discussed.

1 - Project Schedule and Contracting Strategy

In the conceptual feasibility stage of field developments, alternatives are considered, involving different combinations of export conceptions. The competing solutions may vary in characteristics, number, distribution, configuration and size / rate.

The reservoir engineering and drilling strategy govern the trends and impose a continuous and dynamic pace to the process, which lasts up to late stages. However other actions must start earlier even without conclusive guideline for final layout. The situation is better defined in advanced stages of phased developments, such as Marlim field, in which, the project contour is more predictable.

Field developments have been re-engineered, led by the drive to reduce cost and speed them up. The search for the first oil must be followed by a compatible and timely capacity to flow it away. A typical pipeline campaign must be flexible to accommodate the inevitable aforementioned dynamics. This involves a comprehensive interaction, well in advance, with the different fields management teams, in order to define the real pipeline export installation demand, in the Basin, for the subsequent season.

The lengthy bidding process requires a deadline for such a set of definitions, in order to establish the scope to be designed and subsequently tender. The general export pipeline project schedule must pursue to accommodate the requirements and the needs, imposed by the different fields development schedules, which are consorts of the same campaign .

A typical deep water pipeline project duration is 18 months, encompassing two basic phases, namely, engineering and bidding phase and, secondly, the construction and commissioning phase, after contract award.

In planning a deep water pipeline installation project, the overall scope will determine the project contracting profile. Technical and economic compromise leads to an iterative system approach which must consider all the constraints and facilities.

Time is a severe constraint, which impose deadlines for critical path decisions, some times taken prematurely. It can be difficult to incorporate a high degree of flexibility, in the contracting process, and reconcile technical challenges with economic optimisation. However, the in-house design phase must adopt the philosophy to widen the range of management alternatives and allow delays in this critical decisions. The wider the range and the longer the timeframe to take such a decisions, the more benefits for the project.

For example the detailed design must assume to maintain multiple installation method options in order to maximise competition among feasible installation methods and avoid committing to use a particular method. This requires the analysis of the design impacts for using different installation methods.

Moreover, the riser configuration will impact other disciplines within the pipeline project sphere, and the situation becomes even worse when the impact affects tasks within the field development context. The decision to apply flexible or SCR risers will have a direct effect in interfacing areas and it is extremely difficult to keep both options alive up to further stages of the field development project.

Within the field development sphere such decision will impact the platform pull-in system, the platform hang-off design and reinforcements, mooring system in terms of differentiated horizontal and vertical loading, the field layout, schedule of flexible installation spread (commonly fully committed with flowline installations), etc. The timing to install the floating production units and mooring system also may be relevant.

Within the pipeline project environment, this decision will impact the overall workscope, preliminary and detailed design, installation and pull-in procedure, procurement (top devices, pipes, Pipeline End Terminations (PLETs), anodes), onshore and offshore fabrication and installation, anchor system installation (piles procurement, fabrication and installation), spread requirements which may lead to an additional riser installation contract, etc.

The experience has shown that SCRs deserve a comprehensive and timely design effort to ensure endurance against VIV, fatigue and extreme condition. The main input areas for the design are: 1)The scenario, meteocean and soil data (provided by Petrobras), 2) The floating production system movements and support location (available through Petrobras) and 3) The top connection device characteristics. The third, which also requires a specific design, needs also input from SCR design and produces also input for the floating production unit (FPU) interface. Due to this circled relationship, the contracts for design of the SCR systems and supply of the flex joints, in the recent projects, have been awarded to the flex joint manufacturer.

Close co-ordination of the workforces in each activity is required to achieve synergetic and successful multi-tasking. Very often, the different teams may have conflicting interests. An effective management must minimise technical and economic overlap whilst ensuring that gaps are not permitted to develop between the different disciplines involved.

2 - Engineering

The engineering stage, which encompasses preliminary engineering, pipeline route survey and detailed design, will impact the contracting strategy and, in turn, the selection of the pipeline installation methods and the overall project schedule.

Preliminary engineering starts with the iterative process to evaluate the development alternatives and layout alternative solutions, identifying operating parameters and interfaces with the purpose of overall project optimisation and identification of potential cost savings. In new developments, such as Roncador field, this stage is characterised by a number of uncertainties carried over from the fields development overall strategies. It is necessary to adopt an overall system approach. Fluid properties, flow rates, pressures, temperatures and all other functional requirements, as well as other design basis constituents, are under continuous review. However, the hydraulic analysis is completed, which leads to the establishment of the requirements for pipeline internal diameter. Based on the available reservoir evaluation and drilling strategy, a basic layout is conceived and the interfaces are defined.

Detailed pipeline design starts following completion of pipeline routes survey along preliminary routes. The mechanical design, pipeline routing, free span analysis, crossings, coating and corrosion protection analysis, preliminary installation analysis, testing and commissioning requirements are comprehensively addressed to produce drawings, material specifications, construction and installation requirements. All pipelines appurtenances, such as mid line valves, anchoring devices, and pipeline end/midline terminations are also specified. Material and construction specifications are issued for subsequent project tender.

The still conventional mechanical design philosophy, has been governed by propagating buckle criteria. Recent research have been made, covering lower D/t ratios, assessing the different available formulation, to produce optimised guidelines for the design.

In addition, at this stage, the interfaces are addressed and the riser system, for connection to the floating production unit (FPU), is defined and designed.

3 - Riser System - Flexible x SCrs

Flexible risers options have been the natural candidates, comprising a typical configuration of free hanging flexible riser, connected, in a goose neck second end fashion, to the Pipeline End Termination (PLET), which is devised with a standardised vertical connector. In regard to this matter, the vertical connection, showed to be reliable, and cost effective compact diverless, easy to install connection system, actually commonly utilised in Campos Basin.

Although costly, the presence of a Pipeline End Termination (PLET) brings a series of advantages, in the sense that it provides more flexibility to the overall project by allowing the riser installation at a convenient time, when the FPU is already in place.

The riser design runs in parallel and will dictate the target position for PLET location, properly defined to allow tension dissipate to adequate levels, required to protect the vertical connection. The flexible riser system is installed and connected to the rigid section by another vessel, under long term contract, for flexible lines installation.

The spread available, under long term contract, for flexible lines and risers installation represent additional benefit for flexible alternative.

Recently, the adoption of the SCR concept, have introduced important variation in this scenario. Apart from special fabrication requirements, the SCR is considered an extension of the pipeline and no PLET is provided. Instead, depending on the layout, a likewise costly anchoring system is required to isolate the pipeline from the usual exacerbated bottom tension, imposed by the platform movements through the SCR. Moreover, in this context, the platform must be in place for second end SCR transfer.

4 - Recent Pipeline projects

Petrobras have recently completed a large scope pipeline installation campaign, ranging in diameter from 6" to 12", in Roncador, Marlim Sul and Marlim fields, encompassing 130 km (15000 tonnes) deep water pipe length, in Campos Basin, offshore Brazil. The deepest field, Roncador, is in 1300 m of water depth, which is presented in more detail, as below:

4.1 - Roncador field export system

The initial phase of Roncador field development philosophy establishes that the production and injection wells are connected to the platform Semi Submersible P-36, in 1340 m water depth, which is equipped with topside production treatment facilities. The oil and gas export systems are described herein after.

4.1.1 - Oil Export System

The oil export system, designed for 180.000 BPD, comprises three similar 10" steel oil pipelines (RO1, RO2 and RO3) connecting the Semi submersible P-36 to the FSO P-47 in 1150m water depth, from where the oil is offloaded.

On the FSO side, the steel sections were be installed in a conventional fashion with PLET/vertical connector on pipeline ends. Two oil pipelines (RO1 and RO2) are commingled through a "Y" manifold, from which a single riser goes up to the turret. The third line is connected straight from the PLET to the turret. Flexible jumpers are used to connect the RO1 and RO2 PLETS to the "Y" manifold, all using vertical connection modules. Steep wave flexible risers are used to connect the pipelines to the FSO.

On the Semi Submersible P-36 side, two oil lines (RO2 and RO3) will be installed with PLETS on pipeline ends and connected through independent free hanging flexible riser to inboard supports on the portside pontoon of the platform.

The third line (RO1) is planned to be connected to the outboard receptacle on the portside pontoon through a SCR. The strategic SCR application reinforces the technical availability of this competing alternative and provide a safe technical back up for flexible riser.

The desired straight route from P-36 to P-47 was not possible, due to the occurrence of midway outcrops formation, presenting considerable unevenness of the seabed. As a result the defined pipeline paths were displaced down to a southern more favourable region, imposing a curved shape of the pipeline routes, as indicated in Figure 1.

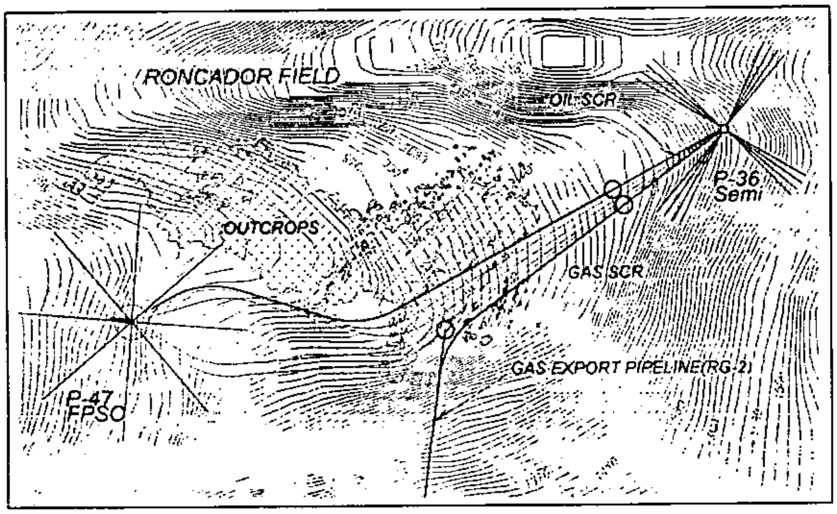

Figure 1 – Pipeline routes in roncador field

4.1.2 - Gas Export System

The gas export system, designed for 3MCM a day, comprises an extensive gas pipeline system, from P-36 to shore station, encompassing four main sequential sections as describes below:

1. The first section is a 10" SCR connected to the outboard receptacle on the portside pontoon of P-36.

2. The second section is a 10" steel pipeline from the SCR interface, in depth of 1300 m, heading towards shallow waters through the continental slope, including a canyon crossing, up to a manifold (PLAEM), in shallow waters.

3. The third section is a 20", 48 km long, shallow water pipeline from the PLAEM location to a existing fixed platform, PNA-1 (145 m wd), which will serve as an intermediate compression station. The topsides had been upgraded to compress the additional gas production to shore.

4. The last section is a 20", 87 km long shallow water pipeline, connecting the fixed platform PNA-1 to shore.

4.1.3 - SCRs to P-36

- *Installation*

PETROBRAS is installing two twin 10-in free hanging SCRs for oil and gas export from P-36 Semi Submersible, in Roncador field. The oil export SCR was laid between Feb 17th and Feb

29th of the current year. The oil export pipeline, which have been previously installed, was recovered to be welded to the first end of the SCR. Subsequently, the oil export SCR was laid by the Hybrid Reel/JLay method, being its second end successfully connected to P-36 Semi Submersible.

- *Design*

The SCRs design encompassed a extensive analysis, involving comprehensive combination of meteocean data (magnitude and directionality), resulting mooring system response and platform movements. The critical design issue for the risers was found to be the cumulative fatigue damage in the critical regions, namely the top and the touch down regions. In this regard, the design considered Petrobras special requirements, including a set of pre-determined load cases and recommendations regarding critical parameters such as design minimum fatigue life, corrosion, fatigue S-N curve, local seabed slope, stress concentration factor and soil stiffness. Furthermore, a VIV analysis methodology is specified.

- *Fatigue*

The identified critical zones, in which the fatigue predicted life is considerably reduced, deserve special attention during fabrication. Figures 2 depicts some aspects related to the predicted stresses and fatigue life for 3 locations along the SCR body, namely the touch down region, the top region (at the flexjoint connection point) and finally an intermediate point where fatigue action is not as critical as it is in the previous two points.

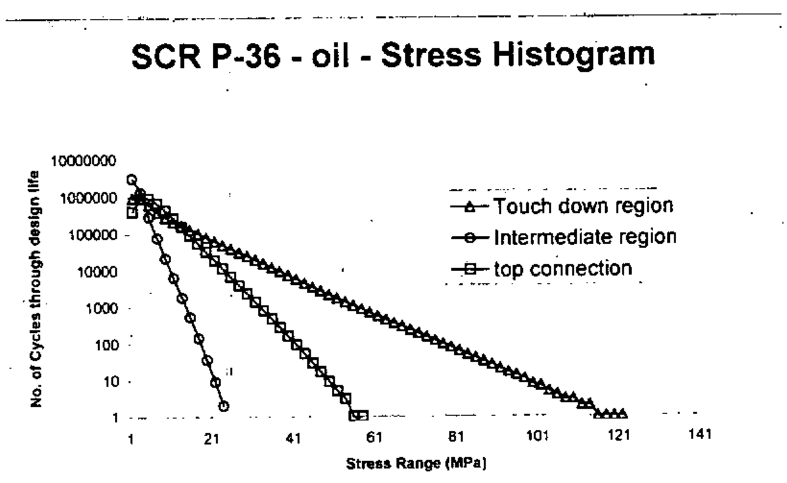

Figure 2 – SCRs stress histogram

- *Interfaces*

Diligent management and extensive pre-planning of operations, have been required to adjust the interfaces with the adjacent linking pipeline installation and, on the other side, with the host platform. During abandonment, the pipeline Contractor will install a recovery system, incorporated to the abandonment head. The riser contractor will then reconnect a recovery cable by means of a diverless procedure and resume recovery operation of the dewatered pipeline.

From this point, pipelay operation will take place up to the completion of the design riser length fabrication. At this point the flexjoint is connected and the riser is transferred to the platform pontoon.

- *Commissioning*

On completion of the SCRs transfer and connection, flooding and hydrotesting operations are required for the entire systems (Platform piping, SCRs and previously tested pipelines).

In addition, the gas line will require subsequent dewatering and drying for gas use. This operation involves the displacement of seawater inventory and swabbing of the internal pipe wall with glycol, in order to prevent hydrate formation. The displacement of the pig train will be performed by injecting Nitrogen behind the last pig. Appropriate flow rates, involving high pressure are required to overcome the considerable hydrostatic head of water being displaced due to the water depth profile along gas line from P-36 pig launcher facilities (1340 m water depth), passing through a deep canyon and heading to the shallow water manifold, PLAEM (100m water depth).

- *Platform preparation*

The original design of the platform conceived all the risers supporting structures, as well as the pull-in systems, tailored for flexible risers. Therefore, as mentioned before, the decision to apply two SCR risers, has entailed, a comprehensive and costly set of additional modifications in the platform, in order to accommodate the receptacles and to provided a tailor made high tension pull-in system to assist the typical SCR second end transfer operations. The reduced number of risers, served by the extra pull-in system, makes it as a low dilution cost ratio item, with direct impact on the overall installation cost per riser.

Due to the congested platform topside layout, the large pull-in machine had to be installed at the main deck. Therefore a comprehensive pull-in cable deviation system had to be designed, fabricated and installed to the platform, from the main winch location, at the main deck, to the platform pontoon, serving the two risers transfer operations. Additionally, specific structural hull modifications were implemented to receive the risers receptacles.

Likewise, the coupling path concept requires a robust auxiliary pull-in system, in order to cope with the high horizontal riser tension at the end of transfer operation.

5 - Trends

5.1 - SCRs for FPSO Applications

The profusion of ship-shaped production, storage and offloading concept led Petrobras to investigate the extension of SCRs application in this area. A multi-partners research project, has reiterated that the unusual combination of wave configuration and steel, for the conventional bow turret location, showed great potential for FPSO applications. The study, comprising screening of alternatives, detailed design and installation feasibility, was performed for both scenarios, Barracuda field (800 m water depth) and Espadarte field 1000m water depth).

5.2 - Reel Method for SCR installation

The reel method, due to its high installation rate and other well know advantages, has been a strong competitor is the last pipeline tenders. In this connection, another important aspect, related to the adoption of SCR concept, is that there is a degree of skepticism with regards to the fatigue damage arising from the plastic deformation imposed from the reeling operation and reverse bending in the straightener.

Therefore, the large scope pipeline installation campaigns may require a second contract for J-lay SCRs installation, as it had happened in the Roncador field project. In this case the project is penalized due to the attention required to manage the additional interfaces and the consequent impact in the overall pipeline project schedule and cost.

Fatigue life predictions based on S-N curves and fracture mechanics approaches could be employed in the preliminary stages of the design. Nevertheless, the necessary confidence to establish a consistent planning for SCR's installations in deepwater should be built upon laboratory fatigue tests using full-scale pipes and realistic welding processes. In order to assess the possible detrimental effect of such installation procedures into the riser fatigue performance, welded segments of pipe must be bent over a rigid surface, unbent and straightened prior to the cyclic loading test.

Considering the current Brazilian offshore scenario, with the possibility of installing several risers in the near future, and the economical attractiveness of such methods, PETROBRAS, COPPE-Federal University of Rio de Janeiro (COPPE/UFRJ) and Contractors are developing the project "Plastically Strained SCR's – Qualification Program for Installation Methods." The primary purpose of this project is to qualify these methods as feasible options for installing SCR's in deep and ultra-deep waters, with the following objectives:

a) Qualify installation methods that infer plastic deformation in pipelines aiming at SCR's laying in deep and ultra-deep waters;

b) Recommend guidelines for SCR's installation using the above methods, including technical specifications for fabrication of pipes and welded joints (PGTAW + PGMAW) to be used in future PETROBRAS' bids.

5.3 - Hybrid Reel / J-lay for SCRs installation (Patent Pending)

An intermediate alternative to employ a reel method devised ship to install SCRs would be the hybrid solution, by applying the reel technique, for the installation of the pipeline and SCR intermediate region (where fatigue action is less severe) and the J-lay mode, for the hot spot regions (the touch down and top sections), as indicated in Fig 3. This concept, depicted in fig 3 involves two separate reeled sections. The outer section is deployed for the pipeline segment and the inner section for the intermediate zone of the SCRs. The hot spot regions (touch down and top)are installed through the offshore pipe to pipe welding, alike the J-lay procedure, using j-lay collars to sustain the column and the A&R system to assist deployment.

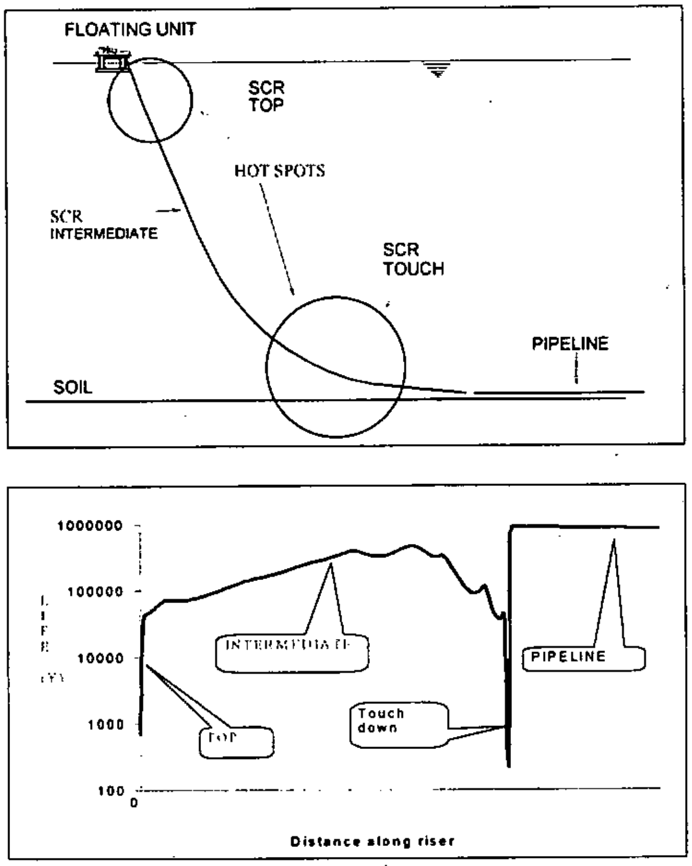

Figure 3 – Fatigue life along riser

5.4 -Steel pipes for flowlines & Insulation requirements

Deepwater fields, using longer multiphase flowline systems, operating in low ambient temperature are often connected to high thermal insulation requirements. This circumstances open a prosperous area of opportunity for steel utilization. However, the attractiveness of steel flowlines are closely related to the installation method, the application of a properly specified insulation system, the field layout conception, method of diverless connection to a subsea structure and interface with the host production unit. In addition, the ability to extend the installation scope, using steel risers, is of prime importance to optimize this alternative. Therefore, this concept requires an integrated approach, which should start at the conceptual stage of the field development.

When we consider a flowline placed on the seabed in order to conduct hot oil from a wellhead to a production facility or an export pipeline, the heat transfer takes place from the hot oil in the direction of the cold seawater. This phenomenon normally should be avoided due to production requirements as fluid flow conditions (viscosity, two-phase flow), hydrate formation or wax deposition, which may cause pipeline blockage, process requirements on platform.

In order to avoid or reduce the heat loss the flowline generally is insulated. To accomplish this objective different methods and materials are used.

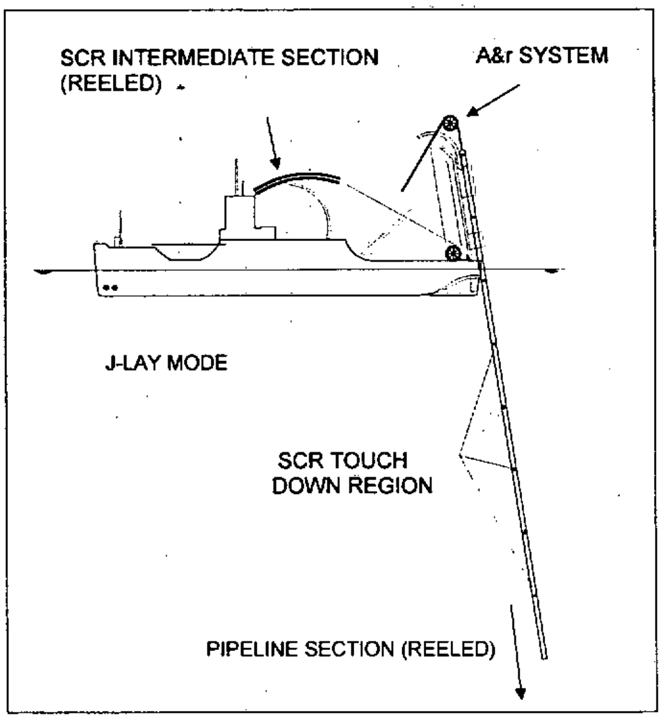

Figure 4 – J-lay/Reel Hybrid System

Insulated Pipeline Model

The real insulated pipeline, Fig 5, shall be considered as a compound tube of 'n' concentric layers, with fluid flowing through it and around it. In this case the heat transfer through the wall of the pipeline shall be evaluated by the expression:

$$Q = -U\,(T2 - T1) \qquad \textbf{(1)}$$

The overall heat transfer coefficient (U) per unit of length of tube for two concentric layers is:

$$1 / U = (1 / 2\pi R_0\, hi) + [\ln (R_1/R_0) / 2\pi\, k_1\,] + [\ln (R_2/R_1) / 2\pi\, k_1\,] + (1 / 2\pi R_3\, ho\,) \quad \textbf{(2)}$$

Sometimes however for a pipeline it should be better to consider the overall heat transfer coefficient U defined per unit of internal or external surface of the steel pipe, instead per unit of length. So equation 3.5 is multiplied by $2\pi R_0$.

$$1 / U = R_0\,\{(1 / R_0\, hi) + [\ln (R_1/R_0) / k_1\,] + [\ln (R_2/R_1) / k_1\,] + (1 / R_3\, ho\,)\} \quad \textbf{(3)}$$

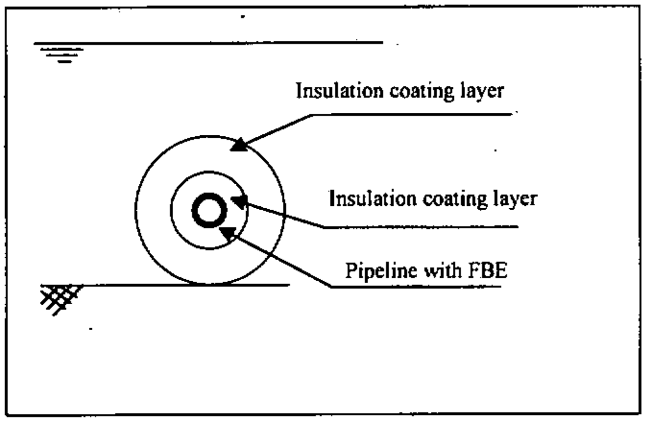

Figure 5 – Cross section of NA insulated pipeline model

Insulation Materials

- *Polypropylene*

Table 1					
Reference	Max. Temp. (Celsius)	Water Depth (m)	Density (kg / m3)	k (w/m / K)	Micro-sphere
Solid PP	130	4000	910	0.22	None
Syntatic PP	120	600	660	0.16	Glass

TABLE 1 – Polypropylene properties

- *Polyurethane*

Table 2					
Reference	Max. Temp. (Celsius)	Water Depth (m)	Density (kg / m3)	k (w/m / K)	Micro-sphere
Solid PU	105	3000	1150	0.19	None
Syntatic PU	105	600	830	0.14	Glass

TABLE 2 – Polyuretane properties

Insulation thickness - example

Some real case examples of insulation requirements are indicated in tables 3 to 5:

Table 3 - ESPADARTE FIELD			Insulation Thickness (mm)			
			Polyurethane		Polypropylene	
Well	Outside Diameter	Urequired	Solid	Syntactic	Solid	Syntactic
	(inches)	(W/mK)	k = 0.19 (w/m/K)	k = 0.14 (w/m/K)	k = 0.22 (w/m/K)	k = 0.16 (w/m/K)
RJS 504	6.625	6.0	18	13	21	15
	4.500	10.4	7	5	8	6
409P-1	6.625	6.0	18	13	21	15
	4.500	10.4	7	5	8	6
RJS-409	6.625	2.0	67	46	82	54
	4.500	10.4	7	5	8	6
RJS-424	6.625	2.0	67	46	82	54
	4.500	10.4	7	5	8	6

TABLE 3 – Insulation – Espadarte Field

Table 4 - MARLIM FIELD			Insulation Thickness (mm)			
			Polyurethane		Polypropylene	
Well	Outside Diameter	Urequired	Solid	Syntactic	Solid	Syntactic
	(inches)	(W/m^2K)	k = 0.19 (w/m/K)	k = 0.14 (w/m/K)	k = 0.22 (w/m/K)	k = 0.16 (w/m/K)
RJS 460	6.625	7.2	35	24	41	28
	4.500	0	-	-	-	-
B6P1-H	8.625	7.2	32	23	37	26
	6.625	0	-	-	-	-

TABLE 4 – Insulation – Marlim Field

Table 5 - RONCADOR FIELD			Insulation Thickness (mm)	
			Polyurethane	Polypropylene
Well	Outside Diameter	Urequired	Solid	Solid
	(inches)	(W/m²K)	k = 0.19 (w/m/K)	k = 0.22 (w/m/K)
P-1-01	6.625	5.3	50	60
	4.500	0	-	-
P-1-02	6.625	5.3	50	60
	4.500	0	-	-

TABLE 5 – Insulation – Roncador Field

- *Soil Effect on Insulation Thickness*

Recent projects indicate that the technique of buried the pipeline or the use of sand and/or gravel cover for thermally insulate subsea flowlines can be a feasible solution to meet the required target temperature for the fluid to be properly transported in the flowline.

The main advantage of burried pipeline or the use of sand/gravel cover is that both can substantially reduce the insulation thickness.

For Roncador Project a tendency is to consider soil effect, which will cause reduction of the insulation thickness. Laboratory tests are been prepared to properly evaluate the thermal conductivity of Roncador soil. If necessary a real model of the flowline placed on seabed will be developed. The results of these tests will define the economical benefits to Roncador Project and to direct future actions.

Examples of typical values for soil thermal conductivity, which can be considered to evaluate the soil effect, are indicated in table 6.

Table 6			
Material	Density (kg/m3)	Specific Heat (J/kgK)	Th. Conductivity (watt/mK)
Sandstone	2300	962	2.90
Limestone	2500	921	1.68
Granite	2600	879	3.50

TABLE 6 – Typical soil thermal conductivity

Figures 7 TO 10 show the possible reduction of the insulation thickness in accordance with the soil characteristics. These diagrams consider: a flowline of 6.625 inches external diameter, thermal conductivity of the insulating material equal to 0.19 W/m/K, and both the parabolic distribution of heat in soil and soil as a single layer. Two values (7.2 w/m^2/K ; 2.0 w/m/K) for the total heat transfer coefficient (U) were considered.

Conclusions

The use of steel pipelines is a cost effective and well established alternative for export large diameter systems for deepwater applications. The hybrid solution, has been the usual practice in the Brazilian deepwater scenarios. PLETs devised with vertical connector, are used as interfaces for flexible jumpers and risers.

The SCR application, as a natural extension of the pipeline, makes this alternative even more attractive. However early definition is required so that specific prescriptions are followed and relevant interfaces are properly and timely arranged.

The strategic use of the SCR concept set specific requirements in regard to essential project aspects, such as design, fabrication, vessel, installation procedure, pull-in system, platform hang-off structure, seabed layout, anchoring system and project schedule. The observance of such requirements must preserve the economical attractiveness of this concept.

A real case project is presented describing the steel application for Roncador field export system, involving two SCRs. The large scope required a combined installation method, using the more efficient reel lay method for pipelines and a dedicated contract for J-lay SCRs installation. Diligent management and extensive pre-planning of operations, have been required to adjust the interfaces with the adjacent linking pipeline installation and, on the other side, with the host platform.

Petrobras is investigating alternative solutions for the use of steel risers connecting pipelines to ship-shaped units. The lazy wave configuration has been selected as the natural alternative to accommodate the severe vessel motions.

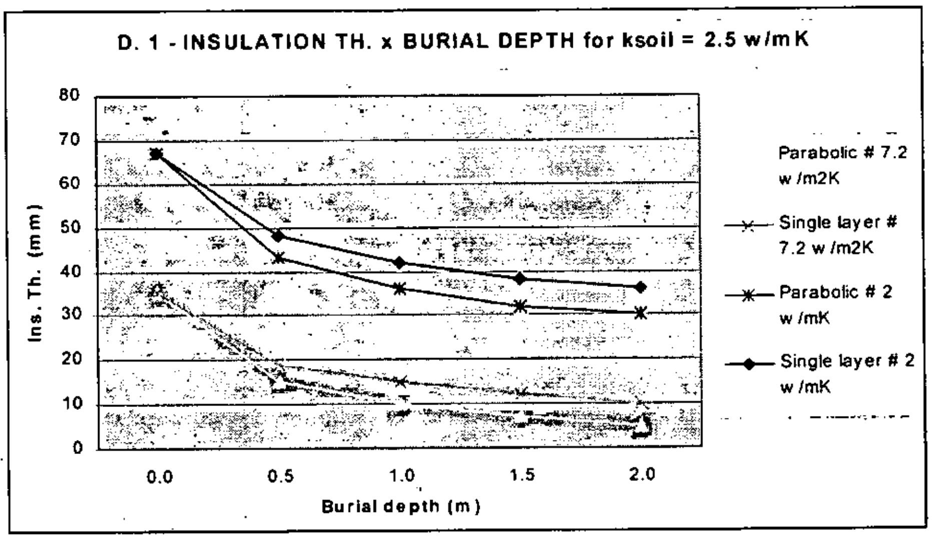

Figure 7 – Insulation thickness x burial depth ksoil=2.5 w/mk

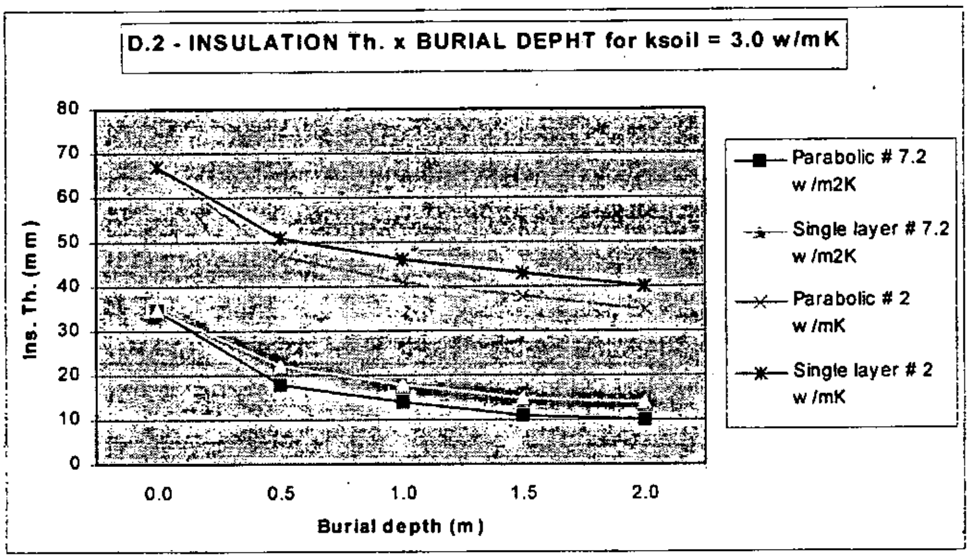

Figure 8 – Insulation thickness x burial depth ksoil=3.0 w/mk

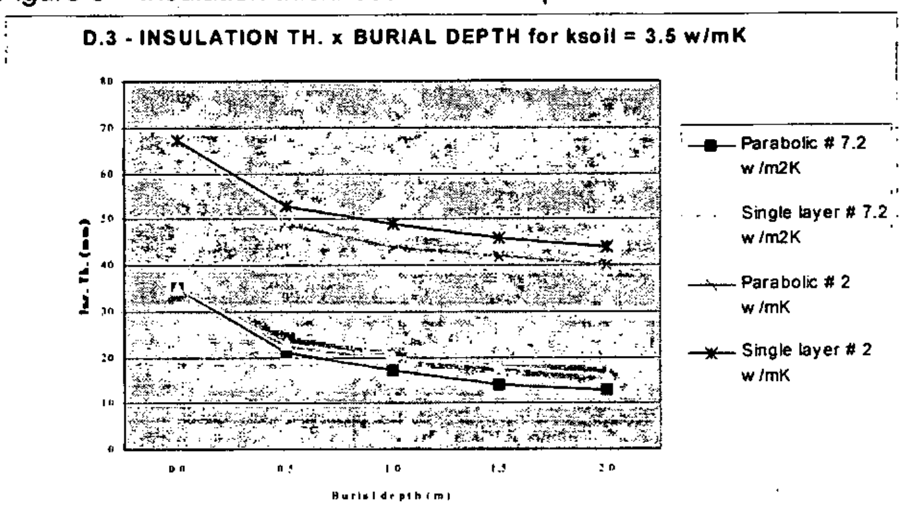

Figure 9 – Insulation thickness x burial depth ksoil=3.5 w/mk

Another area of investigation rely on the possibility of installing SCRs using the reel method or the hybrid reel/J-lay concept. Petrobras is organizing a qualification short term program envisaging upcoming projects.

Deepwater fields, using longer multiphase flowline systems, operating in low ambient temperature open a prosperous area of opportunity for steel utilization, in deepwater Brazil. Insulated steel flowlines should be employed and an insulation material able to support the real operational environmental conditions represents an actual challenge. Also, the attractiveness of steel flowlines are closely related to the ability to extend the installation scope, using steel catenary risers.

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Strength and Fatigue of Deepwater Metallic Risers

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Strength and Fatigue of Deepwater Metallic Risers

Abstract

The industry has met today's challenge of developing reserves in 4,000 ft (1,200m) water depths, and there are now plans for developments in depths of 6,000 ft (1,800m) and even 10,000 ft (3,000m) with even larger diameter risers.

Metallic risers, and specifically Steel Catenary Risers (SCRs), are one of the simplest, cost effective solutions compared to other available deepwater riser systems. The incentive is to use metallic catenary risers, however this simple solution has raised numerous technical challenges. The industry has recognised these challenges and has set about on several Joint Industry Projects (JIP's) to increase the industries knowledge, and in doing so permit the identification of safe, cost effective solutions. Some of these technical challenges include:

- Flow assurance through control of temperature;
- High top tensions for fully suspended systems;
- Buckling/collapse strength at Touch Down Point;
- Fatigue uncertainties due to complex hydrodynamic loading and soil interaction.

Tremendous effort has been expended in the determination of the global response of these systems, which is paying back in the form of our knowledge in areas where we are conservative and those areas where we still don't know. However, the local strength of these systems has not yet undergone such a detailed review.

This paper addresses the local strength issue and asks whether the acceptance criteria and the analytical approaches are still valid as we approach water depths of 10,000 ft for metallic risers. The approaches adopted for flexibles and, in part, new composite risers are not addressed here. These materials (unlike steel) usually undergo physical failure testing to demonstrate their suitability for the intended application, and merit a separate review. There are many failure modes for a metallic riser. However, two modes of failure are expected to be dictating in greater water depths, these are:

Local buckling capacity due to combined axial load, pressure and bending;

Fatigue.

A review of the industry's knowledge for each failure mode is performed followed by a comparison of the recently issued API & ISO riser codes and analytical/ Finite Element Analyses (FEA) results.

The paper reviews the industry's present approach to these modes of local failure and questions whether the present rationale of applying existing approaches gives a consistent level of safety for the greater water depths.

Introduction

There are several modes of local failure by metallic risers, these include local buckling/ collapse/bursting, fatigue, excessive ovalisation, fracture and accumulated strain. Of these it is the local buckling/collapse and fatigue which are expected to be the limiting failure modes, and as such are reviewed by this paper.

Analytical and FEA approaches have been developed for both these failure modes, and are employed by the designer with the stated load/resistance/safety factors to develop a

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functional/safe design. These approaches are developed based on theory/research and experience. However we have no experience for the water depths planned, hence the designer needs to know whether the design is conservative and what is the level of safety.

Design Code Approaches

To meet the new challenges being placed on the industry two new riser codes/guidelines have recently been issued, these are:

ISO 13628-7, (1999) "Petroleum and natural gas industries – Design and operation of subsea production systems", Part 7: "Completion/workover riser systems", International Standardisation Organisation (ref. 9);

API RP 2RD, (1998) "Recommended Practice for Design of Risers for Floating Production Systems and TLP's", First Edition, 1998 (ref. 1).

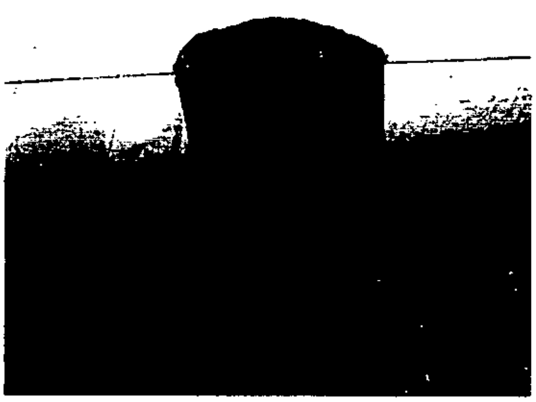
These two codes adopt different approaches, the first being a 'Limit State Design' (LSD) approach and the second an 'Working Stress Design' (WSD) approach. Both these approaches are valid. However, because of the different approaches adopted, a direct comparison is difficult. In addition to these codes ABB OS have been investigating over the last 4 years the local strength characteristics of pipe under combined loads based on detailed Finite Element Analysis (FEA) and comparing the numerical results with physical testing (Ref. 2, 3 & 4). The three approaches are subject to a comparative review.

Riser Capacity Under Combined Axial Force, Bending and Pressure

Dynamic, unsupported (catenary) metallic risers are a relatively new development, having been used by Shell on Tension Leg Platforms (TLPs) since 1994 and more recently by Petrobras on semi-submersibles since 1998 in water depths of circa 3,000 ft (Ref. 12). Based on this limited practical experience it is very difficult to identify/confirm in which areas of strength criteria and methodology the industry is being conservative or un-conservative.

Dynamic catenary risers will experience a combination of external/internal pressure, axial compression/tension and bending moments. As the metallic catenary risers are employed in deeper water depths with greater diameters, the existing boundaries on acceptable moment capacities will be challenged – the question is whether the boundaries set by the new codes are applicable to these ultra deepwater applications (i.e. 10,000 ft – 3,000m)

A metallic pipe will suffer local buckling when subjected to an excessive combination of bending, external pressure and axial loads. In shallow waters this will lead to local deformation (see Figures 1a & 1b below), however for deep waters this will result in catastrophic collapse of the line.



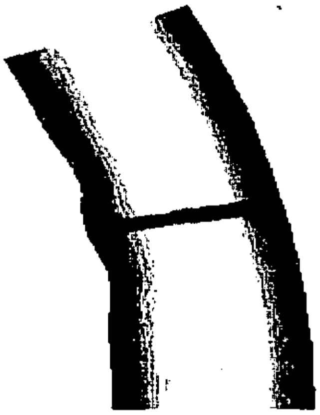


Figure 1b – FEA model of local buckle

Figure 1b – FEA model of local buckle

The criterion used to determine when local buckling occurs can be stress based (WSD approach) or maximum bending capacity (LSD approach), the magnitude of this criterion is a function of many parameters. The main parameters are as follows:

Pipe characteristics:

- Diameter over wall thickness ratio (D/t);
- Material work hardening characteristics;
- Material imperfections;
- Welding (Longitudinal and circumferential welds);
- Dents;
- Initial out-of-roundness;
- Reduction in wall thickness due to corrosion/erosion;
- Cracks (in pipe and/or welding);
- Local stress concentrations due to coating;

Loads applied:

- External and internal pressure;
- Axial tension/compression;
- Temperature;
- Bending moment.

Elastic-plastic buckling of pipes under external pressure was solved by Timoshenko as described in his book "Theory of Elastic Stability" Timoshenko and Gere (Ref. 13.). In recent years, non-linear finite element analysis has been used as an accurate tool to predict buckling/collapse capacity of pipes under external pressure, bending and axial force.

The finite element model has been validated against laboratory tests and applied to derive design equations. The review of the historic work and the latest research results on this topic may be found from Murphey and Langner (Ref. 11), Ellinas et al. (Ref. 17), Mohareb et al. (Ref. 19) and a series of journal papers by Bai et al. (Ref. 2, 3 & 4). This paper summarises the findings of this ongoing debate, which has resulted in a good understanding of the local buckling/ collapse/bursting strength of a pipe.

Figure 2a – *Normalised bending moment capacity as a function of pressure. (No longitudinal force is applied.)*

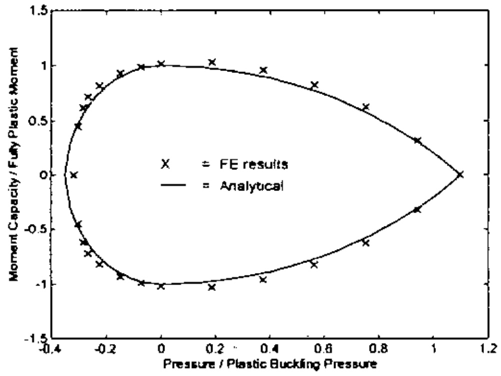


Figure 2b – *Normalised bending moment capacity as a function of longitudinal force. (Pressure equal to zero)*

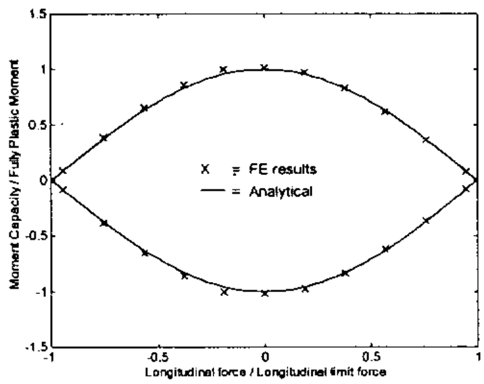
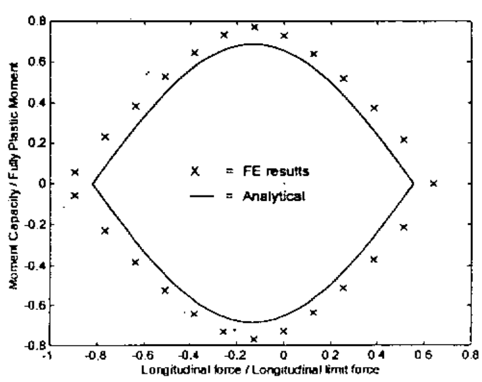


Figure 2c – *Normalised bending moment capacity as a function of longitudinal force. (Pressure equal to 0.8 times collapse pressure)*



The culmination of this work has resulted in the development of comprehensive Finite Element Analysis models that compare extremely well with the physical test results, see Figures 2a, 2b & 2c (Ref. 7). Based on these models the relationship between pressure, axial load and moment has been fully explored, permitting the development of analytical equations which are representative of the pipe behaviour, see Figures 2a, 2b & 2c (Ref. 7). The results are summarised in analytical form in Appendix A (after Hauch & Bai - Ref. 7), and illustrated in Figure 3.

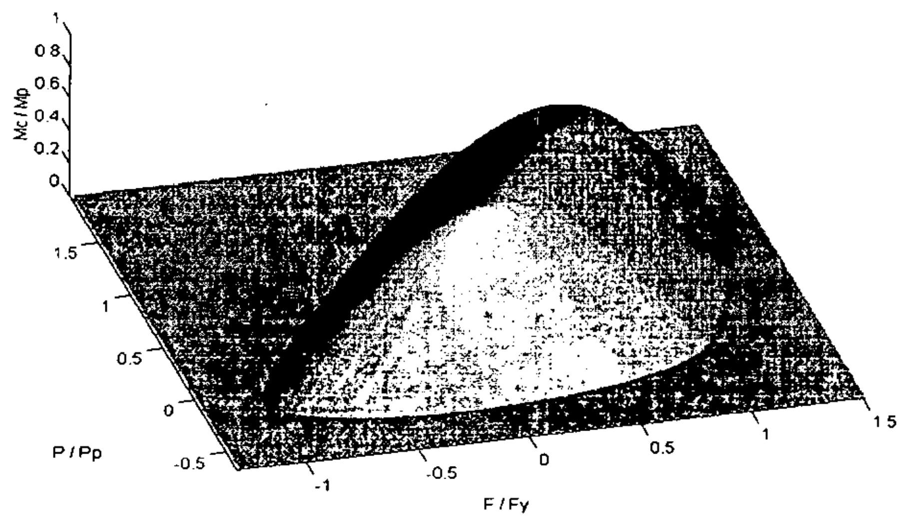


Figure 3 - Limit bending moment surface as a function of pressure and longitudinal force

Application of codes. The riser design codes vary in the way they interpret the allowable loads on the riser (i.e. ASD vs. LSD) and hence differences are expected between the two approaches. To answer the question of whether the approaches generate consistent levels of safety over the full range of axial loads, bending moments and pressures, all methods have been normalised based on allowable bending moments.

Comparison is performed for:

The moment for failure based on the Hauch & Bai (Ref. 7) and summarised in Appendix A:

Allowable moments (including utilisation factors) for each of the three approaches. For the API approach, based on allowable stresses, FEA analysis is performed to quantify the equivalent moments for the allowable stress limit. The utilisation factors used for each approach are summarised in Table 4.

Table 4 - Maximum utilisation factors for Hauch & Bai (1999), Bai (1999), API and ISO

Code	API	ISO	Hauch & Bai (Ref. 7)	Bai (Ref. 3)	
Criteria	Von Mises equivalent stress	Moment	Moment	Equivalent stress	Longitudinal stress
Empty	0.4261	0.4899	0.6275	N/A	N/A
Operation	0.6945	0.6917	0.6365	0.7716	0.3412
Pressure test	0.5956	0.1221	0.1062	0.8376	0.4378

The comparison is illustrated for four load cases, these are:

a. Normalised bending moment capacity as a function of pressure, illustrated in Figure 5a. This shows the moment capacity of the pipe for the classical bursting (positive pressure) and collapse (negative pressure). The ISO and Hauch & Bai have relative consistent levels of safety for the range of pressures. However API, which is based on a WSD approach, does not reflect well the local strength for combined loading conditions. A good example would be when the riser is installed in deep water with riser bending near the Touch Down Point (TDP). The API code may indicate that excessive bending moment is within allowable limits.
b. Normalised bending moment capacity as a function of longitudinal force (with no pressure), illustrated in Figure 5b. This load case is only applicable if the riser is flooded (no differential pressure) or for the riser at the surface with ambient pressure. All three approaches provide consistent levels of safety for both tension (positive) and compression (negative).
c. Normalised bending moment capacity as a function of longitudinal force (with low internal pressure – 72 barg), illustrated in Figure 5c. This load case could be experienced throughout the riser lifetime in periods of planned inspection and/or at end of life. All three codes are safe – but do not provide a consistent level of safety. ISO would appear to be overly conservative, whereas API would appear too close to failure limits in compression. What can be observed is that both API and ISO appear to be conservative for combined tension and bending.

Figure 5a – Normalised bending moment capacity as a function of pressure

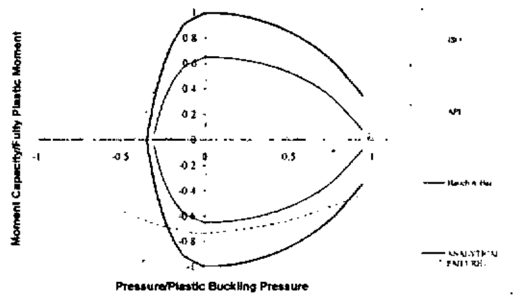


Figure 5b – Normalised bending moment capacity as function of longitudinal force (no pressure)

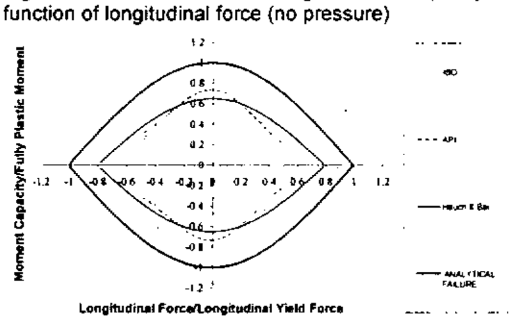


Figure 5c – Normalised bending moment capacity as function of longitudinal force (Pressure = 72 barg)

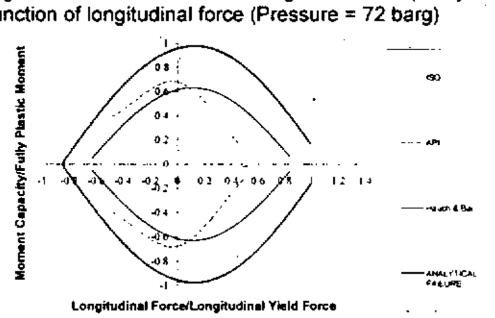
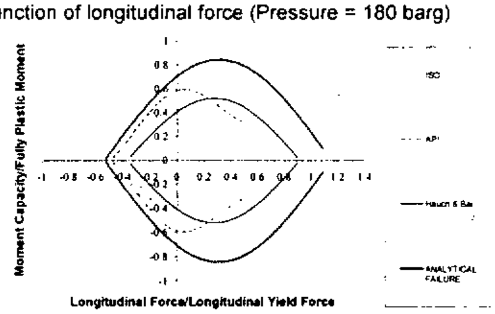


Figure 5d – Normalised bending moment capacity as function of longitudinal force (Pressure = 180 barg)



d. Normalised bending moment capacity as a function of longitudinal force (with high internal pressure – 180 barg), illustrated in Figure 5d. This load case represents the riser during normal operation. What can be observed is that all three approaches are safe. However the level of safety is not maintained, both API and ISO would appear to have very low factors of safety in compression and very high factors of safety in tension.

The ideal scenario is if the 'target safety levels' are uniformly maintained for all load combinations. An immediate observation is that a uniform level of safety (margin between allowable and failure) is not being maintained with the codes reviewed. However, the authors would emphasise that these codes do result in safe designs. The authors would recommend when designers are approaching the identified limits that they use the Hauch & Bai method verify the reserve strength of the riser and decide whether a limit state design is justified.

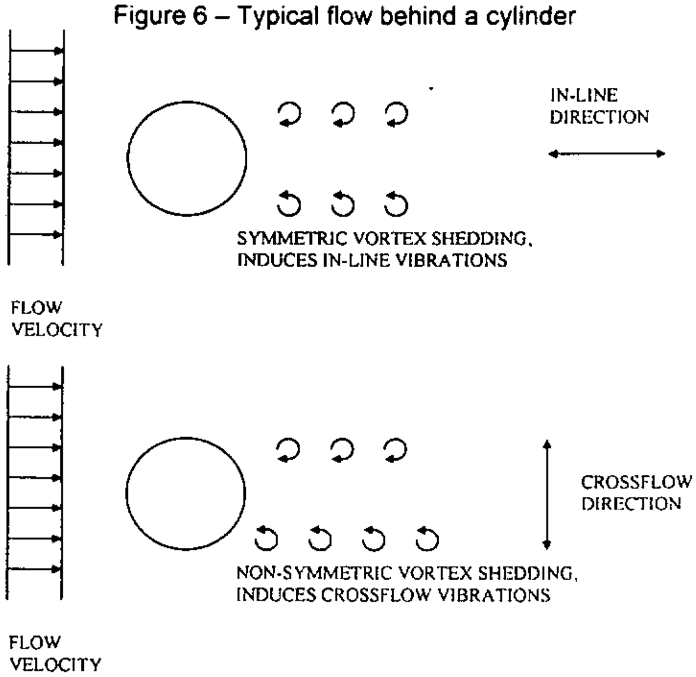
From this review of the local bucklng/collapse limit state it can be concluded that the three approaches presented are safe for deeper water applications, although some do not maintain a consistent level of safety for the load combinations.

Riser Fatigue

As for the local buckling, there is limited practical experience of riser in ultra deep water, which makes it very difficult to identify which areas the industry is being conservative and un-conservative. Riser fatigue will be experienced from the stress variations in the riser induced by:

- Vessel motions (first and second order) – including the change in shape of the catenary and seabed/touchdown point interaction;
- Vortex Induced Vibrations (VIV) induced by current, wave induced current and relative current velocity induced by riser motions from due to vessel motions;
- Riser motions induced by slugging (pressure cycling);
- Riser pressure variations (i.e. shutdown).

Figure 6 – Typical flow behind a cylinder



The stress ranges induced by the majority of factors can be determined with a high level of confidence with the exception of VIV induced stresses, the effects of slugging and stresses due to seabed/touchdown point interaction. These are discussed in turn:

Vortex Induced Vibrations

VIV is probably the most debated design issue for metallic catenary risers, particularly for high current locations. High frequency vibration of the riser pipe due to vortex shedding leads to accumulation of cyclic stresses, which can result in unacceptable fatigue damage. VIV occurs when a body is exposed to super critical turbulent flow that produces vortex shedding at, or near, a structural natural frequency of the body (see Figure 6). Deepwater risers are especially susceptible to complex VIV response because:

- currents can be high at different depths in deepwater areas (shear currents);
- the increased length of the riser affects its natural frequency and modes of vibration thereby increasing the complexity of fluid/structure interaction; and
- effect of vessel motions.

Deepwater risers are sufficiently long that significant currents will excite vibrations at modes that are much higher than the fundamental modes. Since deepwater currents usually change in magnitude (and direction) with depth, it is therefore likely that multiple modes of the riser will be 'locked' into VIV. This makes deepwater riser VIV prediction much more complex than that for short riser spans typical of fixed platforms in shallow water.

VIV is perhaps more sensitive to the current profile than to any other parameter. For short riser spans the current magnitude determines whether or not VIV will occur, and determines whether the response is in-line or transverse to the flow direction (or both). The cross-flow response is more significant than the inline response. For deepwater risers a low current will, for a catenary with low horizontal components of tension, produce some VIV due to the low natural frequency of the riser. The variation of the current along the riser span (i.e. with depth) then determines which modes will be present in the response. Here it should be noted that:

- Current profiles that are conservative for platform offsets are not necessarily conservative for deepwater riser VIV prediction (this is because VIV of deepwater risers is much more dependent upon the shape of the current profile with depth);
- The current profile should be varied during the analysis to determine the sensitivity of the results to current profile shape;
- Currents change with time, so some kind of probabilistic description of the current magnitudes and/or profile shapes is necessary for a sufficiently accurate VIV analysis;
- It is possible that even if numerous modes are potentially excited by a current profile, a single mode (or a small number of modes) can dominate the response due to "lock-in" in which the vortex shedding tends to

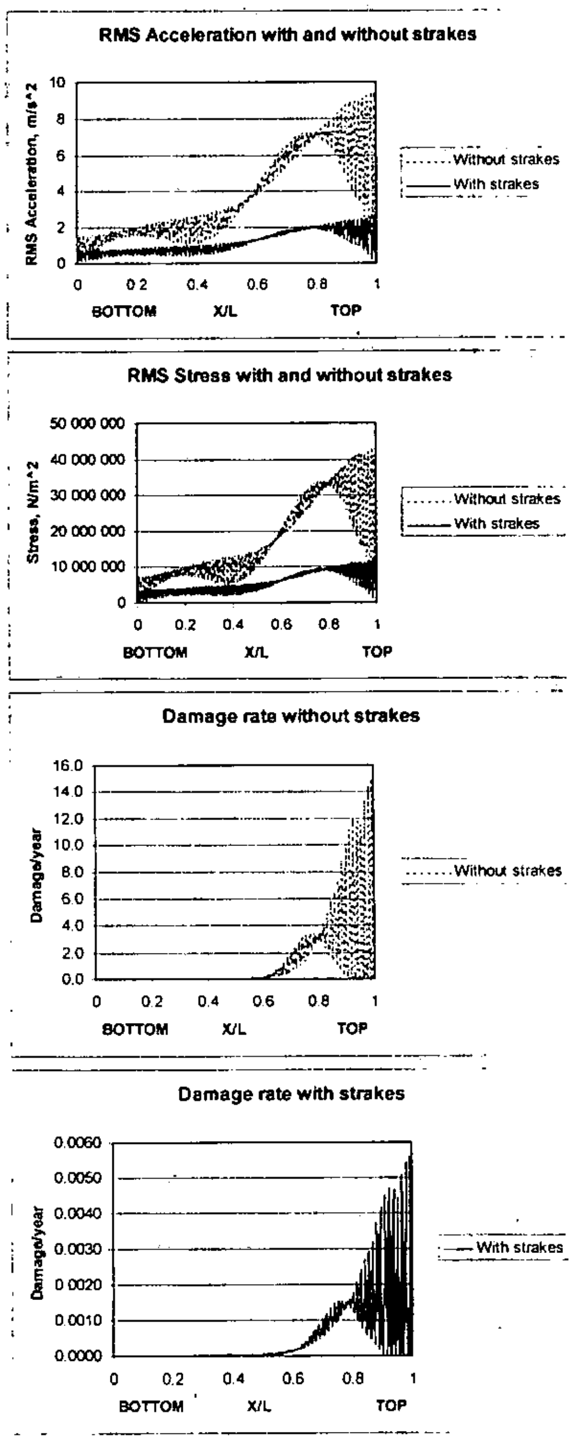


Figure 7a – VIV Analysis using SHEAR7

adjust to the vibration frequency within certain limits (dependent upon mass ratio and Reynolds number etc.;
- Even in a highly sheared current it is possible for a single mode (or a small number of modes) to dominate the response.

Time domain analysis can identify the governing modes because interaction between vibrations and axial loadings is modelled.

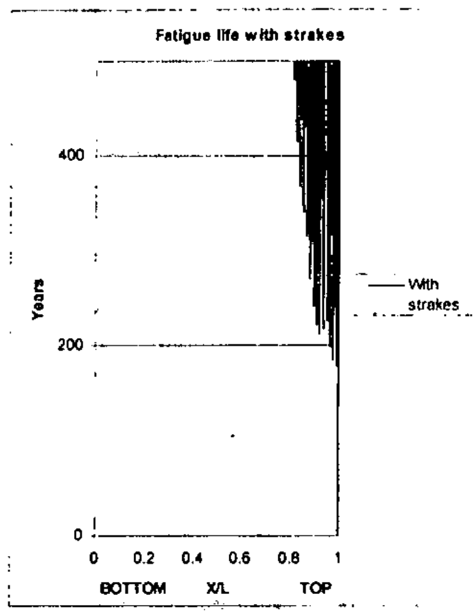


Figure 7b - VIV Analysis using SHEAR7

Analysing VIV

The most recognised used program to predict VIV is the MIT program SHEAR7 (Ref. 14 & 15) which is a non-linear, fluid-structure interaction, frequency domain model. The interaction model allows for the local lift coefficient and local hydrodynamic damping coefficient to depend on the response amplitude. SHEAR7 is based on mode-superposition and therefore has a practical limit of about one hundred participating modes. The program was initially written to model straight risers with constant diameter with spatially varying tension. It has been extended to model structures such as catenaries, by hybrid techniques in conjunction with finite element models. As with all existing VIV design programs for risers, SHEAR7 requires calibration with measured data.

The relative lack of data at super-critical Reynolds numbers limits the absolute accuracy of all programs currently available. In many straight riser scenarios in sheared currents, common to the industry today, the likely error in the response amplitude prediction may be as high as a factor of two. Much of the reason for this lack of accuracy is to be found in the complexity to model the hydrodynamics and in the lack of calibration data at high Reynolds numbers.

The conclusion from this review of determination of VIV is that the level of uncertainty in analysis is relatively large, this alone will result in conservative, or inappropriate (un-conservative), factors of safety being applied which in turn could mean unnecessary VIV mitigation measures are adopted. The industry is addressing this issue, the most notable being the STRIDE Joint Industry Project (Ref. 6 & 16)

Slugging

If the hydrocarbons being transported from the seabed is in a liquid phase then there will be no slugging. However a large proportion of developments either have condensate (a mixture of gas and liquid hydrocarbons) or require gas lift to get the hydrocarbon to the surface (due to low well pressure – shallow reservoirs). In the case of both the condensate and gas lift there will be a tendency for the gas/liquid to separate, which will result in a change in momentum.

The effect of two and three phase flow in the riser should be included in the fatigue life estimation, but the software available to the industry can not handle this effect yet. The slugging inside the riser makes the riser to move with large deflections. The stress induced by the deflection should be included in the fatigue analysis.

With present design practices it is not normal to include slugging effects in the fatigue analysis, and when it is performed there are large question marks about how representative the analysis is. This is an area that requires attention from the industry.

Seabed Touchdown point (TDP): Riser TDP varies due to vessel 1st and 2nd order motions, current drag, VIV and effects due to slugging. The change in the TDP changes the natural frequency of the riser, and in turn affects the response and so the loadings generated by VIV, current drag et al. With the uncertainties of the loads generated by VIV and slugging for a quasi-static situation then the loads for a dynamic situation are questionable. Bearing mind the uncertainty of analysis, there is potentially interaction between the riser and seabed. Should the seabed act in a rheotic way i.e. the seabed will increase in stiffness when the riser is pulled out from an embedded position. This effect will have a dramatic increase in local stresses and will have a direct impact on the fatigue life of the riser. This concern is being addressed by the industry (Ref. 5,13 & 19).

The Industry Response

Significant effort has been spent to both predict (by analyses) the responses of these systems and to monitor what is actually happening – which are to be used as a baseline for these predictions (Ref. 8 & 12). Implementation of these findings will increase the level of confidence in the analysis results. However, the industry recognises there is little experience for fatigue of SCRs, consequently the approach is conservative - or is it?

How the Codes Address Fatigue

The paper has highlighted that there is a large level on uncertainty in the analysis of the response of the systems for both VIV related and slugging induced fatigue. The codes address fatigue in similar fashions, cumulative fatigue can be calculated using the 'Miners Rule' and this is factored by a safety factor. To provide direct comparison of the approaches an example is performed for a Ø8" catenary riser in 3,000 ft (1,000m) water depth. The method adopted for determining the cumulative fatigue is to use Shear7 for the VIV analysis throughout the installation, testing and operation phases of the riser life.

The results of this analysis are illustrated in Figures 7a & 7b, and the results are applied for both ISO and API to determine if the cumulative fatigue is acceptable. From a review of Figures 7a & 7b the analysed benefit of 'strakes' on the top portion of the riser are illustrated. The top portion of the risers suffers more from VIV and strakes are analysed to mitigate VIV, so the cumulative fatigue damage from VIV is reduced by a factor of 250. The industry is investigating if VIV is such a critical issue and if strakes are as effective as analysed (Ref. 8, 12 &17). For the sake of this comparison of codes, it is assumed that strakes are attached to the top portion of the riser, the results for each code are addressed in turn:

- **ISO** requires a fatigue life safety factor equal to 3.0 when the riser is inspected. With ISO's requirement the associated fatigue with our example is 0.3587, giving a comfortable margin in comparison to the allowable limit of 1.0. The fatigue results from ISO are shown in Table 8.

	Calculated damage/year	Design length (years)	Damage	Safety factor	Damage with SF
Empty	0.00734	1	0.00734	-	-
Operation	0.00561	20	0.1122	-	-
Pressure test	0.00442	1/365	0.000012	-	-
Accumulated fatigue damage			0.1196	3	0.3587

Table 8 Fatigue damage ISO code

- **API** uses different safety factors for the three different states and then adds the damages, still the fatigue allowable limit is set at 1.0. The fatigue damage is calculated be the equation below:

$$\sum_{i} SF_i D_i < 1.0$$

The fatigue results from API are shown in Table 9.

	Calculated damage/year	Design length (years)	Damage	Safety factor SF	Damage with SF
Empty	0.00734	1	0.00734	3	0.0220
Operation	0.00561	20	0.1122	10	1.122
Pressure test	0.00442	1/365	0.000012	3	0.000037
Accumulated fatigue damage			0.1196	-	1.144

Note: SF = 3, safety and pollution risk are low.
SF = 10, safety and pollution risk is significant

Table 9 Fatigue damage API code

The two approaches do conclude in different outcomes for the same design. With the API approach the cumulative fatigue would have exceeded allowable limits, whereas for ISO the fatigue is within acceptable limits. Although there is a factor of three between the two approaches, no conclusion should be drawn on the relative accuracy of either. An observation for the designers of these SCRs when determining fatigue is that the codes have set a fixed level of safety based on experience for the uncertainties on loads and responses. These levels of safety are set whether the risers are in 1,000 ft or 10,000ft, an estimate based on experience has been made by the code authorities to provide sensible (and not overly conservative) levels of safety. What is potentially happening now is that the technology is not keeping pace with the ambitions of the industry – and hence the assumption that the analysis is providing a similar level of confidence in the deep waters as the shallow waters may not be sound. The designers should ask themselves when going into deeper waters what the level of confidence in their analysis is compared to shallower water analyses and review their results accordingly.

Rationalisation of Approaches

Upon review of this paper one can question if the predicated pipe responses are realistic and the stated utilisation factors (safety factors) are appropriate. This question is difficult to answer as historically both the analysis and levels of safety have been built up based on years of experience. In our case we have no experience of ultra deep waters (10,000ft) so the inclination is to be very conservative. However, modern analysis methods using FEA sy\uch as a numerical laboratory has increased the confidence in riser designs.

Probably the most rational approach to address this situation is to adopt a 'Load Resistance Factor Design' (LRFD) method. The principal is to look individually at the loads (i.e. weight, current, vessel motions etc) and the resistance to the loads (i.e. stiffness of the catenary, vessel support, seabed support etc.) and factor based on our level of uncertainty for each. This level of uncertainty would include how accurately we know the pipe strength, predict its response and what loads are being applied. Adopting a LRFD approach for both the local buckling and fatigue then the following can be observed:

Local Buckling/collapse:

	Area	Level of confidence
Load		
	Pressure	High
	Bending loads	Medium
	Axial loads	High
Resistance		
	Material resistance	High
	Structural response	High

Fatigue:

	Area	Level of confidence
Load		
	VIV induced loads	Low
	Vessel motion induced loads	Medium
	Slugging loads	Low
Resistance		
	Material resistance	High
	Structural response	Medium

Based on this simplified LRFD approach the local buckling analysis will have relative high levels of confidence for both the loads and responses, indicating that the utilisation factors do not have to be conservative. However, for the fatigue the levels of confidence for both the loading and resistance are not high, meriting that the utilisation factors are justified as being high.

Conclusions

This paper reviews the state of the industry with respect to the design of SCR in deep waters with respect to two of the most critical failure modes, local strength (collapse/bursting/buckling) and fatigue.

As a result of extensive FE analysis and testing there is a high level of confidence for local strength design that the loads, resistance and the responses, and as such the basis applied is sound for the deeper water applications. However, the paper flags potential areas where the reviewed approaches may not provide consistent levels of safety, which the designer should be aware of when applying extreme conditions. The Hauch and Bai (Ref. 7) criteria presented in the Appendix provides a more consistent level of safety for all loads and load combinations.

The conclusions are different are different for fatigue. With deeper water depths the level of uncertainty for both the loads and responses increases, and as such the basis applied in shallower water designs does not give the same level of confidence. Engineers designing risers for deeper water depths should be cautious of just satisfying the code requirements and should ask themselves what is the level of safety in their analysis compared to shallower water analyses and review their results accordingly. More work needs to be done with respect to modelling the complexity of the fluid/structure/soil interaction and calibration with full-scale measurements to achieve the same level of confidence for fatigue design of deepwater risers as for local strength design.

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Appendix A
Moment Capacity of Pipelines

The diameter to thickness ratio (D/t) defined for the formulae in this Appendix are to be less than 60 (after Hach & Bai (1999)).

(i) Maximum Allowable Moment

The maximum allowable bending moment criterion for local buckling given in this Appendix is valid for both internal- and external- overpressure situations and can be expressed as:

$$M_{All} = \frac{\eta_{RM}}{\gamma_c} M_l \cdot \sqrt{1-\left(1-\alpha^2\right)\cdot\left(\frac{p}{\eta_{RP} p_l}\right)^2} \cdot \cos\left(\frac{\pi}{2}\cdot\frac{\dfrac{\gamma_c F}{\eta_{RF} F_l} - \alpha\cdot\dfrac{p}{\eta_{RP} p_l}}{\sqrt{1-\left(1-\alpha^2\right)\cdot\left(\dfrac{p}{\eta_{RP} p_l}\right)^2}}\right)$$

where

M_{All} = Allowable bending moment
M_l = Limit moment
p = Pressure acting on the pipe
p_l = Limit pressure
F = Longitudinal force acting on the pipe [1)]
F_l = Limit longitudinal force
α = Correction factor [2)]
γ_C = Condition load factor
η_R = Strength usage factor

Notes:

1) In the calculation of load effects, load factors for functional loads and environmental loads are to be applied to the individual loads.

2) If possible, the correction factor α should be verified by finite element analyses, otherwise the following equations may be applied:

$$\alpha = \frac{\pi \cdot D^2}{4} \cdot \left|\frac{p_c}{F_l}\right| \quad \text{for external overpressure}$$

$$\alpha = \frac{\pi \cdot D^2}{4} \cdot \left|\frac{p_b}{F_l}\right| \quad \text{for internal overpressure}$$

(ii) Limit Loads

The limit moment may be given as:

$$M_l = \left(1.05 - 0.0015 \cdot \frac{D}{t}\right) \cdot SMYS(T) \cdot D^2 \cdot t$$

where

SMYS (T) = Specified Minimum Yield Strength in longitudinal direction
D = Average diameter
t = Wall thickness

The limit longitudinal force may be estimated as:

$$F_l = 0.5 \cdot \left(SMYS(T) + SMTS(T)\right) \cdot A$$

where

A = Cross sectional area, which may be calculated as $\pi \times D \times t$.
SMYS(T) = Specified Minimum Yield Strength in longitudinal direction
SMTS(T) = Specified Minimum Tensile Strength in longitudinal direction

The limit external pressure 'p_l' is equal to the pipe collapse pressure and is to be calculated based on:

$$p_l^3 - p_{el} \cdot p_l^2 - \left(p_p^2 + p_{el} \cdot p_p \cdot f_0 \cdot \frac{D}{t}\right) \cdot p_l + p_{el} \cdot p_p^2 = 0$$

where

p_{el} = $\dfrac{2 \cdot E}{(1-\nu^2)} \cdot \left(\dfrac{t}{D}\right)^3$

p_p = $k_{fab} \cdot SMYS(T) \cdot \dfrac{2 \cdot t}{D}$

f_0 = Initial out-of-roundness [1], $(D_{max}-D_{min})/D$
SMYS(T) = Specified Minimum Yield Strength in hoop direction
E = Young's Module
υ = Poisson's ratio
k_{fab} = Fabrication derating factor

Notes:
1) Out-of-roundness caused during the construction phase is to be included, but not flattening due to external water pressure or bending in as-laid position. Increased out-of-roundness due to installation and cyclic operating loads may aggravate local buckling and is to be considered. Here it is recommended that out-of-roundness, due to through life loads, be simulated using finite element analysis.

The limit pressure for the internal overpressure situation will be equal to the bursting pressure given by:

$$p_l = 0.5 \cdot \left(SMTS(T) + SMYS(T)\right) \cdot \frac{2 \cdot t}{D - t}$$

(iii) Material Derating Factors and effects of manufacturing process

Temperature derating factors are introduced to account for reduced material strength at elevated temperatures T.

The material strength in the hoop direction will be influenced by the manufacturing process and if no test data are available for the hoop strength the following values for the reduction factor shall be used.

k_{fab} = 1.000 for seamless pipes
k_{fab} = 0.925 for UO pipes
k_{fab} = 0.850 for UOE pipes

(iv) Usage Factors

Usage factors η_R are listed in Table 10.

Table 10: Usage factors.

Usage Factors	η_{RP} Limit Pressure	η_{RF} Limit Long. force	η_{RM} Limit Moment
Low	0.95	0.90	0.80
Normal	0.93	0.85	0.73
High	0.90	0.80	0.65

The Application of Bundled Pipeline Installation to Drilling and Hybrid Risers

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The Application of Bundled Pipeline Installation to Drilling and Production Risers

Introduction

Hydrocarbons are being discovered in deeper waters, which result in more risks, complexity, and costs involved in carrying out these developments. This applies to all aspects, including; drilling, completion, production and transportation. It is becoming apparent that cross-fertilization of the latest technologies developed in the various offshore components could well improve efficiencies within other areas, when properly employed. Also the engineer should borrow from other areas of expertise; i.e. aerospace technology, the use Mother Nature's assets, etc. and combine these innovatively. It is becoming apparent that the pipeliner's development of the towed-bundle systems can be employed beneficially within the drilling industry to:

- reduce the cost of riser materials, and buoyancy;
- reduce the weight of risers;
- permit makeup of the complete riser on shore, install the casing connectors and test;
- permit makeup of utility lines including; choke, kill, booster, and control systems on the beach, install them on the riser and execute final in-place testing of each;
- reduce the time required for the drilling operation by minimizing the mobilization of the drilling risers;
- reduce the time required for demobilization of the drilling riser to other locations by low cost supply vessels;
- use low cost supply vessels for the transportation and erection;
- be able to extend the second and third generation drill rigs' operating depths by repositioning the BOP's to an elevation above the seabed;
- in the deeper waters, be able to utilize hydraulic controls versus the need for the more complicated electro-hydraulic systems;
- have available a quick response emergency riser in the event of a blowout in deep water.

Approach

The differences between the drillers and pipeliners is the orientation of the final product. The pipeliners use them horizontally while the drillers use them vertically. Essentially they are the same tubular members which are required to maintain a product within its bounds, resist collapse, corrosion, wax formations, hydrates, high temperature variations and be subjected to high longitudinal loads. The pipeliner's makeup lines into long strings off of a barge or on shore to be launched and towed to an offshore location. The drillers, on the other hand, makeup their lines vertically from a floating facility in a casing housing their drilling apparatus and products produced. The makeup system being described in this paper is on a beach in Texas on Matagorda Peninsula next to the Gulf of Mexico. Fourteen bottom tows have been successfully completed from this site since 1985. The purpose of this paper is to demonstrate that a preliminary design for a riser system is viable by the methods and procedures normally utilized by pipeliners. This includes the entire scope of makeup, launch, tow, erection and removal.

Proceedings of the 3rd Deepwater Pipeline & Riser Technology Conference, Houston, Texas, March 7-9, 2000.

History

Figure 1 shows the towing route that has been established in the Gulf of Mexico for the bottom-towed bundle installations. Figure 2 shows a brief history of the bundles installed by the on-bottom towing techniques in various areas such as Australia and the Gulf of Mexico. The technologies have improved and been honed to a fine state-of-art, such that lengths up to 10 miles, with diameters up to 28 inches, and tow distances of up to 450 nautical miles have been completed. Actually a single pipe pull of 19 miles was completed in 1960 in the Persian Gulf between the Island of Karghu to Ganavah on the mainland of Iran. During the one year development of this methods and procedures several companies preferred a surface tow method therefore both surface and below surface methods were developed and analyzed.

Methods and Procedures

The methods and procedures described in the following are well established and proven over four decades of pipeline installation in various parts of the world. This paper describes the following types of riser installations and applies equally to drilling, work-over, production, hybrid types and SCR's. There are variations in the handling of the risers during the installation process, which from experience are simple and low risk steps as long as prudent engineering and equipment handling procedures are realistically developed and employed. The methods and procedures for riser handling described in this paper are subdivided into the following;

- launch and surface tow to site, with a **light** riser system;
- launch and surface tow to site, with a **heavy** riser system;
- launch and combined bottom and below surface tow to site;
- moving of a riser system after competition of specific task.

The use of this technology is directly applicable to the design, beach fabrication, and installation of the various risers described earlier. The pipeliners have started down this path with the installation of several catenary risers (SCR's) for both pipe-in-pipe and pipeline bundles.

In the Gulf of Mexico conventional bottom-tow installation utilizes a pipe made up on a beach parallel with the water surface. The towing end is deflected offshore, and the bundle is launched and towed at speeds of up to 6-1/2 knots to its desired location. For the drillers, the riser maximum lengths are in the range of 8,000 feet, which gives the pipeliner a very simple and low risk method for the makeup, launch, tow, and erection. The pipeliners have towed bundle lengths up to ten miles in the Gulf of Mexico and 19 miles elsewhere.

The surface towed riser system consists of permanent buoyancy at the top end of the riser, temporary buoyancy along its length and a system for releasing the temporary buoyancy during the erection process. Figure 3 shows the preliminary designs for the permanent and temporary buoyancy for a typical drilling riser. .

- Launch and surface tow to site, with a **light** riser system;

  Figure 4 shows to scale the step by step procedures for the riser erection at the site. When the tow vessel arrives at the site a second vessel removes pontoons with a continuous trip cable with sea catches while a third vessel recovers the temporary buoyancy. This light riser system is utilized with the BOP positioned on the seabed.

- Launch and surface tow to site, with a **heavy** riser system;

Raising the BOP to a position above the seabed requires that the casing be designed to handle full field pressure which increases the submerged weight of the riser such that tensioning the riser is required during the erection process. Figure 5 shows the same procedures as in Figure 4 plus an additional vessel with a clump weight for providing the additional tension.

- Launch and combined bottom and below surface tow to site;

The installation depicted in Figure 6 more closely resembles the bottom-towed systems used so successfully during the 14 tows from Matagorda. The main difference is that during the tow the length of the riser is short enough to permit the trailing end to lift off and the riser section to be flown sub-sea to its destination. This can be applied to all of the bottom-towed systems and would be directly applicable to all the riser types described earlier. From the standpoint of the pipeliner, the attractive aspect of the risers are that the lengths are short which provide considerable additional flexibility during the towing and erecting process.

Once the riser is launched and is under tow, the bottom profile increases from sea level and at -600 feet the trailing end of the can lift off. This is the edge of the continental shelf, which is approximately one hundred miles from the initial launch position. With a proper design, setting the submerged weight at approximately 40 lbs. per foot, the entire riser system will become waterborne (lifted off the seabed in a very relaxed, stress-free, flying mode). Higher speeds up to 11 knots will raise the trailing end of the riser to within 200 feet below the surface. The riser is then in this relaxed mode, low stressed condition. Figure 7 depicts the towing configurations for two submerged riser weights (10 and 40#/ft), which shows the riser end depth in terms of towing speed.

At these higher speeds the transient times will be short for this type of operation and will permit long-distance tows to other areas such as Brazil, Africa and so on, at a reasonable cost. The towing spread for this is a supply-anchor handling type of vessel. When initially discussing this, the first response is, "What happens if the engines on the towing vessel fail?" The answer is, "The riser automatically goes through its erecting procedure and stands vertical awaiting the vessel to resume its tow again. Figure 8 is a computer-generated series of positions that the riser descends through during the erection process.

- Moving of a riser system after competition of specific task.

Once the drilling operation has been completed the question then arises what to do with the riser system. There are several possibilities including; moving it with either the drilling rig a short distance to another well, or wet storage locally. The supply-anchor boat could move it to storage or return it to shore for inspection, refurbishment, lengthening, shortening or whatever. Figure 9 shows a scenario where the rig disconnects the riser at the seabed passes the recovery and towing lines to the anchor handling spread which, as it gets under way, causes the riser end to lift off and return to the same flying mode as shown in Figure 6. This same procedure can be long distance tows to other sites.

Figure 10 is a picture of the beach at Matagorda with seven-mile casings.

Figure 11 is a picture of flowline and casing makeup and bundling of lines with insulation.
Figure 12 is a picture of the pipe cradling to the waters edge with side boom tractors.
Figure 13 is a picture of the pipe with marker balloons at the end, 2,000', 6,000' and 10,000' from the end prior to lateral launch.
Figure 14 is a view from the towing vessel of the pipe with marker balloons at the end, 2,000', 6,000' and 10,000' after launch.

Identified Risks and mitigation

The riser erection surface tow procedures as shown using temporary buoyancy are very similar to the installation of tendons. In one case during a tow, weather related problems occurred causing the tendons to be lost. The mitigation of this, using the below surface tow, is to stop the tow, let the riser erect and rest comfortably and safely in its wet storage configuration until the tow can be recommenced.

Conclusions

- Considerable economies can be realized by cross-fertilization within the different sectors of the offshore industry;
- The riser systems as described in this paper can be launched, towed, erected, wet stored and moved by supply-anchor handling vessels;
- The dead and live loads on a drilling rig and vessel increase dramatically with depth. This is reducing the operating safety factors to critical minimums.
- By eliminating the normal drilling riser collars considerable monies and weight can be saved;
- By raising the BOP above the seabed the drilling depths of the second-generation vessels can be extended;
- If a BOP is used at an elevation above the seabed an additional shut-in tool is required and apparently is available in the industry;
- Since hydraulic control systems are limited to depths of 5,000' the raising of the BOP permits the rig operator to maintain this system versus the more complicated electro-hydraulic system;
- By pre-installing the risers, time can be saved during the initial setup of the rig prior to drilling;
- The main difference between the surface and below surface tows is the need for temporary buoyancy on the surface towed system.
- Of the two methods of transport for the risers, the <u>bottom</u> tow initially and <u>below surface tow</u> method is preferred;
- The use of the buoyancy cans at the top of the riser reduces the cost of riser support during the installation and operating phase;
- The onshore makeup of the riser casing, choke, kill, booster, control lines etc. can be tested and certified prior to launch, tow and erection at site.
- The <u>surface tow</u> of the riser is more vulnerable to the Sea State than the <u>bottom and below surface tow</u>;
- The <u>bottom and below surface tow</u> in transit is in a very relaxed and low stress condition for the riser;
- The erection riser stresses for all three systems are controllable within acceptable limits. (See Figures 4, 5 and 6);
- As far as the methods and procedures described in this paper are concerned there is very little new and different from the pipeliners experienced point of view;

- Should a blowout in deep water occur, the use of this type of make-up on the beach would enhance the industry's ability to respond rapidly; similar to that of a Fire Brigade;
- In proven field drilling, the use of a movable riser by supply vessels is attractive to improve drilling rig efficiency.
- For makeup of the risers on land improves the quality control aspects.
- By transferring makeup of the risers to shore reduces the number of the various engineering, inspection, and quality assurance control personnel required on the rig.

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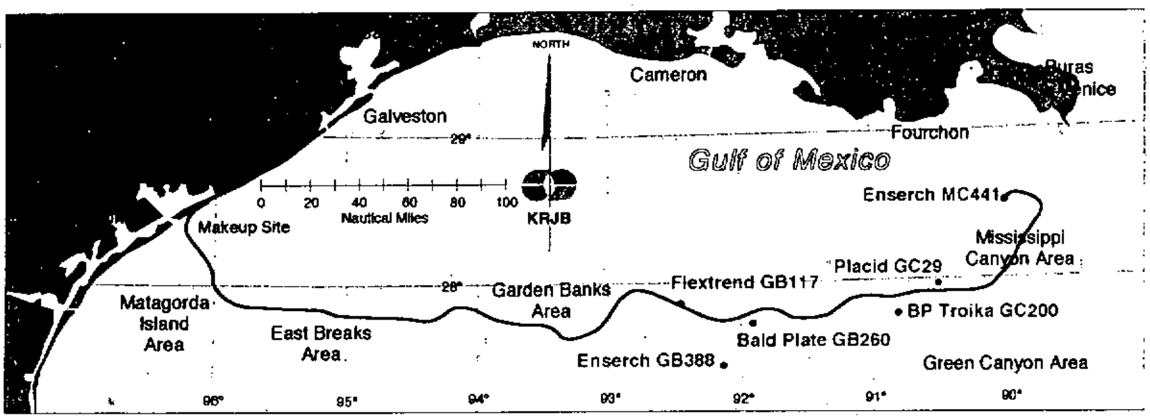


Figure 1

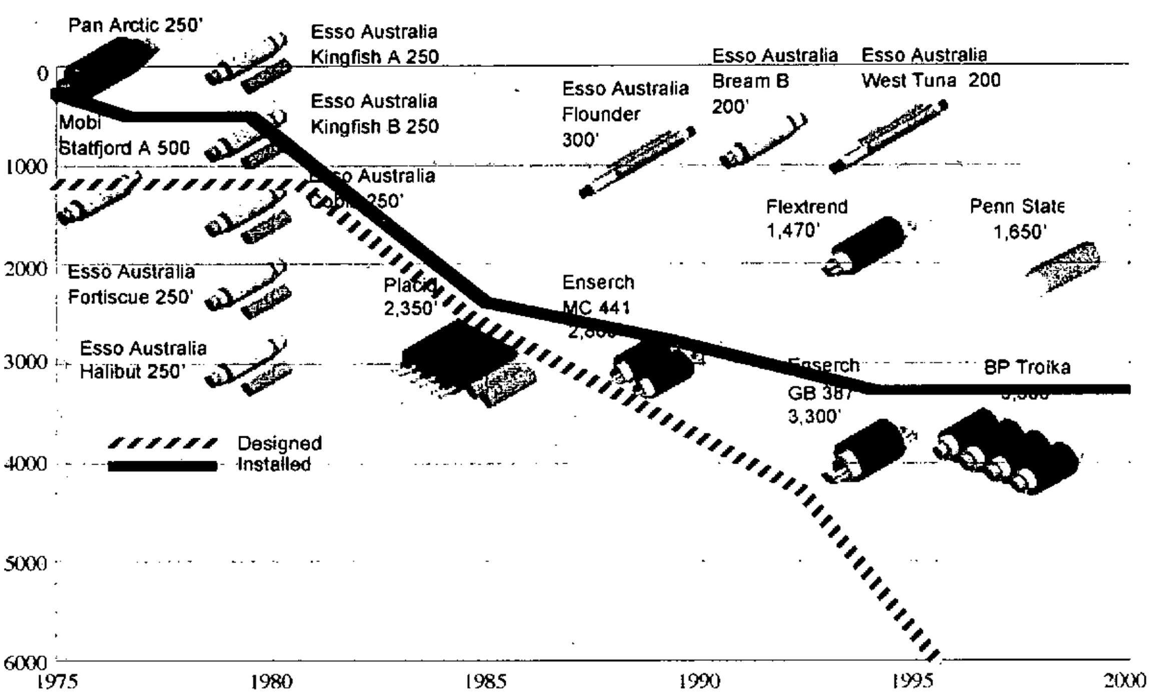
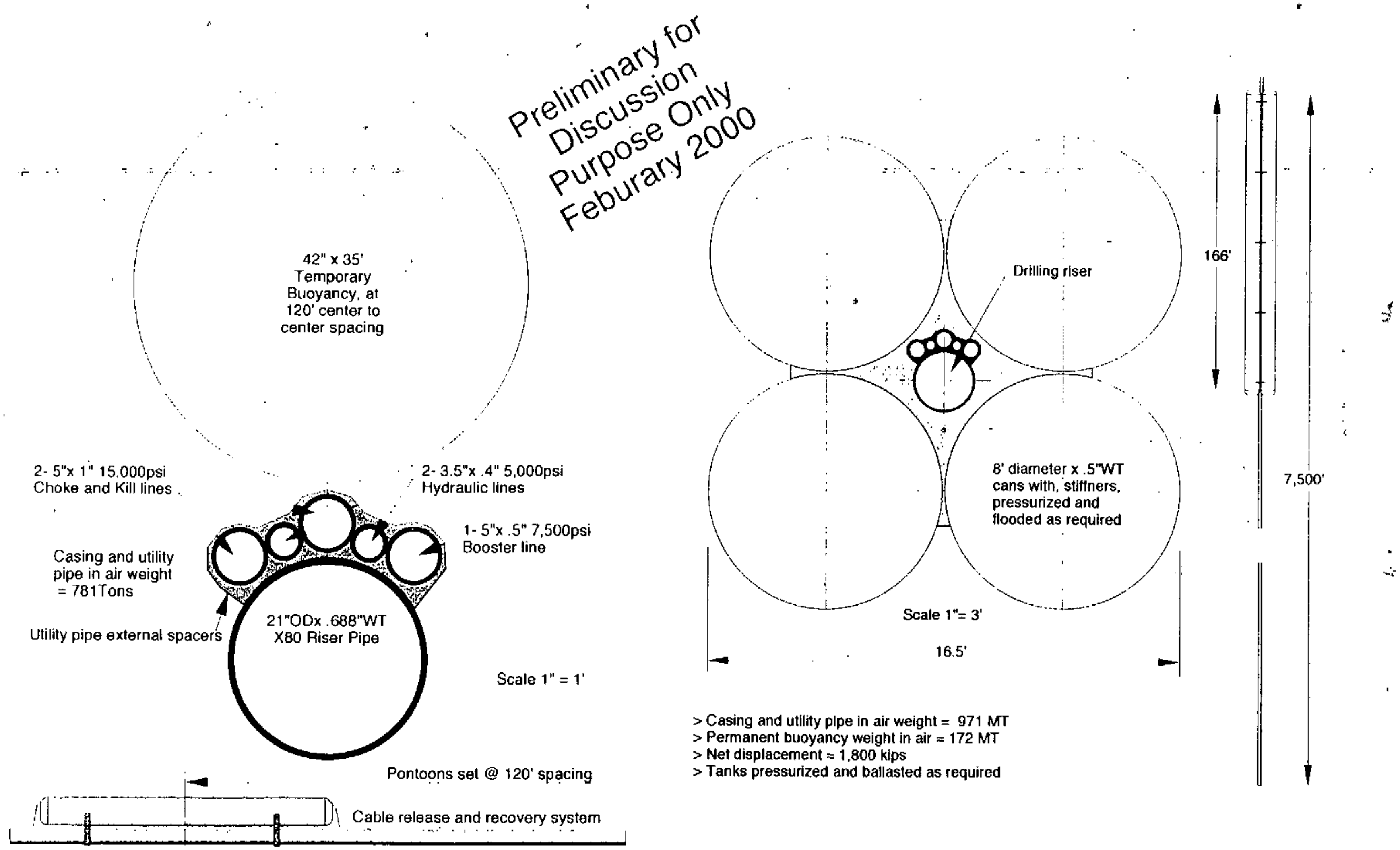
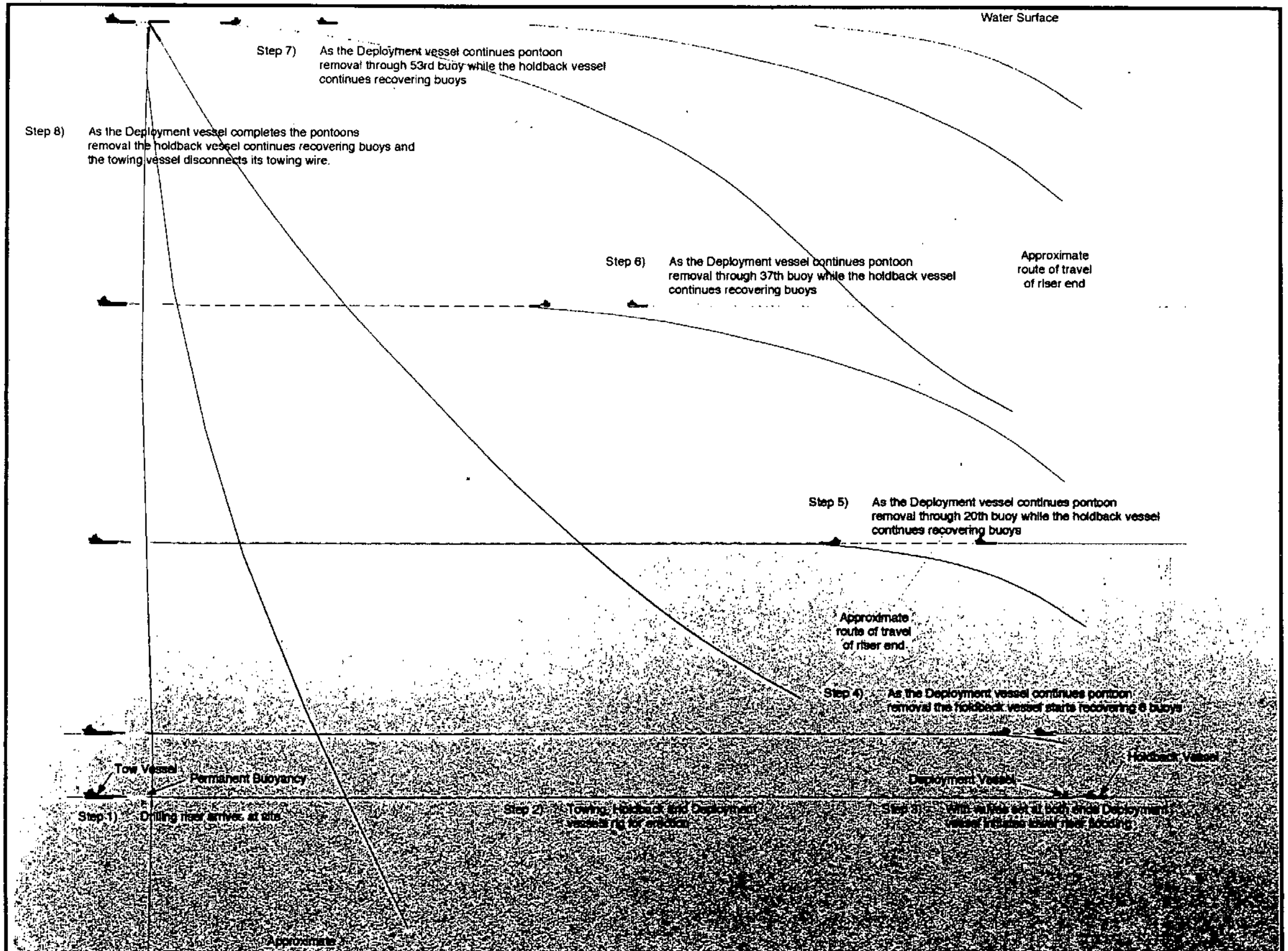


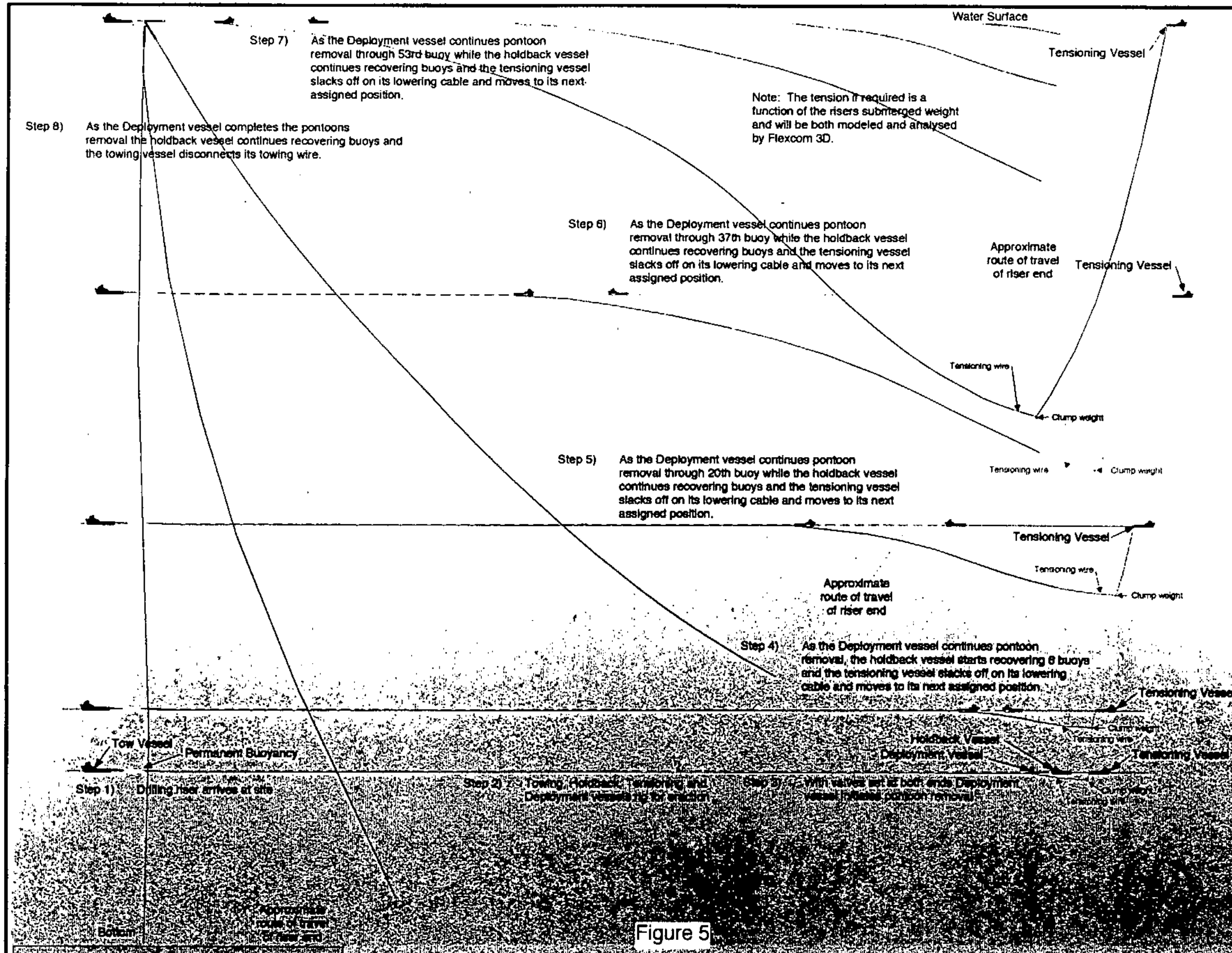
Figure 2

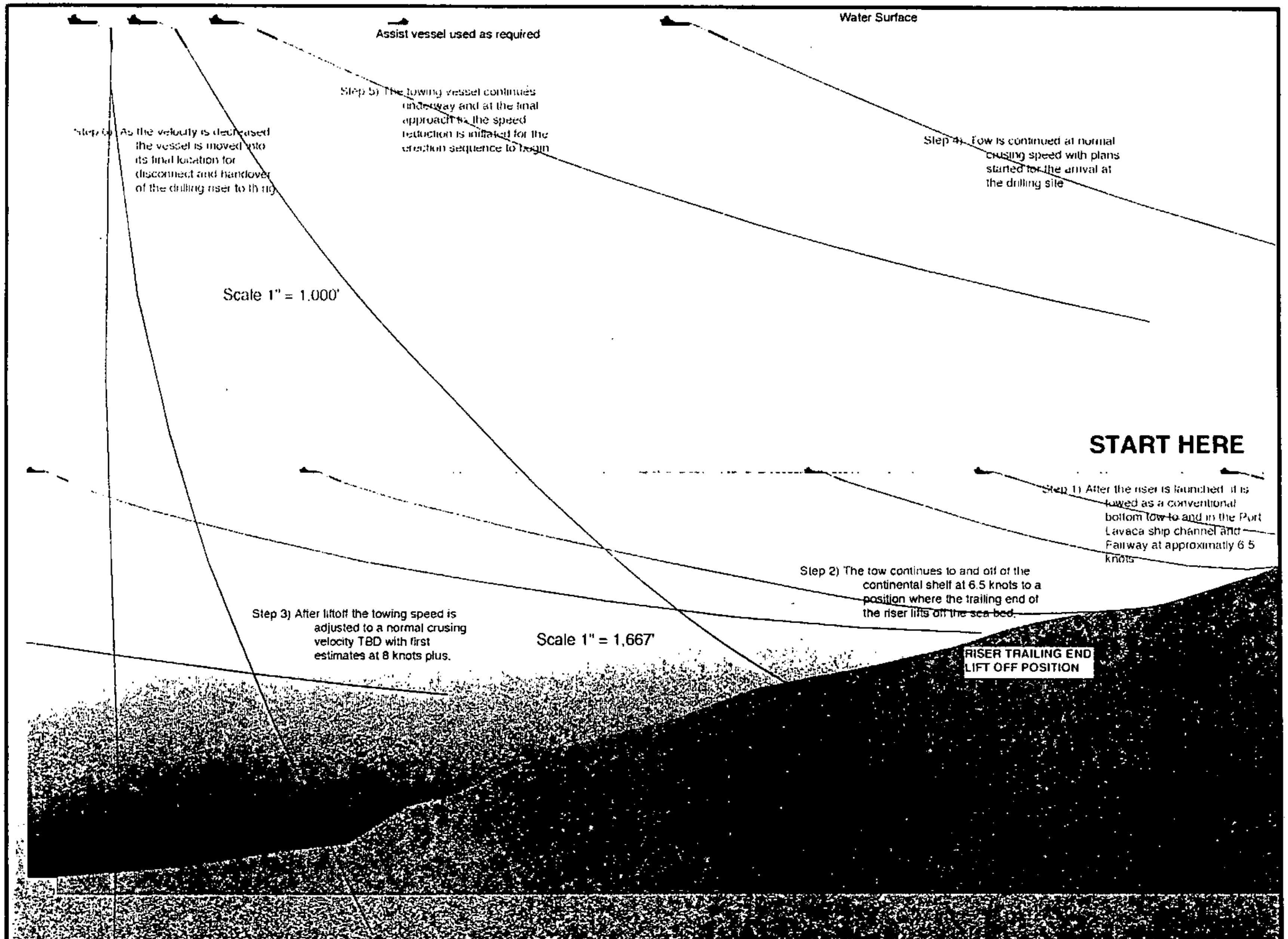


> Casing and utility pipe in air weight = 971 MT
> Permanent buoyancy weight in air ≈ 172 MT
> Net displacement ≈ 1,800 kips
> Tanks pressurized and ballasted as required

Figure 3

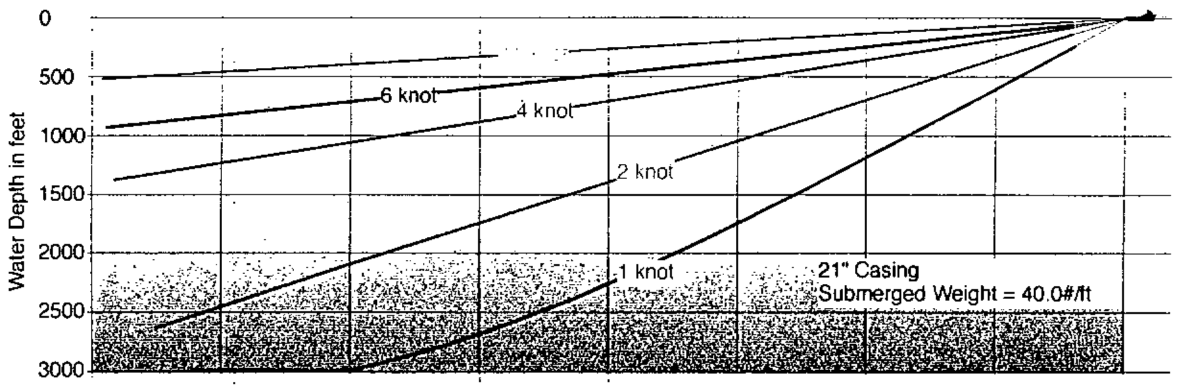

Water Surface
Step 7) As the Deployment vessel continues pontoon removal through 53rd buoy while the holdback vessel continues recovering buoys
Step 8) As the Deployment vessel completes the pontoons removal the holdback vessel continues recovering buoys and the towing vessel disconnects its towing wire.
Step 6) As the Deployment vessel continues pontoon removal through 37th buoy while the holdback vessel continues recovering buoys
Approximate route of travel of riser end
Step 5) As the Deployment vessel continues pontoon removal through 20th buoy while the holdback vessel continues recovering buoys
Approximate route of travel of riser end.
Step 4) As the Deployment vessel continues pontoon removal the holdback vessel starts recovering 6 buoys
Tow Vessel
Permanent Buoyancy
Deployment Vessel
Holdback Vessel
Step 1) Drilling riser arrives at site
Step 2) Towing, Holdback and Deployment vessels rig for erection
Bottom
Approximate route of travel of riser end
Figure 4


Water Surface
Tensioning Vessel
Step 7) As the Deployment vessel continues pontoon removal through 53rd buoy while the holdback vessel continues recovering buoys and the tensioning vessel slacks off on its lowering cable and moves to its next assigned position.
Step 8) As the Deployment vessel completes the pontoons removal the holdback vessel continues recovering buoys and the towing vessel disconnects its towing wire.
Note: The tension if required is a function of the risers submerged weight and will be both modeled and analysed by Flexcom 3D.
Step 6) As the Deployment vessel continues pontoon removal through 37th buoy while the holdback vessel continues recovering buoys and the tensioning vessel slacks off on its lowering cable and moves to its next assigned position.
Approximate route of travel of riser end
Tensioning Vessel
Tensioning wire
Clump weight
Step 5) As the Deployment vessel continues pontoon removal through 20th buoy while the holdback vessel continues recovering buoys and the tensioning vessel slacks off on its lowering cable and moves to its next assigned position.
Tensioning wire
Clump weight
Tensioning Vessel
Tensioning wire
Clump weight
Approximate route of travel of riser end
Step 4) As the Deployment vessel continues pontoon removal, the holdback vessel starts recovering 8 buoys and the tensioning vessel slacks off on its lowering cable and moves to its next assigned position.
Tensioning Vessel
Tow Vessel
Permanent Buoyancy
Holdback Vessel
Deployment Vessel
Tensioning Vessel
Step 1) Drilling riser arrives at site
Step 2) Towing, Holdback, Tensioning and Deployment vessels rig for erection
Step 3) With valves set at both ends Deployment vessel initiates pontoon removal
Bottom
Approximate route of travel of riser end
Figure 5



Water Surface
Assist vessel used as required
Step 6) As the velocity is decreased the vessel is moved into its final location for disconnect and handover of the drilling riser to th rig
Step 5) The towing vessel continues underway and at the final approach to the speed reduction is initiated for the erection sequence to begin
Step 4) Tow is continued at normal crusing speed with plans started for the arrival at the drilling site
Scale 1" = 1,000'
START HERE
Step 1) After the riser is launched it is towed as a conventional bottom tow to and in the Port Lavaca ship channel and Fairway at approximatly 6.5 knots
Step 2) The tow continues to and off of the continental shelf at 6.5 knots to a position where the trailing end of the riser lifts off the sea bed.
Step 3) After liftoff the towing speed is adjusted to a normal crusing velocity TBD with first estimates at 8 knots plus.
Scale 1" = 1,667'
RISER TRAILING END
LIFT OFF POSITION

Figure 6


0
500
1000
1500
2000
2500
3000
Water Depth in feet
6 knot
4 knot
2 knot
1 knot
21" Casing
Submerged Weight = 40.0#/ft

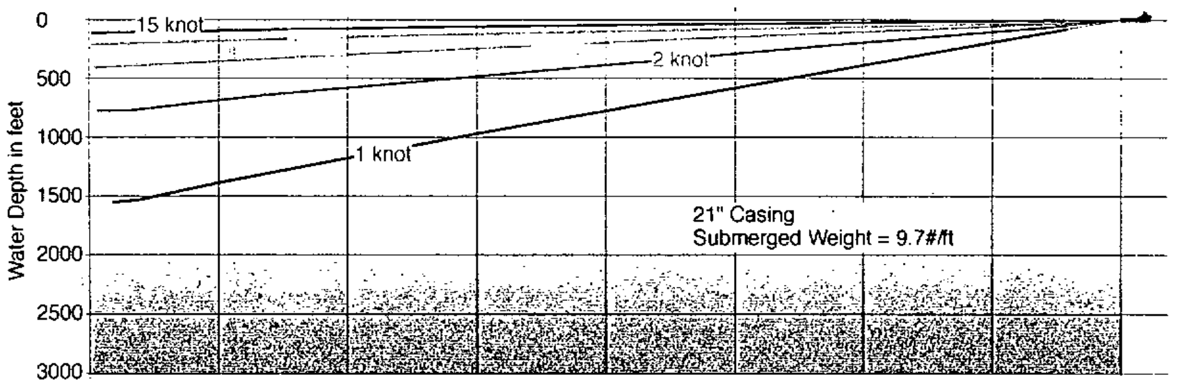

0
500
1000
1500
2000
2500
3000
Water Depth in feet
15 knot
2 knot
1 knot
21" Casing
Submerged Weight = 9.7#/ft

Figure 7

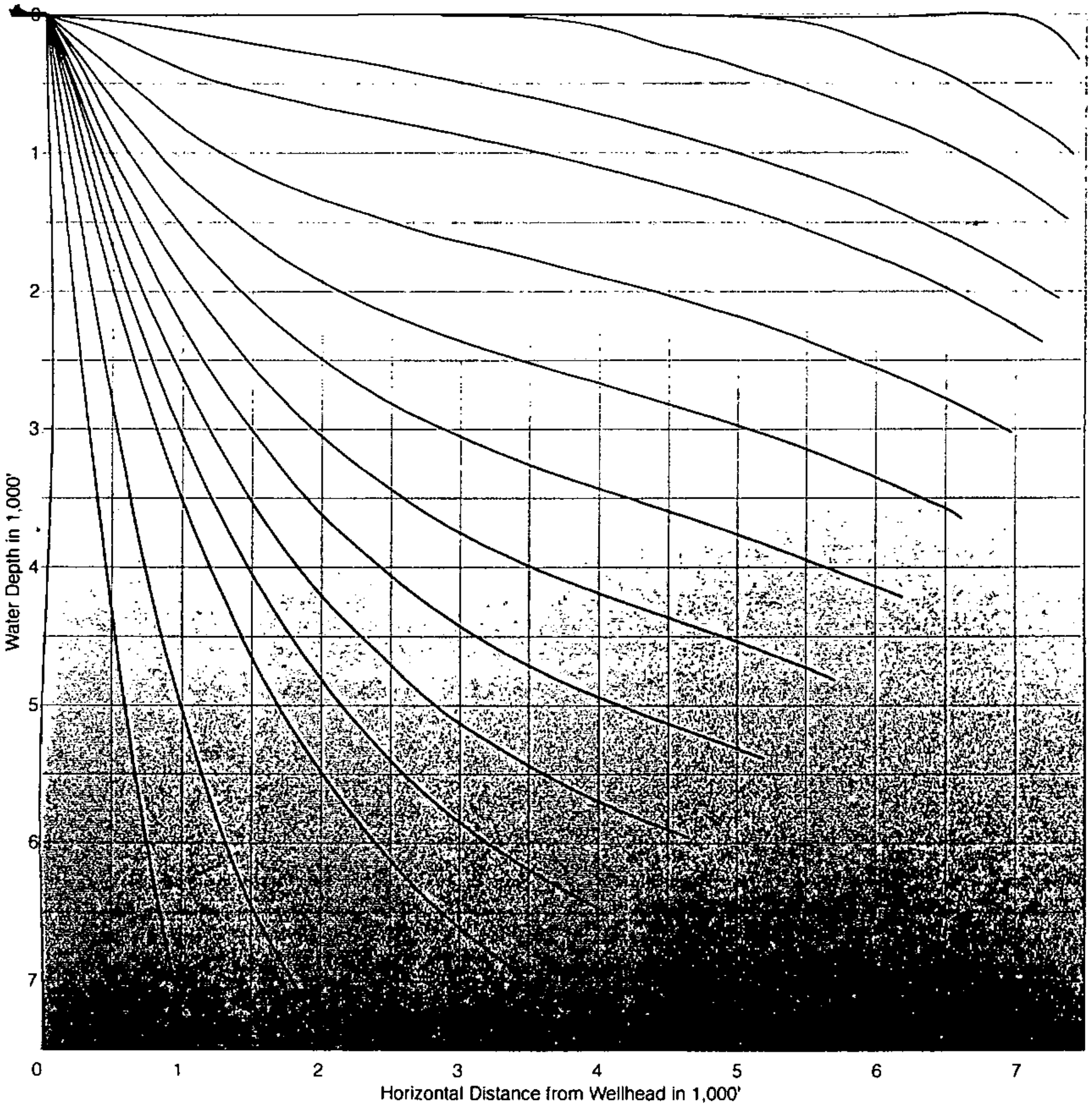

Water Depth in 1,000'
0
1
2
3
4
5
6
7
0
1
2
3
4
5
6
7
Horizontal Distance from Wellhead in 1,000'

Figure 8

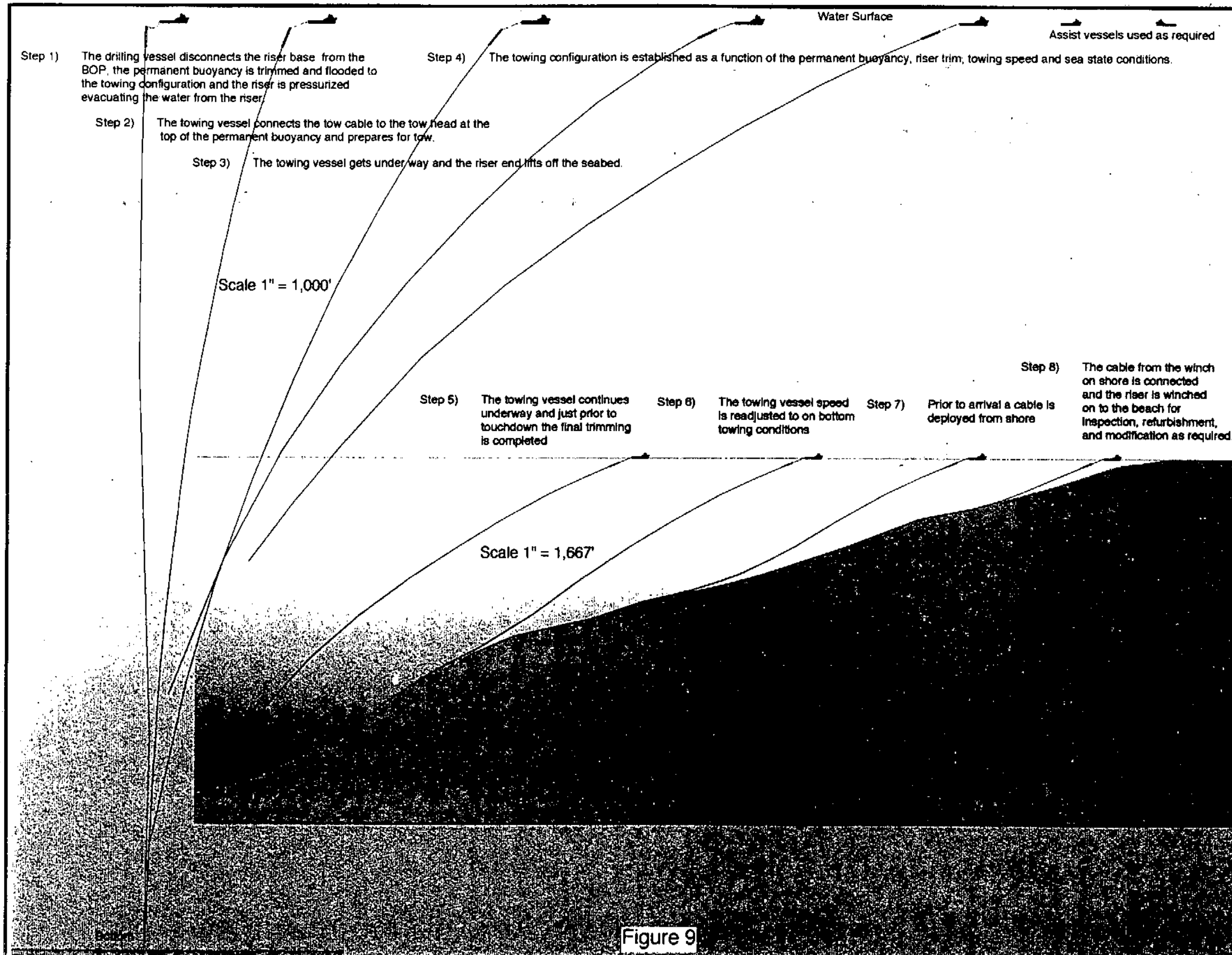

Water Surface
Assist vessels used as required
Step 1) The drilling vessel disconnects the riser base from the BOP, the permanent buoyancy is trimmed and flooded to the towing configuration and the riser is pressurized evacuating the water from the riser.
Step 2) The towing vessel connects the tow cable to the tow head at the top of the permanent buoyancy and prepares for tow.
Step 3) The towing vessel gets under way and the riser end lifts off the seabed.
Step 4) The towing configuration is established as a function of the permanent buoyancy, riser trim, towing speed and sea state conditions.
Scale 1" = 1,000'
Step 5) The towing vessel continues underway and just prior to touchdown the final trimming is completed
Step 6) The towing vessel speed is readjusted to on bottom towing conditions
Step 7) Prior to arrival a cable is deployed from shore
Step 8) The cable from the winch on shore is connected and the riser is winched on to the beach for inspection, refurbishment, and modification as required.
Scale 1" = 1,667'
Bottom

Figure 9

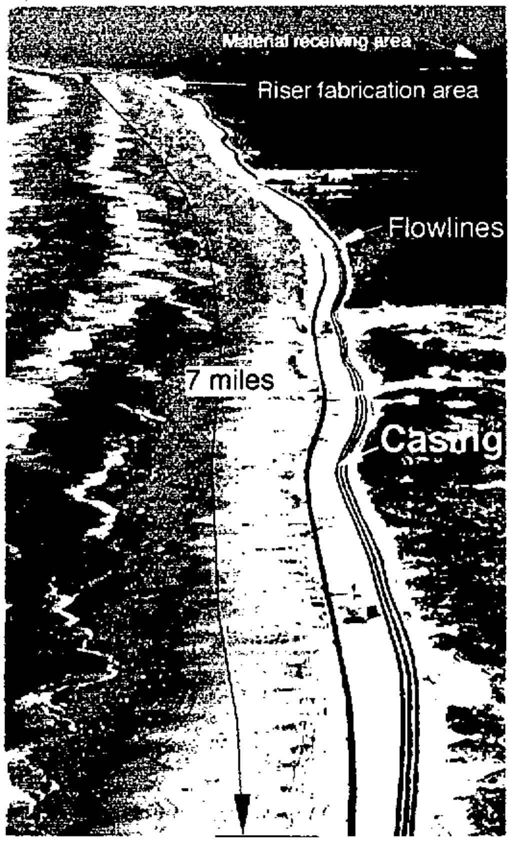


Figure 10

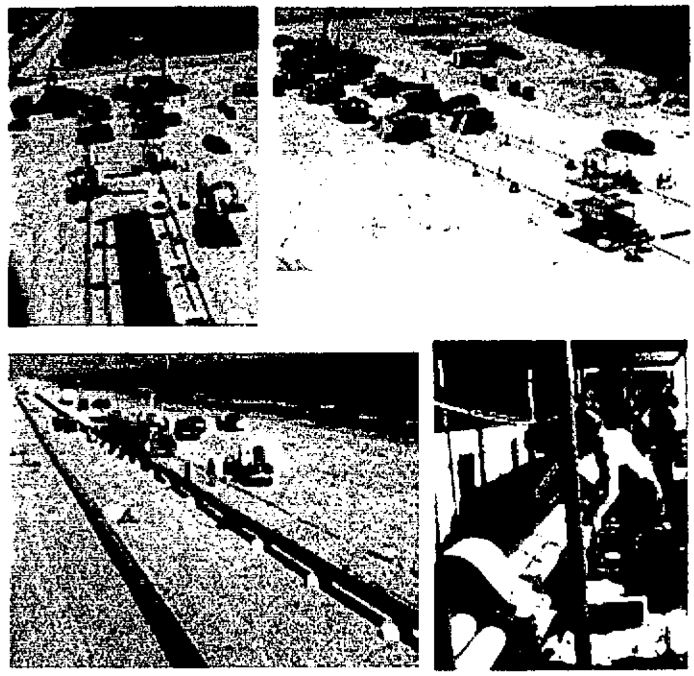


Figure 11

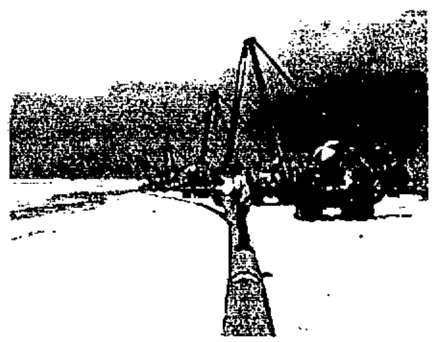


Figure 12

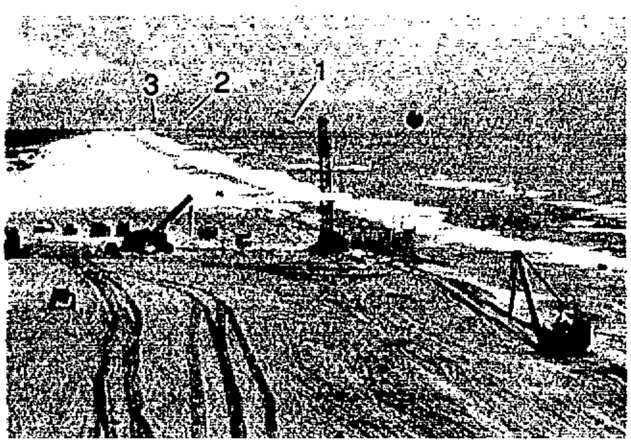


Figure 13

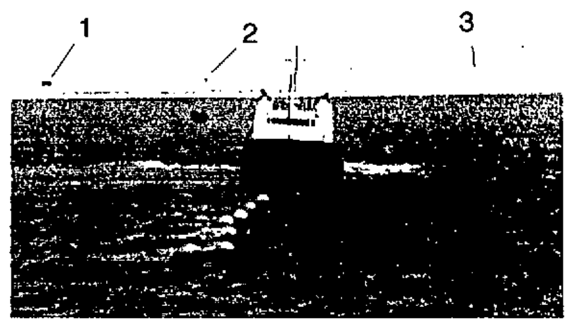


Figure 14

Catenary Riser Interaction with the Seabed at the Touchdown Point

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and
Pipes & Pipelines International

Catenary Riser Interaction with the Seabed at the Touchdown Point

Introduction

A steel or flexible catenary riser offers an attractive and economical way of connecting a deep-water floater or a fixed platform to a seabed pipeline. It is structurally efficient and straightforward to install, and lends itself to clever ways of hooking it to a platform. The riser touches down tangentially on the seabed, and the measures that need to be taken at the touchdown point are minimal.

One concern has been what happens in the soil/riser/water interfaces near the touchdown point. Some calculations suggest that the contact could develop in a such a way that the riser becomes significantly overstressed, particularly if the riser is prevented from lifting (so that it tends to kink near the touchdown point), or if a floater moves sideways (so that the riser is dragged sideways, in a direction transverse to the plane in which it hangs, and again kinks if it is restrained from moving freely).

This paper examines the factors that are likely to govern what happens around the touchdown point. It is primarily qualitative and introductory. Much research remains to be done, particularly in the areas of sediment transport and geotechnics. The pipeline mechanics is better understood.

Qualitative description of Interaction between the pipe and the seabed at the touchdown point

Figure 1 illustrates some of the different cases schematically.

Imagine first a completely flexible pipeline suspended in a stationary catenary between a floating vessel and a rigid horizontal seabed. The touchdown point is not constrained in position: the location of the touchdown point is determined by the interaction between the water depth, the horizontal tension (or the position of the pipe at the surface), and the submerged weight. The pipe reaches the bottom tangentially. Beyond the touchdown point the reaction between the pipeline and the seabed, denoted R per unit length, is equal to the submerged weight w per unit length. Before the touchdown point, the pipe is supported by the tension in the catenary, and there is no contact with the bed. There is no point reaction at the touchdown point. Before the touchdown point, the curvature is the catenary curvature; beyond the touchdown point, the curvature is zero.

Now suppose that the pipe is still completely flexible, but that the bottom is deformable. The indentation of the bottom is determined by the local reaction R per unit length between the pipe and the bottom, and there is some relation between R and the local deflection u, in which u increases as R increases (but not necessarily linearly). At the point where the pipe first reaches the bottom, R is zero and the deflection u is zero. In the region just beyond touchdown, R

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increases towards the submerged weight w, and u increases towards the deflection that corresponds to that submerged weight. The length of the transition region is determined by the local curvature, which is less than the catenary curvature because of the effect of R.

Next suppose instead that the pipe is not completely flexible, but has a linear relationship between bending moment and curvature, governed by a flexural rigidity F, but that the bottom is rigid. In the suspended span away from the touchdown point, the curvature is determined by the interaction between the tension, the submerged weight, and the flexural rigidity, but in deep water the flexural rigidity has only a minor influence. Beyond the touchdown point, the curvature is zero because the pipe is continuously in contact with the bottom, and therefore the bending moment is zero. Close to the touchdown point, there is a transition region within which the bending moment increases from zero at the touchdown point to the catenary curvature further away. At the touchdown point, there is a concentrated reaction from the seabed. Analysis [1] determines the extent of the boundary layer and the reaction at the touchdown point. The concentrated reaction at the touchdown point can be shown to be close to $w\sqrt{F/U}$, where in addition U is the horizontal component of the tension applied at the surface. This load is quite large: if w is 1 kN/m, F is 800 MN m^2 and U is 1 MN (typical values for a large-diameter pipeline), then the concentrated force is 28 kN, almost 3 tonnes, large enough to induce significant deformation of many seabed soils. The boundary layer is analogous to a boundary layer in fluid mechanics: the moment diminishes exponentially as the touchdown point is approach, with a characteristic length $\sqrt{F/U}$ [1], which is 28 m in this instance, small by comparison with the suspended span. The seabed reaction and boundary-layer length are much smaller for flexibles.

Next suppose that the pipe has a finite flexural stiffness and the bottom is deformable. There will now be a transition region on both sides of the touchdown point, caused by a combination of the effects described in the last two paragraphs. The length of the transition region depends both on the pipe flexural rigidity and on the relationship between R and u. Within the transition region, the curvature is less than it is in the free catenary further away. If the relationship between R and u is linear, the curvature can be determined analytically. Pesce [2] analysed that case, and determined the relationship between the pipe and seabed stiffnesses and the inclination of the pipe where it first touches down. Finally, if the seabed response is inelastic, as it normally will be, the additional loads near the touchdown point will press the seabed downward, but the deformation will be almost entirely plastic, and the seabed level under the pipe will not rebound when the loading is reduced.

In the context of pipelaying, it has been recognised for a long time that the additional reactions close to the touchdown point, which make R locally greater than the submerged weight, would create an additional indentation of the seabed. The effect on the pipe has not been of any great concern, because the curvature in the boundary layer is smaller than the curvature in most of the suspended span. The effect is almost certainly beneficial, because the additional reaction presses the pipe further into the bottom, and creates an additional resistance to lateral movement, valuable for stability and in preventing sideways drag movements if the pipe is being laid in a curve.

The small effect on the pipe can be seen in qualitative terms by thinking of pipelaying across a horizontal seabed with a constant relationship between u and R. Elastic deflections are very small indeed, a few mm at most, and so their effects are negligible. Plastic deformations may be larger, but the pipe is still laid horizontally, at a depth below the seabed which depends on the maximum value of R in the transition region. That maximum must be larger than w. As far as the suspended span is concerned, the effect will be as if the pipe were laid on a rigid bottom in very slightly deeper water. It seems reasonable to conclude that the consequences will be negligible unless the bottom is so soft that the pipe can sink in several metres.

The above discussion has been for the static case, which is well understood and can largely be assessed analytically. The same factors arise in the much more complicated corresponding dynamic problem, which arises when the pipe is a catenary riser from a floating system moving in a seaway, or a pipe laid from a laybarge in a rough sea. There will again be a transition region where the detailed effects are determined by the interaction between tension, flexural rigidity, pipe weight, the seabed force-deflection relationship, and (additionally in the dynamic problem) pipe mass, added mass, hydrodynamic forces, and possibly seabed mass and strain-rate effects on the dynamics of the seabed. However, it seems likely that the curvature close to touchdown will still generally be smaller than it is further away: Pesce [2] confirmed this in the elastic case.

A possibility is that though the geotechnical interaction with the seabed is not important as far as its direct effect on the bending stresses in the stresses in the riser is concerned, it is indirectly important because of the additional geotechnical damping it introduces into the system. Geotechnical damping is thought to be a significant factor in moderating oscillations in the related problem of vortex-induced vibration of pipeline spans.

It is helpful first to consider the geotechnical side of the problem in qualitative terms.

Geotechnics

The area of the bottom that the pipe contacts is deformable, and its response may influence the behavior of the pipe in significant ways. It is instructive to consider first a very simple analogy which illustrates the soil behavior to be expected when a riser contacts the seabed.

Think of an area of bare ground, and a person walking in boots. Imagine first that a boot is placed on the ground lightly, and then removed. If the maximum load was very small indeed, no footprint is left behind, because the stresses induced while the boot was in place were so small that the soil response was purely elastic, and therefore reversible when the stresses were removed. We know from everyday experience that this is an extremely unusual case, and that elastic deformations are tiny.

Now imagine that the boot is placed on the ground more heavily. When it is removed, it leaves a footprint. The stresses induced by the boot were large enough to cause plastic deformations, and they were not recovered when the load was removed. In many instances, moreover, the plastic shear deformations lead to changes in pore pressure. In a normally-consolidated or lightly over-consolidated clay or silt, plastic shear induces a immediate increase in pore pressure [3]. The changes in pore pressure induce diffusion of water within the soil, so that the water content of the most heavily deformed regions decreases and their shear strength increases. If, on the other hand, the soil were heavily overconsolidated clay or a dense sand, shear would be accompanied by a decrease in pore pressure, which would tend to suck water into the soil and increase the water content.

Next suppose that the boot is repeatedly placed heavily onto the ground and then replaced. The soil is repeatedly remolded. With time, the soil properties change, and the pore-pressure effects described in the previous paragraph lead to a permanent change in the soil properties. If the boot is not set down in the same place each time, the soil will be plastically deformed in different directions, and the effect will be to churn the soil into a different state: this the effect seen when cattle crowd round a water trough in a muddy field. Turning back to the pipe/seabed problem, deformations produced by repeated loading of the contact between a pipe and the seabed have been shown to have a very large effect on the resistance to lateral motion [4].

Now suppose that the boot is placed on the ground much more heavily, or the ground is very soft. The boot then sinks in a long way, perhaps to the wearer's knee. Gross deflections occur, and change the whole geometry of deformation. In the terms of a geotechnical bearing capacity problem, the geometry changes from a surface footing (boot 100 mm wide on soil with a deflection of 3 mm, say) to a deep footing (boot on soil with a deflection of 300 mm).

Finally, imagine that the ground is under water. If the boot is put down very slowly, say at 1 mm/s, the velocities induced in the water are very small, and they have no effect. If the boot is put down more rapidly, say at 1m/s (the order of magnitude of the velocities involved in rapid walking), then similar velocities are induced in the water. The water is squeezed out of the gap between the boot and the soil as the boot comes down, and sucked back as the boot lifts up. We know from the experience of walking in shallow water on a sandy beach that the velocities are more than enough to move the sand and modify the footprint. This is confirmed by sediment transport analysis (see, for example, Sleath [5]), which shows that the critical velocity which initiates the movement of sand is less than 0.6 m/s for coarse sand (particle diameter 0.8 mm) and less than 0.3 m/s for fine sand (0.2 mm). In cohesionless silt the particles are smaller and the threshold velocity is lower still. Repeated lowering and lifting of a boot pumps water back and forth, and sediment transport rapidly crates a small scour hole quite different from the original footprint. If the soil adheres to the sole of the boot, negative pore pressures may allow tensile stresses to develop, until the soil tears and lifts a clod of soil.

Thought of in the context of repeated lowering and lifting of a pipe at the touchdown point, this appears to be an effective mechanism for moving soil, and perhaps accounts for some of the large embedments seen in some riser projects in the Gulf of Mexico, whose fine-grained bottom sediments and known to be soft and easily transported.

This analogy illustrates some of the points that a realistic model of the soil at the touchdown point ought to incorporate:

1. Elastic deformations are small and reversible, but almost certainly so small as to be negligible (and of little or no interest);

2. Plastic deformations are much larger, but are not recovered when the load is removed (and therefore cannot be represented by elastic springs which return to their original lengths);

3. Large deformations change the geometry of the contact between the pipe and the bottom.

4. Repeated application of a load leads to progressive remolding which alters the soil properties, so that the response to the hundredth application of the load is not the same as the response to the first application;

5. Independently of structural deformation of the soil itself, the pumping action between the pipe and the bottom is potentially an effective mechanism for moving soil and creating a hole under the pipe, and ought to be incorporated in a model.

Many of these factors are factors are significant in many soil-structure interaction problems in offshore engineering. In many problems it is customary to represent the deformation of the soil by a series of "soil springs". In problems such as lateral deflections of piles, this is acceptable, because the most of the pile system is well below mudline in reasonably component soils, and because the system is designed so that the deflections are small and the hypothesis that the response is elastic is not unreasonable. In other instances, the concept is frequently misused, but often in contexts where the deflections are not significant anyway.

In the present problem, however, large deformations might occur, and only large deformations are important. Points such as 2 and 5 become central.

A difficulty is that many programs designed for riser analysis are not well prepared to accept sophisticated models of soil behavior. In particular, models will not always easily accept progressive changes of soil response over time. There is a risk that models that reflect the true behavior of the soil will not be used because they cannot easily be brought into the framework of riser analysis, but it is important to reject the temptation to apply inadequate models of the soil.

Paving

Repeated loading on any soft soil produces deformations and changes that are troublesome in engineering terms. If a vehicle is driven once across soft soil, it may get through, but the soil is remolded and deformed. If the same vehicle is driven over the same ground ten or a hundred times, the soil is almost inevitably rutted and softened to an extent that makes further traffic more difficult. Simultaneous flows of water or air across the soil surface make things worse.

The solution is to pave the soil, in general to provide a somewhat more cohesive and erosion-resistant coating to the upper surface. There is no need for the paving to be rigid, and rigidity may indeed be undesirable. Temporary roads on construction sites are covered with geotextiles, seabeds under pipelines and next to platforms are covered with flexible antiscour mattresses, geotextiles and artificial seaweed (on their own or in combination), roads are paved with lime-stabilised soil, or with bricks or small stones, and so on.

This appears to be the straightforward solution to problems at the seabed contact. There are several options. A mattress such as "Link-lok", composed of hexagonal polyethylene units filled with concrete and tied together with polypropylene rope is flexible but strong, and resists seabed erosion. The edges can be made heavy enough to resist hydrodynamic forces. Very large mattresses can be put together. One mattress constructed and installed for a defense project was some 50 m long and 5 m broad, which in the present context would allow a substantial area of seabed to be paved with one unit. A possibility is to lower and lay out the mattress with the plastic units empty, so that the mattress is roughly neutrally buoyant, and then when it is in its final position to fill the units with concrete.

Acknowledgment

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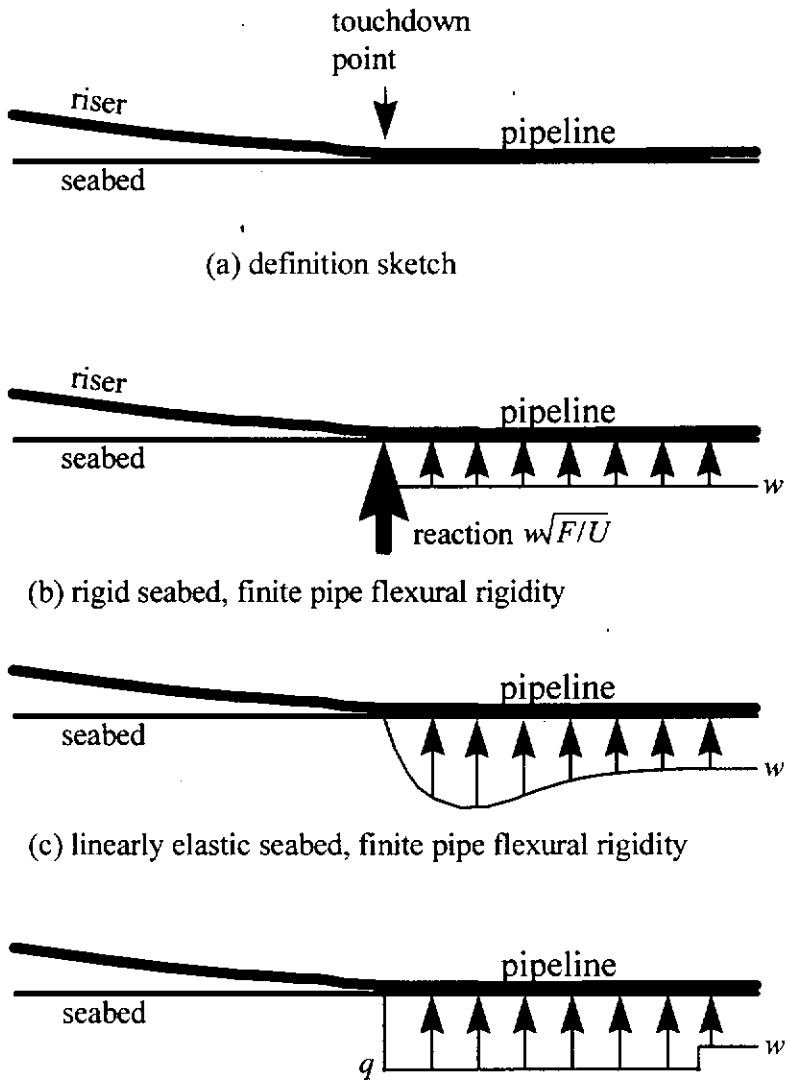

(a) definition sketch

(b) rigid seabed, finite pipe flexural rigidity

(c) linearly elastic seabed, finite pipe flexural rigidity

(d) rigid/plastic seabed, finite pipe flexural rigidity

Figure1 Seabed/pipe contact forces

Ultra Deepwater Production Riser Analysis

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presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

Ultra Deepwater Production Riser Analysis

Summary

Ultra deepwater floating production units will require the use of coupled and uncoupled riser systems to facilitate the conveyance of oil, gas and multiphase fluids.

Design methodology and associated work flow processes have been developed to assist in the systematic assessment of extreme loading, fatigue, vortex induced vibrations and interference. Also, as part of the overall evaluation, installation and abandonment issues must be addressed. This paper not only outlines the design methodology but also develops a classification for appropriate software packages and presents a case study illustration covering a steel catenary riser (SCR) suspended from a Floating Production Unit (FPU). The use of primers is introduced as a simple and fast means of determining a satisfactory riser configuration.

1.0 Introduction

The exploitation of remote ultra deepwater oil and gas reserves will require the use of manned and unmanned floating production units (FPU); typified by semi-submersibles, mono-hull tankers, tension leg platforms and deep draft caissons. As indicated in Figure 1 there are over 200 floating production units either planned or under study; each with its own unique production and export riser system. Characteristically ultra deepwater production risers have been categorized as:

1) Top tensioned; those used with TLPs and DDCVs
2) Free standing; uncoupled configuration for semi-submersibles and FPSOs
3) Highly compliant; coupled compliant and simple catenary designs for all four production units

As would be expected, each riser system is faced with its own set of technical challenges. For example, highly compliant steel catenary riser are subjected to fatigue loading, dynamic bending stresses, interference trenching and vortex induced vibration. The design methodology and work process used in defining the safe operating perimeter for a steel catenary riser system are discussed within the paper.

2.0 Efficient Ultra Deepwater Riser Design Methodology

Deepwater riser technology is still sufficiently new that it is common practice to use prototype design solutions. This presents unique requirements with regard to the capabilities and analytical skills of engineering personnel. Design engineers must have wide experience and need to be flexible with regard to the use of engineering methods and software tools.

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To meet these challenges, a recommended deepwater riser design methodology has been developed that is characterized by:

- Higher efficiency – providing faster and more cost efficient services;
- Increased scope of engineering analyses and design work;
- Specially developed flexible software tools available for specific project work;
- High level Quality Assurance (QA) practice with minimum acceptable levels defined by the ISO 9000 standard.

Recommended methodology flow charts that illustrate this approach are depicted in Figure 2 and Figure 3. The approach shown is flexible, with a wide range of design routes available to accommodate specific project needs. The charts are somewhat self-explanatory and therefore will not be described in detail.

An important issue that is, to some extent, reflected in both Figure 2 and Figure 3 is that throughout the design process important installation and/or manufacturing issues are discussed with specialists. In this way the risk of needing to revise important design choices at later stages is minimized. As an example, the selection of a particular welding process and a corresponding S-N relationship to be used in the fatigue analysis is highlighted. Changes in these selections at a later stage would require extensive modification of earlier designs and repetitions of dynamic analyses. Accordingly, the manufacturers are consulted very early and the dialogue maintained throughout the design process. In order to note this early consultation process, relevant links on the flow charts are shown in blue.

2.1 Classification of Engineering Tools

Software tools are classified in three levels and accordingly a particular class of tool is selected for use based on specific requirements. Lower level tools are the fastest, use the simplest engineering models and tend to be used more in initial design stages or in stages that do not require the utmost levels of accuracy. This classification can be best illustrated using examples pertaining to ultra deepwater riser engineering:

- **Class 1** – tools using simple or approximate models and mathematical techniques. For example, in Steel Catenary Riser (SCR) engineering the use of simple catenary equations, which disregard bending stiffness, would be generally acceptable at this level.

- **Class 2** - complex tools that use acceptable model simplifications in order to optimize the efficiency of the design process. For example, the tensioned riser frequency domain program DERP, based on linearized one degree of freedom models for fast and extensive dynamic computations. Other examples would include the use of the familiar flexible pipe programs FLEXCOM 3-D or ORCAFLEX for dynamic modeling of rigid pipe risers.

- **Class 3** – highest level of accuracy tools, such as Finite Element (FE) general application programs ABAQUS/Explicit, ABAQUS/Standard, ANSYS, etc. that allow the modeling of riser components with a high degree of accuracy. This high degree of accuracy might imply a need to use more engineering time than that necessary for use with lower Class programs.

JP Kenny's SIMULATOR (Ref. 5) suite of pre/post-processor interfaces to ANSYS would be classified as a Class 3 tool. However, the engineering time involved in modeling complex non-linear problems with SIMULATOR is actually comparable with that required for using Class 2 or Class 1 tools, not Class 3.

In addition to the above, there is a database of validated design and code check worksheets or spreadsheets that facilitate simple calculations, design and code check tasks.

2.2 Deepwater Riser Software Primers

The name of primers is given to Class 1 design tools that perform relatively complex engineering tasks. The primers use typically one or several familiar interface tools, like for example MathCad or/and Microsoft Excel. Electronic data transfer between an interface and a computation engine is typically used. The engineering primers are modular, fast and can be flexibly molded to a wide variety of engineering needs. This, together with numerical results, allows numerical checks to be performed even without access to the solution engines used.

Figures 4 through 10 summarize the present scope of deepwater riser engineering covered by the primers. New primers are continuously being added to the software suite.

A brief understanding of the rationale behind the development and the use of the primers follows. This is necessary in order to demonstrate the specifics of the approach adopted in spite of the fact that commercially available sophisticated engineering tools are relatively inexpensive and widely available.

The main reason for using the primers is their power. The methods used are simple, there is easy access to the code and the primers are modular so that they can be either used as they are or can quickly be modified to carry out different work. Primers list computed values, include extensive plots and provide closed form equations for computing the loads and stresses. Primers use the same stress definitions provided by codes, rather than some similar definitions that cannot be modified. The results are displayed on the same computer screen of a MathCad or Excel file, therefore there is no need to scroll between different pages of input and output interfaces of commercial programs. The need of looking for results in lengthy tables, etc. is avoided and electronic transfer of data between different primer modules is designed or modified once, rather than done manually or with a mouse at each design iteration. All this results in significant time saving and in streamlining the design process. In addition to this, any modification of riser geometry modifies geometry plots for all design loadcases the engineer needs to review at a particular time. The same happens with regard to all the stresses and stress component plots. Commercial software usually provides only subsets of information needed and the remaining information requires manual postprocessing. Commercial programs tend to look at one load case at a time, that implies time consuming repetitions of lengthy scrolling, reading, writing and comparing all the important parameters separately for each load case.

Most of the above listed advantages of the primers over even the most user friendly commercial programs apply even in simple cases. Primer is quickly molded to an exact need on a simple level, while commercial programmers have wider needs in mind. Another set of advantages comes to play where a task cannot be performed simply by a program and a useful primer can be easily written with the advantage of reuse of most or all of the existing modules.

The primers are used in the preliminary design stage (Figure 2), for installation engineering, and to a limited extent for low frequency motion fatigue analyses (Figure 3).

Using simple methods in riser installation engineering is an established practice. For example, it is common practice to disregard bending stiffness for SCR installations in deepwater. The difference between these primers and other tools is that the code can be easily modified to model any piece of installation equipment. This includes cranes, winches, fair leads, connections, etc. In the latter cases, tools are written as black boxes and code modifications are consequently not so straightforward. This gives the primer approach several important advantages, namely:

- Shorter execution time
- More flexibility
- Option to use existing primer modules or to replace some of them with commercial programs, for example FE programs. In this case primer modules are used as custom made pre- and post-processors capable of performing more complex tasks
- Streamlining QA checks of FE or similar work – in most cases validated benchmark tools already exists

All the above translates to improvements in the quality of engineering provided and also to direct commercial advantages for the Client.

2.3 Design of Deepwater Risers

The flow chart of a typical design process is shown on Figure 3. As already mentioned, the design process has been streamlined with the use of the primers, wherever their accuracy is sufficient.

In performing the dynamic analyses the speed of the frequency domain approach is used, whenever acceptable. For tensioned risers this approach is common, because programs such as DERP are commercially available. With regard to SCRs the situation is different. Some companies use their own software because at this moment no program is commercially available. One such example is TIARA, a proprietary software program developed in house by Shell Oil Company. Additionally, ABAQUS can be used with a general application pre-processor, which is at present in an advanced stage of development for frequency domain analyses. The pre-processor allows the carrying out dynamic analyses of linearized models of riser systems, including Steel Catenary Risers. Because of the capabilities of ABAQUS, the pre-processor allows for the inclusion of torsion in the models, which increases the accuracy for risers subject to three dimensional loading. Another feature of the pre-processor is the capability for linearized modeling in the riser touch down area. This is a step forward in comparison with providing the riser with a pinned or fixed end, which is the common approach.

The capability to carry out a significant portion of the dynamic analyses in the frequency domain is a big advantage when considering the amount of computer time that is saved. Large numbers of dynamic loadcases can be combined together in a single computer run. It is also natural to combine this analysis with fatigue computations using a fatigue postprocessor.

Typically, limited time domain runs would be performed in order to validate the linearized model. Additional time domain computations would be carried out on a smaller, faster running riser model to correctly evaluate the effects of non-linearities. The combined analysis time is thus significantly shorter than in a case where all dynamic modeling is performed in the time domain, such as when flexible line programs FLEXCOM3-D or ORCAFLEX are used for the analyses of SCRs.

3.0 Example Primer Plots

Features of the primers are reviewed in Figures 4 through 10. Examples of the kinds of output generated by primer tools are included on Figures 11 through 20.

Figures 11 through 13 illustrate steps of installation of SCRs. The equipment geometry plotted is accurate, the risers and handling wires shown are real catenaries. Water depths and horizontal distances shown are expressed in meters. Figure 13 is a zoom-in of Figure 12 that was obtained by changing range selections on the axes and manually scaling the graph, so that the horizontal and vertical scales are equal. Plots that have been accepted by Clients as substitutes for electronic drafting have the following advantages:

- Savings in drafting time
- Simplified illustration
- More accurate representation of geometry
- Speed in confirming feasibility of the geometry of the design
- Plots are useful in presenting the work, plots and pseudo-animations are generated as a byproduct of the engineering process
- Excel plots and PowerPoint animation files are familiar and portable

For clearer presentation the natural scale was used in the plot for depicting the FPSO and inflated scale for the support vessels. The shapes of the vessels are deliberately schematic. In case a need arises, crane arms, winches, etc. can be also represented in the analyses and on plots with a higher degree of accuracy.

Figure 14 shows a plot of effective tensions in flowlines of a deepwater riser tower designed for operating in a water depth of 8,200 ft. The flowlines use bulkheads at intermediate depths and there is no central member in the tower, thus reducing the weight and the size of buoyancy. In a more typical design greater buoyancy is required in order to tension the central member as well as carry the weight of the central member. The flowlines are arranged such that the wall tensions in the flowlines are symmetrical and the bending stiffness of the tower is the same in all directions.

Figure 15 shows the primer computed shape of the transverse oscillation mode 8 of a tensioned riser. The riser has two segments that differ in weight and bending stiffness. Effective tension varies along the length of the riser.

Figure 16 is a sketch showing values used in primer to illustrate initial dimensioning of the base and keel stress joints of a DDCV platform riser.

4.0 A Specific Example – Floater Low Frequency Motions and Fatigue Load on a Steel Catenary Riser

Floating Production Systems are subject to several classes of motions that generate dynamic stresses in deepwater riser systems. In particular, low frequency vessel motions can result in time variable stressing in the touch down zones of Steel Catenary Risers (SCR). Low frequency motions are induced by wave drift forces and by wind gusts that are capable of causing relatively high fatigue damage.

The design of simple configuration SCRs can be particularly critical in this context. In this case there exists a straightforward functional relationship between the amplitude of the motions of the vessel in the design deployment plane of the riser and the combined bending and axial stress cycling in the riser (Figure 19). Low frequency vessel motions typically have periods of the order of a few hundreds seconds, dynamic forces are small and can be ignored. It is thus acceptable to base this part of the fatigue analysis on static loads in the risers.

