R. Pomeroy 11-20-96

NOV 25 1996

Memorandum

To: Regional Supervisor, Resource Evaluation
Attention: Frank Neary

From: Regional Supervisor, Field Operations

Subject: Geological Well Data Release Date

On November 20, 1996, our office released to the public the well data for Leases OCS-Y 0866 #1, Kuvlum #1, OCS-Y 0865 #1, Kuvlum #2, and OCS-Y 0866 #2, Kuvlum #3. The well samples for these wells can now be released to the Geologic Materials Center in Eagle River as soon as practicable.

cc: John W. Reeder, Ph.D.
Department of Natural Resources
P.O. Box 772116
Eagle River, Alaska 99577-2116

bcc: OCS-Y 0866#1, 0866#2, and 865#1 6-C
Chron (area/cc/rd)
RPomeroy:rdp:11/21/96:Neary10.mem

SPE 37954

Development of Marginal Fields Through Technical and Commercial Innovation - A Case History from the UK North Sea

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This paper was prepared for presentation at the Hydrocarbon Economics and Evaluation Symposium of the Society of Petroleum Engineers held in Dallas, TX, March 15th-18th, 1997.

Abstract

The biggest development in the North Sea for a decade has attracted industry attention as one of the most innovative projects to date. Seven economically marginal fields with different owners and different hydrocarbons have been brought together to create the £1.6 billion Eastern Trough Area Project (**ETAP**). Innovation on both technical and commercial fronts has been created by an unprecedented level of co-operation between companies. This paper outlines the basis of the project and the approach adopted to its formulation which resulted in novel technical and commercial solutions.

The challenge for today's North Sea, with ever decreasing field size, is to reduce development costs/bbl to acceptable levels and to do this through working the two available levers: cost and the number of barrels. The ETAP solution to reduce cost and add barrels is to combine small fields into a single project with development cost/bbl similar to a single giant field, but with the reservoir risk mitigation inherent in accessing multiple independent reservoirs. This approach created many hurdles, both technical and commercial, and has stimulated innovative solutions.

Technical hurdles include the need for long distance sub sea multiphase tiebacks in excess of 35 Km which have innovative chemical control and multiphase metering. Commercially, the project presented a major challenge as all parties agreed that a conventional unitisation of all the fields into unified ownership interests was neither practical or desirable in light of the range of fluid types and reservoir uncertainty. Accordingly a structure was developed to a) share Capital and Operating costs equitably, b) provide for production rights and production allocation and c) encourage full utilisation of the shared facilities.

The significant cost savings needed to make ETAP viable were largely achieved in the conceptual design phase by designing shared and centralised facilities for both oil and gas field management. In the current project execution phase additional cost savings are being delivered through further application of "alliance contracting" with the contractors for design, fabrication and installation of the facilities and for the development drilling.

Introduction

Located within the Eastern Trough in the UK Central North Sea, the project encompasses the simultaneous development of seven accumulations (Mamock, Mungo, Monan, Machar, Heron, Egret and Skua) which lie approximately 140 miles east of Aberdeen in water depths of around 85 to 95 metres, and separated by distances of between 3 and 35 Km. Field interests are held by BP, Shell, Esso, Agip, Total, Murphy and Moex. While no one company holds an interest in all seven fields, BP, Shell and Esso have the widest interest across the fields.

The Mamock field contains gas condensate and the Skua, Heron and Egret fields contain oil, all of which occur in over-pressured Triassic sandstone within tilted fault blocks. Mungo and Monan are diapir flank oil fields with separate gas caps reservoired primarily within Palaeocene sandstone. Machar is also a diapir field containing oil within fractured Chalk and in overlying Palaeocene sandstone.

The seven fields have total combined reserves of 400 million barrels of oil, 35 million barrels of Natural Gas Liquids and 1.1 trillion cubic feet of sales gas and thus is equivalent to the largest oil field to be developed in the North Sea in the last 10 years. In terms of off take, the fields will produce over 180mbd (annual average) of oil on plateau for 3 years. In addition, gas produced from each field, after processing and planned injection will be exported at around 350mmscfd (annual average) with an anticipated plateau of 5 years with a peak rate on plateau of up to 450mmscf/d.

Project Description - Facilities

The design principle was to consolidate facilities into a single Central Processing Facility (CPF) which provides the processing requirements of all the fields. The location of the CPF over the Mamock field was selected as it provided the lowest overall development cost for the project. Such a development concept enabled all but the Mungo field to be developed as sub sea tie-backs. Mungo is developed through a minimum facilities - Normally Unmanned Installation (NUI) in light of the well numbers and anticipated intervention requirements. This resulted in an overall reduction in cost in comparison to separate "standalone" development of the fields and also to a reduction in operating costs. The facilities have been designed to satisfy all regulatory and BP corporate requirements in respect of health, safety and the environment.

The CPF comprises a two platform complex with a Process, drilling and Riser platform (PdR) and a separate Quarters and Utility platform (QU). The PdR and QU platforms are sited approximately 60m apart, and will be linked by two bridges. This design maximises the separation between the production risers and Mamock wellheads on the PdR platform and the population centres on the QU platform. The PdR design provides spatial separation between the riser area and the Mamock wellheads and jack-up drilling unit when this is present.

The PdR platform contains the process equipment (P), the Mamock well bay (d) and the risers (R). The jacket for this platform is six legged, weighing approximately 7,200 tonnes. The topsides consists of a cellar deck (weight approximately 5,600 tonnes), which will be lifted onto the jacket over suspended wells, and a process module (weight approximately 8,100 tonnes). The total topsides net weight for the PdR platform, including bridges and the flare structure comes to around 14,600 tonnes.

The QU platform contains accommodation (Q) facilities for 85 persons and utilities (U), including the main power generators and the central control room. The jacket for this platform is four legged. The topsides will be lifted onto the jacket in a single lift. The total topsides net weight for the QU platform comes to around 6,900 tonnes.

Primarily for safety reasons, the bridges are both at the lowest platform levels and are arranged such that the bridge ends on the PdR platform are at the riser area and well bay area for rapid egress from these areas of the PdR platform to the QU. Apart from fuel gas and chemicals there are no hydrocarbons on the QU platform.

A total of 20 risers and sufficient J-tubes to accommodate up to 12 umbilicals for electrical power, hydraulic control and chemical injection are installed on the PdR jacket. Dedicated slug catchers are provided on the CPF for each group (Cluster) of fields, except Mamock, in order to manage slugging and also to provide initial separation and allocation metering. Mamock enters directly into the HP separator as the wells rise directly on to the PdR.

The NUI at Mungo provides a platform for bulk separation of liquids and gas. The liquids flow directly to the CPF in a 12" pipeline. Eighteen slots are provided for the anticipated number of production, water injection and gas injection wells. Chemicals and electrical power for Mungo will be supplied via an umbilical from the CPF. It is anticipated that around one to two day-time visits per week will be required to carry out pigging and other day-to-day operations. An emergency shelter is provided on Mungo in the event that a crew may be unable to return to the CPF for any reason. The Mungo platform supports both a production

and a test separator. A production manifold feeds the single three-phase production separator and a test manifold feeds the test separator which can measure individual well flows. Any separated produced water is fed to a hydrocyclone and degasser before being discharged locally or fed back to the CPF for re-injection. There are no cooling or sea water lift pumps provided, consistent with the aim of minimising equipment in order to achieve the not normally manned status of this platform. The total topsides net weight for the Mungo deck is around 1,840 tonnes. A 16" wet gas line from the Mungo is routed to the CPF via Monan. A combined Mungo/Monan slug catcher is provided at the CPF.

All fields other than Mamock and Mungo are to be developed by means of sub sea well clusters manifold and tied back to the CPF. Control and chemicals service will be provided by umbilical from the CPF. Hydrate inhibition will utilise innovative Threshold Hydrate Inhibitor removing the requirements for costly methanol recovery facilities.

Machar is being developed with water injection with a five well producing cluster tied back through a 16" pipeline to the CPF and a dedicated slug catcher. Water injection will be provide by a 12" flow line from the CPF and the injection water will be used to power a sub sea multiphase pump, installed in the 16" pipeline at Machar to assist in the return of the produced fluid to the CPF.

Monan is configured as a three well cluster. The flow streams are commingled and fed back to the CPF via the 16" wet gas pipeline from the Mungo NUI and into the dedicated slug catcher which also receives the 12" oil line direct from the Mungo NUI.

Heron, Egret and Skua are developed sub sea as three separate well head clusters tied into two 10" flow lines back to the CPF and in to two separate slug catchers, one for each flow line.

Project Description - Commercial

Three alternative commercial approaches were identified in the initial work to identify the commercial feasibility of the project:

- Unitisation of all fields into a single ownership
- Development of the CPF by a subset of Owners and tariffing of other Users
- Development of the CPF with all ETAP participants as Owners.

Within the ETAP fields, the range of partnership interests, reservoir fluid types, appraisal maturity, differing development costs and reservoir uncertainties meant that "unitisation" of the fields into a single equity holding was not viable. The determination of interests in light of the relative value of the different products, the uncertainties in development costs and reserve level would have required prolonged negotiation which would be open to failure through the miss-alignment of any one party's view.

The development of the CPF as a shared facility presented a more manageable problem - defining a basis of sharing costs and the production rights across the CPF. This retains the key uncertainties (drilling costs, reserves and different product values) within each of the Clusters (groups of fields of common ownership). In development of such arrangements early discussions established a series of principles to be adopted:

- Maximise alignment - in avoiding conflict, development and operation of the facilities would be simplified and agreement would be forthcoming on any necessary decisions. Where such conflict cannot be avoided clear rules must be defined to manage the inherent miss-alignment.

- Equitably share cost - key to the development concept is the avoidance of pre-investment and the sharing of costs in relation to each field's needs and usage. No fields were to benefit or dis-benefit from the location of the CPF over the Mamock field.

- Encourage high utilisation - key in the development concept is the use of the shared facilities in a manner that minimises operating costs and maximises production on the day. In providing this contractually, the rights of the original investors who paid for the facilities must be safeguarded. During the development phase, maximum use of any installation vessels should be encouraged to provide flexibility and reduce costs.

- Mitigate risks within defined limits - arrangements should seek to clearly define the liability to risks and only seek to mitigate risk within pre-defined limits as follows:

  Facilities Risks - cost and liabilities should flow to the underlying fields owners for the field facilities and to the collective shared facilities owners for the CPF. Mitigation of the facilities risks associated with design and installation costs should be within pre-defined limits.

  Drilling Risks - costs and drilling performance should remain with the field owners.

  Reservoir Risks - should lie with the individual field unless upside within another Cluster can access the facilities. However, in providing for this protection, no party should unreasonably be exposed to negative cash flows in later production life and a reasonable balance should be taken. In the event that one field were to encounter a reservoir downside, this should be mitigated through either use of that capacity by development of another field and/or through the use by another existing field or fields of the unused capacity thereby accessing reservoir upside.

Ownership of the CPF: The ETAP commercial arrangements are based on the development of the CPF as a shared facility owned by all the participants (CPF Owners) in the fields essentially comprising an amalgamation of the necessary facilities for each field into a common facility designed for the specific requirements of these investing fields. The fields are grouped into Clusters which are based on the alignment of partner holdings, and which also reflect commonality of reservoir types and risks. This provides the Cluster parties with an element of risk mitigation as they will be able to manage their multiple reservoirs within the original investment and obligations to the CPF.

Identification of the CPF as a separate commercial entity from the Clusters enables differentiation of the role of the field operator (reservoir/drilling activity) from facilities operator of the CPF and Cluster Facilities. All facilities will actually be operated by BP as Operator of the CPF and as a provider of services to each of the Clusters.

Cost Sharing of the CPF: The CPF costs (Capex and Opex) are allocated to each of the Clusters on the basis of usage. The capital cost shares are fixed and were based on the nominated processing requirements of each Cluster. The CPF operating costs are split into Sustaining Opex (maintaining the platform for future use) and Throughput Opex (variable costs as a function of use). The Sustaining Opex is a fixed proportion of the costs and is allocated to each cluster with the balance of the costs deemed to be Throughput Opex which is allocated on the basis of production. This seeks to reduce late life unit costs for fields with longer production profiles and reflects the future value in maintaining the platform for all owners. This aligns costs to production and future production options within each Cluster enabling future decisions to be managed within each Cluster.

Production Rights in the CPF: Each Cluster has a contractual "Right To Throughput" on the CPF which is defined by a profile for each of 7 major systems (HP Gas, LP Gas, Oil export, Gas Export, Gas Injection, Water Injection and Produced Water). The contractual right is initially defined by the design profiles but is subject to rights of extension and increase. Associated with these rights is a fixed Opex Sharing Obligation to meet operating costs which deters "over-booking" of the system thus sterilising capacity. On the day, should ullage exist in any of the systems, each Cluster has equal right to access the available ullage enabling access to upside and encouraging high utilisation of the facilities, thereby reducing unit operating costs. This enables uncertainty to be managed within each Cluster through bringing on additional production where possible. The obligation to Opex prevents other Clusters from being exposed to downside performance by any other Cluster.

Any ullage on the CPF is aggregated and is owned in undivided rights by each of the CPF Owners. The Ownership shares were derived from the Capex Cost allocated to each Cluster and hence to each participant. Management of the aggregated ullage by the CPF Operator on behalf of the collective owners ensures that most effective use of the facilities is made.

Resulting Economic Benefits: The sharing of facilities clearly leads through economies of scale to reduced capital and operating costs. In comparison to the standalone development alternatives, these savings have been estimated on aggregate to be around 30%. In addition, the production management of the CPF encourages high utilisation of the facilities. In light of the very different nature of each of the main reservoirs (they can be considered as risk independent of each other), the opportunity exists for any Cluster to access additional capacity unused by another, thus accessing upside and reducing unit costs for all participants. Extensive use of such capacity is subject to tariff payments which deter under-booking of capacity by any Cluster (to avoid the Opex sharing obligation) and equitably reflect the use of capacity not previously invested in. When such capacity is used however, the tariffs incurred are allocated initially to any under-performing Cluster (relative to its original forecast) and then to CPF Owners. This effectively further mitigates the downside of any under-performing Cluster should additional production be available from other Clusters to take up the under-used capacity.

Project Description - Alliance Contracting
During the Front End Engineering and Design phase of work it became clear that significant cost savings could be delivered through the execution of the project as a single integrated entity under an 'Alliancing' contracting strategy. For the BP Operated aspects of the project - CPF, oil and gas export spurlines and the Mamock, Mungo, Machar cluster facilities and wells, BP has established two separate alliances - one for the facilities and one for the wells.

The ETAP Facilities Alliance involving Brown & Root, AMEC, Barmac, Kvaerner Oil and Gas, Consafe, ECS and Heeremac is believed to be the largest project to be undertaken under an alliance contracting approach in the North Sea. This alliance has continued the expansion of the scale of these arrangements from the small Hyde development through the medium sized Andrew development to ETAP, the BP operated part of which has a capital budget of some £1.2 billion. Much has been made of alliance type relationships in recent times and many believe the very word now causes confusion. The definition of an alliance relationship is one in which all parties are aligned to a common business outcome and have a contractual relationship in which their financial settlement is influenced by the performance of the joint endeavour against the business outcome targets which were agreed.

Alignment of objectives has been established by developing a risk and reward sharing mechanism that compensates or penalises for achievement or failure to meet the ETAP key success factors - Capex, Opex, first oil/gas dates, and plant performance (availability, productivity).

The drilling and well engineering activity within the ETAP development will be carried out by the ETAP Wells Alliance, currently consisting of BP, Schlumberger Well Engineering Services, Santa Fe Drilling, and Nedrill. The ETAP wells alliance partners were selected following an initial market enquiry and subsequent tender process involving five consortia. In evaluation of the tenders equal weighting was given between the tendered costs and the organisational, behavioural and systems attributes of the bidders. The successful bidder had to demonstrate best overall value for ETAP as a whole and for each of the clusters when considered in isolation.

The contract strategy for ETAP well activity is founded on the premise that there is value in:

- building an alliance between BP and the contractors with aligned objectives.
- contracting a single consortium for well construction, well management and data acquisition.
- establishing the well alliance early, to enable the contractor to influence outcomes rather than provide prescribed solutions.
- the integrated service contractor and drilling unit provider both play a key role, so where these are separate companies they would hold equivalent positions in the alliance.

Project Inception
From the early 80s' and through to 1990, BP discovered and started appraisal on Mamock, Machar, Mungo, Monan and Medan fields. In the same period, Shell discovered and started appraisal on Skua Heron and Egret, and Ranger the Pierce Field. BP led studies for the separate and standalone development of Mamock and Machar and these resulted in a project proposals in 1990. Unfortunately the investment opportunities were considered insufficiently attractive to their respective owners in the environment of continued low oil price and growing concern on escalating industry costs in the UK North Sea at that time. In the light of this failure to commit to the projects and the knowledge that other investment opportunities would seek the available investment funds, something radical had to be done to further reduce costs if these fields were to be developed in the foreseeable future. This was the catalyst for the development of the ETAP concept.

The initial idea for ETAP came from BP and Shell who through early studies established that integration of oil and gas field facilities was technically possible and looked likely to significantly reduce overall costs. The ongoing appraisal and continuing exploration programme in the Central North Sea provided an excellent opportunity to add to the reserves base for the development. However, as no field alone could justify the pre-investment to enable development of the other fields, a simultaneous and "integrated" development was necessary.

In 1992 BP instigated internal studies on the technical feasibility of a simultaneous multi-field development involving known undeveloped accumulations within the area covered by the Mamock, Mungo and Machar fields. The BP studies covered Mamock, Skua, Mungo, Monan, Mungo, Monan, Medan and Pierce. The results were made available to all interest holders and were sufficiently encouraging for twelve companies to agree to jointly continue the study to confirm the technical and commercial viability of a fully integrated development. Before the studies commenced Shell proposed including the Heron Field which they operated; this was a significant milestone in that it provided the commitment of Shell as an operator into the project.

Over the subsequent years the project was shaped with the participation of all the various field owners. Early in this process, it was agreed that both Medan and Pierce were too far from the centre of the development and that this presented unacceptable risks that the respective field owners could not agree on. Accordingly these fields where excluded from the project.

Project Management
Project approval in December 1995 represented the culmination of four years of work through five main steps. Firstly the technical and commercial feasibility was proven. Secondly, the concept was selected where multiple development options were considered and the commercial principles agreed. Thirdly, once appraisal was completed, the concept was confirmed, all design elements were fixed, a technical case with cost definition to ±30% was produced and the design contractors selected. Fourthly, Front End Engineering and Design was conducted by BP and the design contractors and produced a technical definition and cost estimate to within ±15% which was suitable for sanction. Fifthly, the sanction process commenced along with the formation of the Facilities Alliance. In April 1992 it was estimated that these five stages would take a minimum of 30 months to complete; they took just over 43 months.

Step 1- Technical and Commercial Feasibility Testing (Apr. 92 - Oct. 93): A Joint Integration Studies Agreement was put in place with the objective of assessing the technical and commercial feasibility of an integrated development of nine fields; Mamock, Mungo, Machar, Heron, Monan, Skua, Scoter, Medan and Pierce. One of the key conditions set at the beginning of the study was that integration would be compared against realistic standalone development options and that all information would be freely available to all parties. In addition the results of the study had to be sufficiently flexible to accept surprises in the ongoing appraisal programme on the Mungo, Monan, Heron and Scoter Fields.

The studies revealed that there was potential to achieve in the region of 25% (ca. £450 million) cost saving through integration. They also confirmed that, although the development was technically and commercially viable, there were significant challenges which would need to be overcome before the project could be taken forward and defined in more detail. The technical challenges largely involved the feasibility of long sub sea multiphase tiebacks without pressure support. The commercial challenges stemmed from the need to reduce the costs of gas processing and export while maintaining market competition, and in the definition of cost sharing for common facilities if the development was not unitised.

These conclusions were reached in March 1993 and it took further studies up to October 1993 before the oil companies were sufficiently satisfied to proceed to more detailed definition of the project. These latter stage of studies confirmed the design with a Central Processing Facilities (CPF) would be optimal located over the Mamock field. The location of the CPF over Mamock was of sufficient concern to the owners of the most distant fields (Pierce and Medan) that these owners decided to withdraw from ETAP at this stage. At the same time the studies were sufficiently encouraging for Shell to add the Egret accumulation to the studies and for BP to add the Mirren field which had recently been appraised successfully.

In retrospect, one of the most important outcomes of the Joint Integration Studies was the recognition that there was a narrow window of opportunity to use existing gas export infrastructure in the year 1998; if this window was missed then a new build gas export system was considered inevitable at considerable extra capital expenditure. This established at an early stage in the project a important backstop which (although somewhat speculative at the time) served to drive the project schedule for the next two years.

Step 2 - Concept Selection (Nov. 93 - Apr. 94): The objective of the Concept Selection phase of studies was to:

- Fix the reservoir depletion schemes.
- Select a single development concept with process variations to support continuing transportation and sales negotiations.
- Selection of competitive oil and gas export and processing options to enable the design to be matured and negotiations continued.
- Agree principles of the commercial structure, the allocation of both capital and operating costs and the management of production.

This was the major period of reservoir and engineering option screening. The last appraisal wells had only just been completed and a wide variety of reservoir depletion schemes and facilities types were reviewed with full economic evaluation. Natural depletion, water injection and gas injection depletion schemes were assessed for each reservoir. A wide variety of fixed and floating installations were assessed. Pipeline and offshore loading export options were reviewed.

On the basis of this work the depletion scheme for each reservoir was selected and a fixed installation was chosen with pipeline export, although the nature of the fixed installation remained open for market tendering to the next phase.

One of the major achievements of this phase of studies was the agreement to the principles for ownership of common facilities, for the cost sharing of the common facilities and for the management of production. These principles gave sufficient comfort that a development was feasible without full unitisation and allowed progress into the next phase of the project.

Step 3 Concept Confirmation (May 94 - Nov. 94): The objective of the Concept Confirmation Phase was to :

- Fix all reservoir service requirements
- Fix design rates for all product streams
- Produce a technical definition and cost estimate with an accuracy of ± 30%
- Confirm the validity of the concept selection in the marketplace
- Select the design contractor.
- Produce a design Statement Of Requirements for entering the next phase.
- Produce Field Development Programmes for each field
- Commence export negotiations with potential transport and process services providers with the minimum number necessary to provide realistic competition.
- Finalise agreement on the mechanisms and procedures for the ownership, cost sharing and production management of the shared facilities.

This phase closed down many of the options associated with a fixed installation. Safety, cost benefit analysis led to the selection of a twin platform for the CPF with steel jacket substructures, together with a Normally Unmanned Installation for the Mungo field; the remainder of the fields being sub sea developments. Brown & Root were selected as the design contractor.

At this time it was recognised that the Scoter and Mirren fields were not sufficiently robust to progress to sanction. The emphasis on these fields switched from full inclusion to making provision for their possible later tie-in to ETAP. The core scope of the development to be defined further was therefore Mamock, Mungo, Machar, Monan, Heron, Skua and Egret. The economics confirmed that the development remained attractive so a Statement Of Requirements was produced with the aim of being fixed; this proved overly ambitious.

Step 4 - Front End Engineering and Design (Dec. 94 - Aug. 95) : The objective of the Front End Engineering And Design Phase was to :

- Produce a technical definition and cost estimate with an accuracy of ± 15%
- Select the procurement and fabrication contractors
- Establish alliance and agree risk and reward.
- Produce Field Development Programmes for each field
- Complete export negotiations and select export routes.
- Execution of ETAP Joint Development Agreement.
- Draft of Operating Agreements

The engineering definition progressed into Front End Engineering Design to provide both sanction requirements and a basis for detailed design. Initial costs estimates from this work were completed in March 95 but indicated a significant increase in costs from earlier work. A process of "challenge" was adopted to identify savings from within this initial estimate in order to bring the costs more in line with previous estimates albeit at a higher accuracy of around +15%/-15% to produce the final statement of requirement.

Step 5 - Sanction (Sept. 95 - Dec. 95) : Through the period of obtaining individual company investment sanction, work progressed into detailed design in order to maintain a 3Q98 first production date. Field Development Plans and an overall Integrated Development Plan were submitted to the Department of Trade and Industry for approval. All necessary commercial operating agreements were extensively reviewed and finally agreed pending some limited further drafting from agreed principles in discrete areas. Sanction and development consent was achieved late in December 1995.

Lessons Learned

The challenges presented by ETAP to both BP and the various other field participants required extensive consideration of how such projects are managed. No pre-existing formula for success existed and many in the UK industry at the time were very sceptical that such a project concept was feasible given the prevailing lack of co-operation between Operators. In progressing ETAP through development approval, a number of key lesson were learnt.

In the formulation of ETAP in 1992, the two most enduring lessons were learned. The key to securing the attention of the companies to any radical new development concept was to focus on the increased value accessible through such an approach, and not in seeking to answer all the "99 reasons why it can't be done". This lead to the second - not all the questions could even be established let alone answered. These two insights lead to the development of a step by step program to define the investment opportunity (outlined above).

Team Formulation : Success in any complex endeavour is reliant on teams of people and not on individuals. Establishment of the teams and ensuring that each team understands the overall objectives of the project and their contribution is essential to success. It is important to recognise

that this is the role of management every bit as much as decision making, or rather endorsement, and that this is a major endeavour requiring significant time commitment. Key is -

- early establishment of a small team to explore the perceived issues.
- ensuring partners are effectively part of the teams.
- integration across disciplines to ensure shared understanding.
- establishing the project team early with formation of the alliance to ensure ownership of the design and cost estimate.

Exploring the Options : To allow productive and creative discussions to take place in an environment which is typically the exclusive domain of the hard bitten negotiator requires that all of the stakeholders allow each other the space to "experiment" without prejudicing either the individual or the company which they represent. We achieved this in ETAP to great effect and it speaks highly for the quality of the contribution to the commercial structures which all of the co-venturers have made. Commercial meetings in the ETAP were likened more to seminars with everyone round the table seeking to find the solution rather than the traditional model of the operator bringing "the answer" to the table and then attempting to convince all concerned why it is the *right* answer. Key is -

- establishing an environment of trust and willingness to step forward through complex issues with working assumptions which are open to subsequent ratification.
- being willing to challenge internally the wish for each company to optimise its position on each decision.

Decision Making : Acknowledgement and alignment of the objectives of all of the players in the endeavour is an imperative which never goes away. It is as true for the equity participants as it is for the Alliance contractors, and the various regulatory authorities. It is as true at the strategic level as it is at the detailed issue level. These objectives may change with time and by individual player but the key to maintaining progress in complex relationships is to manage to maintain as high a degree of alignment as possible around the table. When progress seems to be lacking, the root cause nine times out of ten is that the underlying alignment has gone, although the "apparent" problem may be something else entirely. Key is -

- establishing what external factors drive the timetable and identifying key backstops.
- defining a series of steps in taking decisions, and taking one step at a time.
- driving the timetable by decision making and establishing when a decision really does need to be made.
- establishing early what it takes for each company to make decisions and their corporate internal requirements.
- planning for success will ensure that the next step is formulated before the current one is finished.
- ensuring thorough and complete analysis of discarded options otherwise they tend to continue to be considered diverting focus within the team.
- recognising that sometimes making a decision is more important than the decision itself.

Conclusion

Every day the industry faces a barrage of technical information describing the latest new technology which will enhance the performance of the exploration and production business. In the particular case of the North Sea, great reliance is currently placed on what floating production systems may offer, and also upon the ever increasing complexity of operations which can be carried out using sub sea developments. Technological advances are to be welcomed and embraced but of their own accord will not access all of the remaining prize in the North Sea.

The smaller fields of the future UKCS will need more novel arrangements - both technical and commercial - if their value is to be unlocked. The industry needs to develop a competency in developing these arrangements and we can no longer rely totally on the traditional approaches.

ETAP was sanctioned and approved by the UK Government on 20th Dec 1995, almost 5 years to the day from when the project was first conceived within BP and 4 years after the initial proposal to partners. The project has challenged the UKCS industry to what can be achieved through increased co-operation. ETAP was a bigger behavioural and commercial challenge than it was a technical one, and the achievement is a tribute to all of the companies concerned. It seems hard to believe that it will remain a 'one of a kind example' of what can be done to unlock the value of the smaller fields of today and tomorrow's North Sea and other mature basins.

Acknowledgements

The authors would like to thank (the contributions of) both other members of the BP project team and the partners for their contribution to the development of this paper.

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13 May 1993

Mr Rodney Smith
Field Operations
MMS
Anchorage

RECEIVED
Anchorage, Alaska

MAY 18 1993

REGIONAL SUPERVISOR
FIELD OPERATION
MINERALS MANAGEMENT SERVICE

Dear Rod,

Attached is the Final Report of "Kuvlum #1 Exploration Prospect Site Specific Monitoring Program" prepared by Coastal & Offshore Pacific Corporation for ARCO Alaska, Inc. (May 14, 1993).

For those who made them, we appreciate the comments which you provided on the Draft Final Report. Each was carefully taken into account in the preparation of this Final Report.

Marine mammal monitoring by COPAC at the Kuvlum exploration prospect will also be conducted ~~conducted~~ in summer/fall of this year. This is the first occasion on which a site specific monitoring effort will be carried out at the same Beaufort Sea location in successive years. The program objectives will therefore remain the same with the added expectation that, given adequate sighting data, even more robust statistical analyses on bowhead whale migratory patterns in the vicinity of an oil and gas exploratory operation can be performed.

Thank you for your interest in this scientific effort.

With best regards,

Bob Griffeth
Senior Consultant--Environmental Sciences
Tel. (907) 265-1551

Attachment: Kuvlum #1 Final Report (2 copies)

UNITED STATES GOVERNMENT
MEMORANDUM

To: Regional Supervisor, Field Operations

Through: Supervisor, Rules, Orders, and Standards

From: Petroleum Engineer Breitmeier 8/25/92

Subject: Kuvlum Special PINC List and Critical Operations and Curtailment Plan (COCP) Questions

Completion of the Kuvlum Special PINC list has been held up pending receipt from the District Supervisor of information on the COCP. Approval of the Application for Permit to Drill (APD) was made contingent upon satisfactory answers to a number of important questions and needed clarifications on the COCP (see attachment 1). This request was made formally on August 7, 1992. ARCO replied with a fax transmission late on Friday, August 14, 1992 with the rig already on location. Several of the questions were not answered adequately; most notably, a request to supply a complete explanation of ARCO's kick tolerance policy for this well, which forms an integral part of the Kulluk alert system and information as to how they propose to collect information sufficient to calculate hazard time at least to Secure Time + 12 hours (Green Alert Status).

The Acting District Engineer and I have attempted, since receipt of this fax, to obtain this information through the District Supervisor, both by verbal and written request. To date we have still not received adequate information on either of these questions.

On the issue of kick tolerance, ARCO has provided a copy of Beaudril's kick tolerance policy which is, on the whole, acceptable. However, they explicitly state that "these calculations do not in any way, provide a substitute for sound engineering judgement." They do not indicate what this "sound engineering judgement" is based on if not these calculations. They also state that "Any final decision regarding alert levels and the impact of kick tolerance on alert levels will be made by the ARCO and Beaudril supervisors onsite." This, in effect, negates the COCP they have provided us. They claim that Beaudril's policy is flawed because it contains "numerous subjective assumptions." The Acting District Engineer and I have examined this policy in depth and find the few assumptions made both reasonable and not uncommon for any engineering calculation. The only safety factor amounts to less than 0.335 pounds per gallon.

It has further been communicated verbally to me by the District Supervisor that ARCO intends to continue drilling below a zero kick tolerance level. In the opinion of the Field Operations petroleum engineering staff, to do so would be irresponsible and a violation of both 30 CFR 250.50, requiring use of best and safest technology to control the well, and 30 CFR 250.54(a)(6), requiring a "safe margin between the mud weight in use and the equivalent mud weight at the casing shoe as determined in the pressure integrity

test." Furthermore, approval of such a policy by this office would almost certainly constitute negligence and make us liable with the operator for any damages, deaths, or injuries, resulting from a blowout where kick tolerance was allowed to drop below zero.

For Hazard time calculations, ARCO has not demonstrated that they have the means to detect multi-year ice at a radius great enough to allow them pull back into casing, hang off, disconnect, and pull anchors, and still have the necessary 12 hours operating time to be in a green alert. Later in the well the Secure time alone may be more than 18 hours.

According to the APD approval letter, ARCO is not supposed to be drilling until these issues have been resolved. I hope this is the case.

John M. Breitmeier

Attachment

bcc: OCS-Y 0866 6A
Chrons(ros/cc)
ROS Supervisor
Author

JBreitmeier:finaled:nep:8/25/92
F:\USERS\ROS\BREITMER\KUV.MEM

ARCO Alaska, Inc.
Post Office Box .0360
Anchorage Alaska 99510-0360
Telephone 907 276 1215

March 5, 1993

U.S. Minerals Management Service
Attention: Mr. Allen D. Powers, Regional Director
949 East 36th Avenue, Room 603
Anchorage, Alaska 99508-4302

Received
OCS District Office

APR 2 3 1993

Minerals Management Service
Anchorage, Alaska

Re: Determination of Well Producibility
Kuvlum #1 Well
OCS-Y-0866, Block 673
Flaxman Island Area
Eastern Beaufort Sea

Gentlemen:

We hereby respectfully request that the Kuvlum #1 Well be determined as a well capable of producing oil in paying quantities, as provided under *30 CFR 250.11.*

The production test on this well began on September 30, 1992 and was completed on October 4, 1992. A representative from your office, Mr. Jim Reggs was present during the time of the testing of the well. The test results from this well have already been provided to your office. Additionally, we have included the PVT data from the oil sample that was taken, as well as a breakdown of lifting costs associated with the Kuvlum #1 Well. Should you need additional information to qualify the Kuvlum #1 Well, please advise the undersigned and I will be happy to provide it to you. We would respectfully request that this data be held confidential in accordance with *30 CFR 250.18.*

We intend to unitize Block 673 with additional leasehold around the block and plan to have a formal unit proposal and a request for suspension of production submitted to you no later the end of this month. Therefore your attention to this request prior to that date would be very much appreciated.

If you have any questions, please feel free to call me at (907) 263-4933.

Very truly yours,

David A. Sutter
District Landman

:jls

cc: Kuvlum Working Interest Owners

ATTACHMENT

Union Texas Petroleum Alaska Corporation
Attention: Bruce Hamilton
1330 Post Oak Boulevard
Houston, TX 77056

Phillips Petroleum Company
Attention: John E. Herndon
6330 West Loop South
Bellaire, TX 77401

Total Minatome Corporation
Attn: J. Kirby Barry
909 Fannin, Suite 2000
Houston, TX 77010

Murphy Oil USA, Inc.
Attention: Mike Shirley
131 South Robertson
New Orleans, LA 70112

Mobil Exploration & Producing U.S. Inc.
Attention: Fred Pierson
3000 Pegasus Park Drive
Dallas, TX 75247

Received
OCS District Office
APR 25 1993
Minerals Management Service
Anchorage, Alaska

ARCO Alaska Inc.

Kuvlum #1

(OCS-Y-0866 #1 Well)

Determination of Well as Capable of Producing in Paying Quantities

Received
OCS District Office
APR 23 1993
Minerals Management Service
Anchorage, Alaska

Received
OCS District Office

APR 23 1993
Minerals Management Service
Anchorage, Alaska

Discussion in Support of the Kuvlum #1 Well
(OCS-Y-0866 #1 Well)

Paying Quantities

The following discussion provides necessary information required to certify the Kuvlum #1 (OCS-Y-0866 #1) well as capable of producing in paying quantities. This discussion will include a review of tested oil rates from the well, a complete reservoir fluids analysis of the produced oil, a brief discussion of anticipated well production operations, the anticipated incremental well operating costs, and a paying quantities calculation. ***It is understood that this information is confidential and should not be released to any 3rd party.***

Tested Oil Rate:

Two separate drill stem tests from the single hydrocarbon bearing perforated interval are available to illustrate the productive capability of the Kuvlum #1 well.

During the final 8 hours of the flow period of **DST #1** (Oct. 1, 0130-0930 hrs), the well flowed at a **stabilized oil rate of 1680 BOPD** of 33.5 Degree API oil with flowing tubing pressure of 652 psig. The detailed well production report for DST #1 is included as attachment 1.

During the final 3 hour flow period of **DST #2** (Oct. 4, 0200-0500 hrs) the well flowed at a **stabilized oil rate of 3550 BOPD** with flowing tubing pressure of 300 psig. The detailed well production report for DST #2 is included as attachment 2.

This information, along with additional test information, is available in the report entitled "Kuvlum #1, September 30 - October 4, 1992, Drill Stem Test" prepared by Halliburton Reservoir Services of which two (2) copies were previously sent to your office. Mr. Jim Regg of your office was present to witness testing of the Kuvlum #1 well.

Reservoir Fluid Analysis:

Attachment 3 is a standard reservoir fluid study of the Kuvlum #1 well prepared by Core Laboratories. For security purposes, the Kuvlum #1 well name was not referenced in the reservoir fluid analysis report. The laboratory measured oil gravity of 34.2 Degree API confirms the field oil gravity measurements and indicates that the produced oil is of high quality.

Production Operations:

A typical production completion for a Kuvlum well would consist of drilling through the productive sand interval and cementing production casing in place. The well would then be perforated through casing. The completion would consist of production tubing with gas lift mandrels, a production packer, and subsurface safety valve. The well would be manifolded to allow for gas lift operation as needed. Fluid production of a typical Kuvlum well would be by either natural flow or gas lift assisted flow. Replication of Kuvlum #1 testing parameters of wellhead pressure, tubing size, reservoir pressure drawdown, and oil production rate would be easily attainable in a continuous field production operation.

Incremental Well Operating Costs:

The incremental operating costs of a well are assumed to be those costs directly related to the operation of a given well such as chemical usage, metering, maintenance, and routine wireline work. Incremental well operating costs do not include a prorated share of the processing facility, drillsite or platform operating and maintenance costs.

Average incremental well cost for a typical Kuvlum well is estimated to be approximately 100,000 $/Well/Year. This estimate is based on a study of routine Kuparuk River Field incremental well operating costs exclusive of significant remedial repair work. It is assumed that the typical Kuvlum well would be burdened by incremental well costs similar to those seen at the Kuparuk River Field.

Break-even Oil Rate to Yield Paying Quantities

The Kuvlum #1 well can be determined to be capable of producing in paying quantities if the production of oil and/or gas in quantities sufficient to yield a return in excess of incremental well operating costs is achieved. In addition, excess returns are considered after the payment of any production royalties. A federal royalty of 12.5% is included in the paying quantities calculation.

The incremental well operating costs and royalty payments described above were used to determine the break-even oil rate required to yield paying quantities for The Kuvlum #1 well. The oil price(s) used in these calculations are based on the West Coast ANS Oil Price Projections contained in the Revenue Source Book (Fall 1992) published by the Department of Natural Resources, State of Alaska. A copy of the pertinent price table is shown in attachment 4.

An example of the break-even oil rate needed to yield paying quantities given an oil price of 17.13 $/STBO, an incremental well operating cost of 100,000 $/year/well, and a federal royalty of 12.5% is shown below.

$$\text{Break-even Oil Rate} = \frac{\text{Incremental Well Operating Cost(\$/Year/Well)}}{\text{Oil Price(\$/STBO)*(1-Royalty \%)*365(Days/Year)}}$$

$$= \frac{\text{100,000(\$/Year/Well)}}{\text{(17.13(\$/STBO)*(1-.125)*365(Days/Year)}},$$

$$= 18.3 \text{ STBO/Day/Well}$$

The break-even oil rate of 18.3 STBO/Day/Well from the above example corresponds to the minimum 1993 oil price estimate of 17.13 $/STBO from the State of Alaska ANS price projection. This calculation is before federal income taxes (BFIT).

The break-even oil rate requirement to achieve economic returns in excess of operating costs was determined for a wide range of oil prices. The break-even oil rate as a function of oil price is shown in attachment 5. For the State of Alaska's 1993 range of oil price projections, the break-even oil rate to achieve economic returns is approximately 18 STBO/Day/Well. In a lower oil price scenario of 10 $/STB, it can be seen that oil rates greater than 31 STBO/Day/Well provide returns in excess of operating costs. For a higher oil price scenario of 25 $/STB, oil rates greater than 13 STBO/Day/Well provide returns in excess of operating costs.

Conclusion:

Based on the above calculations, the break-even oil rate required to achieve economic returns in excess of well operating costs and therefore achieve paying quantities ranges from 13-31 STBO/Day/Well. The drill stem testing of the Kuvlum #1 well demonstrated oil rate productivity up to 3550 STBO/Day. The Kuvlum #1 well therefore meets the MMS requirements of being capable of producing in paying quantities.

Halliburton Reservoir Services Surface Test Data

Company: ARCO Alaska,Inc.
Well: Kuvlum #1 DST #1
Date: 30-Sep-1992

				Tank And Separtor Data					SCAN Data					
Time	Whp (psig)	Wht (deg F)	Choke (64ths)	Inc Vol (bbls)	Rate (bbl/day)	Cum Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Mtr Corr Vol (bbls)	Oil Rate (1.108) (bbl/day)	Mtr Prod Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Comments
30-Sep-92														Page No. 3.1.1
08:43:15	0.00	21.00	12 Adj											Open Well For Initial Flow(Tank #2).
08:53:15	319.00	20.00	Closed	0.00	0.00	0.00								Close Well In @ LPR-N.
08:54:00	315.37	43.89	Closed											Colse Sub Sea Retainer Valve.
09:00:00	0.00	42.01	Closed											Rig Up Wireline w/SRO Gauge & "E" Probe.
09:37:00	329.15	39.68	Closed											Press Up To Open Sub Sea Retainer Valve.
09:43:00	329.40	38.19	Closed											RIH w/Wireline.
10:19:00	332.20	33.57	Closed											Attempt To Latch "E" Probe. Pulls Out @700# Over
10:19:00	332.20	33.57	Closed											Line Wt. Make Five Attempts To Latch "E" Probe.
10:20:00	332.20	33.40	Closed											POOH w/Wireline.
11:12:00	331.70	30.81	Closed											Out Of Hole w/Wireline. Close Sub Sea Retainer.
11:31:00	0.00	34.03	Closed											WL Rigged Down. Open Sub Sea Retainer.
11:40:30	327.00	34.00	12 Adj	0.00	0.00	0.00								Open Well For Test(Tank #2).
12:00:00	321.00	42.00	16 Adj	0.00	0.00	0.00								Divert To Heater. Dirty Diesel Returns.
12:15:00	287.00	38.00	20 Adj	2.50	240.05	2.50								BS&W=0.01% Solids and Diesel Returns.
12:30:00	286.00	38.00	24 Adj	2.50	240.05	5.00								BS&W=0.001% Solids and Diesel Returns.
12:45:00	239.00	39.00	24 Adj	5.83	560.11	10.84								BS&W=0.02% Solids and Diesel Returns.
13:00:00	284.00	38.00	24 Adj	9.59	920.18	20.42								BS&W=0.001% Solids and Diesel Returns.
13:15:00	370.00	39.00	28 Adj	15.00	1440.29	35.42								BS&W=0.001% Solids and Diesel Returns.

Note: 1.) Opening Sub Sea Retainer Valve Requires Pressuring Up Tubing Above Retainer.

2.) Failed Attempts To Latch "E" Probe Could Be The Result Of Debris From Initial Flow. The Buffer Tube Assembly Still Pluged At Surface.

3.) Possible Failure Of LPR-N Invalidates Initial Flow And Buildup.

Halliburton Reservoir Services Surface Test Data

Company: ARCO Alaska,Inc.
Well: Kuvlum #1 DST #1
Date: 30-Sep-1992

				Tank And Separtor Data					SCAN Data					
Time	Whp (psig)	Wht (deg F)	Choke (64ths)	Inc Vol (bbls)	Rate (bbl/day)	Cum Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Mtr Corr Vol (bbls)	Oil Rate (1.106) (bbl/day)	Mtr Prod Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Comments
30-Sep-92														Page No. 3.1.2
13:30:00	519.00	39.00	28 Adj	10.42	1000.20	45.84								BS&W=0.01% Solids 27% H2O and Diesel.
13:45:00	592.00	39.00	28 Adj	2.92	280.06	48.76								Oil At Surface.
14:00:00	611.00	41.00	28 Adj	0.42	40.01	49.18								Gas At Surface Divert To Lo Stage.
14:15:00	665.00	38.00	28 Adj	2.50	240.05	51.68	176.57	1.66						BS&W=1.0% H2O.
14:30:00	691.00	38.00	28 Adj	0.83	80.02	52.51	N/A							BS&W=1.0% H2O.
14:45:00	751.00	38.00	28 Adj	0.83	80.02	53.34	N/A							BS&W=0.5% H2O 0.001% Solids.
15:00:00	745.00	37.00	28 Adj	10.42	1000.20	63.76	663.05	8.98				588.06	2.04	BS&W=0.1% H2O 0.001% Solids CO2=0.2%.
15:15:00	784.00	38.00	28 Adj	11.25	1080.22	75.02	663.78	16.10						BS&W=0.75% H2O.
15:30:00	782.00	38.00	28 Adj	9.17	880.18	84.18	661.56	22.99				588.47	14.30	BS&W=0.75% H2O.
15:45:00	780.00	38.00	28 Adj	17.09	1640.33	101.27	665.24	29.92						BS&W=0.25% H2O.
16:00:00	782.00	38.00	28 Adj	6.67	640.13	107.94	745.60	37.69				701.95	28.93	BS&W=0.1% H2O CO2=0.3% Divert To HI Stage
16:15:00	780.00	38.00	28 Adj	0.00	0.00	107.94	785.32	45.87						BS&W=0.2% H2O.
16:30:00	780.00	38.00	28 Adj	0.00	0.00	107.94	768.97	53.86				775.11	45.07	BS&W=0.0%.
16:45:00	759.00	38.00	28 Adj	0.00	0.00	107.94	1047.53	64.79						BS&W=0.0%.
17:00:00	713.00	38.00	28 Pos	0.42	13.34	108.36	1061.17	76.05				934.13	64.53	BS&W=0.0% OG= 34 @ 60 D.F. CO2=0.2%
17:15:00	705.00	38.00	28 Pos	9.17	880.18	117.52	1093.88	87.44						BS&W=0.1% H2O Lo Stage Meter Freezing Up.
17:30:00	703.00	38.00	28 Pos	25.84	2480.50	143.36	1102.63	98.93				1094.68	87.34	BS&W=0.01%.
17:45:00	701.00	38.00	28 Pos	24.59	2360.48	167.95	1083.45	110.22						BS&W=0.02%. Inject Defoamer Data Header.
18:00:00	699.00	39.00	28 Pos	22.50	2160.43	190.45	1088.68	121.56				1079.40	109.83	BS&W=0.25% OG= 33.3 @ 60 D.F. CO2=0.35%
18:15:00	698.00	39.00	28 Pos	19.17	1840.37	209.63	1077.14	132.78						BS&W=0.1% Gel.
18:30:00	695.00	39.00	28 Pos	19.17	1840.37	228.80	1094.93	144.18	33.93	1801.65	33.93	1073.45	132.19	BS&W=0.1% Gel.
18:45:00	695.00	40.00	28 Pos	20.00	1920.38	248.80	1108.81	155.73						BS&W=0.05% Gel. Gas Gravity = 0.722.

Halliburton Reservoir Services Surface Test Data

Company: ARCO Alaska,Inc.
Well: Kuvlum #1 DST #1
Date: 30-Sep-1992

				Tank And Separtor Data					SCAN Data					
Time	Whp (psig)	Wht (deg F)	Choke (64ths)	Inc Vol (bbls)	Rate (bbl/day)	Cum Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Mtr Corr Vol (bbls)	Oil Rate (1.106) (bbl/day)	Mtr Prod Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Comments
30-Sep-92														Page No. 3.1.3
19:00:00	693.00	40.00	28 Pos	21.25	2040.41	270.05	1107.18	167.27	33.54	1760.57	67.47	1095.41	154.80	BS&W=0.1% Gel OG= 33.9 @ 60 D.F. CO2=0.4%
19:15:00	691.00	40.00	28 Pos	22.09	2121.42	292.14	1102.43	178.75						
19:30:00	690.00	40.00	28 Pos	18.34	1760.35	310.48	1102.01	190.23	32.99	1751.01	100.46	1107.25	177.87	
19:45:00	689.00	40.00	28 Pos	20.42	1960.39	330.90	1140.28	202.11						
20:00:00	687.00	41.00	28 Pos	18.34	1760.35	349.24	1086.31	213.42	33.02	1752.96	133.48	1091.94	200.62	BS&W=0.0% OG= 34.0 @ 60 D.F. CO2=0.02%
20:30:00	685.00	41.00	28 Pos				984.96	233.94	32.61	1731.53	166.09	1110.89	223.76	Started One Hour Tank Straps.
21:00:00	683.00	42.00	28 Pos	81.68	1960.39	430.92	1061.68	256.06	32.45	1722.63	198.54	1067.78	246.43	BS&W=0.0% OG= 33.9 @ 60 D.F. CO2=0.4%.
21:30:00	680.00	42.00	28 Pos				1068.90	278.33	32.49	1724.55	231.03	1068.37	269.10	
22:00:00	678.00	43.00	28 Pos	47.09	1130.23	476.01	1061.40	300.44	31.96	1696.71	262.99	1054.75	291.07	BS&W=0.0% OG= 33.6 @ 60 D.F. CO2=0.4%.
22:30:00	675.00	44.00	28 Pos				1038.21	322.07	31.83	1689.75	294.82	1029.66	312.53	
23:00:00	672.00	44.00	28 Pos	80.02	1920.38	556.03	1018.32	343.29	31.71	1683.55	326.53	1016.96	333.71	BS&W=0.0% OG= 33.8 @ 60 D.F. CO2=0.3%.
23:30:00	672.00	44.00	28 Pos				1005.92	364.24	31.83	1689.88	358.36	1005.74	354.67	
01-Oct-92														
00:00:00	671.00	44.00	28 Pos	70.43	1690.34	626.46	1000.98	385.10	32.08	1702.94	390.44	991.84	375.33	BS&W=0.0% OG= 33.7 @ 60 D.F. CO2=0.3%.
00:30:00	668.00	45.00	28 Pos				979.35	405.50	31.18	1655.24	421.62	1001.11	396.19	Gas Gravity = 0.730.
01:00:00	666.00	45.00	28 Pos	75.02	1800.36	703.47	995.71	426.24	31.69	1682.44	453.31	1012.74	417.29	BS&W=0.0% Oil Grav= 33.6 @ 60 D.F.
01:30:00	664.00	45.00	28 Pos				1006.68	447.22	31.26	1659.82	484.57	1014.50	438.42	
02:00:00	663.00	46.00	28 Pos	74.18	1780.36	777.66	1000.11	468.05	31.14	1652.85	515.71	991.20	459.07	BS&W=0.0% OG= 33.9 @ 60 D.F. CO2=0.3%.
02:30:00	661.00	46.00	28 Pos				990.80	488.69	30.95	1643.39	546.66	1009.60	480.10	
03:00:00	659.00	46.00	28 Pos	67.51	1620.32	845.17	1024.99	510.05	30.85	1637.43	577.51	1018.51	501.32	BS&W=0.0% Oil Grav= 33.6 @ 60 D.F.
03:30:00	657.00	46.00	28 Pos				1030.16	531.51	30.67	1628.26	608.18	1041.26	523.02	
04:00:00	656.00	47.00	28 Pos	62.51	1500.30	907.68	1027.72	552.92	30.71	1630.81	638.90	1045.93	544.81	BS&W=0.0% OG= 33.6 @ 60 D.F. CO2=0.2%.

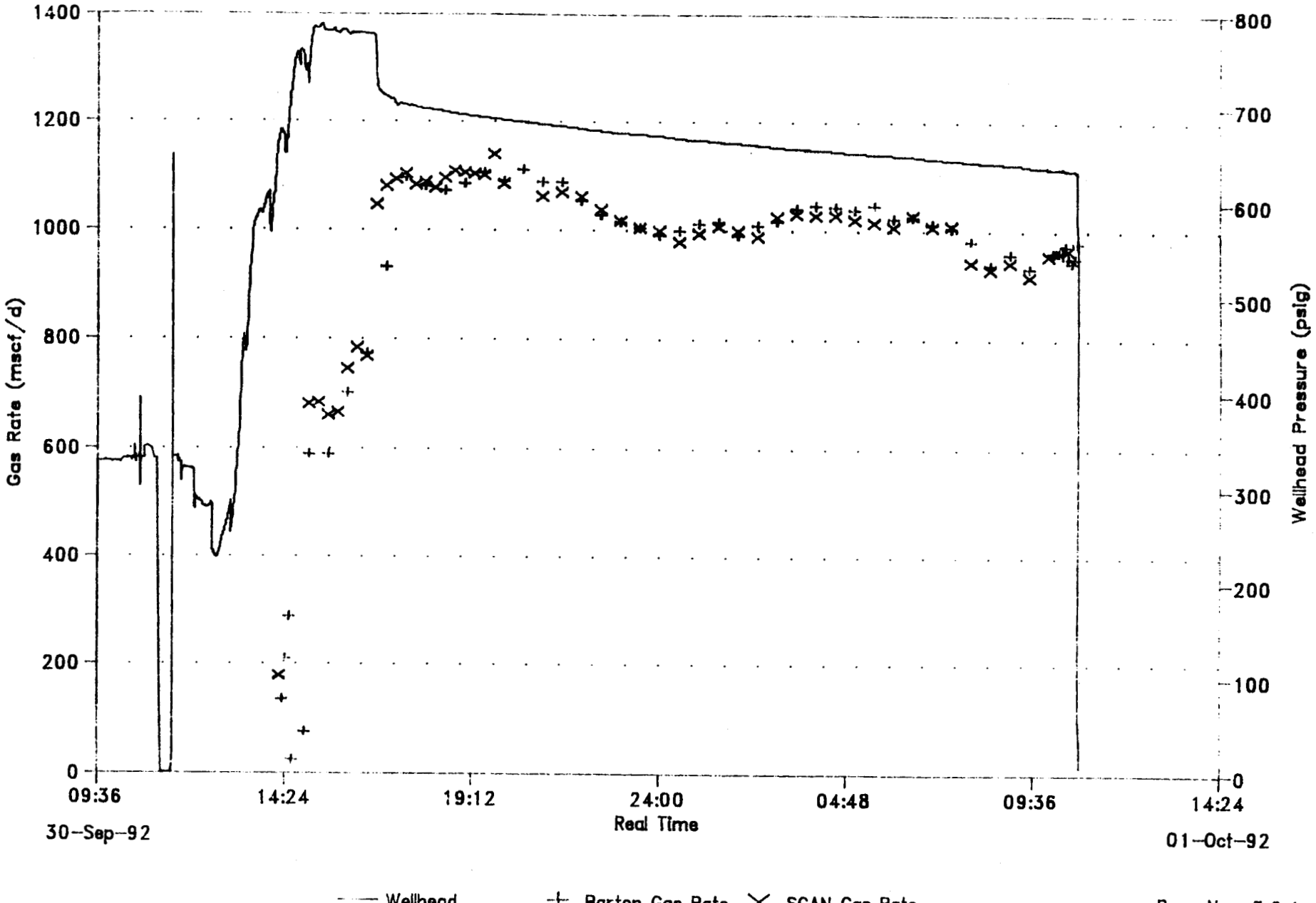
Halliburton Reservoir Services Surface Test Data

Company: ARCO Alaska,Inc.
Well: Kuvlum #1 DST #1
Date: 30-Sep-1992

				Tank And Separtor Data						SCAN Data				
Time	Whp (psig)	Wht (deg F)	Choke (64ths)	Inc Vol (bbls)	Rate (bbl/day)	Cum Vol (bbls)	Gas Rate Total (mcf/day)	Cum Gas (mscf)	Mtr Corr Vol (bbls)	Oil Rate (1.106) (bbl/day)	Mtr Prod Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Comments
01-Oct-92														Page No. 3.1.4
04:30:00	655.00	48.00	28 Pos				1027.76	574.33	30.58	1623.37	669.48	1043.70	586.55	
05:00:00	653.00	47.00	28 Pos	76.77	1890.36	986.45	1019.84	595.58	31.62	1678.66	701.10	1037.76	598.17	BS&W=0.0% Oil Grav= 34.8 @ 60 D.F.
05:30:00	652.00	47.00	28 Pos				1016.07	616.75	31.45	1669.55	732.54	1047.78	610.00	
06:00:00	651.00	48.00	28 Pos	67.51	1620.32	1053.96	1007.72	637.74	30.45	1616.47	763.00	1023.84	631.32	BS&W=0.0% OG= 32.1 @ 60 D.F. CO2=0.2%.
06:30:00	649.00	48.00	28 Pos				1028.29	659.16	31.66	1681.09	794.66	1026.58	652.71	
07:00:00	647.00	48.00	28 Pos	74.18	1780.36	1128.14	1007.08	680.14	32.09	1703.80	826.75	1012.53	673.81	BS&W=0.0% Oil Grav= 32.9 @ 60 D.F.
07:30:00	646.00	48.00	28 Pos				1009.29	701.17	31.25	1659.23	858.00	1005.23	694.75	
08:00:00	644.00	48.00	28 Pos	84.18	2020.40	1212.33	942.29	720.80	30.76	1633.26	888.77	982.16	715.21	BS&W=0.0% OG= 33.2 @ 60 D.F. CO2=0.2%.
08:30:00	643.00	49.00	28 Pos				931.59	740.21	31.06	1650.14	919.85	937.87	734.75	
09:00:00	642.00	49.00	28 Pos	54.18	1300.26	1266.50	942.94	759.85	31.69	1682.17	951.54	959.12	754.73	Started 30 Minute Tank Straps.
09:30:00	640.00	49.00	28 Pos	30.84	1480.30	1297.34	918.01	778.98	31.77	1686.86	983.32	933.33	774.18	Attempt To Close LPR-N Valve. Did
10:00:00	637.00	49.00	28 Pos	32.92	1580.32	1330.27	956.13	798.90						Not Close. Continue To Cycle Annulus
10:30:00	635.00	49.00	28 Pos	40.42	1940.39	1370.69	966.90	819.04				962.52	794.23	Pressure With No Success.
10:46:00	558.00	47.00	28 Pos	17.09	1537.81	1387.78						957.75	804.20	Close OMNI Valve.
10:47:00	160.00	41.00	Closed	0.83	1200.24	1388.61								Close Sub Sea Retainer Valve.

