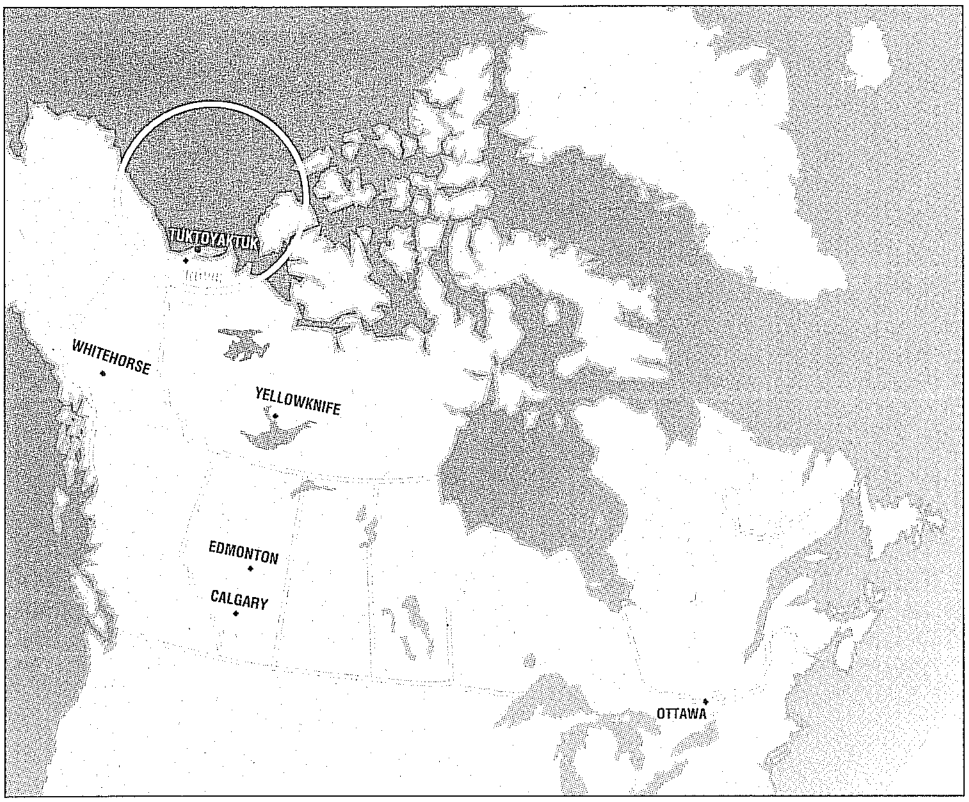
VOLUME 2

REPORT OF TASK GROUP ONE
Worst Case Scenario
A Report Prepared On Behalf of
the Canadian Petroleum Association



FOR THE
BEAUFORT SEA STEERING COMMITTEE
April 1991

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REPORT

by

TASK GROUP NUMBER ONE

WORST CASE SCENARIO
A REPORT PREPARED ON BEHALF OF
THE CANADIAN PETROLEUM ASSOCIATION

for

BEAUFORT SEA STEERING COMMITTEE

APRIL, 1991

CANADIAN PETROLEUM ASSOCIATION
FRONTIER DIVISION
3800, 150 Sixth Avenue S.W., Calgary, Alberta T2P 3Y7
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1991-04-09

Mr. Robert Hornal
Chairman, Beaufort Sea Steering Committee
Hornal Consultants Ltd.
401, 1755 West Broadway
VANCOUVER, British Columbia
V6J 4S5

Dear Mr. Hornal:

RE: Report on Worst Case Blowout Scenario by Adams Pearson Associates Inc.

The above noted report was prepared for CPA member companies participating in the work of the Beaufort Sea Steering Committee as part of their studies of issues arising from recommendations of the Environmental Impact Review Board. On behalf of CPA, this report is being released to you under separate cover, for your use as backup material to the Beaufort Sea Steering Committee final report. We trust that this report will add to the information base developed during the work of the Beaufort Sea Steering Committee.