Several existing modules described in Ref. 1 were combined into a module computing stress ranges at all riser locations for a scenario wherein the riser top moves between arbitrary locations within its footprint of motions. By combining several calculations of stress ranges between extreme locations there is a comprehensive assessment of longitudinal stresses in the riser during low frequency motions. A combined example plot obtained in this way is shown on Figure 17. By reading the data shown in Figure 17 into an Excel spreadsheet and adding S-N curve equations to the spreadsheet a new primer was written that was capable of carrying out fatigue analysis due to low frequency motions. On Figures 17 through 20 labels related to low frequency motion amplitudes are expressed in feet and as percentage of the water depth (WD = 3281ft (1000m)).

Generating the new primer and carrying out the analysis for the first time took less than half a day. Obviously, the primer was rather simplistic because it did not include bending stiffness of the riser. Accordingly, it was also provided with the capability of accepting data from FE programs. Figure 18 shows a plot of corresponding data with stresses computed by ORCAFLEX. Note the reduction in the stress ranges caused by including the bending stiffness in the model in comparison with Figure 17. Modeling a softer seabed in ORCAFLEX would have enhanced this effect even more. It was noted that it took less engineering time to generate the original primer and obtain the first, simple set of data than to redo the same analysis using ORCAFLEX. A brief summary of capabilities of this new primer is listed on Figure 7.

Figures 19 helps to determine the maximum acceptable number of low frequency cycles as a function of the motion amplitude. The result is presented in Figure 20. In order to complete this part of the fatigue analysis, the probability densities of the motion amplitudes (also included in the primer) need accounting.

It can be seen from Figure 20 that the design of a 14-inch SCR would be acceptable to the API RP2A Code with regard to low frequency FPSO motion fatigue. However, it must be noted that the allowable number of cycles N plotted on Figure 20 was determined with no design factor (normally taken as 10) and that the Stress Concentration Factor (SCF) used is SCF = 1.0. In addition to these, the wall thickness used in this example was unusually high. The large wall thickness was selected deliberately above the standard API wall thickness range. Had this wall thickness been smaller, or the riser outside diameter larger, the acceptability of the design would have depended on the frequencies of occurrence of low frequency motion amplitudes together with fatigue damage caused by wave induced stress cycling.

It was also noted that the bending stiffness is important in the lower end of the riser top motion amplitudes. For higher motion amplitudes, a fairly accurate riser life prediction can be made on the basis of ideal catenary calculations.

The primer can be used both for assessing the fatigue due to wave drift forces and the fatigue due to motions of the vessel in wind gusts. In both cases the vessel will be moving around some equilibrium location where motion amplitudes could be considerable even in a moderate wind and wave. In known wind and wave climate the overall fatigue usage at any location on the riser can be assessed with the tool described.

The above analyses demonstrate the importance of mooring system characteristics on the fatigue life of SCRs. As shown in Figure 20, the fatigue damage can be reduced by using a hard mooring system whereas softer characteristics allow the touch down zone to be spread over a longer segment of the riser, which could help to increase the life expectancy. For softer mooring system characteristics or in a more severe climate low frequency motions of the riser top might conceivably exceed the amplitudes covered on Figures 17 through 20. In such cases the maximum stress ranges would occur at the right end of the touchdown zone depicted in the Figures and would be higher than the stress ranges represented. This pertains to the second family of peaks in Figure 18, at the horizontal coordinates close to 2000 ft. For motion amplitudes exceeding 5% of the water depth the peaks in this family grow and exceed the higher peaks shown in Figure 18. Again, this could be modeled by the simple primer using an ideal catenary (Figure 17).

The design for fatigue would thus involve optimization of both the mooring system and the risers. On offshore fields where the weather might cause problems with low frequency motion fatigue, the economics might make the mooring system the primary target for optimization. This is not new in deepwater riser technology; catenary mooring lines have already been installed on TLPs to reduce stress cycling in the SCR touch down area. At this moment no SCRs have been installed on FPSOs, but development projects are well under way. Design of SCRs for an FPSO is more demanding than that for a TLP. Vessel motion printouts tend to be larger and even in locations with very mild and predictable wave conditions like that of West Africa, low frequency vessel motions in wind gusts may have considerably greater amplitudes than those due to wave drift forces (see Figure 20). It is conceivable that new design solutions might become economical. For example, by analogy with frame structures that are stiffened with brace members, one could imagine mooring systems that use branch line connections in order to modify their characteristics in deepwater. A whole class of such solutions is presented in Ref. 6.

Acknowledgement

The authors wish to express their thanks to Mr. Colin McKinnon for originating the development of deepwater riser primers and to Mr. Khosro Nekonam and Mr. Uwa Eigbe for developing primers in the U.K. and for their help in validating the software solution developed by JP Kenny, Inc.

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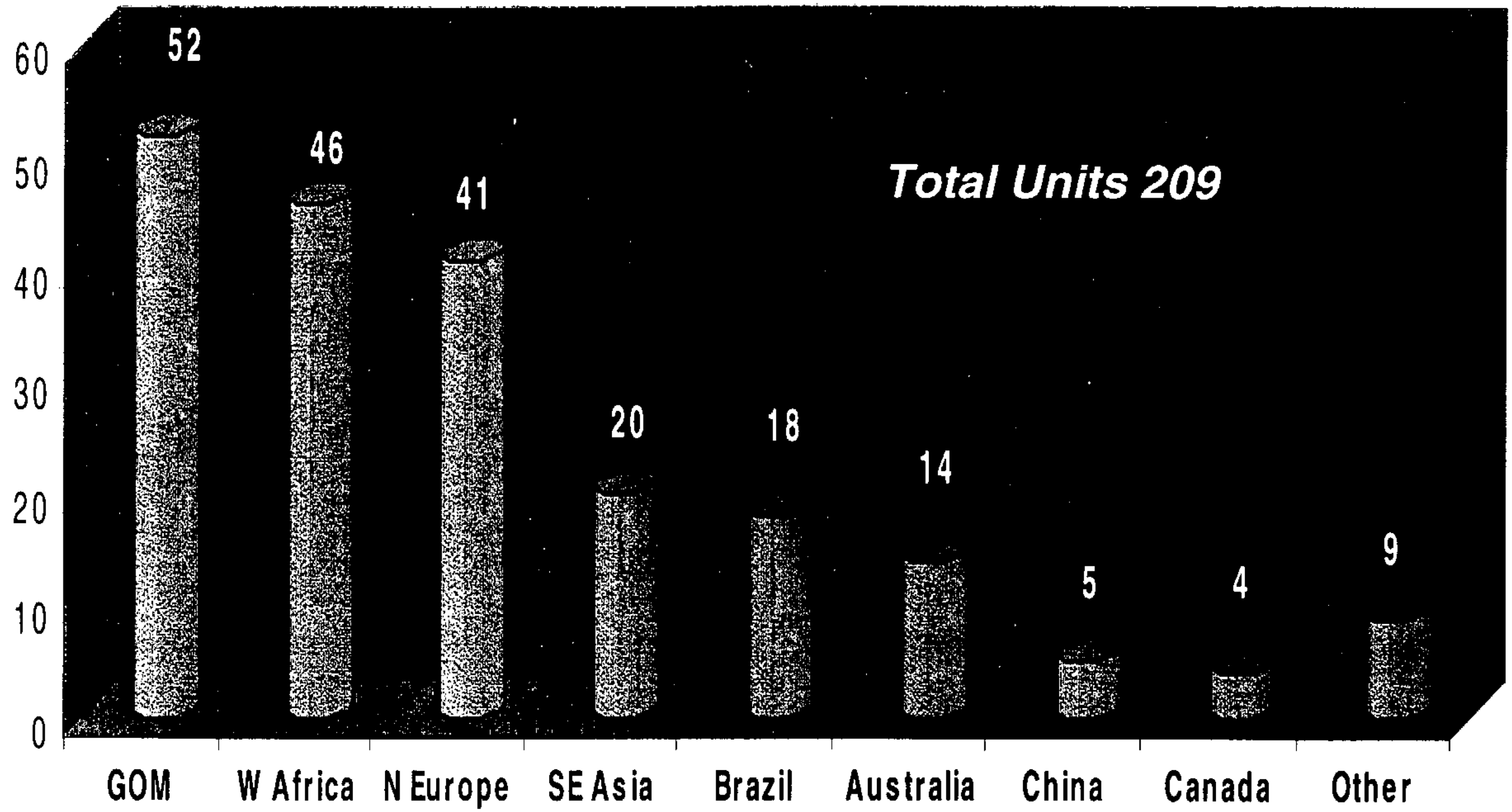

(Source: International Maritime Associates 8/99)

Figure 1 - Worldwide Floating Production Systems Planned Or Under Study

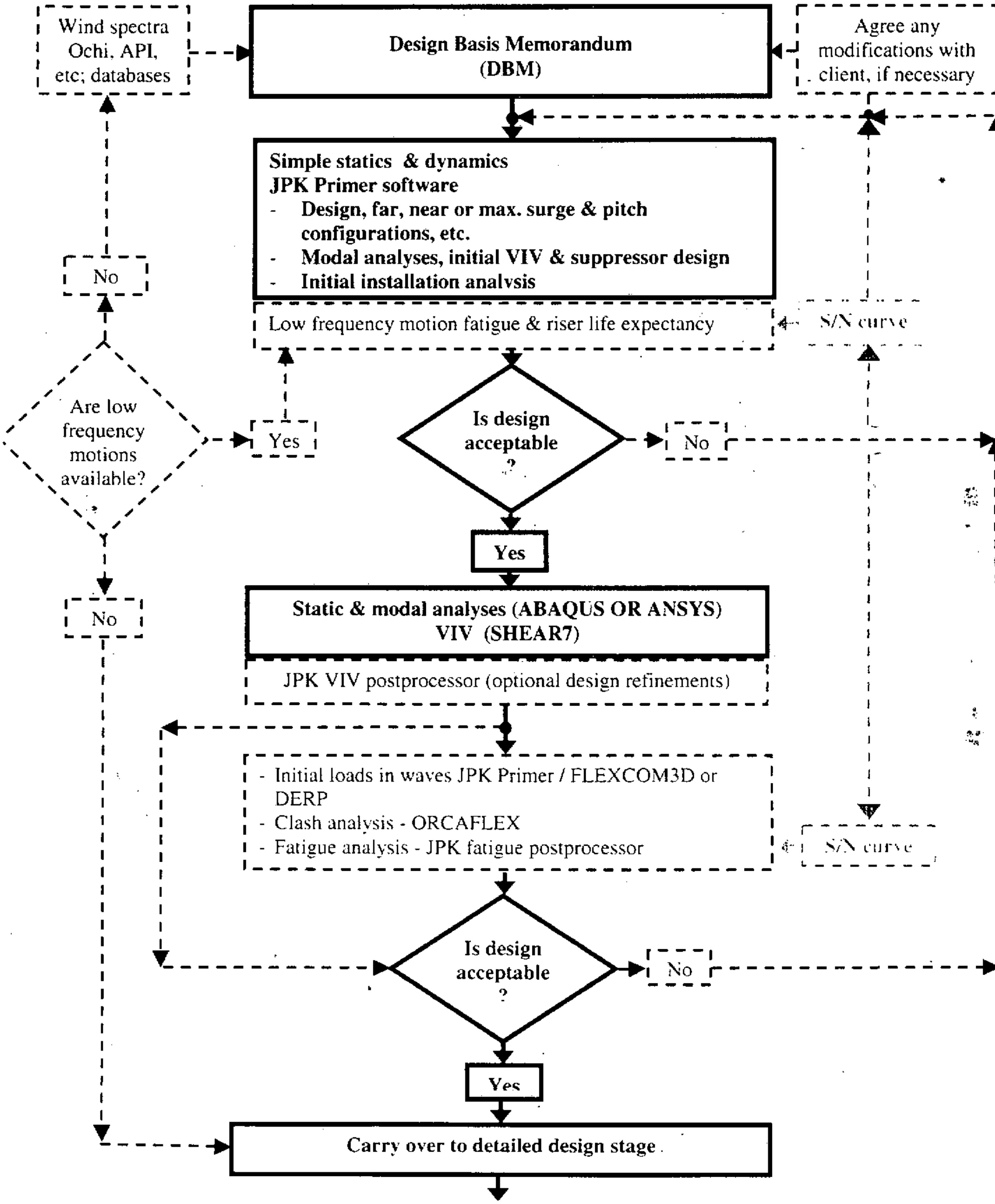

Figure 2. Approach to Preliminary Deepwater Riser Design

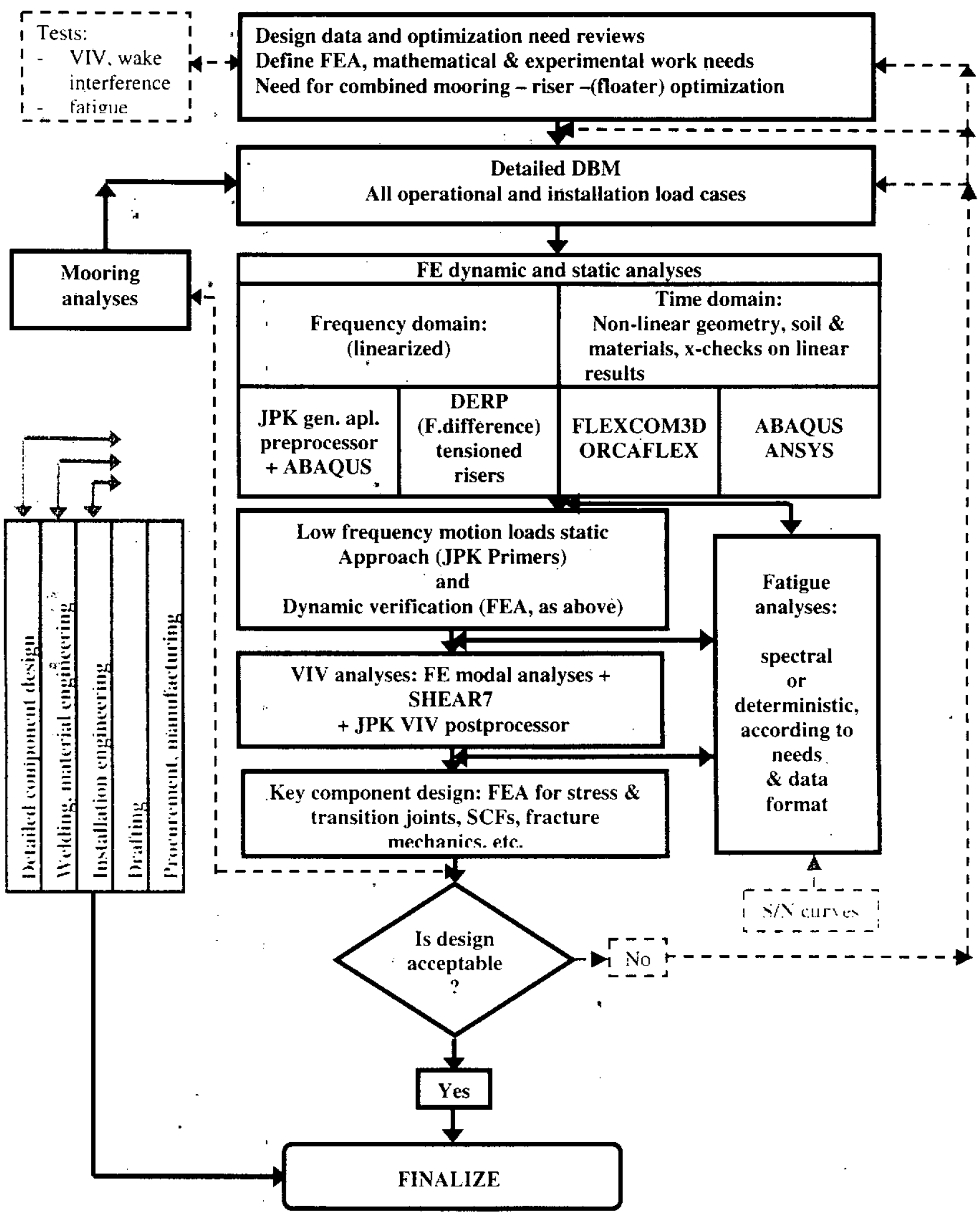

Figure 3. Detailed Deepwater Riser Design

Deepwater Riser Configurations

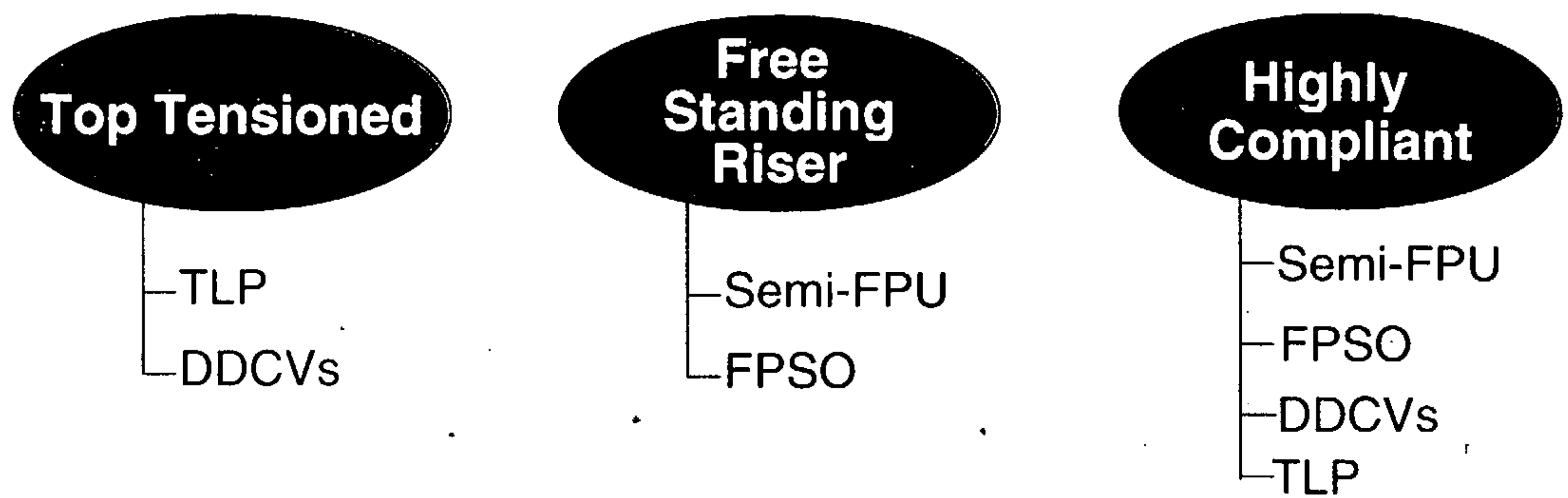

Figure 4: Software Primers For Deepwater Risers

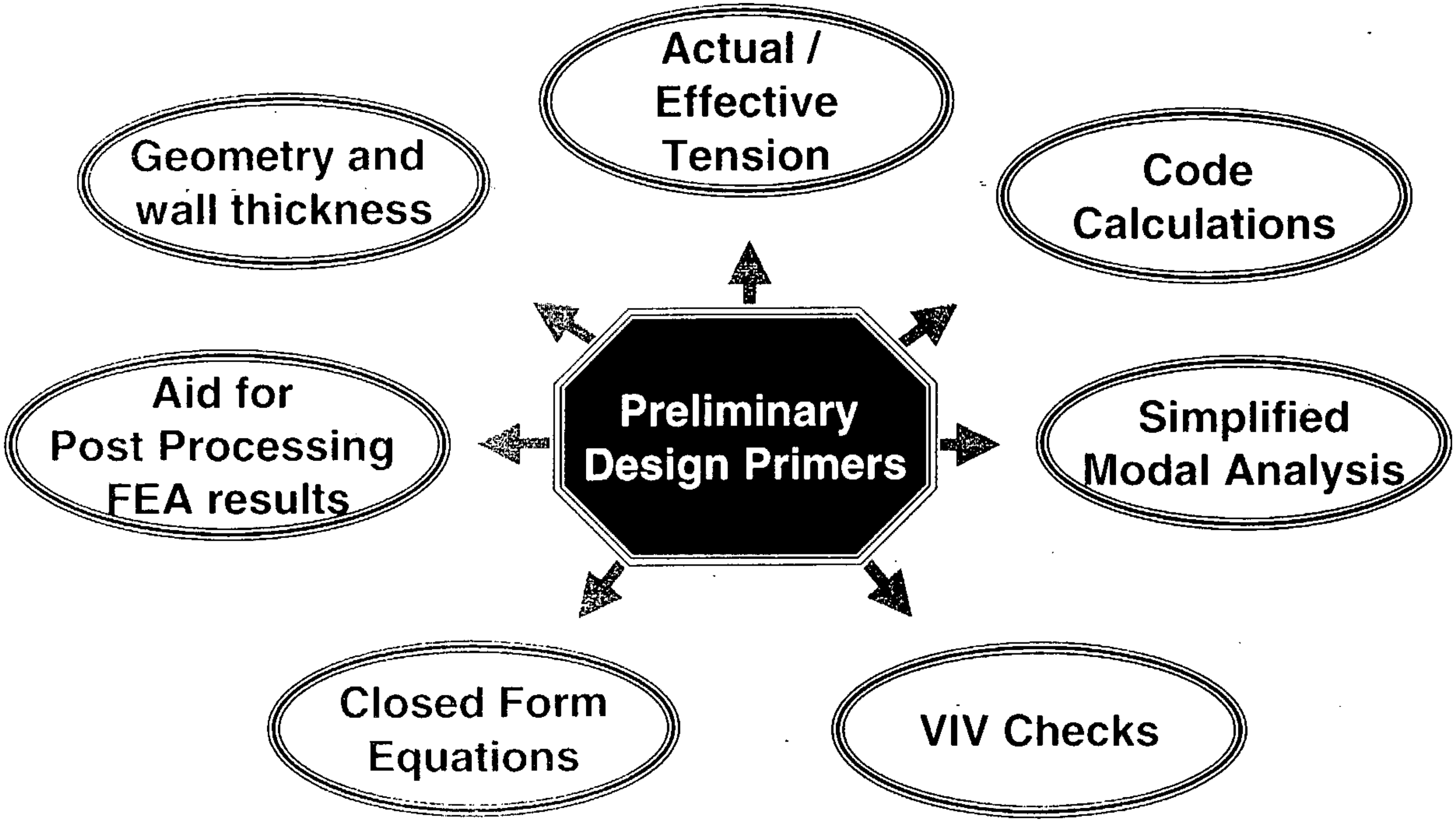

Figure 5 – Scope Of Coverage For Preliminary Design

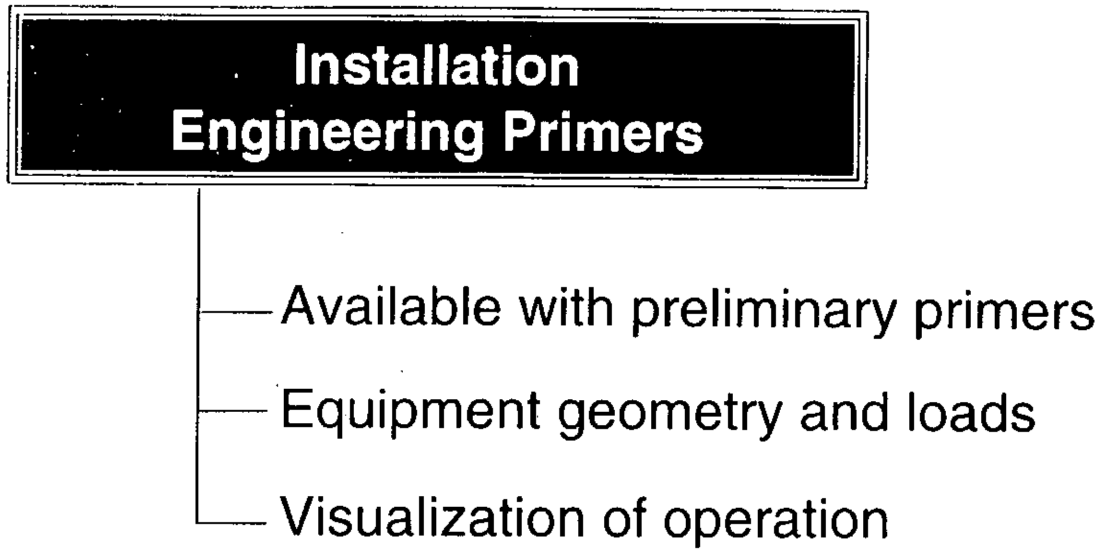

Figure 6 – Attributes Of Installation Primers

Fatigue Analyses Primers

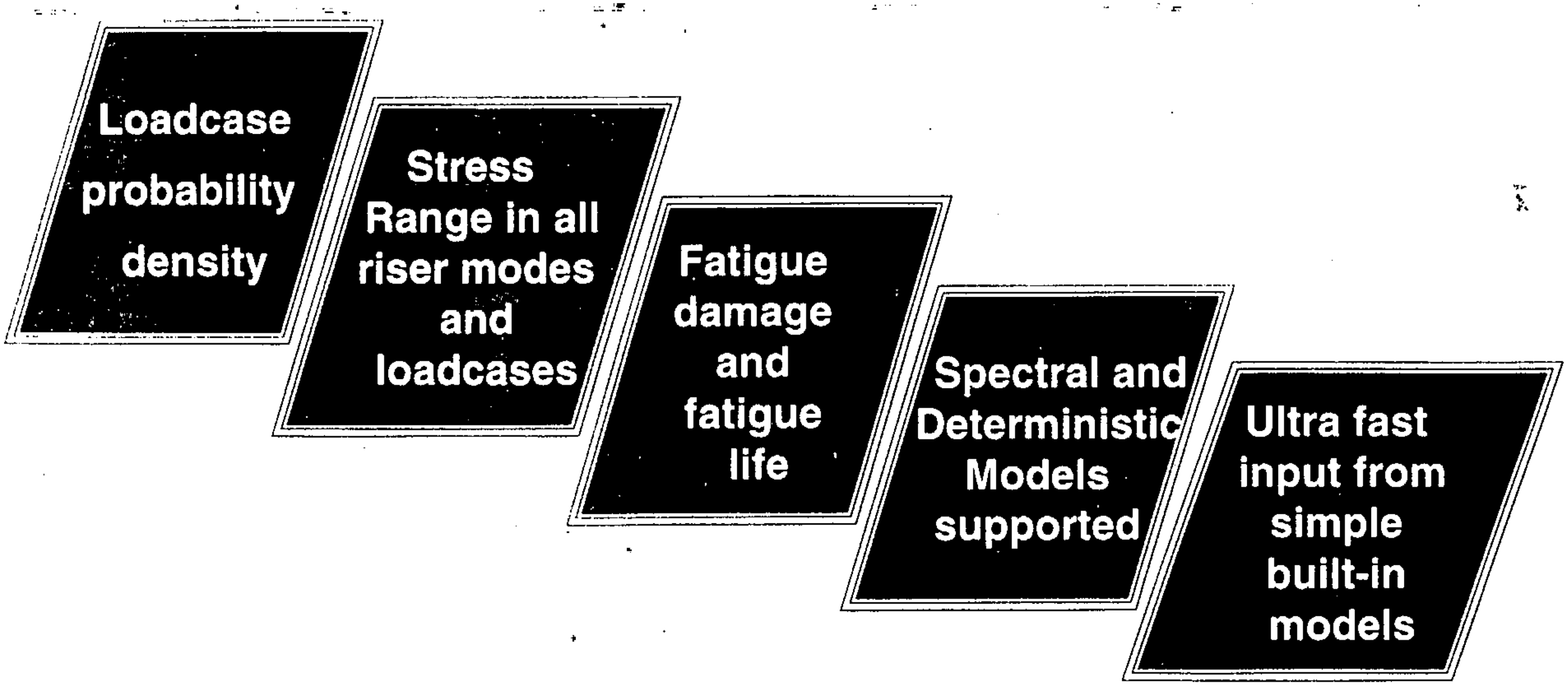

Figure 7 – Characteristics Of Fatigue Analysis Primers

- Non-linear dynamic simulation, 1 through 5 D
- User defined or database force coefficients
- Constant or variable current direction
- Independently variable wind direction
- Ochi, API or user defined gust spectrum
- Non-linear or linearized mooring (spring)
- Time domain & spectral output of motions (surge, sway, yaw or pitch), velocities & accelerations at any riser location.

Figure 8 – Floater Low Frequency Motions In Wind Gusts

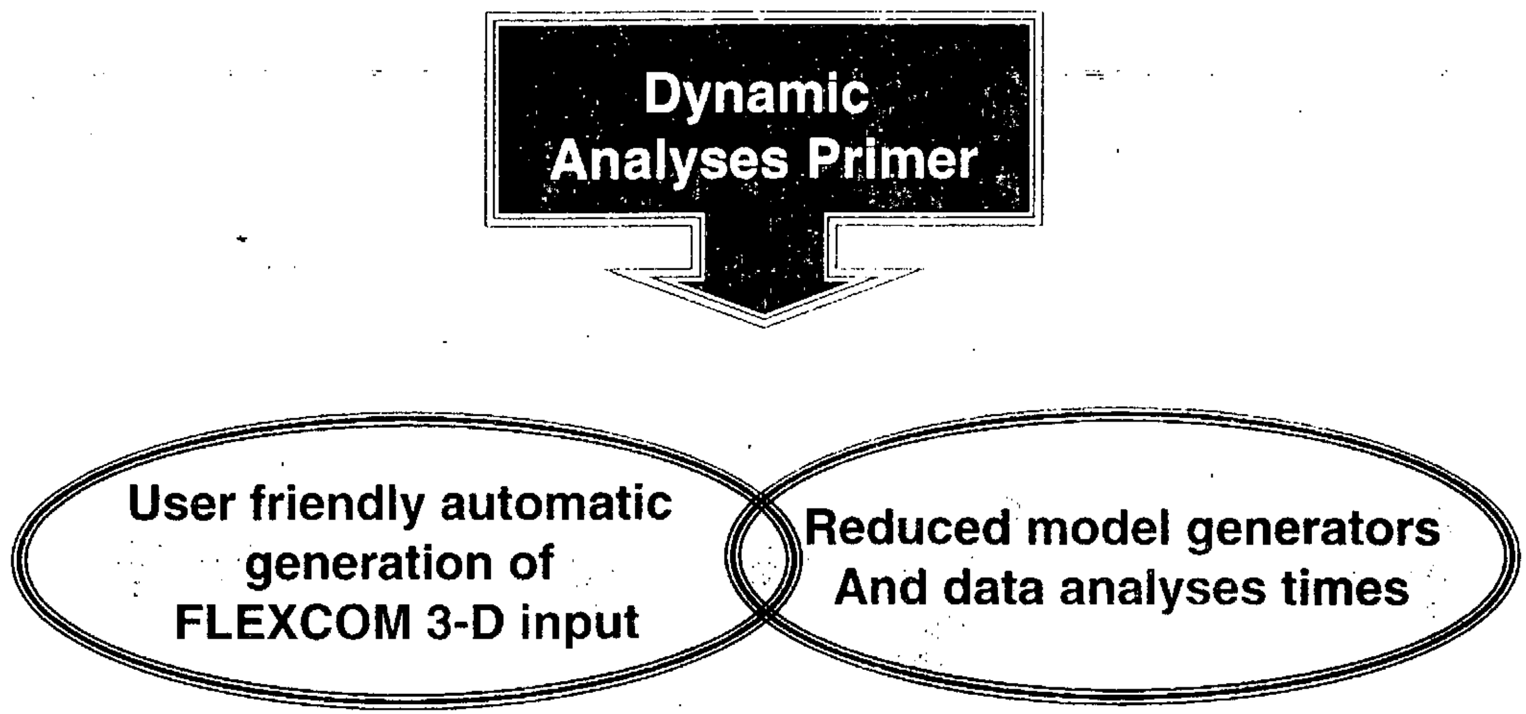

Figure 9 – Aspects Of Dynamic Analyses Primer

FEA Static & Modal Analyses SIMULATOR

- **ASCII format automatic pre/post-processors to ANSYS program**
- **Fully non-linear static models of simple configuration and lazy wave SCRs Modal Analyses**
- **Dynamic modules under development**

Figure 10 – Characteristics Of Static And Modal Analyses Using Simulator

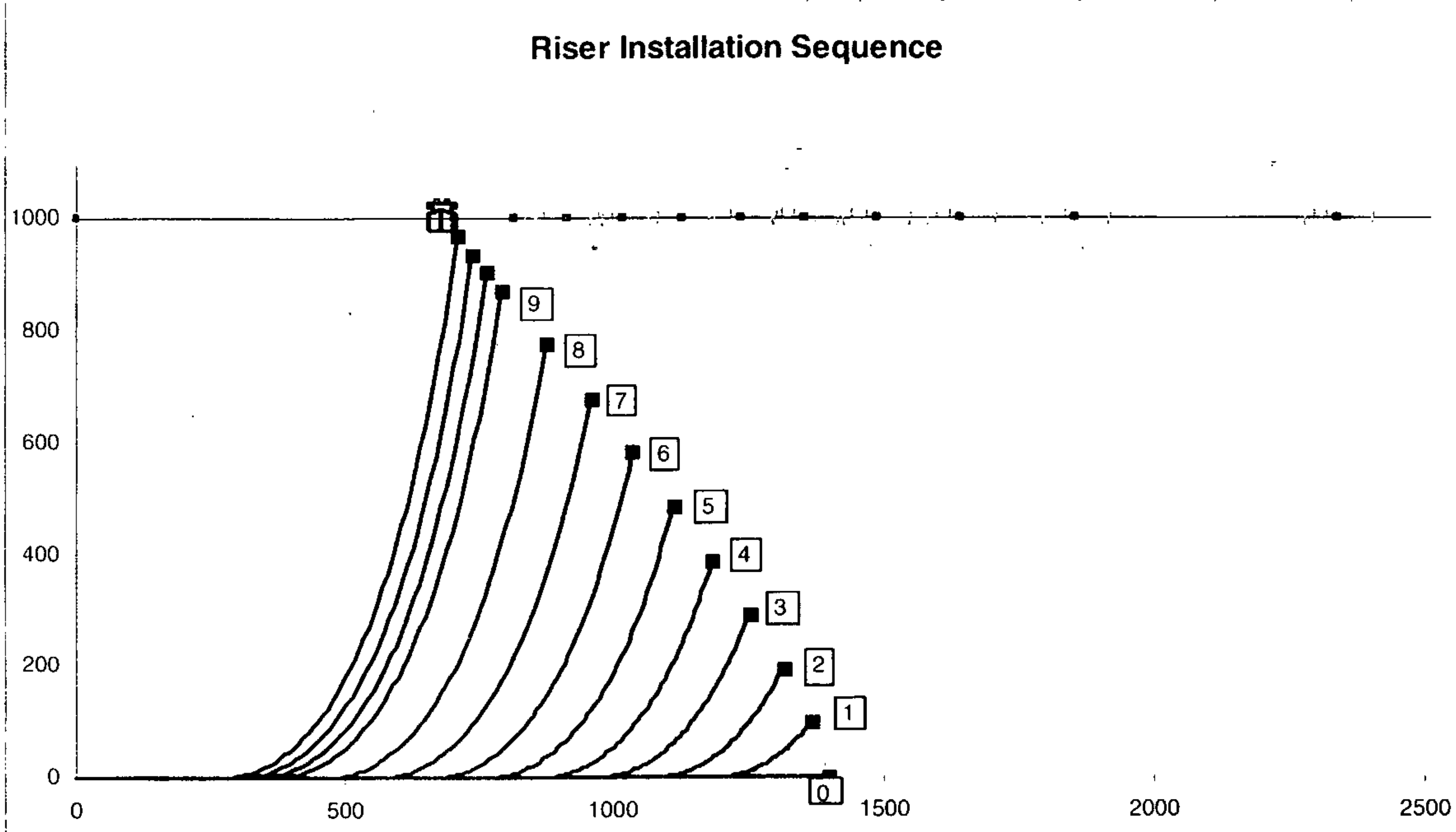

Figure 11 - Example Of SCR Installation Primer Output

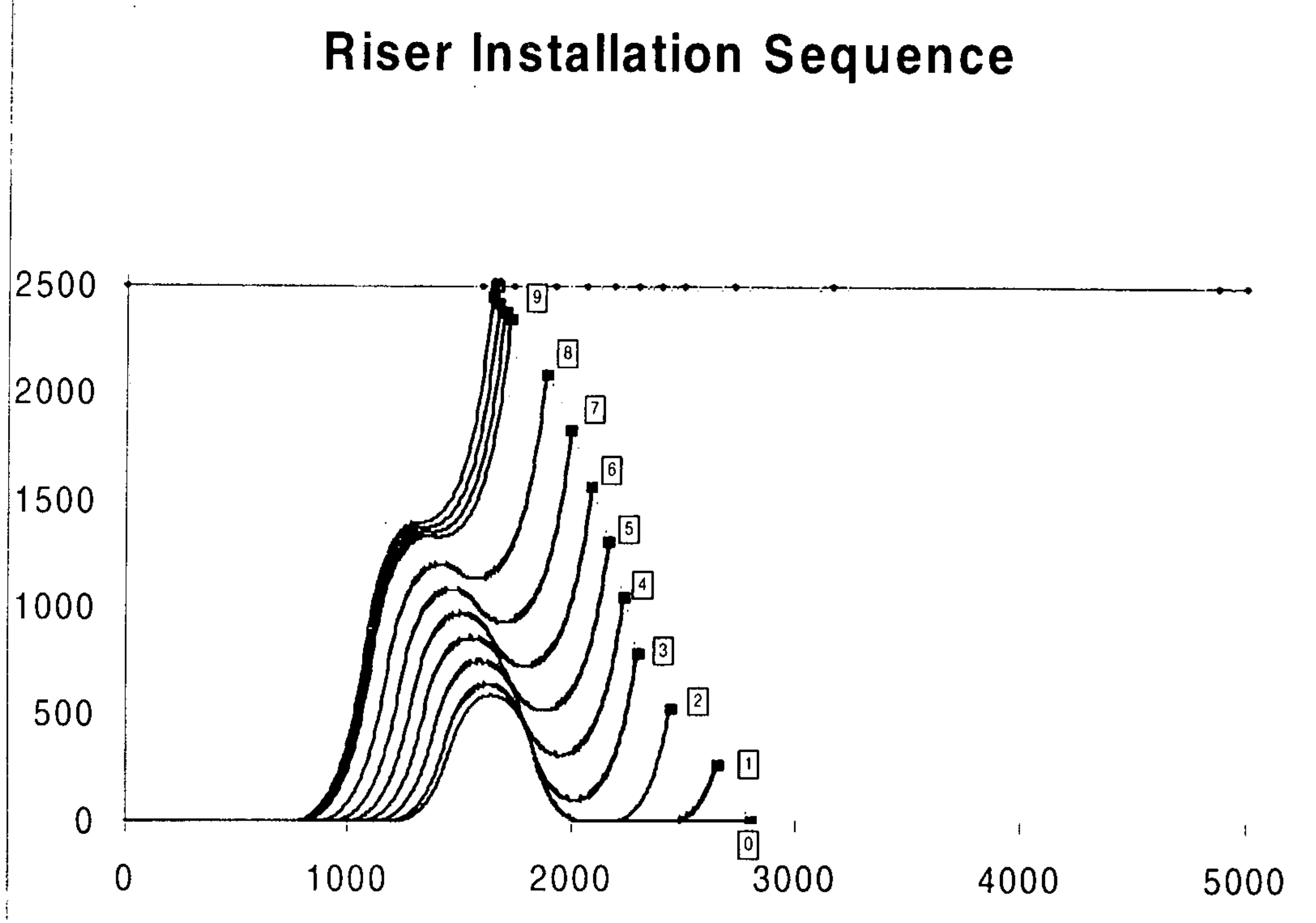

Figure 12 - Example Of SCR Installation Primer Output

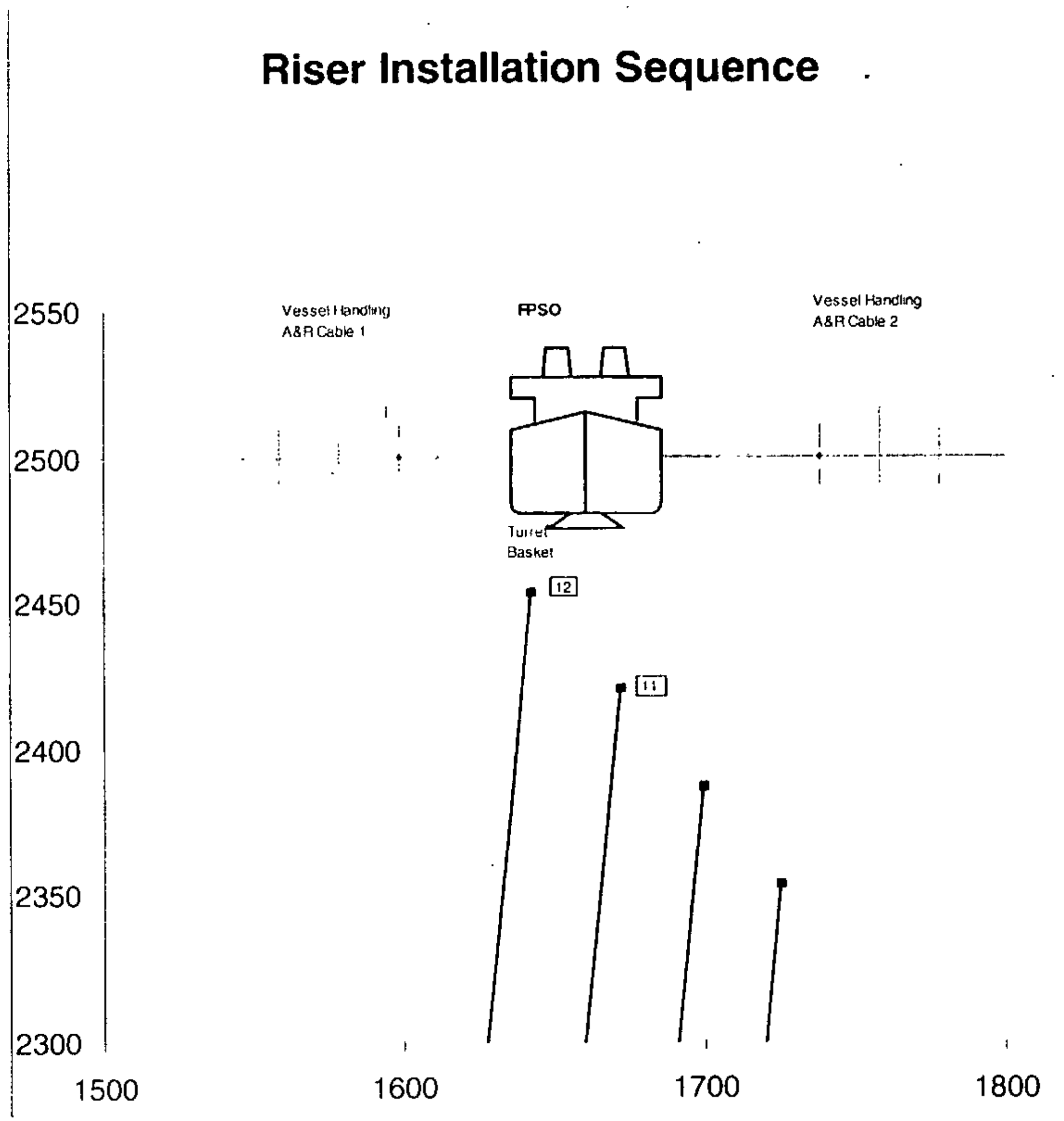

Figure 13 - SCR Primer Output - Installation Detail

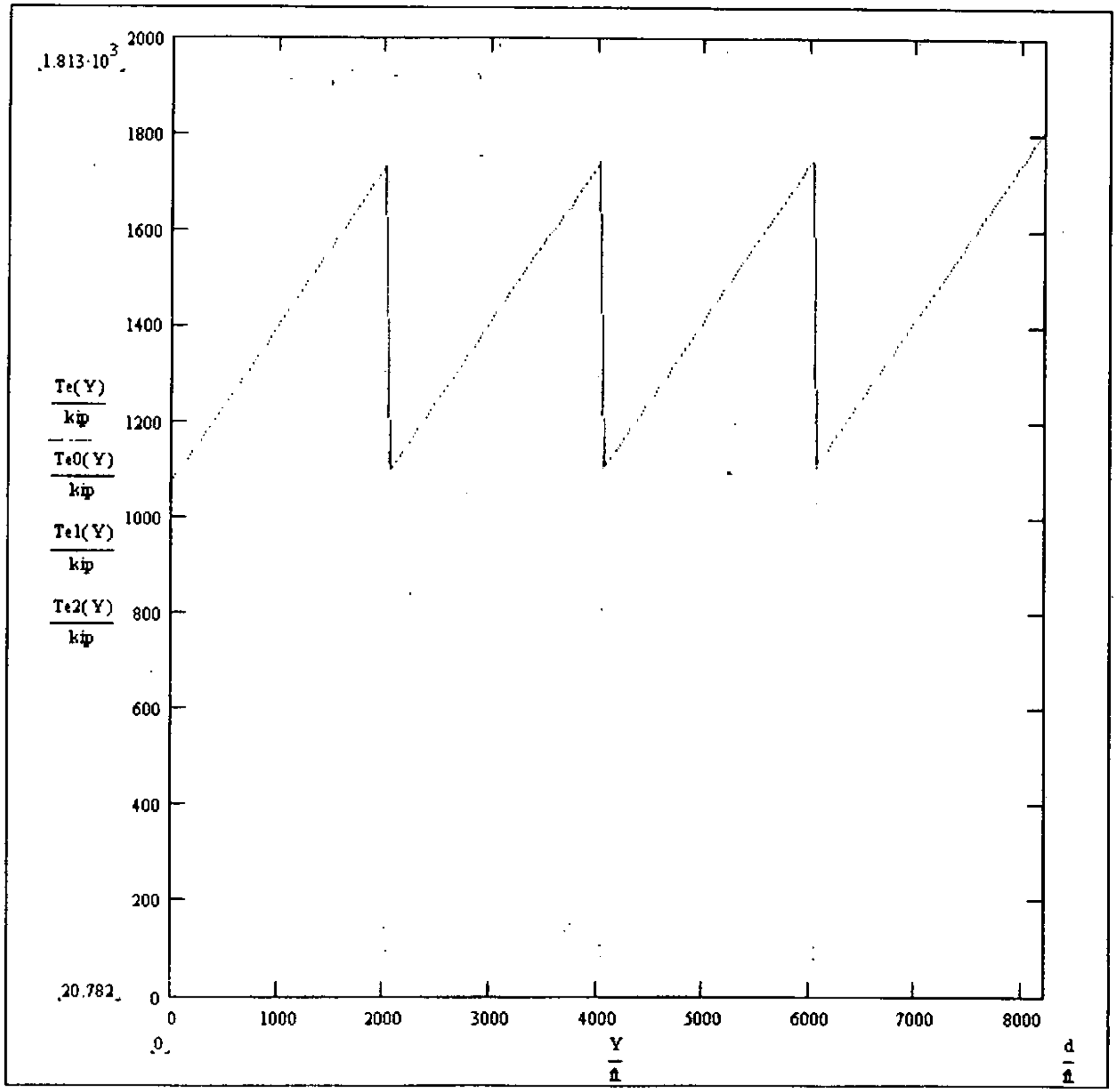

Figure 14 - Effective Tensions In Flowlines Of A Novel Design Ultra Deepwater Hybrid Riser Tower (JPK Primer)

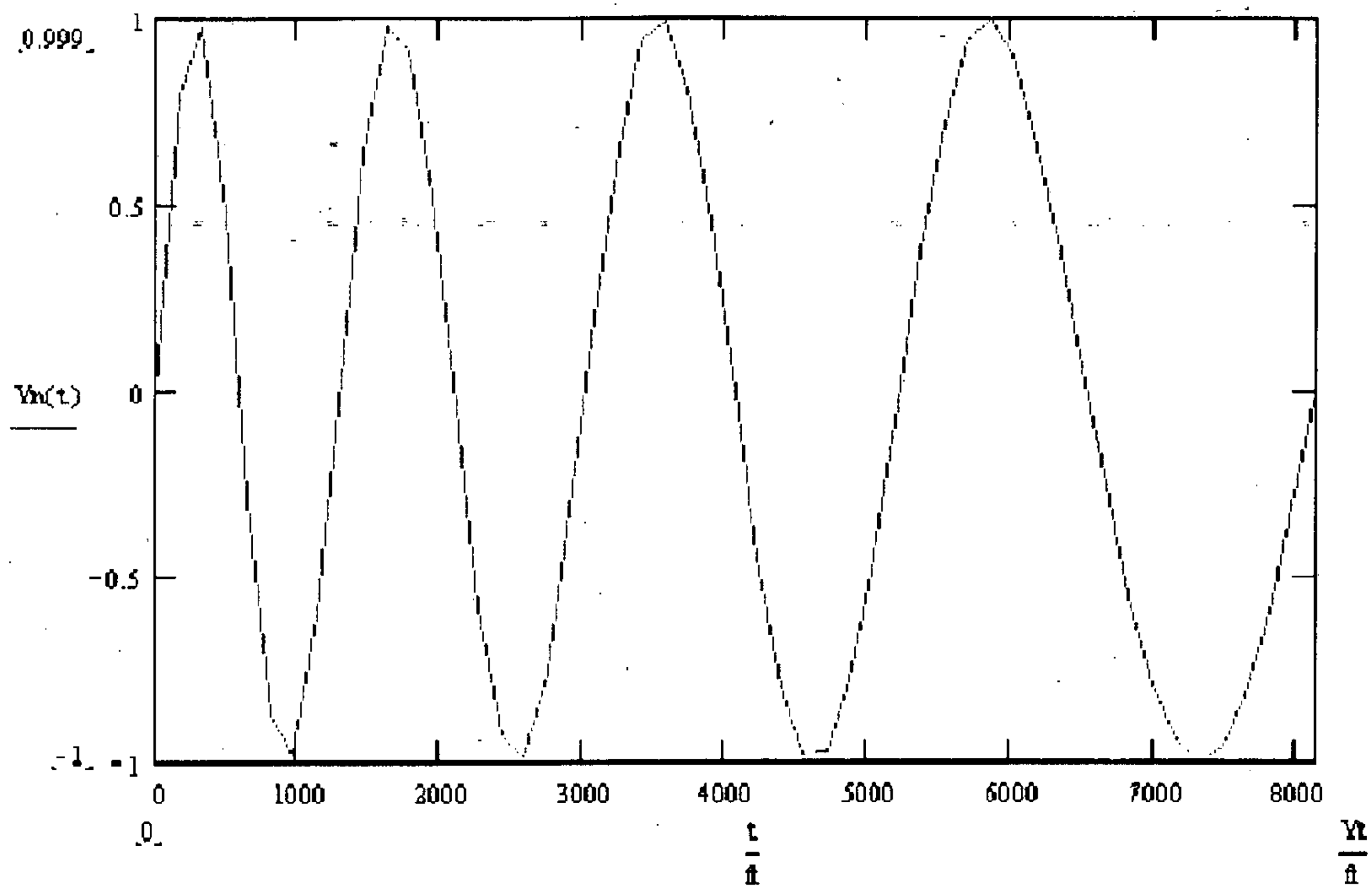

Figure 15 - Mode Shape Of A Tensioned Riser, Note The Effect Of The Effective Tension, Mass & Bending Stiffness Varying With Water Depth (JPK Primer)

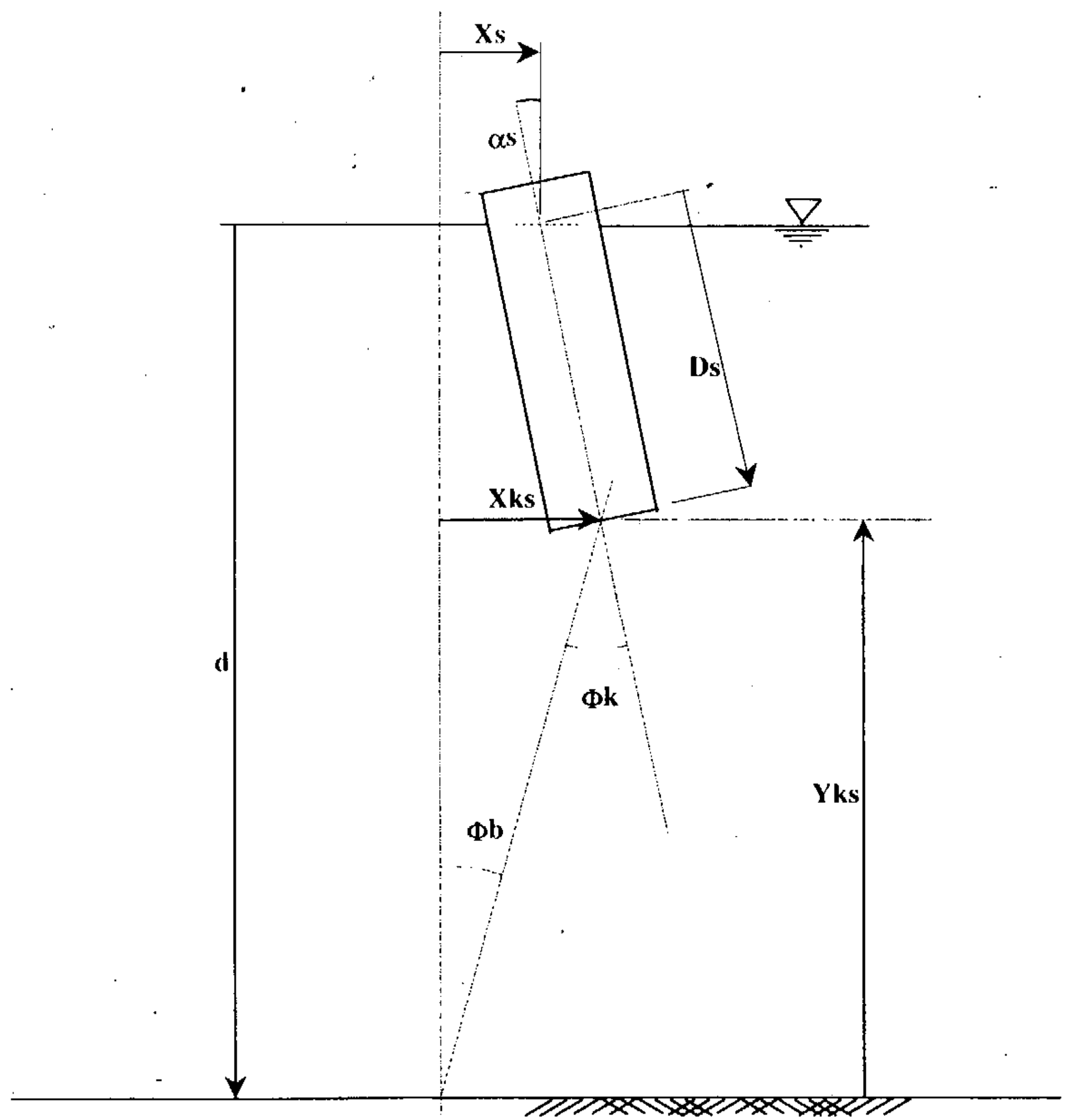

Figure 16 - Riser Deformation Geometry, As Governed By The Surge And Pitch Of The SPAR With Regard To The Riser Base Location

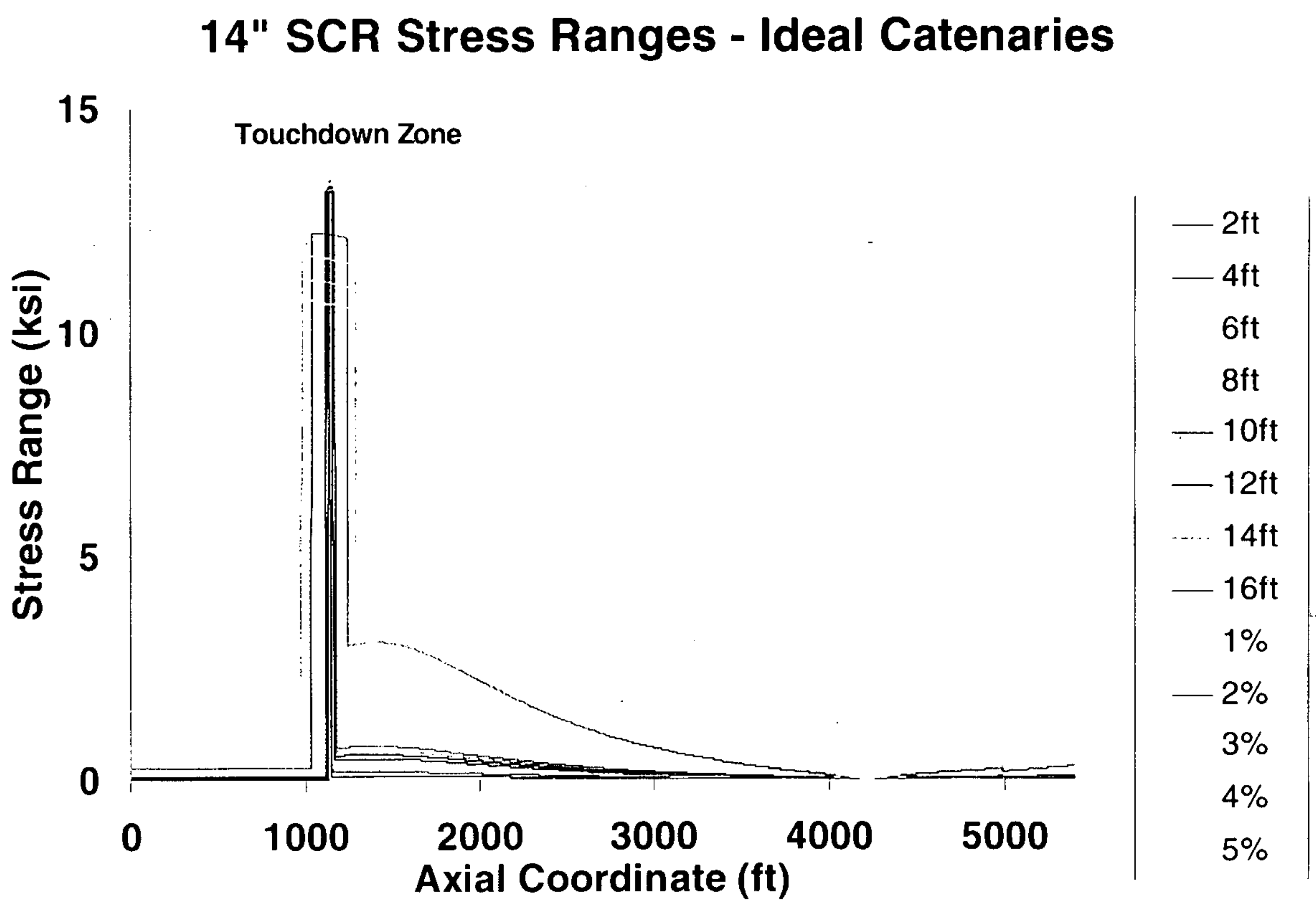

Figure 17 - Low Frequency Motion Primer Calculation

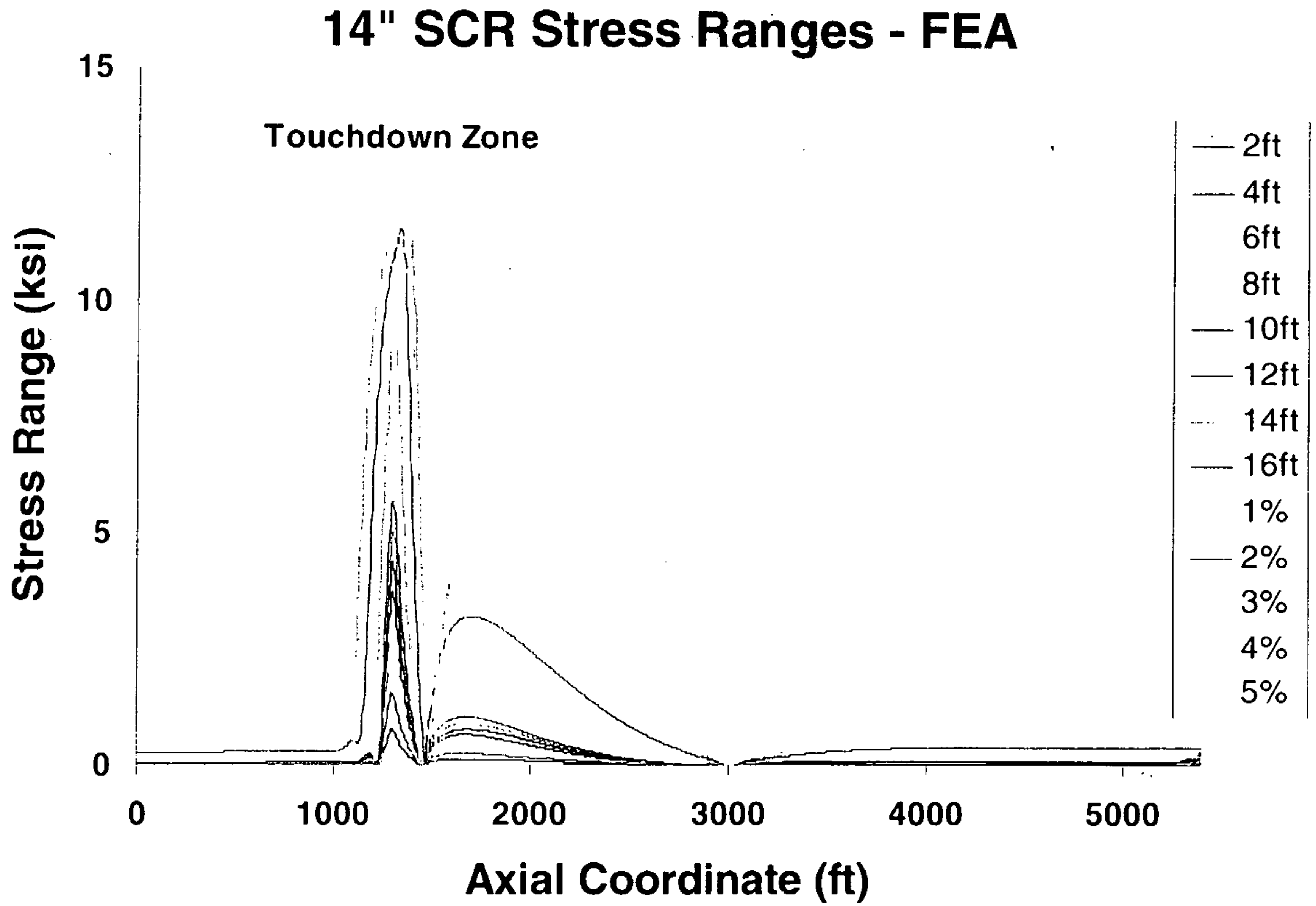

Figure 18 - Low Frequency Motion Primer Calculation

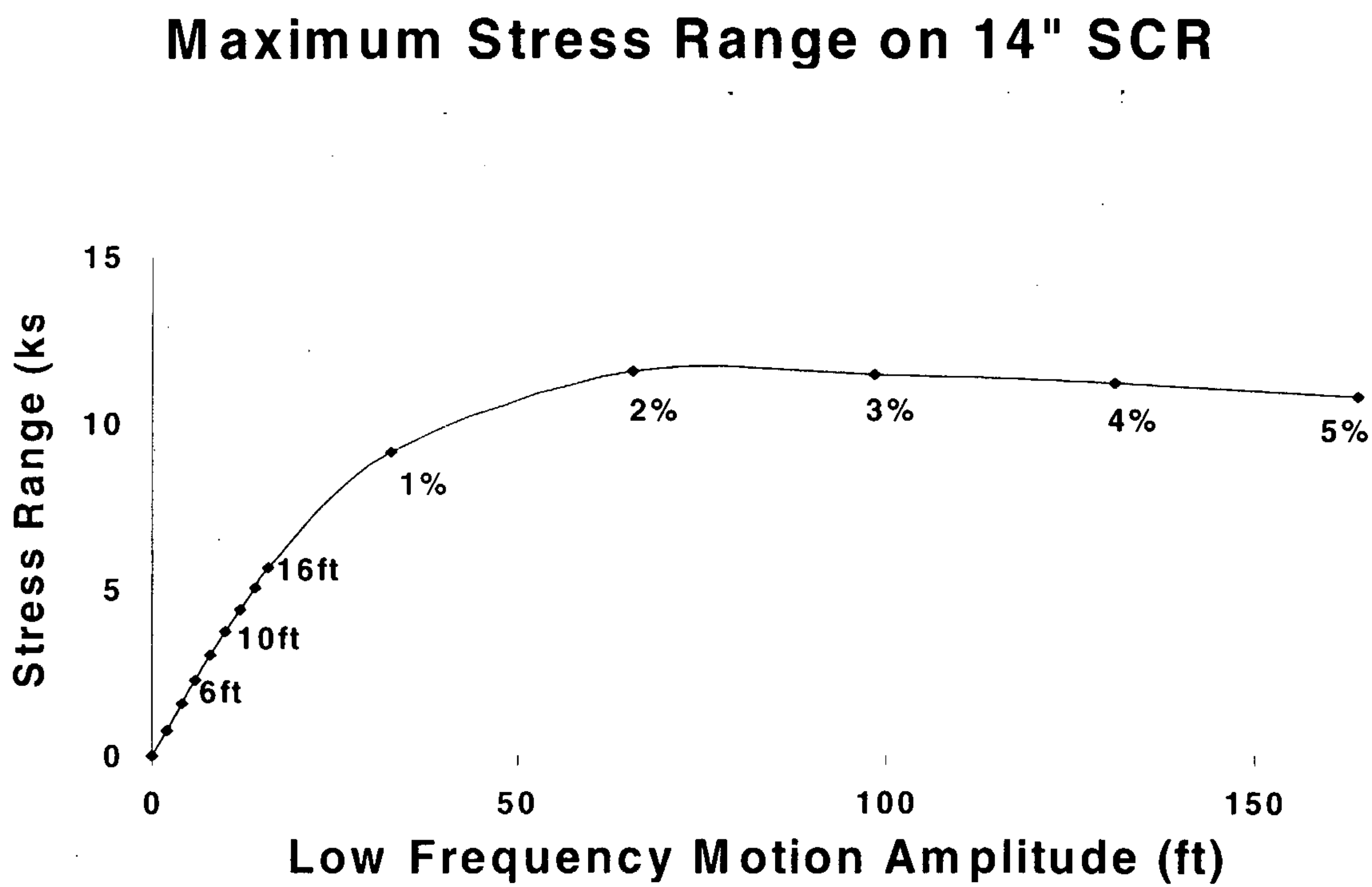

Figure 19 - Low Frequency Motion Primer Calculation

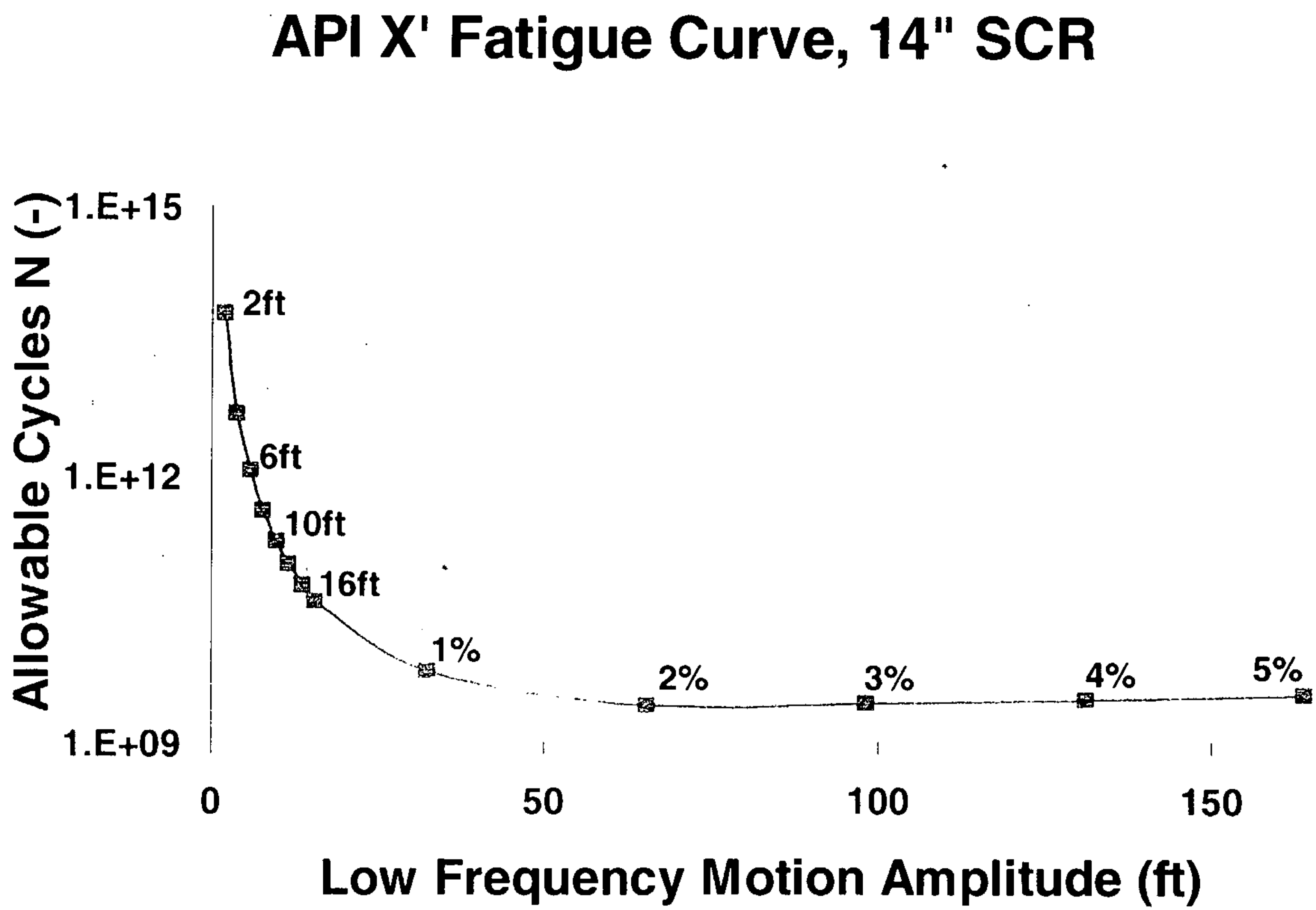

Figure 20 - Low Frequency Motion Primer Calculation

The Combined Riser Mooring (CRM) System : An Innovative Concept for Deepwater Mooring and Riser Design

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The Combined Riser Mooring (CRM) System :
An Innovative Concept for Deepwater Mooring and Riser Design

Abstract

Tanker based Floating Production, Storage and Offloading Systems (FPSO's) are being used in increasingly deeper waters. The use of spread moored tankers for deep water applications is widely accepted to be a viable and cost effective solution for developments in areas with relatively benign environmental conditions (e.g. West of Africa). With the constant drive towards deepwater floating production, the costs of the riser and mooring systems are a significant percentage of the overall field costs and it is essential to minimise these costs.

The concept and design presented in this paper involves combining the risers and moorings into a single integrated system, which offers the potential for very large cost savings. The concept combines standard steel wire mooring components with a hybrid type riser system. The hybrid system comprises steel catenary risers (SCRs) connected to a subsea buoy with flexible jumpers located between the buoy and the vessel. The system utilises the full potential restoring force capability of the SCRs which are positioned in tandem with mooring lines of minimal length. The subsea buoy located just below the wave zone provides an interface to which all mooring and riser components of the combined system are connected. The system is both feasible and cost effective for a spread moored FPSO in a largely directional environment.

This concept offers significant benefits over the independent riser and mooring systems, in terms of:

- Large economic savings in the mooring system.
- Optimised design conditions for both steel and flexible risers.
- Reduced vessel offsets (allow easier access to the field for drilling and workover vessels).
- Large reduction in the seabed area required for the riser and mooring systems.
- Ability to make maximum use of weather directionality effects.

Introduction

The selection and design of the riser system for deepwater floating production represents a critical component of overall system feasibility and cost. Design methods and conventional materials that have been accepted and validated for shallower water need to be challenged for deeper waters. Alternative innovative mooring and riser configurations, materials and design approaches are now being proposed for deepwater applications.

The limits of current deepwater flexible pipe technology restrict the diameter for which a totally flexible riser solution is feasible, largely due to limits on the collapse pressure capabilities

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of current designs. Other issues affecting the choice of risers in deeper water include insulation requirements for flow assurance, the high tensile loads in flexible and steel risers using conventional materials, the ability to install risers effectively and without damage, integrity monitoring and riser cost. All of these issues have fuelled the search for alternative riser solutions, an example of which is presented by Uittenbogaard et al. [1].

Many commentators, including Kota et al. [2], argue that steel catenary mooring systems designed by the conventional approach are either not feasible or not cost effective in ultra-deep waters. Line sizes, anchor radii and pretensions required to meet the design requirements and offset limits become excessive in deepwater. Where traditional anchoring methods using drag embedment anchors are used, relatively long sections of ground chain are necessary to keep anchor uplift to a minimum.

The integrated design of deepwater risers and moorings has the potential to bring substantial benefits in terms of overall system response, cost and safety to offshore development as demonstrated by the examples of Connaire et al. [3] Existing design methods, with their origin in shallower water design, have typically not considered design integration.

The innovative combined riser and mooring system described in this paper results in substantial reductions in quantity, sizes and cost, particularly of the mooring components, by taking full advantage of the mooring contribution and compliancy of a hybrid type riser system in a directional environment. The combined system comprises a large Combined Riser Mooring Buoy (CRMB), tethered to an anchoring system by wire rope, Steel Catenary Risers (SCRs) suspended from the buoy to the sea floor, flexible jumpers connected between the CRMB and the FPSO, and additional wire ropes connecting the CRMB to the FPSO.

In this paper, the system is considered for a West of Africa spread moored FPSO application in 1400m water depth. The response of the riser and mooring components to mean, low frequency and wave frequency loading is demonstrated. To illustrate the relative overall system response, quantity of mooring components and sizes and overall system cost, a comparison is made throughout with a conventional type mooring and riser system design for a similar type application.

Description of Combined Riser and Mooring System

The CRM system, incorporating a CRMB, SCRs, flexible jumpers, chain and wire tethers is shown in Figures 1 and 2 and is described in detail in this section. The design philosophy and economics of the system emerge as results are presented and comparisons are made with other systems in the following sections.

The following components of the CRM, outlined in Section 1, are described in detail in this section:

- a large CRMB providing both a required buoyancy force and an interface for all riser and mooring components of the system
- wire ropes connecting the CRMB to the FPSO and the CRMB to the seabed
- SCRs located between the seabed and the CRMB
- flexible jumpers connected between the CRMB and the FPSO

The main particulars and dimensions for the steel CRMB are given in Table 2.1. The length of the CRMB is determined by the buoyancy requirement, number of risers and riser separation.

Six sheathed, spiral strand, steel wire rope tethers are used to connect the CRMB to the seabed and also to connect the CRMB to the FPSO. The main particulars for the wire tethers are given in Table 2.2. Fibre rope mooring lines can also be used to connect the CRMB to the vessel.

Four 10-inch SCRs are located between the CRMB and the seabed with four flexible jumpers located between the CRMB and the FPSO, as presented in Table 2.3.

Figure 3 presents a detailed view of the system configuration at the CRMB location. The SCRs and both the upper and lower mooring line groups are connected to a single support beam. Shackles and SCR receptacles are used to connect the mooring lines and SCRs to the beam, respectively, for ease of installation. A second beam is positioned a short distance above the main support beam to which the flexible jumper support arches are attached. The cylindrical buoy is positioned above both riser support beams and is connected at both ends by vertical members. Note that as an alternative to the cylindrical buoy shown in Figure 3, two vertically positioned buoys could be connected to both ends of the support beam to give the required uplift. Although this may lead to a marginal increase in cost it may be more advantageous for installation, particularly with regard to accessibility to the flexible jumper support arches and the flexible jumper/SCR connection mechanisms.

In order to minimise the bending response of the SCRs, the flexible jumpers and the entire buoy structure, it is desirable to minimise all rotations of the buoy. The proposed buoy configuration is such that rotations are minimised in the main buoy support beam. The forces generated by SCRs and both the upper and lower mooring line groups act through the centre of moment, M, as illustrated in Figure 4, thus having a negligible contribution to support beam rotation. The main contribution to the support beam rotation will be from the flexible jumpers. Upon rotation of the buoy, a large restoring moment however will be provided by the buoy, whose centre of buoyancy is positioned a sufficient distance above the support beam to minimise the rotation.

Comparison with Conventional Type System

A typical conventional mooring system for a spread moored FPSO in the West of Africa comprises catenary lines of steel wire rope and chain with a drag embedment anchor. Figure 5 shows the conventional mooring and riser system for the FPSO to which the CRM system is compared. The mooring system comprises four groups of lines with three lines in each group. Each mooring group is oriented at a 45 degree angle to the bow-aft plane of the vessel. The length of each mooring line is 3575m and the anchor radius of each group is 3000m. The pre-tension of each line is 2500 kN resulting in an angle of 55.6 degrees relative to the horizontal. The main particulars and dimensions for this mooring system are given in Table 3.1.

The components of the riser system for the conventional configuration are assumed similar to those used in the CRM system. In effect, there is no significant difference in riser lengths or sizes used for the CRM and those used (in isolation from the mooring system) for the conventional system.

Combined Riser and Mooring System Analysis Design Basis

Vessel

The CRM system is designed for a tanker of approximately 100 KTDW, 230m length and 45m breadth.

Environment

The environmental conditions used for the design of the mooring and riser system are typical 100-year storm and 10-year wind and current conditions for a West of Africa location. Directional environmental conditions are considered which contributes to the optimisation of the combined riser and mooring design. Specifically, a swell wave with a Hs of 3.6m which dominates in the SSW direction is assumed to be confined to a 40° sector in this region. Locally generated waves with a Hs of 1.9m, current with a surface velocity of 1.0m/s and wind with a velocity of 14.6m/s are, however, assumed to approach from all directions. Wind, swell, locally generated waves and current are also assumed collinear.

System Orientation

In order to minimise any adverse effect of the environment, in particular the swell condition, on the FPSO and CRM system, the FPSO is oriented with the bow towards the SSW direction (i.e. towards the prevailing swell) with the initial plane of the CRM configuration oriented in the NNE direction. The orientation of the FPSO and the CRM are as shown in Figure 6. The swell conditions are therefore only applicable for the near case with respect to the CRM system (which corresponds to Head Sea with respect to the vessel). Loading on the CRM from the cross (Beam Sea with respect to the vessel) and far (Following Sea with respect to the vessel) directions incorporates local waves, wind and current only, and excludes the swell condition. This is also illustrated in Figure 6.

Loading and Response

The behaviour of a floating system moored to the seabed and subjected to wind, waves and current loading is complex. Although the complex behaviour may be estimated by non-linear time domain simulation tools, the responses in this study are simplified and described in three distinct responses, which are:

1. Mean offset due to current, mean wind and mean wave drift loading
2. Low frequency motions in the horizontal plane due to low frequency and wave loading
3. Wave frequency motions in all six degrees of freedom due to first order effects

The offshore analysis software programs, Flexcom-3D [4] and ARIANE-3Dynamic [5] are used to calculate all system and component responses.

Combined Riser and Mooring System Results

Mean Loading and Response

Mean environmental loading on the FPSO are presented in Table 5.1. The contribution to mean loading on the vessel due to current acting on the CRM system is also taken into account and is seen to represent 26% and 6% of the total mean loading on the vessel for the Head Sea and Beam Sea loading directions, respectively.

A comparison of the FPSO offset under mean load for the CRM system and the conventional system is presented in Figure 7. The offset envelope for the FPSO with the CRM system is shown to be less than that using the conventional system. Offsets for the CRM system are up to 10% less than those for the conventional system. This is due to the semi-taut nature of the CRM system in comparison to the conventional system.

System Stiffness

Figure 8 presents a comparison of the mooring system stiffness curves for the CRM and conventional type system for the transverse direction relative to the vessel axis. The CRM system is designed such that is exhibits a restoring force of similar magnitude to the conventional system for mean and low frequency offset regimes. For offsets larger than mean plus low frequency values, the CRM system stiffness will increase at a higher rate than that of the conventional system. This, again, is due to the semi-taut nature of the system.

Mooring Component Tensions

Figure 9 presents a comparison of the quasi-static tensions in the various mooring components of the CRM and conventional system as a function of offset in the plane of the CRM system. In order to achieve an optimised CRM system, it is necessary to maintain similar levels of utilisation in each component of the system. Figure 9 shows that similar levels of tension are maintained in both upper and lower mooring lines of the CRM. Furthermore, in establishing the optimum buoyancy requirement for the CRMB, a balance of forces is taken vertically through the centre of rotation, M, as shown in Figure 4. The minimum required buoyancy is then described as follows:

Low and Wave Frequency Responses

Low and wave frequency motions and tensions were calculated using a non-linear time domain simulation approach. Figure 10 shows snapshots of the CRM system in the extreme near and extreme far positions. The combined mean, low and wave frequency excursions of the vessel are presented in Table 5.2.

The dynamic behaviour of the CRM system is such that all vertical vessel motions tend to cause the CRMB to react in the horizontal plane through the action of both the upper and lower mooring line groups, as shown in Figure 11. (The lower mooring lines restrict the CRMB motions to the horizontal plane.) Furthermore, regarding the riser components, all of the vertical motions transmitted by the vessel, are dissipated throughout the flexible jumpers. Both of these effects (reduced dynamics and reduced vertical response of the CRMB) tend to minimise the dynamic and bending response of the SCR, particularly at the touchdown region. This results in a more robust SCR design allowing tensions (and hence system restoring forces from the SCRs) to be large.

Table 5.3 presents key results for various structural components of the CRM system, namely the SCRs, the flexible jumpers and both the upper and lower mooring lines. The results include maximum tensions, von Mises stresses and minimum bend radii.

Figures 12 to 15 show envelopes of tension for the SCRs, flexible jumpers and the upper and lower mooring lines, respectively. The design of the CRM is such that dynamic effects are low in both the riser and mooring line components of the system. Dynamic tension effects in the SCRs, flexibles, upper and lower mooring lines are 7%, 5%, 3% and 14%, respectively. The variation of maximum tensions in each component with environment is illustrated in Figure 16. For an optimised CRM system, the tensions and utilisation levels in the restoring force components, namely, the SCRs and the mooring lines should be similar under the maximum loading condition. Specifically, from Figure 16, similar levels of tension in the SCRs and mooring lines are observed under far case loading (180 degrees w.r.t incidence on bow), with the utilisation of the SCR tension capacity maximised for the less onerous directions.

The responses of the various components of the CRM system are within allowable limits. Figure 17 presents an envelope of von Mises Stress in the SCR under extreme far case loading. The maximum von Mises stress in the SCR is well below the allowable value with the main contributor to the von Mises stress being the axial stress component at the CRMB connection. Furthermore, the critical loading orientation with regard to the SCRs is the far case where the utilisation of tension in the SCRs is maximum.

The design of the flexible jumpers for the CRM system is relatively straightforward in that the flexible is at all times free to respond in the water column without any interaction from the seabed. The presence of the semi-taut upper mooring lines ensures that the instantaneous distance between the vessel and the CRMB remains relatively constant thus protecting the jumpers against excessive tensions due to stretching. The contribution from the flexible jumpers to the station-keeping forces on the vessel can, in effect, be ignored. The design of the jumpers is not such that horizontal forces on the vessel are maximised (maximising hang-off angles) but rather that the lines have sufficient length (and therefore low hang-off angles) to allow the dissipation of all dynamic effects. Furthermore, it is desirable in the design of the flexible jumpers to minimise the departure angle relative to the vertical at the CRMB. The lower departure angle minimises the moments induced on the buoy support beam and hence minimises buoy rotations.

Cost

The primary advantage of the CRM system for production to a spread moored FPSO in a relatively benign environment is the potential significant cost savings which can be achieved when used as an alternative to the more conventional riser and mooring systems. The results and discussions in the previous sections show that the CRM configuration requires considerably less hardware than the conventional system. Table 6.1 presents a summary comparison of the major procurement cost drivers for both the CRM and conventional systems. The basis for the comparison of both systems is that the riser systems' components, including the SCRs, flexible jumpers, buoyancy tank and buoyancy tank tether are necessary for both systems; the difference being that full advantage is taken of the mooring contribution of the riser system components in the CRM system.

The comparison of both systems illustrates that the CRM system procurement costs are approximately 20% lower than those of the conventional system. Another economic benefit of the CRM system is that it allows flexibility in the sequence of the installation of the entire system. In particular, the buoyancy tank, lower tethers and SCRs can be installed prior to the arrival of the FPSO. As flexibility in installation has a close link with cost, it is envisaged that the CRM type system has the potential for notable installation cost savings when compared with more conventional systems. The evaluation of the installation methodologies, procedures and cost benefits and investigations of the sensitivity of the CRM to various design parameters are the subject of ongoing work and are not described in this paper.

Conclusions

An innovative combined riser and mooring system is presented in this paper and an appropriate level of optimisation is achieved for a preliminary assessment of the system. The application considered most suitable for the CRM system is West of Africa due to the directional nature of the environment at this location. Results from analyses of the system under design conditions are presented and a comparison is made with results from analyses of a more conventional type system for a similar application.

Specific conclusions with regard to system, behaviour and response, drawn from the study of the CRM system, are as follows:

- The horizontal restoring force from a single SCR is of similar magnitude to the mooring lines used in the CRM system. Maximum advantage is taken of the SCR with regard to their contribution to vessel restoring force.
- The CRM system offers flexibility with regard to installation in that the CRMB, lower mooring lines and SCRs can be installed prior to the arrival of the FPSO.
- Similar levels of utilisation are achieved for the individual components of the CRM system for the maximum loading condition. This confirms that the relative lengths, sizes and quantity of each of the individual components are appropriate and optimum at a preliminary design level.
- In more conventional applications of SCRs, vertical motions of the vessel transferred to the SCRs tend to induce large bending responses in the touchdown region. In the case of the CRM, however, all vertical motions of the vessel, are transferred as horizontal motions to the CRMB, to which the SCRs are connected. This implies less onerous conditions for the SCR design for a given seastate and vessel type.
- The dynamic effects imposed on the riser system due to the interaction of top motions and wave kinematics are dissipated throughout the flexible jumpers. The jumpers have the ability to withstand such dynamic effects as their response is not complicated by seabed interaction. Therefore dynamic effects imposed by the waves on the riser system are effectively decoupled from the SCRs benefiting their response in the critical touchdown region.
- An efficient and optimised buoyancy level for the CRMB can be established by balancing the vertical forces on the main support beam of the CRMB.
- The design of the CRMB is such that rotations are minimised thus minimising the dynamic rotational response of the riser and mooring components in the CRMB region.

- There is also benefit in having the top connection point of the SCRs positioned some distance below the mean water line. The susceptibility of the SCRs to vortex induced vibration effects is reduced as the SCR is strategically located below the area of high surface current regimes. The CRM system therefore, yields an optimised SCR design in that it minimises the effects of both VIV and touchdown dynamics, which are industry accepted as being two of the most crucial aspects in SCR design.

In summary, the CRM system is considered a feasible solution to the riser and mooring system for a FPSO in a West of Africa location. There are notable cost benefits in adopting a CRM system as an alternative to a more conventional system in an appropriate location.

Secondary benefits of the CRM system include a significantly reduced footprint for the mooring system (allows easier access for drilling/workover vessels) and improved topsides layout (the entire import facility is confined to a single location aft of the vessel). This is beneficial with regard to processing, maintenance and safety (distance to accommodation compartments can be maximised). Finally, the CRM system may also be applicable to other deepwater areas, but this is yet to be fully evaluated.

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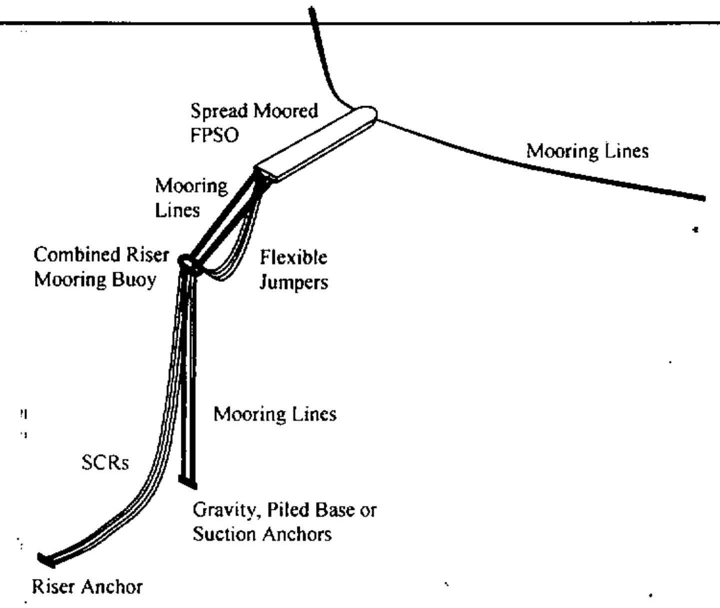

Figure 1 Isometric View of Combined Riser Mooring System Concept

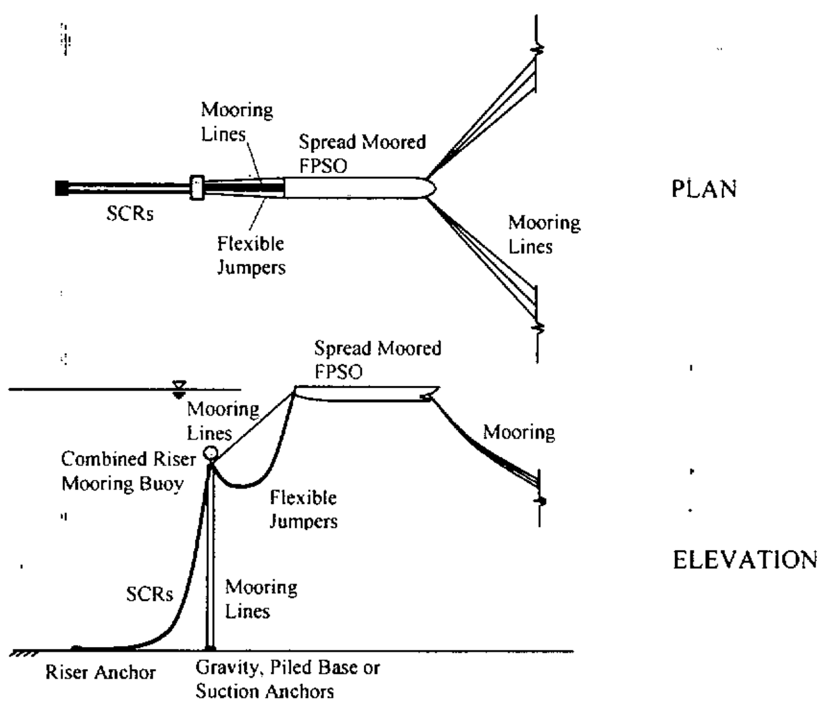

Figure 2 Combined Riser Mooring System

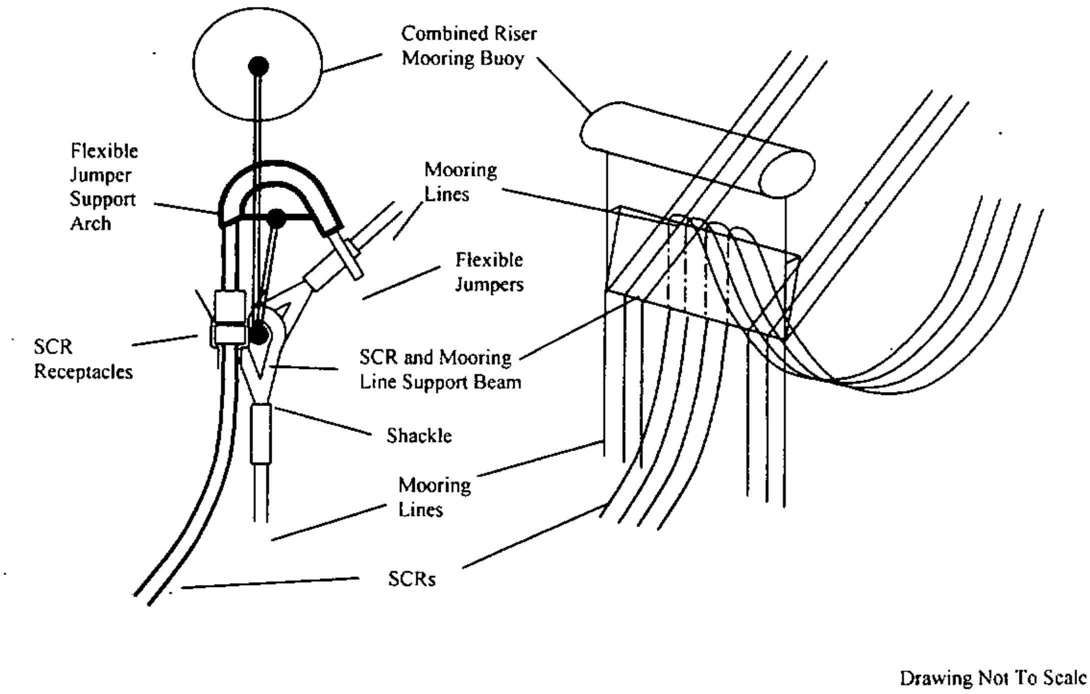

Figure 3 Detail of CRM Configurations in Buoy Region

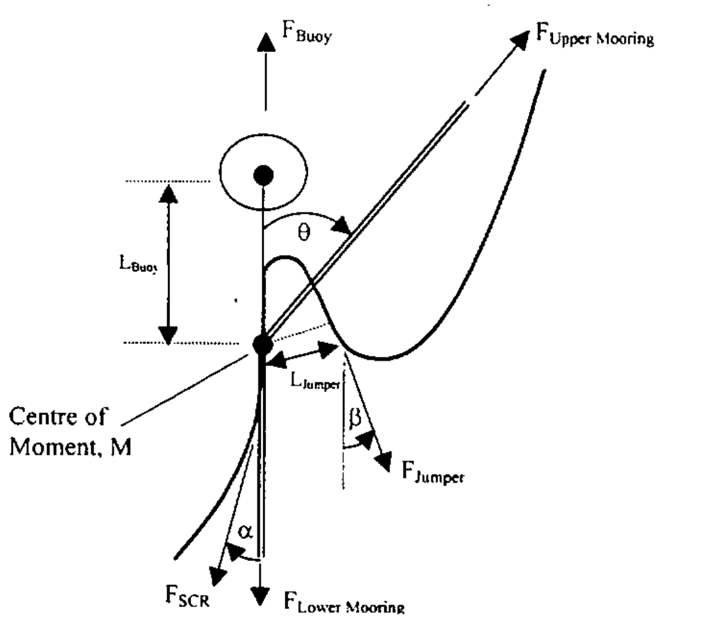

Figure 4 Moment Balance in Buoy Support Region

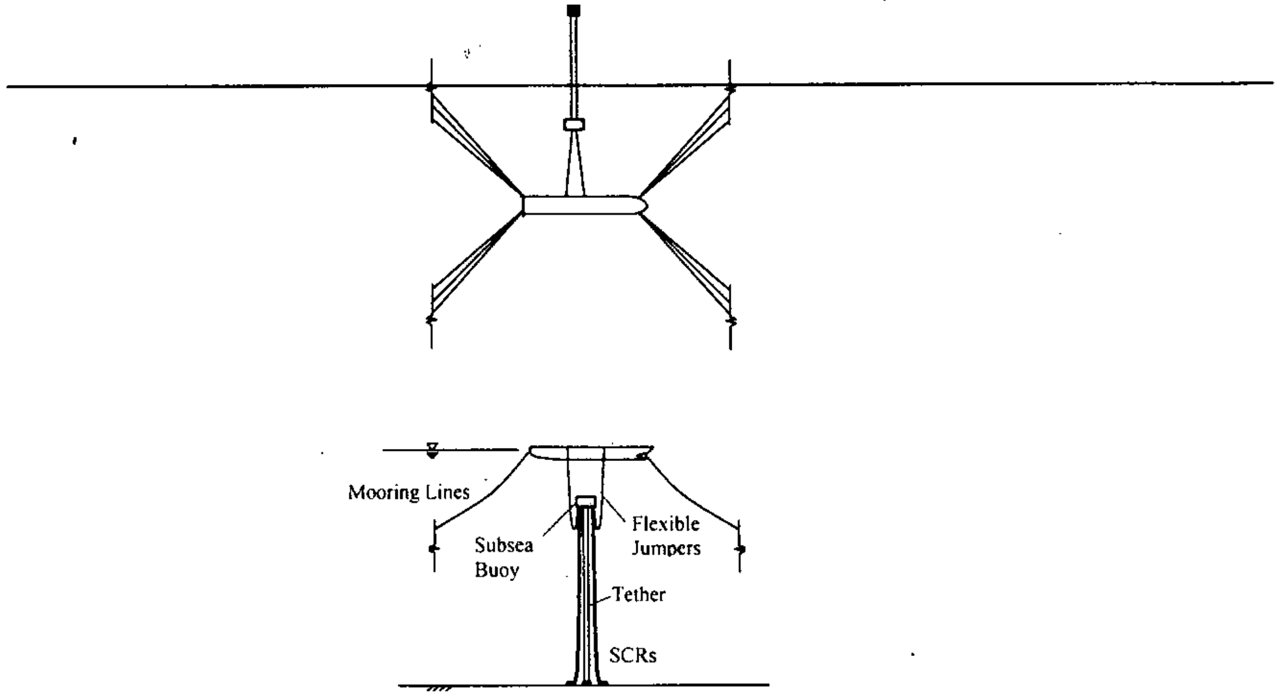

Figure 5 Schematic of Conventional Type System for Comparison

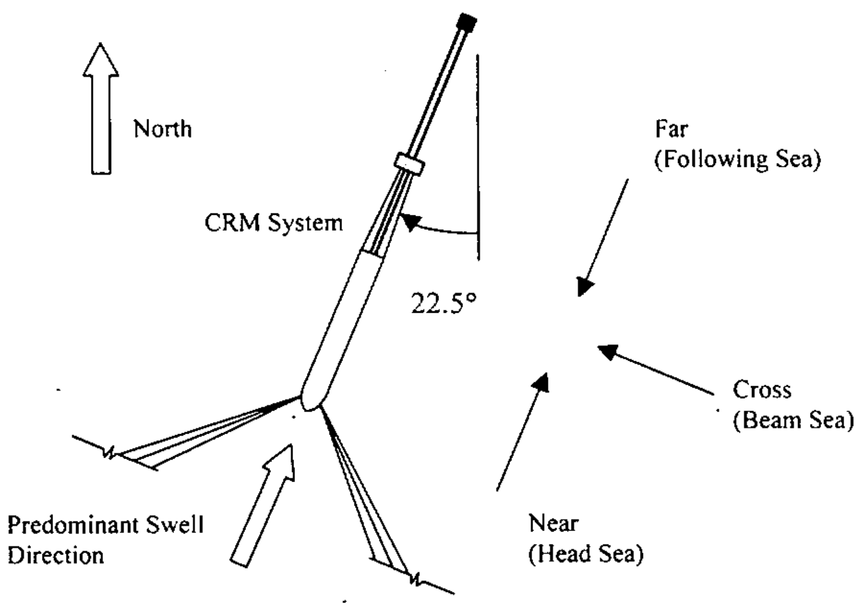

Figure 6 Orientation of CRM System and Environment

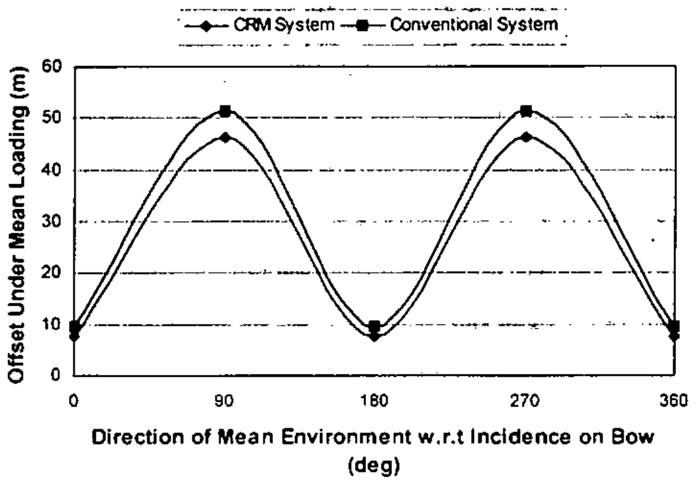

Figure 7 FPSO Stern Excursion Under Mean Loading

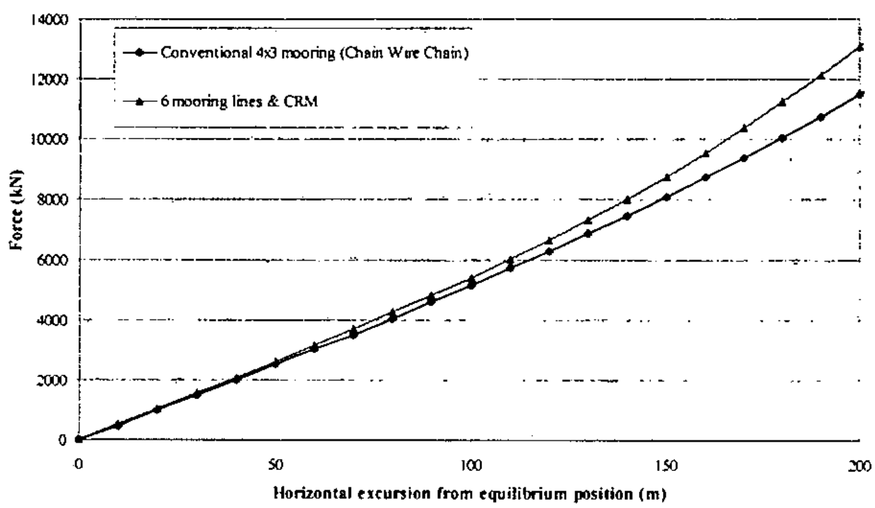

Figure 8 CRM System Stiffness Curve in Transverse Direction

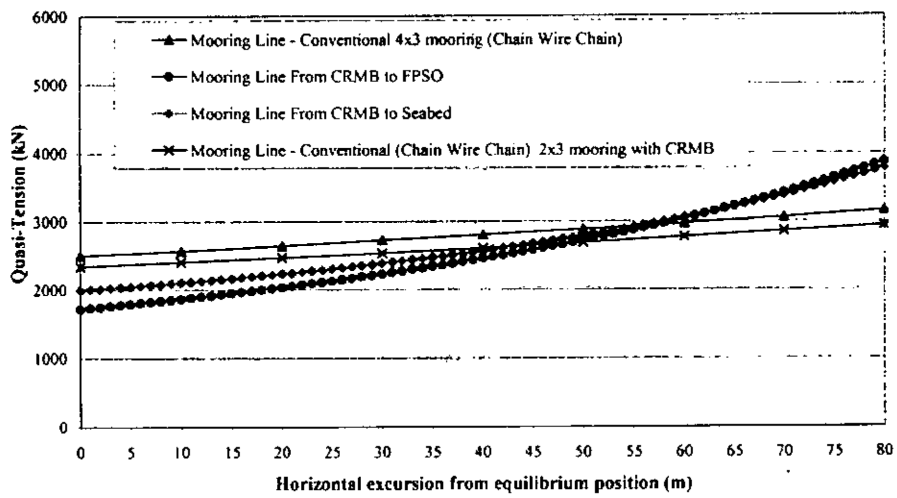

Figure 9 Quasi-static Tension versus Offset relationships for the Mooring Line Components of the CRM System for Cross Direction

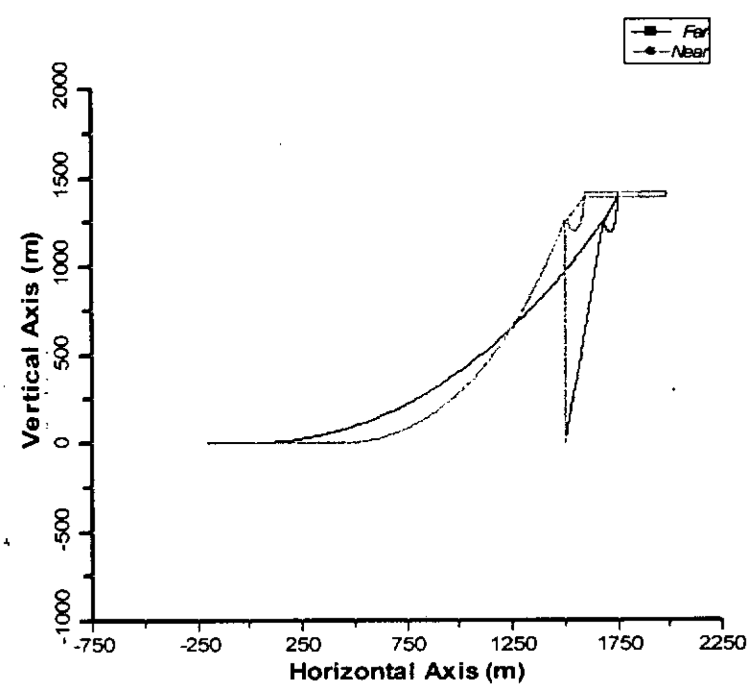

Figure 10 Snapshots of the CRM System in the Extreme Near and Far Positions

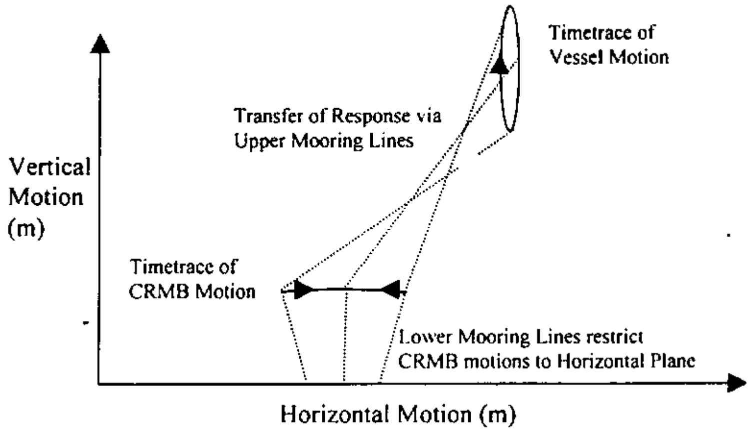

Figure 11 Envelopes of Motions of CRM Buoy and Vessel in the Plane of the CRM System

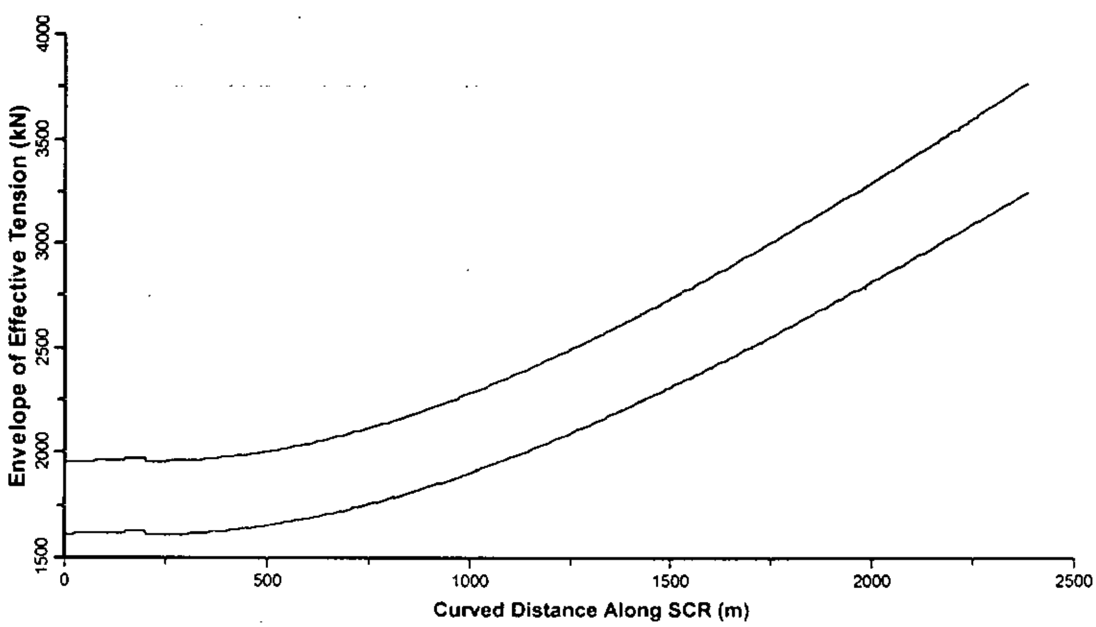

Figure 12 Envelope of Effective Tension in SCR under Far Case Loading

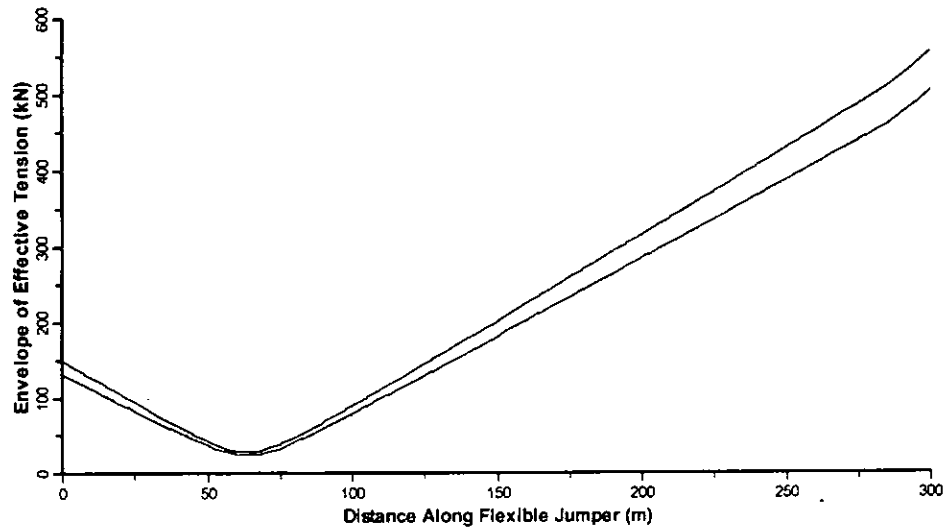

Figure 13 Envelope of Effective Tension in Jumper under Far Case Loading

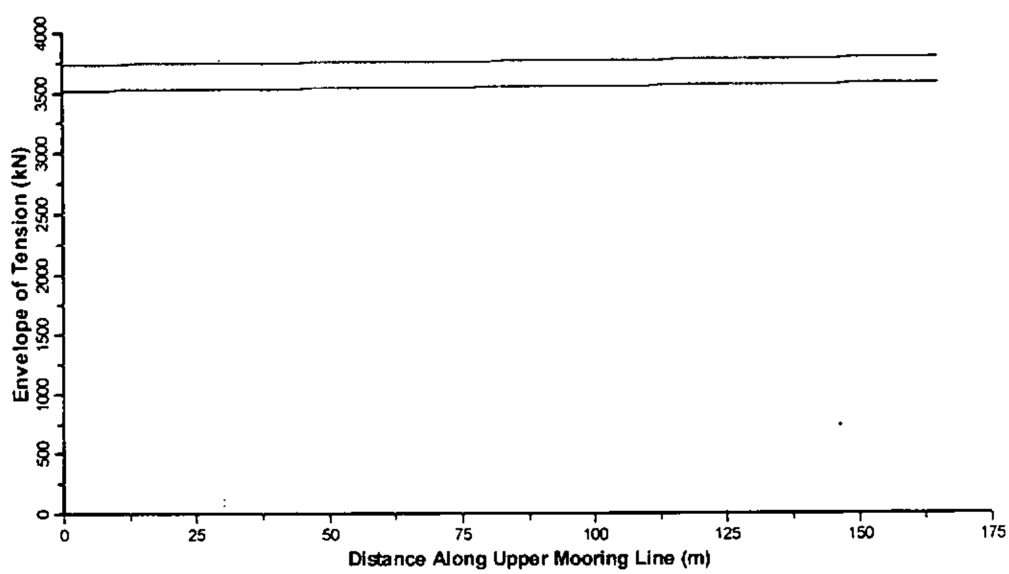

Figure 14 Envelope of Effective Tension in the Upper Mooring Line Under Far Case Loading

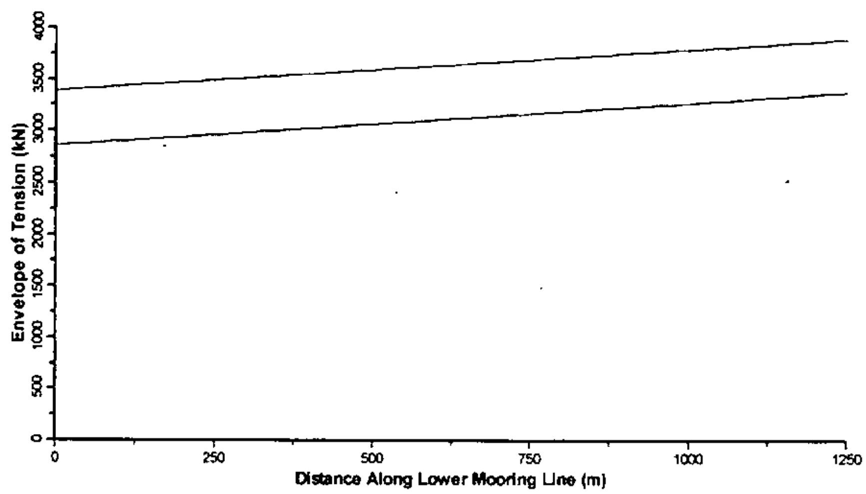

Figure 15 Envelope of Effective Tension in the Lower Mooring Line Under Far Case Loading

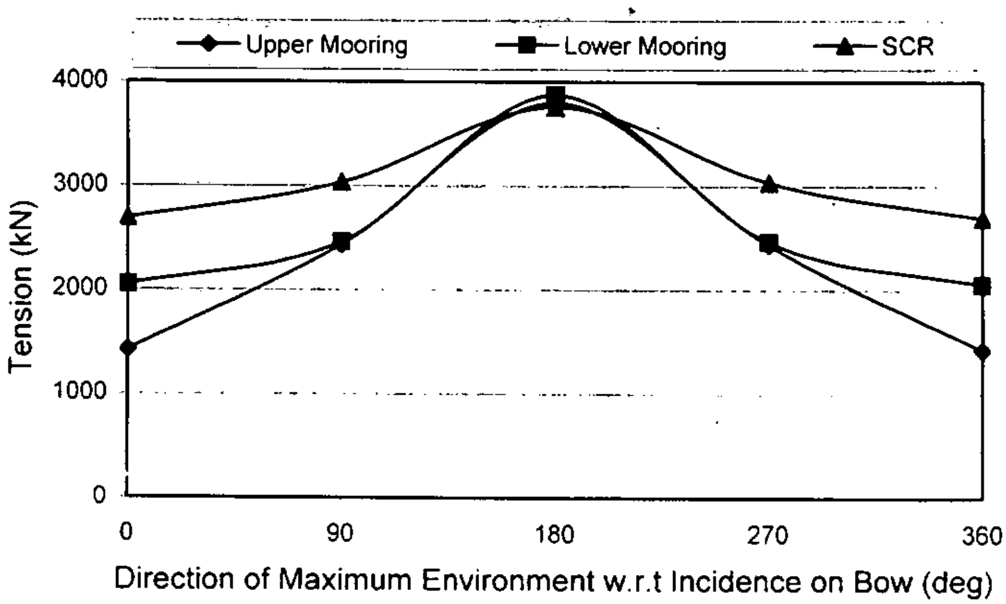

Figure 16 Variation in Maximum Tension in Mooring Lines and SCRs of CRM System with Environmental direction

Figure 17 Envelope of von Mises Stress in SCR under Far Case Loading

Table 2.1 CRMB Particulars

Parameter	Units	Value
Diameter	m	10.2
Length	m	25
Mass per unit length	tonnes/m	24
Buoyancy per unit length	tonnes/m	84
Total Net Buoyancy	tonnes	1500

Table 2.2 Wire Rope Tether Particulars

Parameter	Units	Tethers Connecting CRMB to Seabed	Mooring lines from CRMB to FPSO
Quantity	-	6	6
Grade	-	Spiral Strand	Spiral Strand
Diameter	mm	100	100
Length	m	1250	165
MBL	kN	8500	8500
Axial Stiffness	MN	910	910

Table 2.3 Particulars for SCRs and Flexible Jumpers

Description	Units	SCRs	Flexible Jumpers
Quantity	-	4	4
Function	-	Oil Production	Oil production
Grade	-	X65	-
Length	m	2185	300
Inner Diameter	mm	254 (10-inch nominal)	254 (10-inch nominal)
Outer Diameter	mm	304.8	340
Wall thickness	mm	25.4	-
Mass per unit length	kg/m	175	275
SMYS	MPa	448	-

Table 3.1 Conventional Mooring System Details

Parameter	Units	Lower Chain	Middle Wire	Upper Chain
Grade	-	R4 Studless Chain	Sheathed Spiral Strand	R4 Studless Chain
Diameter	mm	100	110	100
Length	Mm	2100	1425	50
MBL	kN	9864	9941	9864
Axial Stiffness	MN	768	1085	768

Table 5.1 Mean Loads On Vessel

Mean Load Components	Mean Environmental Loading on Vessel (kN)	
	Head Seas	Beam Seas
Mean Wave Drift	97	401
Wind	223	1049
Current: Load on Vessel due to current on Vessel	121	1125
Load on Vessel due to current on Combined Riser and Mooring System	156	171
Total	597	2746

Table 5.2 Summary of CRM and Conventional Mooring System Motion Responses

Motion Response of The Vessel Stern	Head Seas		Beam Seas		Following Seas	
	CRM	Conv[1]	CRM	Conv	CRM	Conv
Excursion under Mean Loading (m)	7.7	9.6	46.4	51.5	7.2	9.4
Mean + Max Low Frequency Excursion (m)	9.4	11.4	57.1	63.4	8.3	10.5
API Max Excursion (m)	15.5	17.4	58.0	64.3	15.0	17.2

Notes: 1. Conv: Conventional Mooring System

Table 5.3 Key Results for the Components of the CRM System

Description	SCRs [Percentage Yield[1]]	Flexible Jumpers	Upper Moorings [Percentage MBL[2]]	Lower Moorings [Percentage MBL[2]]
Near (Head Seas)				
Maximum (Effective) Tension (kN)	2693	570	2050 [25%]	1422 [17%]
Maximum Von Mises Stress (MPa)	131 [29%]	-	-	-
Minimum Bend Radius (m)	-	10.2	-	-
Cross (Beam Seas)				
Maximum (Effective) Tension (kN)	3035	540	2432 [30%]	2460 [30%]
Maximum Von Mises Stress (MPa)	157 [35%]	-	-	-
Minimum Bend Radius (m)	-	12.4	-	-
Far (Following Seas)				
Maximum (Effective) Tension (kN)	3758	556	3796 [46%]	3872 [47%]
Maximum Von Mises Stress (MPa)	198 [44%]	-	-	-
Minimum Bend Radius (m)	-	12.7	-	-

Notes 1. Yield Stress of API 5L X65 Grade Steel = 448 MPa
2. Minimum Breaking Load (MBL) of 100mm Sheathed Spiral Strand Wire Rope = 8223 kN

Table 6.1 Summary of CRM and Conventional System Procurement Costs

Description	CRM System Costs (STG£1000)	Conventional System Costs (STG£1000)
Mooring Components		
CRM Lower Mooring Wires	750	750
CRM Lower Tether Suction Anchors	600	600
CRM Upper Mooring Wires	100	-
CRM Buoyancy Tank	3000	3000
Chain/wire/chain catenary Mooring Lines	4436	8872
Chain/wire/chain catenary Mooring Line Anchors (non-suction)	600	1200
Fairleads and Winches	3360	3360
Riser Components		
Insulated 10-inch API 5L X-65 SCRs	4720	4720
SCR Suction Piles	400	400
Flexible Jumpers	3000	3000
Bend Stiffeners/Bellmouths	200	200
Totals	21,166	26,102

Dynamic Aspects of Deepwater Pipeline Risers

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Dynamic Aspects of Deepwater Pipeline Risers

Abstract

Hydrocarbon resources exploitation is progressively moving into deeper waters, and extracting these resources require different forms of risers. The deepwater pipeline risers are mainly connected to floating structures. It is imperative that the dynamic behavior of these risers is fully understood through proper use of numerical simulation techniques. Normally, general purpose Finite Element Analysis (FEA) and specific proprietary riser computer programs are used. This paper discusses problems associated with the dynamic simulation of pipeline risers with a particular focus on:

- Vortex Induced Vibrations
- Fatigue Damage Calculation
- Random wave analysis
- Soil-structure interaction
- Riser dynamics in enclosed hull section of floaters
- Tow-out and up-ending of riser towers

The paper also provides an overview of some of the analysis methods that have been used for different types of existing risers. The relative strength and weaknesses of these analyses are presented together with recommendations for current methodologies.

Introduction

Oil and gas developments have been progressively moving into deeper water and increasingly using floating production structures. For these deepwater developments, pipeline riser dynamic analyses can be expensive and time consuming but are essential to the overall system design. Depending on the type of riser and the type of floating support structure, different dynamic analysis methods can be used, which can range from a simplistic hydrodynamic force model to a more sophisticated random wave analysis in both time and frequency domains.

The deepwater pipeline risers form a substantial part of the overall field development cost. To optimize this cost and to insure the risers' structural performance, dynamic analysis has to be performed to assess one or more of the following:

- Pipeline mechanical strength and structural integrity - These include stress checks, fatigue analyses, and clashing analyses between the risers and mooring lines.

Proceedings of the 3rd Deepwater Pipeline & Riser Technology Conference, Houston, Texas, March 7-9, 2000.

- Estimation of the dynamic loads due to structure and riser motions - As the water depth increases, hydrodynamic loads on the riser vary along the riser together with the increase of the riser's load imposed on the floating facility. As such, accurate simulation of the riser response is required to ensure riser integrity and the ability of the structure to withstand the additional loads.
- Installation analysis to establish suitability of equipment selected for each step of the installation procedure.

Pipeline riser systems suitable for deepwater explorations considered herein include Steel Catenary Risers, Top Tensioned Risers and Hybrid Risers (such as a Bundle Riser Tower). For these risers, the main sources of the dynamic loads include current, waves and structure motions. Analyses for these must include understanding of material characteristics, hydrodynamic force modeling, structural response simulation techniques and soil-structure interaction. Some of these issues are addressed in the paper.

Riser Types

Steel Catenary Riser

Since the first installation on the Auger TLP in 1994 in the Gulf of Mexico, the Steel Catenary Riser (SCR) has become a viable option for risers in deep waters. Several studies have been conducted by oil companies and contractors in Italy, Norway, Britain, Brazil and the USA on the design and installation of the SCRs. These studies have provided much improved confidence in the use of this type of risers. Some of the major studies that have been completed or are underway are

- DEEPSTAR Project (DEEPSTAR, 1996)
- The STRIDE Project (Hatton, 1998, and Willis et al., 1999)
- PMB BECHTEL Test (Grant et al., 1999)
- PETROBRAS (Edwards et al., 1999)

In the case of the SCR installed on the Auger Tension Leg Platform (TLP) which had limited heave, pitch and roll motions, damage to critical sections such as the top joint area and the sag-bend/touch down area is significantly reduced as the SCR experiences little dynamic motions. Another example with limited structural motions is the first SCR installed on a fixed platform in the Gulf of Mexico for Mobil's GC 18 A Platform. Along with the increase in the understanding of the dynamic behavior, SCRs have been considered for other types of floating structures with different motion characteristics. These include variations of TLPs and Mini-TLPs, SPAR type structures including Deep Draft Caisson Vessel (DDCV), Semi-Submersibles such as Petrobras P18 facility, and Floating Production, Storage and Offloading vessels (FPSO).

Monitoring of the behavior of the risers at the top end, where it is connected to the floater, may be readily achieved; however, the same degree of integrity monitoring is not always easily possible for the portions of the riser in deep waters. These portions include the sagbend and touch down regions where significant bending and abrasion can be expected. To reduce some of this uncertainty, a monitoring program was initiated for an SCR attached to the Petrobras P18 Semi-Submersible (Serta, 1996). The objectives of this project were to evaluate and verify the methodologies and to calibrate the numerical models used in the riser design. The parameters being measured are as follows:

- Environmental conditions
- Platform motions and positions
- Riser loads and stresses at the top connection and at the touch down area
- Riser loads due to vortex induced vibration.
- Riser transversal oscillation that is measured using accelerometers to investigate the VIV behavior.

Petrobras is also including in their overall study program objectives, the evaluation of the effectiveness of the VIV suppression strakes, which are scheduled to be installed at a later date after the completion of the first phase of the study.

Although the SCR concept is now a proven technology, SCRs have yet to be installed on FPSOs due to their large amplitude motions. There is growing confidence in their use with FPSOs, particularly in relatively benign environmental conditions such as those typical of West Africa. As a result, several ongoing FPSO projects have included SCRs as part of the overall design.

Petrobras is currently studying the feasibility of using SCRs connected to an FPSO (Silva et al., 1999). In general, the technical issues to be addressed when designing an SCR for an FPSO are similar to those for a semi-submersible. Some aspects being investigated are of particular interest for FPSOs such as the relative location of the turret with respect to mid-ship for the SCR installation. The SCR being considered in the study has a 12.75-inch outside diameter with 1-inch wall thickness.

Silva et al. (1999) also investigated an alternative way of reducing the stress levels at the top of the riser by uncoupling the riser motion from that of the vessel. The parametric study concluded that the value for a/L should be less than 0.22 (a is the distance from mid-ship and L is the length of the FPSO) for a free hanging SCR connected to an FPSO.

Petrobras is also studying the possibility of reducing the stresses at the critical sections of the SCR by proposing the use of different types of top joints and riser sections (Silva et al., 1999) such as:

- Flex-joints and stress joints
- Flexible pipe section
- Titanium sections
- Buoyancy sections
- Concentrated buoyancy elements

The SCR fatigue damage due to wave and low frequency motions and Vortex induced vibrations (VIV) is discussed later in the paper.

Top Tensioned Riser or Buoyant Riser

Some of the behavioral aspects of a top tensioned pipeline riser in very deep water can be derived directly from the behavior of drilling risers. For example, for drilling risers it is essential to ensure that the angle at the bottom Lower Marine Riser Package (LMRP) does not exceed 3 degrees. This would also be applicable to top tensioned production risers (TTR) in deep waters. In very deep water (e.g. 10,000 feet) the riser deflection would be even more pronounced due to loop and multi-directional currents effects.

Tests conducted by ENI-Agip (Guaita et al., 1998) indicate that the riser's top tension varies significantly because of the compliancy of the riser.

Top tensioned or buoyant risers operating from the moon-pool of Spar type floating structure are subjected to hydrodynamic forces, which the present computer programs cannot analyze. This is the hydrodynamic load induced by the oscillating water column within the moonpool of the Spar hull. It was shown in Strathclyde experiments, that the period of the oscillating water in the moonpool is longer than the ambient wave period (Lee and Day, 1986).

The horizontal direction flow regime within the moonpool can be established by the use of diffraction analysis, but it is not clear how to combine the radiating flow from the wall of the moonpool with the oscillating free surface. Using the wake formulation theory, Morison's loads can be estimated (Huse, 1993); however, it is worth noting that the wake formulation was developed for TTR where the risers are in relatively close proximity. As such, the method may not be directly applicable for example to SCRs connected side by side to an FPSO. The wake formulation also does not detail how far downstream of the first riser the free stream velocity will start dominating again.

Riser Tower or Hybrid Riser

A riser tower is a hybrid riser with a vertical bundle of steel pipes supported by external buoyancy. The advantages of the riser tower concept include smaller footprint on the seabed than that of SCRs, the ability to decouple the riser from the vessel motion and reduced structure loads. Compliancy is provided through the use of short flexible jumpers, located near the surface to accommodate motions between the vessel and the top of the riser. A benefit of this type of riser is that at the end of the field life, the riser tower may be de-commissioned for future use. This type of riser was first studied in a Joint Industry project conducted by INTEC and then subsequently studied during the DEEPSTAR project and reported by Hatton (1997) for a Gulf of Mexico scenario.

The first hybrid riser was installed on the Placid Green Canyon development. Subsequently, the riser was refurbished and re-installed for use on Ensearch's Garden Bank development in 670m water depth. Cottrill (1994) and Hatton (1997) provided a complete description of this type of risers.

The Ensearch hybrid riser was installed similarly to a drilling riser by assembling individual joints from a semi-submersible to form a vertical string. Hatton (1997) showed that an alternative installation method using a near surface tow of a prefabricated riser bundle and then upending at the site was also feasible. The riser would be neutrally buoyant during tow-out.

The Girassol field riser (Michelle et al., 1998) is the only active development concept for a free standing riser tower. It was designed and model tested by Doris Engineering and field tests were conducted in a lake to evaluate the loads for upending the riser; however, their test results are not yet published. In the analysis of the Girassol concept (Michelle et al., 1998), it was shown that the fatigue damage during operational conditions is minimal. The large buoyancy diameter has the effect of producing high wave's loads and VIV may not be an issue because of high

TABLE 1: RESULTS OF HATTON (1997) AND GARRET (1998) STUDIES

	Gulf of Mexico	West of Shetland
Water Depth (m)	1300	1500
Upending time (which is also a function of the net weight)	60 minutes @ 0.4m/s	30 minutes peak @ 2.5m/s
Fatigue damage during Tow-out	1%	15%
Total Installation time (days)	7-10	14-21

Riser Analysis

Vortex Induced Vibrations (VIV)

One of the main concerns with the SCR and TTR analysis and design is the issue of VIV. The magnitude and frequency of the fluctuating lift force caused by vortex shedding is dependent on the component of flow perpendicular to the riser. The fatigue damage due to VIV increases with increasing the perpendicular flow velocity. For currents perpendicular to the plane of the SCR, the current velocity is always perpendicular to the pipe. For currents parallel to the SCR plane however, the velocity component perpendicular to the pipe is equal to the current speed multiplied by the cosine of the SCR slope from vertical. Close to the seabed, where the SCR is nearly horizontal, the perpendicular component of the flow is substantially less than the full speed, resulting in reduced VIV and fatigue damage. If the currents are assumed to have a direction perpendicular to the plane of the SCR, they will therefore give a conservative estimate for the fatigue damage (Vandiver et al., 1996).

Experience indicates that using single-mode analysis gives more conservative results than multi-mode analysis. However, using single-mode analysis with both kinds of shear currents, i.e. normal and low shear (see Figure 1), would be over conservative since multi-mode response dominates the VIV response to low shear current (Vandiver et al., 1997) (Mekha et al., 2000). The boundary between single mode and multi-mode response should be considered carefully, since the parameter . V/Vaverage can vary depending on the accuracy and reliability of the current data. It is more realistic to use single mode analysis with normal shear current and multi-mode analysis with low shear current. Sample results for normal and low shear currents are given in Figures 2a and 2b, respectively (Mekha, et al., 2000).

Vortex Induced Vibrations depend on the active modes of vibration and their relation to the incoming velocity profile. The regions of lock-in are dictated by the velocity profile. It was shown by Humphries et al. (1987) in Figure 3 that the higher the shear of the current, the larger the amplitude of vibration and lower the range of the reduced velocity that causes lock-in.

BP Amoco has been conducting experiments on drilling risers in 3,800ft of water depth in the Norwegian sector of the North Sea (Moros and Fairhurst, 1998). The current data recorded in one case showed that the current profile decreasing with depth to a point after which the profile increases again. It becomes more difficult to predict lock-in if a velocity profile applied is similar to that recorded by BP Amoco.

In a particular experiment where the riser displacement envelopes and current profile were recorded, it was seen that the measured current profile was not uniform as shown in Figure 4. Two possible current profiles were fitted to the recorded data. It was found that the field measured riser displacement matched well with one but not with the other. This experiment demonstrates the importance of measuring the current profile with high accuracy.

Strakes are used to suppress the VIV motion of riser; however, their installation is a complicated procedure. A rigorous analysis is required to determine the size of the strakes and the sections of the riser where strakes are required. Hatton (1998) provided a method for optimizing the size of the strackes.

In the absence of current, a heaving motion of the vessel will also cause vortex induced vibration especially in the touch down area where the riser is not vertical. This was observed in the PMB experiments (Grant et al., 1999), however, this type of lock-in will only occur if the frequency of the heaving motion is equal to one of the natural frequencies of the riser. Trave et al. (1993) analyzed riser vibrations induced purely by the motion of the vessel, in the absence of waves and currents. The equation below is used to calculate the reduced velocity on a particular point (z) along the riser length based on the frequency of the induced motion (f), the riser natural frequency (fn) and the amplitude motion (A(z)).

$$V_{Rn}(z) := 2\cdot\pi\cdot\frac{1}{D}\cdot\frac{f}{f_n}\cdot A(z)$$

Guaita et al. (1998) showed that current induced vibration is not a sustainable process. The lock-in may occur in the first cycle, but because of the fluid structure interaction (where the flow conditions are modified in the neighborhood of the cylinder) and the variation of tension along the riser, the lock in condition is broken in the following cycle. Lock-in conditions seem to occur over a limited portion of riser length and for limited duration probably due the spatial and time variation of the fluid flow. This is true for the case of a compliant cylinder than a stiff cylinder (with higher effective tension). SCR behavior is more like a compliant cylinder than a stiff cylinder.

Random Wave Analysis

For some field studies, using a regular wave analysis with Hs or Hmean may be sufficient to estimate the fatigue damage. In cases where the estimated fatigue life is close to or less than the design fatigue life, a full random wave analysis may be necessary. Other studies have also shown that performing a full random wave analysis can lead to a less conservative estimate of fatigue life.

Fatigue Damage

In all riser concepts under consideration, the fatigue assessment is arbitrary and needs to be investigated by more rigorous techniques. Fatigue life is normally assessed by using the S-N curves as given in API RP2A Code. However, different operators/designers have used these curves in different ways. For example, Shell has used the X' curve with a stress intensification factor of one. Whilst Petrobras has used the X curve with stress intensification of 1.48 for the P18 SCR, the X' curve with a stress intensification of 1.08 is planned to be used SCR with the P36 floater (Cristinellis and Braga, 1999). BP-Amoco conducted some tests on the material that was to be used on the King SCR (Harrison et al., 1999) and showed that the fatigue life is 4.7

times longer than that predicted by the E curve (which is nearly parallel to the X' curve of the API RP2A code).

Larsen (1998) suggested that a 2D-frequency domain analysis was sufficient to check fatigue damage in the wave zone, however, this method does not address the damage problem close to the touch down point. For this area of the SCR, Larsen recommended to use the work of Pesce (Pesce, 1997).

Campbell (1999) presented the complexities of fatigue analysis for deepwater risers. It was noted that for an FPSO, vessel motions could be severe enough to cause compression and buckling at the touchdown point. Low frequency motions are dependent on the type of the mooring system being used. Typically, taut leg mooring increases the natural frequency and reduces the amplitude of the low frequency motions in comparison to a slack catenary mooring. But with a slack mooring, the amplitudes are larger and therefore the fatigue life is improved by spreading the damage across a longer length of the riser.

Campbell discussed addition of fatigue damage by various methods. Among those suggested were combining low frequency and high frequency process using statistics as suggested by Jiao and Moan (1990). Then the stress cycle counting can be carried out by either the rainflow method or the reservoir method (Gurney, 1979) (Kulak et al., 1993). Simple addition of the fatigue damage by summing up the contributions from the 1st order motion, 2nd order motion and VIV was not recommended even though in STRIDE II such a procedure was followed (Hatton, 1998). If the wave spectrum is narrow-banded then it is reasonable to use this method.

The fatigue life from 3 different cases, STRIDE II, a Semi-submersible in Gulf of Mexico, and a mini-TLP in Gulf of Mexico, are given below as obtained by simple addition.

TABLE 2: FATIGUE LIFE COMPARISON

	First Order	**Second Order**	**VIV**
West of Sheatland (Stride II) TLP 14-inch SCR in 800WD	57	85	185
Gulf of Mexico Mini-TLP 12-inch SCR	205		17094
Gulf of Mexico Semi-Submersible 14-inch SCR	192	161	272

Soil Structure Interaction

The main area of investigation of the PMB project (Grant et al., 1999) was the dynamics of risers at the touch down point. The results showed the necessity to correctly model the seabed soil and the behavior of intermittent vortex induced vibration. Unfortunately, the existing computer programs are not capable of correctly modeling the seabed. Another area of concern, is the problem of riser entrenchment where seabed consolidation and suction from soft clays can contribute to the overall fatigue damage of the riser.

Risers have been observed to sink in 6 times their own diameter (Offshore, 1999). The CARISMA JIP (Catenary Riser/Soil Interaction Model for Global Risers Analysis) will address issues such as prediction of the depth and shape of the trench based on the long term statistics of vessel motions, riser configuration and soil data. The JIP will also look at the suction forces imparted to the riser due to vessel motions. Other effects to be studied are the resistances in bell mouth type of trenches, overfill of soil on top of the riser and consolidation of the soil beneath the riser.

Conclusions

A review of various types of Steel Catenary Risers (SCR), Top Tensioned Risers (TTR) and Riser Towers has been presented. The following conclusions can be drawn from this review:

Considerable information exists for riser systems which are suitable for deepwater. Development scenarios are characterized by different floating structure type and local environmental conditions.

SCRs vortex induced vibration (VIV) analysis requires the selection of the number of active vibration modes and a true assessment of the current profile.

Most of the fatigue damage for riser towers comes from the tow-out and upending process. Sufficient structural simulations around the natural periods of the riser should be conducted.

For the initial design stages of the SCR, a deterministic wave analysis may be sufficient for fatigue life estimation. This is especially true if the seastate is narrow banded.

The fatigue damage due to 1st order and 2nd order motion of the vessel should be assessed by rainflow counting methods especially if the nature of the seastate is ill-defined.

Soil structure interaction in case of an SCR is still not well understood. The SCR tends to find its own natural position in the touch down area.

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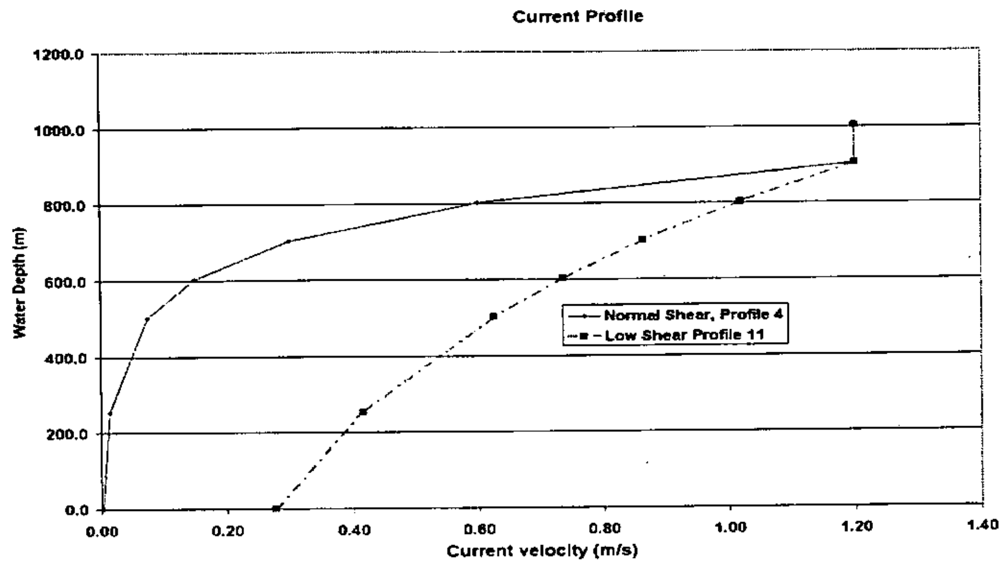


Figure 1: Normal & low shear current profile.

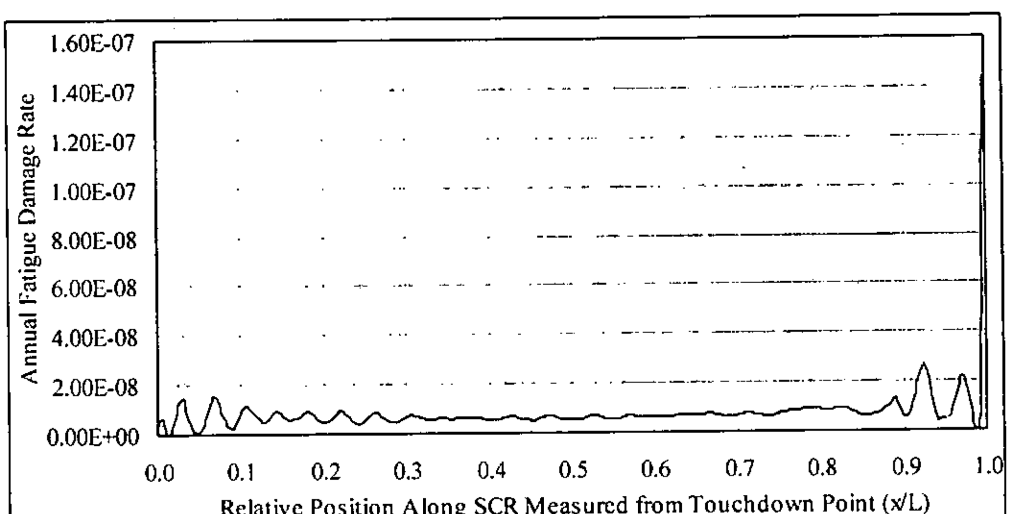


Figure 2a: Annual fatigue damage rate along the SCR subjected to normal-shear current (Mekha et al., 2000).

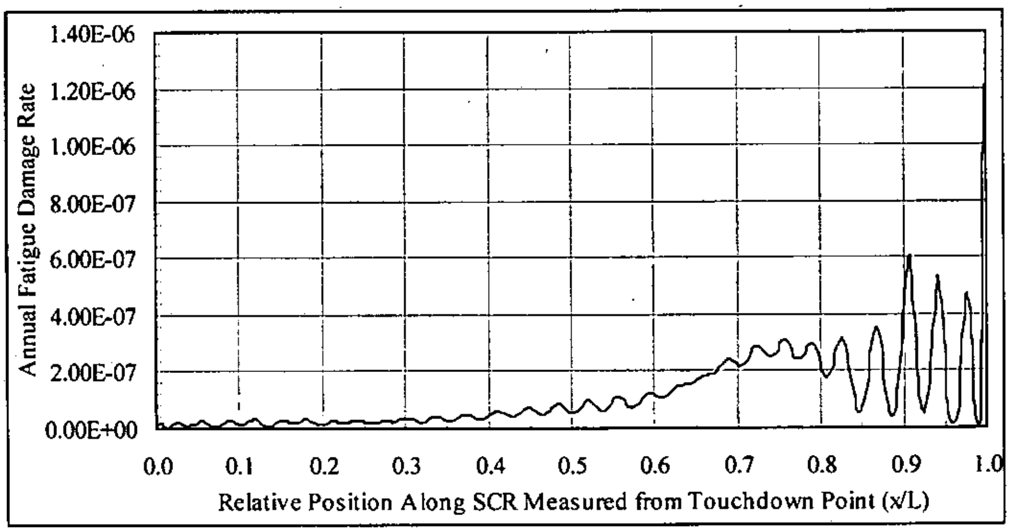


Figure 2b: Annual fatigue damage rate along the SCR subjected to low-shear current (Mekha et al, 2000).

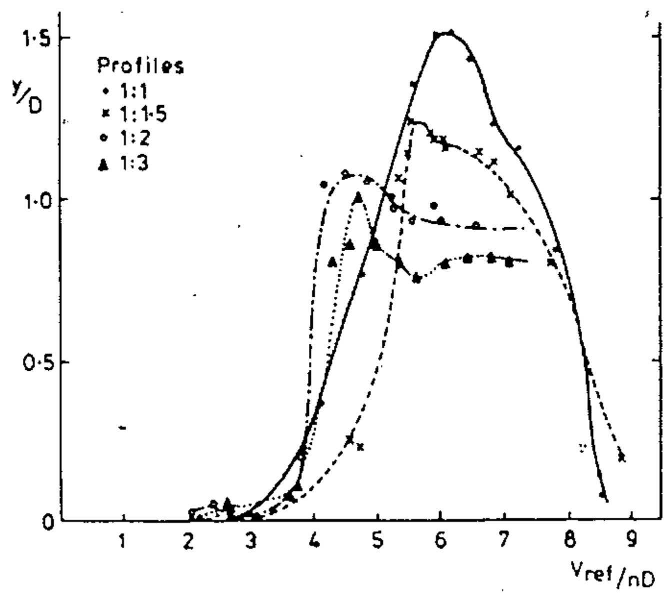
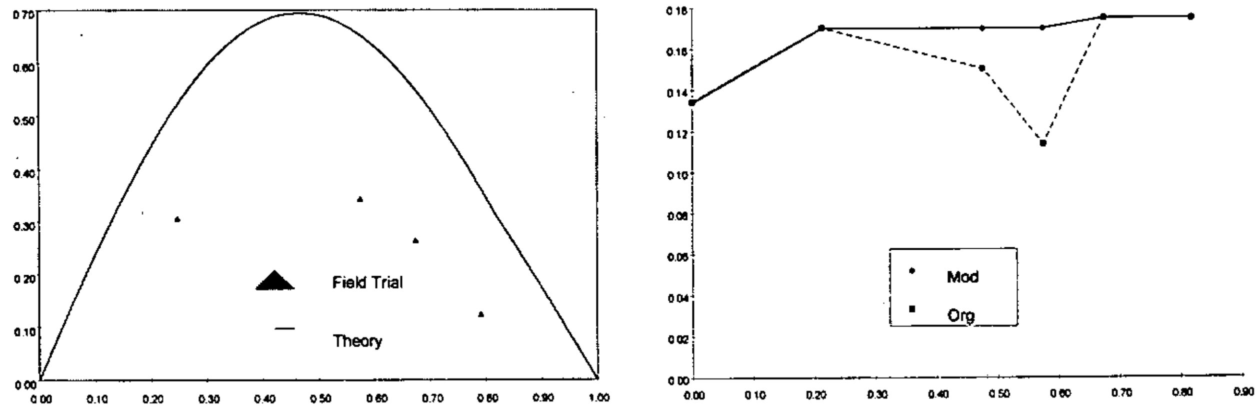


Figure 3: The effect of the profile of the current on the relative amplitude (Humphries and Walker, 1987)

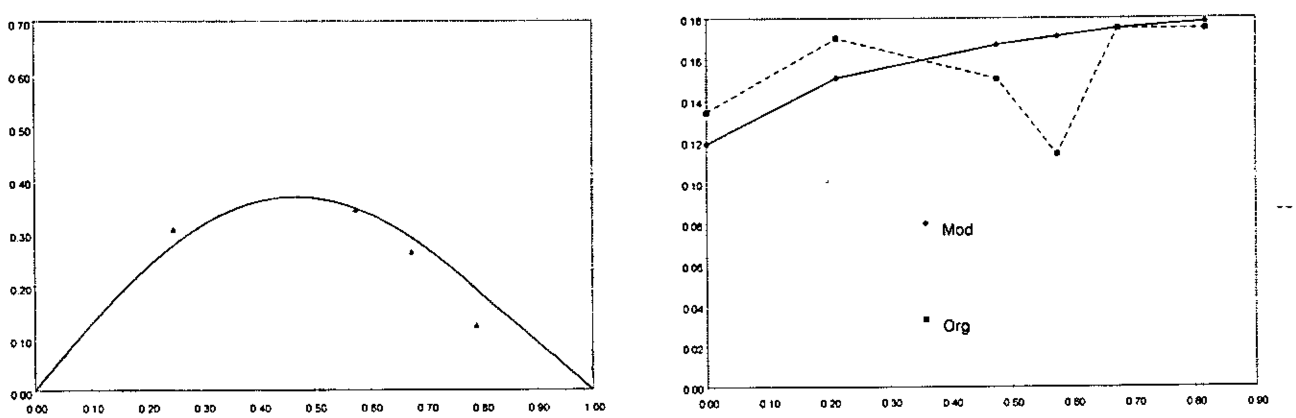


(i) (ii)

In (i) the horizontal axis is height of cylinder above sea-bed (x/L) and the vertical axis is the displacement of the cylinder (y/D)

In (ii) the horizontal axis is height of cylinder above sea-bed (x/L) and the vertical axis is the current velocity

<u>Case (A)</u>



(i) (ii)

In (i) the horizontal axis is height of cylinder above sea-bed (x/L) and the vertical axis is the displacement of the cylinder (y/D)

In (ii) the horizontal axis is height of cylinder above sea-bed (x/L) and the vertical axis is the current velocity

<u>Case (B)</u>

Figure 4: Measured & fitted current profile with theoretical and recorded displacement envelope

Deepwater Riser VIV, Fatigue and Monitoring

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Deepwater Riser VIV, Fatigue and Monitoring

Abstract

Vortex induced vibration is (VIV) is a major design issue for all deepwater riser systems operating in regions where severe current can be expected, such as the Gulf of Mexico and offshore Brazil. Cross-flow vibrations of a riser in severe currents can diminish the riser fatigue life, dictate the riser arrangement, fabrication details, vessel layout, installation method, and thus have significant cost impacts at all stages of the field development. The limitations of existing analytical methods and test data for predicting deepwater riser VIV response are discussed. This shows that in-service monitoring or full scale testing is essential to improve our understanding of VIV response and confidence in its predictions. A number of monitoring and test programmes are described and some of the key findings reported. Based on the experience, instrumentation requirements for monitoring VIV response are described and a design approach to deal with VIV is proposed.

Introduction

Oil and gas production in deep and ultra-deep water depths presents many challenges, one of them being the design of technical and cost effective riser systems. In almost all deepwater areas where hydrocarbons are found, severe current loading is invariably expected. High current can generate vortex-induced vibrations that give rise to high rates of riser fatigue damage accumulation. As water depth increases, riser designs become more varied and VIV behaviour presents one of the biggest uncertainties facing the riser engineers.

A great deal of experimental work, mostly on a reduced scale, has been conducted from which analytical tools to predict riser VIV response have been developed. However, as new riser configurations are developed to cope with the increasing water depths and reservoir challenges, the similarities between test models and real riser systems are diminishing rapidly. This has led to a need for more work to be conducted to understand VIV of real riser systems by full scale testing and in-service monitoring.

Implications of Riser VIV

Under steady current flow conditions, cross flow vibrations of risers have two immediate consequences:

1. Increased fatigue damage (Figure 1)
2. Increased in-line drag (Figure 2)

These effects can influence the design and operation of riser systems in different ways, according to riser type, as described below.