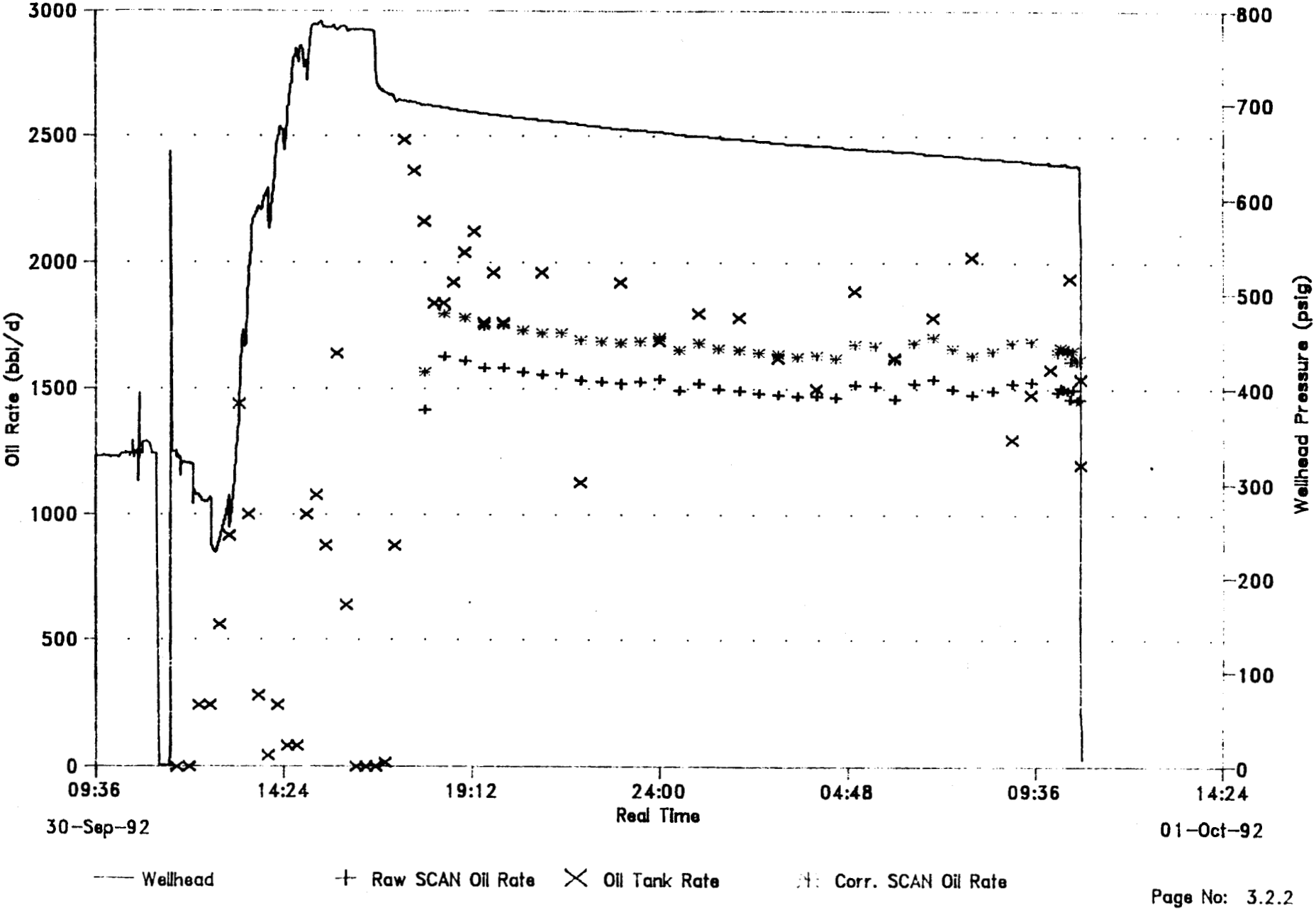
Halliburton Reservoir Services

Wellhead Press & Rates VS Real Time



Halliburton Reservoir Services

Wellhead Press & Oil Rates VS Real Time



Halliburton Reservoir Services Surface Test Data

Company: ARCO Alaska,Inc.
Well: Kuvlum #1 DST #2
Date: 02-Oct-1992

				Tank And Separtor Data					SCAN Data					
Time	Whp (psig)	Wht (deg F)	Choke (64ths)	Inc Vol (bbls)	Rate (bbl/day)	Cum Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Mtr Corr Vol (bbls)	Oil Rate (0.80446) (bbl/day)	Mtr Prod Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Comments
03-Oct-92														Page No. 6.1.1
10:36:00	0.00	36.71	16 Adj											Open LPR-N For Flow.
11:00:00	0.00	37.56	28 Adj	6.25	375.08	6.25								Diesel Returns.
11:30:00	0.00	36.55	28 Adj	2.08	100.02	8.34								No Sample - Gas Only.
12:00:00	0.00	36.35	28 Adj	0.42	20.01	8.75								No Sample - Gas Only.
12:30:00	0.00	35.74	28 Adj	0.83	40.01	9.59								No Sample - Gas Only.
13:00:00	0.00	35.61	28 Adj	0.42	20.01	10.00								No Sample - Gas Only.
13:30:00	0.00	36.36	28 Adj	0.00	0.00	10.00								No Sample - Gas Only.
14:00:00	0.00	35.96	28 Adj	1.67	80.02	11.67								No Sample - Gas Only.
14:30:00	0.00	34.46	28 Adj											No Sample - Gas Only.
15:00:00	0.00	32.99	28 Adj	0.42	20.01	12.09								No Sample - Gas Only.
15:30:00	0.00	31.49	28 Adj											No Sample - Gas Only.
15:43:00	0.00	30.80	Closed	0.00	0.00	12.09								Close In Well @ LPR-N & Cycle OMNI To Clr Pos
15:55:00	0.00	30.02	Closed											LPR-N Valve Closed - OMNI Valve In Clr. Pos.
16:03:00	179.50	35.16	28 Adj											Open Choke Manifold To Reverse Out To Tanks.
16:15:00	406.10	39.42	28 Adj											Oil & Gas Returns.
16:16:00	415.13	39.79	28 Adj											Emulsified H2O @ Data Header.
16:20:00	382.63	40.05	32 Adj											
16:23:00	380.08	40.75	36 Adj											
16:30:00	391.48	42.53	36 Adj											BS&W=90% H2O 0.25% Solids.
16:45:00	387.50	43.76	36 Adj											BS&W=99.8% H2O 0.2% Solids.
16:55:00	296.75	44.13	Closed											Finish Reversing Out. 61 bbls Returned To Tank.
17:05:00	10.65	42.32	Closed											Start Displacing w/Diesel. Returns Going To Rig.
17:30:00	307.62	38.59	Closed											Continue Pumping Diesel.

Halliburton Reservoir Services Surface Test Data

Company: ARCO Alaska,Inc.
Well: Kuvlum #1 DST #2
Date: 02-Oct-1992

				Tank And Separtor Data					SCAN Data					
Time	Whp (psig)	Wht (deg F)	Choke (64ths)	Inc Vol (bbls)	Rate (bbl/day)	Cum Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Mtr Corr Vol (bbls)	Oil Rate (0.80446) (bbl/day)	Mtr Prod Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Comments
03-Oct-92														Page No. 6.1.2
17:55:00	642.50	36.39	Closed											Finish Displacing w/Diesel. 44 bbls Pumped.
18:05:00	2176.75	36.01	Closed											Cycle OMNI Valve To Well Test Pos.
18:21:00	0.00	34.05	28 Adj											Open Well To Flow @ LPR-N And Ch. Man.
18:23:00	151.60	43.47	32 Adj											
18:24:00	97.52	41.22	37 Adj											
18:24:30	42.82	39.05	40 Adj											
18:25:00	28.02	39.53	44 Adj											
18:30:00	0.00	42.15	44 Adj	4.58	733.48	16.67								Sample - Clean Diesel.
18:36:00	0.00	41.68	40 Adj											Sample - Clean Diesel.
18:37:00	0.00	41.61	36 Adj											Sample - Clean Diesel.
18:38:00	0.00	41.57	32 Adj											Sample - Clean Diesel.
18:42:00	0.00	41.37	28 Adj											Sample - Clean Diesel.
18:45:00	0.00	41.27	28 Adj	7.08	680.14	23.76								Sample - Clean Diesel.
18:49:00	0.00	41.54	20 Adj											Sample - Clean Diesel.
18:52:00	0.00	41.52	16 Adj											Sample - Clean Diesel.
19:00:00	0.00	41.23	16 Adj	4.58	440.09	28.34								Sample - Clean Diesel.
19:15:00	0.00	40.82	16 Adj	3.33	320.06	31.67								Sample - Clean Diesel.
19:30:00	0.00	40.31	16 Adj	2.50	240.05	34.17								Sample - Clean Diesel.
19:45:00	1.88	39.61	16 Adj	3.33	320.06	37.51								Sample - Clean Diesel.
19:55:00	21.95	39.47	20 Adj											Sample - Clean Diesel.
19:58:00	29.90	39.41	24 Adj											Sample - Clean Diesel.
20:00:00	31.30	39.25	28 Adj	5.00	480.10	42.51								Sample - Clean Diesel.
20:07:00	75.27	40.63	36 Adj											Sample - Clean Diesel.

Halliburton Reservoir Services Surface Test Data

Company: ARCO Alaska,Inc.
Well: Kuvlum #1 DST #2
Date: 02-Oct-1992

				Tank And Separtor Data					SCAN Data					
Time	Whp (psig)	Wht (deg F)	Choke (64ths)	Inc Vol (bbls)	Rate (bbl/day)	Cum Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Mtr Corr Vol (bbls)	Oil Rate (0.80446) (bbl/day)	Mtr Prod Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Comments
03-Oct-92														Page No. 6.1.3
20:15:00	55.33	38.60	36 Adj	12.50	1200.24	55.01								Sample - Clean Diesel.
20:19:00	34.35	38.55	36 Adj											Trace Formation Fluids To Surface.
20:30:00	125.88	39.82	36 Adj	3.75	360.07	58.76								BS&W=75% H2O Salinity=110,000 ppm PH=7.5.
20:45:00	230.65	39.91	36 Adj	15.84	1520.30	74.60								BS&W=90% H2O 0.3% Solids PH=8.
21:00:00	289.25	40.24	36 Adj	3.33	320.06	77.93	567.80	5.91						BS&W=30% H2O 0.2% Solids CO2=0.15%.
21:15:00	356.50	40.47	36 Adj											BS&W=6% H2O 0.1% Solids Sal.=108,000 ppm.
21:30:00	449.00	40.85	36 Adj	0.00	0.00	77.93						342.78	1.19021	BS&W=0.3% H2O Salinity=108,000 ppm PH=7.5.
21:45:00	439.25	41.06	40 Adj									336.5	2.35661	BS&W=5% H2O Trace Solids.
22:00:00	478.75	42.00	40 Adj	20.00	960.19	97.94								BS&W=0.5% H2O Trace Solids.
22:30:00	553.75	43.01	40 Adj	35.42	1700.34	133.36	847.71	23.58				750.52	9.13414	BS&W=0.5% H2O Trace Solids.
23:00:00	564.50	41.89	40 Adj	26.67	1280.26	160.03	904.66	42.42	44.67	1724.89	44.67	902.364	27.9334	BS&W=0.1% H2O. Oil Grav.= 31.5 @60 D.F.
23:07:00	576.00	41.68	Closed	2.08	428.66	162.12	898.25	46.79	6.06	1002.29	50.73	879.436	32.2084	Shut Well In @ Choke Manifold.
23:11:00	688.75	42.71	Closed											Shut Sub Sea Retainer Valve.
23:12:00	688.50	42.24	Closed											Bleed Off Press. To Rig Up Wireline PLT.
23:15:00	0.00	31.17	Closed											Rig Up Wireline PLT.
04-Oct-92														
00:11:00	831.00	52.24	Closed											Open Sub Sea Retainer Valve And RIH w/PLT.
01:15:00	933.25	39.05	16 Adj											Open Well @ Choke Manifold. Increase Choke Slow
01:30:00	511.75	39.52	46 Adj	3.75	360.07	165.87	1110.43	58.36				1116.55	33.7592	BS&W=0.5% H2O Trace Solids.
01:37:00	466.75	40.93	52 Adj											Increase Choke.
01:44:00	425.00	42.23	60 Adj											Increase Choke.
02:00:00	351.75	43.76	60 Adj	91.27	4380.88	257.14	1640.30	92.53	49.06	5711.89	99.79	1664.27	66.9341	BS&W=0.1% H2O Trace Solids CO2=0.15%.
02:30:00	309.25	45.91	60 Adj	65.85	3160.63	322.98	1513.79	124.07	106.93	4129.07	206.72	1532.17	98.8543	BS&W=0.3% Emulsion. @02:00 Start Defoamer.

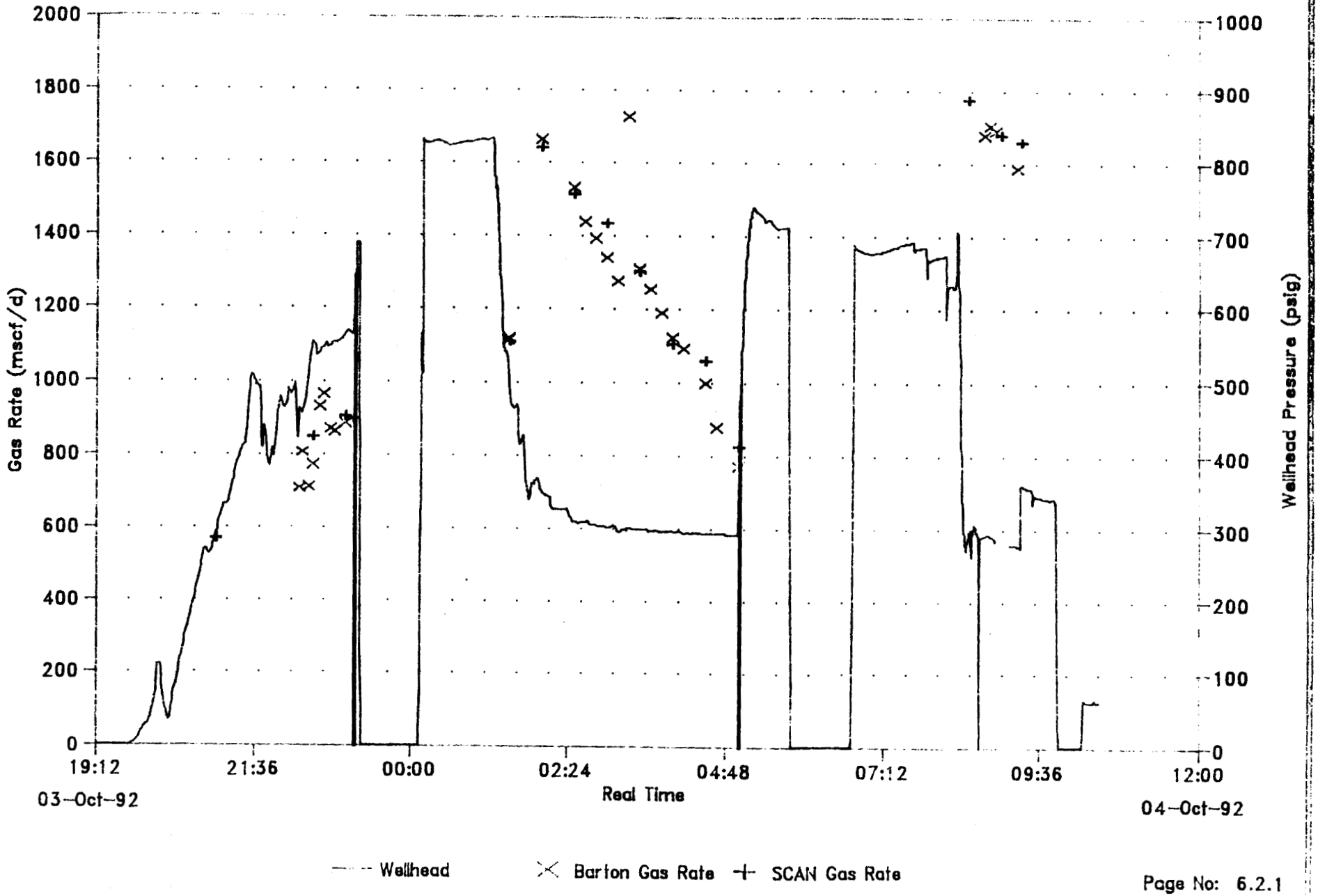
Halliburton Reservoir Services Surface Test Data

Company: ARCO Alaska,Inc.
Well: Kuvlum #1 DST #2
Date: 02-Oct-1992

				Tank And Separtor Data					SCAN Data					
Time	Whp (psig)	Wht (deg F)	Choke (64ths)	Inc Vol (bbls)	Rate (bbl/day)	Cum Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Mtr Corr Vol (bbls)	Oil Rate (0.80446) (bbl/day)	Mtr Prod Vol (bbls)	Gas Rate Total (mscf/day)	Cum Gas (mscf)	Comments
04-Oct-92														Page No. 6.1.4
03:00:00	302.50	47.38	60 Adj	65.85	3160.63	388.83	1435.90	153.98	100.58	3883.80	307.30	1389.86033	127.81	BS%W=0.1% Emulsion. Trace Sand.
03:30:00	299.50	48.66	60 Adj	61.68	2960.59	450.51	1301.30	181.09	101.63	3924.35	408.93	1436.267	157.774	BS%W=0.1% Emulsion. Trace Sand.
04:00:00	298.25	49.83	60 Adj	67.93	3260.65	518.44	1101.92	204.05	93.09	3594.58	502.02	1168.303	182.53	BS&W=0.0% Trace Sand. OG=31.6 @60 D.F.
04:30:00	294.50	50.74	60 Adj	70.01	3360.67	588.45	1059.25	226.12	96.55	3805.42	600.57	1045.22	204.305	
05:00:00	292.25	51.64	Closed	95.02	4560.91	683.47	823.50	243.27	96.24	3793.45	698.81	823.88	221.47	Close Well In @ Choke Manifold.
05:12:00	737.00	49.01	Closed											Close LPR-N Valve.
05:41:00	711.50	39.13	Closed											Close Sub Sea Retainer Valve.
05:50:00	0.00	31.63	Closed											Rig Down PLT & Rig Up SRO Gauge w/"E" Probe.
06:42:00	0.00	31.73	Closed											Open Sub Sea Valve.
06:45:00	688.00	40.72	Closed											Run In Hole w/SRO Gauge.
07:26:00	687.75	31.89	closed											Latch "E" Probe. Pull 1100# Over Line Wt.
08:09:00	673.50	29.20	Closed											2 Attempts Can Not Open Valve. Remain Latched.
08:18:00	630.25	31.60	Closed											Open LPR-N Valve.
08:19:00	653.00	30.97	16 Adj											Open Well @Choke Man. Increase Slowly.
08:30:00	287.25	44.55	128 Adj	22.09	2891.49	705.56	1774.84	256.83						BS&W=0.25% H2O. Trace Sand.
09:00:00	279.83	48.75	128 Adj	60.43	2900.58	765.99	1676.68	291.76				1697.27	233.256	BS&W=0.0% Trace Sand. Oil Grav.=31.8 @60 D.F.
09:18:00	275.75	49.22	Closed	62.51	5001.00	828.50	1658.23	326.31						Close Well In @ LPR-N And Ch. Man. For Ice Event.
09:20:00	359.53	49.44	Closed											Unlatch "E" Probe And POOH.
09:47:00	342.99	39.44	Closed											OOH w/Wireline.
09:51:00	336.03	38.55	Closed											Close Sub Sea Retainer Valve. Bleed Off Press.
10:20:00														Rig Down CoFlex Line. Rig Up Kill Line.

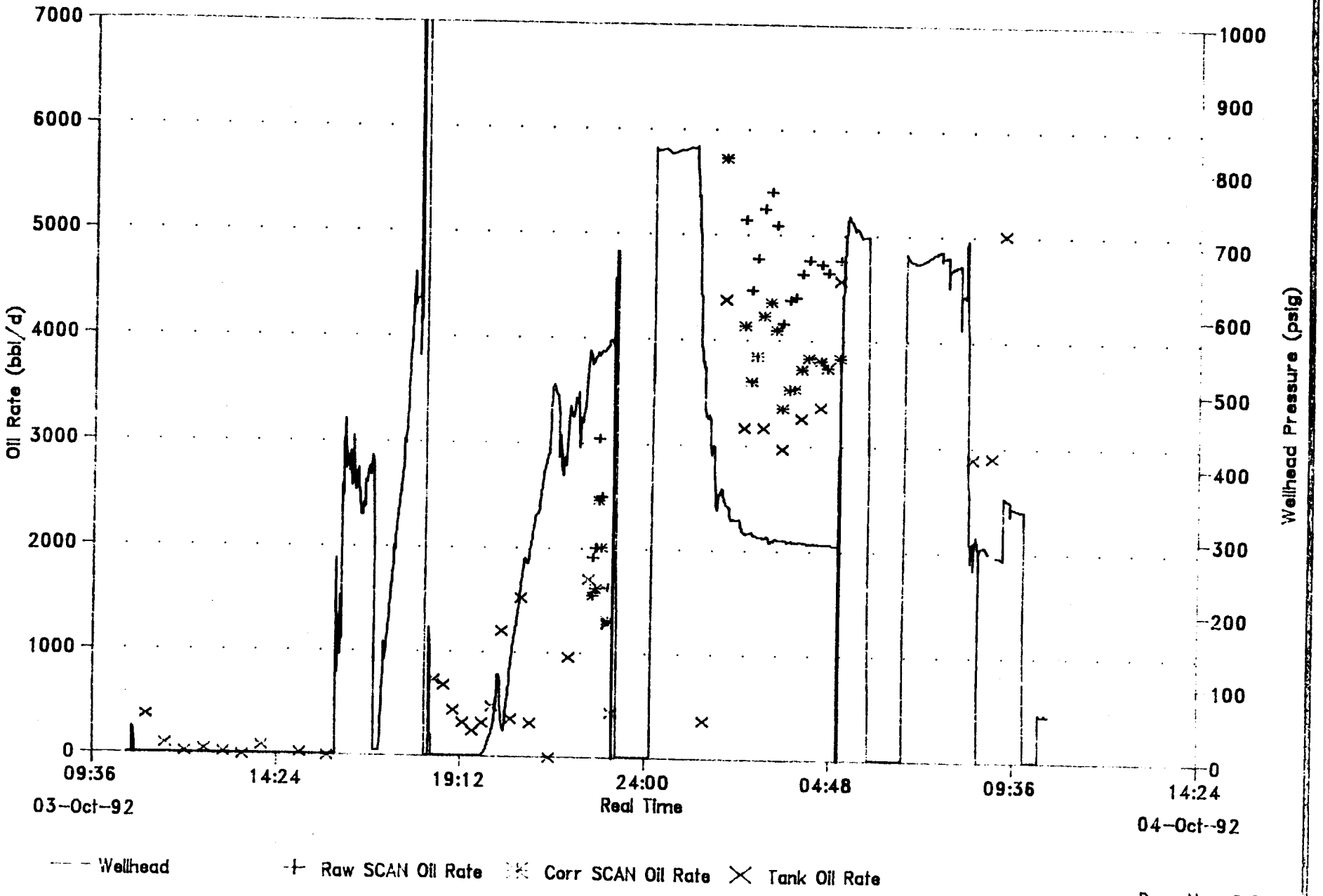
Halliburton Reservoir Services

Wellhead Press & Gas Rates VS Real Time



Halliburton Reservoir Services

Wellhead Press & Oil Rates VS Real Time



CONFIDENTIAL

Western Atlas International

CORE LABORATORIES

Reservoir Fluid Study
for

Arco Exploration & Production Technology

*
*

RFL 920279
19-Nov-92

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Core Laboratories
a division of Western Atlas International, Inc.

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Western Atlas International

CORE LABORATORIES

November 19, 1992

Arco Exploration and Production Technology
2300 West Plano Parkway
Rm PRC -E1115
Plano, TX 75075

ATTENTION: Mr. Russ Bone

Subject: **Reservoir Fluid Study**
Well:
File: **RFL 920279**

Dear Mr. Bone,

Multiple samples of separator gas and oil were collected from the subject well by representatives of Arco Exploration and Production Technology. These samples were shipped to our laboratory in Carrollton, Texas for use in a reservoir fluid study. The results of this study are presented on the following pages.

It has been a pleasure to perform this reservoir fluid study for Arco Exploration and Production Technology. Should any questions arise or if we may be of further service in any way, please do not hesitate to contact us.

Sincerely,

Karl W. Karnes

Karl W. Karnes
Supervising Engineer
Reservoir Fluid Analysis

KWK
16 cc: Addressee
15 bound & 1 unbound

Laboratory Procedures

Arco Exploration & Production Technology
Reservoir Fluid Study

RFL 920279

On October 16, 1992, multiple samples of separator gas and oil were received in our Carrollton, Texas laboratory. Bubblepoint determinations of each liquid sample were measured at lab ambient temperature as a quality check. Gas opening pressures were also measured. A summary of samples received in the laboratory may be found on page four.

Each of the six separator gas samples was analyzed by extended gas chromatography to determine gas composition to the last detectable peak. These data are presented on pages five through ten. The compositions of the two separator oil samples were measured through a heptanes plus residual fraction by low temperature fractional distillation. The heptanes plus fractions were further analyzed by gas chromatography through hexatriacontanes plus. The composition and density of the fluids can be found on pages 11 through 16.

A routine quality control check of separator products' compositions is a "K-value" plot of relative component content versus component boiling point. Specifically, the K-value is the mole percent of a particular hydrocarbon component of the gas divided by the mole percent of this component of the separator oil. When the logs of the K-values of methane through hexanes plus nitrogen, carbon dioxide and hydrogen sulfide are plotted against the boiling points of the individual components, the results should yield a smooth line. Additionally, theoretical equilibrium ratios (K-values) can be determined for specific separator conditions and plotted with the measured data. When these plots were made for the above compositional data, the plots did not agree well with the theoretical data. An example of the K-value plots is presented following the separator products' compositions and is designated figure QC-1.

The separator gas was combined with the separator oil to yield a saturation pressure of 3000 psig at 119°F. This recombined reservoir fluid was used for all further analyses. The composition of the reservoir fluid was determined through a heptanes plus residual fraction by low temperature fractional distillation. The heptanes plus fractions were further analyzed by gas chromatography through hexatriacontanes plus. These data are presented on pages 17 through 19.

A portion of the reservoir fluid was charged to a high pressure, windowed cell heated to the reported reservoir temperature of 119°F. During the constant composition expansion at this temperature, a bubblepoint was observed at 3019 psig. The results of the pressure-volume relations are presented on pages 20 and 21.

During the differential vaporization at the reservoir temperature, the fluid evolved a total of 612 cubic feet of gas at 14.65 psia and 60°F per barrel of residual oil at 60°F. The resulting relative oil volume factor was 1.272 barrels of saturated fluid per barrel of residual oil at 60°F. The oil density and the properties of the evolved gases were measured at each point during the differential pressure depletion and the data included in the summary of the differential vaporization data on page 22.

The viscosity of the reservoir fluid was measured over a wide range of pressures at 119°F in a rolling ball viscosimeter. The viscosity of the fluid was found to vary from a minimum of 1.014 centipoises at the saturation pressure to a maximum of 3.623 centipoises at atmospheric pressure. The results of the viscosity measurements are presented on page 23.

Small portions of the reservoir fluid were subjected to two two-stage and one three-stage separator tests to determine gas/oil ratio, stock tank oil gravity and formation volume factor. These data can be found on page 24. The gases and stock tank oil evolved from the "base case" separator test were collected and analyzed. These compositions are presented on pages 25 through 28. The separator test data were used to adjust the differential vaporization data to surface conditions and are summarized on pages 30 and 32.

A large portion of reservoir fluid was charged to a PVT cell at 119°F. From this sample three gas depleted oils were prepared at specified saturation pressures. A separator test was performed on the individual "DV" oils at the same conditions as the "base case" multi-stage separator test investigated above. The results of these analyses are presented on page 29.

Equations and nomenclature are included in the appendix of the report which extend and define the analytical expressions and data relationships presented in the study.

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Arco Exploration & Production Technology

RFL 920279

SUMMARY OF PVT DATA

Reservoir Conditions

Current Reservoir Pressure	3000	psig
Reservoir Temperature	119	°F

Pressure-Volume Relations

Saturation Pressure	3019	psig
Avg Single-Phase Compressibility	8.08	E-6 v/v/psi (5000 to 3019 psig)
Thermal Exp @ 5000 psig	1.02791	V at 119 °F / V at 70 °F

Differential Vaporization Data

(at 3019 psig and 119 °F)

Solution Gas/Oil Ratio	612	scf / bbl of residual oil at 60 °F
Relative Oil Volume	1.272	bbl / bbl of residual oil at 60 °F
Density of Reservoir Fluid	0.7448	gm/cc

Reservoir Fluid Viscosity

1.01 cp at 3019 psig and 119 °F

Separator Test Data

Separator Conditions		Formation Volume Factor (A)	Total Solution Gas/Oil Ratio (B)	Tank Oil Gravity (°API at 60 °F)
psig	°F			
100	90	1.276	625	34.1
100	140	1.284	632	34.0
500	90	1.260	593	34.6

(A) Barrels of oil at 3019 psig and 119 °F per barrel of stock tank oil at 60 °F.

(B) Total standard cubic feet of gas per barrel of stock tank oil at 60 °F.

Arco Exploration & Production Technology

RFL 920279

General Well Information

Company	**Arco Exploration & Production Technology**
Well Name	**Brad Berg #1**
API Well Number	*
File Number	**RFL 920279**
Date Sample Collected	*
Sample Type	**Separator**
Geographical Location	*
Field	*

Well Description

Formation	*	
Pool (or Zone)	*	
Date Completed	*	
Elevation	*	ft
Producing Interval	*	ft
Total Depth	*	ft
Tubing Size	*	in
Tubing Depth	*	ft
Casing Size	*	in
Casing Depth	*	ft

Pressure Survey Data

Data from Original Discovery Well

Date	*	
Reservoir Pressure	*	psig

Data at Sample Collection

Date	*	
Reservoir Pressure	**3000**	psig
Reservoir Temperature	**119**	°F
Pressure Tool	*	
Flowing Bottom-Hole Pressure	*	psig
Flowing Tubing Pressure	*	psig

* Data not forwarded to Core Laboratories.

Arco Exploration & Production Technology

RFL 920279

Production Data

Data from Original Discovery Well

Location	*	
Date	*	
Oil Gravity @ STP	*	°API
Separator Pressure	*	psig
Separator Temperature	*	°F
Production Rates		
Gas	*	Mscf/D
Liquid	*	STbbl/D
Gas/Liquid Ratio	*	scf/bbl

Separator Conditions

Primary Separator Pressure	*	psig
Primary Separator Temperature	*	°F
Secondary Separator Pressure	*	psig
Secondary Separator Temperature	*	°F
Primary Separator Gas Production Rate	*	Mscf/D

Gas Factors -

Field Values:		
Pressure Base	*	psia
Temperature Base	*	°F
Compressibility Factor (Fpv)	*	
Gas Gravity Factor (Fg)	*	
Laboratory Values:		
Pressure Base	14.65	psia
Temperature Base	60	°F
Compressibility Factor (Fpv)		
Gas Gravity Factor (Fg)		

Primary Separator Liquid Rate	*	bbl/D	at	°F
Stock Tank Liquid Rate	*	bbl/D	at	°F
Separator Gas / Separator Liquid Ratio	*	scf/bbl		
Separator Gas / Stock Tank Liquid Ratio	*	scf/bbl		
Stock Tank Liquid / Separator Gas Ratio	*	bbl/Mscf		
Separator Liquid / Stock Tank Liquid Ratio	*	bbl/bbl	at	°F

* Data not forwarded to Core Laboratories.

PRELIMINARY QUALITY CHECKS PERFORMED ON SAMPLES
RECEIVED IN LABORATORY

Separator Gas					
Cylinder Number	Sampling Conditions		Laboratory Opening Conditions		
	psig	°F	psig	°F	Liquid Recovered (cc)
257903D	127	106	125	71	2
349859C	127	106	135	71	2
349869D*	127	106	127	71	2
8EK080	127	106	125	71	2
G20033	127	106	125	71	1
CLH478	127	106	125	71	0

Separator Oil					
Cylinder Number	Sampling Conditions		Laboratory Bubblepoint		
	psig	°F	psig	°F	Water Recovered (cc)
193471D*	127	106	98	71	3
W3A8814	127	106	61	69	2

* Sample selected for recombination.

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Composition of Separator Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.41		44.010	.8172
Nitrogen	0.24		28.013	.8086
Methane	82.30		16.043	.2997
Ethane	5.67	1.508	30.070	.3558
Propane	5.17	1.417	44.097	.5065
iso-Butane	1.43	.465	58.123	.5623
n-Butane	1.93	.605	58.123	.5834
iso-Pentane	0.88	.320	72.150	.6241
n-Pentane	0.51	.184	72.150	.6305
Hexanes	0.58	.224	84.000	.6850
Heptanes	0.47	.197	96.000	.7220
Octanes	0.29	.131	107.00	.7450
Nonanes	0.09	.045	121.00	.7640
Decanes plus	0.03	.017	141.00	.7840
Totals	100.00	5.113		

Sampling Conditions

125 psig
106 °F

Sample Characteristics

Cylinder No. 257903D

Critical Pressure (psia)	644.2
Critical Temperature (°R)	376.3
Average Molecular Weight	21.79
Calculated Gas Gravity (air = 1.000)	0.752
Gas Gravity Factor, Fg	1.1528
Super Compressibility Factor, Fpv at sampling conditions	1.0091
Gas Z-Factor at sampling conditions *	0.982

at 14.65 psia and 60 °F

Gross Heating Value (BTU/scf dry gas)	1299

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	0.88	103.7	0.736	44.6
Decanes plus	0.03	141.0	0.784	38.3

Air Content, mol %

Air Oxygen	0.20
Air Nitrogen	0.72
Total Air Content	0.92

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

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Composition of Separator Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.43		44.010	.8172
Nitrogen	0.13		28.013	.8086
Methane	81.03		16.043	.2997
Ethane	5.86	1.559	30.070	.3558
Propane	5.50	1.507	44.097	.5065
iso-Butane	1.55	.504	58.123	.5623
n-Butane	2.24	.702	58.123	.5834
iso-Pentane	1.07	.389	72.150	.6241
n-Pentane	0.62	.223	72.150	.6305
Hexanes	0.68	.282	84.000	.6850
Heptanes	0.48	.201	96.000	.7220
Octanes	0.25	.113	107.00	.7450
Nonanes	0.10	.050	121.00	.7640
Decanes	0.06	.033	134.00	.7780
Undecanes plus	0.00			
Totals	100.00	5.543		

Sampling Conditions

125 psig
106 °F

Sample Characteristics

Cylinder No. 349859C

Critical Pressure (psia)	641.1
Critical Temperature (°R)	378.3
Average Molecular Weight	22.34
Calculated Gas Gravity (air = 1.000)	0.771
Gas Gravity Factor, Fg	1.1387
Super Compressibility Factor, Fpv at sampling conditions	1.0093
Gas Z-Factor at sampling conditions *	0.982

at 14.65 psia and 60 °F

Gross Heating Value (BTU/ecf dry gas)	1330

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	0.89	104.5	0.737	44.5
Decanes plus	0.06	134.0	0.778	39.1

Air Content, mol %

Air Oxygen	0.11
Air Nitrogen	0.40
Total Air Content	0.52

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

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Composition of Separator Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.43		44.010	.8172
Nitrogen	0.14		28.013	.8086
Methane	81.53		16.043	.2997
Ethane	5.81	1.545	30.070	.3558
Propane	5.33	1.461	44.097	.5065
iso-Butane	1.47	.478	58.123	.5623
n-Butane	2.07	.649	58.123	.5834
iso-Pentane	0.97	.353	72.150	.6241
n-Pentane	0.56	.202	72.150	.6305
Hexanes	0.66	.255	84.000	.6850
Heptanes	0.54	.226	96.000	.7220
Octanes	0.37	.167	107.00	.7450
Nonanes	0.10	.050	121.00	.7640
Decanes	0.02	.011	134.00	.7780
Undecanes plus	Trace			
Totals	100.00	5.397		

Sampling Conditions

127 psig
106 °F

Sample Characteristics

Cylinder No. 349869D

Critical Pressure (psia)	641.6
Critical Temperature (°R)	376.7
Average Molecular Weight	22.18
Calculated Gas Gravity (air = 1.000)	0.766
Gas Gravity Factor, Fg	1.1426
Super Compressibility Factor, Fpv at sampling conditions	1.0093
Gas Z-Factor at sampling conditions *	0.982

at 14.65 psia and 60 °F

Gross Heating Value (BTU/scf dry gas)	1321

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	1.03	103.1	0.735	44.8
Decanes plus	0.02	134.0	0.779	39.0

Air Content, mol %

Air Oxygen	0.20
Air Nitrogen	0.72
Total Air Content	0.92

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

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Composition of Separator Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.43		44.010	.8172
Nitrogen	0.13		28.013	.8086
Methane	81.39		16.043	.2997
Ethane	5.68	1.511	30.070	.3558
Propane	5.28	1.447	44.097	.5065
iso-Butane	1.47	.478	58.123	.5623
n-Butane	2.04	.640	58.123	.5834
iso-Pentane	1.02	.371	72.150	.6241
n-Pentane	0.60	.216	72.150	.6305
Hexanes	0.73	.282	84.000	.6850
Heptanes	0.59	.247	96.000	.7220
Octanes	0.38	.172	107.00	.7450
Nonanes	0.12	.060	121.00	.7640
Decanes	0.09	.049	134.00	.7780
Undecanes plus	0.05	.030	154.00	.7950
Totals	100.00	5.503		

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	1.23	107.0	0.740	44.1
Decanes plus	0.14	141.1	0.784	38.3
Undecanes plus	0.05	154.0	0.795	36.9

Sampling Conditions

127 psig
106 °F

Sample Characteristics

Cylinder No. 8EK080

Critical Pressure (psia)	639.3
Critical Temperature (°R)	374.9
Average Molecular Weight	22.46
Calculated Gas Gravity (air = 1.000)	0.775
Gas Gravity Factor, Fg	1.1356
Super Compressibility Factor, Fpv at sampling conditions	1.0092
Gas Z-Factor at sampling conditions *	0.982

at 14.65 psia and 60 °F

Gross Heating Value (BTU/scf dry gas)	1336

Air Content, mol %

Air Oxygen	0.00
Air Nitrogen	0.00
Total Air Content	0.00

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

Arco Exploration & Production Technology

RFL 920279

Composition of Separator Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.40		44.010	.8172
Nitrogen	0.25		28.013	.8086
Methane	82.65		16.043	.2997
Ethane	5.73	1.524	30.070	.3558
Propane	5.21	1.428	44.097	.5065
iso-Butane	1.39	.452	58.123	.5623
n-Butane	1.87	.586	58.123	.5834
iso-Pentane	0.85	.309	72.150	.6241
n-Pentane	0.49	.176	72.150	.6305
Hexanes	0.51	.197	84.000	.6850
Heptanes	0.36	.151	96.000	.7220
Octanes	0.21	.095	107.00	.7450
Nonanes	0.07	.035	121.00	.7640
Decanes plus	0.01	.006	141.00	.7840
Totals	100.00	4.959		

Sampling Conditions

125 psig
106 °F

Sample Characteristics

Cylinder No. G20033

Critical Pressure (psia)	646.6
Critical Temperature (°R)	377.3
Average Molecular Weight	21.49
Calculated Gas Gravity (air = 1.000)	0.742
Gas Gravity Factor, Fg	1.1610
Super Compressibility Factor, Fpv at sampling conditions	1.0091
Gas Z-Factor at sampling conditions *	0.982

at 14.65 psia and 60 °F

Gross Heating Value (BTU/scf dry gas)	1283

Air Content, mol %

Air Oxygen	0.10
Air Nitrogen	0.37
Total Air Content	0.47

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	0.65	102.9	0.735	44.8
Decanes plus	0.01	141.0	0.784	38.3

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

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Composition of Separator Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.48		44.010	.8172
Nitrogen	0.12		28.013	.8086
Methane	78.87		16.043	.2997
Ethane	5.49	1.460	30.070	.3558
Propane	5.48	1.502	44.097	.5065
iso-Butane	1.62	.527	58.123	.5623
n-Butane	2.41	.756	58.123	.5834
iso-Pentane	1.28	.466	72.150	.6241
n-Pentane	0.80	.288	72.150	.6305
Hexanes	1.27	.490	84.000	.6850
Heptanes	1.47	.615	96.000	.7220
Octanes	0.53	.240	107.00	.7450
Nonanes	0.11	.055	121.00	.7640
Decanes plus	0.07	.040	141.00	.7840
Totals	100.00	6.439		

Sampling Conditions

125 psig
106 °F

Sample Characteristics

Cylinder No. CLH478

Critical Pressure (psia)	625.8
Critical Temperature (°R)	370.8
Average Molecular Weight	24.09
Calculated Gas Gravity (air = 1.000)	0.832
Gas Gravity Factor, Fg	1.0966
Super Compressibility Factor, Fpv at sampling conditions	1.0089
Gas Z-Factor at sampling conditions *	0.982

at 14.65 psia and 60 °F

Gross Heating Value (BTU/scf dry gas)	1421

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	2.18	101.4	0.732	45.1
Decanes plus	0.07	141.0	0.784	38.3

Air Content, mol %

Air Oxygen	0.01
Air Nitrogen	0.04
Total Air Content	0.06

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

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Composition of Separator Oil*

Component	Mol %	Wt %	MW	Liq Dens (gm/cc)
Hydrogen	0.00			
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.05	0.010	44.010	0.8172
Nitrogen	0.00			
Methane	2.34	0.180	16.043	0.2997
Ethane	0.69	0.100	30.070	0.3558
Propane	1.61	0.340	44.097	0.5065
i-Butane	0.83	0.230	58.123	0.5623
n-Butane	1.51	0.420	58.123	0.5834
i-Pentane	1.27	0.440	72.15	0.6241
n-Pentane	1.47	0.510	72.15	0.6305
Hexanes	3.05	1.230	84.00	0.6850
Heptanes plus	87.18	96.540	231.00	0.8750
	100.00	100.00		

Note: Heptanes plus MW and Density are measured values.

* Corrected for hexanes minus fraction identified in residue analysis.

Sampling Conditions

127 psig
106 °F

Sample Characteristics

Cylinder No. 193471D

Average Molecular Weight 208.6
Sample Density (at 60 °F) 0.8596

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Composition of Heptanes Plus Fraction

(From Chromatographic Technique)

Component	Mol %	Wt %	Density (gm/cc)	MW	Vol %
Hydrogen Sulfide	.00	.00			
Carbon Dioxide	.00	.00			
Nitrogen	.00	.00			
Methane	.00	.00			
Ethane	.00	.00			
Propane	.00	.00			
iso-Butane	.00	.00			
n-Butane	.00	.00			
iso-Pentane	.00	.00			
n-Pentane	.00	.00			
Hexanes	.00	.00			
Heptanes	6.70	2.76	.722	96.0	3.35
Octanes	10.58	4.85	.745	107.0	5.70
Nonanes	7.84	4.07	.764	121.0	4.67
Decanes	7.40	4.25	.778	134.0	4.78
Undecanes	5.93	3.74	.789	147.0	4.15
Dodecanes	5.01	3.46	.800	161.0	3.79
Tridecanes	5.58	4.19	.811	175.0	4.53
Tetradecanes	4.96	4.06	.822	190.0	4.33
Pentadecanes	4.90	4.33	.832	206.0	4.55
Hexadecanes	3.86	3.67	.839	222.0	3.83
Heptadecanes	3.38	3.44	.847	237.0	3.56
Octadecanes	3.40	3.66	.852	251.0	3.77
Nonadecanes	2.75	3.10	.857	263.0	3.17
Eicosanes	2.25	2.65	.862	275.0	2.69
Heneicosanes	1.98	2.47	.867	291.0	2.50
Docosanes	1.80	2.35	.872	305.0	2.36
Tricosanes	1.57	2.14	.877	318.0	2.14
Tetracosanes	1.39	1.97	.881	331.0	1.96
Pentacosanes	1.24	1.84	.885	345.0	1.82
Hexacosanes	1.08	1.66	.889	359.0	1.64
Heptacosanes	1.07	1.72	.893	374.0	1.69
Octacosanes	1.00	1.66	.896	388.0	1.62
Nonacosanes	.91	1.57	.899	402.0	1.53
Triacontanes	.87	1.56	.902	416.0	1.52
Hentriacontanes	.74	1.36	.906	430.0	1.31
Dotriacontanes	.64	1.21	.909	444.0	1.16
Tritriacontanes	.57	1.12	.912	458.0	1.08
Tetratriacontanes	.45	.91	.914	472.0	0.88
Pentatriacontanes	.35	.73	.917	486.0	0.70
Hexatriacontanes plus	9.78	23.50	1.070	560.3	19.23
Totals	100.00	100.00			100.00

Sample Characteristics

Cylinder No. 193471D

Total Liquid Molecular Weight	233.2
Total Liquid Density (gm/cc)	0.8760
Total Liquid API Gravity	30.0

Properties of Heavy Fractions

Plus Fractions	Mol %	Wt %	Density (gm/cc)	°API	MW
Heptanes plus	100.00	100.00	0.876	30.0	233.2
Decanes plus	74.88	88.32	0.897	26.3	275.1
Undecanes plus	67.48	84.07	0.904	25.1	290.5
Pentadecanes plus	45.96	68.62	0.929	20.8	348.1
Eicosanes plus	27.69	50.42	0.964	15.3	424.7
Pentacosanes plus	18.70	38.84	0.995	10.6	484.3
Triacontanes plus	13.40	30.39	1.029	6.1	528.9
Pentatriacontanes plus	10.13	24.23	1.065	1.4	557.7

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Composition of Low Temperature Distillation Residue

(From Chromatographic Technique)

Component	Mol %	Wt %	Density (gm/cc)	MW	Vol %
Hydrogen Sulfide	.00	.00			
Carbon Dioxide	.00	.00			
Nitrogen	.00	.00			
Methane	.00	.00			
Ethane	.00	.00			
Propane	.00	.00			
iso-Butane	.00	.00			
n-Butane	.04	.01	.583	58.1	0.02
iso-Pentane	.10	.03	.624	72.2	0.04
n-Pentane	.10	.03	.630	72.2	0.04
Hexanes	1.21	.44	.685	84.0	0.56
Heptanes	6.62	2.75	.722	96.0	3.33
Octanes	10.40	4.83	.745	107.0	5.67
Nonanes	7.73	4.05	.764	121.0	4.64
Decanes	7.29	4.23	.778	134.0	4.76
Undecanes	5.85	3.72	.789	147.0	4.12
Dodecanes	4.94	3.44	.800	161.0	3.76
Tridecanes	5.50	4.17	.811	175.0	4.50
Tetradecanes	4.91	4.04	.822	190.0	4.29
Pentadecanes	4.83	4.31	.832	206.0	4.53
Hexadecanes	3.80	3.65	.839	222.0	3.80
Heptadecanes	3.33	3.42	.847	237.0	3.53
Octadecanes	3.35	3.64	.852	251.0	3.73
Nonadecanes	2.71	3.08	.857	263.0	3.14
Eicosanes	2.22	2.64	.862	275.0	2.68
Heneicosanes	1.95	2.46	.867	291.0	2.48
Docosanes	1.77	2.34	.872	305.0	2.34
Tricosanes	1.55	2.13	.877	318.0	2.13
Tetracosanes	1.37	1.96	.881	331.0	1.94
Pentacosanes	1.23	1.83	.885	345.0	1.81
Hexacosanes	1.06	1.65	.889	359.0	1.63
Heptacosanes	1.06	1.71	.893	374.0	1.67
Octacosanes	.98	1.65	.896	388.0	1.61
Nonacosanes	.90	1.56	.899	402.0	1.52
Triacontanes	.86	1.55	.902	416.0	1.50
Hentriacontanes	.73	1.35	.906	430.0	1.30
Dotriacontanes	.62	1.20	.909	444.0	1.15
Tritriacontanes	.56	1.11	.912	458.0	1.07
Tetratriacontanes	.45	.91	.914	472.0	0.87
Pentatriacontanes	.35	.73	.917	486.0	0.70
Hexatriacontanes pl	9.63	23.38	1.070	560.3	19.12
Totals	100.00	100.00			100.00

Sample Characteristics

Cylinder No. 193471D

Total Liquid Molecular Weight	231.0
Total Liquid Density (gm/cc)	0.8746
Total Liquid API Gravity	30.3

Properties of Heavy Fractions

Plus Fractions	Mol %	Wt %	Density (gm/cc)	°API	MW
Hexanes plus	99.76	99.93	0.875	30.2	231.4
Heptanes plus	98.55	99.49	0.876	30.0	233.2
Decanes plus	73.80	87.86	0.897	26.3	275.0
Undecanes plus	66.51	83.63	0.904	25.1	290.5
Pentadecanes plus	45.31	68.26	0.929	20.8	348.1
Eicosanes plus	27.29	50.16	0.964	15.3	424.7
Pentacosanes plus	18.43	38.63	0.995	10.7	484.3
Triacontanes plus	13.20	30.23	1.028	6.1	528.9
Pentatriacontanes plus	9.98	24.11	1.064	1.4	557.7

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Composition of Separator Liquid*

Component	Mol %	Wt %	MW	Liq Dens (gm/cc)
Hydrogen	0.00			
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.03	0.010	44.010	0.8172
Nitrogen	0.01	0.000	28.013	0.8086
Methane	2.65	0.200	16.043	0.2997
Ethane	0.74	0.100	30.070	0.3558
Propane	1.72	0.350	44.097	0.5065
i-Butane	0.90	0.240	58.123	0.5623
n-Butane	1.70	0.460	58.123	0.5834
i-Pentane	1.40	0.470	72.15	0.6241
n-Pentane	1.37	0.460	72.15	0.6305
Hexanes	3.71	1.460	84.00	0.6850
Heptanes plus	85.77	96.250	240.00	0.8740
	100.00	100.00		

Note: Heptanes plus MW and Density are measured values.

* Corrected for hexanes minus fraction identified in residue analysis.

Sampling Conditions

127 psig
106 °F

Sample Characteristics

Cylinder No. W3A8814

Average Molecular Weight 213.9
Sample Density (at 60 °F) 0.8575

Arco Exploration & Production Technology

RFL 920279

Composition of Heptanes Plus Fraction

(From Chromatographic Technique)

Component	Mol %	Wt %	Density (gm/cc)	MW	Vol %
Hydrogen Sulfide	.00	.00			
Carbon Dioxide	.00	.00			
Nitrogen	.00	.00			
Methane	.00	.00			
Ethane	.00	.00			
Propane	.00	.00			
iso-Butane	.00	.00			
n-Butane	.00	.00			
iso-Pentane	.00	.00			
n-Pentane	.00	.00			
Hexanes	.00	.00			
Heptanes	5.71	2.28	.722	96.0	2.76
Octanes	9.08	4.04	.745	107.0	4.74
Nonanes	7.09	3.57	.764	121.0	4.08
Decanes	6.87	3.83	.778	134.0	4.30
Undecanes	5.64	3.45	.789	147.0	3.82
Dodecanes	4.88	3.27	.800	161.0	3.58
Tridecanes	5.55	4.04	.811	175.0	4.35
Tetradecanes	5.11	4.04	.822	190.0	4.29
Pentadecanes	5.17	4.42	.832	206.0	4.65
Hexadecanes	4.04	3.73	.839	222.0	3.89
Heptadecanes	3.61	3.56	.847	237.0	3.67
Octadecanes	3.71	3.87	.852	251.0	3.97
Nonadecanes	3.02	3.30	.857	263.0	3.37
Eicosanes	2.48	2.84	.862	275.0	2.88
Heneicosanes	2.22	2.69	.867	291.0	2.71
Docosanes	2.03	2.57	.872	305.0	2.58
Tricosanes	1.80	2.38	.877	318.0	2.37
Tetracosanes	1.61	2.21	.881	331.0	2.19
Pentacosanes	1.57	2.26	.885	345.0	2.23
Hexacosanes	1.21	1.81	.889	359.0	1.78
Heptacosanes	1.28	1.99	.893	374.0	1.95
Octacosanes	1.19	1.92	.896	388.0	1.87
Nonacosanes	1.09	1.82	.899	402.0	1.77
Triacontanes	1.05	1.81	.902	416.0	1.76
Hentriacontanes	.89	1.60	.906	430.0	1.55
Dotriacontanes	.77	1.42	.909	444.0	1.36
Tritriacontanes	.69	1.32	.912	458.0	1.27
Tetratriacontanes	.56	1.10	.914	472.0	1.05
Pentatriacontanes	.44	.89	.917	486.0	0.85
Hexatriacontanes plus	9.64	21.97	1.047	546.8	18.35
Totals	100.00	100.00			100.00

Sample Characteristics

Cylinder No. W3A8814

Total Liquid Molecular Weight	240.4
Total Liquid Density (gm/cc)	0.8740
Total Liquid API Gravity	30.4

Properties of Heavy Fractions

Plus Fractions	Mol %	Wt %	Density (gm/cc)	°API	MW
Heptanes plus	100.00	100.00	0.874	30.3	240.3
Decanes plus	78.12	90.11	0.891	27.3	277.2
Undecanes plus	71.25	86.28	0.897	26.3	291.0
Pentadecanes plus	50.07	71.48	0.918	22.6	343.1
Eicosanes plus	30.52	52.60	0.948	17.8	414.0
Pentacosanes plus	20.38	39.91	0.975	13.6	470.1
Triacontanes plus	14.04	30.11	1.006	9.2	514.7
Pentatriacontanes plus	10.08	22.86	1.041	4.4	544.1

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Composition of Low Temperature Distillation Residue

(From Chromatographic Technique)

Component	Mol %	Wt %	Density (gm/cc)	MW	Vol %
Hydrogen Sulfide	.00	.00			
Carbon Dioxide	.00	.00			
Nitrogen	.00	.00			
Methane	.00	.00			
Ethane	.00	.00			
Propane	.00	.00			
iso-Butane	.00	.00			
n-Butane	.04	.01	.583	58.1	0.02
iso-Pentane	.07	.02	.624	72.2	0.03
n-Pentane	.03	.01	.630	72.2	0.02
Hexanes	.71	.25	.685	84.0	0.31
Heptanes	5.65	2.27	.722	96.0	2.74
Octanes	9.00	4.03	.745	107.0	4.73
Nonanes	7.03	3.56	.764	121.0	4.07
Decanes	6.81	3.82	.778	134.0	4.29
Undecanes	5.59	3.44	.789	147.0	3.81
Dodecanes	4.84	3.26	.800	161.0	3.56
Tridecanes	5.50	4.03	.811	175.0	4.34
Tetradecanes	5.07	4.03	.822	190.0	4.28
Pentadecanes	5.15	4.42	.832	206.0	4.67
Hexadecanes	4.00	3.72	.839	222.0	3.87
Heptadecanes	3.58	3.55	.847	237.0	3.66
Octadecanes	3.68	3.86	.852	251.0	3.96
Nonadecanes	2.99	3.29	.857	263.0	3.35
Eicosanes	2.46	2.83	.862	275.0	2.87
Heneicosanes	2.20	2.68	.867	291.0	2.70
Docosanes	2.01	2.56	.872	305.0	2.57
Tricosanes	1.78	2.37	.877	318.0	2.36
Tetracosanes	1.59	2.20	.881	331.0	2.18
Pentacosanes	1.56	2.25	.885	345.0	2.22
Hexacosanes	1.20	1.80	.889	359.0	1.76
Heptacosanes	1.27	1.98	.893	374.0	1.94
Octacosanes	1.18	1.91	.896	388.0	1.86
Nonacosanes	1.08	1.81	.899	402.0	1.76
Triacontanes	1.03	1.80	.902	416.0	1.75
Hentriacontanes	.89	1.60	.906	430.0	1.55
Dotriacontanes	.76	1.42	.909	444.0	1.36
Tritriacontanes	.69	1.32	.912	458.0	1.27
Tetratriacontanes	.56	1.10	.914	472.0	1.05
Pentatriacontanes	.44	.89	.917	486.0	0.85
Hexatriacontanes pl	9.56	21.91	1.047	546.8	18.25
Totals	100.00	100.00			100.00

Sample Characteristics

Cylinder No. W3A8814

Total Liquid Molecular Weight	239.0
Total Liquid Density (gm/cc)	0.8736
Total Liquid API Gravity	30.5

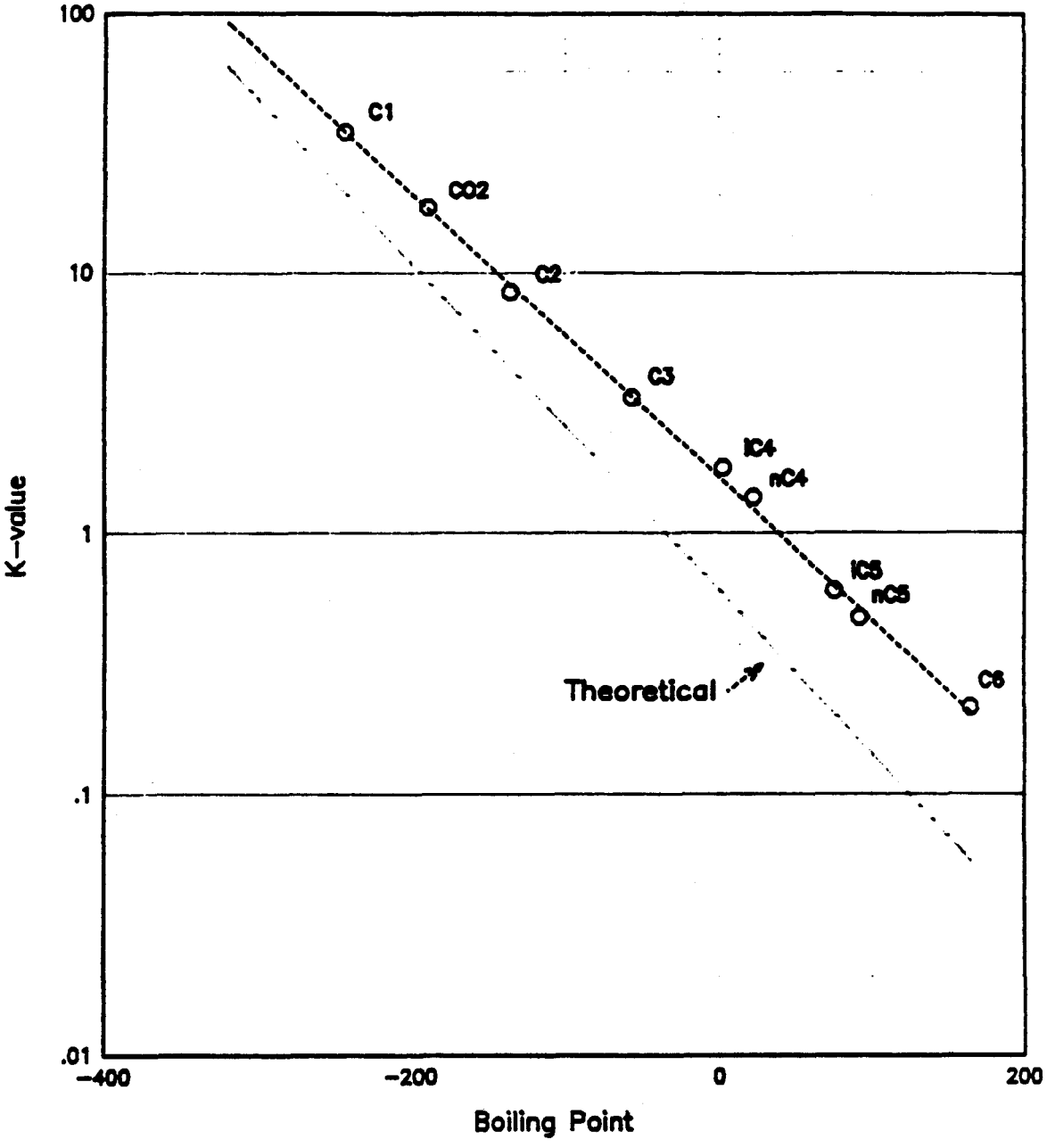
Properties of Heavy Fractions

Plus Fractions	Mol %	Wt %	Density (gm/cc)	°API	MW
Hexanes plus	99.86	99.96	0.874	30.4	239.2
Heptanes plus	99.15	99.71	0.874	30.3	240.4
Decanes plus	77.47	89.85	0.891	27.3	277.2
Undecanes plus	70.66	86.03	0.897	26.3	291.0
Pentadecanes plus	49.66	71.27	0.918	22.6	343.0
Eicosanes plus	30.26	52.43	0.948	17.8	414.0
Pentacosanes plus	20.22	39.79	0.975	13.6	470.1
Triacontanes plus	13.93	30.04	1.006	9.2	514.7
Pentatriacontanes plus	10.00	22.80	1.042	4.3	544.1

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Equilibrium Ratios
(at 106 °F)



Separator Pressure 127 psig	K-Value Plot Figure QC-1

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Composition of Reservoir Fluid*

Component	Mol %	Wt %	MW	Liq Dens (gm/cc)
Hydrogen	0.00			
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.27	0.110	44.010	0.8172
Nitrogen	0.07	0.020	28.013	0.8086
Methane	45.49	6.790	16.043	0.2997
Ethane	3.59	1.000	30.070	0.3558
Propane	3.75	1.540	44.097	0.5065
i-Butane	1.21	0.650	58.123	0.5623
n-Butane	2.01	1.090	58.123	0.5834
i-Pentane	0.93	0.620	72.15	0.6241
n-Pentane	1.05	0.700	72.15	0.6305
Hexanes	2.02	1.580	84.00	0.6850
Heptanes plus	39.61	85.900	233.00	0.8670
	100.00	100.00		

Note: Heptanes plus MW and Density are measured values.