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Top Tensioned Risers

Top tensioned risers as used on tension leg platforms (TLP's) and spars may require increased top tension or suppression devices to limit the fatigue damage induced by VIV. The use of suppression systems adds to cost and the difficulty of installation. Increased top tension results in increased loading on the riser base and wellhead system and increased platform loading in the case of TLP's. For spar riser systems, an increased number of buoyancy cans may be needed. The additional buoyancy cans must be located near the base of the spar, where they are subjected to increased external hydrostatic pressure and thus are less effective than those near the water surface. On both TLP's and spars, increased spacing between risers may be needed to avoid clashing or to accommodate the buoyancy cans needed (spar). In extreme cases, the required spacing may limit the number of top tensioned risers that can be used on these vessels.

Steel Catenary Risers (SCR's)

Limitation of VIV induced fatigue damage in SCR's may require the use of suppression devices or increased top tension, as for top tensioned TLP or spar risers. The SCR's on the Auger and Mars TLP's employ helical suppression strakes (Figure 3) over the top 500ft where current loading is most severe [1]. On the 10in SCR attached to the Petrobras XVIII in the Campos basin, the riser top angle is set at 20 degrees in order to provide a high riser tension and avoid the need for suppression devices. This approach reduces riser costs, but adds to platform loading. If large diameter SCR's or a large number of SCR's are used, this approach may not be feasible.

Drilling Risers

Joint rotation programmes may be implemented in order to distribute damage throughout the riser string rather than concentrate damage in just a few riser joints, and reduced intervals between inspections may be necessary to confirm fitness-for-purpose. However, the use of different joint types or buoyancy ratings in different parts of the riser string may limit the effectiveness of a rotation programme. Riser tension may be increased to reduce the fatigue damage incurred in the riser, but vessel tension capacity limits the feasibility of this approach on many vessels and increased VIV fatigue loading may be incurred in the wellhead and conductor system. This area is often overlooked, and though time spent on the wellhead may be a matter of a few months, the rates of fatigue damage accumulation can be considerably higher than in the riser system itself. The wellhead and conductor can therefore form the fatigue critical section of the well control system. In extreme environments, where prolonged drilling programmes are to be conducted, VIV suppression devices may be necessary to reduce the rate of fatigue damage accumulation.

Increased drag due to VIV results in increased flex-joint rotations. As flex-joint rotation dictates the limits for conducting drilling operations, increased downtime is also incurred as a result of VIV.

Uncertainties of Riser VIV Predictions

Current design tools used to predict riser VIV such as SHEAR7 [2] and VIVA [3] are based on experimental observations. Most of the test programmes that calibrate these tools have been conducted at small-scale, in sub-critical flow with low Reynolds numbers. In most riser systems, the highest rates of fatigue damage accumulation and the greatest contribution to long term fatigue damage is obtained from extreme currents. Consequently, flow in the critical and post-critical flow regimes is of most concern for practical riser systems, for which relatively little experimental data exists.

A further limitation of small scale testing is the use of idealised riser configurations with well-defined shapes and boundary conditions. While such arrangements are necessary to further our basic understanding of VIV behaviour, quite different responses may be obtained with real riser arrangements. An overview of the areas in which risers may differ from the idealised arrangements that form the basis of VIV analytical tools are described below.

Riser orientation and shape – the response of risers inclined to current flow and risers shaped with buoyancy to accommodate large vessel motions are not well researched. Both in-plane and out-of plane VIV vibrations may be generated simultaneously and further work needs to be conducted to provide an understanding of the VIV response of different riser shapes, and the effectiveness of VIV suppression systems when used on these risers.

Riser length – in very long risers, damping over a large proportion of the riser length may result in a travelling wave type response as opposed to standing wave as assumed in SHEAR7 [2]. Predictions of fatigue damage remote from the regions of greatest excitation may therefore be greater than in practice.

Riser terminations – the end conditions of deepwater riser systems can vary considerably. In top-tensioned risers, conductor-soil interaction can affect riser response and the seabed touchdown point of SCR's bares little resemblance to the boundary conditions typically used for analytical modelling purposes. Hydro-pneumatic tensioner systems used in top tensioned TLP risers and drilling risers may also have an influence on VIV response and tension fluctuations may be generated as result of VIV. Further testing is needed in order that the influence of varying boundary conditions on riser VIV can be quantified.

Multiple riser strings – many riser systems do not consist simply of a single pipe. Top tensioned production risers have one or two casings, in addition to the tubing for transport of well fluids. Drilling risers have a large diameter central pipe, choke and kill lines, umbilical and possibly a booster line and buoyancy modules, in addition to the drill string that rotates inside and is under tension. Interaction of the different lines is likely to have an influence on VIV response that needs to be quantified for design purposes.

Riser clusters – the VIV response of a riser lying downstream of an adjacent riser is different from that of a stand-alone riser [4]. The response is further complicated when many risers are grouped together, as in the case of TLP or spar production risers.

Riser profile – variability in the outer profile of a riser is found in drilling risers where a combination of slick and buoyant joints is used. Careful arrangement of the different joint types may produce less severe VIV response [5], though confirmation of this possibility is yet to be obtained.

Current profile – widely differing current profiles are found in different deepwater locations. Highly localised currents are found in the Gulf of Mexico in the form of loop currents and eddies, whereas more severe through depth currents are experienced in West Africa and the West of Shetland. The predicted response of risers to the different flow profiles varies significantly, but further data is needed to confirm these predictions.

Current directionality – variation in current flow direction though the water depth, particularly significant in Brazil, adds further difficulty to reliable prediction of VIV fatigue damage. For design purposes it may be assumed that either the current flows in the same direction throughout the water column or the current may be resolved into a single flow direction. The two approaches can produce significantly different results and more work is needed to understand the most appropriate method to model such environments.

In each of the above areas, the riser analyst must make simplifying assumptions in order to produce estimates of VIV response. Out of necessity, such assumptions err on the side of conservatism. However, due to the lack of available data, the levels of conservatism may not be understood even when parametric analysis is conducted. Consequently, further experimental data is needed to enable calibration of VIV analytical tool for practical riser arrangements and to obtain an improved level of confidence in predicted VIV response. Such data needs to be obtained at large scale or though in-service monitoring in order that differences in behaviour between idealised analytical models and real systems can be properly quantified.

In-Service Monitoring and Full-Scale Testing

The authors have been involved with a number of in-service riser monitoring programmes and test programmes conducted at full scale. Brief descriptions of these programmes and the current status are given below.

BP Schiehallion - Paul B. Loyd Jr drilling riser in 375m (1230ft) water depth, accelerometers at 3 locations along the length, monitoring over a period just longer than 1 month. Data processing completed;

NDP, BP Nyk High [6] - Ocean Alliance drilling riser in 1300m (4250ft) water depth, accelerometers at 5 locations along the length, monitoring over a period of 74 days. Data processing in progress;

STRIDE JIP, 2H Offshore Engineering Limited [7] - Tow tank test on 6in pipe to investigate the effects of inclination to flow of bare and straked pipe. Data processing completed;

STRIDE JIP, 2H Offshore Engineering Limited [7] - Open water tow test of 10-3/4in, 200m long curved riser to investigate inclination effects on bare and straked pipe, accelerometers at 40 locations (Figure 4). Data processing completed;

Chevron GoM – Glomar Explorer drilling riser in 2350m (7700ft) water depth, retrievable accelerometers at 2 locations, deployed in loop current events. Data recorded, awaiting processing;

British Borneo Allegheny – Seastar mini TLP 12in export SCR in 1005m (3300ft) water depth, retrievable accelerometers at 12 locations (Figure 5). Data recorded, awaiting logger retrieval and data processing.

Based on the data processed so far, predicted vibration amplitudes are consistently higher than those measured. This gives us confidence that riser design is erring on the side of safety.

However, the processed data do not provide sufficient information to explain the reasons for the conservatism in the theoretical predictions. Explanation for the over-predictions may be the higher effective damping inherent in the real systems, due to physical interactions and complex loading conditions, than is understood theoretically.

The sources of such differences vary with riser arrangement and may consist of the following:

1. Tension variations - all cases
2. Environmental loading from wave action - drilling risers and full scale tests
3. Multiple strings and wellhead-soil interaction - drilling riser
4. Use of GRP pipe – tow tank tests

Further testing is needed to quantify the changes in VIV response that may result from the effects described above. Tow tank and current flume tests can be used to provide some of the required information, with further field monitoring and full scale tests to establish the relationships between ideal and real conditions.

In-Service Monitoring Requirements

When conducting any riser test or monitoring programme, sufficient data must be available and measurements taken to define the following:

- Riser Physical Arrangement
- Loading Conditions
- Boundary Conditions
- Response

The riser arrangement can be simply defined in terms of riser weight and hydrodynamic diameter. Account must be taken of the pipe string, any couplings and buoyancy and internal fluids. As internal fluid weights can vary, steps must be taken to record the densities that correspond to monitored response. The weight of internal or attached lines must also be accounted for in multi-string risers together with the tension applied to each line.

Current flow speed and direction can be measured using acoustic current Doppler profilers (ACDP's). Due to limitations in the depth over which these devices can operate, they may need to be placed both near the surface and the seabed in order that the flow profile and direction can be defined throughout the entire water depth.

The boundary conditions applied to risers are often considered well defined. The tension applied to top tensioned production risers or drilling risers is dictated by the pressure in the accumulators, and can be readily recorded. However, tension fluctuations may be induced by VIV for which special monitoring devices may be needed. At the riser base, the wellhead system is often assumed to be rigid, but significant movements can occur particularly in the soft soils encountered in many deepwater locations. Care should therefore be taken to ensure that the tension applied at the top and fixity that is realised at the bottom are properly monitored.

Monitoring of riser response poses many additional difficulties to those encountered monitoring loading and boundary conditions. Some of the issues that must be addressed when determining instrumentation requirements to monitor riser response in-service are described below.

Active vs. Passive – In ideal circumstances, it would be possible to inspect all riser response data during testing through use of an active (on-line) monitoring system. Active devices must transmit signal back to the drilling or production vessel. This may be achieved by way of telemetry, but the power needed for such an approach would require large batteries or limit the time over which data could be recorded. Hardwiring has been used for permanent riser systems (TLP production and export risers) but is not well suited to drilling risers that are regularly disassembled. Routing of power and signal cables can add to installation time and cables may be easily damaged. Passive monitoring devices may be mounted on the riser joints either prior to or during installation using straps or clamps (Figure 6). Following riser retrieval (drilling riser) or by ROV retrieval of the monitoring devices (production and export risers, Figure 7), data can be downloaded and interpreted carefully (Figure 8). The passive approach has been successfully implemented for monitoring riser VIV response in all the monitoring programmes described above. Recently developed passive monitoring devices can record a considerable quantity of data at relatively low cost. Unless it is proposed to adjust the riser configuration in reaction to VIV response, such as may be attempted with a drilling riser, there may be little benefit in using an active monitoring system. However, when using passive devices, difficulties may arise when attempting to assess the relative motion between different points along the riser length due to drift of the monitoring clocks, which may vary from one device to the next [8]. Start and end times must therefore be carefully recorded and means of applying and recording time signatures evaluated if monitoring over a long period of time.

Strain or Displacement - Measurements may be taken from strain gauges to give riser stresses directly or from accelerometers to give displacements. Using the latter approach, riser stress variations and accumulated fatigue damage may be inferred from comparisons between analysis results and field measurements. The readings obtained from accelerometers are subject to gravitational effects that can introduce errors in results interpretation. Care must therefore be taken to ensure that such effects are properly accounted for when evaluating response.

Number of Monitoring Locations – To further our understanding of VIV response of practical riser systems the deflected shape of the riser system along its entire length should be known at any time. This would require the use of 4 or 5 monitoring points per mode of vibration, which in longer riser strings would result in the need for many 10's or 100's of monitoring devices and considerable expense. However, if the objective is simply to calibrate analysis tools, effort can be focused on monitoring critical regions where loading and fatigue damage is expected to be greatest, typically the top and bottom of the riser. This would not provide the complete response picture, but much could be inferred from observations made in this way.

Sampling Frequency and Filtering – Riser response data is often filtered prior to recording to remove response signals outside the expected frequency bands. However, it is important, particularly for practical riser systems, that as much data as possible is gathered. System responses outside the expected frequency bands of riser response, that may be generated in multi-string risers or from tension fluctuations, may have an influence on predicted vibration response. Detailed evaluation of the system being monitored must therefore be conducted in order that the sampling and filtering frequencies can be set.

Sampling Period and Interval – In tow-tank or current flume tests of VIV, response monitoring is likely to be conducted continuously for the duration of each test. When monitoring in-service, continuous monitoring of response is unnecessary, and intermittent monitoring of response may be used. The frequency at which devices are activated depends on the expected variations in the environment. One would not wish to miss monitoring a significant event, hence intervals of the order of 2 to 6 hours may be sufficient. The period for which monitoring is then conducted depends on the period of riser VIV and to some extent, the monitoring frequency selected. Sufficient data points must be accumulated to enable processing of the results, typically by fast Fourier transform, and to enable processing of individual segments of the monitoring period in order that any variations in response over the total sampling period can be defined.

Design for VIV

When designing risers for long term service on floating production systems a factor of safety of 10 is generally applied to service life to give the required fatigue life. Due to the uncertainties in VIV predictions, a safety factor of 50 to 100 has been adopted in some instances. Coupled with the potential conservatism of VIV analytical tools based on the evidence of full-scale tests, current riser designs may be considerably more conservative than necessary. This can lead to unnecessary use of VIV suppression devices that can cost as much as $400/ft. For a Gulf of Mexico development where such devices may be used over a length of 500ft, the cost for 10 risers would be $2M. In areas where through depth currents are greater, such as West of Shetland and Brazil, suppression devices may be required over a much longer length and suppression system costs would be much greater. Furthermore, use of suppression systems can affect the installation methods used, which may further increase costs.

Where VIV fatigue life predictions for riser systems without suppression are found to be marginal, the designer may question whether VIV suppression devices need to be used. An effective, but costly, suppression system may provide almost total suppression of VIV, when only a 50% reduction of vibration amplitudes is needed to provide a 10-fold increase in fatigue life. For short term developments, or developments where the reserves are uncertain, an alternative to fitting these high cost suppression devices right from the start could be considered. It is proposed for these cases that the riser VIV response is monitored and, if necessary, VIV suppression devices are retrofitted subsequently if rates of fatigue damage accumulation are found to be high.

The monitoring system cost can be relatively small and is estimated to be $300k over 5 years as follows: capital costs of monitoring devices 10 @ $10,000, and data processing once per year at $40,000. In addition, suppression systems have been developed that may be retrofitted to the riser at relatively low cost [9].

This approach may appear complex without offering the protection afforded by suppression systems, but the capital costs of suppression devices are at worst delayed and may be completely avoided. In order to determine whether such an approach can be adopted the distribution and rate of fatigue damage accumulation from different current loading conditions must be examined. Provided the majority of long term fatigue damage does not result from just a very small number of extreme events, the use of suppression devices from day one may be avoided.

Conclusions

The analytical tools used to predict VIV and the associated fatigue damage are based on a vast amount of small scale tests. However, there are substantial gaps in the experimental data base that limits our ability to reliably predict VIV in real riser systems. This may lead to undue conservatism and increased costs at best, or under-conservatism and unsafe design at worst. Practical riser arrangements and current conditions that induce VIV can be substantially different from many of the idealised test arrangements that form the basis of existing analytical tools. Consequently, there is a need to conduct further testing and in-service monitoring of risers in order to calibrate these tools. Much has been learnt from work conducted already and low cost equipment has been developed that can ensure that future monitoring programmes are properly directed and are conducted economically. This will ultimately lead to more reliable design for riser VIV and reduced riser costs, which will assist in establishing the feasibility of future developments in deep and ultra-deep waters.

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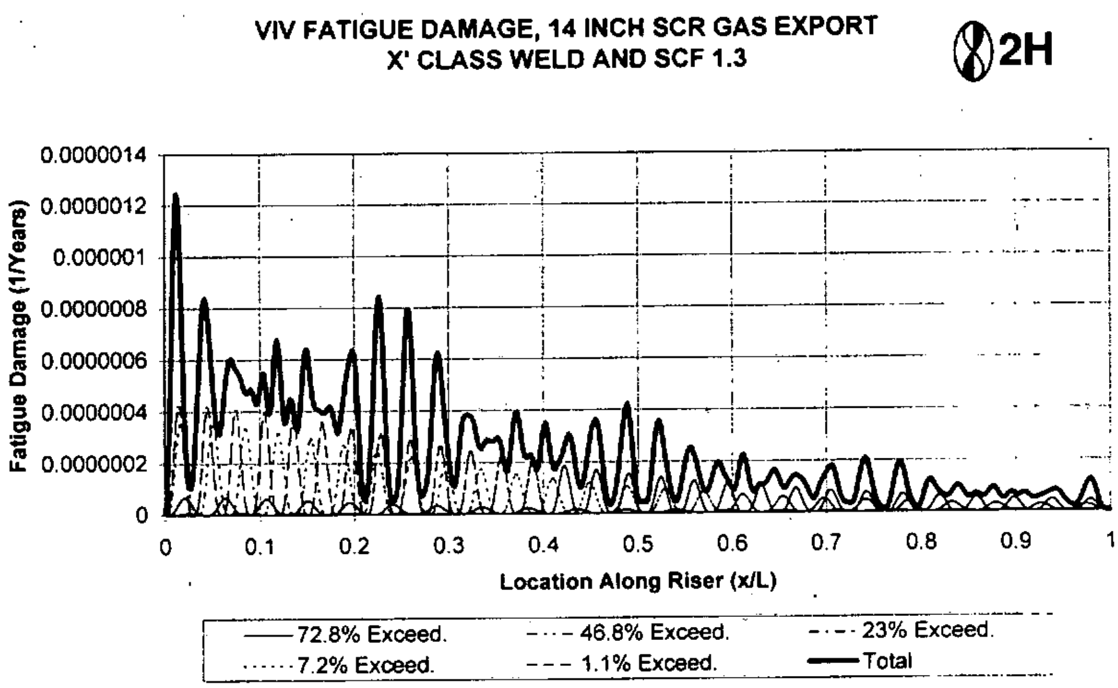

Figure 1 – Example SCR VIV Fatigue Damage Distribution

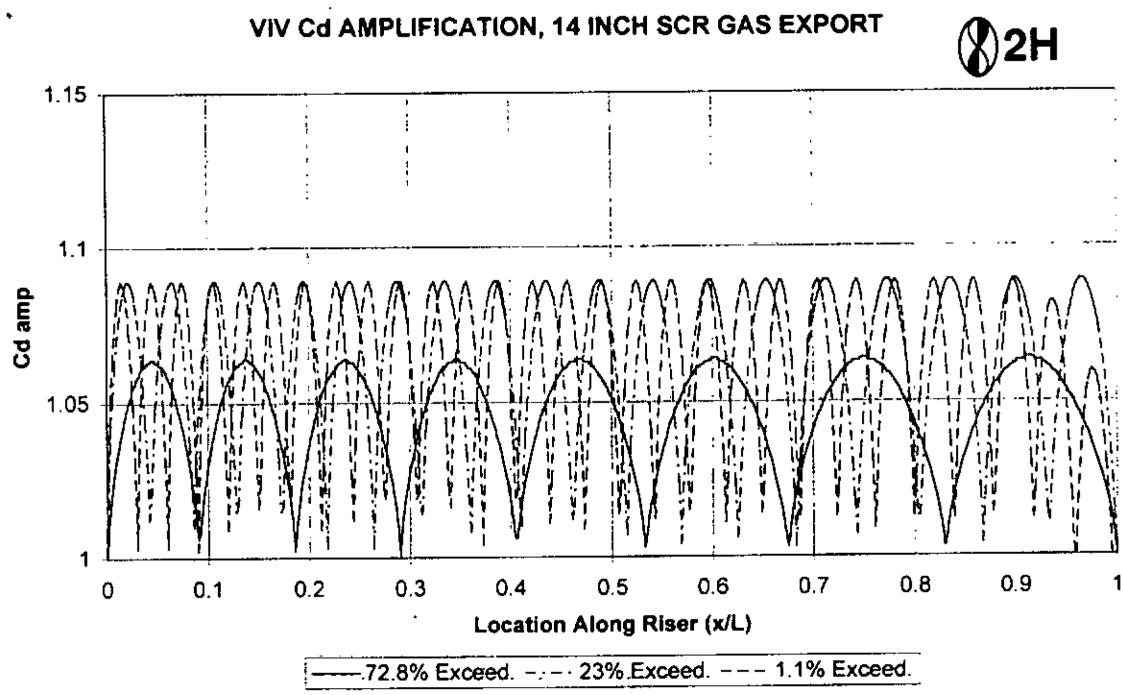

Figure 2 – Example SCR VIV Cd Amplification

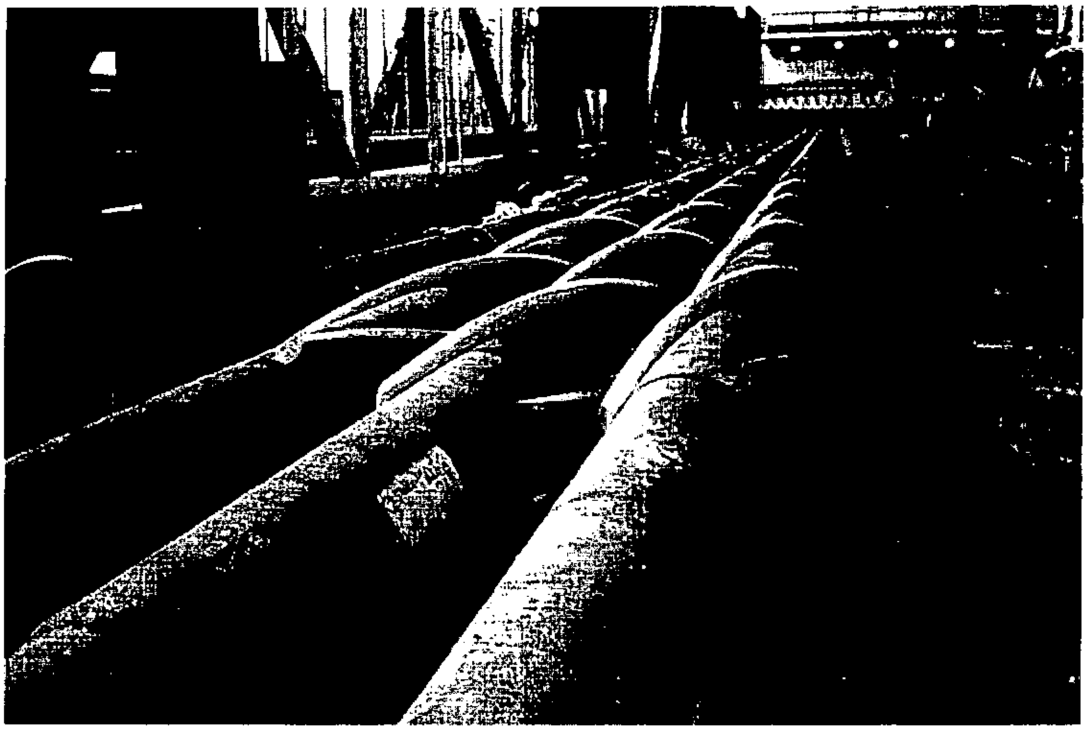

Figure 3 – Helical VIV Suppression Strakes

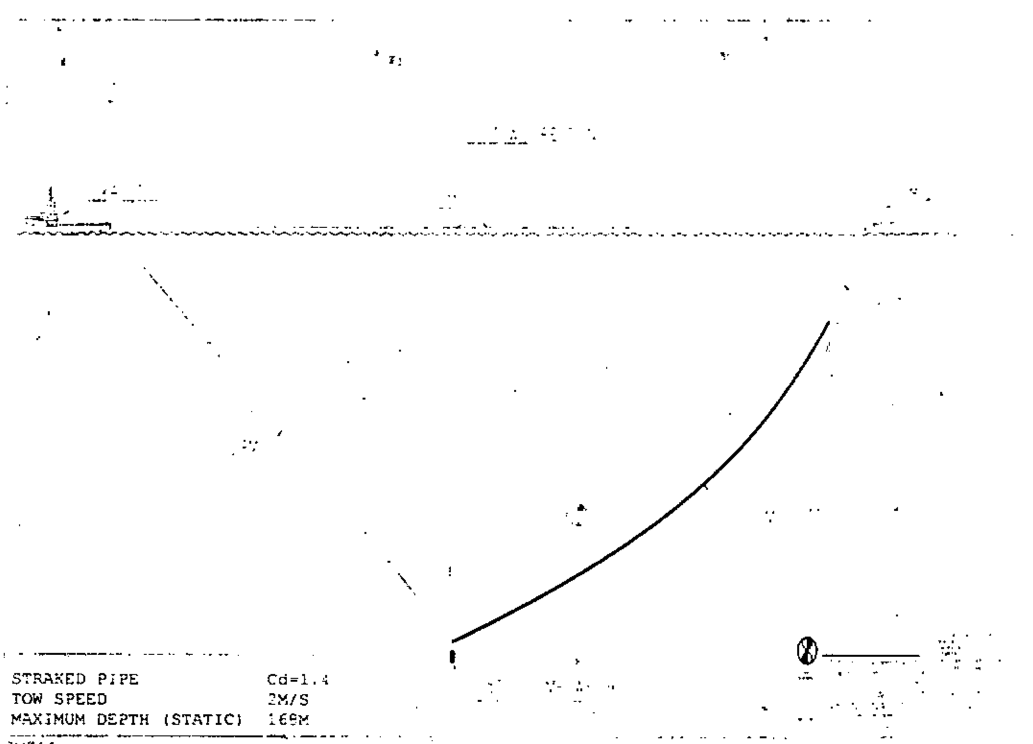

Figure 4 – STRIDE Full Scale Open Water Test Arrangement

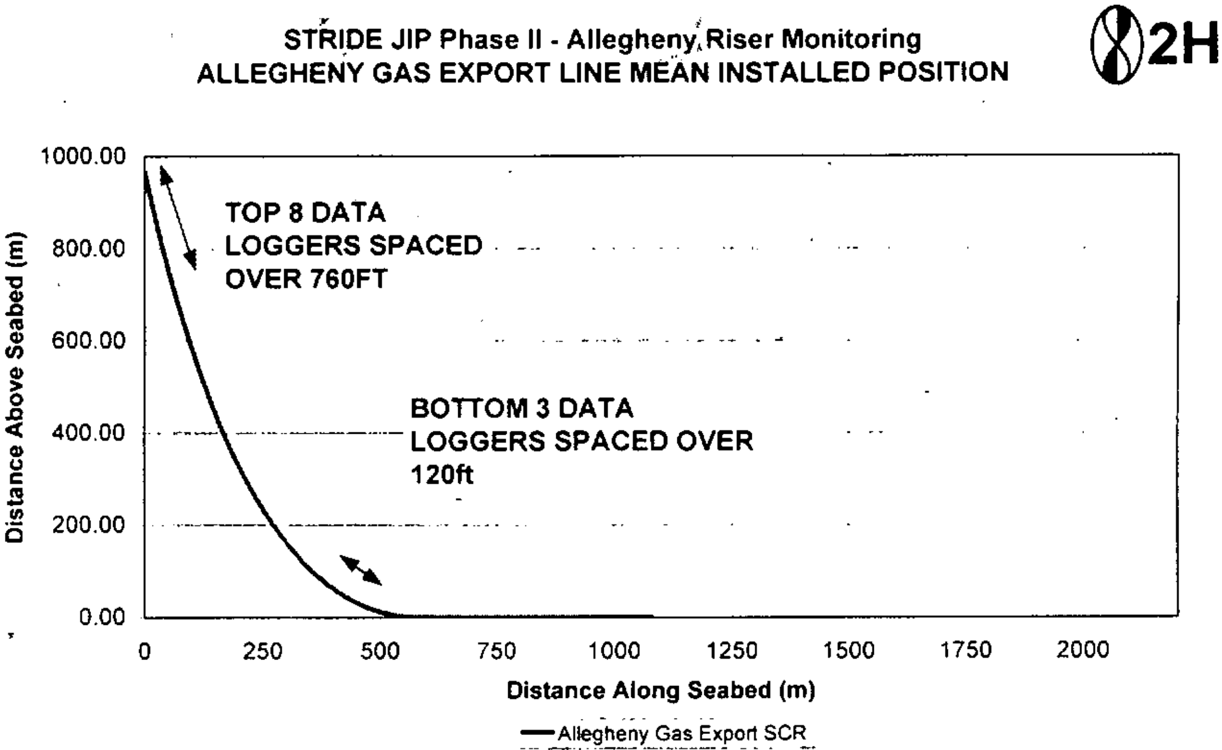

Figure 5 – Allegheny SCR Data Logging Positions

Figure 6 – Strapped on Passive Data Loggers

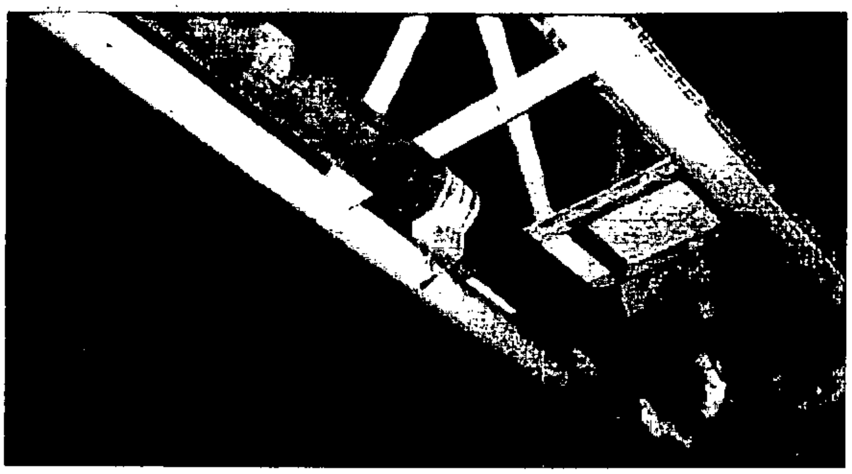

Figure 7 – ROV Retrievable Passive Data Loggers

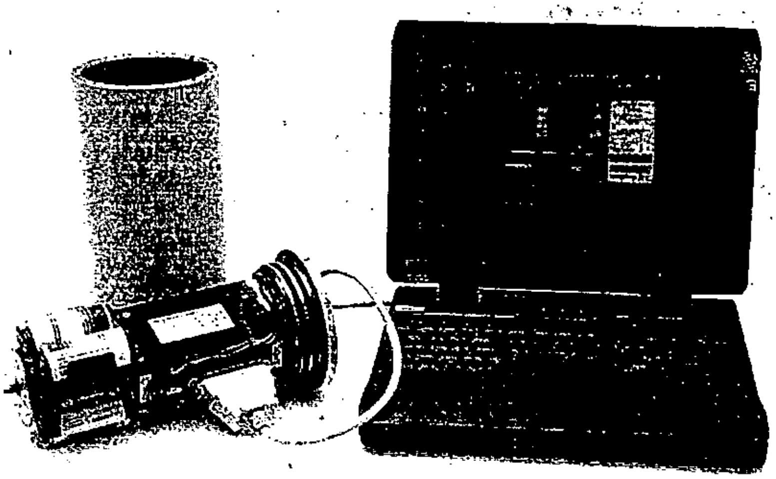

Figure 8 – Logger Download and Processing

Fatigue Performance of Catenary Risers Installed by Reelship

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and
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SUMMARY

A two and a half year development programme was performed by CSO, to qualify Reeled Steel Catenary Risers (RSCR). This programme has been completed successfully and a summary of the results are presented in this paper. The following subjects were included in detail, which makes this programme unique amongst other development programmes on SCR's. The fabrication, installation and in-service integrity were all covered, allowing the reeled SCR to be offered as a complete product.

The fatigue testing and the mechanical testing was performed at TWI. Full scale tests used a fatigue test rig that is cost effective and unique in its ability to apply a high mean axial stress, in addition to cyclic bending stresses. The use of this test rig enabled the generation of a large amount of full scale test data. The large amount of mechanical testing included, CTOD, JR-curve, Charpy, Tensile and Hardness tests, for three different levels of reeling strain. In total 275 samples were tested. Extensive analysis and evaluation of data resulted in the following conclusions.

- Full scale fatigue testing of Reeled Pipe, giving a well defined absolute fatigue performance, equal to, or above currently applied SCR welds. No noticeable difference exists between the performance of strained welds and un-strained welds.

- Allowable Defect Assessment. The effect of reeling on defect growth is extensively investigated and results in NDE criteria are in line with typical existing criteria and equipment.

- Reeled pipe and girth welds, fabricated and installed as per methods and procedures of the CSO development programme are qualified for use in dynamic SCR's.

INTRODUCTION

Steel Catenary Risers (SCR's) installed to floating facilities have been used in offshore oil & gas developments for a number of years. The possibility of using reeled SCR's offers further significant advantages, such as decreased cost and installation time, fabrication occurs onshore and off the critical path, see reference [1] for more detailed information. Reeled SCR's are also ideally suited for plastic lined pipe. The main aspect to address in design of SCRs is the in-service fatigue endurance of the girth welds, [2,3]. Showing that reeled SCR's have equally good or better fatigue performance than more traditionally installed SCR's was therefore an important objective of the CSO development programme. Integrating the development testing, fabrication and installation is furthermore important in order to offer the SCR as a complete product. The focus of the programme was therefore to establish the fatigue strength of reeled welds and to compare this to un-strained welds. Full scale welds were fabricated and used for full scale and small scale fatigue tests.

The objective of the work was also to ensure the in-service integrity of the reeled SCR, and to show that reeled SCRs can be used wherever non plastically strained, e.g. J-Lay installed SCRs are used. To do this a large amount of mechanical tests and results evaluation was made. This included : CTOD, JR-curve, Charpy, Tensile and Hardness tests, for three different strain levels.

A total of fifty 10" and 16" girth welds were fabricated and used for both full scale and strip specimen's, resulting in a test programme that is unique in both the wide scope and in the volume of achieved results.

FATIGUE TESTS

The governing design aspect of a free hanging SCR, connected to a floating facility is the in-service fatigue endurance. The majority of work performed as part of the reeled SCR qualification programme was therefore to prove fatigue performance of reeled girth welds. To do this a large test programme was undertaken at TWI, using 10" and 16" welded pipe. Both full scale tests and strip test were performed. The strip test used samples cut from both the 10" and 16" pipe. API 5L seamless pipe joints were used and fatigue loaded in both zero mean stress and high mean stress. An overview of the fatigue tests are presented in the table below. The zero mean load test subject the pipe to a cyclic bending load, while the high mean load tests subject the pipe to both a static axial tensile load, plus a bending cyclic load. The strip tests use a tension-tension load, i.e. a cyclic tensile stress range superimposed on a static tensile stress. The resultant stress ranges are schematically shown in figure 1.

Table 1, Fatigue Test Overview

Sample Type	*OD*	*WT (mm)*	*Steel Grade*	*Loading*	*No. of Samples*
Full Scale	10"	20.6	X65	Zero mean	12
Full Scale	10"	20.6	X65	High mean	6
Full Scale	16"	23.8	X60	Zero mean	8
Strip Tests	10"	20.6	X65	High mean	74
Strip Tests	16"	23.8	X60	High mean	8

Figures 5 and 6 show results of 10" full scale samples tested both at zero mean stress and at high mean stress. Review of the zero mean stress results used conservatively estimated effective stress ranges, the calculation of which is not further detailed in this paper. Basically this means that when the stress range is partly compressive not the full stress range contributes to fatigue, but a part of it called the effective stress range. To achieve a safe evaluation of results, a conservative estimate of this effective stress range was made. Achieving full scale high mean test results in 1999, with the then newly modified TWI resonance rig allowed comparison of zero mean stress with high mean stress results. This further increased the confidence in the applicability of zero mean stress data. This comparison between strained and un-strained results complemented the high mean load results achieved by the strip tests.

The review by both TWI and CSO concluded that the absolute performance of the welds is high. A number of reasons exist for this high performance. The main reason is the quality of the developed weld procedure. The objectives in developing the weld procedure where to achieve a consistent root profile, of a very high quality with low defect levels, and good weld metal and HAZ mechanical properties. The resultant procedure was a special manual GTAW throughout the weld using welding consumables which had proven weldability and a track record with CSO. CSO's experience with the manual GTAW has been very successful, over the past eight years all the critical spooling welds have as a minimum a manual GTAW root and hot pass and the repair and defect levels have been very low. It was felt that the manual GTAW was the most controllable process available to CSO, also giving a high level of consistency and quality of weld root profile.

All welds for the test programme were manufactured under spoolbase conditions identical to those during any production phase, using spoolbase facilities and personnel. Another aspect explaining repeatability of the fabrication process is that all welds fabricated for the testing programme were used and tested, i.e. no repair or rejections occurred. This truly is a reflection of the consistent quality achieved by CSO spoolbase manufacturing. The use of state of the art NDE equipment, such as Automated Ultrasonics, can only further enhance performance of actual production welds. If non acceptable defects are found in a critical weld, this weld will simply be cut out and a new weld will be made. There will be no pressure on the spoolbase to accept welds with defects that are on the limit of their acceptance criteria.

Another less obvious aspect of the high absolute performance of the welds is that the stress concentration factors are low. This has been achieved by both the quality weld geometry as well as by match boring the pipe ends. A low allowable axial misalignment was defined, which was achieved by the majority of samples. After fatigue testing the welds to failure, a post mortem investigation was carried out. This included measurements of wall thickness, axial misalignment (surface mismatch) and ovality at four clock positions, 90° apart around the circumference of the test weld. The fracture faces of each test specimen were also visually examined, and photographed to record any peculiar features with respect to fatigue life, e.g. welding flaws. Where required additional investigation of the fracture faces was done using a light microscope and a scanning electron microscope.

The post mortem investigations revealed for a limited number of samples misalignment larger than the target allowable. One of the reasons for these larger misalignment figures was that samples were made by sectioning 40' length of seamless pipe to create 6m long full scale weld samples, with one weld at midspan. Dimensional tolerances in the pipe body are worse when compared to pipe ends, thus it was more difficult to achieve the target misalignment. In production welds will be made only between pipe ends, plus dimensional tolerances will be minimised prior to match boring by sorting pipe joints on dimensions. This will improve on the misalignment values achieved during the test programme, which will further improve the fatigue performance of production welds.

STRAINED VERSUS UN-STRAINED SAMPLES

Full scale un-strained samples and strip samples cut from un-strained pipe were fatigue tested to failure for comparison to strained samples. Although the level of absolute performance of the strained samples was shown to be high, comparing strained versus un-strained samples further enhances the confidence in achieved results. This comparison was made by TWI and CSO, in much the same way as results from different weld qualities or processes would be compared, and showed that there is no noticeable difference between strained and un-strained samples. This important conclusion was further confirmed by investigating three possible effects from strain that might cause a difference, possible defect growth, change to basic crack growth properties and change to residual stress.

Defect Growth

The effect of reeling strains on weld defects was investigated by using post-mortem results from the test programme and by using results from existing tests and studies made by CSO previously. Reference [4], provides an example of the existing work on this subject. An overview of pipe sizes and defect types tested are presented in table 2. All reeling tests were done using full scale pipe and welds. The samples were subjected to a reeling simulation, subjecting the pipe to strain cycles equal to the CSO Apache reeling strains. Pipes of study cases 6 and 8 were subjected to twice the Apache reeling strain cycles. After the reeling simulation, pipe samples were frozen in liquid nitrogen and broken open at the defect location, thus allowing investigation of the crack faces. Images taken of the crack faces using a scanning electron microscope, thus revealed whether ductile tearing, or defect growth occurred during the reeling simulation.

Table 2, Overview of Studied Defects

Case	*Pipe Size*		*Defect Type*	*Defect Size*
	OD	wt		Depth
1	8"	15.9 mm	gross defect, surface breaking	2 – 3.5 mm
2	8"	15.9 mm	gross defect, embedded	2 – 3.5 mm
3	10"	20.6 mm	microscopic surface intrusions	< 0.05 mm
4	16"	23.8 mm	microscopic surface intrusions	< 0.05 mm
5	16"	23.8 mm	detectable, surface breaking	1 – 2 mm
6	16"	23.8 mm	large defect, surface breaking	2 – 3.5 mm
7	16"	23.8 mm	large defect, embedded	2 – 3.5 mm
8	16"	23.8 mm	gross defect, surface breaking	3.5 – 5 mm

Studying the crack surfaces using a Scanning Election Microscope showed defect growth, or ductile tearing, in only one instance. An example from study case 1 is shown on figure 7, three different surfaces can be distinguished. The artificially induced gross defect (at the top), the brittle surface from breaking the weld open, plus saw marks that were made to aide breaking the weld. No tearing or defect growth was found from the scanning electron microscope investigation of the boundary between the initial defect and the brittle surface. Some of the SCR test programme samples showed minute ductile tearing from internal lack of fusion defects. The maximum depth of tearing found was 0.005 inch (0.12 mm). The internal lack of fusion defects, maximum defect size was 0.08 inch (2 mm) by 0.75 inch (19 mm), however do not cause fatigue failure and there was therefore no effect from this minute tearing on the fatigue lives. Furthermore, these defects can be picked up by the accurate NDE methods applied with SCR fabrication, such as automated ultrasonic inspection, and can thus be avoided. None of the other investigations showed any significant ductile tearing, as can be seen from the results overview in table 3. Negligible ductile tearing occurred at one gross surface defect in a sample subjected to 1.3% strain, a sample from case 1 of table 2. The depth of tearing was only 35 micron (0.0014 inch), i.e. insignificant in size. As mentioned above, these gross defects were artificially induced in some test samples only.

Table 3, Defects Subjected to a Simulated Reeling Process

Classification		***Strain Level***	***Defect Growth***	***Number of Samples***
Microscopic Intrusion	Surface	1.6%	Zero tearing	100
Detectable Defects	Surface	2.4%	Zero tearing	14
		2.4%	Zero tearing	4
Large Defects	Surface	2.4%	Zero tearing	4
	Embedded	2.4%	Minor tearing	4
Excessive Defects	Surface	1.3%	Occasional negligible tearing	6
	Embedded	1.3%	Zero tearing	4
	Surface	2.4%	Zero tearing	7

The stability of defects subjected to the reeling strain cycles was also proven by Engineering Criticality Assessment (ECA) type analyses. A range of pipe sizes and defect sizes were analysed using fracture mechanics. Real data achieved from the mechanical test programme performed were used in the fracture calculations. This work confirmed the conclusions from the reeling trials of defects. It showed why significant defects are stable, even when subjected to reeling strains. The ECA work used measured toughness data in the form of CTOD and J-R curves. Although an ECA is known to be conservative when used for reeling analysis, it is very useful in assessing required toughness values and in assessing allowable defects.

We then compared the allowable defect criteria to prevent fracture with defect criteria derived from fatigue life requirements, which showed fatigue defect criteria to be more onerous. This means that reeled SCR welds, when fabricated and tested as described above, do not require NDE criteria beyond criteria currently applied to non reeled SCR's.

Effect of Strain on Crack Growth Properties

Crack growth properties of strained and un-strained samples were measured in Air and in H2S. Further crack growth tests in other corrosive fluids are ongoing, as well as crack growth tests at threshold stress intensity values. No difference between crack growth of strained and un-strained samples was found, i.e. the crack growth properties of reeled and of un-reeled samples are the same. Figure 8 presents results of a crack growth test in Air, using both strain and un-strained samples, taken from 10" pipe. As can be seen from the graph, no noticeable difference exists between the strained and the un-strained samples. This therefore means that reeling has no effect on crack growth properties. In other words, once a fatigue crack starts, given equal loading, the speed of crack growth in a reeled weld is equal to a non reeled weld.

Effect of Strain on Residual Stress

Welding causes peak residual stresses of around yield stress magnitude to exist around the weld circumference. Reeling strain cycles, followed by a straightening cycle will redistribute these stresses and possibly decrease peak values. Residual stresses vary from weld to weld, in otherwise identical structures. The unpredictable nature of residual stresses makes it difficult to quantify the redistribution from the reeling strain cycles. The programme included residual stress measurements at various locations around the circumference of the weld, at both the inside and outside of the pipe. Both strained and un-strained samples showed tensile and compressive residual stresses of comparable magnitude. Although the re-distribution of residual stress will make a difference to individual samples, overall there will be no effect from this residual stress re-distribution on fatigue performance of the reeled welds.

Evaluation

The above evaluation of possible effects from reeling on fatigue life, explain why there is no difference in performance between the strained and the un-strained samples of the test programme. It did however highlight the importance of qualification processes to control weld quality and achieve consistent mechanical properties. Assuring that defects are stable is key in assuring in-service integrity of an SCR. To bring the knowledge and experience of (reeled) pipeline and riser fabrication and installation achieved to date, such as highlighted by references [4, 5 and 7], into the programme was crucial in successfully completing this development.

CONCLUSIONS

A high performance fabrication and weld procedure was developed, resulting in reeled pipe girth welds, for use in dynamic steel catenary risers.

Excellent fatigue performance, proven through an extensive test programme, enables fatigue design based on both X' and E curves.

No noticeable difference was found between strained and un-strained samples.

Three possible effects of reeling strains on fatigue performance were investigated. None of these have shown to cause a difference. Fatigue design of reeled SCR's can therefore use industry standard curves and NDE criteria.

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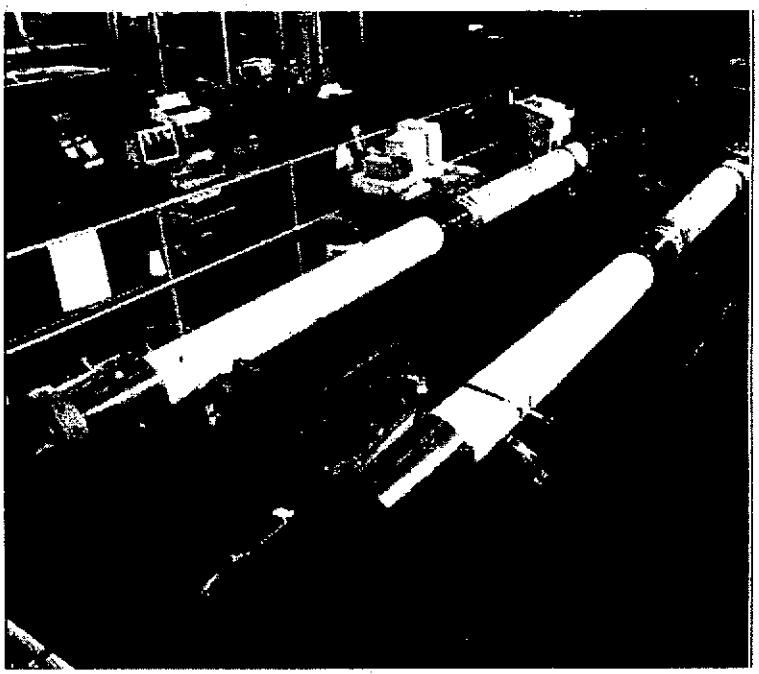

Figure 2.1: Resonant Fatigue Rig

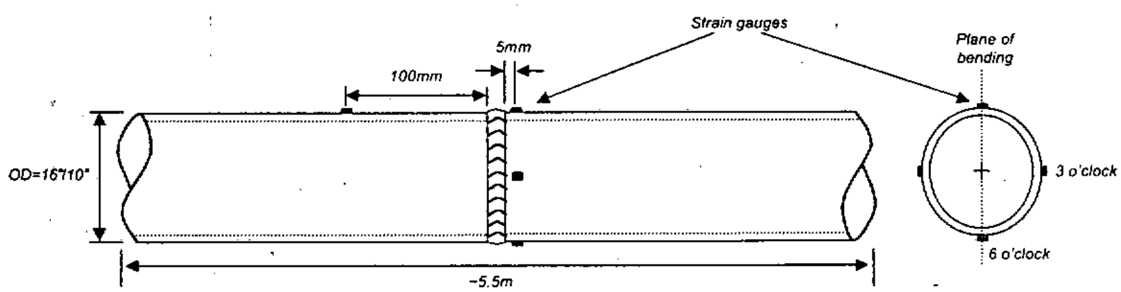

Figure 2.2: Typical Full Scale Specimen

Fatigue Performance of Catenary Risers Installed by Reelship

Mike Bell
Coflexip Stena Offshore, Aberdeen, UK

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

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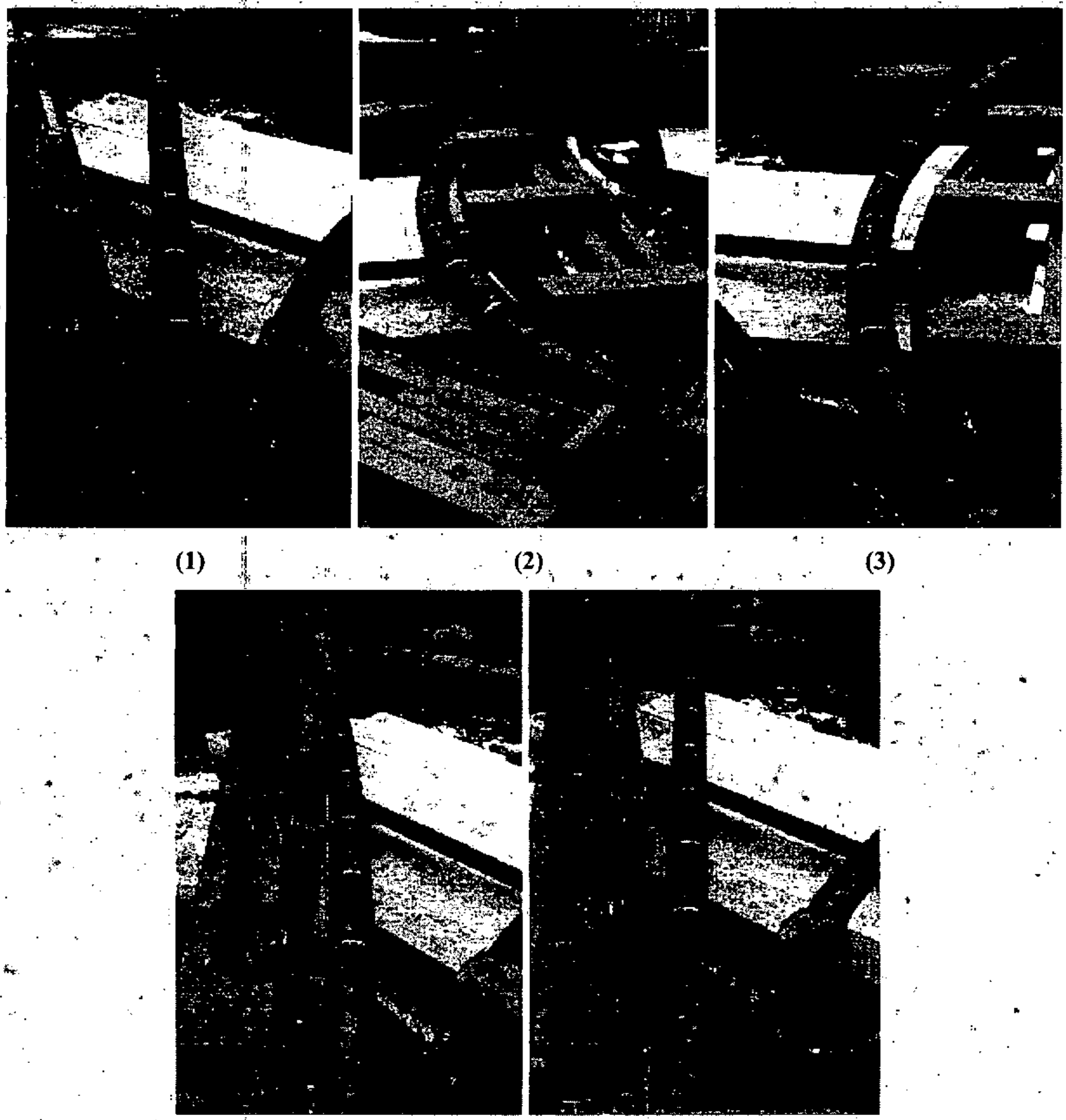

(1) (2) (3)

(4) (5)

Figure 1: Bending Trial - 16" API 5L:X60 Welded Line Pipe

Pictures (refer to numbers) (1) initially straight pipe; (2) Pipe bent round reeling former; (3) Residual curvature when pullhead released; (4) Pipe bent round the straightening former; (5) Pipe residual shape once all loads released

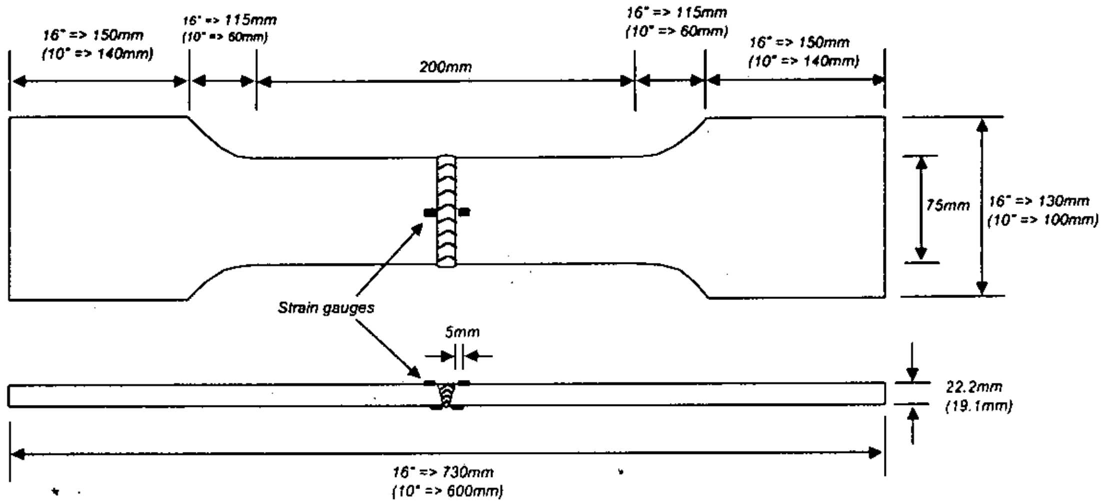

Figure 3.1: Geometry of Typical Strip Specimens Extracted from the 10" and 16" OD Girth Welds

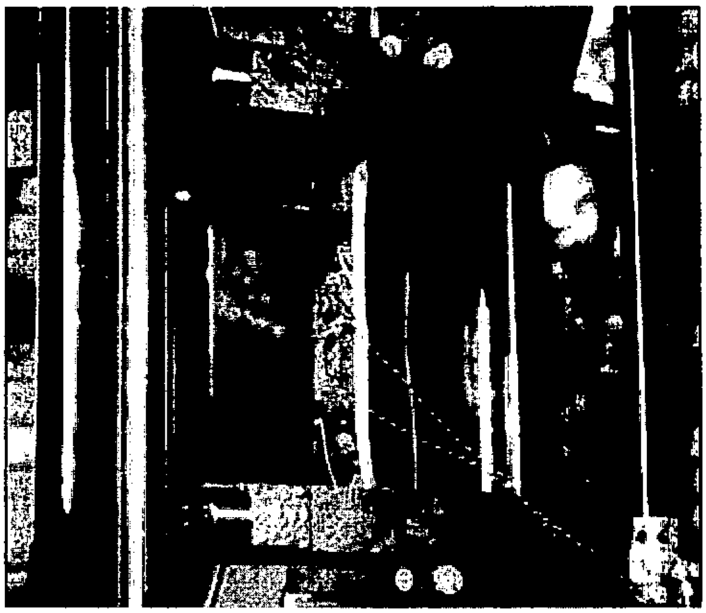

Figure 3.2: Picture of Strip Specimen Fatigue Test Machine

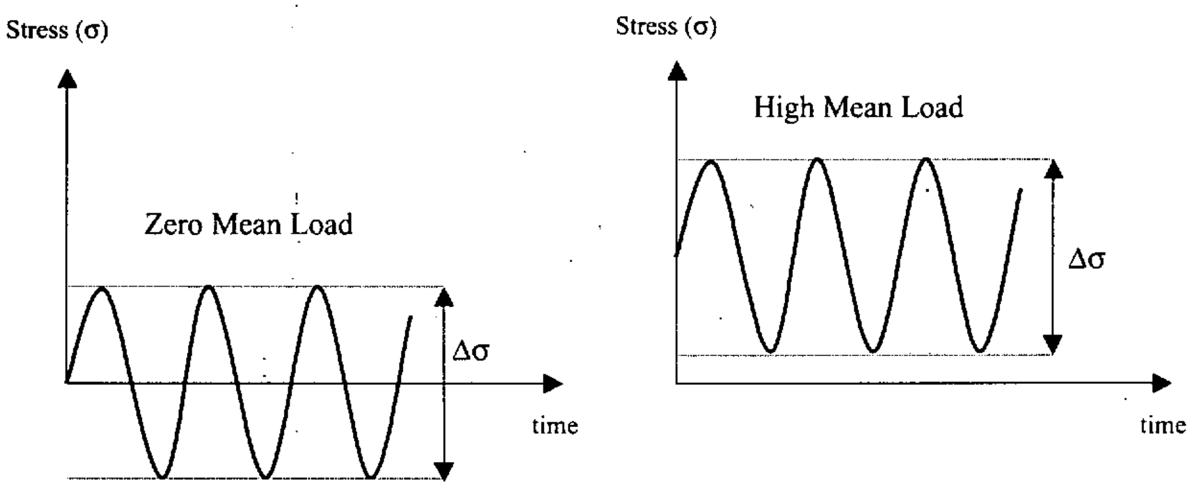

Figure 4: Fatigue Loading

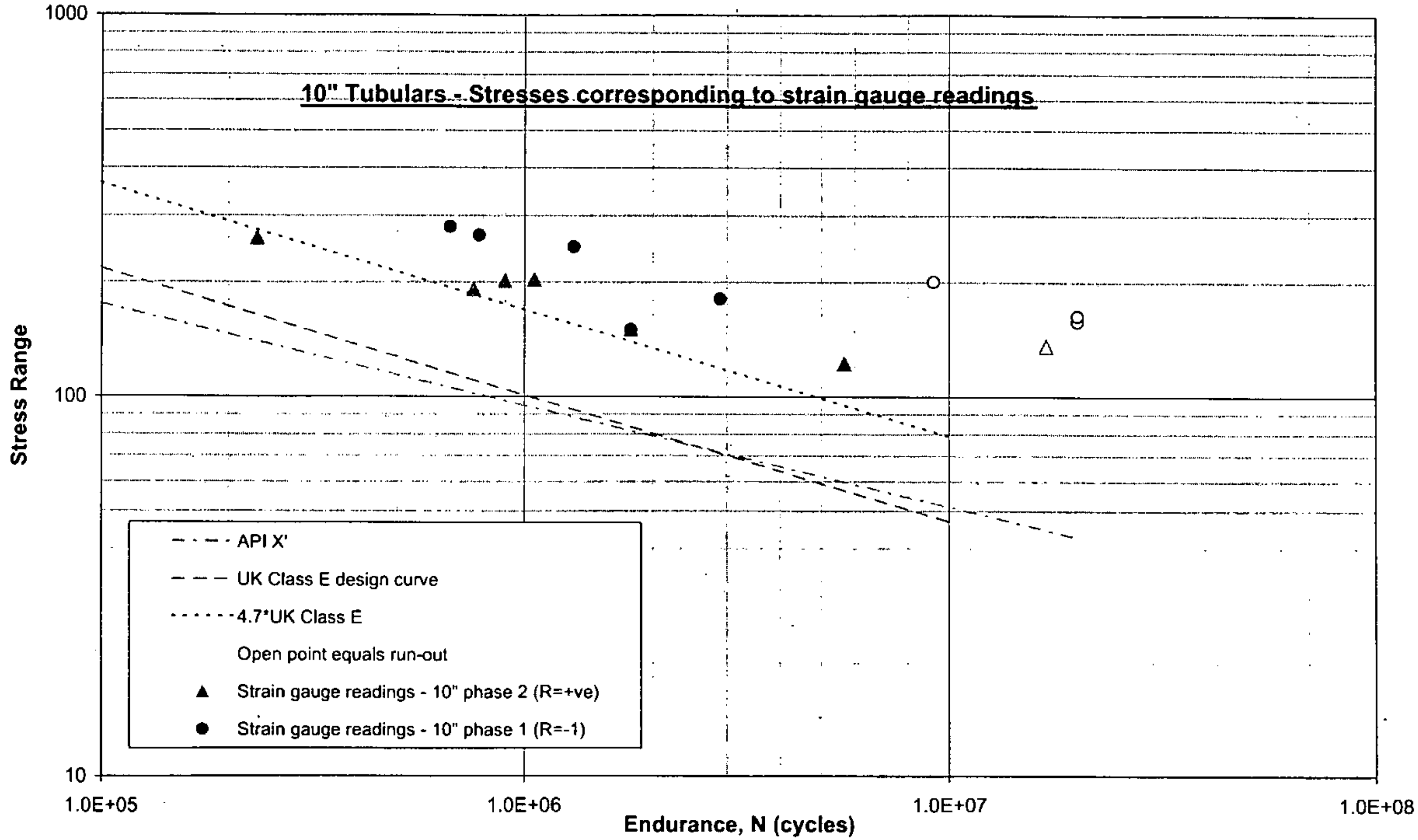

Figure 5: Stress Range According to Gauge Reading

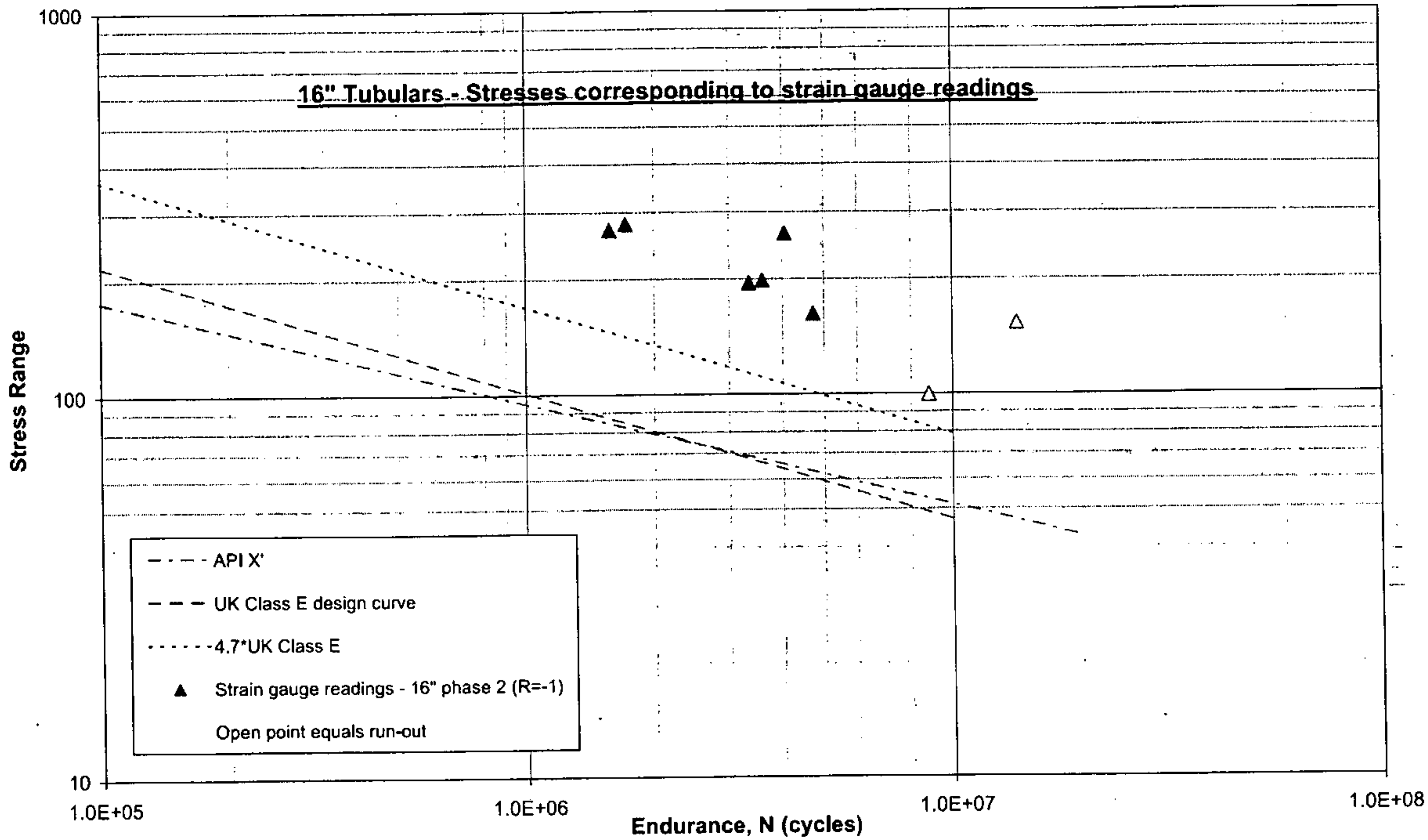

Figure 6: Stress Range According to Gauge Reading

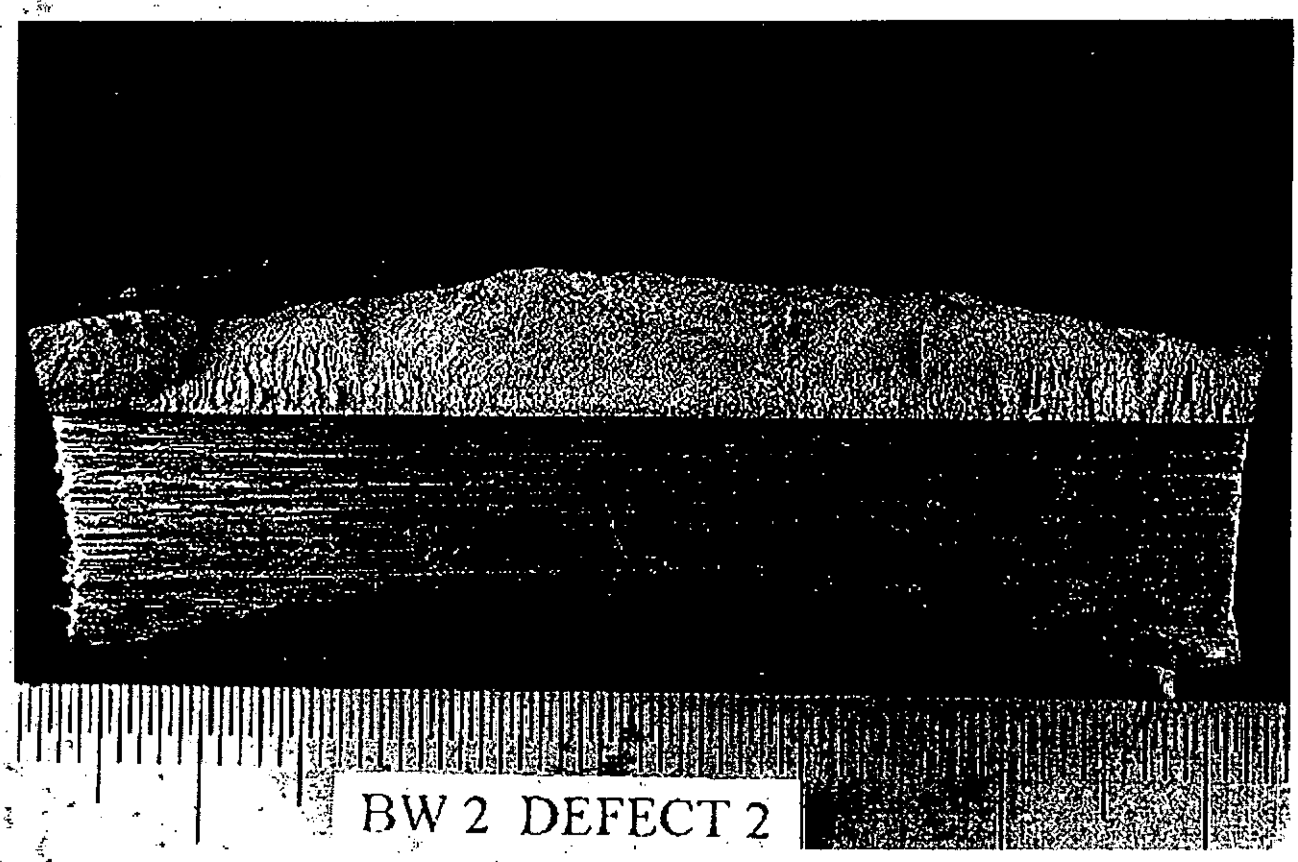

Figure 7: Reeling of Gross Defects, Artificial Surface Breaking Defect, No Defect Growth Occurred During Reeling Simulation of this Defect

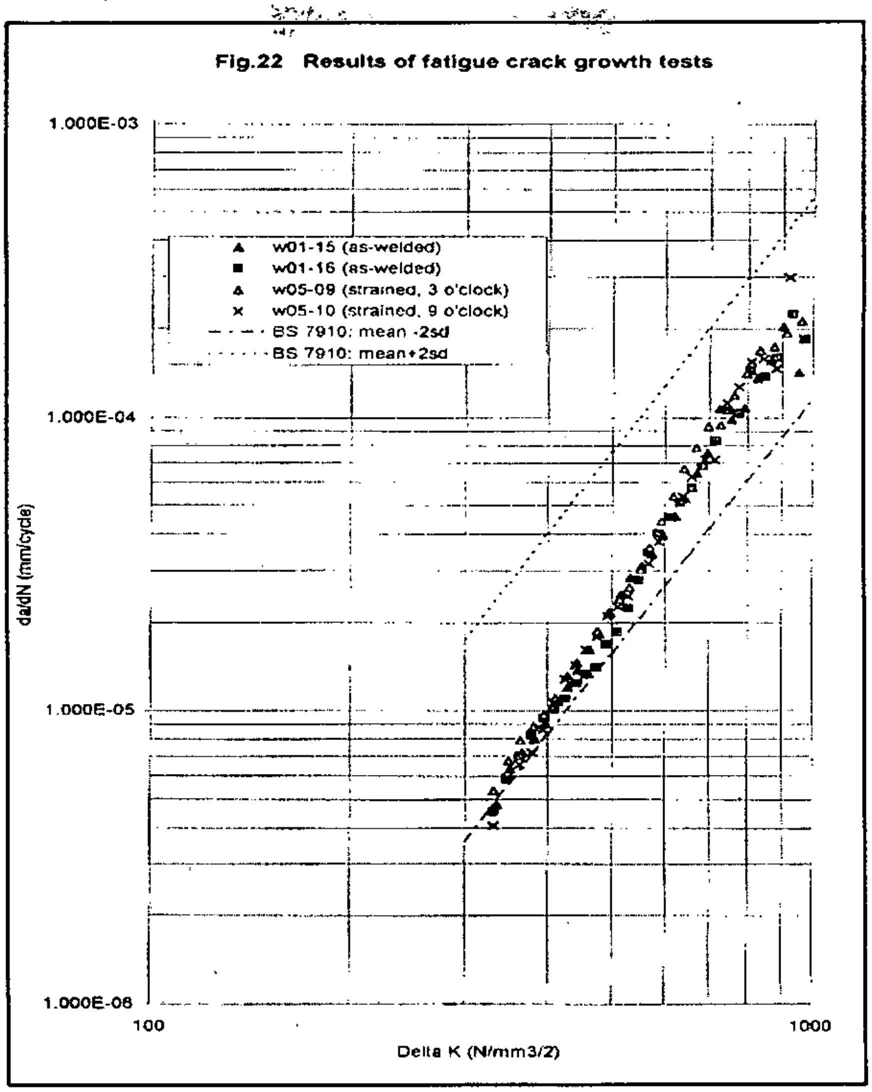

Figure 8: Crack Growth Tests in Air, of Strained and Un-strained Samples

Deepwater Development and Cost Optimization: A New Approach

Richard T. Hill and **John Pierce**
JP Kenny, Inc., Houston, USA

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

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Deepwater Development and Cost Optimization: A New Approach

Summary

The activities in advancing a deepwater oil or gas field to production stage are numerous and the interdependency of the activities complex. Determining how to best extract the discovered fluids from the reservoirs and deliver the products to the market while minimizing CAPEX, OPEX and risk of failure is critical.

A dynamic and time dependent costing and optimization technique for field development has been developed that allows flexibility in technical decision revisions, commercial re-evaluation of options available and time value assessment of money. The service combines the application of Geographical Information System (GIS) technology to handle the spatial context of the subsurface, surface and above water field components and Cost Model spreadsheets to facilitate economic evaluation. The GIS is linked via a GIS Interface with the Cost Model. The Cost Model is in spreadsheet format producing a transparent costing system instead of the more common "Black Box" model.

Field layout scenarios are developed using the available output from reservoir simulation analysis, drilling constraints and well trajectories, production concerns, facilities requirements and intra-field pipeline architecture. A costing sub-system generates costs for each scenario based upon the set of cost components detailed in the GIS dataset.

The system permits rapid and cost effective analysis of feasible options for the field development. The flexibility of the system allows sensitivity analysis and "what-if" investigations to be carried out while evaluating the economic viability of each scenario. The system incorporates economic factors specific to the operator individual needs, such as Net Present Value (NPV), Net Cost per Barrel and Return on Capital to assist in commercial decision making.

1 Introduction

The Capex cost for deepwater developments are projected to be in the $billions and as such are an order of magnitude increase in cost above most of the field developments to date. The total planned Capex expenditure for deepwater developments, over the next five years, is over $35 billion. The geographic breakdown of Capex expenditure is shown in Figure 1.

The efficient development of deepwater fields for each new development is crucial in assuring the economic viability of these fields.

Proceedings of the 3rd Deepwater Pipeline & Riser Technology Conference, Houston, Texas, March 7-9, 2000.

To date the development of deepwater oil and gas reserves have, to a large extend, employed many of the methodologies used for shallower water fields. Project development on the shallow fields have been based on sound engineering judgment that relies heavily on a knowledge database built from existing fields.

The applications of existing technologies in deepwater developments no longer applies. Commercial viability of the deepwater developments demand efficient design philosophy and implementation of new technologies in materials, construction, operation and management.

Depending on the size of the field, its complexity and its location, a team of experts derive a number of feasible development scenarios. Each scenario has input from disciplines such as reservoir, drilling, production and facilities. This input is typically supplemented with the involvement of Business Managers, Commercial Managers and Operation Managers. During the execution of such work the volume of information generated by the field development team and the inter-dependency of the different sets of information is often the cause of difficulties in maintaining the integrity of the project developed data, long project execution schedules and high costs.

Hence, integration of the information within a single system to allow auditing of the decision-making process coupled with a dynamic economics model .that will shorten the development time, while providing evaluation of economic indicators for each scenario is required.

A system for the integration of technical, commercial and managerial issues related to the field development process has been developed. The system is applicable to both offshore and onshore fields whether new or existing; and can be applied at all stages of field development from the initial coarse screening of options, through the detailed engineering phase, as well as carrying on through field maturity and eventual abandonment. This service is known as FOCU$.

2 Field Development Process

Responding to the myriad of questions arising on how best to extract the discovered fluids from the reservoirs and deliver the products to the market is a daunting task. Additionally, to minimize CAPEX, OPEX and the risk of failure, while maximizing profits and meeting the environmental goals, is complex. At the early stages of a field development there is very little reliable information available. However, based on what little information is available, a number of field development scenarios can be investigated assuming a series of potential outcomes of fluids contained within the reservoir(s).

Hence, the field development process is executed in a cyclic fashion. That is, based on initial preliminary information field development scenarios are developed, then with the next revision of new data the scenarios are modified and normally reduced in total number. This process is repeated several times before an optimum solution is reached. At the start of each cycle the phasing of the development is also reconsidered. That is, the number of wells needed to be drilled to reach a target production, the number of manifolds and flowlines required to be installed and the corresponding offshore facilities for the first phase of the development are identified. The CAPEX, OPEX and economic factors are evaluated based on the total income from the field over the first. The second phase components of the field are then added on and the commercial implication studied. The trade offs between installation of components in the first rather than the second phase of the development are identified.

The field development team's task can be further complicated by subsurface issues, location and environmental consideration, as well as technical, commercial and geo-political constraints. Detailed discussion on the full spectrum of issues is beyond the scope of this paper, however, a number of the key issues often considered are presented below.

FOCU$ provides an interactive graphical representation of all the scenario models and shows immediate cost implications brought about by changes within a given scenario or scenarios. FOCU$ maintains trace ability of changes made to the scenario models and provides a complete history of the evolution of the field development. FOCU$ brings the various disciplines together in a workshop environment thereby facilitating efficient information transfer and decision-making. Figure 2 shows some of the disciplines involved in a field development.

A generic field development depicting an FPSO with flexible risers, flowlines and umbilicals, manifold, trees and bottom hole locations are shown in Figure 3.

Subsurface

The reservoir characteristics govern the ease of fluid transportation throughout the reservoir strata and into the producing wells as well as from the injection wells into the reservoir. The well types whether conventional, deviated, extended reach, horizontal or multi-laterals are selected to suite the reservoir characteristics and production requirements.

The reservoir may contain a combination of oil, gas, condensate and water. The strategy for the reservoir exploitation strongly depends on the dominant reservoir fluid and it's characteristics. The production targets from each well, the mudline components and type, the flowlines and the associated flow assurance issues, the riser types and numbers and the offshore facilities necessary to manage the incoming fluids are all affected by the reservoir fluid characteristics.

Location

Critical parameters related to the location of the field are the water depth in which the reservoir(s) lie and the distance from existing infrastructure. Water depth strongly affects the technical solutions, commercial viability and risk of failure elements of the field development process. Another aspect is the availability of the required personnel, material and equipment for construction, transportation, and installation. Clearly, this has a marked influence on the commercial factors of the development. Remoteness of the reservoir may require a standalone solution rather than a tie-back to a mature infrastructure.

Environmental

The need to protect the environment from the exploration and production activities and similarly the engineering installations from the environment is critical. Preliminary assessment of the impact on the environment from activities such as construction, disposal of solids and harmful liquids and gases needs to be made at an early stage. Issues such as drill cutting disposal, gas flaring, and re-injection into the reservoir needs to be technically assessed from an environmental protection point of view. The technical and commercial implications of such issues must be considered at an early stage of the field development to allow identification of "bottle-necks" in the system while evaluating commercial impact of any technical or managerial decisions to remove the bottle-necks. The environmental protection tasks need to continue throughout the field life, up to and including field abandonment.

Technical

The subsurface parameters such as single or multiple reservoir features, and complex reservoir fluids need to be assessed for the generation of expected production profiles associated with the field.

When sufficient data is available, reservoir simulation runs are made to develop an early prediction of fluid production from the field and the corresponding well production profiles. Additionally to water and/or gas injection requirements are considered. These predictions are refined through additional reservoir simulation runs when more data is available regarding the reservoir properties and trapping mechanisms.

Often there are suitable zones throughout the reservoir(s) where well bottom hole locations can be landed as oppose to fixed locations. The flexibility in choosing a bottom hole location for each well can be used for optimization of the well trajectory design while honoring production requirements and drill rig placement options. The well trajectories are used as input data for FOCU$.

Subsea wellhead locations are selected to suit the governing subsurface conditions. Acquisition of more information on the subsurface features may change some of the governing conditions and result in a revision of the wellhead locations during the course of the front-end engineering and design.

The wellhead locations govern the subsea architecture and define the components required for distribution and transportation of produced and injection fluids. The offshore facilities required, together with the technical and environmentally dominant features strongly influence the number, type and location of manifolds along with the intra-field pipelines and export pipeline corridors on the seabed. Clustering of wells may be required by linking the wellheads to a manifold and then via a flowline to a riser or another manifold. In selecting the location of field architecture components, risk factors such as rough terrain, mudslide zones, mud volcanoes, fishing zones and earthquake zones are considered. Risk maps are overlaid within the GIS to facilitate contingency planning.

The impact of uncertainties in reservoir fluid behavior and production forecasts together with the fluid dynamics interaction between the reservoir and surface network needs to be carefully assessed. The flowline type whether single, pipe-in-pipe or bundle is strongly influenced by the reservoir and above mudline fluid. Flowline configuration and related costs are incorporated with FOCU$.

Commercial

The level of confidence in evaluation of CAPEX, OPEX, NPV and the Return on Investment (ROI) for each scenario strongly depends on the lower and upper boundaries of the costs of the individual components of the field architecture.

Based on the individual range of possible price fluctuations provided by the operators, an overall level of confidence in the cost model output, per development scenario, can be established.

The risk of component failure during installation and operation together with the resulting loss of production and deliverability penalties can also be evaluated.

The tax implication at all stages of the field development including the production phase and its impact on commercial parameters needs to be included in the final field development scenario. The economic indicators incorporated in FOCU$ are dictated by the operator.

3 The Field Optimization And Cost Updating Solution

As previously discussed to meet the field development challenges a GIS based service for the integration of management, commercial and multi-discipline engineering issues have been developed of "planned" and "mature" fields both offshore and onshore.

The system provides a platform for the field development team to record subsurface, geohazards, environmental, technical, and commercial concerns while examining the interaction between a large number of parameters affecting the optimum solution. The integration of multitude of issues within one system in a consistent manner with measurable relationships between the parameters allows for fast engineering decision made in a workshop environment. A generic field development scenario incorporating an FPSO unit is shown in Figure 4.

FOCU$'s flexibility in selection of field development scenarios for offshore architecture is base on Stick Diagram Logic (SDL) for the database rationalization of the components. Figure 5 shows a typical Stick Diagram for a daisy chained dual production flowline system.

FOCU$ accelerates the decision-making process combining cost optimization and economic evaluation in a traceable manner. A means of recording the decisions made and the reasoning behind each decision is offered while covering the whole scope of a field development from the reservoir up to and including the point of export.

The system is designed to benefit from operating in a workshop environment, which allows all relevant specialists to raise their concerns for incorporation into the system in an interactive environment thus enhancing confidence in the results.

The system provides a means for the comparison, evaluation and optimization of alternative layouts using common and consistent data.

To aid in the selection process, sensitivity checks on the main cost drivers are performed to determine the degree of overlap, if any, between the different options. This is done using a Cost Model spreadsheet; an example of a typical cost sheet is presented in Figure 6.

Project specific data sheets, developed for each element of the field architecture are used to determine the unit costs that form the building blocks of the cost estimate.

By combining the unit costs with the detailed list of hardware required for a particular layout, as produced by the GIS, the CAPEX cost is obtained. Time phasing of the CAPEX costs using a pseudo schedule allows calculation of present value, (PV).

Similarly, OPEX can be estimated over the life of the development. This, coupled with revenue forecasts derived from the production data (both total recoverable reserves and monthly production rates over the life of the development), allows the calculation of such economic factors as NPV, Net Cost per Barrel and Return on Investment.

The economic indicators for each field development scenario are compared together with "soft" issues such as risk, operability and local content in order to determine the "optimum economics".

The accuracy of the resulting estimate is dependent on the accuracy of the input data. Initially, generic prices are used for coarse screening purposes but as the project develops, the data is expanded and refined to progressively improve the accuracy of the model.

Once a preferred layout has been selected, the costs output from the system are used to form the basis of the control estimate and budget. The costs can be further refined as necessary and risk analysis performed to determine contingency requirements.

An example of such a comparison between an existing scenario layout and a revised layout is presented below.

Example

In the generic field layout presented in Figure 4 the position of a manifold may need to be moved, which in turn will alter both the length of the flowlines connected to it and the well trajectories of the associated wells. The manifold can be moved easily on screen and the resulting cost impact viewed immediately. Figures 7 shows the manifold in its original location and the associated Total Capex Cost of $1,576.96 MM. Figure 8 show the manifold at the new location resulting in a Total Capex increase of $7.34 MM with a new Total Capex Cost of.$1,584.30 MM.

This is only one example of the flexibility of FOCU$. Components may be added, removed or modified in the scenarios and the cost implications viewed immediately.

Conclusions

Industry experience indicates that development and through life costs of a field development for oil and gas reserves can be drastically reduced by comprehensive front-end engineering. A system that allows fast creation of many field development alternatives, while integrating technical, commercial and managerial concerns in a consistent manner is a part of FOCU$. The basic features of FOCU$ are;

- Platform for the integration of multi-disciplinary engineering, commercial and management concerns;
- Methodology for rapid preparation of alternative field development scenarios;
- Interactive dialogue windows for easy manipulation of components with immediate cost implications;
- In-built logic for sub-component connectivity;
- Transparent cost modeling;
- Dynamic and time dependent cost optimization allowing for time value assessment of money;
- Economic factor evaluation such as Capex, NPV, Net Cost per Barrel and Return on Investment;
- Traceable decision-making process;
- Consistent application of data for all scenarios.

The models created in FOCU$ are customized for the unique characteristics of each field development. However, the fundamentals of its philosophy remain the same for each application by integrating the field knowledge and the experience of the operator's experts.

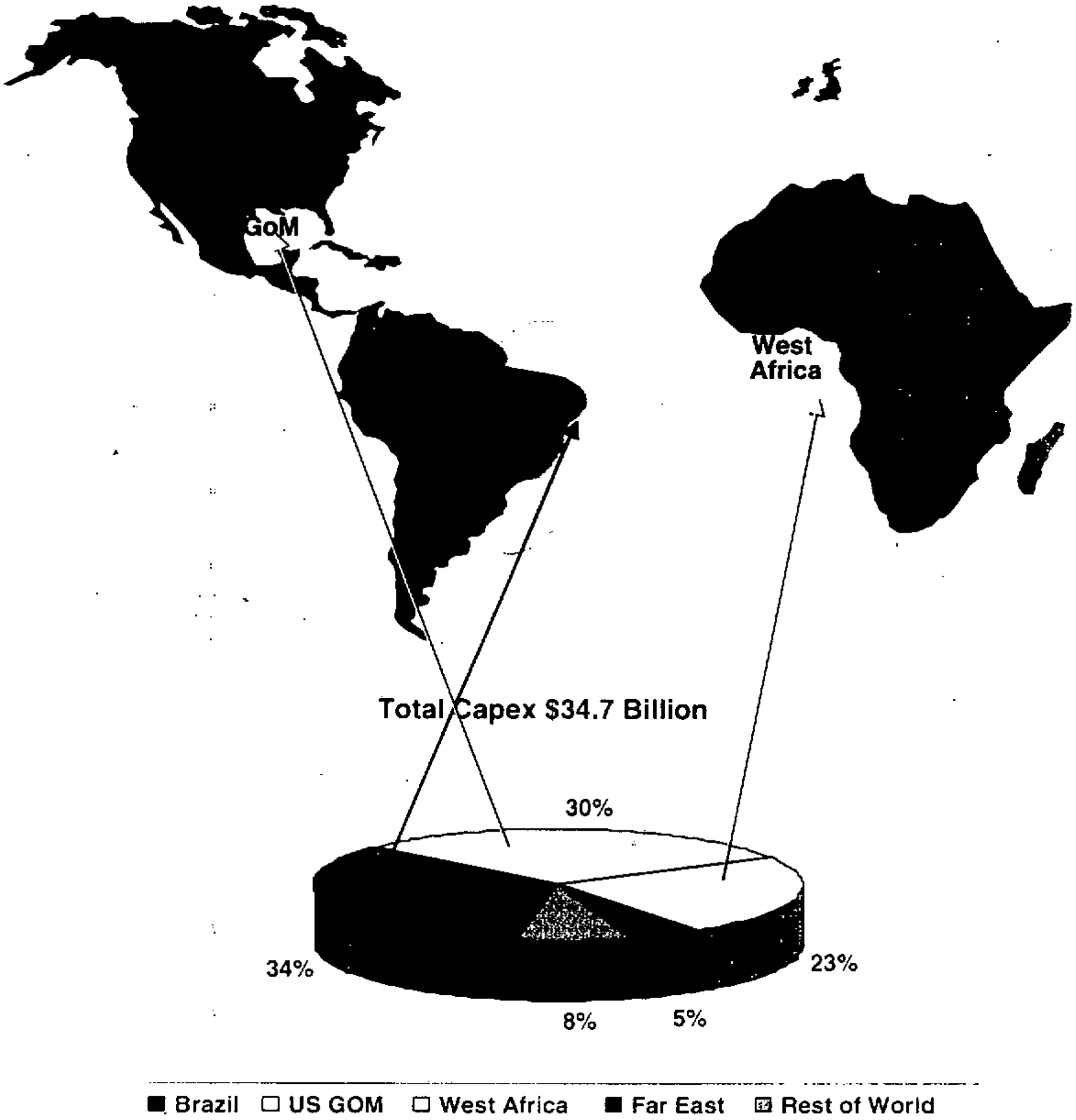

FIGURE 1

Projected Total Capex Expenditure over the next 5 years

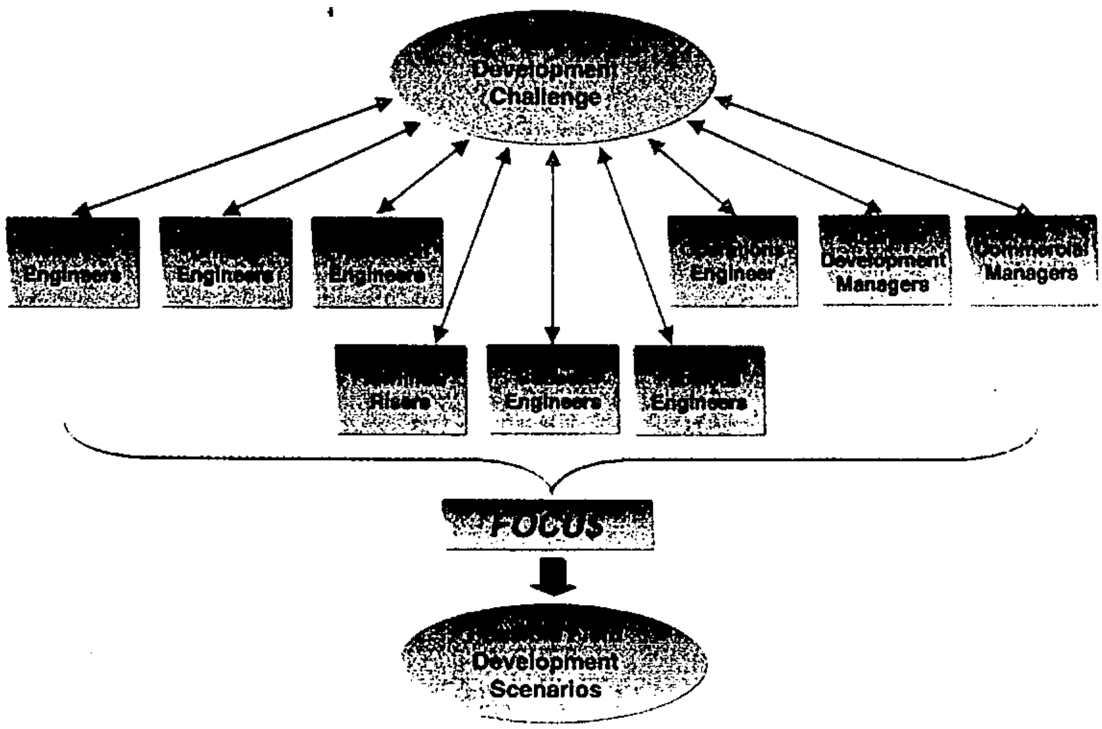

FIGURE 2

Various Disciplines Involved in a Deepwater Development

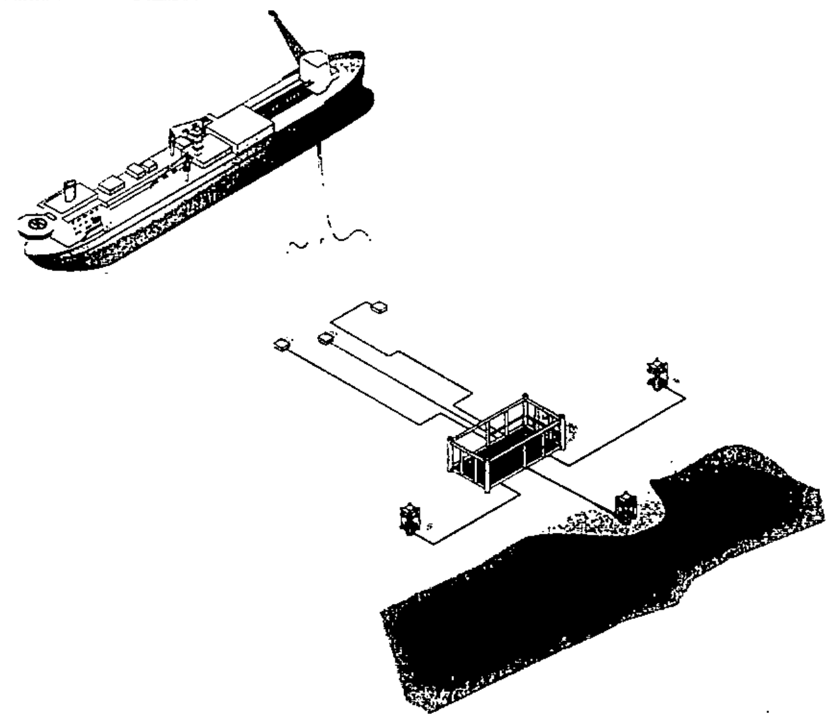

FIGURE 3

Generic Schematic of a Simple Field Development

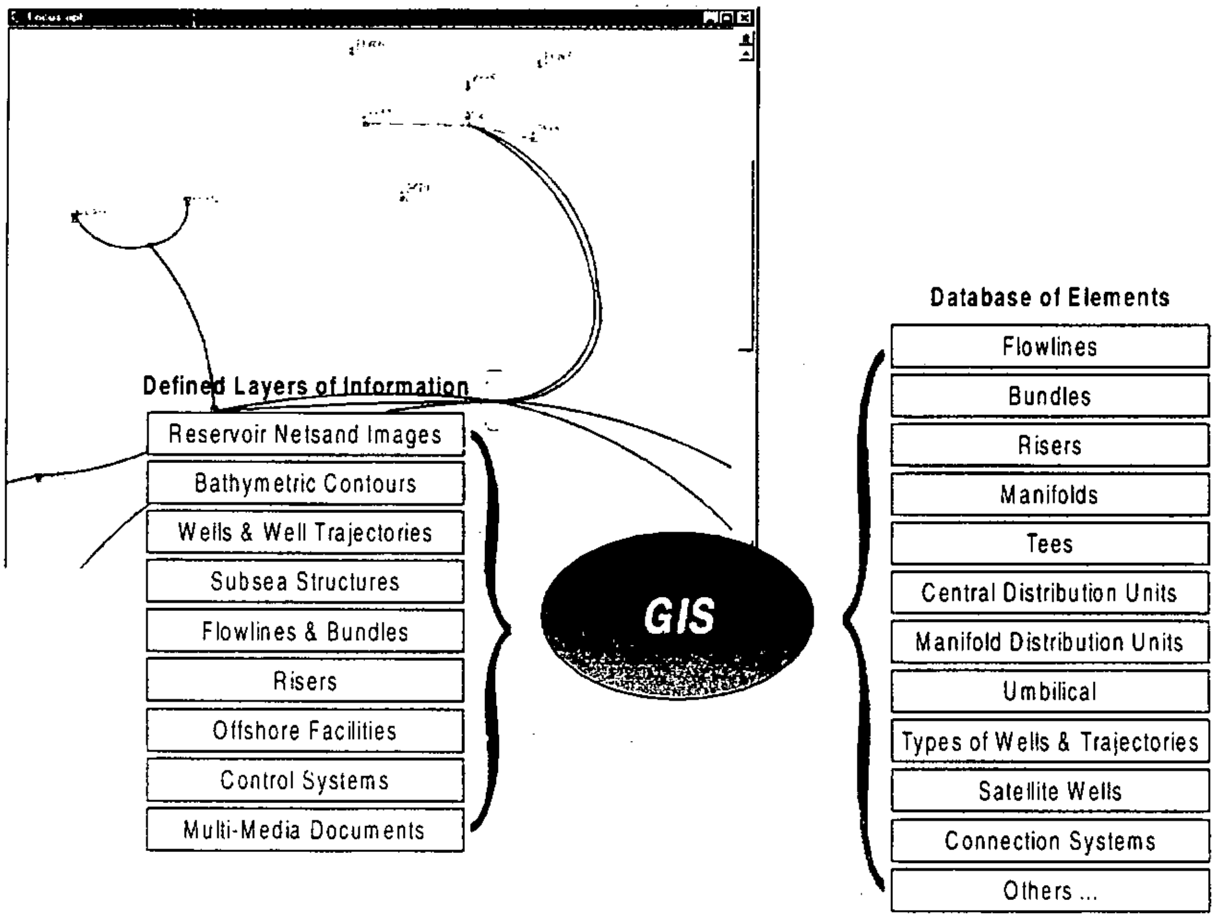

FIGURE 4

Overview of the GIS System

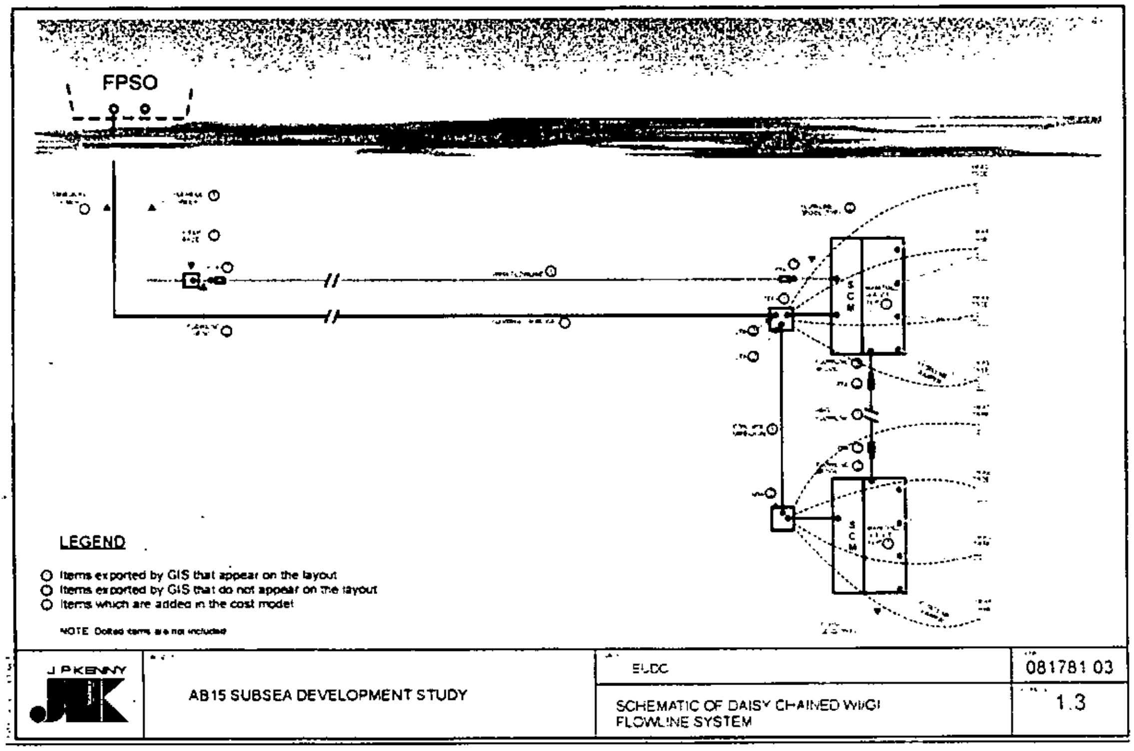

FIGURE 5

Stick Diagram of a Typical Daisy Chained Water or Gas Injection Flowline System

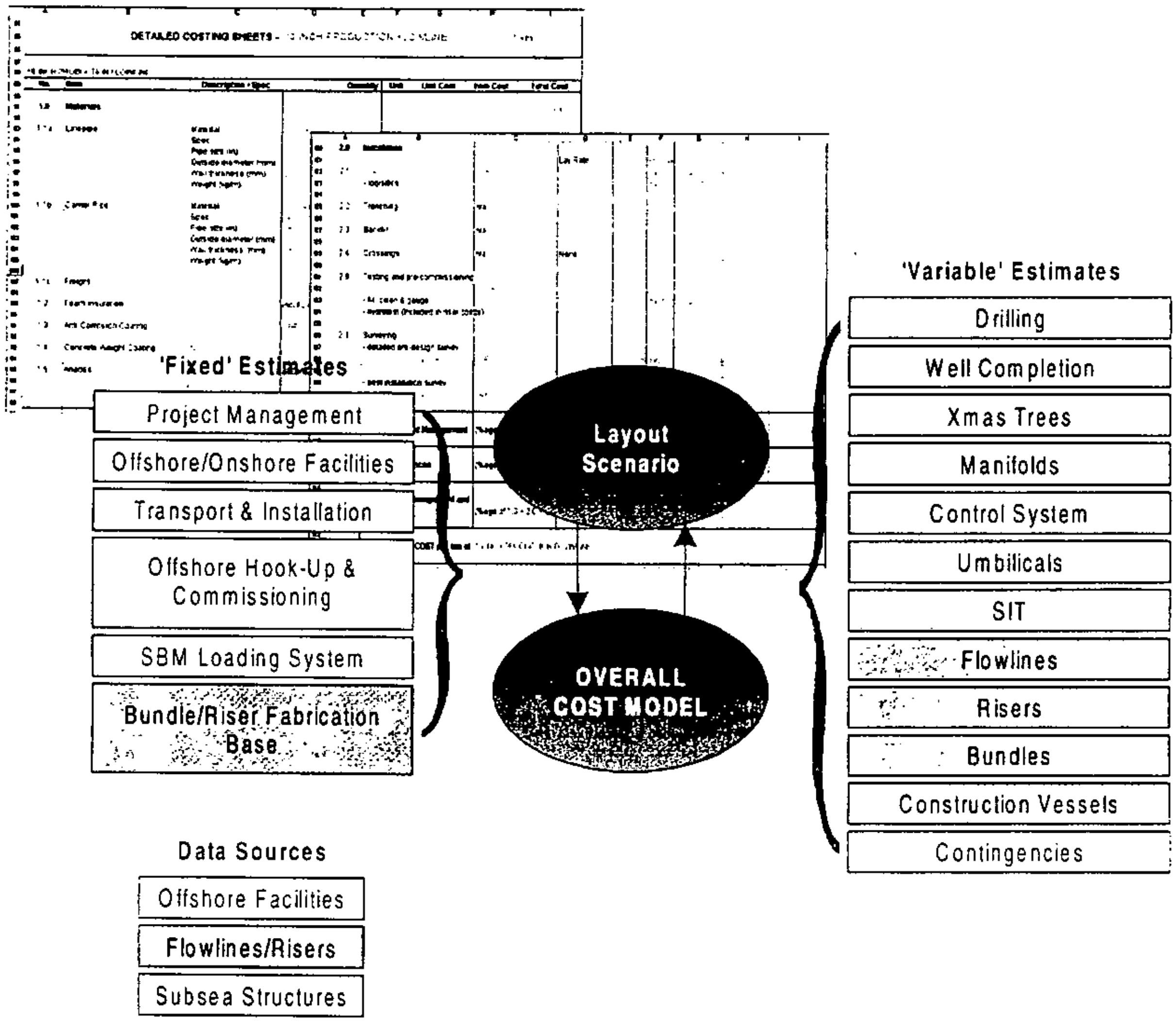

FIGURE 6

Overview of the Cost Model Spreadsheet

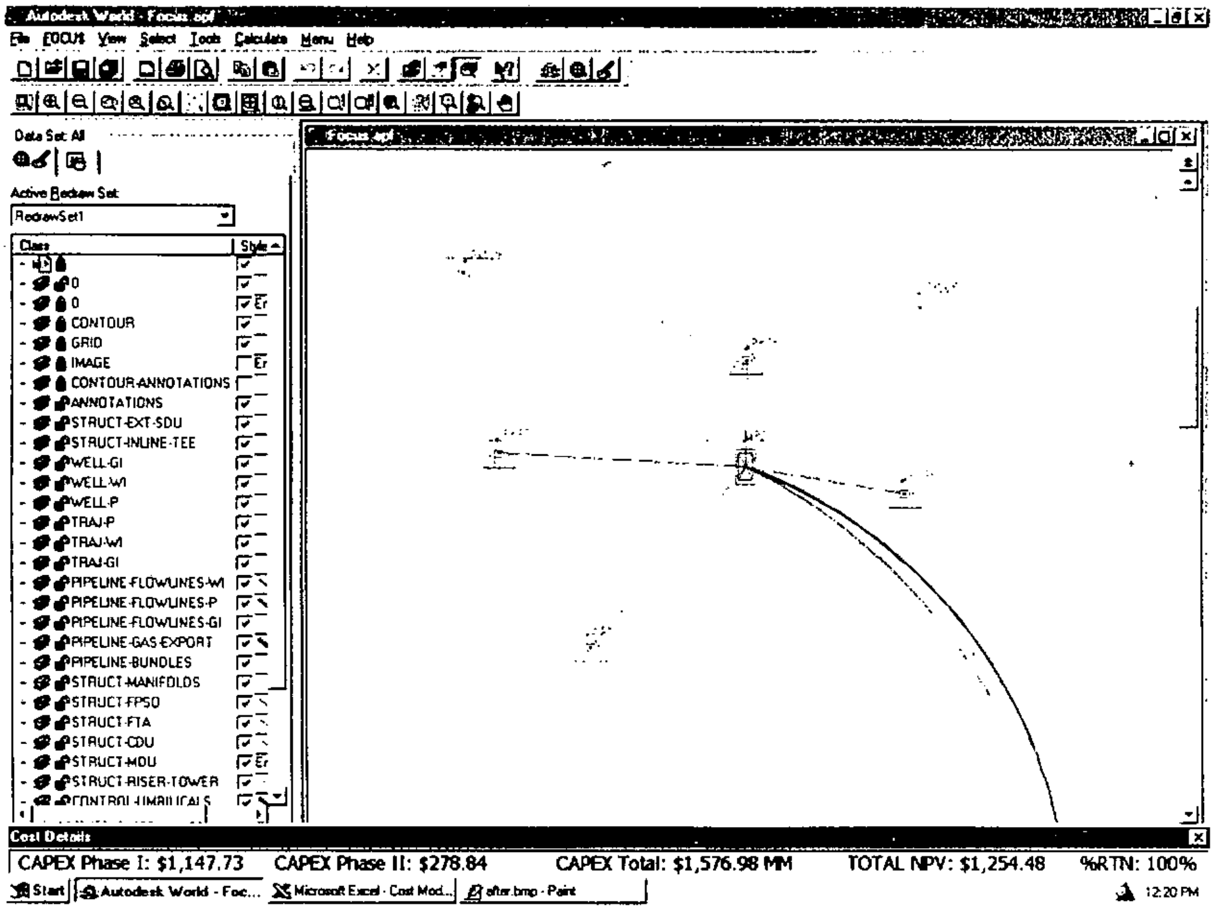

FIGURE 7

Manifold in its Original Position:

Field Development Total CAPEX Cost $1.576.96 MM.

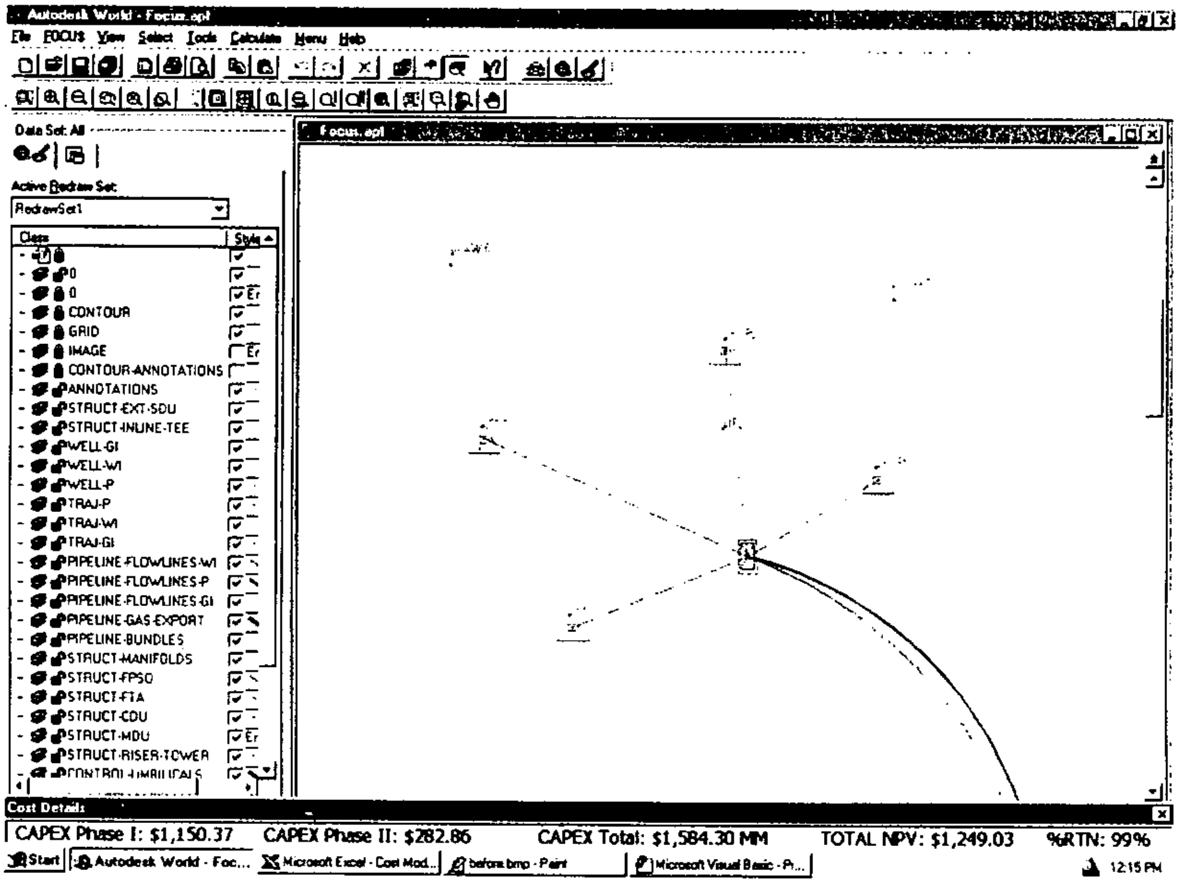

FIGURE 8

Manifold After Repositioning:

Revised Field Development New Total CAPEX Cost $1,584.30 MM.

Recent Advances in Deepwater Pipeline Technology

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presented at the
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RECENT ADVANCES IN DEEPWATER PIPELINE TECHNOLOGY

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ABSTRACT

In recent years, limit state principles have been more frequently adopted in pipeline design all over the world. This is mainly caused by the introduction of limit state principles in several recently published or updated codes. Further, it has now been widely accepted that a good limit state design code provides the most consistent safety level for a pipeline and that it will provide an optimum design from material cost point of view. It should, however, be noted that a material cost optimized design not necessarily is the same as a total project cost optimization, this is particularly true for pipeline projects where the material cost not is a major part of the overall project cost. Also applied to more challenging projects, the limit state concept may constitute the difference between a feasible or non-feasible design.

As such, the limit state methodology is particularly well suited for design of deep-water pipelines. There are, however, some aspects which need more development and which will be discussed in this paper, namely:

- the validity of some limit states to deep water
- uncertainties related to collapse limit states
- inconsistency in industry practice for design for propagating buckling

The paper will constitute a discussion basis, as well as recommend directions, for further research related to deep-water specific limit states.

The discussion will primarily be based on the limit states as defined in the recently issued DNV OS-F101 Submarine Pipeline Systems, but is also applicable in general.

INTRODUCTION

One of the first applications of pressurized pipes was in the steam engine. The pipes were in general short and the internal pressure by far the most important load. This was also reflected in the first pipeline codes published in the beginning of the last century where the hoop stress should be less than a certain portion of the yield stress. The criterion was based both on a pressure containment proof test at the mill as well as typical pressure variations in a pipeline.

As the development continued and more advanced pipelines were laid, it was found required to include not only the circumferential stress but also the longitudinal stresses. A requirement to the equivalent stress to be less than a certain portion of the yield stress was therefore added. This criterion became especially important for the installation condition when the stinger configurations were changed from supporting the pipeline all the way from the lay barge to the sea bottom to the installation methods of today where the pipeline is hanging from the lay vessel acting more as a cable. A good "rule of thumb" turned out to be allowing for 33% dynamic loading during installation and, hence, the criteria of 72% and 96% for functional alone and functional plus environmental load was established. The above criteria reflect the design up to the 1960's and were all well justified from the need of the projects at that time.

Hence, the "old-fashioned" design criteria that we even see used today were not the result of erroneous development but reflected the need of the time and were therefore part of the technical evolution.

Around 1980, several companies put an impressive research effort into studying different failure modes. One of these was the collapse capacity, i.e. the resistance to external pressure. Some of the collapse predictions (external pressure acting alone or in combination with bending) were based on classical methods and documented by tests. And collapse is, indeed, a deep-water specific limit state.

It took, however, a long time before this development was implemented in design codes applying the limit state methodology. However, in the mid 1990's several codes were published with, in part or complete, limit state based principles, see GL (1995), CSA (1996), DNV (1996) and API (1999). The

DNV code included limit state formulation with structural reliability based safety factors, calibrated to specific values and has recently been updated, DNV (2000). It is fair to say that the pipeline industry now has accepted the advantages with the limit state philosophy, some 20 years after it was introduced for load carrying structures.

Background for Determination of Safety Factors

Basis for Modern Pipeline Design

The most fundamental basis for modern pipeline design, as reflected in DNV (1996), should be that the risks are acceptable. Further, the acceptable risks should be equal/similar for all limit states. This is a logical basis which not always is that obvious. Especially in the public opinion it is often stated that an abject shall be designed in such a way that it doesn't fail. This can never be done because there will always be a small probability to get a failure, even though this may become very small.

"Risk" is a combination between probability of failure and consequence of failure, i.e. the larger the consequences of a failure are, the smaller should the failure probability be. In DNV (1996) the consequences are classified in safety class low, normal and high in combination with the kind of failure (limit state category). Therefore, for a certain safety class and limit state category, the failure probability should be equal for different failure modes (limit states).

To determine the "acceptable risk" as a number, is impossible. However, for a certain consequence (i.e. safety class and limit state category) it should be possible to calculate an approximate allowable failure probability. Further, if the safety level shall be consistent, this failure probability has to be equal for each failure mode, and limit state principles have to be applied.

Target Safety Levels

In order to determine and suggest acceptable failure probabilities, the SUPERB project, ref. Sotberg (1997), calculated the implied safety level in existing codes. It shall be emphasized that the derived numbers are method dependent and that acceptable failure probabilities preferably should be done by comparison with similar limit states with known adequate failure probability.

The work revealed, as expected, a large variation in existing codes, not necessarily between the codes but between the different limit states within a code. Based on these findings, recommendations on target safety levels were made. A quantitative illustration of these is shown in Figure 1. Note that this is for illustration only, and for more detailed results, reference is made to the SUPERB specific report.

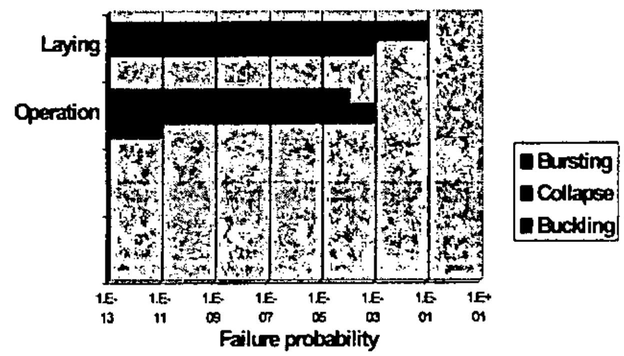

Figure 1 **Approximate Failure Probabilities in Some Common Design Codes. (The figure is for illustration purpose only and for more accurate values refer to the SUPERB reports)**

The extreme values in the figure shall be considered as indications only and care shall be taken when using these, see e.g. Palmer (1995). The overall failure probability is the overall failure probability which includes aspects such as human errors, operations etc. These have to be ensured by procedures and other quality control measures and are not reflected directly in the above target safety levels and corresponding design equations. The importance of the quality control measures shall not be neglected since failure statistics clearly indicates that these may be the most contributing factors to the overall failure probability. However, for the remaining part of this paper, only the impact on the design equations is discussed.

Partial Safety Factors

Given target safety levels, partial safety factors can be determined by use of structural reliability methods for each individual limit state.

All the design criteria provided in the DNV OS-F101 are given in the LRFD-format including partial safety factors calibrated to give an overall failure probability level directly linked to the requirement of the safety class.

$$L_d = \gamma_F \cdot \gamma_c \cdot L_F + \gamma_E \cdot L_E + \gamma_A \cdot \gamma_c \cdot L_A \leq \frac{R_k(f_k)}{\gamma_{SC} \cdot \gamma_m} = R_d \qquad (1)$$

γ_F , γ_E = Functional and environmental load effect factors

L_F, L_E = Functional and environmental characteristic load effects

γ_{SC} = Safety class resistance factor

γ_m = Material resistance factor

The design criteria in the LRFD format consist of one design load effect part, L_d, (left hand side) and one design resistance part, R_d. The design effect side consists of characteristic load effects and load effect factors. The load effect factors are closely linked with the choice of characteristic load effects, which usually are upper fractiles of the corresponding distribution, with the corresponding uncertainty.

The resistance side consists of a characteristic resistance, R_k, based on a characteristic material strength, f_k, and resistance factors. An illustration of the adopted LRFD principles in DNV OS-F101 is given in Figure 2.

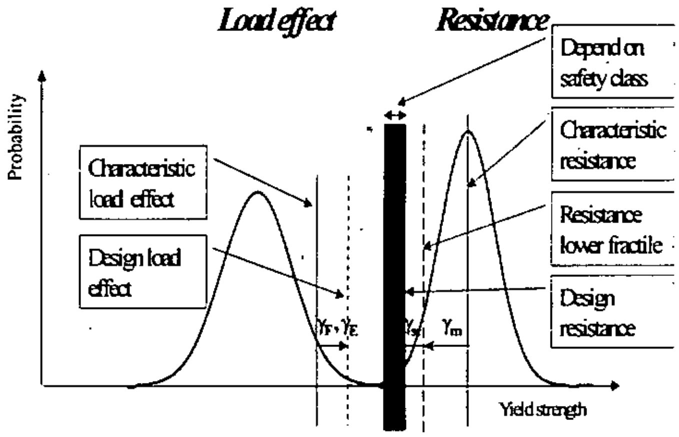

Figure 2 Illustration of the Adopted LRFD Format in DNV Offshore Standard

Note that the above figure is for illustration only and the "overlapping" area is commonly, erroneously, referred to as "failure probability". Identical probability functions for resistance and load (i.e. 100% overlap) that are un-corrolated have a failure probability of 50%.

Even though the limit state principle states that "all limit states shall be checked independently" this may not always be possible since there may be a strong interaction between different failure modes as well as problems to separate different failure modes.

One example of this may be the local buckling check, where pressure, axial load and bending interact. The sensitivity for these different loads varies. In order to maintain a consistent safety level for these loads (e.g. the selected "tail" in the above figure) with maintained safety factors, the choice of characteristic capacity may be altered. Hence, the characteristic resistance is sometimes an average value and sometimes a lower fractile, see Figure 3. Independent of the choice of characteristic value, the overall failure probability level is, however, maintained.

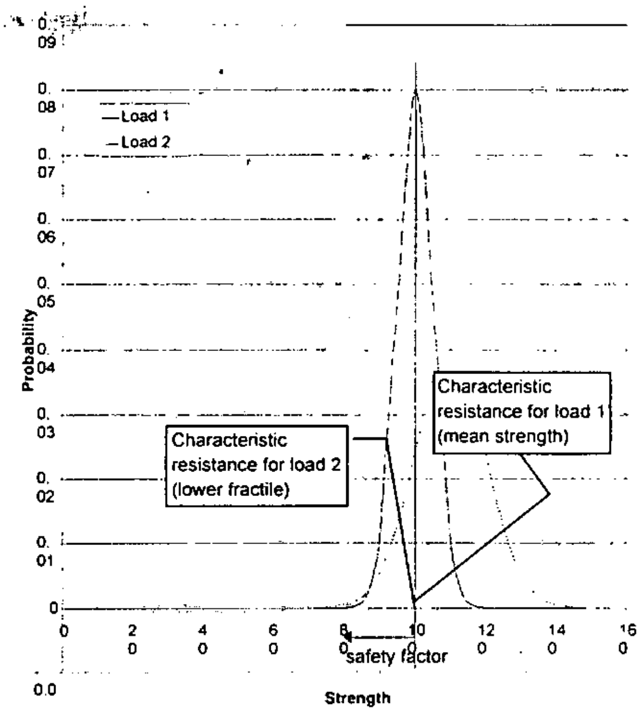

Figure 3 Illustration of resistance as function of different loads

Uncertainties

As indicated by the above discussion, a fundamental input to the calibration of partial safety factors is the related uncertainties. Maintaining the LRFD format, these are related to uncertainty in load effects and in resistance.

The load effect uncertainties arising from functional loads may be given by the requirements to pressure regulating and pressure safety system for the pressure load effect. For other loads, e.g. weight, this is mainly caused by the variation in geometry. Environmental load effect uncertainty may be based on environmental recordings etc.

For the purpose of the main topic of this paper, the discussion will focus on the resistance uncertainties. Further, it will be made in a simplified manner without any aim of being accurate or complete but to illustrate some aspects.

The resistance uncertainty is usually divided into two main groups:

- Variation in parameters
- Model uncertainty

Variation in parameters is e.g. variation in

- thickness,
- yield strength,
- diameter,
- ovality etc.

The uncertainties in the parameters which constituted the basis for the DNV'96 partial safety factors as well as the correlation between these were established in the SUPERB project based on several thousand tests, see Jiao (1995).

The model uncertainty may include elements from

- Simplification in the resistance formula, i.e.
  - use of SMYS instead of a complete material formulation.
  - assumption of isotropic material
  - adoption of a lower polynom ("curve fitting")
- Uncertainty in empirical data e.g.
  - uncertainty in FE-calculations
  - uncertainty in test data

One of the above factors that in the author's opinion really should be re-evaluated is the definition of the SMYS, the stress at a strain of 0.5%. What is the physics behind this definition other than the simplicity to measure it?

However, a too detailed and accurate description of a parameter, e.g. the stress-strain curve, may not be relevant since this may not be known in the design stage. This aspect should be duly considered when "converting" a research formula to design application.

The model uncertainty must be determined for each developed limit state based on analysis as well as experience.

COLLAPSE LIMIT STATE

General

Most proposed collapse formulas are based on interaction between the plastic capacity and the elastic capacity. In addition, the influence of the ovality is included. The SUPERB project reviewed different formulations and concluded that Haagsma's formulation, fitted the available test data best. This is the same formulation as included in the BS8010. This formulation is given in Eq. **Error! Reference source not found.**.

$$(p_c - p_{el}) \cdot (p_c^2 - p_p^2) = p_c \cdot p_{el} \cdot p_p \cdot f_0 \cdot \frac{D}{t_2} \qquad (2)$$

$$p_p = 2 \cdot f_y \cdot \alpha_{fab} \cdot \frac{t_2}{D}$$

$$p_{el} = \frac{2 \cdot E \cdot \left(\frac{t_2}{D}\right)^3}{1 - \nu^2}$$

For low D/t the plastic capacity will be dominating while the elastic capacity will dominate for high D/t's. This makes the formulas valid for a large range of D/t's. Haagma's formulation is based on a yield assumption and considers only properties in the circumferential direction. Any strengthening effect from the longitudinal direction is not accounted for. However, the collapse prediction formula fits well with available data.

Validation

Several test results exist in the literature. These have normally been performed on small-scale seamless pipe tests. However, during the last 10 years some major deep water projects have performed full scale tests of welded pipes, especially the Oman-India project (water depth 3500m), and the Blue Stream project (water depth 2150m). One major finding in both these projects, has been the significant effect of the welded pipe fabrication process, the UOE-process, on the collapse capacity which has given a significant larger spread in the test results. This has also been verified by other independent research work. The general assumption is that the cold deformation process which the pipes undergo during the U-ing, O-ing and Expansion process gives rise to a substantial Bauchinger effect. The strain hardening in the tensile direction will influence the yield properties in the compressive direction, which will reduce the circumferential compressive yield strength.

DNV OS-F101 specifies that the yield stress shall be reduced by at least 15% for UOE-pipes in collapse calculations. However, it has been found that the degradation due to the UOE process varies from pipe mill to pipe mill. A nearby solution to account for this Bauchinger effect directly would be to base the collapse calculation on the circumferential compressive yield stress test results. This seems to be a logical way forward since this material property is expected to be the governing parameter. Surprisingly, both the Oman-India project as well as the Blue stream project investigated this but concluded that the SMYS should be used, with a factor applied on this.

Material uncertainties

It is assumed that the apparent inconsistency in collapse prediction based on circumferential compressive yield stress measurements is caused by a considerably larger variation in this stress compared to other material properties. This larger variation is revealed both in the Oman-India project as well as in the Blue Stream project. In some cases there are examples of variation in the order of ±15 MPa for plate and longitudinal yield stress and a corresponding variation in circumferential compressive yield stress of ±60 MPa. If the above assumption is correct, then the apparent inconsistency can easily be explained.

Assume that the variation follows a Normal distribution with e.g. N(485, 15) for the longitudinal direction and N(420, 45) for the circumferential compressive yield stress, i.e. a three times larger standard deviation (spread) for the circumferential direction. If one specimen is taken and tested for each of these two properties, there is a 68% probability that the first test will be within ±15 MPa from the mean yield stress while the corresponding value for the circumferential direction is 26%, ref. Figure 4. Hence, the circumferential test value will more likely be further away from the circumferential average value than the longitudinal test result from the longitudinal average value. It would therefore be more appropriate to use the longitudinal test result and reduce it with a bias.

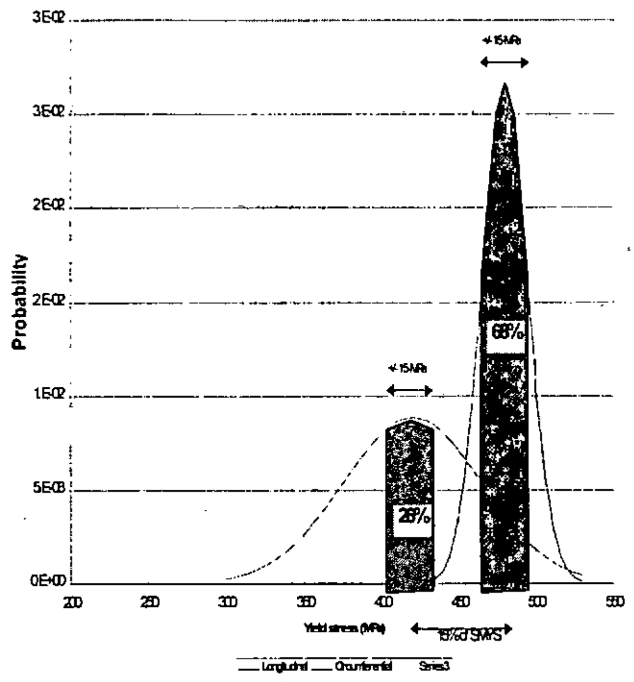

Figure 4 Illustration of probability to get a value close to the average value for two different distributions

Given this, the apparent inconsistency in collapse prediction based on one circumferential compressive yield stress test is because the test may be a poor representation of the average yield stress for the second case. This is true, given that the variations are very local and that the collapse failure mode utilizes an area considerably larger than the local variation. It is likely to believe that a pipe length of approximately 1 diameter will be utilized in the initiation of the collapse, hence if the variations are within a fraction of this, the hypothesis above will be valid.

The task that remains is then, how to get a representative value of the circumferential compressive yield stress? If such a representative value could be found in a "simple manner " i.e. not by full scale tests of pipes, this could be a useful tool for the pipe mills to modify their fabrication process to optimize the collapse capacity of the pipe.

First, it is necessary to identify possible contributing factors to the overall variations, which all accumulate. Examples may be:

- natural variations in the original plate
- differences due to test-setup
- differences due to varying cold deformation in the circumferential direction
- differences due to varying cold deformation in the radial direction
- differences due to varying cold deformation in the longitudinal direction

Possible contributions of these to the above will be touched upon in the following.

The ASTM (1989) specifies test set-up for compressive yield stress measurements. However, the experience with this test set-up may be limited at the pipe mills, contributing to variations. Projects have shown that experience gained during consecutive testing will reduce the variations, reflected also in the recorded stress-strain curves.

Accurate measurements of pipe ovality have revealed pronounced sinusoidal variations along the circumference. This deformation pattern matches with the mechanical expander used during the Expansion process. Hence, there may be local shell bending along the circumference which has impact on the Bauchinger effect, and as such variations along the circumference in compressive yield stress.

The mechanical expander is not one pipe joint long, but divided in smaller parts. This may also give variations in the longitudinal direction of the circumferential yield stress properties.

All these variations are added on top of the natural variations in the properties from the fabrication of the plate.

Discussion

Given these likely explanations on the contributing factors to the circumferential yield stress variations, the main task remain, how to achieve representative values from a test? One possible answer is to describe a different set-up, that provides a value reflecting the average property. However, in order to do this, it is also required to identify what property is valid for the collapse prediction, is it shell bending capacity or shell compressive capacity?

One proposal would be to test a sector of the pipe, with sufficient extent in both longitudinal direction and in the circumferential direction. This could then be bent or compressed in order to get an averaged result.

The intention of the paper is to initiate a discussion along these lines and get support for further research, or that such projects are initiated.

PROPAGATING BUCKLING LIMIT STATE

General

A propagating buckle is a running buckle due to external overpressure which has been initiated by an initiating event. The pressure required for a propagating buckle, the propagating pressure, is lower than what is required to initiate a buckle as well as propagating it.

The propagating buckle runs very fast and includes also inertia forces. The speed implies that also dynamic material properties could be justified, e.g. a higher yield strength, in the capacity formula. This is, however, only true for the running buckle, when the buckle stops due to a too low pressure, the buckle will be exposed to a static condition. Therefore, the propagating pressure shall always be calculated with the most conservative values and this will not be too conservative.

The pipeline is normally not designed for the propagating pressure but when the propagating pressure is exceeded, buckle arrestors are normally installed. These are thicker pipes, installed with certain spacing, which will arrest a running buckle and limit the amount to buckled pipe joints to between two buckle arrestors. The spacing is determined by the risk and cost involved in destroying, e.g. flattening a pipe between two buckle arrestors.

Recent characteristic propagating pressure formulas are given in (3) and (4).

$$p_{pr} = 35 \cdot f_y \cdot \alpha_{fab} \cdot \left(\frac{t}{D}\right)^{2.5} \quad \textbf{DNV OS-F101} \tag{3}$$

$$p_{pr} = 24 \cdot SMYS \cdot \left(\frac{t}{D}\right)^{2.4} \quad \textbf{API RP1111} \tag{4}$$

The difference is marginal between the two where a safety factor between 1.20 and 1.45 is applied on the DNV formula depending on safety class and 1.25 on the API formula.

Safety factors

The safety factors in the two above formulas are quite small and give a failure probability as large as in the order of 1%. The argument for this high failure probability is what is referred to as *dependent* failure probability. That is, in order to get a running buckle, an event is required. The likelihood of an event to happen should therefore also be included in the failure probability for the propagating pressure.

Two typical initiation events may happen:

- A buckle occurs in the sag bend during installation
- An object is dropped onto the pipeline

To illustrate the inconsistency in design of pipeline for propagating pressure, two scenarios are illustrated. For the purpose of this illustration, assume that there is no variation in material or geometrical parameters within a pipe joint.

In the first case, the design propagating buckling resistance (i.e. including the safety factors) is equal to the external pressure. If a dropped object is hitting the pipeline and there is enough energy to initiate a running buckle, there is a 1% probability that the buckle will propagate through this pipe joint. The probability that the buckle will propagate over two pipe joints is even smaller.

In second case, the same pipeline (i.e. same thickness) is installed in deeper water where the design propagating pressure is by far exceeded by the external pressure. Buckle arrestors are therefore installed for, let say, every 50 pipe joints. If an object is dropped on this pipeline, a running buckle will initiate and 49 pipes will be pressed flat, see Figure 5.

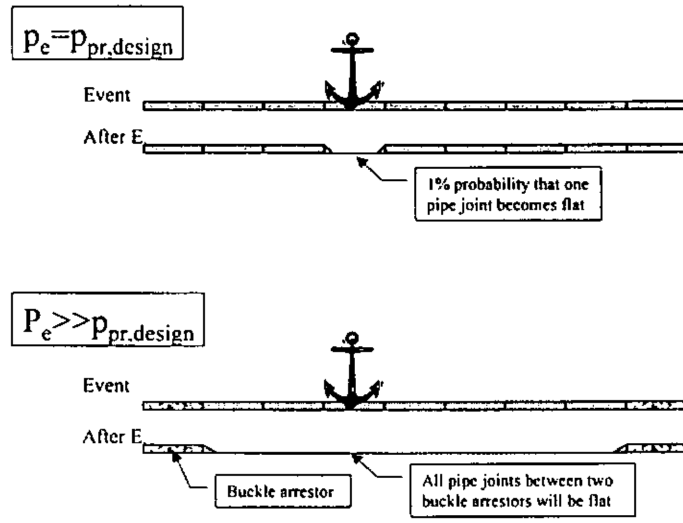

Figure 5 Illustration of industry accepted consequence for design for propagating buckling

Failure probability discussion

The above illustration clearly indicates an inconsistency in the safety of a pipeline without buckle arrestors and when buckle arrestors are installed. In the first example it is only a 1% probability that one pipe joint should fail the propagating pressure when hit, while it in the second example is accepted that 49 out of 50 pipe joints fails. It could therefore be argued that no safety factors should be applied on the propagating pressure, i.e. to let the design propagating strength be equal to the mean strength. There would still be less damage caused on such a pipeline compared to a pipeline with buckle arrestors.

The above illustration is a simplified comparison, assuming each pipe joint to has no variation in geometrical or material parameters (which of course is not true), and there are many aspects that are not included in such an example, e.g. how local is the variation. If the variation is very local there may be a possibility for "crossover", i.e. it is important that a pipe segment with a higher yield stress is sufficiently long to stop a running buckle. This and other comments regarding the comparison will not change the fact that there is a general inconsistency in safety level between pipelines designed for propagating buckling and those were buckle arrestors have been installed.

SUMMARY

The paper provides a discussion basis for two different deep water limit states from the safety level point of view. The first discussion is related to the collapse capacity for UOE pipes were there is an unreasonably large variation in the collapse prediction. The paper has proposed an explanation for this large uncertainty as well as proposed a direction for further research on this in order to both reduce the uncertainty as well a provide a rational measure to calculate the collapse capacity. Such a rational measure would also help the pipe mills to refine and adjust the pipe fabrication in order to increase the collapse capacity.

The second deep water limit state that has been discussed is the propagating pressure. The paper has focused on an inconsistency in design practice with respect to propagating pressure and has indicated that the safety factors should be reduced to unity. This could give a substantial reduction on the pipeline cost.

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The Royalty-in-Kind Program for Offshore Gas Production in the Gulf of Mexico

Bonn Macy
Minerals Management Service, Herndon, VA, USA

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

Royalty-In-Kind Pilot Program

Reengineering Federal Royalty Collection

Bonn Macy
Minerals Management Service
Deepwater Pipeline and Riser Technology Conference
Houston, Texas March 8, 2000

Reengineering our Business

- RIK part of a larger effort to re-think our business
- Our goals:
  - Can create value for the Taxpayer?
    - Can we effectively market our production
    - are there efficiencies and advantages can we realize?
  - Can we save money by reducing to cost and burden of collecting royalties?
  - For the taxpayer? -- For industry?
  - Striving for simplicity, clarity, accuracy, and certainty
- Identify the key success factors for RIK

MMS-Wyoming Oil RIK Pilot

- Today, with our partner, we are selling~ 5100 bbls/day of royalty oil
  - 400 bbls is from State of Wyoming leases
- Has it been a success?
  - Preliminary figures indicate we've had ups and downs but will be positive over the first year
  - all have been satisfied with the results
- We have learned a lot in Wyoming
  - productivity and transportation arrangements are key
  - administrative costs determine viability
- The Wyoming pilot becomes the first to graduate to a full-fledged ongoing program

Texas 8(g) Gas RIK Pilot

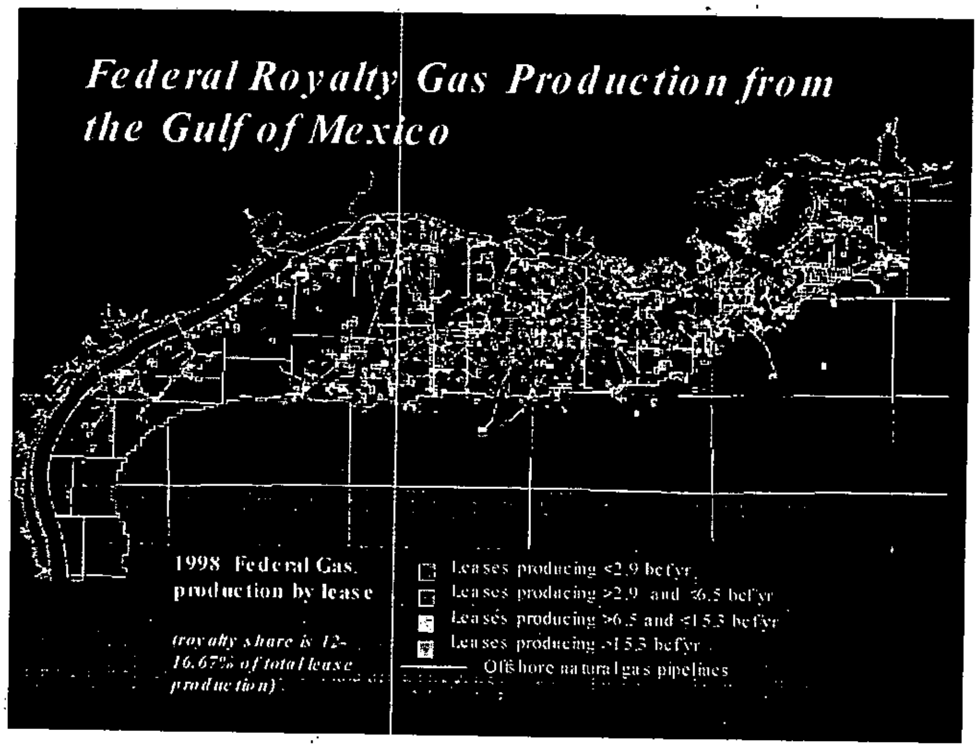
- We started in the shallow water off the coast of Texas
  - getting our feet wet before we go swimming
  - test new ideas, growing as customers are identified
  - build on the experience of the Texas General Land Office
- Everything we learn and develop here gets applied throughout the GOM
  - examine how we sell our production
    - started monthly bid offerings and refined them
    - develop arrangements for transport gas, participate in its administration, and understand the procedures
    - integrate methods and understanding gained into the organization

SPR Oil RIK Project

- We joined with the Dept. of Energy to replace oil sold from the Strategic Petroleum Reserve with RIK oil.
  - 28 million bbls. of oil at the lease to be taken-in for the SPR
- 1st phase: get oil into reserve quickly to realize the then current low oil prices
  - MMS, with DOE, negotiated directly with the largest producers
  - shipments for April - July 1999, 55,000 bbls/day
- 2nd Phase: DOE conducts auction, designed by MMS, to introduce competition, and allow everyone to participate.
  - contracts won by 4 bidders for 65,000 bbls/day, 8/99 - 12/99
  - second round of bids for deliveries Jan - October 2000, completed
- It is a viable and efficient method for putting oil in the SPR

GOM RIK Pilot Program

- Federal Royalty Position in the GOM 2.5 bcf/day
  - we have an interest in every producing gas well in the GOM
    - makes us one of the largest producers in the Gulf
  - pilot will take about 1/3 in-kind, ~800 million cf/day
- Size indicates that we will deal with many more leases, operators and lessees at once that we have in the past
  - We have had the luxury in the past of individual attention to many of the properties in the RIK pilots
  - with size more public methods will be used to convey our policies and procedures
- Organize production by pipeline system
- work with producers to create an efficient program



Sales of RIK Volumes

- We intend to use several methods to sell gas
  - the basic objective is to see what works best for us
- Auctions to bringing gas onshore where we can use it
  - transport, processing, gas control, scheduling, nominations, etc.
  - essential in the short term, cost-effective in the long term?
- Bidding systems to sell gas to the public
  - use of the "Notice of Availability" and prequalification of bidders to reduce bid administration and simplify bidding
    - work with SBA to reliably bring gas to smaller companies, expanding our potential market

Transfer to Federal Agencies

- Partnership with the General Services Administration (GSA)
  - transfer of RIK specifically permitted in MLA and OCSLA
  - they can serve all other agencies,
- Partnership with GSA in place now for 9 months.
  - Jointly form a "Federal gas utility" for Federal users
  - MMS "produces" the gas, GSA ensures it is reliably delivered, managed, and properly billed to Federal end users.
  - a successful arrangement that has increased royalty revenue, and reduced agencies' energy costs
  - planning expansion + further development
  - MMS is currently transferring 200 million cf/day; and will increase.

Summary

- The success of the RIK programs is all about people working together
  - Federal and State
  - different Federal agencies
  - government and industry
- Reengineering is about applying best practices
  - adapting the organization
  - bringing new ideas and methods into the agency
  - find what works, and increase productivity for your tax dollars
  - everyone brings something unique to the party
    - skills, abilities, experience, resources, etc.

Burst Test Basis for the Internal Pressure Design Formulation in the Revised API Recommended Practice 1111 for Offshore Pipelines

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presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
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Burst Test Basis for the Internal Pressure Design Formulation in the Revised API Recommended Practice 1111 for Offshore Pipelines

Abstract

The recently revised API Recommended Practice 1111 [Ref. 1] introduced a radical new formulation for the internal pressure design of pipelines. This formulation was obtained by comparing numerous formulas, including several derived from theoretical burst considerations, with a database of 276 burst tests. The two formulas which best fit these data, with appropriately adjusted coefficients, were selected to predict the minimum burst pressure. The pipeline design procedure provides a hydrostatic test pressure as a fraction of the predicted burst pressure at each critical point along the flowline. The design pressure is then calculated as a fraction of the hydrotest pressure. This procedure eliminates the possibility of burst failure during hydrotest.

These new design formulas were found to match the conventional code design formulas for thin-wall pipes, while simultaneously correcting the tendency of the conventional code designs to be overly conservative for high-pressure low-D/t flowlines. An even less conservative design is permitted under this revised RP 1111 code for line pipe subjected to additional inspections beyond those required by API 5L. This paper presents some of the burst test data and shows the comparisons between the data and the proposed formulas that led to the selection of the minimum burst pressure formulation.

Introduction

An OTC paper by Langner and Shah [Ref. 2] expressed a rationale for making changes to offshore pipeline codes, with emphasis on reducing the conservatism inherent in existing codes for high-pressure subsea flowlines and risers. Design of these flowlines are dominated by the well shut-in pressure, which typically is between 5000 and 10,000 psi, but may be as high as 15,000 psi. Conventional ASME pipeline codes applied to these flowlines result in overly thick-wall pipe designs having burst safety factors typically between 2 and 4. This compares with burst safety factors of most existing pipelines between 1.5 and 2.5. Consequently, unnecessarily large steel and welding cost penalties are paid for these flowlines and risers, and upgrades to layvessels and platform structures may be required to handle their increased weight.

The main factor leading to this conservatism is the Barlow formula and associated design factors, which was introduced into pipeline design practice in the 1930's and which loosely relates the maximum hoop stress with initial yield. For thick-wall pipe the initial yield pressure is much lower than the actual burst strength. Additional conservatism (or unconservatism!) can occur if hydrostatic pressures are not fully taken into account in the design. For steel catenary risers, design rules in the existing API RP 2RD [Ref. 3] prescribe arbitrary limits on extreme

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stress, which also can result in overly conservative designs. It was estimated that as much as $4-8 milion per year in material and installation costs could be saved by changing to a Limit State design method for future deepwater flowlines and risers.

Beginning in March 1997, a task force chaired by Bharat Shah of Conoco Inc. and co-chaired by Steve LeBlanc of Mobil Technology Company, began meeting monthly to revise the existing API RP 1111 (Second Edition, Nov. 1993) for offshore pipelines. This task force included representatives of Amoco, Chevron, Conoco, Exxon, Mobil, Shell, the Minerals Management Service, and the American Petroleum Institute. The main purposes of this revision effort were: (1) to include within the RP all design limit states appropriate to offshore pipelines and risers, such as internal pressure burst, external pressure collapse, excessive ovalization or buckling due to bending, fatigue due to cyclic bending, corrosion, flow assurance, and on-bottom stability; and (2) within the extent possible, to formulate these design limits in terms of actual failure conditions of the pipe, while eliminating arbitrary limits on the stresses and strains such as appear in many of the existing pipeline codes. Guidelines for this effort included ensuring safety of the pipeline design, so that no failures (burst, collapse, etc.) will occur as a result of following the design rules, and promoting economy by employing the full strength capacity of the steel pipe.

In less than two years, this task force produced a revised API RP 1111 [Ref.1] which incorporates the following major changes from the previous edition:

1. Provides a more uniform safety factor against burst failure, because the design formulas were fitted to actual pipe burst data. The formulas match the conventional code design formulas for thin-wall pipes, where $D/t > 40$, while correcting the tendency of the conventional code designs to be overly conservative for high-pressure flowlines with low D/t ratios.

2. Specifies a design procedure in which the minimum burst pressure is calculated; then the hydrotest pressure is calculated as a fraction (90% for pipelines, 75% for risers) of the minimum burst pressure; and finally the design pressure is calculated as a fraction (80%) of the hydrotest pressure. This procedure prevents inadvertent burst failure during hydrotest, which can happen for certain high-pressure gas pipelines.

3. Permits a less conservative design, having 10% thinner wall, for pipelines in which the line pipe is subjected to additional inspections beyond those required by API 5L [Ref. 4], as specified in Appendix B of RP 1111 and [Ref. 5].

4. Requires that the hydrostatics both inside and outside the flowlines must be fully taken into account, as necessary to avoid problems in deep water.

5. Includes formulations for buckling, collapse, fatigue, and other limit states not addressed in many of the existing pipeline codes.

The limit state design approach, in the present context, refers to any formulation or method that provides a uniform safety factor relative to an actual failure mode over a wide range of design conditions. The remainder of this paper demonstrates how the limit state formulation for internal pressure design was obtained for RP 1111. The specific goal is to provide safety factors against burst failure in the range 1.5-2.5 for the class of high-pressure flowlines and risers, thus bringing this class of flowlines and risers into line with the majority of existing pipelines.

Candidate Design Formulas

The majority of pipeline design formulas specified in the various design codes around the world are based on the Barlow formula, Equations (1–3) below. The formulas differ primarily by the design factors and by which measure of pipe diameter, wall thickness, and material strength are utilized [Ref. 6]. For example, the ASME B31 codes specify the nominal outside diameter, nominal wall thickness, and specified minimum yield stress in the design formulas. Others use the mean pipe diameter and/or the minimum wall thickness instead of nominal values, and some use the ultimate strength instead of the yield strength. For the limit state design approach, a design formula must accurately predict the burst pressure. Following are the candidate formulas that were considered in the RP 1111 study for predicting the burst pressure of pipe:

(1) $P_b = 2\,K\,S\,t\,/\,D$

(2) $P_b = 2\,K\,S\,t\,/\,D_m$ — Barlow formulas

(3) $P_b = 2\,K\,S\,t\,/\,D_i$

(4) $P_b = K\,S\,\ln(D\,/\,D_i)$ - Plasticity formula

(5) $P_b = KS\,(D^2 - D_i^2)\,/\,(D^2 + D_i^2)$ - Lamé formula

where P_b is the burst pressure,
D is the nominal outside diameter,
t is the nominal wall thickness,
$D_m = D - t$ is the mean diameter,
$D_i = D - 2t$ is the inside diameter,
S is the strength measure, either Y or U or F,
Y is the tensile yield strength (at 0.005 strain),
U is the tensile ultimate strength,
$F = (Y + U)/2$ is the "flow stress" assumed to lie midway between initial yield and ultimate, and
K is the design coefficiant utilized to fit the data in some sense (mean fit or minimum fit, etc).

A few comments about the theoretical basis of these formulas are in order. Equation (4) is a form of the ductile burst formula for thick walled tubes derived from the theory of plasticity [Ref. 7]:

6. $P_b = (2\,S\,/\,\sqrt{3}\,)\ln(D\,/\,D_i)$. Here $K = 1.1547$.

Equation (2) closely approximates Equation (4) and may be considered the algebraic equivalent of this "log" formula for $D/t > 10$. Equation (5) is obtained by equating S with the maximum stress in an internally pressurized elastic thick wall cylinder [Ref. 8]. Not surprisingly, Equations (2), (4), (5) provide the best fits with the actual pipe burst data, as will be seen below.

Burst Test Data

As a prerequisite to developing this Limit State Recommended Practice it was considered essential to compile a data base of burst test results for seamless line pipe, which typically is employed for subsea flowlines. Ref. 2 included a call for such burst test data, and a committee of the DeepStar JIP was charged with searching for available burst data among oil/gas producing companies and from various testing laboratories. Several burst databases were discovered, but most of these were either not available or not ideal for the present purposes. Several burst test programs [Refs. 9-11] focused on the effects of internal corrosion in large diameter gaslines. A large amount of burst testing has been done on high strength seamless casing pipe and threaded connections, the so-called oil country tubular goods. Unfortunately, most of these latter test data are not available, having been classified as confidential by the companies who paid for the testing.

In order to assure at least some quality burst data for the RP development purposes, Shell E&P Technology Company undertook to perform limited burst testing of seamless pipe, with samples taken from the surplus pipe following various subsea construction projects. Table 1 presents the results of 33 tests, performed between July 1995 and October 1998, listing the diameter D, wall thickness t, tensile strength parameters Y and U, and the observed burst pressure P_b for each pipe sample. In these tests, pipe diameters varied between 4.50" and 12.75", D/t ratios between 7.4 and 17.4, and observed burst pressures between 8,500 and 26,000 psi. Five of the test pipes were bent well beyond yield, with bending strains between 2.8% and 4.0%, and then were held at constant curvature while the pipes were internally pressurized to failure. Comparing the burst pressures of the bent and straight test pipes, there does not appear to be any influence of the very large bending strains on the burst strength of these pipes, which contradicts some current pipeline design and operational practices.

Figures 1 – 5 are photographs showing burst failures of both straight and pre-bent test pipes. Note that most of the failures are ductile longitudinal splits. Some have characteristic ductile upturns at the ends. Others are more complex with multiple cracks branching from the ends of the split. An important observation was that none of the prebent specimen failed near the middle where the bending strains were greatest.

During the course of the API RP 1111 revision activities, it became apparent that more pipe burst data would be beneficial. Therefore, in October 1997, Mobil Technology Company elected to donate some 290 burst test data from their large internal database on high strength seamless casing. These data were provided to the Task Force for their evaluations from an extensive testing program carried out by Mobil. After eliminating tests with missing data (primarily yield or ultimate strengths) and after eliminating test pipes with yield strengths exceeding 120 ksi (which were considered too far removed from typical line pipe), the Mobil database was reduced to 243 useable burst test data. These data, together with the 33 test data from Shell, provided a total burst database of 276 tests. Unfortunately, this paper has space to list only the Shell data, not the entire database. Figures 7 and 9 to be presented later show the entire database in relation to the various pressure levels required by the design process.

Comparisons Between Burst Data and Candidate Design Formulas

Tables 2 and 3 compare the Shell burst data with the 15 candidate design formulas introduced earlier. Listed in these tables are the design coefficients K obtained by inverting the design formulas ($K = P_bD/2Yt$ instead of $P_b = 2Kyt/D$) and inputting the observed burst pressures P_b as well as the pipe dimensions and strength measures. Thus, Table 2 lists K for the nine Barlow-type formulas, Eqns (1-3) above, and Table 3 lists K for the Plasticity formula and the Lame' formula, Eqns (4-5), for each of the 33 burst test data. At the bottom of Tables 2 and 3 are listed the mean value, the standard deviation, and the standard deviation divided by the mean (often called the coefficient of variation) of the K values listed in each column. The smallest values of this COV are indicative of the formulas that provide "best fits" to the data listed in Table 1.

The five "best fit" formulas, in this case, are:

(7) $P_b D_m / 2 U t = (0.9757)(1 \pm 0.0383)$

(8) $P_b D_m / 2 F t = (1.1323)(1 \pm 0.0398)$

(9) $P_b / U \ln(D / D_i) = (0.9718)(1 \pm 0.0374)$

(10) $P_b / F \ln(D / D_i) = (1.1278)(1 \pm 0.0400)$

(11) $P_b (D^2 + D_i^2) / F (D^2 - D_i^2) = (1.1456)(1 \pm 0.0400)$

These formulas are expressed as the mean value with a plus/minus variation of one standard deviation about the mean. The related Equations (8) and (10) were selected to represent the burst pressure in the RP1111 design formulation. Equations (7) and (9), while providing a slightly better fit of the data, were considered too radical departure from standard practice, because they exclude the yield stress and include only the ultimate stress. It was felt that the hoop strains, if dependent only on ultimate stress as in Equations (7) and (9), could become excessive under hydrotest conditions; whereas for formulas such as Equations (8) and (10) which include both the yield and ultimate stresses, a pipeline would never experience such large hoop strains. Finally, it is observed that the Lame' formula, Eqn (11), also provides a good fit to the burst data. However, in spite of its added complexity this formula does not provide any improved accuracy over the other formulas, and hence was eliminated from further consideration.

It is interesting to compare the above "best fit" formulas with the standard Barlow design formula specified in the ASME B31 codes [Refs. 12, 13]. From Table 2, this formula may be expressed as:

(12) $P_b D / 2 Y t = (1.4950)(1 \pm 0.0873)$

Note that the coefficient of variation (0.0873) for the conventional Barlow formula is more than two times larger than the COV's for any of the "best fit" formulas, indicating that Equation (12) does not represent the burst data nearly as well as Equations (8) and (10), which were selected for the RP 1111 document.

Limit State Design Formulation

Figure 6 lists the RP 1111 Standard Design equations, applicable for any steel pipe purchased under the API 5L specification. Two basic formulas are presented for the minimum burst pressure P_b, one involving the natural "log" function (analogous to the plasticity formula discussed previously) and the other an algebraic equivalent of the "log" formula. These two formulas give the same results for all conditions except very low D/t's (< 10), where the "log" formula is preferred. The algebraic equation is included because it is easier to manipulate when performing design calculations. The strength measure is the sum of the yield stress Y and the ultimate stress U, and is identical to the strength measure 2F discussed in the previous section. The various design factors are justified by noting that these formulas result in essentially the same designs as the ASME B31 design formulas for high D/t pipes. In their simplest form these Standard Design equations may be written as:

(13)	Minimum burst pressure	$P_b = 0.90\,(Y+U)\,t/(D-t)$	$N = 5.16$
(14)	Flowline hydrotest press	$P_t = 0.90\,P_b$	$N = 7.16$
(15)	Flowline design pressure	$P_d = 0.80\,P_t = 0.72\,P_b$	$N = 10.76$
(16)	Riser hydrotest pressure	$P_{rt} = 0.75\,P_b$	$N = 10.16$
(17)	Riser design pressure	$P_{rd} = 0.80\,P_{rt} = 0.60\,P_b$	$N = 13.16$

Here N is the number of standard deviations below the mean observed burst pressure for each of these design pressure limits, relative to the Shell burst data. The hydrotest pressure is the highest pressure level to which a pipeline or flowline will be subjected. At more than seven standard deviations below the mean burst pressure, the hydrotest pressure for the Standard Design should be completely safe from burst failure. Figure 7 graphically illustrates the relationships between the Shell burst data and these various design pressure limits.

Figure 8 presents the RP 1111 Enhanced Design equations, applicable for API 5L steel pipe that has passed additional inspections as specified in Appendix B of RP 1111 and the ANSI/ASQC A1.9 document [Ref. 5]. These additional inspections include more detailed measurements of wall thickness and yield strength, and a limited amount of burst testing. This further inspection effort permits the utilization of 10 percent thinner wall for a given design pressure, or 10 percent higher pressure for a given wall thickness, as compared with the Standard Design equations. In their simplest form these Enhanced Design equations may be written as:

(18)	Minimum burst pressure	$P_b = 1.00\,(Y+U)\,t/(D-t)$	$N = 2.94$
(19)	Flowline hydrotest press	$P_t = 0.90\,P_b$	$N = 5.16$
(20)	Flowline design pressure	$P_d = 0.80\,P_t = 0.72\,P_b$	$N = 9.16$
(21)	Riser hydrotest pressure	$P_{rt} = 0.75\,P_b$	$N = 8.50$
(22)	Riser design pressure	$P_{rd} = 0.80\,P_{rt} = 0.60\,P_b$	$N = 11.83$

The only difference between the Standard Design and the Enhanced Design is the burst factor, which is 0.90 for the former and 1.00 for the latter. As before, N is the number of standard deviations below the mean observed burst pressure for each of the design pressure limits, and the hydrotest pressure is the highest pressure level to which the pipeline or flowline will be subjected. At more than five standard deviations below the mean burst pressure, the hydrotest pressure for the Enhanced Design should also be safe from burst failures. The additional inspections specified in Appendix B, are required to insure that rare flaws in the pipe wall or metallurgical errors, etc., will not intrude and obscure the normal behavior of the line pipe. Figure 9 graphically illustrates the relationships between the Shell burst data and these various design pressure limits.

It is instructive at this point to compare the design formulas from RP 1111, as presented in Figures 6,8 and summarized in Equations (23-26), with the design formula from the B31 codes, as presented in Figure 12 and summarized in Equation (27). Figure 10 compares these formulas as a function of the D/t ratio. Here Equation (23) is taken as the "true" design formula and Equations (24-27) are plotted as ratios of Equation (23).

(23)	Enhanced "log" design	$P_{do} = 0.360\ (Y+U)\ \ln\ (D/D_i)$
(24)	Enhanced algebraic design	$P_d = 0.720\ (Y+U)\ t\ /\ (D-t)$
(25)	Standard "log" design	$P_d = 0.324\ (Y+U)\ \ln\ (D/D_i)$
(26)	Standard algebraic design	$P_d = 0.648\ (Y+U)\ t\ /\ (D-t)$
(27)	ASME B31 design pressure	$P_d = 1.44\ Y\ t\ /\ D$

Figure 10 shows that the Enhanced Design provides 10 percent higher design pressures than the RP 1111 Standard Design, and that the Standard Design provides higher pressures than the design formula from the B31 codes. While approaching the RP 1111 Standard Design pressure at higher D/t ratios, the B31 design formula, Equation (27), becomes increasingly conservative for pipes with low D/t ratios, such as typically used for high pressure subsea flowlines. Correcting this tendency of the existing codes to become overly conservative at low D/t's, has been one of the main purposes of the present code revision effort.

The RP 1111 document applies directly to any carbon-manganese steel pipe that meets the API-5L standard, including pipe manufactured by different methods. However, the design formulas do not automatically apply to pipe made from other metals such as ferritic-austenitic duplex steel or nickel based corrosion resistant alloys (CRAs). Appendix A of RP1111 provides a procedure by which the internal burst pressure design criteria can be developed and qualified for these other pipe materials. The procedure involves a minimum of six burst tests together with corresponding mechanical property tests and analyses.

Design Procedure for Subsea Flowlines

The following procedure is recommended for design of high-pressure subsea flowlines to insure that hydrostatic pressures are properly taken into account. The internal/external pressure difference $P_i - P_o$ must be used throughout the design process, recognizing that the fluid hydrostatic pressures both inside and outside the pipe will vary with depth along the flowline. Assume that the flowline design condition is a shut-in subsea well with the pressure blocked at the platform end.

For the Shut-In Pressure P_s Specified at the Wellhead:

1. Obtain the oil/gas fluid specific gravity (SG) at pressure P_s. If SG is unknown, then a gas-filled riser with SG = 0.2-0.3 must be assumed.

2. Calculate the shut-in pressure at the top of the riser using the water depth H and the above fluid specific gravity: $P_{rs} = P_s - \gamma H (SG)$.

3. Calculate the hydrotest pressure at the top of the riser: $P_{rt} = P_{rs}/ 0.80$. The constant in this equation may be changed to 0.90 if shut-ins are unplanned and the pressure may be justified as incidental.

4. Calculate the hydrotest pressure at the wellhead using the water depth H and the seawater density γ: $P_t = P_{rt} + \gamma H$.

5. Design the flowline and riser, including wall thickness and steel grade, based on P_t and P_{rt} using the appropriate RP1111 design equations.

For the Shut-In Pressure P_{rs} Specified at the Surface:

The design procedure for pressure specified at the surface is the same as above, beginning with Step (3).

Other Pipeline Design Considerations

In addition to internal pressure design, as discussed above, RP 1111 addresses many other design considerations as well. Figure 11 presents two other pipeline design formulations that are incorporated into RP 1111. At the top of the figure is the basic design formulation to prevent collapse of a pipeline due to external pressure and bending, which obviously becomes more important as pipelines are laid in deeper water. These equations were developed in the 1970's by Shell [Ref. 14], and are similar to collapse formulations in the DNV96 code [Ref. 15]. Different collapse factors are provided for Seamless or ERW pipe versus cold-expanded pipe such as UOE/ DSAW pipe. Bending restrictions are included against buckling and against failure due to combined bending and external pressure. However, no other limits on the bending stresses or strains are imposed.

At the bottom of Figure 11 is a formulation for computing the interaction between the internal pressure and the tension. This interaction occurs primarily at the top of a riser in deep water, and becomes critical when the internal pressures are highest, as during the hydrotest or during a well shut-in event with the pressure blocked from the platform. Remarkably this formulation, derived by D.L. Garrett [Ref. 16], is expressed in terms of the effective tension instead of the material tension. Different load factors are provided for operational loads, extreme loads, and hydrotest loads.

Figure 12 presents the internal pressure design formulation specified in the ASME B31.4 and B31.8 codes [Refs. 12,13] and in the Code of Federal Regulations 30 CFR 250 [Ref. 17]. The latter document is important since it is the only Gulf of Mexico code, with exception of the RP 1111, that applies to subsea interfield flowlines. As indicated in Figure 12, the B31 codes allow external pressure to be taken into account in determining the maximum operating pressure, $P_i - P_o \leq P_d$. However, the 30 CFR code is silent on use of external pressure in pipeline design.

Following are some additional notes on the external pressure design and longitudinal stress limits imposed by the B31.4, B31.8, and 30 CFR codes. The B31 codes mention that external pressure collapse should be considered in designing a pipeline, and B31.8 mentions that pipelines should be designed to avoid bending buckles, but no formulas are given. The 30 CFR code is silent on both bending and collapse failures. The B31 codes contain elaborate restrictions on the longitudinal stress, allowing stresses up to various fractions of yield (54%, 75%, 80%, 90%, or 100%) depending on different combinations of pressure, weight, and environmental loads. These restrictions on longitudinal stresses are burdensome for offshore pipelines.which frequently must be bent into the plastic range. Thankfully, the 30 CFR code is also silent on longitudinal stress.

Conclusions

1. The revised third edition of RP 1111 applies to all offshore pipelines, but will be especially useful for high-pressure subsea flowlines that transport unprocessed well fluids between subsea wells and platform processing facilities.

2. The RP 1111 internal pressure design formulation provides a more uniform safety factor against burst failure, because the design formulas were fitted to actual pipe burst data. The formulas match the conventional code design formulas for thin-wall pipes, while correcting the tendency of the conventional code designs to be overly conservative for high-pressure flowlines with low D/t ratios.

3. Existing codes can lead to burst failure during hydrotest for deepwater high-pressure gaslines. RP 1111 design procedure specifies that the hydrotest pressure is calculated as a fraction of the burst pressure, and then the design pressure is calculated as a fraction of the hydrotest pressure. This procedure eliminates the possibility of burst failure during hydrotest.

4. RP 1111 permits a less conservative design, having 10% thinner wall, for pipelines in which the line pipe is subjected to additional inspections beyond those required by API 5L. The RP also permits qualification of other pipeline materials than carbon-manganese steel.

5. The RP 1111 design procedure requires that hydrostatics both inside and outside the flowlines be fully taken into accounp, as necessary to avoid problems in deep water. If the fluid specific gravity is unknown during the design pressurization event, then a gas-filled riser must be assumed.

6. RP 1111 includes formulations for buckling, collapse, fatigue, and other limit states not addressed in many of the existing pipeline codes. The effect of tension on burst failure is included because of deepwater riser applications.

7. The ASME B31 codes contain arbitrary restrictions on longitudinal stresses. All such restrictions are removed from RP1111 except the effects of bending on buckling and collapse, and the effect of cyclic bending on fatigue.

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Table 1. Burst Tests of Seamless Line Pipe, Performed by Shell E&P Technology Company 1995 - 1998

Test No.	Test Date	Pipe Dimensions D(in)	t(in)	D/t	Tensile Strength Y(ksi)	U(ksi)	Observ'd Burst Pb(ksi)	Bending Strain D/2R
A1	7/95	5.562	0.750	7.42	62.7	86.4	25.46	0
A2	8/95	5.562	0.750	7.42	62.7	86.4	25.80	0
A3	8/95	5.562	0.750	7.42	62.7	86.4	25.98	0
A4	8/95	5.562	0.750	7.42	62.7	86.4	26.32	0
A5	8/95	5.562	0.750	7.42	62.7	86.4	26.09	0
A6	10/96	5.562	0.750	7.42	61.6	76.1	24.93	0
A7	10/96	5.562	0.750	7.42	61.6	76.1	24.08	0.0294
A8	10/96	5.562	0.750	7.42	61.6	76.1	24.97	0.0395
B1	3/97	6.625	0.562	11.79	65.7	86.2	15.90	0
B2	3/97	6.625	0.562	11.79	65.7	86.2	15.87	0
B3	3/97	6.625	0.562	11.79	65.7	86.2	16.01	0.0283
B4	4/97	6.625	0.570	11.62	47.8	72.8	13.17	0
B5	4/97	6.625	0.570	11.62	47.8	72.8	13.27	0
B6	4/97	6.625	0.570	11.62	47.8	72.8	13.30	0.0344
B7	1/97	6.625	0.569	11.64	47.7	73.1	12.90	0
B8	1/97	6.625	0.569	11.64	47.7	73.1	12.94	0
B9	1/97	6.625	0.569	11.64	47.7	73.1	12.98	0.0345
C1	7/97	4.500	0.345	13.04	51.2	77.5	12.81	0
C2	7/97	4.500	0.345	13.04	51.2	77.5	12.80	0
C3	7/97	4.500	0.345	13.04	51.2	77.5	12.80	0
C4	1/96	12.750	0.750	17.00	74.0	90.0	11.37	0
C5	1/96	12.750	0.750	17.00	74.0	90.0	11.14	0
C6	1/96	12.750	0.750	17.00	74.0	90.0	11.25	0
D1	7/97	8.625	0.495	17.42	57.7	78.7	8.71	0
D2	7/97	8.625	0.495	17.42	57.7	78.7	8.55	0
D3	7/97	8.625	0.495	17.42	57.7	78.7	8.64	0
D4	2/98	8.625	0.507	17.01	44.0	73.7	8.76	0
D5	2/98	8.625	0.507	17.01	44.0	73.7	8.77	0
D6	2/98	8.625	0.507	17.01	44.0	73.7	8.83	0
E1	9/98	8.625	0.875	9.86	78.9	95.0	21.72	0
E2	9/98	8.625	0.875	9.86	78.9	95.0	21.93	0
E3	10/98	8.625	1.000	8.63	71.5	91.6	23.56	0
E4	10/98	8.625	1.000	8.63	71.5	91.6	23.69	0

Table 2. Comparison of Various Barlow -Type Formulas with the Burst Test Data from Table 1

Test No.	Normalized by Yield Stress Y K=PbD /2Yt	K=PbDm /2Yt	K=PbDi /2Yt	by Flow Stress F= (Y+U)/2 K=PbD /2Ft	K=PbDm /2Ft	K=PbDi /2Ft	by Ultimate Stress U K=PbD /2Ut	K=PbDm /2Ut	K=PbDi /2Ut
A1	1.5057	1.3026	1.0996	1.2663	1.0956	0.9248	1.0927	0.9453	0.7980
A2	1.5258	1.3200	1.1143	1.2833	1.1102	0.9372	1.1073	0.9579	0.8086
A3	1.5364	1.3292	1.1221	1.2922	1.1180	0.9437	1.1150	0.9646	0.8143
A4	1.5565	1.3466	1.1368	1.3091	1.1326	0.9561	1.1296	0.9773	0.8249
A5	1.5429	1.3349	1.1268	1.2977	1.1227	0.9477	1.1197	0.9687	0.8177
A6	1.5007	1.2983	1.0959	1.3426	1.1616	0.9805	1.2147	1.0509	0.8871
A7	1.4495	1.2540	1.0586	1.2969	1.1220	0.9471	1.1733	1.0151	0.8569
A8	1.5031	1.3004	1.0977	1.3448	1.1635	0.9821	1.2167	1.0526	0.8886
B1	1.4264	1.3054	1.1844	1.2339	1.1293	1.0246	1.0872	0.9950	0.9027
B2	1.4237	1.3030	1.1822	1.2316	1.1271	1.0226	1.0851	0.9931	0.9010
B3	1.4363	1.3145	1.1926	1.2425	1.1371	1.0317	1.0947	1.0019	0.9090
B4	1.6012	1.4634	1.3257	1.2693	1.1601	1.0508	1.0513	0.9609	0.8704
B5	1.6133	1.4745	1.3357	1.2789	1.1689	1.0588	1.0593	0.9682	0.8770
B6	1.6170	1.4779	1.3387	1.2818	1.1715	1.0612	1.0617	0.9704	0.8790
B7	1.5744	1.4392	1.3040	1.2434	1.1366	1.0298	1.0273	0.9391	0.8509
B8	1.5793	1.4436	1.3080	1.2472	1.1401	1.0330	1.0305	0.9420	0.8535
B9	1.5842	1.4481	1.3120	1.2511	1.1436	1.0362	1.0337	0.9449	0.8562
C1	1.6330	1.5078	1.3826	1.2983	1.1987	1.0992	1.0774	0.9948	0.9122
C2	1.6317	1.5066	1.3815	1.2973	1.1978	1.0983	1.0766	0.9940	0.9115
C3	1.6317	1.5066	1.3815	1.2973	1.1978	1.0983	1.0766	0.9940	0.9115
C4	1.3060	1.2292	1.1524	1.1786	1.1093	1.0399	1.0738	1.0107	0.9475
C5	1.2796	1.2043	1.1291	1.1548	1.0868	1.0189	1.0521	0.9902	0.9283
C6	1.2922	1.2162	1.1402	1.1662	1.0976	1.0290	1.0625	1.0000	0.9375
D1	1.3160	1.2405	1.1650	1.1131	1.0493	0.9854	0.9644	0.9091	0.8537
D2	1.2919	1.2177	1.1436	1.0927	1.0300	0.9673	0.9467	0.8924	0.8381
D3	1.3055	1.2305	1.1556	1.1042	1.0408	0.9774	0.9567	0.9018	0.8469
D4	1.6938	1.5943	1.4947	1.2658	1.1914	1.1170	1.0105	0.9511	0.8917
D5	1.6958	1.5961	1.4964	1.2673	1.1928	1.1183	1.0116	0.9522	0.8927
D6	1.7074	1.6070	1.5066	1.2759	1.2009	1.1259	1.0185	0.9587	0.8988
E1	1.3564	1.2188	1.0812	1.2309	1.1061	0.9812	1.1267	1.0124	0.8981
E2	1.3695	1.2306	1.0917	1.2428	1.1168	0.9907	1.1376	1.0222	0.9068
E3	1.4202	1.2556	1.0909	1.2459	1.1014	0.9570	1.1097	0.9810	0.8524
E4	1.4281	1.2625	1.0969	1.2528	1.1075	0.9623	1.1158	0.9864	0.8571
Mean K =	1.4950	1.3570	1.2189	1.2484	1.1323	1.0162	1.0763	0.9757	0.8752
Std Dev =	0.1305	0.1249	0.1352	0.0627	0.0450	0.0582	0.0635	0.0373	0.0382
StD/Mean	0.0873	0.0920	0.1109	0.0502	0.0398	0.0573	0.0590	0.0383	0.0437

Table 3. Comparison of the Plasticity and Lame' Formulas with the Burst Test Data from Table 1

Test No.	Plasticity Burst Formula K=Pb/Y /ln(D/Di)	K=Pb/F /ln(D/Di)	K=Pb/U /ln(D/Di)	Lame' Formula K=Pb/Y *(D2+Di2) /(D2-Di2)	K=Pb/F *(D2+Di2) /(D2-Di2)	K=Pb/U *(D2+Di2) /(D2-Di2)
A1	1.2920	1.0867	0.9376	1.3343	1.1222	0.9683
A2	1.3093	1.1012	0.9501	1.3521	1.1372	0.9812
A3	1.3184	1.1088	0.9568	1.3615	1.1451	0.9881
A4	1.3357	1.1234	0.9693	1.3794	1.1601	1.0010
A5	1.3240	1.1135	0.9608	1.3673	1.1500	0.9922
A6	1.2877	1.1521	1.0424	1.3298	1.1898	1.0765
A7	1.2438	1.1128	1.0068	1.2845	1.1492	1.0398
A8	1.2898	1.1540	1.0440	1.3320	1.1917	1.0782
B1	1.3017	1.1260	0.9921	1.3166	1.1390	1.0035
B2	1.2992	1.1239	0.9902	1.3142	1.1368	1.0016
B3	1.3107	1.1338	0.9990	1.3258	1.1468	1.0105
B4	1.4591	1.1566	0.9580	1.4764	1.1703	0.9694
B5	1.4702	1.1654	0.9653	1.4876	1.1792	0.9767
B6	1.4735	1.1680	0.9675	1.4910	1.1819	0.9790
B7	1.4349	1.1332	0.9363	1.4519	1.1466	0.9474
B8	1.4394	1.1367	0.9392	1.4564	1.1502	0.9503
B9	1.4438	1.1402	0.9421	1.4609	1.1537	0.9533
C1	1.5043	1.1960	0.9925	1.5182	1.2070	1.0017
C2	1.5031	1.1950	0.9918	1.5170	1.2061	1.0009
C3	1.5031	1.1950	0.9918	1.5170	1.2061	1.0009
C4	1.2276	1.1078	1.0093	1.2340	1.1136	1.0146
C5	1.2028	1.0854	0.9889	1.2090	1.0911	0.9941
C6	1.2146	1.0961	0.9987	1.2210	1.1018	1.0039
D1	1.2390	1.0480	0.9080	1.2451	1.0531	0.9125
D2	1.2162	1.0287	0.8913	1.2222	1.0338	0.8957
D3	1.2290	1.0395	0.9007	1.2351	1.0447	0.9051
D4	1.5922	1.1899	0.9498	1.6005	1.1960	0.9548
D5	1.5940	1.1912	0.9509	1.6023	1.1974	0.9559
D6	1.6049	1.1994	0.9574	1.6133	1.2056	0.9624
E1	1.2136	1.1013	1.0081	1.2343	1.1202	1.0253
E2	1.2253	1.1120	1.0178	1.2463	1.1310	1.0352
E3	1.2483	1.0951	0.9754	1.2772	1.1204	0.9979
E4	1.2552	1.1011	0.9808	1.2842	1.1266	1.0034
Mean K =	1.3517	1.1278	0.9718	1.3727	1.1456	0.9873
Std Dev =	0.1256	0.0452	0.0363	0.1232	0.0458	0.0412
StD/Mean	0.0929	0.0400	0.0374	0.0897	0.0400	0.0417

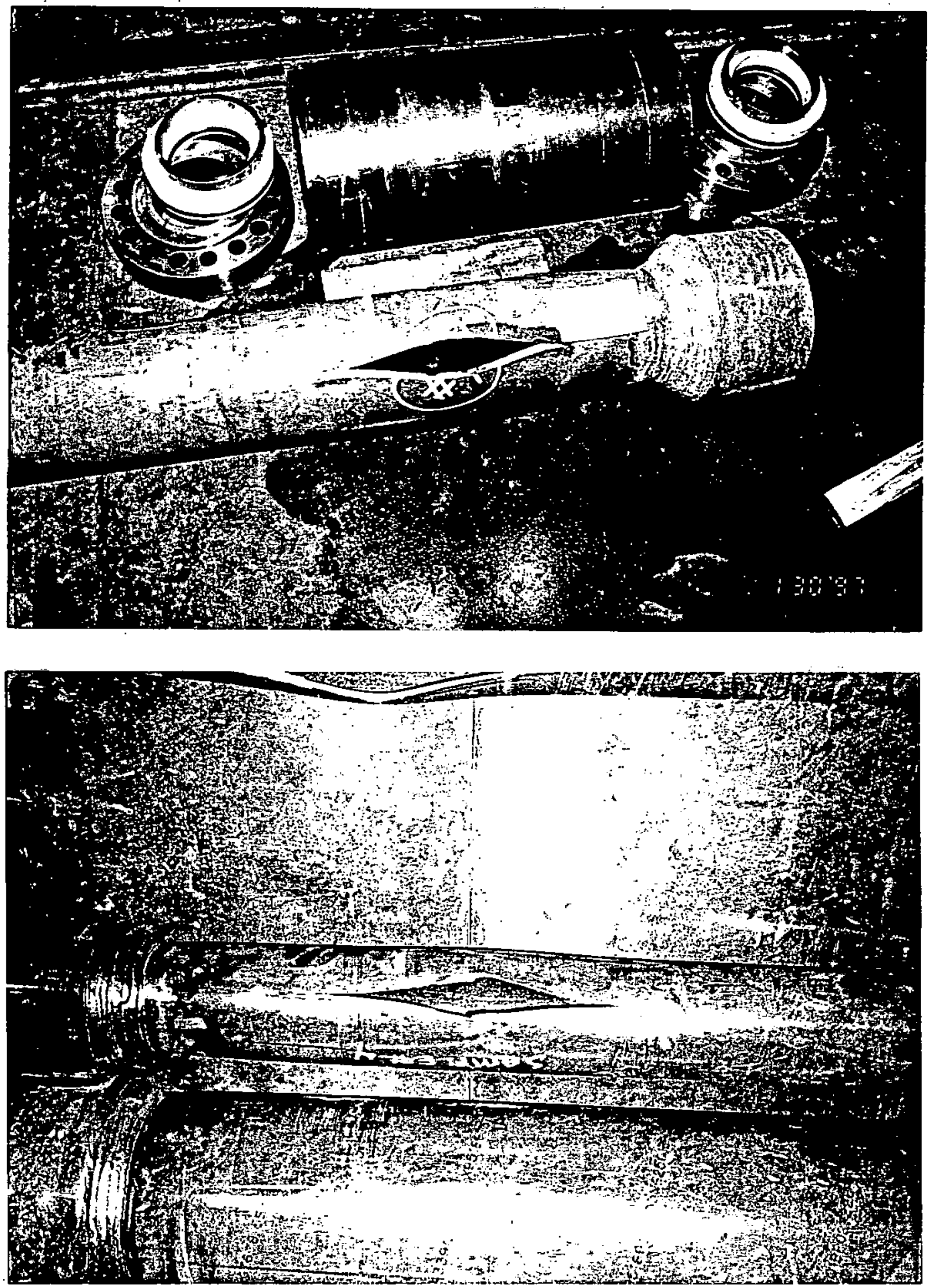


Figure 1. Typical Ductile Burst Failures of Seamless Line Pipe

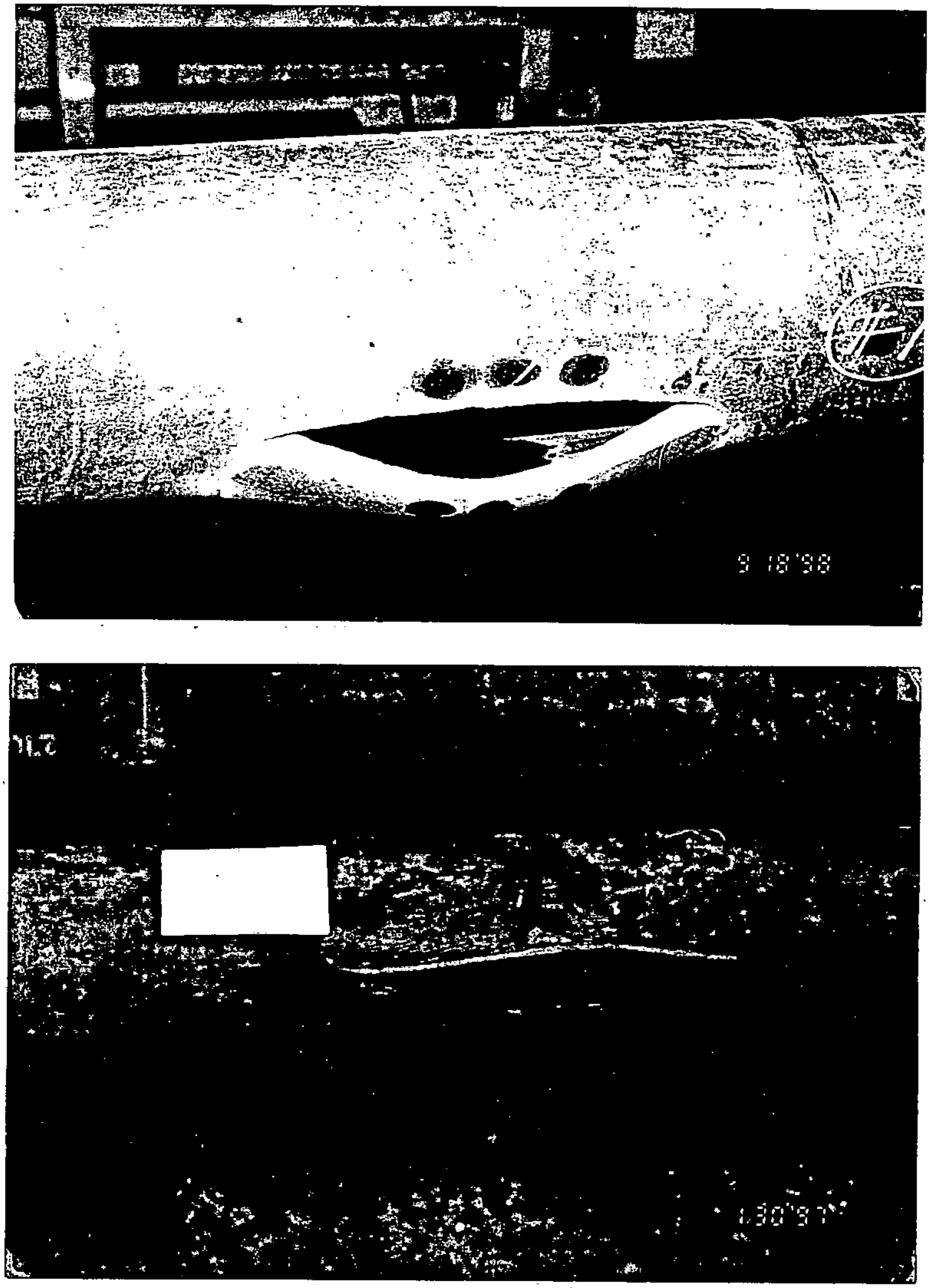
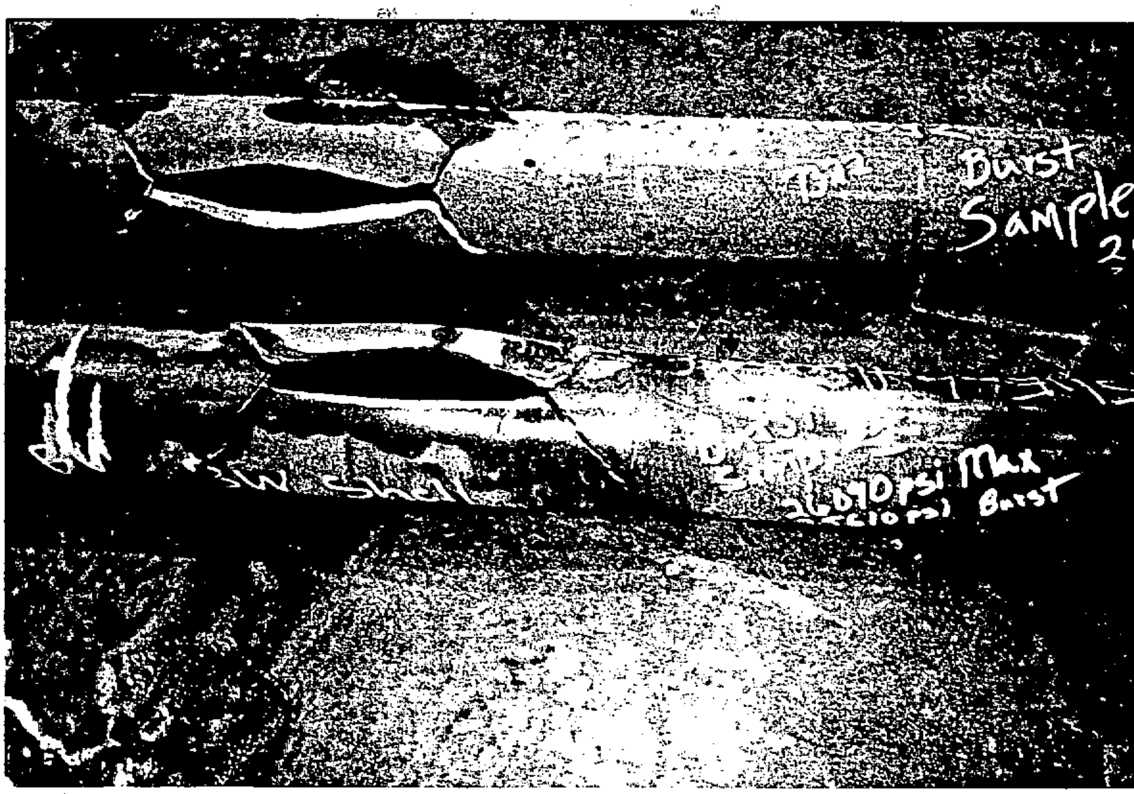


Figure 2. Typical Ductile Burst Failures of Seamless Line Pipe



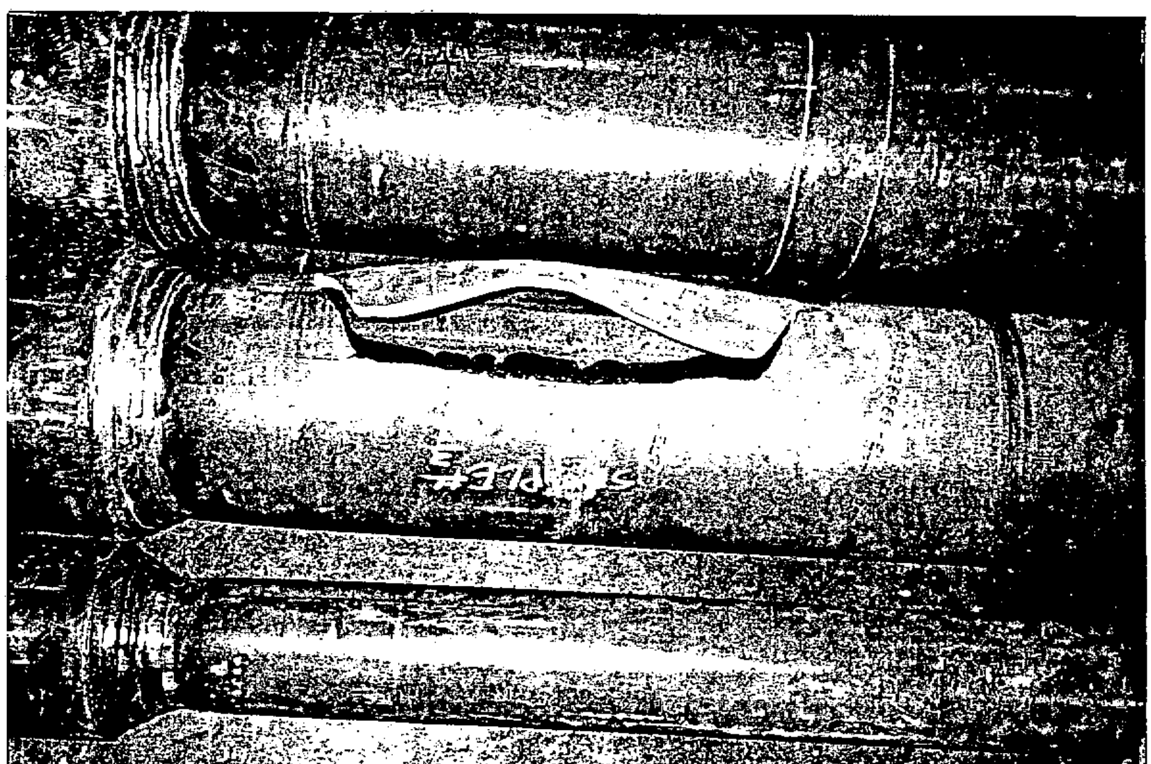
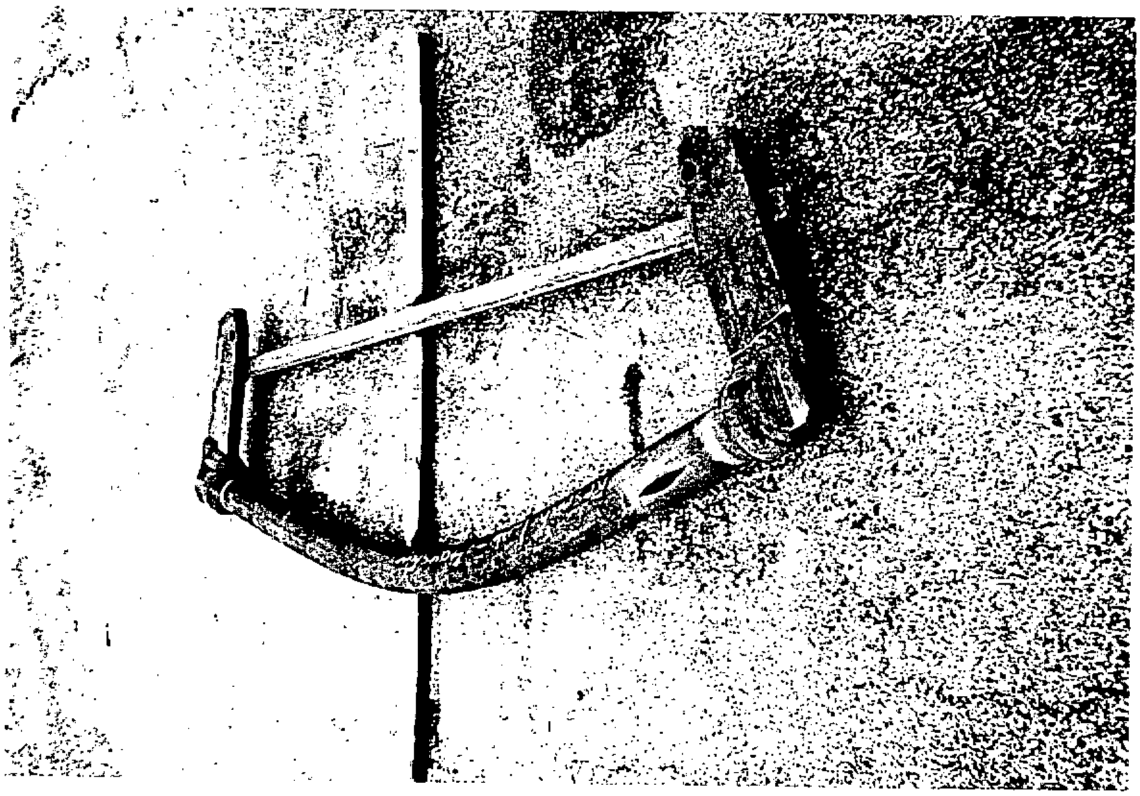


Figure 3. More Complex Burst Failure Configurations



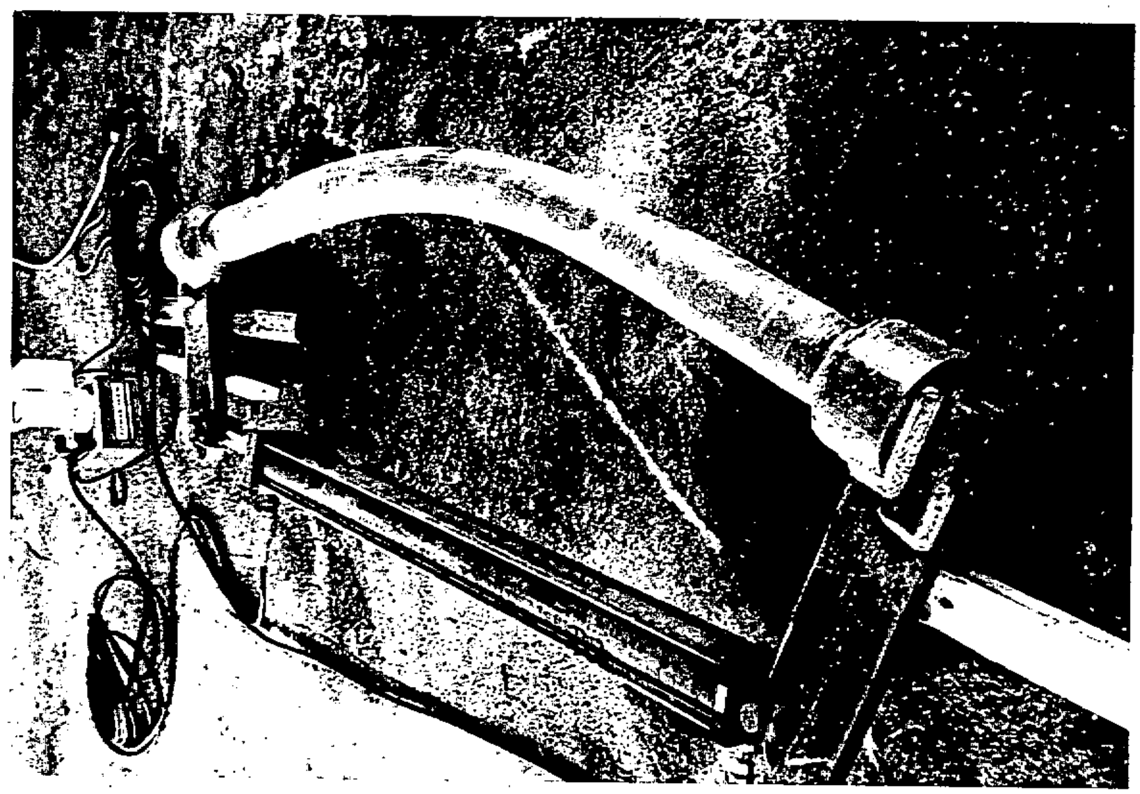
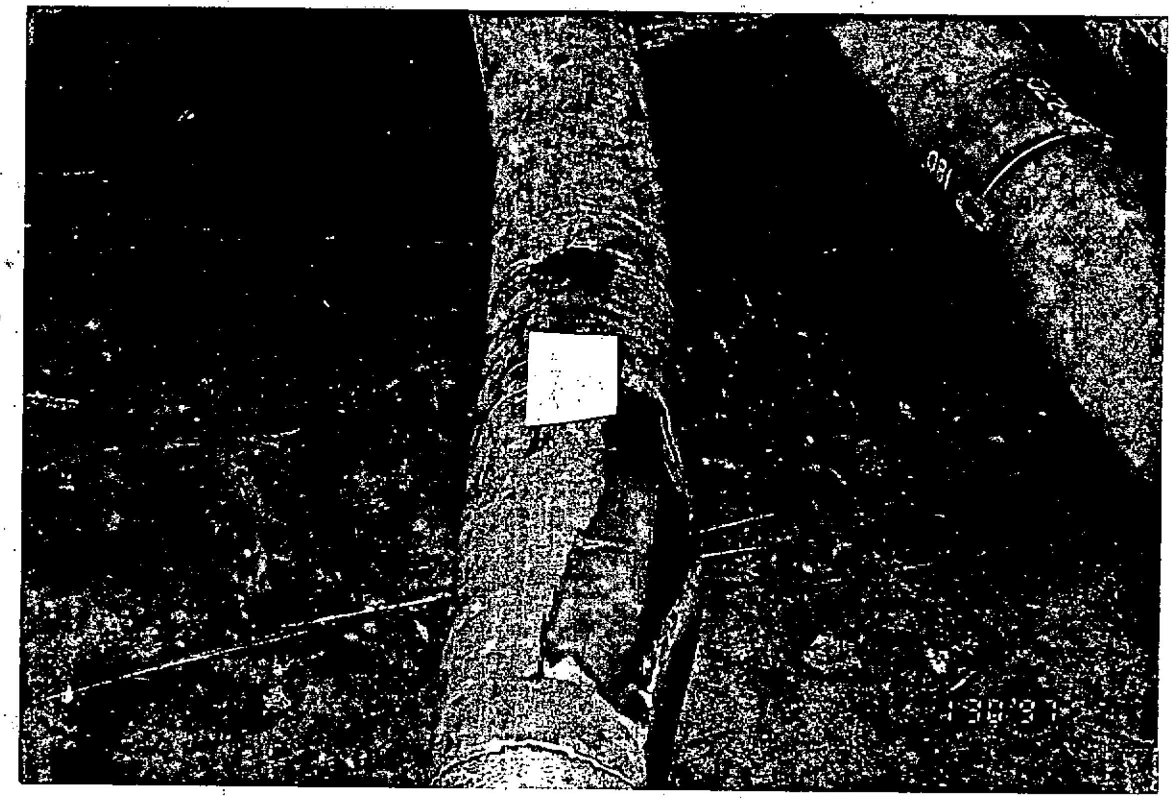


Figure 4. Pre-bending of Some Pipe Samples Before Burst Testing



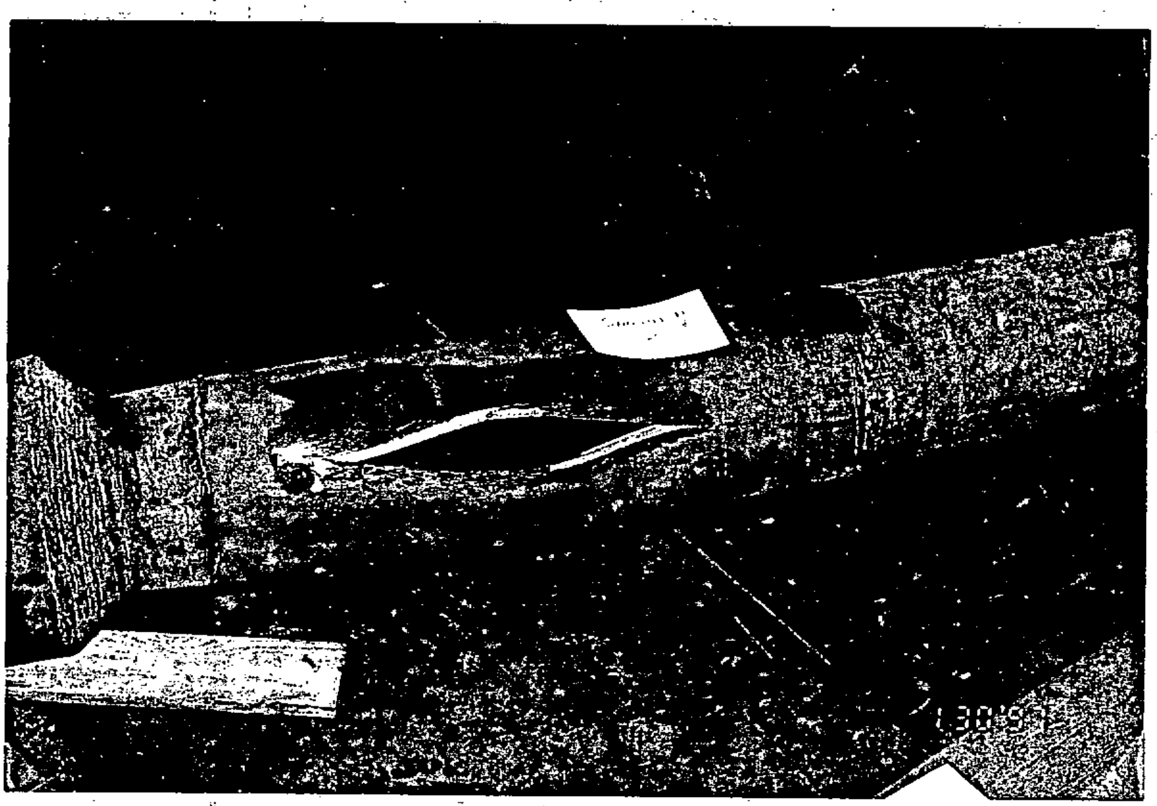


Figure 5. Typical Burst Failures of Pre-Bent Pipe Samples

Figure 6. RP1111 Standard Design Equations Applicable to Pipe Purchased Under API-5L Specifications

Internal Pressure Design

Minimum Burst Pressure $P_b = 0.45(Y+U)\ln(D/D_i)$

or $P_b = 0.90(Y+U)t/(D-t)$

Hydrotest Pressure $P_t \le f_d f_e f_t P_b$

Design Pressure $P_d \le 0.80 P_t$

Incidental Overpressure $P_a \le 0.90 P_t$

For Planned Maximum Operating Pressure: $P_i - P_o \le P_d$

For surge pressures and unplanned shut-ins: $P_i - P_o \le P_a$

where
D = Nominal outside diameter of pipe
$D_i = D - 2t$ = Inside diameter of pipe
t = Nominal wall thickness of pipe
Y = Specified minimum yield strength
U = Minimum ultimate tensile strength
f_d = Internal pressure design factor
= 0.90 for pipeline; 0.75 for riser
f_e = Seam weld factor (=1.0 typically)
f_t = Temperature factor (=1.0 for <250°F)
P_i = Internal pressure, variable with depth
P_o = External pressure, variable with depth

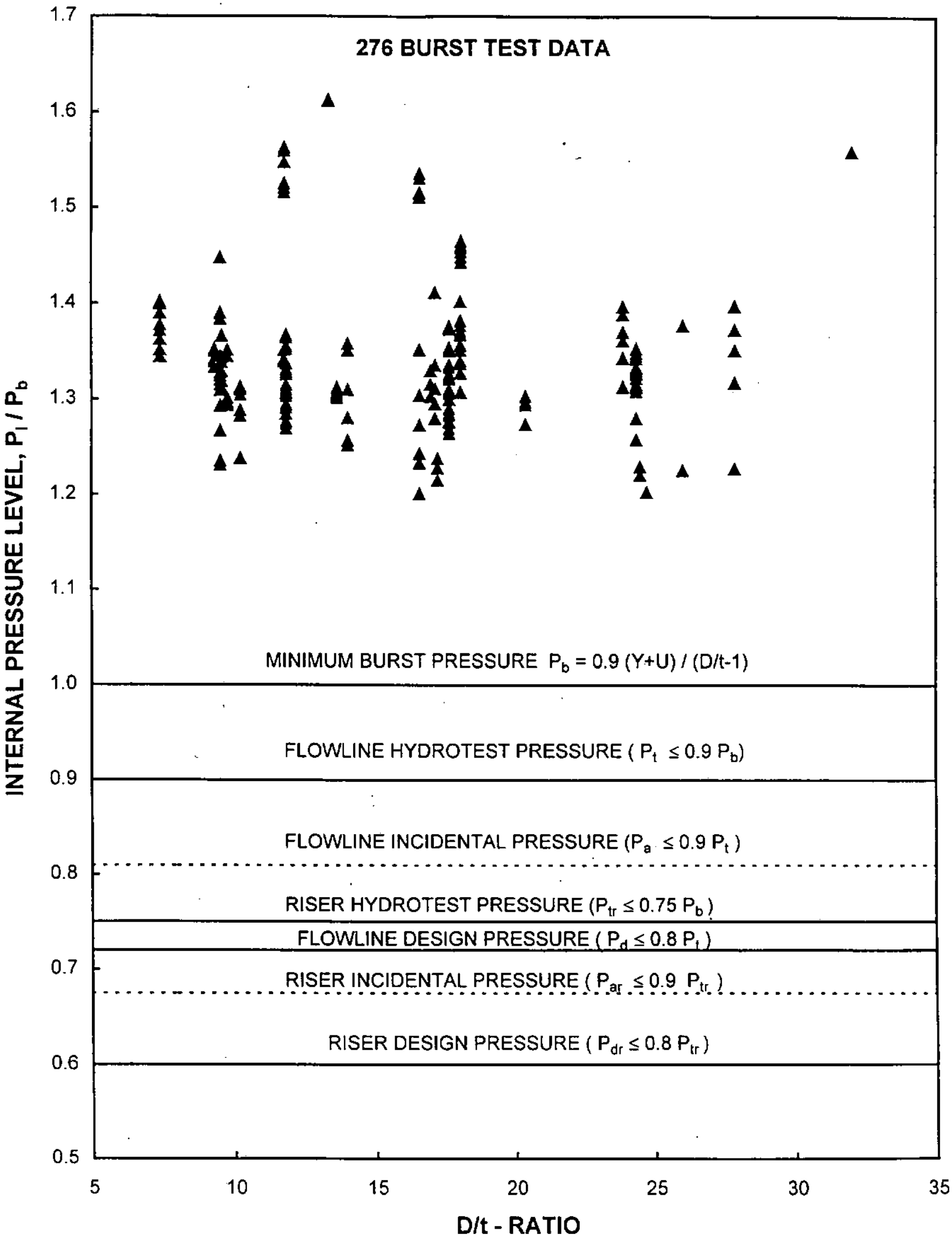


Figure 7. RP1111 Standard Design Pressure Limits Compared with the Pipe Burst Data from Shell and Mobil

BurstCHART.xls0.9(S+U)

Figure 8. RP1111 Enhanced Design Equations Applicable to API-5L Pipe with Additional Inspections as Specified in Appendix B and ANSI/ASQC Z1.9

Internal Pressure Design

Minimum Burst Pressure	$P_b = 0.50\left(Y+U\right)\ln\left(D/D_i\right)$
or	$P_b = 1.00\left(Y+U\right)t/\left(D-t\right)$
Hydrotest Pressure	$P_t \le f_d f_e f_t P_b$
Design Pressure	$P_d \le 0.80\,P_t$
Incidental Overpressure	$P_a \le 0.90\,P_t$

For Planned Maximum Operating Pressure: $P_i - P_o \le P_d$

For surge pressures and unplanned shut-ins: $P_i - P_o \le P_a$

where
D = Nominal outside diameter of pipe
$D_i = D - 2t$ = Inside diameter of pipe
t = Nominal wall thickness of pipe
Y = Specified minimum yield strength
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f_d = Internal pressure design factor
= 0.90 for pipeline; 0.75 for riser
f_e = Seam weld factor (=1.0 typically)
f_t = Temperature factor (=1.0 for <250°F)
P_i = Internal pressure, variable with depth
P_o = External pressure, variable with depth

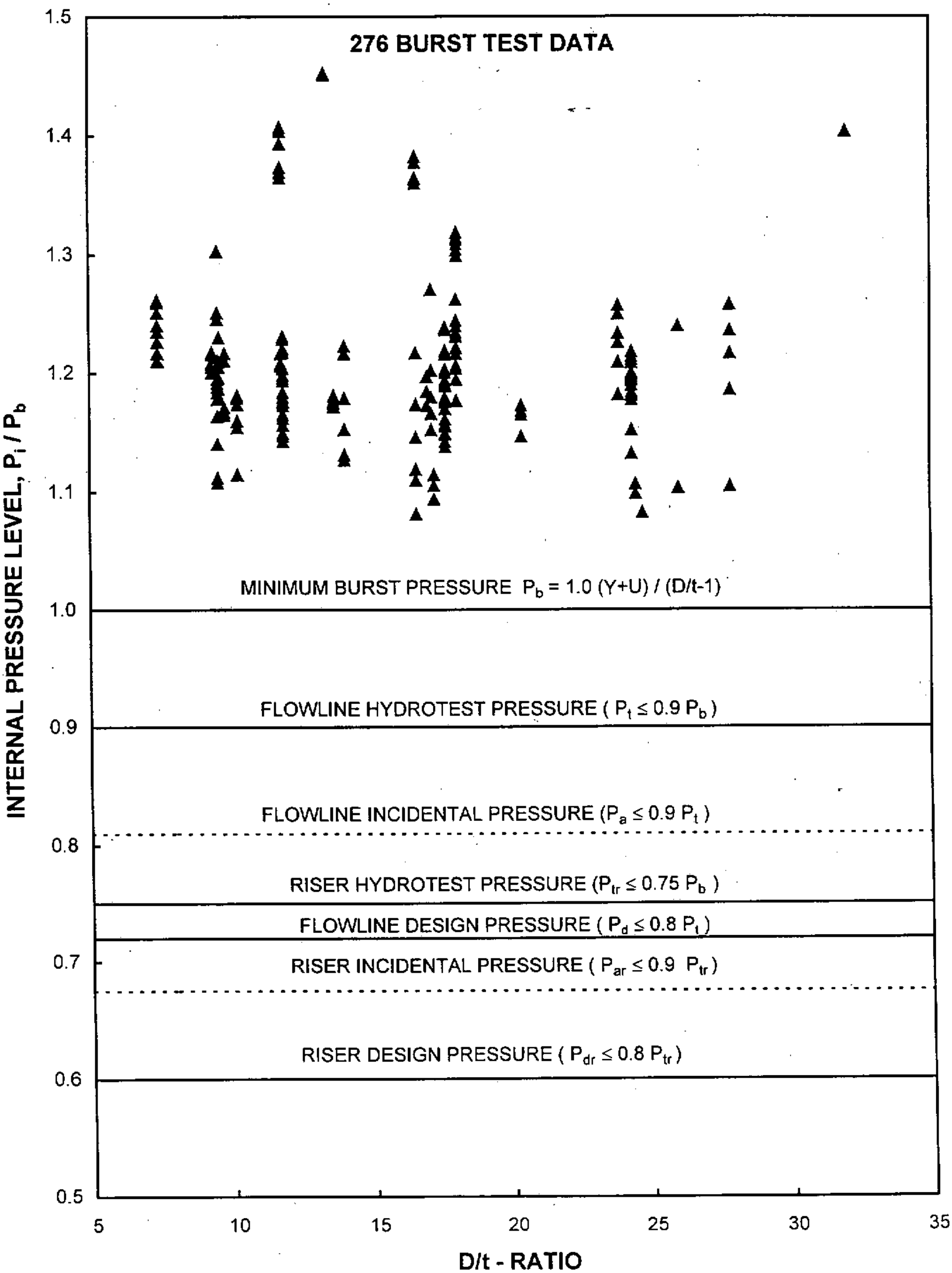


Figure 9. RP1111 Enhanced Design Pressure Limits Compared with the Pipe Burst Data from Shell and Mobil

BurstCHART.xls1.0(S+U)

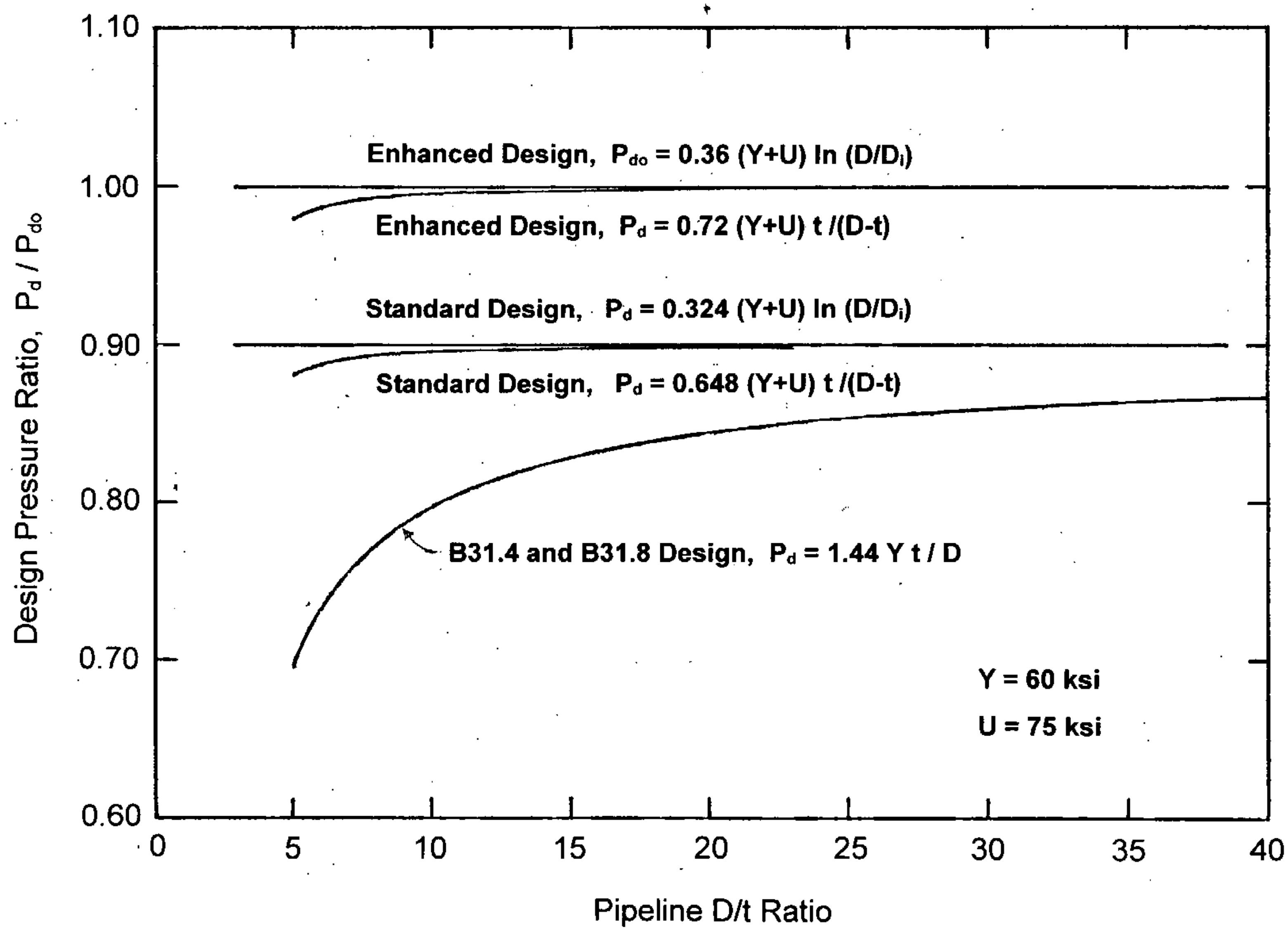


Figure 10. Comparison of the RP1111 and the B31 Design Formulas at Low D/t Ratios

Figure 11. Collapse Pressure Design and Tension Effects on the Burst Pressure included in the RP1111 Code

External Pressure Design

Pressure and Bending Criterion $(P_o - P_i)/P_c + \varepsilon/\varepsilon_b \le f_o$

Collapse Pressure $P_c = P_y P_e / \left(P_y^2 + P_e^2\right)^{1/2}$

Yield Pressure $P_y = 2Yt/D$

Buckling Pressure $P_e = 2E(t/D)^3/(1-\nu^2)$

Buckling Strain $\varepsilon_b = t/2D$

where ε = Bending strain along pipeline or riser

f_o = Collapse factor = 0.7 for SMLS or ERW;

= 0.6 for cold expanded pipe such as DSAW

E,ν = Elastic properties of pipe material

Constraints on Effective Tension $T_{eff} \le 0.6T_y$

$$\sqrt{\left(\frac{P_i - P_o}{P_b}\right)^2 + \left(\frac{T_{eff}}{T_y}\right)^2} \le \begin{cases} 0.90 \text{ for operational loads} \\ 0.96 \text{ for extreme loads} \\ 0.96 \text{ for hydrotest loads} \end{cases}$$

where $T_{eff} = \sigma_a - P_i A_i + P_o A_o$ = Effective tension

$T_y = SA$ = Yield tension of pipe

σ_a = Mean axial stress in pipe

A_i = Internal cross sectional area

A_o = External cross sectional area

$A = A_o - A_i$ = Steel cross section

Figure 12. Internal Pressure Design for Conventional Pipeline Codes Used in the Gulf of Mexico

(1) ASME B31.4 - Liquid Transportation Systems for Hydrocarbons...

(2) ASME B31.8 - Gas Transmission Distribution and Piping Systems

(3) 30 CFR 250-J - Pipelines and Pipeline Rights-of-Way

<u>Internal Pressure Design</u>

Design Pressure $P_d = (2St/D)FET$

Hydrotest Pressure $P_t \geq 1.25P_d$

where D = Nominal outside diameter of pipe
t = Nominal wall thickness of pipe
S = Specified minimum yield
F = Internal pressure design factor
= 0.72 for pipeline; 0.60 for riser
E = Seam weld factor (= 1.0 typically)
T = Temperature factor (= 1.0 for <250 °F)

For codes 1 and 2, external pressure P_o may be taken into account in setting the maximum operating pressure P_i: P_i-$P_a \leq P_d$. Code 3 silent on use of external pressure in the pipeline design.

Gulf of Mexico Pipeline Failures and Regulatory Issues

Alex Alvarado
Minerals Management Service, New Orleans, USA

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

Gulf of Mexico Pipeline Failures and Regulatory Issues

Alex Alvarado
Minerals Management Service

MMS

Pipeline Infrastructure

- 28,779 total miles of pipelines
- From1995 to 1998 MMS approved 5,747 miles
- 1,555 miles approved in 1997 (record)
- 18 major lines to shore/state waters from 1994 to present

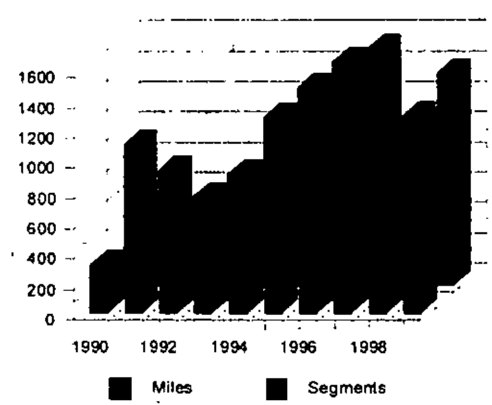
MMS

Pipeline Infrastructure

- Master database
- GOM pipeline maps digitized
- Data available on Internet
  - www.gomr.mms.gov
- Working with States to include lines in State waters

MMS

Pipelines Approved



MMS

GOM Production

- 0.9 MMBOPD in 1995
- Up to 1.8 MMBOP Projected by 2003
- 13 BCFPD in 1995
- Up to17 BCFD Projected by 2003
- Production 22% of US oil and 27% gas at present time

MMS

"Leaks" Database

- All failure/incidents reported to MMS
  - » MMS maintains database
  - » Tracks failures on each pipeline segment
    - – Analysis of database
  - » Tracks maintenance (no leak) records

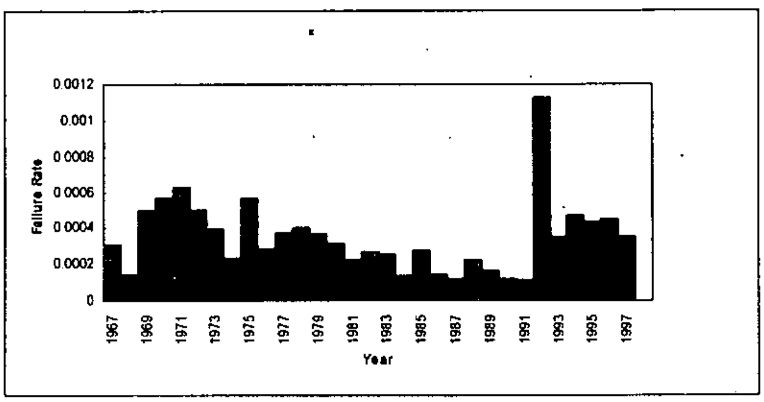
MMS

Overview

- Summary of leaks database
  - » All failures
  - » Impact failures
  - » Corrosion failures
    - – Internal
    - – External
- Failures related regulatory issues
- Adoption of API RP 1111

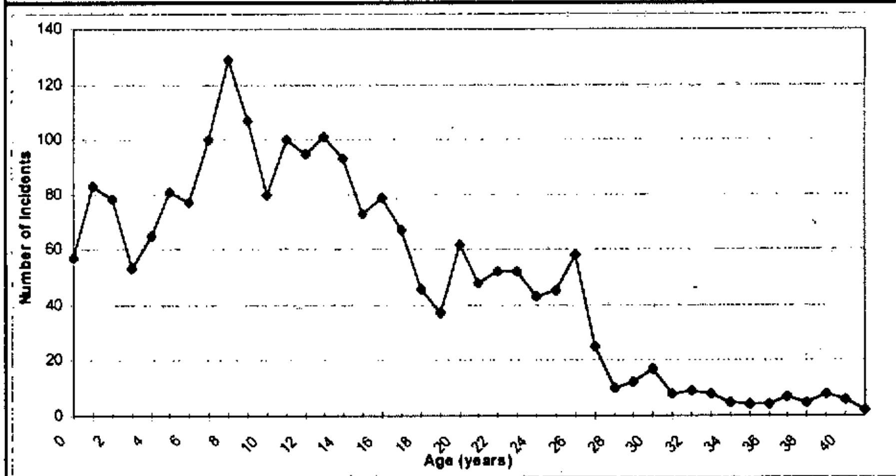
MMS

Annual Distribution of Failure Rates



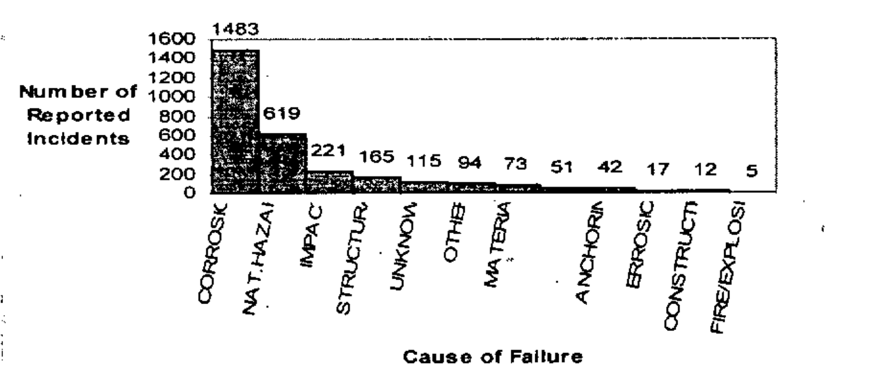
MMS

Distribution of Failures by Age of Pipeline



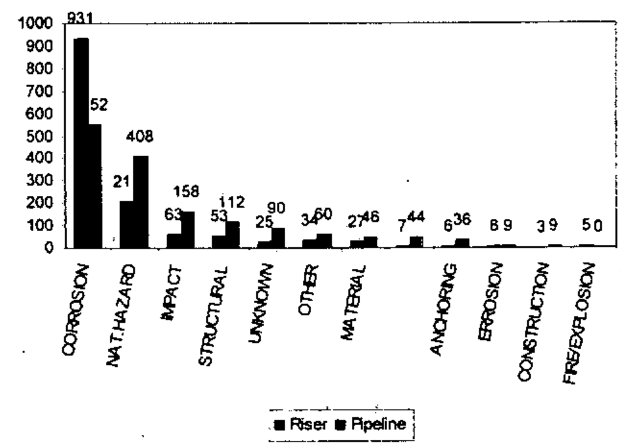
MMS

Distribution of Incidents by Cause of Failure



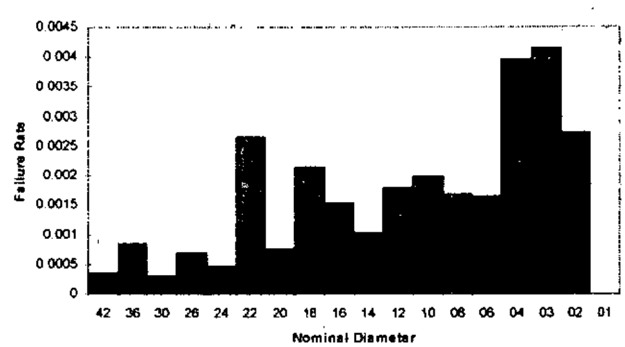
MMS

Breakdown of all Failures by Cause and Location



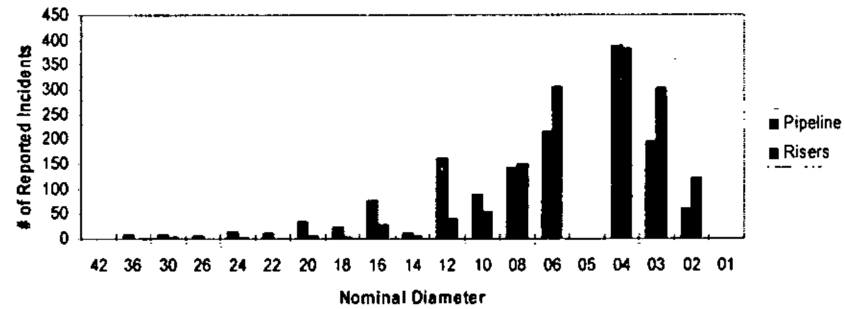
MMS

Distribution of all Failure Rates by Nominal Diameter



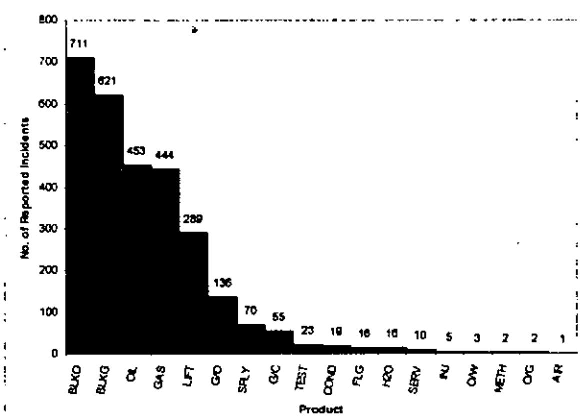
MMS

Distribution of all Failures by Nominal Diameter



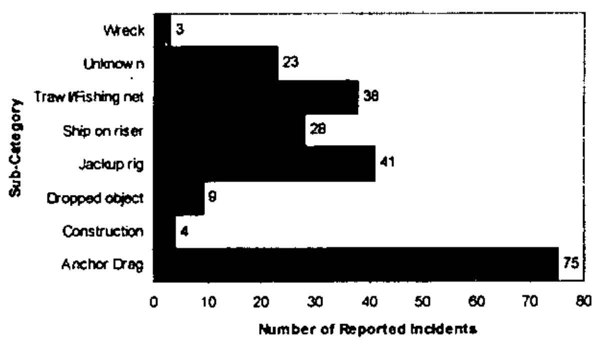
MMS

Distribution of all Failures by Product



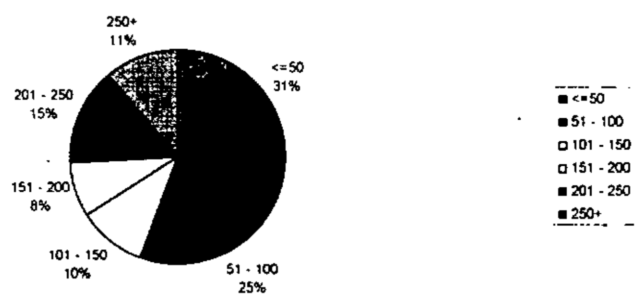
MMS

Breakdown of failures due to impact by sub-category



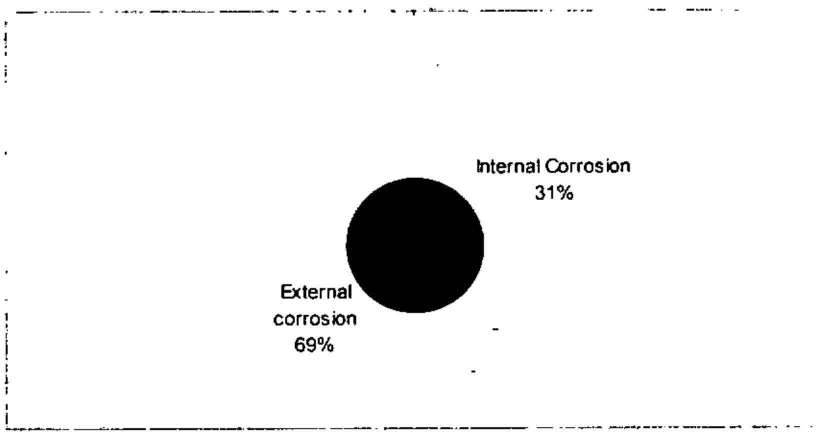
MMS

Variation of impact incidents with water depth



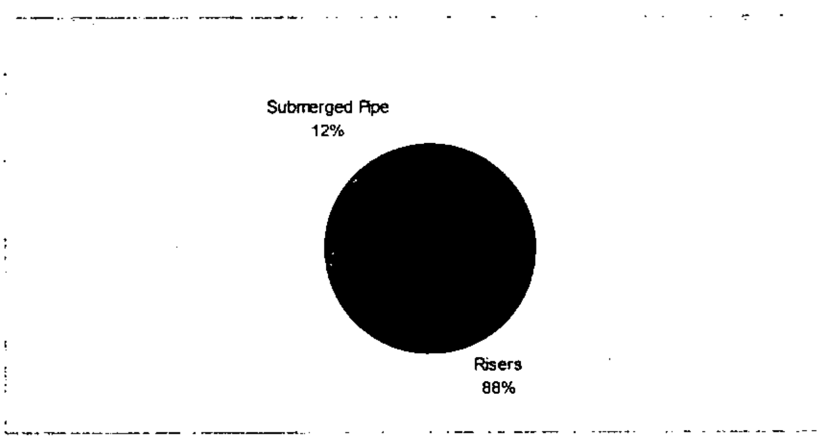
MMS

Failures due to corrosion



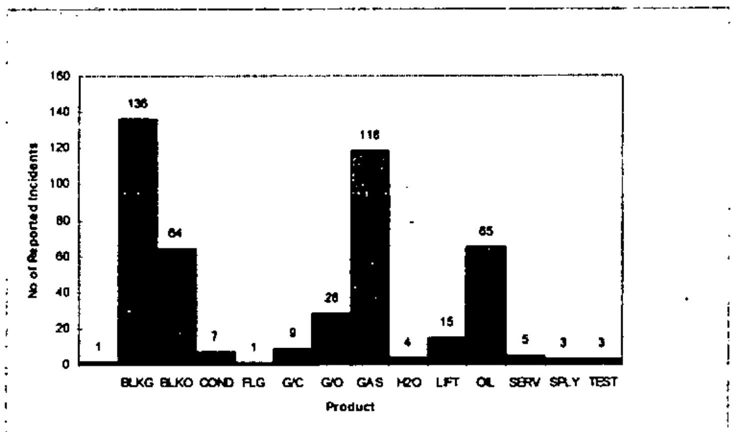
MMS

Location of Damage Due to External Corrosion



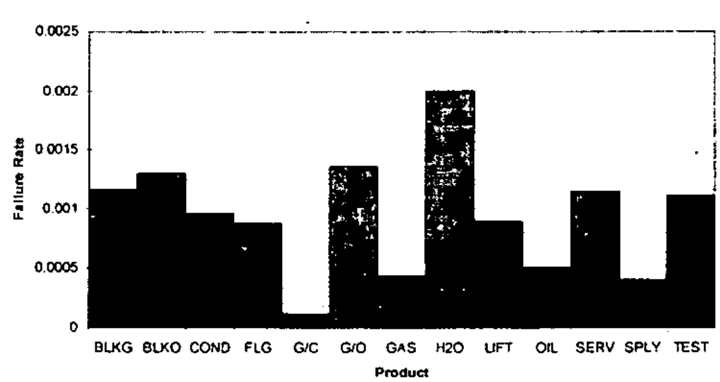
MMS

No. of Failures Due to Internal Corrosion by Product



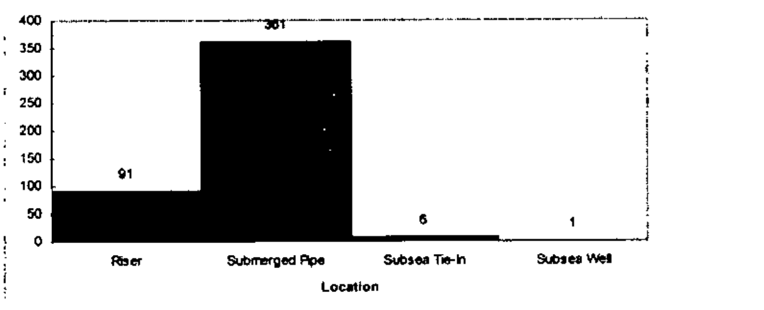
MMS

Internal Corrosion Failure Rate by Product



MMS

Location of damage due to internal corrosion



MMS

Pipeline Failures Regulatory Issues

- Riser field inspection/maintenance
- Production monitoring and treatment
- Assessment of flushing/filling & abandonment requirements for out-of-service lines
  - » Effectiveness of inhibitor

MMS

Conclusions

- Corrosion responsible for majority of failures
- Support any action to reduce failures
- Focus MMS inspections
- Need to look into improving the effectiveness of regulations

MMS

Adoption of API RP 1111

- MMS regulatory incorporation of standards
  - » Conflict with regulations?
  - » Provide guidelines not previously covered
- Recent documents not incorporated
  - » API RP 14C 5th Edition
  - » API SPEC 6D
    - – Supplements 1 and 2

MMS

Adoption of API RP 1111

- Review of API RP 1111
  - » RP presently not referenced in MMS or DOT regulations
  - » Formed MMS team to review RP

MMS

Adoption of API RP 1111

- Some items in RP not presently addressed in MMS regulations
  - » Pipe internal pressure (burst) design
  - » Pipe external pressure (collapse) design
  - » Buckling considerations
  - » Span limitations due to vortex shedding
  - » 12 inch separation at pipeline crossings

MMS

Adoption of API RP 1111

- What will it take to incorporate RP into MMS regulations
  - » Team may recommend whole or partial incorporation of document
  - » Will require Federal Register notice for comment

MMS

Material Test Methods and Data Requirements for Pipeline Design

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presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
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Material Test Methods and Data Requirements for Pipeline Design

Abstract

Increasingly onerous operating conditions for submarine pipelines have imposed greater demands on the technology applied to pipeline design and installation. Engineers have risen to these demands and have shown that successful pipelines can be constructed at great depths and for the transport of very high temperature and pressure fluids. However the ability to apply sophisticated analysis methods requires more detailed knowledge of the properties of the pipeline materials.

This paper reviews the state of information about pipeline steels as required by codes, and compares that information with the detailed material properties of actual steels. The paper also presents the methodology of, and results from tests on pipeline materials to determine their mechanical properties at high temperature.

It is concluded that methods are available commercially to obtain the properties of pipeline steels to enable the detailed design of offshore pipelines operating in deepwater and at high temperatures. However, care must be taken in the test methods to ensure that the results are accurate and truly representative of the actual material properties.

Introduction

The operating conditions for which engineers are required to design submarine pipelines become more onerous year by year. Until the 1980's the operating temperatures and water depths were less than 38°C (100°F) and 300 feet. The past twenty years have seen the maximum operating temperatures for flowlines increase to 165°C (330°F) and the water depths to 6500 feet. An additional aspect has become more evident in recent years: this is that operators regard offshore pipeline engineering as a mature industry and sometimes do not recognise the complexity and extremely onerous nature of the design task that pipeline engineers have to face. This attitude by operators has generally meant that they demand lower Capex costs, even for quite novel pipeline conditions.

Thus the initial simple design requirements have become progressively more complex. The design codes, originated in the 1960's and often based on codes relevant to onshore civil engineering and petrochemical plant, have given way to limit state based design guidance specific to offshore pipeline systems. The older design codes simply required that the stresses induced in the pipeline during installation and operation were less than a proportion of the material yield stress. The specification for the material properties needed for design were therefore very simple:

- a specified level for the minimum values of the yield stress, i.e. the SMYS, and

Proceedings of the 3rd Deepwater Pipeline & Riser Technology Conference, Houston, Texas, March 7-9, 2000.

- the ultimate strength exceeded the yield stress by a reasonable margin, usually 10% of the yield stress, and
- the material has a good ductility.

The application of limit state design means that the actual limit state of failure, serviceability and ultimate, are calculated by detailed design of the pipeline responses to the imposed installation and operating conditions. The limit states calculated by detailed analysis imply that the pipeline material exceeds the yield level and in many cases pipeline design involves a strain-based approach. It is not uncommon for the analysis to be carried out using non-linear finite element modelling in which the non-linearity encompasses large geometric deformations and the material stress-strain properties. Thus in order to progress a limit state or strain-based design it is necessary to have a much more detailed knowledge of the material properties, across the operating range of temperatures, than was previously required.

The usual reason for applying a limit state approach to a pipeline is to obtain economic savings in comparison to the previously established limiting stress based codes. However, there are instances where the stress-based approach will not result in a feasible design. This is particularly the case for pipeline being designed to transport fluid with temperatures greater than about 140°C (285°F). Such an operating condition implies that the expansion of the pipeline, if it is restrained by frictional interaction with the seabed or because it is encased in a bundle, will induce thermal and mechanical strains significantly in excess of the yield strain. The normal operating conditions of start-up and shut-down cycles further impose onerous cyclic strain conditions on the pipeline steel. It is evident that before embarking on the detailed design of a pipeline to transport fluids at a very high temperature it is necessary to know the relevant detailed material properties. These include:

- stress-strain relationship at the operating temperature and at various temperatures between ambient and the operating condition
- the cyclic stress-strain relationships across the temperature range experienced by the pipeline material
- the coefficient of thermal expansion relevant to the temperature range between ambient and the operating condition

These conditions imply a comprehensive program of testing. Considerable experience has been gained in the UK on appropriate methods of testing at high temperature and the accurate determination of the coefficient of expansion. The following sections present an outline of the test methods developed during the design of various pipeline systems to operate at very high temperature and also during a joint industry funded program of research into the whole area of pipeline design for high temperature and pressure operation.

Relevance of Mill Tests

There is a standard requirement that all pipeline steel should be accompanied by a mill certificate reporting the values of the SMYS and the UTS. It has been the practice to prepare stress-strain curves for the steel, for use in design, by fitting the available steel strength data using some empirical description, such as the Ramberg-Osgood formula. Also, the preparation of the limit state codes, particularly the strength design factors, have made use of statistical data gathered from mill certificates for various grades of steel made by various mills. If the material data is to match the high level of numerical analysis in which it is incorporated, it is important to understand the relevance of the information from the mill certificate to the accurate measurement of the corresponding steel stress-strain relationship.

This section presents results from testing the strength and the detailed stress-strain properties using various methods. The tests were carried out on a typical API 5LX65 pipeline steel that had been prepared as plate and then the pipeline manufactured using the plate and the U-O-E method. The tests were carried out on specimens cut from the pipe in the longitudinal and transverse direction.

Figure 1 shows the details of the test specimen geometry for the tests on the material around the pipe, i.e., in the transverse direction and Figure 2 shows the corresponding geometry in the longitudinal directions. Specimens 1T and 1L were machined from the pipe thickness and were in accordance with appropriate test standards. The material in these specimens had not been subjected to any form of cold working subsequent to the U-O-E deformations. Specimen 2T was machined from material cut from around the pipe wall and then flattened whereas specimen 3T was also flattened but retained its full initial thickness of 17.6mm. Specimen 2L had been flattened and then reduced in thickness by machining whereas specimen 3L was not deformed after the U-O-E process and retained the full pipe thickness.

Figure 3 shows the measured stress-strain curve in the longitudinal direction using the specimen 1L and Figure 4 shows the corresponding result measured using specimen 3L. It may be seen that the fairly distinct yield observed with the round bar specimen is not so evident with the flattened specimen.

Table 1 shows averaged values of the 'SMYS' measured in the tests using the various forms of test specimens. If we consider the round bar specimens, 1L and1T, as the 'standard' it may be seen that the full-section specimens, 3L and 3T, underestimate the standard SMYS by about 5%. This is an encouraging confirmation of the use of the mill certificate value of SMYS.

Specimen Geometry	**Averaged Value of Stress at 0.5% Strain (N/mm^2)**
1L	529
2L	540
3L	500
1T	546
2T	525
3T	517

Table 1 Averaged Comparative 'SMYS' Values for the Various Specimen Geometries

Figure 5 shows the variation of the measured longitudinal SMYS for a number of nominally identical specimens with the geometries shown in Figure 2. It is evident that the full section specimen 3T shows a significantly greater scatter in the measured SMYS than the round bar specimens machined from the pipe wall. This is an important factor for the statistical data that is used in the reliability analysis for deriving the design factors in limit state codes.

The most important aspect concluded from the test results described above is that great care must be taken in deciding the form of the test specimen that is to be used to obtain the stress-strain curve for the material in a strain-based design for high temperature pipelines. The accuracy of the curve and its relevance to the high temperature properties of the pipeline steel are considered in the next section.

Coefficient of Thermal Expansion

The coefficient of expansion is an important factor in the development of the axial forces due to the operating temperature. Essentially, the force P, is

$$P = \alpha \Delta T \, E \, A_s$$

where

α is the coefficient of thermal expansion

ΔT is the change of temperature

E is the elastic modulus for the material

A_s is the cross-sectional area of the pipe

Generally in pipeline design it is assumed that the coefficient of thermal expansion is a constant. This is reasonable for small temperature changes, but for the large temperature range, from 0oC (32oF) to 165oC (320oF) considered here, the coefficient is known to vary with temperature. Because of the central character of the coefficient in calculating the axial force in the flowline it was decided to determine the variation of the coefficient with temperature for the actual material to be used in the manufacture of the flowlines.

The tests to evaluate the coefficient of thermal expansion were carried out on a thermo-mechanical analyser at a specialist centre in the University of Loughborough in UK. A calibrated quartz probe is placed on top of the specimen and heat is applied to increase the temperature of the specimen at a rate of 5oC/min (41oF/min). The temperature and output from the probe are recorded at specified temperatures during the test. The coefficient of thermal expansion is then calculated at these specific values of temperature.

The expansion of the specimen is measured over a range of 20oC (68oF) and the coefficient of expansion is calculated for the mid-point of that range. This is exemplified by the case of a temperature rise from 90oC (194oF) to 110oC (230oF). The strain in the specimen is measured across this range and the result divided by 20 to give the result reported as the coefficient of thermal expansion for 100oC (212oF), i.e. α(100).

It is evident from the above description that the values of the coefficients of expansion, $\alpha(T)$; reported from the tests are temperature dependent and correspond to a specific temperature, T. This is in contrast to an averaged value, αa($\overline{T}$), across a temperature range. $\overline{T}$, which is the value relevant to the design calculations for the flowlines in which the magnitude of the expansion is calculated over the range 41oF to 329oF. The definition of these two forms of the coefficient of thermal expansion are:

Coefficient $\alpha(T)$ related to a specific temperature T

$$\alpha(T) \equiv \frac{d\varepsilon(T)}{dT}$$

where $\varepsilon(T)$ is the thermal strain measured at the specific temperature T.

Coefficient $\alpha_a(\overline{T})$ related to the range of temperature $\overline{T} \equiv (T_2 - T_1)$.

$$\alpha_a(\overline{T}) \equiv \frac{1}{(T_2 - T_1)} \int_{T_1}^{T_2} \alpha(T) dT$$

The averaged value is the property relevant to the design of the pipeline axial forces since the material experiences a variation of the coefficient of thermal expansion as the flowlines heat and cool. The results obtained from the tests are shown in Figure 6 for an EP450 material. A quadratic interpolation of these points is carried out to give the relationship between the temperature and the coefficient of thermal expansion and an averaged value of the coefficient, from an initial temperature, T_1 is

$$\alpha_a(\overline{T}) = \left[a + \frac{b}{2}(T_1 + T_2) + \frac{c}{3}\left(T_2^2 + T_1 T_2 + T_1^2\right) \right] \times 10^{-6}$$

with

$$a = 8.044 \qquad b = 0.064 \qquad c = 1.806x10^{-4}$$

This enables the evaluation of the design values of the coefficient of expansion over the range from an initial temperature, $T_1 = 10°C$ to a maximum temperature of $T_2 = 165°C$ to be determined and for EP450 it is;

$$\text{EP450} \qquad a_a = 11.9 x 10^{-6}$$

It is evident from Figure 6 that there is considerable scatter in the results for the measured coefficients of expansion. This is an important aspect in deciding upon an appropriate level of safety to apply in the detailed design calculations for the forces induced in the flowlines by the high temperature of the fluid and for determining the design factors for the limit state approach. Generally, it is valuable to carry out a sensitivity analysis during the design to assess the effect of this scatter on the integrity of the system.

The Route to an Optimised Full-Scale Testing Methodology

Full scale testing has always been viewed as being very expensive and because of this test programmes involving full-scale tests have been kept to a minimum. Over the last few years of involvement in subsea pipeline testing we have striven to optimise the full-scale testing and so develop tests that provide the necessary high quality test data without being excessively expensive. The fact that more pipelines require to be designed by limit state analysis, puts greater emphasis on the quality of the test data used to provide more economic designs in increasingly arduous operating conditions. The current test methodologies have been developed over a number of years on a number of projects and the following section describes how the present methodologies have been reached.

Small-Scale Tests

In the earlier section describing the mill tensile tests it was clear that great care has to be taken when preparing specimens and avoiding any bending of the specimens during testing. The current tensile test method, is to use extensometry that allows the strain to be measured up to fracture. In addition strain gauges are applied to the specimens to measure any bending during the test set-up as shown in Figure 7. For compression specimens cut from the pipe wall four small strain gauges are attached and the specimen is placed on plattens that have spherical seats so that any lack of parallelism is accommodated as shown in Figure 8. Using this test set-up has been shown to prevent buckling occurring during the compression tests and is shown in Figure 9. Both the tensile and compression tests have been carried out at temperatures up to 410°F and specimens have been removed from the pipe material in both the longitudinal and transverse directions. When comparing the results of the controlled small scale tests described above with the results of the mill tests described earlier, it can be seen that whilst the ultimate stress values are similar there are variations in the yield stress values measured.

Cyclic stress strain tests are carried out to look at the effect of cyclic loading on material stress-strain properties. Generally these tests are only carried out for a small number of cycles and the test is stopped after the stress-strain hysteresis loops have stabilised as shown in Figure 10.

Recently much more complex thermo-mechanical cyclic tests have been carried out to try and provide an intermediate stage in the analysis between uniaxial constant temperature tests and full-scale ratchetting tests on subsea linepipe as shown in Figures 11 and 12. These tests were carried out to determine whether cyclic stress-strain behaviour derived from thermal cycling tests could be synthesised using the results from tests carried out at constant temperature.

In all the small scale tests, the data from the tests is recorded in electronic format, which allows the data to be used in deriving mathematical models, like Dafalias or Chaboche, for applying to non-linear Finite Element modelling. It is the area of modelling test data that still requires further work before the modelled data will reflect the actual stress-strain characteristics of the material, especially for the first cycle.

Full-Scale Tests

Full-scale component testing had been carried out at Mitsui Babcock for many years before the involvement in the oil industry testing. Early involvement was mainly in hydraulic testing of linepipe to validate burst criteria models[1]. When becoming involved in limit state design test work on line pipes, one of the first developments was to carry out detailed dimensional surveys of the pipe joints to determine variations in wall thickness and diameter along its length, shown in Figure 13. This provided statistical information and also aided in the location of instrumentation.

An early problem found was Euler buckling of the some specimens due to bending within the test specimen under compressive loading of up to 1760 Tons as shown in Figure 14. To ensure that Euler buckling is not induced due to specimen set-up, each test specimen has the faces of the end flanges machined after manufacture. Another early development was the addition of 'sliding-fit' collars local to the flange welds to minimise reinforcing effects of the welds on the pipe material and therefore prevent weld failures, on very ductile materials like super duplex, of the type shown in Figure 15.

Crucial to any limit state analysis is the quality of the test data used in the analysis. To this end, great care is taken when installing instrumentation to the test specimens. Normally around twenty-four strain gauges would be carefully attached to each pipe, in a biaxial pair formation. Using qualified technicians ensures reliable installation of the strain gauges and results in a very low failure rate, even under the extreme test environments found in these tests (temperatures of up to 210°C (410°F), internal pressures of up to 10,000psi and loads of up to 1760Tons).

As the strain gauges are operating in test temperatures of up to 210°C (410°F), the strain gauges have to be calibrated to allow on-line corrections of apparent strain. Apparent strain is the result of a mismatch in thermal coefficient of expansion of the strain gauge material and the substrate material to which it is attached when subjected to thermal changes. All strain gauges are affected by apparent strain to some extent.

The calibration is carried out by attaching a strain gauge and thermocouple to a small stress relieved block of the pipe material under investigation, then thermally cycling it in an oven and recording the strain output. This data is then fitted as shown in Figure 16, and the equation is used to correct the active strain gauges during the tests. A thermocouple is also attached adjacent to each strain gauge to allow control over the operating temperature of the test specimen and apply thermal corrections to the strain gauges. It can not be emphasised enough the need to be able to correct strain gauges for apparent strain when operating at temperatures which are on the limits of practical application for foil strain gauges. Apparent strain should not be confused with the thermally induced strains that we try to measure along with the mechanical strains during any material validation tests.

In addition to the strain gauges and thermocouples, linear potentiometers are used to measure global strain changes in the test sections of pipe by installing them in a frame as show in Figure 17. All instrumentation on the test section of pipe, along with pressure transducers and load cells are connected to PC controlled datalogging equipment for monitoring the tests.

Early full-scale test programs were invariably carried out in compression with various combinations of internal pressure and temperature. Heating being supplied by the use of bracelet heaters wrapped around the pipe along its entire length. Pressure is applied by hydraulic expansion of synthetic oil with a flash point well above the operating temperature of the pipe. The pressure within the pipe is kept constant throughout the test, even when subjected to cyclic loading, by means of an electrical controller and relief valves on the hydraulic pump. During the early programmes of tests, Euler buckling and barrelling as shown in Figure 14, were problems that had to be overcome. This was partly overcome by the methods mentioned earlier of machining the ends of the specimens and attaching 'sliding fit' collars. However, the more significant problem of thermal gradients in the pipe sections had to be overcome, as the pipe simply became a 'plastic hinge' during the compressive tests. Initially, thermal gradients through the pipe section were of the order of 10°C (50°F) or worse especially on super duplex, however with careful attention to the positioning of the heater bracelets and heater control thermocouples thermal gradients have been reduced to around 2°C (36°F) as shown in Figure 18. This has resulted in pipe joints being tested without the fear of bending within the specimen even at very high compressive loads. Again this removes the problems associated with interpreting data which has a large bending component in the active strain measurement as shown in Figure 19.

Having optimised the specimen manufacture, instrumentation and control of the test conditions. It was the load cycles to be applied to the pipe material that was next to be addressed. Initially most pipeline tests, for limit state design, were carried out in compression. No tensile loads were applied, except when carrying out fatigue tests on line-pipe butt welds containing defects, which were subjected to tensile and compressive elastic load cycles. Tests were carried out to simulate the operation of the pipeline on the seabed with various load and pressure combinations being carried out. However, it was soon realised that this test regime was not appropriate and did not truly reflect the operation of the subsea pipeline.

Thermal cycling tests, although time consuming, were the conditions that finally resolved the understanding of the test parameters that require to be applied to the pipe material for limit state design. As simple theory, based on the derived values of the thermal co-efficient of expansion discussed earlier, could be applied to this type of test it was initially found that the thermal expansion and measured strain did not agree. This anomaly had been noticed on a previous set of tests using a different test set-up but had not been fully resolved. However, as bending had been eliminated, the test set-up was investigated and it was found that the test rig, which had previously been thought of as being rigid, was in fact deforming under the applied loads. By installing potentiometers on the machine backplate and crosshead as shown in Figure 20, movements were easily detected and corrected for in the loading within the test specimen. This allowed the simple theory of thermal expansion to be confirmed by the strain gauge results.

Another fundamental change in the test philosophy as a result of thermal cycling was to use the potentiometers mounted on the gauge length to control the tests, rather than machine displacement or load control. This allows the test section to be held constantly at its initial length throughout the heating cycle, simulating the operation the pipeline on the seabed.

That is

$$\varepsilon_T = \varepsilon_{ther} + \varepsilon_{mech}$$

where

ε_T is the total strain in the flowline including the effects of strain localisation

$\varepsilon_{ther}(\alpha\Delta T)$ is the thermal strain

ε_{mech} $(\Delta L/L)$ is the mechanical strain that is imposed during strain localisation

Keeping control over the initial length of the test sections also resulted in tensile forces being applied by the test machine to bring the specimen back to its original length after having been yielded by thermal and mechanical loading. This method of test control allowed thermal and mechanical loading to be applied to test sections that replicated the operation of the pipeline on the seabed, i.e. thermal loading putting the pipe in to compression above yield and resulting in the pipeline going into tensile loading on cool down. This control methodology as described above has been used for subsequent tests and has resulted in tests that provide high quality data for the limit state analysis[2], an example of which is shown in Figure 21. Figure 21 shows a perfect example of pipeline buckling, which was only possible as a result of the experience gained over a number of test programmes and the perfection of the test methodologies. Figure 22 shows a typical load versus strain plot for a recent test carried out to look at the ratchetting characteristics of a subsea pipeline material for a joint industry program on limit state design of HT/HP pipelines.

Conclusions

Although the test work described in this paper is mostly based on limit state design of line-pipe, the good practices developed and the emphasis on representative test conditions can be applied to many other component or riser tests.

The fully developed and validated test methodologies described in this paper, now provide the opportunity for full scale tests programmes to be carried which accurately simulate the operation of a subsea pipeline and all test data generated will be of high quality for use in the pipeline design.

We have also shown that carrying out full-scale tests for limit state design of pipelines operating at high temperatures requires a test machine which can apply tensile forces of a similar level to its compression force capability.

It has been shown that quality testing both small and full scale although initially appearing expensive to carry out, do present bigger savings at the design stage than would be possible if less controlled test data was used.

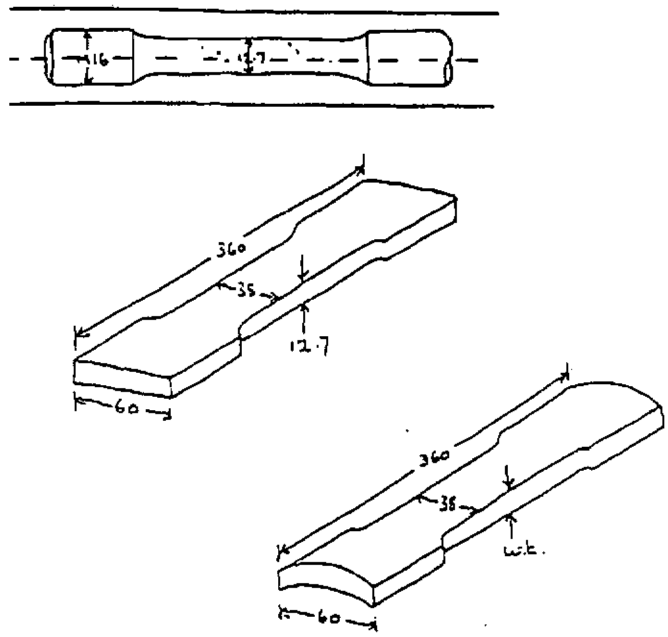
References

1. Stewart, G., Klever, F.J., "Accounting for Flaws in the Burst Strength of OCTG", presented at the SPE Applied Technology on Risk Based Design of Well Casing and Tubing, The Woodlands, Texas, USA, 7-8 May 1998
2. Walker, A., Spence, M., Reynolds, D. "Use of CRA Lined Pipe in High Temperature Systems", presented at OPT 2000 in Oslo, 28-29 February 2000.

Geometry for Specimen 1L

Geometry for Specimen 2L

Geometry for Specimen 3L



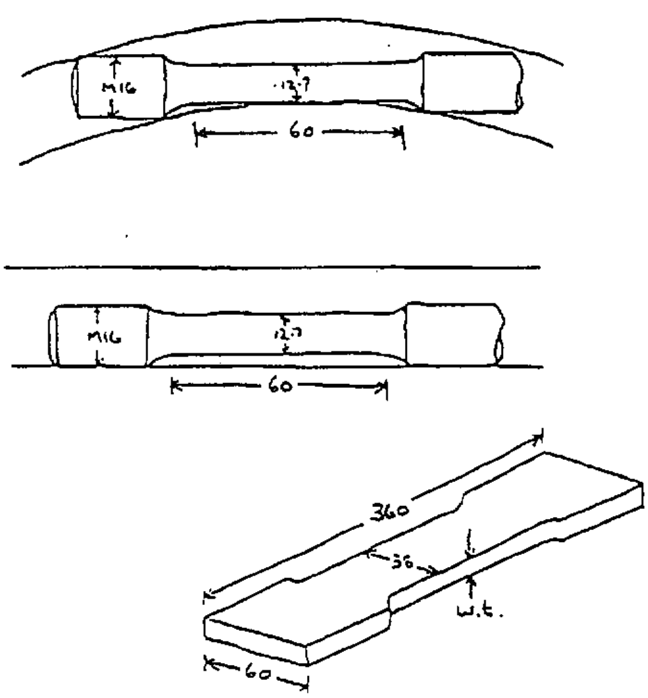
Geometries for Longitudinal Specimens

Figure 1

Geometry for Specimen 1T

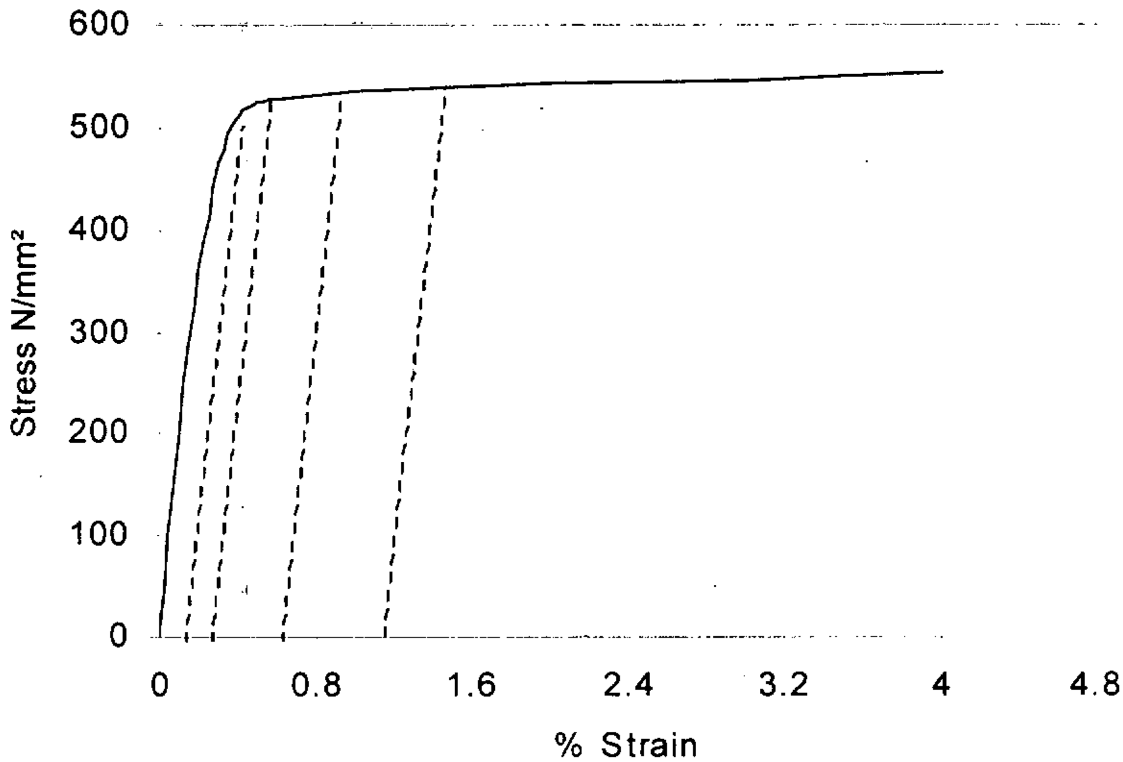
Geometry for Specimen 2T

Geometry for Specimen 3T

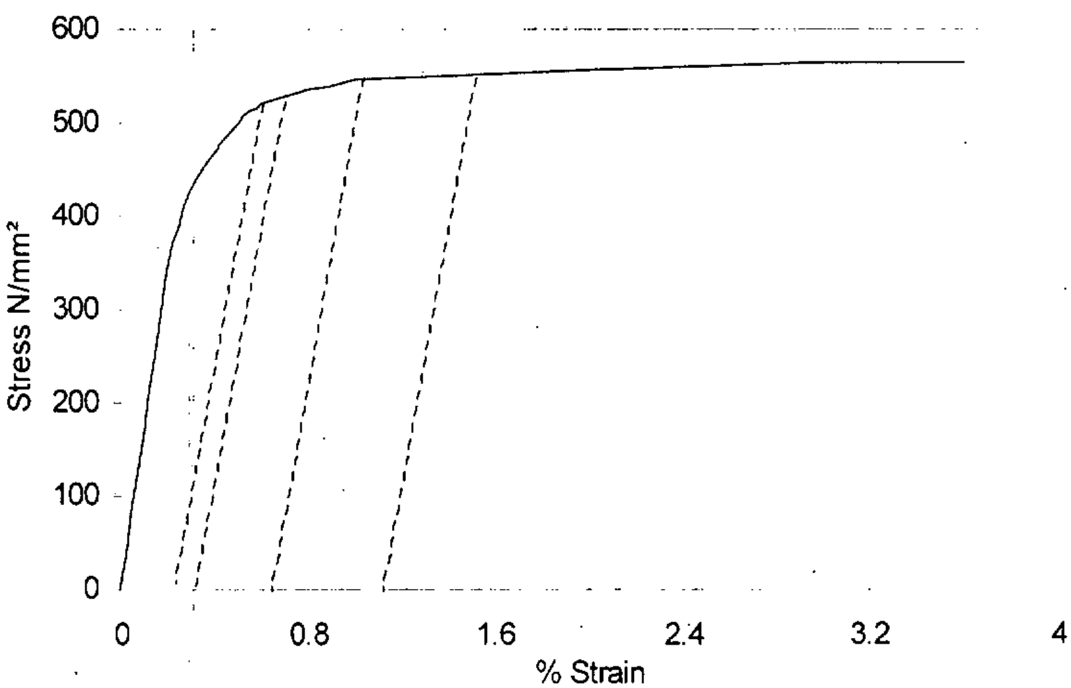


Geometries for Transverse Specimens

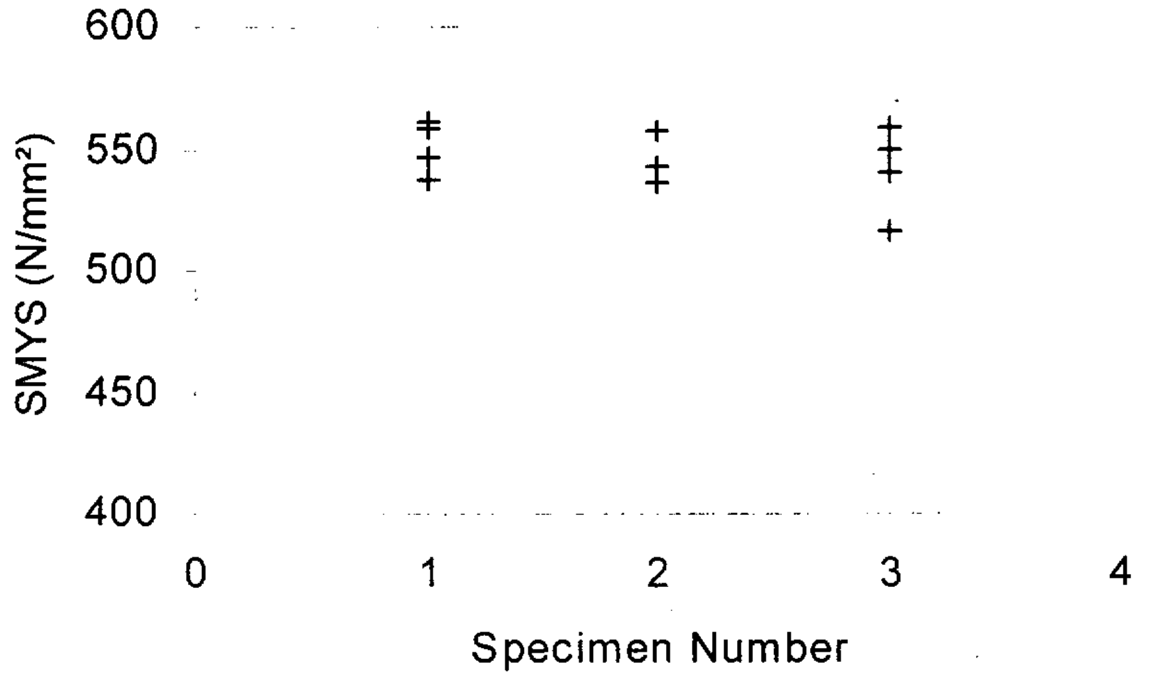
Figure 2



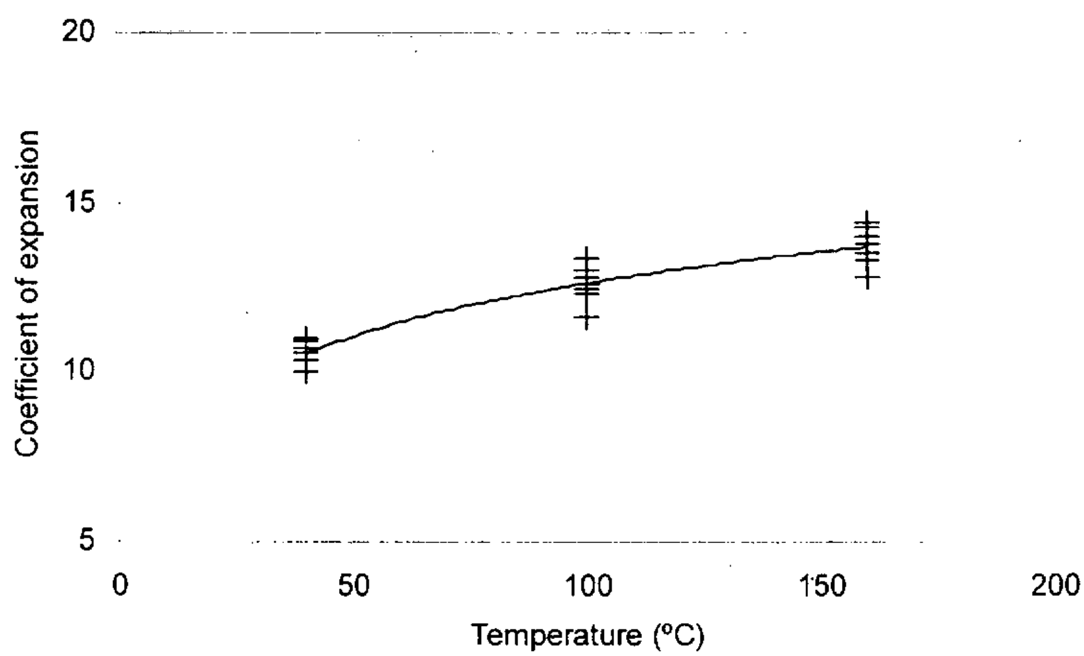
Stress-Strain test results for Specimen 1L Figure 3



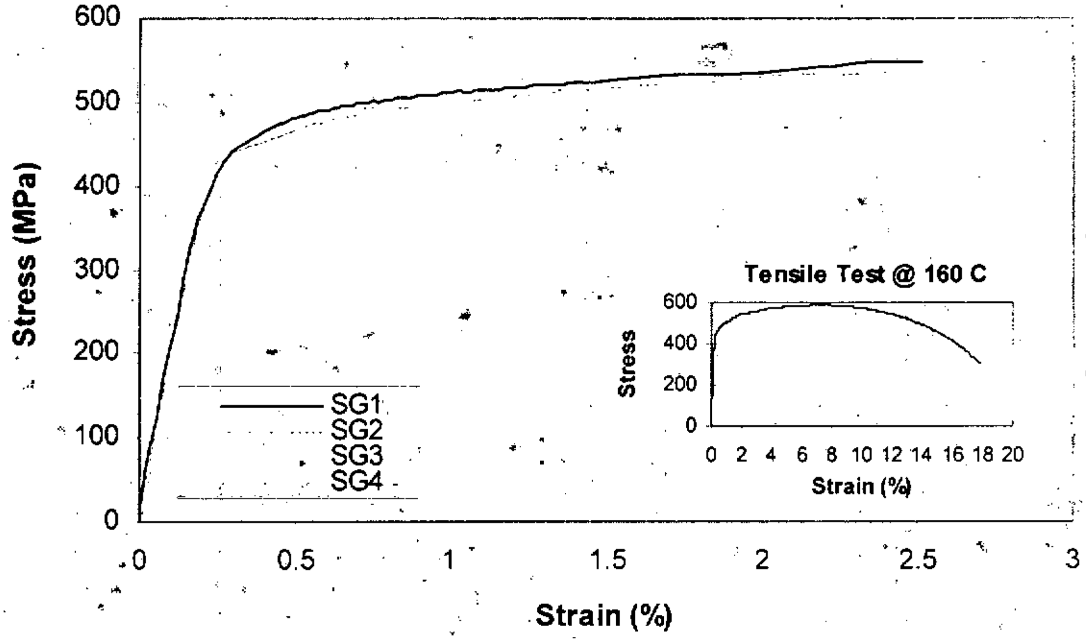
Stress-Strain Test Results for Specimen 3L Figure 4



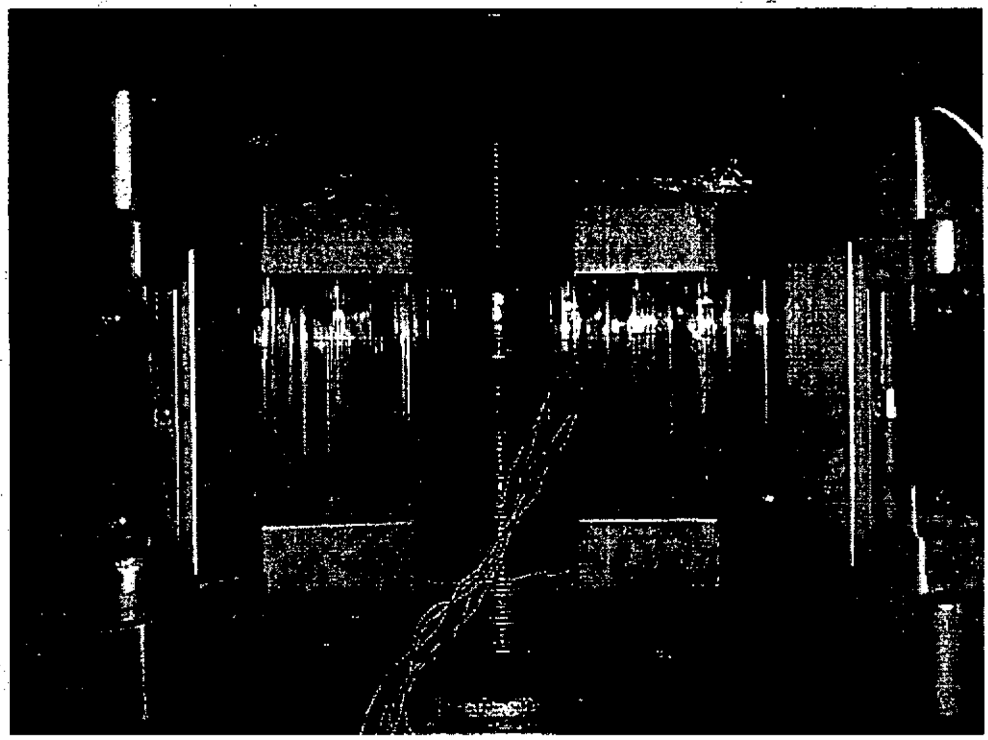
Plot of Measured SMYS Corresponding to Geometries, 1L,2L,3L Figure 5



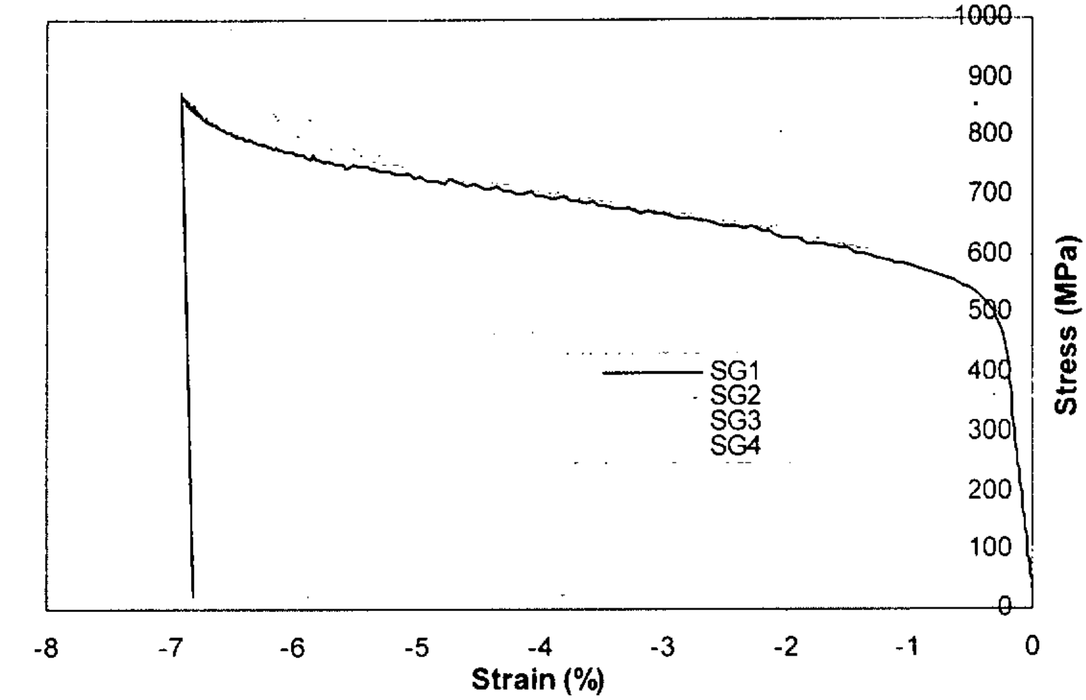
Plot of Coefficient of Thermal Expansion for EP450 Carbon Steel Figure 6



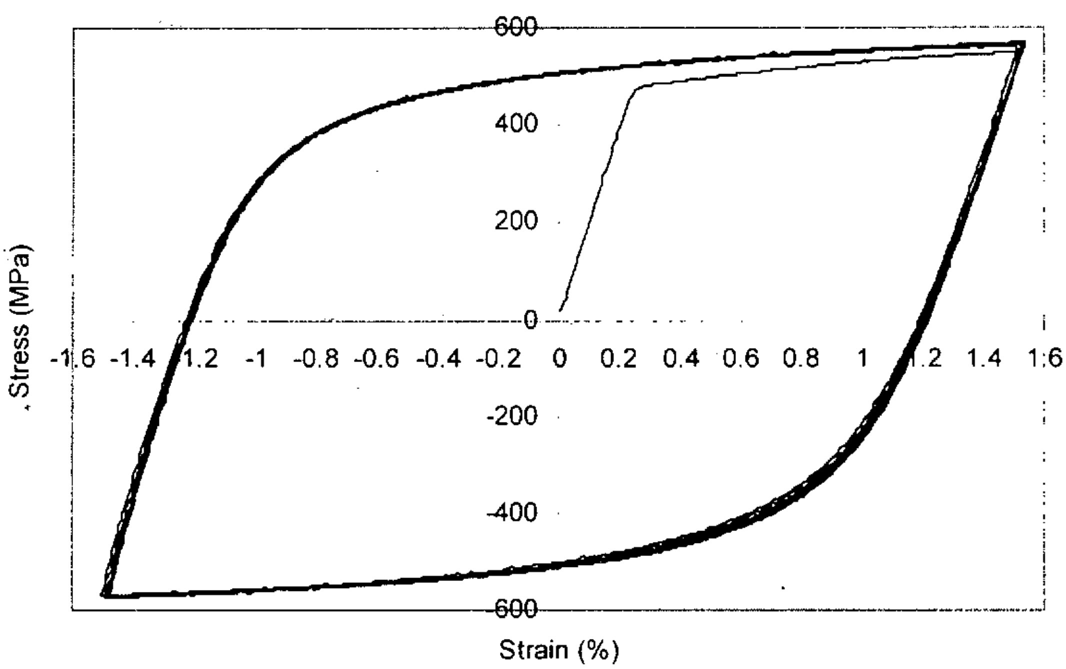
Stress-Strain Measurements During Tensile Tests at 160C Figure 7



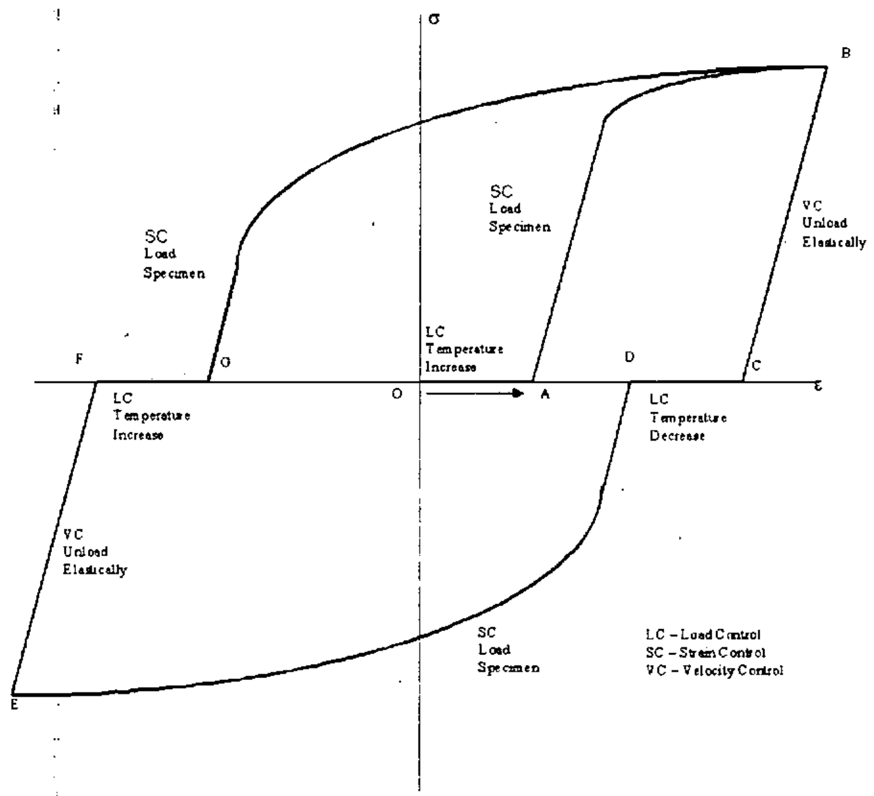
Set-Up For Small Scale Compression Tests Figure 8



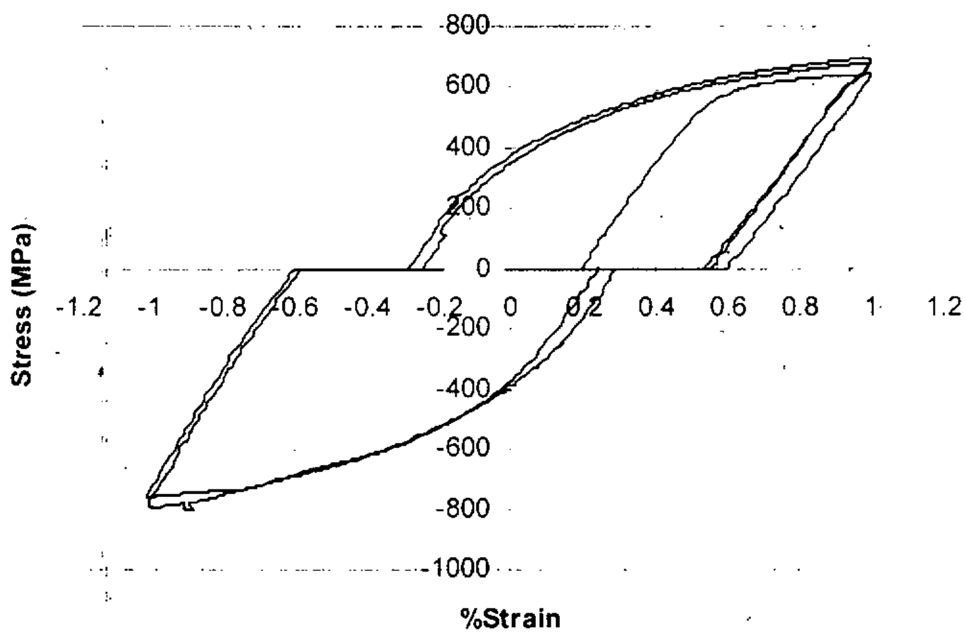
Stress- Strain Measurements During Compression Tests at160C Figure 9



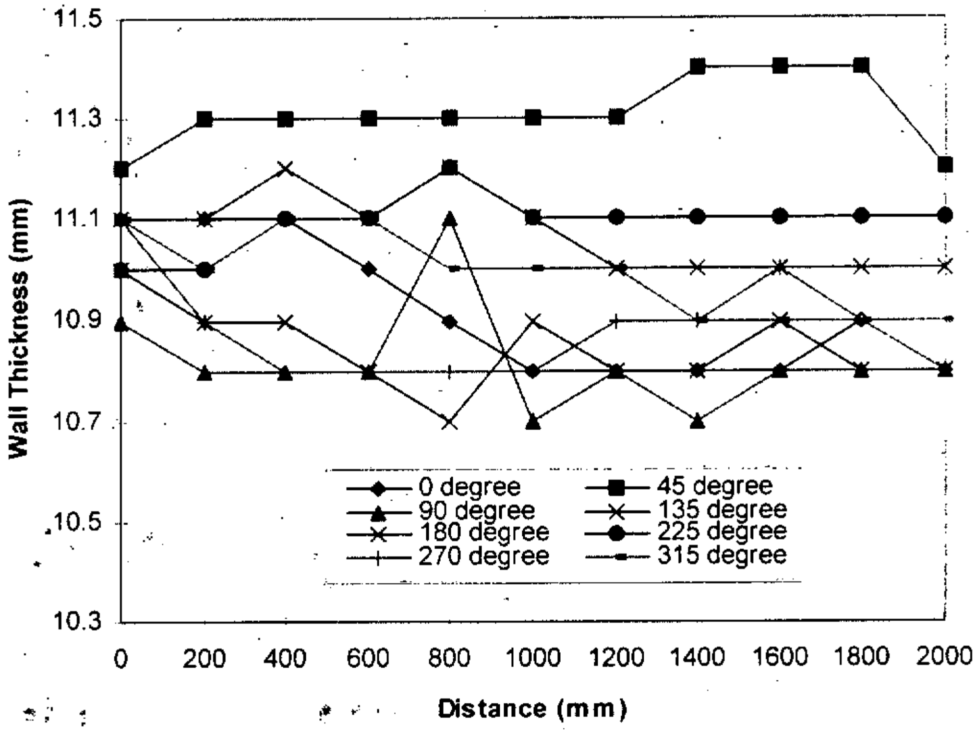
Stress-Strain Hysteresis Loops from Cyclic Tests at 210C Figure 10



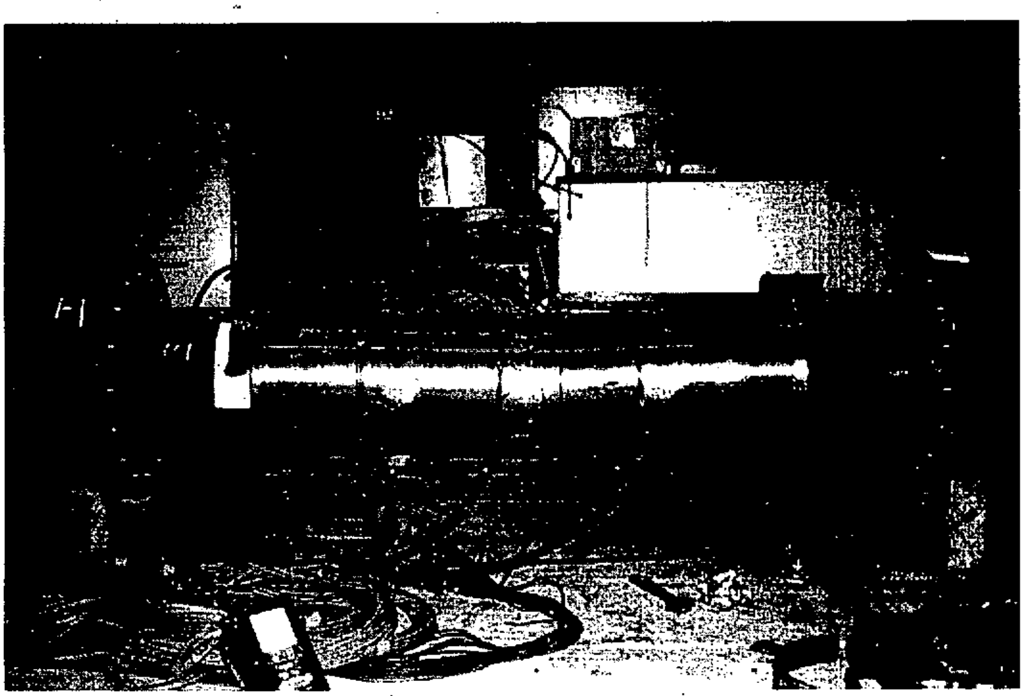
Small-Scale Thermo-Mechanical Test Procedure Figure 11



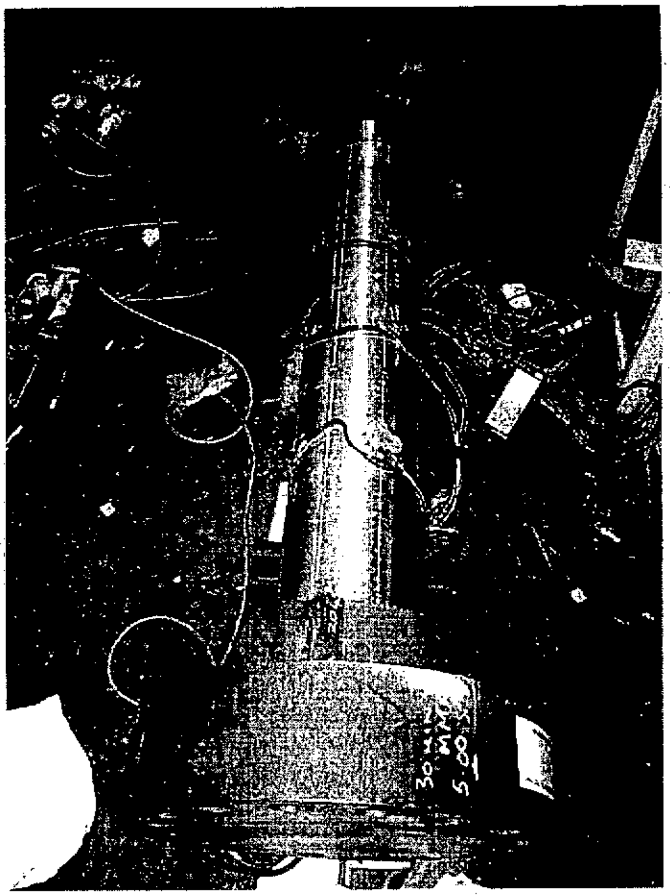
Small-Scale Thermo-Mechanical Stress-Strain Hysteresis Loops Figure 12



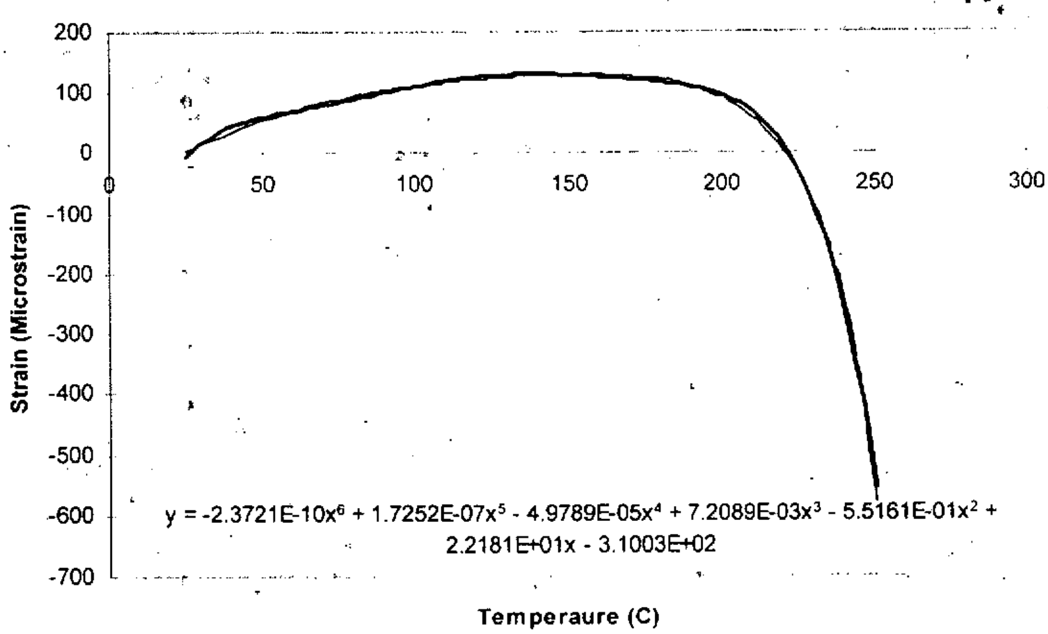
Wall Thickness Variations Along Pipe Joint — Figure 13



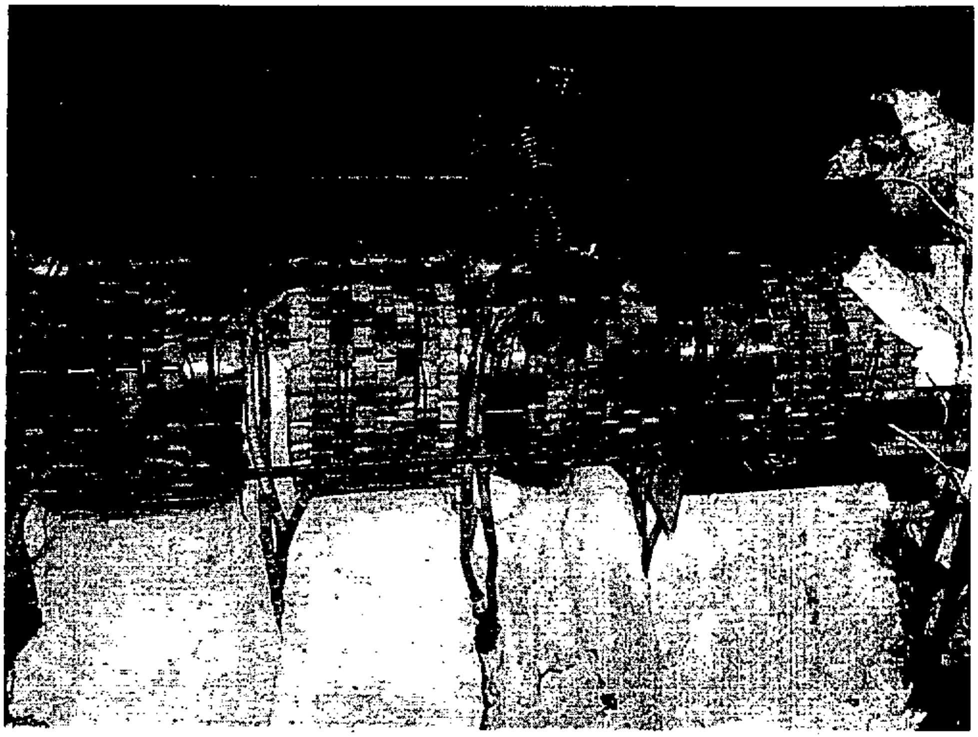
Specimen After Test Showing Euler Buckling — Figure 14



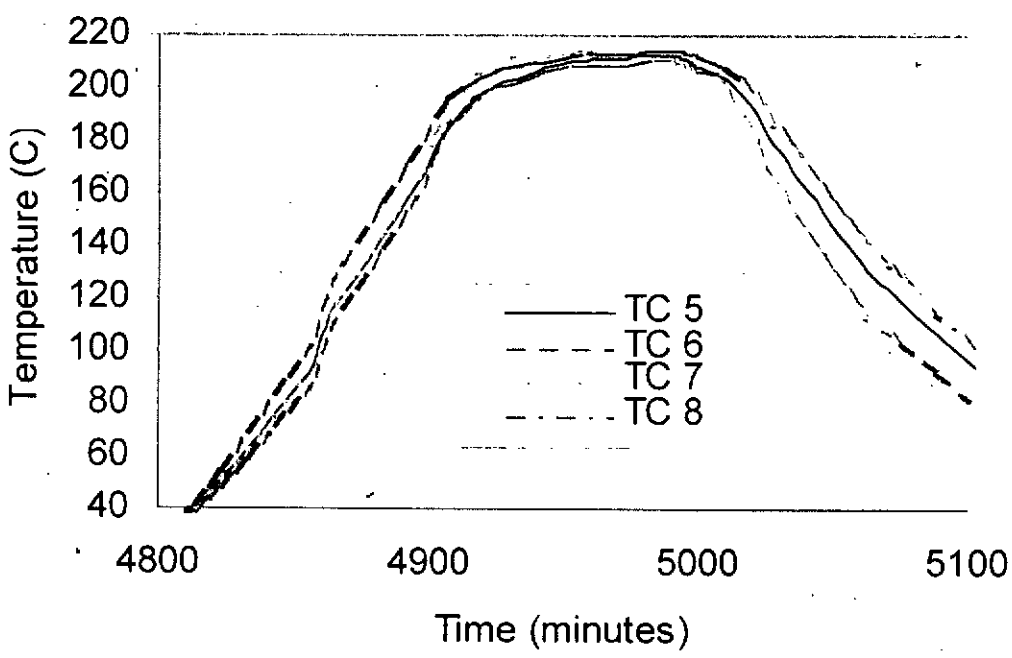
Test Specimen Set-Up Showing Collars and Machined End Flanges Figure 15



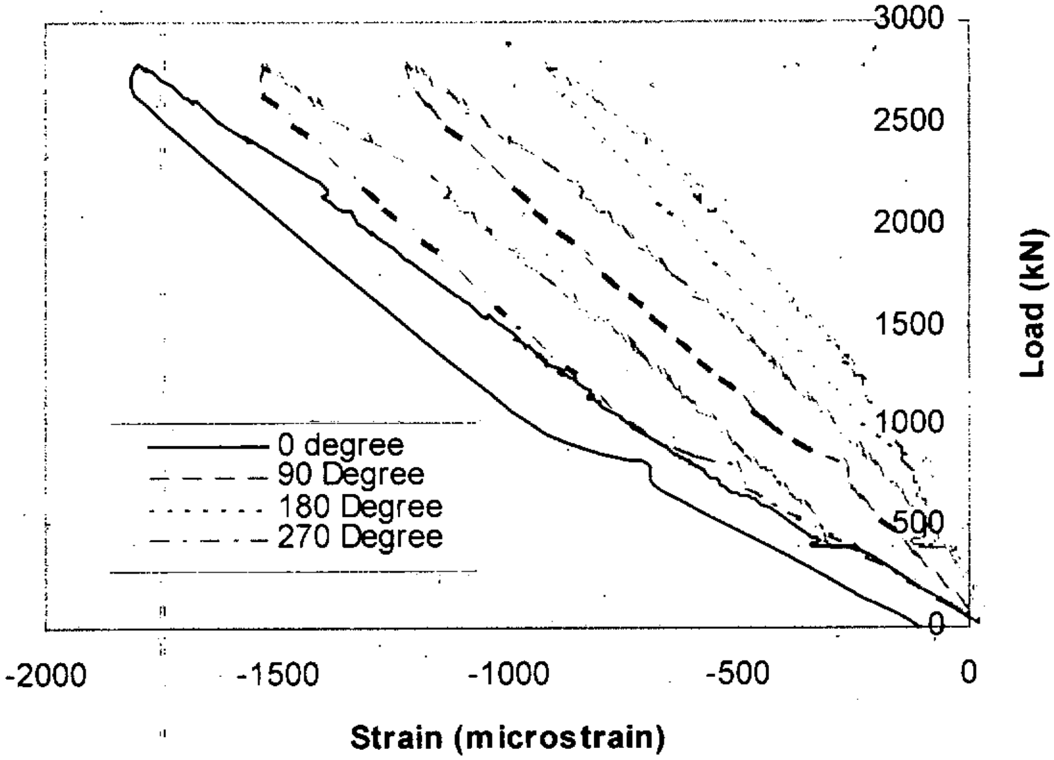
Apparent Strain Calibration Used for Correction of Strain Gauges Figure 16



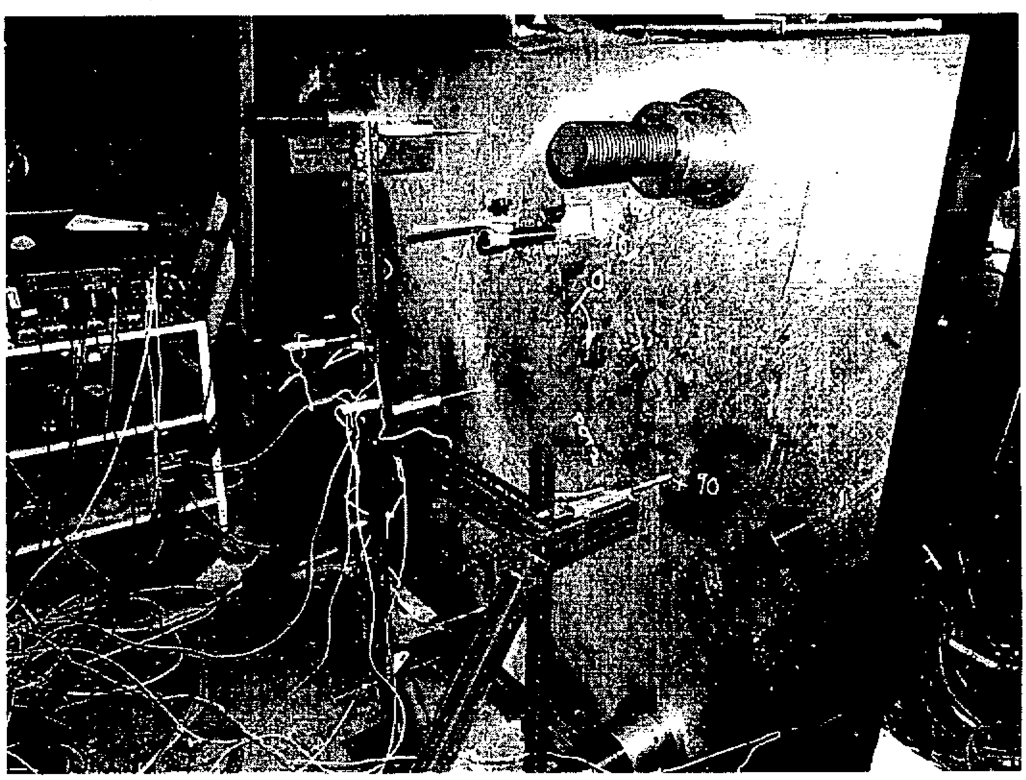
Potentiometer Frame Over Specimen Gauge Length Figure 17



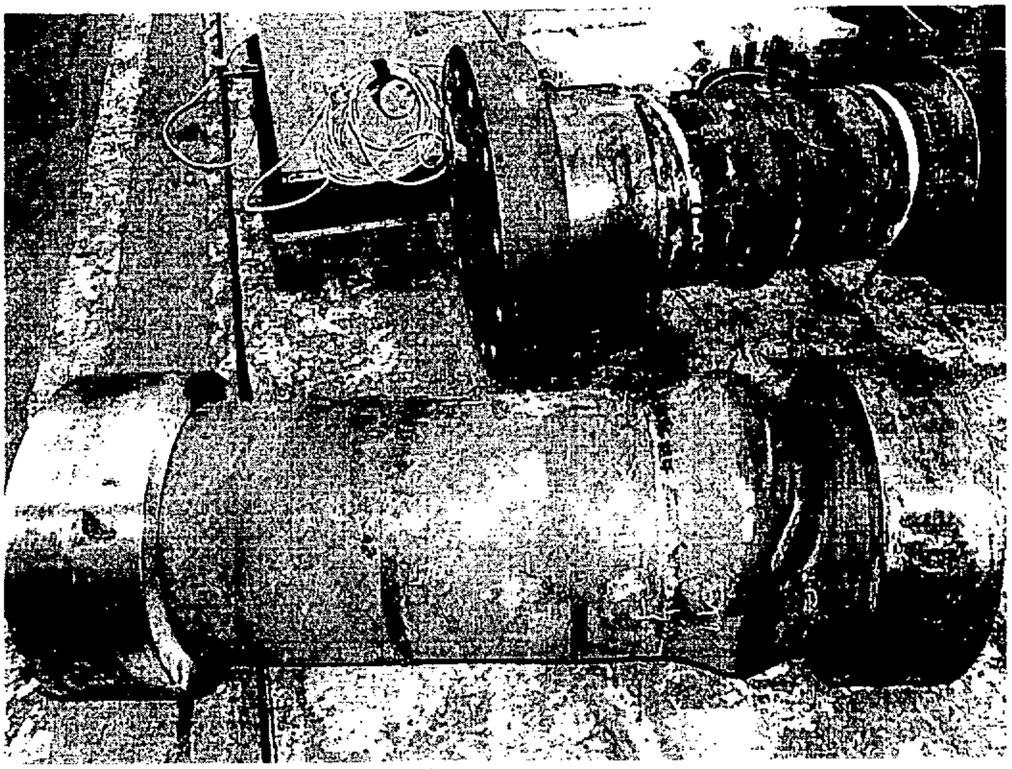
Temperature Measurements On Pipe During Full-Scale Test Figure 18



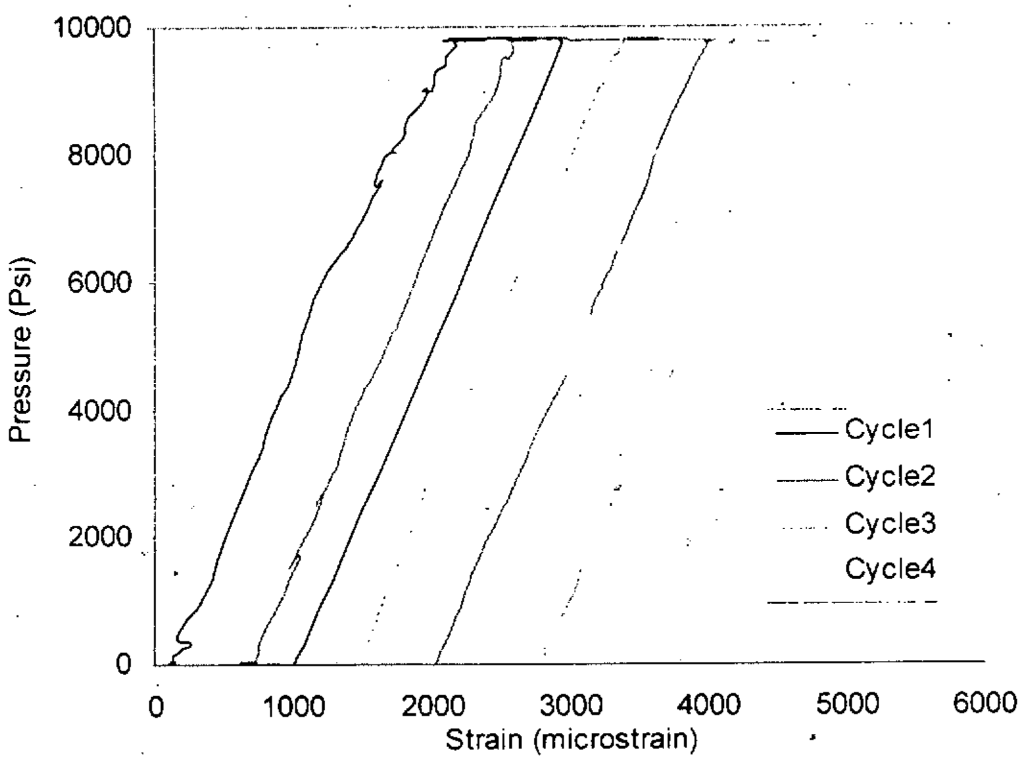
Strain Measurements Showing Bending During Full-Scale Test Figure 19



Potentiometers Installed on the Machine Backplate Figure 20



Pipe Specimens Showing Buckling Due to Compression Loading Figure 21



Typical Results From Full-Scale Pipe Ratchetting Test Figure 22

Deepwater Pipeline Repair System

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March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

Deepwater Pipeline Repair System

Shell International Exploration and Production

Background

Due to the potential environmental threat and tremendous economic impact that a deepwater producing property would sustain if a pipeline release occurred, Shell Deepwater Producing Inc. (SDPI), Equilon Enterprises and Coral Gas Transmission have entered into an agreement to develop a deepwater pipeline repair system. The Deepwater Pipeline Repair System (DPRS) is designed to be utilized on all oil and gas export lines in the Gulf of Mexico in water depths beyond diver intervention. The main intent of the DPRS is to minimize the downtime of the export pipeline if a failure should occur. To this end, several facets of the repair system have been addressed, including the following:

- Development of repair procedures/repair manual
- Development, manufacture and testing of connectors and tooling necessary to perform a repair
- Arrangements with offshore contractors and service companies that may participate in the repair
- Analysis/Design and fabrication of jumpers
- Development of hydrate remediation procedures
- Development of Commissioning/Start-Up procedures
- Table-Top Drill exercises
- Marketing system to other operators

A value-engineering workshop sponsored by Shell in October of 1997 selected the Surface Lift repair method, which will be described later in this paper, as the most reliable and acceptable method for repairing a damaged deepwater pipeline.