* Corrected for hexanes minus fraction identified in residue analysis.

Sample Characteristics

Pb Adjusted Recombination

Average Molecular Weight	107.5
Sample Density (at 60 °F)	0.7397

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Composition of Heptanes Plus Fraction

(From Chromatographic Technique)

Component	Mol %	Wt %	Density (gm/cc)	MW	Vol %
Hydrogen Sulfide	.00	.00			
Carbon Dioxide	.00	.00			
Nitrogen	.00	.00			
Methane	.00	.00			
Ethane	.00	.00			
Propane	.00	.00			
iso-Butane	.00	.00			
n-Butane	.00	.00			
iso-Pentane	.00	.00			
n-Pentane	.00	.00			
Hexanes	.00	.00			
Heptanes	6.54	2.70	.722	96.0	3.24
Octanes	10.25	4.70	.745	107.0	5.47
Nonanes	7.30	3.80	.764	121.0	4.31
Decanes	6.91	3.98	.778	134.0	4.44
Undecanes	5.44	3.44	.789	147.0	3.78
Dodecanes	4.75	3.29	.800	161.0	3.56
Tridecanes	5.52	4.15	.811	175.0	4.44
Tetradecanes	5.19	4.24	.822	190.0	4.47
Pentadecanes	5.35	4.74	.832	206.0	4.94
Hexadecanes	3.83	3.66	.839	222.0	3.78
Heptadecanes	3.43	3.49	.847	237.0	3.57
Octadecanes	3.39	3.66	.852	251.0	3.73
Nonadecanes	2.91	3.29	.857	263.0	3.33
Eicosanes	2.30	2.72	.862	275.0	2.74
Heneicosanes	2.03	2.54	.867	291.0	2.54
Docosanes	1.86	2.44	.872	305.0	2.43
Tricosanes	1.62	2.22	.877	318.0	2.19
Tetracosanes	1.46	2.06	.881	331.0	2.05
Pentacosanes	1.46	2.17	.885	345.0	2.12
Hexacosanes	1.09	1.68	.889	359.0	1.64
Heptacosanes	1.21	1.95	.893	374.0	1.89
Octacosanes	1.06	1.77	.896	388.0	1.72
Nonacosanes	.92	1.59	.899	402.0	1.53
Triacontanes	1.00	1.79	.902	416.0	1.72
Hentriacontanes	.85	1.58	.906	430.0	1.51
Dotriacontanes	.68	1.30	.909	444.0	1.24
Tritriacontanes	.62	1.23	.912	458.0	1.17
Tetratriacontanes	.57	1.16	.914	472.0	1.10
Pentatriacontanes	.48	1.00	.917	486.0	0.95
Hexatriacontanes plus	9.98	21.64	1.021	504.2	18.38
Totals	100.00	100.00			100.00

Sample Characteristics

Pb Adjusted Recombination

Total Liquid Molecular Weight	232.6
Total Liquid Density (gm/cc)	0.8670
Total Liquid API Gravity	31.7

Properties of Heavy Fractions

Plus Fractions	Mol %	Wt %	Density (gm/cc)	°API	MW
Heptanes plus	100.00	100.00	0.867	31.7	232.5
Decanes plus	75.91	88.80	0.885	28.3	271.9
Undecanes plus	69.00	84.82	0.891	27.3	285.8
Pentadecanes plus	48.10	69.70	0.912	23.6	336.8
Eicosanes plus	29.19	50.86	0.940	19.0	404.9
Pentacosanes plus	19.92	38.86	0.964	15.4	453.3
Triacontanes plus	14.18	29.70	0.988	11.7	486.7
Pentatriacontanes plus	10.46	22.64	1.016	7.8	503.4

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Composition of Low Temperature Distillation Residue

(From Chromatographic Technique)

Component	Mol %	Wt %	Density (gm/cc)	MW	Vol %
Hydrogen Sulfide	.00	.00			
Carbon Dioxide	.00	.00			
Nitrogen	.00	.00			
Methane	.00	.00			
Ethane	.00	.00			
Propane	.00	.00			
iso-Butane	.00	.00			
n-Butane	.00	.00			
iso-Pentane	.00	.00			
n-Pentane	.00	.00			
Hexanes	1.07	.39	.685	84.0	0.49
Heptanes	6.47	2.69	.722	96.0	3.23
Octanes	10.09	4.68	.745	107.0	5.44
Nonanes	7.24	3.79	.764	121.0	4.30
Decanes	6.83	3.96	.778	134.0	4.41
Undecanes	5.39	3.43	.789	147.0	3.77
Dodecanes	4.71	3.28	.800	161.0	3.55
Tridecanes	5.45	4.13	.811	175.0	4.41
Tetradecanes	5.13	4.22	.822	190.0	4.45
Pentadecanes	5.29	4.72	.832	206.0	4.91
Hexadecanes	3.80	3.65	.839	222.0	3.77
Heptadecanes	3.39	3.48	.847	237.0	3.56
Octadecanes	3.36	3.65	.852	251.0	3.71
Nonadecanes	2.88	3.28	.857	263.0	3.32
Eicosanes	2.28	2.71	.862	275.0	2.72
Heneicosanes	2.01	2.53	.867	291.0	2.53
Docosanes	1.84	2.43	.872	305.0	2.42
Tricosanes	1.61	2.21	.877	318.0	2.18
Tetracosanes	1.44	2.07	.881	331.0	2.04
Pentacosanes	1.45	2.16	.885	345.0	2.11
Hexacosanes	1.07	1.67	.889	359.0	1.63
Heptacosanes	1.20	1.94	.893	374.0	1.88
Octacosanes	1.05	1.76	.896	388.0	1.70
Nonacosanes	.91	1.58	.899	402.0	1.52
Triacontanes	.99	1.78	.902	416.0	1.71
Hentriacontanes	.84	1.57	.906	430.0	1.50
Dotriacontanes	.67	1.29	.909	444.0	1.23
Tritriacontanes	.62	1.23	.912	458.0	1.17
Tetratriacontanes	.57	1.16	.914	472.0	1.10
Pentatriacontanes	.48	1.00	.917	486.0	0.94
Hexatriacontanes plu	9.87	21.56	1.021	504.2	18.29
Totals	100.00	100.00			100.00

Sample Characteristics

Pb Adjusted Recombination

Total Liquid Molecular Weight	231.0
Total Liquid Density (gm/cc)	0.8664
Total Liquid API Gravity	31.8

Properties of Heavy Fractions

Plus Fractions	Mol %	Wt %	Density (gm/cc)	°API	MW
Hexanes plus	100.00	100.00	0.866	31.8	231.0
Heptanes plus	98.93	99.61	0.867	31.7	232.6
Decanes plus	75.13	88.45	0.886	28.3	272.0
Undecanes plus	68.30	84.49	0.891	27.3	285.8
Pentadecanes plus	47.62	69.43	0.912	23.6	336.8
Eicosanes plus	28.90	50.65	0.940	19.0	404.9
Pentacosanes plus	19.72	38.70	0.964	15.3	453.3
Triacontanes plus	14.04	29.59	0.988	11.7	486.7
Pentatriacontanes plus	10.35	22.56	1.016	7.7	503.4

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VOLUMETRIC DATA
(at 119 °F)

Saturation Pressure (Psat)	3019	psig
Density at Psat	0.7448	gm/cc
Thermal Exp @ 5000 psig	1.02791	V at 119 °F / V at 70 °F

AVERAGE SINGLE-PHASE COMPRESSIBILITIES

Pressure Range psig			Single-Phase Compressibility v/v/psi
5000	to	4500	7.64 E -6
4500	to	4000	7.95 E -6
4000	to	3500	8.31 E -6
3500	to	3019	8.65 E -6

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PRESSURE-VOLUME RELATIONS

(at 119 °F)

Pressure psig	Relative Volume (A)	Y-Function (B)	Density gm/cc
5000	0.9840		0.7569
4500	0.9878		0.7540
4000	0.9917		0.7510
3500	0.9958		0.7479
3400	0.9967		0.7473
3300	0.9976		0.7466
3200	0.9984		0.7460
3100	0.9993		0.7453
b=3019	1.0000		0.7448
3007	1.0008		
2999	1.0014		
2990	1.0020		
2981	1.0027		
2902	1.0086		
2747	1.0219		
2535	1.0442	4.299	
2237	1.0864	4.019	
1937	1.1483	3.737	
1670	1.2297	3.486	
1438	1.3330	3.268	
1241	1.4592	3.083	
1078	1.6062	2.930	
868	1.8917	2.733	
679	2.3201	2.556	
516	2.9634	2.402	
371	4.0298	2.266	

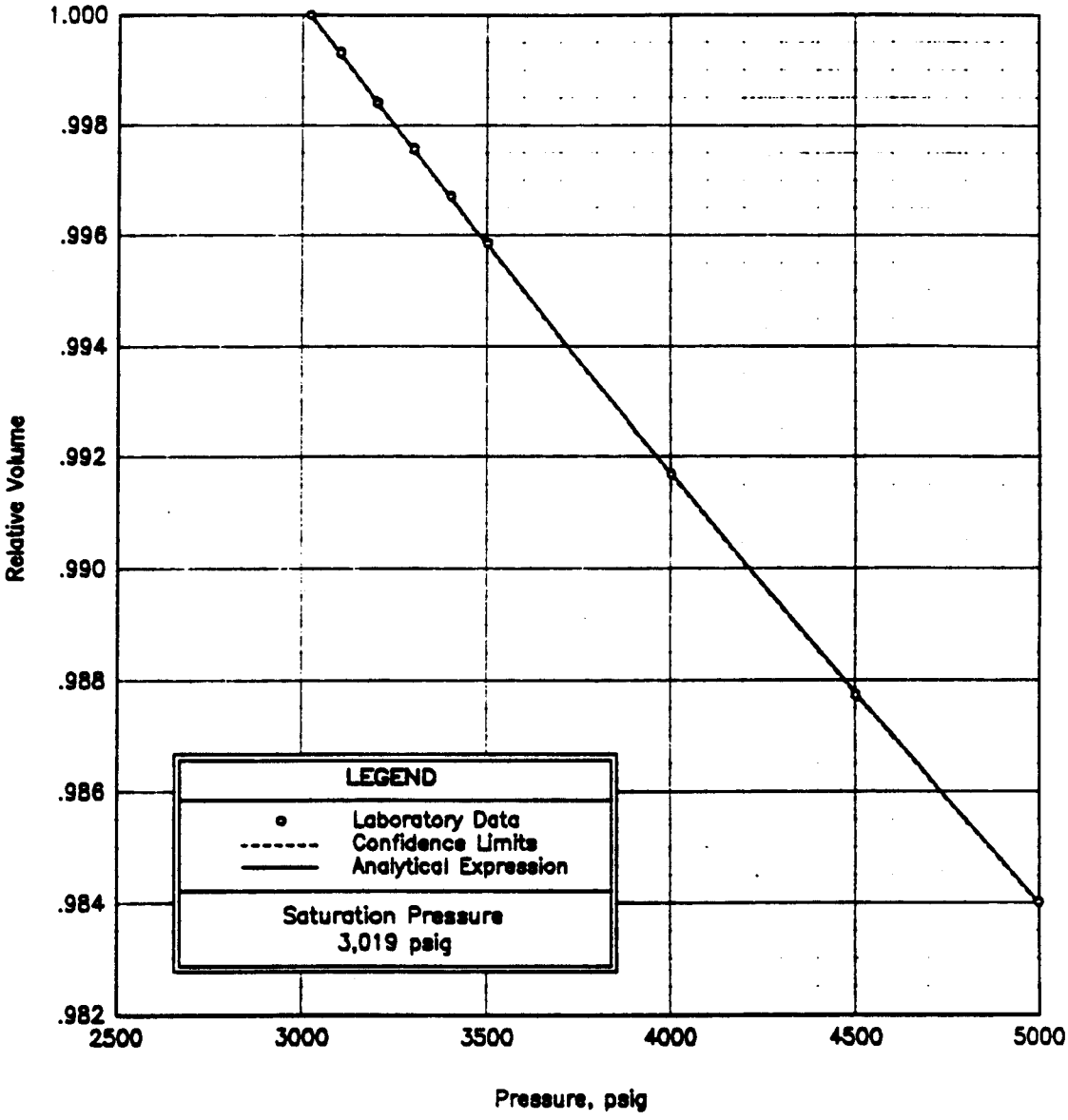
(A) Relative Volume: V/Vsat or volume at indicated pressure per volume at saturation pressure.

(B) Where: Y-Function $= \dfrac{(Psat - P)}{(Pabs) * (V/Vsat - 1)}$

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RELATIVE VOLUME
(at 119 °F)



Analytical Expression

$$1 - 10^{[\ -5.124E00\ +\ 1.033E00\ (\log(\ dP\ ))\ +\ -1.982E-04\ (\log(\ dP\ ))^{5}\ ]}$$

Note: dP is defined as | Pi − Psat |, psig

Statistical Summary	
r squared:	0.999981
Confidence Interval (+/−):	0.0000
Confidence:	99 %

Pressure–Volume Relations

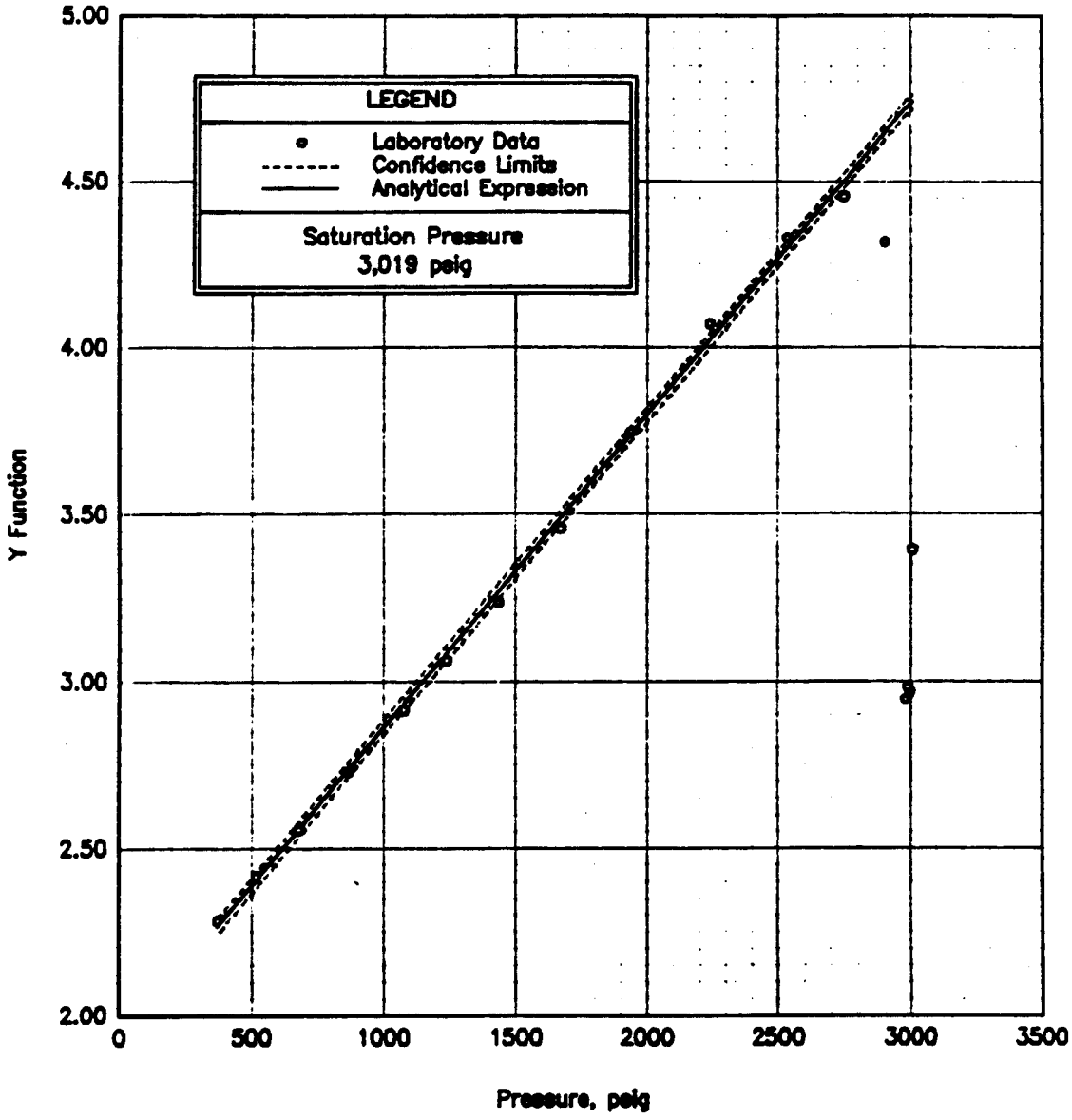
Figure A–1

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Y–FUNCTION
(at 119 °F)



Analytical Expression	9.393E–04 (Xd) + 1.918E00
Note: Xd is defined as Pi / Pest	

Statistical Summary	
r squared:	0.998527
Confidence Interval (+/–):	0.0227
Confidence:	98 %

Pressure–Volume Relations

Figure A–2

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DIFFERENTIAL VAPORIZATION

(at 119 °F)

Pressure psig	Solution Gas/Oil Ratio Rsd (A)	Relative Oil Volume Bod (B)	Relative Total Volume Btd (C)	Oil Density gm/cc	Deviation Factor Z	Gas Formation Volume Factor (D)	Incremental Gas Gravity (Air=1.000)
b=3019	612	1.272	1.272	0.7448			
2700	550	1.249	1.305	0.7512	0.825	0.00496	0.653
2400	493	1.228	1.344	0.7576	0.820	0.00554	0.650
2100	435	1.207	1.408	0.7644	0.828	0.00639	0.646
1800	378	1.185	1.502	0.7715	0.843	0.00758	0.642
1500	321	1.164	1.645	0.7789	0.863	0.00929	0.640
1200	264	1.142	1.880	0.7866	0.886	0.01190	0.640
900	206	1.121	2.298	0.7945	0.912	0.01627	0.645
600	148	1.099	3.163	0.8025	0.940	0.02495	0.665
300	87	1.076	5.773	0.8107	0.970	0.05028	0.720
105	42	1.059	14.767	0.8164	0.989	0.13489	0.825
0	0	1.029		0.8293			1.256
	@ 60 °F	= 1.000					

Gravity of Residual Oil = 34.2 °API at 60 °F
Density of Residual Oil = 0.8531 gm/cc at 60 °F

(A) Cubic Feet of gas at 14.65 psia and 60 °F per Barrel of residual oil at 60 °F.

(B) Barrel of oil at indicated pressure and temperature per Barrel of residual oil at 60 °F.

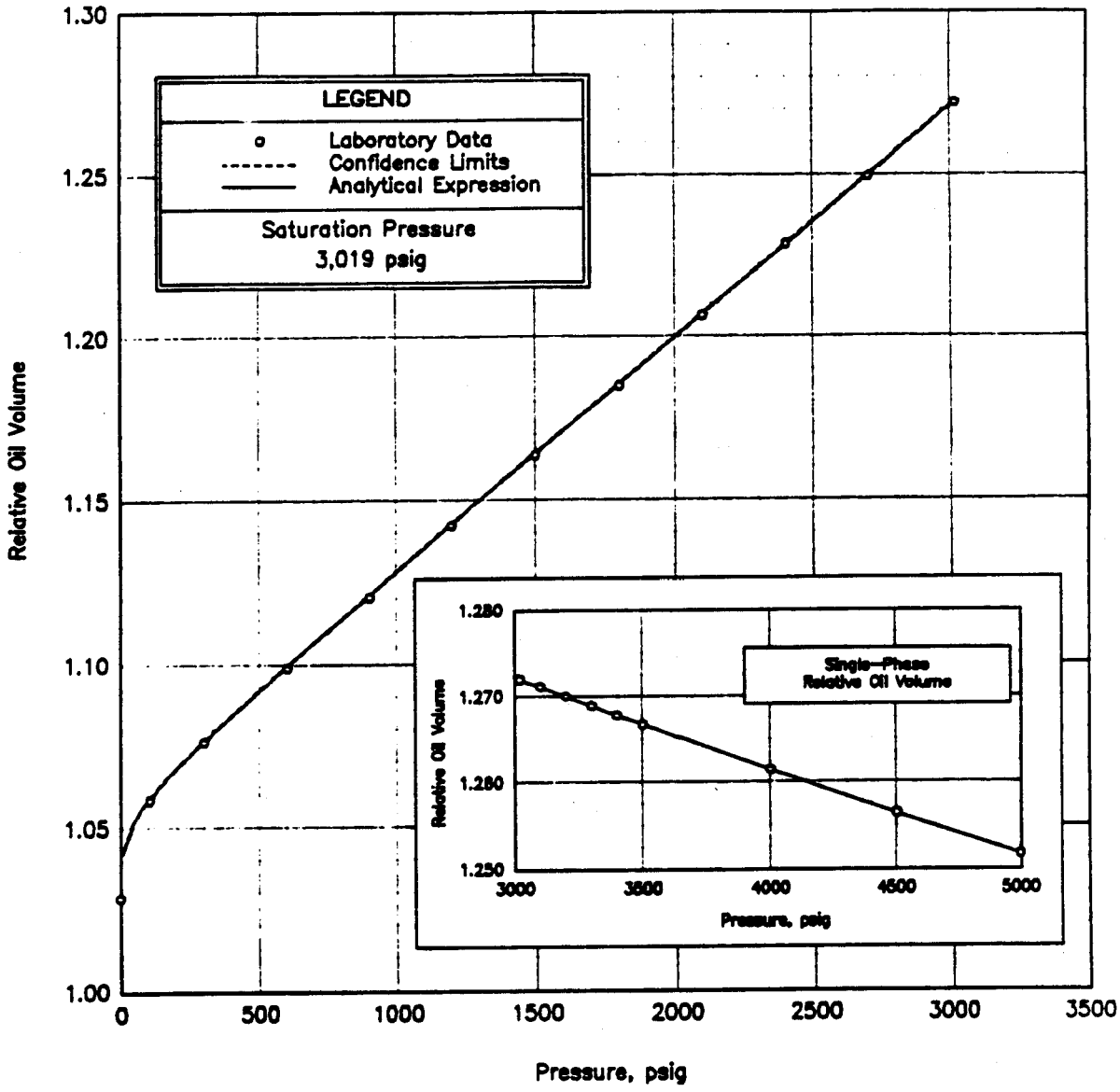
(C) Barrels of oil plus liberated gas at indicated pressure and temperature per Barrel of residual oil at 60 °F.

(D) Cubic Feet of gas at indicated pressure and temperature per Cubic Feet at 14.65 psia and 60 °F.

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RELATIVE OIL VOLUME
(at 119 °F)



Analytical Expression (below bubblepoint)

1.029E00 + 8.010E-05 (Pi) + 2.150E-02 (Pi)^0.4 + -1.435E-02 (Pi)^0.45

Note: Pi is defined as pressure, psig

Statistical Summary	
r squared:	0.999995
Confidence Interval (+/-):	.0002
Confidence:	99 %

Differential Vaporization

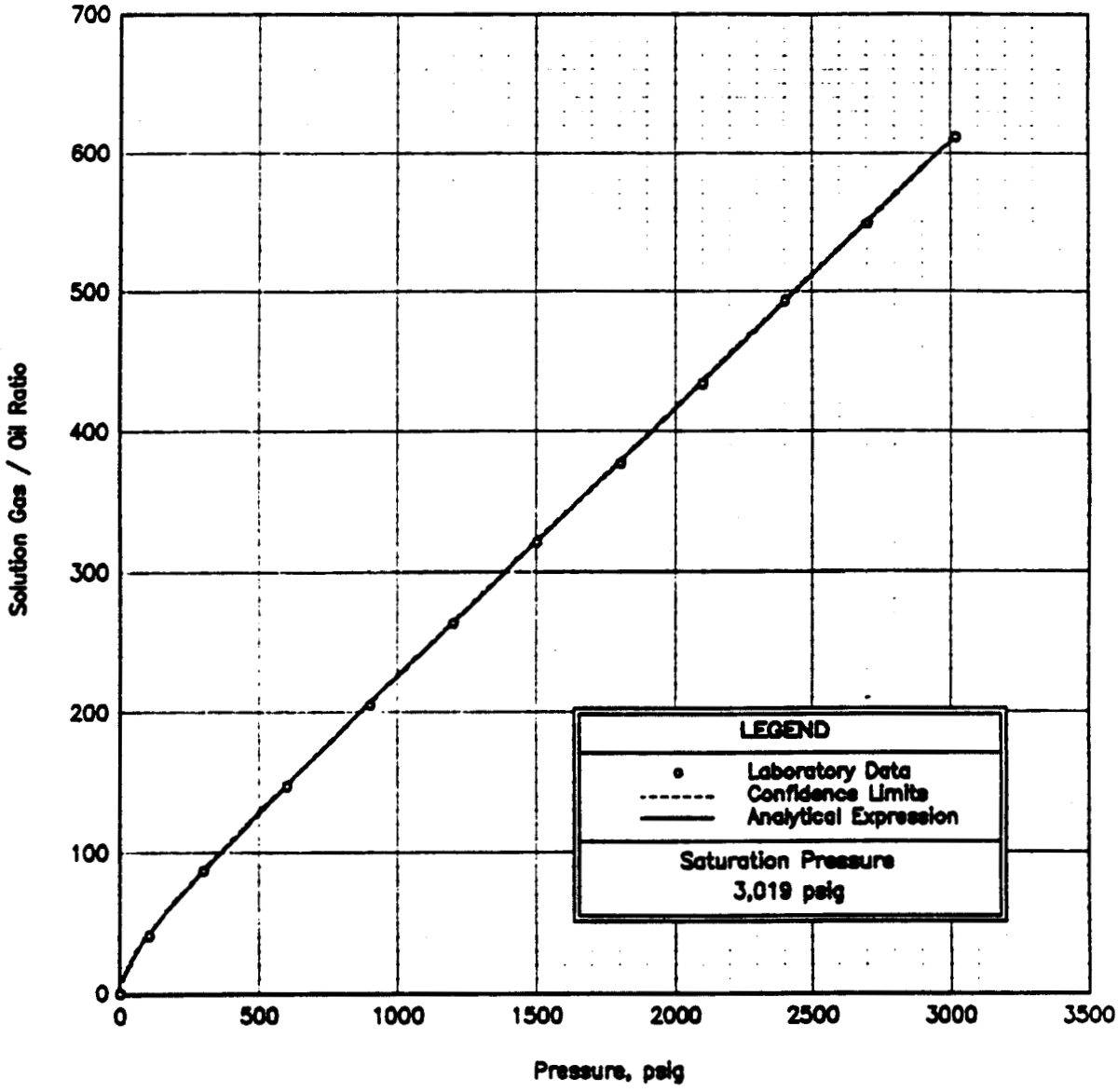
Figure B-1

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SOLUTION GAS/OIL RATIO
(scf/bbl at 119 °F)



Analytical Expression (below bubblepoint)

$$6.418E{-}02\ (Pi)^{-1.1} + 3.038E00\ (Pi)^{-0.5} + 1.460E{-}06\ (Pi)^{-2}$$

Note: Pi is defined as pressure, psig

Statistical Summary	
r squared:	0.999990
Confidence Interval (+/−):	1
Confidence:	99 %

Differential Vaporization

Figure B−2

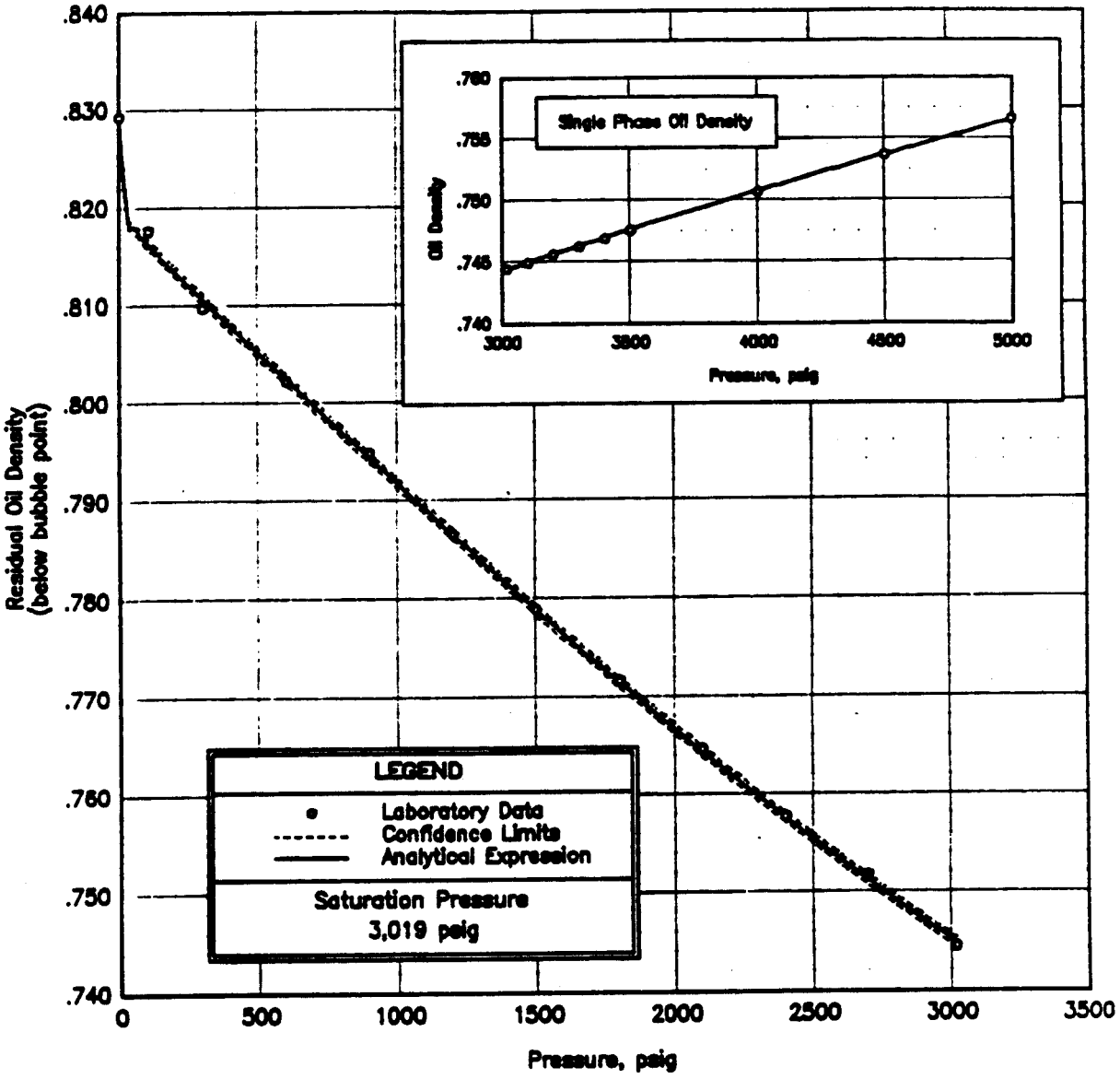
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OIL DENSITY

(gm/cc at 119 °F)



Analytical Expression (below bubblepoint)

0.82934 + −6.833E−03 (Pi)^0.1 + −1.241E−05 (Pi)^1.1 + 2.820E−11 (Pi)^2.5

Note: Pi is defined as pressure, psig

Statistical Summary	
r squared:	0.999603
Confidence Interval (+/−):	0.0005
Confidence:	99 %

Differential Vaporization

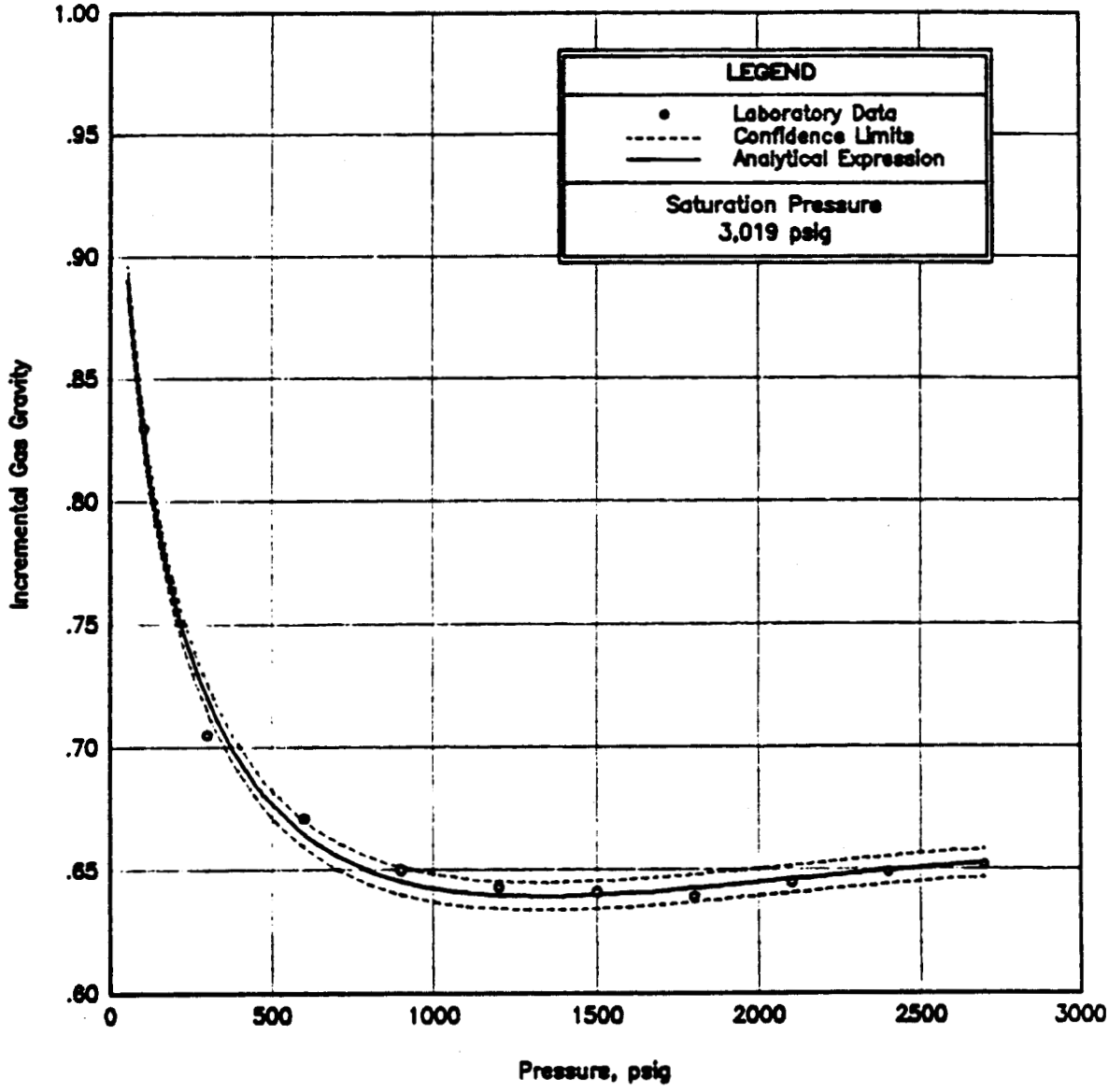
Figure B−3

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GAS GRAVITY
(at 119 °F)



Analytical Expression

2.177E00 + −1.221E−01 (PI)^0.300 + 3.054E−03 (PI)^0.500 + −9.210E−01 (exp(−Xd))

Note: Xd is defined as PI / Pest

Statistical Summary	
r squared:	0.999009
Confidence Interval (+/−):	0.0056
Confidence:	99 %

Differential Vaporization

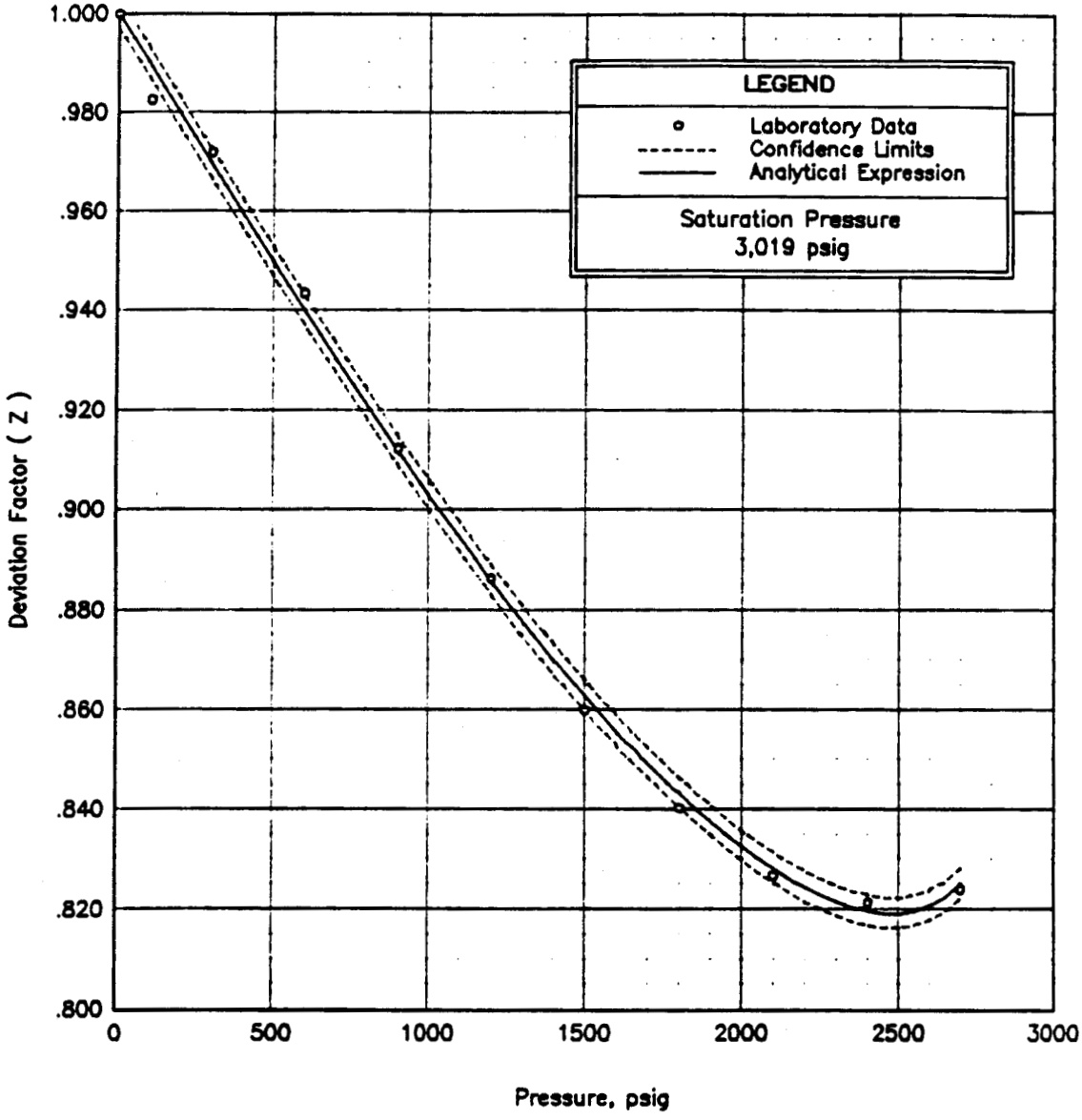
Figure B−4

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Z–FACTOR
(at 119 °F)



Analytical Expression

1 + −1.012E−04 (Pi) + 4.173E−54 (Pi)^15 + 4.377E−12 (Pi)^3

Note: Pi is defined as pressure, psig

Statistical Summary		Differential Vaporization
r squared:	0.998154	Figure B–5
Confidence Interval (+/−):	0.003	
Confidence:	99 %	

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RESERVOIR FLUID VISCOSITY

(at 119 °F)

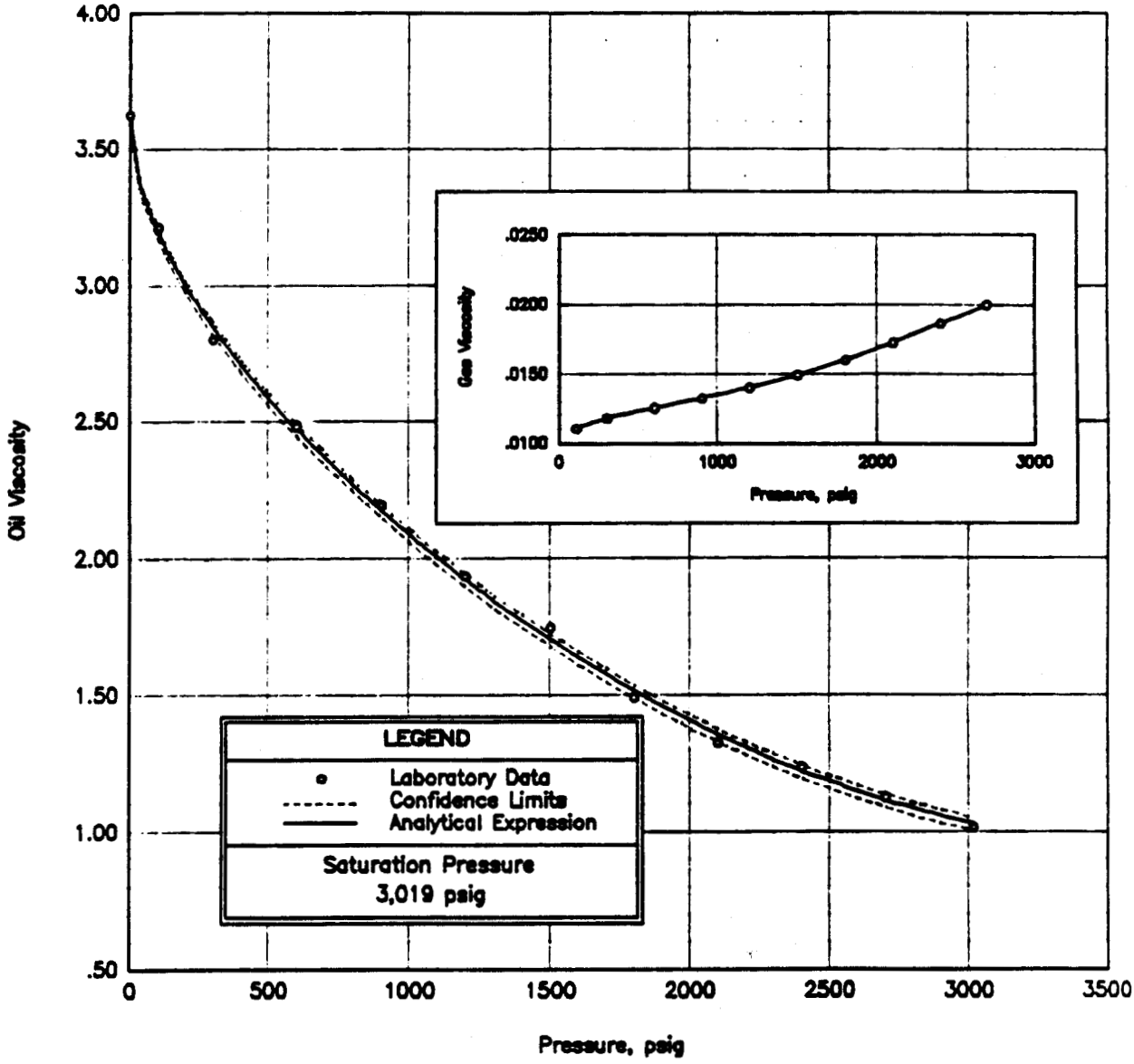
Pressure psig	Oil Viscosity cp	Calculated Gas Viscosity* cp	Oil/Gas Viscosity Ratio
5000	1.18		
4500	1.14		
4000	1.10		
3600	1.06		
3200	1.03		
b»3019	1.01		
2700	1.11	0.0200	55.8
2400	1.22	0.0186	65.7
2100	1.36	0.0172	78.8
1800	1.52	0.0160	95.0
1500	1.70	0.0149	114
1200	1.92	0.0140	138
900	2.18	0.0132	165
600	2.47	0.0125	198
300	2.84	0.0118	242
105	3.19	0.0110	289
0	3.62		

* Gas Viscosity data calculated from correlation of Lee A.L., Gonzalez M.H., and Eakin B.E., "The Viscosity of Natural Gases", Journal of Petroleum Technology, August, 1966, pp. 997-1000.

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RESERVOIR FLUID VISCOSITIES
(cp at 119 °F)



Analytical Expression (below bubblepoint)

3.623 E00 + −3.144E−04 (Pi) + 4.742E−10 (Pi)^2.6 + −3.958E−02 (Pi)^0.5

Note: Pi is defined as pressure, psig

Statistical Summary	
r squared:	0.999161
Confidence Interval (+/−):	0.023
Confidence:	99 %

Viscosity Analyses

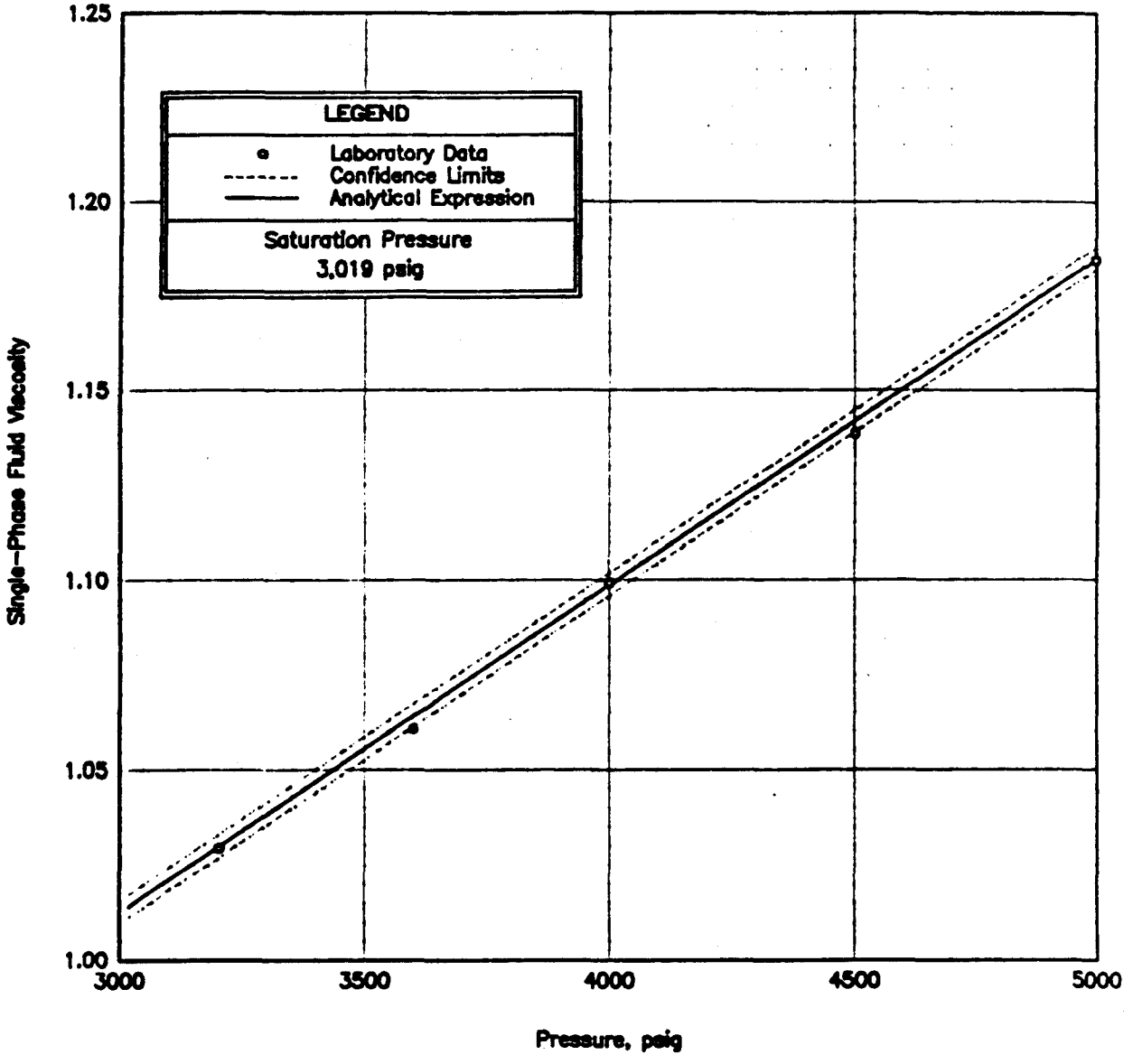
Figure C−1

CORE LABORATORIES

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SINGLE-PHASE VISCOSITY
(cp at 119 °F)



Analytical Expression	
	1.014E00 + 1.017E00 (dP)
Note: dP is defined as | Pi - Pest |, psig	

Statistical Summary		Viscosity Analyses
r squared:	0.998835	Figure C-2
Confidence Interval (+/-):	0.003	
Confidence:	99 %	

CORE LABORATORIES

RFL 920279

SEPARATOR FLASH ANALYSIS

Flash Conditions		Gas/Oil Ratio	Gas/Oil Ratio	Stock Tank Oil Gravity	Formation Volume Factor	Separator Volume Factor	Specific Gravity of Flashed Gas	Oil Phase Density
		(scf/bbl)	(scf/STbbl)	at 60 °F				(gm/cc)
psig	°F	(A)	(B)	(°API)	Bofb (C)	(D)	(Air=1.000)	
3019	119							0.7425
100	90	580	596			1.026	0.670 *	0.8386
25	140	17	17			1.038	0.908 *	0.8260
0	60	12	12	34.1	1.276	1.000	1.308 *	0.8538
			Rsfb = 625					
3019	119							0.7448
100	140	587	615			1.048	0.745	0.8179
25	140	12	12			1.038	0.782	0.8238
0	60	4	4	34.0	1.284	1.000	1.300	0.8540
			Rsfb = 632					
3019	119							0.7448
500	90	426	457			1.073	0.638	0.8160
100	90	96	99			1.033	0.749	0.8319
25	140	25	26			1.039	1.064	0.8212
0	60	10	10	34.6	1.260	1.000	1.007	0.8510
			Rsfb = 593					

* Collected and analyzed in the laboratory by gas chromatography.

(A) Cubic Feet of gas at 14.65 psia and 60 °F per Barrel of oil at indicated pressure and temperature.

(B) Cubic Feet of gas at 14.65 psia and 60 °F per Barrel of Stock Tank Oil at 60 °F.

(C) Barrels of saturated oil at 3019 psig and 119 °F per Barrel of Stock Tank Oil at 60 °F.

(D) Barrels of oil at indicated pressure and temperature per Barrel of Stock Tank Oil at 60 °F.

RFL 920279

Composition of Primary Separator Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.46		44.010	.8172
Nitrogen	0.15		28.013	.8086
Methane	86.88		16.043	.2997
Ethane	5.85	1.556	30.070	.3558
Propane	4.17	1.143	44.097	.5065
iso-Butane	0.81	.264	58.123	.5623
n-Butane	0.96	.301	58.123	.5834
iso-Pentane	0.30	.109	72.150	.6241
n-Pentane	0.15	.054	72.150	.6305
Hexanes	0.13	.050	84.000	.6850
Heptanes	0.08	.033	96.000	.7220
Octanes	0.04	.018	107.00	.7450
Nonanes	Trace			
Decanes plus	0.02	.011	141.00	.7840
Totals	100.00	3.539		

Sampling Conditions

100 psig
90 °F

Sample Characteristics

"Base Case" Separator Test

Critical Pressure (psia)	664.5
Critical Temperature (°R)	380.7
Average Molecular Weight	19.39
Calculated Gas Gravity (air = 1.000)	0.670
Gas Gravity Factor, Fg	1.2221
Super Compressibility Factor, Fpv at sampling conditions	1.0081
Gas Z-Factor at sampling conditions *	0.984

at 14.65 psia and 60 °F

Gross Heating Value (BTU/scf dry gas)	1172

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	0.14	105.6	0.739	44.2
Decanes plus	0.02	141.0	0.784	38.3

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

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Composition of Secondary Separator Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.66		44.010	.8172
Nitrogen	0.00			
Methane	63.64		16.043	.2997
Ethane	12.86	3.421	30.070	.3558
Propane	13.50	3.700	44.097	.5065
iso-Butane	3.14	1.022	58.123	.5623
n-Butane	3.61	1.132	58.123	.5834
iso-Pentane	1.12	.408	72.150	.6241
n-Pentane	0.56	.202	72.150	.6305
Hexanes	0.46	.178	84.000	.6850
Heptanes	0.28	.117	96.000	.7220
Octanes	0.13	.059	107.00	.7450
Nonanes	0.04	.020	121.00	.7640
Decanes plus	Trace			
Totals	100.00	10.259		

Sampling Conditions

25 psig
140 °F

Sample Characteristics

"Base Case" Separator Test

Critical Pressure (psia)	654.3
Critical Temperature (°R)	456.4
Average Molecular Weight	26.30
Calculated Gas Gravity (air = 1.000)	0.908
Gas Gravity Factor, Fg	1.0494
Super Compressibility Factor, Fpv at sampling conditions	1.0036
Gas Z-Factor at sampling conditions *	0.993

at 14.65 psia and 60 °F

Gross Heating Value (BTU/scf dry gas)	1539

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	0.45	101.4	0.732	45.1

* From: Standing, M.B., "Volumetric and Phase Behavior of Oil Field Hydrocarbon Systems", SPE (Dallas),1977, 8th Edition, Appendix II.

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Composition of Stock Tank Gas

(From Chromatographic Technique)

Component	Mol %	GPM	MW	Liq Dens (gm/cc)
Hydrogen Sulfide	0.00			
Carbon Dioxide	0.54		44.010	.8172
Nitrogen	0.12		28.013	.8086
Methane	32.39		16.043	.2997
Ethane	16.07	4.274	30.070	.3558
Propane	26.17	7.172	44.097	.5065
iso-Butane	7.06	2.297	58.123	.5623
n-Butane	9.63	3.020	58.123	.5834
iso-Pentane	3.42	1.245	72.150	.6241
n-Pentane	1.78	.641	72.150	.6305
Hexanes	1.50	.579	84.000	.6850
Heptanes	0.88	.368	96.000	.7220
Octanes	0.40	.181	107.00	.7450
Nonanes	0.04	.020	121.00	.7640
Decanes plus	Nil			
Totals	100.00	19.797		

Sampling Conditions

0 psig
60 °F

Sample Characteristics

"Base Case" Separator Test

Critical Pressure (psia)	624.6
Critical Temperature (°R)	572.7
Average Molecular Weight	37.87
Calculated Gas Gravity (air = 1.000)	1.308

at 14.65 psia and 60 °F

Gross Heating Value (BTU/scf dry gas)	2156

Properties of Plus Fractions

Component	Mol %	MW	Liq Dens (gm/cc)	API Gravity
Heptanes plus	1.32	100.1	0.730	45.4

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Composition of Stock Tank Oil

(From Chromatographic Technique)

Component	Mol %	Wt %	Density (gm/cc)	MW	Vol %
Hydrogen Sulfide	.00	.00			
Carbon Dioxide	.00	.00			
Nitrogen	.00	.00			
Methane	.00	.00			
Ethane	.00	.00			
Propane	2.23	.48	.506	44.1	0.81
iso-Butane	.00	.00			
n-Butane	3.88	1.10	.583	58.1	1.61
iso-Pentane	2.56	.90	.624	72.2	1.23
n-Pentane	1.76	.62	.630	72.2	0.84
Hexanes	4.10	1.68	.685	84.0	2.09
Heptanes	6.66	3.12	.722	96.0	3.69
Octanes	9.13	4.79	.745	107.0	5.48
Nonanes	6.74	3.98	.764	121.0	4.45
Decanes	6.32	4.13	.778	134.0	4.53
Undecanes	4.99	3.58	.789	147.0	3.88
Dodecanes	4.33	3.40	.800	161.0	3.63
Tridecanes	4.93	4.21	.811	175.0	4.43
Tetradecanes	4.59	4.25	.822	190.0	4.41
Pentadecanes	4.68	4.70	.832	206.0	4.82
Hexadecanes	3.39	3.67	.839	222.0	3.73
Heptadecanes	3.02	3.49	.847	237.0	3.52
Octadecanes	3.01	3.68	.852	251.0	3.69
Nonadecanes	2.53	3.24	.857	263.0	3.23
Eicosanes	2.15	2.88	.862	275.0	2.85
Heneicosanes	1.84	2.61	.867	291.0	2.57
Docosanes	1.69	2.51	.872	305.0	2.46
Tricosanes	1.49	2.31	.877	318.0	2.25
Tetracosanes	1.33	2.15	.881	331.0	2.08
Pentacosanes	1.27	2.14	.885	345.0	2.07
Hexacosanes	.98	1.72	.889	359.0	1.65
Heptacosanes	1.08	1.97	.893	374.0	1.89
Octacosanes	.97	1.83	.896	388.0	1.74
Nonacosanes	.83	1.62	.899	402.0	1.54
Triacontanes	.88	1.79	.902	416.0	1.69
Hentriacontanes	.76	1.59	.906	430.0	1.49
Dotriacontanes	.60	1.29	.909	444.0	1.21
Tritriacontanes	.56	1.24	.912	458.0	1.16
Tetratriacontanes	.50	1.15	.914	472.0	1.08
Pentatriacontanes	.35	.84	.917	486.0	0.79
Hexatriacontanes plu	3.87	15.34	1.149	811.5	11.41
Totals	100.00	100.00			100.00

Sample Characteristics

"Base Case" Separator Test

Total Liquid Molecular Weight	205.0
Total Liquid Density (gm/cc)	0.8538
Total Liquid API Gravity	34.2

Properties of Heavy Fractions

Plus Fractions	Mol %	Wt %	Density (gm/cc)	°API	MW
Hexanes plus	89.57	96.90	0.866	31.9	221.8
Heptanes plus	85.47	95.22	0.870	31.1	228.4
Decanes plus	62.94	83.33	0.892	27.2	271.5
Undecanes plus	56.62	79.20	0.899	26.0	286.8
Pentadecanes plus	37.78	63.76	0.924	21.6	346.1
Eicosanes plus	21.15	44.98	0.962	15.6	436.1
Pentacosanes plus	12.65	32.52	1.002	9.7	527.0
Triacontanes plus	7.52	23.24	1.054	2.7	633.3
Pentatriacontanes plus	4.22	16.18	1.134	-6.7	784.5

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SEPARATOR FLASH ANALYSIS*

Flash Conditions		Gas/Oil Ratio (scf/bbl)	Gas/Oil Ratio (scf/STbbl)	Stock Tank Oil Gravity at 60 °F	Formation Volume Factor	Separator Volume Factor	Specific Gravity of Flashed Gas	Oil Phase Density (gm/cc)
psig	°F	(A)	(B)	(°API)	Bofb (C)	(D)	(Air=1.000)	
2200	119							0.7557
100	90	453	466			1.030	0.733	0.8365
25	140	28	29			1.038	0.952	0.8242
0	60	15	15	34.4	1.238	1.000	**	0.8518
			Rsfb = 510					
1500	119							0.7706
100	90	314	324			1.033	0.772	0.8359
25	140	33	35			1.039	0.985	0.8239
0	60	10	10	34.6	1.191	1.000	**	0.8537
			Rsfb = 369					
800	119							0.7822
100	90	153	159			1.038	0.817	0.8258
25	140	35	36			1.039	1.032	0.8172
0	60	10	10	34.8	1.132	1.000	**	0.8467
			Rsfb = 206					

* Performed on prepared differential vaporization fluids.

** Insufficient quantity for measurement.

(A) Cubic Feet of gas at 14.65 psia and 60 °F per Barrel of oil at indicated pressure and temperature.

(B) Cubic Feet of gas at 14.65 psia and 60 °F per Barrel of Stock Tank Oil at 60 °F.

(C) Barrels of saturated oil at indicated pressure and 119°F per Barrel of Stock Tank Oil at 60°F.

(D) Barrels of oil at indicated pressure and temperature per Barrel of Stock Tank Oil at 60 °F.

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DIFFERENTIAL VAPORIZATION
ADJUSTED TO SEPARATOR CONDITIONS*

	Pressure psig	Solution Gas/Oil Ratio Rs (A)	Formation Volume Factor Bo (B)	Gas Formation Volume Factor (C)	Oil Density gm/cc	Oil/Gas Viscosity Ratio
	5000	625.	1.255		0.7569	
	4500	625.	1.260		0.7540	
	4000	625.	1.265		0.7510	
	3500	625.	1.271		0.7479	
	3400	625.	1.272		0.7473	
	3300	625.	1.273		0.7466	
	3200	625.	1.274		0.7460	
	3100	625.	1.275		0.7453	
b»	3019	625.	1.276		0.7448	
	2700	563.	1.253	0.00496	0.7512	55.8
	2400	505.	1.232	0.00554	0.7576	65.7
	2100	448.	1.210	0.00639	0.7644	78.8
	1800	390.	1.189	0.00758	0.7715	95.0
	1500	333.	1.167	0.00929	0.7789	114.0
	1200	276.	1.146	0.01190	0.7866	138.0
	900	218.	1.124	0.01627	0.7945	165.0
	600	160.	1.102	0.02495	0.8025	198.0
	300	98.	1.079	0.05028	0.8107	242.0
	105	53.	1.062	0.13489	0.8164	289.0
	0	11.	1.032		0.8293	

*Separator Conditions	
First Stage	100 psig at 90 °F
Second Stage	25 psig at 140 °F
Stock Tank	0 psig at 60 °F

(A) Cubic Feet of gas at 14.65 psia and 60 °F per Barrel of Stock Tank Oil at 60 °F.

(B) Barrel of oil at indicated pressure and temperature per Barrel of Stock Tank Oil at 60 °F.

(C) Cubic Feet of gas at indicated pressure and temperature per Cubic Feet at 14.65 psia and 60 °F.

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DIFFERENTIAL VAPORIZATION
ADJUSTED TO SEPARATOR CONDITIONS*

	Pressure psig	Solution Gas/Oil Ratio Rs (A)	Formation Volume Factor Bo (B)	Gas Formation Volume Factor (C)	Oil Density gm/cc	Oil/Gas Viscosity Ratio
	5000	632.	1.264		0.7569	
	4500	632.	1.269		0.7540	
	4000	632.	1.274		0.7510	
	3500	632.	1.279		0.7479	
	3400	632.	1.280		0.7473	
	3300	632.	1.281		0.7466	
	3200	632.	1.282		0.7460	
	3100	632.	1.284		0.7453	
b»	3019	632.	1.284		0.7448	
	2700	569.	1.261	0.00496	0.7512	55.8
	2400	511.	1.240	0.00554	0.7576	65.7
	2100	453.	1.218	0.00639	0.7644	78.8
	1800	395.	1.197	0.00758	0.7715	95.0
	1500	338.	1.175	0.00929	0.7789	114.0
	1200	280.	1.153	0.01190	0.7866	138.0
	900	222.	1.132	0.01627	0.7945	165.0
	600	163.	1.110	0.02495	0.8025	198.0
	300	101.	1.087	0.05028	0.8107	242.0
	105	56.	1.069	0.13489	0.8164	289.0
	0	14.	1.039		0.8293	

*Separator Conditions	
First Stage	100 psig at 140 °F
Second Stage	25 psig at 140 °F
Stock Tank	0 psig at 60 °F

(A) Cubic Feet of gas at 14.65 psia and 60 °F per Barrel of Stock Tank Oil at 60 °F.

(B) Barrel of oil at indicated pressure and temperature per Barrel of Stock Tank Oil at 60 °F.

(C) Cubic Feet of gas at indicated pressure and temperature per Cubic Feet at 14.65 psia and 60 °F.

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DIFFERENTIAL VAPORIZATION
ADJUSTED TO SEPARATOR CONDITIONS*

	Pressure psig	Solution Gas/Oil Ratio Rs (A)	Formation Volume Factor Bo (B)	Gas Formation Volume Factor (C)	Oil Density gm/cc	Oil/Gas Viscosity Ratio
	5000	593.	1.240		0.7569	
	4500	593.	1.245		0.7540	
	4000	593.	1.250		0.7510	
	3500	593.	1.255		0.7479	
	3400	593.	1.256		0.7473	
	3300	593.	1.257		0.7466	
	3200	593.	1.258		0.7460	
	3100	593.	1.260		0.7453	
b»	3019	593.	1.260		0.7448	
	2700	532.	1.238	0.00496	0.7512	55.8
	2400	474.	1.217	0.00554	0.7576	65.7
	2100	418.	1.195	0.00639	0.7644	78.8
	1800	361.	1.174	0.00758	0.7715	95.0
	1500	304.	1.153	0.00929	0.7789	114.0
	1200	248.	1.132	0.01190	0.7866	138.0
	900	191.	1.111	0.01627	0.7945	165.0
	600	133.	1.089	0.02495	0.8025	198.0
	300	72.	1.066	0.05028	0.8107	242.0
	105	28.	1.049	0.13489	0.8164	289.0
	0		1.019		0.8293	

*Separator Conditions	
First Stage	500 psig at 90 °F
Second Stage	100 psig at 90 °F
Third Stage	25 psig at 140 °F
Stock Tank	0 psig at 60 °F

(A) Cubic Feet of gas at 14.65 psia and 60 °F per Barrel of Stock Tank Oil at 60 °F.

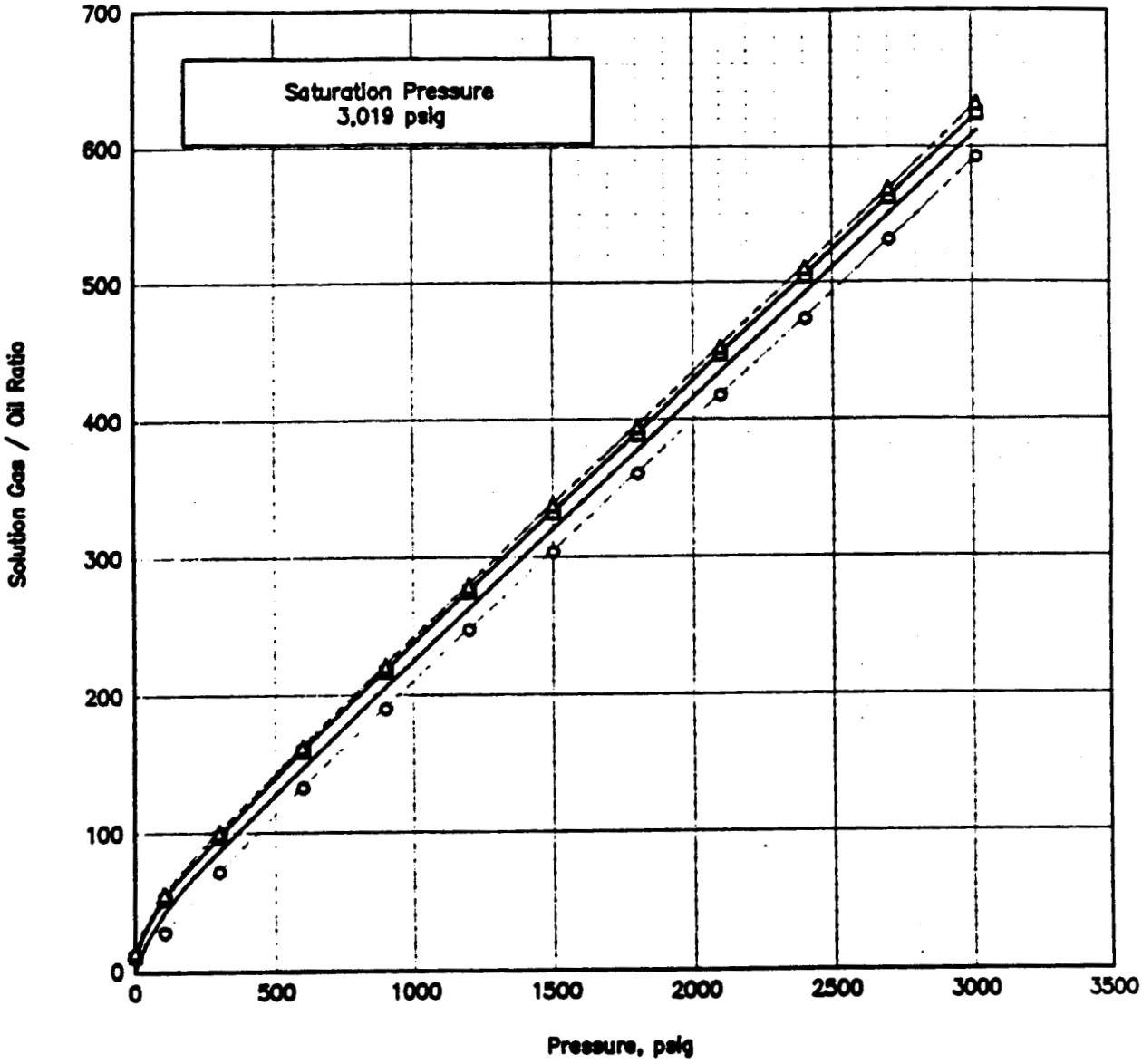
(B) Barrel of oil at indicated pressure and temperature per Barrel of Stock Tank Oil at 60 °F.

(C) Cubic Feet of gas at indicated pressure and temperature per Cubic Feet at 14.65 psia and 60 °F.

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SOLUTION GAS/OIL RATIO
(scf/STbbl)



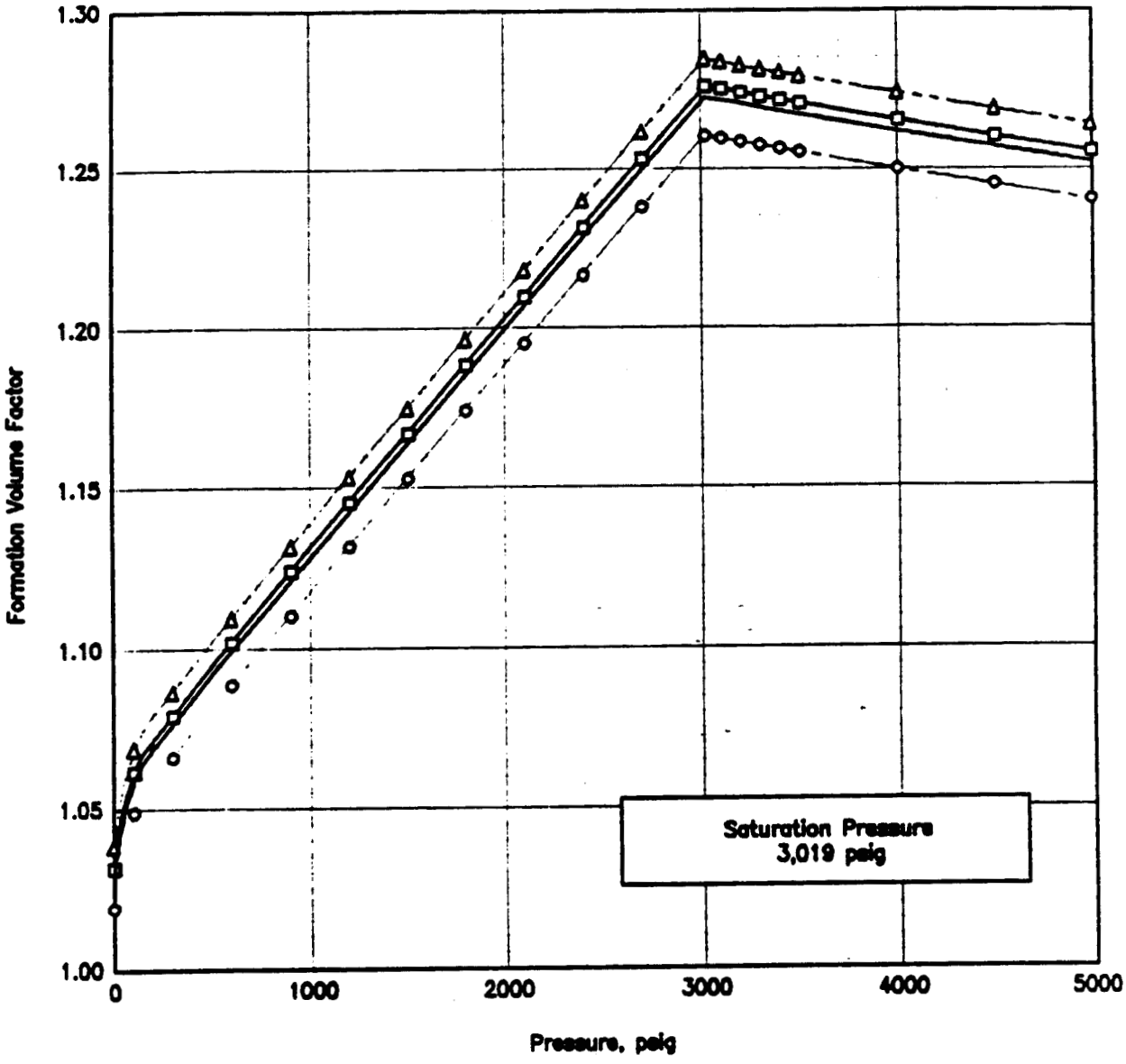
LEGEND	
Differential Vaporization 100 psig at 90 °F 100 psig at 140 °F 500 psig at 90 °F	DV Adjusted to Separator Figure D–1

CORE LABORATORIES

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RFL 920279

FORMATION VOLUME FACTOR



LEGEND	
Differential Vaporization 100 psig at 90 °F 100 psig at 140 °F 500 psig at 90 °F	DV Adjusted to Separator Figure D–2

CORE LABORATORIES

Appendix
Nomenclature and Equations

PRESSURE-VOLUME RELATIONS

Nomenclature and Equations

P_b	=	Bubblepoint Pressure
X_d	=	Dimensionless Pressure (P_i / P_b)
dP	=	Pressure Difference ($P_i - P_b$)
Y_f	=	Y-Function (dimensionless compressibility)
RV	=	PV Relative Volume
C_{sp}	=	Average Single-Phase Compressibility of Reservoir Fluid

For Relative Volume below bubblepoint pressure:

$$RV_i = ((P_b - P_i)/P_i) / Y_f$$

For Average Single-Phase Compressibility above bubblepoint pressure:

$$C_{sp} = (RV_i - RV_{i-1})/[RV_i(P_{i-1} - P_i)]$$

DIFFERENTIAL VAPORIZATION

Nomenclature and Equations

P_b	=	Bubblepoint Pressure
P_{base}	=	Base Pressure
T_{base}	=	Base Temperature
T_{res}	=	Reservoir Temperature
X_d	=	Dimensionless Pressure (P_i / P_b)
dP	=	Pressure Difference ($P_i - P_b$)
RV	=	Relative Volume from Pressure-Volume Relations
Dens	=	Single-Phase Oil Density
$Dens_b$	=	Oil Density at Bubblepoint Pressure
ROV	=	Relative Oil Volume
ROV_b	=	Relative Oil Volume at Bubblepoint Pressure
B_g	=	Gas Formation Volume Factor

For Oil Density above bubblepoint pressure:

$$Dens_i = Dens_b / RV_i$$

For Relative Oil Volume above bubblepoint pressure:

$$ROV_i = ROV_b * RV_i$$

For Gas Formation Volume Factor below bubblepoint pressure:

$$B_g = P_{base} * Z_i * T_{res} / (P_i * T_{base})$$

Over the longer term, as demand on the West Coast grows and ANS production declines, the West Coast oil glut will disappear. In this forecast West Coast and Gulf Coast oil prices are assumed to converge when the West Coast surplus disappears. The long term forecast for ANS is illustrated below.

Table 8 Scenarios for ANS Oil Price
Gulf Coast and West Coast
($/bbl)

Fiscal	Low		Mid		High	
Year	West	Gulf	West	Gulf	West	Gulf
1993	17.13	17.71	18.11	18.73	18.56	19.21
1994	16.35	17.07	18.26	19.07	19.06	19.90
1995	16.43	17.15	18.91	19.74	19.67	20.52
2000	19.48	19.48	24.67	24.67	27.02	27.02
2005	22.65	22.65	30.68	30.68	37.14	37.14

Table 9 Marine Transportation Costs
Valdez to Lower 48
($/bbl)

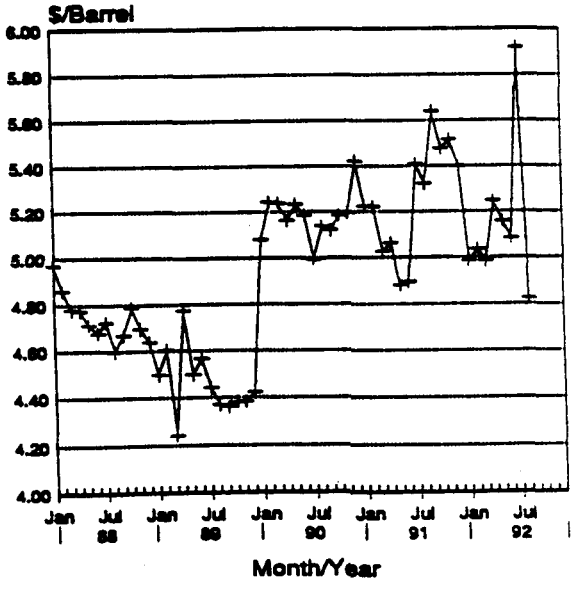
Fiscal Year	Low	Mid	High
1993	1.83	1.83	1.83
1994	1.95	1.95	1.95
1995	1.90	1.90	1.94
2000	1.68	1.71	1.73
2005	1.46	1.50	1.59

Transportation Costs to Lower 48 Markets

The weighted average Lower 48 shipping cost averaged $1.75/bbl in FY 1992, $0.40/bbl higher than in the prior year. This increase was mostly attributable to tight markets in the higher cost Gulf trade, where there is significant chartering, and results of the Oilspill Pollution Act of 1990 (OPA90).

As ANS production declines and West Coast petroleum demand increases, shipments to the Gulf will diminish. This will free up excess tonnage. Consequently, average shipping costs are expected to stay fairly constant over the next few years. In the long term the double hulling requirements of OPA90 will result in increased shipping costs.

Figure 9
Total Transportation Costs to Lower 48
Pipeline and Tanker



Forecast Assumptions

ANS Lower 48 Prices

Beginning with this forecast, the oil price assumptions start with the price of ANS at the U.S. Gulf Coast. ANS Gulf is now used as a benchmark instead of West Texas Intermediate (WTI) for the following practical and theoretical reasons:

1. Saudi Light is marketed in the U.S. based on the Gulf ANS spot price. This provides a link to worldwide markets.

2. WTI is a lighter gravity, lower sulfur crude than ANS, and is thus valued higher. By using ANS itself as a marker, any price variations that occur due to quality differentials are eliminated and forecasting error can be attributed solely to incorrect assumptions about ANS price.

We do continue to forecast a WTI price based on the historical relationship between WTI and ANS.

The discussion of price forecast assumptions starts with the Gulf Coast ANS price and outlines the other variables which translate this price into the wellhead price for ANS crude oil. The wellhead price determines the value of production and thus the state's severance tax and royalty income.

The price of West Coast ANS is forecasted based on its historical relationship to Gulf Coast ANS. West Coast ANS sells at a discount to the Gulf because the presence of ANS on the West Coast creates a crude oil glut there. It is this glut that necessitates the shipment of ANS to the Gulf. The short term forecast for ANS is illustrated below.

Figure 7 ANS at the U. S. Gulf

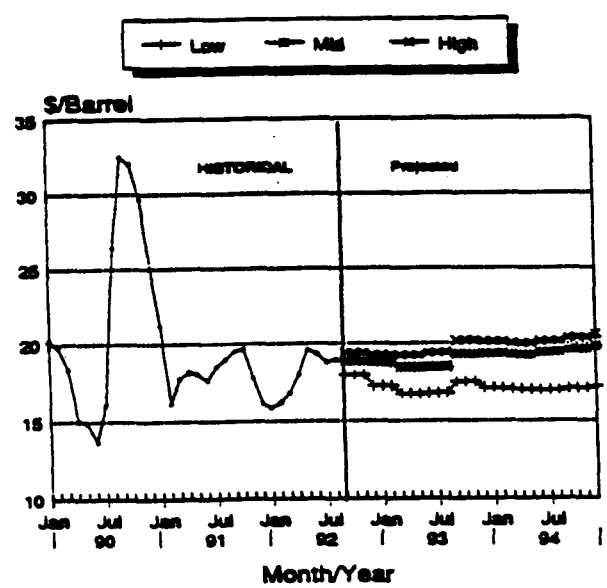
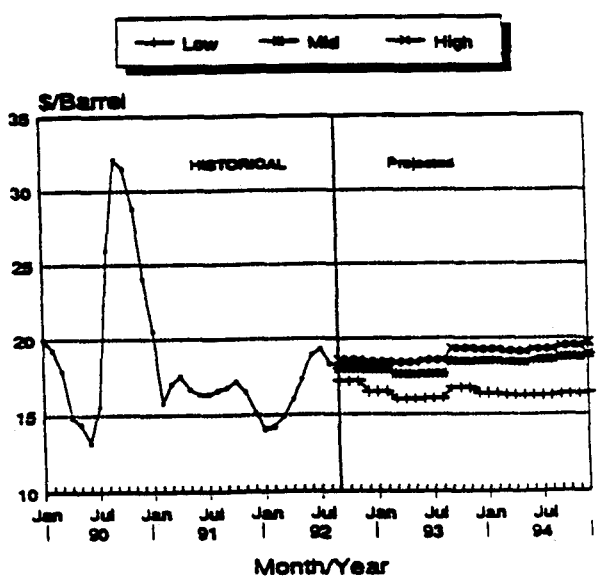
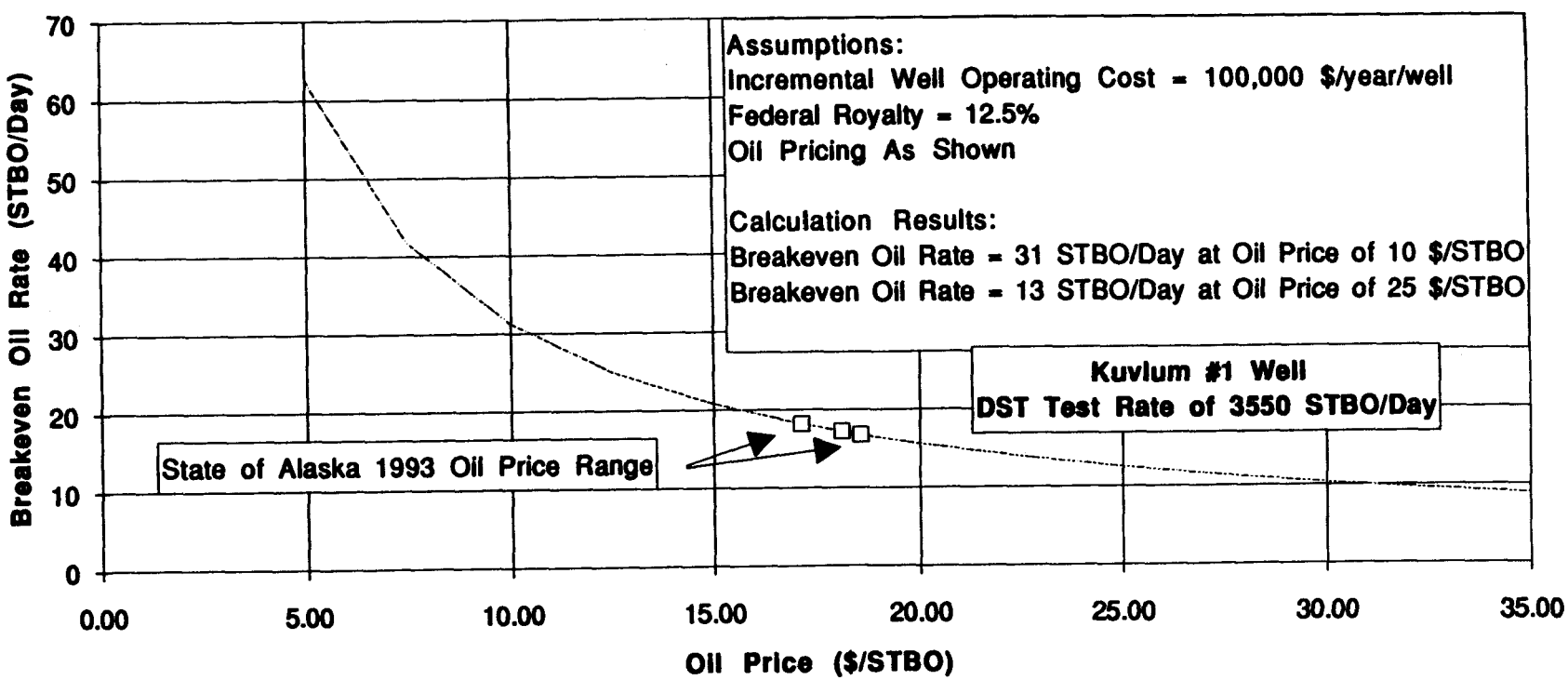


Figure 8 ANS at the U. S. West Coast



Kuvlum #1
Breakeven Oil Rate vs. Oil Price
Paying Quantities Determination



3/5/93

CRITICAL OPERATIONS AND CURTAILMENT PLAN

KUVLUM PROSPECT

OCS-Y-0866 #1

BLOCK 673

Kuvlum #1

BEAUFORT SEA, ALASKA

SUBMITTED TO:

MINERALS MANAGEMENT SERVICE

ALASKA OCS REGION

ANCHORAGE, AK

SUBMITTED

BY:

ARCO ALASKA, INC.

JULY 10, 1992

Critical Operations and Curtailment Plan

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Alaska North Slope Market

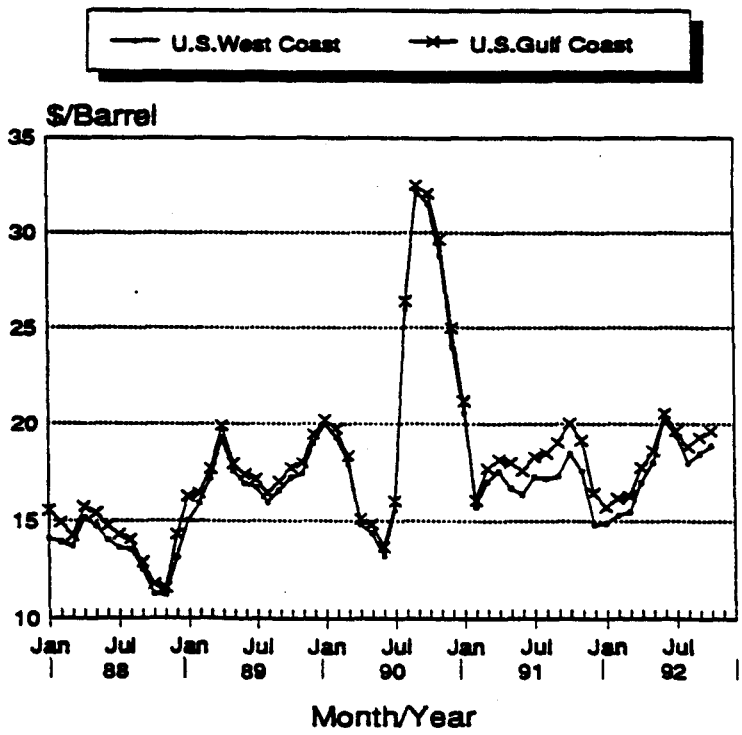
Alaska North Slope (ANS) prices have ranged between $17.00 and $20.00/bbl since last Spring. For the past six months, concern over the health of the global economy, plus uncertainty as to when Iraqi exports will return to the world market, have led to the price fluctuations of ANS. The price increase this year has been driven mainly by OPEC's decision to maintain fourth quarter production at its summer quota. ANS Lower 48 price has averaged just under $19.00/bbl so far for FY 1993.

BP Exploration announced its official selling prices for November 1992 as $18.80/bbl on the West Coast and $19.40/bbl on the Gulf Coast. Recent spot prices have been running $0.10/bbl lower than the official price.

Roughly 85 percent of ANS production is sold on the West Coast while 15 percent is marketed in the Eastern half of the United States and the Caribbean. As ANS production declines, it is expected that shipments to Eastern U.S. destinations will cease after 1996. Greater transportation costs to the more distant markets result in a Gulf Coast derived wellhead price which is lower than the West Coast price. ANS spot prices are graphed below in Figure 6.

Figure 6

ANS Spot Price
January 1988 - October 1992



CRITICAL OPERATIONS AND CURTAILMENT PLAN

KUVLUM PROSPECT

OCS-Y-0866 #1

A. INTRODUCTION:

1. General

ARCO Alaska Inc. (ARCO) is the operator for the drilling of a wildcat well, (OCS-Y-866 #1) on Block 673 located 16 miles northeast of Brownlow Point, Alaska offshore in the Beaufort Sea. (Figures 1-2). The test, named the Kuvlum Well[1] , will be drilled during the 1992 open water drilling season with an anticipated spud date of August 15, 1992.

BeauDril Limited Inc. (Beaudril) has been contracted to drill the well using the Kulluk Drilling System (Kulluk). The Kulluk (Unit) is a mobile, conically shaped, ice strengthened semi-submersible drilling barge designed for use in the ice infested waters of the Arctic ocean. A description of the Unit can be found in Section 3.0.

This Critical Operations and Curtailment Plan (COCP) and the Kulluk Alert Manual (Attachment I) outline the comprehensive effort that ARCO and Beaudril are providing to ensure drilling operations are conducted in a safe and prudent manner in the unique environment of the Beaufort Sea. ARCO assigns the highest priority in conducting its operations to the safety of personnel and protection of the surrounding environment.

The following COCP defines certain standards and guidelines for the conduct of operations at Kuvlum to absolutely minimize any hazard to personnel or the environment. In the Alaskan Beaufort Sea, the two primary factors which can impact curtailment of critical operations while drilling are sea ice and heavy weather. The objective of this COCP is to detail the critical drilling operations and the conditions under which such operations will be curtailed. The availability, capability and response time of oil spill response and containment equipment is detailed in the Kuvlum Oil Spill Contingency Plan (OSCP).

2. Person-In-Charge Of Overall Drilling Operations

The ARCO Drilling Manager, located in Anchorage, Alaska, will be the person who has responsibility as the person-in-charge of overall drilling operations on the Kuvlum Prospect. His name and office address are as follows:

Mr. Doug J. Ruckel
Drilling Manager
ARCO Alaska, Inc.
P. O. Box 100360
Anchorage, AK 99510-0360

Office phone: (907) 263-4614
Home phone: (907) 345-5331

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[1] The APD for the Kuvlum Well will be submitted to the Minerals Management Service (MMS) in July, 1992 with the COCP identified as an attachment to the APD.

3. Drilling System Description

The Kulluk was constructed in 1982 by Mitsui Engineering & Shipbuilding Company, Ltd. The floating semi-submersible incorporates a 24-faceted conical shaped hull which has been ice strengthened to meet Arctic Class IV ice classification. The double hull is shaped in the form of an inverted cone which causes the ice to break downward and away from the vessel, thus protecting its anchor lines and drilling riser system from ice movement (See Figure 3). The unit is towed to location where twelve radially deployed 3-1/2" diameter anchor lines are deployed to moor the Unit.

The bottom of the Kulluk hull is equipped with a skirt system. The skirt is designed to protect the mooring lines whose fairleads depart from the center of the Unit below this skirt. Ice is deflected away from the lines allowing the Unit to remain on location during conditions when ice is present. The Kulluk is assisted by icebreaking support vessels which, in BeauDril's case, are also Arctic Class IV ice strengthened. At Kuvlum, the Kalvik, and/or Ikaluk and Miscaroo are planned to assist the operation during certain time periods (See Figures 4,5 and 6). Together with the icebreakers, the Kulluk is referred to as the "Kulluk Drilling System". The Canmar Supplier I is also scheduled to support the operation.

The conical hull design was developed by Earl and Wright - Lavalin to withstand the ice forces encountered during early summer and early winter in the southern Beaufort Sea; thus potentially increasing the drilling season to eight months.

3.1 Drilling System Specifications

The principal dimensions of the Kulluk are listed in Table 1 and Table 2, and the specifications of the support vessels are listed in Tables 3,4, and 5 attached.

4. Field Operations Schedule

The KULLUK will mobilize to Kuvlum location on or about August 11, 1992. The rig will be in a warm standby mode in June and July, and the well is scheduled to spud around August 15, 1992, or earlier, if possible. Drilling and evaluation operations of the initial Kuvlum Well are estimated to require 40-50 days with the possibility of drilling a second well of similar duration. Upon completion of drilling activities, the Unit will demobilize from location and return to a designated over-wintering point, currently planned to be Summer's Harbor, Canada.

5. Wellhead/BOP Configuration

A conventional subsea wellhead/BOP system will be used on the Kuvlum well.

The following provides a description of the wellhead and BOP equipment to be used during the different stages of drilling:

(a) The 30" structural casing will be set at approximately 320' TVD. The 30" structural casing will be "drilled in" to the well using a rock bit and mud motor. The 30" will be installed without the use of a riser if possible. The 26" hole for the 20" will also be drilled riserless if possible.

(b) The 20" conductor casing will be run, and cemented, to approximately 1,000' TVD. The 20" string is equipped with a subsea, high pressure wellhead which will be located just above the guide base positioned at the bottom of the "glory hole" excavated in the ocean floor to protect this equipment from ice scours. Prior to drilling out below the 20" casing the diverter system will be function tested and the subsea BOP stack will be pressure tested.

(c) The diverter system and subsea BOP stack will be used while drilling below 20" casing and for the running of the 13-3/8" surface casing and all further casing strings run in the well. (Figures 7 and 8).

Additional details of the wellhead configuration and BOP arrangement are described in the Kuvlum Application for Permit to Drill.

In summary, the wellhead/BOP configuration satisfies the main objective of well control integrity. The subsea wellhead/BOP system, in conjunction with the wellbore securing procedures discussed in Attachment III, protect the environment from an uncontrolled exposure of the wellbore.

6. Threshold Depth:

The middle interval of the Oligocene age formations, is the primary objective of the Kuvlum Well. Located at an estimated depth of approximately 4000' TVD, the mid-Oligocene is the shallowest objective of the well. Above the top of the mid-Oligocene, major accumulations of hydrocarbons are not likely. This prediction is based on the offset well data obtained from the onshore Point Thompson wells, ARCO's Stinson Well #1, Unocal's Hammerhead Wells (OCS-Y-0849 #1 & #2), SWEPI's Corona Well (OCS-Y-0871 #1), Amoco's Galahad Well (OCS-Y-1092 #1), Amoco's Belcher Well (OCS-Y-0917 #1) and ARCO's geological mapping and interpretation of the Kuvlum structure. Thus, for the Kuvlum Project Well #1 ARCO petitions that the top of the mid-Oligocene Formation should be recognized as the official 'Threshold Depth'. Below the mid-Oligocene is the secondary objective, the lower Oligocene Formation.

B. RESPONSIBILITIES of KEY PERSONNEL:

ARCO, as Operator, has the ultimate responsibility for the well and the overall safety of the lease operations. The Operator and Contractor are jointly responsible for the safety of the Unit itself and all personnel on board. Specific responsibilities of key personnel with respect to this Critical Operations and Curtailment Plan are as listed below. Additional responsibilities are also outlined in the Kulluk Alert System (Attachment I).

1. ARCO Drilling Superintendent

   (a) The ARCO Drilling Superintendent has the responsibility as the person-in-charge of overall drilling operations.

   (b) In the event of an emergency, he is responsible for directing any emergency response team that may be sent to the drillsite.

   (c) Responsible for notifying the MMS District Supervisor in Anchorage, Alaska, whenever the ARCO Drilling Supervisor on the Unit reports curtailment of a critical operation pursuant to this Plan or a deviation from the Plan required by an emergency action.

2. ARCO Drilling Supervisor(s)

   (a) The ARCO Drilling Supervisor is the person-in-charge of overall drilling operations at the drillsite. He is responsible for ensuring that key supervisory personnel are aware of regulations and procedures pertinent to their activities with respect to this Plan.

   (b) In conjunction with the Contractor Drilling Superintendent and the Contractor Barge Master, he is responsible for ensuring that all safety and emergency procedures outlined in this Plan are observed by all personnel on board the Unit.

   (c) Responsible for thoroughly understanding and implementing all aspects of this Plan.

   (d) Responsible for minimizing the number of third party personnel and visitors aboard the Unit during expected hazardous operations.

   (e) Responsible for obtaining the necessary equipment and personnel needed for the drilling operations.

   (f) Responsible for advising the Contractor Offshore Installation Manager of the curtailment actions needed to comply with this Plan.

3. ARCO Drilling Engineer

   (a) The ARCO Drilling Engineer is responsible for keeping the ARCO Drilling Supervisor(s) informed of impending ice and weather conditions and how those conditions might effect the planned drilling operations.

   (b) Responsible for ensuring that the Kulluk Alert Manual is followed as intended.

   (c) In the absence or incapacitation of the ARCO Drilling Supervisor(s), the ARCO Drilling Engineer will assume the Supervisor's responsibilities as specified above.

4. Contractor Offshore Installation Manager

(a) Responsible for executing the drilling program according to directions from, and subject to, the approvals of the ARCO Drilling Supervisor.

(b) Responsible for thoroughly understanding all aspects of this Plan.

(c) Responsible for the maintenance of the rig and associated equipment and training of the drilling crews to ensure sound operations.

(d) In conjunction with the ARCO Drilling Supervisor and the Contractor Marine Superintendent, is responsible for seeing that all safety and emergency procedures outlined in this Plan are observed by all personnel on board the Unit.

(e) In the absence or incapacitation of the ARCO Drilling Supervisor and ARCO Drilling Engineer, the Contractor Offshore Installation Manager will assume all responsibilities designated herein to the ARCO Drilling Supervisor.

(f) Assists the ARCO Drilling Supervisor in determining the necessary levels of personnel and equipment for conducting particular operations.

5. Contractor Rig Superintendent

(a) In the absence or incapacitation of the Contractor Offshore Installation Manager, the Contractor Rig Superintendent will assume the Contractor Offshore Installation Manager's responsibilities as specified above.

6. Contractor Marine Superintendent

(a) As the senior marine operations officer for the Unit he is responsible for the safety of the Unit and all of the personnel on board.

(b) Responsible for thoroughly understanding all aspects of this Plan and the attached Kulluk Alert Manual.

(c) In conjunction with the ARCO Drilling Supervisor and Contractor Offshore Installation Manager, he will decide in what manner the Unit would be evacuated and in what order personnel would leave.

C. CRITICAL OPERATIONS

Listed below are the key critical drilling operations that are typically conducted in the drilling of an exploration well. Depending upon the actual conditions encountered, some of these critical operations may not apply to the Kuvlum Exploration Program as explained in the accompanying paragraphs.

1. Drilling in Close Proximity to Another Well.

No curtailment action, due to drilling in close proximity to another well, will be considered while drilling the subject well since this well is the first to be drilled in the Block 673 (Lease OCS-Y-0866). However, directional surveys will be obtained in accordance with 30 CFR 250.51,(e),(2) to avoid future wellbore intersections should a second Kuvlum well be drilled.

2. Drilling Below Threshold Depth

3. Coring

4. Logging or Wireline Operations.

5. Running and Cementing Casing.

6. Cutting and/or Recovering Casing.

7. Drill Stem Testing.

8. Well Completion Operations.

This permit application contemplates an expendable exploratory well and does not consider plans for well completion. In the event a requirement for well completion does occur, ARCO will submit the necessary documentation required by the MMS.

9. Moving the Drilling Vessel Off Location in an Emergency, Repositioning the Vessel on Location, and Re-establishing Entry into the Well.

Detailed procedures for the operations conducted during an emergency to release the Kulluk from the well, repositioning the vessel, and then re-entering the well are contained in Attachment III, "Emergency Well Suspension Procedures".

10. Fuel Transfer.

The KULLUK has a storage capacity of 9,995 barrels of diesel fuel. The KULLUK will be refueled at Tuktoyaktuk during August, 1992. This quantity of fuel will meet drilling and service requirements for operations throughout the 1992 summer season. Therefore, diesel fuel re-supply operations while on site should not be required unless extended operations are conducted, or unusually severe ice conditions are encountered. Detailed procedures for refueling and fuel transfer operations are addressed in the Operations Manual for the KULLUK.

D. ENVIRONMENTAL MONITORING

A comprehensive Environmental Monitoring Program will be undertaken at the drill-site to support the Critical Operations Curtailment Plan and the Kulluk Ice Alerts System. The following sections describe the monitoring activity that will be under taken and introduces the personnel and equipment that will be used to carry out the program. Additional information on the Environmental Monitoring Program can be found in the Kuvlum Exploration Plan (ARCO, 1992).

During the operating season while drilling activity is underway, the monitoring program will be carried out as specified in this Plan and the Kuvlum Exploration Plan. Prior to and following the conclusion of drilling activity, the program may be scaled down and amended as deemed appropriate by ARCO and as approved by the District Supervisor, MMS.

1. General

An essential component of the alert system and a prerequisite to safe and efficient Arctic operations is an environmental monitoring and forecasting system. During BeauDril's operations, a comprehensive environmental monitoring and forecasting system has been established to support KULLUK's drilling activities. This system consists of site specific and regional services provided for or contracted by BeauDril and publicly available regional services acquired from the government. The system is designed to monitor and forecast the weather, wave and ice environment in the drilling area on both regional and local scales for input into strategic and tactical planning for KULLUK operations.

The various components of the environmental monitoring and forecasting system that is recommended for Kuvlum are shown in Table 6. The following sections describe the system in terms of its meteorological, ice and oceanographic components. This system is similar to that used in the Beaufort Sea in previous years and meets the operational requirements of KULLUK. It also adheres to the monitoring guidelines as specified by MMS.

2. Meteorological Observations

Weather conditions drive the other offshore environmental conditions and are key inputs to ice and wave forecasting. Weather observations will be made regularly aboard KULLUK by observers who have been certified by the relevant Canadian and American authorities. The weather observations, taken hourly, and the standard reports encoded into the Offshore Weather Observing Station *(OWOS)* format are shown in Table 7. The instruments used to collect this information will conform to government standards.

The meteorological sensors aboard KULLUK are highlighted in Figure 11. In addition to these site specific observations, weather reports from the Alaskan land stations and from public remote weather stations drifting on the pack ice will also be accessed aboard KULLUK in real time.

Observation reports from the offshore drilling site will normally be transmitted to shore and to the Operator's weather forecasting contractor every three hours, except during aviation operations and storms. Aviation operations will receive continuous observation reports from two hours before the planned time of arrival of an aircraft until the flight is complete. When winds exceed 33 knots, a continuous watch will be kept on winds and waves, and weather will be logged at least hourly.

3. Onsite Weather Forecasts

Onsite weather forecasts and a continuous weather watch will be provided by Fairweather, Inc. Regular forecasts will be issued for KULLUK's location every 12 hours, with an update, if required, at each intermediate six hours. The content of regular forecasts will include:

a. A synoptic discussion of relevant pressure patterns and their expected effects on the wind and weather,

b. A table of expected winds, temperatures and, where appropriate, waves each 6 hours to 24 hours, and each 12 hours to 48 hours. A qualitative outlook should be provided for 48 to 120 hours ahead along with a forecast reliability estimate,

c. An outlook for visibility and weather for the first 48 hours.

Storm forecasts will be issued or updated as required. All storm or gale warnings issued by the weather forecast service company will be passed on to both the facilities at sea and operational management ashore. If additional aviation forecasts are necessary, they will be generated by Fairweather, Inc.

4. Oceanographic Observations

The oceanographic component of the forecasting and monitoring system is relatively small because the operational requirements for this information are limited.

KULLUK's oceanographic program will consist of sea surface temperature measurements and visual estimates of waves taken by certified observers aboard KULLUK. The oceanographic observations that will be acquired are shown in Table 8. These observations will be encoded into OWOS format and transmitted with the weather reports every three hours during open water from the operating site.

5. Sea State Forecasts

Sea state forecasts generated by Fairweather, Inc. will be issued with the weather forecasts including wave heights and periods. Clearly, wave conditions will be forecast only during ice free periods for KULLUK.

6. Ice Monitoring

The ice monitoring and forecasting system used to support KULLUK operations includes all weather ice monitoring capability. This system depends heavily on marine radars, aboard KULLUK and support vessels, and an airborne imaging radar system if required. The marine radars on KULLUK and vessels continuously cover a small local area, while the airborne imagery radar provides regional coverage of the ice conditions as required. A downlink for the imaging radar will also be located onboard KULLUK. To supplement this radar imagery, regional ice information will be acquired from the NOAA satellite and various ice chart products. Visual ice observations from small fixed wing aircraft and helicopters will also be made whenever necessary as the weather permits.

Local ice conditions and movements will be observed regularly from KULLUK by trained ice observers and an environmental advisor. During the presence of ice, ice observations will be made at least every three hours and reports will be issued in the OWOS format for ice as shown in Table 9.

7. Ice Forecasting

Tactical and strategic ice forecasting on KULLUK will be conducted by a team of two watchkeepers/ice observers (hereafter referred to as "observers") *(24 hour coverage)* and an environmental advisor using all the local and shore based ice and weather information, plus their own radar and occasional helicopter reconnaissance.

8. Personnel

KULLUK environmental monitoring team consists of three people within KULLUK's marine department, the environmental advisor and two observers. This team monitors the performance of KULLUK and maintains an observational routine for all major weather, ice and oceanographic parameters. These functions are performed on a 24 hour basis.

The team interfaces directly with KULLUK's management personnel, reporting to the Marine Superintendent, to keep them informed of environmental and performance conditions as they are relate to KULLUK's "Alert" status.

9. Reporting

All environmental data recorded at the Kuvlum drilling site will be logged on an IBM PC, using BeauDril's Beaufort Environmental Archive Reporting System *(BEARS).* This is a custom data base package which allows data entry and retrieval and generates various report products. The reporting of environmental data, meteorological, oceanographic and ice conditions, will be performed on a schedule which meets the Operator's requirements.

For example, clear, legible logs or data printouts containing environmental observations at the site can be submitted on a weekly basis. All summary reports submitted can be accompanied by data in digitized *(disc)* form in an acceptable format.

10. Performance Monitoring System

In addition to the environmental monitoring and forecasting system, real time measurements on KULLUK's performance in ambient conditions is obtained from a performance monitoring system installed onboard. This system provides continuous real time monitoring of KULLUK's responses to ice, wind and wave effects and stores the response information for later assessment, if required. An ongoing knowledge of KULLUK's motions and line tensions is also an important component of the environmental alert procedure.

KULLUK's performance monitoring system includes real time measurements of the vessel's response including translational and rotational motions with respect to the wellhead and tensions in the twelve mooring lines. This information is acquired from sensors deployed around the vessel as shown in Figure 11. The individual anchor line tensions are measured with strain gauges installed on the turndown sheaves for the mooring lines and global environmental loads are calculated by vectorially summing these individual line tensions. KULLUK pitch and roll motions are obtained from inclinometers in a Vertical Reference Unit, yaw responses from the vessel's gyrocompass and marine riser angle from an electronic bullseye mounted on the riser. Surge, sway and heave can be measured with an acoustic position indicator and are also inferred from the marine riser inclination information.

Performance data from these sensors is obtained at frequencies ranging from 10 to 1 Hz by a real time data acquisition system. KULLUK's responses are processed, displayed and recorded by the performance monitoring system highlighted schematically in Figure 12. Key response information is displayed continuously in real time on a computer screen in the KULLUK's Control Room so that the performance status of the vessel is known at all times (Figure 13). Chart recorders also provide time series of primary response parameters such as offset, tensions in the lines and global load so that trends can be identified.

The vessels performance is monitored on an ongoing basis by KULLUK's marine staff. The performance monitoring system is an integral part of KULLUK.

E. CIRCUMSTANCES OR CONDITIONS UNDER WHICH CRITICAL OPERATIONS SHOULD BE CURTAILED

A descriptive list of the circumstance or conditions under which the identified critical operations should be curtailed is presented below.

1. Availability of Personnel and Equipment for Particular Operations to be Conducted.

A critical operation will be curtailed or not executed if the required number of qualified personnel are not available to properly supervise and perform the given operation. The same will hold true if the necessary support and emergency equipment for that operation are not available. The necessary compliment of personnel and equipment required for the critical operation will be determined based on sound engineering and prudent industry practices. This determination will be made by the ARCO Drilling Supervisor in consultation with the Contractor Offshore Installation Manager and, if applicable, the appropriate service company personnel. The critical operations include, running and cementing casing, cutting and/or recovering casing, coring, drill stem testing and any other operations which increase the exposure with respect to well control or for the prevention of fire, explosion, oil spills, and other discharges or emissions to the surrounding environment.

2. Ice and Weather Conditions

As a floating semi-submersible drilling unit operating in the Arctic ocean, the Kulluk's operation is dictated by ice and weather conditions. As such, the following discussion is provided regarding the circumstances under which critical operations may be curtailed.

a. Environmental Overview

(1) Operating Area

The Alaskan Beaufort Sea, which lies off the North Slope, is a large region stretching for about 450 miles in an east/west direction from the Canadian border to Point Barrow, and an equivalent distance north to the Arctic Ocean. The majority of the drilling prospects in this area are located in a relatively narrow band, typically within 5 to 50 miles of the coastline. As is shown in Figure 1, ARCO's Kuvlum prospect is situated in the eastern sector of the Alaskan Beaufort Sea, roughly 20 miles north of the coast and about 65 miles northeast of Prudhoe Bay.

(2) Bathymetry

The Kuvlum prospect lies on the broad continental shelf of the Alaskan Beaufort Sea, in 110 ft of water. The main bathymetric features of the region are shown in Figure 14 where three main physiographic zones are evident. These are the continental shelf, which slopes gently towards water depths of 300 ft, the continental slope falling steeply from the shelf edge to water depths of about 3000 feet and the more northerly Arctic Ocean. In general, the bathymetric gradients around Kuvlum are quite mild, sloping gently northwards to the shelf break which is approximately 100 miles off the mainland coast. However, seafloor scour is common in the Kuvlum area, resulting in substantial microrelief locally.

(3). Ice Conditions

(a) General

The primary environmental constraint in the Alaskan Beaufort Sea is sea ice since the area is usually ice covered for at least nine months of the year. When considering drilling operations in this area, site specific information on the nature of the ice cover is required. Factors such as ice concentrations, ice type, ice thickness, pressure ridges, multi-year ice and ice dynamics along with their time dependent variability must be known. Various types of sea ice information are available for the general area including systematic ice cover observations collected by the Canadian Atmospheric Service and the U.S. Navy on a weekly and biweekly basis, satellite and airborne remote sensing data and information obtained from ship and ice based investigations. A brief description of the relevant ice conditions in the Alaskan Beaufort Sea is given in the following sections, based upon the information available to BeauDril.