After the funding was secured and the project team began working on the project, it was realized that an On-Bottom solution was also necessary. This requirement was dictated by the fact that there may be occasions that make the recovery of the pipeline to the surface unviable, such as pipeline damage near another pipeline crossing. Other circumstances make a surface lift undesirable, such as unavailability of a heavy lift vessel and proximity of damage to a riser. These realizations led the project team to develop two repair methods, the Surface Lift repair and the On-Bottom repair. With the myriad of possibilities a damaged pipeline may present itself, both solutions have been designed with flexibility in mind.

Both solutions consider the following line sizes: 12", 14", 16", 18" and 20", with operating pressures up to 6000 psig at 120 degrees Fahrenheit. Both methods use conventional rigid jumper spool technology and collet connectors to connect one end of the repaired pipeline to the other end. The difference between the two solutions lies in how the upward-looking male hub is placed on the end of the pipeline.

Proceedings of the 3rd Deepwater Pipeline & Riser Technology Conference, Houston, Texas, March 7-9, 2000.

Repair Solutions

The Surface Lift repair relies on a heavy lift vessel to retrieve the pipe to the surface, which allows access to the pipe bore for the remediation of hydrates. Once the pipeline is lifted, a male hub is welded to the pipe end, clamped to a Pipe Line End Manifold (PLEM) and deployed back to the seabed. These steps are repeated for the other side of the cut pipeline to leave two upward-looking hubs on the seafloor. Either acoustics or taut-wire technology is then used to determine the relative angles and slant range between the hubs. These measurements are used to fabricate a jumper, which is then deployed to the hubs on the seafloor. Hydraulically actuated collet connectors incorporating metal seals are utilized to make the connection between the two pipeline sleds. The repaired pipeline is now ready for commissioning.

The On-Bottom repair is designed to complete the repair without lifting the pipeline to the surface. Pipe lifting frames are used to elevate the end of the pipe above the seafloor to cut out the damaged pipe and prepare the end of the pipe with a concrete/FBE removal tool and end prep tool. A gantry sled/PLEM assembly is then landed near the end of the pipe, which allows the Remotely-Operated Vehicle (ROV) to position a grip and seal connector, already welded to an elbow with an upward-looking male hub, onto the end of the pipe. After actuating the grip and seal connector, testing the seal, and removing the gantry frame, the system is configured similar to the Surface Lift repair, with two upward-looking male hubs that are latched onto by a jumper with collet connectors.

The Surface Lift repair allows a welded connection to be made to the pipe in lieu of an elastomeric seal if the pipe were to be repaired on the seabed. However, the Surface Lift Repair places more emphasis on vessel capabilities, requiring the repair vessel to have lift capabilities up to approximately 260 kips. This requirement varies depending on which pipeline is damaged and at what depth it is damaged. The following table lists the maximum loads for the various pipelines in a dewatered condition.

Pipe Size & Grade	Project	Maximum Depth (ft)	Abandonment and Recovery Force (kip)
20 x .812 60	Brutus	2650	80
20 x .750 60	Ursa Gas	3400	53
18 x .750 52	Ursa Gas	3510	99
18 x .688 60	Ursa Oil	3400	51
18 x .688 52	Ursa Oil	2970	47
18 x .688 42	Mars Oil	2960	50
16 x .688 52	Auger Oil	1300	38
16 x .625 52	Auger Oil	2100	32
14 x .625 42	Mars Gas	1740	46
14 x .562 52	Ram Powell Gas	3210	43
14 x .562 42	Mars Gas	2958	41
12.75 x .812 70	Mensa Gas	1050	58
12.75 x .750 70	Mensa Gas	5325	219
12.75 x .625 52	Ram Powell Oil	3265	87
12.75 x .562 52	Auger Gas	2860	52
12.75 x .562 42	Ram Powell Oil	1400	25
12.75 x .500 52	Ram Powell Oil	3210	30

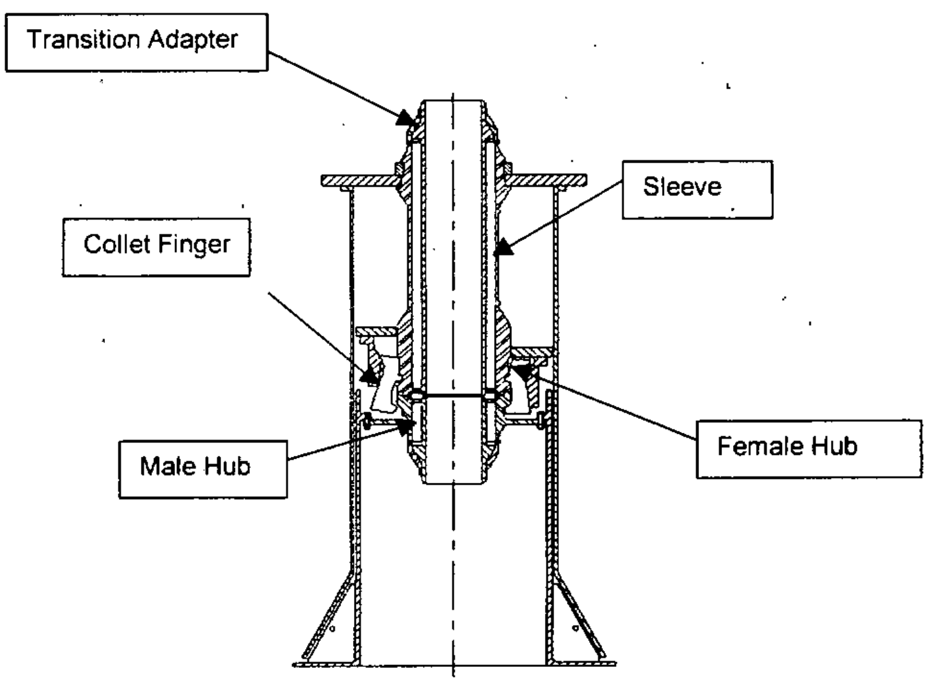
Repair Procedures/ Repair Manual

A repair manual is being developed which describes all the required engineering, hardware and offshore procedures associated with a repair effort. The repair manual will contain connector design and installation procedures, arrangements with heavy lift pipeline vessels and service contractors, ROV tooling descriptions and operation manuals, lift frames and end connector details, hydrate location and remediation methods, as-built alignment sheets for all SDPI/Equilon/Coral deepwater pipelines, and storage/maintenance contracts to keep the system in a state of readiness. The manual will also contain copies of all testing performed for the development of the various tooling, including proof of concept tests, Factory Acceptance Testing (FAT), and Systems Integration Testing (SIT).

Connectors And Tooling

Connectors

The connection type selected for jumper connectors for the Surface Lift repair is a metal seal collet connector manufactured by Oil States Hydrotech. These connectors have been used in several subsea connections similar to the system described herein, and provide good misalignment tolerances, high strength, and good operability. To mitigate the high capital equipment costs related to purchasing connectors for each size of pipeline, a novel concept of sleeving the connectors is being developed. This concept utilizes a 20" integral collet connector, which is sleeved down to any of the other four sizes to cover the range of pipelines being protected by the DPRS. A sketch of this concept is shown below. In the case of Mensa, which is a 6000-psi system, a pressure boundary at the 12" diameter is being provided.

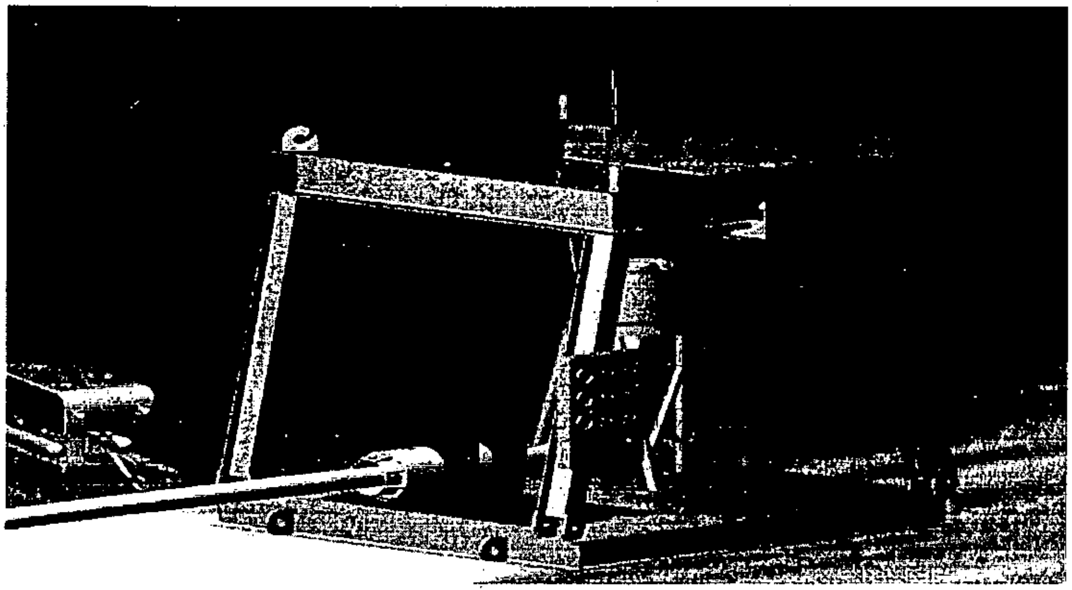


Sleeved Collet Connector

The On-Bottom repair utilizes Hydrotech's Grip and Seal Connectors, which have been utilized in numerous diver-installed spools over several years. This connector provides an elastomeric seal element that is squeezed to form a seal around the outside diameter of the pipeline. Grips plastically deform the pipe to provide a mechanical connection between the connector and pipeline. This type of connector, with the help of the Gantry Frame described below, allows the installation of the upward-looking hub and elbow onto the end of the pipeline without the requirement of welding. As diverless bolted flange technology becomes proven, the system can be modified to utilize bolted flange/in-line spool components by welding a swivel ring flange directly to the Grip and Seal Connector.

Gantry Frame/Plem

The On-Bottom repair requires the installation of the Grip and Seal Connector, elbow, and hub onto the end of the pipeline on the seafloor. For this operation, Hydrotech is designing and fabricating two Gantry Frame/PLEMS, which will be lowered to the seafloor on a downline. An ROV operates the gantry frame to position the Grip and Seal Connector over the end of the elevated pipe end. After testing the seal, the ROV will lock down the assembly to the mudmat with clamps, which will transfer any torsional loads from the connector into the mudmat. The gantry frame structure is then removed from the assembly to leave it configured as the Surface Repair system, with two upward-looking hubs ready for jumper measurement.



Gantry Frame/PLEM Concept

Pipe Lift Frames

Lifting frames from the URSA project, which involved 18" and 20" diameter pipe, have been modified to handle all sizes of export lines protected by the DPRS. These frames will be used to lift the pipe off the seafloor for either attaching a recovery hook in the case of a Surface Lift repair, or providing an elevated pipe tip for installation of the Grip and Seal Connector via the Gantry Frame.

Recovery Hooks

Recovery hooks consist of both overshot-type tools and drop-on recovery tools. Use of which type of tool will be dictated by the damaged pipeline and whether or not j-lay collars are available to react the load.

ROV Tooling

There are a number of ROV tools that are needed to perform tasks for the Surface Lift and On-Bottom repair scenarios. Some of the tasks required of the ROV include cutting the pipe, removing concrete and/or FBE coating, capturing any product that may be escaping from the pipeline, and measuring the distance between hubs for jumper fabrication. Tools are being built to accomplish these tasks, which include the following:

- Diamond Wire Cutting Module (DWCM)
- Concrete and FBE Removal Tool (CFRT)
- End Preparation Tool (EPT)
- Isolated Hydraulic Power Supply (IHPU)/Module Docking Skid
- Discharge Containment Tent (DCT)
- Hydrate Detection Tool (HDT)
- Pre Measurement Tool (PMT)

Two contractors have been selected for supplying the ROV tooling. Sonsub Inc. has responsibility for the Diamond Wire Cutting Module, Concrete and FBE Removal Tool, End Preparation Tool, and an Isolated Hydraulic Power Supply (IHPU)/Module Docking Skid. Oceaneering has responsibility for the Discharge Containment Tent and the Hydrate Detection Tool. Oceaneering has also provided Shell on a previous project with a Pre-Measurement Tool for performing jumper metrology. Each of these tools is described below.

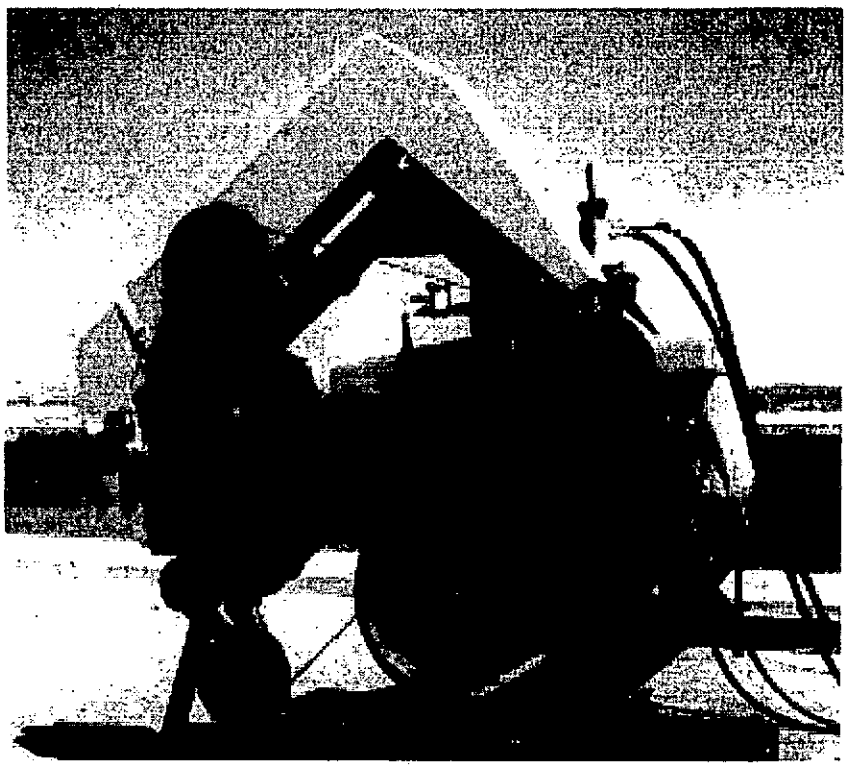
Diamond Wire Cutting Module (DWCM)

The Diamond Wire Cutting Module originally developed for Sonsub's Diverless Sealine Repair System (DSRS) will cut both concrete weight-coated and Fusion Bond Epoxy (FBE) coated steel pipelines. The Diamond Wire Cutting Module consists of two basic subassemblies:

- cutting module
- clamping module

The cutting element is a special diamond-coated wire, formed into a closed loop. The cutting module is made up of an arc-shaped tubular frame that houses a high-speed traction pulley with its motor. This pulley, plus the two free pulleys that are located at the two ends of the frame, serves as a support for the diamond wire. One of the two pulleys is mounted on a mobile arm operated by a hydraulic cylinder that is used to keep a constant tension on the cutting wire.

The clamping module is a hydraulic clamp that keeps the machine clamped to the pipe to be cut. It is built from an upper rigid structure, supporting four moving arms operated by hydraulic cylinders. The upper structure and the mobile arms are supplied with reduction kits profiled according to the diameter of the pipe to be clamped.



Diamond Wire Cutting Module (DWCM)

The system is designed to be deployed to the sea bottom with its own deployment frame, and then moved and operated by a work class ROV of opportunity. During recent testing trials it was demonstrated that the tool could cut through a 20" pipeline with 3½" thick concrete coating in approximately 45 minutes.

The primary system parameters are as follows:

Pipe Diameters:	8" OD to 36" OD
Weight-coat Thickness:	4" thick impinged or wrap on concrete weight-coating with reinforcing steel
Pipe loading:	Will cut pipe that is highly loaded in tension, compression and torsion.
Visibility:	High visibility not required – does not require ROV operator to see the operation being performed.
Soil Conditions:	Since tool is neutrally buoyant, seabed soil conditions are not relevant.
Pipe Orientation:	Can be used to cut vertical members as well as horizontal pipelines.
Hydraulic Operation	Two hot stabs from the ROV IHPU.
ROV	Work Class ROV of opportunity.

Concrete & FBE Removal Tool (CFRT)

The Concrete & FBE Removal Tool is designed to efficiently remove both the concrete weight-coating and FBE coating from the pipe surface to allow a connector to be installed over the outside of the cut pipe. The tool will operate on pipe sizes between 12" and 36" pipes with up to 4½" thick, reinforced concrete weight-coat (i.e. 45" maximum pipe OD).

This tool has a clamping arrangement that is similar to the DWCM for clamping to the pipeline. Mounted to the frame is a pair of extend/retract cylinders that are capable of moving a tooling plate along the pipeline up to 3 feet. The tooling plate has a mechanism similar to that used on pipe beveling machines used for rotating the concrete cutting heads around the pipe. There are two concrete cutting heads, mounted to the front rotating tool plate, that work together to efficiently remove all concrete and FBE from the pipe surface. The cutting heads are designed to eliminate potential damage to the pipe surface and leave it with a surface finish similar to that achieved by sand blasting.

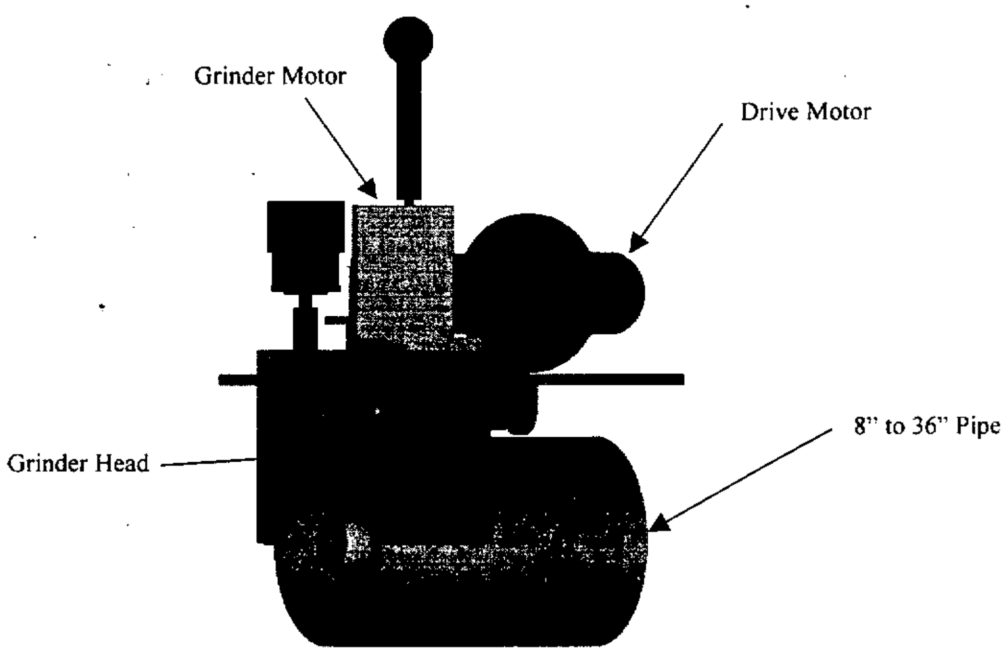
Following are the performance requirements for the CFRT:

Pipe Diameters	Between 12" and 36"
Concrete Thickness	Between 1" to 4.5" thick.
Concrete Type & Thickness Variation	Wrap-on concrete and impinged concrete. Impinged concrete may have a thickness variation of up to 1".
Pipe Types	The CFRT must operate on standard pipe as well as "DSAW" pipe that has a longitudinal weld seam that is typically 1/8" high.
Concrete Reinforcing	The CFRT must operate on concrete weight-coat with either Bekaert wire (1.6mm x 1.6mm square profile) or standard GOM reinforcing wire. Typically, concrete over 2½" in thickness will have two layers of wire reinforcing.
Concrete Removal Scenarios	Anticipated scenarios for operating the CFRT are: Case 1: Removal on middle of pipe (for hot tap etc). Case 2: Removal from the end of a pipe where the concrete has already been cut back some distance from the end. Case 3: Removal from the end of a pipe where the concrete is right up to the very end. There may also be times when the tool is to operate on pipe where some of the concrete has broken off.

ROV	Work with a Work Class ROV of opportunity.
Docking Interface	Same as diamond wire cutting module.
Visibility	Must work with little or no visibility.
Allowable Steel Removal	The system must not remove more than 0.01" of steel from the pipe surface.
Minimum Removal Rate	The CFRT must remove concrete at an approximate rate of 1250 inches^3/hour.
Operating Depth	Operating depth of 6000 fsw.

End Preparation Tool (EPT)

The purpose of the End Preparation Tool is to clean burrs and ragged edges from the end of subsea pipelines after having been cut with Sonsub's Diamond Wire Cutting Module (DWCM). The tool ensures that there are no rough edges that may cause damage to either the connector seals or any future pigs run through the pipeline. The tool is operated via two hotstabs from the ROV IHPU and is positioned onto the end of the pipe by the ROV manipulator. It operates on pipe sizes ranging from 8" to 36" diameter (or larger, if required, without modification).



End Preparation Tool (EPT)

The concept of the tool is that, rather than using a central mandrel to hold the tool in place, the tool grips with three (3) rollers on the wall of the pipe. Two of the rollers are on the outside of the pipe, with the third on the inside of the pipe.

To install the tool onto the pipe a hydraulic cylinder is operated to swing the bottom roller open. This allows easy access for the ROV manipulator to install the tool onto the pipe edge. The cylinder is a spring retract cylinder to ensure the tool opens automatically upon hydraulic failure (fail open).

Rotation around the pipe is accomplished using a hydraulic motor connected to the two top drive rollers. The cutting head is also rotated at high speed by another hydraulic motor and consists of a grinding wheel head that is mounted on two sliding rods that allow a linear motion towards and away from the pipe end. The sliders are spring loaded to force it out from the pipe end when a cam is out of the way. Rotating the cam (by swinging the connected lever) allows the grinding head to move onto the pipe end.

The grinding head is fixed to the tool sliding rods via a pivot point located near the center of the grinder. To rotate the cutter a lever is moved by the manipulator. This allows the grinder to swing 45° to allow for the inside and outside corners to be dressed by the grinder, as well as the end flat of the pipe if required.

Isolated Hydraulic Power Supply (IHPU) & Module Docking Skid

This system allows the ROV to provide isolated hydraulic power to the tools required to execute a repair, and to actuate and perform high-pressure external seal tests on the pipeline connectors. Also included is the docking system to allow for an in-water mechanical connection to the DWCM and CFRT for transportation by the ROV.

The IHPU is designed in a modular concept allowing the major components to be distributed within the frame of an ROV of opportunity. Hydraulic power is provided to the tooling modules through standard dual port hot stabs and a special high flow hot stab. The IHPU provides the following circuits:

- A 10,000 psi circuit for performing external seal tests of the pipeline connectors and actuating the Grip and Seal Connectors.
- A high flow, 20 GPM, 2000 psi circuit, required for operating the DWCM and CFRT cutting/removal heads.
- A 3 GPM, 3000 psi circuit for operating the various module functions such as clamping etc.

The system compensator provided with the system provides a 5.5 gallon capacity.

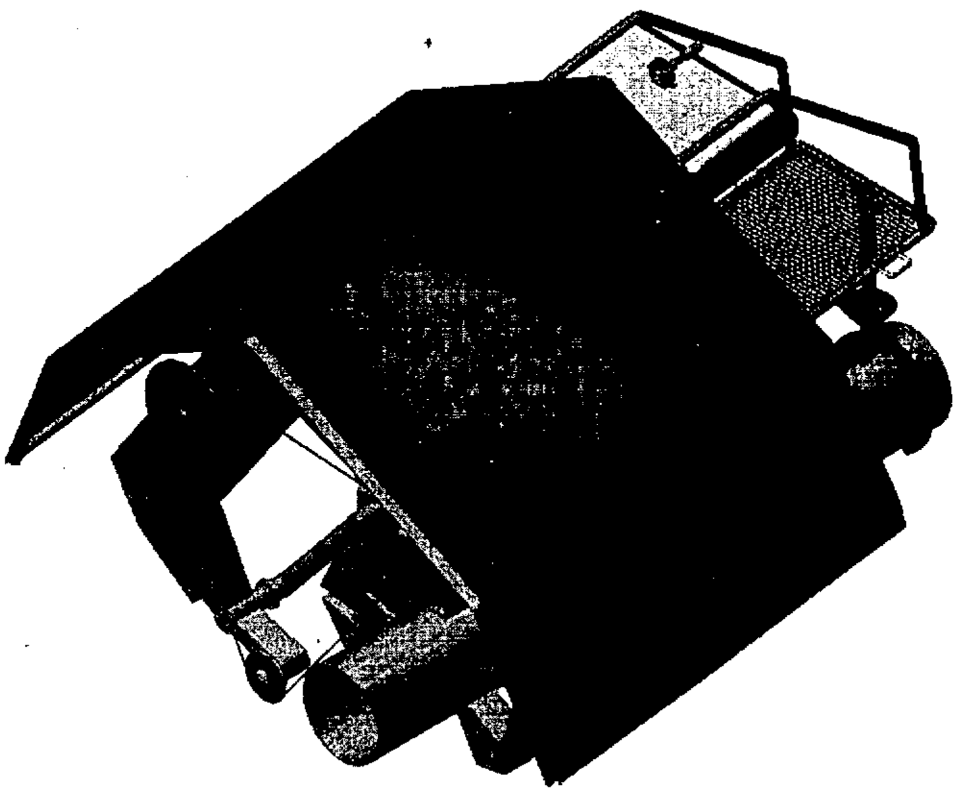
Discharge Containment Tent

The Discharge Containment Tent (DCT) by Oceaneering is an important tool designed for pipeline repair and associated release mitigation. The DCT can be used as both a first response to pipeline damage, to control the release until the pipe can be repaired, and as a capture device to place over the DWCM when making a cut. The DCT is a 'tent-like' structure, with a frame fabricated from two-inch diameter Aluminum pipe (6061-T6). The fabric covering of the DCT is a highly durable, Urethane-coated Nylon fabric. The DCT is designed so that during deployment and recovery, the fabric along the top and sides of the tent can be retracted against the rear wall.

This is done so that the DCT can be lowered through the water column without creating a lot of drag.

The back wall of the tent is fully enclosed, and the front has a partial curtain (not shown) that will come half way down the tent to increase the tent's containment volume, but still allow visibility for repair operations. The landing pins at the rear of the DCT are different lengths, which creates a slope that causes the oil to gather at the top, rear end of the tent, where it can be pumped into secondary containment.

The first piece of equipment deployed for the installation of the DCT will be the pipe-clamping frame. This frame has interchangeable parts allowing it to fit pipelines ranging from twelve to twenty inches in diameter. It also has compliant pads on the clamps to allow attachment to slightly irregular or damaged surfaces, and to protect the pipe's coating from further damage.



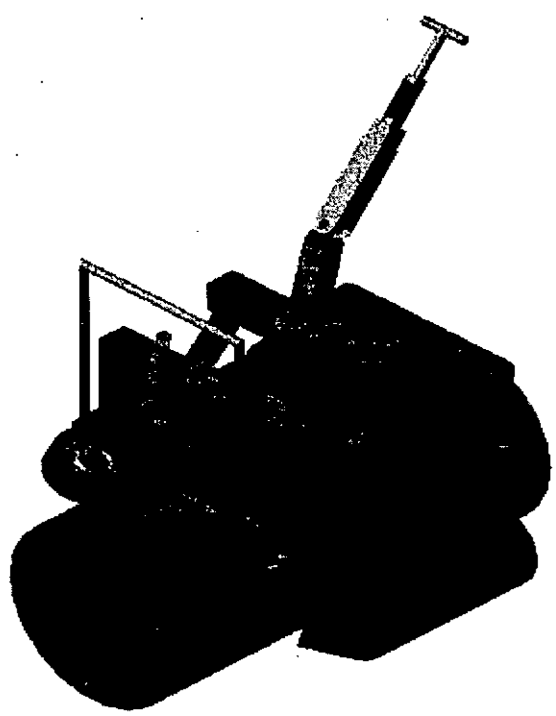
Discharge Containment Tent

When serving as a first response unit, the ROV will clamp the frame close to the leak. Another frame can later be added at a point on the pipe where the repair can be made. The tent can then be easily relocated to the second frame when repair equipment arrives at the scene. The DCT is sized to accommodate the DWCM in the open position.

After installing the pipe-clamping frame, the DCT will be lowered on a line and the ROV will help to guide the landing pins into the receptacles on the clamp, then lock the pins in place. When the ROV operator notices that the containment volume is nearly full, the ROV will use a hot stab to operate a centrifugal pump which will move the discharge into a two cubic meter (528 gallon) containment bladder. A second bladder will also be on site, so that when the first one fills, the pump hose can be connected to the empty bladder through use of an ROV compatible quick disconnect. The containment bladder that is full can then be brought to the surface, emptied and re-deployed.

Hydrate Detection Tool (HDT)

The Hydrate Detection Tool is a tool being designed by Oceaneering, in conjunction with Synetix and the Shell E&P Technology Company (SEPTCO), to help detect hydrate plugs and wax/paraffin build ups in pipelines. Synetix's Tracerco Gamma Ray Transmission Equipment has been used in the Gulf since 1990 to locate hydrate plugs. The system consists of a low strength radioactive source and detector. The system works by placing the source and detector on opposite sides of a pipe. By measuring the absorption of the source's Gamma waves through the material, the average density of the sample can be determined. Once a baseline has been established for a particular pipeline, variations in density can be measured. From this data, hydrate locations and even magnitude, can be determined. This information is transmitted to the ROV, and then to the surface via a twisted pair electrical connector.



Hydrate Detection Tool (HDT)

A critical requirement in preserving the precision of the measurements is ensuring that both the source and detector are in-line with the center of the pipe. If the source or detector were slightly higher or lower than center, the cross sectional area of the measurement is altered, and the measurement is inaccurate due to the change in the amount of the water, product and metal that is being measured. Until now, the only way to use the equipment was to place it on a U-shaped frame and place the frame at points along the pipe to detect the plug. This method left gaps between the inspection points, which could leave a hydrate build-up or blockage undetected.

Oceaneering is developing the Hydrate Detection Tool designed to roll along the top of the pipe, carrying the equipment on a stable platform, and allow for continuous real-time scanning of the pipe. The sled is pushed or pulled along the pipe by an ROV holding the T-handle. The shank of the handle has a U-joint that allows the ROV to not be in perfect line with the pipe, without affecting the motion of the tool sled.

The source and detector are mounted in housings that can be adjusted to fit pipelines ranging from 12 to 20 inches in diameter. The housings can be positioned so that they are in line with the centerline of the pipe. Even if the sled rolls slightly to one side of the pipe, the source and detector will still be in line with the center of the pipe, so the measurement will be accurate. A block of syntactic foam will be mounted to the top of the tool, which will provide a righting moment when the sled is no longer on the very top of the pipe.

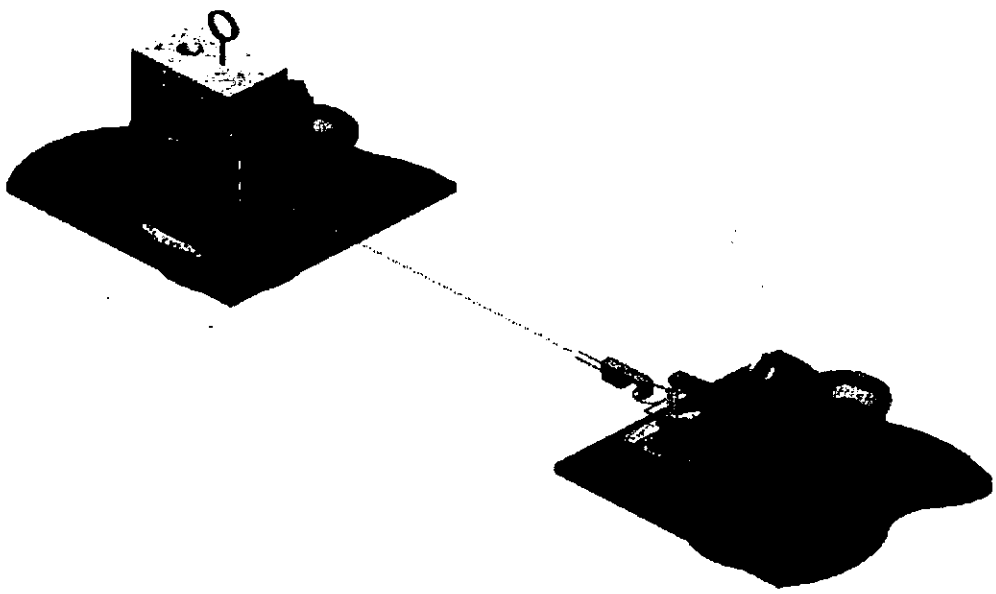
J-lay collars and anodes present an obstacle for the tool sled rolling along the pipe. Rather than try to lift the sled off the pipe, fly over the obstacle (which could be as often as every 160 feet), and then try to re-acquire the pipe, the sled has been designed to roll over these obstacles. The wheels are six inches in diameter, which will easily roll over the two inch high obstacles, and there is an angled piece of Ultra-High Molecular Weight Polyethylene (UHMWPE) mounted beneath the main plate, which will cause the sled to rise up over the obstacle. A piston and linkage assembly will allow the ROV operator to extend the source and receiver away from the pipeline while the sled clears the obstruction. Once clear of the obstacle, the source and receiver can be brought back into position, and detection can be resumed.

The Hydrate Detection Tool Sled can be launched and recovered in the grip of the manipulators of the ROV. A loop on the front of the sled, and the handle on the back, provide the ROV with holds, and a steel cable will be connected between the ROV and sled, in case of a "dead vehicle recovery", where the ROV may have lost hydraulic power.

Pre-Measurement Tool

The Pre-Measurement Tool (PMT) has been designed, fabricated and tested to physically measure distances, relative bearings and elevations between subsea structures. Use of the PMT for the DPRS will be to determine the spool piece length and configuration required between the upward-looking collet connector hubs.

The PMT assembly consists of two parts: the Measurement Tool (MT) and Measurement Pin (MP). Measurements are made with the tool assembly by inserting in sequence the MT and MP in their respective receptacles, which are located on the hubs that the jumper connects to. The ROV then connects the measurement cable from the MT to the MP. The MT measurement cable is stored on a small winch drum powered by a low speed, high torque hydraulic motor. This motor is used to develop tension in the cable once it is connected. Once the cable is properly



Pre-Measurement Tool

tensioned, a ratchet wheel and latch pawl assembly engages to maintain the desired cable tension without operating the hydraulic motor. The pawl can be released by independently operating a hydraulic cylinder. The hydraulic motor and the pawl release cylinder are operated via a manipulator-deployed, dual port hot stab using ROV hydraulics.

The deployed cable length is measured by passing the measurement cable over a calibrated measuring wheel. Three pressure rollers ensure the cable remains in contact with the measuring wheel at all times. Measuring wheel rotations are counted, and the length of cable paid out is obtained from the difference between the initial and final counter readings displayed on a mechanical counter. The wheel and counter are designed such that one complete rotation of the wheel pays out one foot of cable. The counter has a resolution of 0.1 ft.

Several protractor scales are used in conjunction with the PMT. Scales located on the MT and MP provide relative elevation (vertical) angle between the MT and MP. The elevation angle is indicated by the position of the tensioned cable with respect to each vertical protractor. The azimuth angle is indicated by alignment of an indicator on both the MT and MP with respect to previously supplied and installed horizontal protractors mounted on the base structure.

The PMT is designed to be a relative measurement device rather than an absolute measurement device. When the subsea measurements (both linear and angular) are repeated with identical receptacles on the surface, the relative positions of the two subsea connector hubs can be simulated to a high degree of accuracy.

Offshore Contractor and Service Company Arrangements

Another aspect of the DPRS is knowing what floating assets with various capabilities are available to perform various functions for a repair. Knowing which vessels are available and what their capabilities are will help minimize the amount of time required to choose a vessel and to begin working on the repair. To this end, arrangements will be made with deepwater contractors that have either heavy lift pipeline equipment or ROV/DSV vessels in the Gulf of Mexico on a routine basis. Technical as well as commercial arrangements will be made with a number of contractors so that a vessel of opportunity can be used at the time of the repair. This work involves investigating the contractors capabilities to make the required lifts, preplanning of all lift equipment mobilization activities, design of pipeline sled A-frames and their functionality, rigging required to utilize existing A&R systems and other technical concerns.

Spoolpiece Analysis/Design And Fabrication

Installation as well as operational loads will govern the configuration of the spoolpiece, which is being analyzed by the Shell E&P Technology Company (SEPTCO). Consideration for thermal expansion of the pipeline, as well as measurement and fabrication tolerances are some of the variables that must be addressed in the design of the jumper to prevent overstressing either the pipe or connector. At the end of the engineering, the process and all required analysis tools will be developed so that an engineer assigned to a repair project could perform the required engineering work to design the spoolpiece for either repair scenario (On-Bottom repair or Surface Lift).

A work package associated with the spoolpiece fabrication and testing will be contracted out. Jumper fabrication will take place at a dockside location using prefabricated jumper sections and fabrication/measurement jigs. Once the jumper metrology is completed, the measurements will be used to set up the fabrication stands to complete construction of the jumper. After inspecting the welds and hydrotesting the jumper, it will be shipped out to location, run to the bottom on a spreader bar, and latched to the male hubs on the PLEMs. At this point commissioning can begin. Fabrication of a jumper for SIT will also be a part of this work.

Hydrate Location and Remediation

Hydrates, which are crystalline compounds formed by combination of water and components in natural gas, can completely impede the flow in a pipeline. High pressures and low temperatures are conducive to hydrate formation, which may occur in both oil and gas pipelines. Virtually all of the existing hydrate plug detection methods are indirect, such as monitoring pressure drops, monitoring pigging returns, or a drop in water production rates. The scope of this work is to develop tooling that will allow hydrates to be located on the seabed and remediation techniques that can be used to melt hydrates in situ. The Shell E&P Technology Company (SEPTCO), Oceaneering, and Synetix are currently working on the hydrate location problem. The ROV Tooling section of this paper contains a description of the hydrate detection tool. SEPTCO is also developing hydrate disassociation curves for the various pipelines operated by Shell. The disassociation curves, based on product composition, assist in determining how best to remediate any hydrate after it has formed.

Tabletop Drill Exercise on a Periodic Basis

To ensure the DPRS is maintained and exercised, tabletop exercises will be performed on a routine basis. This operation will be performed in conjunction with the emergency response group already in place within Shell.

Marketing System to Other Operators

Once the system is designed, it is the intent of the owner companies to solicit support and participation from industry. Operators interested in the DPRS will have an opportunity to join a consortium and become part owners of the DPRS. Although defining the structure and legalities of the agreement are work-in-progress, it is predicted that participation will be on a diameter and line length formula similar to cooperatives that have been developed for diver depth repair tooling.

Conclusion

Of paramount importance for the DPRS is the use of proven technology. The proposed repair system incorporates many of the tools and connection systems that Shell has used on a number of new construction projects over the past few years. The sled concept for pipeline termination has been used by Shell and others to successfully land a pipeline on the seabed with an upward looking hub. The connectors purchased for the DPRS have a proven track record on several projects in the past. Metrology for the spoolpiece fabrication has been successfully accomplished on a number of projects using both acoustics and taut line systems to measure vertical and horizontal separation between connector hubs.

Minimization of the time required to effect a repair is the motivation for proceeding forward with the DPRS. By purchasing all the connectors and tooling necessary for a repair, the DPRS has eliminated the long lead-time required for the equipment, which is typically 30-40 weeks.

Flexibility and adaptability are important characteristic to whatever repair scenario presents itself. With an On-Bottom and Surface Lift solution, the system is configurable for numerous repair scenarios. As technology changes, the system can change with it, configuring itself with the latest proven technology.

There is a need to address repair of steel catenary risers, deepwater flowlines (both Pipe-in-Pipe and single pipe insulated), and higher pressure rated systems beyond the export line program currently being protected. Shell plans to build from the base established in creating the DPRS to address these needs in the future.

Forming a Deepwater Pipeline Repair Alliance

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presented at the
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organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

Forming a Deepwater Pipeline Repair Alliance

Introduction

As oil companies move to deeper waters of the Gulf of Mexico to construct and operate oil and gas production systems, a need has also been recognized to have developed and put in place a system to make diverless emergency repairs to the pipelines that transport such production. The incentive for the oil/gas producers is to minimize the expensive downtime of the production systems, since oil and gas loss to the environment, our other concern, can be minimized by quickly shutting in the production system.

A precedent for a deepwater pipeline repair alliance outlined in this report is co-ownership project formed in 1978 by a group of gas pipeline transmission companies to have pipeline connectors and repair clamps available to its co-owners to make diver-assisted repairs. Lessons learned from negotiating trans-oceanic telephone cable repair agreements are also reflected in this report, where applicable. But now, in 1999, the need is to make diverless emergency repairs in water depths beyond 1000 feet, a more difficult and expensive process, calling for an improved framework. The information contained herein makes use of experience gained from and lessons learned from the past, yet recognizes the significant differences from the past project.

The Subsea Committee (Committee 4300), of the Deepstar Phase IV Joint Industry Project awarded a contract to Shell E&P Technology Company to produce a document containing all information needed to start up a deepwater pipeline repair alliance for the Gulf of Mexico. Shell (as contractor), and Stress Engineering Services (as subcontractor), have prepared this report to completely fulfill the obligations of the contract. Shell has a keen interest in the success of this DeepStar project because Shell is presently (September 1999) developing a Deepwater Pipeline Repair System under its own funding, and they desire to transfer its ownership to a group of co-owners, of which Shell would be one. The Shell Deepwater Pipeline Repair System is summarized in Appendix A.

Scope of the Alliance

It is proposed that the Alliance be a co-ownership project that would be formed to own, upgrade and maintain one or more diverless deepwater pipeline repair systems and associated parts. The principal use of the repair system(s) will be to make emergency pipeline repairs (during construction or normal operations) of deepwater transmission pipelines, varying in size from 12 inches to 20 inches, principally in the Gulf of Mexico, but open to international participation. Included in the repair system are all hardware and equipment, both expendable and reusable, required to affect either an on-bottom repair or a surface lift and on-bottom tie-in repair

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of all pipelines dedicated to the co-ownership project in water depths of approximately 800 feet and greater. It is anticipated that the repair system will be deployed utilizing the rented services of a suitable lift vessel as well as of a Remotely Operated Vehicle (ROV) system. ROV tooling could be either rented with the ROV system or included in the repair system, depending on what will be best for the alliance.

The alliance covers co-ownership, maintenance, upgrading, warehousing and shipping the system to a co-owner user, but does not include actual offshore operations to make the repairs.

System Components

It is anticipated that the Shell system, which is being developed, might consist of the following kinds of diverless components:

- Leak Detector Tool
- Concrete Removal Tool
- FBE Removal Tool
- Pipe Cutter(s)
- Pollution Containment Tool
- Pipe End Grippers/Connectors and Sleds
- Jumper Measurement Tool
- Hydrate Plug Detector
- Pipe Uncovering Tool
- Pipe Lifting/Recovery Tool

A determination has not yet been made of what components will be owned, and which will be rented.

Likely Participants and Proposed Co-Ownership Calculation Methods

We have searched the most recent Minerals Management System records of owners of deepwater (1000 feet or greater) transmission pipelines in the size range between 12 and 20 inches, and find the following list of owners and miles of pipeline in 1000 ft or greater depths (See Table 1):

Table 1 shows that the Shell Companies and Exxon own 77 % of the deepwater pipelines in the 12-inch to 20-inch size range. If Shell or Exxon want to minimize their investment in an alliance, it would be useful to invite international participation, include smaller size (10-inch) pipe, or make the system cost-effective for use in shallower waters.

More detailed information is contained in Table 2. The reader should be cautioned that the data shown has not been confirmed with the respective owners, and should be treated as "preliminary".

Table 1.

DEEPWATER PIPELINES IN THE GOM

ACTIVE PIPELINES IN DEEP WATER - GOM

OPERATOR	NO. LINES,	PIPE SIZE	TOTAL MILES
Amerada Hess	1	12"	13.
BPX	2	12"	23.
British Borneo	1	12"	20.
Manta Ray	1	12"	8.
Shell Companies	7	12"	204
Texaco	2	12"	54.
Shell Companies	3	14"	96.
Conoco	1	14 to 10 ¾	12.
Shell Companies	1	14 to 16"	40.
Poseidon	1	16"	17
Shell Companies	2	16"	51.
Southern Natural Gas	1	16"	17.
Shell Companies	1	18"	40.
Southern Natural Gas	1	20"	50.

PLANNED PIPELINES IN DEEPWATER GOM

OPERATOR	NO. LINES,	PIPE SIZE	TOTAL MILES
British Borneo	2	12"	4.
Texaco	1	12"	12.
Amoco	1	14"	18.
Manta Ray	1	14"	41.
Dauphin Island	1	16"	18.
Shell Companies	1	18"	45.
Exxon Companies	2	18 to 20"	224.
Shell Companies	1	18 to 20"	45.

ACTIVE AND PLANNED PIPELINES: %OWNERSHIP

COMPANY	TOTAL LENGTH	% OF TOTAL
Shell Companies + Texaco	599	56
Exxon Companies	224	21
Southern Natural	67.	06
British Borneo	24.	02
Amoco +BPX	41.	04
Conoco	12.	01
Hess	13.	01
Manta Ray	49.	05
Poseidon	17.	02
Dauphin Island	18.	02
TOTALS	*1064*	*100*

Funding the Alliance

It is anticipated that each owner who joins the co-ownership project by dedicating their miles of pipeline (with various diameters) will be grouped by pipeline size into ownership groups. Each owner will then share equally (by miles of pipeline) in the size-independent components of the repair system (like handling frames), as well as share equally with other co-owners in their particular size group of size-dependent components (like connectors). Each user of the system will be responsible for the total cost of repair and replacement of system components following emergency usage. The cost of administering the repair project (administration, warehousing, routine maintenance, and upgrading) will be shared by the co-owners according to their percentage ownership in the size-independent as well as the size-dependent components.

Yet to be determined are the terms and conditions that would apply to non-co-owners wishing to use the systems and parties wishing to use the system for shallower waters. Equipment will be provided to co-owners for their dedicated pipelines on a first-come, first-serve basis.

Shell, with a keen interest in making co-ownership of a repair system a reality, is taking the responsibility of forming an interested group of participants in a co-ownership agreement (at no cost to DeepStar). Because of the potentially high percentage ownership based on the table above, Shell will be interested in exploring the possibility of international ownership.

Priorities for Use of the Repair System

Since the Repair System and its components can at least in part be used for construction or repair, it would seem prudent to give its use for emergency repairs prescience over use for construction operations. For repairs, the earliest callout will take precedence

Management of the Alliance (Co-Ownership) Project

The Alliance Co-Owners will likely want to select a company to manage the project for them. Tasks to be taken by the manager should include (in summary):

- Handling all logistics of meetings of representatives of the Co-Owners
- Conducting all routine business of the Co-Owners as delegated to the manager
- Assist the Co-owners in handling the addition or withdrawal of Co-Owners
- Consulting appropriate Co-Owner Committees for decisions on matters not delegated to the manager.
- Providing 24-hour emergency services to the Co-Owners in shipping the Repair system and Parts as instructed by the Co-Owner having an emergency.
- On a three to five year cycle, conduct on an appropriate out-of-water mock-up test of key repair system components (system integration test), and conduct monthly inspections of all components warehoused. The manager would fix any problems, taking into account those responsibilities delegated and those held by the co-owners.

- Insure that components repaired or replaced after use meets or exceeds the performance capability of the system as a whole.
- Purchase additional components for the Co-Owner's inventory as directed by the Co-Owner's Committees.
- Annually provide a determination of the state-of-art of diverless pipeline repair systems and compare/contrast with the systems owned by the Co-Owners. Recommend any changes to the Co-Owners for their decision.
- Annually assist the Co-Owners as requested in obtaining Co-Owners evaluation of the effectiveness of the Alliance and the manager.

We recommend that the management of the Co-Ownership project be outsourced to a third party supplier of services not connected to a co-owner, or a supplier of system components, or to a supplier of vessel or ROV services. This will make possible the future purchase of system components and vessel and ROV services other than those initially selected, and thus serve to control costs for future components and services. The anticipated large size of certain components might require dockside (temperature- and humidity-controlled) warehousing of at least the larger components of the repair system.

It is anticipated that technology in this area of deepwater pipeline repair systems will rapidly change, and hence, the manager should be charged with providing to the co-owners an annual presentation to the co-owners of the state-of-the-art of potential upgrades to the system along with the potential cost benefit.

Selection of Repair Systems for Inclusion in the Alliance

Shell is interested in forming the alliance around the Deepwater Pipeline Repair System it is presently developing. They will likely offer the system to a co-ownership group by forming a Limited Liability Company to own and sell the system to the co-ownership group. It is anticipated that the group will want to change, add or delete systems and components to its inventory as time progresses and technology advances.

Process Steps for Forming an Alliance

The summarized process steps for forming an alliance would consist of:

1. Developing a deepwater repair system to form an alliance around. (Shell/Tejas/Equilon)
2. Developing a draft business framework for forming an alliance. (DeepStar CTR 4306)
3. Determining potential deepwater pipeline owners who might be interested in forming an alliance. Shell)
4. Communicating with the potential owners, both individually and collectively, providing a draft proposal for forming an alliance. (Shell)
5. When sufficient collective interest is perceived, calling a meeting of prospective co-owners to present and evaluate an alliance proposal. Collect feedback and revise the proposal as called for. (Shell)
6. Communicating changes to prospective owners and collect feedback. (Shell)
7. When sufficient collective interest is perceived, calling an initial organizational meeting of the potential co-owners. (Shell)

8. Setting a deadline for co-owner signup. (Co-Owners)
9. Engaging a repair alliance administrator. (Co-Owners)
10. Setting up operating committees, setting a budget, and beginning operations. (Co-Owners and Manager)

Issues/Barriers for the Proposed Alliance

- Use of the repair system by non-alliance members
- Use of the system by alliance and non-alliance members for shallow water projects
- Maintaining a not-for-profit business vs. accepting penalty payments from non-alliance members to buy into the alliance once an emergency occurs.
- Admitting international alliance members (Brazil, North Sea, etc.), and dealing with the consequent problem of system availability during multiple emergencies
- Assuring the availability of the system for alliance members who are constructing a previously dedicated new line.
- Handling pipeline design incompatibility problems of alliance members vs. the design scope Shell has chosen. What about other pipeline sizes and pressures.
- Keeping the system and parts upgraded to reflect use of the latest technology and avoid obsolescence. This includes keeping the inventory of parts turned over.
- Voting rights: Since two companies might own most of the pipelines dedicated to the co-ownership project, how should voting be handled? One vote per company does not appear to be suitable.

Conclusions

This paper has discussed the key issues associated with forming a deepwater pipeline repair alliance. There are no major barriers that cannot be dealt with. Included in the project report, but not contained herein are draft legal documents appropriate for forming an alliance. The final form of the alliance will depend on future business negotiations between Shell and other prospective participants.

Appendix A

SHELL DEEPWATER PIPELINE REPAIR SYSTEM

(9/13/99)

Background

Shell Deepwater Producing Inc. (SDPI), Equilon Enterprises and Tejas Offshore have agreed to develop a deepwater pipeline repair system to be used on oil and gas export lines in water depths where diver intervention is not possible. The companies have collectively undertaken a program to develop a sled and jumper repair system for the following line sizes: 12", 14", 16", 18" and 20."

System Overview

The repair system will be designed to accommodate either surface lift repair scenario or the on-bottom repair scenario. In the surface lift repair scenario, the system will be designed so that each end of the damaged line can be brought to the surface where a sled can be welded to the line. Then the assembly is lowered to the seabed. Measurement will be made between two upward looking hubs on the sled using acoustic or taut line techniques. A vertical U-spool piece will be fabricated/installed to connect the two sections of line. Hydraulically actuated collect connectors, incorporating metal seals, will be utilized to make the connection between the two pipeline sleds. The U-shaped jumper provides a high degree of flexibility in making up the required connections and in accommodating subsequent operating loads. In cases where hydrates are not a problem, an alternate version of the repair can be made completely on-bottom, without lifting the pipe ends to the surface. For small leaks, diverless on-bottom repair clamps will be available.

Due to the tremendous economic impact that a deepwater producing property would sustain if a pipeline leak occurred and shut-in would be necessary, the repair project involves development of all preplanning tools necessary to engineer a repair effort. The elements include: (1) pre-arrangements with key offshore contractors and service companies, (2) development of all required tooling for on-bottom and on the surface, (3) manufacture and testing of pipeline end termination sleds and (4) development of hydrate remediation equipment that would be used to remediate hydrates.

Relevant Shell Experience

The repair system incorporates many of the tools and connection systems that Shell has used on recent deepwater projects, both planned and unplanned. The sled concept for pipeline termination had been used by Shell and others to successfully land a pipeline on the seabed with an upward looking hub. All major deepwater contractors working in the Gulf of Mexico have a means to retrieve a pipeline to the surface, land it in a frame, weld a sled to the pipe and lower the sled to the seabed. Shell will make pre-arrangements with appropriate deepwater contractors so that an emergency event can be responded to quickly. The use of existing abandonment and retrieval (A&R) winches will be incorporated into the plan.

To gain access to the line to prepare it for lifting, on-bottom-lifting frames have been designed to raise the pipe from the mud so that a proper cut can be made. Frames for such an activity have been fabricated for the Ursa project (which involves both 18" and 20" pipe).

The pipe lifting equipment will incorporate the use of a metal slip connector with pressure sealing elastomeric seals to be used as an "overshoot" tool on the cut pipe ends. The end of the lift connector would have a suitably sized hook to connect a lift line from the surface. This technique was successfully used on the Mensa 12" project to lift a line to the surface in 4800 feet

Metrology for the spool piece fabrication has been successfully accomplished on a number of projects using both acoustic and taut line systems to measure vertical and horizontal separation between connector hubs. Accuracy of both systems has been very good.

The connection type that has been chosen, based on Shell experience, is a metal-sealed collect connector system for the surface lift repair scenario. This system provides the required angular misalignment to make up connectors, and can be designed to resist all anticipated operating loads. The connection type chosen for the on-bottom repair is a "grip and seal" connector. The grip and seal technology is similar to the pipe recovery tools utilized by Shell on past construction projects.

Hydrate Location and Remediation

The scope of this work is to develop tooling that will allow hydrates to be located on the seabed and techniques to remediate hydrates in situ. Shell experts will evaluate hydrate location issues. Tooling will be designed, once a suitable approach is identified. Remediation techniques for the surface lift scenario will be coordinated by Shell, working with companies that supply coil tubing services. Interfaces will be identified so that the tubing can be inserted into the line through the pipe lift connector.

ROV Tooling

A work package will be issued to ROV Company to develop tooling to perform the following functions:

- remove concrete
- remove fusion bonded epoxy
- inspect the pipe (NDE) in the area where the end connector will grip the line
- cut the pipe squarely so that end connectors can be placed on the line
- position an end connector on the line
- identify hydrate plug locations
- measure the horizontal and vertical separation between pipeline sled hubs.
- connect the U-shaped spool piece, and
- other related functions

Offshore Contractor and Service Company Arrangements

Pre-arrangements will be made with the deepwater contractors that have heavy lift pipeline equipment in the Gulf of Mexico on a routine basis. Technical as well as commercial arrangements will be made so that a vessel of opportunity can be used at the time of the repair. This work will involve investigating the contractor's capabilities to make the required lifts, preplanning of all lift equipment mobilization activities, design of pipeline sled A-frames and the functionality and rigging required to utilize existing A&R systems

Pre-arrangements will also be made with service companies supplying ROV vessels, navigational positioning systems, acoustic measurement systems and other required tooling.

Sled and Jumper Systems

Shell will solicit bids to design, fabricate, factory test and system integrate test (S. I. T.) the sled and jumper systems. The contractor selected for this work will be required to interface his equipment with the service provider's tooling and installation equipment. All required ROV tooling would be interfaced at the SIT.

Spoolpiece Analysis

Shell will contract out a work package associated with the spoolpiece (jumper) analysis. Installation as well as operational loads will govern the configuration of the spoolpiece. The intent of this work package is to develop the process and all required analysis tools so that an engineer assigned to a repair project could perform the required engineering work to design the spoolpiece repair.

Emergency Response Procedures

This work would encompass development of all required engineering and offshore procedures associated with a repair effort. A process would be designed to manage a repair effort along with development of all engineering tools necessary to analyze lifting loads. The document will contain information concerning: (1) pre-arrangement for heavy-lift pipeline vessels and service contractors, (2) ROV tooling, (3) connection design and installation procedures, (4) lift frames, (5) end connector details, (6) hydrate location and remediation methods, (7) as-built alignment sheets for all deepwater pipelines in the SDPI/Equilon/Tejas systems, and (8) stock materials necessary to affect a repair.

Once the system is designed, it would be the intent of Shell to solicit support and participation of the system from industry. When schedule permits, third party companies interested in joining the effort will have an opportunity to comment on the design and implementation plan. Financial participation would be on a diameter and line length formula similar to cooperatives that have been developed for diver depth repair tooling.

It would be Shell's intent to solicit a party to manage the pool of equipment co-owned by the participants. Arrangements will be made to have warehousing space made available to store the equipment indoors, service the equipment as required and ship it to a shore base facility when needed.

Closure

There is a need to address repair of steel catenary risers, deepwater flowlines (both Pipe-in-Pipe and single pipe insulated), and higher pressure rated systems beyond the export line program currently proposed. This work will be addressed as initial work proceeds.

The Dulcimer and Pluto Pipeline Repair Projects

Norb Gorman and **Mike Ellis**
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presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

REPAIR OF MARINER ENERGY'S DEEPWATER HIGH PRESSURE FLOWLINES

by Mike Ellis and Norb Gorman, Oceaneering International Inc.

INTRODUCTION

A spool-piece pipeline repair performed last October in the Gulf of Mexico established what is believed to be a new water depth record of 2,150 feet for this type of subsea intervention. The repair was made to an 8-in. gas pipeline connecting a well in Mariner Energy's Pluto field, Mississippi Canyon 541, to a platform 29 miles distant. The repair was performed by Oceaneering International, Inc., and Global Industries, the pipeline installation contractor, working with Mariner's in-house engineering and operations staff.

The Pluto job was the second deepwater pipeline repair in the Gulf of Mexico performed by Oceaneering during 1999. The first was made to dual 4.5-in. gas pipelines connecting a subsea well on the Dulcimer field, Garden Banks 367, to a platform in Garden Banks 236. The water depth for this repair was 996 ft. Mariner Energy is also the operator of the Dulcimer field.

The two repairs were performed in broadly similar fashion. Both utilized the following equipment and methods:

- On-bottom removal of the damaged pipeline section
- On-bottom insertion of a straight, in-line flanged spool piece to reconnect the severed pipeline ends
- A combination of atmospheric diving system (ADS) and ROV for subsea intervention
- The 243-ft MSV *Ocean Intervention* for surface support.

The repairs differed in two principal respects. Dulcimer was performed entirely on-bottom without raising the pipeline to the surface and utilized proprietary Oceaneering sleeve-type mechanical connectors called Smart Flange Plus® to join the spool pieces to the pipelines. For the Pluto repair, standard bolted flanges were used to join the spool piece to the pipeline, and the pipeline ends were raised to the surface by a pipelay barge for welding, then lowered back to the seabed for insertion of the spool piece.

DULCIMER PIPELINE REPAIR

Damage to the duel 4.5-in. Dulcimer pipelines was discovered when pressuring up the flowlines to commission the subsea system from the host platform. Based on residual pressure in the flowline after it bled down, the water depth of the leak was quickly identified. A small ROV operated dredge was immediately dispatched to clear the soil from around the damaged areas revealing oval-shaped holes 4 inches long by 2 inches wide in each flowline. The holes were later found to be the result of a towed pipeline bundle being drug across the flowlines.

A variety of flowline options were considered and an on-bottom repair using the MSV *Ocean Intervention* with a combination of ADS and ROV for subsea intervention was chosen. Engineering, manufacture, and testing then ran concurrently to meet the fast-track schedule for vessel mobilization.

Once on site the ROV inspected and photographed the damage and the flowlines were then raised out of the mud and the WACHS guillotine saw made the first pipeline cut. The flowlines were lifted onto pipe stands and aligned. Accurate alignment was confirmed and the pipe was measured and marked prior to cutting out the damaged sections. The pipe ends were prepped with the milling tool and 16 inches of the Fiber Bonded Epoxy (FBE) coating were removed from the pipe ends with the coating removal tool.

One Smart Flange Plus® Connector was slipped onto the south end of each flowline end on bottom. The spool pieces were built with weldneck flanges on each end as well as a Smart Flange Plus® connector pre-rigged on the north end, then lowered into position, and slipped over the north ends of the flowlines. Then the weldneck flanges on the south end of the spool pieces were bolted to the connectors on the flowlines. The bolts on both ends of the spool pieces were tensioned by hydraulic impact and hydraulic torque wrenches, setting, locking, and sealing the connectors on the parent pipelines permanently.

The repaired flowlines were replaced on the seabed prior to pigging and hydro testing and the installation hardware was recovered to the surface. The repaired lines were hydro-tested to 7,800 psi for eight hours. The repair spools were then subjected to a maximum gas test at maximum SITP of 6,200 psi prior to flowing the well.

PLUTO PIPELINE REPAIR

The leak in the Pluto pipeline was discovered during hydro testing prior to the start of production. No hydrocarbons were released into the environment. The leaking section of pipe was soon located by an ROV.

This repair was performed in three phases. The first and shortest phase, requiring two days, involved removal of the damaged section of the pipeline. This was performed by the *Ocean Intervention* with the WASP ADS and ROV for the subsea work. The seabed sediments were excavated around the 10-ft section of pipe to be removed. A WACHS guillotine hydraulic saw was positioned on the pipeline to make the cuts, and the damaged piece was pulled to the surface for analysis. Great care was taken during the initial cut to guard against recoil of the pipeline from residual strain imparted during installation.

The second phase was performed by the *Chickasaw*. The severed pipeline ends were pulled to the surface and a 100-ft length of curved pipe was cut from each end. To replace the curved pipe, a 100-ft length of new, straight pipe was then welded onto each pipeline end. Flanges were welded on and nut retainer rings were installed on each flange. The pipeline ends were then laid back down on the seabed taking care to align them with each other as precisely as possible.

The *Ocean Intervention* returned to perform the third repair phase, which was accomplished in 6-1/2 days. This phase began with placement of the four alignment frames over the pipeline, two on each side of the gap to be filled by the spool piece. The frames are large but lightweight structures resembling sawhorses with mudmats on each end designed to lift and hold the pipe some 8 feet above the seabed. They are equipped with simple winches, lift lines and clamps that grab and hold the pipe for lifting. The elevation is necessary to allow proper alignment of the pipeline ends for spool piece installation and to give the ROV and WASP the required access. The two frames on each side were placed at 25 ft and 85 ft from the gap. Deployment of the frames was accomplished using the vessel crane and deck winches without any need for heave compensation.

With the pipe elevated, the pulling heads used to lower the pipe ends from the *Chickasaw* were removed and the taut-wire metrology tools were placed on the pipeline just behind the two flanges. The pipe ends were then leveled to horizontal and roughly aligned. The taut-wire from one tool was carried across the gap to the other tool and tightened. Levels on the two tools and the location of the taut-wire against protractors mounted on the tops of the tools were read to determine alignment. Judicious lifting and maneuvering of the pipeline ends enabled the ROV / WASP team to bring the pipe ends into alignment. Redundant distance readings were then made by two WASP pilots and the ROV crew. These measurements were used to fabricate the spoolpiece aboard the *Ocean Intervention.*

The spool piece with flanges welded to each end was placed in its installation frame aboard the MSV, and the frame was then lowered to the seabed and positioned in the gap between the pipeline ends. The WASP performed final alignment of the pipeline ends with the spool piece and then began to insert bolts and make up the flanges. Final bolt tightening was accomplished with a hydraulic impact wrench and Hy-Troq wrench. Hydraulic power was supplied by the ROV, which worked in coordination with the WASP throughout the third phase repair. With the spool piece securely bolted in place, the pipeline was lowered to the seabed. The alignment and installation frames were then recovered to the deck of the *Ocean Intervention.* Mariner then hydro-tested the repaired pipeline in preparation for production startup.

Throughout the 6-1/2-day spool-piece installation, the *Ocean Intervention* held station within a few feet of the designated target position, independent of vessel heading. The Millennium ROV performed flawlessly through long hours of continuous operation on-bottom. The WASP systems also logged long hours at depth and experienced no breakdowns that interfered with performance of the work.

CONCLUSIONS

As with most complex subsea intervention jobs, the Pluto and Dulcimer repairs experienced minor difficulties that required adjustments to planned procedures. In some instances, these adjustments could be made without difficulty by the ROV. In others, however, the involvement of the WASP, with its direct human presence, all-around visibility, delicate touch and dexterity, greatly facilitated the required adjustment or adaptation.

The WASP and ROV are a powerful subsea intervention spread for performing complex workscopes in water depths to 2,300 feet. The combined capabilities of the two systems reduce the offshore time required to complete a job, permitting savings on vessel costs. Below 2,300 ft, the basic repair procedures can be adapted for the ROV alone, with only small modifications to the tooling and equipment.

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REPAIR OF MARINER ENERGY'S DEEPWATER HIGH PRESSURE FLOWLINES

Norb Gorman
&
Mike Ellis

Oceaneering International, Inc.

OCEANEERING

DULCIMER AND PLUTO REPAIR PROJECTS

DULCIMER REPAIR
- GB-323
- 1,000 FSW
- TWO 4" FLOWLINES
- ON BOTTOM REPAIR
- STRAIGHT IN-LINE SPOOL-PIECES
- SMART FLANGE PLUS CONNECTORS

PLUTO REPAIR
- MC-541
- 2,150 FSW
- ONE 8" FLOWLINE
- 3 PHASE REPAIR
- STRAIGHT IN-LINE SPOOL-PIECE
- STANDARD BOLTED FLANGES

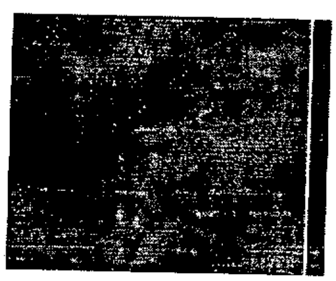
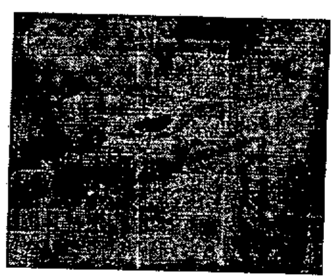
OCEANEERING

MARINER ENERGY, INC. - DULCIMER FLOWLINE REPAIR - GARDEN BANKS 323 - MARCH 1999

- Number of Flowlines: Two
- Pipe: 4.5" by .438 wall X-52 SMLS FBE
- MAOP: 6,200 psi
- Water Depth: 1000 fsw
- Vessel: MSV OCEAN INTERVENTION I
- Systems: * WASP Atmospheric Diving System
  * MILLENNIUM 150 HP Heavy Work ROV
- Connectors: * 4" NPS Class 2500 RTJ Smart Flange Plus
- Equipment: * Pipe Stands
  * WACHS Guillotine Saw
  * De-burring Tool
  * Pipe Cleaning Tool
  * Spool-Piece Deployment A-Frame
  * Hydraulic Impact Wrench & HYTORC

OCEANEERING

DULCIMER FLOWLINES REPAIR PROJECT DAMAGE TO FLOWLINES AND CONTROL UMBILICAL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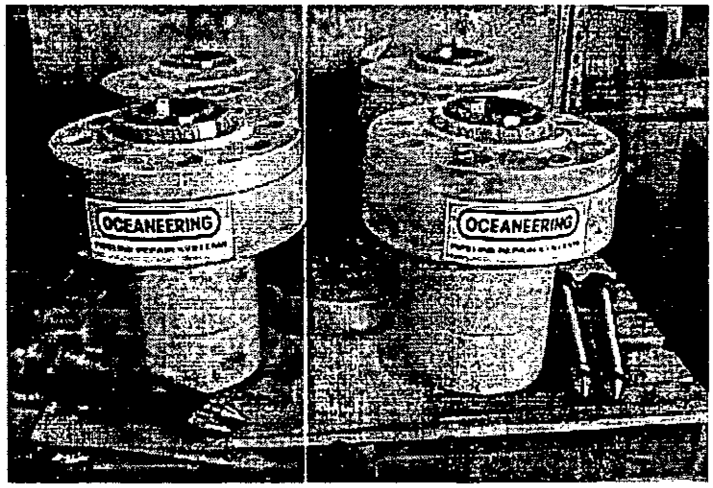
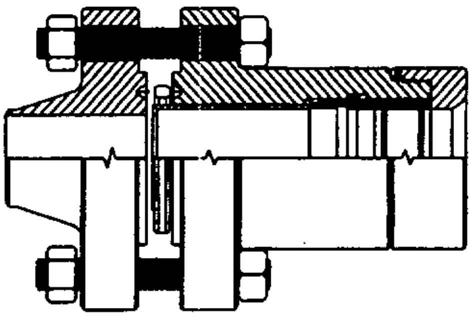
DULCIMER FLOWLINE REPAIR PROJECT
SMART FLANGE PLUS CONNECTORS



OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT
SMART FLANGE PLUS CONNECTOR MADE UP TO FLANGE

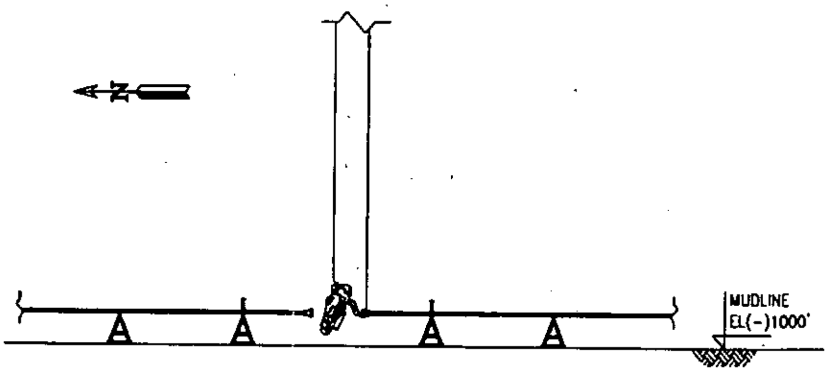


GENERAL ASSEMBLY
4" SMART FLANGE PLUS
CLASS 2500 ANSI W/ L.O.C.

OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT

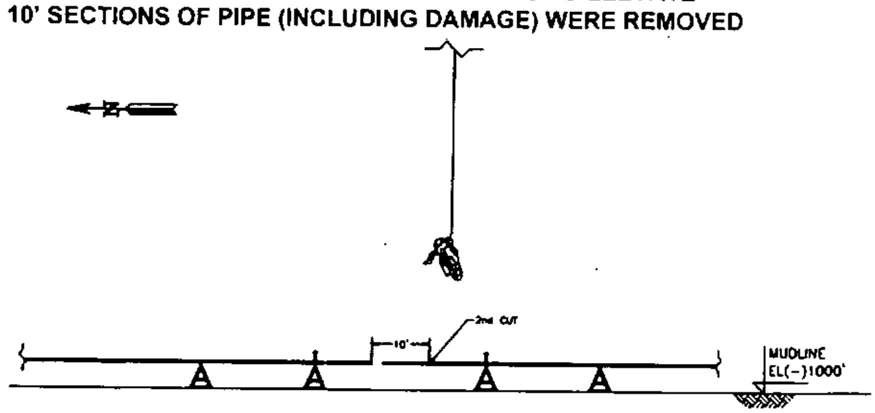
* PIPE ENDS WERE MACHINED SQUARE
* FBE COATING WAS REMOVED
* SMART FLANGS PLUS CONNECTORS WERE INSTALLED



OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT

* SPOOL-PIECES WERE PRE-FABRICATED (10' LONG)
* FLOWLINES WERE CUT TO RELIEVE STRESSES
* FLOWLINES WERE PLACED ON PIPE STANDS TO ELEVATE
* 10' SECTIONS OF PIPE (INCLUDING DAMAGE) WERE REMOVED



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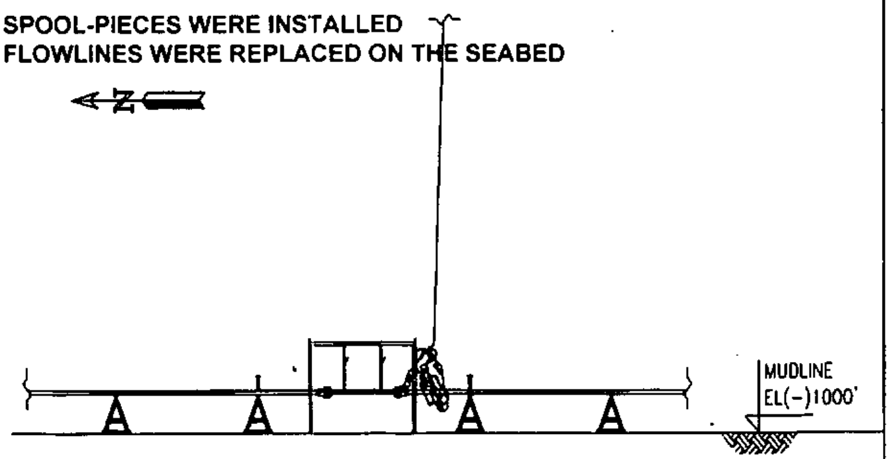
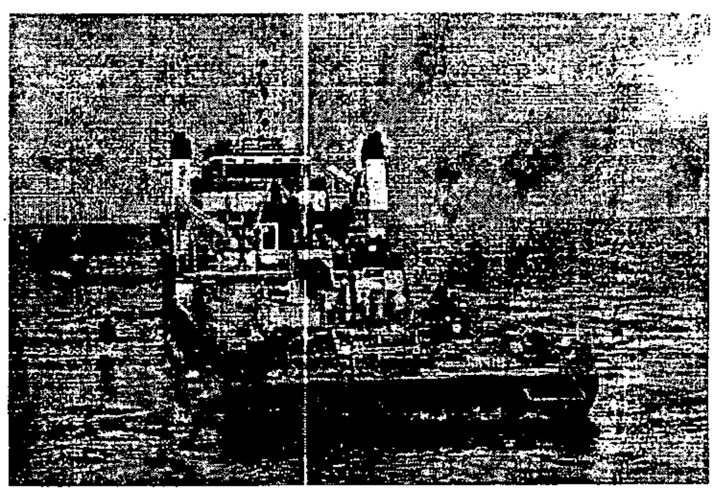
DULCIMER FLOWLINE REPAIR PROJECT

* SPOOL-PIECES WERE INSTALLED
* FLOWLINES WERE REPLACED ON THE SEABED



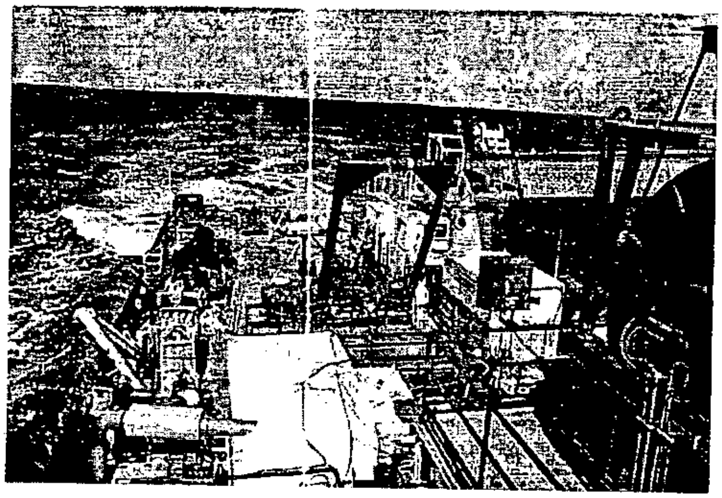
OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT
REPAIR VESSEL - MSV OCEAN INTERVENTION I



OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT
REPAIR SPREAD ENROUTE TO GB-323



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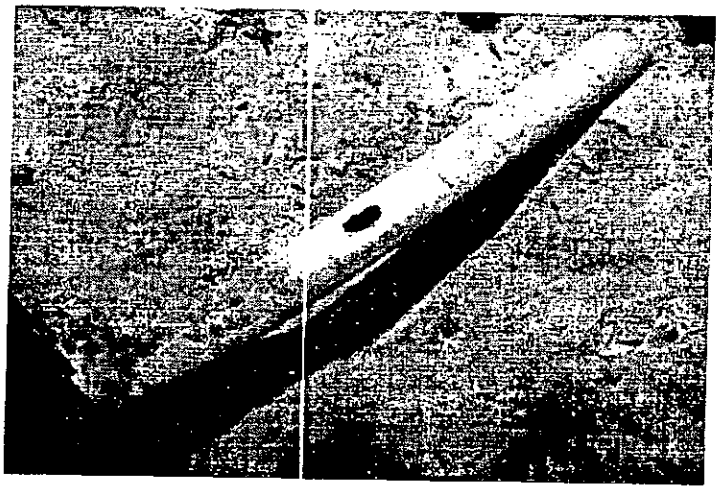
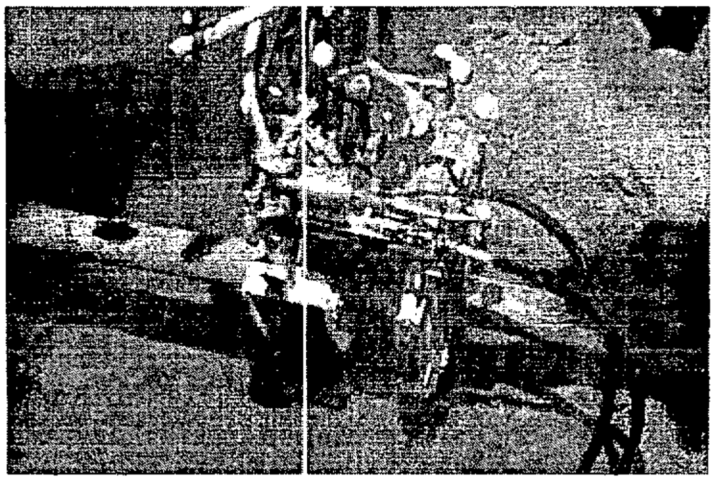
DULCIMER FLOWLINE REPAIR PROJECT
FLOWLINES WERE EXCAVATED FOR CUTTING



OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT
FLOWLINES WERE CUT WITH WACHS GUILLOTINE SAW



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DULCIMER FLOWLINES REPAIR PROJECT
SUBSEA PIPE CUTTING - WACHS GUILLOTINE SAW

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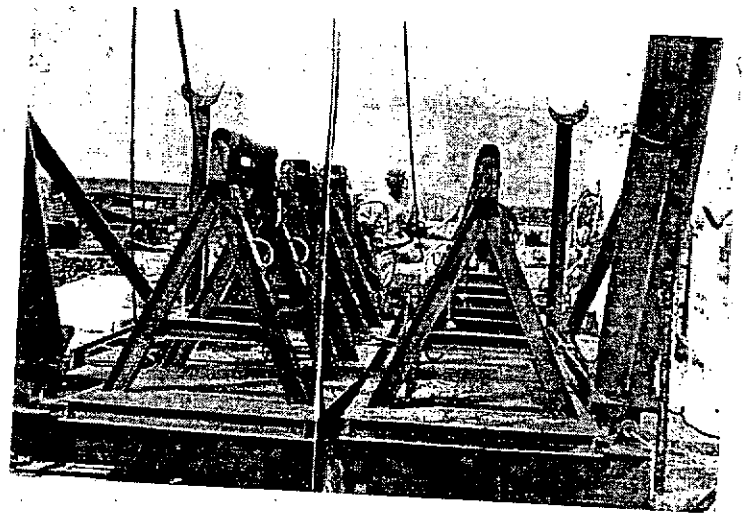
DULCIMER FLOWLINE REPAIR PROJECT
PIPE STANDS WERE USED TO ELEVATE THE FLOWLINES



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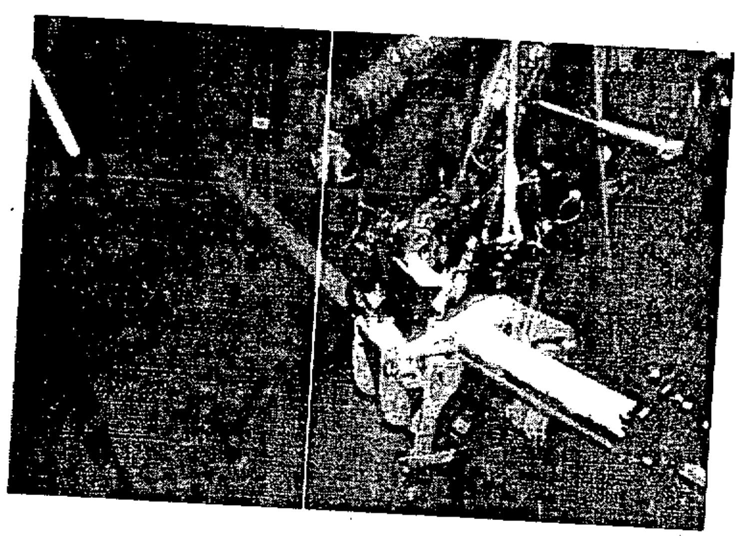
DULCIMER FLOWLINE REPAIR PROJECT
DAMAGED (10') SECTIONS WERE REMOVED



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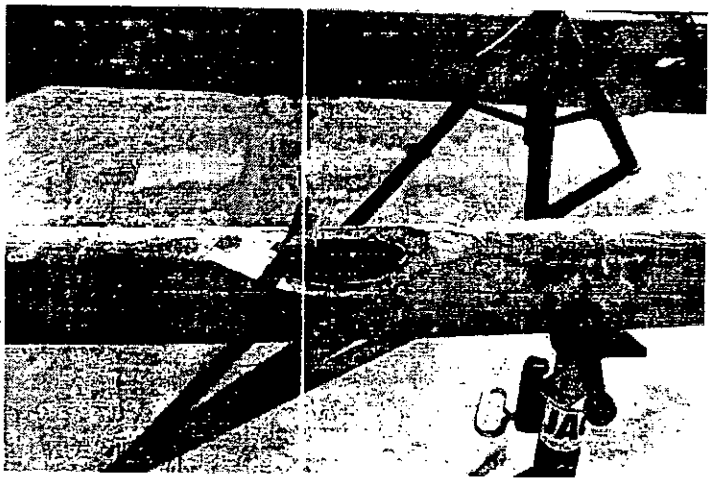
DULCIMER FLOWLINE REPAIR PROJECT
DAMAGE ON FLOWLINE "A"



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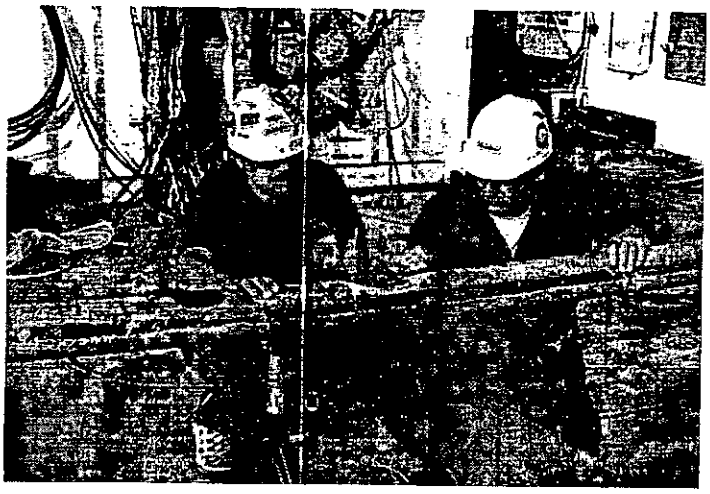
DULCIMER FLOWLINE REPAIR PROJECT
PM AND PE INSPECT FLOWLINE DAMAGE



OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT
PIPE ENDS WERE MACHINED SQUARE

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DULCIMER FLOWLINE REPAIR PROJECT
PIPE ENDS WERE MACHINED SQUARE

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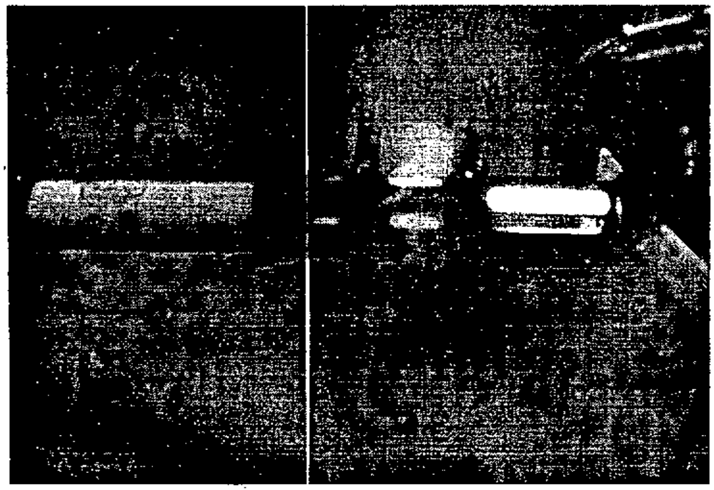
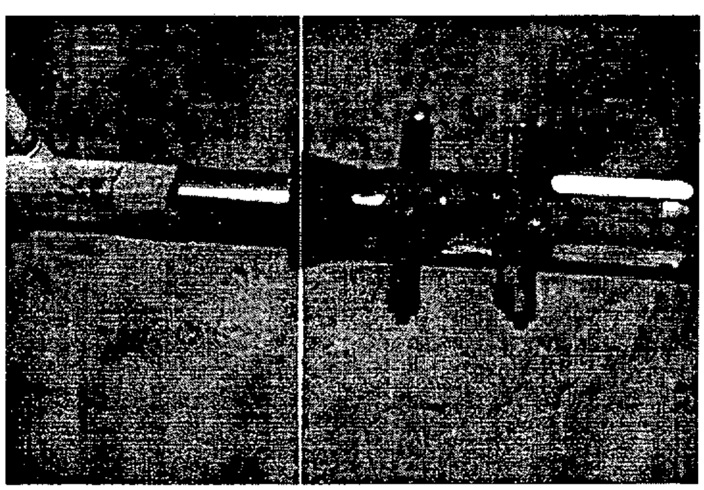
DULCIMER FLOWLINE REPAIR PROJECT
PIPE (FBE) COATING WAS REMOVED



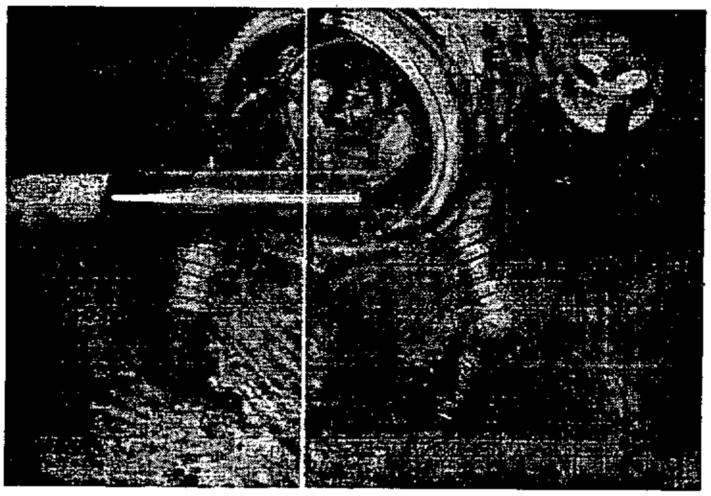
OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT
PIPE WAS CLEANED TO BARE METAL



OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT
PIPE ENDS WERE CLEANED TO BARE METAL



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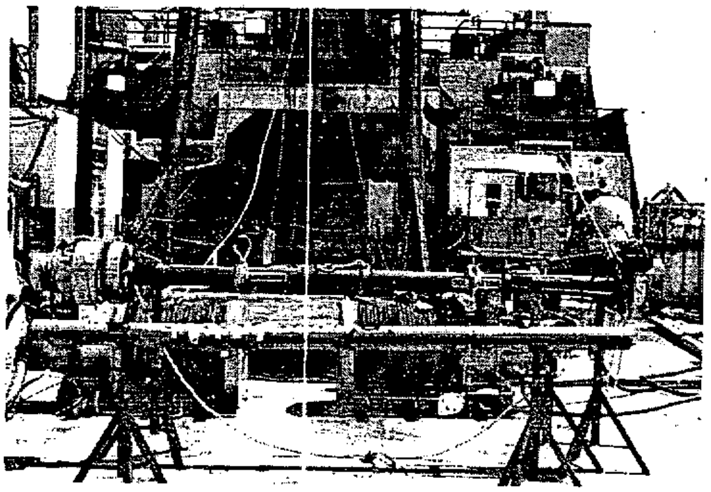
DULCIMER FLOWLINE REPAIR PROJECT
SPOOL PIECE WITH SMART FLANGE PLUS CONNECTOR



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DULCIMER FLOWLINE REPAIR PROJECT
SPOOL-PIECE WITH ONE CONNECTOR INSTALLED

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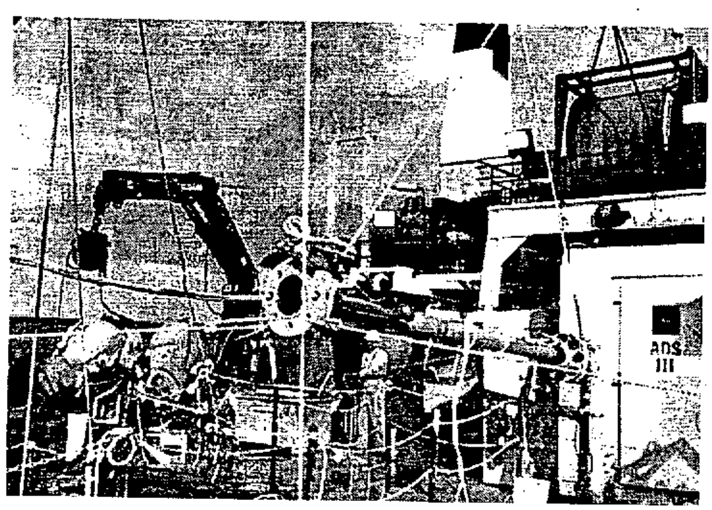
DULCIMER FLOWLINE REPAIR PROJECT
SECOND SPOOL-PIECE RIGGED FOR DEPLOYMENT



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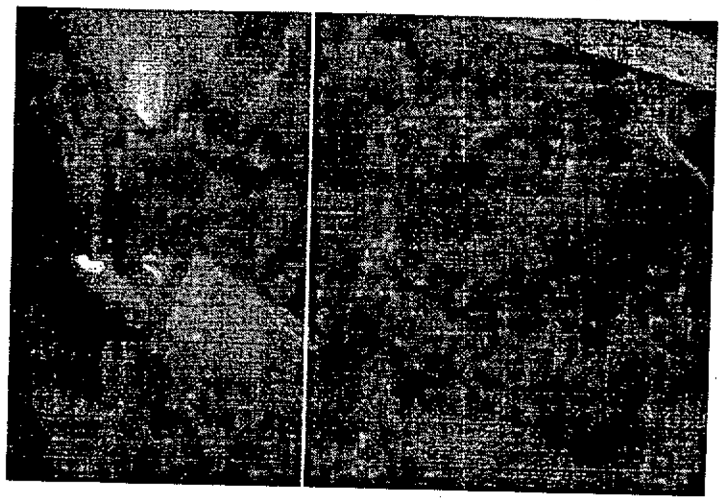
DULCIMER FLOWLINE REPAIR PROJECT

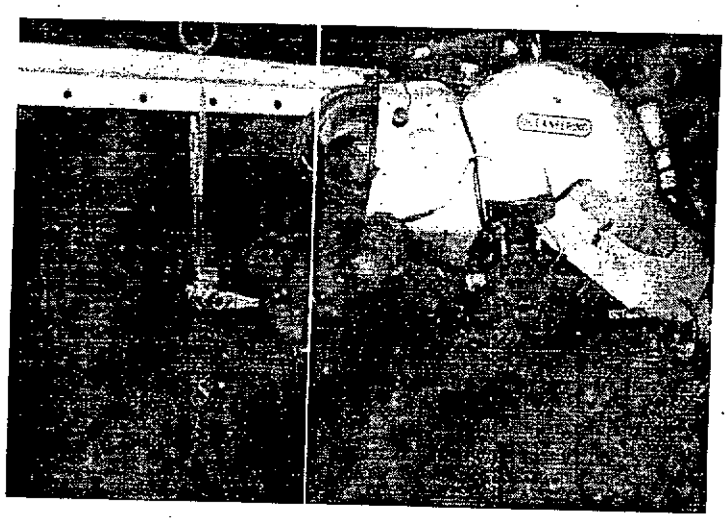
SPOOL PIECE AND CONNECTOR DEPLOYED ON A-FRAME



OCEANEERING

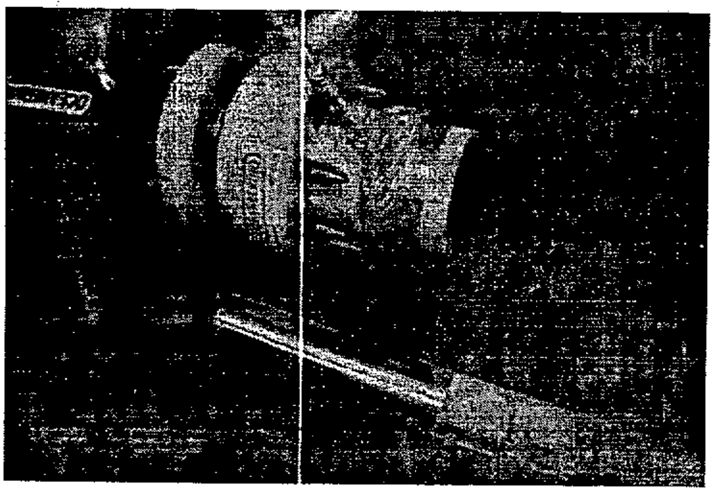
DULCIMER FLOWLINE REPAIR PROJECT

WASP ADJUSTS SPOOL-PIECE WITH CHAIN FALL



OCEANEERING

DULCIMER FLOWLINE REPAIR PROJECT
SPOOL PIECE WITH CONNECTOR STABBING ONTO FLOWLINE



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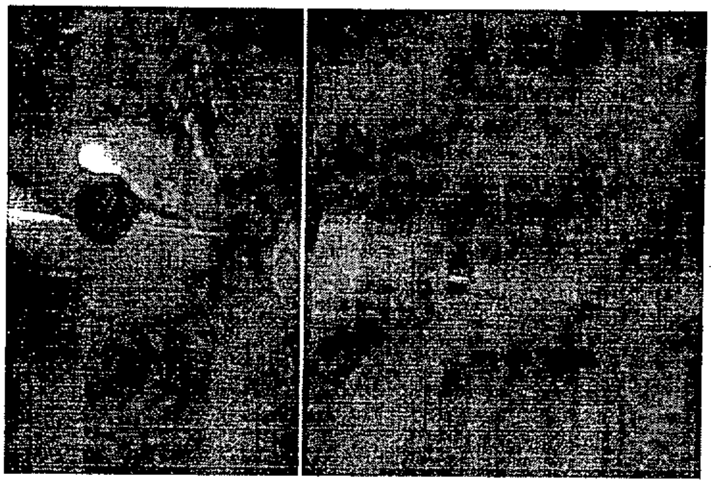
DULCIMER FLOWLINE REPAIR PROJECT
BOLTS MADE UP WITH HYDRAULIC IMPACT WRENCH



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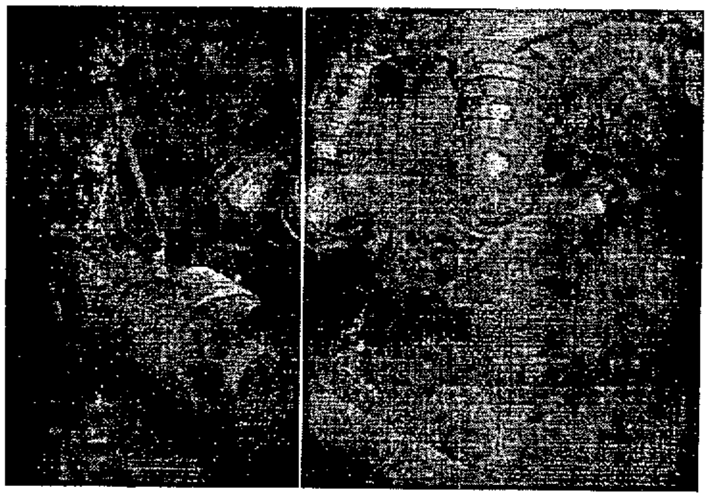
DULCIMER FLOWLINE REPAIR PROJECT
BOLTS TENSIONED WITH HYTORC WRENCH



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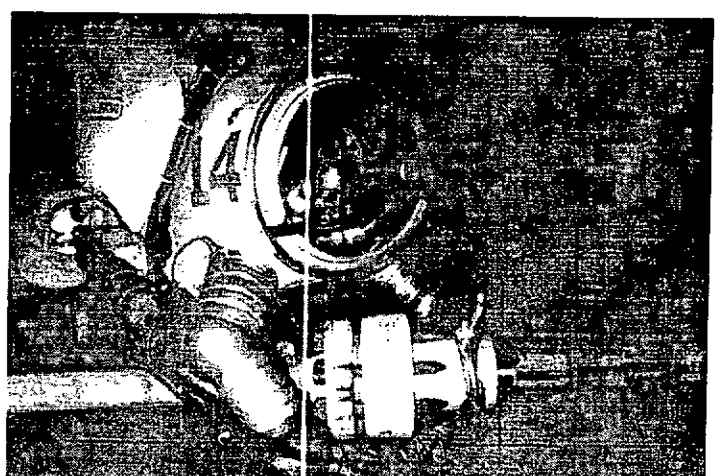
DULCIMER FLOWLINE REPAIR PROJECT
CONNECTORS WERE CHECKED FOR PROPER INSTALLATION



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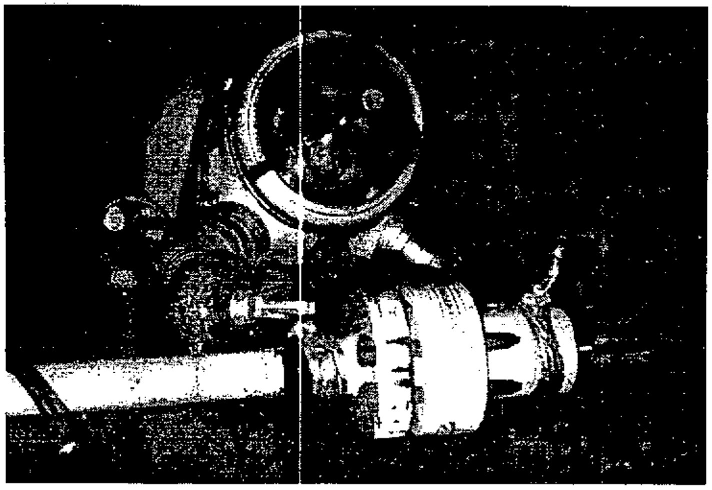
DULCIMER FLOWLINE REPAIR PROJECT
INSTALLED SMART FLANGE PLUS CONNECTOR



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MARINER ENERGY, INC. - PLUTO FLOWLINE REPAIR
MISSISSIPPI CANYON 541 - OCTOBER 1999

- Number of Flowlines: One
- Pipe: 8.625 inch by .866 wall X-65 SMLS
- MAOP: 9400 psi
- Water Depth: 2150 fsw
- Phase 1 Vessel: MSV OCEAN INTERVENTION I
- Phase 2 Vessel: Pipelay Barge Chickasaw
- Phase 3 Vessel: MSV OCEAN INTERVENTION I
- Systems:
  * WASP Atmospheric Diving System
  * MILLENNIUM 150 HP Heavy Work ROV
- Connectors:
  * Standard Bolted Flanges
- Equipment:
  * Pipe Alignment Frames (4)
  * WACHS Guillotine Saw
  * Taut-Wire Metrology Jig
  * Spool-Piece Deployment A-Frame
  * Hydraulic Impact Wrench & HYTORC

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PLUTO FLOWLINE REPAIR PROJECT

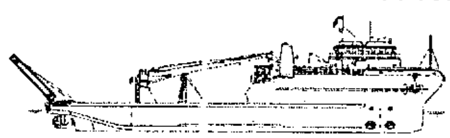
* PHASE 1 - OCEAN INTERVENTION I
  DAMAGED FLOWLINE SECTION WAS CUT OUT

* PHASE 2 - CHICKASAW
  FLOWLINE ENDS WERE PICKED UP BY CHICKASAW
  CURVED PIPE (100') WAS CUT OFF EACH END
  STRAIGHT PIPE WAS WELDED TO FLOWLINE ENDS
  FLANGES WERE WELDED ONTO FLOWLINE ENDS
  NUT RETAINER RINGS WERE INSTALLED ON FLANGES
  FLOWLINE ENDS WERE REPLACED ALIGNED ON SEABED

* PHASE 3 - OCEAN INTERVENTION I
  FLOWLINE ENDS WERE RAISED / ALIGNED WITH FRAMES
  PULLING HEADS WERE REMOVED
  SPOOL-PIECE WAS MEASURED AND FABRICATED
  SPOOL-PIECE WAS INSTALLED
  FLOWLINE WAS LOWERED TO SEABED

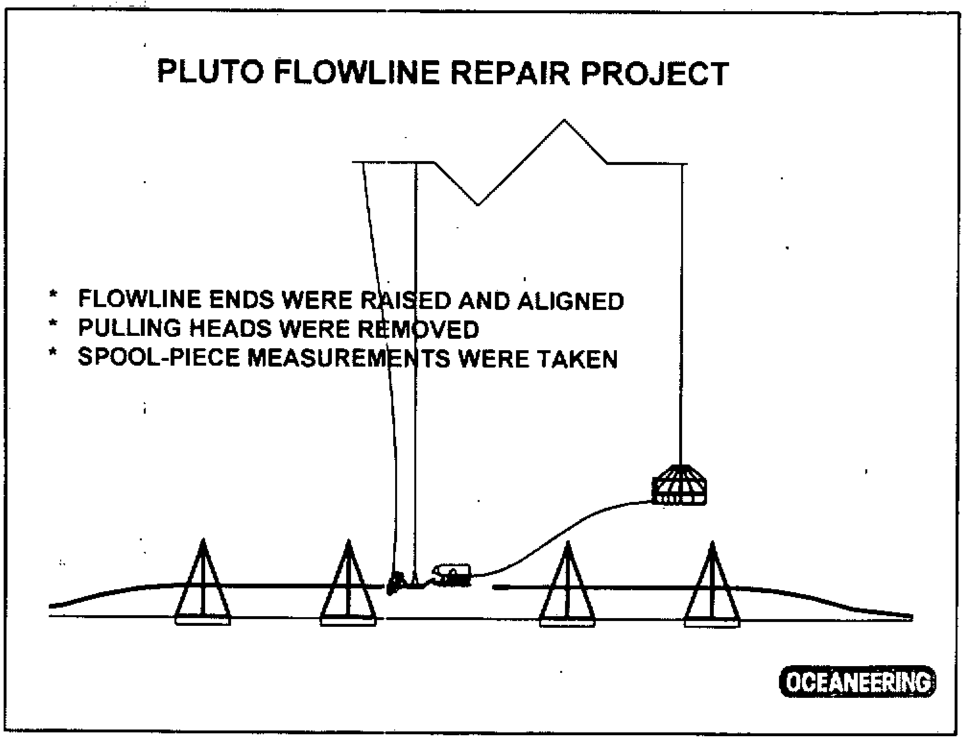
OCEANEERING

PLUTO FLOWLINE REPAIR PROJECT



* PIPE ALIGNMENT FRAMES ARE LOWERED AND INSTALLED ON FLOWLINE ENDS

OCEANEERING


PLUTO FLOWLINE REPAIR PROJECT
* FLOWLINE ENDS WERE RAISED AND ALIGNED
* PULLING HEADS WERE REMOVED
* SPOOL-PIECE MEASUREMENTS WERE TAKEN
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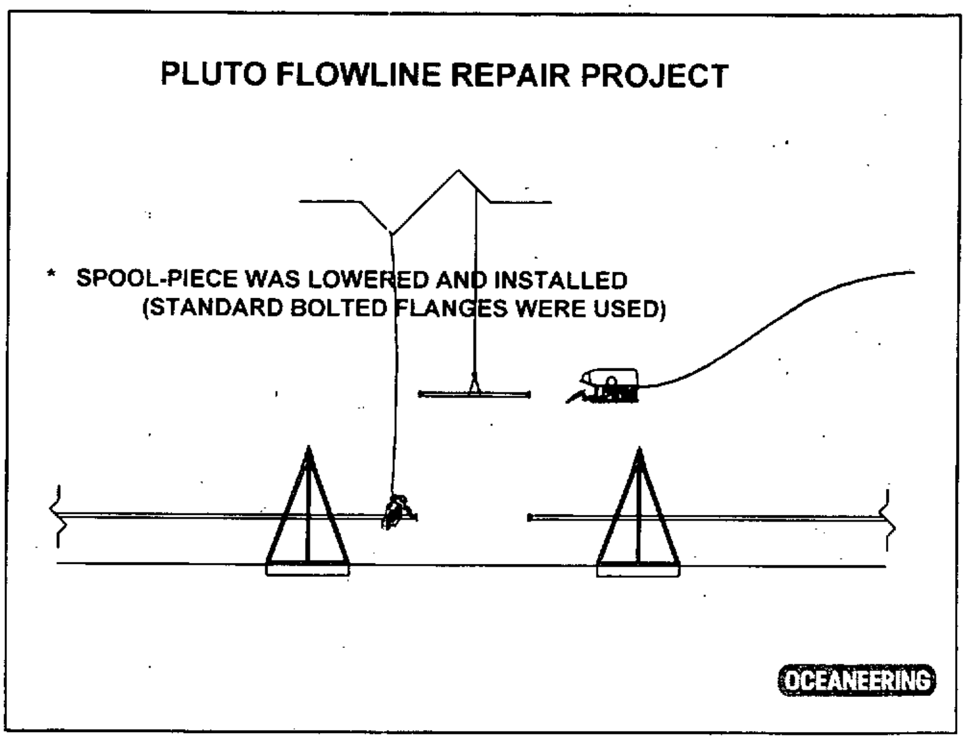
PLUTO FLOWLINE REPAIR PROJECT
* SPOOL-PIECE WAS LOWERED AND INSTALLED
(STANDARD BOLTED FLANGES WERE USED)
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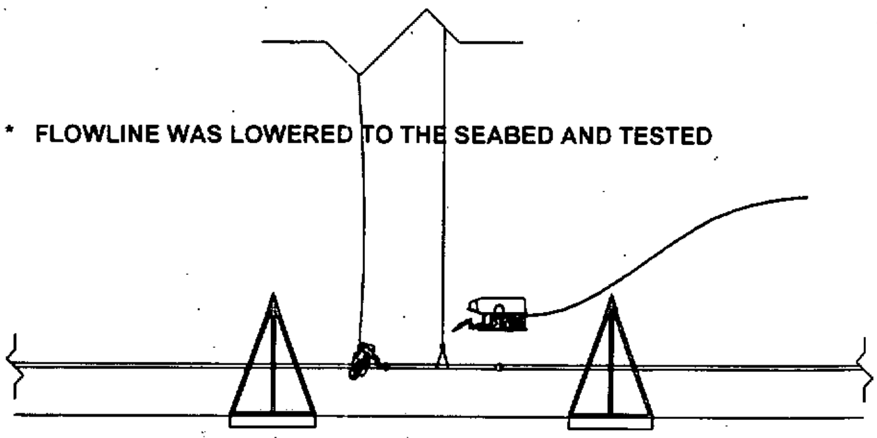
PLUTO FLOWLINE REPAIR PROJECT

* FLOWLINE WAS LOWERED TO THE SEABED AND TESTED



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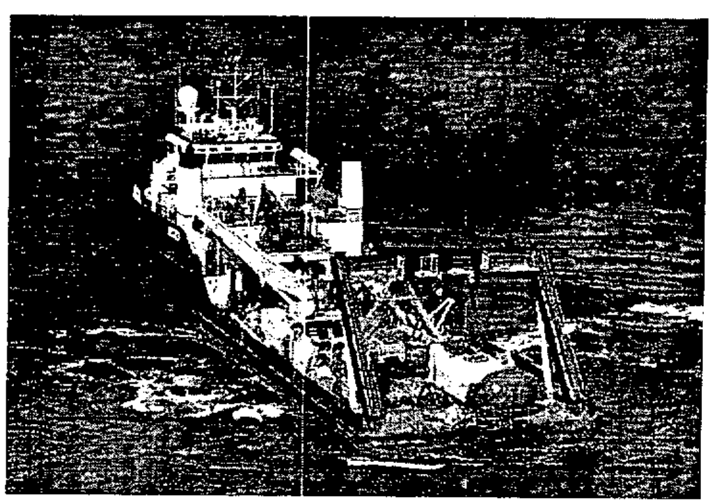
PLUTO FLOWLINE REPAIR PROJECT
REPAIR SPREAD OCEAN INTERVENTION I



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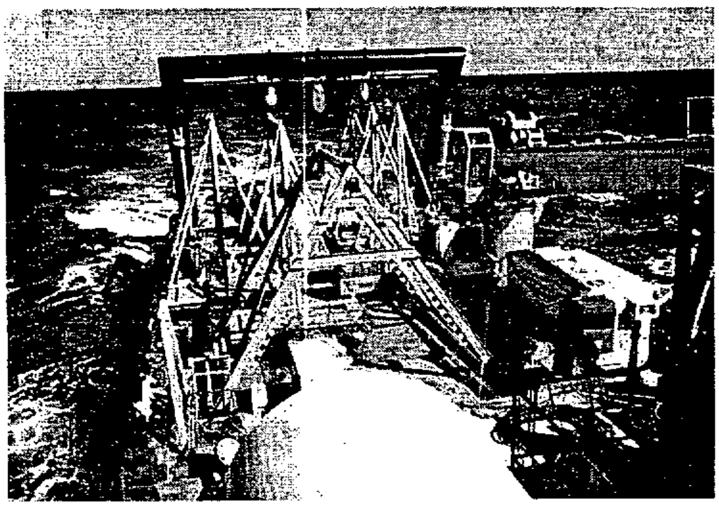
PLUTO FLOWLINE REPAIR PROJECT
REPAIR SPREAD ENROUTE TO MC-541



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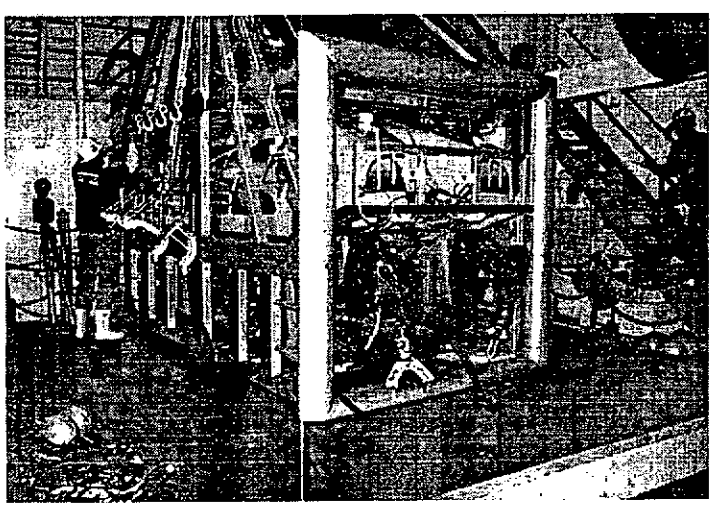
PLUTO FLOWLINE REPAIR PROJECT
MILLENNIUM 150 HP HEAVY WORK ROV SYSTEM



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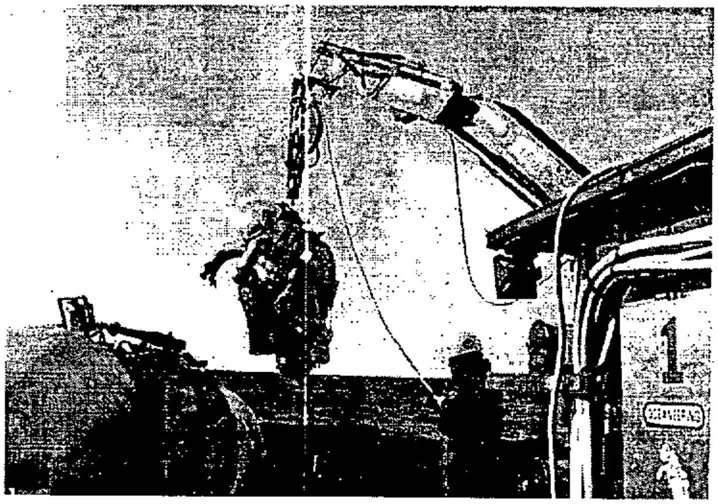
PLUTO FLOWLINE REPAIR PROJECT
WASP ATMOSPHERIC DIVING SYSTEM



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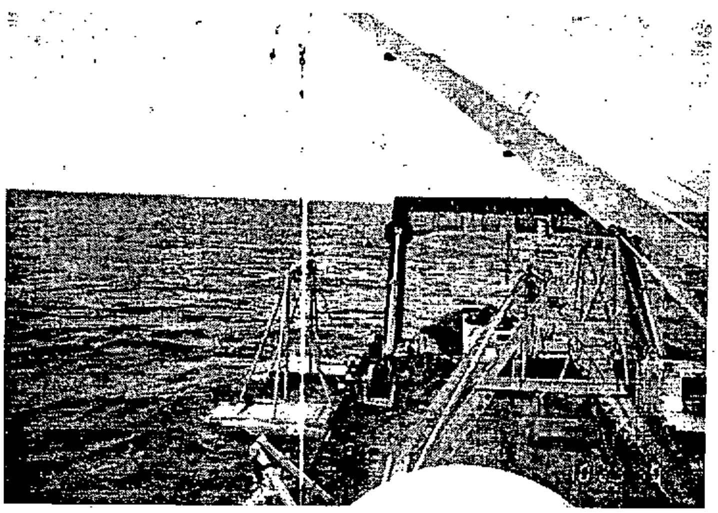
PLUTO FLOWLINE REPAIR PROJECT
PIPE ALIGNMENT FRAMES WERE DEPLOYED



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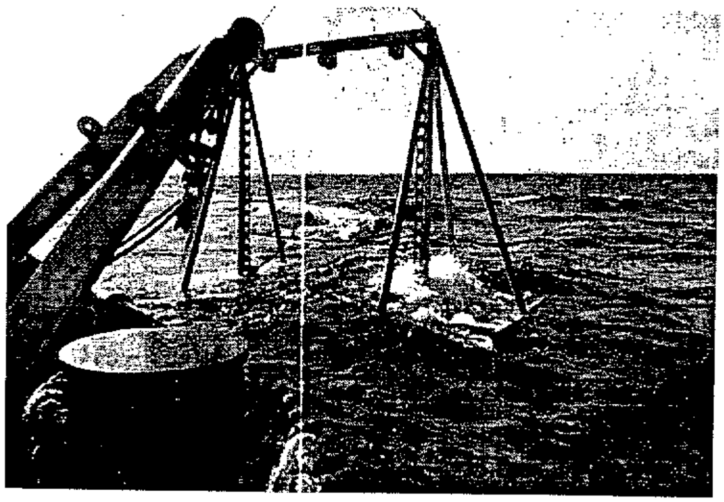
PLUTO FLOWLINE REPAIR PROJECT
PIPE ALIGNMENT FRAME WITH WINCHES / RIGGING POINTS



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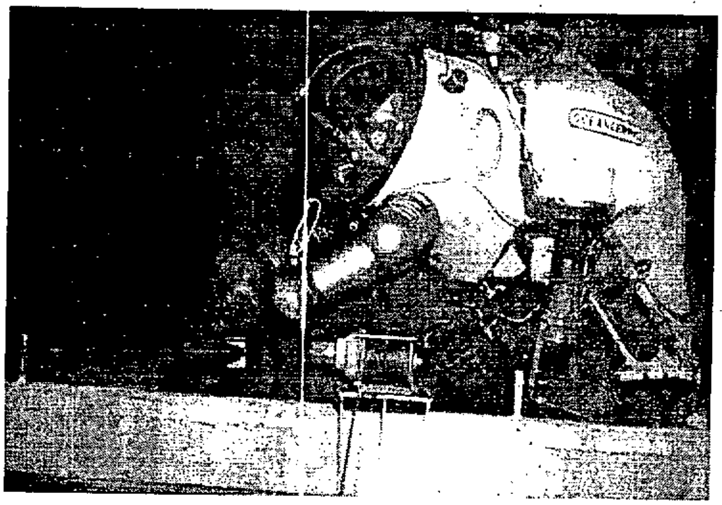
PLUTO FLOWLINE REPAIR PROJECT
FLOWLINE ENDS WERE RAISED AND ALIGNED



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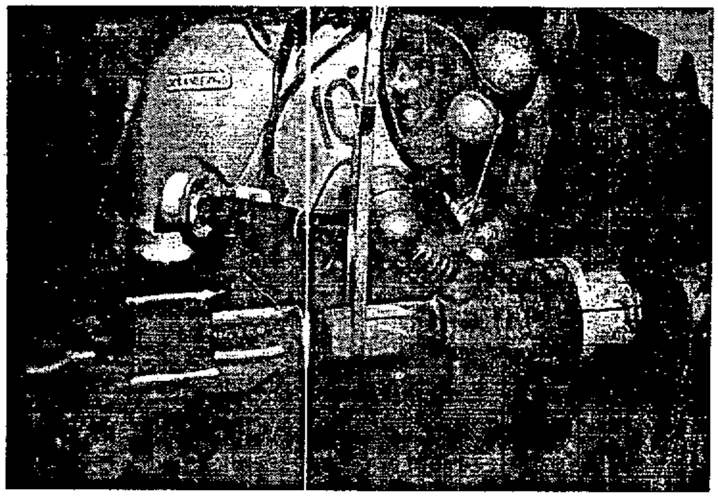
PLUTO FLOWLINE REPAIR PROJECT
PULLING HEADS WERE REMOVED AND RECOVERED



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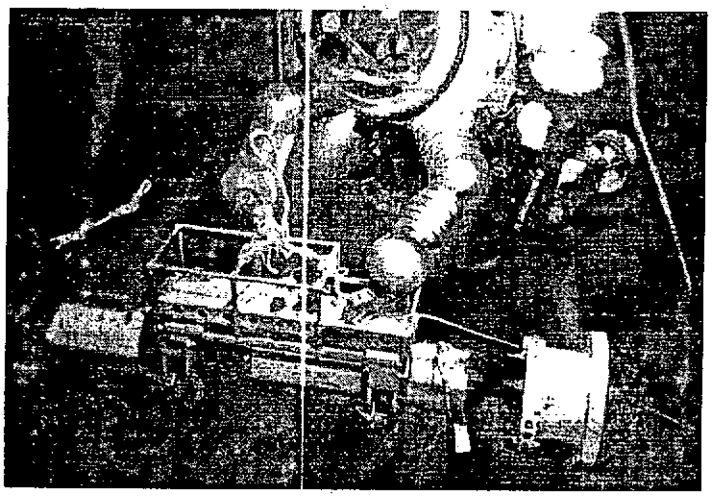
PLUTO FLOWLINE REPAIR PROJECT
TAUT-WIRE MEASUREMENT TOOL WAS INSTALLED



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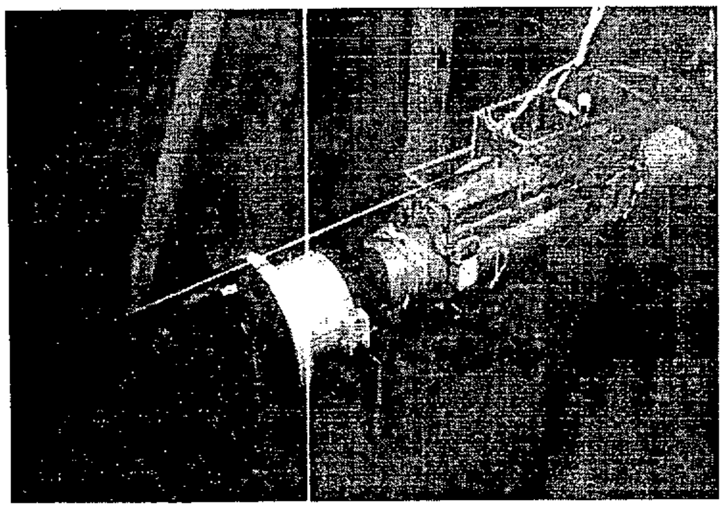
PLUTO FLOWLINE REPAIR PROJECT
SPOOL-PIECE WAS MEASURED WITH TAUT-WIRE TOOL



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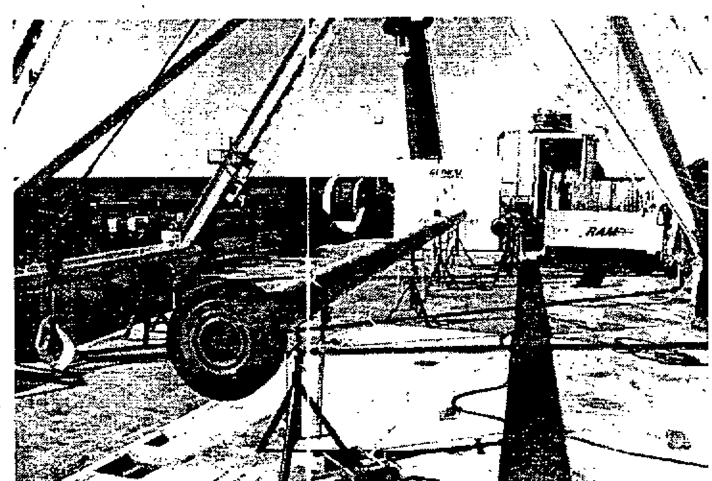
PLUTO FLOWLINE REPAIR PROJECT
SPOOL-PIECE WAS FABRICATED AND TESTED ONBOARD



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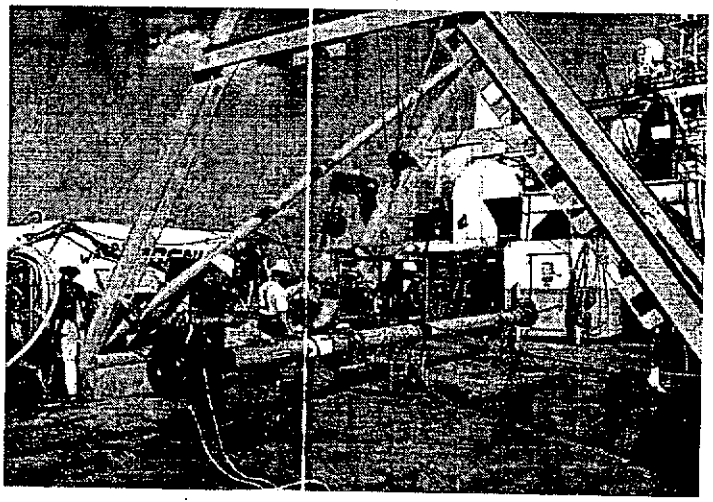
PLUTO FLOWLINE REPAIR PROJECT
SPOOL-PIECE WAS RIGGED IN DEPLOYMENT FRAME



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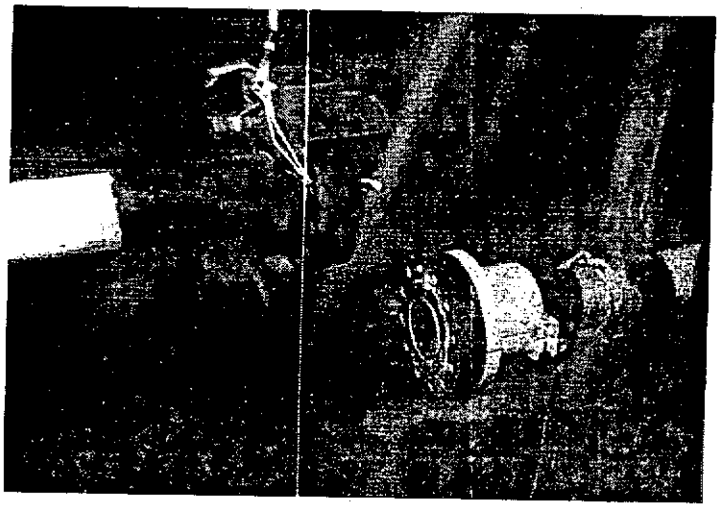
PLUTO FLOWLINE REPAIR PROJECT
SPOOL-PIECE WAS INSTALLED USING DEPLOYMENT FRAME



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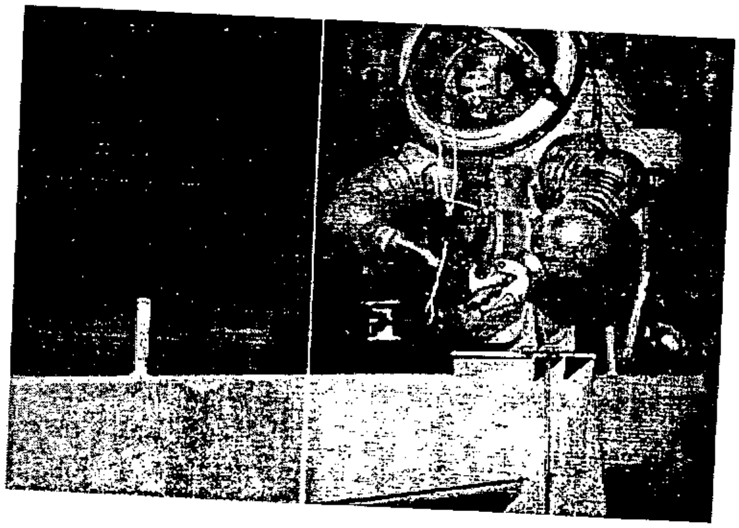
PLUTO FLOWLINE REPAIR PROJECT
ALIGNMENT FRAMES WERE USED TO POSITION PIPE



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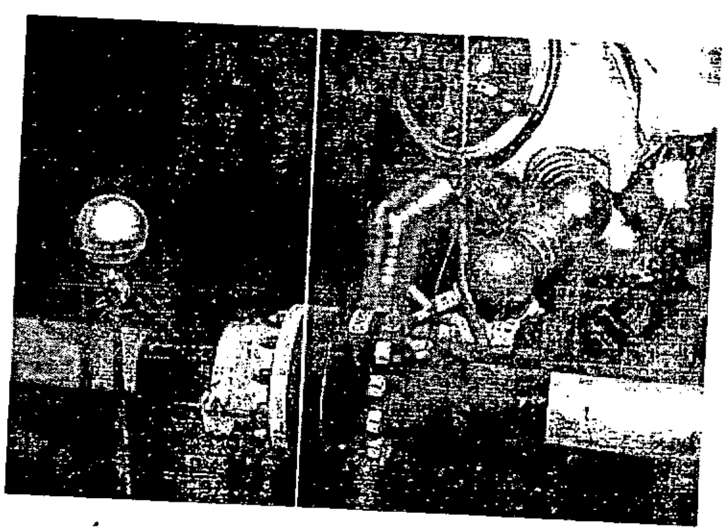
PLUTO FLOWLINE REPAIR PROJECT
BOLTS WERE INSTALLED IN FLANGES (NUT RETAINER)



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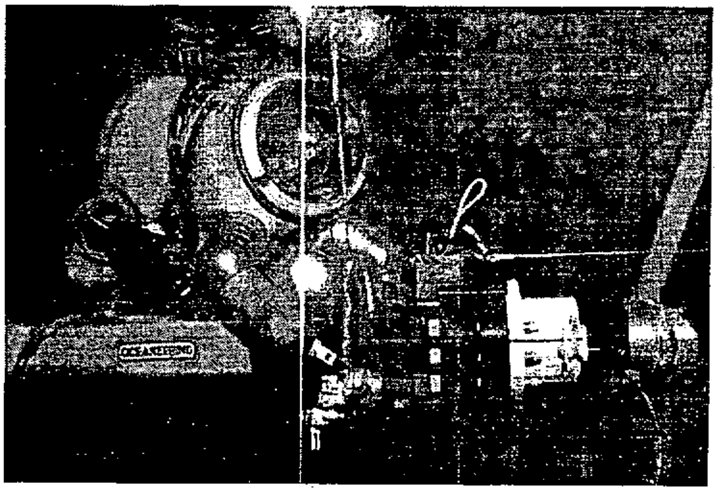
PLUTO FLOWLINE REPAIR PROJECT

BOLTS WERE TENSIONED WITH IMPACT & HYTORC WRENCH



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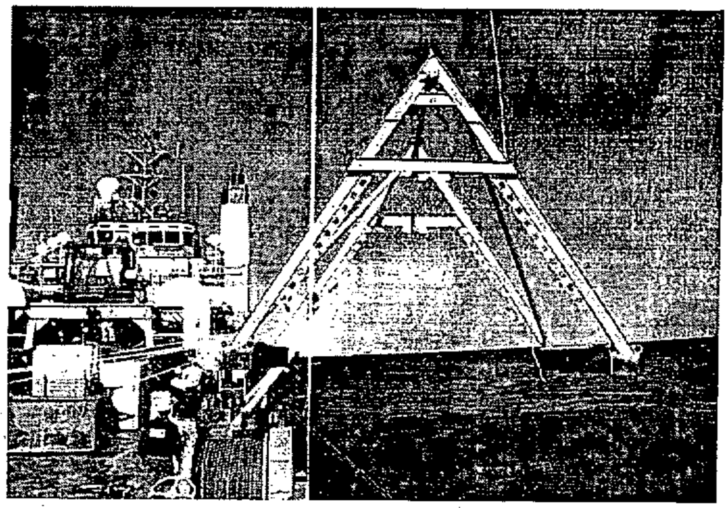
PLUTO FLOWLINE REPAIR PROJECT

FLOWLINE WAS LOWERED AND FRAMES WERE RECOVERED



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FOR TECHNICAL INFORMATION
REGARDING THE DULCIMER FLOWLINE REPAIR
OR THE PLUTO FLOWLINE REPAIR
PLEASE CONTACT:

JOHN CHARALAMDIDES
MANAGER - PIPELINE REPAIR SERVICES
OCEANEERING INTERNATIONAL, INC.
(713) 329-4500

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Review of the State of Art of Pipeline Blockage Prevention and Remediation Methods

Y. Doreen Chin[1] **and John G. Bomba**
Kværner R J Brown, Houston, USA

[1]Currently with JP Kenny, Inc.

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

Review of the State of Art of Pipeline Blockage Prevention and Remediation Methods

Abstract

As the offshore activities go to deepwater, ensuring the well stream flow from downhole to process facilities is becoming a critical issue for economic development of the reservoirs. Flow assurance addresses the problems and solutions of solid depositions of waxes, hydrates, paraffins, asphaltenes, and scales from reservoir to topsides.

When physical conditions are "wrong", hydrates form, or waxes and asphaltenes come out of the well stream fluids, plugging up flowlines and processing equipment. Cleaning of a plugged flowline/pipeline is often very costly, time consuming, and technically challenging. Production has to be interrupted, sometimes may require a complete shut-down. Maintenance and repair methods get more complicated and more expensive as the water depth increases. Procedures for cleaning out a blockage are also addressed as these procedures may influence the design of the Xmas tree and/or the flowline.

This paper briefly discusses the fundamentals of hydrate, wax, and asphaltene formation and associated blockage of flowlines. The deposition prevention and remediation methods are also discussed with case studies.

Deepwater Producing Environment

The deepwater production environment is characterized by low seafloor ambient temperatures, high tubing head flowing pressures, and higher external hydrostatic pressure. The high external pressure has a direct impact on the mechanical design of the flowline/pipeline while the low ambient temperature generally has a larger impact on the hydraulics of a flowline/pipeline. Solid deposition can occur at steady and transient states, and can build up into restrictions and blockages in the reservoirs, well-bores, flowlines, risers and process facilities.

Flow assurance is a common issue in design consideration for almost all producing areas, both onshore and offshore. The industry has established solutions to prevent problems, and remedial means employed when problems occur. However, implementation of these well-known flow assurance measures has unique challenges in deepwater. Its impact on deepwater oil and gas production is major. Some of these issues are:

- Large elevation change of the produced fluid flow path,
- Large hydrostatic head,
- More difficult, more expensive, sometimes not effective intervention,

Proceedings of the 3rd Deepwater Pipeline & Riser Technology Conference, Houston, Texas, March 7-9, 2000.

- Impacted by high well head pressures and low ambient temperatures,
- Constituents/components of the produced stream, including: hydrates, waxes, asphaltenes, scale, sand/silt, salt, emulsions/viscous flow, and slugging resulting from the usually multi-phase flowing conditions.

Pipeline blockages mean a monetary loss. However, blocked flowline does not simply mean deferred production. If the blockage lasts a long time, it might cause the reservoir damage, and result in a real loss of producible reserves.

For deepwater field developments, it is necessary to implement all flow assurance measures required to insure that hydrates do not form and that waxes do not deposit in the flowlines within the budgetary constraints of the project. The management of deposition consists of prevention and remediation. The principle effects of deposition management on both *Capital Expenditures*(CAPEX) and *Operational Expenditures* (OPEX) are summarized in Table 1.

Prediction of deposit formation is a key factor in elaboration of the flow diagrams and system design in offshore engineering. Flowlines and risers are often insulated, chemical injection umbilicals are required, and topsides are designed to cater for treating the "treated" well stream. Provisions for pigging facilities need to be incorporated in the tie-back design. The difference in workover costs between a platform (fixed, compliant, or SPAR/FPF) based rig and a drill ship rig used for workovers can be an order of magnitude higher ($25,000 vs. $250,000 per day). Chemical costs are higher for tied-back flowline production. Pigging facilities should be incorporated for routine as well as intervention pigging.

The Problem Makers

Hydrates

Hydrates are solidified, metastable compounds. Their properties and stability depend on the physical conditions --- pressure and temperature. The ice-like compounds of gas hydrates crystallize from the lighter hydrocarbons (and hydrogen sulfide and other gases), free water, a seed (scale/silt, etc.). Low temperature, high pressure and the gas at or below the water dew point in the presence of free water promote formation of hydrates. The duration of hydrate formation can range from instantaneous to a few hours. As long as free water is present, hydrate formation can take place in a gas stream (methane, CO_2, H_2S), in a live oil stream, or in multi-phase flow. [1-5].

Figure 1 is the hydrate portion of a phase diagram for a typical mixture of water and a light hydrocarbon, which illustrates the hydrate formation process and conditions. Point 1 is a quadruple point at which ice, free water, hydrate and hydrocarbon gas co-exist in equilibrium. Point 2 is a quadruple point at which free water, solid hydrate, hydrocarbon liquid and hydrocarbon gas co-exist at equilibrium. Point 3 is the three phase critical point at which the properties of the hydrocarbon gas and liquid merge to form a single hydrocarbon phase in equilibrium with free water. The co-exist area of free water and hydrocarbon gas and the co-exist area of free water and hydrate are separated by Line 1-2. Therefore, Line 1-2 represents the conditions at which hydrocarbon gas and free water combine to form hydrate. For each hydrocarbon, Line 1-2 is the pressure and temperature conditions for which hydrate formation occurs for the mixtures of that hydrocarbon with free water.

Three types of hydrates have been identified so far. Type I forms from natural gases containing molecules lighter than propane, mainly forms with methane, ethane, and hydrogen sulfide. Type I hydrate has a body-centered cubic crystalline lattice. Type II hydrate has diamond crystalline lattice within a cubic framework, normally forms from natural gases or oils containing molecules larger than ethane, like propane and butane.

Type H hydrates were recognized quite late compared to Type I and II, and the structure has not been clearly determined in natural gas system [6]. Formed with a mixture of heavier hydrocarbon gases, Type H hydrates must have a small occupant like methane, or carbon dioxide, but large molecules like ethylcyclohexane. Methane, xenon, or hydrogen sulfide must be present to stabilize the lattice structure. While of no real concern offshore, molecules of gasoline and naphtha could stabilize a Type H hydrate [2].

Waxes/Paraffins

As a solid organic phase, mainly long-chain n-alkanes (C16-C80+), wax comprises a mixture of components. Wax in oils crystallizes within the fluid as the fluid temperature is below the cloud point, but only deposits on the pipe wall when the wall temperature is below the cloud point, and when the wall is colder than the bulk fluid.

The wax crystallization process develops at three stages; Nucleation, at which the first nuclei appears; Growth, at which mass is transported from the solution toward the nuclei; and Agglomeration, at which the developed crystals join together and bigger crystals are formed. Wax precipitation can occur in the reservoirs , in the production column, in the flowlines, and in the surface production equipment..

Cloud Point/Pour Point. Cloud point is the temperature at which paraffin wax begins to crystallize and is identified by the onset of turbidity as the temperature is lowered. In another word, cloud point is the highest temperature at which the wax crystal forms. The cloud point of a particular crude is dependent on the oil composition and is affected by small amounts of high molecular weight paraffin in the crude. As the temperature falls below the cloud point, wax crystals begin to precipitate from the oil phase.

Pour point is the lowest temperature at which the liquid is observed to flow when heated up under prescribed conditions. Therefore the crystals of waxes or paraffins start to liquefy as their temperature reaches the pour point.

Controlling Factors. Wax deposition is controlled by many factors besides the fluid properties. The key controlling factors are the temperature difference between fluid and pipe wall (thus the heat flux), the concentration gradient, and the mass transfer resistance determined by fluid properties and flowrate, etc.

In single phase flow, higher flowrate has higher heat and mass transfer coefficients. These two factors have opposite effects on the fluid temperature. A higher mass flowrate intends to increase the fluid temperature. As a result, the wax appearance will shift further to downstream, as displayed in Figure 2. In multiphase flow, variation of flowrate can cause changes in the flow regime. The flow regime effects on the wax deposition location, wax/paraffin thickness, and hardness have been investigated experimentally and numerically [7,8]. Figures 3 and 4 are the wax thickness distribution for various flow patterns in horizontal and vertical multiphase flows.

For stratified flow in a horizontal pipe, wax only deposits around the bottom of the pipe. For annular flow, deposition occurs around in entire perimeter. In some flow regimes, like slug flow, the high shear may slow down or limit the overall wax deposition rate.

Pressure has different effects on the wax formation in single phase system and multiphase system. In a single phase oil system, since the wax phase is more dense than the oil, increase in pressure slightly increases the wax deposition tendency. In a multiphase system, increase in pressure drives the light ends of the mixture into the liquid phase and tends to decrease the cloud point, therefore, tends to reduce the amount of wax formed at a particular temperature.

Paraffin precipitation is normally associated with changes in the physical environment surrounding the crude oil. Due to the normal subsurface temperature gradient, and due to the hydrostatic pressure variation in a crude oil as the oil is produced up the tubing, pressure and temperature change, allowing the lighter hydrocarbons to break out of solution and become a gas phase. These lighter hydrocarbons help keep the heavy end paraffins in solution. Their liberation can cause paraffin to precipitate from the solution. Sudden pressure drops may also promote precipitation.

Asphaltenes

While hydrate formation and paraffin precipitation are direct results of physical (temperature and pressure) changes, asphaltene deposition is more affected by chemical changes in the crude. Asphaltenes do not dissolve in crude. They float as dispersed colloids – in the crude. Change in pH (lowering), CO_2 injection, and/or introduction of non-aromatic solvents strips away the "outer part"—the part that supports the dispersion of the asphaltenes in the crude. Without the outer part, the asphaltene molecules will flocculate and precipitate [9,10]. After precipitation of asphaltenes, the remaining part of the crude are maltenes.

There is general agreement in the industry that asphaltenes are not chemically identifiable class of compounds [11]. However, there is not a universally accepted definition of what an asphaltene is. They are thought to be high-molecular-weight complex hetero-atomic aromatic macro-cyclic species that exhibit a polymorphic aggregate behavior [12,13]. Asphaltenes differ from waxes in that they form amorphous solids that include significant amounts of the heteroatoms present in the crude. Heteroatoms are those of $C_nR_mR'_{(5-m)}$, where R_m = O, N and S, and $R'_{(5-m)}$ = H, alkane, alkene, etc.

For most crudes, the lower molecular weight paraffins, such as pentane, are precipitants for asphaltene, while aromatic hydrocarbons are asphaltene solvents. Crude oils with high percentages of wax accompanied by asphaltenes exhibit lower pour points, but higher viscosities due to the high molecular with of the asphaltenes.

Controlling Hydrate Formation, Wax Deposition, and Asphaltene Dropout

Generally, there are three basic methods, thermal, chemical, and mechanical, of controlling hydrates, waxes, and asphaltenes. They may be used alone or in combination.

Thermal methods encompass heat conservation using a passive insulation system, an active addition of heat, or an active system of insulation and heating. The active heating can be fluid heating, electric heating, or thermal-chemical exothermal, heating. For fluid active heating, the scenario can be auxiliary line heating [14] (for bundle system) or annulus heating [15,16] (for pipe-in-pipe and bundle system).

Electrical heating systems such as SECT™ (Skin Electric Current Tracing) and Combipipe are available to be used with bundles, pipe-in-pipe and wet thermal insulation systems, on-shore and in shallow water [17,18]. The technique of direct impedance heating system for subsea flowline is still under development as a DeepStar project [19]. Figure 5 is a general view of the SECT™ system [20]. Figure 6 is the schematic of the Combipipe heating system [18]. There are also other systems such as ITTI (Induction Through Thermal Insulation) [21] and TTDPIS (Therm Trac Double Pipe Insulated System) [20,22]. Electrical heating can be a very attractive alternative for both prevention and remediation of hydrate or wax blockage, because of its potentially high reliability and little adverse operational impact. Electric heating has not been used extensively in deep water but has been very successfully used in shallower water for heavy crude oils. For deepwater pipelines, electrical heating still faces numerous technical and engineering challenges.

Chemical methods include both inhibition and dehydration for hydrate prevention and the use of long chain polymers to maintain waxes and asphaltenes in the fluid.

Mechanical means, such as pigs, may be used for "prevention" if operate on a planned frequency. Pigs are also a part of the remediation package, used when a blockage occurs or is about to occur. Other mechanical tools include coiled tubing.

Combating Hydrate Formation

There are three ways currently in use to combat the formation of hydrates:

- The preservation and application of heat by using insulation and supplemental heating.
- The use of inhibitors, and
- Dehydration - removing enough of the water from the stream so that a hydrate will not form, using Glycols. In future, subsea separation may become a viable means of water removal.

Inhibition. Inhibition of the hydrate formation process is commonly used practice. There are two kinds of inhibition: thermodynamic and kinetic [5, 23].

Thermodynamic inhibition prevents hydrate formation by adding third active component into a two-component system (water and gas) to change the energy of intermolecular interaction and to change thermodynamic equilibrium between molecules of water and gas, hence modify the hydrate formation temperature.

Kinetic inhibitors are adsorbed on the surface of hydrate microcrystals and microdispersed droplets of water in the flow of a fluid; sharply change the diffusive-sorptional exchange at the gas-inhibitor-water interface; decrease the rate of microcrystal growth, their coagulation, sedimentation and adhesive parameters, thus preventing the formation of large gas hydrate plugs in wells and in pipelines. Unlike thermodynamic inhibitors, kinetic inhibitors do not lower the hydrate formation temperature. In other words, kinetic inhibitors do not preclude the process of hydrate formation, but only delay nucleation or prevent the growth of hydrated crystals. Kinetic inhibition is a temporary inhibition. It is effective in production and transportation of hydrocarbons.

For most situations, only inhibitor injection is possible without a great deal of expense. Thermodynamic inhibitors, such as methanol and ethylene glycol are the most widely used inhibitors in the natural gas industry, particularly in offshore flowline hydrate control operations. A series of new kinetic hydrate inhibitors (KHI) has been developed and field-tested by Exxon in black oil flowlines and gas flowlines [24,25]. The KHIs are comprised of a water-soluble polymer with N-vinyl-, N-methyl acetamide-co-vinyl caprolactam (VIMA-Vcap). The KHI lately was successfully used to inhibit hydrates in a 28-miles long gas pipeline between SP89 and WD 73 platforms, and showed much lower dose requirement and higher cost effectiveness.

High pressure pumps located on the topside facilities are used to inject inhibitors into the production tubing and flowlines through umbilicals or service lines, and into the topside process lines and equipment. The KHI injection pump used on SP89A platform is shown in Figure 7.

Dehydration. The Glycols may be more efficient, but requires expensive downstream process (recovery) facilities. Triethylene glycol has been used by Shell to dehydrate produced gas in the Mensa flowlines.

Combating Wax Deposition

The downhole paraffin and asphaltenes control problems and practices, followed by several producers in 23 counties of three states (Texas, New Mexico, and North Dakota), were discussed in Ref. [26]. Operators were surveyed to determine the effectiveness of their control procedures—responses ranged from poor (14%), to fair (32.6%), to good (48.8%), to excellent (4.6%) effectiveness of their programs.

Wax remedial treatments often involve the use of solvents, hot water, hot water and surfactants, or hot oil treatments to revitalize production. Seven (or eight) methods are available for removal of wax, paraffin, and asphaltenes. These are:

- Removal by hot fluid
- Use of solvents

- Use of dispersants
- Use of crystal modifiers.
- A combination of the above
- Removal by mechanical means (scraping)
- SNG (or NGS) system – thermo-chemical cleaning and
- The use of microorganisms (only on wells to date)

There are chemicals available that can be tailored to work with a particular crude oil composition. Tests should be carried out on samples of the crude to be sure that the chemical additives would prevent the wax deposition. The chemical additives are selected based on the crude oil samples. For example, the Moomba field, in Australia has a particularly troublesome crude. After experiencing some difficulties with the chemicals being used, a test loop was designed and set up to prove the worth of chemicals proposed to be used by various suppliers. Many were tested and eliminated prior to selection of the better of the two that actually worked.

Heating. Removal by means of a hot fluid works best for downhole and for short flowlines. The hydrocarbon deposits is heated above the pour point by the hot oil, hot water or steam circulated in the system. It is important that the melted hydrocarbons are removed from the wellbore to prevent re-deposition.