(b) Ice Zonation

With the onset of winter in mid-October, freeze-up in the Beaufort Sea generally begins with the progressive growth of landfast ice seaward from the coastline. During the late fall to late spring period, the ice cover in the offshore region can be subdivided into three basic ice zones. These are:

- The relatively stable *landfast ice zone* which extends from the shoreline to water depths between 50 and 70 feet.

- The sporadically moving *transition or seasonal pack ice zone* which lies between the outer edge of the landfast ice and the more northerly polar pack. This zone may be anywhere from a few tens of miles to a hundred or more miles in width.

- The more northerly *permanent polar pack* which contains primarily multi-year ice and is in constant motion.

During the winter period, the shallower water prospects typically lie within the landfast ice zone while the medium to deeper water locations lie within mobile transition zone area. The Kuvlum drilling prospect, in 110 ft of water, is located in this moving transition ice zone.

(c) Winter Conditions

During the late fall to spring period, the mid to deeper waters of the Alaskan Beaufort Sea are covered by a continuous pack ice cover, comprised of a matrix of first-year ice types and increasing concentrations of multi-year ice towards the polar pack. In the 70 to 200 foot water depth range, where Kuvlum is located, first-year ice usually predominates growing to a maximum thickness of nearly 6 feet by early May (Figure 15). However, because this is an area of moving pack ice, substantial quantities of new, gray and gray-white ice *(less than 1 foot thick)* are present throughout the winter and spring periods. Multi-year ice floes in varying concentrations are also found in this transition zone ice cover and have mean thicknesses of between 10 and 20 feet. This area, although not as rough as the outer edge of landfast ice, contains substantial numbers of first and multi-year pressure ridges which may average 15 to 30 feet in total thickness. Typical pack ice velocities in the transition zone are in the order of 1 to 2 miles per day, although the ice may remain stationary for time periods of a week or more, or experience extreme motions of 10 to 20 miles/day.

(d) Summer Ice Conditions

Break-up in the Beaufort Sea's transition zone, including the Kuvlum location, normally commences in the late July period with significant open water usually occurring earlier in the east than in the west. Throughout early August, the ice regime in the Beaufort's mid to deeper water areas becomes typical of a marginal ice zone. Decreasing concentrations of drifting ice usually occur throughout the month as the ice moves off to the northwest. The summer "open water period" normally commences in mid August and in most years, persists until early to mid October when freeze-up begins again.

During the summer and freeze-up period, ice intrusions are more frequent in the offshore area than nearshore with variable concentrations of thick first-year and old ice often moving into the operating area under the influence of northerly winds. Again, a range of first-year ice thicknesses are expected over this period as shown in Figure 15. At break-up, first-year ice thicknesses of 5 to 6 feet are common, decreasing to several feet in thickness as the summer progresses. Old ice that occurs in the area is between 10 and 20 feet in mean thickness, with floe sizes typically from a few hundred feet to several miles in diameter. Weathered pressure ridges and rough ice fragments from the stamuki zone with thicknesses exceeding 60 feet are also quite frequent within this "summer ice cover". Movements are quite variable in terms of both speed and direction during summer and freeze-up but average about .5 kt with extremes in excess of 1 kt.

As noted earlier, freeze-up typically commences in the early to mid October time frame with thin first-year ice forming across the Alaskan Beaufort Sea. As the ice moves during freeze-up, leads and large areas of open water are common but by mid November, a continuous 9 to 10/10ths concentration ice cover is typical. Areas where old ice was present during freeze-up will have variable concentrations of this ice type contained within the growing ice cover. The predominantly first-year ice cover in the operating area is typically two feet in thickness by mid November and three feet in thickness by mid December with significant ridging.

(4) Meteorological Conditions

Weather conditions in the Arctic are extremely severe and are directly responsible for the formidable environment of the area. In the Alaskan Beaufort Sea, temperatures vary from lows of -50° F in the winter to highs of 80° F during the summer, while mean annual temperatures are roughly 10° F. These temperatures are not as low as those in some of the more southerly inland areas, but the persistence of the Arctic cold, combined with other unfavorable factors, such as remoteness, darkness, winds and poor visibility, make these temperatures a severe operating problem.

The wind climate of the southern Beaufort Sea is relatively calm, although combined with low temperatures, winds present a significant operating constraint. Annual wind speeds in the region average roughly 10 knots, while extremes in the order of 70 knots may be expected.

Annual precipitation in the area is low and usually averages 6 to 12 inches per year. Snowfall is not an important hindrance to operations through its cumulative thickness, but is a more serious operating problem when continually blown by winds into hard packed drifts. Blowing snow also restricts travel by land and air due to reduced visibility.

The most obvious restriction to visibility is the long polar night in winter when the Beaufort Sea region is in darkness. Visibility in the area is also reduced by fog, white-outs and blowing snow. Fog is usually the result of warm, moist air passing over cold water, snow or

ice, and is worst during the break-up and early freeze-up periods. White-outs are most common during low overcast, in freshly fallen or blowing snow, or with fog. In general, visibility is best in the late winter, although the continuous daylight during the summer months is obviously a great advantage to operations.

(5) Oceanographic Conditions

In a relative sense, waves in the Beaufort Sea are quite small since the presence of pack ice limits the wind fetch, and thus wave heights, during the open water period. Generally, significant wave heights in the area are in the order of several feet, although extremes during storms may be as great as 20 feet. Although little information on currents exists, they are expected to be typically less than 0.5 kts and thus, are not a significant factor.

b. Kulluk System

(1) Design Capabilities

KULLUK is a second generation Arctic drilling unit that is purpose built to operate in the ice and wave conditions characterizing the Beaufort Sea's break-up, summer, freeze-up and early winter periods. The vessel has a unique twenty-four faceted circular hull which, combined with its radially symmetrical mooring, provides an omni-directional capability to resist ice and storm forces (Figure 3). KULLUK's inverted conical hull form fails the oncoming ice in flexure at low force levels while the outward flare near the bottom of the hull ensures that broken ice pieces clear around it and do not enter the moonpool or become entangled in the mooring lines. This efficient ice breaking and clearing of KULLUK's hull minimizes the tensions in the unit's mooring lines along with the vessel's response motions in ice.

KULLUK's mooring system provides resistance to environmental forces and is comprised of twelve radially deployed anchor wires. An important feature is the through hull path of the mooring lines and the underwater fairleads which, combined with the unit's hull form, minimizes the threat of ice fouling the lines.

KULLUK is designed for continued drilling operations in the wind and waves associated with one-year return period Beaufort Sea storms and to maintain location and survive 100 year return period events (Table 10). In terms of ice, KULLUK is designed to operate with no icebreaker support in level, unbroken first-year ice up to four feet in thickness. The vessel is built to Arctic Class[2] IV specifications and as such, has a normal design operating season from June 1st until January 31st.

The operating and survival capabilities of KULLUK in ice are enhanced by the ice management support provided by BeauDril's Class IV ice-breaking vessels. These icebreakers fragment thicker ice within the general ice cover along with more extreme features such as pressure ridges and old ice floes.

This ice management support reduces the ice forces on KULLUK's mooring system and allows drilling operations to proceed in more severe ice environments. In level ice, 4 feet thick, BeauDril's 24,000 and 14,900 HP icebreakers proceed continuously at speeds of

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[2] Arctic Class - is a Canadian Coast Guard classification system which rates icebreakers for use in the Canadian Arctic. The normal design operating season from June 1st until January 31st is established by the Canadian Coast Guard for Class IV vessels.

seven knots and four knots respectively (Figures 4,5, and 6). In addition to ice management, these support vessels carry out supply, anchor handling and towing operations.

(2) Operating Experience

The capabilities of KULLUK are particularly well suited to safe and efficient drilling operations in the Alaskan Beaufort Sea where late break-up, early freeze-up and frequent ice intrusions limit the operating season available to more conventional drilling systems.

Since entering the Beaufort Sea in August 1983, the KULLUK system has successfully drilled nine wells in water depths ranging from 80 to 180 feet. During drilling operations, KULLUK has been exposed to a wide range of ice and wave conditions and has developed ice management techniques and procedures for safe and efficient operations within its performance limits. Ice management has been a key element to the success of KULLUK's station-keeping in thick first-year ice, large pressure ridges and old ice intrusions.

The conditions in which KULLUK has operated can be subdivided into three characteristic ice scenarios: spring break-up with thick moving first-year ice and some old ice; summer open water with first and multi-year ice intrusions; and freeze-up/early winter with a growing first-year ice cover and some old ice. KULLUK has experienced very little downtime in these conditions and has commenced drilling operations as early as June 1st and continued working as late as December 11th. KULLUK has also operated through a number of Beaufort Sea storms with maximum wave heights in the 20 foot range, performing in accordance with design expectations.

3. Abnormal or Unusual Conditions Encountered During Drilling Operations

a. Logging or Wireline Operations

(1) Logging will not be attempted until the hole is stable, which means the following conditions exist: no mud flow; no lost circulation; mud is not being gas cut; and the hole is clean as indicated by the returns at the shale shaker.

(2) Conditions that are considered unfavorable for successful logging and require consideration for correction are as follows:

(a) high solids content in the drilling mud;

(b) tight hole sections in wellbore on first logging run;

(c) excessive time since circulating the well.

(3) Logging operations which will not be allowed are:

(a excessive spudding of logging tools to get downhole; or

(b) repeat runs in a hole that gives evidence of being in bad condition. Instead, a conditioning trip will be considered before the logging program is resumed.

b. Running and Cementing Casing

(1) Casing should not be run or cemented unless hole conditions are stable which means the following conditions exist:

(a) mud is not gas cut and rheological properties are in order;

(b) fluid level in wellbore is stable, not flowing or taking fluid;

(c) wellbore is free of obstructions.

(2) If fluid is lost or the well begins to flow while running casing, remedial measures will be considered. This could include, but not limited to, rigging up to circulate through casing, the use of loss circulation materials and the application of conventional well control procedures, etc.

(3) Casing will not be run and cemented under conditions deemed unsafe due to weather, ice, equipment problems, or personnel availability.

c. Cutting and/or Recovering Casing

(1) During the abandonment of the well, each casing string may be cut and/or recovered in such a manner that additional cement plugs are set if open hole is exposed by the removal of the casing string.

(2) The casing cutting and/or recovering operation would not be commenced until the ARCO Drilling Supervisor is confident that the well is properly plugged in accordance with all existing regulations.

d. Drill Stem Testing

(1) Drill stem testing will not be conducted:

(a) in open hole; or

(b) using the drill pipe as a test string unless it can be tested to a pressure in excess of the anticipated reservoir pressure.

(c) without first pressure testing all circulating lines and manifolds, testing head, manifold and other associated surface testing equipment to at least the maximum anticipated surface pressure.

(2) The ARCO Drilling Supervisor will be prepared to cease any testing operations if:

(a) surface pressure exceeds the design or tested rating of the surface equipment;

(b) the surface facilities, burner, or storage become overloaded by the producing rate (This applies to both liquid and gas capacities);

(b) the annulus-pressure behavior is erratic, after taking into account that some variation in pressure is normal from the effect of temperature and tubing pressure; or

(d) at any time there is concern about safety because of weather, ice, integrity of any equipment, abnormal presence of hydrocarbon vapors or hydrogen sulfide, or any other reason deemed unsafe for the personnel onboard.

(3) During drill stem testing, the following will be prohibited in the testing area: smoking, welding, open flames, and exposed lights.

(4) Before commencing any testing operations, a meeting of key ARCO, Contractor, and service company personnel will be held to review the procedures and equipment to be utilized during the test. All flowlines will be tested to the maximum anticipated surface pressure upstream of the test choke. All personnel will be alerted to the possible hazards of the testing operations to be conducted.

4. Availability of Oil Spill Containment and Cleanup Equipment

The KULLUK and Canmar Supplier I have initial oil spill response equipment onboard at all times. This equipment is listed in ARCO's Oil Spill Contingency Plan (ARCO, 1992). In addition to the oil spill response equipment and materials located on board the KULLUK, the CANMAR SUPPLIER I shallow draft support vessel will maintain an extensive inventory of spill response supplies onsite as identified in the Oil Spill Contingency Plan. In case of an emergency, ARCO would obtain additional oil spill response equipment through Alaska Clean Seas (ACS), and other sources both in Alaska and out-of-state as identified in of the Oil Spill Contingency Plan.

If an uncontrolled well emergency on a different Beaufort Sea well occurs while the Kuvlum well is being drilled, ARCO will track the ACS equipment dedicated to that cleanup operation. ARCO will make an assessment of its planned drilling activities and the availability of off-site cleanup equipment. If drilling operations or other downhole activities are being conducted, ARCO will consult with the District Office of the MMS on what safeguards may be necessary to continue or commence such operations.

5. Lease Stipulations Affecting Drilling Operations.

Two Lease Stipulations for OCS-Y-0866 directly impact the operations scheduled for drilling the Kuvlum Prospect.

a. The first stipulation requires a seasonal drilling restriction for protection of bowhead whales from potential effects of oil spills. This stipulation has been waived by the MMS because the operator is performing a "whale monitoring program".

   ARCO has contracted an outside firm to conduct such a program on the Kuvlum project. A whale monitoring program has been prepared and submitted to all appropriate governmental agencies for approval and implementation.

b. The second stipulation prohibits Drilling Below Threshold Depth in Broken Ice Conditions.

   With regard to oil spill cleanup capability (Lease Sale 87, Stipulation No. 6), the MMS has approved the Oil Spill Contingency Plan (OSCP) for broken ice conditions (reference August 30, 1990 correspondence).

   This approval is conditional based upon the operator (ARCO) performing an oil spill response exercise prior to the commencement of drilling operations. This exercise will be conducted by ARCO to fulfill this requirement.

   In addition, a table top/communications oil spill response exercise will be conducted to demonstrate ARCO's ability to respond to simulated major oil spill. This exercise will also be conducted to fulfill this obligation.

   As previously mentioned, ARCO will provide immediate response capability at Kuvlum by stationing the Canmar Supplier I at the location, fully equipped with oil spill equipment and materials as specified in the OSCP.

   Also, ARCO has arranged for a spill response barge and tug to be located on standby, at West Dock in Prudhoe Bay, in the event a major response is required.

6. Seasonal Considerations

This COCP is primarily intended to detail the responsibilities, circumstances, and procedures to safely and securely curtail critical operations if necessary. All procedures contained herein specify a temporary well suspension as the desired course of action.

In the later part of the normal design operating season, environmental conditions may dictate that a permanent well abandonment be implemented. All curtailment opportunities and decisions will account for the need for a permanent well abandonment to be undertaken if necessary. As an example, in late season, careful consideration will be given to the decision as to whether or not to drill out of a previously set casing string.

Under all circumstances, ARCO intends to follow the guidelines set forth in this COCP with careful consideration given to the particular environmental conditions as they relate to the seasonal window for drilling operations.

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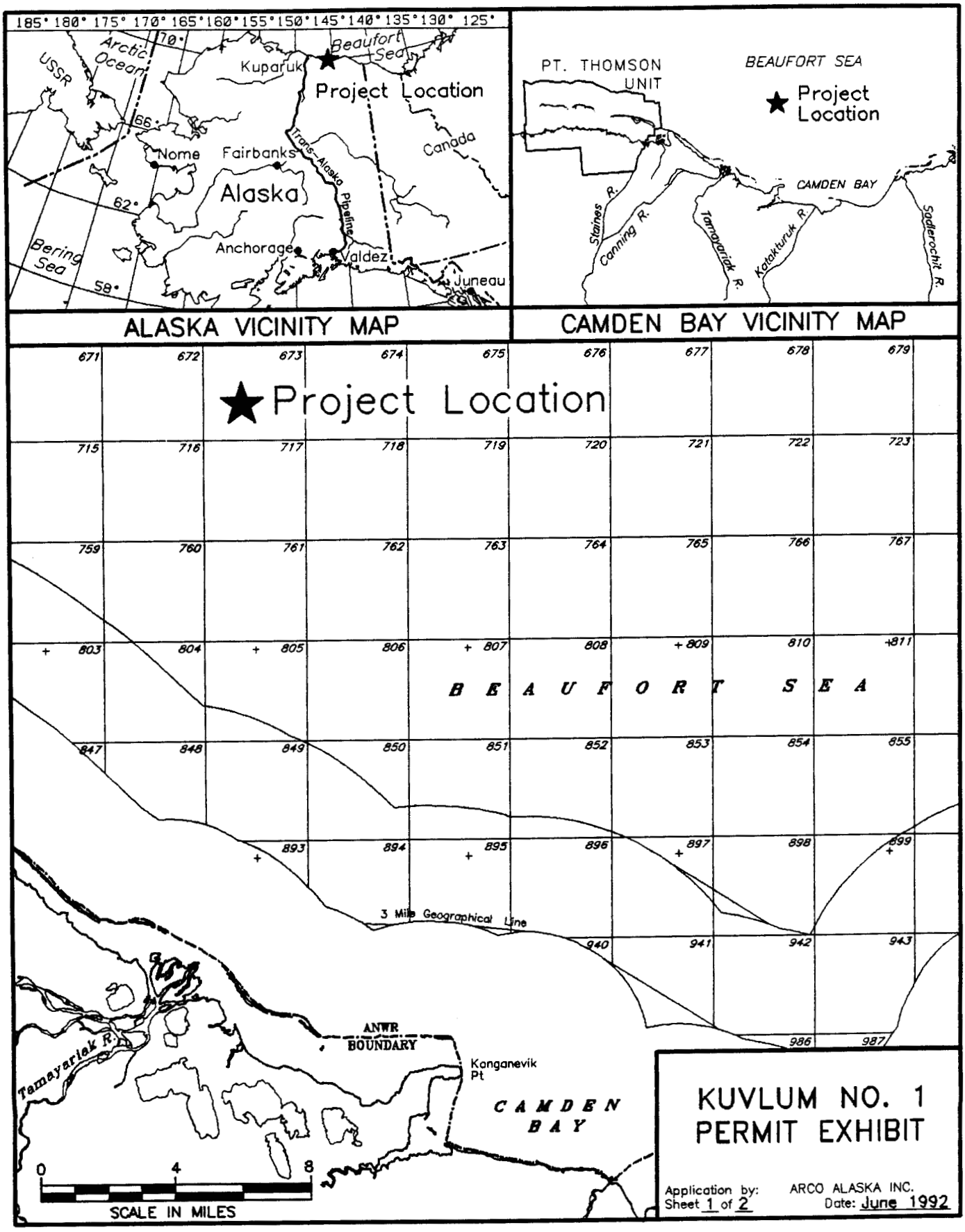


FIGURE 1 AK92 060804A01

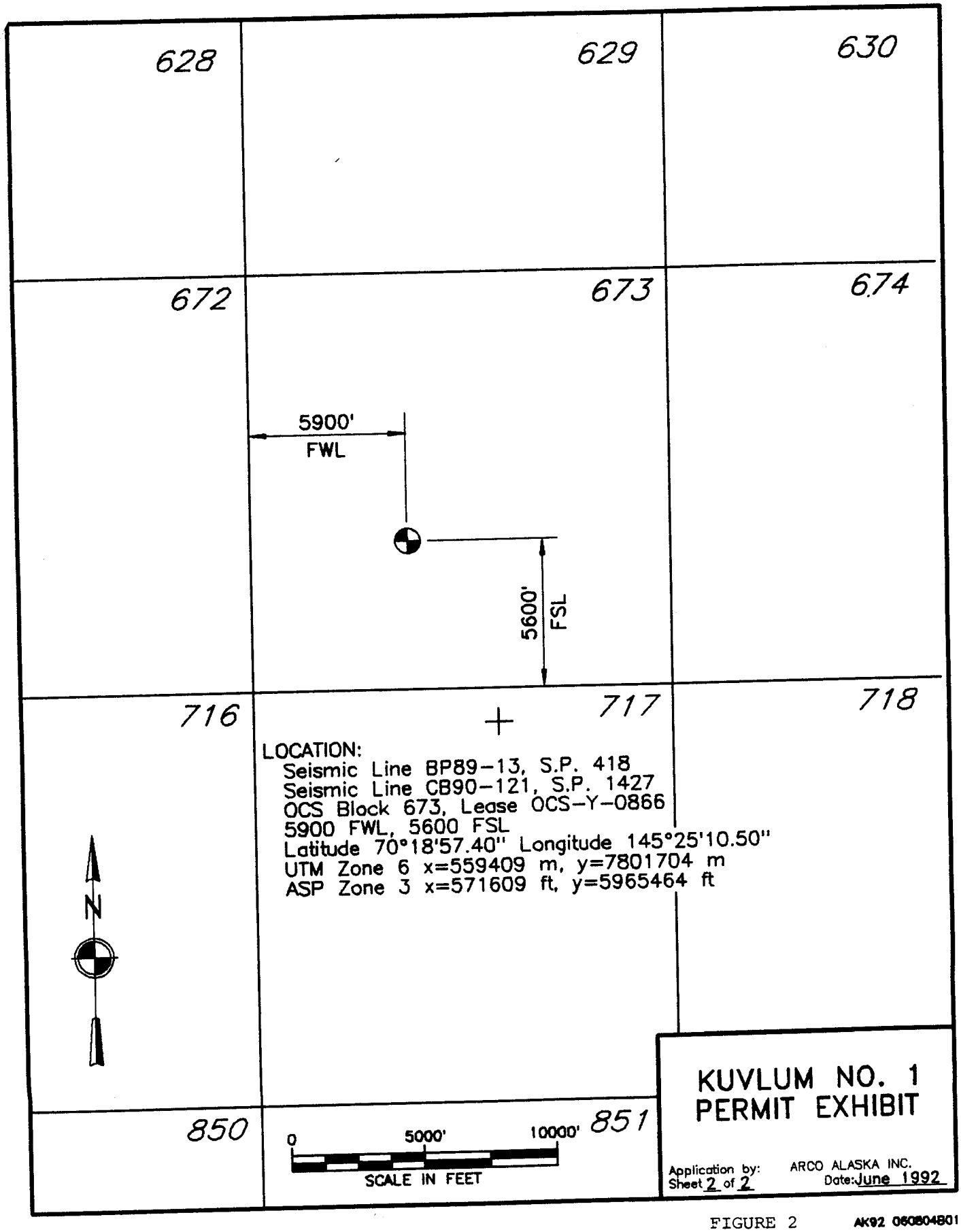
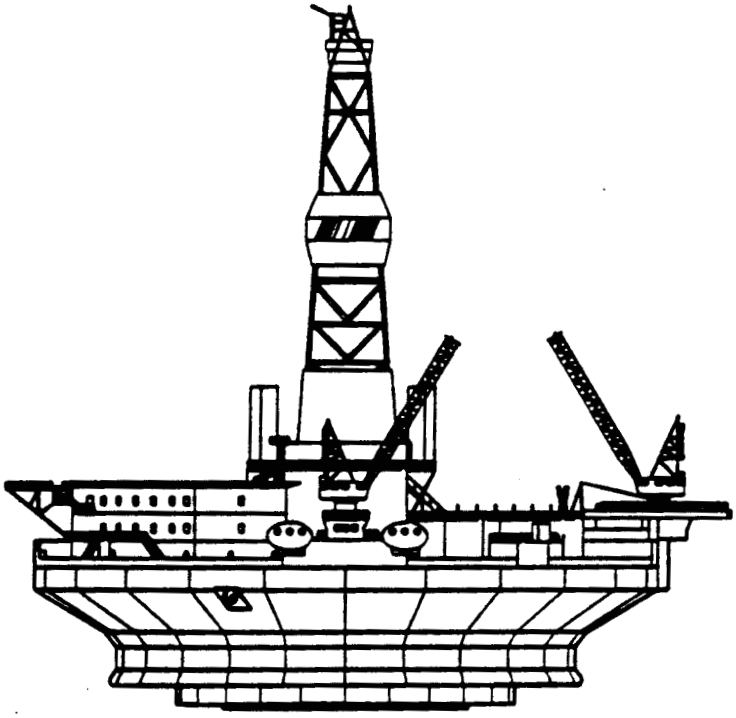


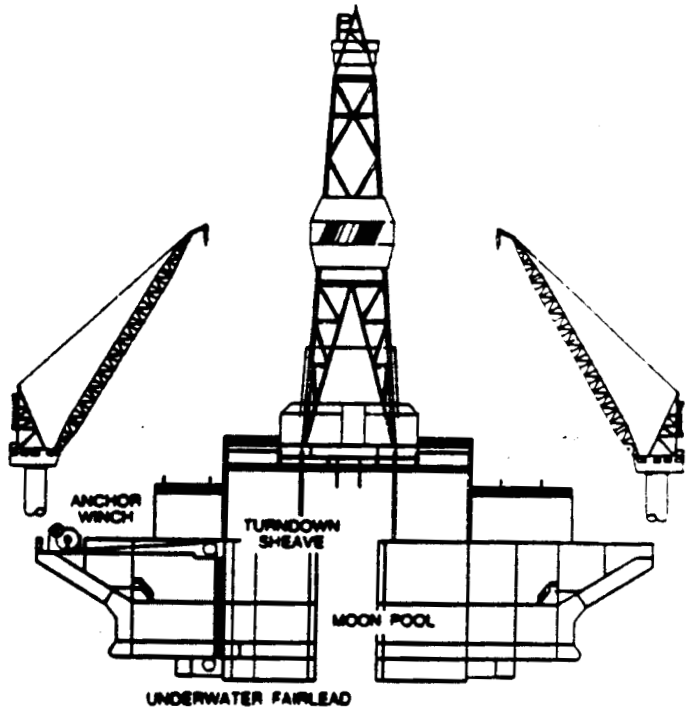
FIGURE 2 AK92 060804B01

Kulluk

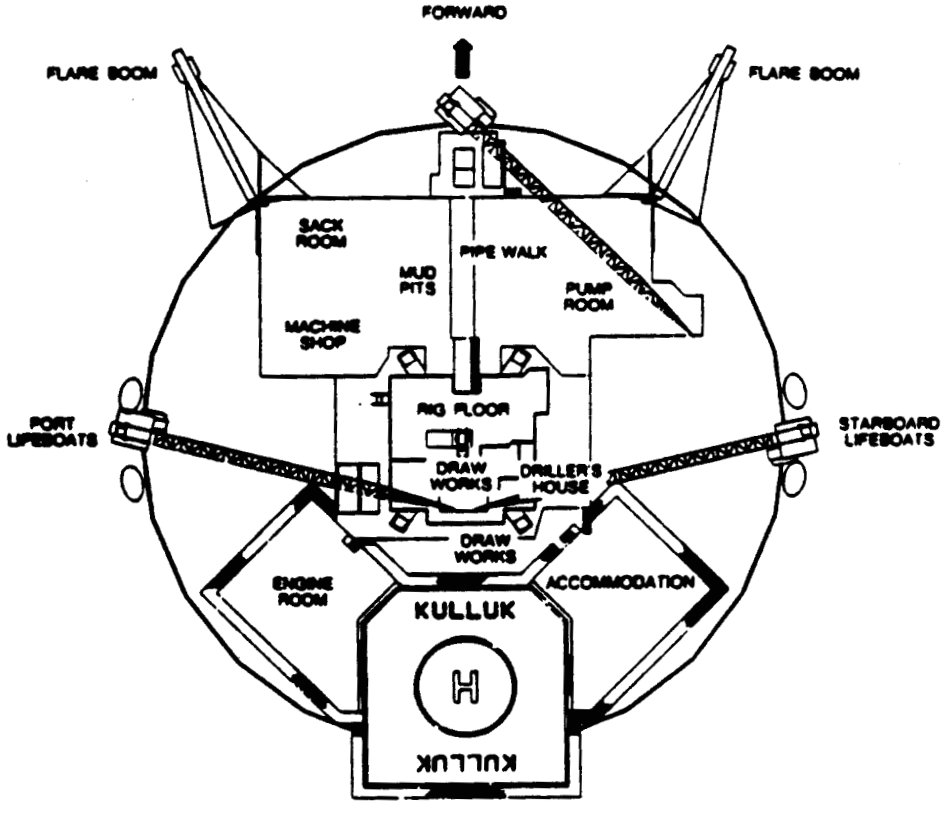
Principal schematic drawings and layouts.



PROFILE



SECTION VIEW

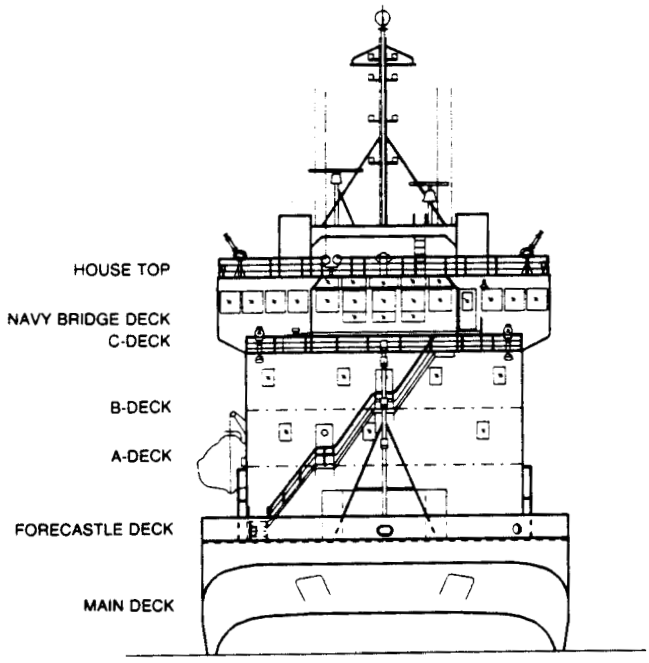


PLAN VIEW

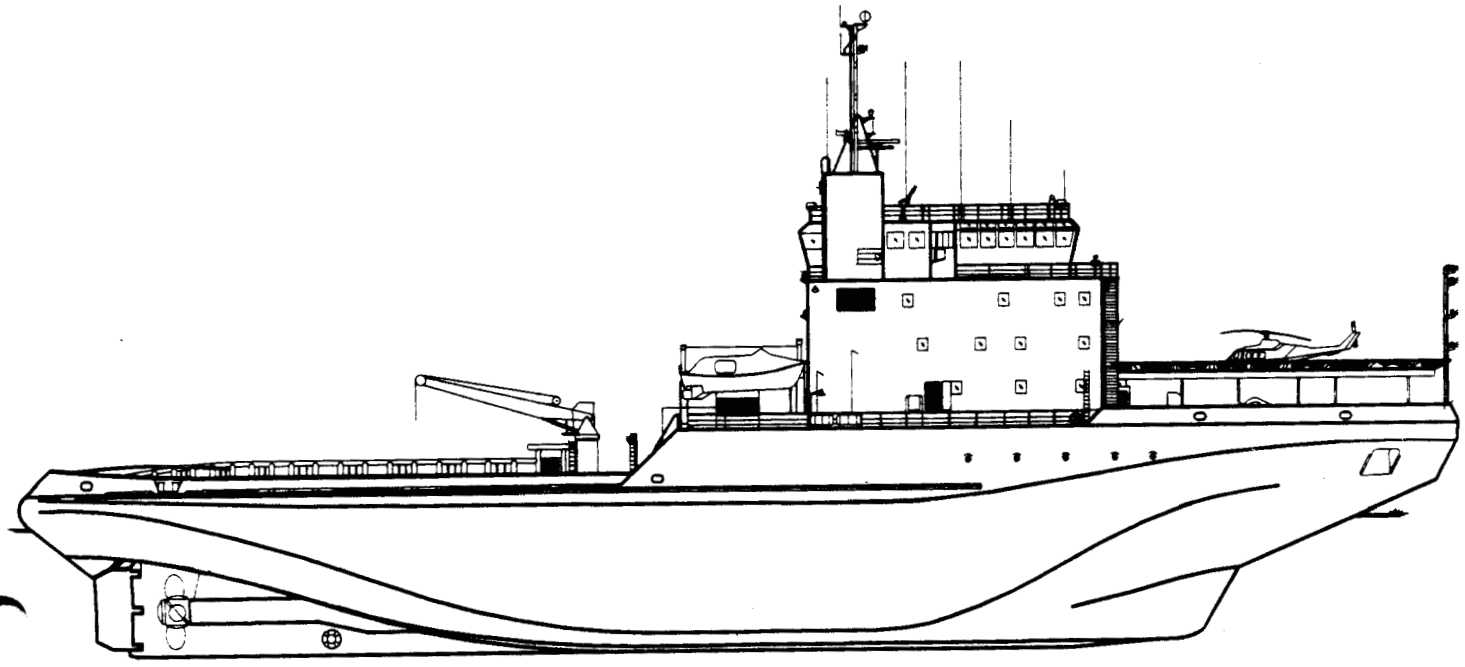
FIGURE 3

Kalvik

Principal schematic drawings and layouts



BOW ELEVATION

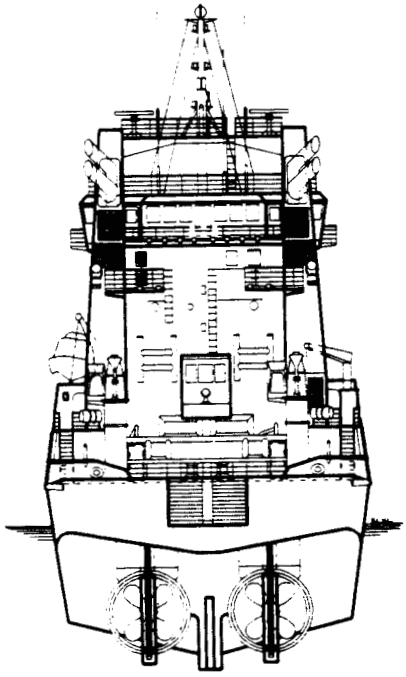


PROFILE ELEVATION

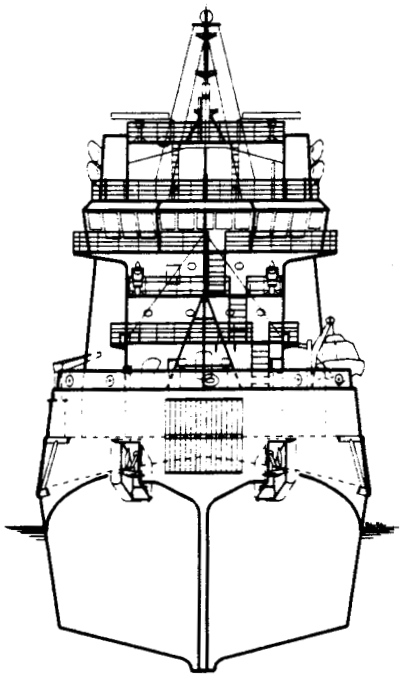
FIGURE 4

Ikaluk

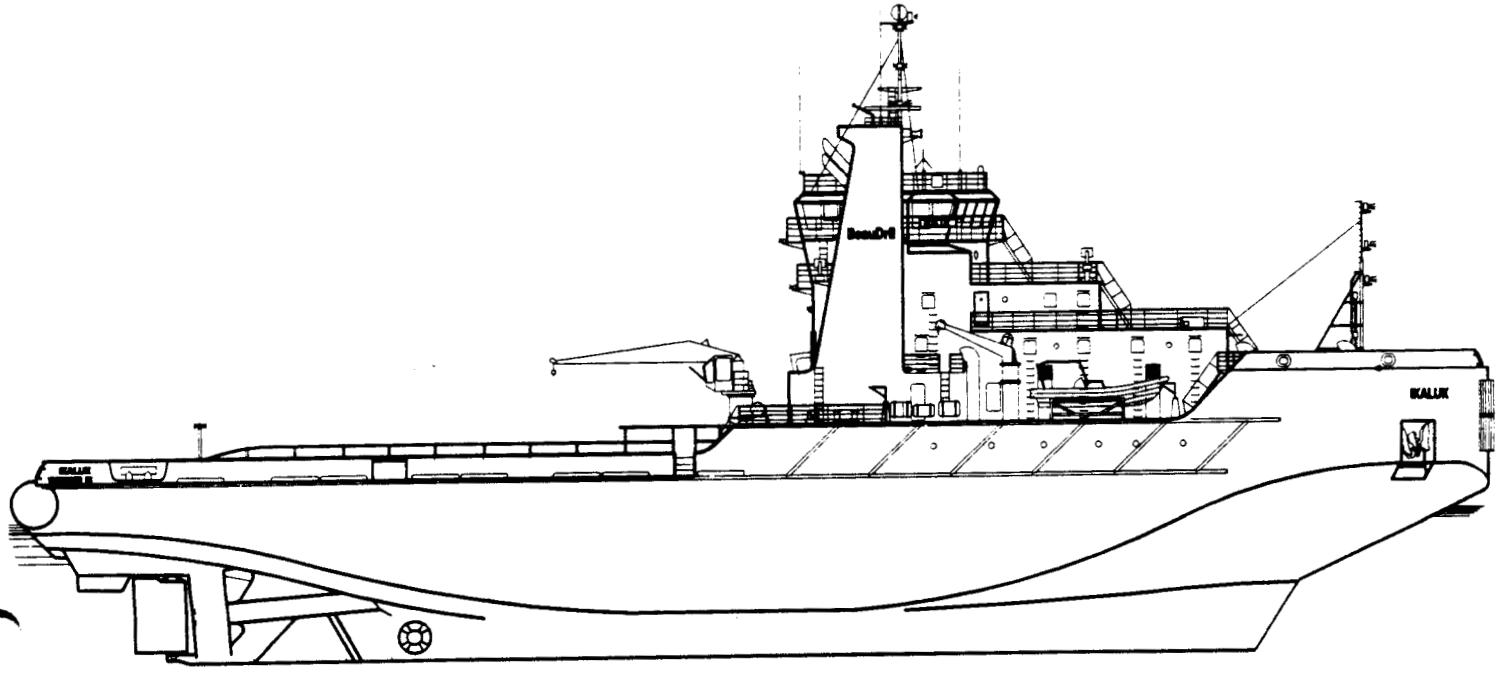
Principal schematic drawings and layouts



STERN ELEVATION



BOW ELEVATION

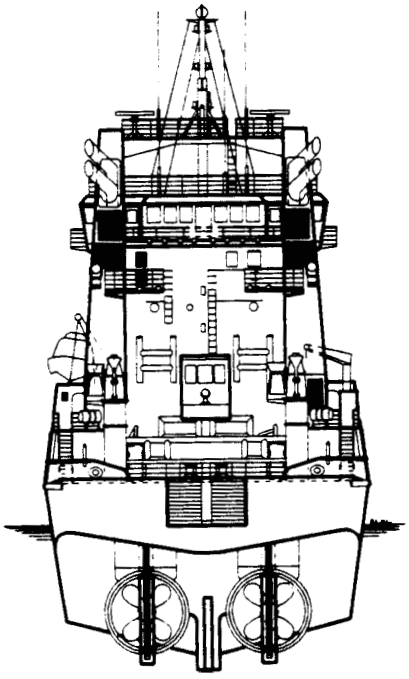


PROFILE ELEVATION

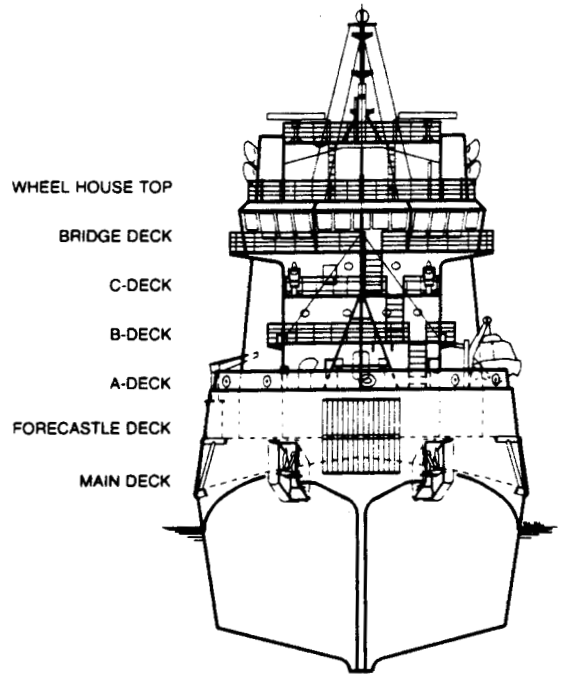
FIGURE 5

Miscaroo

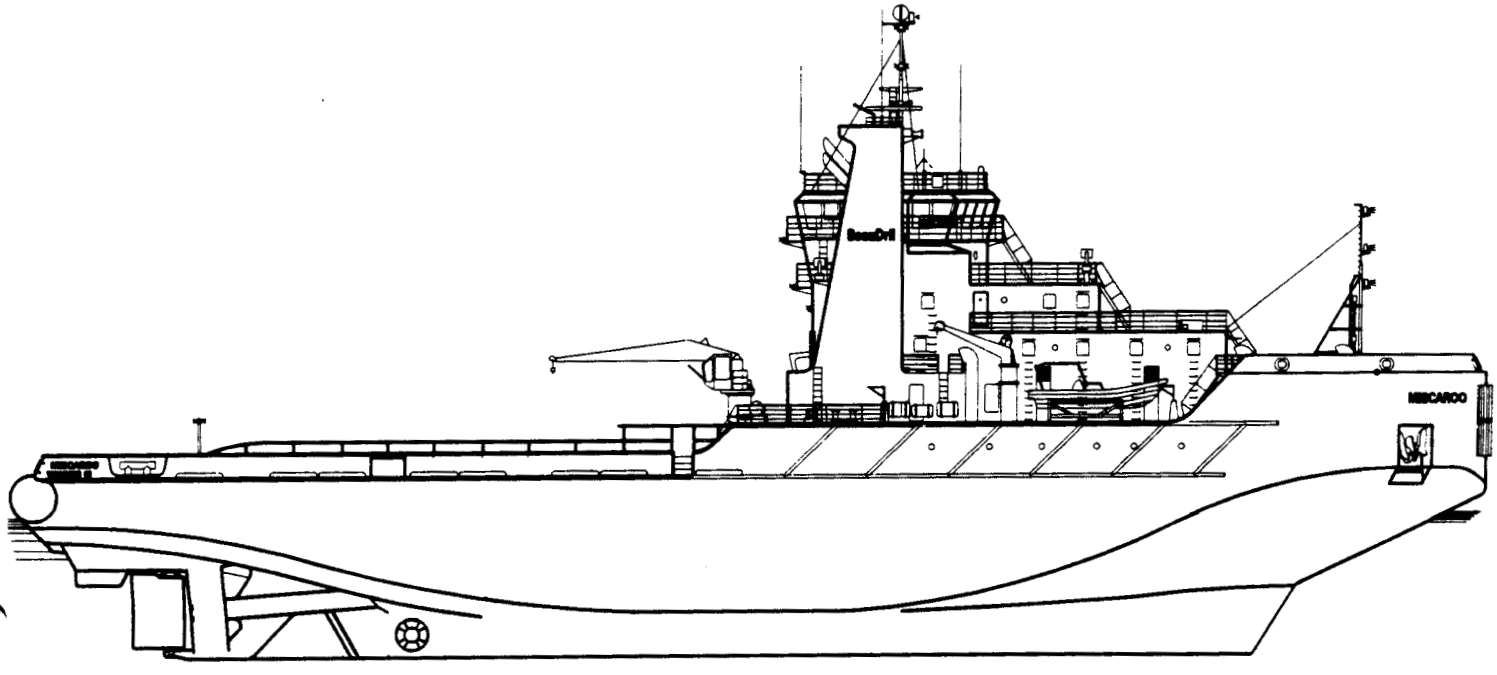
Principal schematic drawings and layouts



STERN ELEVATION

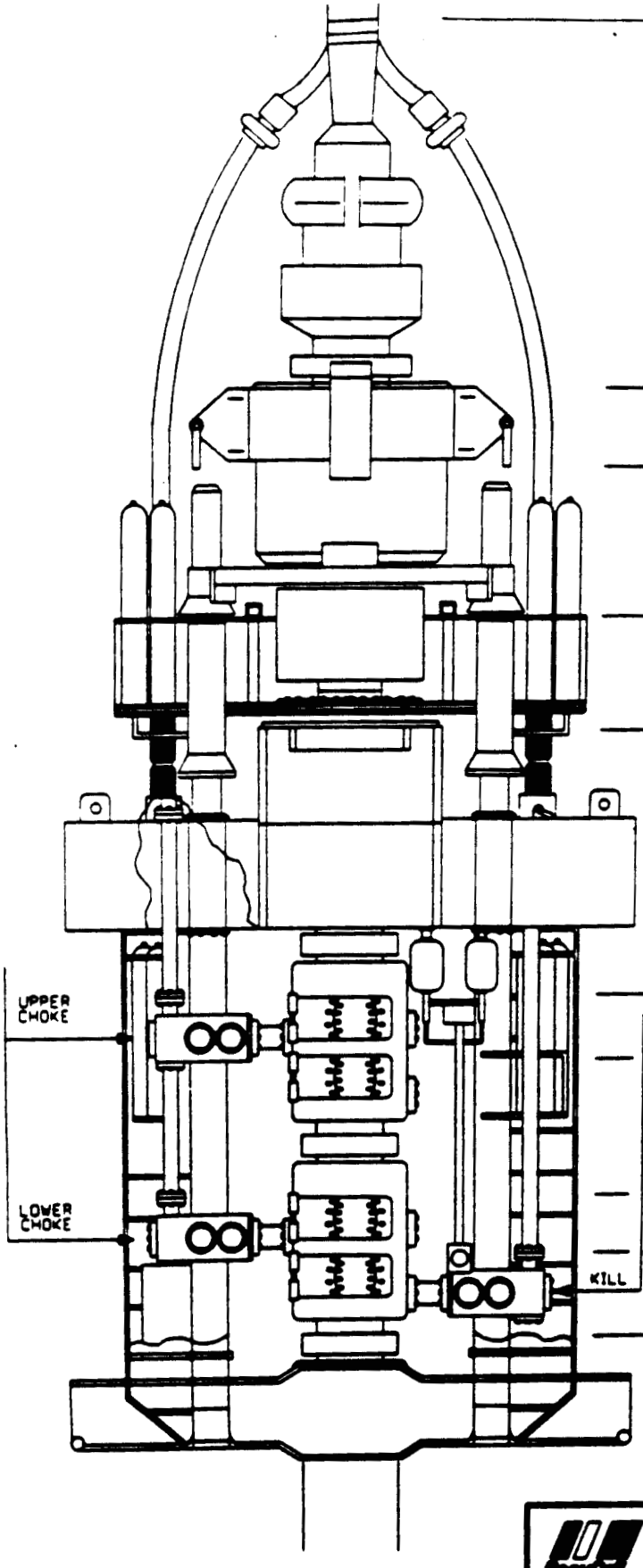


BOW ELEVATION

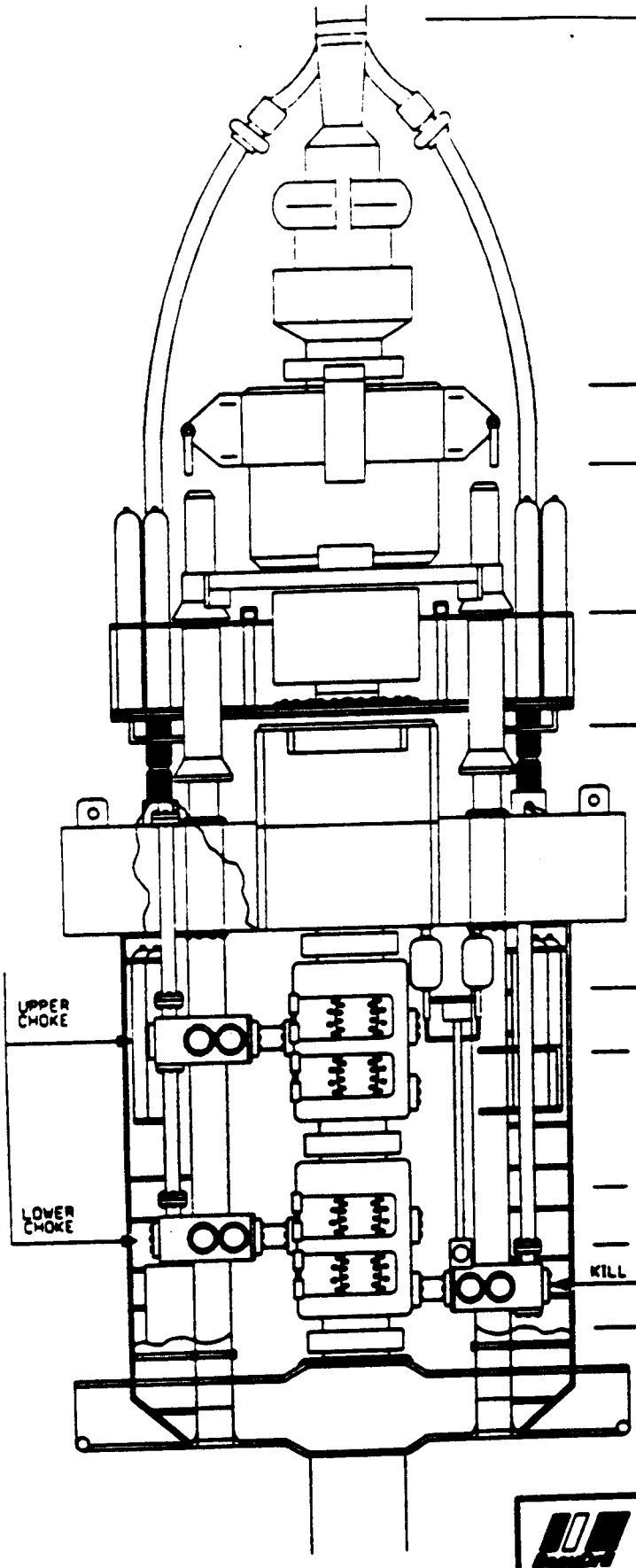


PROFILE ELEVATION

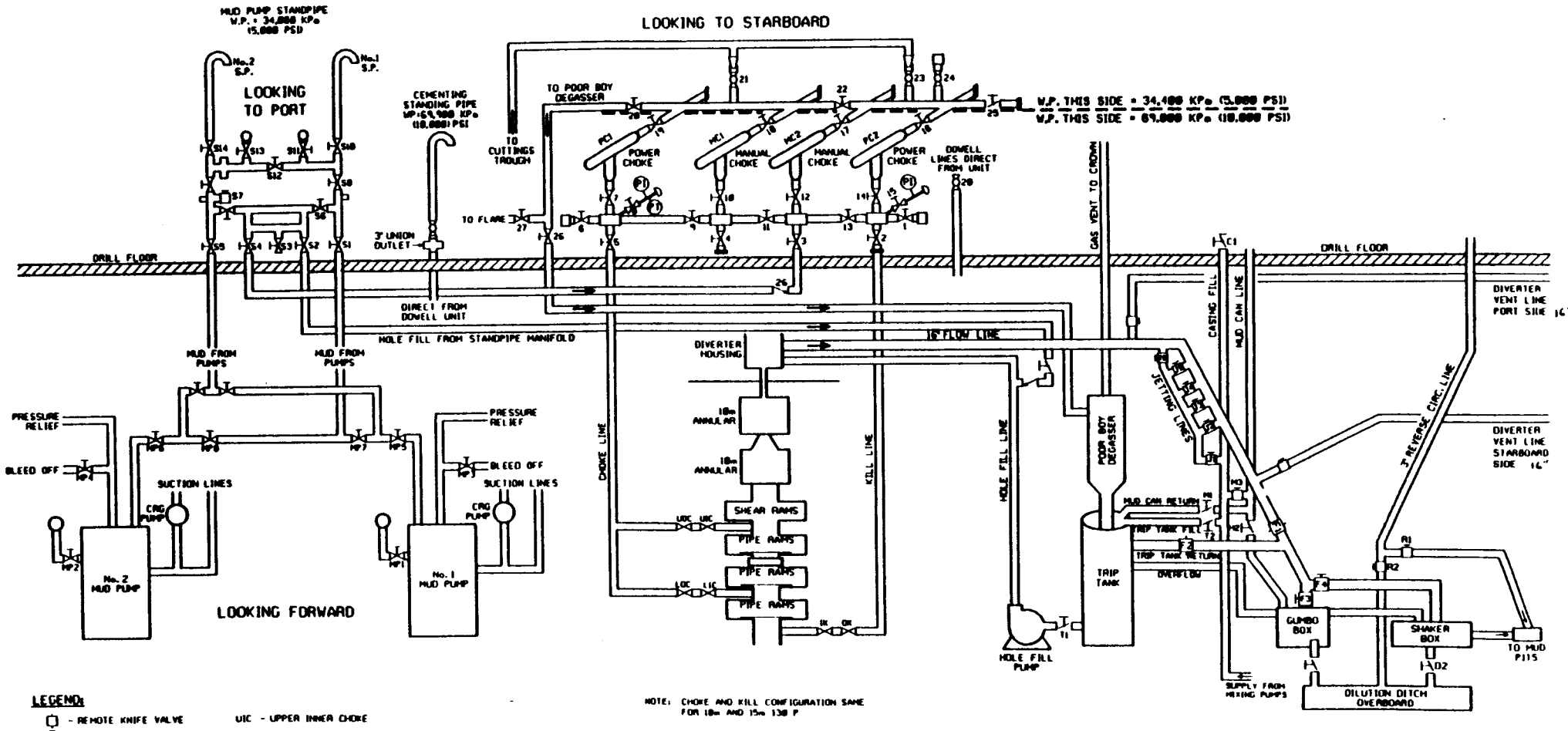
FIGURE 6



10M STACK		
METER	FEET	
11.13	36.52	TOP OF BALL JOINT & ADAPTOR
8.63	28.31	TOP UPPER SPHERICAL
7.69	25.23	TOP GUIDE POST (EXTENDED)
6.78	22.24	TOP LMRP CONNECTOR
5.53	18.14	TOP LOWER SPHERICAL
3.35	10.99	TOP SHEAR RAMS
2.86	9.38	TOP UPPER RAMS
1.60	5.25	TOP MIDDLE RAMS
1.12	3.67	TOP LOWER RAMS
0.0	0.0	TOP OF WELLHEAD



15M STACK		
METERS	FEET	
11.25	36.91	TOP OF BALL JOINT & ADAPTOR
8.75	28.71	TOP UPPER SPHERICAL
7.86	25.79	TOP GUIDE POST (EXTENDED)
6.95	22.80	TOP LMRP CONNECTOR
5.70	18.70	TOP LOWER SPHERICAL
3.70	12.14	TOP SHEAR RAMS
3.19	10.47	TOP UPPER RAMS
1.77	5.80	TOP MIDDLE RAMS
1.26	4.13	TOP LOWER RAMS
0.0	0.0	TOP OF WELLHEAD



NOTE: CHOKE AND KILL CONFIGURATION SAME FOR 18m AND 15m 138 P

LEGEND:

- ▯ - REMOTE KNIFE VALVE
- ▯ - MANUAL KNIFE VALVE
- ⊢◁▷⊣ - REMOTE BUTTERFLY VALVE
- ⊢▷◁⊣ - MANUAL BUTTERFLY VALVE
- ⋈ - REMOTE GATE VALVE
- ⋈ - MANUAL GATE VALVE
- ⊣◁ - CHECK VALVE
- PI - PRESSURE INDICATOR
- PT - PRESSURE TRANSMITTER

- UIC - UPPER INNER CHOKE
- UOC - UPPER OUTER CHOKE
- LIC - LOWER INNER CHOKE
- LOC - LOWER OUTER CHOKE
- IK - INNER KILL
- OK - OUTER KILL

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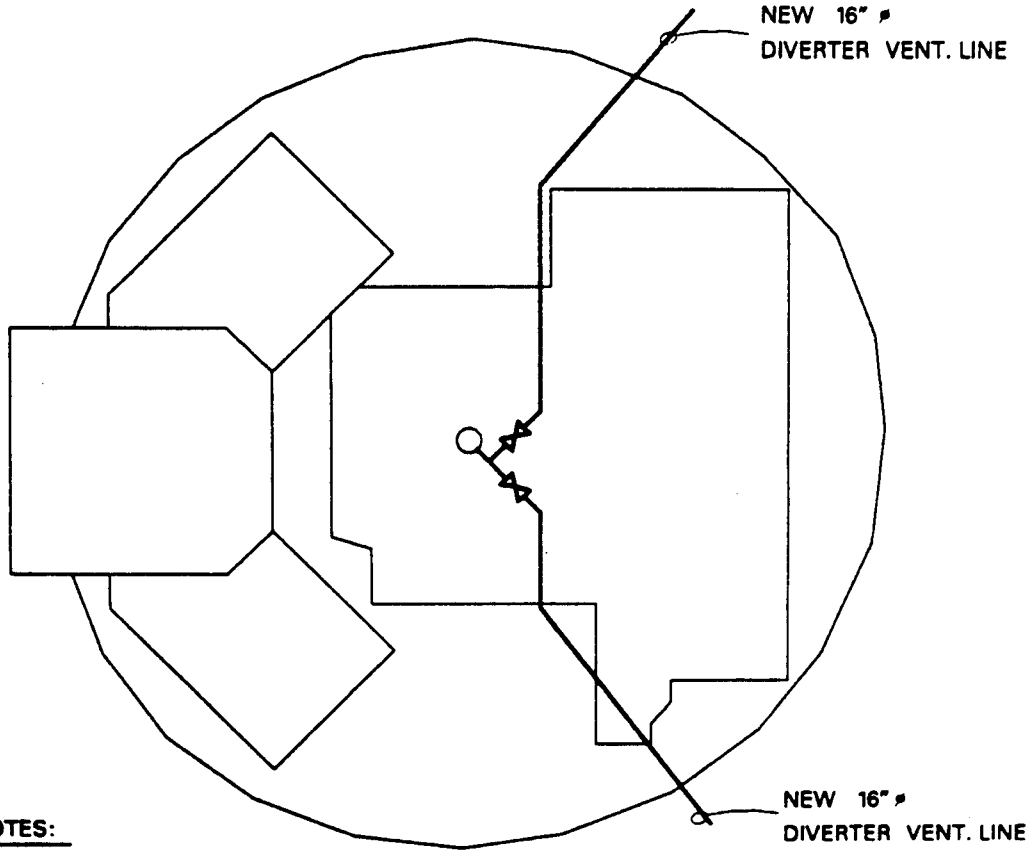
KULLUK OPERATIONS MANUAL

DATE:
FILE No. PA-040
PROJECT No. 0004

WELL CONTROL FLOW DIAGRAM
FIGURE 9

Figure 3-4

BEAUDRIL KULLUK
DIVERTER SYSTEM
PLAN VIEW



NOTES:

1) 16" DIAMETER SYSTEM
2) VALVES C/W HYDRAULIC ACTUATORS.
3) 45° & 90° ELBOWS SHALL BE, VORTICE-ELL OR TARGETED TEES.
4) ALL OTHER ELBOWS SHALL BE, R=3 DIA. ELBOWS

ZHO=[200,12]KULLUK.DGN'FONT

FIGURE 10

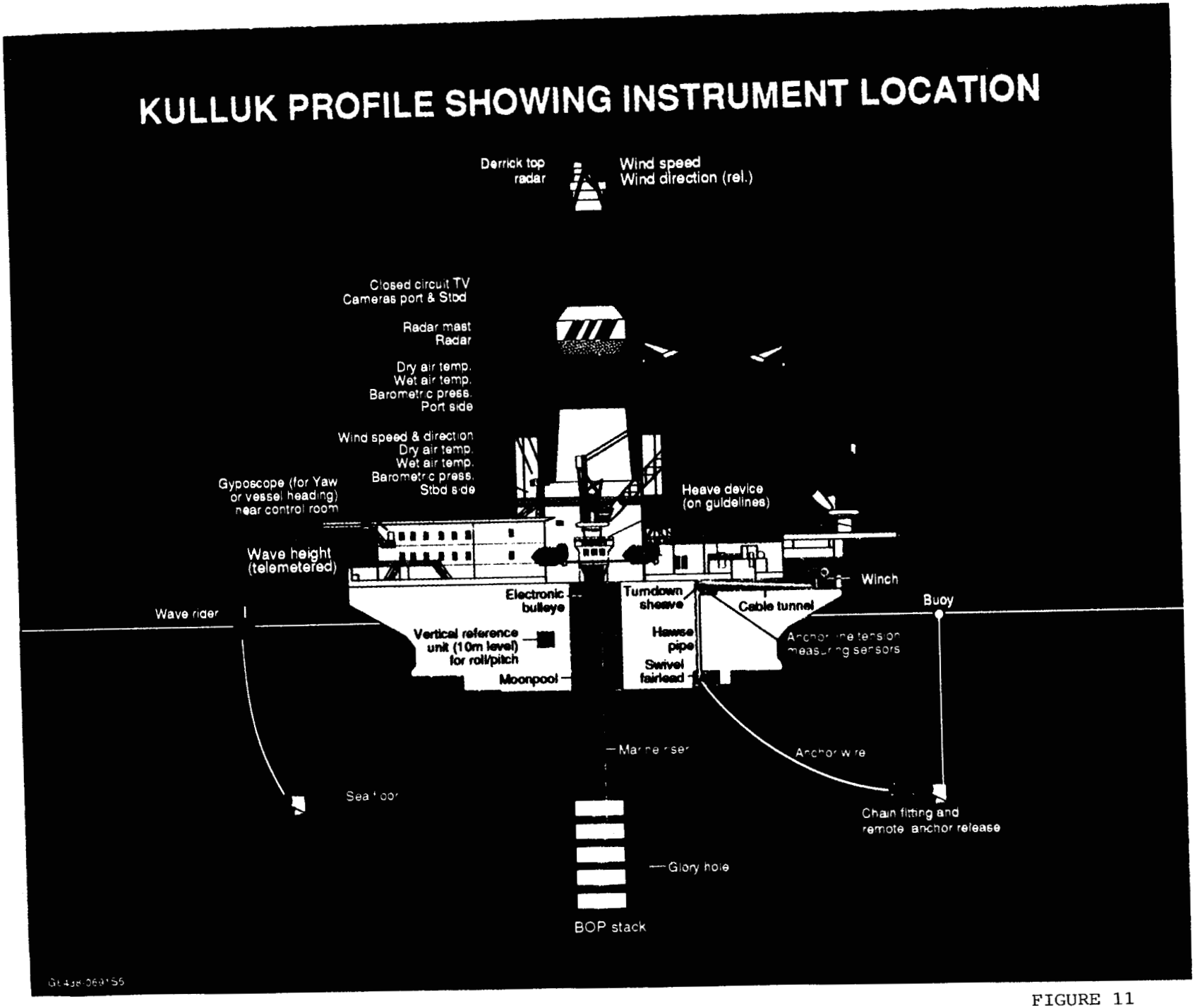

KULLUK PROFILE SHOWING INSTRUMENT LOCATION
Derrick top radar
Wind speed
Wind direction (rel.)
Closed circuit TV Cameras port & Stbd
Radar mast Radar
Dry air temp.
Wet air temp.
Barometric press.
Port side
Wind speed & direction
Dry air temp.
Wet air temp.
Barometric press.
Stbd side
Gyroscope (for Yaw or vessel heading) near control room
Heave device (on guidelines)
Wave height (telemetered)
Winch
Buoy
Wave rider
Electronic bulleye
Turndown sheave
Cable tunnel
Vertical reference unit (10m level) for roll/pitch
Hawse pipe
Swivel fairlead
Moonpool
Anchor line tension measuring sensors
Marine riser
Anchor wire
Sea floor
Chain fitting and remote anchor release
Glory hole
BOP stack

FIGURE 11

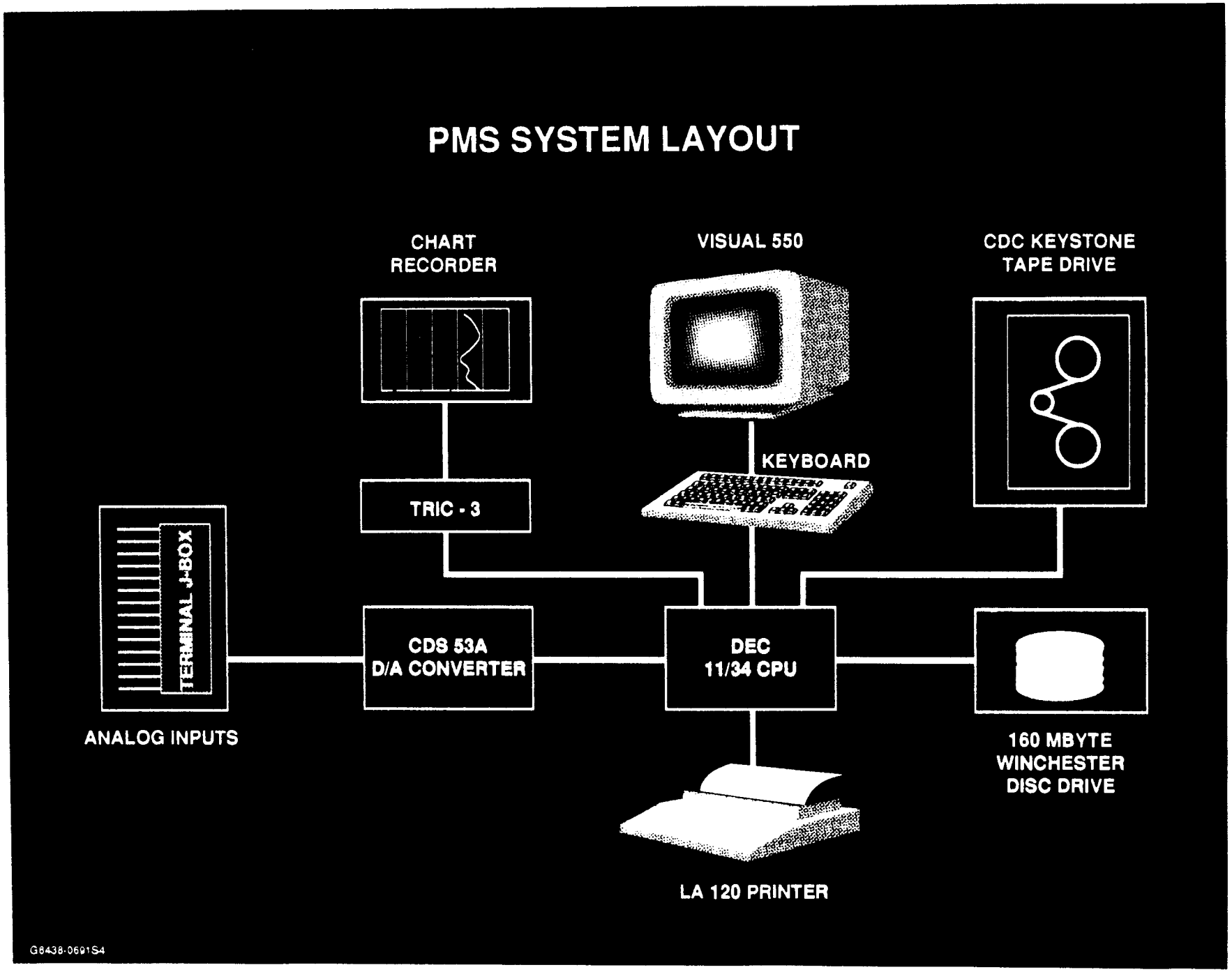

PMS SYSTEM LAYOUT
CHART RECORDER
VISUAL 550
CDC KEYSTONE TAPE DRIVE
KEYBOARD
TRIC - 3
TERMINAL J-BOX
CDS 53A D/A CONVERTER
DEC 11/34 CPU
ANALOG INPUTS
160 MBYTE WINCHESTER DISC DRIVE
LA 120 PRINTER
G8438-0691S4

FIGURE 12

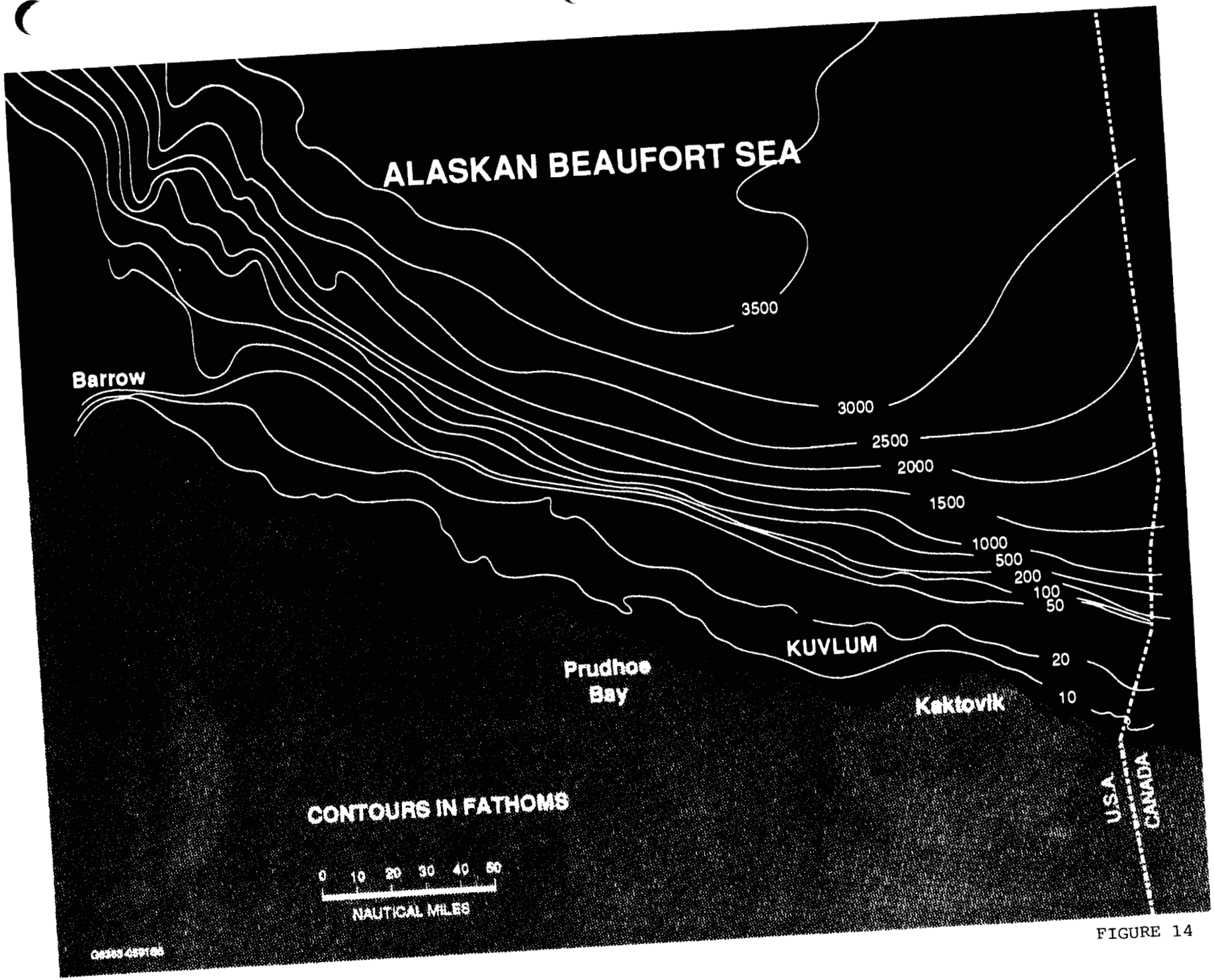

ALASKAN BEAUFORT SEA
3500
3000
2500
2000
1500
1000
500
200
100
50
20
10
Barrow
Prudhoe Bay
KUVLUM
Kaktovik
USA
CANADA
CONTOURS IN FATHOMS
0 10 20 30 40 50
NAUTICAL MILES

FIGURE 14

Table 6

COMPONENTS OF ENVIRONMENTAL MONITORING AND FORECASTING SYSTEM

WEATHER		BEAUDRIL	OPERATOR
SITE SPECIFIC			
- WINDS	ANEMOMETERS	YES	
- TEMPERATURE	DRY AND WET BULB THERMOMETERS	YES	
- PRESSURE	BAROGRAPH, BAROMETERS AND ALTIMETERS	YES	
- VISIBILITY	BALLONS, CEILING LIGHT PROJECTOR, VISUAL	YES	
- PERSONNEL	CERTIFIED OBSERVERS	YES	
- DATA RECORDING	ONBOARD COMPUTER ARCHIVING SYSTEM	YES	
- DATA TRANSMISSION	PHONE LINES		YES
(HOURLY OBSERVATIONS)			
SITE SPECIFIC / REGIONAL			
- WEATHER FORECASTS			YES
- UNMANNED WEATHER STATIONS*			YES
(TYPICALLY 4 FORECASTS PER DAY)			

OCEAN		BEAUDRIL	OPERATOR
SITE SPECIFIC			
- WAVES	VISUAL OBSERVATIONS DIRECT MEASUREMENTS	YES	 YES
- CURRENTS*			YES
- SEA STATE FORECASTS			YES
- SALINITY AND TEMPERATURE PROFILES*			YES
- SEA SURFACE TEMPERATURES*	SEA BUCKET	YES	

ICE		BEAUDRIL	OPERATOR
SITE SPECIFIC			
- ICE CONCENTRATION, TYPE ROUGHNESS, THICHKNESS	VISUAL OBSERVATION	YES	
- ICE DRIFT	MARINE RADAR	YES	
SITE SPECIFIC / REGIONAL			
- ICE CONDITIONS / ICE MOVEMENT	AIRBORNE IMAGERY RADAR (SAR/SLAR) AND DOWNLINK NOAA SATELLITE IMAGERY VISUAL ICE RECCES (FIXED WING, CHOPPERS) ARGOS BUOYS* GOVERNEMNT ICE CHARTS		YES YES YES YES YES
- REGIONAL ICE FORECASTS	GOVERNMENT ICE FORECASTS ONBOARD ASSESSMENT	YES	YES

* IF REQUIRED

B-1034

COPY DISTRIBU...
1 – WHITE - C... ...AY OFFICE
2 – YELLOW - TUK BASE
3 – PINK - ORIGINATOR

BeauDril (1987) Partnership Limited

TABLE 7

OFFSHORE ENVIRONMENTAL OBSERVATIONS PART I — WEATHER

LATITUDE _____

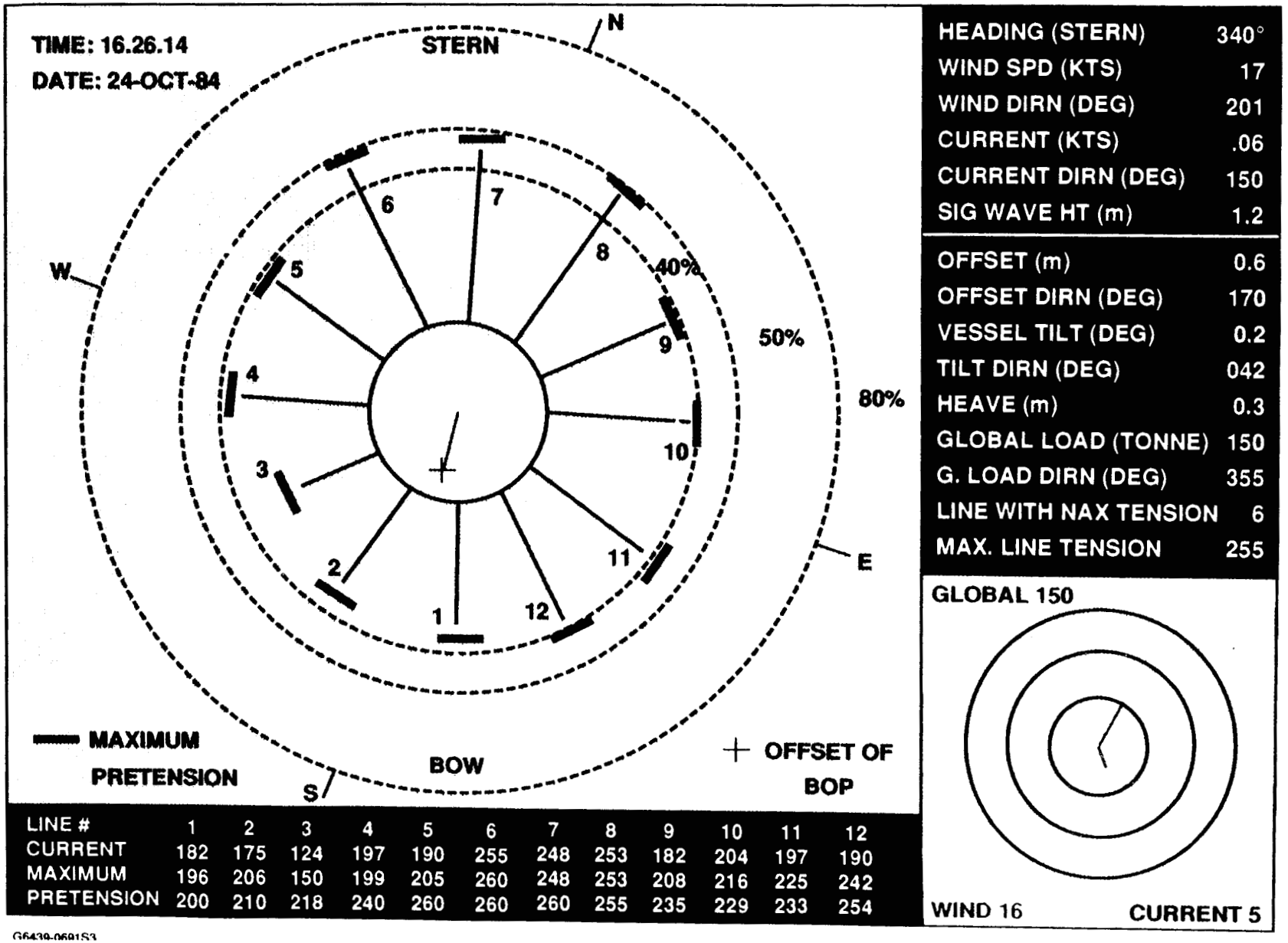
LONGITUDE _____

VESSEL _____ CALL SIGN _____ WELL SITE _____ OBSERVER(S) _____

DATE _____ YEAR MONTH DAY

TIME GMT MINUS ... Hours	TYPE OF REPORT	TIME (GMT)	SKY CONDITIONS	CEILING (100's of Feet) (2)	VISIBILITY (Nautical Miles) (9)	WEATHER CODE (1)	MSL PRESSURE (Millibars) (7)	DRY BULB TEMPERATURE (Nearest 0.1°C) (6)	DRY BULB TEMPERATURE (Nearest °C) (6)	DEW PT. TEMPERATURE (Nearest °C) (6)	WIND			ALTIMETER SETTING (Inches)	CLOUDS/OBSCURING PHENOMENA (Type, Opacity in Tenths)	TOTAL CLOUD (Tenths) (12)	REMARKS	PRESSURE TENDENCY	ALTIMETER SETTING No 1 (Inches)	ALTIMETER SETTING No 2 (Inches)
											DIRECTION FROM (10's of Degree True) (10)	SPEED (Knots) (11)	CHARACTER							

DISPLAY OF KULLUK KEY RESPONSE INFORMATION



LINE #	1	2	3	4	5	6	7	8	9	10	11	12
CURRENT	182	175	124	197	190	255	248	253	182	204	197	190
MAXIMUM	196	206	150	199	205	260	248	253	208	216	225	242
PRETENSION	200	210	218	240	260	260	260	255	235	229	233	254

G6439-0691S3

FIGURE 13

B-1035

COPY DISTRIBUTION
1 — WHITE - CALGARY OFFICE
2 — YELLOW - TUK BASE
3 — PINK - ORIGINATOR

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TABLE 8

OFFSHORE ENVIRONMENTAL OBSERVATIONS PART II — SEA

LATITUDE _____ LONGITUDE _____ VESSEL _____ CALL SIGN _____ WELLSITE _____ OBSERVER(S) _____

DATE _____ (YEAR / MONTH / DAY)

TIME GMT MINUS HOURS	SEA SURFACE TEMPERATURE (123)		WIND WAVES				SWELL DIRECTION FROM			SWELL FIRST SET				SWELL SECOND SET				ICE ACCRETION CODE	REMARKS	HELIDECK VERTICAL MOTION (METRES)	CURRENT METERS						SHIP MOTION			
	IDENTIFIER 1 = MINUS SIGN	MINUS SIGN DEGREES C	1 = WAVE BUOY 2 = VISUAL	PERIOD (SEC) (128)	SIG. HEIGHT (HALF METRES)	SIG. HEIGHT (METRES) (132)	IDENTIFIER	FIRST SET	SECOND SET	IDENTIFIER	PERIOD (SEC)	SIG. HEIGHT (HALF METRES)	SIG. HEIGHT (METRES)	IDENTIFIER	PERIOD (SEC)	SIG. HEIGHT (HALF METRES)	SIG. HEIGHT (METRES)				AT DEPTH m SET (°T) TOWARDS (101)	AT DEPTH m SPEED (cm/sec) (100)	AT DEPTH m SET (°T) TOWARDS (103)	AT DEPTH m SPEED (cm/sec) (102)	AT DEPTH m SET (°T) TOWARDS (105)	AT DEPTH m SPEED (cm/sec) (104)	HEADING (DEG TRUE)	ROLL (DEGREES) (124)	PITCH (DEGREES) (125)	HEAVE (METRES) (133)
	0		1 2				3			4				5				6											

B-1036

COPY DISTRIBUTION
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2 - YELLOW - ...ASE
3 - PINK - ORIGINATOR

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TABLE 9

OFFSHORE ENVIRONMENTAL OBSERVATIONS PART III — ICE

DATE ____ YEAR MONTH DAY

LATITUDE _____ LONGITUDE _____ VESSEL _____ WELLSITE _____ OBSERVER(S) _____

TIME			ICE COVER			THICKEST ICE					SECOND THICKEST				THIRD THICKEST				OTHER ICE							RIDGE HEIGHTS			ICE DRIFT			
GMT MINUS HOURS	GMT	A.E.S. ICE CODE PREFIX	TOTAL (210)	IN STRINGS (211)	THICKNESS OF THICKEST ICE TYPE (228)	CONCENTRATION (212)	TYPE (220)	FLOE SIZE (213)	MELT STAGE (214)	IDENTIFIER	CONCENTRATION (215)	TYPE (216)	FLOE SIZE (217)	IDENTIFIER	CONCENTRATION (218)	TYPE (219)	FLOE SIZE (220)	IDENTIFIER	THICKEST TYPE < 1/10 COVER (221)	REMAINING TYPE (222)	IDENTIFIER	RAFTING (223)	RIDGES/HUMMOCKS (224)	SNOW COVER (225)	SNOW DEPTH (226)	IDENTIFIER	MEAN HEIGHT (227)	EXTREME HEIGHT (228)	IDENTIFIER	DIRECTION TO (decadegrees T) (202)	SPEED (knots) (201)	REMARKS
		ICEOB								2				3				4			5					6			9			

ICEOB

FIGURE 15

SEASONAL ICE THICKNESSES

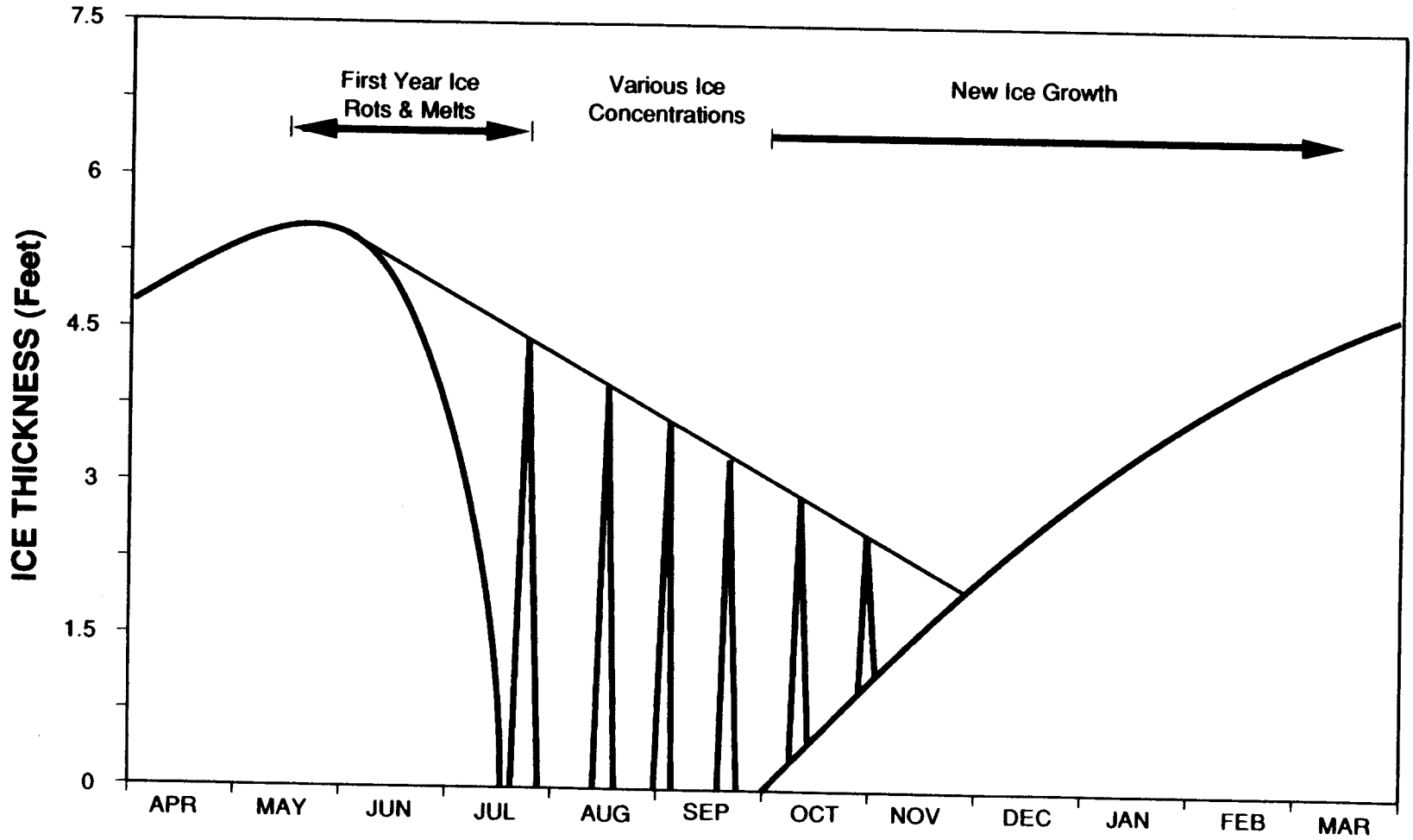


TABLE 1

DRILLING UNIT DIMENSIONS & SPECIFICATIONS

PRINCIPAL DIMENSIONS AND CAPACITIES

(a)	Hull		
	Hull Depth	60.69 ft	(18.50 m)
	Radius at pump deck (+ 5.0 m)	97.93 ft	(29.85 m)
	Radius at storage deck (+ 10.0 m)	103.35 ft	(31.50 m)
	Radius at main deck (+ 18.5 m)	132.87 ft	(40.50 m)
	Radius of moon pool	13.12 ft	(4.00 m)
(b)	Draft/Displacement		
	Lightship	26.3 ft/19,300 ton	(8.0 m/17 510 tonnes)
	Minimum operating	32.8 ft/25,904 ton	(10.0 m/23 500 tonnes)
	Maximum operating	41.0 ft/35,825 ton	(12.5 m/32 500 tonnes)
(c)	Performance		
	Water Depth	60 ft - 600 ft	(18.3 - 183 m)
	Drilling Depth	20,000 ft	(6 100 m)
(d)	Helicopter Deck Capacity		
	Sikorsky S-61, Super Puma or equivalent		

QUARTERS

Accomodation for 108 people maximum (minimum of 75 reserved for Contractor's people) plus adequate office space and service facilities.

Kulluk

❑ Principal Dimensions

Radius @ main deck	40. 5m (133')
Radius @ pump deck	29.85m (98')
Hull Depth	18. 5m (60.69')
Water Depth	25 - 183m (60 - 600 ft)
Light Ship	8m/17 500 tonne (26'/19,234 ton)
Maximum Operating ton)	12.5m/32 500 tonne (41'/35,832
Helideck	Sikorski S-61 or similar plus fueling station
Accommodations	Bunks for 108 people, hospital, sauna & exercise, recreation rooms

❑ Major Drilling Equipment

Derrick	Dreco Dynamic 48.8m (160') high with a 12.2m (40') × 12.2m (40') base load capacity of 635 tonnes (700 tons) with 14 lines
Drawworks	Ideco E3000 with three GE motors rated @ 940 kW each
Rotary Table opening	Ideco LR 495, 1 257mm (49.5")
Top Drive	Varco TDS-3 with one GE traction motor rated @ 940 kW
Motion Compensator	NL Rucker Model 18/400, 181.4 tonnes (200 tons) 5.5m (18') travel
Mud Pumps	Two Ideco T1600 triplex
Solids Control	Four Thule VSM-120 shakers, one Brandt SR-3, 3-cone desander, one Brandt SE24 24-cone desilter, one Wagner Sigma 100 centrifuge, one Thule VSM 200 mud cleaner, one Alfa-Laval AX30 mud cooler
Drill String	Rig equipped with adequate tubulars to drill 216 mm (8 1/2") hole to 6096 m (20,000 ft).

❑ Power Plant

Engines	Three Electric-Motive diesel rated 2 100 kW each @ 900 rpm, 600 volts
Emergency Power	One Cullen Detroit rated 650 kW

❑ Storage Capacity

KCl Brine	319.5 m^3 (2,012 bbl)
Bulk Cement and Barite	A total of 13 bulk tanks capacity 608.1 m^3 (21 478 cu. ft) used in any configuration for bulk requirements
Liquid Mud	411.2 m^3 (2,589 bbl)
Fuel	1 603.3 m^3 (9,995 bbl)
Pipe & Casing Deck	1 400 tonnes (1,543 tons)
Potable Water	311.8 m^3 (1,961 bbl)
Drill Water	672.0 m^3 (4,227 bbl)

❑ B.O.P.

B.O.P. Equipment	One NL Shaffer 10M, 476.25 mm (18 3/4") B.O.P.; stack with two annular and four ram type preventers 69 mPa (10,000 psi) One NL Shaffer 15M, 476.25 mm (18 3/4") B.O.P. stack, with two annular preventers 103 MPa (15,000 Psi) and four ram type preventers 102 MPa (15,000 psi)
Risers	184m (600') 233mm (21") riser complete with slip joint and ball joint one complete 762mm (30") riser system complete with pin-connector and ball joints
Diverters	One Regan KFDS 610mm (24") One Regan KFDS 711mm (27.9")
B.O.P. Controls	NL Shaffer with 378.5 L fluid reservoir (100 gal)
Riser tensioner	Western Gear 4 @ 35,700 daN (80,000 lbs.) capacity each
Guide Line System	Western Gear 4 @ 1717 daN (16000 lbs.)

❑ Well Testing

Portatest	(1590 m^3/day),complete testing Suite with 2 flare booms and burners

❑ Positioning

Mooring System	12 Hepburn winches with 89mm (3 1/2") × 1 147m (3,763') anchor wires a variety of Bruce/Stevpris and LWT anchors from 15 tons to 9 tons to provide adequate mooring for most bottom conditions

❑ Auxiliary Equipment

Cranes	Three Liebherr 65 tonne @ 9.14m (30')
Fork Lift	Toyota electric
Re-position	Honeywell RS 904

❑ Special Features

Ice Standards	Built to Canadian Arctic Shipping Pollution Prevention Act Class IV
Cathodic Protection	Englehard 7 Goodall
28" Riser System	Built to negate the need to underream in the 26" hole section
Glory Hole Bit	7.32 m (24 ft.) diameter bit capable of drilling a glory hole and setting a 12 m deep steel caisson in one pass

KALVIK SPECIFICATIONS

Table 3

Ship's particulars

BeauDril

❑ General Information

Designed by:	German and Milne Inc.
Built By:	Burrard Yarrows Corporation (Victoria) Division
Delivered:	July 22, 1983
Official Number:	803564
Call Sign:	VY 9403
Flag:	Canadian
Port of Registry:	Vancouver, B.C.
Type:	Ice-breaker, Anchor-handling, Supply, Tug
Arctic Capability Rating:	CASPPR Arctic Class 4
Lloyd's Class:	100AI Ice-Breaker, Tug
Berths Total:	34
Crew:	19
Helideck:	Can handle up to Bell 214 ST (with skids)

❑ Dimensions

Length O.A.:	88 m
Length B.P.:	75 m
Breadth Extreme:	17.82 m
Depth Moulded:	To Main Deck-10 m
Draft: Maximum:	8.3 m

❑ Tonnage

Gross Tonnage:	4233.71
Net Tonnage:	1970
Deadweight Winter Draft:	1823.7
Displacement Winter Draft:	6820.96

❑ Deck (Loading Capacities)

Deck Measurements:	34 m x 13 m
Deck Cargo Capacity:	800 tonnes
Bulk Barite/ Cement Capacity:	34 m^3 x 3 = 102 m^3
Fuel Oil:	1919 m^3
Ballast Water:	1628 m^3
Fresh Water:	237.79 m^3

❑ Engine

Main Engine:	(4) Stork Werkspoor Diesel
RPM:	600
BHP:	23,200
Thrusters FWD:	Twin Wartsila Air Bubbler System (22,000 m^3/Hr. ea.)
Thrusters AFT:	Maritime Industries (Pleuger CPP) 500 HP Fresh
Water Maker Capacity:	15 tonnes/day
Propellers:	2 LIPS, N.V.C.P. 4 blades
Bollard Pull:	Over 200 tonnes
Service Speed (two engines):	13.28 knots
Speed (four engines):	15.57 knots
Fuel Consumption Open Water:	30 m^3/day Fuel Consumption
Heavy Ice:	50 - 75 m^3/day

❑ Deck Machinery

Tugger Winches:	2 x 15 tonne pull
Capstans:	2 x 25 tonne pull
Towing and Work Winches:	Complete Van der Giessen electric winch package. Tow winch has a nominal brake holding capacity of 450 tonnes and is equipped with a friction rollerset. Tow wire is 1500m long. Double anchor handling winch can generate 220 tonnes line pull (at stall). Unit has a water cooled high speed brake.
Deck Cranes:	2 x 5 ton SWL Hagglund (can be rigged for limited 10 ton lifts)

❑ Life-saving Units

Life Boat:	37 person Watercraft Model 7.8 m
Rescue Boat:	Lucas Model 700D (High speed rigid bottom inflatable with 6 cylinder turbo diesel)

Table 4

Ship's particulars

BeauDril

❑ General Information

Designed by:	Robert Allan Ltd.
Built By:	Nippon Kokan KK (NKK), Tsurumi, Japan
Delivered:	April 15, 1983
Official Number:	802786
Call Sign:	CZ 9982
Flag:	Canadian
Port of Registry:	Vancouver, B.C.
Type:	Ice-breaker, Anchor-handling, Supply, Tug
Arctic Capability Rating:	CASPPR Arctic Class 4
Lloyd's Class:	IOOAI Ice-Breaker, Offshore Supply Ship, Ice Class IA
Super Berths Total:	34
Crew:	19

❑ Dimensions

Length O.A.:	78.95 m
Length B.P.:	70.0 m
Breadth Extreme:	17.22 m
Depth Moulded:	9.707 m
Draft: Arctic Class IV:	7.532 m
Arctic CLass 111:	8.11 m

❑ Tonnage

Gross Tonnage:	3255.80
Net Tonnage:	1432.43
Deadweight Summer:	1898.50
Displacement:	5107.30

❑ Deck (Loading Capacities)

Deck Cargo Area:	12.7 m x 35.6 m
Deck Cargo Capacity:	1000 tonnes
Bulk Barite/Cement Capacity:	4 x 35.5 = 142 m^3
Fuel Oil:	1596 m^3
Ballast Water:	1146 m^3
Fresh Water:	152 m^3

❑ Engine

Main Engine:	Wartsila VASA 8R32 x 4 DIESEL
RPM:	750
BHP:	3725 x 4 = 14,900
Thrusters FWD:	Omnithruster/Airbubbling System 1200 HP
Thrusters AFT:	Kamewa 800 HP
Fresh Water Maker Capacity:	10 tonnes/day
Propellers:	2 LIPS, CPP with Nozzle 4 blades
Bollard Pull:	150 tonnes
Service Speed (two engines):	12 knots
Speed (four engines):	14.7 knots
Fuel Consumption Open Water:	20 m^3/day
Fuel Consumption Heavy Ice:	35 - 58 m^3/day

❑ Deck Machinery

Tugger Winches:	2 x 12 tonne pull
Capstans:	2 x 10 tonnes pull
Towing and Work Winches:	2 Double Drum Towing/Anchor-Handling Winches
Deck Cranes:	2 x 5 ton SWL Hydralift

❑ Life-saving Units

Life Boat:	37 person Watercraft Model 7.8 m
Rescue Boat:	Lucas Model 700D (High speed rigid bottom inflatable with 6 cylinder turbo diesel)

Ship's particulars

BeauDril

❑ General Information

Designed by:	Robert Allan Ltd.
Built By:	Vancouver Shipyards Co. Ltd.
Delivered:	June 11, 1983
Official Number:	803537
Call Sign:	VY 9292
Flag:	Canadian
Port of Registry:	Vancouver, B.C.
Type:	Ice-breaker, Anchor-handling, Supply, Tug
Arctic Capability Rating:	CASPPR Arctic Class 4
Lloyd's Class:	IOOAI Ice-Breaker, Offshore Supply Ship, Ice Class IA
Super Berths Total:	34
Crew:	19

❑ Dimensions

Length O.A.:	78.85 m
Length B.P.:	70.0 m
Breadth Extreme:	17.22 m
Depth Moulded:	9.70 m
Draft: Arctic Class IV:	7.53 m
Arctic CLass 111:	8.11 m

❑ Tonnage

Gross Tonnage:	3338.36
Net Tonnage:	1461.76
Deadweight Summer:	1940.00
Displacement:	5047.00

❑ Deck (Loading Capacities)

Deck Cargo Area:	12.7 m x 35.6 m
Deck Cargo Capacity:	1000 tonnes Bulk
Barite/Cement Capacity:	4 x 35.5 = 142 m^3
Fuel Oil:	1500 m^3
Ballast Water:	1018 m^3
Fresh Water:	143 m^3

❑ Engine

Main Engine:	Wartsila VASA 8R32 x 4 DIESEL
RPM:	750
BHP:	3725 x 4 = 14,900
Thrusters FWD:	Omnithruster/Air Bubbling System 1200 HP
Thrusters AFT:	Kamewa 700 HP
Fresh Water Maker Capacity:	10 tonnes/day
Propellers:	2 LIPS, CPP with Nozzle 4 blades
Bollard Pull:	150 tonnes
Service Speed (two engines):	12 knots
Speed (four engines):	14.7 knots
Fuel Consumption Open Water:	20 m^3/day
Fuel Consumption Heavy Ice:	35 - 58 m^3/day

❑ Deck Machinery

Tugger Winches:	2 x 12 tonne pull
Capstans:	2 x 10 tonnes pull
Towing and Work Winches:	2 Double-Drum Towing/Anchor-Handling Winches
Deck Cranes:	2 x 5 ton SWL Hydralift

❑ Life-saving Units

Life Boat:	37 person Watercraft Model 7.8 m
Rescue Boat:	Lucas Model 700D (High speed rigid bottom inflatable with 6 cylinder turbo diesel)

TABLE 10

KULLUK DESIGN CRITERIA FOR WAVES

- MAINTAIN LOCATION AND CONTINUE DRILLING IN A 1 YEAR RETURN PERIOD BEAUFORT SEA STORM

  H_S = 9 FT.

  H_{MAX} = 18 FT.

  T = 8.5 SEC

- MAINTAIN LOCATION IN A SURVIVAL MODE (BIASED MOORING) IN A 100 YEAR RETURN PERIOD BEAUFORT SEA STORM

  H_S = 24 FT.

  H_{MAX}= 48 FT.

  T = 12.5 SEC.

- SURVIVE A 100 YEAR NORTH PACIFIC STORM WHILE UNDER TOW (STABILITY AND MAJOR STRUCTURE)

  H_S = 50 FT.

  H_{MAX}= 100 FT.

  T = 16 SEC.

NOTE: H_S = SIGNIFICANT WAVE HEIGHT (AVERAGE OF THE HIGHEST 1/3RD OF THE WAVES)

H_{MAX} = MAXIMUM WAVE HEIGHT (ROUGHLY TWICE THE SIGNIFICANT WAVE HEIGHT FOR LONG DURATION STORMS)

ATTACHMENT I

KULLUK ALERT SYSTEM

Note: The following text has been extracted from the BeauDril Kulluk Operations Manual, Chapter 27.

ATTACHMENT I

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27.8 EMERGENCY PROCEDURES

27.8.1 The Alert System

The purpose of an "Alert System" is to anticipate hazardous events, and assign to all concerned personnel, general pre-determined responses. It is recognized that such a system can never anticipate all the situations that may arise, nor completely outline the required responses. The intention is that the considerate formulation of certain responses will relieve on site personnel of some of the time consuming deliberations at the scene, and ensure that everyone is following consistent, and complimentary courses of action.

27.8.1.a A Consideration of Hazards

For purposes of definition, the Alert System considers that all hazards which may threaten the ***Kulluk*** fall into one of three categories.

i) Environmental Hazards

These are hazards resulting from the forces of the natural environment.

ii) Well Hazards

Hazards which may result from the drilling operation such as well bore pressure, gas liberated by drilling, and well bore instability.

iii) Vessel Hazards

All hazards, other than environmental or well, which compromise the vessels stability, and/or integrity. Examples are: fire, collision, the failure of equipment essential for the conduct of safe operations, and conducting operations which require extreme vigilance such as loading heli fuel, etc.

27.8.2 The Color Code

A code of five colors, (green, blue, yellow, red, black), in ascending degrees of gravity, is used to define the status of the well, the vessel, the environment and adjust the response as the degree of the hazards severity changes.

By applying the color code to each one of the categories the nature and coincidence of different hazards can be recognized. This is essential as drilling operations secure procedures, and times will differ considerably when more than one hazard is influential. For example if an environmental yellow alert exists, while the well and vessel are on green, normal drilling operations might continue within the available lead time. However if the yellow environmental alert was accompanied by a yellow well alert, drilling operations would be severely restricted, or suspended until the environmental situation was less threatening.

~~Since vessel and well hazards are essentially unpredictable, the Alert System defines them in terms of present status only.~~

~~Environmental hazards can be forecast.~~ Therefore, the Alert System defines not only their present status, but also considers how they may influence operations at some point in the future. This is done in terms of Hazard Time, Secure Time and Operating Time. (Table 27.8.2)

27.8.3 Communicating The Emergency Response System

27.8.3.a The Alert Systems Board

The alert systems color code, with definitions and a brief generalized explanation of the responses required, is posted throughout the rig on a large white board entitled "***Kulluk*** Alert System."

27.8.3.b The Alert Status Level

The actual, moment to moment, alert status level for the environment, the well, and the vessel, along with the procedures and times to secure the well and vessel, is posted throughout the rig on a small white board entitled "The Alert Status Level."

Consequently, at a glance the particular status concerning all aspects of the operations is evident.

27.8.4 Response Times

27.8.4.a The Hazard Time (HT)

Hazard Time is the forecast time before the arrival of hazardous environmental conditions which will disrupt or exceed the operating capability of the ***Kulluk***.

27.8.4.b Secure Time (ST)

Secure Time is the time required to bring the ***Kulluk*** to a state in which it is ready to handle the environmental hazards, without compromising the security of the well, or the integrity of the vessels equipment.

27.8.4.c Operating Time (OT)

Once a hazard has been forecast, and the secure time determined the remaining is the time available for conducting operations, or: HT-ST=OT.

27.8.5 Secure Time

27.8.5.a Determining Secure Time

A precise consideration of "Secure Time" involves three operations, the time to secure the well, the time to disconnect from the wellhead, and the time to secure the vessel. The first operation will always be done; the second and third operations may or may not, depending on the nature of the hazard.

i) The Time To Secure the Well

The specific procedure chosen to secure the well may depend on many variables. These would include well bore stability, well bore pressure and the time anticipated that the vessel may be off location, etc.

The essential aspect of such a consideration is that the well bore is securely isolated from the natural environment.

Whether or not the hazard is environmental, well, or vessel, the well must always be rendered secure.

ii) The Time To Disconnect The Vessel

(From the seabed, or wellhead)

This operation must be done in a manner that ensures no equipment damage will occur.

The operation should ensure that the disconnect is completed in a normal manner and that emergency, or last resort procedures are not required.

This operation would only be carried out in the cases where keeping the vessel on location would compromise vessel, and/or personnel safely.

iii) The Time To Secure The Vessel

After the well is secure, and the equipment is disconnected, the vessel must be prepared to resist or accommodate the impending environmental hazard.

This operation may involve biasing the anchor system, retrieving anchors, lashing down loads etc.

Securing the vessel must not interfere with securing the well and disconnecting the wellhead equipment. Therefore, the Secure Time may be the sum of these three operations, or in the case where some portion of the vessel securing procedure is occurring simultaneously with well and disconnect operations, the Secure Time will be a smaller value than the sum.

Examples

When the Secure Time is the sum of the times to secure the well, disconnect and secure the vessel:

- The well securing procedure requires hanging off the drill string, and disconnecting the LMRP. This would take six hours.
- The vessel securing procedures require that the anchoring system be biased. This would take two hours.
- However, biasing the anchors will result in a horizontal displacement which could interfere with disconnecting the LMRP, and therefore this operation cannot commence until the LMRP is disconnected.
- The Secure time is the sum of the two operations, or eight hours.

When the Secure Time is a partial sum of the times to secure the well, disconnect and secure the vessel:

- The well securing procedures require that the drill string be hung off, and the LMRP disconnected. This would take six hours.
- The vessel securing procedures require that all twelve anchors be retrieved. This would take eight hours.
- However six anchors may be retrieved while well securing operations are taking place. This would require four hours.
- The remaining anchors cannot be retrieved without interfering with the well securing procedures. Retrieving the last six anchors would take four hours.
- Therefore the secure time is the sum of the well securing operations six hours and a partial sum of anchor retrieving operations four hours, or ten hours.

27.8.5.b Adjusting Secure Time

When the hazard is unpredictable, reliance cannot be placed on a single secure time or procedure. Therefore, Secure Times should be considered from these perspectives.

i) Optimum Secure Time

The time required to finish or undertake certain operations which would leave the well in an ideal condition, but which are not essential to well securing operations, plus the essential secure time.

Examples of non essential operations may be tripping, circulating, pulling the LMRP to surface, displacing the riser prior to disconnect, etc.

ii) Minimum Secure Time

The time required to conduct only those operations essential to securing the well, and to disconnect from the wellhead, using normal procedures.

These operations are denoted on the Alert Status board by a star (*).

iii) Emergency Secure Time

This is the time required to secure the well and disconnect from the wellhead using emergency procedures.

Such procedures are used only as a last resort.

Note: In all cases, operations should be determined by the optimum Secure Time. The minimum secure time is only noted so that if the situation deteriorates more rapidly than anticipated, personnel are made aware of the procedures to be eliminated.

27.8.5.c The Secure Time Safety Factors

For all operations the secure time used to determine the Alert Status should be the Optimum Secure Time. Since this time may already contain operations which are not absolutely essential to the securing procedure, it may have a certain "built in" safety factor. However at the Supervisor's discretion, a safety factor, to cover various contingencies can be added to the secure time. This safety factor must be individually identified on the "Alert Status" board.

27.8.6 Calculating Operating Time

i) Once hazard time has been forecast and secure time determined the time remaining is the time available for conducting operations or HT-ST = Operating Time (OT).

ii) The difference between HT and ST determines the amount of time available before a response to the hazard must begin. For example, if a large ice ridge is expected in twelve hours, and it requires six hours to properly secure the well, the following might occur.

An environmental "Yellow Alert" is declared, since by definition this is in effect any time there is six hours or less remaining in which operations may be conducted, before well securing procedures must commence.

- A calculation of Operating Time (OT) is made:
  HT - ST = OT
  12 - 6 = 6

- The ice ridge moves to within six hours of contacting the *Kulluk*, and the ST has remained at six hours.

- A calculation of Operating Time (OT) is made:
  HT - ST = OT
  6 - 6 = 0

- An environmental Red Alert is declared. Since there is no time left during which operations may be conducted, all remaining time must be used to secure the well.

27.8.7 The Time Analysis

~~An historical analysis of the times to complete~~ various operations is kept, and constantly updated with each wells completion.

~~This analysis is used to determine the time required to complete various operations. Secure times must not be subjectively estimated.~~

The only significant variables involved in establishing the time required to conduct operations are weather, distance, hole conditions and equipment failure. Once these factors are considered the times to complete repetitive operations should be very consistent.

Weather:	The analysis averages the times to conduct operations over years and therefore, should account for unfavorable environmental conditions.
Distance:	Operations conducted at different water depths, or drilled depths will obviously vary. When appropriate depths are not found in the analysis use a factor to estimate the time. For example, it would take twice as long to pull 200 m of riser as it would to pull 100 m.
Hole Conditions:	Open hole operations are entirely dependent upon hole conditions at the time and therefore, times must be adjusted for every case. Previous trip and drill records will assist in determining open hole operations.
Equipment Failure:	Most equipment that is prone to failure has redundant back-up. However, a safety factor may be added to the secure time to cover such occurrences.

27.8.8 The Alert System Color Codes

The following is a sequential list of the alert status color codes with reference to their source, some examples, and a brief explanation of the actions they require. Hazards can occur individually, or simultaneously, in any combination of the three categories namely: the environment, the well, or the vessel. This discussion can not itemize all the situations which would be defined under the alert levels, nor can it consider the complications resulting from different alert levels in more than one category. This is left to the discretion of the personnel on the scene.

27.8.8.a An Alert Status *"Green"* means *Normal* Operations

The Environment:	No environmental hazards exist, or are anticipated which may interrupt operations.
The Well:	Kick tolerance* (KT) level is on 1. The hole is stable and no well control, stuck pipe or fishing operations are anticipated.
The Vessel:	The vessel is fully operational with no deficiencies. No operations which require vigilance above the level of a normal watch are taking place.

The Drill Crew's Response

1. An Environmental *"GREEN"* Alert
   - Restrict operations to available lead time.

2. A Well *"GREEN"* Alert
   - Apply normal drilling practice, and normal well monitoring procedures as defined by KT = 1.

3. A Vessel *"GREEN"* Alert
   - Normal drilling practices apply.

The Marine Crew's Response

1. An Environmental *"GREEN"* Alert
   - Maintain a normal watch.

2. A Well *"GREEN"* Alert
   - Maintain a normal watch.

3. A Vessel *"GREEN"* Alert
   - Maintain a normal watch.

27.8.8.b An Alert Status *"Blue"* means *Early Alert*

The Environment:	All conditions are normal, but it is possible for an environmental hazard to develop within the time required to secure the well, disconnect and secure the vessel, plus 12 hrs.
The Well:	The kick tolerance is on Level II and/or; incidental well bore instability, which requires attention, has been detected.
The Vessel:	Vessel stability and integrity is adequate to conduct drilling operations. Minor equipment has failed, or is being repaired. Boats are along side and loading operations are taking place. Vessel movement is appreciable but does not significantly interfere with operations.

ST + 12 hrs

The Drill Crew's Response

1. An environmental *"BLUE"* Alert
   - Restrict operations to available lead time.

---

* Kick Tolerance refers to a system derived by BeauDril that may be replaced by the operator's criteria.

2. A Well *"BLUE"* Alert
   - Increased vigilance in well monitoring procedures ~~as defined under Kick tolerance Level II~~.
   - Implement drilling operations as necessary to rectify or accommodate well bore problems.

3. A Vessel *"BLUE"* Alert
   - Normal operations with allowances for minor equipment malfunctions, vessel movement and loading operations.

The Marine Crew's Response

1. An Environmental *"BLUE"* Alert
   - Maintain a normal watch.

2. A Well *"BLUE"* Alert
   - Maintain normal watch.

3. A Vessel *"BLUE"* Alert
   - Maintain a normal watch.

27.8.8.c An Alert Status "*Yellow*" means *Early Secure Warning*

The Environment:	There is less than six hours remaining in which operations may be conducted, before well securing procedures must commence.
The Well:	~~Kick Tolerance~~ is on Level III and/or; well bore stability is tenuous and remedial work is constantly taking place.
The Vessel:	Major equipment which will affect operations but not jeopardize safety has malfunctioned. Loading heli fuel, fuelling choppers or other operations which require extreme vigilance are taking place. Vessel movement requires that operations be conducted with extreme caution.

5T + 6 hrs

The Drill Crew Response

1. An Environmental *"YELLOW"* Alert
   - Drilling operations are restricted to available lead time.
   - Determine the method by which the well will be secured and make all the required preparations.

2. A Well *"YELLOW"* Alert
   - Drilling operations are restricted ~~as defined under Kick tolerance Level 3~~, to enhance well monitoring procedures and avoid stuck pipe.

     Refer to Chapter 12, General Drilling Procedures. Consideration may be given to setting casing.

3. A Vessel *"YELLOW"* Alert
   - Operations are restricted to accommodate equipment malfunctions, vessel movement or potentially hazardous operations such as heli fuel transfers, etc.

The Marine Crew Response

1. An Environmental *"YELLOW"* Alert
   - Maintain an "alert watch".
   - Begin preparations for the "Hazards" arrival.

2. A Well *"YELLOW"* Alert
   - Maintain an "alert watch".

3. A Vessel *"YELLOW"* Alert
   - Maintain an "alert watch".
   - Restrict operations as required to accommodate equipment malfunctions, vessel movement, and potentially hazardous operations.

27.8.8.d Alert Status *"Red"* means a *Hazard Is Imminent*

The Environment:	There is no time left in which operations may be conducted. All remaining time available must be used to secure the well and the vessel.
The Well:	Well control procedures are in effect. Tubulars are stuck in the hole.
The Vessel:	Equipment essential to the conduct of safe operations has failed. The stability, or integrity of the vessel has been compromised. Fire, or collision has occurred. Vessel movement is beyond the operating criteria.

The Drilling Crew Response

1. An Environmental *"RED"* Alert
   - Cease all drilling operations, and secure the well.
   - Standby to disconnect, or disconnect from the wellhead, as required.

2. A Well *"RED"* Alert
   - Control the well as required.
   - Conduct fishing operations as required.
   - Continually advise Marine as to severity of situation.

3. A Vessel *"RED"* Alert:
   - Cease all drilling operations and secure the well.
   - Standby to disconnect, or disconnect from the wellhead as required.
   - Standby to assist marine crews as required.

The Marine Crews Response

1. An Environmental *"RED"* Alert
   - Secure the vessel.

2. A Well *"RED"* Alert
   - Maintain a standby watch.
   - Assist drill crews as required.
   - Prepare to evacuate non essential personnel or take the vessel off location if kick severity requires.

3. A Vessel *"RED"* Alert
   - Maintain a standby watch.
   - Secure the vessel as required.

27.8.8.e An Alert Status "Black" Means a Hazard Has Compromised Personnel Safety, and/or Vessel Integrity.