However, this practice has a drawback. The use of hot oil treatments in wax-restricted wells can aggravate the problem in the long run, even though the immediate results appear good. Lighter waxes, which act as mortar for the heavier waxes, are removed. The higher melting fractions, higher molecular weight waxes become concentrated, since the higher waxes tend to be less soluble an elevated temperatures. These treatments tend to concentrate the higher or harder waxes. This effect is particularly damaging to the area near the wellbore. Repeated treatments may cause severe obstructions that will require increasingly severe treatments to remove.

Hot water and combined hot water and surfactant treatments must be carefully considered prior to implementation. Because some producing formations are water sensitive.

The combined hot water surfactant method allows the suspension of solids by the surfactant's bipolar interaction at the interface between the water and wax. Thus, much of the higher fractions are carried out of the well as suspension. One additional advantage of the use of combined hot water surfactants treatments over hot oil is that water has a higher specific heat than oil, and therefore it usually arrives at the site of deposition with a higher temperature.

Solvent treatments. Solvent treatments of wax and asphaltene depositions are very often the most successful remediation methods, but they are much more costly. Therefore, solvent remediation methods are usually reserved for applications where hot oil or hot water methods have shown little success.

When solvents contact the wax, the deposits are dissolved until the solvents are saturated. If they are not removed after saturation level is reached, there is a strong possibility that the waxes will precipitate (re-crystalize). Re-crystalization and precipitation may result in a situation more severe than that prior to treatment.

The solvents used to remove heavy hydrocarbons are carbon disulfide, chlorinated solvents, benzene, xylene, and toluene. Carbon disulfide is probably the most efficient solvent for removal of wax deposits. However, it is extremely dangerous to handle, and most countries have banned its use. It is explosive, has a flash point of –22oF, and an auto-ignition temperature of 212oF. Benzene, Xylene, and Toluene are also considered as good solvents.

Crystal modifiers (pour point depression), dispersants. Paraffin wax crystal modifiers are those chemically functionalized substances that range form poly-acrylate esters of fatty alcohol to copolymers of ethylene and vinyl acetate. Because of their special structures, the portions of the backbone of the polymer or their pendent groups of these substances can interact with the crystallizing waxes present in a crude oil mixture. Crystal modifiers attack the nucleating agents of the hydrocarbon deposit and break down and prevent the agglomeration of paraffin crystals by keeping the nucleating agents in solution. Petrobras has developed a pour pint reducer and organic deposit inhibitor based on EVA (ethylene-co-vinyl acetate) copolymers [27].

Dispersants are also used with the modifiers for removal of wax deposits. Dispersants do not dissolve wax but disperse it in the oil or water through surfactant action. Dispersants divide the modifier polymer into smaller fractions that can mix more readily with the crude oil under low shear conditions. Nonionic poly-ethers produced from ethylene oxide and/or propylene oxide are usually used as dispersants.

There are commercially available chemicals that have been successfully applied to oil industry for deposit removial. PARC 400, developed by Phoenix Chemicals, is a chemical that can be used as a solvent, a dispersant, a crystal modifier and a inhibitor [28]. It can be used both downhole and in production flowlines, usually in a two part treatment, part one being remediation/removal of deposits from the tubing and flowlines while part two is a maintenance operation—continuous injection or periodic treatment into the tubing to insure optimum production at lowest maintenance cost.

Another such chemical is LODI 7061, a proprietary mixture of detergents and surfactants developed by Lobo Environmental, Inc. LODI 7061 can be effectively used for deposit removal of normal paraffins, cycloparaffins, isoparaffins, and aromatic paraffins. The chemical has been successfully used in storage tank, marine tankers, liquid-carge barges, offshore pipelines, and subsea wells [29, 30].

SGN. Nitrogen Generating System (SNG), introduced by Petrobras in 1992, is a thermo-chemical cleaning method [31-33]. The basic concept of SNG is related to the irreversible fluidization process of the organic deposits. Such process is caused by the simultaneous actions of the temperature increase of the fluid and paraffin, the internal turbulence during the flow, and the incorporation of the organic solvent into the deposits. The heat is generated with nitrogen simultaneously by the chemical reaction between two inorganic salts in aqueous saturated solution. The SNG process combines thermal, chemical and mechanical effects by controlling nitrogen gas generation to comprise the reversible fluidity of wax/paraffin deposits. Such an exothermal chemical reaction causes the deposits melt down from the pipe wall. Figure 8 is the schematic diagram of SGN "gravitational" operation system.

Pigging The oldest way of cleaning out a flowline, which is not completely plugged, is mechanically scraping the inside of the line by pigging. Pipeline pigs are devices that are inserted into and travel along the length of a pipline driven by fluid. A variety of pigs, either soluble or insoluble, are introduced into the flowline. These pigs remove some of the buildup off the pipe walls as they move through the line. Many pig runs may be required to effectively clean the line. The effectiveness of the pigging operation can vary widely depending on the design of the pigs and other pigging parameters.

The strategies for pigging in subsea projects, piggable equipment for subsea systems, and the pigging requirements for subsea equipment, flowlines, platforms and FPSO designed were discussed in Ref. [32,34].

Modular pigging loops for subsea manifolds hve been developed. Figure 9 is the pigging loop for subsea system. Figure 10 is the dual diameter scraper pip applied in Campos Basin wax removal operation. The pigs are launched from the platform through an auxiliary line to the subsea equipment, from there they return to clean the main flowline. Figure 11 is the pig launcher and receiver at a FPSO in Preventive solutions of wax such as frequent pigging have become a part of operational routine in Albacora, Marlin and Barracuda fields located Campos Basin. Up to today, 39 pig cross-overs and 10 subsea piggable manifolds have been installed in theses fields.

A great deal of experience in managing hydrate and wax problems using pigging in subsea flowlines has been accumulated by Petrobras. Figure 12 shows a packed hydrate block removed from the pig receiver at P-34-platform at Campos Basin [31].

Various pigs can be used for pipeline cleaning. Figure 13 demonstrates different shapes of pigs have been or can be applied for subsea system [36,37].

Microbes. Microbes are routinely used for oil spill remediation. Recently in Venezuela and Alaska, microbes were successfully used to clean out well bores. Based on the reported results of these tests, it is conceivable to assume that this method would be successful for paraffin removal from flowlines. The time required to accomplish the paraffin removal by microbes in flowlines is unknown, but likely would be long.

Combating Asphaltene Deposition

Many attempts have been made to interfere with asphaltene depositions, but only a very limited progress has been reported. Aromatic fatty sulfates, fatty amine aromatic fatty sulfate salts, and aromatic amines are of a few chemicals that have been used, with limit success [13].

Case Studies - Unplugging Flowlines

Attempts have been made to unblock plugged up flowlines in various parts of the world. Some of these attempts were highly successful, some less so. Some examples of both are presented here.

North Sea A description of the planning required to clean out a pipeline is reported by Marshall [35], for the pipeline cleaning operation undertaken at the Valhal oilfield in North Sea.

The basic reason for cleaning the pipeline was a request by the Norwegian government for Amoco to establish the baseline wall thickness and pipeline internal geometry. The pipeline had been in operation for approximately two years at the time of the request. The pressure drop in the 23 mile long pipeline was gradually increasing, indicating a wax buildup on the pipe walls. Calculations indicated that about 7,500 barrels of solids had been deposited. Assuming uniform deposition, the internal diameter would have been reduced from 18.75 inches to 17 inches. As the produced oil in the pipeline cooled from about 115^{c} to 130°F, to 60^{c} to 75^{cF}, below the 80^{c}F cloud point, solids deposition would not be uniform, with the thicker deposits toward the receiving platform. Gel pigs and foam pigs were examined.

Considerable thought was given to the various methods available for removing the solids from the pipe wall. Solids removal with a pig is risky. Using the wrong kind can result in the solids building up in front of the pig and forming plug, stopping the flow. The objectives of the cleaning operation:

Minimizing the risk of a stuck pig

Removing only a little of the solids at a time to avoid the 2% bs&w specification at the receiving platform

Complete removal of the solids was required to permit the use of the smart pigs.

The actual flow in the pipeline was well below the design flow resulting in low velocities, about 2 feet per second. Pigs are generally design to operate at a minimum velocity of about 3 feet per second. This factor resulted in a thorough review of available pig types from gel pigs to hard, hydro-mechanical pigs and in-between.

A decision was made to begin with undersized foam pigs. A batch of natural gas liquids was sent in front of the 16 inch diameter, 2 pound per cubic foot density, foam pig. This particular pig was selected because it was small enough to allow fluid bypass and soft enough to disintegrate if it hung up. This pig went through the pig receiving basket in the receiver and was recovered in pieces in the equipment downstream of the receiver. Something like 400 barrels of solid passed through downstream. Roughly 4 barrels of wax and sand was removed from the receiver barrel.

This first pig was then followed by two 16 inch, two 17 inch, and two 18 inch, 5 pound per cubic foot density, after which, 19 inch pigs were used. This combination was estimated to have removed about 85 percent of the deposited solids. The type of pig to be used was then changed. A pressure bypass pig, developed by McAlpine Kershaw, was employed. A major hitch in plans developed at this point.

The smart pigs would not operate at the reduced velocity now observed with the cleaner line. Further cleaning was deferred until additional production could be brought on line. Foam pigs, with densities gradually increasing from about 5 to about 9 pounds per cubic foot, were sent weekly to prevent additional buildup.

Cleaning resumed using the bypass pigs with a variety of different cups, discs, brushes, and scrapers. Results obtained varied, with discs being the most effective. See the paper for additional details. A caliper pig was successfully run. Most of the line was clean—parts of the line had a 3/16 inch thick was coating. The British Gas smart pig was successfully run.

This paper described several piping design problems in the topside pig receiving system. The receiver barrel was not designed for foam pigs and had no bar on the tee. The first basket would not contain the foam pig. Pigs sometimes plugged up flowmeters.

Brazil. Combinations of chemical and mechanical methods have been used successfully by Petrobras for almost 14 years. The techniques developed by Petrobras are described in Refs [29, 31, 34]. Local companies, such as Ernie Casey's, CalDive, Ambar can offer similar services.

Gulf of Mexico. Each year, flowlines plug up here in the GOM area, in the swamps, in shallow water and in deep water. The problems and success of the unplugging operations are seldom publicized.

At the 1998 IBC Wax and Hydrate Conference in New Orleans, J. Ileman, of Elf, the chair of the DeepStar Pipeline Blockage Remediation Committee, discussed the DeepStar work in some detail. He then discussed two of Elf's paraffin removal jobs (6 miles of 6" and 3 miles of 3.5") in 50 to 60 feet of water, describing the practical problems encountered in cleaning the lines and in trying to keep them clean.

At the same conference, Y. Wu, of Phillips Petroleum Company, described paraffin, asphaltene and hydrate prevention techniques employed offshore Louisiana and in the South China Sea. Prediction methods, prevention ideas, implementation of pigging, monitoring of the inlet and outlet pressure differential and of the pressure change at these points are described.

Flextrend Development Company installed a single well tie-back in about 1000 feet of water to a new build platform in 700 feet of water. Dual 3-inch flowlines were installed. To maintain constant internal diameter for pigging, the flowlines were fabricated from API 5L X60 pipeline grade steel and the risers were fabricated with 4140 steel tubing. Modified Graylock connectors were use to tie the riser section into the flowline section and the flowlines into the well.

The drill stem tests indicated a rich gas, with about 2000 barrels of condensate to 1 MMscfd gas and minimal water. Hydrates could be easily controlled with methanol, so the flowlines were not insulated. Shortly after production started, the condensate ratio increased. Within 6 months, the gas well was producing waxy crude oil. Chemical injection to control wax deposition was tried without much success. The flowlines plugged up and attempts were made with coiled tubing and steam injection to clean out the paraffin deposit. The line was cut in several location and steam injection via coiled tubing was tried with no success. The flowlines were subsequently replaced. The well is currently shut in.

Prudent operators shut in their offshore production when a named hurricane pops up in the Gulf and is predicted to enter into the northern gulf, where most of the production takes place. In this instance, the operator shut in a 13-mile tie-back, located in 550 feet of water, when Hurricane Brett entered the Gulf and came ashore between Kingsville and Brownsville. After the hurricane threat had past, the operator tried to start up the well. Nothing happened! A hydrate plug was predicted. The flowline was blown down from the platform end and nothing happened. The next logical step was to blow down the line from the Christmas tree end. The available blowdown connection was not large, 3/8" OD, so several options were explored. A modification to one of the valve ports was made to permit a full opening to be accessed. These modifications have recently been completed. Blowdown of the flowline section between the tree and the blockage was attempted after the modified port was installed. The line is still not operating. What was originally thought to be a hydrate plug is now considered to be a wax plug

Summary

The state-of-the-art and some novel techniques of flowline blockage prevention and remediation are briefly discussed.

Hydrate formation, wax deposition, and asphaltene drop-out can be serious problems in an onshore flowline, where remediation is possible with relative ease (the pipeline is within three feet of the ground and one can get to the line with a shovel). When these problems occur offshore, the problem of locating and unblocking the line becomes much more serious and costs go up as the water depth increases.

Continuous efforts must be made to improve flow assurance techniques. New tools are currently being developed for unblocking flowlines in deepwater.

As drilling activities move toward deep and ultra deep water regions, the recrudescence of flow assurance problem is expected. Flow assurance increases in importance as water depths increase.

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30. _______. "Paraffin Treating Chemical Improves Oil Well Performance", *World Oil*, pp.98-99, February, 1999.
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33. Pereira, A. Z. I. and Khlil, C. N., "Advances in Multiphase Operations Offshore – New process for the Chemical De-Waxing of Pipelines", *Advances in Multiphase Technology* – An International Two-Day Conference. June 24-25, 1996, Houston, Texas, USA.

Table 1 Impacts of deposition management on CAPEX/OPEX

	Apply to	CAPEX	OPEX	Effect on Production
Burial	Hydrate, wax/paraffin, asphaltene	Trench/burial	N/A	N/A
Insulation	Hydrate, wax/paraffin, asphaltene	Insulation materials	N/A	N/A
Inhibition	Hydrate, asphaltene	Pump/pipe	Chemicals	N/A
Pigging	Hydrate, wax/paraffin, asphaltene	Pigging loop	Pigs/power	Reduced production or shut down
Solvent flushing	Wax/paraffin	Pumps/storage	Chemicals	Reduced production or shut down
Hot water flushing	Wax/paraffin	Pump/heater	Heating utility	Reduced production or shut down
SNG	Wax/paraffin	Pumps	Chemicals	Reduced production or shut down

ADDENDUM

Deepwater Pipeline and Riser Technology Proceedings, March 7-9, 2000

[This page follows page 13 in paper #21, *Review of the State of the Art of Pipeline Blockage Prevention and Remediation Methods*, by Y. Doreen Chin and John Bomba]

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34. Pereira, F. B., and Gomes, M. G. F. M., "The Engineering of the Pigging Equipment for Subsea Systems in Campos Basin", OTC 8540, *the Proceedings of 1989 Offshore Technology Conference*, May 5-8, 1989, Houston, Texas, USA.
35. Marshall, G. R., "Cleaning of the Valhall Offshore Oil Pipeline", OTC 5743, *the Proceedings of 1988 Offshore Technology Conference*, May 2-5, 1988, Houston, Texas, USA.
36. _______, *Buyers' Guide*, Pigging Products and Service Association, 1999-2000.
37. _______, *Introduction to Pipeline Pigging*, Pigging Products and Service Association, 1999.

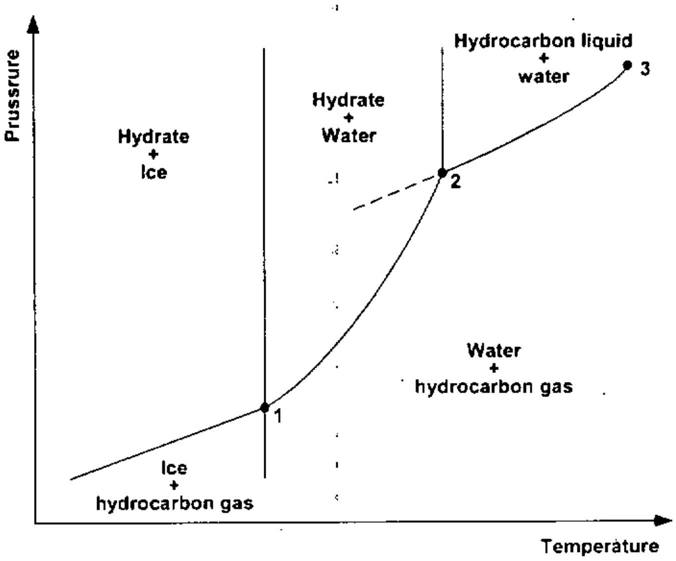


Figure 1 - Phase diagram of a typical mixture of water and a light hydrocarbon --- hydrate portion.

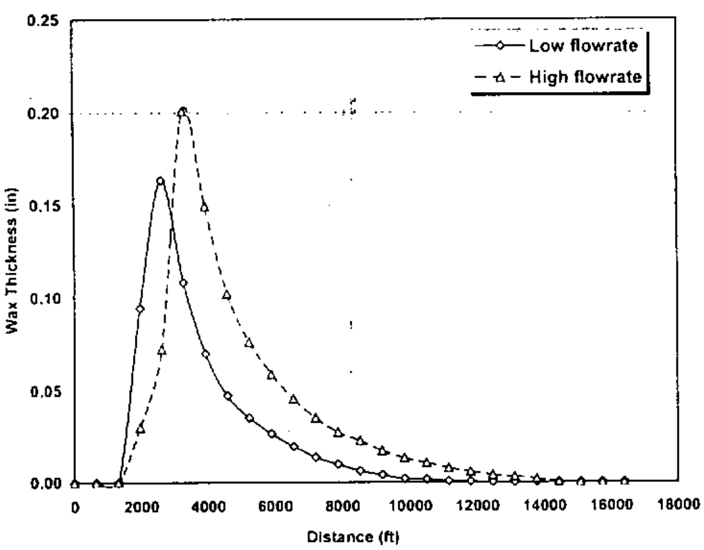


Figure 2 Effect of flowrate on wax deposition

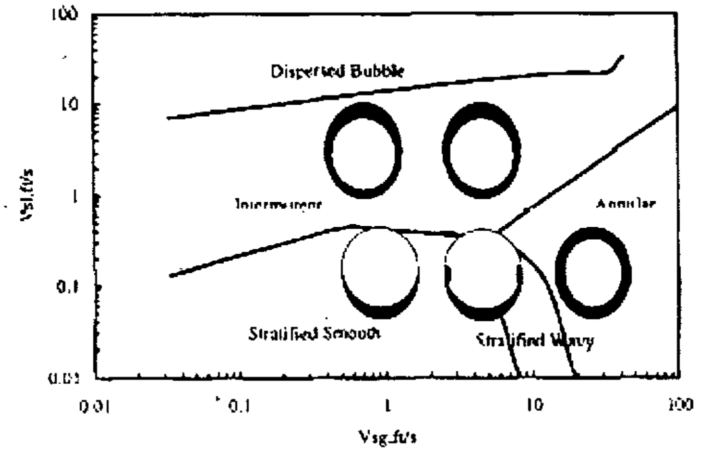


Figure 3 - Wax thickness distribution for various horizontal flow patterns[7].

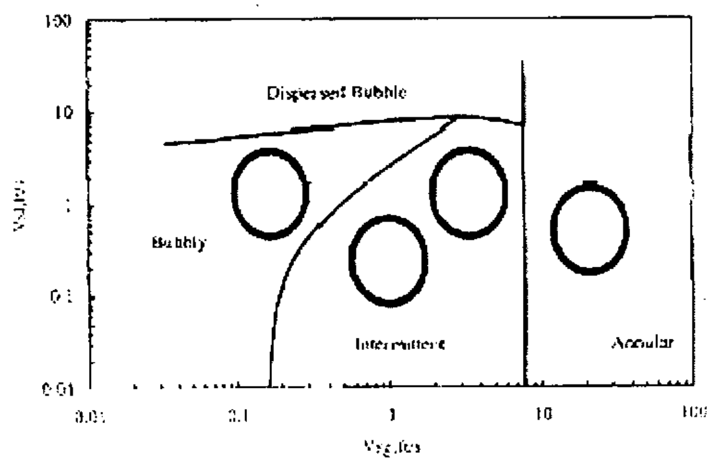


Figure 4 - Wax thickness distribution for various vertical flow patterns[7]

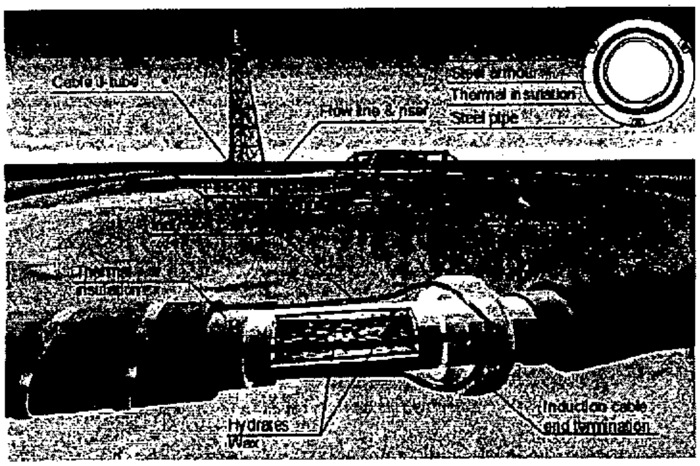


Figure 6 – Combipipe heating[23].

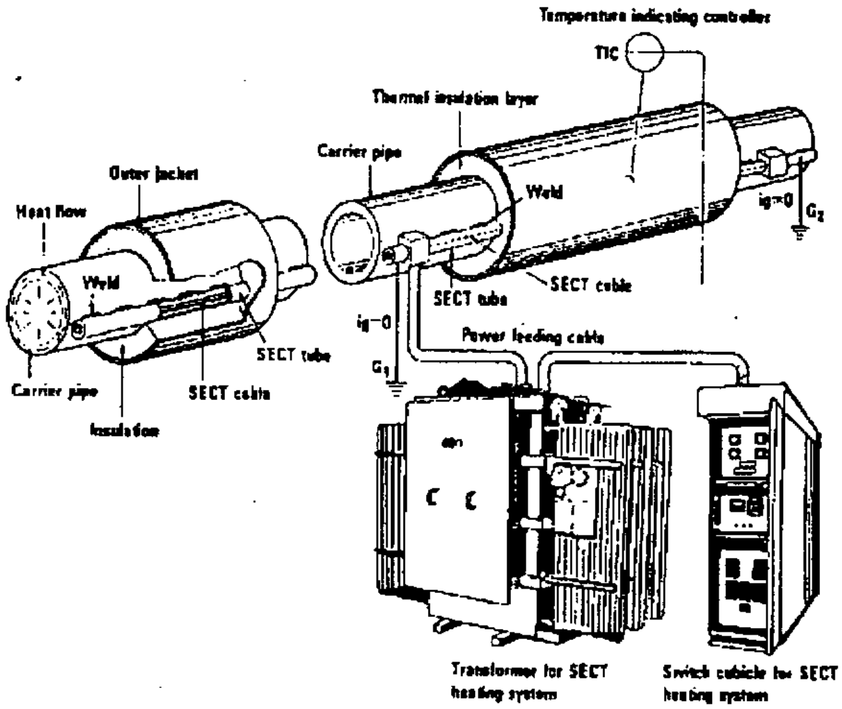


Figure 5 – General view of SECT™ system[26]

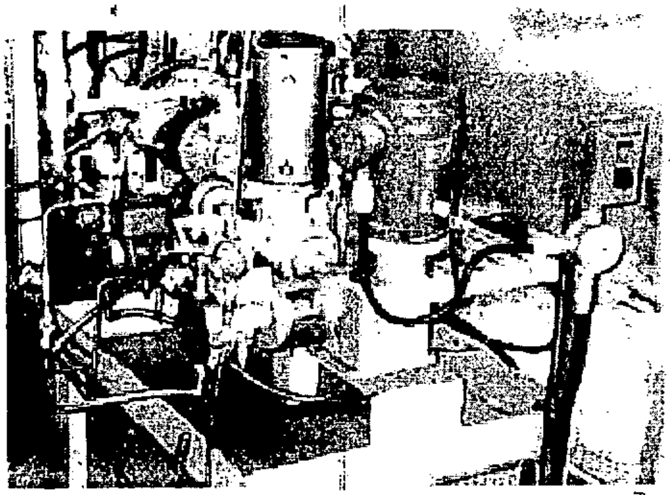


Figure 7- KHI injection pump on SP89A. A chemical metering pump with a 3 mm diameter plunger was used[29].

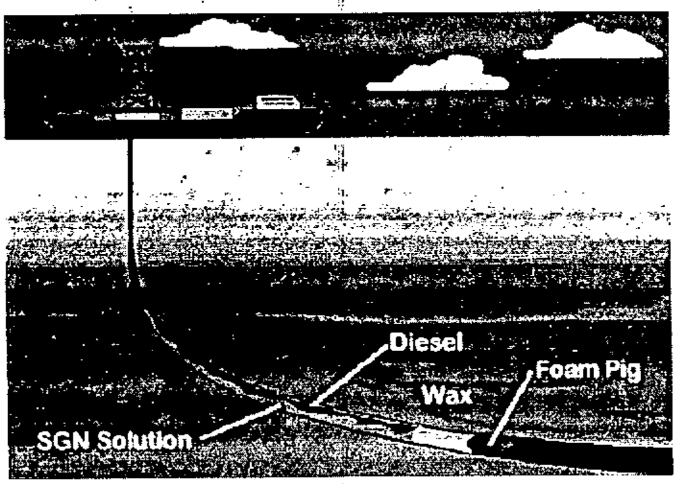


Figure 8 - Schematic Diagram of SGN "gravitational" Operation[31].

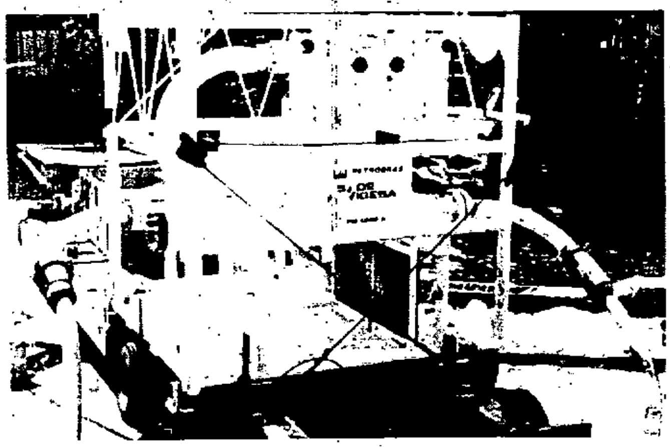


Figure 9 - Pig loop for subsea system in Campos Basin, Brazil[34].

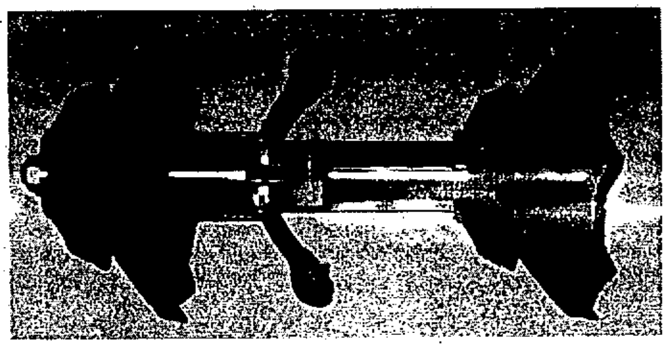


Figure 10 - Dual diameter scraper pig[34].

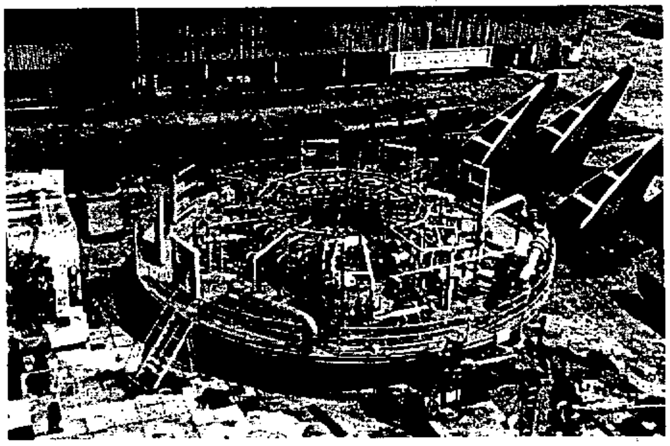


Figure 11 - Pig receiver and pig launcher at a FPSO in Campos Basin, Brazil [34].

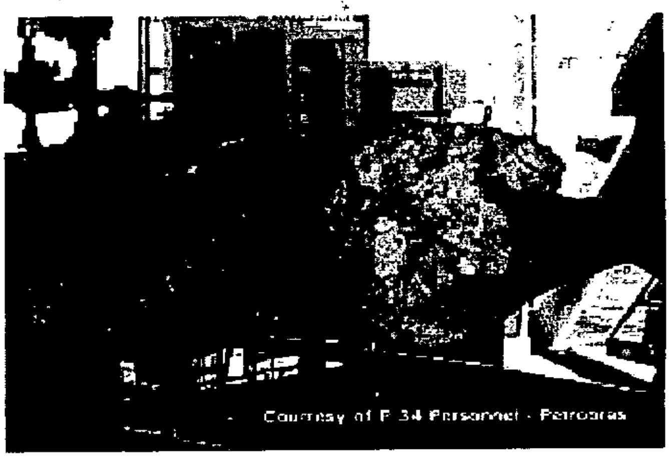
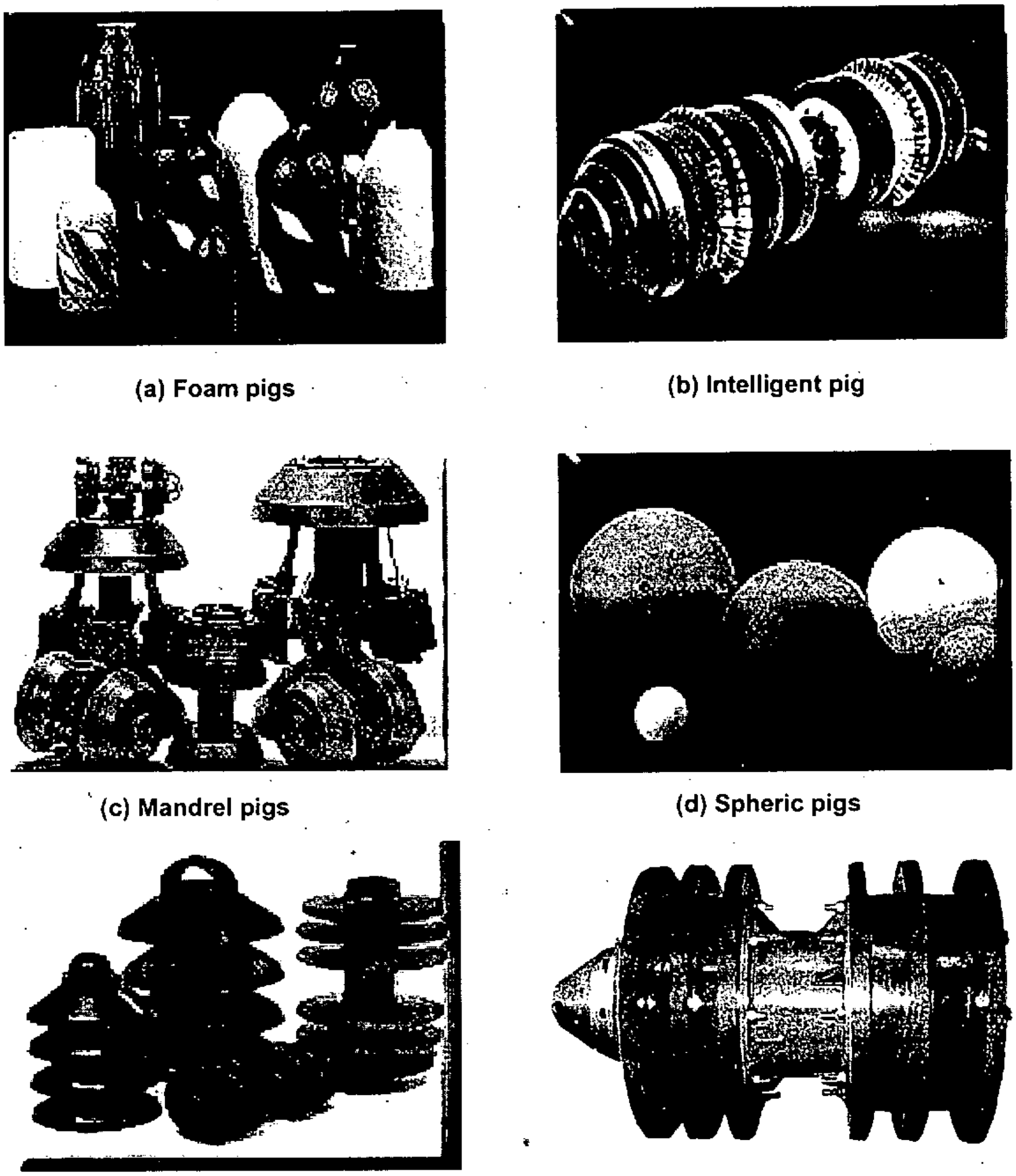


Figure 12 - Packed Hydrate Block Removed from Pig Launcher at P-34 platform at Campos Basin, Brazil[31].



(a) Foam pigs

(b) Intelligent pig

(c) Mandrel pigs

(d) Spheric pigs

(e) Solid cast pigs

(f) Jet stream pig

Figure 13 – Various candidate pigs for subsea flowline cleaning[36].

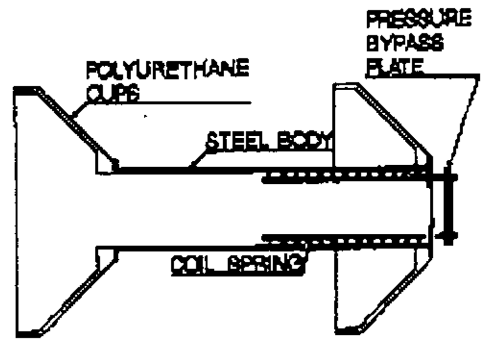


Figure 14 - The pressure bypass pig used for wax blockage removal in Valhall field[35].

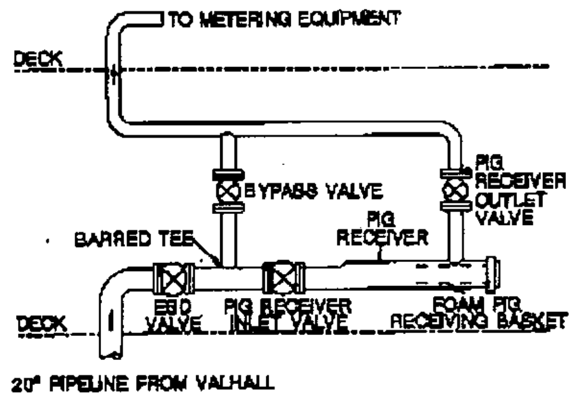


Figure 15 - Pig receiver system used in Valhall offshore oil pipeline cleaning[35].

Review of the State-of-the-Art of Pipeline Blockage Prevention and Remediation Methods

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by
Y. Doreen Chin
&
John G. Bomba
Kvaerner R J Brown
Houston, Texas

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With help from:

- Ed Gerber, Nita Oza, Martyn Witton, Geoff High, Steve Johnson, T. Alan Johnson
- Jill Buckley, John Carroll, David Lizne, G A Mansoori, Ben Bloys, S. Behrens, Dennis Cai
- Kim Covington, P. Tome, Linda Coates, Brad Bliss, Skipper Guy, Chuck Horn, Stuart Bell
- and many others,

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THE 3 (OR 4) STEP APPROACH
TO
PREVENTION
AND/OR
CONTROL

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1. Identify Potential Hydrate & Wax Problems
2. Find methods of preventing Hydrate and Wax problems
3. Determine methods of cleaning partly blocked flowlines
4. Determine methods for cleaning totally blocked flowlines

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1. Identify Potential Hydrate & Wax Problems

How?

A complete flow assurance study of the entire system--from reservoir to separator

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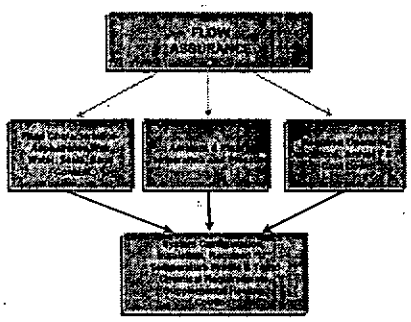

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Flowlines plug up when the flowing fluid reaches a temperature and pressure that induces hydrate formation, wax deposition and/or asphaltene precipitation

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Clarion

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Temperature

and

Pressure

Clarion

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What is a HYDRATE?

It is an ice-like solid that forms when:

- sufficient water is present
- a hydrate former is present
- right combination of P and T (low T &high P) exists

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Source:
SINTEF'S
WEBSITE

Research manager David [illegible] with a hydrate plug of the sort that forms in wells, pipelines and process equipment during offshore oil and gas production. These plugs form when water and light hydrocarbons come into contact under moderate to high pressures and at temperatures below 25 °C.

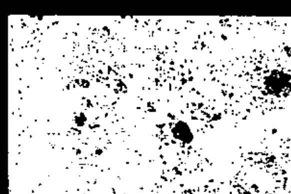
What is a **WAX (PARAFFIN)**?

- **Wax** is Not an **Asphaltene**
- it is a hydrocarbon
- it forms crystals
- it melts at elevated temperatures

What is an ASPHALTENE?

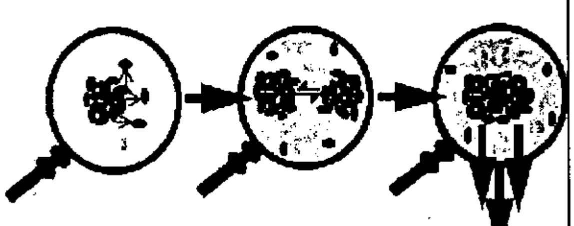
- **It is Not a wax**
- **It has a high molecular weight**
- **It is polar and**
- **It is aromatic**
- **it doesn't melt**

Asphaltenes under the microscope



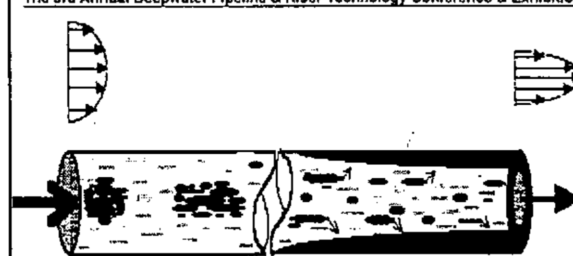
Microscopic depiction of a crude oil containing light fractions, heavy paraffins, aromatics, resins, and asphaltenes

Courtesy of GA "Ali" Mansoori, UIC



Aggregation and growth of heavy organic colloids and their eventual deposition

Courtesy of GA Mansoori



Courtesy of GA Mansoori,

U of Illinois, Chicago

Is it WAX or is it ASPHALTENE?

If it	Wax	Asphaltene
Dissolves in Hexane	Yes	No
Crystalline	Yes	No
Melts	Yes	No

2. Find methods of preventing Hydrate and Wax problems

Hydrate formation
- Temperature Control
- Water Control

Wax Deposition
- Temperature Control
- Chemical additives

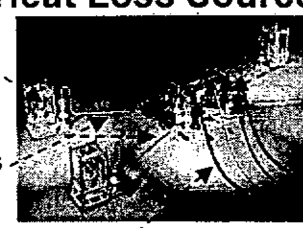
DON'T FORGET THE FOLLOWING SOURCES OF HEAT LOSS IN THE SYSTEM

- DOWNHOLE TUBING
  - XMAS TREES
    - CONNECTORS
      - JUMPERS
        - CONNECTORS
        - MANIFOLD PIPING AND VALVES
      - CONNECTORS
    - FLOWLINES
  - RISERS

Heat Loss Sources

Xmas Tree

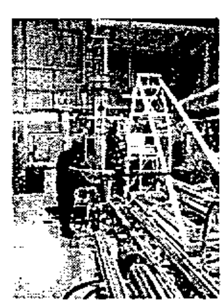
Jumpers



Manifold piping, valves, and connectors

Flowlines

Research Tools



ARC HP/ HT Deposition Flow Loop now located in Malaysia

PHOTO COURTESY OF:

Peter Tome & Linda Coates

Alberta Research Council

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PREDICTIVE TECHNIQUES

- HYDRATE FORMATION
- WAX DEPOSITION

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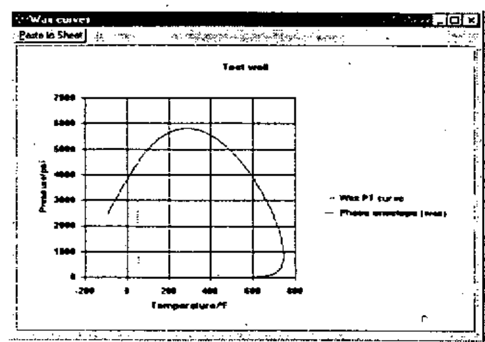
PVTsim, version 10, wax PT curve and phase envelope



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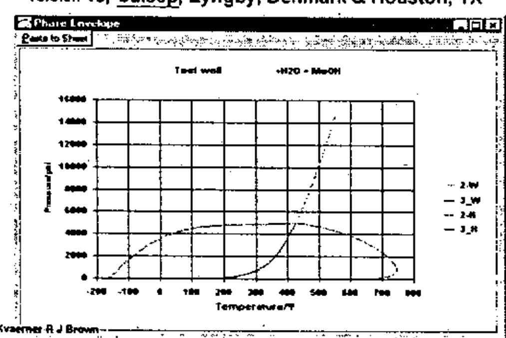
Phase Envelope with Water Dew Point Line, PVTsim, version 10, Calsep, Lyngby, Denmark & Houston, TX



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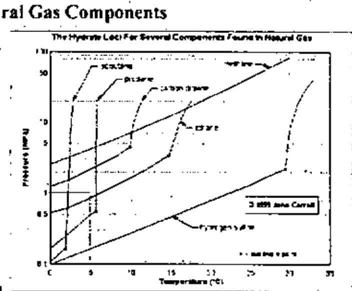
Hydrate Loci for Natural Gas Components

At temperatures less than the loci and at pressure greater than the loci (i.e., to the left and above) are where hydrates will form.

At 5°C and 1MPa, hydrogen sulfide, ethane and propane form hydrates, carbon dioxide, methane and isobutane will not.

The extension to mixtures is not obvious from this diagram. Other methods should be used for estimating the hydrate forming conditions for mixtures.



John J. Carroll, AQUAlibrium
P.O. Box 55219, Temple Postal Outlet
Calgary, Alberta, CANADA T1Y 6R6

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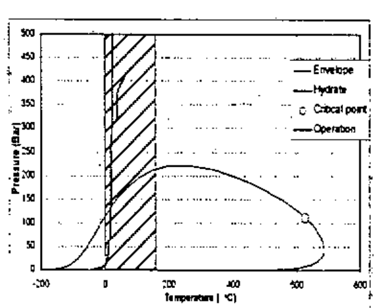
Computer generated Hydrate Prediction Curve (Typical GOM field)

Shaded Area is our concern



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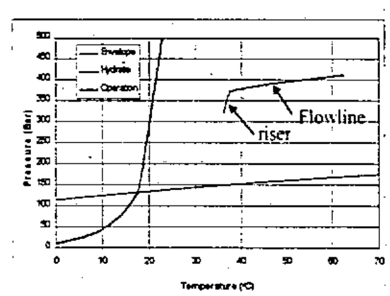
Area of concern to pipeliners



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Insulation

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Need Insulation?

- Where?
- How much?
- And what kind?
- Proposed installation method?

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- Typical Material Properties, K-value of pipe-in-pipe insulation

Material	K value Btu.in/hr.ft^2.°F	W/m. °K
Neoprene Rubber	1.820	0.263
Solid polypropylene	1.524 - 1.380	0.220 - 0.200
Coal tar enamel	1.513	0.218
Solid polyurethane	1.320 - 1.120	0.190 - 0.161
PP syntactic	1.104	0.160
PU syntactic	1.020 - 0.960	0.147 - 0.138
Syntactic epoxy	1.164 - 0.552	0.100 - 0.080
PP light foam	0.420 - 0.280	0.060 - 0.040
Glass fiber	0.270 - 0.240	0.040 - 0.415
PVC light foam	0.21	0.03
PU light foam	0.14	0.02
Phenolic foam	0.118	0.0204
IZOFLEX (requires pressure reduction)	<0.07	<0.01

Pressure Sensitive

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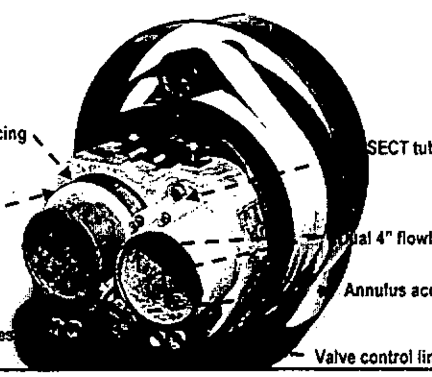

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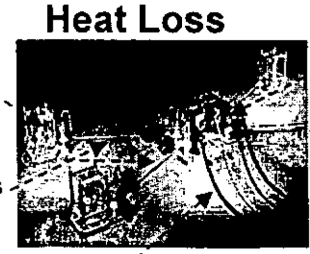
Heat Loss



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CHEMICAL INJECTION

- DEW POINT DEPRESSANTS
- POUR POINT DEPRESSANTS
- LONG CHAIN POLYMERS
- WATER?????

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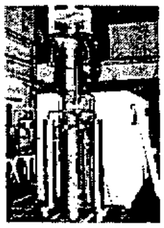
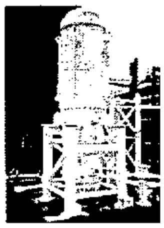
Kværner Booster Station Modules

Separator Module



Pump Module



Compressor Module

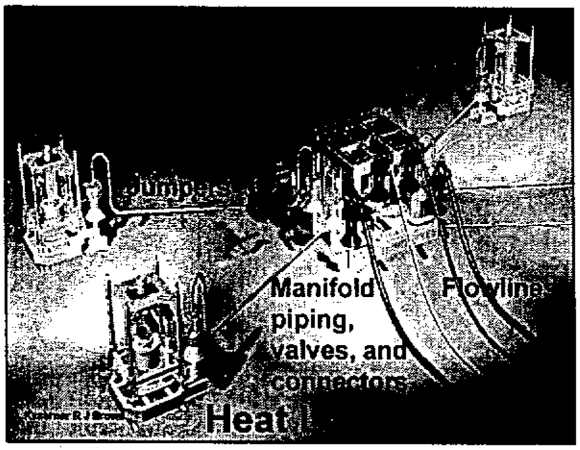
3. Determine methods of cleaning partly blocked flowlines

Hydrates

- Location of partial plugs
- Addition of Heat
- Blowdown the flowline
- Methanol - Methanol - Methanol
- Pigging - foam pigs followed by cup pigs

Wax

- Location of partial plugs
- Temperature Control
- Chemical additives
- Pigging - foam pigs followed by cup pigs

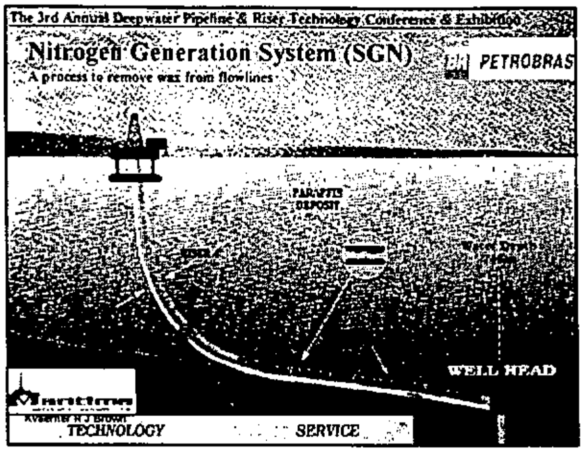


- How Does One Remove a Wax Plug?
- A Hydrate Plug??

- A thermal recovery method would be the best approach for wax removal **if** there was some way to maintain the heat.
- Hot water and hot oil have been used to "clean out" a well. Sometimes this only made matter worse because of the heavier components dropping out

PETROBRAS:

- has a two-part chemical solution that generates nitrogen and **heats up** when mixed.
- The technique has had success.
- The chemical is injected at the wellhead through a small pipeline (large umbilical).

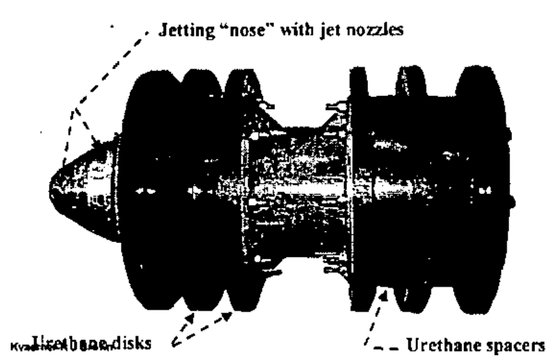


PRODUCTION IMPROVEMENTS WITH SGN

FLOWLINE	LENGTH (m)	BEFORE SGN (m^3/d)	AFTER SGN (m^3/d)
BJ-438	4,648	250	900
MRL-9	5,450	576	648
BJ-438	4,648	260	790
MSP-2	7,290	470	792
ML-377	5,263	393	645
ML-403	4,142	390	590
MRL-4	18,430	996	1,459
MRL-2	4,644	660	1,200

Ernie Casey in Houston:

- has developed a similar system
- no known data on testing



INTERVENTION TECHNIQUES

COILED TUBING

- WITH HOT WATER OR STEAM
- WITH CHEMICAL INJECTION

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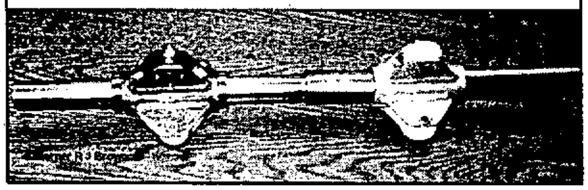
- **DeepStar** sub committee developed:
- Coiled Tubing methods.
- Tests completed last year suggest the coiled tubing can be run up to 18.9 Miles.
- Special "skate boards" at front
- push pull arrangement



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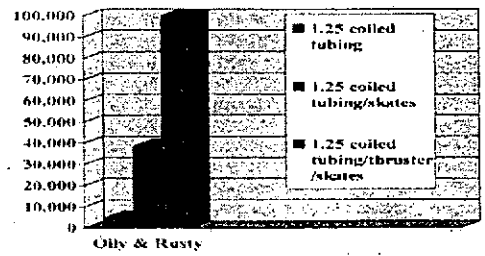
DeepStar 3202 Test Trials Results

6" nominal pipe.



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POSSIBLE COILED TUBING INSERTION POINTS:

- **AT RISER,**
    - **WELLHEAD,** MANIFOLD, **OR**
- **INTERMEDIATE POINTS IN LINE**

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- 90° bends in Riser
- Access points (piggable "Y")
- Cut the line and raise to surface

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Several Contractors have developed tools & procedures for flowline intervention, including:

- CalDive
- Oceaneering
- SonSub
- Coflexip Stena Offshore

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CalDive & Ambar

Have formed an alliance to clear blocked flowlines using coiled tubing and the"StarTac" system developed in the DeepStar program.

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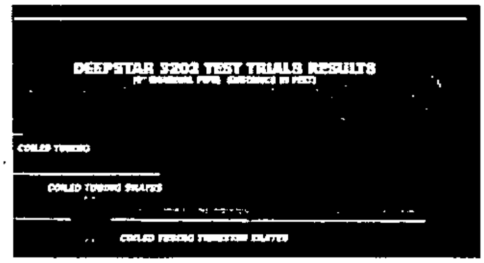
The StarTac process involves the use of a combination thrust and carry system to propel coiled tubing down a pipeline up to, but not limited to, distances of five miles or greater.

INTRODUCING STARTAC®

AMBAR'S Revolutionary Extended Reach Coiled Tubing Subsea Pipeline Remediation System.



Oceaneering

Designed and fabricated intervention tool for Shell's Mensa development

specifically for blowing down the system

Steel tubed umbilical deployed from DP vessel

Stab and Hingover connection at lower end

Shell Mensa:

- long tie-back, no insulation
- individual flowlines to manifold
- gas cooled below hydrate temperature
- TEG used to dehydrate the gas stream
- can blow down individual flowlines if necessary

4. Determine methods for cleaning totally blocked flowlines

Hydrates

- Locate partial plug(s)
- Addition of Heat
- Blowdown the flowline
- Methanol - Methanol - Methanol
- Mechanical intervention - coiled tubing
  - hot taps and bypass around block
- Pigging - foam pigs followed by cup pigs
- Combinations of above

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4. Determine methods for cleaning totally blocked flowlines

Wax

- Locate Plugs
- Temperature Control
- Chemical Additives
- Mechanical intervention - coiled tubing
  - hot taps and bypass around block
- Pigging - foam pigs followed by cup pigs
- Combination of above
- REPLACE THE LINE!!!!!

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SOME CASE HISTORIES

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- The Valhall pipeline in the North Sea
- was successfully pigged and cleaned out
- before plugging up
- cleaned to allow caliper and smart pig runs for establishing baseline wall thickness and "roundness"
- started with small foam pigs
- gradually increased size until possible to run
- cupped pigs, caliper and smart pig
- had many small problems

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- FLEXTREND DEVELOPMENT CO.
  - EB 914 in 950 feet of water
  - began life as a rich gas well with not much water, hydrates controlled with methanol
  - no indications of potential problems
  - in 6 months was producing waxy crude
  - soon plugged up
  - coiled tubing tried--both flowlines replaced
  - now shut in

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Routine shut downs sometimes lead to flowline blockages.

Pipelines in the Gulf blocked due to hydrates after shutting down for Hurricane Brett that hit South Texas last August

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- 550 feet water depth, 550 BOWPD, 400Mscfd
- 3" un-insulated flowline, 13 miles long
- Routine shut-in for Hurricane Brett
- Line would not restart-PLUGGED!!
- Hydrates suspected!!

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- Blown down from Shallow end -- no luck!
- So, plan to blow down from tree end
- Some modifications to tree required
- New, larger diameter connection added
- Attach Blowdown line to new connection
- De-pressure between tree and plug(s)
- Nothing happens
- NOW WHAT????

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- Even though originally told that it had to be a **hydrate** and Not a wax plug, it must be a **wax Plug!**
- **SO, what to do now?**

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Conclusions:

1. Always carry out a **flow assurance** study of the "**system**", **not just the flowline.**
2. **Prediction** of potential problems is possible and reasonably accurate.
3. In theory, removing a hydrate blockage is easier than removing a wax plug.
4. **Building in** intervention means is relatively low cost insurance.
5. **Subsea trees or manifolds** should have full opening access ports to facilitate blowdown or coiled tubing or pig access.
6. Designing in the location(s) **where blockages should occur** to facilitate unblocking is prudent.

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Conclusions:

7. **Evaluate the entire production system.** Start with the down hole **tubing** and work your way through the **Christmas** tree, the **jumper system**, the **manifold**, the **jumpers**, the **flowline**, the **riser**. Decide which segment has the highest heat loss. Can it be made more efficient relative inexpensively. One or two thousand feet of vacuum **tubing** might give you 10 to 30 extra degrees at the wellhead. **Insulate** the jumpers—consider **convective heat loss** through the space between insulation and the jumper and through the seams of the insulation. Look at the **manifold** (if there is one) in the same way. Look at the **flowline** and the **riser**.

   The flowline and riser may be the most efficient part!
8. Talk to the Contractors. They may have the answer.
9. **Think** it though. Proper Prior Planning Prevents ____ Poor Performance!

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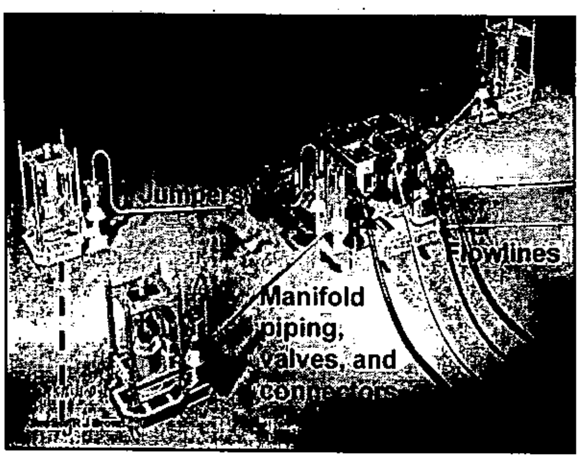

Flow Assurance Techniques—Relative Costs vs. Effectiveness

Chuck Horn
Paragon Engineering Services, Houston, USA

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

Flow Assurance Techniques

Relative Cost vs. Effectiveness

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Subsea Pipeline Technologies

Flow Assurance Is A <u>SYSTEMS</u> Problem,

And…

There Is No <u>TEXTBOOK</u> System.

I.E. In Practice, All Systems Are Different

(There Are <u>MANY</u> Variables)

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Flow Assurance Issues

- Fluid Power/Drive
- Multi-Phase flow
- Hydrates
- Wax
- Asphaltines
- Scale
- Equipment Failure

Architect -vs.- Analyst

Engineer

Designer

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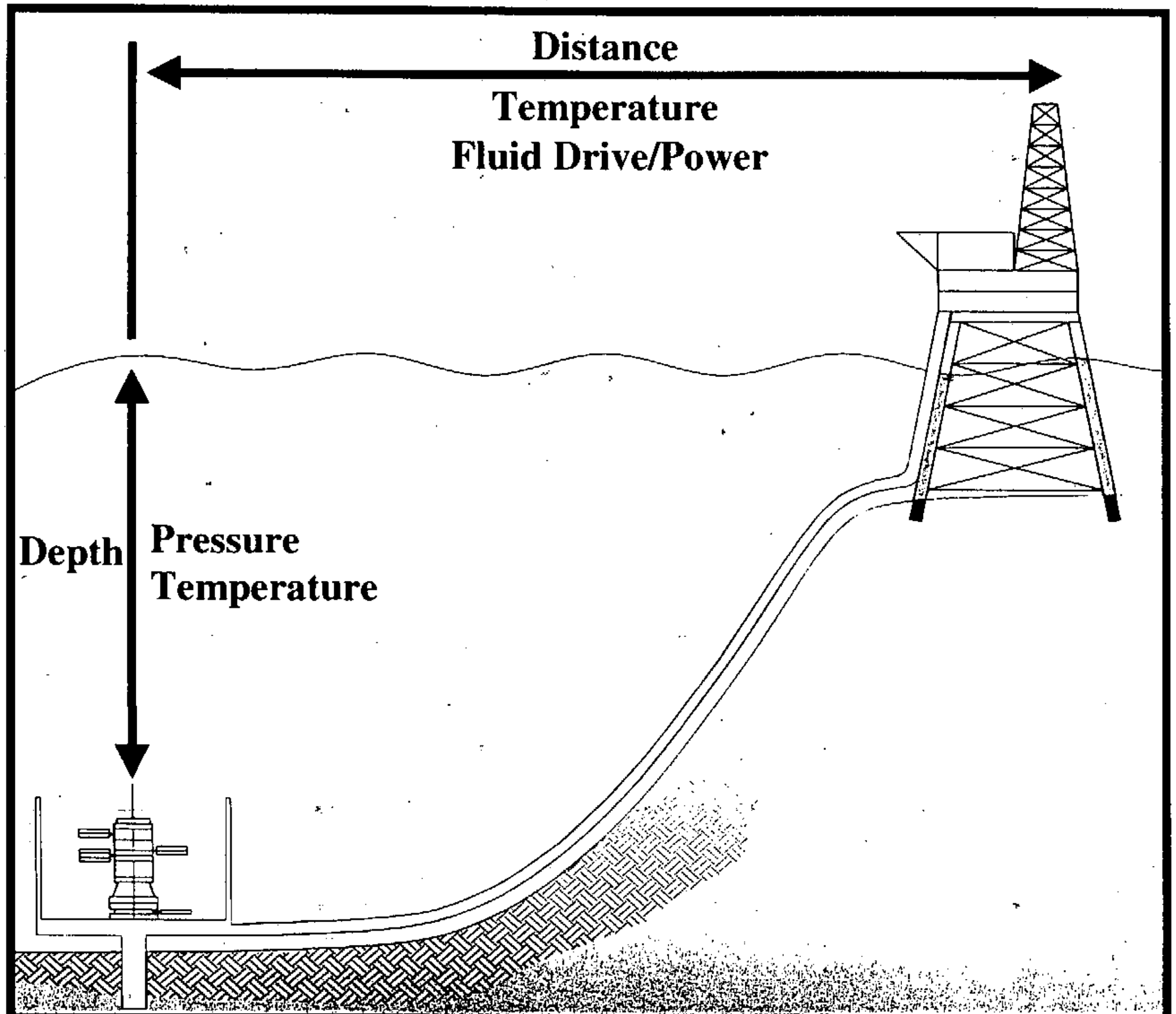
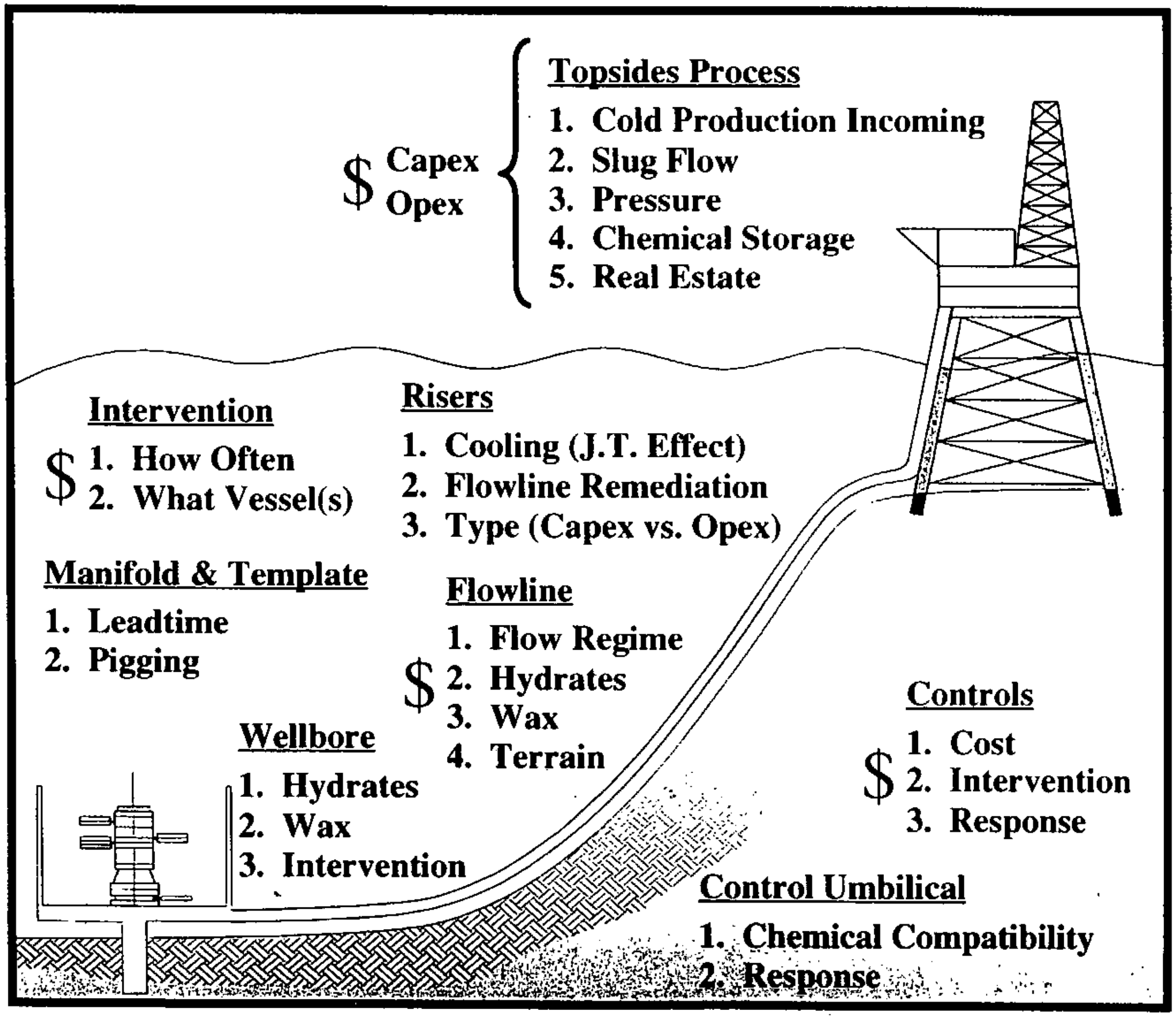
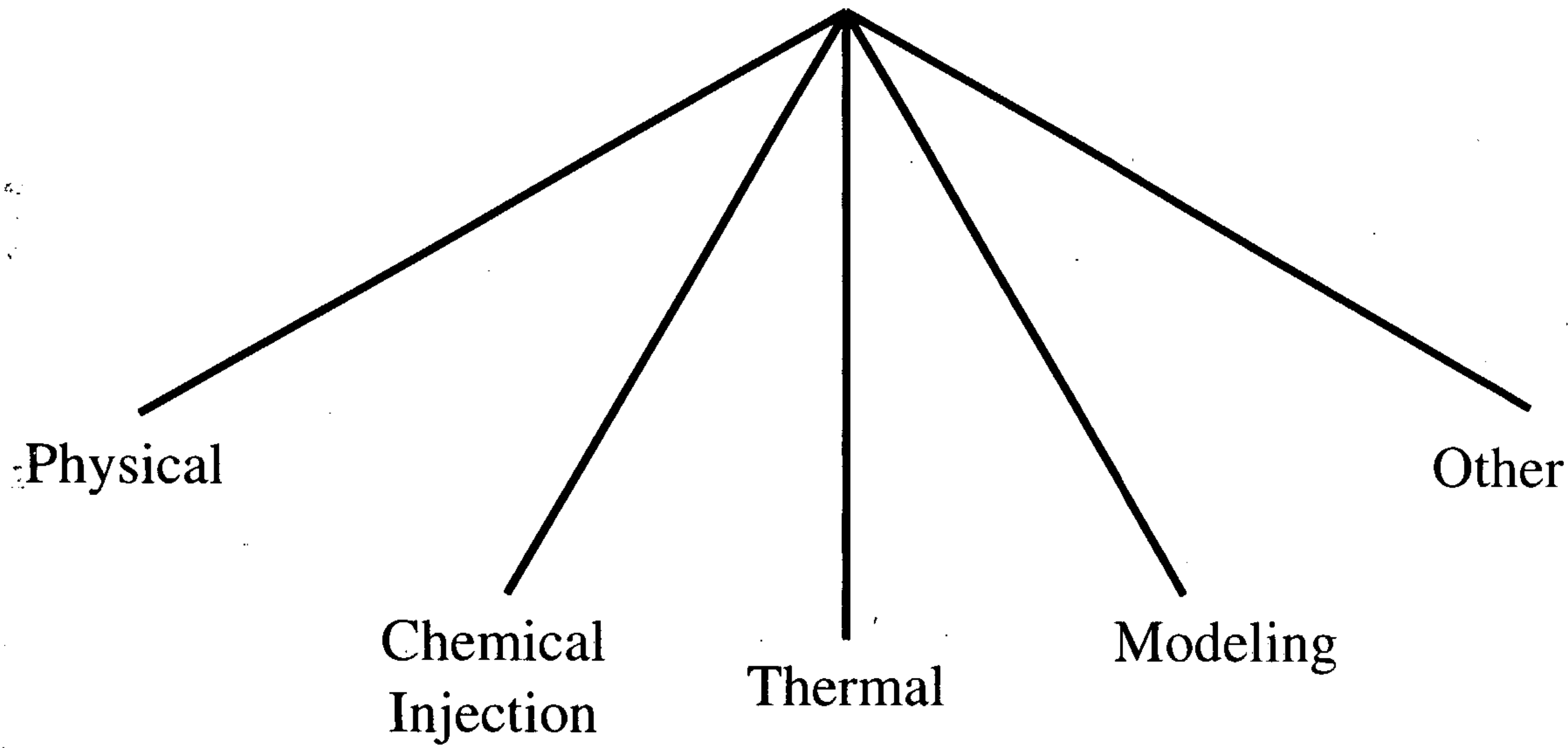


Subsea Pipeline Technologies



Subsea Pipeline Technologies

Flow Assurance Techniques



Subsea Pipeline Technologies

What's Important?

Real Estate → Location, Location, Location

Flow Assurance → Systems, Systems, Systems

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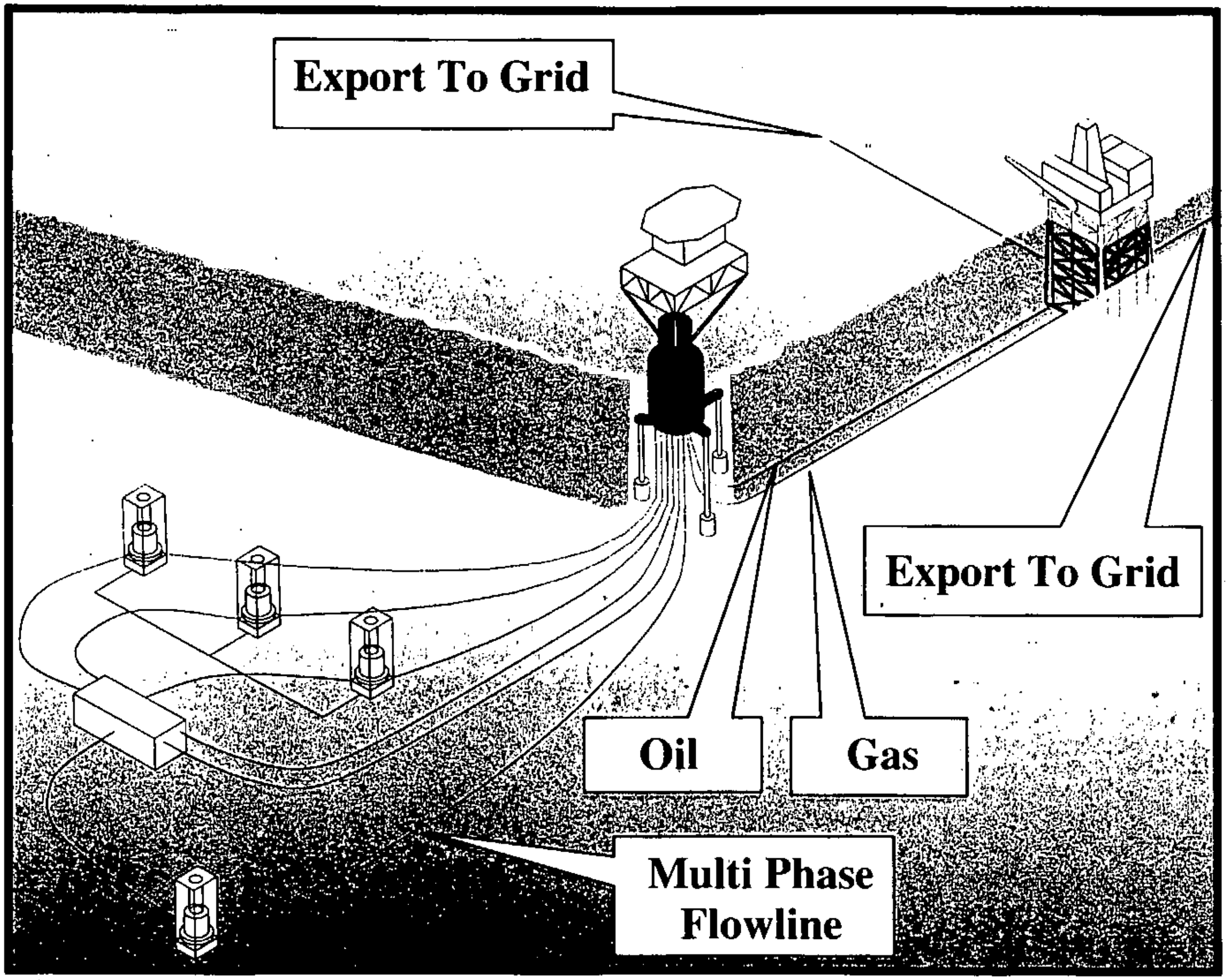

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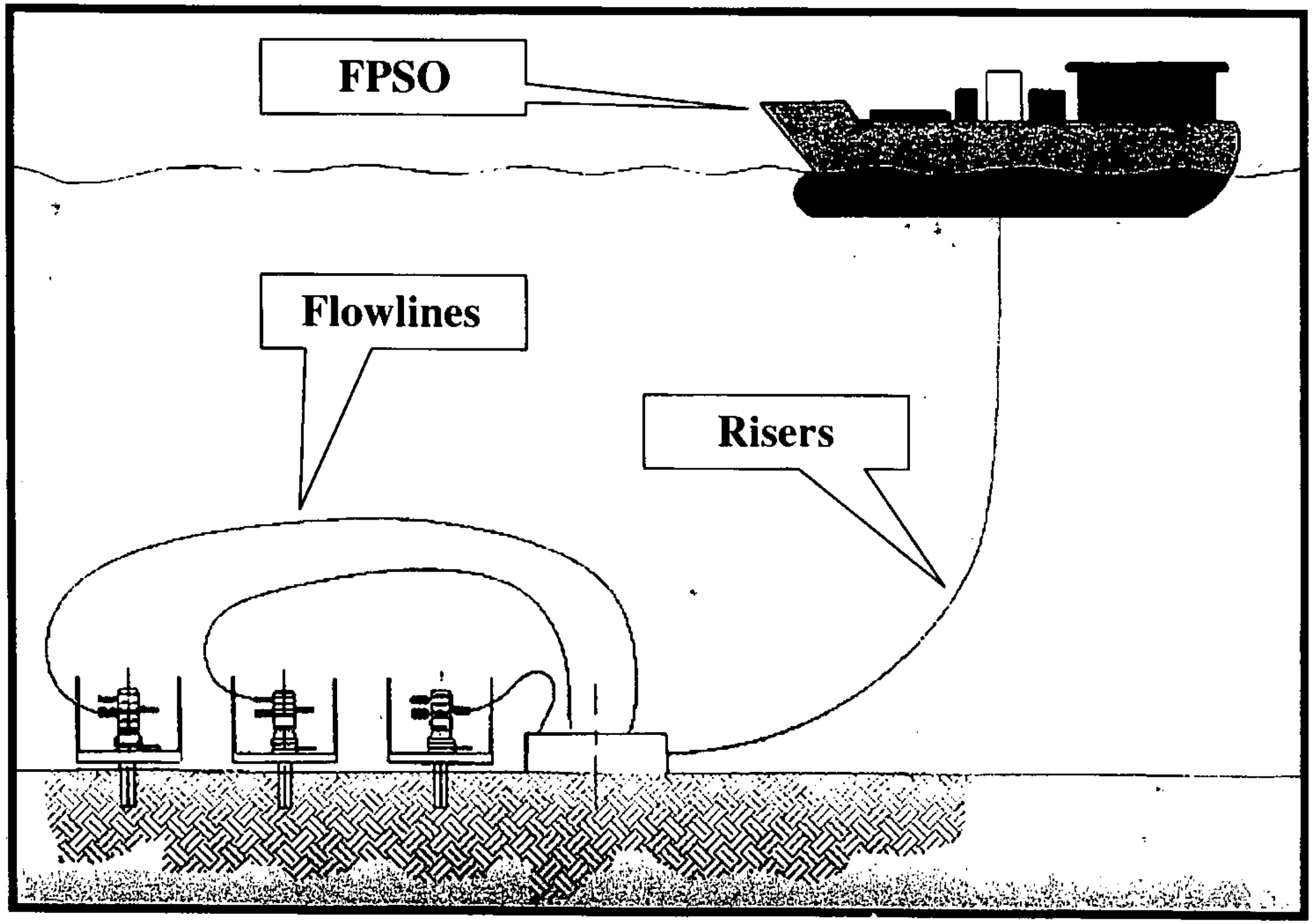
Subsea Pipeline Technologies

Physical Location



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Subsea Pipeline Technologies

Physical

- Pigging
  - Round Trip
  - Subsea Launcher
- Process Options
  - Gas Lift
  - Multi-Phase Pumps
  - Seabed Separation
  - Downhole Separation
  - Seabed Re-Injection
- Location/Architecture

Gas Lift, Multi-Phase Pumps: Established

Seabed Separation, Downhole Separation, Seabed Re-Injection: Emerging

Chemical Injection

- Inhibitors
- Kinetic

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Subsea Pipeline Technologies

	$ Cost $		Effectiveness	Ongoing Study Interest
	Capex	Opex		
Physical				
* Round Trip Pigging	High	Low	Good	Low
* Subsea Pig Launcher	High	?	Good	Medium
* Gas Lift	High	Medium	Fair	Low
* Multi Phase Pumps	High	High	Fair	High
* Sea Bed Separation	High	?	?	High
* Down Hole Separation	High	?	?	High
* Sea Bed Re-Injection	High	High	?	High
* Location/Architecture	? ? ? ? Large Value Influence		Very Good (If Done Right)	Low

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Subsea Pipeline Technologies

	$ Cost $		Effectiveness	Ongoing Study Interest
	Capex	Opex		
Chemical Injection				
* Inhabitors	Low	High	Good	High
* Kinetic	Low	High	Emerging - Looks Good	High

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Subsea Pipeline Technologies

Thermal

- Insulation
- Burial
- Pipe - In - Pipe
- Heating
  - Electrical
  - Hot Fluid Circulation

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Subsea Pipeline Technologies

	$ Cost $		Effectiveness	Ongoing Study Interest
	Capex	Opex		
Thermal				
* Insulation	High	Low	Fair	High
* Burial	High	Low	Fair	Low
* Pipe - In - Pipe	High	Low	Very Good	Medium
* Electrical Heat	High	?	? Could Be Very Good ?	High
* Hot Fluid Circulation	High	?	? Could Be Very Good ?	Medium

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Subsea Pipeline Technologies

Modeling

- Analysis
  - CMC - PROP
  - D - Spice
  - D - Wax
  - Equiphase
  - Hysim/Hysis
  - Multiflash
  - OLGA
  - Parasim
  - Pipephase
  - Pipesym
  - PLAC
  - Provision
  - Tacite
  - W - OLGA

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Subsea Pipeline Technologies

	$ Cost $		Effectiveness	Ongoing Study Interest
	Capex	Opex		
Modeling				
* Analysis	Low	Low	Good	High

Subsea Pipeline Technologies

Other

- Magnets
- Ultrasonics
- Microwaves
- Internal Coatings

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Subsea Pipeline Technologies

	$ Cost $		Effectiveness	Ongoing Study Interest
	Capex	Opex		
Other				
* Magnets	?	?	?	?
* Ultrasonics	?	?	?	?
* Microwaves	?	?	?	?
* Internal Coatings	?	?	?	?

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Subsea Pipeline Technologies

	$ Cost $		Effectiveness	Ongoing Study Interest
	Capex	Opex		
Chemical Injection				
* Inhabitors	Low	High	Good	High
* Kinetic	Low	High	Emerging - Looks Good	High
Thermal				
* Insulation	High	Low	Fair	High
* Burial	High	Low	Fair	Low
* Pipe - In - Pipe	High	Low	Very Good	Medium
* Electrical Heat	High	?	? Could Be Very Good ?	High
* Hot Fluid Circulation	High	?	? Could Be Very Good ?	Medium
Physical				
* Round Trip Pigging	High	Low	Good	Low
* Subsea Pig Launcher	High	?	Good	Medium
* Gas Lift	High	Medium	Fair	Low
* Multi Phase Pumps	High	High	Fair	High
* Sea Bed Separation	High	?	?	High
* Down Hole Separation	High	?	?	High
* Sea Bed Re-Injection	High	High	?	High
* Location/Architecture	? ? ? ? Large Value Influence		Very Good (If Done Right)	Low
Modeling				
* Analysis	Low	Low	Good	High
Other				
* Magnets	?	?	?	?
* Ultrasonics	?	?	?	?
* Microwaves	?	?	?	?
* Internal Coatings	?	?	?	?

Underwater Joining to 8,200ft - An Alternative to Mechanical Connectors

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and
Pipes & Pipelines International

Underwater Joining to 8,200ft - An Alternative to Mechanical Connectors

Abstract

Arc welding is traditionally used for pipeline construction, tie-ins and repair on land and at water depths ranging from the splash zone to a few hundred metres. Considerable quantities of hydrocarbons have been located offshore at depths inaccessible to divers and exploitation of these reserves has already begun. There are a number of installation and repair techniques available to the offshore engineer, all of which have advantages and limitations. This paper reports on the recent results of a joint industry sponsored programme to examine the feasibility of arc welding technologies for deep water, diverless installation and repair. The work highlights the major operational features of the Plasma and GMA welding processes at water depths down to 2,500m (equivalent to 8,200ft). The paper introduces some of the key results and the major conclusions from this work and discusses the associated equipment and engineering problems involved in the provision of a welding solution.

1. Introduction

The 50 year history of exploitation of the world's offshore oil and gas reserves has resulted in an established engineering knowledge base for shallow water working. The problems associated with working at depths of a few metres or a few hundred metres are mostly known and understood, and techniques are well established to deal with the majority of underwater operations.

While historically divers have been employed for inspection, manipulation and repair activities in shallower waters, this is not viable at water depths greater than about 400m (1,310ft) as the ambient pressure has an incapacitating effect on the human body. Although divers have reached water depths well over 400m, functionality and co-ordination deteriorate and working duration is considerably reduced due to rapid fatigue. With the steady move to exploit hydrocarbon reserves at water depths substantially greater than the manned diving limit, engineering methods are likely to differ from those utilised in shallower waters and automation plays a crucial role.

As the oil industry becomes more established in deeper waters the necessity for an installation methodology and contingency repair system for very deepwater pipelines is apparent from both the practical/economic and political/environmental perspectives. Existing systems, which primarily use semi-automated arc welding techniques, are limited by their reliance on the human diver-welder for key tasks in the repair cycle. Although these tasks are relatively simple in terms of human capability, full automation presents some interesting, but not insurmountable, challenges. Before the operators develop suitable solutions, fundamental questions concerning welding process capability in deeper waters have to be answered. The work described in this paper demonstrates that welding processes can operate successfully, and even somewhat routinely, at simulated water depths down to 2,500m (8,200ft).

Proceedings of the 3rd Deepwater Pipeline & Riser Technology Conference, Houston, Texas, March 7-9, 2000.

Given the remoteness of pipeline locations it is perhaps surprising that a large number of potential failure mechanisms are apparent. These may be identified and then collated into the broad groups of environmental effects (seabed movement and current action), impact damage, corrosion, material and welding defects, fittings failures and design faults [1-4]. Environmental and natural hazards can also cause significant damage [4]. Joining is also required for functions such as pipeline tie-ins and welding can offer significant cost benefits, particularly when considering larger diameter pipelines [5].

2. Joining Techniques

At water depths accessible to divers, repairs or modifications have generally been accomplished by direct human intervention utilising either manual or semi-automated welding or mechanical connectors. Each technique has its own advantages and drawbacks and the selection of the most appropriate technique is likely to depend on engineering considerations including location, access, depth, and size as well as operational costs.

Welded joints have a long established history of use in the field and are widely trusted by the operating industry, especially in the North Sea region. Of importance for contingency requirements, a single integrated piece of equipment may be constructed which is able to address all pipeline sizes. Capital expenditure is therefore relatively limited and system running costs are reduced to those associated with routine maintenance. Of great advantage for certification requirements is the basic nature of a welded joint which ensures that the full integrity of the structure is regained on a permanent basis. Unfortunately from a welding process perspective, the stable arc behaviour exhibited at normal atmospheric pressure degrades with increasing ambient pressure and care must be taken to ensure adequate process performance.

As an alternative to welding, mechanical connectors offer a substantially pressure independent repair method. The knowledge base for their use is developing with operator experience and anecdotal evidence suggests that they have gained widespread acceptance for smaller diameter pipelines. However, their use with larger diameter pipelines remains a matter for some concern and has yet to be proven, even at the prototype stage. The cost of a connector for a 42" diameter pipeline (currently estimated at ~£1M each) may make their use impractical or at least somewhat undesirable. Given that these connectors may be expected to have significant lead times, local stocks for each specific pipeline diameter must be held as part of any contingency repair system. Thus the capital expenditure involved is considerable and the life cycle costs may become significant.

3. Underwater Welding

It is useful to consider the current state of the art in underwater welding as a basis for comparison with the approach adopted for deep waters. Of the techniques available for arc welding in water, only two are routinely used offshore for major repair scenarios; wet welding and dry hyperbaric welding [6]. Whilst wet welding is self descriptive, dry hyperbaric welding may be described as an underwater welding operation carried out in a high pressure gaseous habitat or chamber which, although dry, is usually open to the water. The humidity in the habitat environment is high, typically approaching 95% [5].

Wet welding is widely employed for welding in shallow waters and offers a cost effective approach when low to moderate joint quality is acceptable. Application becomes more difficult when high quality welds are required, although advances in electrode formulation and deposition techniques in the past decade have made wet welding acceptable for many repair scenarios. The problems associated with wet operation occur due to the thermal and chemical properties of water. Very rapid cooling occurs resulting in increased hardness and decreased toughness and ductility [7,8]. Cooling rates are typically reported to be three to four times greater than in air [9]. Problems also occur due to hydrogen ingress into the weld leading to an increased likelihood of porosity and hydrogen induced cold cracking [7]. This problem is exacerbated as operational depth increases and it is unlikely that wet welding will be extensively employed at depths greater than about 75 to 100m (245 to 330ft). The main advantages of wet welding are related to the simplicity of operation and to costs, which have been shown to be less than half those for dry hyperbaric welding [10].

Dry chamber arc welding under hyperbaric conditions may be accomplished by shielded metal arc welding (SMAW), gas metal arc welding (GMAW), flux cored arc welding (FCAW), gas tungsten arc welding (GTAW) or plasma arc welding. The increased control over operating conditions and process performance obtained by fully surrounding the weld with a gaseous atmosphere leads to significant improvements in weld quality compared with wet operation. The part may be easily heated both prior to welding, during inter-pass periods and after the weld, and thus the metallurgical problems associated with quenching by water are avoided. Where weld quality is important, such as for structurally significant parts, dry chamber welding can be used to advantage to provide weld properties comparable and in many cases superior to those obtained during initial fabrication [11].

SMAW offers the benefits of low cost and process simplicity, and has a considerable history of offshore application [12]. The arc is struck between the workpiece and the rod like electrode which has an outer coating of flux. The flux serves to protect the hot electrode and molten droplets from oxidation by the atmosphere and provides easily ionisable material to stabilise the arc. It also contains materials for control of weld metal chemistry and provides a slag coating for the protection of the weld pool during cooling. The stability of the SMAW process depends to a large extent on the chemical composition of the electrode flux which in turn determines the type. Basic electrodes are most commonly used as these are least affected by changes in ambient pressure [13]. Pressure has a significant influence on chemical reactions making flux formulations pressure sensitive. At water depths greater than about 300m (985ft) acceptable metallurgical properties are difficult to achieve [14], metal transfer is usually of the globular-dip type and the frequency of destabilising short circuits increases [15].

In the repair of structures at depths exceeding 100m (330ft), GTAW is often selected due to the quality of the welds produced. [16]. GTAW has several advantages: it is well understood, produces very fine grained weld metal with high toughness and is clean (producing little or no fume or spatter). The process is versatile in application and has an established history of root pass completion [17]. These factors more than offset the drawback of relatively low metal deposition rates. Whilst remaining effective at depths to at least 400m (1,310ft), the stability of the GTAW arc gradually decreases as ambient pressure rises. At high pressures, the arc roots contract and become highly mobile and, whilst the central current carrying core of the arc also contracts, the outer regions of the arc expand [18]. The gas flow in the outer regions becomes turbulent and the plasma velocity falls [19] causing the arc to become less directionally stable and more susceptible to external forces, such as stray magnetic fields. Considerable evidence suggests that even under laboratory conditions, these instabilities make the process unworkable at a depth limit somewhere in the range 500m (1,640ft) to 750m (2,460ft) [20].

The GMAW process offers potential advantages in terms of continuous operation and ease of manipulation; however, it has only been occasionally employed for dry hyperbaric applications. At elevated pressures, the process alters dramatically; the arc contracts rapidly and fume generation and spatter levels increase [21]. The highly dynamic nature of the process, coupled with rapid changes in behaviour with even modest increases in ambient pressure lead to instabilities and resultant lack of fusion. Richardson and Nixon [19] suggested that efficient control over the welding power source in the various stages of arc development (i.e. short circuit and open arc conditions) would be necessary to achieve a stable process, a suggestion which has been confirmed in the laboratory [19,20]. Provided control is achieved, stable and practical welding conditions may be maintained [20] over a wide pressure range.

FCAW benefits from the advantages of flux assisted operation and has many features in common with the solid wire GMAW process. The electrode flux is chosen to assist the stability of the arc, whilst the slag produced modifies the weld metal chemistry and may also support the molten pool during positional welding [21,22]. Suitable choice of flux composition can be made to increase the deposition rate and improve the tolerance to parametric variations [23]. The removal of the flux deposit between weld runs presents an additional task for the operator and, in common with SMAW, the process chemistry is pressure sensitive. Nevertheless, FCAW has been employed for a number of dry hyperbaric applications.

The plasma welding process has not been used in any practical applications offshore but has been studied in the laboratory and shows promise for enhanced stability at higher pressures [24]. Although the potential advantages have been recognised since the late 1970s, development of the process for hyperbaric applications has not been pursued due to the adequacy of GTAW for welding repairs at water depths accessible to divers. The inherent directional stability offered by the constricted arc offsets the decrease in stability found with the free burning GTAW process. Although the process still becomes progressively less stable with increasing pressure, the positional instabilities are constrained due to the higher gas velocity in the arc.

Of the above processes only plasma welding and GMAW/FCAW remain viable at water depths greater than about 500m (1,640ft). SMAW is not used due to problems associated with automation, whilst GTAW suffers from an unacceptable deterioration in process stability.

4. Equipment for Hyperbaric Welding

4.1 Current Offshore Systems

Welded pipeline tie-ins and repairs offshore have so far taken place in water depths of less than 400m and have therefore made use of divers and either manual or semi-automated welding methods. Existing equipment such as THOR and OTTO is capable of performing pipeline repair welds over the full pressure range accessible to divers. Such systems have performed repairs at depths down to ~250m (820ft). The Statoil managed Pipeline Repair Spread (PRS) operating in the North Sea, has seen substantial use in the field utilising semi-automated (i.e. diver assisted)

GTA welding. Figure 1 gives a schematic impression of the deployed system, showing the manipulation 'H' frames used for pipeline lifting and initial alignment.

It is notable that the range of tasks involved in performing a subsea pipeline repair using either mechanical or welding techniques are extremely similar. For both techniques, before joining can occur the pipeline must be excavated and lifted. Unserviceable parts must be removed along with weight and anti-corrosion coatings, and surfaces must be cleaned. A typical sequence of events for a welded subsea pipeline repair using the PRS is given below.

The pipeline region must be excavated and cleared of debris in preparation for lifting [25]. Two large 'H' frames (each weighing 70 metric tonnes and having a lifting capacity of 120 tonnes) are used for pipeline manipulation and are capable of moving the pipeline in the lateral and vertical directions, as well as walking the pipeline axially [26]. A combined tool (figure 2) cuts the pipe metal using a high pressure water-grit jet [27]. When the pipeline is cut, the tooling is changed and two longitudinal cuts and a full circumferential cut are made in the concrete, which is prised off the pipeline in two halves. A high-pressure jet is also used to remove the anti-corrosion coating.

The replacement part, commonly referred to as the spool piece, is lowered by crane and then roughly aligned to the pipeline using the hydraulic 'H' frames (figure 1) and the habitat is lowered over the pipe ends (figure 3). Integral remotely operated pipe doors with flexible sealing skirts make the seal around each pipe, allowing injection of pressurised gas to displace the water contained in the chamber. Operations up to this point can be made without diver intervention. Utilising an Integrated Modular Tool (IMT) the pipe out-of-roundness is minimised by activation of 8 hydraulic clamps which squeeze the pipeline circumferentially. Using a machining tool attached to the IMT, a bevel preparation is machined onto the pipe end, to match that of the spool piece. The IMT provides the orbital movement around the pipeline, all tooling, including the welding head being loaded and unloaded by a diver situated inside the chamber. Once finished, fine alignment of the two pipe ends can be started.

Integral to the habitat, and crucial to the repair, is the fine alignment frame (figure 3). This is specified to align the prepared pipe ends to within 0,+1mm root gap and 0,+2mm high/low under the control of a diver [27]. Achieving this tolerance is a key factor for welding procedure development and for full automation. Once the pipe ends are aligned, the diver sets up the welding head, pre-heat mats and degaussing coils ready for welding operations to begin [26]. Surface based operators then take over to perform the welding operation. The parameters for each weld pass are set by test welds which are completed on shore in a hyperbaric chamber prior to deployment. On completion of the welding, an NDT assembly is mounted onto the IMT and joint integrity is checked and verified by standard ultrasonic NDT principles [26]. To complete the repair a protective coating is applied to the area, the chamber is flooded and all equipment is recovered to the surface.

4.2 The HyperWeld 250 Deepwater Welding Simulator

The HyperWeld facility at Cranfield was developed in the mid 1990s for the purpose of re-creating high pressure gaseous environments and conditions similar to those found offshore. Welding is carried out inside an enclosed chamber with a maximum working pressure of 250bar (equivalent to 8,200ft water depth); the HyperWeld is therefore the deepest underwater water welding simulator in the world. The chamber has an internal diameter of 1.1m and working length of approximately 1.2m giving a total volume of $1.15m^3$. Vessel services are provided through a static end plug and a cast 200mm (8") thick shell slides over the work frame and service module and is locked in place by four hydraulically activated radial rams which extend into the shell (figure 4). The end plug supports penetrators for welding power (3), shielding gas supplies (2) cooling water (3 circuits), video camera controls and signals (3) and electrical equipment connections, comprising more than 180 individual lines which service motor drives, encoder feedback, lighting, and electrical power supplies to water, clean gas and fume extraction equipment. Fibre optic pressure wall penetrators have also been developed.

The feasibility of welding at high pressures has been shown to be critically dependent on power source performance (see for example [19,20]) and voltage requirements are known to increase with water depth [28]. Two hybrid welding power supplies have been developed in conjunction with Fronius Schweisstechnik, Austria. The first provides an output of 450A at up to 200V with dynamic response rates suitable for high pressure operation. A further set provides up to 700V and a 100A output capability for plasma welding operations. Control of the power sources is achieved using hybrid digital and analogue computing facilities to provide feedback control and process sensitive response.

Pressurisation and shielding gases are pumped into the chamber to achieve the required pressure and re-cycled after welding to reduce operational costs. Shielding gases are supplied from separate storage facilities pumped to 350bar prior to welding. Flow monitoring and regulation is achieved using motorised needle valves linked to software which carries out calibration and monitoring services during welding. Gases may also be mixed 'on-line' where required for enhanced process operation.

The welding control system is based on Statoil's current semi-automated Pipeline Repair Spread (PRS), and was supplied by Isotek Electronics Ltd. The control is supervised by a surface based operator (top station) who passes instructions to the repair site control module (bottom station). The HyperWeld retains the '*top station*' user interface and '*bottom station*' real time control architecture, providing compatibility between the laboratory system and functional offshore welding equipment.

The HyperWeld is equipped with a modular three axis linear welding head (figure 5) which can be rotated to provide any welding orientation in the 5G position. The head is driven by high speed and high torque stepper motors specified to match or exceed the requirements of the target welding process. An orbital welding head is currently under construction which is compatible with the linear system and suitable for pipelines of up to 400mm (16") diameter (figure 6). Facilities for counter rotation of the specimen are included in order to simulate welding on larger diameter pipelines. The orbital head specification matches or exceeds that of the existing equipment.

5. Results from Recent Deepwater Welding Research

Results from welding investigations carried out under the umbrella of the '*Deepwater Hyperbaric Welding*' joint industry sponsored research programme are reported for both the plasma and GMA welding processes. The research has been undertaken in two phases, with initial emphasis placed on the demonstration of process feasibility. The present (phase II) programme focuses on process control, weld procedure development, repeatability and joint performance, and is due for completion by the end of December 2000.

5.1 Arc Stability

A large number of experiments have been carried out to examine the influence of pressure on GTA and plasma process stability at pressures in the range 40 to 250bar (1,280 to 8,200ft), including measurements of weld bead geometry variations, investigation of voltage variation and the measurement of arc root oscillations and arc root dimensions using planar probe techniques. Full details may be found in reference [28].

Figure 7 shows the influence on weld bead stability of process selection for autogenous welds made in the pressure range 75 to 250bar (2,430 to 8,200ft). Lateral bead wander is particularly evident on the GTA welds for all currents in the range 20 to 70A. In contrast, the plasma welds show reduced stability at the lower currents (30 and 40A) and virtually no instabilities at the higher currents (with the exception of the 70A, 250bar weld where orifice erosion occurred).

The standard deviation of GTA voltage (a measure of the variation of load which in turn is related to process stability) normalised to the mean arc voltage is shown as a function of operating pressure in figure 8. This suggests that the arc is becoming increasingly stable as pressure rises and is at variance with the observed behaviour of the autogenous weld beads. Similar results have also been obtained for the plasma arc.

In order to investigate this behaviour, a water cooled anode probe was employed. The probe comprised two electrically isolated halves, separated by a thin (0.2mm mica) insulating layer. The arc was positioned such that equal mean current flow through each probe section was achieved, and stability was examined based on frequency and amplitude changes due to arc oscillations. Typical results are illustrated for different processes and welding torch configurations in figure 9. The curves suggest that as the GTA shielding cup diameter reduces and as the plasma arc becomes more constricted, the arc oscillation frequency rises. The transition from free burning GTA to constricted plasma arc appears to be smooth and continuous. It is notable however, that the oscillation amplitude remains relatively unaffected by the choice of welding process or the process operating conditions at any given pressure.

The practical influence of arc oscillation on weld bead formation is illustrated in figure 10 which shows a longitudinal section through a 70A autogenous GTA weld made at 200bar (6,530ft) . Under these conditions the penetration varies from 1.2 to 2mm over a length scale of about 6mm.

5.2 Plasma Melt-In

The plasma melt-in process operates in a manner similar to conventional hyperbaric GTAW, although with significantly higher process powers and greater arc stability. Welds are deposited using a cold wire addition technique. Figure 11a shows a photo-macrograph of a plasma weld made in 29mm thick X65 linepipe steel at a pressure of 100bar (equivalent to 3,250ft water depth). The weld required 43 passes and was made at a deposition rate of 0.8kg/hour. Figure 11b shows a section through a similar weld made at 160bar (5,220ft water depth) with a reduced wire feed rate and increased number of weld passes. Note the cosmetically poor final bead which occurred close to the finish of the 160bar weld due to failure of the wire guide (human error) leading to incorrect placement. This should not be regarded as indicative of any process limitation. Both the 100 and 160bar welds were made with fully penetrating root runs.

Welding conditions at high pressures differ from those typically employed at one atmosphere due to the rise in arc voltage associated with the constricted arc column. Hart [28] has shown that plasma arc voltage follows a relationship of the form

$$V = E_1 \ell P^n + aP + c + cf \qquad 1$$

where ℓ is the arc length and P the absolute pressure normalised to one bar. The first term accounts for the voltage change in the free (un-constricted) portion of the arc, and is similar in form to the expressions typically used for GTA voltage prediction at pressures of a few bar to a few tens of bar [29]; n is slightly less than 0.5 and E_l is the one bar electric field strength, which is slightly lower than the field strength typically associated with a free burning arc. E_l is of the order 0.5 to 0.6V/mm for argon plasmas. The second term represents the voltage drop in the constricted portion of the arc, with a being of the order 0.2V. The third term represents the sum of the fall voltages and is of the order 5V. The values of both E_l and a are dependent on the orifice diameter. The term cf is a series of correction factors, taking into account shielding and plasma gas flow rates and welding current; however, these contribute only a few percent at most to the voltage prediction. Ignoring the cf term gives an average error in prediction of 2.8V and a maximum error of less than 7V.

Inspection of equation 1 shows that voltage increases significantly with increasing pressure, arc power rises and welding current must therefore be reduced to prevent the formation of excessively large weld pools. Typical operating voltages and currents for the plasma joints are of the order 80 to 90A and 70 to 80V, giving average arc powers in excess of 6kW.

The weld macro specimens were subject to hardness testing and mechanical test specimens were machined from the remaining joint material. Hardness values were measured using a 10kg Vickers (diamond indent) hardness test. Root weld mean hardness values at 160bar were $253Hv_{10}$ compared to $194Hv_{10}$ at 100bar. A hardness traverse across the centre of each joint gave averages of $213Hv_{10}$ and $207Hv_{10}$ for the 160bar and 100bar joints respectively. The final bead of the 160bar joint supplied hardness values averaging $255Hv_{10}$. Results for both joints are summarised in table 1.

Yield and ultimate strength were measured using a uni-axial tensile test (table 2). All weld metal specimens were prepared from longitudinal sections of the weld measuring 6.4mm in diameter by 25mm in length. For the 160bar and 100bar weld respectively, the average yield strength was found to be 621MPa and 585MPa and the average ultimate tensile strength was 659MPa and 660MPa. The weld metal proved to be quite ductile, with elongations in the range of 25 to 40% for both welds.

Impact toughness was examined with specimens of 10 x 10 x 50mm notched in the T-L orientation. Tests were performed at temperatures ranging from 0 to -80°C and results are shown in figure 12. In most cases, impact energies were extremely high, particularly in the case of the 160bar joint where values generally exceeded 250J across the entire temperature range.

5.3 Gas Metal Arc Welding

GMAW welds have been produced in the downhand, vertical and overhead positions at pressures in the range 40 to 250bar (1,280 to 8,200ft). Initial experimentation indicated a rapid contraction of the operational envelopes within which successful process stability can be maintained as pressure rises. This is associated with the essentially unstable nature of the arc roots which move freely over the surface of the molten weld pool and developing droplet on the tip of the wire [20]. At high pressures it is not possible to maintain a stable welding arc and operating conditions differ substantially from those normally employed at one atmosphere.

Instabilities in the arc have been observed to occur rapidly, with substantial changes in radiation emissions and arc position occurring at frequencies exceeding 10kHz as illustrated in high speed film footage [20]. Despite this inherent instability, the time averaged behaviour of the process remains relatively constant over timescales typically associated with weld pool movement and solidification. The net effect is that a stable welding process can be maintained provided appropriate static and dynamic control measures are implemented.

Typical voltage and current data showing process stability for a 250bar (8,200ft) GMAW weld is presented in figure 13a, whilst the same data, averaged over 0.25s intervals is shown in figure 13b to illustrate overall stability.

Figure 14 shows macrographs of GMAW joints made in 29mm thick X65 linepipe steel at pressures of 160bar (5,220ft), 200bar (6,530ft) and 250bar (8,200ft) respectively in the downhand position. The 160bar joint was made with a 1mm diameter experimental flux cored wire, whilst the 200bar and 250bar welds were produced using a 0.8mm diameter solid wire (Thyssen K-Nova). Optical examination revealed occasional and small lack of fusion defects in the 250bar weld but no defects in the 160bar and 200bar samples. No evidence of porosity or microcracking was found in any of the samples examined.

Weld integrity has been found to be a function of operator experience. This was evident in the appearance of successive joint caps which notably improved with experience and the development of a suitable welding procedure (the joints reported here were completed in reverse order of pressure - compare also with earlier 160bar results [20]).

Good quality welds have also been achieved in the overhead position as illustrated in figure 15, which shows sections from a) two layer (two pass) and b) six layer (multi-pass) fillet welds made on 25mm thick EN 3B grade steel plates.

The weld macro specimens were subjected to a hardness survey, the results of which are summarised in table 3. Little difference is seen in the spread of results at each pressure. There is a slight decrease in maximum hardness and standard deviation as pressure increases, whilst mean hardness increases slowly over the pressure range 160 to 250bar.

All weld metal tensile tests were performed on longitudinally oriented samples taken from the downhand butt welds. Three specimens were produced and tested from each joint, two from the upper region and one from the lower region, near the root. Results are summarised in table 4 indicating that strength and elongation are lowest for the 160bar joint and highest for the 200bar joint with intermediate properties at 250bar. Weld metal strength is considerably greater than that quoted for the consumable and parent metal at one atmosphere, whilst elongation is lower for the 160bar and 250bar joints but comparable for the 200bar joint. Notch toughness was examined with specimens taken from the butt joints and prepared in the T-L orientation. Tests were performed at temperatures ranging from 0 to -80°C and results are shown in figure 16 indicating a wide spread of values, particularly at higher temperatures.

6. Discussion

6.1 Arc Stability

The degradation of arc stability with increasing pressure is widely noted but relatively poorly described in the literature. This degradation has been attributed to increasing turbulence in the shield gas flow and increased susceptibility to buoyancy effects. Recent results showing that the shield cup internal diameter has a significant effect on stability have given an improved insight into the processes involved [28].

The simple consideration of Reynolds numbers to explain the decrease of stability with increasing pressure, as suggested in previous literature, does not provide a very clear picture. It has been shown that at depths greater than a few tens of meters, the cold shielding gas flow is turbulent [30]. As a reduction in shielding cup diameter results in increased shielding gas velocity, it may be expected that the Reynolds number will increase and turbulence will become more fully developed. However, this is not been found to be the case in practice. Consideration must be given to the influence of arc heating on material properties, which acts to reduce the Reynolds number and to generate buoyancy forces.

Further explanation may be offered by consideration of a minimum energy loss principle and the energy required for the arc to move through the cold shielding region. The increased electrical conductivity seen in the hot central core of the arc as pressure increases leads to arc constriction. The arc assumes a new minimum energy loss configuration by minimising its cross-sectional area. With a free burning downhand arc in a slow moving shield gas envelope, buoyancy effects move relatively hot shielding gas in opposition to the flow of arc matter. With a more constricted arc, cold gas moving at higher speeds is forced in the direction of the mass movement surrounding the arc core, suppressing buoyancy effects. The energy required to move the current carrying core through the hot gas is much less than that needed to move through the fast moving cool gas flow. As the movement of the arc into the cooler gas is less energetically favourable, any excursions into this region will be quickly damped by the tendency of the arc to assume an easier electrical path.

While a combination of these effects provides a simple behavioural model which fits well with the observations of arc movements, examination of the voltage characteristics of the hyperbaric arc suggest that other mechanisms also play a part. The standard deviation of arc voltage has often been used as a representation of the stability of the arc, and for a constant pressure condition, this argument appears reasonable. However, with increasing pressure, the absolute arc voltage increases and thus comparison of standard deviation values across a pressure range is invalid [28]. Thus some method of comparison is required to judge the stability. However, when the standard deviation is normalised to the mean arc voltage, a decreasing trend with rising pressure is observed, suggesting a more stable arc. The weld beads produced show that this is clearly not the case.

One explanation for this behaviour involves consideration of the arc as a pair of colliding electromagnetic jets, dominated by the cathode jet which forms the bulk of the plasma column. It has been shown that an increase in pressure results in a decrease in anode root size [28]. If the arc is deflected due to instabilities and the anode root is pinned (which is reasonable considering the high concentration of metallic vapour at the superheated plasma - metal interface), the weak anode jet deflects under the action of the strong cathode jet and current leakage occurs as a shorter, more energetically favourable path forms, resulting in a discrete jump of the anode root position (figure 17) In voltage terms, the normalised standard deviations are reduced by the effects of the leakage current and the constant changes in rooting site reduce the voltage displacements, while the maximum physical displacements increase due to anode jet *'pivoting'* as demonstrated on the welded GTA samples where discrete rooting sites are clearly visible (see figure 7). In the case of the plasma process, the increased arc velocity (associated with the higher current arcs) increases the *'jump'* frequency but suppresses the radial displacement, resulting in a considerable increase in positional stability.

Stability is essential for successful hyperbaric welding. If displacement of the heat source on the workpiece surface is not constrained within set bounds, accurate placement of weld metal cannot be achieved and the properties of the welded joint cannot be guaranteed. Wander of the surface bead manifests as changes in heat profile in the joint metal. This causes changes in penetration along the centreline of the weld, as demonstrated in the GTA weld shown in figure 10. Fortunately, these instabilities are suppressed in the constricted arc and uniform penetration is readily achieved.

6.2 Plasma Melt-In

Hyperbaric joint completion requires the addition of a filler wire. The plasma process operating at high pressures in the melt-in mode has welding characteristics very similar to those of GTA at water depths accessible to divers. Welding parameters were therefore sought to provide reasonable material deposition whilst maintaining a stable arc. Parameter development presented few problems and once operating parameters were established, the process was extremely consistent, reliable and simple to operate.

A wire guide providing remote manipulation in two degrees of freedom was employed to ensure that the wire placement was appropriate. The only problems encountered related to observation of the operation using a single camera [31]. High ambient light levels and the limited control over image filtering available at the time of welding made selection of wire entry position difficult. Image quality in the arc off periods was also poor due to relatively low camera sensitivity and gas refraction resulting from contact between the hot specimen and cool chamber gas. Despite this, acceptable welds were achieved and operator input rapidly became routine.

The limited metal deposition rate achieved is related to the constriction of the arc at elevated pressures (see for example [32]). As ambient pressure is raised the radial extension of the arc column and arc root decrease to minimise energy losses. The plasma arc retains its columnar appearance but both the visual and electrical boundaries contract, resulting in an increased power density due to the reduced cross-sectional area and the increased power generation.

For the 0.8mm diameter filler wire employed, wire feed rates were limited to less than about 3.5m/min due to the limited time spent by each volume element of the wire in the vicinity of the arc. At higher feed rates, insufficient heating occurred and the wire failed to melt, passing through the arc or weld pool. In common with normal GTA practice, improved tolerance to feed variations was noted when the wire was deposited at the front edge of the weld pool. This is associated with the molten pool size which in general extended approximately 2mm beyond the visible arc boundary. No attempt has been made as yet to optimise the deposition rate and tolerance envelopes have still to be established. There may be scope to use less constricted conditions (i.e. larger diameter nozzles) and thus higher currents, allowing the deposition rate to be increased.

Hart's model for the prediction of arc voltage (see equation 1) is of a general form, although the values of the constants are dependent on the design of the welding torch which influences the gas flow behaviour. For application to different welding torch arrangements, the linear factor for constricted voltage is likely change, as are the individual correction factors. However, the form of the model is expected to remain constant.

Inspection of equation 1 indicates a voltage in the constricted region of the arc (term 2) which increases at faster rate with pressure than that associated with the free burning portion of the column (term 1). This results in higher power dissipation in the constricted region and hence, a greater tendency to nozzle failure at elevated pressure. In order to reduce the likelihood of damage, it is necessary to reduce the maximum current level to compensate for an increase in pressure. Thus, the 100bar joint was completed at a current of 86A whilst for the 160bar joint the current level was reduced to 80A.

Optical examination of the plasma welds shows that the microstructure is quite fine, and consists almost wholly of equiaxed ferrite. The pattern of reheating produced a material composed of a patchwork of two microstructural regions, which differ in grain size by a factor of about four. The general microstructure differs considerably from that in the final capping bead, the latter consisting mostly of sideplate ferrite and bainite, with some acicular ferrite.

Hardness values generally meet the hyperbaric welding requirements. AWS D3.6 limits weld metal hardness to below $325Hv_{10}$, whilst the British offshore construction standard BS 4515: (1996), imposes a limit of $275Hv_{10}$ for non-sour service and $250Hv_{10}$ for sour applications. Both the plasma joints meet these requirements for the majority of regions in the weld metal and HAZ with the exception of the final capping beads where no reheating has taken place and the root of the 160bar joint which had a average hardness of $253Hv_{10}$. No weld metal or HAZ region hardness value exceeded $300Hv_{10}$. Again this may be attributed to rapid cooling and reduced refinement from subsequent weld passes.

The results from the all weld metal tensile tests (table 4) show that the ultimate tensile strength, yield strength (0.2%) and elongation values for both the welds overmatch the parent plate. It is notable that the weld metal properties exceed those specified for the consumable at one atmosphere, where the minimum proof strength at 0.2% strain is 440MPa and the minimum ultimate tensile strength is 570MPa. The parent plate properties also exceed the minimum X65 requirements and are closer to an X75 classification, whilst the K-Nova filler wire is recommended for steel pipes up to grade X70. Overall, the testing has shown that weld metal with satisfactory tensile properties can be achieved at the pressures examined. There is a noticeable variation in yield strength between the upper and lower sections of the 100bar joint, the lower being about 50MPa stronger than the upper region. This is also evident in the 160bar joint, although the difference is only of the order 25MPa. The difference is most likely related to the pattern of re-heating in the joint.

The results of the impact tests show that the plasma welds have excellent notch toughness with upper shelf energies above 200J for the 100bar weld and above 250J for the 160bar weld. The transition temperature for the 100bar weld lies below -50°C. Trends for samples taken from the upper and lower parts of the weld are similar, and all measurements at temperatures above -60°C exceed the minimum single sample energy requirement of 23J and minimum average value of 34J specified in AWS D3.6. The relatively low reading obtained at -40°C for the upper sample from the 100bar weld is associated with a lack of fusion defect

The microstructure in the vicinity of the notch influences the notch toughness and a finer grain structure is observed for the 160bar weld due to the smaller bead size, and consequently greater reheating.

The production of a fully welded joint shows that the plasma melt-in process is capable of successful operation at simulated water depths down to 1,600m (the deepest test undertaken to date). It is notable that the main areas of concern were not with the process performance but focused on difficulties associated with ancillary services.

6.3 Gas Metal Arc Welding

The GMAW process has been found to exhibit stable time averaged characteristics over the depth range 200 to 2,500m (655 to 8,200ft), with unit change in pressure exerting a smaller influence as the ambient pressure rises. Optimum operating conditions in the depth range 800 to 2,500m (2,625 to 8,200ft) remained substantially unaffected by ambient pressure. Suitable GMAW process control has been developed to ensure stable operation over the timescales associated with electrode melting and weld pool solidification; i.e., typically less than 50ms. A full discussion of the GMAW process stability may be found elsewhere [20].

Investigations undertaken prior to completion of the test joints indicated that weld bead shape is influenced primarily by heat input, with increased bead width, reduced reinforcement height and smaller wetting angles being associated with greater process powers. The selection of process parameters is a compromise between stability and desirable bead geometry, with conditions chosen to obtain the smallest bead wetting angle, low short circuiting frequencies and minimal spatter formation. Weaving of the welding torch was employed to produce the welds at elevated pressures in order to obtain an acceptable wetting angle (less than about 45°) and to provide control over bead width and reinforcement height which in turn provides the flexibility required to complete multi-pass and multi-layer joints with no lack of fusion defects.

The properties of the test joints welded at 160, 200 and 250bar look promising, although there is scope for improvement of the weld metal microstructure and (in particular) the notch toughness. The hardness values are all well below $325Hv_{10}$ and therefore meet the requirements of AWS D3.6 and BS 4515 for non sour service. The maximum hardness values exceed the $250HV_{10}$ upper limit set by BS 4515 for sour service; however, the maximum value for the 160bar weld occurred in the final capping pass. Excluding the final weld bead, the maximum hardness in this joint was 238HV_{10}. It is therefore likely that the sour service limit can be achieved by using a temper pass technique.

Maximum hardness values in the 200 and 250bar welds (made with Thyssen K-Nova) were found in the body of the joint, in places where there was slightly greater side wall penetration than usual. The weld metal next to the side wall was always harder than the adjoining HAZ, which may be due to the higher carbon equivalent content of the weld metal, compared with the parent plate.

When welding pipelines, overmatching the strength of the parent is highly desirable, in order that any plastic strain is absorbed by the parent metal, to prevent large strains on the weld which are likely to result in fracture. A joint should be able to support a reasonable plastic strain without failure, and elongations of 15% to 20% are often specified. The results of the tensile tests, together with tests on the properties of the parent plate, and the nominal welded properties given for the consumable wire indicate that the welds are overmatching the parent plate with high strengths being achieved. The elongations are all satisfactory, with the highest elongation being achieved at 200bar. The high strength of this joint is indicative of a sound microstructure and may be due to operator experience rather than pressure influences. The welds were performed in the sequence 250bar, 200bar, 160bar with improving confidence in bead placement and the selection of operating conditions (weave widths and welding speeds) for the latter joints. These in turn were likely to result in additional grain refinement due to reheating by subsequent weld passes.

All weld metal tensile tests were also carried out on the larger of the 160bar overhead fillet joints. Both ultimate tensile strength and yield strength show an increase of about 50MPa compared with the downhand butt joints, although elongation remains comparable at about 25%. Caution should be exercised due to the small number of samples taken and further investigation will be required.

In contrast to the plasma welds, the notch toughness of the GMA welds is low, despite the same parent and filler material being used for both sets of joints (with the exception of the cored wire employed for the 160bar GMAW joint). The GMA weld metal under performed compared with the nominal toughness of 120J quoted for K-Nova at -30°C. The increased strength but reduced notch ductility are consistent with inadequate development of an optimised microstructure.

The notch toughness requirements of AWS D3.6 specifies a lower toughness limit of 19J, with a mean toughness of at least 27J at the appropriate minimum service temperature. All the joints meet this requirement down to -60°C, although the specification is not particularly stringent. BS 4515 indicates a minimum impact energy of 41J, and a mean of at least 49J at -20°C, for 25mm thick pipeline steel. The 160bar and 250bar joints also meet this requirement but the 200bar joint falls below the minimum level by 3J. The wide scatter in impact energies indicates that a range of microstructures are being sampled at the notches. One possible explanation for this behaviour is the relatively low oxygen content (0.013 wt%) which is likely to limit nucleation, resulting in a bi-modal behaviour and may provide an explanation for the two low impact energies at -60°C from the 160bar plasma joint. The influence of thermal history is also significant, as indicated by the large differences between the impact properties of the GMA and Plasma joints.

Whilst more research is required to develop a better understanding of the link between consumable chemistry, thermal history and microstructure, the work to date has demonstrated conclusively that very high quality welds can be made in deep waters.

6.4 Deepwater Diverless Welding - Future Prospects

It is notable that during the course of the current programme, parameter development and optimisation has been accomplished over relatively short time periods. The welding processes have proven to be reliable, consistent and (dependent somewhat on the experience of the operator) robust. There appears no immediate indications that the process development cycle will be slowed with the move to full orbital welding. Although the plasma process is successful and produces very high quality welds, the attributes of the GMA welding process (high deposition rate, robustness, simplicity, tolerance to joint preparation variations and ease of automation) make it appear at present the most likely process for deep water welding operations in the future. The philosophy used in the development of the HyperWeld facility, utilising wherever possible commercially available equipment and state of the art offshore controls will significantly reduce the time to commercialisation.

The challenge to take the process from the laboratory to the field is being addressed. In Europe, feasibility and concept design studies have already been completed for a fully diverless, deepwater welding system based around existing repair equipment. Although the range of activities involved appears in the first instance to be daunting, closer consideration suggests that existing and proven engineering techniques may be used to accomplish the majority of tasks required. If the PRS system is taken as a case in point, then the wet operations are already accomplished by remote methods. The main challenges are found inside the welding habitat and relate to manipulation and metrology, where the diver has until now played a more significant role.

The present habitat design is built on the philosophy that a diver is adaptable and can make reliable judgements based on local observations. If automation is to replace the diver a shift away from this philosophy is required and thought must be applied to replacing the habitat structure with tooling and an enclosure more suited to a fully automated system. Where at present the tooling is modular, and is reconfigured for each specific task, a move towards a more flexible and capable single configuration tool is required. Initial studies have found that with careful design, all relevant operations can be addressed by a single, permanently configured machine head such that manipulation tasks are minimised.

As a joining technique, welding may offer substantial advantages over mechanical connectors in terms of equipment capital expenditure, life cycle costs and system flexibility, as well as in joint properties and quality. From an engineering perspective, the development work necessary to construct a diverless welding repair system may be considered comparable in scope to that required for other methods. Thus, for large diameter pipelines, where mechanical connectors become heavy, cumbersome and very expensive, hyperbaric welding may offer a more practical and economic alternative.

7. Conclusions

The programme of work reported here has shown that after development of suitable welding parameters, both GMA and plasma welding are capable of supplying suitable quality welds at very high ambient pressures equivalent to great water depths. Parameters have been developed for downhand, vertical and overhead 5G orientations. Work in the near future to install an orbital welding head in the HyperWeld facility at Cranfield University will facilitate the development of parameters for all welding positions around a pipeline.

1) Hyperbaric plasma and GMAW both offer viable welding process solutions for deep water applications to 2,500m (8,200ft).

2) Process operating conditions become less sensitive to ambient pressure changes as operational depth increases. In the case of GMA welding, parameter sets are largely invariant at depths exceeding 1,000m (3,280ft) whilst plasma operating conditions are primarily influenced by energy transport to the welding torch.

3) Acceptable joints may be produced in the downhand and overhead positions using optimised process control parameters. GMAW joints have been made at 160, 200 and 250bar.

4) At high ambient pressures the plasma welding process exhibits behaviour similar to a stabilised form of the GTA process. High quality joints may be produced with properties which exceed many of the current offshore standards.

5) The thermal history of a welded joint plays a significant role in determining the mechanical and metallurgical properties due to the rapid cooling experienced in high pressure gaseous environments and the effects of reheating and cooling on the microstructure. This has been demonstrated by the process dependent nature of impact properties.

6) Many of the engineering developments required for deepwater diverless welding operations have already been implemented or are being considered. Issues including automation and metrology will be critical to the future development of this technology.

It is envisaged the 'Deepwater Hyperbaric Welding' research at Cranfield University will establish suitable parameters for the major depth increments up to 2,500m within the lifetime of the current programme.

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	Hardness Hv_{10}	
	100bar Joint	160bar Joint
Mean*	207	213
Maximum*	***220***	***228***
Minimum*	196	199
Standard Deviation*	7	17
Final Capping Bead	***261***	***255***
Root Pass	202	***253***

Table 1 Hardness values for joints produced in X65 linepipe steel using the plasma melt-in process at the 100bar (3,250ft) and 160bar (5,220ft).
Note: * measurements exclude the cap and root passes.

	Yield Strength (MPa)		Ultimate Tensile Strength (MPa)		Elongation %	
	160bar	100bar	160bar	100bar	160bar	100bar
Upper	606 577 625 647	560	629 625 682 667	661	29.8 26.2 34.6 36.0	40.8
Centre	-	590	-	657	-	35.7
Lower	590 684	606	641 710	661	31.1 34.1	30.4
Mean	***621***	***585***	***659***	***660***	***32.0***	***35.6***
Parent	565		587		21.4	

Table 2 Results from all weld metal tensile tests performed on joints produced in X65 linepipe steel using the plasma melt-in process at the 100bar (3,250ft) and 160bar (5,220ft).

	Hardness Hv_{10}		
	160bar Joint	**200bar Joint**	**250bar Joint**
Mean	225	229	236
Minimum	199	199	189
Maximum	***264***	***274***	***270***
St. Deviation	7	16	13
Root	-	-	220
Max. HAZ	***253***	-	***238***

Table 3 Hardness values for joints produced in X65 linepipe steel using the GMAW process at the 160bar (5,220ft), 200bar (6,530ft) and 250bar (8,200ft).

	Yield Strength (MPa)			Ultimate Tensile Strength (MPa)			Elongation %		
	160bar	**200bar**	**250bar**	**160bar**	**200bar**	**250bar**	**160bar**	**200bar**	**250bar**
Upper	*607* *653* *646* *645*	*600* *600* *591* *574*	*614* *643*	716 752 738 716	676 657 676 667	679 693	23 24 22 22	30 29 32 34	21 25
Lower	*687* *665*	*626* *653*	*538*	742 730	684 709	651	21 21	28 36	28
Mean	***651***	***607***	***598***	***732***	***678***	***674***	***22.1***	***31.3***	***21.7***
Parent	541			562			20.0		

Table 4 Results from all weld metal tensile tests performed on joints produced in X65 linepipe steel using the GMAW process at the 160bar (5,220ft), 200bar (6,530ft) and 250bar (8,200ft). Note: an experimental cored wire was used for the 160bar joint.

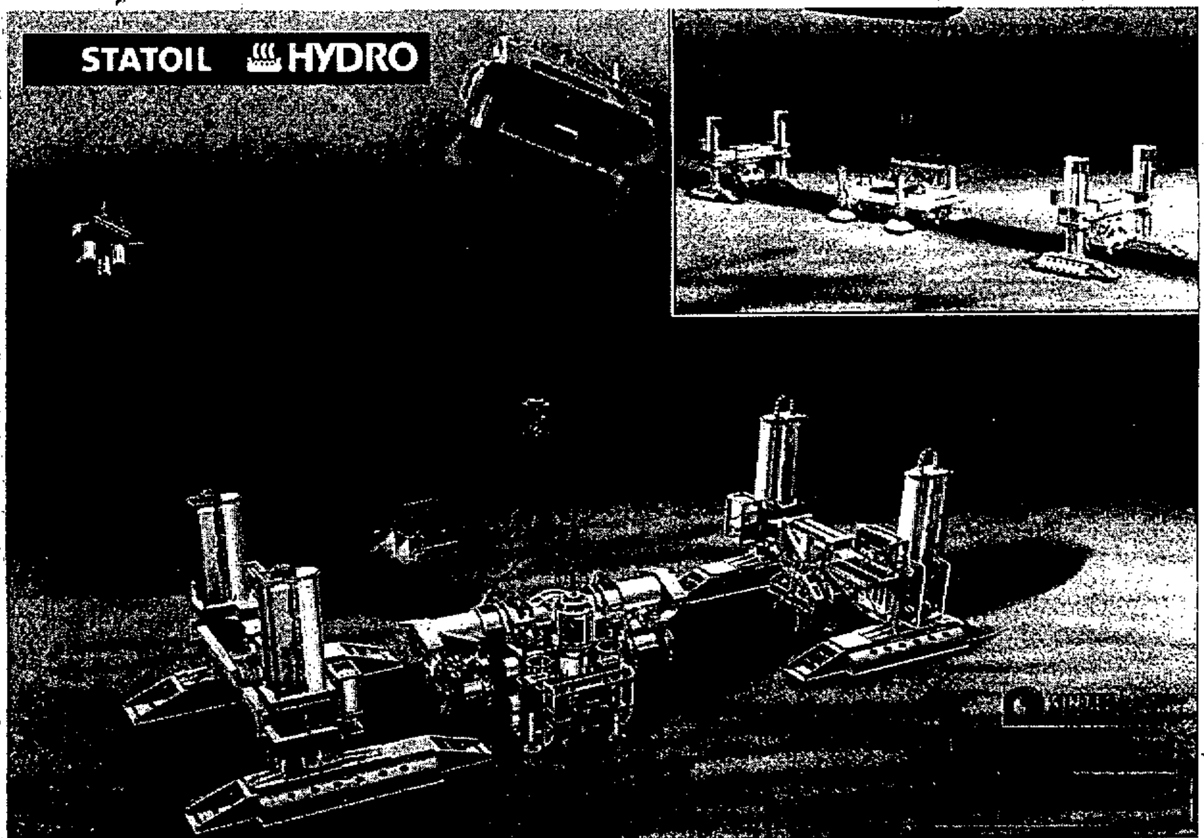


Figure 1 An artists impression of a subsea pipeline welding operation.

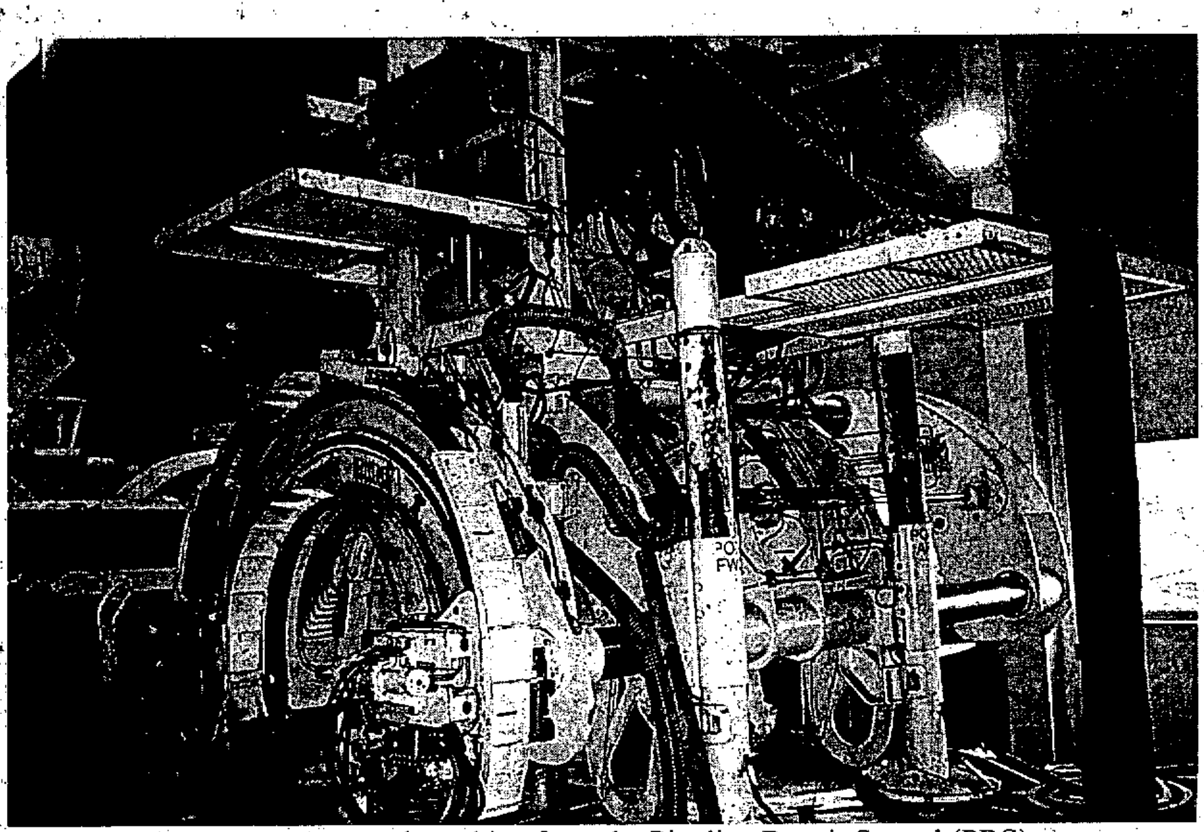


Figure 2 The concrete removal machine from the Pipeline Repair Spread (PRS).

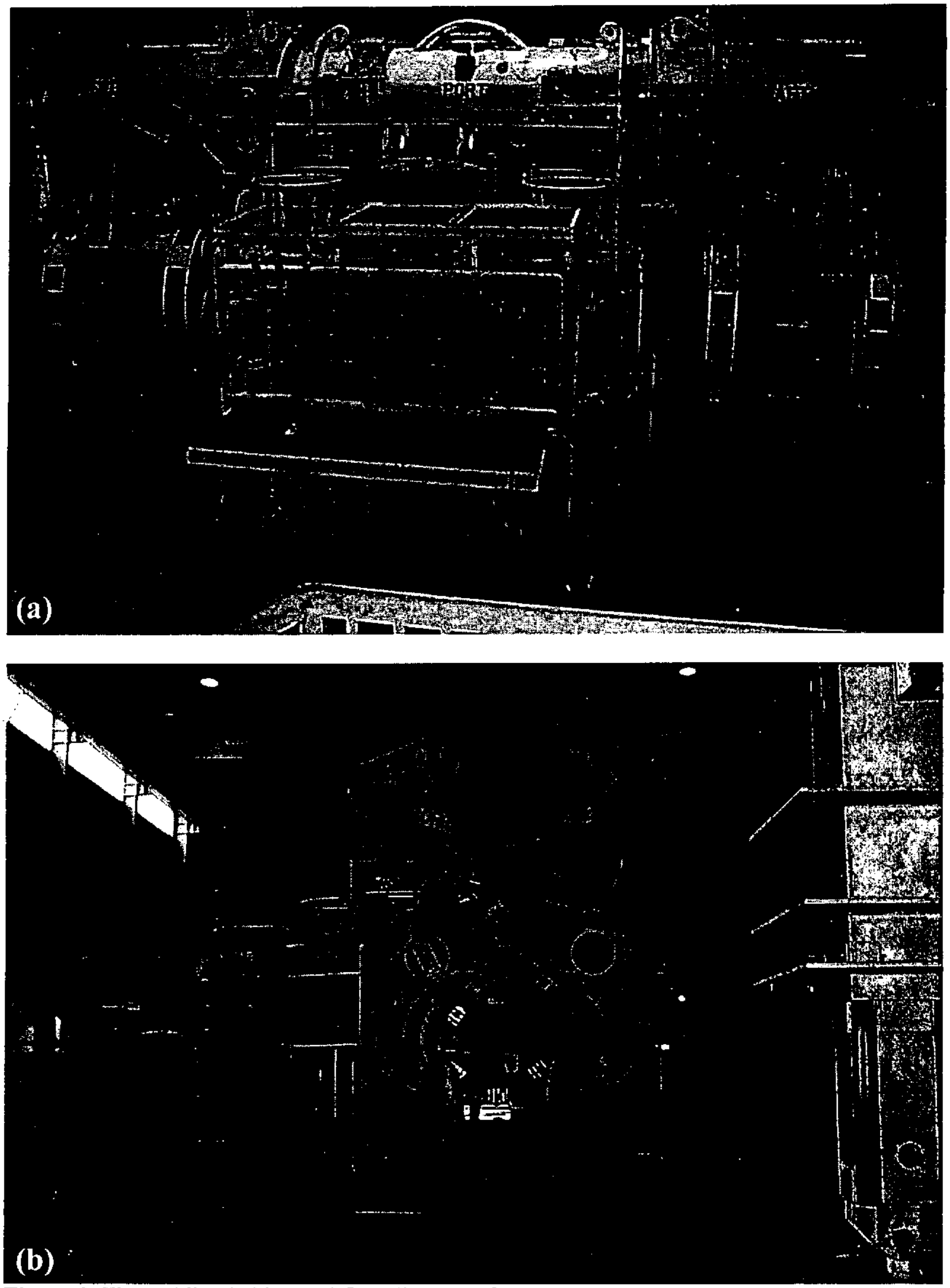


Figure 3 The welding habitat and fine alignment frame.

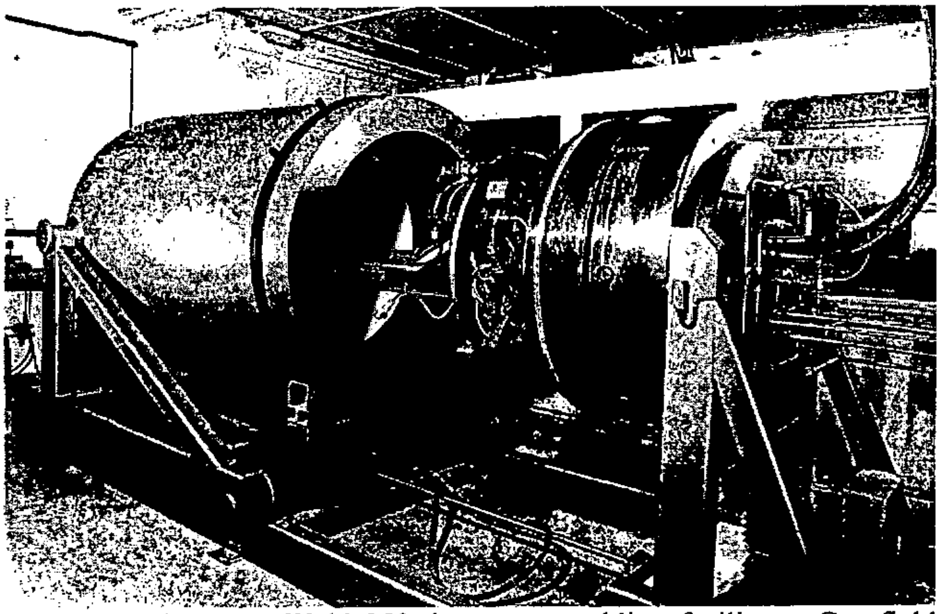


Figure 4 The HyperWeld 250 deepwater welding facility at Cranfield University.

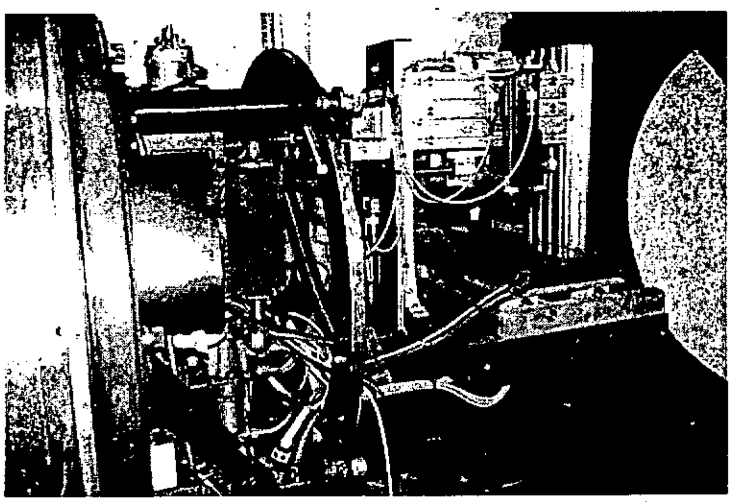


Figure 5 The HyperWeld 250 service module and linear welding head.

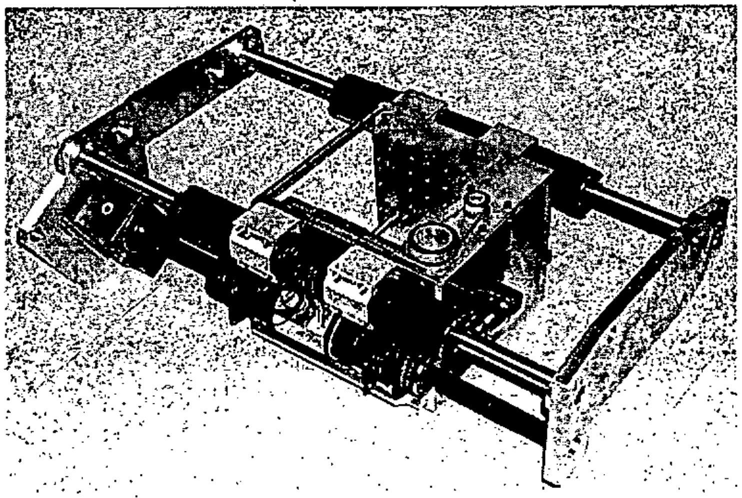


Figure 6 Welding torch manipulation system from the HyperWeld 250 orbital welding head.

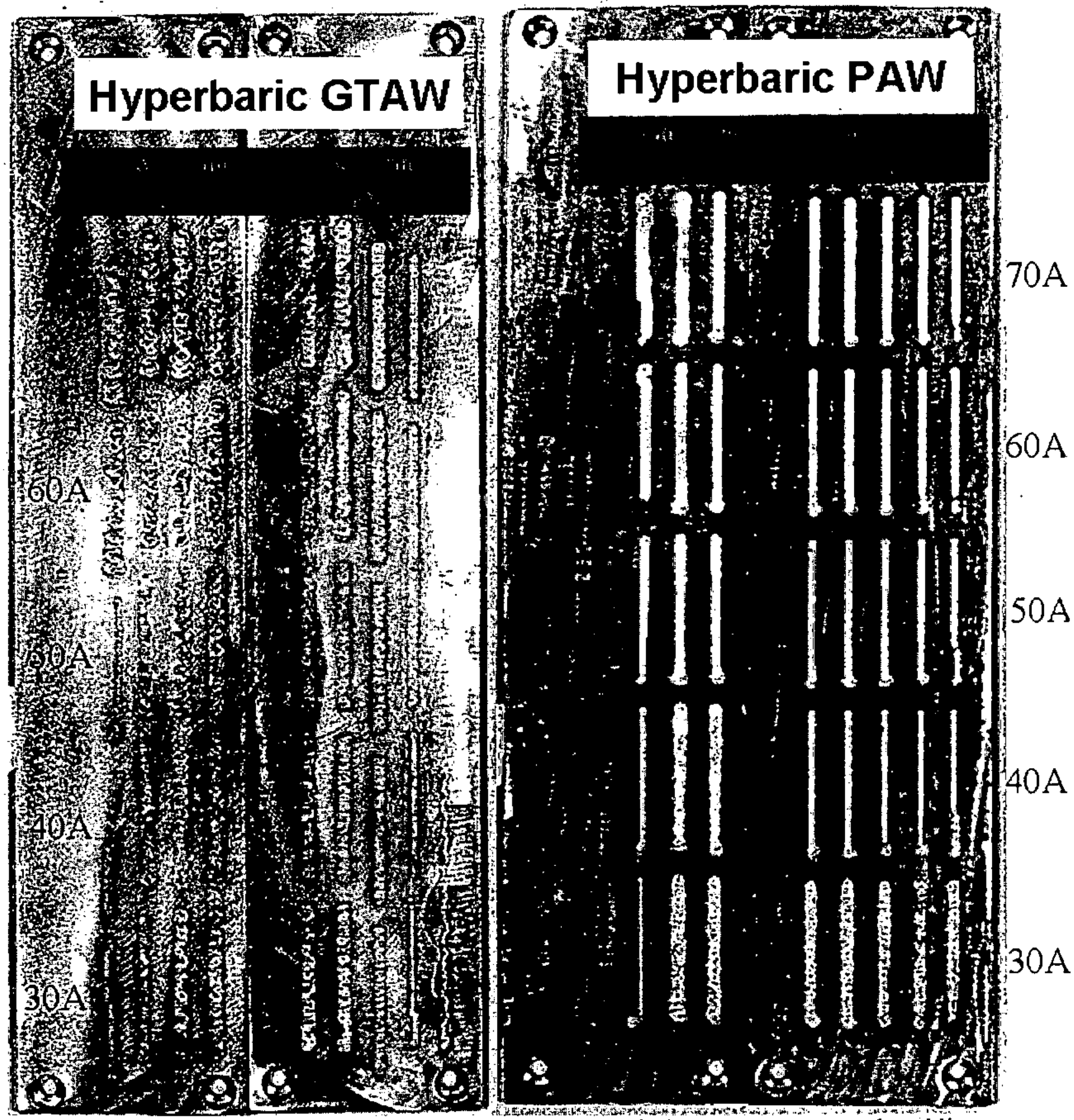


Figure 7 Autogenous welds illustrating the influence of pressure, current and welding process on stability. Welds made with currents in the range 30 to 70A at pressures 75 to 250bar (2,430 to 8,200ft).

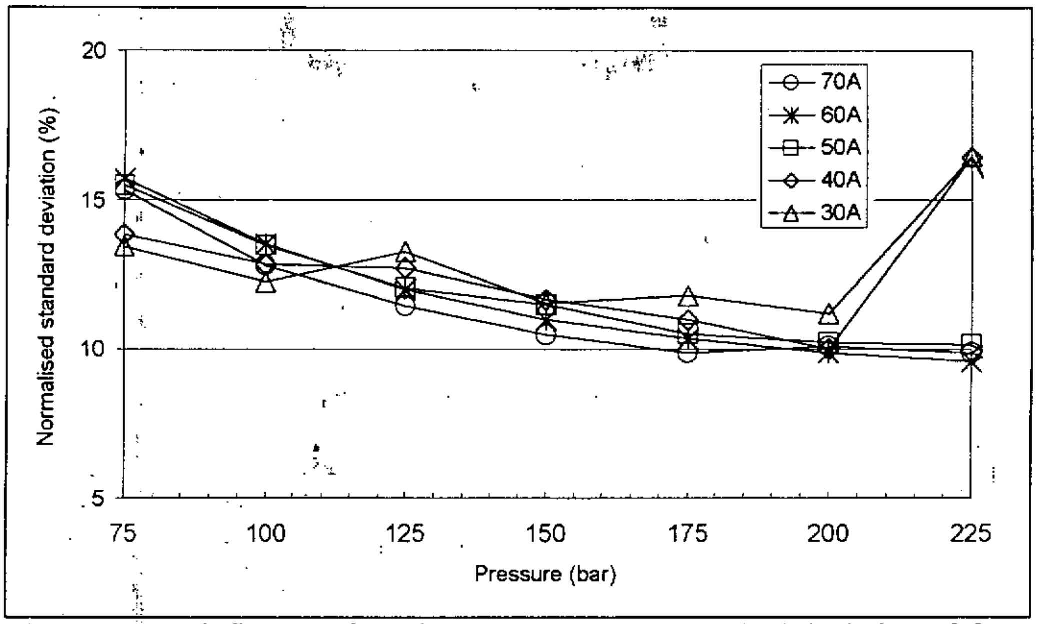


Figure 8 The influence of ambient pressure on the standard deviation of GTA arc voltage normalised to the mean voltage.

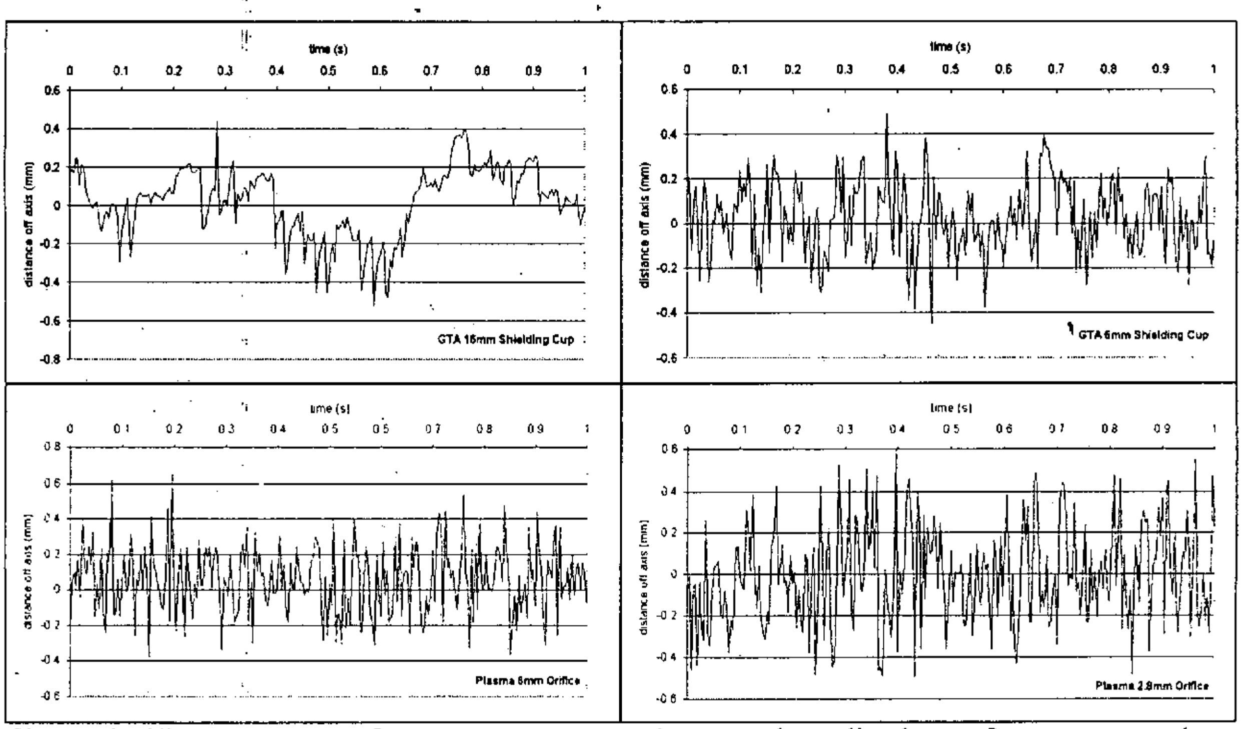


Figure 9 The movement of an arc root measured across the split plane of a copper anode at 100bar ambient pressure (3,250ft). Data shows instability behaviour for different welding processes and configurations.

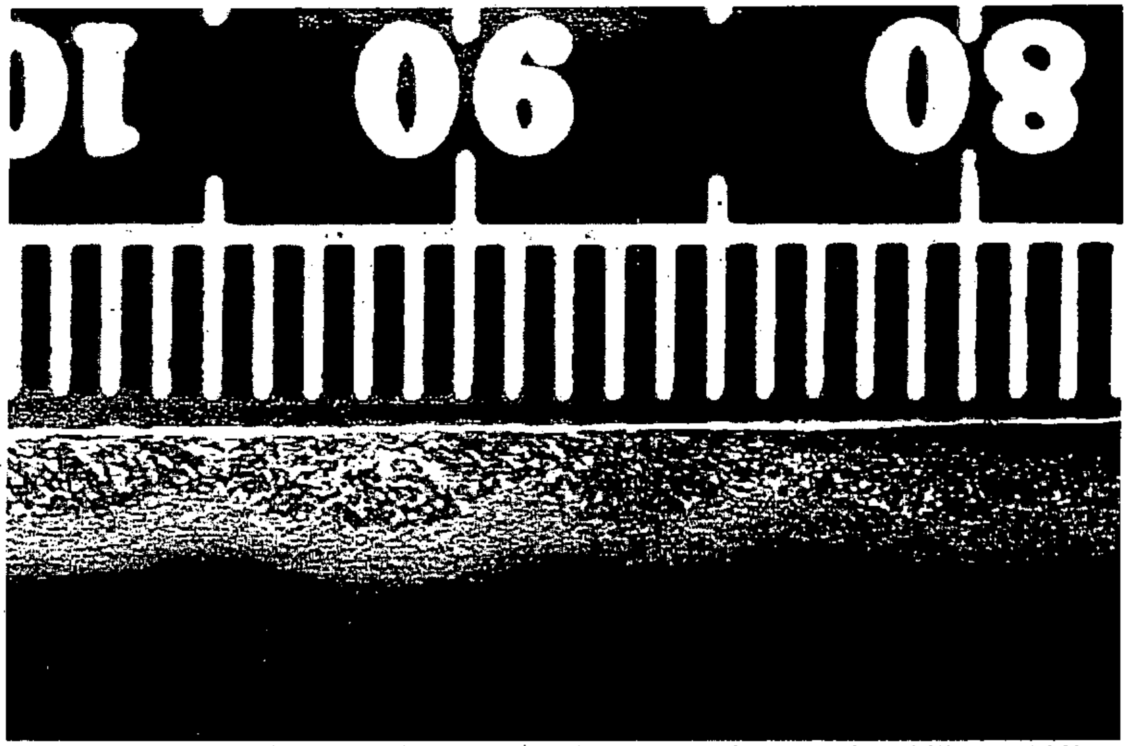


Figure 10 Illustration of variable penetration due to GTA arc instability at 200bar (6,530ft).

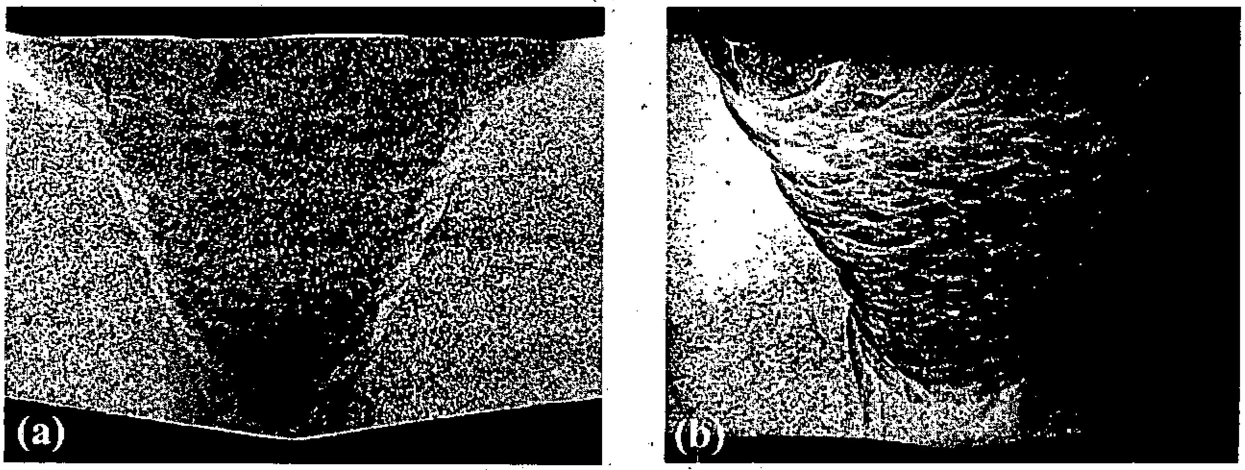


Figure 11 Macrographs from plasma welds made at (a) 100bar (3,250ft) and (b) 160bar (5,220ft).

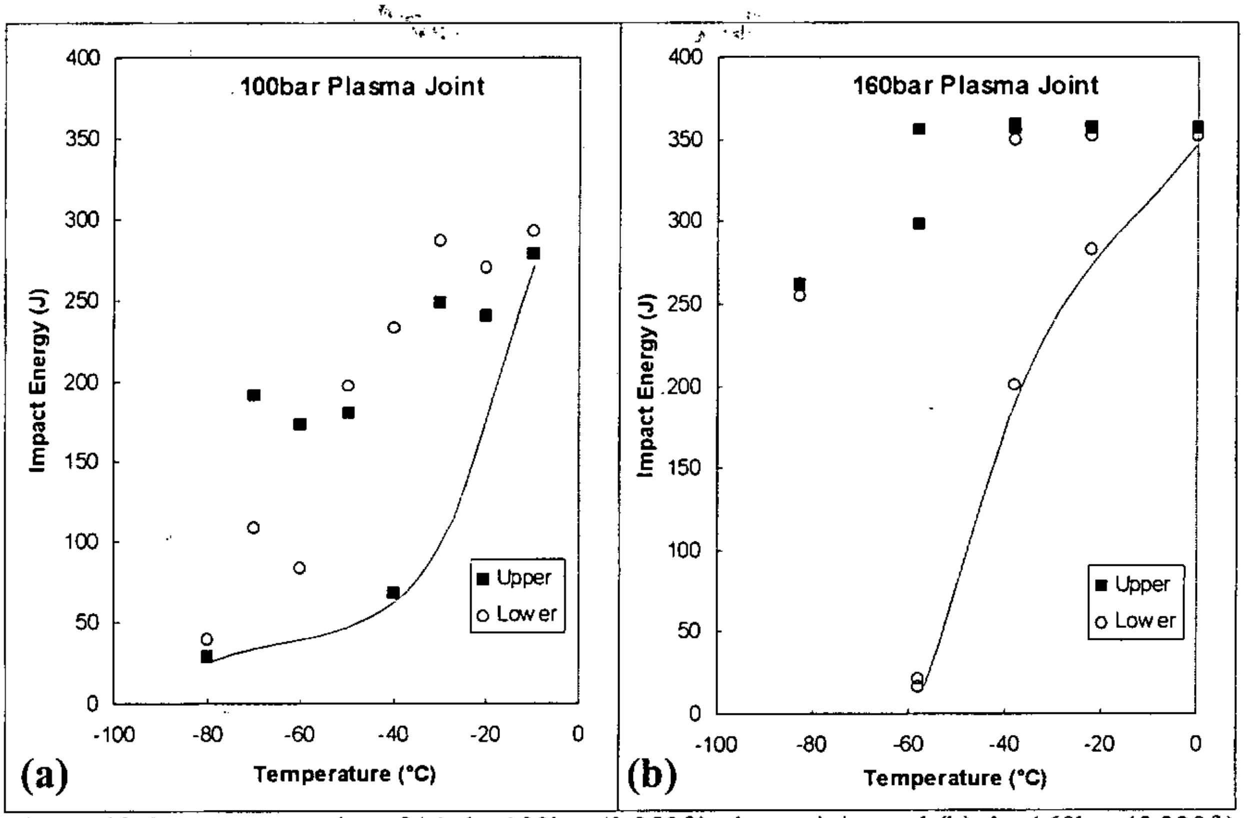


Figure 12 Impact properties of (a) the 100bar (3,250ft) plasma joint and (b) the 160bar (5,220ft) plasma joint. Specimens taken from the upper (filled points) and lower (open points) sections of the joint respectively.

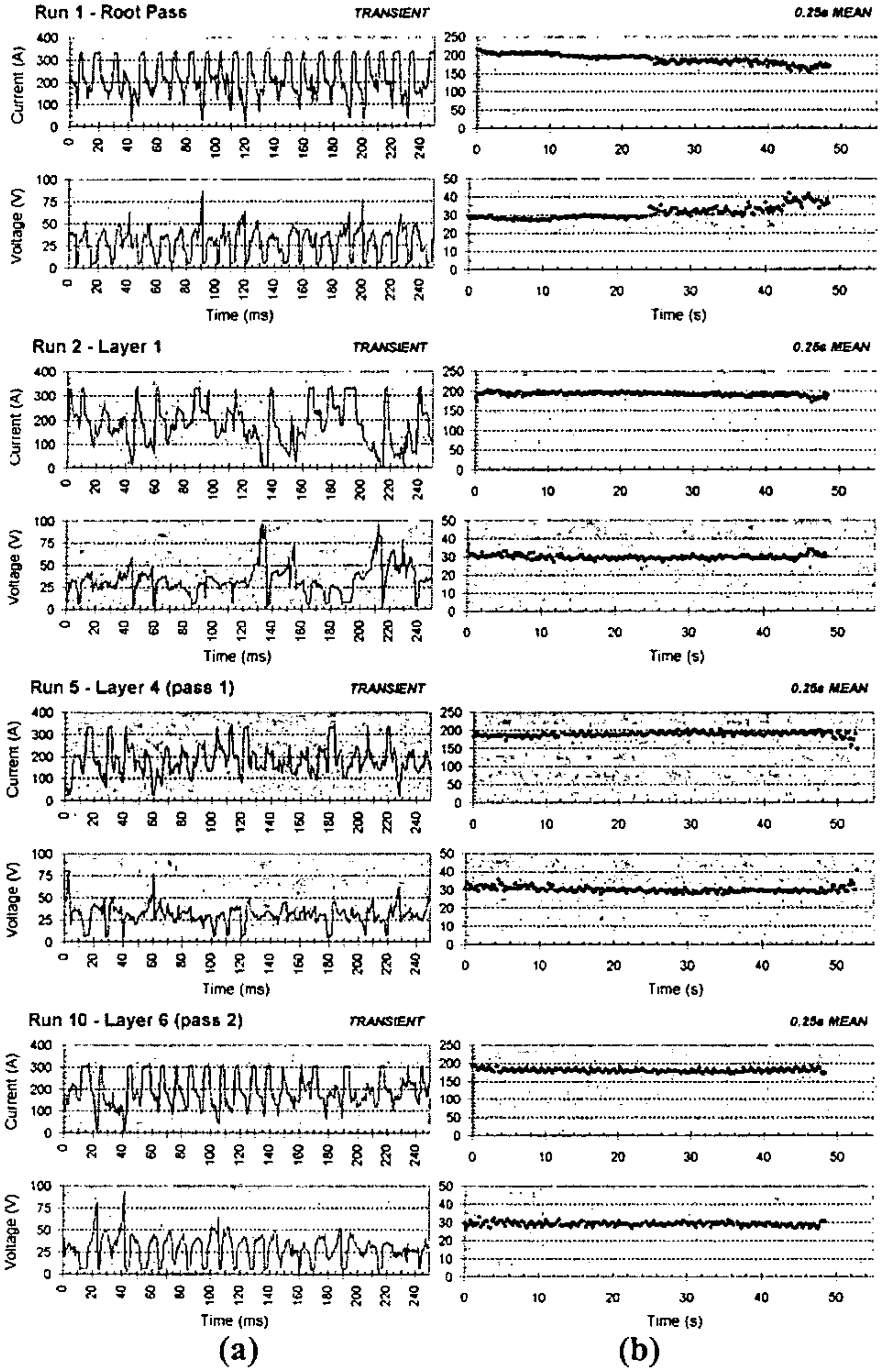
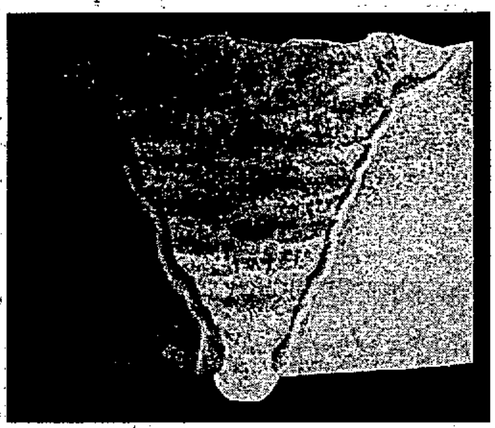
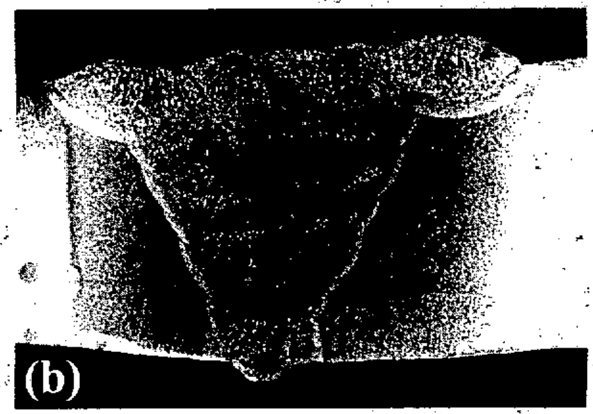


Figure 13 Electrical characteristics of the GMAW process at 250bar ambient pressure (8,200ft) showing (a) transient instability but overall process stability (b). Mean values represent averages over 0.25s duration.





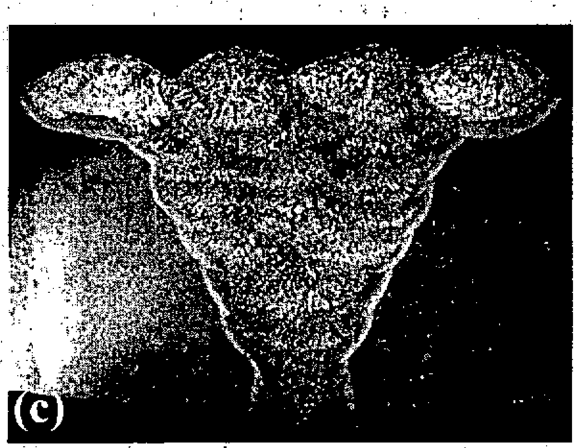


Figure 14 : Macrographs from GMA welded joints in 29mm thick X65 linepipe steel produced at pressures of (a) 160 bar (5,220ft) ; (b) 200bar (6,230ft), (c) 250bar (8,200ft).

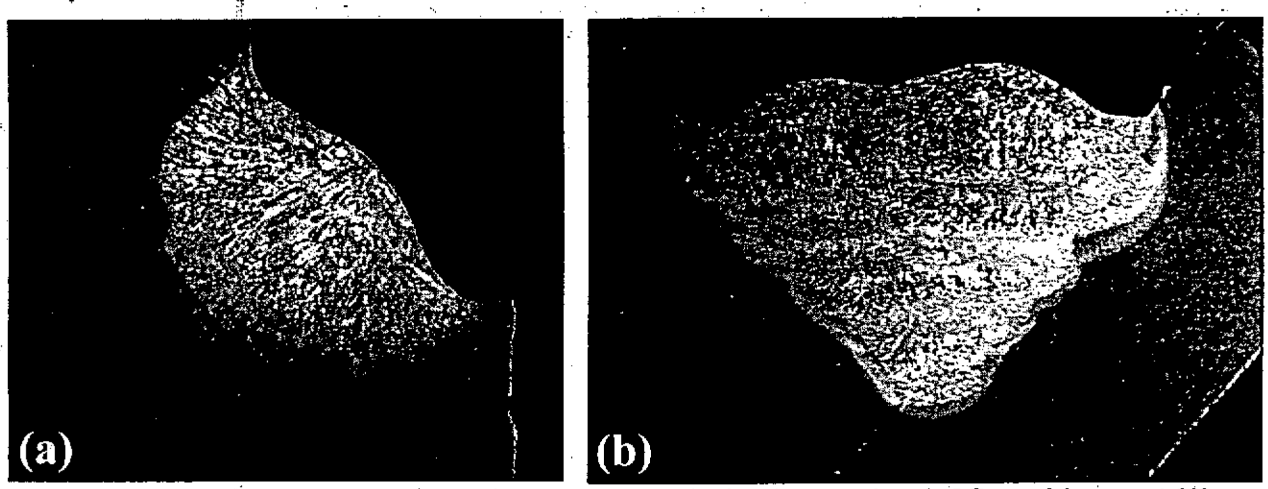


Figure 15 Macrographs of GMA fillet welds made in the overhead 5G position at 160bar ambient pressure (5,220ft). (a) two layer (b) 6 layer.

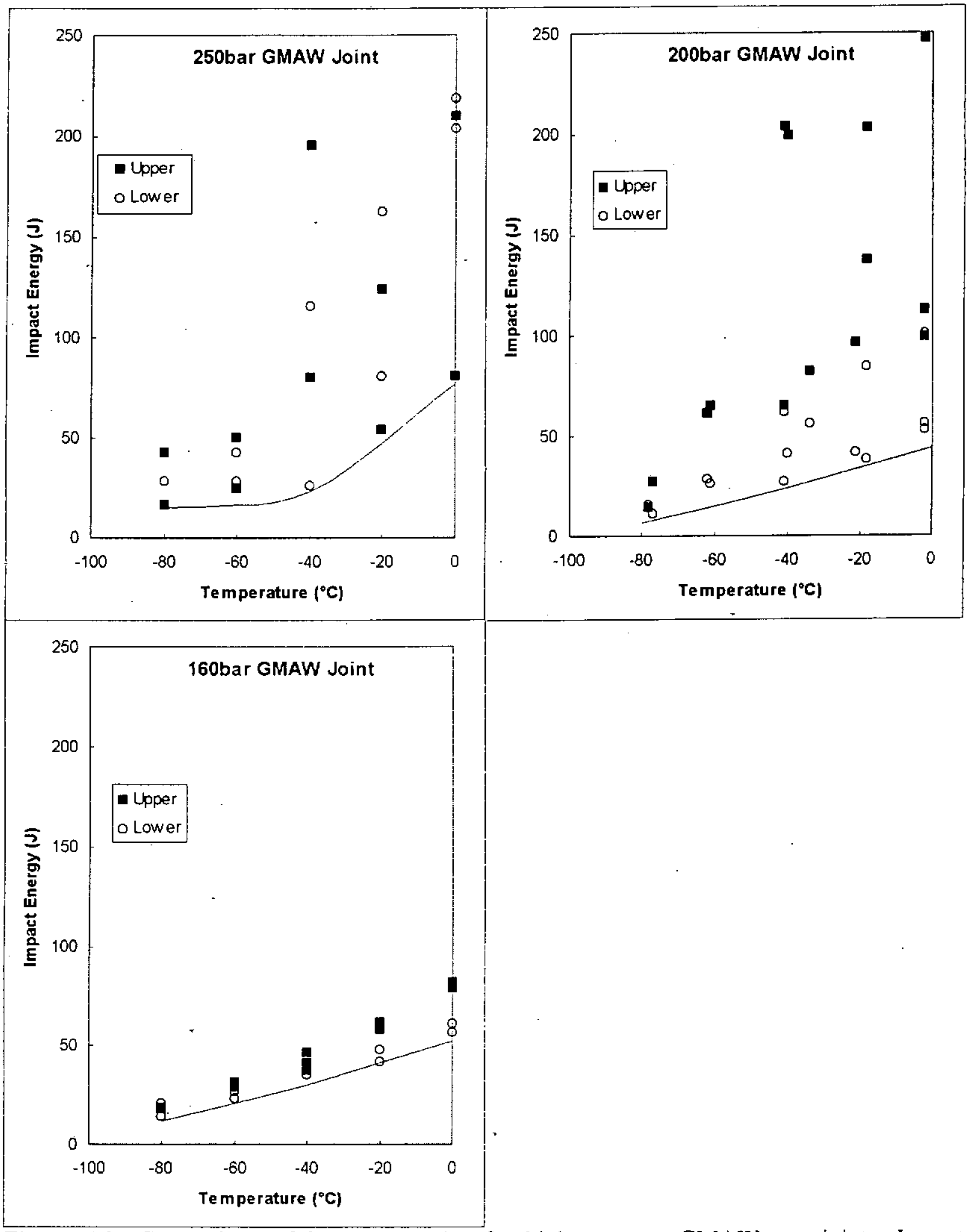


Figure 16 Comparison of impact energies for high pressure GMAW test joints. Impact specimens taken from the upper (filled points) and lower (open points) sections of the joint respectively.

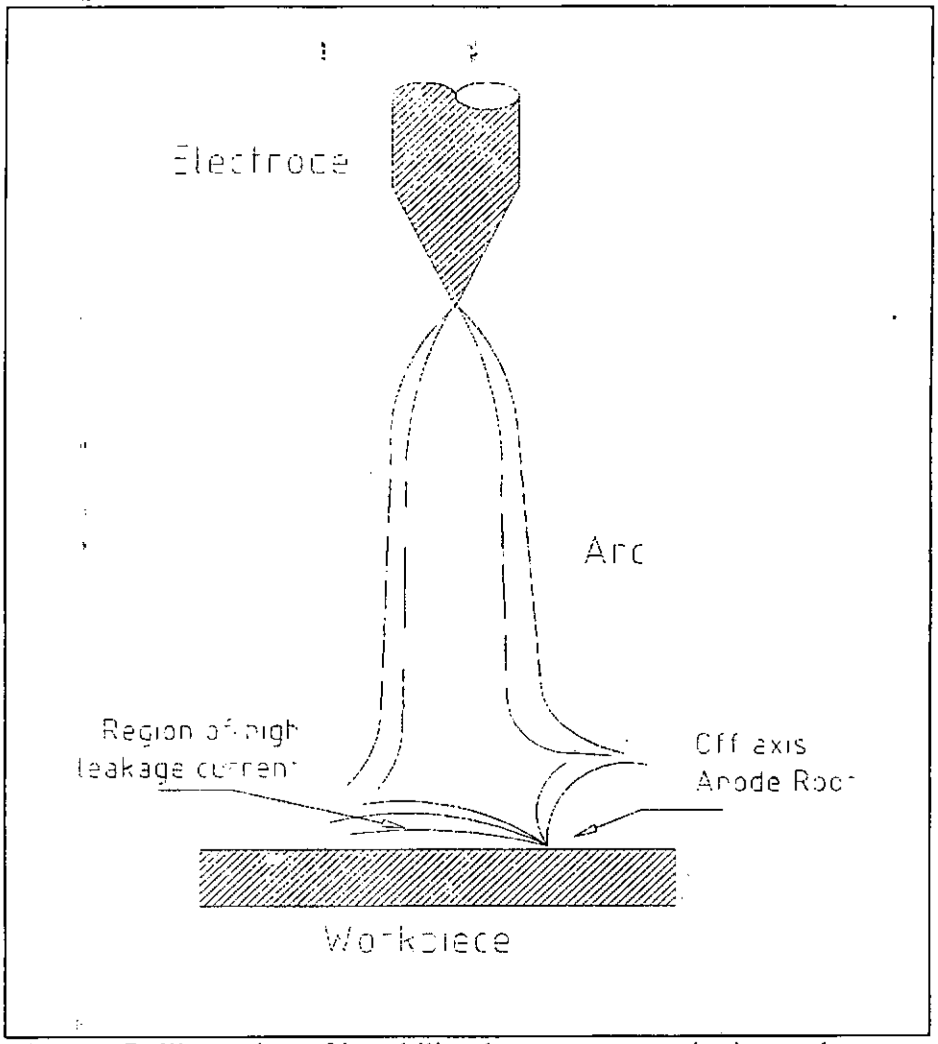


Figure 17 Illustration of instability due to arc root pinning and current leakage resulting in discrete arc root movement.

Subsea Structure Installation Technology

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and
Pipes & Pipelines International

Subsea Structure Installation
(Procedure Basis and Practice)

Abstract

This paper presents the results and observations from both engineering and field work undertaken inconnection with the design and installation of structures integral with the pipeline ends in deepwater fields. These structures are generally installed during the normal pipelay process while either initiating or terminating the pipeline. The design of the structure is not only influenced by its functional performance requirement, but also by the order in which the subsea structure is installed.

The pipeline end termination structures usually have relatively large dimensions to limit bearing pressures on the soils, which in turn exposes the structure to large hydrodynamic loads during installation. Further more during installation, the orientation of the sled changes from close to 90 degrees on the vessel to 0 degrees on the sea floor. The magnitude of the forces and moments due to current, the structure's own weight and center of gravity / center of buoyancy relative positions with respect to the pickup point and pipe span, change as the structure is lowered to the sea floor. Significant local loads, capable of causing pipe failure can occur during installation and should be engineered against.

This paper elaborates practical and proven methods of engineering analysis for developing methods for optimal installing deepwater subsea structures. It includes results from studies dealing with pipe bending at the structure, rotational stability of the structure and improving instability through the use of clump weights.

Finite difference and finite element analysis were used to investigate pipe static and dynamic behavior while handling the structure off the vessel. The presented methods provide valuable information for both designers and operation personnel for the safe and cost effective installation of these structures.

This paper also outlines several new approaches and technologies successfully used in recent projects.

An Overview of Sled Installation Issues

When technological gaps in a given water depth are effectively bridged, the deep-water subsea industry relegates it to the realms of shallow water. Exploration and production in water depths of over 6000 feet is presently underway and pipelines are already operating in over 3000 feet of water. Therefore it may be said that real prospects in over 10000 feet of water depth are merely on the horizon. In the interest of modularization and miniaturization of subsea components, it is common practice to incorporate structures at the ends of pipelines on the

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seabed. These structures are engineered to be installed integral with the pipeline. Depending on the function that they serve these structures are referred to as follows: PLES (Pipe*L*ine End Skid), PLET (Pipe*L*ine End Termination structure), PLEM (Pipe*L*ine End Manifold), FTA (Flowline Termination Assembly), etc. The authors of this paper address and present some simple formulations for critical issues related to these structures relevant to both design engineers and operations personnel.

Offshore installation procedures basically revolve round the 'high strain S-lay', 'Reel-lay' or 'J-lay' techniques. The subsea structure is deployed to the seabed during either pipeline initiation or termination phases. One feature that is common to all the above methods is the large or near vertical departure angle at the last support point on the vessel. This minimizes the sagbend length i.e. length of pipe past the last support point on the vessel to the pipe touch down point on the seabed. This profile tends to minimize the tension that is to be managed on the vessel and also reduces the pipeline component of load to be handled by the vessel thruster. This paper traces the engineering issues relevant to that segment of pipeline with the structure past the last support on the vessel.

The sled's effective drag area per unit length far exceeds that of the pipeline, thereby concentrating the severity of the environmental forces, generated by current and wave, at sled/ pipe interface. As a part of pipelay initiation, sled installation is performed by lowering pipe vertically downward with the sled at the end of it. This arrangement requires as near a vertical departure angle as possible. It is carried out close/ or directly above the target box depending on the existing subsea architecture by simply paying pipe out until the sled is near the mudline. This 'free dangling pipe/ sled' system is very sensitive to the prevailing environment and barge motions. The whole system is subjected to large lateral deflection (and torsion depending on the asymmetric projected areas to orthogonal and diagonal seas), overstressing the pipe (especially at the initial stages of deployment), making it difficult to land the sled within the set target box on bottom. One useful technique for suppressing the sled's deviation and oscillation may be achieved by a clump weight rigged to the sled. This increases the restoring moment and reduces undesirable pipe-sled deviation. The mechanism of the technique and its limitations are considered in the following sections.

From an operational standpoint, it is very attractive to install the sled on bottom as a continuation of the earlier pipe lowering process until the sled touches seabed and establishes full frictional resistance with seabed. By judiciously sizing the mudmat geometry and sled weight, a secondary costly hold back system to resist minimal pipeline on-bottom tension in a near vertical lay during initiation can be avoided. After that, the vessel moves forward paying pipe out, and starting-up the pipelay profile. However, the sled landing process generates an axial/ longitudinal impact force that travels along the vertically suspended long pipe (often more than 3,000 feet). This could induce pipe buckling with undesirable consequences to the integrity of the pipeline. In addition, there is also some uncertainty in establishing a barge movement-to-pipe payout ratio during the pipelay transition period. A new approach given in the following section provides an accurate method to determine key parameters and develop practical recommendations for this process.

Sled stability during lowering or recovering procedure is very much an indeterminate mathematical problem and the authors here provide a simple solution that could be used to perform a sensitivity study of the parameters involved. The term 'stability' is used here to specify any sled rotation during its lowering or recovering, and the need for possible control of the sled orientation during the landing. It should be noted that sled rotation is especially severe for reel-laid pipeline and for a sled close to a curve along the route.

Free-Hanging Pipe/ Sled Stability

Free-hanging pipe/ sled lowering method of pipeline initiation is preferable in deep waters. An inline sled is secured at pipe's first end and pipe is paid out until the sled is in close proximity to the bottom (i.e. within a pipe joint). If a quad/ double jointing process is used, it might be necessary to use an odd sized joint to quickly transition to a pipelay profile. In this method the sled is not connected to any bottom anchor. Therefore, the environmental loading and any barge movement can generate large lateral deflection and bending within the long pipe string. An analytical approach to predict the deviation and bending stress/strain values is developed here that could be used to generate installation-engineering procedures.

The free hanging pipe behavior could be analyzed by the following beam equation:

$$E*I*Y''/(1+Y'^2)^{3/2}=-G*(Y_o-Y)+\int_x^H q*(\xi-x)*dx-\int_x^H w*(\eta-Y)*dx \qquad (1)$$

$$x = 0,\ Y = 0,\ Y' = 0$$
$$x = H,\ Y = Y_o$$

where: E, I – pipe modulus of elasticity, steel moment of inertia
- Y / Y_o – pipe lateral deflection / deflection at sled
- H – sled/pullhead water depth
- G – sled submerged weight
- q(x) – current drag load
- x – current coordinate along pipe axis
- w – pipe submerged weight
- ξ – pipe coordinate within the (x, H) interval
- η – pipe lateral deflection within the (x, H) interval

To avoid numerical difficulties due to the pipe's position in a near vertical profile (differential analysis fails without the introduction of dummy constraints to provide an accurate solution for this kind of task), a catenary approach is used. So, equation (1) can be represented in non-linear form using catenary approximation as follows:

$$Y'=\int_x^H q(x)*dx\,/\,[-w*(H-x)] \qquad (2)$$

$$x = 0,\ Y = 0.$$

The catenary solution for a given current pattern q(x) could expressed as :-

$$Y = \phi(x) \text{ and } \phi(H) = Y_o \qquad (3)$$

That expression could be used to estimate pipe bending strain as follows :-

$$\varepsilon= d / 2*Y'', \text{ and } Y'' = d\,\{\int_x^H q(x)*dx\,/\,[-w*(H-x)]\}/dx \qquad (4)$$

The above equation allows the estimation of the pipe bending strain at every point along suspended pipe, except the area near the last constraint on the vessel. However, this is the most critical location as the highest strain is expected to be here. To enhance the strain estimation accuracy, a beam approach at top clamp proximity is proposed. The pipe-beam length portion near the top clamp is equaled to the pipe characteristic length of L_c, given by:

$$L_c = (E*I/w)^{0.333}$$

This pipe length axis is approximated by the following polynomial:

$$Y = a_1*x^2 + a_2*x^3$$

With boundary conditions as follows:

$$X = 0,\ Y = 0,\ Y' = 0$$
$$X = L_c,\ Y = Y_c,\ Y' = Y_c'$$

where: Y_c, Y_c' – catenary deflection and tangent values at $x = L_c$ from equation (3). Hence:

$$a_1 = 3*Y_c/L_c^2,\ \ a_2 = Y_c'/L_c^2 - 2*Y_c/L_c^3 \qquad (5)$$

and pipe strain value at the top clamp is determined by the expression:

$$\varepsilon = d\ /\ 2*Y_b'',$$

where: $Y_b'' = 2*a_1$.

To perform a numerical analysis, an Excel spreadsheet was developed which allows the estimation of pipe string lateral deflection and bending strain/stress with any given current loading pattern i.e. nominal, loop or extreme Eddy loop current. The spreadsheet results and deflected form is presented in Appendix 1. In the particular case study, a 5 foot per second loop current causes a 5-in diameter pipe significant lateral deviation (about 100 feet for a water depth of 3000 feet), with very high stress levels (approx. 97%SMYS), even with a sled submerged weight of 25 tons. For this particular case, the pipe length associated with pipe maximum bending stress is in the 800 to 900 foot range. For a nominal current (surface velocity about 3 feet per second), the pipe deflection does not exceed 20 feet and the stress range is within 20%SMYS for the same problem.

Sled Impact on Landing

As mentioned earlier, by simply paying pipe out, the sled could be installed by gently landing it on the seabed. However, at the instant of sled contact with the seabed, the resulting impact could generate pipe string instability as in Euler buckling. The analysis below illustrates a means of controlling the procedure, thereby avoiding any localized yielding or buckling.

The tension distribution along the vertically lowered pipe with sled at the end, linearly varies along the pipe's length with its maximum value at the top. The pipe elongation $\delta L(x)$ at a distance 'x' from the top support can be easily calculated. The total elongation, $\delta L(L)$ can be found similarly by substitution 'L' for 'x':

$$\delta L(x) = w*H*x/(A_s*E) + w_a*x^2/(2*A_s*E) - w_a*H*x$$

$$\delta L(L) = w*H*L/(A_s*E) + w_a*L^2/(2*A_s*E) - w_a*H*L$$

where: A_s – pipe steel cross section area
w_a – pipe weight in air
L – pipe length (from top to bottom)

When the sled is already in contact with the seabed, as additional pipe is paid out, a certain length of pipe adjacent to the sled becomes compressed. Assuming the additional length of pipe paid out before the onset of buckling is, V*t :

where: V – velocity of lowering
t_1 – time duration before buckling of the pipe

Then the compressed portion of pipe length, h, at that instant is:

$$V*t_1 = w*h^2 / (A_s*E)$$

Hence: $$h = (V*t_1*A_s*E / w)^{0.5} \quad (6)$$

The compressed length is a sharply growing function dependant on the lowering time duration. Defining in terms of velocity 'C', it can be expressed as follows:

$$C = dh / dt = 0.5* [V*A_s*/(w*t)]^{0.5}$$

The bottom vertical axial reaction 'R' , can be determined as follows:

$$R = w*h/2 = w/2*(V*t*A_s*E / w)^{0.5} \quad (7)$$

This equates to the pipe stability term in the Euler formulation. A vertical bar that is hinged at the ends loses stability under its own weight when the following equation is satisfied:

$$w*h/2 = \pi^2*E*I / h^2$$

Hence, the compressed pipe critical length 'h_c' is:

$$h_c = (2*\pi^2*E*I / w)^{0.333} \quad (8)$$

Therefore the equations (6) and (8) for the time duration for phase #1 i.e. initial phase can be found as follows:

$$t_1 = h_c^2*w / (V*A_s*E) \quad (9)$$

In order to estimate the allowable duration of pipe pay out after the sled touches the bottom, or the amount of additional pipe that can be paid out without a vessel movement, a sinusoidal pipe buckled profile is assumed:

$$z = A*\sin(\pi*x / h_c)$$

The above shape is generated in the second phase as additional pipe is lowered, $V*t_2$.

The compressed pipe length remains the same, but helps to calculate the maximum lateral deflection, A:

$$A = 2/\pi*(V*t2*hc)0.5$$

and pipe bending strain due to buckling:

$$\varepsilon = d/2 * [\max(d^2z/dx^2)] = d*\pi*(V*t_2*h_c)^{0.5} / h_c^2$$

where h_c is determined by (8). If the allowable bending strain, of ε_a, is known, then phase #2 time duration is:

$$t_2 = \varepsilon_a^2 * h_c^3 / (d^2*\pi^2*V) \quad (10)$$

Therefore, the total length of the pipe paid out after sled touch bottom should not exceed the below value:

$$\delta L = (t_1 + t_2)*V \quad (11)$$

The analysis above employs a quasi-static approach to the problem and as such does not consider inertia forces or bending wave propagation through the pipe. However, the pipe lowering procedure is usually characterized by low velocity, especially when sled is near the seabed, thus justifying the simplification used. Author's own experience in installing large manifolds West of Shetlands, North Sea also supports this simplification.

This method can be easily implemented on a spreadsheet and a case study is included in Appendix #2. The study considers, 5 feet of additional pipe (12 x 8 pipe-in-pipe with sled) pay out after sled touch down at a lowering velocity of 10 feet per minute in 3850 feet water depth.

Sled Rotational Stability During Installation

Environmental loading and vessel motion are some of the destabilizing factors effecting sled installation. A long pipe string is relatively flexible to be able to resist rotation or 'pendulum motion' of the sled.

A steady state current tends to rotate the sled about the pipe axis until such time that the overturning moment is equal to the restoring moment. The overturning moment results from the imbalance of the sled drag area about the pipe axis and tends to reduce with rotation as the project area to the flow reduces. The righting moment is a function of the weight and center of gravity of the structure and the systems rotational stiffness. The center gravity position relative to the hinge of the sled supporting bridle and pipe axis position plays an important part in determining the range of stability or alternatively the angle at which the structure comes to rest. It could be argued that for best results the center gravity lies along the pipe's longitudinal axis (pipes' common axis) and close to the bridle hinge. These requirements can be built into the sled structure design to eliminate instability issues during installation.

A pipeline reel-lay procedure presents a completely different problem. The unreeling (i.e. during reel-lay) process causes the pipeline to twist and as more pipe is reel laid the structure continues to rotate with loss of the initial orientation and in cases even landing in an overturned position. Torsion gets built into the system as the pipeline is reeled-on. While pipeline is being reeled and straightened, the built-in torsion gets translated to rotation around the pipe's longitudinal axis. The pipeline remaining on the reel constrains the torsion between the reel and the sled. That induces the structure at the free-end to twist axially. The mathematical formulations related to the above is presented below.

Pipe coiled onto a reel has a spiral form. This causes an axial displacement approximately equal to the pipe's outside diameter at the end of the coil. From helical spring theory, the torque 'M_t' is dependent on the coil's axial displacement 'δh' and can be expressed by the following formula:

$$M_t = 2*G*I_p*\delta h / (\pi*D^2) \tag{12}$$

Where: G – shear modulus of elasticity
- I_p – pipe steel section polar moment of inertia
- D – reeled pipe axis coil diameter (D = Dr+d)
- Dr – reel's drum diameter
- δh – pipe pitch on reel's drum.

During reel-lay, some of the total pipe length is suspended in a sagbend and the remainder is in contact with the seabed. If the pipeline is not buried, the only force restricting the rotation of the pipe is the pipe-to-soil friction force. Assuming the active length of pipe subject to rotation on-bottom is L_a. Then:

$$M_t = w*L_a*f*d/2$$
and
$$L_a = 4*G*I_p*\delta h / (\pi*D^2*d*f*w) \tag{13}$$

Hence, it is possible to calculate the pipe torque angle φ, as function of the pipe length L_d from reel drum .

$$\varphi = \int_0^{L_d} M_t*dL/(G*I_p), \text{ or}$$

$$\varphi = \begin{cases} \text{If: } L_d < L_s,\ \varphi = M_t * L_d / (G*I_p) \\ \text{If: } L_a + L_s > L_d > L_s,\ \varphi = M_t * L_s / (G*I_p) + (M_t * L_a - L_a^2*w*f*d/4) / G*I_p \end{cases} \tag{14}$$

As an example the following pipe parameters are assumed, 6-inch pipe of 0.719-inch wall, 30.0 pounds per foot – submerged weight, 0.5 – pipe-to-soil friction factor, 390.6-inch – pipe axis coil diameter on the reel drum, 7-inch pipe spiral pitch on a drum, 118 inch^4 – pipe steel section polar moment of inertia, 1600-feet – pipe sagbent length, 1200-feet water depth and 11,154 ksi - shear modulus.

Then, according to (12), a torque of 38.4 in-kips is calculated which could generate a pipe active length on-bottom of 9,274-inches (772.8-feet). The pipe and subsea structure according to (14), will rotate a maximum of 39.8°.

A similar situation occurs when the structure is abandoned on a curved part of the route. In this case, the pipe's spiral pitch is equivalent to the water depth and the pipe coil diameter equivalent to the route curve diameter. To evaluate sled rotation resulting from abandonment on a curved route, consider a case where the route radius =3,000 feet (6,000 feet diameter), water depth = 3,000 feet, and pipe span length is 4,400-feet while keeping other parameters the same. Then, according to (12) the torque value is 5.82 in-kips and with a pipe active length on-bottom of 1,405-inches (117.1-feet), the maximum twist angle is about 13.6°.

The proposed analytical tools were used on real projects and results of the same closely matched the field observations made at the time of the pipeline and subsea structure installation.

Conclusions

1. The above methods address key installation issues related to pipeline end skids. They present accurate and easy means to evaluate the feasibility of installing the sleds with the pipeline successfully. Some conclusions drawn from the study are listed below:

2. Subsea structure (sled, PLEM, etc.) abandonment can be performed by lowering the pipe with a sled on a free-end using deep water lay methods. The proposed analytical tool predicts pipe bending stress/strain and lateral deviations caused by environmental factors. The clump weight solution can be effective in reducing the lateral mobility of the installed subsea system.

3. The subsea structure can be landed by continuation of the pipe pay out until it touches the mudline. However, to reduce axial impact due to sled landing, the pipe pay out velocity must be reduced as the sled approaches the seabed. The proposed approach provides a method to specify the installation parameters near seabed.

4. The reel-lay process is always associated with pipe twisting because of the nature of the pipeline unreeling procedure. In other words, it is inevitable. Very similar pipeline behavior is also observed during sled abandonment on a curved part of the route. The proposed approach allows the estimation of the pipe torque and angle of rotation as a result of either pipe unreeling or pipe laying on a curved route.

References

1. Timoshenko S. P. – "Theory of Elastic Stability", McGraw-Hill Publishing Company, Second Edition, 1988.

2. Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design), Pipeline Segment, API Recommended Practice 1111 Third Edition, July 1999.

APPENDIX # 1

Pipe FreeEnd Lateral Deviation

Client: XXXXXXXX
Project: XXXXXXXX
Engineer: N. Kershenbaum
Date: 31-Jan-00

Input Data

Pipe Steel O.D., inches	=	5.5625	
Pipe Equivalent OD.(incl. Isolation), inches	=	19.5	
Pipe WT., inches	=	0.75	
Pipe Cross Sec.Mom.of Inertia, in^4	=	33.624	
Pipe Submerged Weight, plf	=	34.59	
SLED/Clumbweight, lbs	=	50000	
Nominal Current Surface Velocity, ft/sec	=	3	0
Nominal Current Velocity @ 500 ft., ft/sec	=	0.5	500
Nominal Current Bottom Velocity, ft/sec	=	0.3	3000
Hyrdodynamic Drag Coefficient	=	1	
Modulus of Elasticity, psi	=	2.90E+07	
Water Specific Gravity, pcf	=	64	
Pipe Characteristic Length, inches	=	696.78	**58**
Pipe Section Modulus, inch^3	=	12.09	
Water Depth, feet	=	2950	
Pipe Length, feet	=	**800**	
Gravity Acceleration, ft/s^2	=	32.174	
Loop Current Surface Velocity, ft/s	=	5	0
Loop Current Velocity at 500 ft WD., ft/s	=	3.4	500
Loop Current Velocity at 1000 ft WD., ft/s	=	1.7	1000
Loop Current Velocity at 1500 ft WD., ft/s		0.8	1500
Loop Current Velocity at 3000 ft WD., ft/s		0	3000

FLAG = **-1**

(FLAG= - 1,	Loop Current)
(FLAG=1,	Nominal Current)

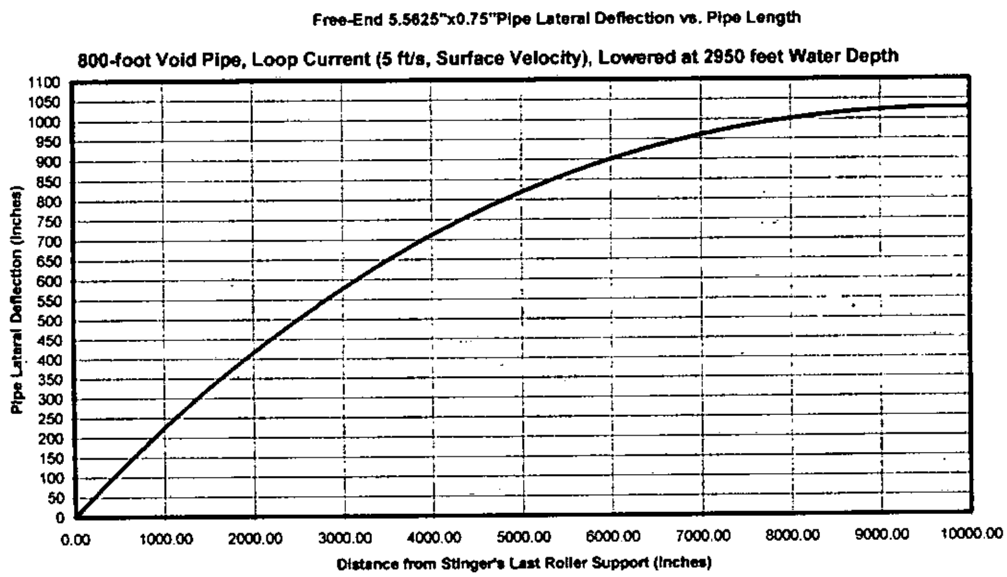
Analysis Results

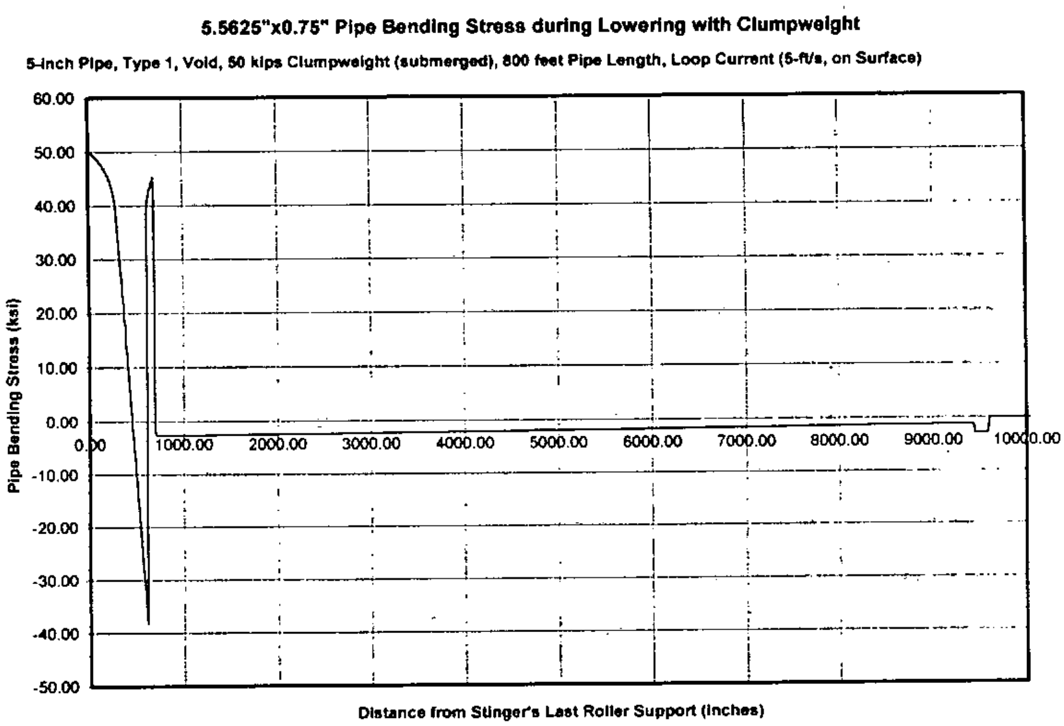
Coefficients, a1 / a2	=	6.73E-04	-4.94E-07
Pipe Specific Length, inch	=	696.78	
Pipe Specific Deflection, inches	=	159.38	
Pipe Specific Slope	=	0.2175	
Pipe Maximum Curvature/Strain, inch^-1	=	-0.001345	0.003742
Pipe Bending Stress at Roller Support Beam Approach), ksi	=	**50.23**	
Pipe Proportional Limit Stress, ksi	=	38.45	0.00133
Hutchinson Exponent	=	11.59	
Pipe Steel SMYS, ksi	=	52	
Free End Lateral Deflection, feet	=	**85.57**	
Pipe Maximum Bending Stress (Catenary Approach), ksi	=	**50.23**	

SLED/CLUMPWEIGHT DATA

Height of the End Structure, feet	=	14.6
End Structure Width, feet	=	3.8
End Structure Hydrodynamic Coefficient	=	1.0

APPENDIX # 1 (cont)





APPENDIX # 2

HEAVY SLED INITIATION SPREADSHEET

Client:	xxxx
Project:	xxxx
Job #:	xxxx
Engineer:	N. Kershenbaum
Date:	31-Jan-00

Input Information

Pipe OD., inches	=	4.5
Pipe WT., inches	=	0.674
PIP Moment of Inertia, in^4	=	15.1
Jacket Pipe Steel Cross Section Area, in^2	=	8.1
Pipe Weight in Air, klf	=	0.046
Pipe Submerged Weight, klf	=	0.015
Water Depth, feet	=	3300
Pipe Length from Tensioner to Bottom, feet	=	3564
Velocity of Lowering, in/sec	=	2
Steel Modulus of Elasticity, ksi	=	29000
PIP Steel Cross Section Area, inches	=	8.1
PIP Allowed Bending Strain, %	=	0.15

Calculation Results

Initial Total Elongation of the Pipe, feet	=	-0.31
Add.Lowering to Reach Allowed Bend.Strain, feet	=	6.49
PIP Critical Length due to Euler Instability, feet	=	158.76
Add. Lowering to Reach PIP Instability, feet	=	0.00
PIP Total Additional Allowable Lowering, feet	=	**6.49**
Allowable Time of the Additional Lowering, sec	=	**38.93**
Sled/Bottom Vertical Reaction, kips	=	**1.19**

Deepwater Pipeline Routing: the Unexpected Challenge

Kerry Campbell
Fugro GeoServices, Houston, USA

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

DEEPWATER PIPELINE ROUTING: THE UNEXPECTED CHALLENGE

Kerry J. Campbell
Fugro GeoServices, Inc., Houston

7 March 2000

1.0 ABSTRACT

Pipelines on the continental shelves (to water depths of about 500 to 600 ft., where most pipelines have been installed), generally run point-to-point in straight lines, deviating only to avoid man-made infrastructure, debris, and shipwrecks. With rare exceptions, the seafloor is flat and smooth. In sharp contrast, seafloor conditions are commonly far more complex and difficult in deepwater, continental-slope areas.

Complex and difficult deepwater conditions include:

-Rugged topography with steep slopes (up to 45° or more) hundreds of feet high.
-Rocky seafloor.
-Strong seafloor currents and sediment scouring.
-Ongoing differential seafloor offset across active faults.
-Seafloor instability (including landsliding and mudflow activity, fluid venting, and turbid flows).

These and other deepwater conditions cause: pipe spanning; vortex shedding and pipe vibration at spans; anomalous bending and tensional stresses; unexpected pipe burial or excavation due to current scouring and sediment transport; sags, with the potential for plugging in gas lines; and other problems. In many cases, significant route deviations are required to avoid the most difficult conditions and to optimize routing, causing increases in route length of up to 40%. Consequently, even allowing for the added costs due to deeper water, pipeline cost-estimating models used on the continental shelf will not always be applicable for deepwater pipelines.

Case histories from recent deepwater pipeline projects will be used to show why longer routes are often less expensive than straight-line routes that would require extensive remediation or other engineering solutions (such as use of flexible steel pipe). The case histories will also demonstrate how 3-D seismic exploration data are routinely being used for preliminary deepwater pipeline route selection and assessment, and to optimize route survey plans. Finally, modern pipeline survey and data vizualization tools specially designed for difficult deepwater areas (including multibeam, bottom-referenced deep-tow, and AUV technology) will be discussed.

2.0 INTRODUCTION

This paper is presented in the style of a self-interview to make for easier reading:

What is this paper about? This paper discusses deepwater seafloor conditions and their significance to pipelining, and a few case histories are summarized. Also, some of the tools used for deepwater route surveys are discussed, along with a suggested approach to deepwater pipeline routing.

Why is this paper important to me? I believe that this paper is especially important to those who are new to deepwater pipelining because they probably don't fully appreciate how complex and difficult seafloor conditions can be. This paper will help put the situation into perspective and will help answer some of the many questions pipeliners have about deepwater conditions. Even those with deepwater pipeline experience may find useful background information here. So, this paper should be of interest whether you are involved in conceptual or feasibility studies, planning, cost estimating, routing, design, or installation.

How can I use it? Well, for one thing, as a quick reference. Specifically, the paper mentions the principal deepwater conditions that can adversely affect pipeline routing, design, installation, and maintenance. Also, some of the latest survey tools and techniques are explained, giving you a basis for preparing route survey specifications. The case histories, on the other hand, are intended to help others avoid the pitfalls some have experienced. Or, in one case, to illustrate good practice. And, finally, I believe that the suggested approach to deepwater pipeline routing is a methodology that will help to both reduce project delays and costs if it is followed.

Why do you use the term "unexpected challenge" in the title? Simply because, in my experience at least, many pipeliners (and others for that matter) still do not realize how difficult deepwater conditions can be, or what the implications for routing and design might be. Although awareness of deepwater conditions is now starting to increase rapidly by necessity, remember, as an industry, we have relatively little deepwater experience with pipelines compared to our decades of experience on the generally benign shelf.

And, at least in the Gulf of Mexico, most of the deepwater pipeline experience to date has been in relatively "easy" corridors. For the most part, we haven't gotten to the "tough areas" yet. Figures 1 and 2 illustrate this by showing that most of the deepwater developments to date, with a few important exceptions, are in relatively shallow water. Most of the deepest exceptions are in Mississippi Canyon, where seafloor conditions are generally relatively favorable for pipelining when compared to many areas in Green Canyon, Garden Banks, and other areas to the west.

Before we begin, tell me how you define deep water. My definition of deep water is water depths greater than about 600 ft. This approximate water depth represents a fundamental geological boundary found virtually everywhere offshore: the boundary between the continental shelf and continental slope. This boundary also represents the boundary between the flat, benign seafloor typical of the continental shelf, and the rugged, steeply sloping, unstable seafloor sometimes typical of the continental slope. For example, the difference is dramatic in the Gulf of Mexico (Figure 1) and in some other parts of the world as well. And, significantly, the shelf – slope boundary is also a defacto boundary between decades of successful pipelining experience on the shelf and, for the marine pipeline industry overall, still relatively limited experience on the slope. Although the water depth where the transition takes place, and the sharpness of the transition vary widely from region to region, 600 ft is a reasonable rule-of-thumb depth.

3.0 DEEPWATER CONDITIONS AND IMPLICATIONS FOR PIPELINING

I've heard that deepwater seafloor conditions can be complex. Is this true? Yes, this is true. In some cases conditions can be very complex and difficult. However, it is important to realize that conditions everywhere are not complex and difficult. So, I believe one of the keys to successfully dealing with this issue is to look at route conditions early, at least in a cursory (and inexpensive) way, to get a preliminary feel for how important route conditions will be on a given project, and then plan accordingly. Given that pipeline costs will be a large percentage of total development cost for many deepwater projects, It doesn't make sense to me to do economic analysis, project budgeting, or preliminary routing, as examples, without considering seafloor conditions in the region.

What are some of the deepwater conditions of concern to pipeliners?

Complex and potentially difficult deepwater conditions in the Gulf of Mexico include:

- Rugged topography with sharp changes in gradient.
- Steep slopes (up to 45° or more) hundreds of feet high.
- Rocky seafloor.
- Strong seafloor currents and sediment scouring.
- Ongoing differential seafloor offset across active faults.
- Seafloor instability (including landsliding and mudflow activity, fluid venting, and turbid flows).

Some of these conditions will be widespread over relatively large areas, and others will be of only local concern.

Do conditions vary from place to place? Yes, greatly, and over short distances. The boundary between benign and difficult conditions is often sharp.

How do deepwater conditions compare to conditions on the continental shelf? Well, it depends, of course, exactly where you are talking about. Although there are important exceptions, in general, the shelf in the Gulf of Mexico is flat, smooth, and featureless, and geologic processes are benign. In other words, nothing much to worry about with respect to natural conditions. Routing issues on the shelf are more likely to involve existing pipelines, platforms, and other infrastructure, shipwrecks, or debris. This has been typical industry experience for decades.

In comparison, natural conditions in deepwater will play a much more dominant role on many projects. Because of the shallow salt that underlies much of the deepwater Gulf of Mexico, the seafloor here is often especially complex over large areas. Deepwater conditions include steep and rugged topography, seafloor instability and downslope flows, active faulting, variable seafloor materials, and other conditions. As an industry, we are still not well experienced in recognizing the significance of or dealing with these issues. There is still much to be learned.

How much of an impact will these conditions have on project economics? Again, cost impact will vary widely, depending on several interacting factors. But in some cases, impact will be large. Some marginal, stand-alone discoveries may not be economically viable once it is realized that pipelines will need to be longer than originally thought to avoid difficult areas.

What about conditions in other parts of the world? Although the deepwater Gulf of Mexico is one of the most difficult areas, most other deepwater areas I've worked in also exhibit similar complex conditions. This is true for West Africa, Brazil, Trinidad, the Caspian Sea, western Australia, and other areas. The biggest difference is that the frequency of occurrence of difficult conditions tends to be higher *over extensive areas* in the deepwater Gulf of Mexico. In other words, if you blindly laid out random routes on deepwater maps of the Gulf and other areas, complex conditions would be found along a higher, and sometimes much higher, percentage of the routes in the Gulf compared to routes in most other places.

Have we, as an industry, seen the full range of deepwater pipelining problems related to seafloor conditions? I don't think so. As I said before, we really haven't gotten to the really tough areas yet, so I think we still have a lot to learn.

Let's talk about spanning. How much of a problem will spanning be? Well, I can't answer that directly because I'm not a pipeline engineer. However, conditions conducive to spanning, that is, sharp changes in seafloor gradient, are very common in much of the Gulf. I think that there is no question that spanning will be, by far, the most common issue that pipeliners will have to deal with. Other conditions will be locally important, even critical in some cases, but spanning will be the biggest issue overall and will get most of the attention. And, as a result of the spanning problem, many lines will end up being longer than the straight-line route. Some preliminary studies in some areas of the deepwater Gulf show lengths for acceptable routes being from 10% to 40% longer than the straight-line route.

Examples of seafloor profiles and images showing rugged topography are shown in Figures 3 through 13. These examples show that not only are sharp changes in seafloor gradient encountered in some places, but steep slopes that extend for hundreds or thousands of feet vertically are also found.

How variable are seafloor soils? Weak clays are, by far, the predominant seafloor soils in the deepwater Gulf. In some areas there has been extensive, deep erosion of the seafloor, and soils now exposed in these areas are noticeably stronger, depending on the amount of erosion. Locally, hard, irregular, rocky outcrop is found, especially on some salt uplifts, along some seafloor faults and around vents. Locally, sands also have been sampled at the seafloor. In rare cases, gas hydrate deposits are at the seafloor or buried by a veneer of sediment. 3-D seismic data analysis can give a preliminary indication of soil types likely to be encountered. Geophysical data collected during the final route survey, coupled with piston-core samples and insitu test results from the geotechnical program, give an integrated characterization of soils along the entire route.

One concern with deepwater soils is that they are sometimes what the geotechnical engineer calls "sensitive". That is, their undisturbed strength is several times that of the strength of disturbed soil. This leads to the possibility that seafloor disturbance during pipelaying, for example, could trigger thin, surficial landslides in some cases. How common and important this possible problem might be remains to be seen. Another unusual condition is where brine, much denser than seawater, has been trapped in enclosed topographic basins. Although this is rare, it might locally be a factor in pipeline design.

Can we route pipelines through these difficult areas? I'm often asked by clients if pipelines can be routed through this or that difficult area. This, of course, is not the right question. Technologically, pipelines could be routed almost anywhere. It is really a matter of how much are you willing to spend to design and install a pipe that will perform as intended. So, the real answer is, of course, not easy to derive, and requires the pipeline engineer to consider several interacting factors. I see my job as doing the best I can to quantitatively characterize the topography and other conditions along the route, and to put reasonable limits on rates, frequencies, and magnitudes on geologic processes that may be active. The final answer has to come from the designer in conjunction with the owner who will have to pay for it all.

4.0 ROUTE CHARACTERIZATION SURVEY TOOLS

What kinds of tools are being used for deepwater pipeline route surveys? The most common tools now being used for deepwater pre-lay route surveys include swath bathymetric, side-scan sonar, and subbottom profiler systems. Sometimes magnetometers are also used. These tools are essentially the same as survey tools used on the continental shelves. However, in order to collect data that clearly images the seafloor and shallow sediments, special deployment techniques are needed. Specifically, the sensors need to be towed close to the seafloor to properly image it. The vehicle that houses the sensors is referred to as a deeptow vehicle or deeptow fish. One complication that results when using deeptow systems is vehicle positioning. There are several methods to do this, but all add complexity and cost to the survey operation.

In contrast, sensors towed near the sea surface, thousands of feet above the seafloor that needs to be imaged, produce data that is reduced in clarity. The deeper the water and the more irregular the seafloor, the poorer the data quality. In many cases, such data is essentially useless. Thus, the current tethered deeptow technology or equivalent is essential to obtain reliable deepwater survey data.

I say "or equivalent" because soon, within the next year or two, autonomous underwater vehicles (AUV's) will begin to be used as geophysical survey platforms for deepwater surveys. AUV's are essentially untethered and unmanned robot submarines that will cruise just above the seafloor and collect the same suite of data now being routinely collected by tethered deeptow systems.

How important is it that deeptow tools be bottom-referenced? One of the keys to collecting quality data is to keep the sensors at a constant height above the seafloor. In areas of smooth and gently sloping seafloor this can easily be done for negatively buoyant towfish by slowly adjusting the tow cable length as the water depth changes. However, in areas of rugged seafloor, where good quality data is especially important, this is extremely difficult if not impossible to do.

The best solution available today that I am aware of is to use a bottom-referenced deeptow system. The bottom-referenced concept was promoted by Shell some 15 years ago after considerable research into how to best collect quality data in rugged deepwater areas. This "bottom-referenced" system uses a positively buoyant towfish with a chain that drags along the seafloor (see Fig. 15 for diagram). Thus, regardless of seafloor elevation, the towfish "flies" at a constant height above the seafloor. An analogy would be a man holding a helium-filled balloon by a string and walking up and down hill. The balloon stays a constant height above the ground no matter how high the hill is. Simple but very effective, and, in my opinion, essential to collect quality data in rugged deepwater areas.

How about using ROV's for geophysical survey work? ROV's are not typically being used for extensive pre-lay survey work because the conventional tools are more efficient. However, in areas of complex seafloor where special detail is needed, ROV's can be used for geophysical as well as visual survey work. Conventional as well as ROV-based geophysical survey work was successfully performed on the Blue Stream pipeline project in the Black Sea. Local detail provided by the ROV survey data was critical to assessing bottom conditions. Steve Bucklew reported on this survey work in a 1999 OTC paper.

I've heard that 3-D seismic exploration data is being used for pipeline routing studies. Is this true? Yes, 3-D seismic data is a tremendously useful resource for preliminary route characterization and planning detailed route surveys. Although 3-D data does not give the level of detail needed for final routing and design, my judgement is that it will typically get you 75% to 90% of the way there. And, if the operator already has access to the data for exploration purposes, it is essentially free, readily available data. It is an exceptionally good planning tool that only recently has been routinely applied to pipeline routing studies. If it is available, it is a "must" for every deepwater project, pipeline or otherwise. And, the sooner in the exploration/development cycle that it is used, the more value it will have to engineering and planning.

How about tools for soil sampling and testing? The simplest and most commonly used deepwater sampling tool is a gravity corer, typically 5 to 20 feet long. Piston corers are similar, but if used properly will give a less-disturbed sample. These simple tools can be used in any water depth to determine basic soil type and index properties, and are limited only by the length of cable available and the handling equipment.

Other, more sophisticated, and more costly, sampling tools are available and can be critical when high quality sampling is required. This would be the case when the potential for turbid flow or seafloor instability, as examples, need to be carefully assessed. In these cases, special detailed stratigraphic analysis of fine core details and age dating is often necessary, and can only be accomplished with the best quality cores. Reed and others discuss this further in a later paper presented at this pipeline conference, as will Niedoroda and others at the upcoming OTC conference.

Sometimes in situ test data, such as shear vane or cone data, is also collected, depending on if the pipe is to be buried or not and on other details of each project. Tools we use to collect these data for pipelining purposes include the Halibut, a vane shear device, and the Sea Scout, a small cone-penetrometer unit.

You've told us about tools to collect data. Tell us about tools being used to analyze data and display results. Well, there are a number of data analysis and display tools that are now being used. In addition to the amazing things that are being done with 3-D seismic data, multibeam bathymetric data is being analyzed and displayed using our interactive Hydrovista and related software.

Specifically, 3-D perspective seafloor images can be generated, at true scale or vertically exaggerated, to illustrate route topography and help identify potential problem areas. Seafloor profiles can be generated in real time for any arbitrary alignment selected on-the-fly by the pipeline engineer. Next, x-y-z data for profiles selected by the pipeline engineer can be output as an ASCII file for direct input into various spanning programs. This is a powerful interactive tool for span analysis and final route selection.

Hydrovista is especially useful for providing animated videos along proposed or actual pipeline routes. Animated videos also help the engineer to better visualize what conditions are like. And, once results of span calculations are available, the resulting pipe x-y-z coordinates can be imported to add the pipe to the movie. Thus, the calculated spans can be visualized, as well.

How are these tools helping the pipeline engineer make better decisions faster? Simply put, they give the pipeline engineer reliable quantitative information in a format that he can easily work with. And, they allow display and visualization so that key topographic relationships can be grasped quickly. Vizualization can also be important in helping to effectively explain project status and issues to colleagues, management, partners, investors, or other interested parties.

What kind of survey production rates can be expected? Using typical deeptow survey tools on long, straight survey lines, as is often the case with pipeline route surveys, production rates are about 50 to 60 miles per day. But, remember, if there are many turns, then production will come down noticeably. Project details, including total amount of survey work, number of survey lines, number of turns, distance to/from the survey area, method of towfish positioning to be used, amount and type of geotechnical sampling/insitu testing to be done, and other factors need to be carefully considered to get a good estimate of total survey time required.

How much do deepwater pipeline route surveys cost? Again, project details are critical to coming up with a reliable cost estimate. And, the most important cost factors are the same as those that determine how long the work will take. However, because special deeptow tools and positioning techniques need to be used, deeptow survey speed is only 2 to 3 knots, and distance to deepwater survey areas is typically farther, deepwater surveys are more expensive compared to surveys for an equivalent project on the continental shelf in the Gulf of Mexico. In international areas, costs can be much higher if the special deeptow equipment is not readily available.

5.0 CASE HISTORIES

Can you tells us, in a general way, how some deepwater pipeline projects have turned out? In a general way I can, yes. **The first case history** illustrates how routing and designing deepwater pipelines without knowledge of seafloor conditions can cause unexpected budget over-runs and, potentially, costly project delays.

A pipeline route survey was conducted for a deepwater development after preliminary route selection and design had been completed based on assumed conditions. Results of the survey showed unexpectedly rugged, and in places, rocky topography. Span analysis of 14 different routes showed that unacceptable spans would result along each of the 14 routings if conventional steel pipe was used as planned. Additional survey and design work was carried out to develop an acceptable solution.

Ultimately, about 10 miles of (expensive and unbudgeted) Coflexip flexible pipe was installed to accommodate the rugged and rocky zones. The operator concluded that if seafloor conditions had been known earlier, planning would have been optimized and overall project costs reduced.

In the second case, field development planning was well underway for a large deepwater field in the Gulf of Mexico. Several subsea completions with flowline tie-backs to a central FPS site were planned. Water depths ranged between about 2000 and 3000 ft. Soil borings were requested for several locations to confirm soil conditions and allow the foundation design work to be completed.

As part of the planning effort prior to drilling the foundation borings, the several drilling hazards reports and hazards data sets available for the planned development area were reviewed. Initial review of this information suggested conditions unfavorable for development. As a result, the planned soil boring work was put on hold while a comprehensive engineering-geologic re-mapping and assessment of site and route conditions was carried out. This detailed engineering assessment confirmed complex and difficult site conditions, including seafloor fault scarps 10 to 40 ft high; rugged, rocky seafloor; and steep slopes with landslides.

The proposed FPS site was subsequently moved to a more favorable site several miles away and in 30% deeper water. This move presumably resulted in costly project delay while the field and flowline layout and other details were re-designed. Other unexpected costs were also incurred, including increased cost for the riser and other components required for the deeper-water site.

For the third example, I like to discuss a case that doesn't directly involve pipelines, but the lessons to be learned from the mistakes made here are directly relevant to deepwater pipeline projects. A discovery well was drilled in about 1000 ft of water with no problems. The operator decided to develop the field and commissioned production facility design to begin. The design concept was that of a conventional pile-supported jacket structure, similar to Shell's Cognac platform design. The base dimensions were to be about 300 by 300 feet. After design was well underway, deep soil borings were requested to define soil conditions needed to complete final design.

As part of the final design effort to confirm site suitability, the existing geohazards data was reviewed. Two separate surveys, the original drilling hazards survey and a post-discovery pipeline route survey, had been completed. Review of this geohazards data suggested an irregular seafloor at the proposed platform location. However, because the survey lines were 1000 feet apart (meeting MMS *minimum* requirements), and the proposed platform location was between survey lines, the seafloor topography could not be defined to the level of detail required for siting and design.

As a result of this severe limitation of the geohazards data, the production 3D exploration seismic data (with data lines effectively spaced at about 66 by 41 feet) was used to prepare a relatively detailed but preliminary bathymetric map. This map and seafloor profiles showed that, with the center of the platform base resting on the seafloor near the discovery wellsite, the four corners would have a "water gap" (height of the platform base above the mudline) of 6, 4, 35, and 17 feet, respectively. Thus, upon generation of this map, it was immediately obvious that the proposed platform location was unsuitable for the planned design concept. At last report, after having already spent considerable money on platform design and field development, and after considerable delay, the development concept was changed to a subsea completion with tie-back to another platform.

No hazards to drilling the well. Its just that apparently no one bothered to think ahead to possible development. Early in the exploration/development sequence, the explorationist identifies prospects. The drilling engineer drills wells. Typically the foundation and structural folks, and the pipeline people, haven't been brought into the picture yet. And may not be for a year or more. The thinking is, "Why bring them in? We don't even have a discovery!" So, who's looking at the big picture to see if the whole deal will work technically and economically? All too often, apparently, no one. Or, the economic analysis is based on economic models that, other than increased water depth and distance to market, assume simple site or route conditions as are typical of the shelf. The result can be very expensive surprises and delays in getting first oil.

At the other extreme, for **the fourth example**, is the case where deepwater pipeline planning work began ***before*** the first exploration well was drilled. Although a discovery had not been made at the time of the study I'm about to relate, this particular operator had a large number of deepwater leases and an aggressive drilling program planned. They were confident of making a discovery, but didn't know, of course, exactly where the find would be. Nonetheless, they wanted to be able to shorten cycle time and fast-track eventual development.

They realized that pipelines from the general area would be one of the key cost and technical issues. They also realized that engineering analysis is very cheap compared to the cost of delays in getting first oil. Thus, they embarked on a generic office study of deepwater pipeline issues to get a handle on just how much of a problem pipelining from this general area would be and the costs involved. And, by the way, they were also the same company that was involved in the first case history discussed above, and obviously learned a valuable lesson as a result of this earlier costly experience.

As part of this planning effort, a possible route was studied in some detail as a test case. Plausible route end points were specified, with the delivery point being an operating platform owned by the operator for whom the study was being done. First, an optimal route was selected based on analysis of a combination of 3-D seismic data and NOAA multibeam data. Spanning and other analyses were then completed. As a result of the study, the operator had developed a first-hand appreciation for deepwater pipeline issues, reliable cost estimates for economic analysis, and a realistic plan for development fast-tracking. They have recently made the expected discovery and are now starting fast-track development. They are about to realize the benefits of their head-start planning efforts.

Finally, I'd like to say that it is now common, but by no means universal, for fairly comprehensive, up-front office planning studies to be done before, and sometimes well before, relatively expensive field survey work is planned. Results also are being used for preliminary design as well as for economic analysis and other commercial purposes. Several recent or current deepwater pipeline projects that we have been involved in have taken this comprehensive planning followed by survey approach. In fact, in one recent case, upon seeing the results of the planning study based on 3-D seismic data, the operator exclaimed "we should have done this study months ago", meaning that study results would have allowed them to make better decisions quicker.

6.0 SUGGESTED APPROACH TO DEEPWATER PIPELINE ROUTING

What do you think is the best approach to deepwater route characterization? Well, before I give you my ideas on an optimum approach, let me tell you about some approaches that can result in costly mistakes or unnecessary delays. All of the mistakes can result from what I call the "shelf mentality". That is, applying to deepwater projects the same approach that has been used so successfully for many years on the continental shelf (that is, where water depths are less than about 600 ft.).

Because of the complex conditions that we've talked about, the following assumptions and approaches can be very costly:

1) Assuming, with little or no basis, that straight-line routing will work and will be the least expensive route (smooth seafloor syndrome).

2) Simply not appreciating the need for a planning study at all. I've had folks tell me with sincerity something to the effect that "if we run into problems, we'll just remediate them". In my mind, potentially a very expensive solution when a much better alternative is usually available.

   Without a planning study - even a minimal-effort one would help save money - what typically happens is that more, relatively expensive field survey time is needed to find an acceptable route. So, delay in getting results may be longer, the optimum route may not be found, and overall costs are likely to be higher, and sometimes much higher – especially if a less-than-optimal route is selected - than if a good planning study had been done.

3) Not starting soon enough/starting surveys too soon on the same project. This results when the project schedule is so tight that there is no time (or, sometimes, money) to do an office planning study, and the survey must start right away. Everyone agrees that a planning study would be a good idea, but it just doesn't happen.

4) Preparing survey scope and survey execution plan before doing an office planning study. This is similar to the case described for item 3). In this case, rather than lack of schedule time being the direct issue, those preparing the survey specifications and survey plan do not appreciate the need for the office planning study as a basis for preparing rational survey specifications. Their approach is to do the planning study after making important decisions that the planning study would affect .

5) Not using all available data. This can happen, for example, when the 3-D or other data requires extra effort to locate and have a copy made, sometimes by folks that are snowed with other responsibilities and for whom the pipeline issue is not a priority.

So, tell us how you think route characterization should be approached. The best approach, in my mind, is what I call it the multiphase approach. It allows one to spend only that effort appropriate to the given stage of the project. That is, early-on, before the development is a go, a cursory look only, at minimal cost, would be appropriate. It could be nothing more than a quick visual review of available maps. Routing favorability maps, NOAA multibeam data, and other convenient sources could be used for this quick, **Phase 1 overview.**

Once the project is authorized for preliminary design, or field survey work is being planned, then it would be appropriate to characterize route conditions to the next level of detail. **Phase 2** would consist of a more detailed review of existing data, preferably including 3-D seismic data. Focus would be on a specific corridor, route, or routes, and relatively detailed maps, cross sections and 3-D visualizations would be developed. Results are typically adequate to develop a detailed scope of work and detailed survey plan for the field survey work. Phase 2 work would, of course, take longer and cost more than Phase 1 work.

In **Phase 3**, the field survey work would be carried out, including both geophysical and geotechnical work. Results would be used for final routing, design, and permitting.

Of course, in practice, details don't always fit this model exactly, but the concept is valid: spend only that amount of effort and money necessary to provide the information required at any given time in the project cycle, and to allow rational planning of the next phase of the project.

7.0 CONCLUDING COMMENTS

What would you say to someone new to the deepwater Gulf who is responsible for planning or designing a deepwater pipeline? Use 3-D seismic exploration and other data to learn about general route conditions early, even if only in a cursory way. And then begin to look in more detail and more carefully as the project starts to develop. Look before you leap, before you begin to make serious decisions, plans, and detailed economic analyses. Remember, everywhere in deepwater is not difficult, but it is unwise to assume simple conditions without looking. If conditions are difficult, then plan and budget accordingly. And, when it comes time for a detailed route survey, use the right survey tools – tools that are "fit for purpose". With detailed knowledge of seafloor conditions, deepwater pipelines can be routed, designed, and installed to perform as intended at optimal cost.

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FUGRO AND CONTACT INFORMATION

Fugro GeoServices is a member of the Fugro Group of companies that provide geoscience, geotechnical, met-ocean, and survey services to the offshore industry worldwide. Among other related services, Fugro GeoServices specializes in deepwater pipeline route planning and survey services using 3-D seismic, swath bathymetric, deeptow, and other data. For more information please contact:

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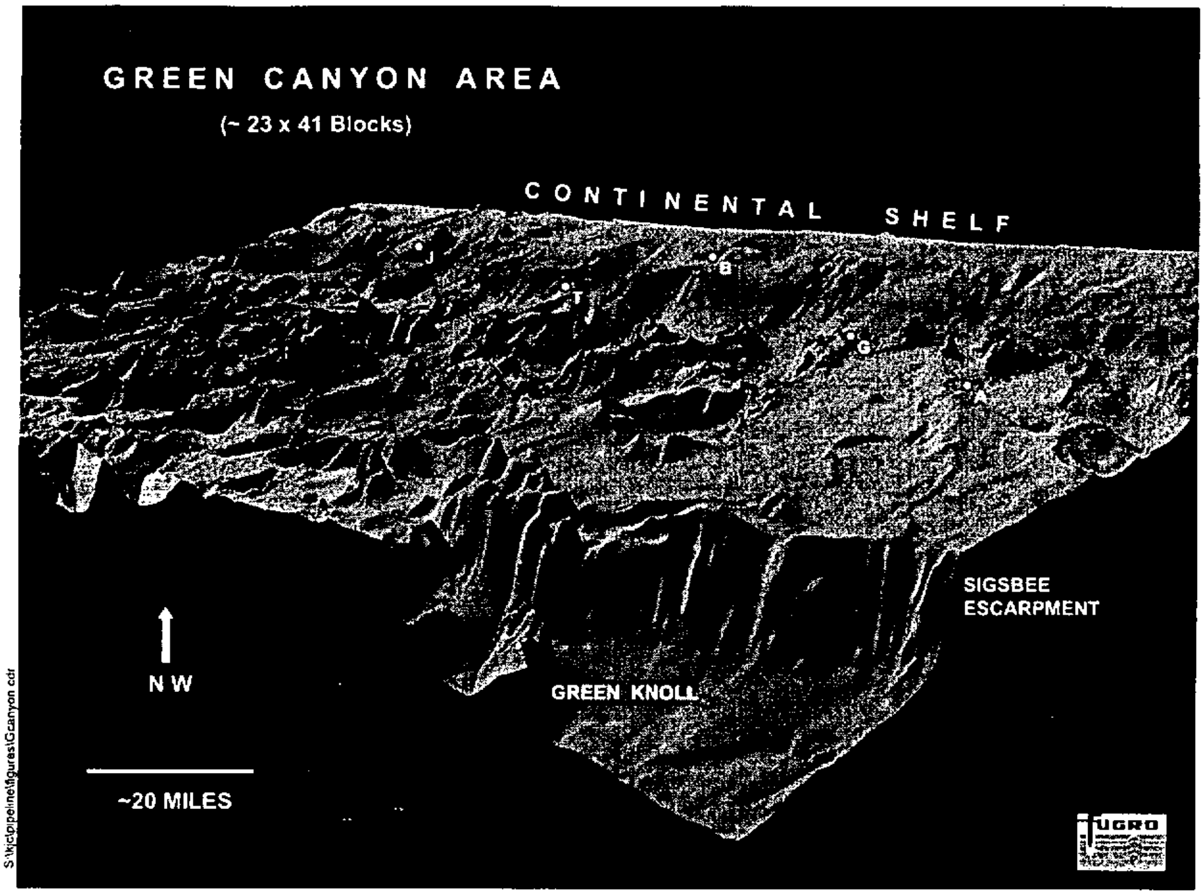

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FIGURE 1. PERSPECTIVE VIEW OF GREEN CANYON LEASE AREA SHOWING RUGGED TOPOGRAPHY. Letters indicate selected development sites (J, Jolliet; T, Typhoon; B, Bullwinkle; G, Genesis; A, Allegheny).

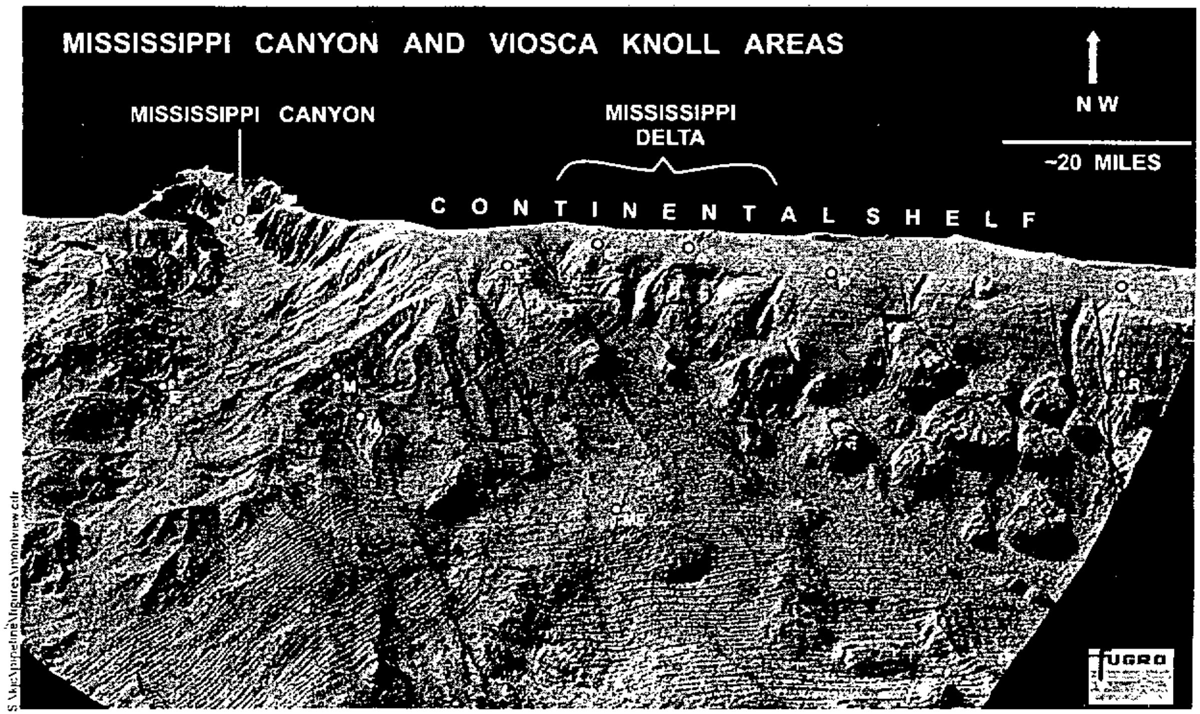

FIGURE 2. PERSPECTIVE VIEW OF PART OF MISSISSIPPI CANYON AND VIOSCA KNOLL LEASE AREAS. Letters indicate selected development sites (E, Europa; Z, Zinc; M, Mars; U, Ursa; L, Lena; C, Cognac; ME, Mensa; A, Amberjack; P, Pompano; V, Virgo; R, Ram-Powell).

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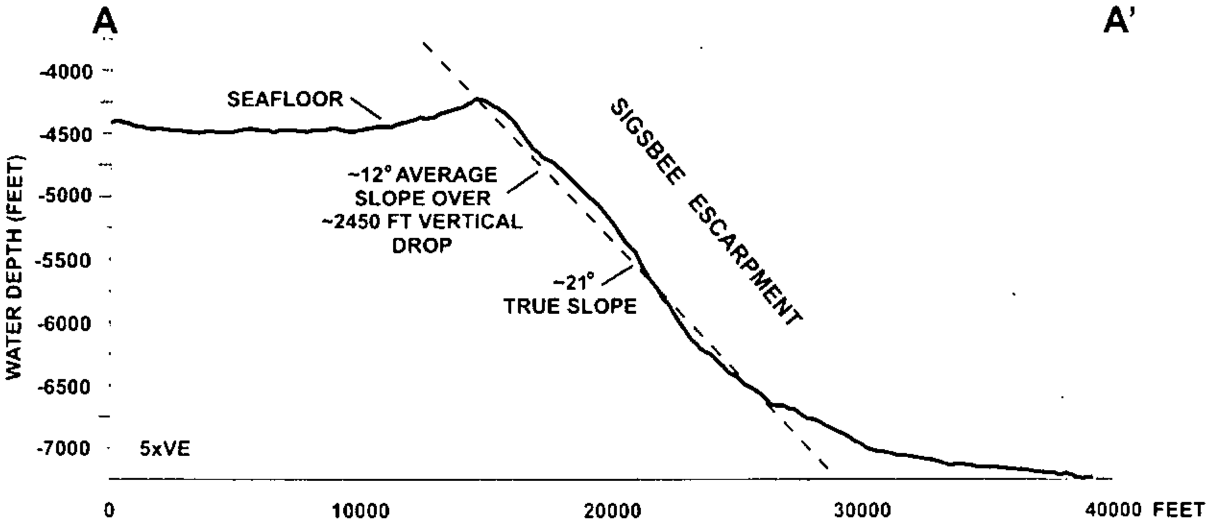

FIGURE 3A. SEAFLOOR PROFILE ACROSS SIGSBEE ESCARPMENT, SOUTHEASTERN PART OF GREEN CANYON LEASE AREA. Escarpment is about 2500 ft high along this profile. See Figure 3B for line of profile.

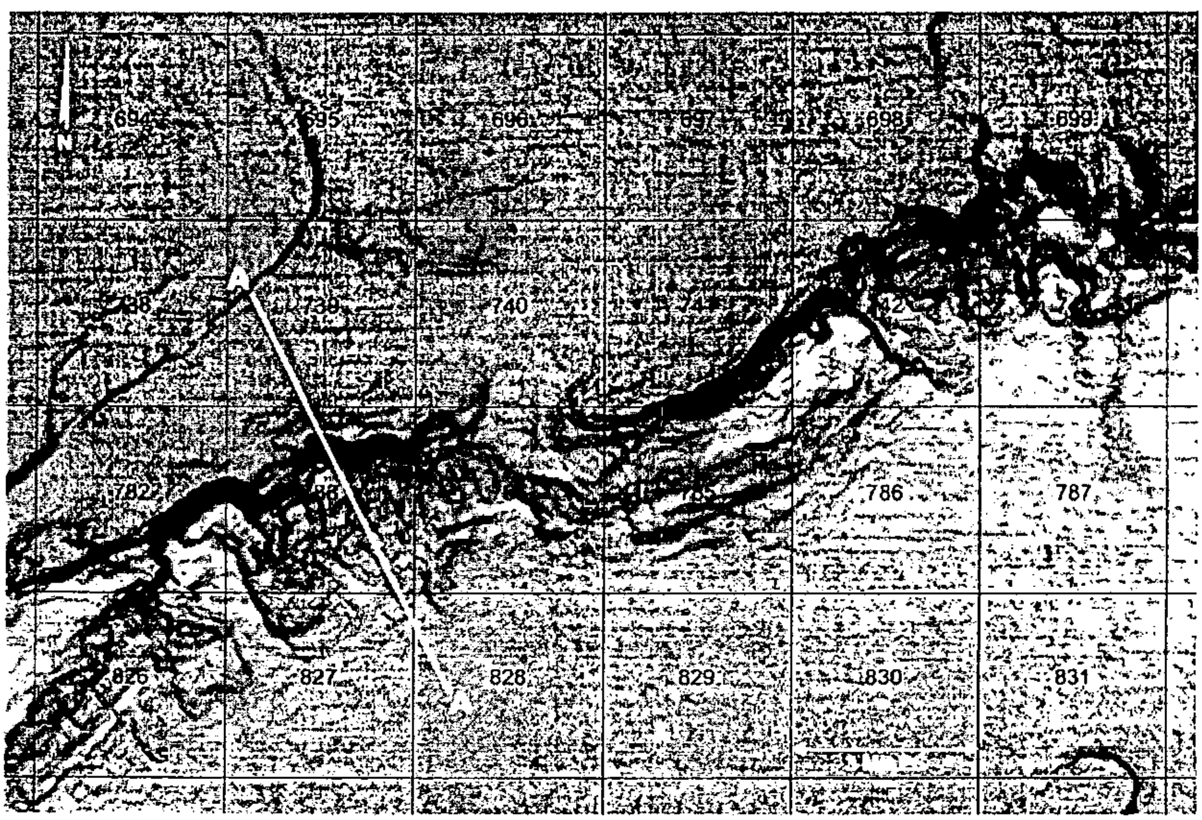

FIGURE 3B. SEAFLOOR IMAGE OF SIGSBEE ESCARPMENT, SOUTHEASTERN PART OF GREEN CANYON LEASE AREA. Image generated from NOAA multibeam bathymetric data. See Figure 3A for seafloor profile along A-A'.

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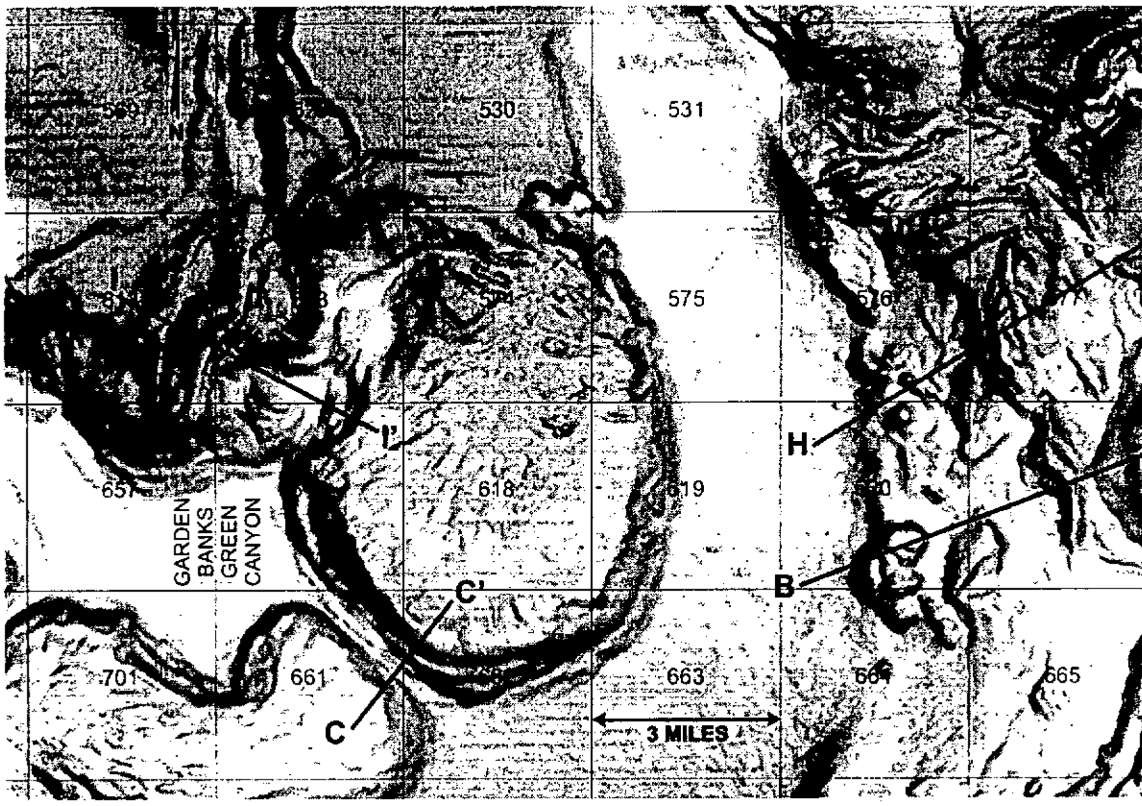

FIGURE 4. SEAFLOOR IMAGE ALONG BORDER OF GARDEN BANKS AND GREEN CANYON LEASE AREAS. Image generated from NOAA multibeam bathymetric data. See other figures for seafloor profiles corresponding to transects indicated.

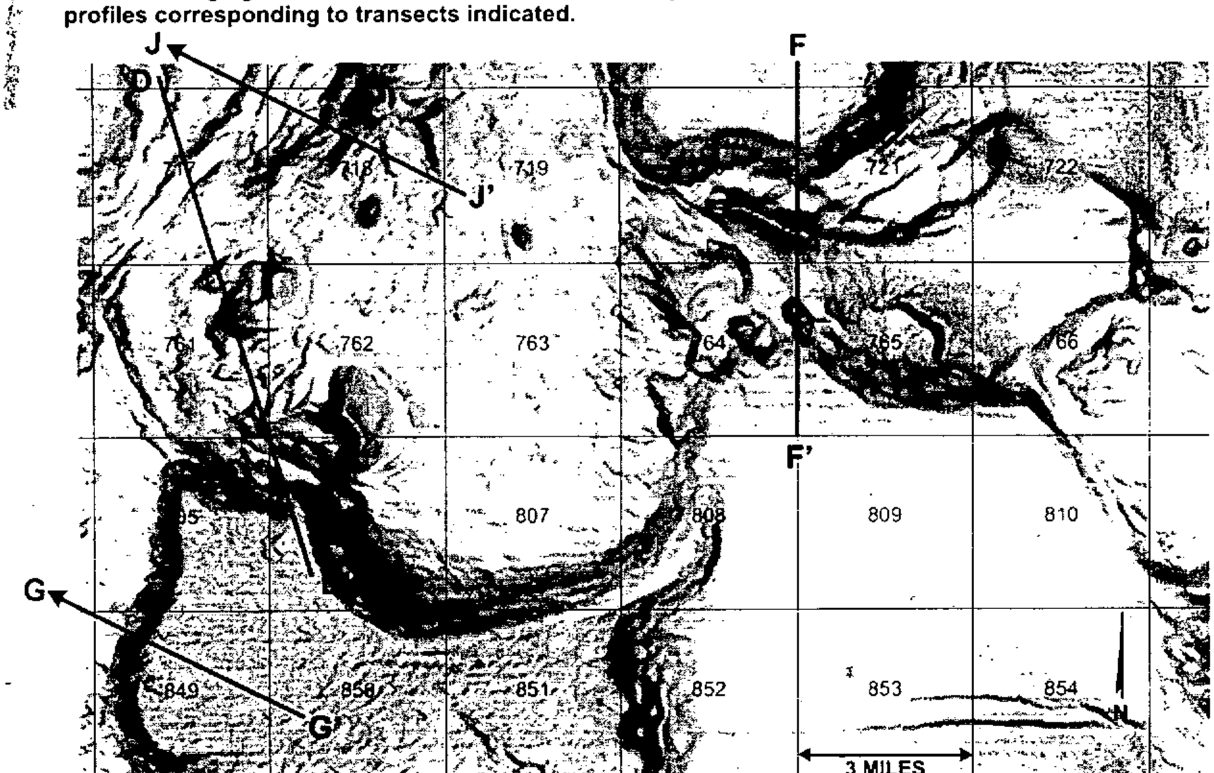

FIGURE 5. SEAFLOOR IMAGE OF AREA IN SOUTHERN PART OF GREEN CANYON LEASE AREA. Image generated from NOAA multibeam bathymetric data. See other figures for seafloor profiles corresponding to transects indicated.

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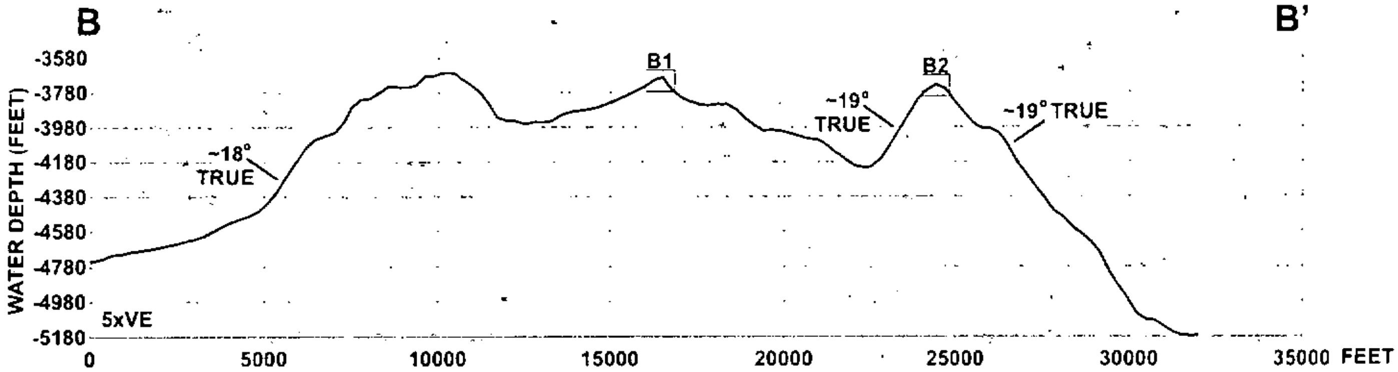

FIGURE 6A. SEAFLOOR PROFILE B-B' AT 5x VERTICAL EXAGGERATION. See true-scale detail below for segments in boxes B1 and B2. Location of profile is shown on Figure 4.

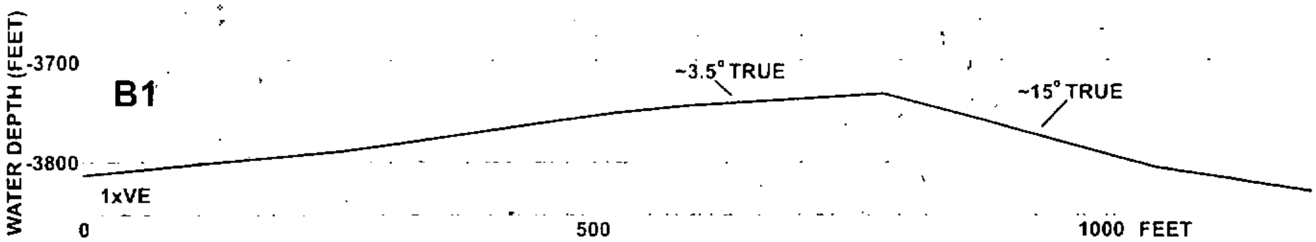

FIGURE 6B. SEAFLOOR PROFILE B1 AT 1:1 SCALE. See box B1 in Figure 6A above for location.

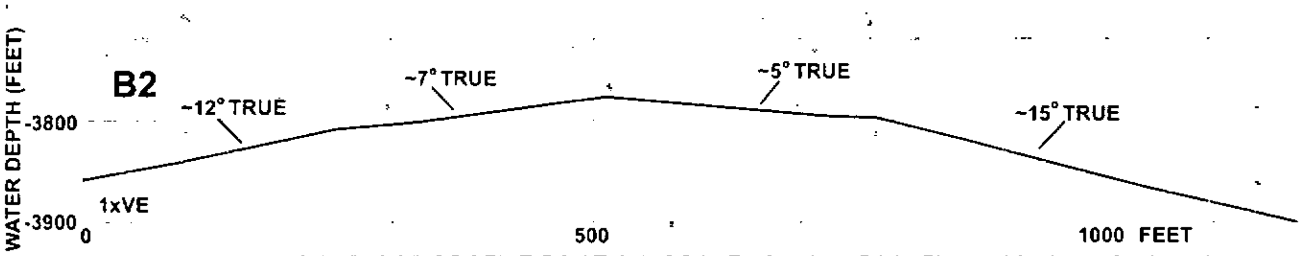

FIGURE 6C. SEAFLOOR PROFILE B2 AT 1:1 SCALE. See box B2 in Figure 6A above for location.

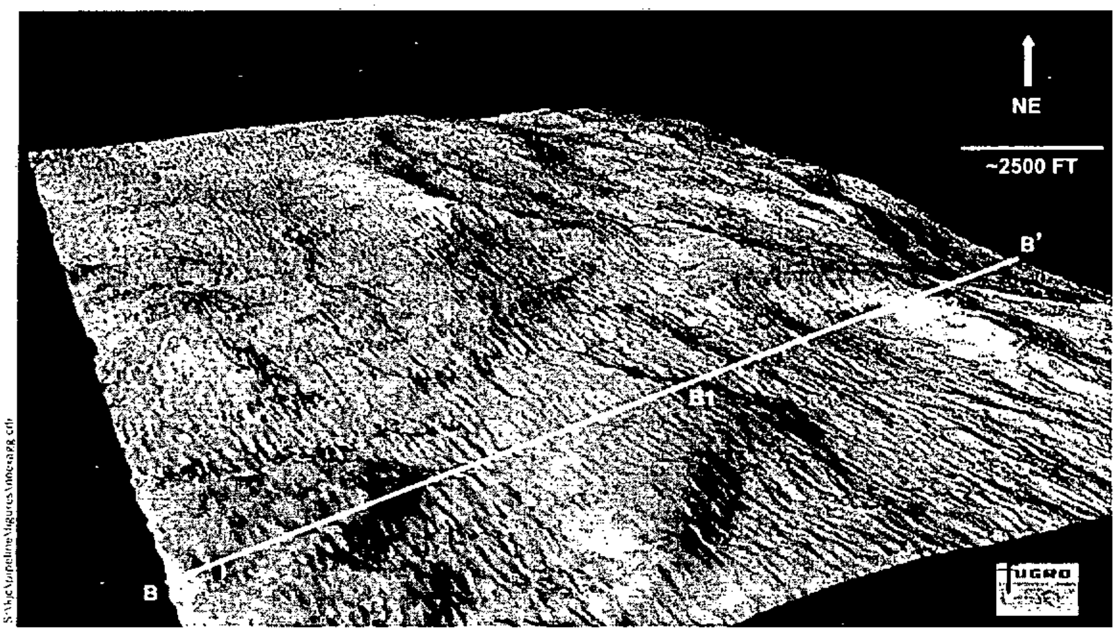

FIGURE 6D. PERSPECTIVE VIEW OF SEAFLOOR IN VICINITY OF GREEN CANYON BLOCKS 576, 577, 620, AND 621. View is to northeast; no vertical exaggeration. B-B' corresponds to line of profile shown in Figure 6A. Image generated from NOAA multibeam bathymetric data. Note that small, high-frequency, north-south-oriented gouges are artifacts and constitute noise in the data set.

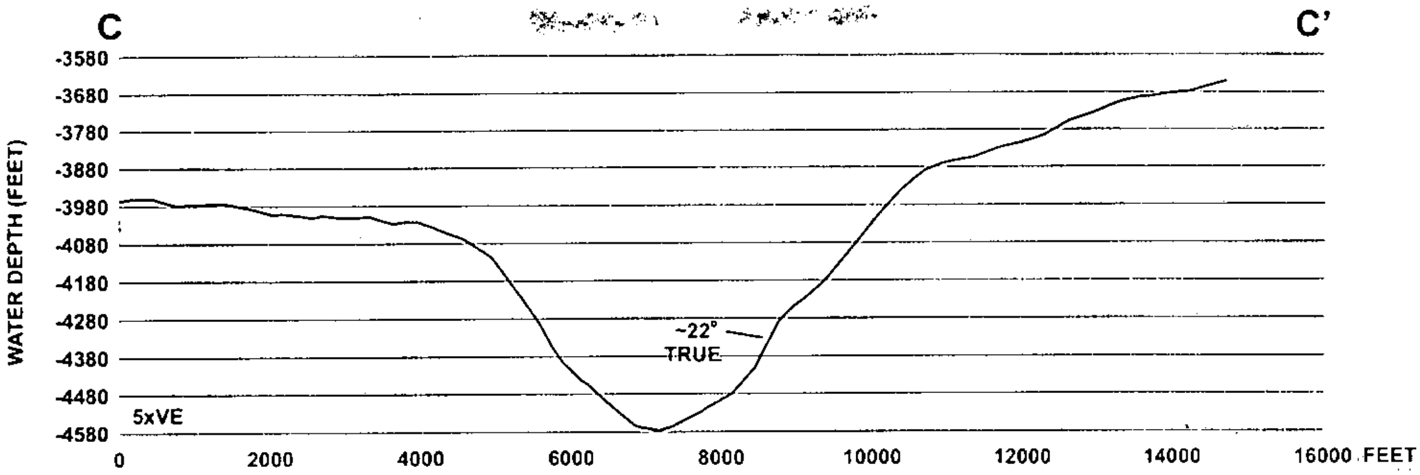

FIGURE 7. SEAFLOOR PROFILE C-C' AT 5x VERTICAL EXAGGERATION. Location of profile is shown on Figure 4.

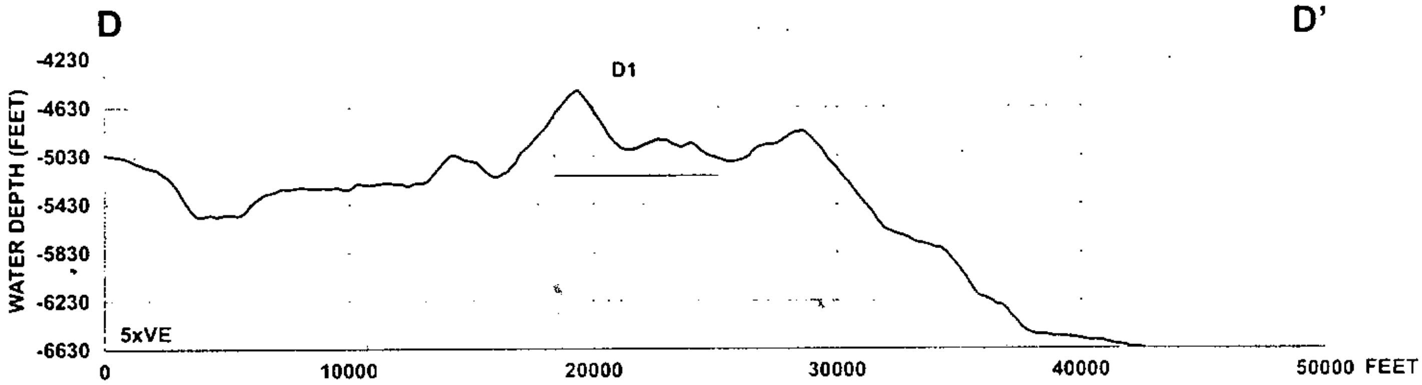

FIGURE 8A. SEAFLOOR PROFILE D-D' AT 5x VERTICAL EXAGGERATION. See detail below for segment in box D1. Location of profile is shown on Figure 5.

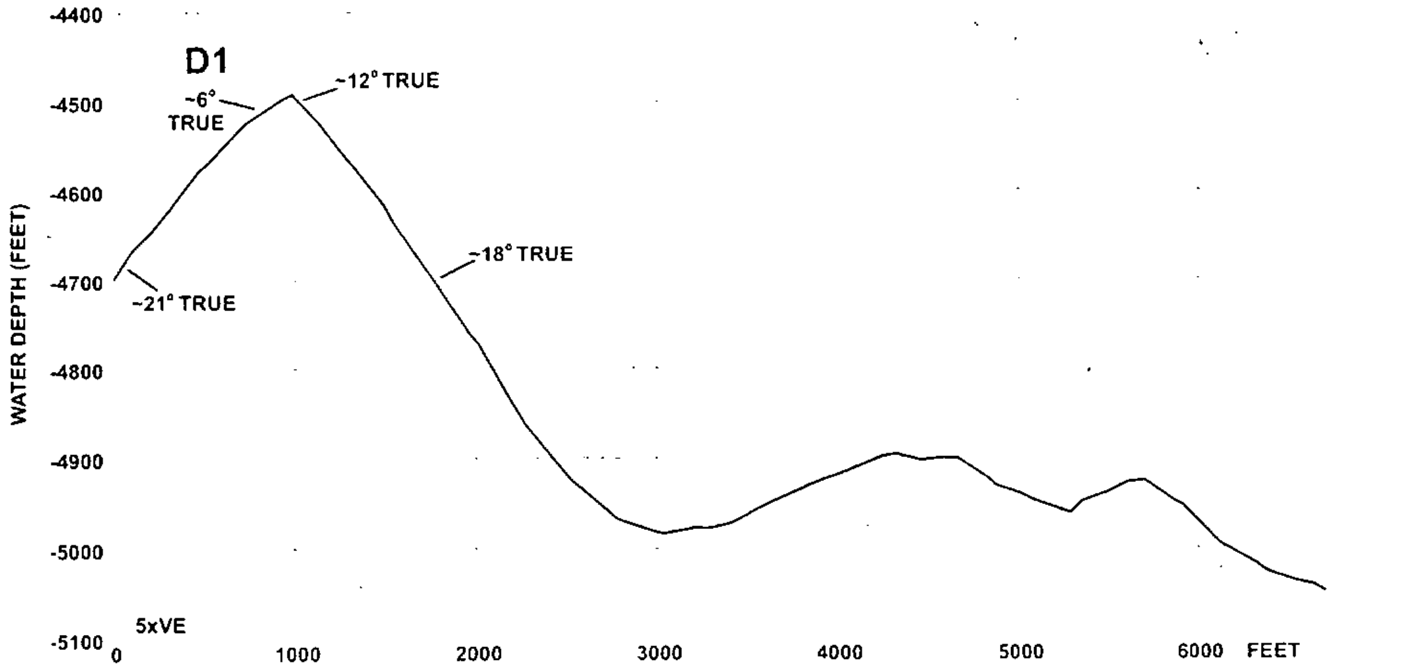

FIGURE 8B. SEAFLOOR PROFILE D1 AT 5x VERTICAL EXAGGERATION. See box D1 in Figure 8A above for location.

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NOTE: PROFILE E-E' INTENTIONALLY NOT INCLUDED

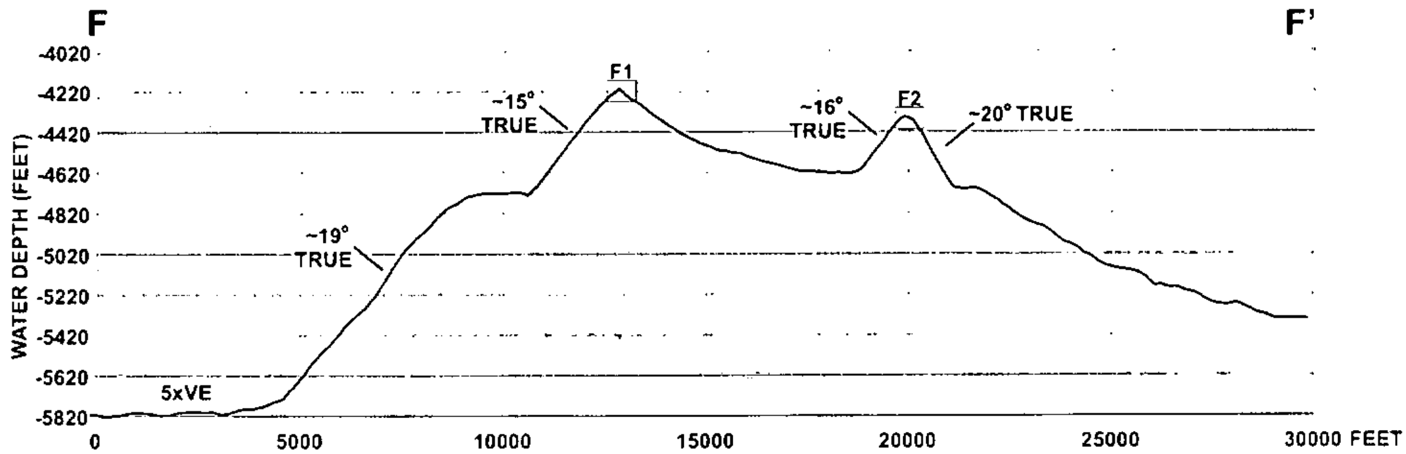

FIGURE 9A. SEAFLOOR PROFILE F-F' AT 5x VERTICAL EXAGGERATION. See true-scale detail below for segments in boxes F1 and F2. Location of profile is shown on Figure 5.

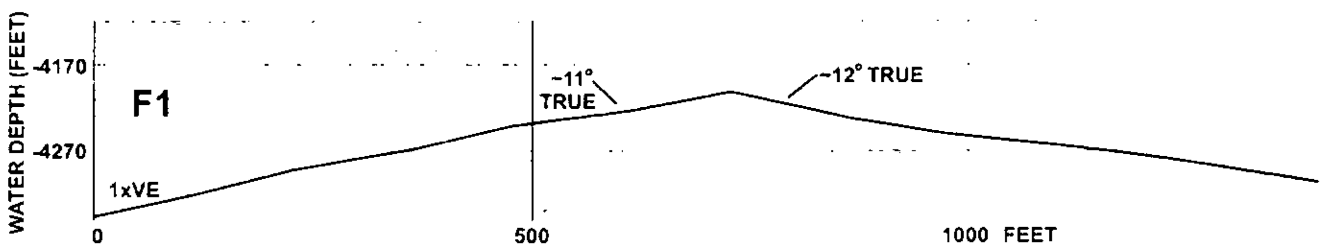

FIGURE 9B. SEAFLOOR PROFILE F1 AT 1:1 SCALE. See box F1 in Figure 9A above for location.

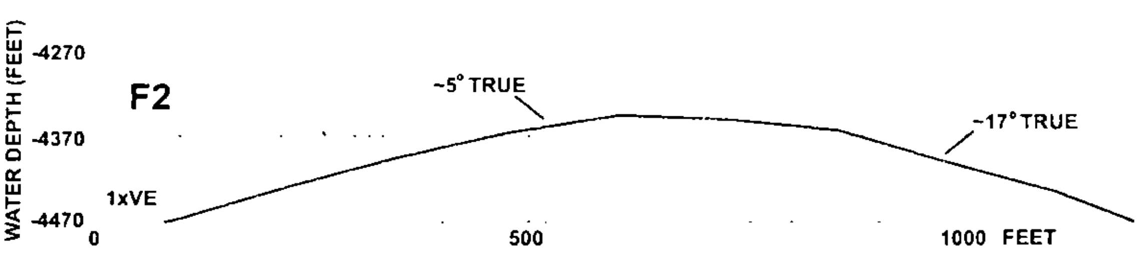

FIGURE 9C. SEAFLOOR PROFILE F2 AT 1:1 SCALE. See box F2 in Figure 9A above for location.

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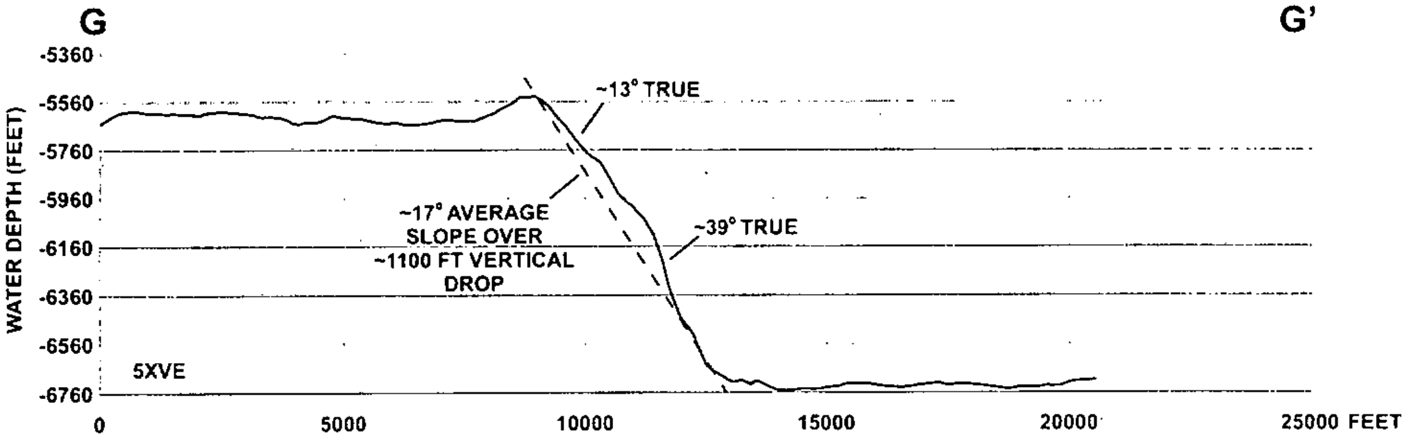

FIGURE 10. SEAFLOOR PROFILE G-G' AT 5x VERTICAL EXAGGERATION. Location of profile is shown on Figure 5.

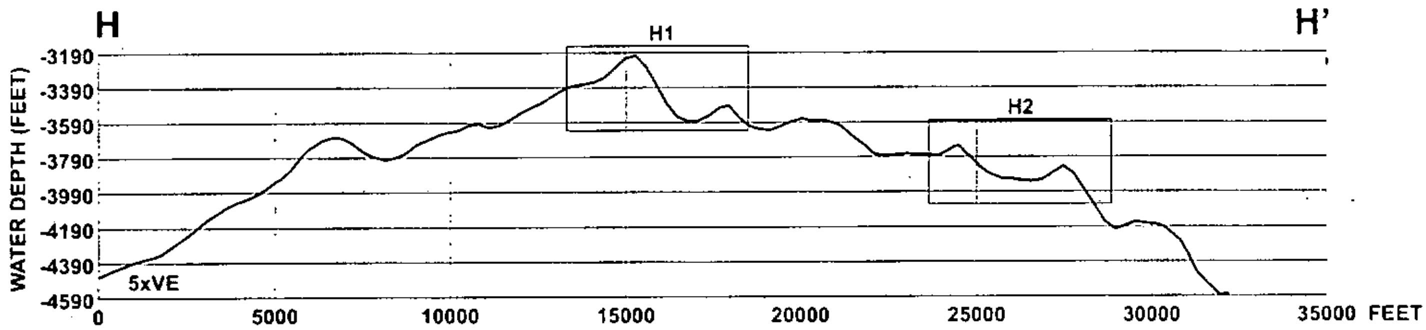

FIGURE 11A. SEAFLOOR PROFILE H-H' AT 5x VERTICAL EXAGGERATION. See detail below for segments in boxes H1 AND H2. Location of profile is shown on Figure 4.

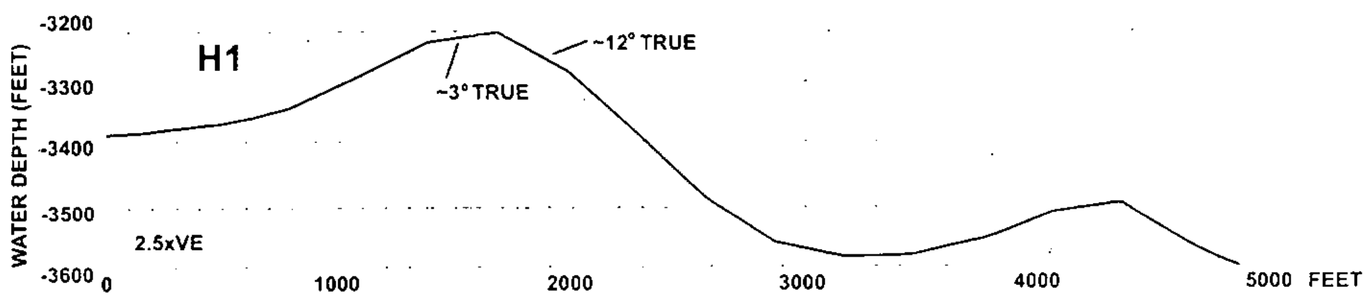

FIGURE 11B. SEAFLOOR PROFILE H1 AT 2.5x VERTICAL EXAGGERATION. See box H1 in Figure 11A above for location.

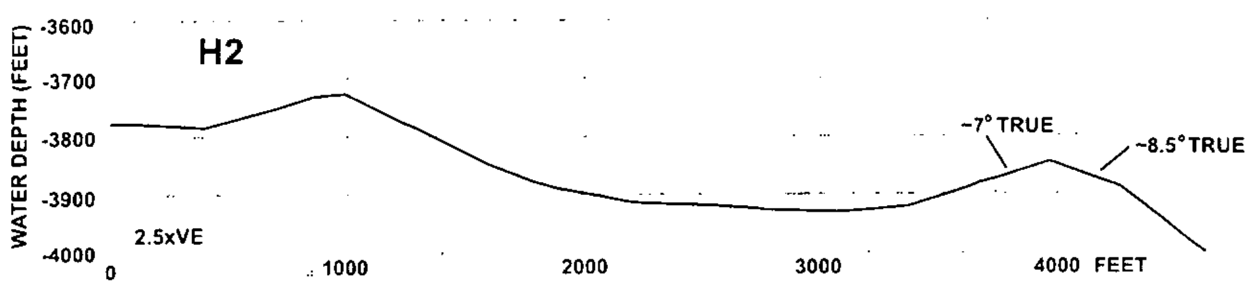

FIGURE 11C. SEAFLOOR PROFILE H2 AT 2.5x VERTICAL EXAGGERATION. See box H2 in Figure 11A above for location.

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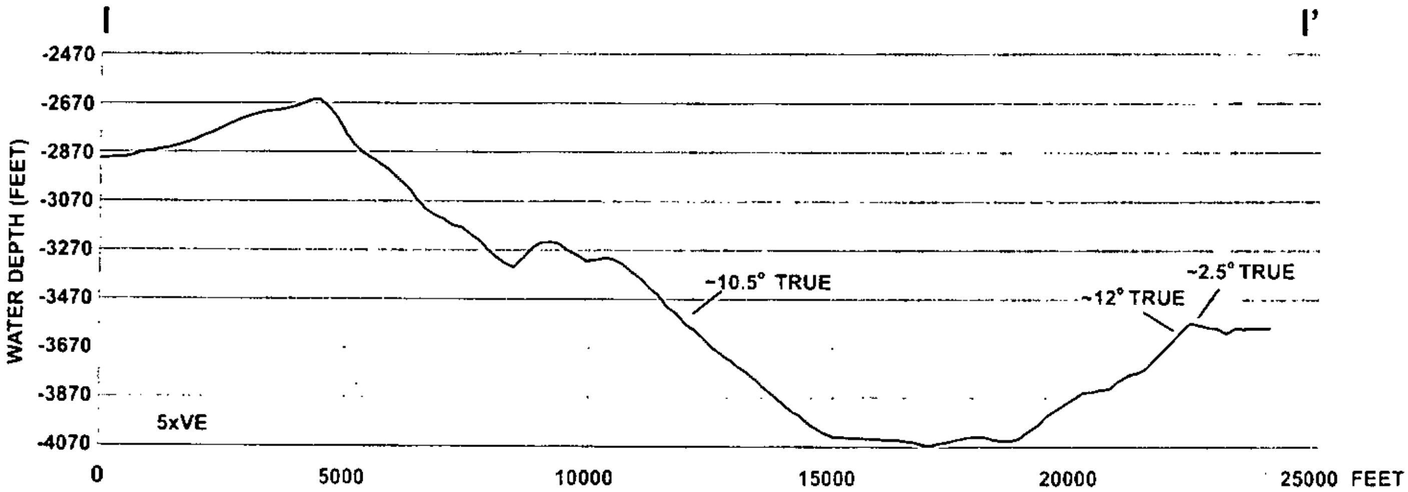

FIGURE 12. SEAFLOOR PROFILE I-I' AT 5x VERTICAL EXAGGERATION. Location of profile is shown on Figure 4.

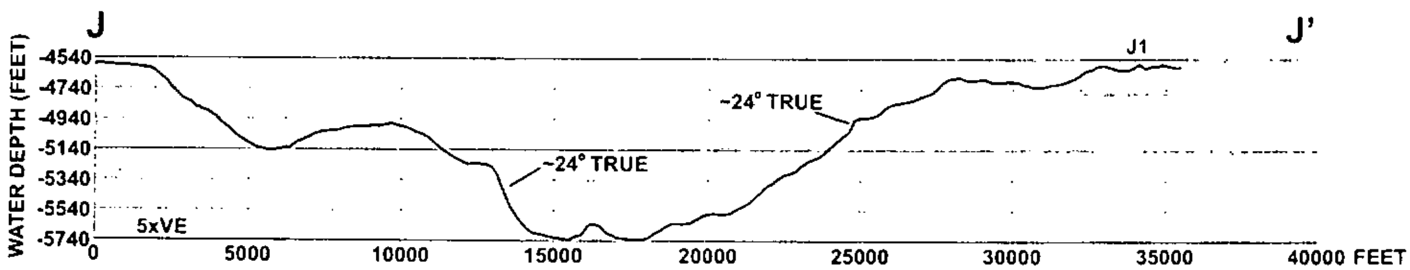

FIGURE 13A. SEAFLOOR PROFILE J-J' AT 5x VERTICAL EXAGGERATION. See true-scale detail below for segment in box J1. Location of profile is shown on Figure 5.

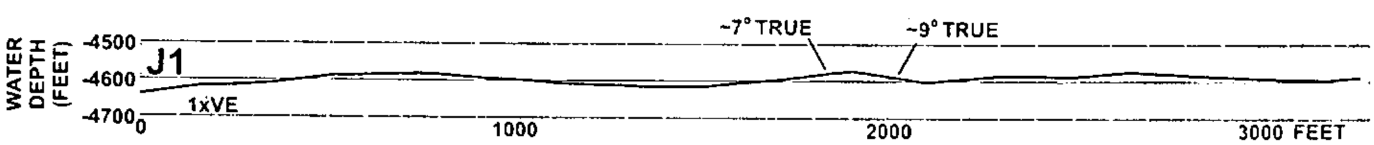

FIGURE 13B. SEAFLOOR PROFILE J1 AT 1:1 SCALE. See box J1 in Figure 13A above for location.

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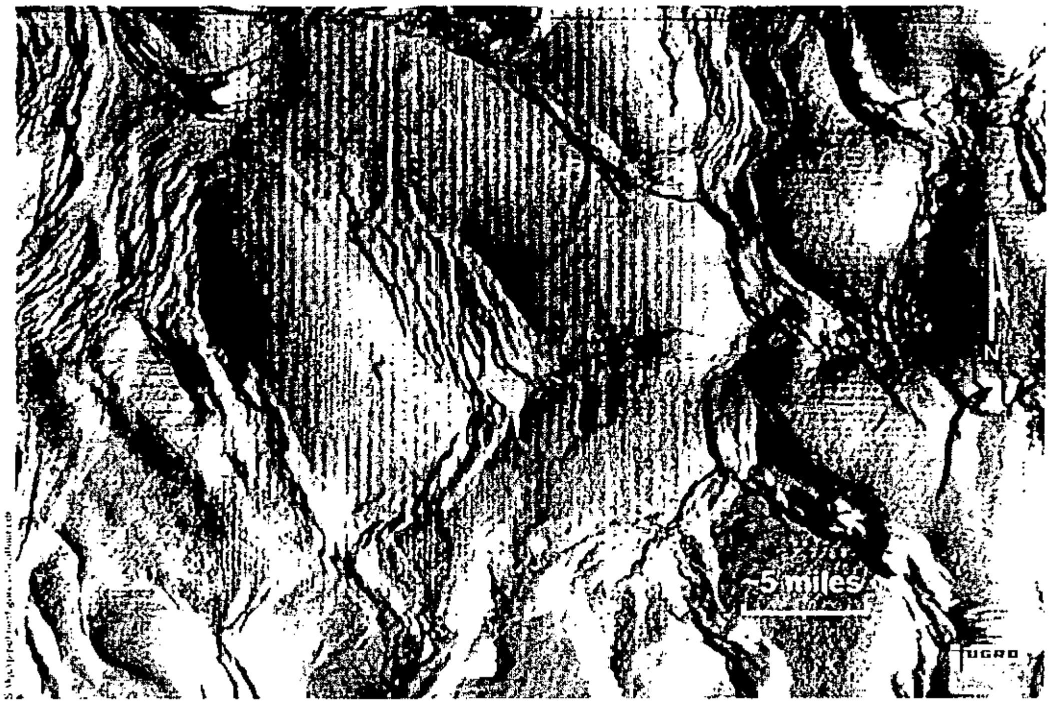

FIGURE 14. SEAFLOOR IMAGE SHOWING COMPLEX FAULT PATTERNS, NORTHERN PART OF KEATHLEY CANYON LEASE AREA. Irregular lineations represent seafloor fault scarps tens of feet or more high. Straight, north-south and east-west lineations are artifacts and constitute noise in the data set. Image generated from NOAA multibeam bathymetric data.

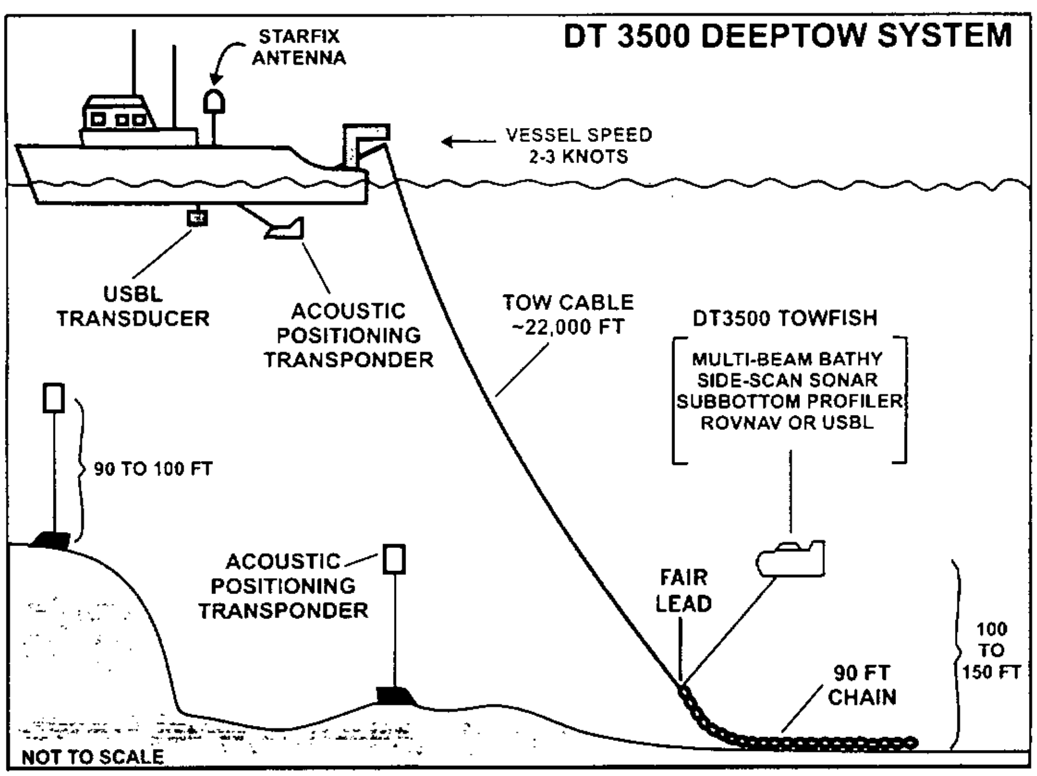

FIGURE 15. CONCEPTUAL DIAGRAM OF BOTTOM-REFERENCED DT 3500 DEEPTOW SURVEY SYSTEM. "Bottom-referenced" refers to chain that drags along seafloor, keeping the positively-buoyant DT 3500 towfish at constant height above the seafloor, regardless of seafloor elevation. Keeping the towfish at constant height results in high-quality data even in areas of rugged seafloor topography.

Pipeline Routing Using 3D Seismic in West Seno (Indonesia) and Ladybug (Gulf of Mexico)

Chuck Hebert and **Mike Reblin**
Unocal, Houston, USA

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
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and
Pipes & Pipelines International

Pipeline Routing Using 3D Seismic in West Seno (Indonesia) and Ladybug (GOM)

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WEST SENO FIELD

Pipeline Route Assessment & Selection

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Agenda

- Introduction
- Pre-Engineering
- Preliminary Engineering
- Conclusions

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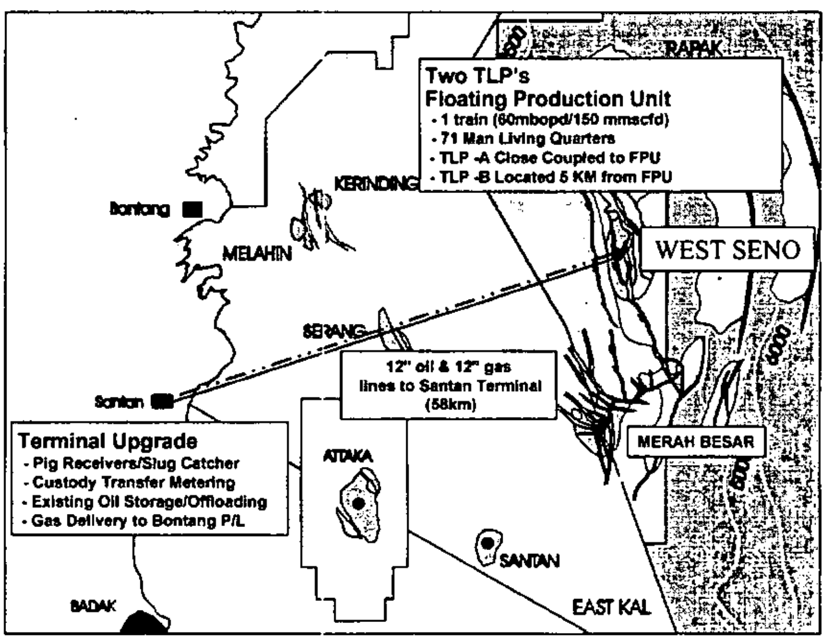

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Pre-Engineering Route Selection

- Pipeline Design
  - Oil Export - 12"
  - Gas Export - 12"
  - Steel Catenary Risers (SCR) at the FPU
  - Shore Crossing at Santan, Follows Existing Pipelines to Terminal
  - Infield Flowlines - TLP B to FPU
    - 6", 12" and 12"
    - SCRs at TLP and FPU

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Pre-Engineering Route Selection (cont.)

- Design Assumptions and Challenges
  - Select Shortest Route
  - Numerous Spans Anticipated
  - Minimize Spans in Deepwater Due to Cost of Rectification
  - Avoid Steep Slopes Where Possible
  - Crossing Several Reef and Fault Trends

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Pre-Engineering Route Selection (cont.)

- Design Assumptions and Challenges
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Pre-Engineering Route Selection (cont.)

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  - Avoid Steep Slopes Where Possible
  - Crossing Several Reef and Fault Trends

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Pre-Engineering Route Selection (cont.)

- Pipeline Route
  - Departed the FPU in Westerly Direction
  - Approximately 50 km
  - Deviated Slightly Near Serang Platform
  - Directly to Santan Terminal

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Pre-Engineering Route Selection (cont.)

- Strategy
  - Minimize Expenditure During Preliminary Engineering
  - Use Existing Data for Preliminary Engineering
    - Learned from Merah Besar Rendered Maps from 3-D Seismic
    - Bathymetry Maps Produced by UIC/Calmarine in Deep Water
    - Existing 3D Seismic Data
  - UIC Produced a Preliminary Seafloor Rendering Map

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Pre-Engineering Route Selection (cont.)

- Conclusions
  - Insufficient Survey Data to Adequately Design the Pipeline Route
  - Needed Better Quality Data in Shallow Water
  - The Seafloor Rendering is Very Useful for Preliminary Route Design, but Needed Higher Resolution to Proceed with Preliminary Engineering
  - There is Sufficient Data in House to Select a Preliminary Pipeline Route

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Preliminary Route Selection

- Next Steps
  - Obtain a Better Quality 3-D Seismic Data Rendering
  - Employ GEMS
  - Deliverables
    - Detailed Bathymetry
    - Seafloor Rendered Map
    - Slope Map
    - Seafloor Features Map
    - Favorability Map
  - Developed Scope of Work for Additional Survey Work
  - Develop an "Optimized" Pipeline Route

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Preliminary Route Selection (cont.)

- Next Steps (cont.)
  - Engaged Aker and GEMS into Planning the Pipeline Route
  - Aker to Develop Alignments Sheets to Define Pipeline Requirements

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Preliminary Route Selection (cont.)

- Design Challenges
  - Maintain Previous Design Assumptions and Challenges
  - Departure from FPU Changed from West to South
  - Avoid Mooring Lines and Well Stubs
  - Minimize Number of Curves
  - Minimum Curve Radius - 1500 m
  - Route will Perpendicular, not Tangent to Reef and Fault Trends
  - Avoid Anchorage Area

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Preliminary Route Selection (cont.)

- Methodology
  - Used Seismic Cross Section Views on a Workstation to Select Locations to Cross Reef and Fault Trends
  - Select Areas with Minimum Slope Gradients
  - Iterative Process Between GEMS, Aker and Unocal
  - Plot Route on GEMS' Maps
  - Make Alignment Drawings

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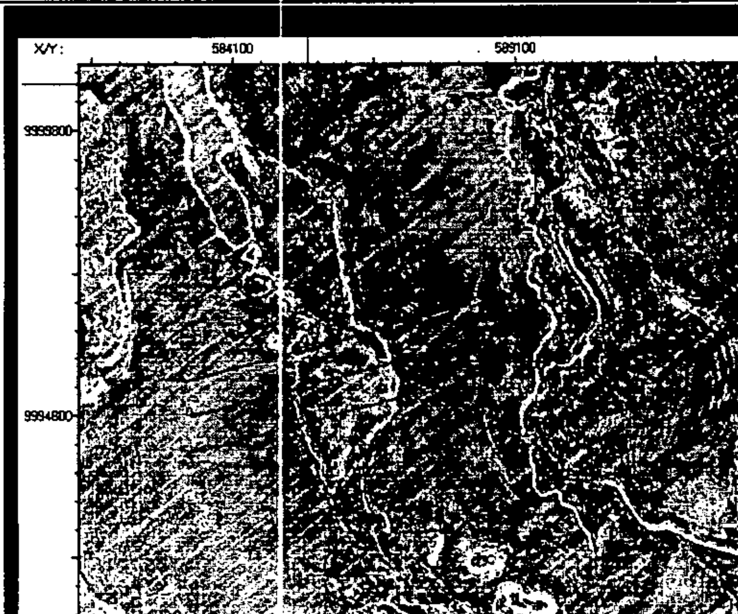

AMPLITUDE IMAGE PI5 TO PI6

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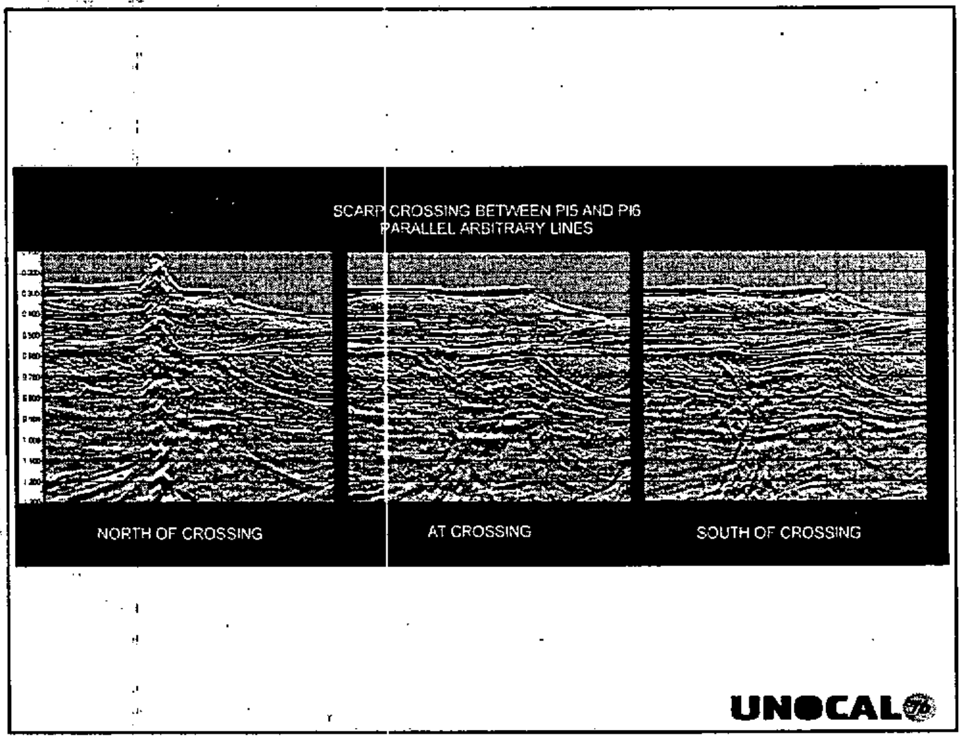
SCARP CROSSING BETWEEN PI5 AND PI6
PARALLEL ARBITRARY LINES
NORTH OF CROSSING
AT CROSSING
SOUTH OF CROSSING
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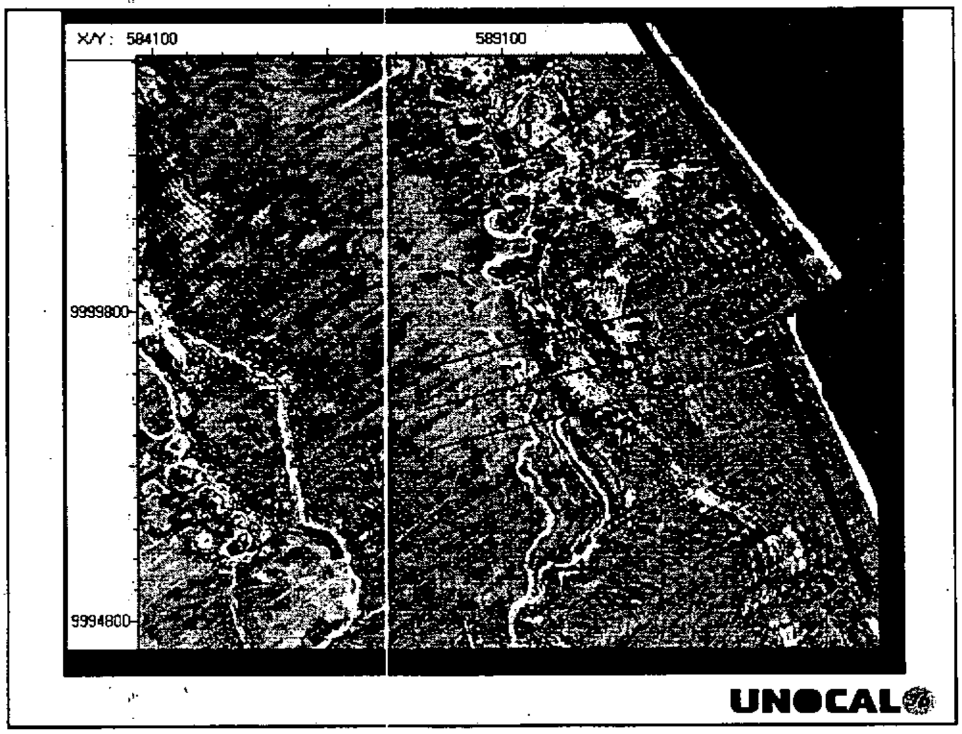
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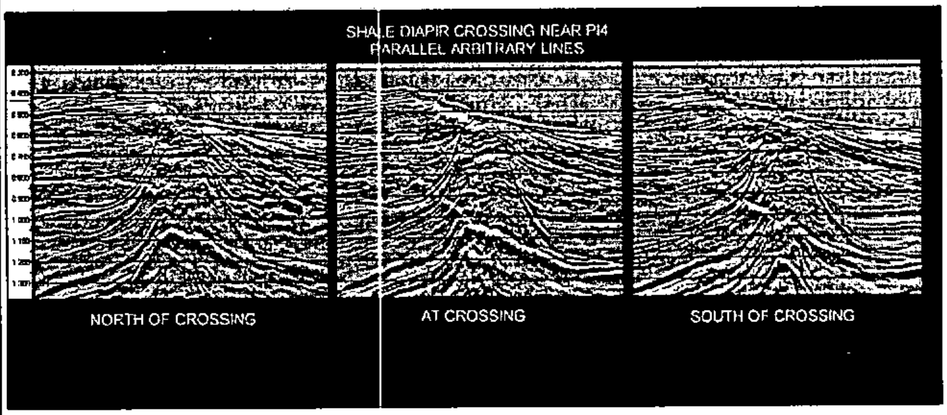

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Preliminary Route Selection (cont.)

- Results
  - Pipeline 60 km
  - Minimum Specific Gravity of Pipe - 1.2
  - An Optimized Pipeline Route
  - Survey Work Was Incomplete, Needed Confirmation of Interpretation of 3D Seismic
  - Developed Red Light/Green Light Map
  - Forward Plan for Additional Survey Activities

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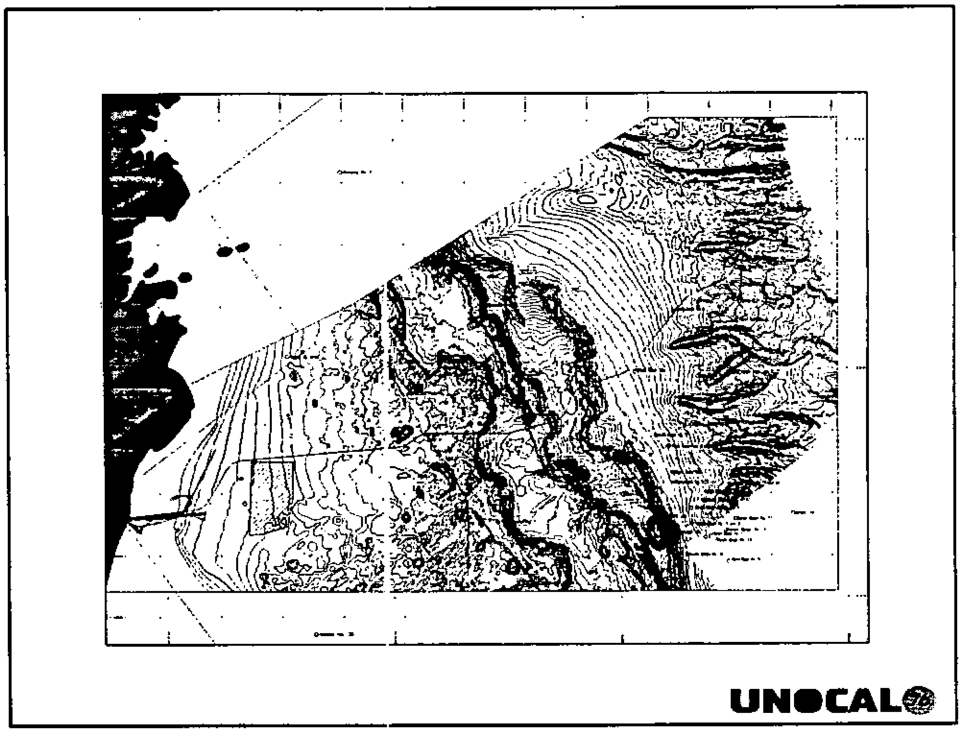
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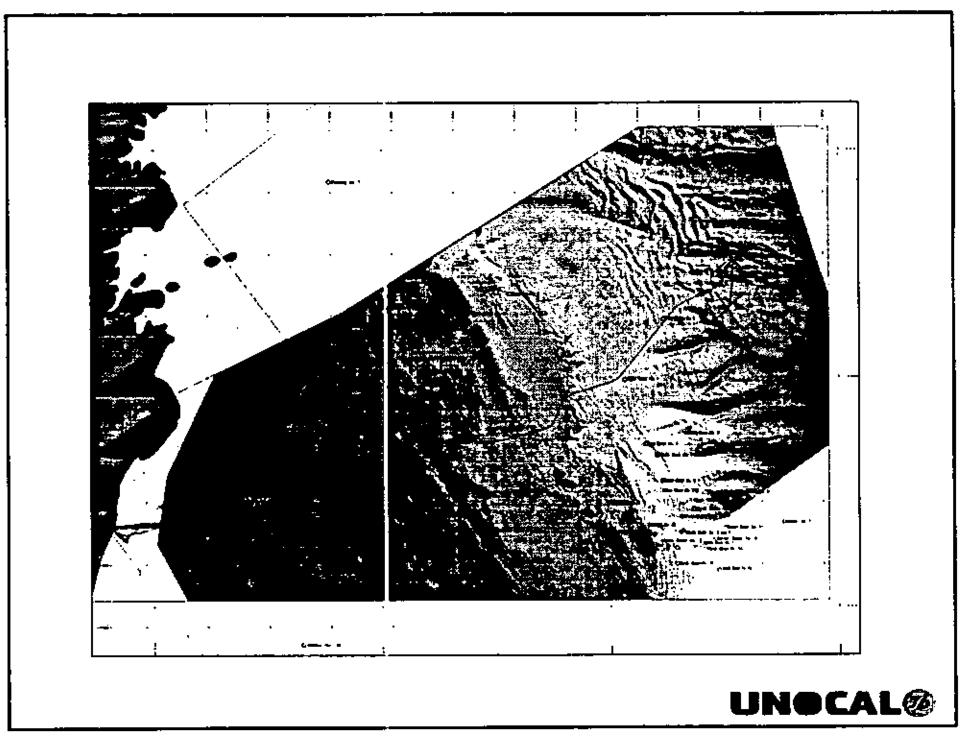
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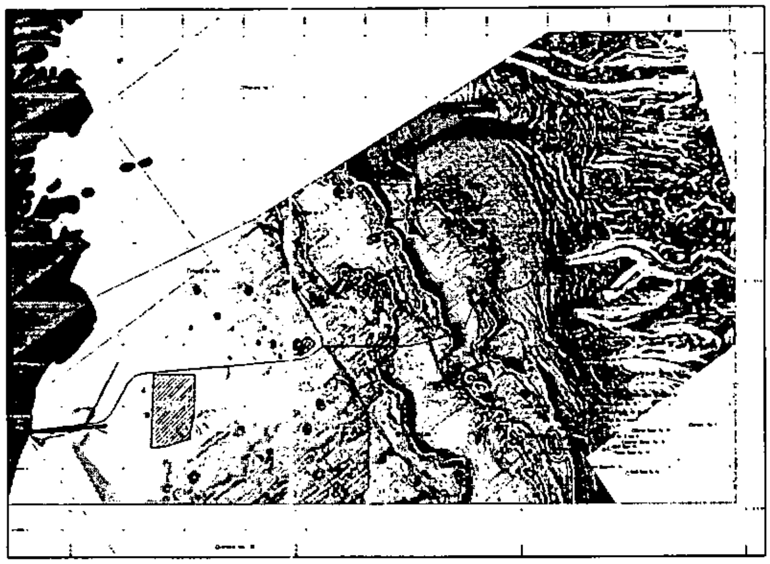

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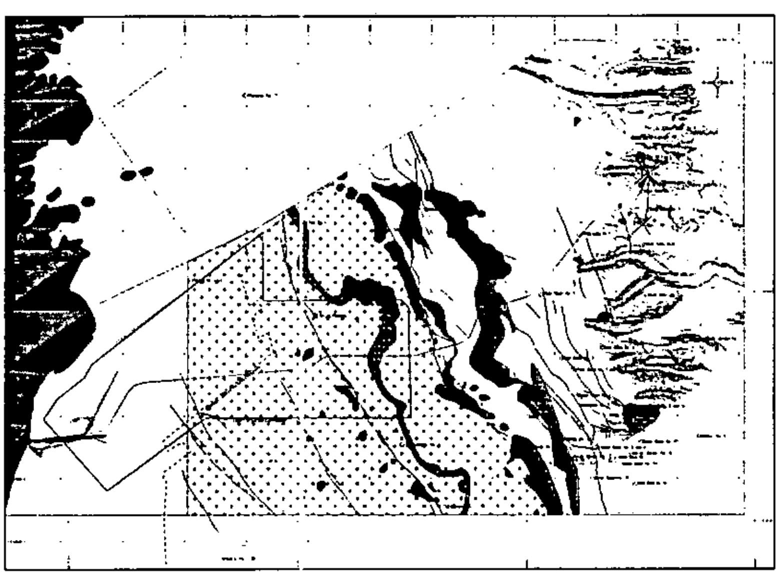

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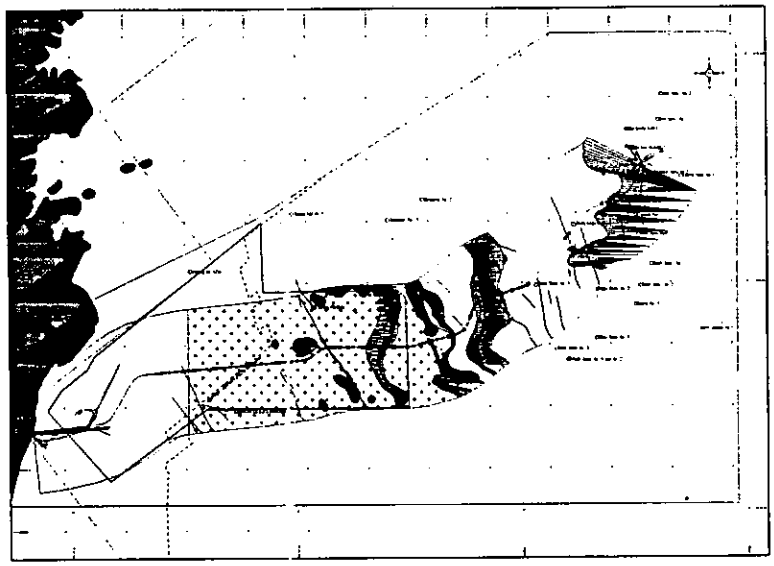

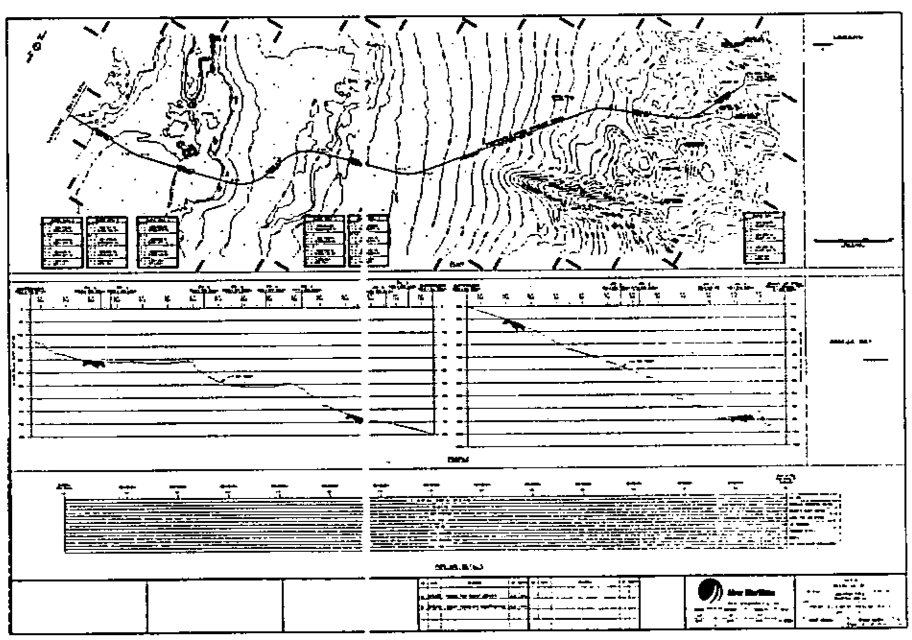

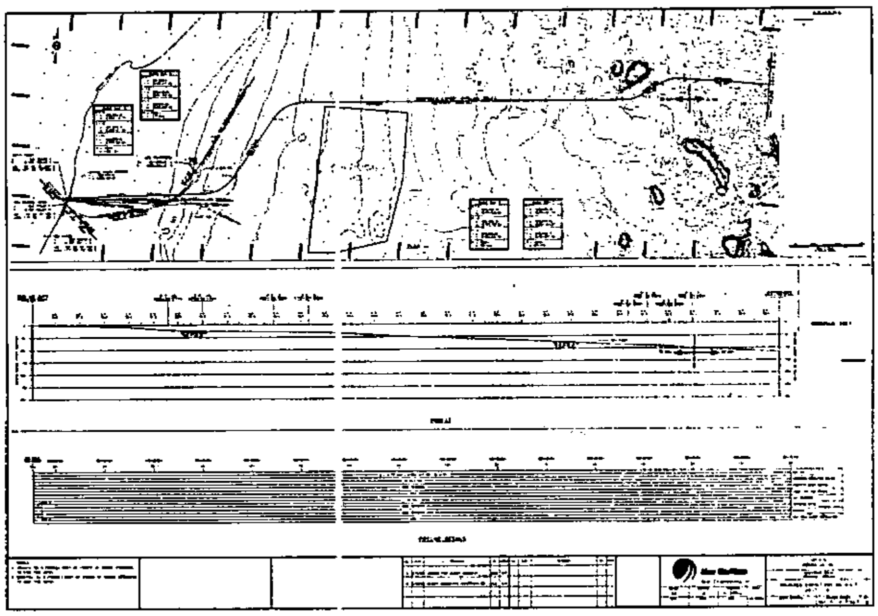

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LADYBUG FIELD

Pipeline Route Assessment & Selection

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Pre-Engineering Route Selection

- Design Assumptions and Challenges
  - Select Shortest Route
  - Numerous Spans Anticipated for the Direct Route
  - Minimize Spans in Deepwater Due to Cost of Rectification
  - Wanted to Avoid Crossing Steep Terrain and Faults
  - Route Around Seafloor Feature East of Tick Platform Needed to be Found

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Pre-Engineering Route Selection (cont.)