The Environment:	An extreme hazard is imminent.
Ice:	The resultant forces will exceed the mooring systems capacity and the *Kulluk* must move off location.
Weather Waves:	The forces will exceed the station keeping ability of the *Kulluk*.
The Well:	Control of the Well has been lost. Well bore pressure has exceeded equipment limitations.
The Vessel:	Control over the stability, or integrity of the vessel has been lost, with the consequence that personnel safety is seriously jeopardized.

$ST_{AVAILABLE} < ST_{OPTIMUM}$

The Drill Crew's Response

1. An Environmental *"BLACK"* Alert
   - Suspend all operations, secure the well, and disconnect from the wellhead by the most immediate means.
   - Secure all pipe deck loads.
   - Secure pipe racked in derrick.
   - Assist Barge as required.

2. A Well *"BLACK"* Alert
   - Suspend all operations by the fastest means possible and take the vessel off location or evacuate as required.

3. A Vessel *"BLACK"* Alert
   - Suspend the well by the most immediate means possible and evacuate the vessel.

The Marine Crew's Response

1. An Environmental *"BLACK"* Alert
   - Disconnect anchors, or bias the mooring system as required. - Evacuate personnel if required.

2. A Well *"BLACK"* Alert
   - Evacuate personnel or take the vessel off location, as required.

3. A Vessel *"BLACK"* Alert
   - Evacuate personnel

27.8.9 Using the Alert system to Determine Operations

27.8.9.a Introduction

The Hazard Time cannot be changed to accommodate the Secure or Operating times. However operating and well securing procedures may be changed to accommodate the hazard times. This is vital in cases where the hazards action cannot be accurately forecast. By adjusting the Operating and Secure Times, the Alert System allows the flexibility required to operate safely when confronted with an unpredictable environmental hazard.

27.8.9.b Adjusting Operating Time and Secure Procedures

In cases where operating time exceeds available lead time, operations may be carried out incrementally to remain within the lead time.

Example: The Operation is running casing.

- An ice feature is stable but with an anticipated weather change would threaten the ***Kulluk*** within 25 hrs.
- The total casing and cement job requires 30 hrs, HT = 25 hrs.
- It is decided that the secure procedure would be to hang the casing and close the shear rams. This would take three hours.
  HT - ST = OT
  20 - 3 = 17

From this, it is determined that adequate time to complete the operation is not available. However, since the ice feature could remain in the static condition for days, it is decided to run the casing. The job is divided into increments each of which can be completed within the available lead time, leaving adequate time to secure the well in every case. In other words each individual operation along with its secure time, must remain under 25 hrs. The following operational analysis along with Secure Times is made.

27.8.9.c The Decision Process

Are the means used to secure the well acceptable to the operator in each case.

A decision is made that leaving uncemented casing in open hole is not acceptable, but that running the seal assembly may be omitted.

The casing running operations begins:

After each step is completed the HT Time is re-evaluated to ensure that lead time is available to complete the next step.

Casing is run to the shoe. This is a critical decision point. From here it would be 21 hrs before the casing was cemented and the well secure.

- If the HT is still adequate the job would continue.
- If conditions have deteriorated and the HT is no longer adequate then the job would be suspended.

27.8.10 Responsibilities

27.8.10.a The Operator

Will determine the alert status level of the well, the means by which the well will be secured, and advise the on duty Drilling Supervisor accordingly.

Will consult with the on duty Rig Superintendent to determine the secure times.

Will ensure that the concerns of government agencies, and regulatory bodies in reference to a suspended well are met.

27.8.10.b The On Duty Rig Superintendent

Will consult with the Operator to determine the well alert status level, the mean by which the well will be secured and the time required.

Will consult with the Marine Supervisor to ensure that operations are being conducted within the available lead time, to determine the "Vessel Alert" status, an the procedures required to secure the vessel.

Will ensure that at all times the drill crews are aware of the alert status level and its consequences, and prepared to implement the appropriate secure procedure.

~~Will continuously update the Alert Status Board in~~ terms of the Well Alert Status, the operations and time to secure the well and disconnect the vessel from the wellhead or seabed.

Note: The on duty Rig Superintendent is the only person authorized to determine secure procedures and secure times.

27.8.10.c The Marine Superintendent

~~Will continuously determine the "Environmental Alert" status~~, the ~~Hazard Times~~, and the ~~procedures required to secure the vessel~~, and immediately inform the on duty Drilling Supervisor of any changes in status.

Will consult with the on duty Rig Superintendent and Maintenance Superintendent to determine the "Vessel Alert" status.

~~Will continuously update the Alert Status Board in terms of the environmental~~ alerts, and procedures to secure the vessel.

Note: The Marine Superintendent, or his designate, is the only person authorized to determine the environmental alert status.

TABLE 27.8.2

ALERT STATUS	INTERPRETATION	HAZARDS SOURCE	ALERT STATUS	DRILLING RESPONSE	MARINE RESPONSE
GREEN	NORMAL OPERATIONS	ENVIRONMENT	HT IS MORE THAN 12 HOURS	RESTRICT OPERATIONS TO AVAILABLE LEAD TIME	NORMAL WATCH
		WELL	KT IS ON LEVEL I	NORMAL WELL MONITORING AS PER KT = I	
		VESSEL	ALL EQUIPMENT FULLY OPERATIONAL	NORMAL DRILLING OPERATIONS	
BLUE	EARLY ALERT	ENVIRONMENT	HT-ST IS LESS THAN 12 HOURS	RESTRICT OPERATIONS TO AVAILABLE LEAD TIME	NORMAL WATCH
		WELL	KT IS ON LEVEL II	INCREASE WELL MONITORING VIGILANCE AS PER KT = II	
		VESSEL	MINOR EQUIPMENT MALFUNCTION	NORMAL DRILLING OPERATIONS	
YELLOW	EARLY WARNING	ENVIRONMENT	HT-ST-ETA IS LESS THAN 6 HOURS	RESTRICT OPERATORS TO AVAILABLE LEAD TIME	PREPARE FOR HAZARDOUS ARRIVAL
		WELL	KT IS ON LEVEL III. GAS LEVELS HIGH	RESTRICT DRILLING TO ENHANCE WELL MONITORING AS PER KT-III	ALERT WATCH
		VESSEL	MAJOR EQUIPMENT MALFUNCTION. PROCEDURES REQUIRE VIGILANCE BEING CONDUCTED	RESTRICT DRILLING OPERATIONS AS REQUIRED	
RED	HAZARD PRESENT	ENVIRONMENT	HT-ST IS 0 OR LESS	STOP OPERATIONS AND SECURE WELL AND DISCONNECT	SECURE VESSEL
		WELL	WELL CONTROL OPERATIONS IN EFFECT	CONTROL WELL, AND ADVISE BARGE AS TO DEGREE OF KICK SEVERITY	SECURE VESSEL STANDBY WATCH
		VESSEL	ESSENTIAL EQUIPMENT MALFUNCTION VESSEL STABILITY OR INTEGRITY COMPRISED	STOP OPERATIONS, AND SECURE WELL	SECURE VESSEL
BLACK	HAZARD THREATENS PERSONNEL SAFETY AND/OR VESSEL STABILITY AND INTEGRITY	ENVIRONMENT	HAZARD IS EQUAL TO OR LESS THAN VESSEL SECURE TIME & EVAC. TIME	USE EMERGENCY PROCEDURES TO SECURE WELL IF NECESSARY	EVACUATE PERSONNEL
		WELL	CONTROL OF WELL IN DANGER OF, OR HAS BEEN LOST	USE EMERGENCY PROCEDURES TO SECURE WELL	
		VESSEL	VESSEL STABILITY, OR INTEGRITY IN DANGER OF, OR HAS BEEN LOST	USE EMERGENCY PROCEDURES TO SECURE WELL	

KULLUK ALERT STATUS SYSTEM

ATTACHMENT II

ICE MANAGEMENT SYSTEM

for the

KULLUK

at

KUVLUM

ATTACHMENT II

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1.0 KULLUK ICE MANAGEMENT SYSTEM

1.1 General

In most ice conditions, ice management support is required to increase the efficiency and safety of drilling operations from KULLUK . This support is provided by BeauDril's Arctic Class IV icebreaking vessels which play a key role in drilling operations from KULLUK.

KULLUK, with no icebreaker support, has been designed to withstand 4 ft. of level ice with its twelve line mooring system deployed. However, it is well known that during break-up, summer ice intrusions, and early winter conditions, various features within the ice cover will be encountered which exceed this design capacity.

During towing operations, ice management support is also required, particularly in thicker ice and ridge conditions where the resistance of KULLUK is quite high. In these conditions, the use of specific ice management strategies reduces KULLUK's resistance and increases the efficiency of towing operations.

1.2 Ice Management

The requirement for ice management and the resultant effects on operational efficiency are schematically shown in Table 1.2. During operations, BeauDril continually evaluates the suitability of applied ice management techniques in real time with KULLUK's performance monitoring instrumentation. This instrumentation provides immediate information on the global ice load and anchor line tensions as an indicator of ice management effectiveness. The most effective ice management strategies in terms of global ice load and line tension reductions have been documented in the form of recommended ice management guidelines which are used during stationkeeping and towing operations. In most circumstances, breaking the ice that moves towards the drilling unit reduces the ice forces it experiences, thus reducing KULLUK's motions and the tensions in its mooring lines. However, because the effect of various icebreaking patterns and ice/KULLUK interactions are different, specific ice management techniques are considered optimal in given ice situations. The basic incentives for the use of these specified ice management techniques are:

1.2.1 to reduce the ice loads from potential ice hazards experienced by KULLUK and accordingly, reduce KULLUK displacements and line tensions and increase drilling efficiency;

1.2.2 to enhance the clearance at large ice pieces around KULLUK and allow it to do significant icebreaking on its own;

1.2.3 to reduce the amount of vessel icebreaking carried out to achieve the required level of ice management support and reduce vessel fuel consumption;

1.2.4 to reduce the ice resistance on KULLUK while under tow and improve its transit efficiency.

1.2.5 to avoid inappropriate ice management strategies that could result in more severe ice forces on KULLUK .

For example, excessive icebreaking during the ice management process in first-year ice encourages rafting and ridging on the upstream side of KULLUK , amplifies ice forces and, given continued icebreaking in the drilling area, creates significantly thicker rubble ice around the unit. This ice rubble increases loads on KULLUK and reduces the transiting

and maneuvering effectiveness of the support vessels around it. Several examples of more effective ice management strategies to support stationkeeping and towing operations are shown in Figures 1.2 (1), 1.2 (2), 1.2 (3).

1.3 Communication and Responsibilities

It is important to recognize that good communication between the ice management vessels and KULLUK is essential when ice management is underway since unmanaged ice features or unexpected ice interactions can lead to high, rapidly applied loads on KULLUK. Ice management is conducted under the guidance of the Marine Superintendent, Icebreaker Masters and Environmental Advisors as shown in Table 1.3 below.

TABLE 1.2

ICE MANAGEMENT LOGIC

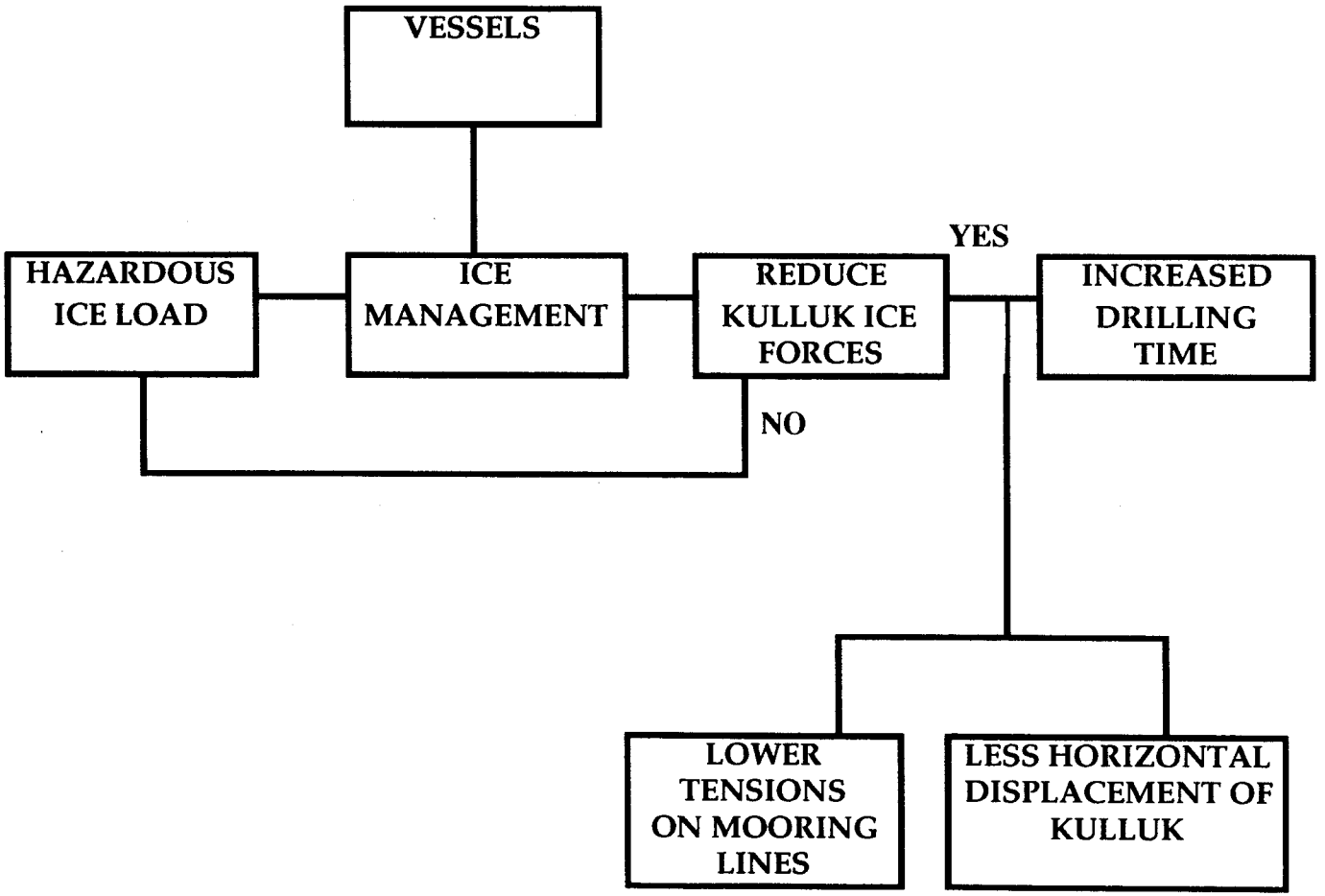
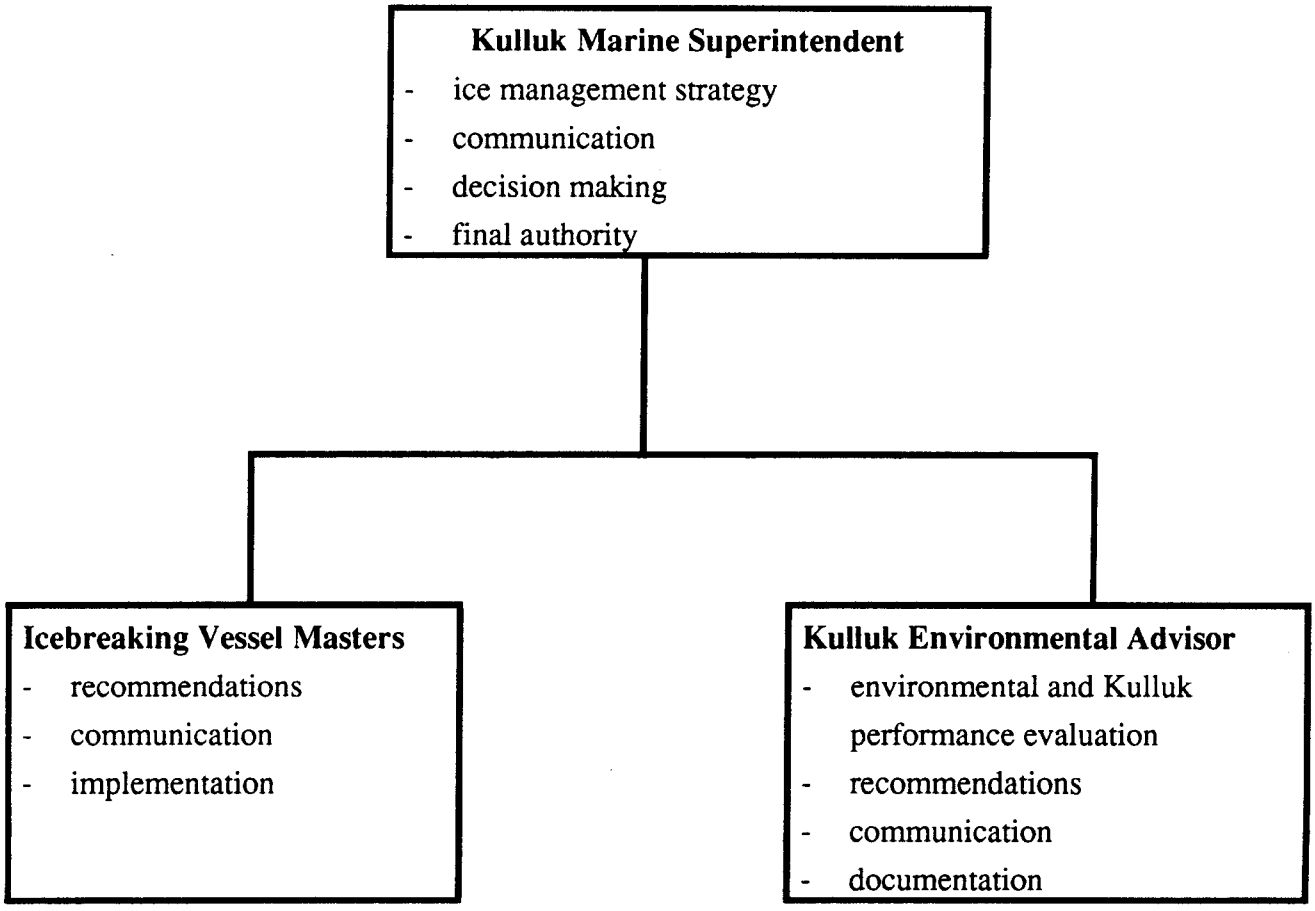
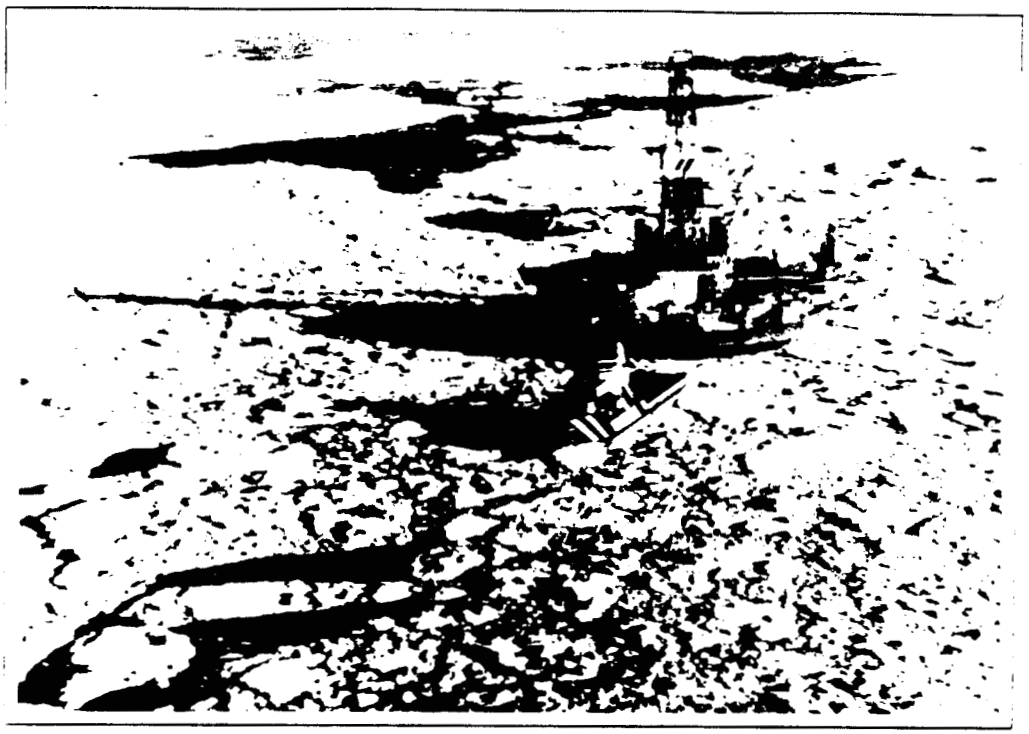
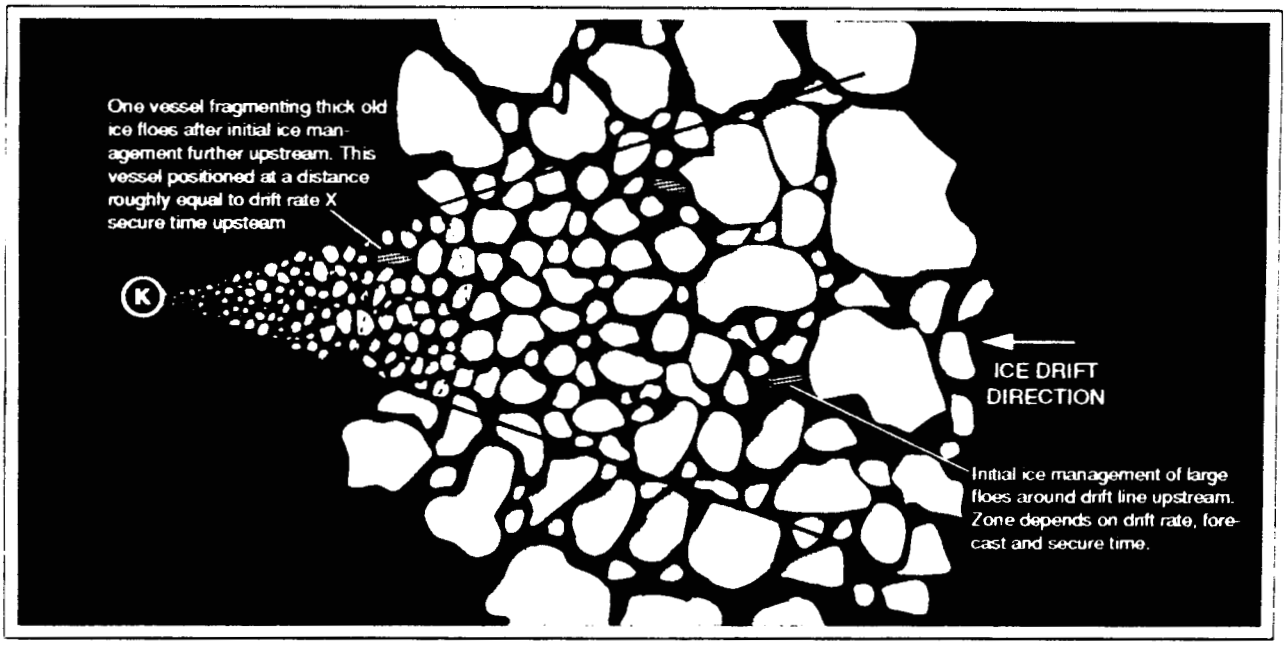


TABLE 1.3

ICE MANAGEMENT RESPONSIBILITIES





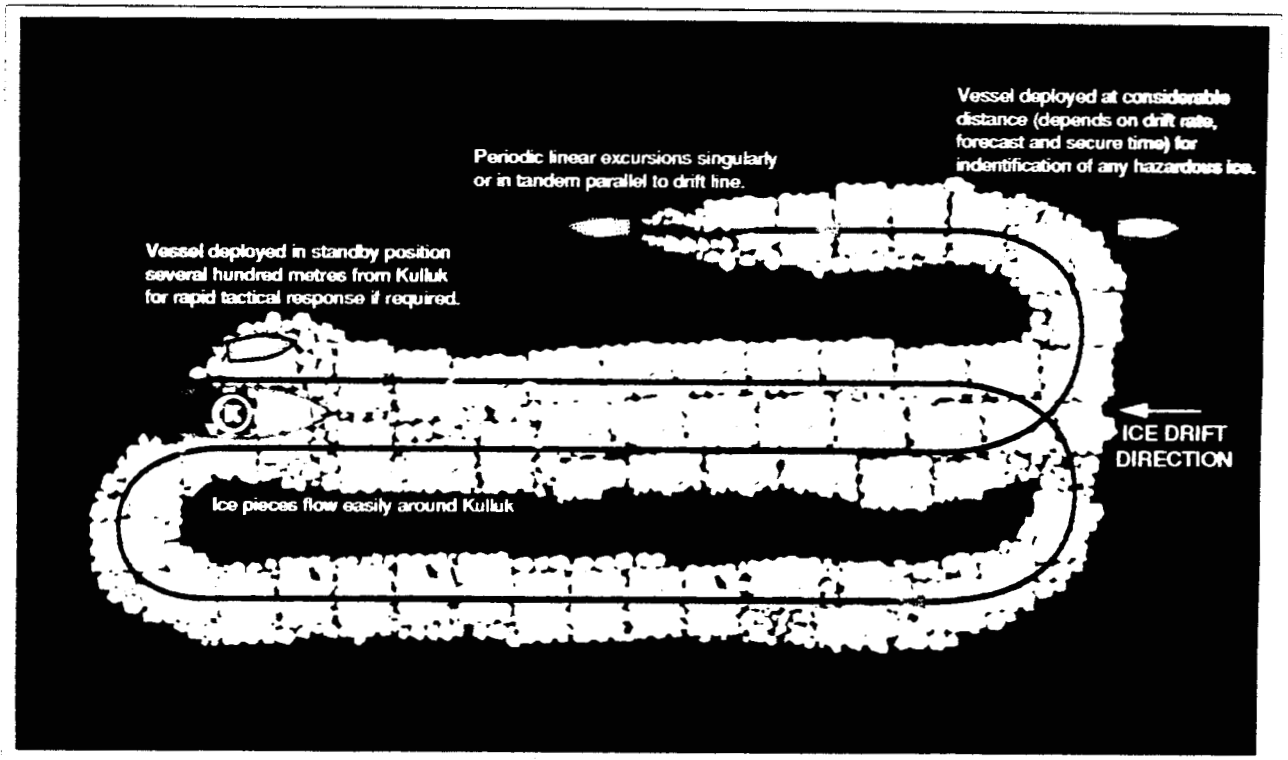


The ice management system usually used in old ice conditions. With an evironmental monitoring capability in place, the general ice cover and hazardous features within the sector of actual and forecasted ice movement are continually known. The icebreakers are deployed in a sector centered along the "ice drift line" at certain distances upsteam. Here, they fragment the approaching ice into smaller pieces roughly 50 to 100 m in extent so that potential impact loads on the Kulluk are acceptable. Typically, the two most powerful icebreakers are positioned further upstream to break larger floes into moderately sized pieces, An icebreaking supply vessel is positioned at a nearer distance equivalent to the well secure time times the ice encroachment speed and fragments these moderately-sized, partially-managed ice floes into smaller pieces. This ice management system is closely related to the alert procedure since hazardous ice floes not manageable by the icebreakers and then the supply vessel are identified in a timely manner, allowing a smooth transition for Kulluk drilling operations from yellow to red alert status.

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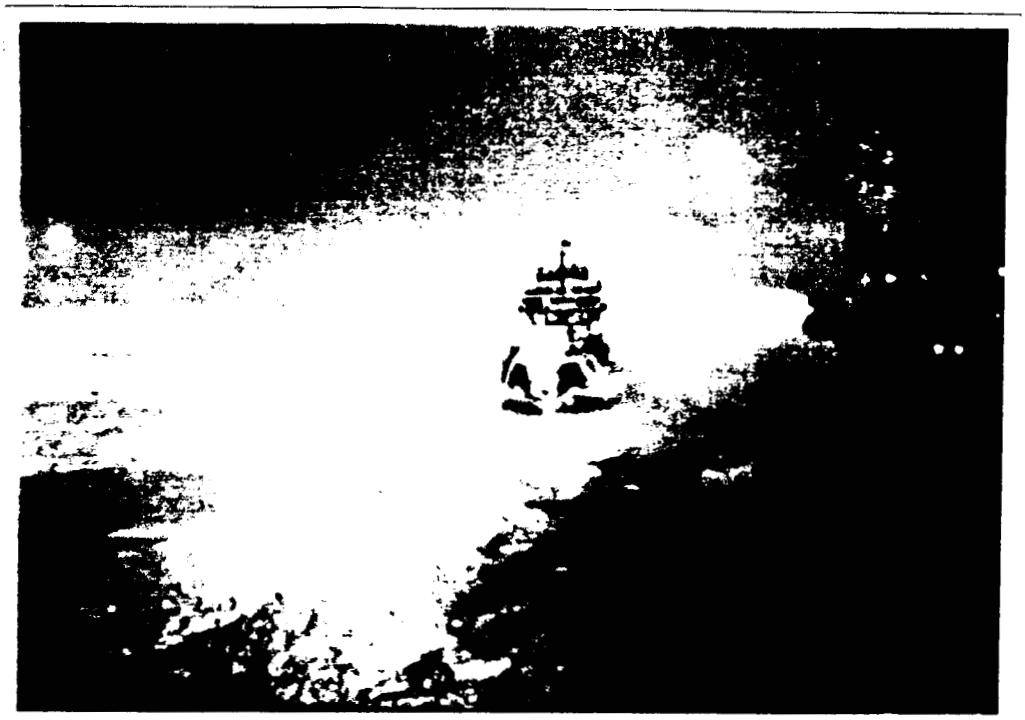
FIGURE 1.2 (1)

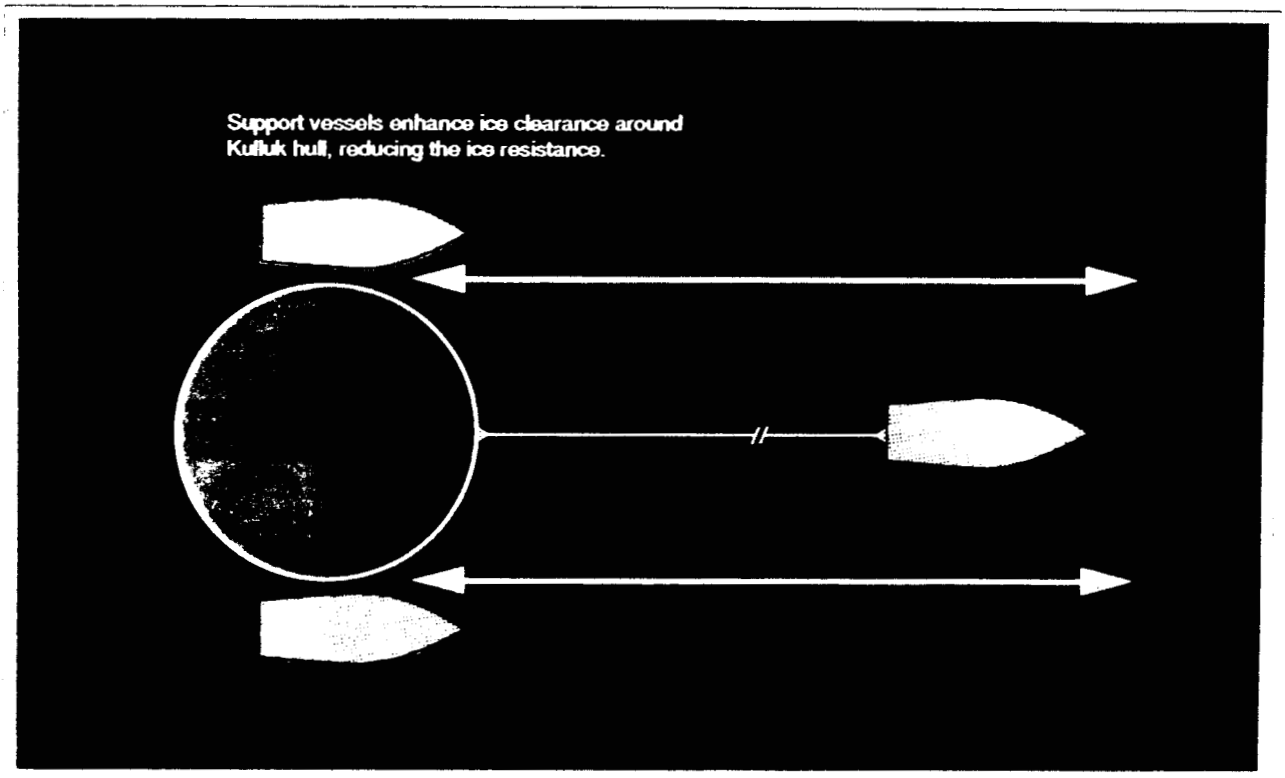




The most effective technique in relatively thin ice is to have the ships proceed at high speed along lines parallel to the ice drift direction on a periodic basis. The vessel's wake waves propagate into and induce flexural failure in the surrounding ice cover, resulting in ice platelets in the 5 - 10 m diameter range. These platelets smoothly flow around the Kulluk and result in very low loads on the system

FIGURE 1.2 (2)





Ice management is important in supporting early winter towing operations. The best strategy for the towing operation involves the deployment of two vessels close to the port and starboard quarters of the Kulluk to enhance the flow of ice pieces around it

FIGURE 1.2 (3)

ATTACHMENT III

EMERGENCY WELL SUSPENSION
for the
KULLUK
at
KUVLUM

NOTE: The following text has been extracted from the BeauDril Kulluk Operations Manual, Chapter 27.

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TABLE 27.8.2

ALERT STATUS	INTERPRETATION	HAZARDS SOURCE	ALERT STATUS	DRILLING RESPONSE	MARINE RESPONSE
GREEN	NORMAL OPERATIONS	ENVIRONMENT	HT-ST IS MORE THAN 12 HOURS	RESTRICT OPERATIONS TO AVAILABLE LEADTIME	NORMAL WATCH
		WELL	KT IS ON LEVEL I	NORMAL WELL MONITORING AS PER KT=I	
		VESSEL	ALL EQUIPMENT FULLY OPERATIONAL	NORMAL DRILLING OPERATIONS	
BLUE	EARLY ALERT	ENVIRONMENT	HT-ST IS LESS THAN 12 HOURS	RESTRICT OPERATIONS TO AVAILABLE LEAD TIME	NORMAL WATCH
		WELL	KT IS ON LEVEL II	INCREASE WELL MONITORING VIGILANCE AS PER KT=II	
		VESSEL	MINOR EQUIPMENT MALFUNCTION	NORMAL DRILLING OPERATIONS	
YELLOW	EARLY WARNING	ENVIRONMENT	HT-ST IS LESS THAN 6 HOURS	RESTRICT OPERATIONS TO AVAILABLE LEAD TIME	PREPARE FOR HAZARD ARRIVAL
		WELL	KT IS ON LEVEL III. GAS LEVELS HIGH	RESTRICT DRILLING TO ENHANCE WELL MONITORING AS PER KT=III	ALERT WATCH
		VESSEL	MAJOR EQUIPMENT MALFUNCTION. PROCEDURES REQUIRE VIGILANCE BEING CONDUCTED	RESTRICT DRILLING OPERATIONS AS REQUIRED	
RED	HAZARD PRESENT	ENVIRONMENT	HT-ST IS 0 OR LESS	STOP OPERATIONS AND SECURE WELL AND DISCONNECT	SECURE VESSEL
		WELL	WELL CONTROL OPERATIONS IN EFFECT	CONTROL WELL, AND ADVISE BARGE AS TO DEGREE OF KICK SEVERITY	SECURE VESSEL STANDBY WATCH
		VESSEL	ESSENTIAL EQUIPMENT MALFUNCTION VESSEL STABILITY OR INTEGRITY COMPROMISED	STOP OPERATIONS AND SECURE WELL	SECURE VESSEL
BLACK	HAZARD THREATENS PERSONNEL SAFETY AND/OR VESSEL STABILITY AND INTEGRITY	ENVIRONMENT	HAZARD IS EQUAL TO OR LESS THAN VESSEL SECURE TIME & EVAC. TIME	USE EMERGENCY PROCEDURES TO SECURE WELL IF NECESSARY	EVACUATE PERSONNEL
		WELL	CONTROL OF WELL IN DANGER OF, OR HAS BEEN LOST	USE EMERGENCY PROCEDURES TO SECURE WELL	
		VESSEL	VESSEL STABILITY, OR INTEGRITY IN DANGER OF, OR HAS BEEN LOST	USE EMERGENCY PROCEDURES TO SECURE WELL	

KULLUK ALERT STATUS SYSTEM

27.9 EMERGENCY DISCONNECT FROM ANCHORS (BLOWOUT)

In the unfortunate event of an uncontrollable blowout, the ***Kulluk*** will be moved from the well site with the utmost speed. This is done primarily to avoid or minimize serious hazards such as fire, explosion, poisonous gases or loss of buoyancy, and secondly, to ensure that the ***Kulluk*** is not damaged and so can be used for relief well operations.

27.9.1 Possible Local Environmental Conditions at the Time of a Blowout

In Open Water: Static conditions.
Wind and/or current at the drill site.
Adverse weather (storm conditions).

In Ice: Static conditions.
Ice drift.
Ice under pressure.

27.9.2 Contingency Plan

The ***Kulluk*** can leave the location in three different ways:

- Heave itself off location.
- Be towed away from location.
- Use wind and current to drift or swing off location.

The three methods are listed in order of preference.

27.9.2.a Abandonment, Open Water, Static Conditions

Since there is no wind or current, the direction of abandonment should be based on wind and weather *forecasts*. The intent then is to stay up wind of the well site.

Method: Slacken down nine anchor wires to a maximum of 100 tonnes tension. The remaining three anchors should be in the direction of abandonment.

- Release the nine slackened anchor wire RARs and heave them in to within 10 m below the fairleads.
- Heave the rig off location with the remaining three anchor wires.
  Time required 1-1/2 to 2 Hours
  If time does not allow for abandonment as described above, use the following method:
- Actuate the emergency brake release system and let the wires run off the drums for the nine winches, decided upon by the weather forecast.
- Heave the rig off location with the remaining three anchor wires.
  Time Required 30 Minutes
- If power to the anchor winches is not available, connect the towing vessel, actuate the manual emergency brake releases, run all the wires off the drums and tow the rig away from the well site.

27.9.2.b Abandonment, Open Water, With Wind and/or Current

The direction of abandonment is 40° to the right of the current and/or wind direction. In the event where wind and current come from different directions, a vector diagram will be made and the resultant will be taken as the direction of the acting force.

Method: Slacken down nine anchor wires to a maximum of 100 tonnes tension. The remaining three anchors should be in the direction of abandonment.
Release the nine anchor wire RARs and heave them into within 10 m below the fairleads.

- Heave the rig off location with the remaining three anchor wires.
  Time Required 1-1/2 to 2 Hours.
  If time does not allow for abandonment as described above, use the following method:
- Actuate the emergency brake release system and let the wires run off the drums for the nine winches decided upon from the resultant force.
- Heave the rig off location with the remaining three anchor wires.
  Time required 30 minutes.
  If power to the anchor winches is not available, connect the towing vessel, actuate the manual emergency brake releases, run all the wires off the drums, and tow the rig away from the well site.

27.9.2.c Abandonment, Open Water In Adverse Weather (Storm Conditions)

Weather conditions could be such that it becomes very difficult to heave the rig into the wind and the oncoming seas. In this case use the following method:

- Keep three anchors, 30°, 60° and 90° to the right of the present seas and wind direction.
- Slack the remaining anchors to 100 tonnes tension.
- Release the RARs of the six down wind anchors and heave them in to 10 m below the fairleads.
- Release the two anchors that are at 30° and 60° to the left of the seas and wind direction and heave them in to 10 m below the fairleads.
- Release the anchor which is facing the wind and the seas and heave it in to 10 m below fairleads as fast as possible.
- The rig will slowly swing off location.
  Time 2 Hours.
  If time does not allow for an abandonment as described above, use the following method:
- Keep three anchors, at 30°, 60° and 90° to the right of the present seas and wind direction.
- Use the emergency brake release but try to keep 10-30 tonnes tension on all but the three selected anchors. This should keep the anchor wires from damaging the wellhead. The rig will slowly swing off location .
  Time 30 Minutes.
  If the power to the winches is not available, actuate the manual emergency brake release system and run all but the three selected anchor wires off their drums.

27.9.2.d Abandonment In Ice, Static Conditions

The method of abandonment is the same as described above.

In addition, ice breaker assistance could be required to ease the winching of ***Kulluk***through the ice depending on the type of ice and percentage of coverage.

27.9.2.e Abandonment in Ice, During Ice Drift

- Keep three anchors at 30°, 60° and 90° to the right of the present ice drift.
- Slacken the remaining anchors to 100 tonnes tension.
- Release the RARs on the six down drift anchors and heave the wires in to 10 m below the fairleads.
- Release the two anchors at 30° and 60° to the left of the ice drift, then heave the wire in to 10 m below the fairleads.
- Release the anchor that is facing the ice drift and heave it in to 10 m below fairleads as fast as possible.
- The rig will now swing off location quickly.
  Time Required 2 Hours.
- Depending on the rate of the ice drift and the ice coverage, a towing vessel would be connected at this time, the remaining three anchors can then be released.

If time does not allow for an abandonment as described above, use the following method:

- Keep three anchors at 30°, 60° and 90° to the right of the present ice drift.
- Use the emergency release to run the wires off the drums of the six down drift anchors.
- Use the emergency brake release on the remaining three anchors, but try to keep tensions between 20 - 50 tonnes until the wires are off the drums. It is hoped that this will keep the anchor wires from damaging the wellhead. The rig will then swing off location quickly.

Time 30 Minutes

- If power to the winches is not available, actuate the manual emergency brake release.
- Run all but the selected three anchor wires of the drums.

27.9.2.f Abandonment in Ice Under Pressure

This condition requires that the rig be towed away from the drill site as fast as possible. It is quite likely that more than one vessel will be required under these circumstances.

The following method should be used:

- Slack all the anchor wires to below 100 tonnes tensions.
- Release the RARs and heave the wires in to 10 m below fairleads.
- Connect the towing vessel while the anchors wires are being heaved in.

In case of a power failure:

- Release the anchors and let the wires run off the drums by actuating the manual emergency brake releases.
- Connect the towing vessel while running the wires off the winch drums.
- Tow the rig away from the well site.

27.9.2.g Preparations For A Severe Storm

The severe storm which is indicated in the titles following and taken from the U.S.C.G. Code of Federal Regulations, is not from the Beaufort wind/sea scale but rather an environmental condition that puts the ***Kulluk*** on a higher alert status. This is readily apparent by utilizing the environmental alert board.

This storm that creates a Red Alert is a Beaufort Sea (not to be confused with the international Beaufort wind/sea scale) 10 year return storm condition.

1 minute sustained wind speed	35 - 53 knots
Significant wave height (Hs)	3-4.5 m (9.8 - 14.7 Fr)
Maximum current speed	1 - 1.5 knots

Preparations For A Severe Storm While Under Tow

1. Have the radio officer procure all weather reports.
2. Commence monitoring of vessel roll/pitch, barometric pressure, sea state, wind speed and direction.
3. Notify all departments to secure the vessel for rough weather.
4. Notify all personnel by public address to secure their personal possessions.
5. Have the Marine Supervisor or Watch Keepers inspect all tow points and ensure that the standby tow equipment is ready for immediate use.
6. Discuss with the Master of the tow vessel the possibilities of weather routing, hoving to, seeking shelter or if in water depths less than 50 meters (150') an alteration of course to deeper water.
7. Have the Marine Supervisor or Watch Keepers service, run and prepare the survival anchor for deployment.

8. Ensure that the weather tight and watertight doors are firmly closed.
9. If the draft is greater than 10.0 meters (33') deballast to a draft of 9.5 m - 10.0 m (31-33').

Preparations For A Severe Storm While Moored On Location

1. Have the Radio Officer procure all weather forecasts.
2. Commence monitoring of anchor line tensions, vessel roll/pitch, barometric pressure, sea state, wind speed and wind direction.
3. Notify all departments to secure the vessel for rough weather.
4. Notify all personnel by public address to secure their personal possessions.
5. Put all R.A.R. command units on standby.
6. Have the Chief Electrician lower the R.A.R. transducer.
7. Secure all weather-tight doors.
8. If the vessel motions are nearing the maximum operating criteria, shut in the well and disconnect the vessel from the well.
9. Once the disconnection has been achieved, bias the mooring wires for a softer mooring pattern.
10. Deballast to vessel to 9.5 - 10.0 meter draft.

Items Of Concern When Securing For Rough Weather

1. Rig Superintendent

Pipe Racks

- Secure pipe with chain and binders.

Drill Stores

- Tie down, chock and chain all drilling equipment likely to move.

Drill Floor

- Tie down all tools.
- Lock the fingers on the setback load.
- Snub the setback load at the pipe midpoint.
- Run the top drive down to the floor.
- Snub the top drive hoses at the midpoint in the derrick.
- Secure all weather tight doors on the drill floor.
- Secure the "V" doors closed.

Miscellaneous

- Secure the sub sea shop.
- Secure the Pump Man's work shop.

2. Maintenance Superintendent

- Tie down and secure all tools in the machine shop, pump rooms, water maker room, boiler room and engine room.

3. Marine Superintendent

Port Deck

- Lash together full barrels.

- Lash together empty barrels.
- Secure lube cube rack.
- Chain down steel rack.
- Chock wheels on forklifts.
- Chock R.A.R. bodies.
- Lash shackles.

Fwd Deck

- Chock R.A.R. bodies.
- Chain and binder slop oil tank.
- Tie down ladders in ladder rack.
- Secure paint locker.

Stbd Deck

- Chock R.A.R. bodies.
- Lash shackles.
- Wire rope/chain and binder caisson if applicable.
- Chain or wire rope with binders all large drilling equipment and miscellaneous. 10 meter Level

Rental Stores

- Tie down all equipment likely to move.

Remaining Compartments

- Secure.

Heli-Deck

- Tie down heli-loader.
- Secure all items stationed on heli-deck and drill floor wings.

27.9.3 Critical Stages Leading to Drill Site Abandonment

27.9.3.a Gas Alarm

The alarm rings on the drill floor, in the control room and in the Rig Superintendent's office only.

The Control Room Operator will activate the general alarm and the Marine Supervisor will make a public announcement.

27.9.3.b Well Control/Blowout Muster

All personnel are required to report to their respective well control stations as stated on their "Emergency Procedure Bunk Cards" and the muster list.

All personnel have been instructed and trained in their assigned emergency duties by their immediate supervisors.

27.9.3.c Decision to Abandon Drill Site

The decision to abandon the drill site must be made in conjunction with the operator's representative and must be made in accordance with pre-established well control principles. It

must be made in the best interests of the personnel and the ultimate safety and integrity of the Vessel.

27.9.4 Personnel With Critical Roles During Emergency Abandonment of the Well Site

27.9.4.a Marine Superintendent

- Go to the Control Room.
- In charge of the Emergency Abandonment.
- Since the Drilling Superintendent is occupied, the Marine Supervisor will notify the operations base and the necessary authorities.

27.9.4.b Marine Supervisor

- Goes to the #3 Remote Winch Control station and waits on stand by.
- Keeps in UHF radio contact with the Control Room and the Deck.
- Has a breathing apparatus with him from #1 locker.
- In direct charge of Crane Crew and Maintenance Foreman.

27.9.4.c On Duty Watch Keeper

- Stays in the Control Room until he is relieved by the Marine Supervisor.
- Then goes to the #1 remote winch control station and waits on stand by.
- In UHF radio contact with the control room and the deck.
- Has a breathing apparatus with him from the #1 locker.

27.9.4.d Off Duty Watch Stander

- Goes to the #2 remote winch control station and waits on stand by.
- In UHF radio contact with the control room and the deck.
- Has a breathing apparatus with him from the #2 locker.

27.9.4.e Radio Operator

- Stays in the Radio Room and stops all normal communications.
- Notify the Ice breakers to go on standby.
- Monitor all communications, assist as required and keep a complete record.

27.9.4.f Medic

- Goes to the first aid room and waits on stand by with the stretcher party.

27.9.4.g Superintendent

- Goes to the boiler room and waits on stand by.
- Maintains UHF radio communication with the control room and monitors all transmissions from the other groups.
- In charge of the Mechanical/Electrical group .
- Will coordinate all the required tasks of this group.
- Has two breathing apparatus from the #2 Locker with his group in case they are needed in one of the winch houses.

27.9.4.h Rig Electrician

- Goes to the switchgear room.
- In UHF radio communications with the control room and the remote control winch stations.

- Will assign SCR power to the anchor winches on request.
- In case an electrician has to go to one of the winch houses, he will take a breathing apparatus with him from the #3 locker.

27.9.4.i Rig Mechanic

- Goes directly to the engine room.
- Have all the three engines running.
- Have all the compressors running.
- After this, with the Offshore Maintenance Engineer, waits on stand by in the boiler room.

27.9.4.j Instrument Technician

- Goes to the control room.
- Prepares the RARs release systems to be ready to use.
- Prepares to take gas readings on the deck.
- In UHF contact with the control room.
- When on the deck takes a breathing apparatus with him from the #3 locker.

27.9.4.k Ice Advisor/Observer

- Goes to the control room.
- Provides the Marine Supervisor with constantly updated information on wind, current, ice drift and any weather forecasts.
- Keeps a record of all communications and operations.

27.9.4.l Crane Operators, Assistants and Deck Foreman

- Stand by on the starboard deck.
- Have a breathing apparatus with them from the #1 locker.
- Act as secondary winch operators in case of accidents or injury to the primary operators.
- Will make the towing gear ready under the direction of the Assistant Marine Supervisor.
- In UHF radio contact with the control room and the Assistant Marine Supervisor.
- Keeps all the doors to accommodation and the 10 m level closed.
- Maintenance Foreman will make constant patrols of the decks and report to control room regularly.

27.9.5 Emergency Well Abandonment Board

In order to give a quick and visual indication of certain critical conditions that affect emergencies such as a well control problem, a large board has been designed. This board contains the following information.

An arrow shows the direction from which either the wind, the current, the resultant of both or the ice drift comes. A line drawn perpendicular to the resultant force and through the center of the ***Kulluk*** divides the anchor diagram into three sectors. The largest sector is down wind or down drift. These anchors will be released first. Next to be released are the anchors in the blue sector. Anchors in the red sector are not released. The board also shows the release codes for all RARs in question and S.C.R assignment for all anchor winches. In addition it shows wind speed and direction plus the direction and the speed of the ice drift. These are constantly updated on this board.

This board is kept in the control room and always is displayed in a prominent place.

27.9.6 Conclusions

The purpose of the fore mentioned procedures is to provide a basic guideline for the orderly abandonment of a well site under emergency conditions.

Experience gained over the last four years in operating the ***Kulluk***, especially abandoning locations in heavy ice conditions has been incorporated into these procedures.

However, to this date, no real data is available that would indicate how acoustically operated anchor releases (RARs) would perform under blowout conditions. Therefore, a secondary method of running anchor wires off their drums is described. The secondary method may also be necessary in case of mechanical problems.

27.10 EMERGENCY WELL SUSPENSION

27.10.1 Introduction

When an environmental or vessel red alert is declared, drilling operations must be suspended, the well secured and possible the vessel disconnected from the seabed, or well head. At all times and for every operation, the appropriate emergency procedures must be determined. This is particularly important in the Beaufort where ice concentrations and movement present a continuous hazard.

Well suspension procedures must consider all aspects of the drilling operation both before and after the vessel is connected to the well head. To account for all situations, operations are divided into three cases.

Case 1: *Operations Conducted With No Connections to the Well Bore.*
- All operations in the 914 mm (36") surface hole section, whether or not a temporary guide base is used.
- Running casing in the 660 mm (26") hole section.

Case 2: *660 mm (26") Conductor Hole Operations.*
- Includes all operations, conducted through an hydraulic wellhead connector.

Case 3: *Operating Through a BOP.*
- Includes all operations conducted through a BOP stack.

27.10.2 Normal and Emergency Well Suspension Procedures

Well suspension procedures will be divided into parts as follows:

i) <u>Normal Suspension Procedures</u>
- These are the predetermined suspension procedures that would be adopted when events transpire more or less as anticipated, and time remains adequate to complete the securing operation.
- These procedures would be adopted on any "Red Alert" status.

ii) <u>Emergency Suspension Procedures</u>
- These are the procedures that would be used if unpredictable events occur which threaten the vessel, and therefore require a suspension of operations by the most immediate means.

27.10.3 A Definition of Secure

This section will propose various emergency means by which a well may be secured. The actual means chosen will depend on Operator preference, environmental circumstances and well bore conditions. However, before determining what well securing procedure is chosen consider that:

i) The well must be securely isolated from the natural environment.

ii) The well bore should be left in a stable state that would minimize permanent formation or casing damage and allow future operations to resume with a minimum of inconvenience.

iii) Any equipment left on the wellhead should not be in danger of being damaged by ice floes.

iv) If the possibility exists that operations may not be resumed within a short time, the well must be secure for as long as the vessel may remain off location.

v) The requirements of all regulatory bodies must be satisfied.

27.10.4 Normal Suspension Procedures While Conducting Operations With No Connection To the Wellbore

27.10.4.a Introduction

This would include all situations in the 914 mm (36") surface hole section, and running casing in the 660 mm (26") conductor hole section. These procedures all assume that:

- Surface hole section is drilled with returns to the seabed, casing is run in the conductor hole section with returns to the seabed, the suspension procedure does not require that the well bore be isolated from the natural environment.

However, if hydrocarbons, fresh water flows, or salt water flows are anticipated, an open well bore may not be acceptable. Therefore, prior to spudding either hole section, the Operator must determine the acceptable suspension methods.

27.10.4.b Normal Suspension Procedures While Drilling With Returns To Surface

i) Circulate as necessary to condition, freeze or depress the drilling fluid.

ii) Trip out the drill string.

iii) If a temporary guide base is in use, shear out and retrieve the guidelines.

iv) Secure the vessel as necessary.

27.10.4.c Emergency Suspension Procedures While Drilling With Returns To Surface

i) If time allows, trip out to place the bit a distance off the bottom equal to the distance from the rotary table to the seabed.
If time does not allow, proceed directly to step (ii).

ii) Drop the drill string by backing out the top drive.

27.10.4.d Normal Well Suspension Procedures While Logging With No Connection To The Well Bore

i) Retrieve the logging tools.

ii) If a temporary guide base is being used, shear out and retrieve the guidelines.

27.10.4.e Emergency Well Suspension Procedures While Logging With No Connection To The Well Bore

i) Shear out the rope socket weak link. This procedure would be used if logging tools were stuck and the rig was being forced off location.

ii) If a temporary guide base is being used, shear out and retrieve the guidelines.

27.10.4.f Normal Well Suspension Procedures While Running Casing With No Connection To The Well

i) Retrieve the casing, or finish the casing job, whichever is faster.

27.10.4.g Emergency Well Suspension Procedures While Running 762 mm (30") Casing

i) This procedure is to be used in the event that time does not allow tripping the casing above the seabed.

- Ensure inner bushings are removed from master bushings.
- Release hydraulic handling tool while rapidly lowering casing string.
- If above procedure won't release the casing, install inner bushings and set the slips.
- Screw top drive into casing handling tool with enough threads to pick up casing string.
- Pick up pull slips and bushings.
- Back out top drive, dropping string.

ii) Emergency Well Suspension Procedures while running the 762 mm (30") Casing Landing String.

- Raise and rapidly lower the casing to lower the tension at the running tool.
- Apply 10,500 kPa (1,500 psi) to the unlock port of the running tool.
- Continue this procedure until the running tool disengages and casing is dropped.
- POH the landing string.
- Shear out the TGB guidelines, if applicable. If there is not adequate time for this procedure, drop the string by reversing the top drive.

27.10.4.h Emergency Well Suspension Procedures While Running 508 mm (20") Casing

i) This procedure is to be used in the event that time does not allow tripping the casing above the seabed.

- First consideration is to make up the wellhead and attempt to land the casing string.
- If time does not allow picking up the wellhead, the casing will have to be dropped.
- Remove the 500T elevator slips from rotary table.
- Rapidly lower the casing, this will reduce the tension on the 500 T elevators. At the same time attempt to release the elevators.

Note: Excessive weight of the casing string might not allow the release of the 500T elevators. Depending on the severity of the situation, consideration should be given to cutting the casing.

ii) Emergency Well Suspension Procedures while running the 508 mm (20") Casing Landing String.

- Make up wellhead joint with running tool.
- Remove master bushings from rotary table.
- Attempt to land casing.
- If time does not allow landing of casing, screw top drive into casing landing string. Rapidly lowering casing, reverse top drive.
- Shear out guidelines.

27.10.4.i Normal Well Suspension Procedures While Drilling Through The Wellhead Tieback Tool

i) POH the drill string to the seabed.

ii) Displace the riser to sea water, recovering mud as the pit capacity allows.

iii) POH to surface.

iv) Disconnect, and pull the tieback tool to surface.

v) Shear out the guidelines.

27.10.4.j Emergency Procedures While Drilling Through The Wellhead Tieback Tool

i) If time does not allow pulling the drill string to surface, disconnect procedures may begin as soon as the bit is above the seabed.

- If time does not allow tripping to above the seabed, POH to place the bit off bottom by a distance equal to the distance from the rotary table to the seabed. Drop the string by reversing out the top drive.
- If the string is stuck, mechanically back out as low in the string as possible.

ii) Disconnect the wellhead connector and lift it as high as possible with the tensioners.

iii) Shear out the guidelines.

iv) Disconnect anchors to move off location.

v) While disconnecting anchors, continue pulling the riser.

27.10.5 Well Suspension When Drilling Through The BOP

27.10.5.a Introduction

When a well must be suspended by leaving the BOP on the wellhead, it is always preferable to have the drill string inside the casing with the bit as close to the casing shoe as is practical. This will facilitate well control operations, which may be necessary, upon returning to the location. Leaving pipe in open hole will almost invariably result in a stuck string. Suspending a well with no pipe in the hole may result in a situation which requires a stripping operation to kill the well.

- Assure that the mud is always in good condition so that solids settling, or chemical degradation will not stick, or plug the drill string.
- Ensure that freeze depression is adequate.
- Drill with the largest size jets practical.

27.10.5.b Using a Lynes Retrievable Self Anchoring Plug

Note: This procedure is only to be used when 508 mm (20") casing is set and the BOP stack is inoperative or must be pulled.

Tool Specifications:

Maximum Tensile Load:	102350 daN (230,000 lbs)
Maximum Burst Pressure:	69000 kPa (10,000 psi)
Maximum Collapse Pressure:	58000 kPa (8,500 psi)
Maximum Differential Pressure: (above or below)	17200 kPa (2,500 psi)
Maximum Deflated OD:	400 mm (15-3/4")
Minimum ID:	41.2 mm (1-5/8")

Lynes Retrievable Plug Running Procedure

i) In any situation, whether drilling, tripping, or out of the hole, it is preferable to set the pipe as deep in the casing as possible.

To determine bit and plug setting depth, let:

a = Depth from RT to the position of the bit prior to picking up the Lynes plug.
b = Depth from RT to set the packer.
c = Casing shoe depth.
d = Safety factor (two stands of DP or equivalent).
e = Length by which BHA exceeds water depth from RT. This would only be applicable when drilling in extremely shallow water. The distance from the Lynes plug to the rotary table should be adequate to allow running BHA in case jarring or milling is necessary to unseat the packer.
f = Wellhead depth from RT.

ii) Pull or run pipe as necessary to position the bit at a.

(a = c - f - d - e).

- Pump a weighted slug into the annulus to compensate for the hydrostatic pressure loss when the riser is removed, if necessary.
- Pump down the hydril latch in dart.

iii) Note and record the string weight prior to picking up the Lynes assembly.

iv) Connect the DP to the 4-1/2" IF box of the plug running tool.

- Do not allow the top sub of the plug to rotate, as this could cause the mandril to move to the deflate position.

v) Run in slowly with the Lynes plug to setting depth.

- When in shallow water, where the length of the drilling BHA exceeds water depth, set the plug at a depth from RT equal to the length of the drilling BHA.

Note: Once the plug is connected to the drill string, do not attempt to circulate, as this will shear open the pump out sub.

vi) Fill the running string with water.

vii) Hook up a circulating wedge, low torque valve and chiksans to the running string.

viii) Set the Motion Compensator at 3/4 open.

ix) Pressure up on the running string to 10000 kPa (1,450 psi) to inflate and set the packer.

- As the packer sets, be prepared to rapidly vent the Motion Compensator , or slack off the blocks to avoid exceeding the tensile limits of the tool when the vessel heaves. If the heave is extreme, it may be advantageous to hang the running string on the rams for setting and releasing from the plug.
- Hold the 10000 kPa (1,450 psi) for two minutes, then rapidly bleed off the pressure to set the check valve.

x) Slack off 5000 to 10000 daN (10 - 20 ton) to assure the plug is set.

xi) Close the upper annular and pressure test the tool through the choke line to 3500 kPa (500 psi).

xii) Pressure up on the running string again to 14000 kPa (2,000 psi), record strokes to shear the pins in the running tool. The pressure should drop, indicating that the pins have sheared.

- Do not exert pressure above the tool after disengaging the DP.

xiii) Pull the stinger to above the shear rams.

xiv) Close and block the shear rams.

xv) Displace the riser to sea water recovering mud as tank capacity allows.

xvi) POH with the landing string.

- Check the mandril and install the protector, before standing back or breaking off the mandril.
- Rope off the landing string.

xvii) Continue operations as required.

xviii) Fully describe the string left in the hole, the running string, and the BOP status in the tour report.

27.10.5.c Retrieving the Lynes Self Anchoring Plug, refer to Lynes Procedure Manual

i) Open the well to surface by opening the appropriate sub sea choke or kill valve by a sensitive pressure gauge to a closed choke. If no pressure is evident, open the choke and check for flow.

- After flow checking, close the choke and kill valves.

ii) Pick up the retrieving tool below a 444.5 mm (17-1/2") stabilizer.

- Check the O-rings.

iii) Run in to above the shear rams.

iv) Set the Motion Compensator to support landing string weight. Lightly engage shear rams. Begin displacing the riser to mud at a high rate to flush out any debris which may have settled above shear rams. After adequate flushing, pick up above shear rams and continue displacing the riser to mud.

v) Open the shear rams and flow check the well.

vi) Run in and engage the plug with 5000 daN.

- Pressure up to 7000 kPa (1,000 psi) to ensure that the retrieving tool is latched.
- Continue pressuring up to 11000 kPa (1,600 psi) to shift the sleeve in the bottom of the tool, thereby establishing communication between the annulus and the running string. A drop in pressure indicates the tool has opened.
- If the tool does not open at 11000 kPa (1,600 psi), pressure under the packer (a live well) must be assumed.
- Continue pressuring up to a maximum of 80% of the casing burst pressure plus 11000 kPa (1,600 psi) to open the tool. Control the well as necessary.

vii) After the tool has opened, flow check the DP.

viii) To unseat the packer, use the Motion Compensator to pick up to running string weight, and rotate the string six right turns.

ix) Pick up to the original string weight and wait five minutes for the elements to deflate.

- Flow check the well.

27.10.5.d Well Suspension with the Primary Emergency Drill Pipe Hang Off Tool

This procedure is to be used:

i) Any time drilling operations are being conducted with either the 10 m or 15 m BOP in place.

ii) With any casing string larger than 178 mm (7") set in the wellhead.

The reason this tool should be used is, the secondary emergency drill pipe hang off tool (wear bushing hang off tool) will prevent working the pipe down. The primary hang off tool will pass through all wear bushings except the 178 mm (7").

i) The running tool which is the 4-1/2 IF box by a 1" pitch left hand general purpose acme box.

ii) The hang off tool has an upper tool joint which is a 4-1/2 IF square shouldered box, with an external 1" pitch left hand acme general purpose thread with 2 - '0' ring seals to ensure a pressure competent seal at low make up torque.

Note: The tool can be retrieved by screwing and torquing the drill string into the 4-1/2" IF box. If a 4-1/2" IF tool joint is used to retrieve the drill string the connection should not be torqued to over 60% of running string make up torque. This would allow the string to be backed out if necessary.

However, it is recommended that at least on the first run to retrieve the string, the left hand running tool be used. This would eliminate the problem of releasing from the string, if necessary.

- This assembly should be racked in the derrick on a stand of drill pipe and kept functional, and immediately accessible at all times when drilling through the BOP.
- Consideration should be given to maintain a unique pre-measured and marked landing string for running the hang off tool. The string should be marked at the rotary table to indicate that the hang off tool is in the landed out position on the middle rams.

Primary Emergency DP Hang Off Tool Preparation

i) Install 2 joints of grade S-135 drill pipe into the 4-1/2 IF Box end of the primary emergency DP. Hang off running tool and torque up to maximum recommended make-up torque.

ii) Install a 3 m (10 ft.) ± HWDP pup joint below the hang off tool (min ID 70 mm).

iii) Install a hydril check guard sub directly below the HW pup.

- Thoroughly clean and generously grease the interior of the check guard sub.
- Ensure the dart latching mechanism functions, grease the dart and latch it into the sub.

iv) Thoroughly clean and grease the interior of the stabbing valve and install it below the check guard sub.

- Function the stabbing valve and leave it in the open position.

v) Make up all 4-1/2 IF connections to the maximum recommended torque.

vi) Ensure the acme connection is well lubricated and made up chain tong tight only.

vii) Rack the primary emergency drill pipe hang off tool assembly in the derrick.

viii) Keep the assembly functional and accessible at all times.

ix) Designate and rope off a unique landing string to be used for the primary hang off tool.

Primary Emergency BOP Ram Hang Off Tool Running Procedure

i) Condition the mud and circulate as necessary, or as time allows.

ii) Anytime casing larger than 7" is set and time permits:

- Whether drilling, tripping, or out of the hole, run, or pull pipe to position the bit as close as possible to the casing shoe depth, minus two stands, minus the distance from RT to the wellhead, before picking up the hang off assembly.

iii) Anytime casing is set and the pipe must be hung off in open hole:

- Pull as much pipe as time allows. If on bottom, pull a minimum of pipe to position the bit, at a depth equal to TD, minus the distance from the rotary table to the wellhead, minus two stands.
- This will ensure that the pipe is two stands off bottom when the string is hung off.

iv) Make up the hang off assembly to the string.

- Check to ensure that the stabbing valve is open.
- Check to ensure the dart is installed in the Check Guard sub.

v) Ensure that the running tool is chain tong tight only.

vi) Run in, measuring the drill string if necessary to ensure proper landing depth, and position the tool hanger 2 m plus rig heave above the middle ram.

- Just prior to landing, note and record the string weight.
- If heave warrants, stroke out the Motion Compensator.

vii) If necessary, spot a heavy slug in the hole to compensate for the hydrostatic pressure lost when the riser is removed.

viii) Vent down the manifold pressure to 3500 - 5000 kPa (500 - 700 psi).

- This assures that if the rams are inadvertently closed on tool joint, or the hang off tool, no damage would occur and that stripping down to land out results in minimum ram rubber damage.
- Close the middle rams.

ix) Strip down until a loss in weight verifies that the hanger is on the middle rams.

- Mark the string at the rotary table.

x) Lift up just off the rams and boost the manifold pressure to 10500 kPa (1,500 psi).

- The minimum pressure required to activate the posilocks is 5500 kPa (800 psi).
- Monitor fluid volume to assume ram closure.

xi) Slack the string back down until a minimum loss of weight verifies the string is on the rams.

- The mark on the drill string should be at the same position as in (ix).
- Block the rams.

xii) Slack off until only the weight of the landing string is supported in the blocks.

xiii) Close the lower rams with 10500 kPa (1,500 psi) manifold pressure and block the rams.

Note: Do not close upper rams.

xiv) To confirm rams closure.

- Pump down through the lower choke line until a pressure build up (approximately 3500 kPa (500 psi) confirms that both rams are completely closed.

xv) If necessary, set the Motion Compensator to support the running string weight.

xvi) Release the running string with seven right hand turns.

xvii) Raise the string 3 m (10 ft) to clear the shear rams.

xviii) Close the shear rams with a minimum of 14000 kPa (2,000 psi) and block the rams.

- Monitor the fluid to ensure the SPM functions.
- Close the upper annular and pressure up to 500 psi to confirm closure.

xvix) Ensure all choke and kill line valves are closed and blocked.

- If time allows pressure up against all choke and kill valves to ensure closure.

xx) If time allows, displace the riser to sea water by pumping through the running string, recovering the mud as the pit capacity allows.

xxi) POH with the landing string.

- Fully describe the string left in the hole, the running string and the BOP status in the tour report, sub sea report and well file.

xxii) WOW or disconnect (see rig procedure), as required.

27.10.5.e Retrieving the Primary Emergency Drill Pipe Hang Off Tool From 10 and 15 m BOPs

Note: If the LMRP has been disconnected, the checks outlined in steps (ii) to (vii) should be carried out. If the LMRP has not been disconnected, and there is no reason to suspect possible BOP system malfunctions, the retrieval procedure may start at step (viii).

i) Run and reconnect the LMRP.

Refer Chapter 16, BOP Operations.

ii) Fill the riser with sea water and flow check to ensure that the rams and drill pipe shut off valves have held.

iii) Ensure that all choke manifold valves are in the drilling position. Yellow open, Red indicates all valves closed.

iv) Put the annulus on the trip tank.

v) Connect a Tee to the #1 valve outlet on the choke manifold.

- Connect the Dowell unit to one outlet of the Tee.
- Connect a closed plug valve to the other outlet of the Tee.

vi) Pressure test the choke and kill lines, to the high and low values of the last BOP test.

vii) To ensure annular and choke and kill functions, after relatching:

a) Set the annular regulator pressure to 4000 kPa (600 psi).
b) Partially close, reopen the upper annular.
c) Repeat (a) and (b) for the lower annular.
d) Open and close the upper outer choke valve.
e) Open and close the upper inner choke valve.
f) Open and close the lower outer choke valve.
g) Open and close the lower inner choke valve.
h) Open and close the outer kill valve.
i) Open and close the inner kill valve.

Note: Flow check continuously at the choke manifold rig floor outlet and at the riser while carrying out these checks.

At this point, we have confirmed that all choke and kill valves and both annulars to be fully operational. However, remember that the LMRP connector has not been pressure tested since relatching, and therefore if any well bore pressure is encountered in subsequent operations, the rams and not the annulars should be used to control the well.

Note: ***DO NOT OPEN EITHER PIPE RAMS.*** *Opening the middle rams will drop the drill string.*

viii) Run in with the hang off assembly running tool to just above the shear rams.

- Use the highest strength pipe aboard, preferably S135.
- Make up all connections in the running string to maximum torque.

ix) Engage the top drive and using the Motion Compensator if necessary, lightly tag the shear rams. Pick up string approximately "0.5 ft" (15 cm)

- Mark the drill string at the rotary table.

x) Begin displacing the riser to mud at a maximum pump rate (2 x 100 SPM) to flush out any debris which may have settled above the shear rams.

- After adequate flushing, pick up and continue displacing the riser to mud.

xi) To flow check the annulus:

- Open the kill line to surface by a sensitive pressure gauge to a closed choke manifold.
- If there is no pressure evident, visually check flow at the rig floor outlet by opening choke manifold valve #1.

Note: Expect some gas in the annulus due to the migration of gas entrained in the mud.

Note: It is recognized that it is preferable not to use the kill line outlets unless absolutely necessary, for if the valves failed to close or seal, the well could not be shut in for disconnect purposes.

However, in this case it has been considered preferable, particularly since the valves have been function and pressure tested, to use the kill line rather than open the rams under potential pressure.

xii) With the Dowell Unit pump a maximum of two times surface plus choke line volume to ensure that the kill line is not plugged.

- Bleed back any pressure from this operation and flow check.
- Shut the inner kill line valve.

Note: This procedure does not confirm that the well is dead, as ice, barite or formation bridges may be isolating well bore annular pressure.

xiii) To flow check the drill string:

- Open the upper choke line to surface by a sensitive pressure gauge to a closed choke.
- If there is no pressure evident visually, flow check at the rig floor by opening choke manifold valve #6.

Note: A lack of pressure only indicates that the drill pipe non return valves have held, that well bore pressure (if any) is not in communication with the upper drill string, and that the pipe rams have held. This check is not a positive indication that the drill string is dead.

Although freeze depressed mud and the proper glycol water mixture should eliminate ice plug problems in the drill string and annulus, and in the BOP, the possibility of these plugs existing still must be considered.

Note: Other problems which may isolate pressure from surface may be as follows:

a) Plugged jets.
b) Barite plugs in the drill string and/or annulus.
c) Formation bridging in the annulus.

xiv) Lower the retrieving string to just above the shear ram.

- Use the previous mark for reference (item ix).

xv) Close the upper annular.

xvi) Line up the stand pipe manifold to monitor pressure and flow.

xvii) Line up the riser on the trip tank.

xviii) Open the shear rams.

- Flow check at the riser and trip tank.

xix) Vent down manifold pressure to 700 psi and close and reopen the shear rams to confirm that they are fully operational.

xx) Pump down the drill pipe until returns at the choke manifold valve #6 confirm that the upper choke line is not plugged.

- Close the upper inner choke.
- We are now sure there was no pressure below the shear rams.

xxi) Open the upper annular.

xxii) Lower the running string to reconnect to the hang off tool.

- Use the mark when the shear rams were tagged as reference.
- The top of the hang off tool will be 1.0 m below the top of the shear rams.

xxiii) To re-engage the hang off tool with:

a) The left hang acme running tool.

- This is the preferred method and should be attempted first.
- Stroke out the Motion Compensator if necessary.
- Lower the drill string and with the minimum possible weight contact the hang off tool.
- Make one turn to the right to align the threads.
- Turn the tool to the left until a slight increase in torque is noted. This should take approximately seven turns.

b) Open ended drill pipe.

- This method can be used if pulling the string requires vigorous working the pipe and rotating.
- Stroke out the Motion Compensator if necessary.
- Lower the drill string and with the minimum possible weight contact the hang off tool.
- Turn the string to the right torquing up the connection to no more than 70% of the make up torque of the running string. This should allow releasing at the tool if necessary.

Note: The first attempt to retrieve the string, should be made with the running tool.

xxiv) Pick up the string weight.

xxv) Open the lower rams.

xxvi) Close and reopen the rams to ensure they are fully operational.

xxvii) Open the middle rams.

xxviii) Close and reopen the middle rams to ensure they are fully operational.

xxix) Open the lower chokes.

xxx) Open choke manifold valves #13 and #9 and with the Dowell Unit Pump down the lower choke until returns at the trip tank confirm the line is clear.

Note: At this point, all BOP functions have been confirmed as "OK" and no pressure has been detected. However, the previously mentioned plugs in the drill string and/or annulus are still a possibility.

xxxi) Hoist the drill string to establish whether or not it is free.

xxxii) Circulate to condition the mud and/or hole.

- Break circulation very carefully as the annulus may be bridged.
- Ensure pit volumes are being accurately monitored.
- If circulation pressures are high or if the integrity of the running strings connection to the hang off tool is suspect, drop a dye marker or a carbide to ensure the connection is not washing out.

xxxiii) POH the drill string as soon as possible to remove the hang off tool.

- Test the BOP if required.

27.10.5.f Well Suspension By Hanging Off On A Drill Pipe Tool Joint

This procedure is only to be used when:

- Pipe must be hung off in open hole when 178 mm (7") casing is set to surface or if the primary emergency hang off tool is not available and it is not advisable to use the secondary (wear bushing) hang off tool which will not allow downward movement of the string.

A description of the assembly:

- If the primary hang off tool is not available and before drilling out of 178 mm (7") casing, the following assembly should be made up and racked in the derrick. From the top:

1) A double of S135 drill pipe.
2) One sub 4-1/2 IF pin by 4-1/2 IF box approximately 1 m long.
   - The clearance between the bottom of the shear rams, and the top of the middle hang off rams is 1.52 m (5 ft) in the 10 m BOP and 1.93 m (6.3 ft) in the 15 m BOP. This sub will aid in retrieval operations if an overshot must be used.
3) One single of S135 drill pipe.
4) One retrievable dart sub with the dart installed.
5) One kelly cock type valve in the open position.

Procedure For Suspending The Well By Hanging Off On A Drill Pipe Tool Joint.

i) Circulate, and/or condition the mud as time allows.

ii) Pull as much pipe as time allows. If on bottom, pull at a minimum, enough pipe to position the bit, at a depth equal to TD, minus the distance from the rotary table to the wellhead, minus two stands.

- This will ensure that the pipe is two stands off bottom when the string is hung off.

Note: The string will be run in, and landed on a loose tool joint. Reaming and circulating must be avoided. Therefore, the hole under the bit must be in reasonably good condition for the distance that the landing string must be run.

iii) Make up the hang off assembly to the string.

- Check to ensure that the stabbing valve is open.
- Check to ensure the dart is installed in the Check Guard sub.

iv) Break the connection between the XO sub box, and the drill pipe pin, and remake it up chain tong tight only.

v) Run in, measuring the drill string if necessary to ensure proper landing depth, and position the loose drill pipe tool joint, 2 m (6 ft) plus rig heave above the middle ram.

- Do not allow the string to turn when making up connections. Left hand turns may back out the landing string. Right hand turns may tighten the connection making release difficult.
- Just prior to landing, note and record the string weight.
- If heave warrants, stroke out the Motion Compensator .

vi) If necessary, spot a heavy slug in the hole to compensate for the hydrostatic pressure lost when the riser is removed.

vii) Vent down the manifold closing pressure to 3500 - 5000 kPa (500 - 700 psi).

- This assures that if the rams are inadvertently closed on tool joint, no damage would occur and that stripping down to land out results in minimum ram rubber damage.
- Close the middle rams.

viii) Strip down until a loss in weight verifies that the tooljoint is on the rams.

ix) Lift up just off the rams and boost the manifold pressure to 10500 kPa (1,500 psi).

- The minimum pressure required to activate the posilocks is 5500 kPa (800 psi).
- Monitor fluid volume to assure ram closure.

x) Slack the string back down until a minimum loss of weight verifies the string is on the rams.

- The mark on the drill string should be at the same position as in (ix).
- Block the rams.

xi) Slack off until only the weight of the landing string is supported.

xii) Close the lower rams with 10500 kPa (1,500 psi) manifold pressure and block the rams.

Note: ***DO NOT CLOSE UPPER RAMS.***

xiii) To confirm ram closure.

- Pump down through the lower choke line until a pressure build up [approximately 3500 kPa (500 psi)] confirms that both rams are completely closed.

xiv) If necessary, set the Motion Compensator to support the running string weight.

xv) Release the landing string with five left hand turns.

xvi) Raise the string ten feet to clear the shear rams.

xvii) Close the shear rams with a minimum of 14000 kPa (2000 psi) and block the rams.

- Monitor fluid volume to ensure SPM functions.

xviii) To ensure shear ram closure:

- Engage the top drive.
- Lower the drill string to just above the shear rams.
- Close the upper annular and pump down the drill string until a sharp pressure increase ±3500 kPa (± 500 psi), confirms that the shear rams are fully closed.

xix) Open the upper annular.

xx) Ensure all choke and kill line valves are closed and blocked.

xxi) If time allows, displace the riser to sea water by pumping through the running string, recovering the mud as the pit capacity allows.

xxii) POH with the landing string.

- Fully describe the string left in the hole, the running string and the BOP status in the tour report, sub sea report and well file.

xxiii) WOW or disconnect, as required.

27.10.5.g Retrieving the String When The Pipe Has Been Hung Off On a Tool Joint

Note: If the LMRP has been disconnected, the checks outlined in steps (ii) to (vii) should be carried out. If the LMRP has not been disconnected and there is no reason to suspect possible BOP systems malfunctions, the retrieval procedure may start at step (viii).

i) Run and reconnect the LMRP.

ii) Fill the riser with sea water and flow check to ensure that the rams and drill pipe shut off valves have held.

iii) Ensure that all choke manifold valves are in the drilling position. Yellow open, Red indicates all chokes closed.

iv) Put the annulus on the trip tank.

v) Connect a Tee to the #1 valve outlet on the choke manifold.

- Connect the Dowell unit to one outlet of the Tee.
- Connect a closed plug valve to the other outlet of the Tee.

vi) Pressure test the choke and kill lines, to the high and low values of the last BOP test.

vii) To ensure annular and choke and kill functions, after re- latching:

a) Set the annular regulator pressure to 4000 kPa (600 psi).
b) Partially close; reopen the upper annular.
c) Repeat (a) and (b) for the lower annular.
d) Open and close the upper outer choke valve.
e) Open and close the upper inner choke valve.
f) Open and close the lower outer choke valve.
g) Open and close the lower inner choke valve.

h) Open and close the outer kill valve.
i) Open and close the inner kill valve.

Note: Flow check continuously at the choke manifold rig floor outlet and at the riser while carrying out these checks.

At this point, we have confirmed that all choke and kill valves and both annulars should be fully operational. However, remember that the LMRP connector has not been pressure tested since relatching. Therefore, if any well bore pressure is encountered in subsequent operations, the rams and not the annulars should be used to control the well.

viii) Run in with open ended drill pipe to just above the shear rams.

- Place a 445 mm (17-1/2") stabilizer one single up.
- Use the highest strength pipe aboard, preferably S135.
- Make up all connections in the running string to maximum torque.

ix) Engage the top drive and using the Motion Compensator if necessary, lightly tag the shear rams. Mark the pipe at the RT for future reference.

x) Begin displacing the riser to mud at a maximum pump rate (2 x 100 SPM) to flush out any debris which may have settled above the shear rams.

- After adequate flushing, pick up and continue displacing the riser to mud.

xi) To flow check the annulus:

- Open the kill line to surface by a sensitive pressure gauge to a closed choke manifold.
- If there is no pressure evident, visually check flow at the rig floor outlet by opening choke manifold #1.

Note: Expect some gas in the annulus due to the migration of gas entrained in the mud.

Note: It is recognized that it is preferable not to use the kill line outlets unless absolutely necessary for if the valves failed to close or seal, the well could not be shut in for disconnect purposes.

However, in this case it has been considered preferable, particularly since the valves have been functioned and pressure tested, to use the kill line rather than open the rams under potential pressure.

xii) With the Dowell Unit, pump a maximum of two times the surface and choke line volume, to ensure that the kill line is not plugged.

- Bleed back any pressure from this operation and flow check.
- Shut the inner kill line valve.

Note: This procedure does not confirm that the well is dead, as ice, barite or formation bridges may be isolating well bore annular pressure.

xiii) To flow check the drill string:

- Open the upper choke line to surface by a sensitive pressure gauge to a closed choke.
- If there is no pressure evident visually, flow check at the rig floor by opening choke manifold valve #6.

Note: A lack of pressure only indicates that the drill pipe non return valves have held, that well bore pressure (if any) is not in communication with the upper drill string and that the pipe rams have held. This check is not a positive indication that the drill string is dead.

Although freeze depressed mud and the proper glycol water mixture, should eliminate ice plug problems in the drill string and annulus, and in the BOP, the possibility of these plugs existing still must be considered.

Note: Other problems which may isolate pressure from surface may be:

- Plugged jets.
- Barite plugs in the drill string and/or annulus.
- Formation of bridging in the annulus.

xiv) Lower the retrieving string to just above the shear ram.

- Use the previous mark for reference, see above (ix).

xv) Close the upper annular.

xvi) Line up the stand pipe manifold to monitor pressure and flow.

xvii) Line up the riser on the trip tank.

xviii) Open the shear rams.

- Flow check at the riser and trip tank.

xix) Vent down manifold pressure to 5000 kPa (700 psi) and close and reopen the shear rams to confirm that they are fully operational.

xx) Pump down the drill pipe until returns at the choke manifold valve #6 confirm that the upper choke line is not plugged.

- Close the upper inner choke.
- We are now sure there was no pressure below the shear rams.

xxi) Open the upper annular.

xxii) Lower the running string to reconnect to the drill string.

- Use the mark when the shear rams were tagged as reference.

xxiii) To re-engage to hang off tool:

- Stroke out the Motion Compensator if necessary.
- Lower end drill string end with the minimum possible weight contact the hang off tool.
- It may be necessary to use the lower annular to help centralize the running string.
- Turn the string to the right torquing up the connection to no more than 70% of the make up torque of the running string. This should allow releasing the running string if necessary.

xxiv) Pick up the string weight.

xxv) Open the lower rams.

xxvi) Close and reopen the rams to ensure they are fully operational.

xxvii) Open the middle rams.

xxviii) Close and reopen the middle rams to ensure they are fully operational.

xxix) Open the lower chokes.

xxx) Open the choke manifold valves #13 and #9 and with the Dowell Unit pump down the lower choke until returns at the trip tank confirm the line is clear.

Note: At this point, all BOP functions have been confirmed as "OK" and no pressure has been detected. However, the previously mentioned plugs in the drill string and/or annulus are still a possibility.

xxxi) Hoist the drill string to establish whether or not it is free.

xxxii) Circulate to condition the mud and/or hole.

- Break circulation very carefully as the annulus may be bridged.
- Ensure pit volumes are being accurately monitored.
- If circulation pressures are high or if the integrity of the running strings connection to the hang off tool is suspect, drop a dye marker or a carbide to assure the connection is not washing out.

xxxiii) Continue with operations as necessary. POH the drill string as soon as possible to:

- Remove the hang off joint.
- Test the BOP.

27.10.5.h Well Suspension with the Hang Off Tool

Note: This procedure is to be used ONLY:

- When 406 mm (16"), 340 mm (13-3/8"), 245 mm (9-5/8"), 178 mm (7") casing has been set. The 441 mm (17-3/8") OD lower hanger body will not set on the larger 447.7 mm (17-5/8") ID wellhead housing wearing bushing.

AND

- The drill string is to be hung off in the cased hole. If the drill string was hung off in the open hole and consequently became stuck, the inability of passing the fluted hanger past the wear bushing would prevent working the pipe down.

Note: This assembly should be racked in the derrick on a stand of drill pipe of convenient height for the derrick man and kept functional, and immediately accessible at all times when the primary tool is not available.

Consideration should be given to maintaining a unique pre measured landing string for running the hang off tool. The string should be marked at the rotary table to indicate that the hang off tool is in the landed out position.

The tool consists of six portions:

1. The running tool which is a 4-1/2 IF box, by a 1" pitch left hand modified acme box. The acme box has an 0-ring which ensures a pressure competent seal at low make up torque.

2. The upper body has an upper tool joint which is a 4-1/2 IF square shouldered box, with an external 1" pitch left hand acme thread.

The tool can be retrieved by screwing and torquing the drill string into the 4-1/2 IF box. If a 4-1/2 IF tool joint is used to retrieve the drill string the connection should not be torqued to over 70% of running string make up torque. This would allow the string to be backed out if necessary.

However, it is recommended that at least on the first run to retrieve the string the left hand running tool be used. This would eliminate the problem of releasing from the string if necessary.

3. A double pin pup designed to space out the tool for ram closure.

4. The lower body is a 441 mm (17-3/8") OD fluted hanger with a 4-1/2 IF box up and a 4-1/2 IF pin down.

5. A hydril "Check Guard" sub with the dart latched in. The sub should be marked "Dart In" to avoid confusion when running the assembly.

6. A lower kelly cock type valve with an adequate ID to allow passage of the hydril check guard "Dart", and a string shot. This would allow for internal string control when removing the tool on the surface.

Emergency Hang Off Tool Preparation

i) Thoroughly clean and generously grease the interior of the hydril check guard.

ii) Ensure that the dart latching mechanism functions. Grease the dart and latch it into the sub.

iii) Function test the dart retrieving tool.

iv) Make up the check guard sub, with the dart latched in, directly below the hang off tool.

v) Thoroughly clean and grease the interior of the stabbing valve, and install it below the check guard sub in the 'open' position.

vi) Make up all connections on the hang off tool, except the acme threaded running tool, to the recommended torque for 4-1/2 IF tool joints.

vii) Make up the running tool to a single.

viii) Check the running tool 0-ring and threads.

ix) Connect the running tool to the hang off assembly with four left hand turns. Ensure that the acme connection is chain tong tight only.

x) Pick up a 3 m (10 ft) pup, and one single to rack the assembly in the derrick.

xi) When racking back, place the valves below the hanger in a chuck filled with soluble oil, to prevent rusting.

xii) Keep the assembly functional and accessible at all times.

<u>Procedure For Running the Secondary Emergency Drill Pipe Wear Bushing Hang Off Tool</u>

i) Condition the mud and circulate as necessary or as time allows.

ii) Pull or run pipe as necessary to position the bit at a depth equal to the casing shoe depth minus the distance from the rotary table to the wellhead, minus the length of two stands.

- This will ensure that the pipe is two stands inside the shoe when the string is hung off.

iii) Prior to picking up the hang off assembly, note and record the string weight.

- Check to ensure that the stabbing valve is open and that the dart is installed.
- Make up the hang off assembly to the drill string.

iv) Ensure that the running tool is chain tong tight only.

v) Run in, measuring the drill string, if necessary to ensure proper landing depth, and land the hang off tool on the wear bushing.

- Install a wiper rubber as soon as the hang off tool has passed the rotary table to prevent debris from entering the well bore.
- Just prior to landing, note and record the string weight.

vi) Paint mark the string at the rotary table.

vii) Close and block the lower pipe rams with 10500 kPa (1,500 psi) operating pressure and block the rams.

viii) Close and block the middle pipe rams with 10500 kPa (1,500 psi) operating pressure.

ix) To confirm ram closure:

- Pump down through the lower choke line until a pressure build up (approximately 3500 kPa (500 psi) confirms that both rams are completely closed.

x) If necessary, set the Motion Compensator to support the running string weight. This is the weight recorded in (iii) minus the weight recorded in (vi).

xi) Release the landing string with four right hand turns.

xii) Raise the string ten feet to clear the shear rams.

xiii) Close and block the shear rams with 14000 kPa (2,000 psi).

xiv) To ensure shear ram closure:

- Engage the top drive.
- Lower the drill string to just above the shear rams.
- Close the upper annular and pump down the drill string until a sharp pressure increase $\pm$3500 kPa ($\pm$500 psi) confirms that the shear rams are fully closed.
- Open the upper annular.

xv) Ensure all choke and kill line valves are closed and blocked.

xvi) If time allows, displace the riser to sea water by pumping through the running string, recovering the mud as the pit capacity allows.

xvii) POH the landing string.

- Inspect the running tool.
- Tie off and mark the landing string.
- Record and write the following in the tour report:

a) A full description of the string left in the hole.

b) The status of every BOP function.

c) A full description of the landing string.

xviii) WOW or disconnect, as required. Refer to Chapter 16.

27.10.5.i Retrieving the Emergency Drill Pipe Hang Off Tool From the 10 and 15 m BOPs

Note: If the lmrp has been disconnected, the following checks should be made to ensure bop functions.

If it has not been disconnected, start the retrieval procedure at step no. (vii).

i) Fill the riser with sea water and flow check, to ensure that the rams and drill pipe shut off valves have held.

ii) Ensure that all choke manifold valves are in the drilling position to start. Yellow valves open, red valves and all chokes closed.

iii) Put the annulus on the trip tank.

iv) Connect a Tee to the #1 valve outlet on the choke manifold.

- Connect the Dowell unit to one outlet of the Tee and a closed plug valve to the other.

v) Pressure test the choke, and kill lines to the high and low values of the last BOP test.

vi) To ensure annular and choke and kill valve functions, after re-latching:

- Set the annular regulator pressure to 4000 kPa (600 psi).
- Partially close, then reopen the upper annular.
- Partially close, then reopen the lower annular.
- Open and close the upper outer choke valve.
- Open and close the upper inner choke valve.
- Open and close the lower outer choke valve.
- Open and close the lower inner choke valve.
- Open and close the outer kill valve.
- Open and close the inner kill valve.

Note: Flow check continuously at manifold and riser while carrying out these checks.

At this point we have confirmed that all choke, and kill valves, and both annulars are fully operational. However, remember that the LMRP has not been pressure tested since re-latching. Therefore, if any well bore pressure is encountered in subsequent operations, the rams and not the annulars should be used to control the well.

vii) Flow check the drill string.

- Open the upper choke.

- If there is no pressure evident open choke manifold valve #6 and visually flow check at the open ended outlet.
- Close the upper inner choke.

Note: A lack of pressure only indicates that the drill pipe non return valves have held, that well bore pressure (if any) is not in communication with the upper drill string, and that the pipe rams have held. This check is not a positive indication that the drill string is dead.

Although freeze depressed mud and the proper glycol water mixture should eliminate ice plug problems in the drill string and annulus and in the BOP, the possibility of these plugs existing still must be considered.

Other problems which may isolate pressure from the surface drill string may be plugged jets, settled out barite in the drill string and/or annulus, or formation bridging in the annulus.

viii) To flow check the annulus.

Note: Expect some gas under the lower rams due to the migration of gas entrained in the mud.

- Open the kill line.
- If there is no pressure evident open choke manifold valve #1 and the plug valve and visually flow check.
- Close the plug valve and with Dowell, pump two times surface volume and kill line volume to ensure that the line is not plugged.
- Close the inner kill.

Note: It is recognized that it is advisable not to use the kill line outlets unless absolutely necessary, for if the valves failed to close or seal, the well could not be shut in for disconnect purposes.

However, in this case, it has been considered preferable, particularly since the valves have been functioned and pressure tested, to use the kill line rather than to risk damaging the rams by opening them under potential pressure.

Again, be aware that a lack of pressure does not prove that the well is dead, as annulus pressure may be isolated from surface by freeze back, formation bridging, or settled out barite.

x) Open the lower rams.

- Flow check at the riser.

x) To confirm that the lower rams are fully operational, close and reopen the rams.

xi) Open the middle rams.

- Flow check at the riser.

xii) To confirm that the middle rams are fully operational, close and reopen the rams.

Note: At this point all BOP functions have been confirmed as fully operational except the shear rams.

xiii) To confirm that the lower chokes are not plugged:

- Open the lower chokes.

- Pump down the kill line with the Dowell unit until returns are observed at choke manifold valve #6.
- Close the lower inner choke.

xiv) To confirm that the upper chokes are not plugged:

- Open the upper chokes.
- Pump down the kill line with the Dowell unit until returns are observed at choke manifold #6.
- Close the upper inner choke.

xv) To retrieve the drill string, run in to above the shear rams with the drill pipe hang off running tool.

- Ensure all drill pipe connections are made up to optimum torque.

xvi) Stroke out the Motion Compensator if necessary. Lightly engage the shear rams. Displace the riser to mud at a high rate to flush any debris which may have settled above the shear rams. After adequate flushing, pick up above the shear rams and continue displacing riser mud.

xvii) Open shear rams - flow check. Close the shear rams to confirm full shear ram function. Reopen the shear rams.

- Place all BOP and choke manifold functions in the drilling position.

xviii) To re-engage to hang off tool with:

a) The left hand acme running tool.

- Stroke out the Motion Compensator if necessary
- Lower the drill string and with the minimum possible weight contact the hang off tool.
- Make one turn to the right to align the threads.
- Turn the tool to the left until a slight increase in torque is noted. This should take approximately four turns.

b) Open ended drill pipe.

- Stroke out the Motion Compensator if necessary.
- Lower end drill string end with the minimum possible weight contact the hang off tool.
- Turn the string to the right torquing up the connection to no more than 70% of the make up torque of the running string. This should allow releasing at the tool if necessary.

xix) Hoist the drill string to establish whether or not it is free.

xx) Circulate to condition the mud and/or hole.

- Break circulation very carefully as the annulus may be bridged.
- Ensure pit volumes are being accurately monitored.
- If circulation pressures are high or if the integrity of the running strings connection to the hang off tool is suspect, drop a dye marker or a carbide to ensure the connection is not washing out.

xxi) Continue with operations as necessary.

xxii) POH and resume operations as necessary.

27.10.5.j Emergency Well Suspension With a Hook Wall Packer When Drilling Through the BOP and Either 340 mm (13-3/8"), 235 mm (9-5/8") or 178 mm (7") Casing Has Been Set

- This procedure is only to be used when the entire BOP must be pulled, or is inoperative.
- Using the Howco RTTS and SSC Valve

PACKER SIZE	TENSILE LIMIT		MINIMUM WT UNDER TO SET
7" (178.0 mm)	150000 daN	(370,000 lbs)	4500 daN (10,000 lbs)
9-5/8" (244.5 mm)	338000 daN	(760,000 lbs)	6800 daN (15,000 lbs)
13-3/8" (340 mm)	743000 daN	(1,700,000 lbs)	9000 daN (20,000 lbs)

RTTS Running Procedure:

In any situation, whether drilling, tripping, or out of the hole, it is preferable to set the pipe as deep in the casing as possible. To determine bit and RTTS setting depth, let:

a = Depth from RT to the position of the bit prior to picking up the RTTS.
b = Depth from RT to set the packer.
c = Casing shoe depth.
d = Safety factor (two stds of DP or equivalent).
e = Length by which BHA exceeds water depth from RT. This would only be applicable when drilling in extremely shallow water. The distance from the RTTS to the rotary table should be adequate to allow running the BHA in the event jarring or milling is necessary to unseat the packer.
f = Wellhead depth from RT.

i) Pump down the hydril latch in dart.

ii) Pull or run pipe as necessary to position the bit at a. (a = c - f - d - e).

iii) Note and record the string weight prior to picking up the RTTS hang off assembly.

iv) Connect the RTTS assembly to the drill string.

- Ensure the acme back off connection is chain tong tight only.
- Ensure the kelly valve is open.

v) Run in slowly with the RTTS. Ensure that all connections above the acme back-off thread are properly torqued.

- When in shallow water where the length of the drilling BHA exceeds water depth, set the RTTS at a depth from RT equal to the length of the drilling BHA.

Note: It is imperative that no junk is allowed to enter the hole above the RTTS.

- Check all handling equipment, and install a wiper rubber as soon as the RTTS passes through the rotary table.

vi) Note and record the string weight at the RTTS setting depth, in the tour report.

vii) Pump a weighted slug to compensate for the hydrostatic pressure loss when the riser is removed, if necessary.

viii) To set the RTTS packer:

- Stroke out the Motion Compensator .
- Raise the string 1 m (3 ft), make a minimum of two right hand turns, and slowly slack off until the weight (record in step 3) is lost. Repeat this procedure if necessary.

Note: Do not exert pressure above the SSC valve after backing off the landing string or the pump out plug will shear. The shear pin valve is normally 21000 kPa (3,000 psi), but different shear pressures are available by changing the shear pin size.

- Determine the desired shear valve when ordering the RTTS.

ix) Close an appropriate annular preventer and pump down the choke or kill line to pressure test the RTTS from the top to 10000 kPa (1,500 psi).

x) To back off from the RTTS and close the SSC valve, rotate the 155.6 mm (6-1/8") and 120.7 mm (4-3/4") tools 22 turns to the left. Rotate the 94.5 mm (3.7") tool 20 turns to the left.

xi) Note the string which is hung off, the running string and the RTTS and bit depths in the tour report.

xii) POH to above the shear rams.

xiii) Close and block the shear rams and all choke and kill valves.

xiv) Displace the riser to sea water, recovering mud as mud tank capacity allows.

xv) POH with the landing string.

- Check the mandril and install the protector, before standing back or breaking off the mandril.
- Rope off the landing string.

xvi) Continue operations as required.

xvii) Fully describe the string left in the hole, the running string, and the BOP status in the tour report.

27.10.5.k Retrieving the RTTS

i) Open the well to surface by opening the appropriate sub sea choke or kill valves by a sensitive pressure gauge to a closed choke. If no pressure is evident, open the choke and check for flow.

- After flow checking, close the choke and kill valves.

Note: If the well is flowing, a decision must be made to:

a) Strip out, remove the RTTS hang off assembly and strip to bottom and kill the well.

b) Unseat the packer and kill the well immediately.

c) Bullhead.

Note: A lack of pressure of flow only indicates that the packer and SSC valve have held, not that the well is dead.

ii)
- Install and lock in the diverter insert packer.
- Pick up the SSC mandril. Remove the protector.
- Check the threads and ensure O-rings are in place and in good condition.
- Run the retrieving assembly to above the shear rams as soon as possible.

iii) Set the Motion Compensator to support landing string weight. Lightly engage shear rams. Begin displacing riser to mud at a high rate to flush out any debris which may have settle above the shear rams. After adequate flushing, pick up above shear rams and continue displacing the riser to mud.

iv) Open the shear rams and flow check the well.

v) Lightly engage the SSC valve and make a minimum 18 right hand turns (or until a slight torque build up is noticed), to engage the RTTS and open the SSC valve.

- If in doubt that the string is fully engaged, back out and repeat the procedure.

vi) Open the standpipe valve, or kelly valve in the case of the Surface Circulating Assembly, and flow check the well.

vii) Pick up to the previously recorded string weight plus 5000 to 10000 daN (10,000 to 20,000 lbs) to unseat the RTTS. Hold this tension for five minutes to allow the rubber element to retract.

viii) Flow check for a minimum of fifteen minutes.

ix) POH slowly with the motion compensator unlocked.

- It is not recommended that a circulation commence until the RTTS has been removed and the bit is as close as possible to bottom.

x) Resume operations as necessary.

Note: Service the RTTS hang off assembly after each run.

27.10.5.I Well Suspension By Shearing the Drill Pipe

i) Pump down the hydril dart sub, if time allows.

ii) Position the pipe so that the tool joint is 2 m (6 ft) plus rig heave above the middle pipe rams.

iii) Vent down the ram closing pressure to 3500 kPa (500 psi) to 5000 kPa (700 psi).

- This will ensure that if the rams are inadvertently closed on the tool joint, no damage will occur, and that stripping down to land out results in minimum ram rubber damage.

iv) Strip down until a loss of weight verifies that the tool joint is on the rams.

- Use the Motion Compensator if necessary.

v) Lift up just off the rams and boost the ram closing pressure to 10500 kPa (1,500 psi) and block the rams.

vi) Set the string back down on the rams and continue slacking off until only the weight of the string above the shear rams is supported.

vii) Close and block the lower rams with 10500 kPa (1,500 psi) closing pressure.

viii) Close and block all choke and kill valves.

ix) Close and block the shear rams with 14000 kPa (2,000 psi).

x) Pick up on the string to confirm that the pipe has been sheared.

- If shear has not been accomplished, open and close the shears as necessary until the pipe is cut.

xi) POH the landing string.

xii) Disconnect at the LMRP if time allows.
Refer to Chapter 16.11.15.

xiii) Fully describe the string left in the hole and the BOP status in the tour report.

27.10.5.m Retrieving A Sheared Off Drill String

Note: If the LMRP has been disconnected, the checks outlined in steps (ii) to (vii) should be carried out. If the LMRP has not been disconnected, and there is no reason to suspect possible BOP systems malfunctions, the retrieval procedure may start at step (viii).

i) Run and reconnect the LMRP.

ii) Fill the riser with sea water and flow check to ensure that the rams and drill pipe shut off valves have held.

iii) Ensure that all choke manifold valves are in the drilling position. Yellow open, Red indicates all chokes closed.

iv) Put the annulus on the trip tank.

v) Connect a Tee to #1 valve outlet on the choke manifold.

- Connect the Dowell unit to one outlet of the Tee.
- Connect a closed plug valve to the other outlet of the Tee.

vi) Pressure test the choke and kill lines, to the high and low values of the last BOP test.

vii) To ensure annular and choke and kill functions after re-latching:

a) Set the annular regulator pressure to 4000 kPa (600 psi).
b) Partially close, open the upper annular.
c) Repeat (a), for the lower annular.

d) Open and close the upper outer choke valve.
e) Open and close the upper inner choke valve.
f) Open and close the lower outer choke valve.
g) Open and close the lower inner choke valve.
h) Open and close the outer kill valve.
i) Open and close the inner kill valve.

Note: Flow check continuously at the choke manifold rig floor outlet and at the riser while carrying out these checks.

At this point, we have confirmed that all choke and kill valves and both annulars are fully operational. However, remember that the LMRP has not been pressure tested since re-latching. Therefore, if any well bore pressure is encountered in subsequent operations, the rams, and not the annulars, should be used to control the well.

viii) Make up the fishing assembly with the appropriate overshot and mill guide.

- The mill guide must be used to dress the sheared off joint back to its original size.
- Use adequate drill collars, jars, and the highest strength drill pipe aboard.

ix) Run in with open ended drill pipe to just above the shear rams.

- Use the highest strength pipe aboard, preferably S135.

x) Engage the top drive and using the Motion Compensator if necessary, lightly tag the shear rams.

- Mark the drill string at the rotary table.

xi) Begin displacing the riser to mud at a maximum pumps (2 x 100 SPM) to flush out any debris which may have settled above the shear rams.

- After adequate flushing, pick up and continue displacing the riser to mud.

xii) To flow check the annulus:

- Open the kill line to surface by a sensitive pressure gauge to a closed choke manifold.
- If there is no pressure evident, visually check flow at the rig floor outlet by opening choke manifold #1.

Note: Expect some gas in the annulus due to the migration of gas entrained in the mud.

Note: If is recognized that it is preferable not to use the kill line outlets unless absolutely necessary for if the valves failed to close or seal, the well could not be shut in for disconnect purposes.

However, in this case it has been considered preferable, particularly since the valves have been functioned and pressure tested, to use the kill line rather than open the rams under potential pressure.

xiii) With the Dowell unit, pump a maximum of two times surface plus choke line volume to ensure that the kill line is not plugged.

- Bleed back any pressure from this operation and flow check.
- Shut the inner kill line valve.

Note: This procedure does not confirm that the well is dead, as ice, barite or formation bridges may be isolating well bore annular pressure.

xiv) To flow check the drill string:

- Open the upper choke line to surface by a sensitive pressure gauge to a closed choke.
- If there is no pressure evident visually, flow check at the rig floor by opening choke manifold valve #6.

Note: A lack of pressure only indicates that the drill pipe non return valves have held, that well bore pressure (if any) is not in communication with the upper drill string and that the pipe rams have held. This check is not a positive indication that the drill string is dead.

Although freeze depressed mud and the proper glycol water mixture should eliminate ice plug problems in the drill string and annulus and in the BOP, the possibility of these plugs existing still must be considered.

Note: Other problems which may isolate pressure from surface may be:

a) Plugged jets.
b) Barite plugs in the drill string and/or annulars.
c) Formation of bridging in the annulus.

xv) Lower the retrieving string to just above the shear ram.

- Use the previous mark for reference.

xvi) Close the upper annular.

xvii) Line up the stand pipe manifold to monitor pressure and flow.

xviii) Line up the riser on the trip tank.

xix) Open the shear rams.

- Flow check at the riser and trip tank.

xx) Close and reopen the shear rams to confirm that they are fully operational.

xxi) Pump down the drill pipe until returns at the choke manifold valve #6 confirm that the upper choke line is not plugged.

- Close the upper inner choke.
- We are now sure there was no pressure below the shear rams.

xxii) Open the upper annular.

xxiii) Lower the running string to dress the sheared off drill string.

- Use the mark when the shear rams were tagged as reference.

xxiv) Begin milling off the flattened portion of the sheared area until the overshot will slip over the pipe.

- Continue lowering the string until the overshot bottoms out.

xxv) Pick up the string weight.

xxvi) Open the lower rams.

xxvii) Close and reopen the rams to ensure they are fully operational.

xxviii) Open the middle rams.

xxix) Close and open the middle rams to ensure they are fully operational.

xxx) Open the lower chokes.

xxxi) Open choke manifold valves #13 and #9 and with the Dowell unit pump down the lower choke until returns at the trip tank confirm the line is clear.

Note: At this point, all BOP functions have been confirmed as "OK" and no pressure has been detected. However, the previously mentioned plugs in the drill string and/or annulus are still a possibility.

xxxii) Hoist the drill string to establish whether or not it is free.

xxxiii) Circulate to condition the mud and/or hole.

- Break circulation very carefully as the annulus may be bridged.
- Ensure pit volumes are being accurately monitored.
- If circulation pressures are high or if the integrity of the running strings connection to the hang off tool is suspect, drop a dye marker or a carbide to assure the connection is not washing out.

xxxiv) Continue with operations as necessary.

27.10.5.n Well Suspension While Running 406 mm (16") or Smaller Casing Through BOP

i) Suspension With Casing In Casing

- Pick up hanger joint.
- ***Do Not*** run seal assembly with hanger.
- Run and land casing in wellhead.
- Measure in to ensure hanger is properly spaced out in housing.
- Back-off and recover landing string.
- Ensure an accurate tally of length, number of joints in hole, shoe depth, etc., is kept.
- Continue suspension procedures as described in 27.10.5.d.

ii) Suspension With Casing In Open Hole

This procedure is used only if time does not allow either finishing running casing or pulling casing back inside previous casing shoe.

- Pick up hanger joint.
- ***Do Not*** run seal assembly with hanger.
- Run and land casing in wellhead.
- Measure in to ensure hanger is properly spaced out in housing.
- Back-off and recover landing string.
- Ensure an accurate tally of length, number of joints in hole, shoe depth, etc., is kept.
- Continue suspension procedures as described above.

iii) Suspension When Running Landing String

- Continue running casing and land out in wellhead.
- Measure in to ensure hanger is properly spaced out in housing.
- Ensure an accurate tally of length, number of joints in hole, shoe depth, etc., is kept.
- Back-off and recover landing string.
- Continue suspension procedures as described above.

iv) Suspension When Running Liner

- Pick up liner hanger and running assembly if not already down hole.
- Pick up and run in with primary hang off assembly and hang off as described in 27.10.5.d.
- Continue suspension procedures as described above.

Emergency Procedures While Running Casing Through BOP

i) Suspension With Casing In Elevators

- Close both annulars.
- Remove 500 ton Spider Slips from rotary.
- Slack-off on blocks and open elevators.
- Open annulars to drop casing.
- Wait a minimum of two minutes to allow casing to pass BOP.
- Continue with emergency disconnect procedures as described above.

27.10.6 L.M.R.P. Disconnect Procedures

27.10.6.a Normal Disconnect

i) Condition

Well has been suspended normally. L.M.R.P. is being retrieved for repair, or a pending ice condition.

ii) Procedure

Refer to normal rig BOP procedures.

27.10.6.b Emergency Disconnect

i) Conditions

- Weather conditions deteriorating rapidly, so that the combined effect of pitch/roll and riser angle is greater than 4°.
- Anchor tensions dangerously high, or 80% of pre-tension values.
- Ice conditions deteriorating rapidly so that time does not allow normal alert status procedures to be carried out.

ii) Procedure

- If no D.P. in hole, close shear rams.
- If pipe in hole, pick up primary hang-off tool. Hang-off on middle pipe rams per procedures.
- Close lower pipe rams.
- Back off running tool with 7 right hand turns.
- Pick up running string at least 3 m and close shear rams.

- Block all functions from main B.O.P. hydraulic panel except riser connector (primary and secondary).
- Set guideline tension at 7,000 lb.
- Have the combined riser tensioner pull set at 10% less than the weight of the slip joint outer barrel + riser + L.M.R.P.
- Ensure all standby and emergency standby APV's are fully charged to 2,200 psi, and that all 3 standby bottles are open to system.
- Select one active APV per riser tensioner system and close the remaining 4 APVs.
- Unlatch L.M.R.P. connector (primary and secondary). Monitor fluid flow and manifold read back to ensure connector has released.
- Increase pressure to riser tensioners until slip joint is fully collapsed.

Note. Slip joint should begin moving at approx. 50,000 lb over weight set in step 7.

- After slip joint collapsed increase weight an additional 50,000 lbs to secure package in this position.

Option 1 If rig moving off location more than 50 ft, imminent.

a) Shear guidelines and bring to surface.

b) Install riser spider and attempt to pull L.M.R.P. into moonpool high enough so that nothing extends below hull.

Option 2 If option 1 is unwarranted.

a) Slack guidelines as situation warrants.

b) Same as Option 1.

Note: In the event pitch and roll is greater than 3.5° (which may exist in a clear water condition) therefor making rig moving off location unlikely, riser should be suspended on tensioners until such times as condition warrants relatching to B.O.P.

27.10.6.c Extreme Emergency Procedures In Open Sea Storm Conditions

i) Condition

Weather conditions deteriorating rapidly, so that the combined effect of pitch/roll and riser angle is greater than 6°.

Emergency disconnect procedures have failed re H-4, L.M.R.P. connector failure, or other?

ii) Procedure

Well is secure.

- Block all functions (from main hydr. unit if possible).
- Drill crew unlatch and pull diverter packer.
- Make up diverter handling tool.
- Vent flowline seals and unlatch diverter from pump room diverter panel.
- Ensure both pod tensioners are at lower end of stroke. (approx .5 m (1.5') of exposed rod depending on heave.)
- Ensure both clutches and brakes are securely engaged on pod hoists.
- Increase podline tension to 14,000 lb (ensure pod hoist drums do not slack off as tension is increased).

- Select active APV for each riser tensioner system. Reduce total applied tension to 30% over weight (slip joint outer barrel + riser + top half of AMF).
- Unlatch AMF (watch for indication on manifold read back and flow meter).
- As riser starts to move upward, increase tension until slip joint fully collapsed.
- Shift both pods to unlatch position. (thereby engaging riser jacks). Pods should now release from L.M.R.P. and pod tensioners should fully stroke out. More air may have to be added to podline tensioners to accomplish above after tensioner begins to stroke out.
- Remove diverter control block.
- Pull diverter slip joint and riser as far as possible into moonpool.
- Remove RBQ's from hose reels.
- Continue pulling pods to surface with hoists, stopping only to remove pod hose clamps. Continue reeling in pod hose.
- If rig starts to move off location.
- Increase tension to 14,000 lb on guidelines shearing out as many lines as possible, if shearing fails.
- Feed out line till line pulls out of drum. Bleed down guideline air to 0 psi while feeding out lines.

Note: To implement above, entire Deck Crew, Sub Sea, Tool Pusher and Drill Crew will be required.

Note: For any of the above, RBQ plates will not be removed from hose reel before slip joint begins to collapse and pods are pulled free.

- Begin releasing RAR's and/or anchor winches.
- Continue pulling riser while releasing anchors.

27.10.6.d Extreme Emergency Procedures In Ice Conditions

i) Condition

A large mass of ice has evaded detection by ice monitors and now is at or near rig, making immediate rig departure from location imminent.

ii) Procedure

- Secure well, by closing shear rams, which may require shearing pipe, casing, logging tools, and/or dropping drill string in fastest way possible.
- Increase manifold pressure to 2,000 psi minimum.
- Try to follow 27.10.6.b procedure if time allows and riser angle under 5°.
- Over 5°, block all functions on stack.
- Clear drill floor of all personnel and unlock A.M.F.

Note: Depending on riser tensioner pressure, riser may sling shot out of water, shear diverter lock down dogs and push rotary bushings and diverter past drill floor.

- Unlock both pods and increase tension on line till pods pull free of receptacle.
- Pull pods to surface.
- Shear guidelines and retrieve.
- Pull diverter, slip joint, riser and lay down.
- If guideline shear pins do not shear, bleed down tensioner pressure to 0 psi and allow line to feed off as rig moves off location. When all line is fed off, line will pull out of drum and drop to sea bed. Insure all personal are clear of moonpool area during this operation.
- If pods do not pull free, remove RBQ and feed off pod hose, cut hose off at drum and drop to sea bed.