- Pipeline Route
  - Tie into Subsea Well at Ladybug Prospect
  - Approximately 15 miles for a Direct Connection, Design to Minimize Increased Distance
  - Needed to Deviate Around Rough Terrain South of Tick Platform and North of Ladybug Prospect
  - Complete with Conventional Riser to Tick Platform
  - Oil Tieback and Dual 6" Pipeline for Pigging Purposes
  - Umbilical Probably Could be Installed on Direct Route for a Substantial Savings

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Pre-Engineering Route Selection (cont.)

- Strategy
  - Had to Select Route for MMS Permitting
  - Use Existing Data for to Plan the Field Work
    - Existing Bathymetry Maps
    - Existing 3D Seismic Data to Produce Seafloor Maps
  - Designed Alternative Routes to Minimize Route Decisions in the Field

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Preliminary Route Selection (cont.)

- Methodology
  - Used 3D Seismic Seafloor Maps to Design Alternative Routes to be Surveyed
  - Select Areas with Minimum Crossing Faults and Rugged Terrain
  - Iterative Process Between Fugro, PCS and Unocal
  - Plot Alternative Routes on Fugro's Maps
  - Make Alignment Drawings

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Pre-Engineering Route Selection (cont.)

- Conclusions
  - The Existing Bathymetry Data was Inadequate for Route Design Due to Sparseness and Age of Data
  - The Seafloor Rendering from 3D Seismic is Very Useful for Preliminary Route Design
  - There Was Sufficient Existing Data in House to Select a Preliminary Pipeline Route
  - Would Use Results of Hazard Survey to Determine Final Pipeline Route Design

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Preliminary Route Selection (cont.)

- Results
  - Selected Pipeline Route is Approximately 18 Miles Long
  - Survey Work Was Successful in Confirming Results of 3D Seismic Seafloor Maps
  - Umbilical Can Be Laid on Direct Route
  - Requirements for MMS Approval Were Met

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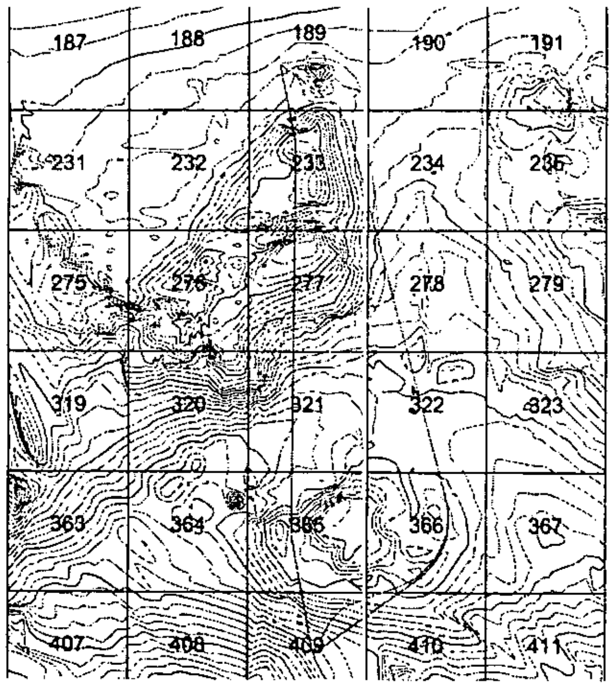

Conventional Bathymetry

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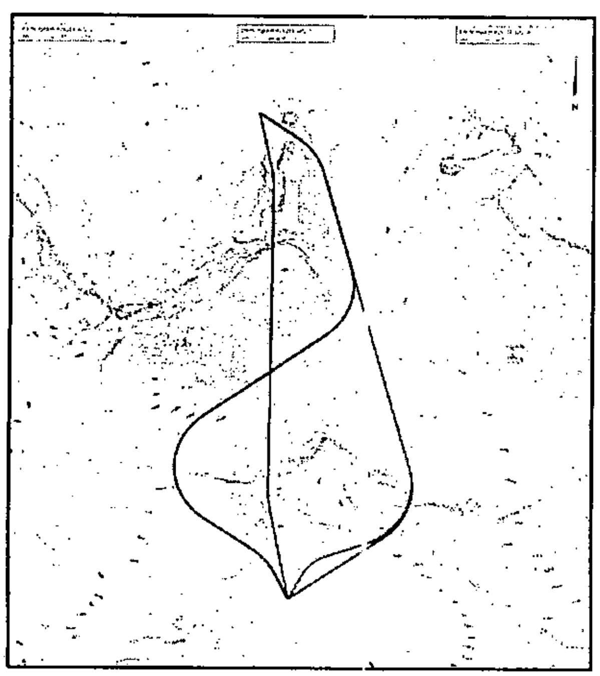

Bathymetry from 3D Seismic

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Seafloor Rendering from 3D Seismic

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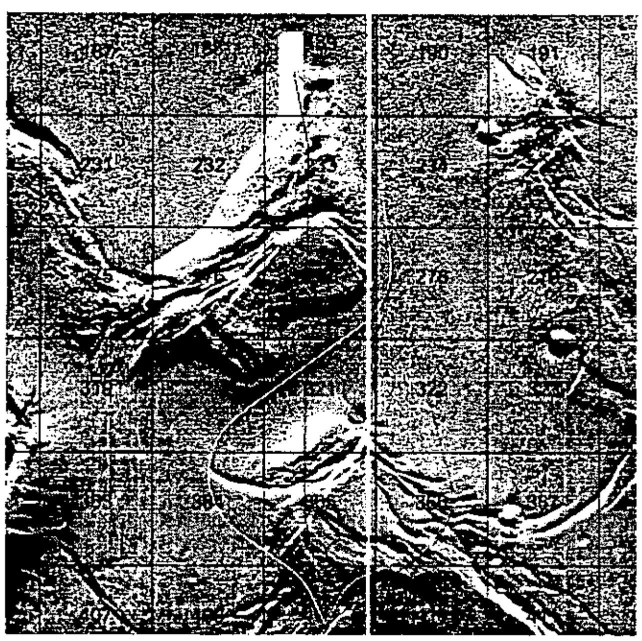

Seafloor Image from 3D Seismic

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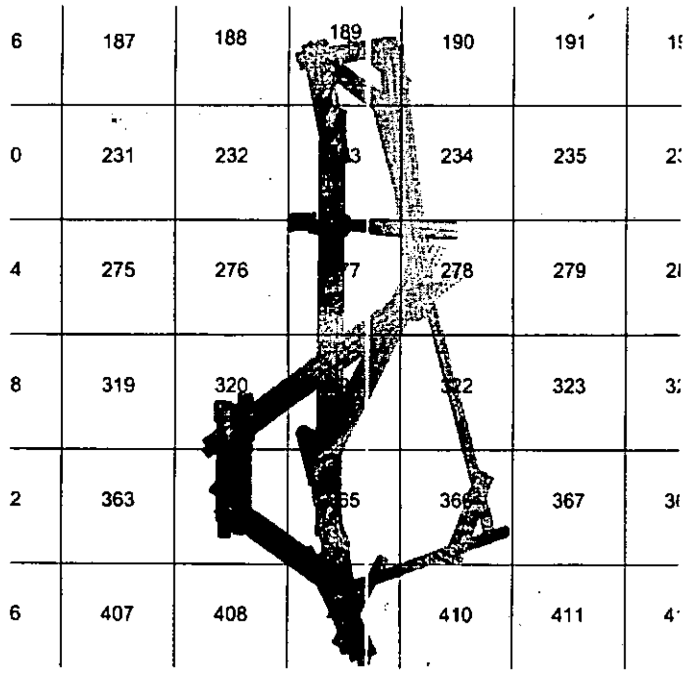

Multibeam Bathymetry

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Final Thoughts

- Pipeline Route Designers Should Utilize 3D Seismic Data Where it is Available
- The Subsurface As Well As Surface Data from the 3D Seismic Can Aid in Pipeline Route Design; ie. Faults, Buried Reefs, Etc.
- 3D Seismic Allows Alternative Routes to be Planned Ahead of Time Saving On Expensive Field Time
- 3D Seismic Is NOT the Final Answer But Will Help You Get There Quicker and Cheaper

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Acknowledgements

- Chuck Hebert - Project Leader
- Rick Dupin
- Betty Johnson
- West Seno Project Team
- GEMS
- Aker
- Fugro
- PCS

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Gel Pig Technology:
An Evolving Flow Assurance Tool

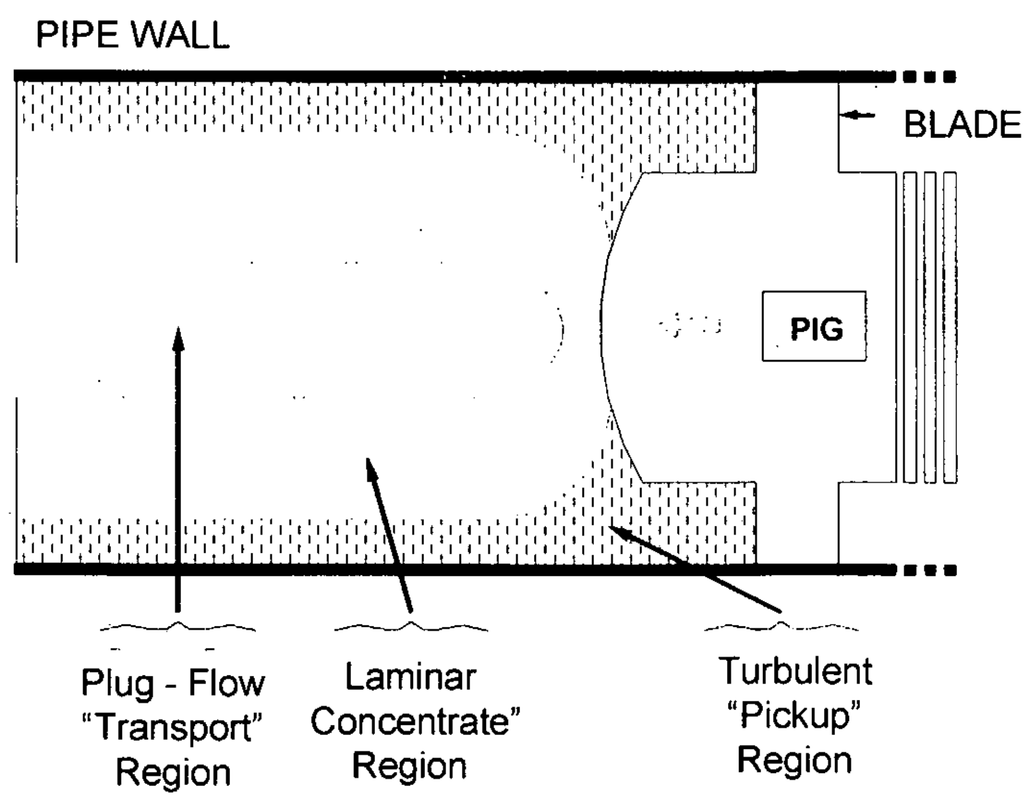
Craig Tucker
Paragon Engineering Services, Houston, USA

presented at the
DEEPWATER PIPELINE & RISER TECHNOLOGY CONFERENCE
March 7-9, 2000, Houston, Texas

organized by
Clarion Technical Conferences
and
Pipes & Pipelines International

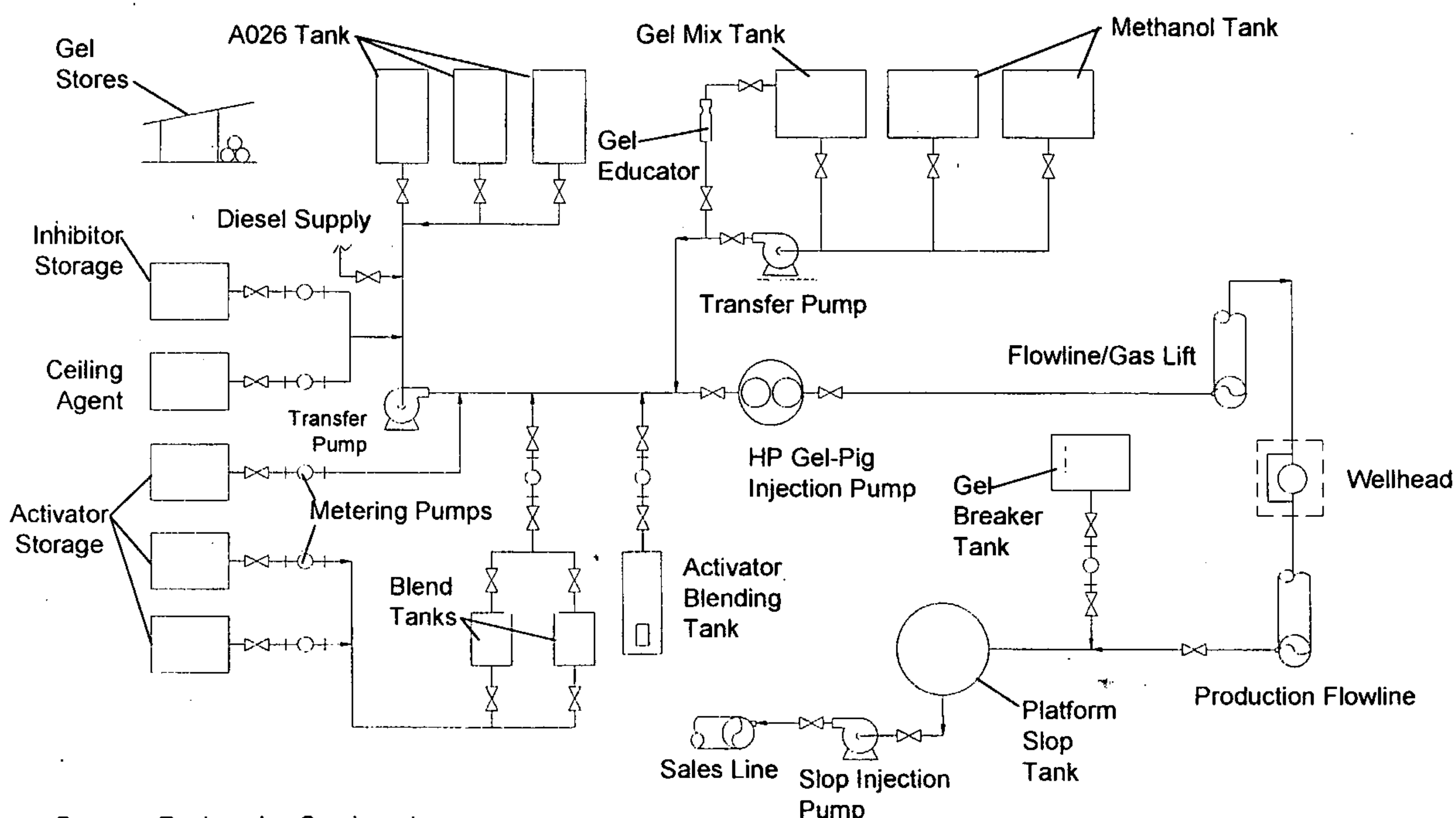
Gel Pigging Technology

Gel Flow Regime



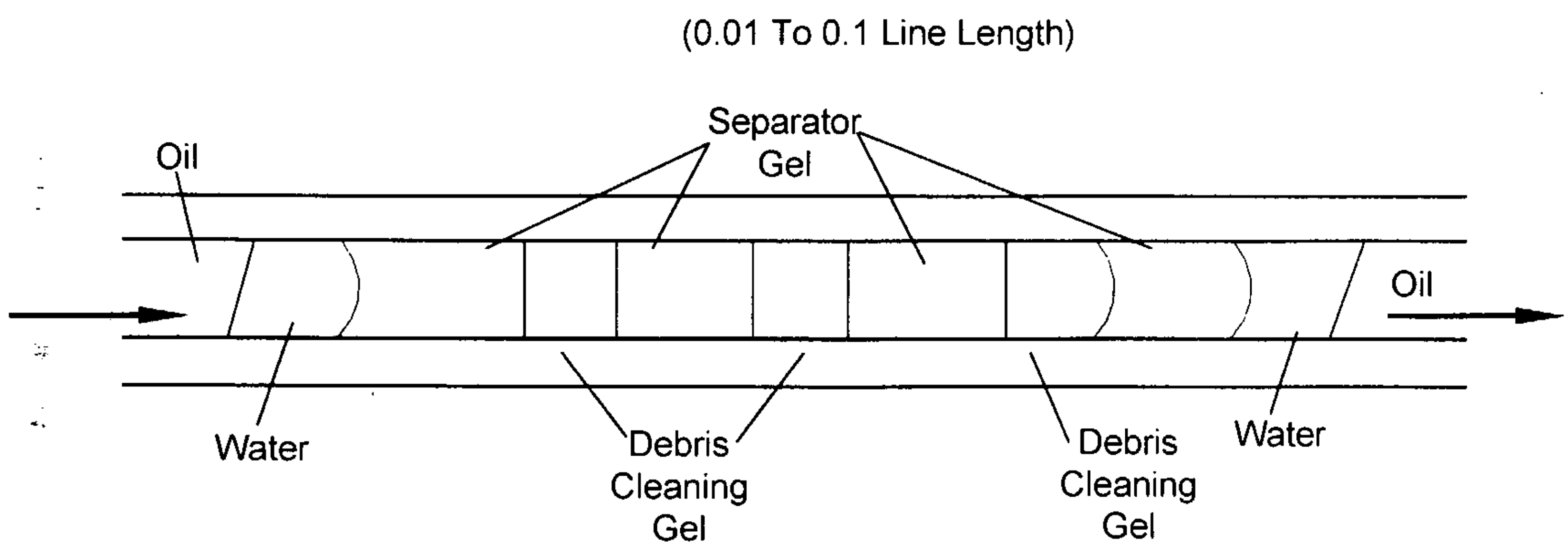
Gel Pigging Technology

Proposed Automated Gel Train Skid



Gel Pigging Technologies

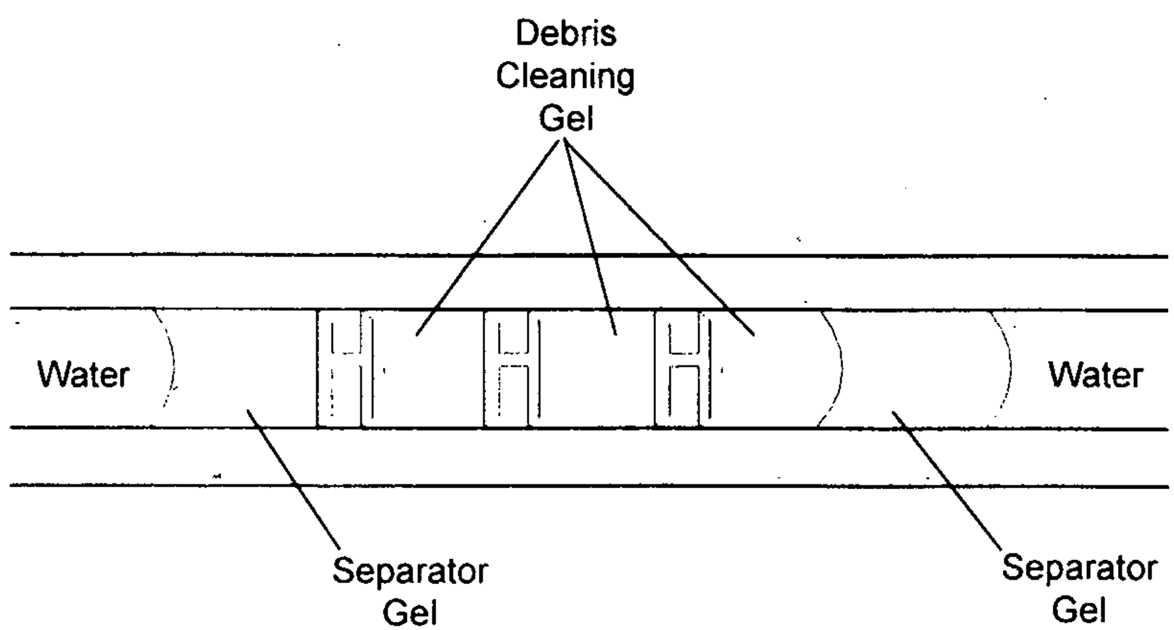
Flow Assurance Gel Pig Train



PARAGON

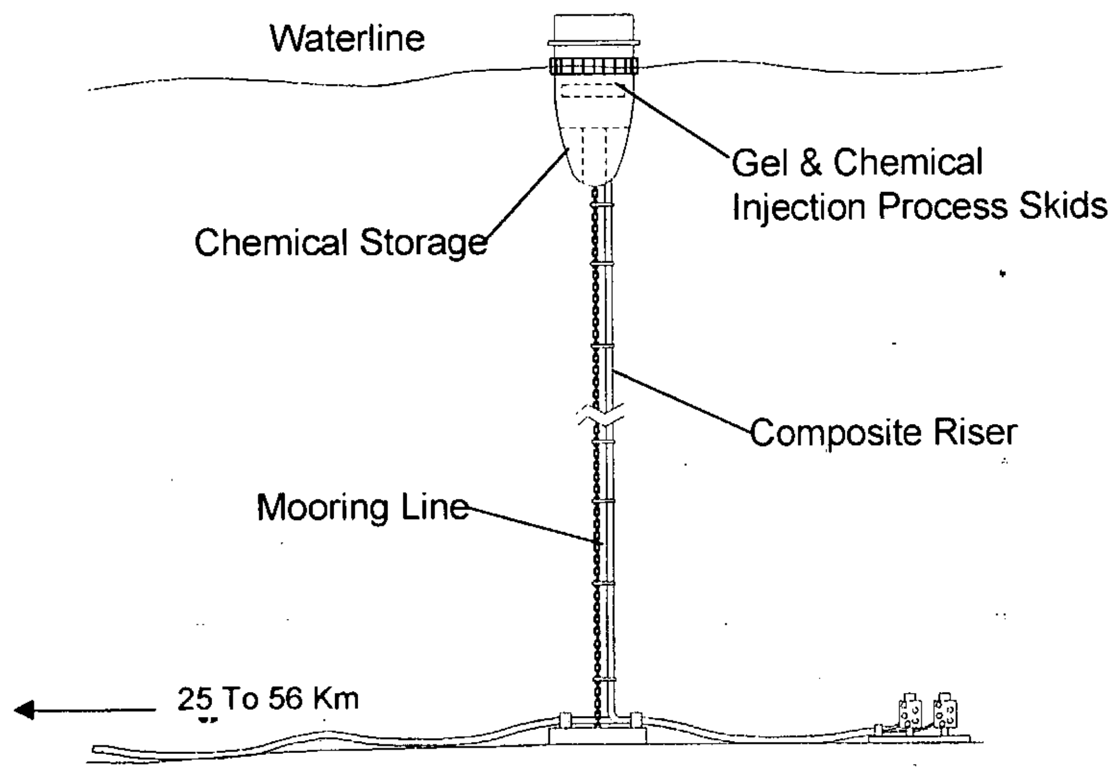
Gel Pigging Technology

Typical Gel Pig Train



Gel Pigging Technology

Tie Back Support Buoy



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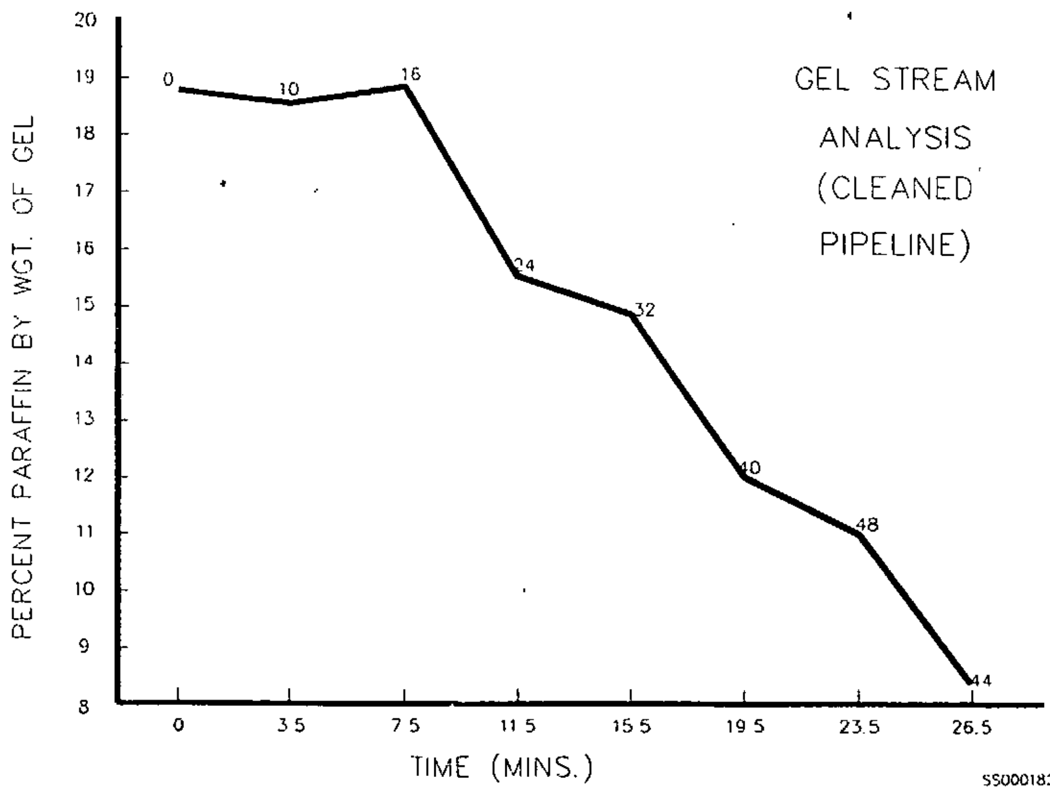
ENGINEERING SERVICES INCORPORATED

Gel Pigging Technology

Oil Based Gel Pig Project



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Gel Pig Technology: An Evolving Flow Assurance Tool

The earliest use of "downhole" drilling fluids for adaptation to pre-commissioning pipelines apparently was achieved by Shell Oil, working with Dowell Schlumberger's Pipeline Services Group.

Because of the ongoing development of downhole gel fluids and their use in general pipeline applications, major advances have been made in gel technology in recent years. New liquid components have replaced "dry" granular or flaked material, allowing more accurate blending and consistent performance characteristics.

Introduction

Gel pig technology is well established in the area of pre-commissioning of natural gas pipelines. The gel pig system for cleaning and drying of gas/gas liquids lines is a proven tool that produces a flow assured pipeline system for the introduction of gas and/or associated liquids.

With the proper "train" configuration, gel pigging will remove all debris, including mill scale and iron oxides. The removal of this debris allows the drying portions of the flow stream (predominately methanol-based) to absorb and transport all potential hydrate moisture from the pipeline facility. Analytical testing of periodically drawn flow stream samples provides a positive indication of a moisture/water-free pipeline.

Pre-commissioning gel train pigging of multiphase or crude oil systems also is very beneficial, particularly if paraffins or asphaltenes are evident in the hydrocarbon stream. Removal of the debris and iron oxides substantially reduces the foundation for the formation of paraffin residual in and on the internal pipe walls. The debris adds structural strength to the paraffin or asphalt and increases resistance to mechanical scraping for removal. Additionally, the debris reduces the available surface area of the paraffin/asphalt deposit. The reduction in surface area greatly reduces the effectiveness of chemical solvents when such a deposit is allowed to form with this "aggregate" make-up.

Studies and field tests have established that after cleaning and external coating as well as internal cleaning, steel line pipe (particularly when stored in a marine environment) will yield approximately 0.018 pounds of metallic debris per square foot of internal pipe surface. One mile of 36-inch line pipe will yield about 1,000 lbs. of this unwanted material.

It is easy to see that the removal of this debris is important in the pre-commissioning stage to avoid residual deposits in instruments, valve stems (especially control valves) and special equipment such as mole sieve's.

In the early 1990s, with the movement into deeper water with colder temperatures and very complex access for remediation, the utilization of gel technology provides an opportunity to develop a non-mechanical pigging system capable of accomplishing the operational pigging task

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Proceedings of the 3rd Deepwater Pipeline & Riser Technology Conference, Houston, Texas, March 7-9, 2000.

without the risk associated with mechanical intervention. The potential for gel slumping/bypassing in pipelines much larger than 8 inches poses an apparent limit on line diameter. However, new, stiffer molded gel pigs or similar systems may extend diameter capability.

Gel pig train volumes and lengths are determined by line length and volumes of contaminant or residue targeted for control or removal. Pipeline service groups have made much progress in the formulation of gel trains for their operational programs.

Short and Long-Term Application

A proper cleaning and drying operation is a large part of the flow assurance battle. Residual moisture can be removed and a layer of hydrate preventative methanol (or other chemicals) deposited to control the potential for hydrate formation. Further research has substantiated the fact that residual mill scale and rusting produced iron oxide are major factors in the consolidation of internally deposited paraffin/waxes/asphaltenes. The metallic residue produces a very strong, hard coating (like gravel aggregate in concrete) and reduces the surface area available to applied chemicals utilized for removal.

In short, flow assurance starts at the beginning of the field development with hydrocarbon analysis and requires a definitive chain of communications to the designer and ultimately to commissioning and operational personnel. With this information, the long-term program can be developed.

Why Gel Pigging?

Gel trains are all liquid and can be flowed from an existing production facility through a 2 to 3-inch injection line to the wellhead for admission/injection into the flowline for its return trip to the production facility, providing lower-cost round-trip pigging with minimal operational risk.

A second alternative for extended well tiebacks could be executed through the injection of a gel train from a surface-moored buoy via a neutrally buoyant riser system for clearing or control of system encumbrances at the required time intervals.

"Gel breakers" can be applied to returning gel trains to produce almost instantaneous liquefaction of viscous gels, allowing line flow to return to a normal regime.

Subsea Application

During the JIP carried out between 1994 and 1996, the concept of an automated gel train production skid was produced and a manual version was constructed by Dowell Schlumberger. The unit was used successfully on several paraffin removal programs and design confirmation for an automated skid/storage facility that could be deployed as a service unit for producers. The skid would be pre-programmed to initiate the required injection of gels, solvents, chemicals, etc., to provide suitable control of paraffins/waxes, moisture (hydrates) and deposit required inhibitors (corrosion).

The development of the "skid unit" and the supply of associated chemicals as well as extended engineered systems may provide a service for production companies as well as a valuable tool that could substantially extend tie-back potential with reduced operational risk.

New gel chemicals can enhance skid simplicity and possibly provide cost incentives for deepwater developments.

Gel Pig Applications for Deep Water

To initiate a gel pig flow assurance program, production hydrocarbons must be taken from a reasonable test flow and completely analyzed to determine the presence and quantity of factors such as:

Paraffin/waxes

Asphaltenes

Water volume in the anticipated flow (hydrate potential)

Well production pressures downhole and in the product stream

Production temperature downhole and at the wellhead

This information should be obtained during well test and utilized as a facility design criteria.

To provide sweeping/pigging functions, the gel pigs with chemicals (solvents, inhibitors, wax modifiers, etc.) must be pumped into the pipeline in a batched gel "train" to actually keep the line clear and clean of problem debris. The indicated volumes of the "train" usually contain a total volume of between 0.01 and 0.1% of the pipeline volume of the existing pipeline.

Utilization of an automated "skid" produced gel train will use a minimal volume, when regulated, to a frequency required to maintain safe successful flow assurance.

The newer liquid-based gel material offers a broader capability in cross-linked gel viscosity as well as a sizeable reduction in storage and, ultimately, skid automating complexity.

Further to the gel technology advances, substantial advances have been made in chemicals capable of breaking waxes and neutralizing the formation of asphaltic residue bonds in flow lines. These chemical additives probably can be gelled or batched in carrier liquids to produce the desired flow maintenance status in the line.

The ability to remove and/or transport unwanted residual water is presently a known science. Extension of the economical use of "frequent" gel trains to remove production debris as well as water is a specific target of further technological development of automated gel pig skids.

Two possible field development concepts using gel pigging in subsea well tiebacks are as follows:

1. Utilizing a 1-1/2 to 2-1/2 inch coiled tubing chemical injection line to transport the gel train from the production unit to the wellhead, where the stream would flow across the wellhead, returning to the production unit via the 4 to 8-inch flowline. (Conventional dual flowline can also be used on existing systems.)

2. Placement of the gel skid on an exposed location buoy moored above the wellhead. The buoy would contain the gel material, process skid and support equipment for gel train production. The train would be pumped down the neutrally buoyant 4 to 6-inch riser (secured by the mooring line) to the wellhead where it would be directed into the flowline for its 25 to 50 mile passage to the production surface unit.

The gels themselves can be "broken" back to a liquid state with only a few PPM of gel break chemical when traversing the production platform or FPSO.

The recent development of composite "coiled" tubing appears to provide the possibility of producing a high-pressure neutrally buoyant riser for deepwater applications. Further review of size (diameter), pressure rating, and hydrostatic collapse resistance must be confirmed to substantiate composite "coiled" tubing utilization in this application.

Summation

It should be noted that the application of the gel pigging systems identified require development of further information, principally cost (i.e. related to unit cost per produced volume of hydrocarbon).

The application of the gel technology requires a definative analysis of the flow assurance boundaries followed by a system design and detailed cost.

Even though gel trains have proven their ability to provide a technical capability to control hydrates, remove pipeline debries and remove waxes and asphalteen from flowlines it is necessary to execute a detailed design review of facilities and chemical costs to confirm the applications viability.

The reduction in mechanical subsea pig traps as well as the accompanying difficulty of operation of mechanical pigging systems is still a motivating force to extend development of gel/pig train flow assurance systems. Certainly the gel tool carries substantially less operating risk than the deepwater mechanical pigging systems.

General Background on Gel Technology Applications

Introduction

Gels are used in pipeline operations for a variety of applications. Some of those applications are listed below:

- Dewatering
- Cleaning
- Sealing
- Corrosion inhibition
- Fluid separation
- Coating
- Drying
- Pipeline isolation
- Valve testing

Gels provide various functions in the applications listed above. They control the gas bypass, lubricate pig seals, carry solid debris in suspension, prevent leakage in valves by offering a high, effective viscosity, provide a semisolid plug for fluid isolation, etc. One primary advantage of gels over mechanical pigs is that they do not require a constant pipeline diameter. Hence, larger diameter changes can be accommodated in certain applications discussed in more details later.

This section describes commonly used types of gels, their selection, preparation, quality control, and disposal. In general, some laboratory testing is required to select gels for a specific application. In certain cases, for example, very large-diameter pipeline where no prior history of pig performance is available, full-scale lab testing may be warranted.

Definitions

Gels (or base gels) are solutions or semisolid dispersions of a polymer in a base liquid. The base liquids commonly encountered in pipeline applications are fresh water, seawater, diesel, kerosene, methanol, glycol, and sometimes isopropanol.

Polymers are composed of fibrous strings of extremely long molecules. (Polymers are derived from guar beans and chemically modified to improve the viscosity characteristics.) The polymer particles swell on contact with a liquid and take part of the fluid into the fibrous structure, which gives the fluid viscosity. The viscosity can vary from a slight thickening of the fluid to the creation of a rigid gel similar to set gelatin. The increase in viscosity is required for various reasons, such as to provide sealing action or for debris pickup.

Polymerizing agents of different types are used for various base fluids in pipeline applications. These agents include guars, cellulose, xanthan, and polyacrylamides for freshwater or seawater gels.

Gel Additives and Characteristics

Some gel additives and their characteristics are described below:

- A biocide/bactericide kills bacteria that would otherwise cause gels to break and lose viscosity.
- A breaker breaks the long-chain polymer molecules of a gel into smaller chains with controlled and predictable viscosity reduction.
- A pH-control agent keeps the pH of a fluid constant. Moderate amounts of acids or bases can be added without appreciable changes in the pH of a buffered solution.
- An inhibitor minimizes the corrosion of pipeline steel.
- A Newtonian fluid has a constant viscosity, regardless of the shear rate. (Example: water or oil)
- A non-Newtonian fluid exhibits a variation in viscosity, depending on the shear rate.
- An oxygen scavenger chemically ties oxygen to prevent corrosion.
- A crosslinker or a complexing agent chemically links two or more polymer chains to increase the effective viscosity of the gel.
- A hydrate is a hard crystalline substance formed at certain pressure and temperature conditions. It consists primarily of water with gas trapped inside and is hard enough to plug pipelines.

Gel Types

Depending on the gelling agents used, four primary categories of gels are available:

- Guar
- Cellulose
- Xanthan gum
- Polyacrylamide

Most of the time, derivatives of these gelling agents are used in the oil industry. The base fluids used to prepare gels can be water, seawater, diesel, methanol, glycol, and other hydrocarbons. Gels can be either linear or crosslinked, depending on the particular application. Various crosslinking agents are used, depending on the type of gelling agent, base fluid, and the application. The common crosslinkers are borate, titanium, zirconium, and aluminum phosphate esters.

Gel Requirements

The factors listed below should be considered when a gel is selected:

- Adequate rheology for the specific application.
- Chemical compatibility with materials in pipeline, such as pipe material, pipeline coating, etc.
- Chemical stability for the duration of the job, including stability during storage.
- Large-scale mixability.
- Low solids residue on drying (applicable for gas pipelines).
- Residue compatibility with downstream equipment and processes.
- Environmental disposability.

Gel Applications

Cleaning

Debris Pickup. Gels are used extensively for debris-pickup applications. The types of debris found in a pipeline depend on the age of the pipeline and the type of fluid transported in the past. New pipelines generally contain sand, rust, millscale, and construction debris. (This debris typically covers 180 g/m^2 of the internal surface of the pipeline, but the actual quantity depends on the length of exposure and the nature of the oxidizing fluids in the line). Millscale is typically 0.1 mm thick and ranges from 1 to 3 cm in diameter. Depending on the type of fluids transported, there may be rust, asphaltene, paraffin deposits, or iron sulfide in sour crude or sour gas transport lines.

Debris-pickup gels should have high viscosity and shear-thinning characteristics, such as high K' and low n'. Crosslinked gels can be used to yield a high K' and a low gel loading.

A laminar flow regime enhances debris transport; therefore, low displacement velocities should be maintained for debris-pickup applications.

Dewatering

Information Required. The information required to calculate the volume and rheology of the gels for a dewatering application is listed below:

- Pipe diameter, in.
- Length of the pipeline, ft.
- Weld projection into the pipeline ID.

- Surface roughness.
- Ovality.
- Ambient temperatures during job, °F.
- Type of line (subsea or land).
- Pipeline coating, if any (coating sample will be required for chemical compatibility testing).
- Pig trap details.
- Required dryness level (either in de point at atmospheric pressure or mass/unit volume at standard conditions of temperature and pressure).
- Maximum gas pressure available for displacement, where applicable.
- Required swabbing agent (methanol, glycol, isopropanol).
- Topography of the pipeline.
- Time available for the dewatering operation.
- Environmental disposal constraints.

Gel Design for Dewatering Train. Based on the technical information described above, the dewatering train is designed through the use of procedures involving software developed in-house. This software attempts to minimize the forward bypass of the gas. The end result of this design is a recommended train. The train design gives the lengths and volumes of the various compartments and the fluid and gel types.

Pipeline Isolation

Gels can be used as temporary plugs to hold fluid pressure, isolating segments of a pipeline. Initially, the means to install the gel slug into the pipeline must be established. Generally, for land pipelines, holes are drilled in the pipeline to introduce the gel slug. Surface roughness of the pipeline (depending on the internal coating) affects the pressure-holding capacity of a gel slug. The effect of changes in temperature on the pressure should be considered. For a subsea application, the effect of tide should also be accounted for in the pressure calculations. Finally, disposing of the gel after the job can pose a problem and should be evaluated.

Valve Testing

Depending on the location of the valve, crosslinked linear gels can be used for valve isolation for pressure-testing purposes. Use crosslinked gels if there is a possibility of the gel moving away from the valve because of density difference or elevation changes. The required gel rheology depends on the openings to be sealed in the valve and the maximum differential test pressure across the valve.

The volume of the gel slug depends on the duration of the test. Generally, the effective opening in the valve is not known, making it difficult to select the proper gel rheology. Hence, it is necessary to have a high-viscosity gel. If no information on the leakage rate or opening is available, use gels having an effective viscosity of at least 500 cp (at 511 sec^{-1}) and a slug length of 50 ft. The size of the leakage path and the test pressure strongly influence the gel rheology and volume selections.

Pig Recovery

Gels can be used to move stuck mechanical pigs in certain cases. The ability of a gel slug to free a stuck pig depends on the following factors:

- Cross-sectional opening in the pig
- The dislodging force required
- Availability of the flow rate to generate the necessary differential pressure across the pig.

Normally these gel slugs are introduced at the inlet of a pipeline far away from the stuck pig location. Crosslinked gels are preferred for these applications because of their ability to retain their structure during travel. The effectiveness of the gel in removing a stuck pig cannot be guaranteed because of the unknown nature of the opening and the dislodging force required for the pig. Consider crosslinked gels of effective viscosity higher than 500 cp (measured at 511 sec^{-1} shear rate). The slug length is dictated by the driving pressure requirements at the required displacement rate.

Fluid Separation

If mechanical pigs are used to separate fluids, the sealing efficiency of the pigs can be enhanced with the use of gels. The gels described earlier for the dewatering application could also be used for fluid separation. Generally, when mechanical pigs can be used, the use of gels is not cost-effective; therefore, gels are not used in those instances. For those applications in which mechanical pigs cannot be used (because of diameter changes or sharp bends, such as a bend radius <3d, or for other reasons), gels can be used effectively as a separation medium to minimize mixing of the two fluids, depending on the diameter and length of the pipeline. Generally, the separation gels are restricted to relatively small-diameter lines (less than 12 in.). For larger diameters, the separation efficiency is drastically reduced. Model for sizing these separation gels are not available. Approximate guidelines are provided below:

- Velocities of the gel slugs should be restricted to 0.5 m/s.
- Length of the gel section should be 0.01 times the pipeline length.

Crosslinked gels are preferred for these applications. Borate gels are suitable for those applications with several diameter changes.

The information required to design the gel slugs follows:

- Lengths and diameter(s) of the pipeline
- Pipeline topography
- Dead areas of the pipeline

Gel Disposal

Depending on the contract, HES may or may not be required to handle the disposal of the used gels and gel-contaminated fluids. In most cases in which the customer or a third party is responsible for the disposal. HES is expected to provide the Material Safety Data Sheets (MSDS) for all of the chemical components of the gels.

In cases in which HES is responsible for the disposal, follow the appropriate local regulations and general HES procedures (where applicable) for disposal of the gels and gel-contaminated fluids at the end of the train travel. Depending on the applicable disposal requirements, various methods can be used to dispose of the gels.

Summary of Pipeline Consent to Discharge Regulations

- A consent from the appropriate government department is required to discharge any substances other than untreated seawater or fresh water. If untreated water is likely to contain millscale or rust, consent is necessary before the discharge is undertaken.

- Proposals for the discharge of pipeline contents must be discussed with all interested government departments. For near-to-shore discharge proposals, other local government bodies and interested parties, such as river boards, local councils, inshore fishery unions, and environmental protection groups must be consulted.

- The application for consent to discharge must state the composition of the line fill, the pig train compartment fluids, and relevant toxicity data.

- Alternative discharge locations, depths, and methods must be proposed.

- Discharge rates and total quantities must be proposed. The government may require the discharge to be confined to a particular time of the year and may also restrict overall quantities of discharge.

Gel Disposal Processes

Train fluids consist of the following gels:

- Water-based gels
- Hydrocarbon-based gels
- Methanol-based gels (natural gas)

Water-Based Gels

The chemicals involved in the manufacture of water-based gels are biodegradable and harmless to marine life. These gels could therefore be passed to settlement tanks and held until the gel breaks and the debris settles out. The gel would then be pumped to the ocean through the outfall or shipped by tanker to a registered safe disposal site.

Hydrocarbon-Based Gels

If subsea disposal of hydrocarbon gels is permitted, a long disposal line should be used to direct the gel away from the platform. When such disposal is not permitted, the following two methods are suggested as alternatives for safe disposal of the hydrocarbon gels:

- Receive the hydrocarbon gels into chemical tanks to be collected at a later time and transported to an authorized disposal site.
- Receive the hydrocarbon gels into chemical tanks and pump the gels to a temporary incinerator.

The second method has the advantage of maintaining control of fluid disposal.

Methanol-Based Gels (Natural Gas)

If gas bypass into the methanol-based fluids occurs during dewatering, a system for separating the gas from the fluids is required.

Direct the methanol-based fluids from the pig receiver to a knockout drum from which the gas will pass to a temporary vent/flare stack, and the methanol will be passed to chemical tanks.

Service Company Technical Data

Pipeline Gel Technology

For over 50 years, Halliburton has been a leader in developing gel technology, continuously improving performance, and expanding capabilities.

Superior performance

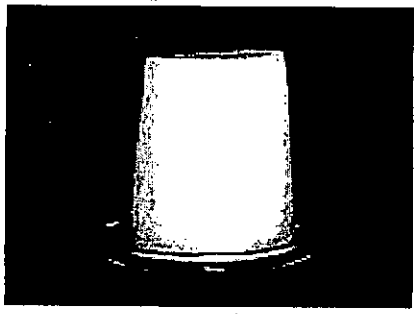
Halliburton's unique technology provides proven, dependable solu tions.

With unequaled experience and technical expertise, Halliburton has developed a number of gels to meet the diverse needs of the pipeline industry.

Complete range of pipeline services

With a Halliburton exclusive gel, developed for a specific purpose, or the right combination of gels, along with Halliburton experience and expertise, we provide the best solutions for a wide range of services:

- Cleaning
- Separation
- Isolation
- Lubrication
- Pig lubrication
- Sealing
- Debris pickup
- Dewatering
- Drying



HN00735

All types of pipelines

In prolonging the life of your pipeline and protecting the quality of your product, the right gels and the expertise of the service provider are important factors in all types of lines:

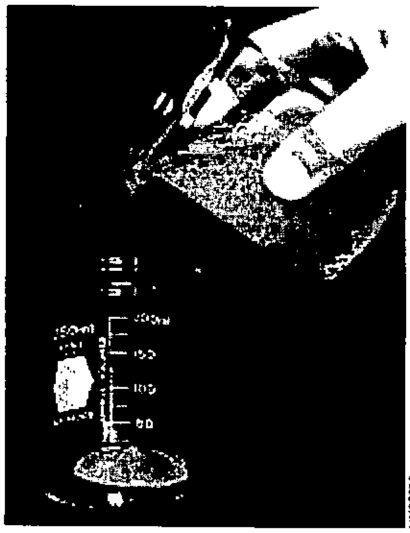
- Water
- Gas
- Dry gas
- Crude
- Refined product
- Multiple-product

Around the world

For many years, Halliburton has been a world leader in pipeline services. We understand the complexities of your industry and the challenges specific to different parts of the world.

Why gels?

Halliburton will select a gel that won't allow contamination of your product. Halliburton gels can service your pipeline without the introduction of water. And we can gel your product—diesel, jet fuel, crude oil, etc.



HN00736

A gel can be run in situations where it is not possible to use mechanical pigs. For example, pipelines of varying diameters or difficult bends. The result: improved pipeline performance.

Tau-Gel™ Service

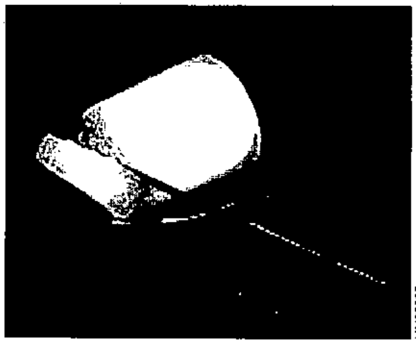
Unlike other pipeline gels, Halliburton's Tau-Gel service provides a semisolid material after being put into place as a liquid. This capability presents unlimited possibilities:

- Superior performance
- Maximum economy
- Unequaled versatility

Performance

Tau-Gel agent is named for its extremely high yield stress properties.

In liquid form, Tau-Gel can travel through different diameters of pipe. Tau-Gel exits the pipe as a semisolid.



HN00737

Tau-Gel can be placed in the pipeline at any point. There is no need to fill the entire pipeline.

During shutdown or repair, use Tau-Gel to help prevent water, product, or gas by-pass.

Economy

For ease of disposal, Tau-Gel is removed as a solid.

Safety

Diver safety is enhanced with the use of Tau-Gel because there is no need to drastically reduce pipeline pressure.

Many other gels

Each pipeline service situation presents its own set of concerns. Halliburton has the right gel or combination of gels to meet the needs of your project. We design a gel system for a superior solution to your challenges.

Listed below are some of our more widely used gels and the processes in which they are typically applied.

Isolation

Tau-Gel Service

Lubrication

WG-II™, WG-17™, WG-18™, and WG-19™ agents

Where pig wear is a serious con cern, gels act as a lubricant, aiding in the wear resistance of most pig materials on the market.

Pipeline drying

WG-28™ agent (methanol-based)

Separation

K-Max™, WG-11, WG-18, WG-19, My-T-Oil™ (oil-based), WG-26™, and WG-31™ agents

Debris pickup

K-Max, WG-11, WG-18, WG-19, MY-T-Oil, WG-26, and WG-31 agents

Sealing

For sealing around a mechanical pig, use My-T-Oil service or any of the others listed, except Tau-Gel and K-Max agents.

When to use gels

Anytime your pipeline needs gel service, Halliburton has a superior solution:

- New pipeline construction
- Existing pipelines
- Pipeline repairs
- Change in service
- Product separation

For more information on how pipeline gels can help improve your operations, contact your local Halliburton representative—your Solution Connection℠.

North America
Specialty Services
Duncan, OK 73536-0437
USA
Phone: 405-251-3741
Fax: 405-251-4948

Europe/Africa
Howe Moss Place
Kirkhill Industrial Estate
Dyce
Aberdeen
Scotland AB2 0GS
United Kingdom
Phone: 44-1-224-795001
Fax: 44-1-224-724862

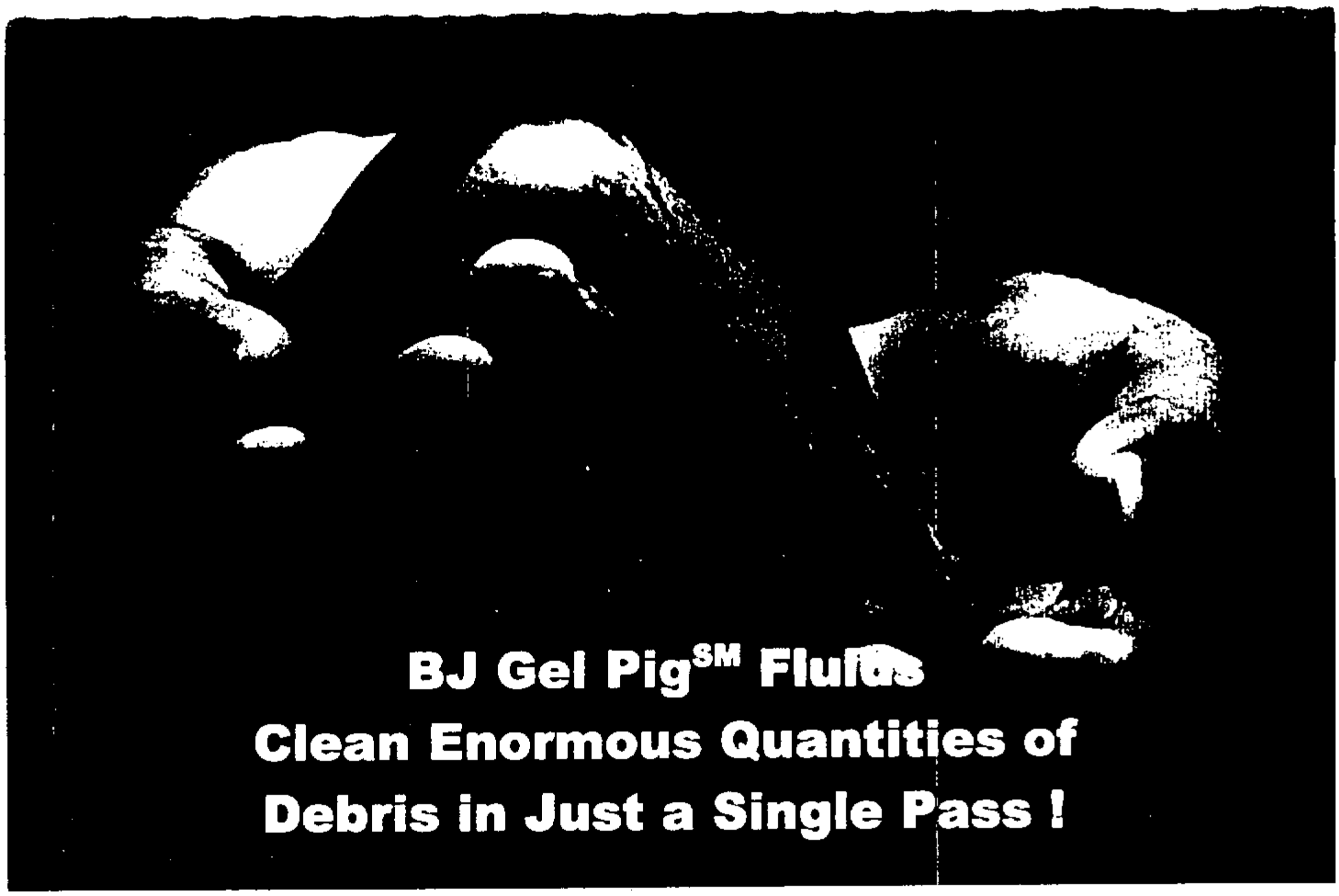
South America
Cia Halliburton de Cementacion
y Fomento S.A.
Avenida Intercomunal
Las Morochas, Edo. Zulia
Venezuela
Phone: 58-65-24254
Fax: 58-65-26961

Praia do Flamengo
200, 23 Andar
22210-030 Rio de Janeiro
RJ Brazil
Phone: 55-21-285-6554
Fax: 55-21-285-6399

Middle East/CIS
1101-1104 Al Moosa Tower
Abu Dhabi Highway
P.O. Box 3111
Dubai
United Arab Emirates
Phone: 971-4-310666
Fax: 971-4-310442

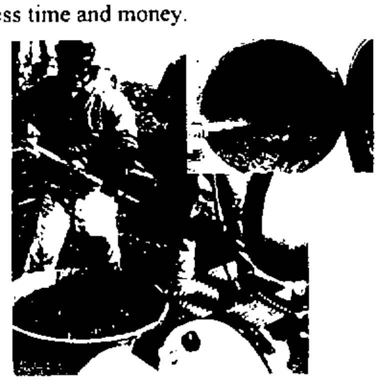
Asia Pacific/China
12th Floor
Menara Tan & Tan
207 Jalan Tun Razak
50400 Kuala Lumpur
West Malaysia
Phone: 60-3-263-4567
Fax: 60-3-263-7128

HALLIBURTON®



BJ Process and Pipeline Services offers a unique method for cleaning and drying long pipelines quicker and more economically than with any conventional method. BJ Gel Pig^{TM} fluids are capable of efficiently suspending huge quantities of debris and effectively removing them, typically in just one pass through the pipeline, without the common risk of sticking mechanical pigs.

Pipeline Conversions are proven to be one of the best applications for BJ Gel Pig^{SM} Services. Many successful conversions of crude oil pipelines to natural gas or finished products have utilized gel pig technology. Superior results are achieved with significantly less time and money.



On-line Cleaning and Drying of natural gas, crude oil, finished product, and other pipelines can be accomplished utilizing a properly designed BJ Gel Pig^{TM} Train to eliminate operational problems, improve flow efficiency or prepare the line for a successful smart pig run.

Added value and benefit for many traditional pigging tasks, are realized:

- *Cleaning and Drying Extremely Long Lines in Just One Pass*
- *Removal of Large Quantities of Debris*
- *Improved Sweeping of Unwanted Fluids*
- *Enhanced Displacement of Pipeline Products*
- *Removal of Stuck Pigs with Minimal Risk*
- *Reliable Analytical Confirmation of Cleanliness*
- *More Effective Application of Inhibitor and Biocides*
- *Reduced Product Contamination*

Uniquely engineered to the specific needs and desired results of your particular pipeline project, BJ Gel Pig^{SM} Services are designed to provide the most cost-effective results for the most difficult tasks

Pipeline gels have been successfully used in virtually all types of new and existing pipelines.

Contact the pipeline cleaning, drying, testing and commissioning specialists at BJ Process and Pipeline Services today for more information.

The World's Leading and Most Resourceful Process and Pipeline Service Company

Europe, Africa and Middle East:
44-1224-401401

North and South America:
713-224-1105

Asia and Australia:
65-545-8798

BJ Process and Pipeline Services

Worldwide Service, Whenever You Need It

A fresh gel sample is taken during injection of a gel train.

Samples at the front of the gel train are heavily laden with debris.

Quantities of solids removed from the pig traps can be large in comparison to conventional pigging, but are only a fraction of the total debris removed suspended in the gel.

The gel is visibly cleaner towards the rear of the train.

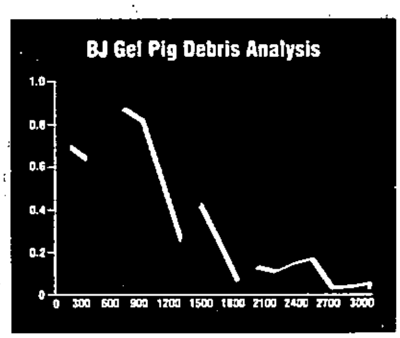
Verifiable results from a versatile system

mation regarding the composition and total amount of deposits removed. More importantly, the condition of the line after cleaning can be accurately determined during the evaluation. On-site testing and evaluation is available for immediate feedback concerning cleanliness and dryness of the line, providing a definitive method for determining the end point of the cleaning and drying process.

Case Study

An operational natural gas pipeline was experiencing excessive amounts of iron oxides and moisture after the recent conversion of the pipeline from crude oil to natural gas service. Crews were changing filters on a daily basis, extra filtration units were being deployed, instruments and equipment were rapidly being eroded. All of this created operational, product quality and safety problems.

BJ Process and Pipeline Services was able to quickly and efficiently clean and dry the entire 789 miles of 20-, 22-, and 24-inch lines, utilizing non-aqueous BJ Gel Pig cleaning trains. Approximately 1 million pounds of debris were removed! The moisture content of the gas dropped to 2-3 lb/MMscf. The line is now safely operating without any problems due to excessive debris or moisture.



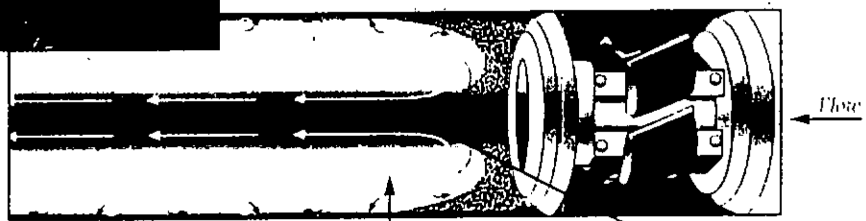
BJ Gel Pig™ debris analysis gives reliable data as to the final results and condition of the line.

Key Advantages and Benefits

- Removes excessive debris
- Cleans and dries long lines in a single pass
- Water gels are biodegradable and environmentally friendly
- Combines chemical solubility with mechanical suspension
- Non-aqueous gels suited for water-sensitive systems
- Hydrocarbon gels combine with crude oil or are recycled for disposal
- Reduces product interfaces
- Reduces product contamination
- Reduces or eliminates stuck pigs
- Enhances mechanical pig performance and reduces pig wear
- Incorporates chemical options
- Improves pipeline efficiency
- Improves inhibitor applications
- Sweeps unwanted fluids
- Analysis provides information to quantify and determine cleanliness of the line

Cost-effective pipeline cleaning in a single pass

Due to their unique flow regime, BJ Gel Pig cleaning fluids are capable of suspending and removing large amounts of debris without sticking mechanical pigs.



BJ Gel Pig™ fluids are highly viscous gelled fluids which can be used to achieve superior results for most pigging operations – cleaning, drying, batching, inhibitor treatments and more. BJ's Gel Pig technology is specifically designed and engineered to suit specific pipeline conditions. Our expertise in pipeline and pumping services, supported by our research and development center in Tomball, Texas, allows us to custom design the most appropriate fluids for the job. BJ's gel technology is a trade secret that relies on chemistry, which has been extensively field-tested, and in some cases patented, in the United States and elsewhere. A typical BJ Gel Pig™ cleaning train may contain hundreds, or thousands of feet of gel, and is used in conjunction with many types of mechanical pigs. Some applications, such as separation of liquids or isolation techniques, can possibly use gel alone, but should incorporate mechanical pigs, whenever possible.

Applications

- Pipeline conversions
- Operational cleaning and drying
- Cleaning prior to smart pigging for reliable first-run data
- Pre-commissioning and commissioning
- Product separation
- Removal of condensate and water
- Stuck mechanical pig removal
- Corrosion inhibitor and biocide treatments
- Isolation techniques
- Hydrotesting
- Pipeline displacements
- Purging

Engineered Service

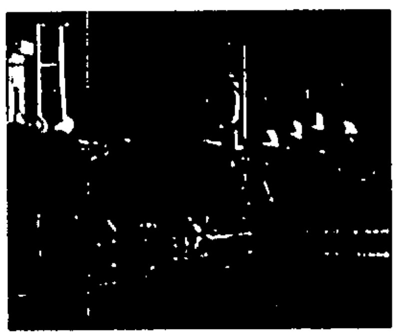
Each BJ Gel Pig service is engineered, based on key parameters and desired objectives, to achieve the most cost-effective results for a particular project.

BJ Gel Pig fluids are sold as a service – not as stand-alone products – engineered and supplied by BJ Process and Pipeline Services. All gels are mixed on site and injected into the pipeline using specialized BJ equipment and personnel.

Enormous quantities of deposits and debris can be suspended and efficiently removed from very long pipelines, with just a single pass of a BJ Gel Pig cleaning train. Mechanical pigs alone could never accomplish this task, even with hundreds of runs.

This BJ cleaning method is particularly effective and economical for long pipelines, producing a cleaner line, in much less time, and with significant cost savings.

Pipeline gels have been successfully used in virtually all types of pipelines – natural gas, crude oil, finished products, water lines,



Specialized crews, equipment and chemistry are required to perform BJ Gel Pig services.

on-shore and offshore. BJ Gel Pig fluids can be made from a variety of base fluids (non-aqueous and aqueous-based) to suit the specific needs of each application.

BJ Gel Pig Services Evaluation

BJ Gel Pig services can verify results with information unmatched by any conventional means of cleaning. A detailed analysis of the cleaning train provides reliable qualitative and quantitative infor-

Analysis of Deepwater Debris Flow, Mud Flows and Turbidity Currents for Speeds and Recurrence Rates

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Clarion Technical Conferences
and
Pipes & Pipelines International

Analysis of Deepwater Debris Flow, Mud Flows and Turbidity Currents for Speeds and Recurrence Rates

Abstract

New developments in pipe lay technology and the increased development of deep water hydrocarbon reservoirs has made the offshore industry face challenges of understanding and designing for phenomena which have not previously been of interest. High speed turbidity currents, debris flows and mud flows are a class of fast near-bottom mass gravity flows. Although the activity of mass gravity flows in shelf and abyssal depths has been known for nearly half a century they are not well understood and reliable measurements are rare.

We have developed a system for establishing engineering design criteria for mass gravity flows that includes methods for acquiring appropriate field data, the application of nuclear age dating and numerical modeling to produce relationships between the magnitude and reoccurrence intervals of these episodic events. The methods are derived from the concept that, although it is impractical to solve this problem with direct measurements of mass gravity flow events, it is possible to collect sufficient data from seafloor features and sediments to adequately constrain numerical models of the flows. To demonstrate the approach and methods, examples for the deep water Malampaya and Blue Stream Pipelines mass gravity flow studies are used.

Introduction

The Shell Malampaya Pipeline in the Philippines (Schneider and Groenveld, 1998), the Gazprom Blue Stream Pipeline across the Black Sea, and the Oman to India Pipeline (Mullee, 1995) are three recent examples of ultradeep water projects that have encountered mass gravity flows as significant geohazards. These and other deepwater projects have promoted the need for methods to quantitatively assess these risks in a wide variety of different types of deep sea floor terrain.

The principal difficulty in quantifying these risks is that mass gravity flows are rare and generally unpredictable events making direct measurements impractical. Normally, however, we do have bathymetric, morphological and sedimentary features that show the previous existence of turbidity currents, debris flows or mud flows and are faced with the need to predict the hazard that future events will pose to a pipeline. This contrasts with more classical oceanographic design criteria studies, where it is possible to quantify the future risk by analyzing a large number of previous realizations of the phenomena. For example, either direct analysis of long records of wave characteristics or similar long records computed from wind data can be used to establish the design wave heights and periods. Both the likelihood and the magnitude of the hazard are well documented.

Also, although mass gravity flows are by far the fastest bottom flows, they occur in a very large range of sea floor settings so that extrapolation from the few available places where there are even approximate measurements is poorly founded. These flows are large-scale phenomena that can be hundreds of meters high and wide and ten to hundreds of kilometers long. This makes

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extrapolation of data acquired in scale laboratory experiments difficult and uncertain. However, there is a wealth of information left in the geological record about their deposits. We attempt to exploit this information by combing the data with processed-based models of the mass gravity flow events. These models represent the balances between entrained mass of sediment, friction and gravitational acceleration and have been developed to reproduce the entire flow episode, from initiating conditions through an unsteady flow down the slope and ultimately the development of the final deposits. When the models have been implemented to reproduce the final deposits, the predicted velocities and densities of the flow can be used in subsequent pipeline force calculations. The combination of detailed field measurements with rigorous numerical modeling yields both credible results and a measure of the confidence with which the results are applied.

In most study areas the sea floor deposits have formed from the action of a large number of individual events whose properties can be sampled and dated. The development of reoccurrence rates from the dating analysis combined with the results of the model simulations provides the information necessary to develop design criteria. In this paper we explain the complete method of analysis that capitalizes on these properties to evaluate the risks of mass gravity flows. Examples are provided from two projects to illustrate the procedures and forms of the results.

Background

The terminology for mass gravity flows in the scientific literature is not standardized, and different names have been given to the same phenomena by different authors. Types of mass gravity flows can be categorized by their conditions of initiation, the details of the fluid behavior during their travel, the means by which they dissipate energy, or their sediment characteristics. For the purpose of quantitative analysis, we can divide the flows into two general categories: a) fluid-soil flows where an entire soil mass undergoes visco-plastic deformation and b) relatively low-density flows (turbidity currents) in which fluid turbulent processes are responsible for maintaining the sediment grains in suspension. We recognize that an even more varied set of phenomena can be classed within the term mass gravity flows (Middleton and Hampton, 1973) but for practical purposes most events of concern can be regarded as one of our two basic classes. We use the term debris flows for visco-plastic flows, including mud flows, and turbidity currents for the relatively low-density sediment suspensions that depend on flow turbulence to persist.

Mud flows and debris flows are mass movements in which the source sediment travels downslope, coming to rest after the initially stored potential energy is dissipated by friction. During the flows, the source sediment is remolded and reconstituted, the degree to which determines the rheological properties and flow type. The water content is sufficient so that the soil mass travels as a fluid, with distinct stress-strain rate characteristics.

Turbidity currents represent a significantly different form of mass gravity flow. Suspended sediment provides the density contrast with the ambient water in these turbulent currents and give rise to the gravitational energy that drives the flows. These flows erode on the steep upper slopes and form deposits further downslope. The density of a turbidity current is on the order of 2 to 4 % greater than that of the surrounding ambient water. These flows could travel as fast as 22 m/s (Heezen and Ewing, 1952) but more recent measurements indicate speeds ranging between 10 m/s to a fraction of 1 m/s (Dengler et al 1984, Hay, 1987).

Models

The mass gravity flow models are a key part of the analysis. A brief description of the turbidity current and debris/mud flow model are given below including a discussion of the required model parameters. The turbidity current model is a width-averaged two-dimensional model representing, the vertical and longitudinal (downslope) coordinates. It consists of three major components; hydrodynamics, sediment transport, and bed evolution. The hydrodynamics component of the model is based on a numerical solution to the Reynolds-averaged Navier-Stokes equations (i.e., momentum including pressure effects). A turbulence closure scheme (Mellor and Yamada, 1982) is used to represent the effects of turbulence. The sediment transport component consists of two parts, a bedload transport algorithm and a numerical solution to the 2-dimensional scalar transport equation to represent suspended sediment transport. The hydrodynamic and sediment transport components are coupled through the turbulence scheme. The scheme calculates the effects of the vertical density field determined from the sediment transport solution on the vertical mixing profile which is present in both the hydrodynamic and sediment transport equations. The last component of the model is the bed composition-tracking algorithm. This algorithm keeps track of the erosion and deposition at the bed surface and adjusts the bed sediment distribution to conserve mass. A more complete discussion is available in Reed et al (2000).

The turbidity current model has been executed for a typical flow scenario to demonstrate its operation. The sediment classes used ranged from clay to gravel. The coarse material travels primarily as bedload. Steady source conditions were applied with Uo = 1.0 m/s, Ho = 10 m, and Co = 0.02 (combined for all grain sizes). The initial bed composition along the profile was set as 100% clay, except at the source area, where the distribution was 30% clay, 30% sand, and 40% gravel. The bottom roughness was 0.01 cm. The model simulation was extended until both steady flow conditions and a fairly steady deposit composition were obtained (approximately 15 hours duration). The results of the model simulation are shown in Figures 1 through 5.

Figure 1 shows typical suspended sediment concentration contours for the computed turbidity current at one specific instance during the simulation. The higher concentrations are near the bed. The concentration is reduced in the upper portions of the current due to sediment settling and mixing with ambient fluid. Figure 2 shows typical vertical profiles for velocity, concentration, stress and turbulent kinetic energy. The high-speed region of the turbidity current is quite evident in the profile. Above the high-speed region, the speed decreases and eventually decreases to the ambient flow speed (i.e., zero). The concentration profile reveals the upward mixing of sediments from the high concentration region near the bed. The stress profile shows the highest stress occurring at the bed, and a decreasing stress upward characteristic of gravity-driven flows. The turbulent kinetic energy (TKE) is highest above the peak velocity, with a local minimum near the height of the peak velocity. This local minimum is due to the low production of TKE in the low shear region (note that the stress is also zero in this region).

Figure 3 shows the canyon profile used in simulation. The longitudinal profile (along the canyon) of the maximum speed is shown in Figure 4. The maximum speed is the highest speed in the vertical profile at each location. The current is seen to accelerate down the steepest part of the profile, and then gradually decrease as the slope becomes more gradual. Figure 5 shows the sediment deposit created by the turbidity current. The clay material content of the sediment deposit in this portion of the canyon is minimal, since its settling velocity is so low. In real flows, these fine sediments may drift with ambient currents after the turbidity current has ceased, and run-out over a large area of the abyssal plain. The fine sand is transported far downstream and much more mobile than the gravel class, which travels only as bedload. The longitudinal grain size class distribution in the deposit reflects the different mobility of the grain sizes.

The debris flow model BING was developed at University of Minnesota by Gary Parker and is based on the model of Jiang & LeBlond (1993) which uses a Bingham rheology (yield strength and viscosity). The model is time dependent and simulates the deformation of an initial block of sediment as it flows down slope and eventually comes to rest, providing predictions of flow speed, flow thickness and run-out distance. The model is based on numerical solutions to differential equations for the conservation of mass and the conservation of momentum. Two layers, an upper plug layer and lower shear layer represent the sediment mass. The plug layer is characterized by a thickness and by a single uniform velocity. This layer represents the portion of the debris flow mass in which the yield strength has not been exceeded, and thus it travels as a coherent undeformed mass. A shear layer characterized by a thickness and a vertical velocity profile underlies the plug layer. This layer represents the portion of the debris flow where the sediment yield strength has been exceeded. The five parameters requiring specification are the water density □w, sediment density □s, the slope S (x), and sediment yield strength □y and sediment viscosity □m. Once the model initial conditions (initial failure geometry) are specified the model implementation proceeds with the numerical solution to the three governing equations. The numerical solution estimates the speed and geometry of the debris flow, starting with the initial conditions and following it downslope until it eventually comes to rest. Output includes time-dependent information on the height, length and speed as a function of time and position down the slope. A detailed explanation of the model is given in Inram et al. (in press).

The debris flow model has been executed for a typical flow scenario to demonstrate its operation. The initial failure block is represented as a parabolic mound on the sea-floor. As shown in Figure 6 the initial block deforms into a debris flow and travels downslope. A few snapshots of the debris flow are given in Figure 6 showing its position relative to the initial failure block and its deformed shape. Eventually the debris flow comes to rest. Figure 7 shows the velocity at the head of the debris flow as the debris flow traveled downslope. The speeds are predicted to be in excess of 20 m/s.

Approach

The approach for developing design criteria for mass gravity flows is divided into five steps. The first step involves collection, review and analysis of field data. The collection and analysis of data provides insight into the controlling processes, and the likelihood of various event triggering mechanisms and provides the basis for developing event scenarios for use with the models. In addition, the data are used to constrain the models and, after specific specialized laboratory analysis of field samples, also provide ranges (i.e. upper and lower bounds) of values for model parameters.

Next a diagnostic modeling is conducted, which consists of implementing the models for the event scenarios developed in the data analysis. Generally, the initial conditions and parameters are varied in a sequence of simulations until the measured deposit characteristics are reproduced. This process is essentially a model calibration and is completed for a number of events that have been identified from the field measurements and data review. Once the diagnostic modeling is completed, flow speeds, densities and heights and their variation along the flow path are predicted for each of the events considered.

The third step in the approach is age dating of the mass gravity flow events and is necessary to develop reoccurrence rates. Field samples associated with the deposits (i.e. within, above or below) are dated to determine the age of each event. Ideally, the range of events for which measurements were obtained represent a range of event magnitudes. The re-occurrence interval for events of different magnitudes can then be determined. Selecting the number and location of the cores is one of the most important steps in planning the overall survey because they must be located where the chances of encountering a stacked sequence of mass gravity flow event beds is good. The thicknesses of these beds vary greatly so that the type of coring equipment must also match the expected conditions of sediment types and bed thicknesses. Core sites selected for age dating purposes are most often located on the periphery of the depositional zones because the event beds tend to be thinner and because there is a better chance that pelagic sediment that was deposited during the time intervals between events has been maintained.

The fourth step in the approach, prognostic modeling, is only necessary if the result of the diagnostic modeling and age dating do not span the range of return intervals necessary to develop the design criteria. For instance, if the oldest event measured is on the order of 1000 years and the design required consideration of a 10,000 year event, additional analysis is required. In this case, the magnitude of the 10,000 year event would be extrapolated from the age dating analysis. The conditions associated with that event are then simulated using the mass gravity flow models to determine the flow speed, density and height profiles.

The final step in the approach consists of summarizing the age dating results and modeling data. This usually consists of a curve plotting a flow parameter (i.e. speed) against the return period for the associated event. Such curves then can be used in a risk analysis for the pipeline design.

An example of the approach is given for three different sites, one for each type of mass gravity flow, turbidity currents, debris flows and mud flows. The first site consists of the Malampaya pipeline route off the east coast of Mindoro Island. The second area consists of the Blue Stream pipeline route from the shoreline in southern Russia near the town of Djuba to the bottom of the Black Sea. The third study area comes from the slope and abyssal plain environments of the southern portion of the Blue Stream pipeline route of the coast of Turkey.

Turbidity Current Analysis (Malampaya)

A geophysical and geotechnical survey was conducted along the Malampaya pipeline route off the east coast of Mindoro Island. The survey to support a mass gravity flow hazard evaluation requires both high resolution geophysical data and specific targeted samples of the sediments. The equipment needed is similar to that required for other aspects of a deep water route survey in rough sea floor terrain. Survey operations for the Malampaya pipeline project consisted of swath bathymetry, sidescan sonar, sub-bottom profiling, and high-resolution digital seismic. Geotechnical evaluation consisted of vibrocoring, box coring, piston coring, hydraulic coring, hydrostatic coring, cone-penetrometer tests, and a ROV for video observations of the seafloor (Schneider and Groenveld, 1998). Additional characterization consisted of seismic velocity whole-core logging, detailed grain size analysis and age dating samples. The erosion characteristics of a number of samples were determined in special laboratory flumes.

A system of submarine canyons was discovered along the pipeline. Because the pipeline route paralleled the coast it crossed a number of individual canyons. One of the larger submarine canyon system is located off the mouth of the Bongabong River. This provides a good example of the analyses of a submarine canyon system formed through the successive action of turbidity currents.

Figure 8 shows an oblique view of the canyon system constructed from the digital bathymetry. The top of the submarine canyon is at the mouth of the river and this view begins a little under 2 km offshore. The system continues down to a depth of 600 m and overall this system is 22 km long. The upper portion of the canyon system has deeply incised and steep-walled valleys that join and extend down to 350 m. We have designated this portion of the system the 'chutes' because they are clearly erosional and have only small deposits of coarse sand, gravel and cobbles at their bottoms.

Beyond the depth of 350 m the sea floor is made up of a system of shifting channels and coarse sediment resembling terrestrial systems of coalesced alluvial fans. These features extend to a depth of 450 m where the channel system becomes more simple and better organized into a individual channel with subsea levee banks to either side. The channel bottom continues to have coarse sand and gravel sediments but the maximum size of the gravel decreases until it no longer occurs near a depth of 500 m. A little further offshore at a depth of 550 m the channel and levees flatten out to a relatively smooth run-out zone.

A profile along the longitudinal axis of the main canyon and channel is given on Figure 9. This figure contains annotations showing the extent of various maximum grain sizes. These data represent a composite of data from several individual events so that the maximum extent should be considered as an envelop of the furthest downslope the turbidity currents exert enough bottom stress to entrain grains of these sizes. In addition to the grain size information the thicknesses of each bed were measured. Beds as thick as 0.5 m were found in cores taken at the 585 m water depth. We do not present detailed data concerning the bed thicknesses in this example because, as discussed in a later section of this paper, it was discovered that bed thickness was not a good parameter to relate the relative intensity of the flows. In other cases, where there is evidence that all flows are of similar short durations because they are triggered by gravitational or earthquake-induced slope failures near the shelf break, the relative bed thicknesses have been used as measures of relative current event intensities.

Prior to obtaining diagnostic modeling results that conform to the grain size data in the measured event beds, a number of sensitivity analyses were. The relevant conclusions form these analyses are listed below:

- The turbidity current speeds could not be maintained down the entire channel system unless a significant portion of very fine material (< 0.032 mm) was present in the source material. Larger grain sizes settled out too rapidly, causing the current to lose its density difference relative to the ambient water. The larger grain sizes, therefore, could be considered "passengers" in the current, that were moved by the hydrodynamic forces, but are not significant in providing the density contrast.

- For a reasonable range of conditions, the current speeds were not sensitive to variations in Ho, Co or Uo when the total mass load Ho*Co*Uo was held constant, but was sensitive to the total load. This simplified the analysis, since changes in only one parameter (we used Co) was necessary to obtain the desired results.

- The bed thicknesses found in the field data were only obtainable through long duration simulations consistent with the view that hyperpycnal flows were the likely source of turbidity currents in the area.

- The predicted model speeds were not highly sensitive to the bottom roughness parameter. The bottom roughness parameter does influence the bottom stress and when increased could produce more drag and also increase the erosion of sediments. The lack of sensitivity is due, in part, to the fact that most of the flow drag is due to the entrainment of ambient fluid. Also, any increase in the sediment loads due to higher erosion rates of the sands are not significant, since they are essentially "passengers" in the flow.

The diagnostic modeling is based on replicating the bed stresses for D90 values corresponding to measured grain sizes in an event bed in a core taken along the channels. This method focuses on the event beds in a single core, and when combined with age dating, can provide reoccurrence intervals for events of different intensities (i.e., speeds). A core with a sufficient number of event beds was selected for analysis. The selection was limited to those cores that have had age dating analysis conducted, so that the model results can be related to reoccurrence intervals. The bed characteristics for a typical core are shown in Table 1 The bed thickness was not found to be useful in this application, because it is associated with duration and not necessarily the intensity. Each event bed has a D90 value that characterizes the larger grain sizes in the bed. Since most of the material at the D90 level is considered to travel as bed load, the critical hydrodynamic stress required to mobilize those grain sizes must have just been met by the flow. Higher stresses than those associated with D90 can be discounted, since the next larger class would have to be present. The method of Wiberg and Smith (1987) was used to determine critical stress for D90 and includes the effect of mixtures of sand and gravel on the mobility of individual grain sizes.

To obtain turbidity currents that matched the characteristic bed stresses, the model was implemented for a range of source conditions, such that the predicted bed stress levels at the location corresponding to the core locations would span the range of critical stresses associated with the range of D90 values in the event beds. The predicted speeds at the pipeline crossing (60 cm above the bed) were also obtained for each simulation. A return interval analysis was conducted on the age dates for the event beds which provided a return interval for each value of D90. It was found that the range of return intervals determined from age dating of the event beds was sufficient to develop the design criteria and therefore additional modeling of (prognostic modeling) of conditions leading to larger or smaller values of D90 were not necessary. Thus speeds predicted from the diagnostic model simulations corresponding to each D90 were used with the return intervals to provide a curve of turbidity current speeds versus return interval. This curve could then be used to develop design criteria for the pipeline.

Example of Debris Flow Analysis (Bluestream – Russian Slope)

The routing of the Blue Stream pipeline from the bottom of the Black Sea to the shoreline in southern Russia near the town of Djubga necessitated mapping an area extending 20 km by 35 km parallel and perpendicular to the shore respectively. In the first phase of the Blue Stream geophysical survey a combined MAK-1M side scan sonar and sub-bottom profiler data were collected. Swath bathymetry was obtained using a SeaBat multi-beam echo sounder. The second phase of the geophysical survey consisted of using a ROV with the following platforms: a SeaBat 8101 multi-beam system, Geoacoustics "Chirp" 3.5-11 kHz sub-bottom profiler and side scan sonar, and a video system for seafloor inspection (Bucklew, 1999). The geotechnical survey consisted of vibra-coring, box coring, piston coring, and cone-penetrometer tests. Additional characterization consisted of detailed grain size analysis, age dating samples and hydrometer tests.

Figure 10 shows a map view of the Russian slope study area. A dendritic complex of submarine canyons was found over this is area extending from the shelf edge at about the 80 m water depth to the beginning of the abyssal plain near a depth of 2000 m. Although many of the canyons begin at the shelf break there are also many that do not. A variety of evidence indicates that these canyons have grown upwards by sequential failures of their head walls, probably triggered by earthquakes. The failed mass of submarine soil is often associated with a tough-like debris flow which extends hundreds to more than a thousand meters further down the canyon. In some cases the survey data was sufficiently well located and detailed to permit distinguishing the scar of the mass soil failure that became the debris flow. This allowed estimates of the height and volume of the initial disturbance which are two parameters needed as input to the modeling.

Figures 11 and 12 shows a map and section view of a debris flow that was mapped in one of the tributary canyons that did not head at the shelf break. This debris flow stopped flowing well before the planned pipeline route. It was modeled because the results provided insight into the conditions and kinematics of debris flows of this scale in the project area. This, in turn can be used to assess the hazard in other areas closer to the planned route that are yet to fail in an earthquake.

The modeling scenario for this feature was taken directly from the information shown on Figure 12. However, the headwall representation changed from the true geometry to that of a mound of sediment 6 m high and 250 m long resting on the general profile of the lower surface of the flow. This is necessitated by the fact that the model assumes that the viscosity of the deforming soil does not change when, in fact, the internal shearing during the initial soil mass failure actually produces the remolded internal viscosity of the deforming mass. Rheological tests were conducted on debris flow deposit samples to provide a relationship between the water content and the three parameters, sediment bulk density, yield strength and viscosity. Although the precise values that occur during actual flows are not known, the test results provide a range of conditions that can be used to constrain values that are used in the diagnostic modeling.

The diagnostic modeling was conducted by implementing the model for a variety of parameter values (bulk density, viscosity and yield strength) until the predicted final deposit was in good agreement with the measured deposit. Results for the diagnostic modeling for this particular feature are shown in Figure 13. The initial failure block was estimated from the filed data and the volume of the measured deposit. The diagnostic modeling was conducted for each of the features for which sufficient field data was available to constrain the model. One of the most notable results of the analysis was the need to use a much larger viscosity than the values obtain in the laboratory tests to simulate the measured deposits. When the laboratory values were used, the model grossly over predicted the downslope extent of the debris flow deposit. This is likely due to differences in the sediment composition assumed in the laboratory rheology test and that which occurred in the field. The laboratory tests assumed a homogeneous liquefaction whereas in the field, large undeformed clasts existed within a nonhomogenious liquefied matrix. This composition probably increased the effective viscosity of the debris flow material.

The age dating of debris flow deposits did not provide sufficient analysis of return intervals and an alternate approach was adopted. The analysis focused on developing debris flow speeds and ranges for events with return intervals occurring between the 500 and 10000 yr. events. In order to implement the model for these conditions both the associated source conditions (failure block height and length) for each event and the model parameters were required. The failure block parameters were adopted from a parallel study of earthquake induced failures. This study provided failure block characteristics and associated return intervals for failures in selected canyons on the Russian slope.

The model parameters required for analysis are the yield strength, the viscosity and the bulk density. A range of values representing conditions on the Russian slope were determined from diagnostic modeling of the documented debris flow deposits. In the prognostic modeling we have taken the average of these properties to represent model debris flows for the various return intervals. When the modeling analysis was completed, the debris flow parameters (speed and runout distance) were tabulated along with the associated return interval. The primary focus of this analysis was on the runout distance of the debris flow. The downslope extent of debris flows on this slope were relatively short (1 or 2 kilometers) when compared to turbidity currents and the analysis was focused on determining which events would trigger a debris flow that would cross proposed the pipeline route.

Example of Mud Flow Deposit (Bluestream – Turkish Slope)

The final example comes from the slope and abyssal plain environments of the southern portion of the Blue Stream pipeline route. A typical depth profile for an area located off the planned pipeline route is given on Figure 14. The top of this profile is actually on the crest of the Archangelsky ridge which lies between the true slope and the deep floor of the Black Sea in this area. Between the depths of 1000 to 1750 m the bottom slopes steeply (~8 degrees). The bottom sediments consist of more than a meter of soft mud with a very high water content. The sidescan images occasionally showed blocks of slight more competent material several meters on a side that appear to be support in the softer sediment. Soft mud also occurs on the more gently sloping abyssal plain. The sediment cores from this part of the profile have layers that are on the order of tens of centimeters thick of soft structureless mud usually separated by zones of pelagic sediments. These appeared to have flowed onto the abyssal plain and then dewatered as they became buried by pelagic sediment. The slow ongoing deformation of the soft surface sediment on the Archangelsky portion of the profile probably serves to eliminate indications of the source of the mudflows deposits

The present condition of the mud layers is not taken to be representative of their condition while flowing because of dewatering and compaction. We have investigated the mud flows on the slope by using the debris flow model with very low yield strength and strain rate (1 Pa and 1 Ps respectively) and a density of 1300 kg/m3. The choice of the low strain rate is equivalent to a viscosity that is two orders of magnitude lower than those for debris flows, but still much higher than that of water. This approach essentially represents a mud flow as a thick laminar flow. Using this approach for the submarine canyon, the model simulated thin layers of sediment extending far out into the run out zone at the base of the submarine canyon consistent with the core data. However, the model predicted extremely high speeds, greater than 50 m/s. In some simulations, speeds on the order of 8 m/s persisted for 3 km into the run out zone. These speeds are not though to be possible given the high fluid content, relatively low viscosity and the onset of turbulence in the fluid layer at high Reynolds numbers. The effect of turbulence is to shed mud flow mass into the ambient water, reducing the mud layer height and restoring the flow to a laminar state.

Consequently, we have modified the debris flow model to account for the effects of turbulence generation. This has been done by monitoring the height of the simulated layer and continually maintaining the layer height such that a laminar flow, based on a critical Reynolds number is maintained. The critical Reynolds number, using the flow height, speed and viscosity is 4000. We have applied the modified approach to mud flows on the Turkish slope and found the predicted velocities in the vicinity of the proposed pipeline route are controlled by the local slope, mud density, and viscosity rather than the initial conditions. For a characteristic set of model parameters, it was found that the predicted speed was insensitive to initial conditions and consequently the initial magnitude of the flow. Thus a curve of mudflow speeds versus return interval could not be constructed, and rather a characteristic speed for mudflow in the vicinity of the pipeline route was computed.

Conclusions

Engineering design criteria can be estimated for a range of different types of mass gravity flows. Although the techniques to accomplish these results are still in a development stage the quantifications that have been demonstrated appear reasonable and realistic. The methods are strongly dependent on having a very good set of high quality survey data and sea floor sampling. Although the general approach for determine design criteria for mass gravity flows is the same, the detail combination of field data, age dating and modeling analysis can be quite different from site to site and depends not only on the type of mass gravity flow, but also on the site-specific characteristics.

Acknowledgments
The authors express their appreciation to the Shell Malampaya Project, as well as PeterGaz and Gazprom, for their support of this work. The work results from the contributions of a very large number of very dedicated engineers and scientists and only an arbitrary cut-off prevents us from adding them to the list of co-authors. However, these individuals and their contributions bear recognition. They include: from PeterGaz Yves Friedmann, Martijn Van Driel, Twan Kleeven, Simon Bonnell, Liu Ping, Richard Snepvangers, and Ruud Schrama, from Shell Cid Green, Gene Mullee, Ruth Rugby, and Bareold Hospers, from Intec Engineering, David McKeehan and Richard Gould, as well as John Lewis, James Nichols, Lloyd Stahl, James Hooper, Jean Audibert, Julie A. Tank, Jacques Locat, Gary Parker and Guy Gelfenbaum. We also thank Prof. Dick Seymour of TAMU for recognizing the potential of our earlier work.

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Table 1 Grain Size Data

Bed Number	D90 (mm)	Tc (Pa)
1	0.64	0.35
2	0.40	0.24
3	0.38	0.22
4	0.27	0.19
5	0.25	0.17
6	0.20	0.16
7	0.15	0.15
8	0.13	0.14

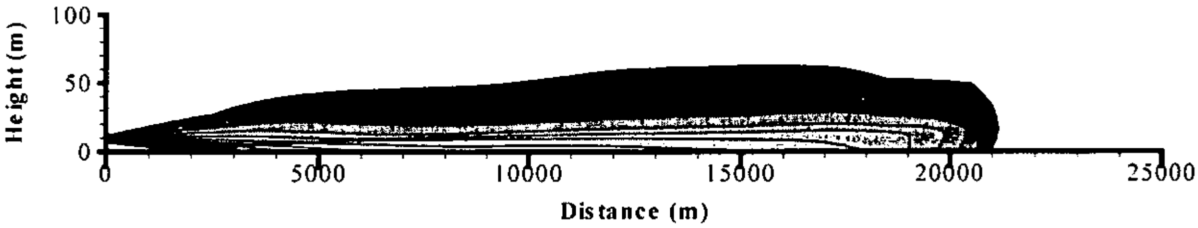

Figure 1 Contour Plot of Turbidity Current Suspended Sediment Distribution

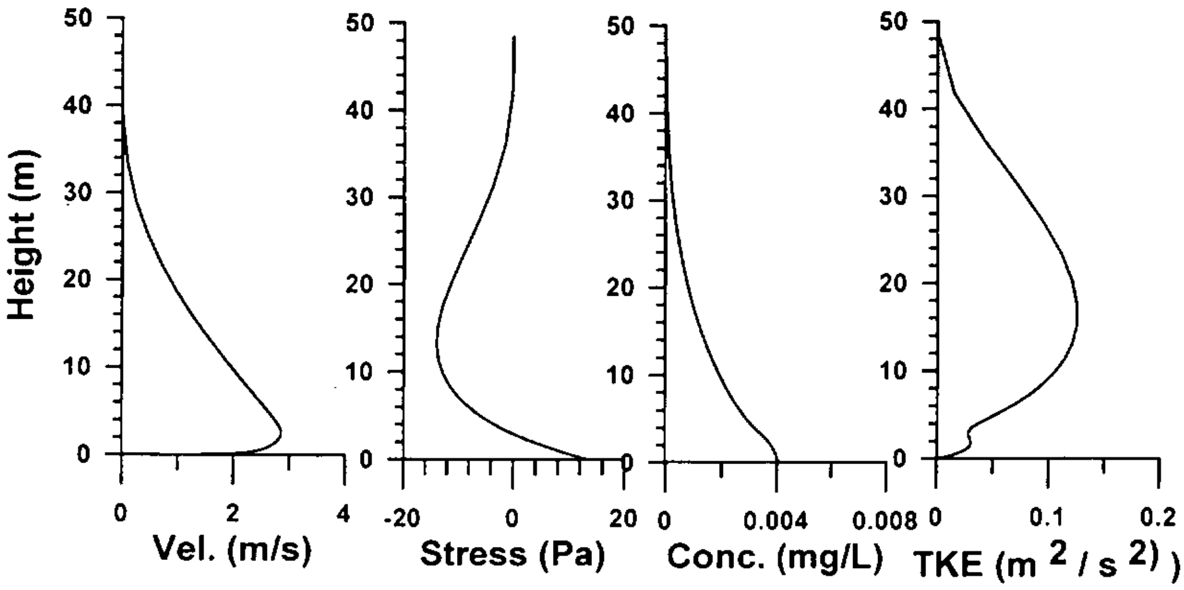

Figure 2 Typical Computed Vertical Profiles

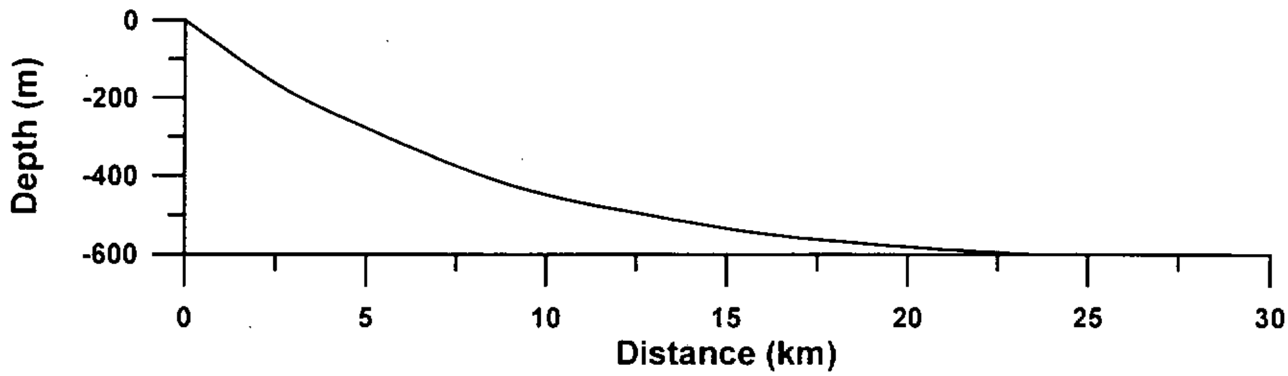

Figure3 Depth profile of canyon

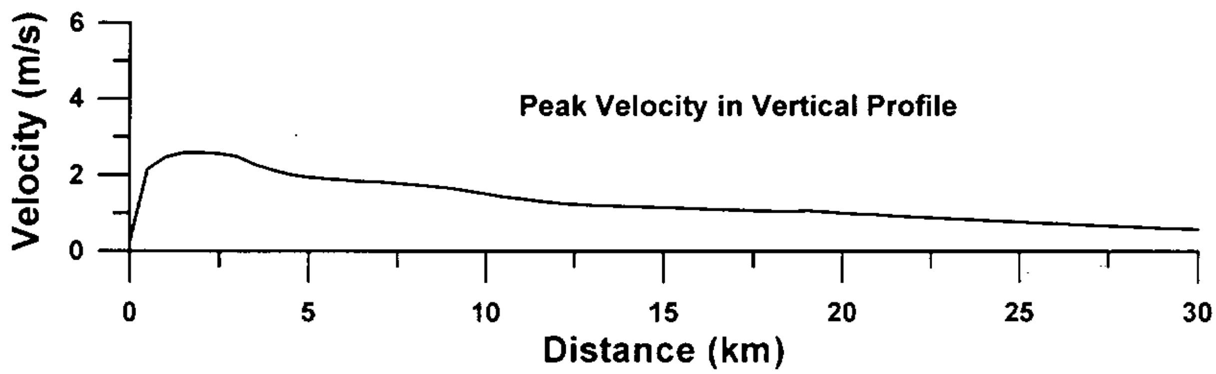

Figure 4 Along-Slope Distribution of the Peak Velocity in the Vertical Profile

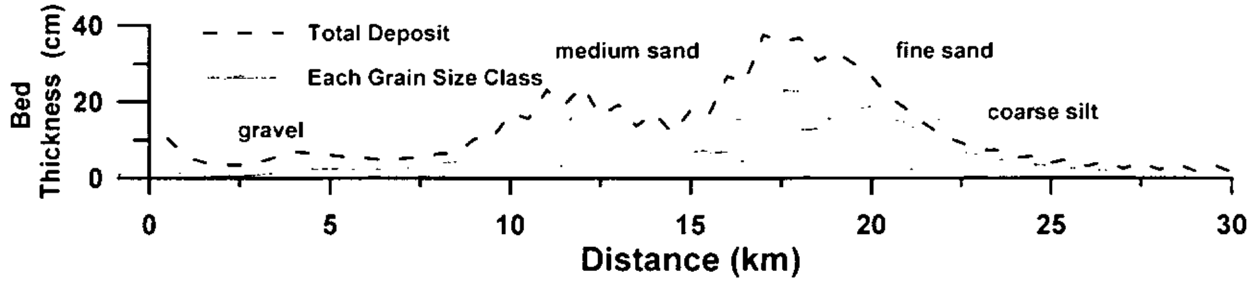

Figure 5 Typical Computed Turbidity Current Deposit Characteristics

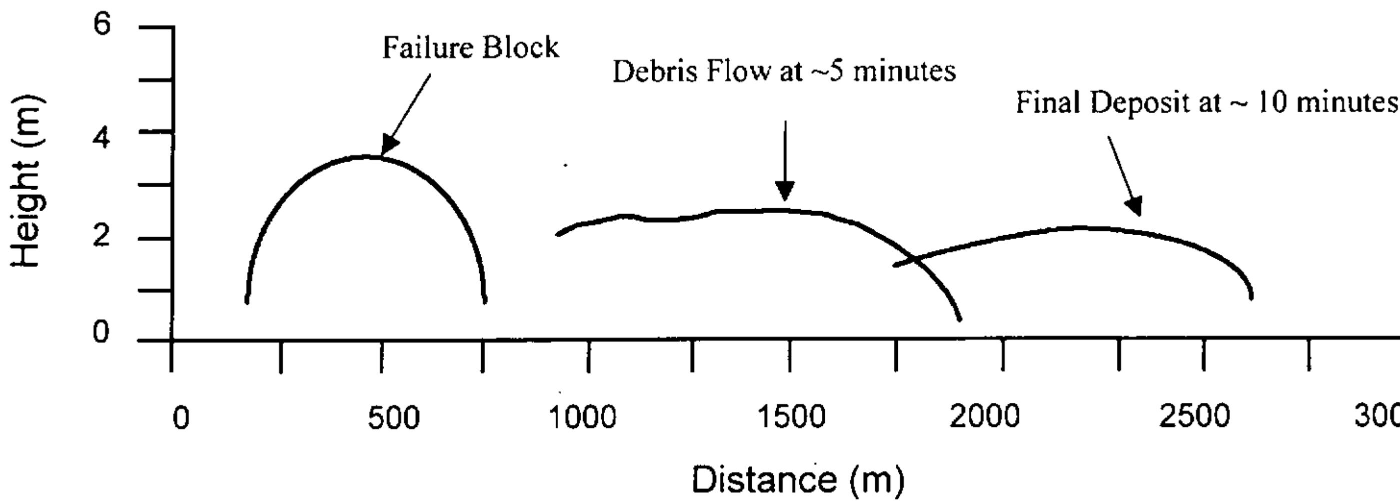

Figure 6. Simulated debris flow

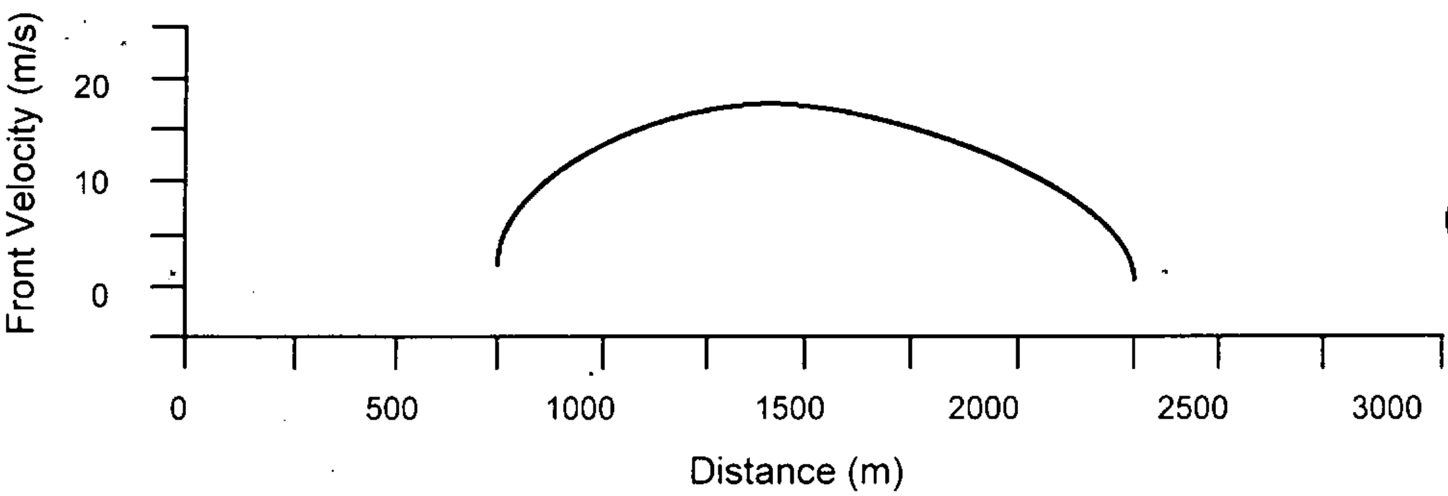

Figure 7. Velocity at debris flow head

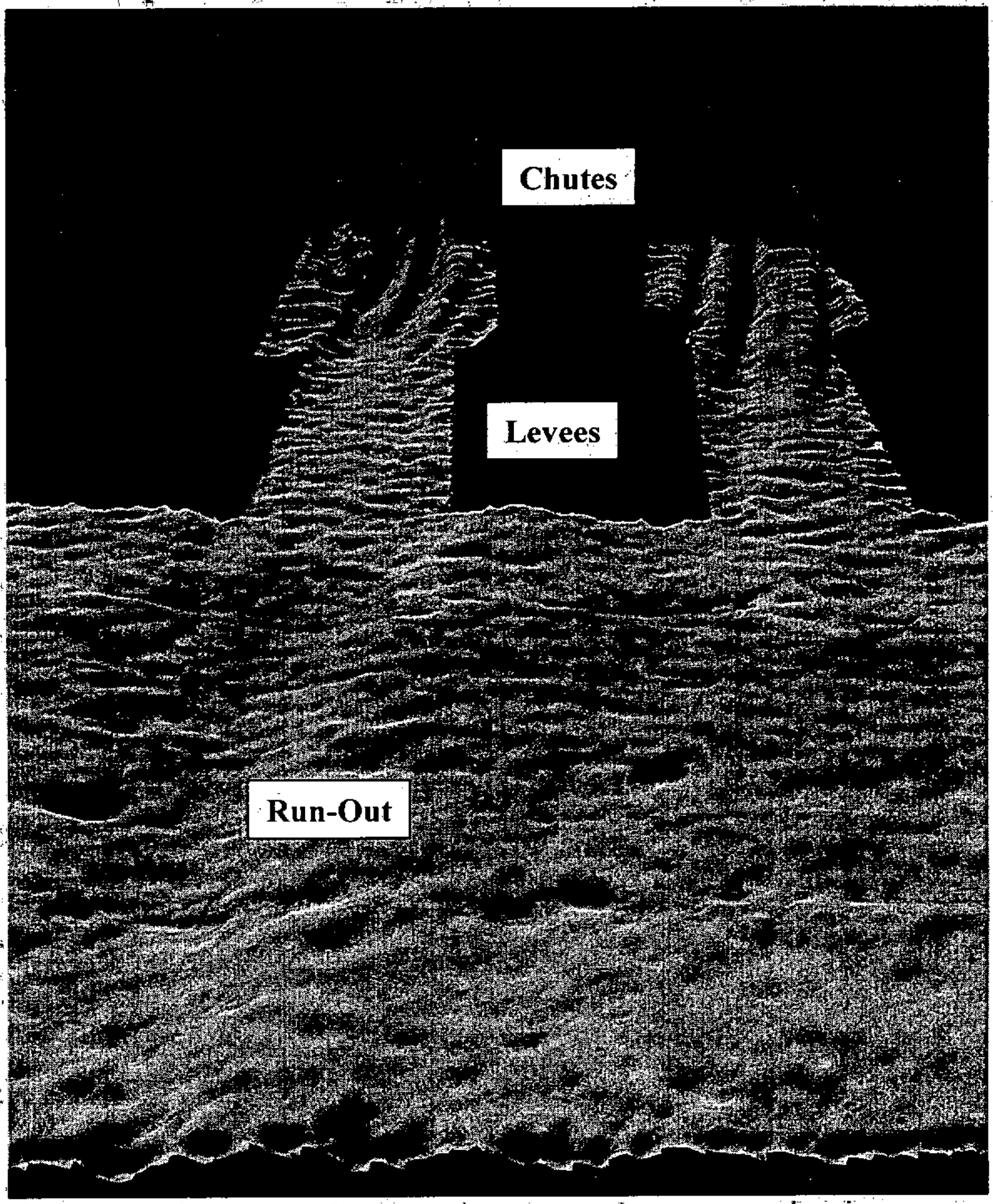

Figure 8 - Sea floor terrain of the Mindoro Island slope

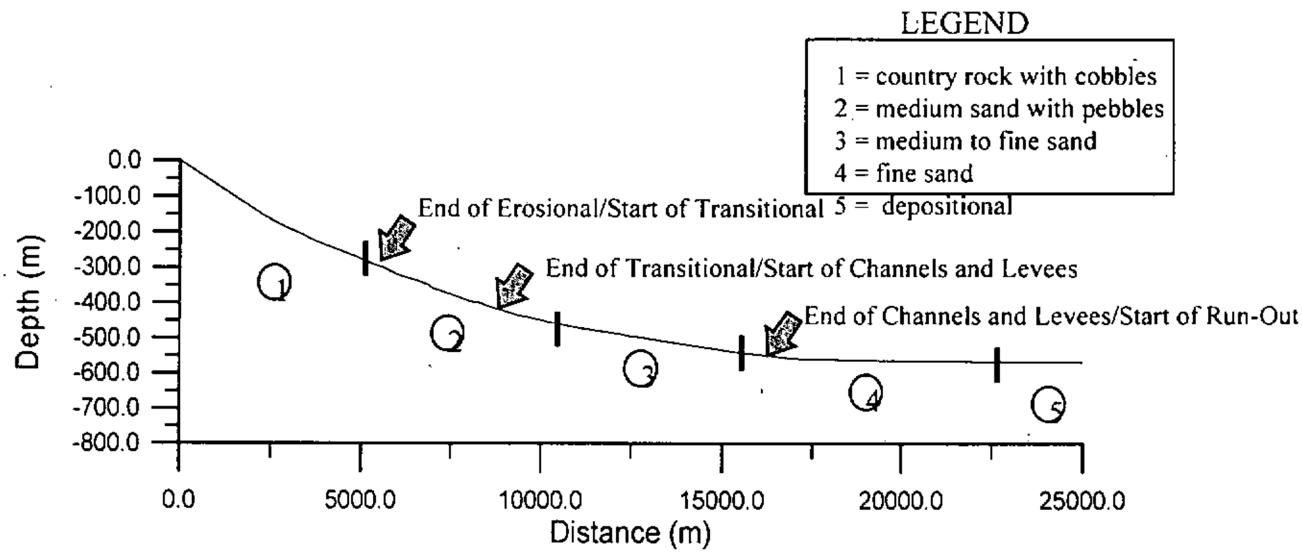

Figure 9. Slope profile of the main canyon and channel.

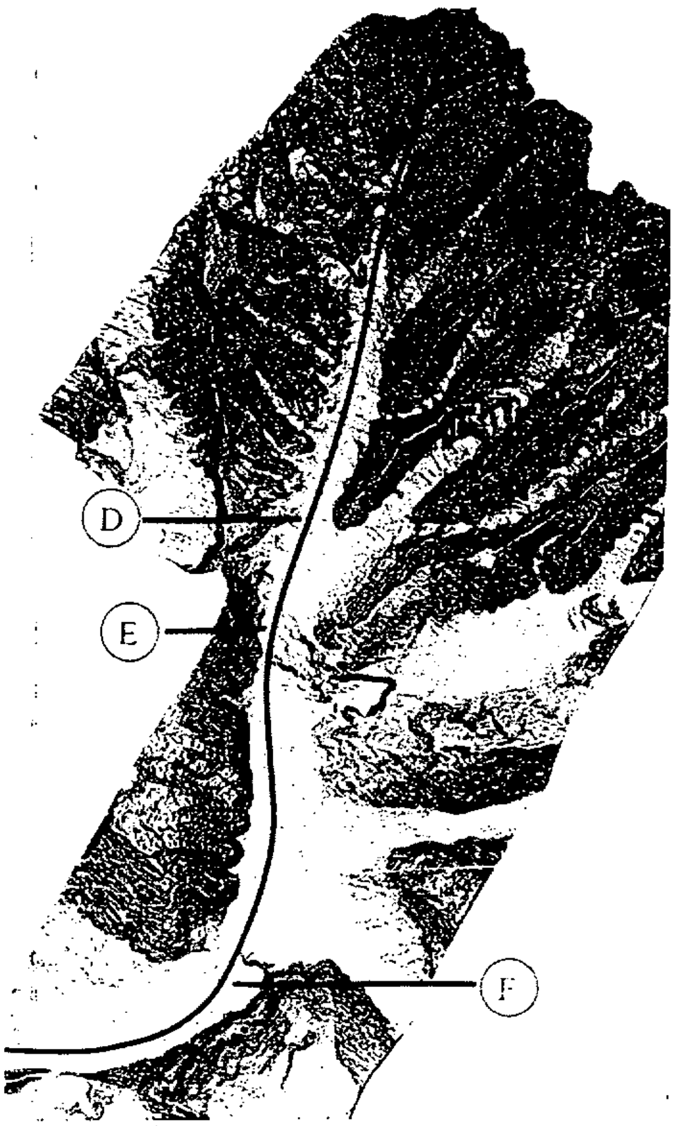

Figure 10. Sea floor terrain of the Russian Black Sea Slope

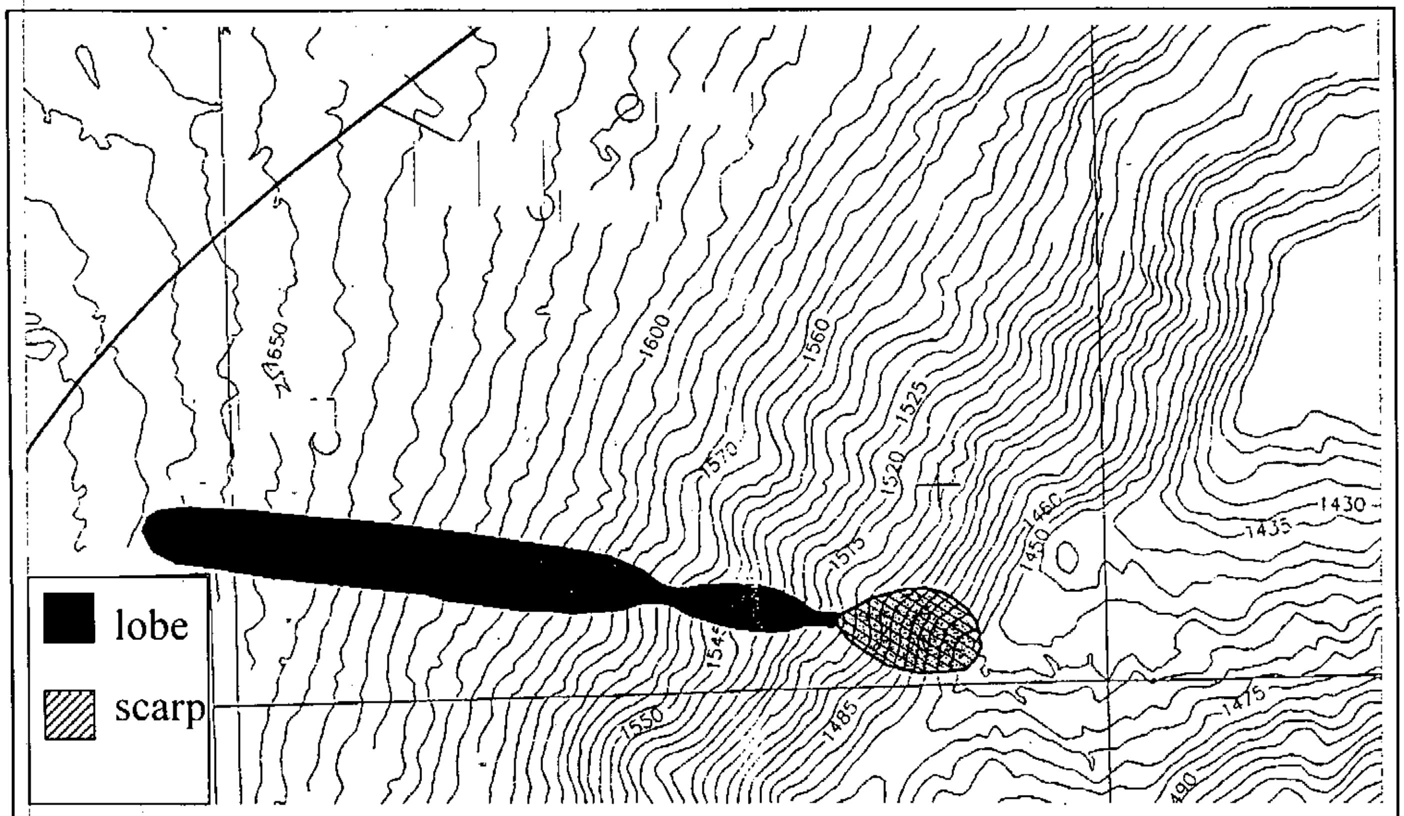

Figure 11   Debris flow scarp and lobe

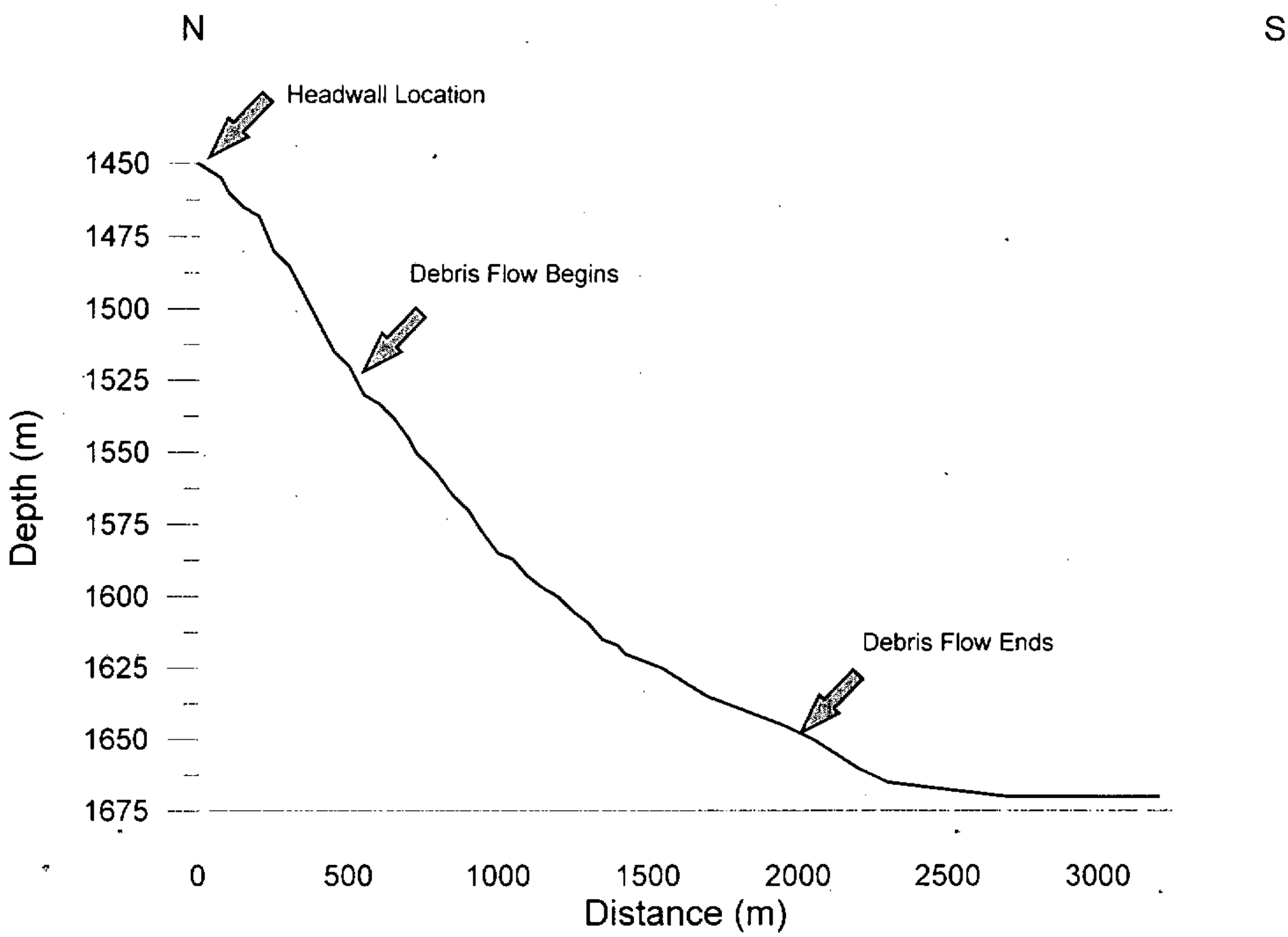

Figure 12. Bathymetric profile used to model debris flows in the Russian Slope

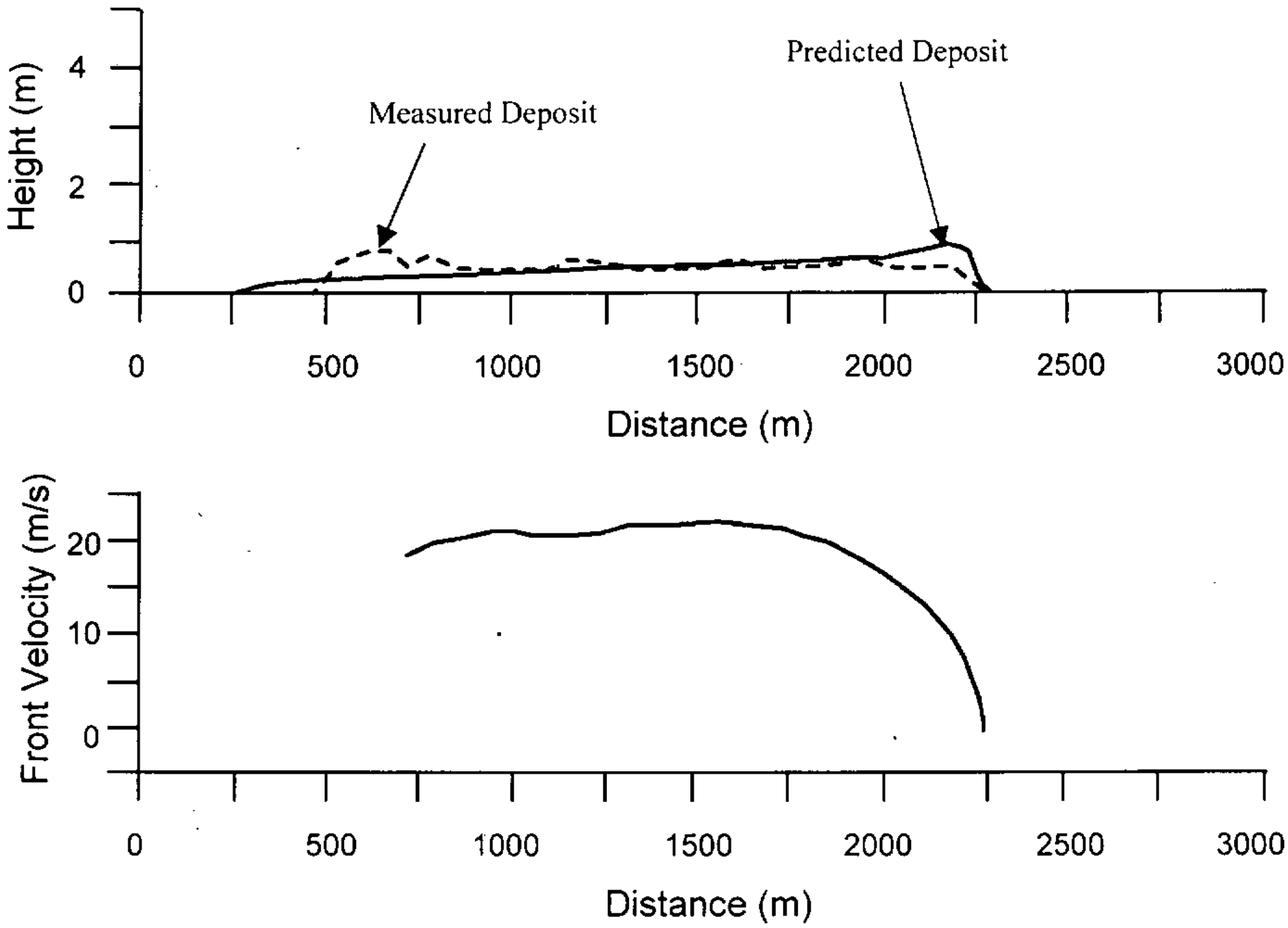

Figure 13. Computed versus measured debris flow thickness and run-out distance (top) and computed maximum nose speeds (bottom).

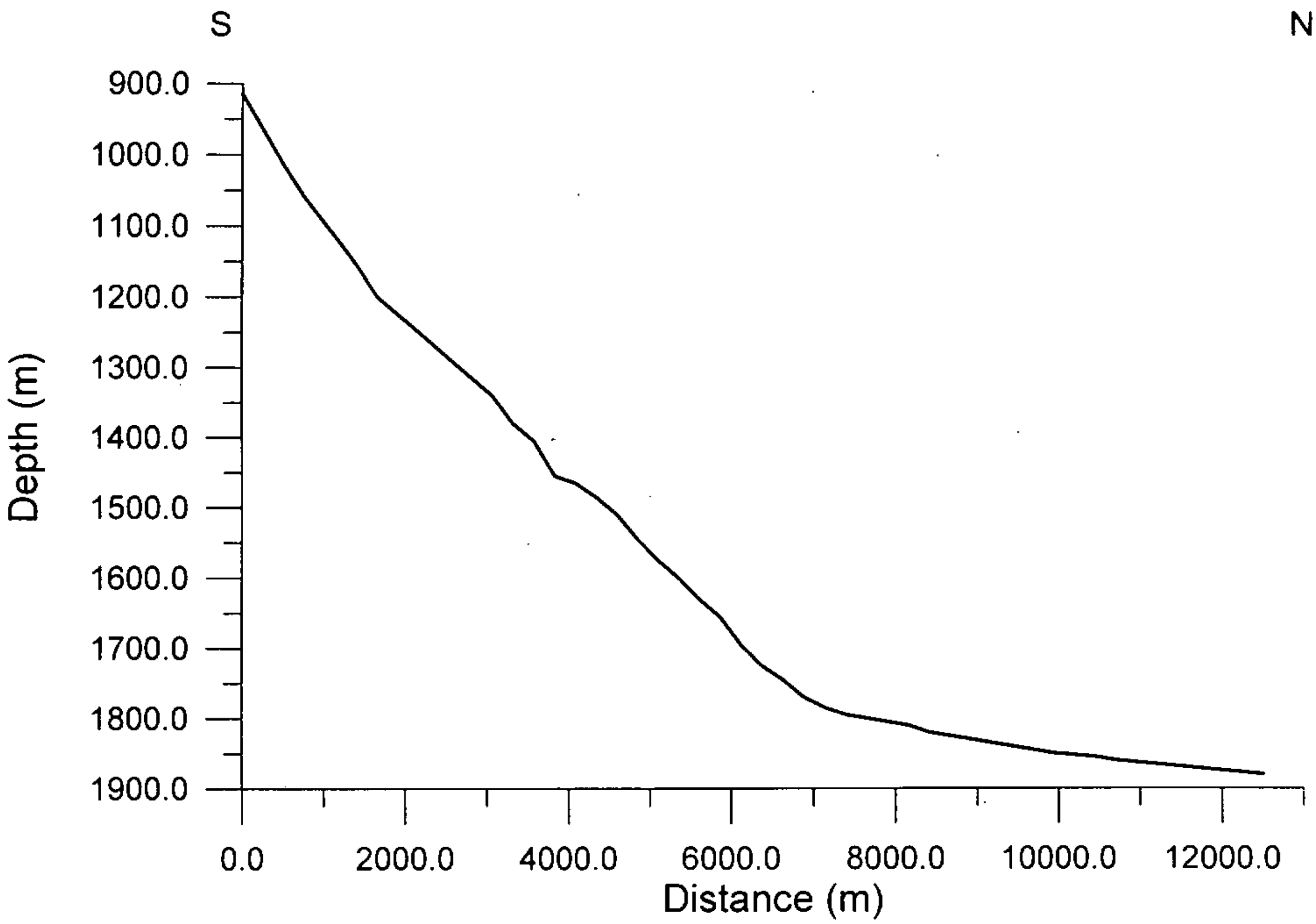

Figure 14. Typical bathymetric profile on the Turkish Slope.

An Improved Formula for Calculating Pipe Hoop Stress

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Pipes & Pipelines International

An Improved Formula for Calculating Pipe Hoop Stress

Abstract

The ASME B31.4 [1] and B31.8 [2] codes use the thin wall formula to predict hoop stress in a pipe subjected to both internal and external pressure, even though the thin wall formula is derived for internal pressure only. To account for external pressure, the thin wall formula simply uses the differential pressure (internal minus external pressure). However, for high external pressures, the thin wall formula does not sufficiently agree with the thick wall formula, which gives, what is considered to be, "exact results". The departure from the thick wall formula increases as the water depth increases.

This paper proposes an improved equation to predict hoop stresses in pipes subjected to both internal and external pressure. Compared to the conventional thin wall formula, the improved formula has additional terms, which improve the agreement with the thick wall formula and account for external pressure. The improved formula is less conservative than the conventional thin wall formula, but slightly more conservative than the thick wall formula. The formula is simpler and easier to use than the thick wall formula and will save pipe material costs as well as installation costs compared to using the conventional thin wall formula. The savings will increase as the water depth increases.

Key Words

Deep Water, Pipeline, Pipe, Wall Thickness, Design Pressure, External pressure, Hoop Stress

Nomenclature

D	Pipe outside diameter
D_i	Pipe inside diameter
P_i	Internal pressure
P_o	External pressure
t	Pipe nominal wall thickness
σh	Hoop stress

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1. Introduction

Subsea pipelines must be designed for installation, hydrotest, and operation. In some cases, the pipe wall thickness may be governed by the internal design pressure or the hydrotest pressure, depending on design factors and code requirements. Pipe wall thickness may also be affected by installation stress limits or free span stress limits due to sea bottom irregularities. If the external pressure exceeds the internal pressure, the pipe must be checked for collapse.

This paper focuses only on the minimum pipe wall thickness needed for internal and external pressure. Wall thickness determination to resist collapse buckling is out of the scope of this paper.

For marine pipelines, the effect of external pressure should be considered in the pipe wall thickness determination. Even though external pressure is considered in the some ASME codes, these codes require conservatively heavier wall pipe, as will be shown below.

This paper proposes an improved hoop stress formula to predict pipe wall thicknesses more accurately, for any water depth. The accuracy of the improved formula compared to the thick wall formula is presented for various D/t and P_o/P_i ratios.

2. Pipe Hoop Stress Formulas

When a pipe is subjected to internal pressure, a hoop stress will be induced across the pipe wall thickness. As shown in Figure 1, the hoop forces will be in equilibrium with the Y-component forces of the internal pressure, which acts on the pipe ID.

Eq. 1 below is called the "thin wall pipe formula". It is derived assuming a uniform hoop stress across the pipe wall with no external pressure.

$$2\sigma h\, t = P_i D_i \Rightarrow \sigma h = \frac{P_i D_i}{2t} \qquad \text{Eq. 1}$$

ASME B31.4 and B31.8 codes conservatively revise Eq. 1 to use the pipe OD, as follows:

$$\sigma h = \frac{P_i D}{2t} \qquad \text{Eq. 2}$$

Equation 2 provides reasonable results for D/t ratios greater than 20, with no external pressure.

To account for external pressure, the **ASME B31.4 and B31.8 codes** simply substitute the pressure differential across the pipe wall for the "P_i" term, as follows:

$$\boxed{\sigma h = \frac{(P_i - P_o)D}{2t}} \qquad \text{Eq. 3}$$

However, in keeping with thin wall theory, the internal and external pressure forces act respectively on the inner and outer diameter, so the following equation should be used to account for the external pressure properly.

$$2\sigma h\, t = P_i D_i - P_o D \Rightarrow \sigma h = \frac{P_i D_i - P_o D}{2t} \qquad \text{Eq. 4}$$

Eq. 4 contains two unknowns (D_i and t) and it is not simple to solve for the pipe wall thickness, t. However, substituting $D_i = D - 2t$ and algebraic manipulation reduces the equation to the following:

$$\boxed{\sigma h = \frac{(P_i - P_o)D}{2t} - P_i} \qquad \text{Eq. 5}$$

Note that Eq. 5 has an additional "(-) P_i" term compared to the thin wall formula used in the ASME B31.4 and B31.8 codes. This equation is recommended by **API RP 2RD** [3].

ASME B31.3 [4] and **ASME Boiler and Pressure Vessel (BPV) Code, Section VIII-Division 1** [5] recommend still another hoop stress formula for D/t ratios greater than 6, for internal pressure only.

$$\sigma h = \frac{P_i D}{2t} - 0.4 P_i \qquad \text{Eq. 6}$$

Substituting the differential pressure, $P_i - P_o$, for the internal pressure yields:

$$\boxed{\sigma h = \frac{(P_i - P_o)D}{2t} - 0.4\,(P_i - P_o)} \qquad \text{Eq. 7}$$

This equation appears similar to Eq. 5, except for the last term.

As shown in Figure 2, the **thick wall formula** for hoop stress (Lame's Equation) is as follows:

$$\sigma h = \frac{P_i a^2 - P_o b^2 + a^2 b^2 (P_i - P_o)/r^2}{b^2 - a^2} \qquad \text{Eq. 8}$$

The above formula accurately predicts pipe wall hoop stresses at a given radius (positive stresses indicate tension and negative stresses indicate compression). The absolute hoop stress, compression or tension, is always maximum at the inner wall surface. The hoop stress varies across the pipe wall and the difference between the inner wall surface and the outer wall surface is the same as the pressure differential (P_i - P_o). Since the pipe is to be designed for maximum stress across the wall, the thick wall pipe formula with r = a, at the inner pipe wall surface, should be used to determine the pipe wall thickness.

By substituting $r = a = D_i/2$, $b = D/2$, and $D = D_i + 2t$, followed by considerable algebraic manipulation, Eq. 8 can be rewritten as follows for hoop stress at the pipe ID.

$$\boxed{\sigma h = \frac{(P_i - P_o)D}{2t} - 0.5(P_i + P_o) + \frac{(P_i - P_o)t}{2(D-t)}} \qquad \text{Eq. 9}$$

The Eq. 8 and Eq. 9 give precisely the same hoop stress results at the pipe ID for a given pipe subjected to the same pressures.

3. Comparison of Pipe Hoop Stress Formulas

Figures 3 through 5 graphically compare each hoop stress formula to the thick wall pipe formula by plotting results from each formula as a ratio to the thick wall formula results versus D/t and P_o/P_i.

Figure 3 compares the ASME B31.4 and B31.8 hoop stress formula (Eq. 3) to the thick wall pipe formula. For lower D/t ratios (thicker pipe wall) and higher P_o/P_i ratios (higher external pressure), the results are shown to be very conservative. At $P_o/P_i = 0.3$ and $D/t = 20$, the thin wall pipe formula gives 10 percent higher stress than the thick wall formula. As the external pressure increases, the conservatively high stress from the ASME B31.4 and B31.8 hoop stress formula increases exponentially. This indicates that the ASME B31.4 and B31.8 hoop stress formula should be reviewed for deep water application.

As shown in Figure 4, the API RP 2RD hoop stress formula (Eq. 5) always predicts lower hoop stresses than the thick wall formula. This is due to assumption of uniform hoop stress across the pipe wall thickness.

The ASME B31.3 and BPV Code hoop stress formula (Eq. 7) shows almost the same trend as the ASME B31.4 and B31.8 formula, as shown in Figure 5. The equation predicts slightly lower hoop stresses than the ASME B31.4 and B31.8 formula.

4. Improved Pipe Hoop Stress Formula

Neglecting the last term and rewriting the second term with a differential pressure in the thick wall formula (Eq. 9) produce the following equation:

$$\sigma h = \frac{(P_i - P_o)D}{2t} - 0.5(P_i - P_o) - P_o \qquad \text{Eq. 10}$$

Reconsidering the neglected last term in the thick wall formula by using a smaller coefficient for the second term in the above equation yields:

$$\boxed{\sigma h = \frac{(P_i - P_o)D}{2t} - 0.4(P_i - P_o) - Po} \qquad \text{Eq. 11}$$

The above equation has both differential pressure and external pressure terms and will be called the "**improved pipe hoop stress formula**" in this paper. This equation has additional "(-) P_o" term compared to the modified ASME B31.3 and BPV code formula (Eq. 7).

Eq. 11 provides very accurate results: maximum 2 percent higher hoop stress than thick wall formula, as shown in Figure 6. At D/t equals 6, Eq. 11 gives exactly same value as the thick wall formula.

The improved hoop stress formula appears slightly more complicated than the thin wall formula; however, it's use in deepwater should be very beneficial. The example below illustrates the benefit of using the improved hoop stress formula.

<u>Example 1</u>

Given> Determine pipe wall thickness due to internal and external pressures.
6.625-inch O.D flowline, API 5L X60
Internal pressure P_i = 6,000 psi at wellhead
Water depth = 4,500 ft

Solution> The allowable hoop stress for flowline is 0.72 x 60,000 = 43,200 psi
Differential pressure $\Delta P = P_i - P_o$
$= 6{,}000 - 4{,}500(64/144) = 6{,}000 - 2{,}000 = 4{,}000$ psi
$(P_o/P_i = 2{,}000/6{,}000 = 0.33)$

(1) Using the ASME B31.4 and B31.8 thin wall pipe formula (Eq. 3),

$$\sigma h = \frac{(4{,}000)6.625}{2t} \le 43{,}200 \rightarrow t \ge 0.307"$$

(2) Using the API RP 2RD hoop stress formula (Eq. 5),

$$\sigma h = \frac{(4{,}000)6.625}{2t} - 6{,}000 \le 43{,}200 \rightarrow t \ge 0.269"$$

(3) Using the modified ASME B31.3 and BPV Code formula (Eq. 7),

$$\sigma h = \frac{(4{,}000)6.625}{2t} - 0.4(4{,}000) \le 43{,}200 \rightarrow t \ge 0.296"$$

(4) Using the thick wall pipe formula (Eq. 9) with trial and error solution,

$$\sigma h = \frac{(4{,}000)\,6.625}{2t} - 0.5(8{,}000) + \frac{4{,}000t}{2(6.625-t)} \le 43{,}200 \rightarrow t \ge 0.281"$$

(5) Using the improved pipe hoop stress formula (Eq. 11),

$$\sigma h = \frac{(4{,}000)\,6.625}{2t} - 0.4(4{,}000) - 2{,}000 \le 43{,}200 \rightarrow t \ge 0.283"$$

As illustrated in the above example, the improved pipe hoop stress formula result (0.283") matches well with the thick wall formula solution (0.281"). It also saves approximately 8 percent of the pipe material cost compared to the thin wall pipe formula (0.307").

5. Conclusions and Recommendation

The ASME B31.4 and B31.8 thin wall pipe formula is not derived specifically to account for external pressure and predicts the most conservative hoop stress compared to any other code. The ASME B31.3 and BPV Code predict less hoop stress than the ASME B31.4 and B31.8 codes, but still predict higher hoop stress than the thick wall formula. However, the API RP 2RD predicts lower hoop stress than the thick wall formula. The inconsistency between codes and conservatism compared to the thick wall formula inspired an improved pipe hoop stress formula presented in this paper.

The improved pipe hoop stress formula (Eq. 11) is presented to properly account for the external pressure. The improved pipe hoop stress formula predicts reasonably accurate hoop stresses with little extra effort. The improved formula will save pipe material and installation costs. For a D/t ratio of 20 and $P_o/P_i = 0.3$, the improved formula will save approximately 10 percent of the pipe material cost over the ASME B31.4 and B31.8 formula. The savings will increase as the water depth increases.

6. References

[1] ASME B31.4, "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids," 1992, The American Society of Mechanical Engineers, New York.

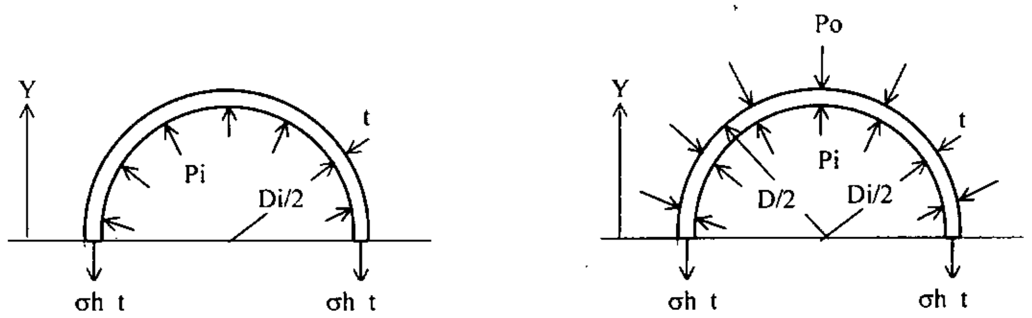
[2] ASME B31.8, "Gas Transmission and Distribution Piping Systems," 1992, The American Society of Mechanical Engineers, New York.

[3] API RP 2RD, "Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs)," 1998, American Petroleum Institute

[4] ASME B31.3, "Chemical Plant and Petroleum Refinery Piping," 1990, The American Society of Mechanical Engineers, New York.

[5] ASME Boiler and Pressure Vessel Code, Section VIII – Rules for Construction of Pressure Vessels, Division 1, Appendix 1, 1998, The American Society of Mechanical Engineers, New York.

Figure 1
Thin Wall Pipe Hoop Stress Diagram



(a) Internal Pressure only (b) Internal + External Pressures

Figure 2
Thick Wall Pipe Hoop Stress Diagram

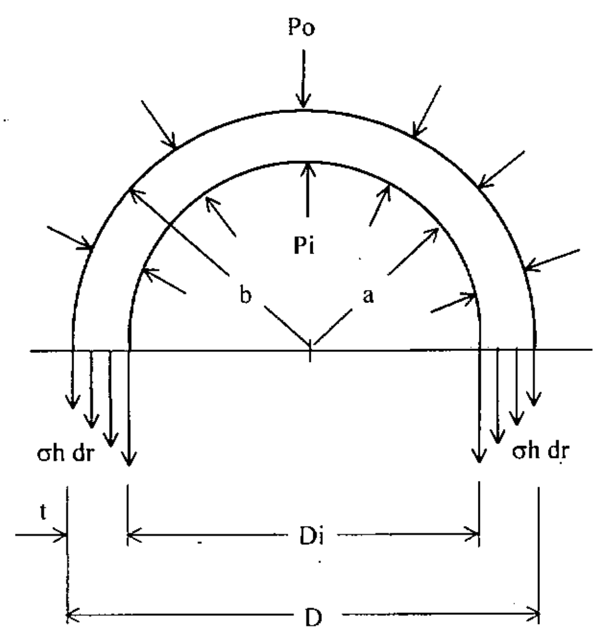


Figure 3
ASME B31.4/B31.8 Hoop Stress Formula (Eq. 3)
Accuracy Compared to Thick Wall Formula
Eq. 3: Sh = (Pi-Po)*D/(2t)

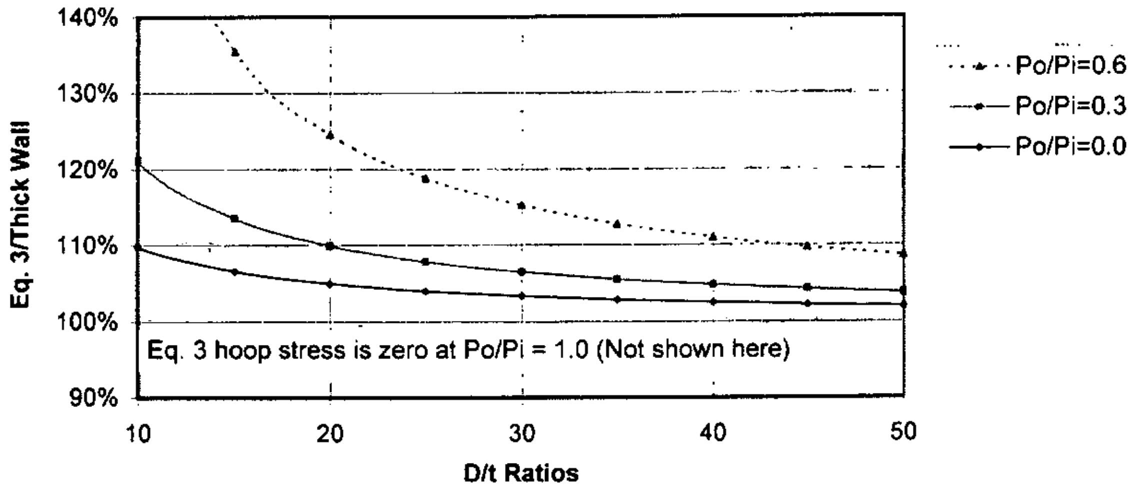


Figure 4
API RP 2RD Hoop Stress Formula (Eq. 5)
Accuracy Compared to Thick Wall Formula
Eq 5: Sh = (Pi-Po)*D/(2t) - Pi

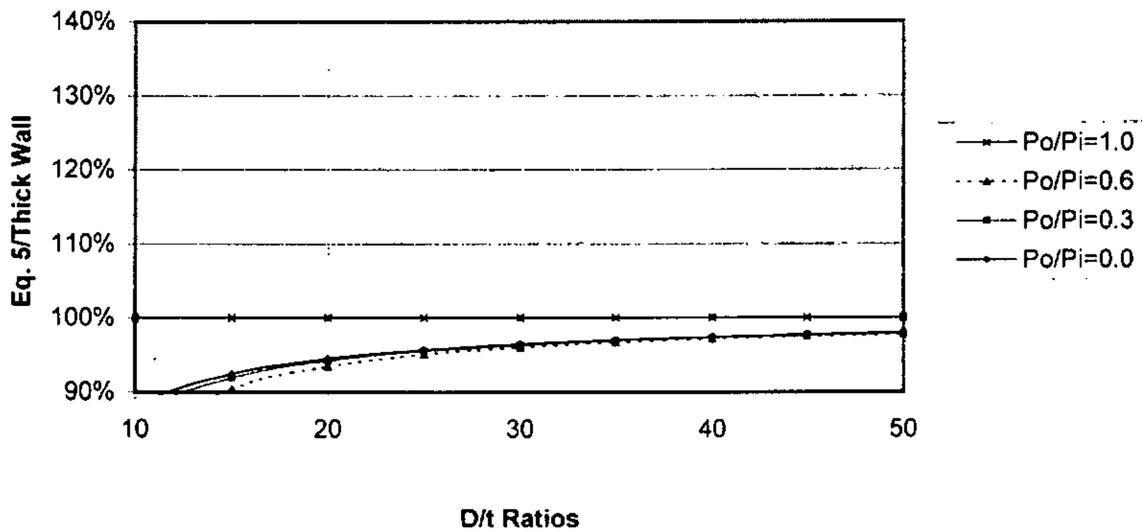


Figure 5
ASME B31.3/BPV Hoop Stress Formula (Eq. 7)
Accuracy Compared to Thick Wall Formula
Eq. 7: Sh = (Pi-Po)*D/(2t) - 0.4 (Pi-Po)

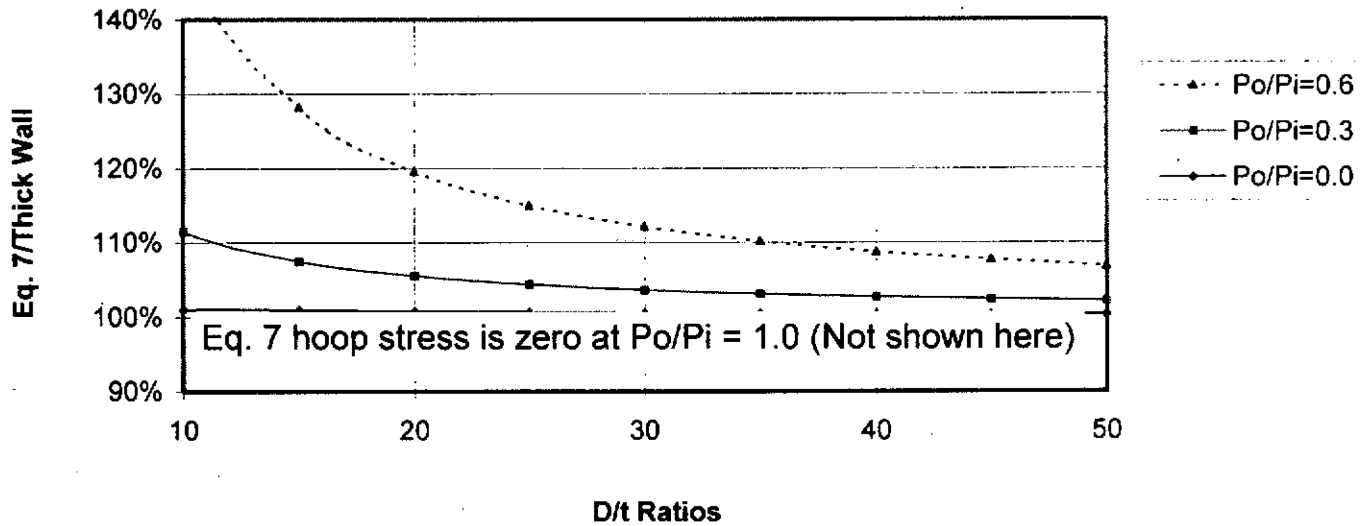


Figure 6
Improved Hoop Stress Formula (Eq. 11)
Accuracy Compared to Thick Wall Formula
Eq 11: Sh = (Pi-Po)*D/(2t) - 0.4 (Pi-Po) - Po