Sincerely,

C. Barry Virtue, Director
Divisional Services

cbv/cvk

cc: E. Bennett
J. Maxim
G. Pidcock
J. Loh

GULF CANADA RESOURCES LIMITED

P.O. BOX 130, CALGARY, ALBERTA T2P 2H7 · TELEPHONE (403) 233-4000

April 5, 1991

SENT BY COURIER

Mr. J. Maxim
c/o Petro-Canada Resources
Room 10100 West Tower
150 - 6 Avenue S.W.
Calgary, Alberta
T2P 3E3

Mr. R. Hornal
Hornal Consulting
401 - 1755 W. Broadway
Vancouver, B.C.
V6J 4S5

RE: CPA REPORT
Recommended Philosophy for
Development of a Worst Case Blowout Scenario

Please find enclosed a copy of the above report. A covering letter from Mr. B. Virtue of the CPA will be sent separately.

If you require any further information, please contact the undersigned.

Yours truly,

Gary A. Pidcock

GAP/afd
l-cparep.doc

Encl.

cc: E. Bennett - (w/o att.)
B. Virtue - (w/o att.)

Gulf

RECOMMENDED PHILOSOPHY

FOR DEVELOPMENT OF

A WORST CASE BLOWOUT SCENARIO

FOR

WELLS DRILLED IN THE BEAUFORT SEA

Prepared for:

CANADIAN PETROLEUM ASSOCIATION

TASK GROUP #1

Beaufort Sea Steering Committee

Prepared by:

ADAMS PEARSON ASSOCIATES INC.

CALGARY

MARCH 1991

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ADAMS PEARSON ASSOCIATES INC.
Petroleum Engineering Consultants

PRINCIPALS
D.M. ADAMS, M.Sc., P.Eng.
R.M. PEARSON, B.Sc., P.Eng.

March 18, 1991

File No. 1130

Re: CPA Task Group #1

Gulf Canada Resources Ltd.
P.O. Box 130
401 - 9 Avenue S.W.
Calgary, Alberta T2P 2H7

Attention: Gary Pidcock

Amoco Canada Petroleum Co. Ltd.
Box 200, Station "M"
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Attention: Dave Schilling

Shell Canada Limited
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Attention: Jamie Sutherland

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Calgary, Alberta
T2P 0L7

Attention: Roy Rettie

Petro-Canada Resources
P.O. Box 2844
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Calgary, Alberta T2P 3E3

Attention: Jack Kercher

Esso Resources Canada Limited
237 - 4 Avenue S.W.
Calgary, Alberta
T2P 0H6

Attention: Ed Bennet

Dear Sirs:

Re: Report on Worst Case Blowout Scenario

Please find attached a copy of our final report on the above subject prepared for the Canadian Petroleum Association Task Group #1.

We thank you for selecting us to undertake this project and trust that this report adequately meets your objectives, but should you have any questions or comments please give me a call.

Yours truly,

ADAMS PEARSON ASSOCIATES INC.

R. M. Pearson, P.Eng.
Vice-President

RMP/dw
Att.

PERMIT TO PRACTICE
ADAMS PEARSON ASSOCIATES LTD.
Signature
Date March 19 1991
PERMIT NUMBER: P 3705
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

Suite 600, 521 - 3rd Avenue S.W., Calgary, Alberta T2P 3T3 Tel: (403) 265-7226 • Fax: (403) 269-3175

WAIVER OF LIABILITY

This report was prepared for the CPA Beaufort Sea Task Group #1 by Adams Pearson Associates Inc. acting as independent consultants. It represents the consultants' best efforts to review the subject within the time frame and budget specified by the client.

There are always risks involved in attempting to predict future performance. There may be factors that have been overlooked at this stage that may subsequently prove to be critical. Because of the inherent risk, no guarantee is given nor implied that conclusions of this report will be achieved. This study represents a best effort to predict well behaviour during a blowout in the Beaufort, but is not based on specific field data.

While it is believed that the information contained herein is reasonably reliable under the conditions and subject to the limitations set forth above, neither the CPA nor the consultants guarantee the accuracy thereof. The use of this report or any information contained therein shall be at the user's sole risk, regardless of any fault or negligence of the consultants.

ACKNOWLEDGEMENTS

Adams Pearson Associates Inc. would like to acknowledge the assistance provided to this study by Gulf Canada Resources and, in particular, by Messrs Pidcock and Mothersele. We would also like to thank other members of the CPA Beaufort Sea Task Group #1 for their comments and suggestions.

We would also like to recognize the contributions made by Woiceshyn Engineering Inc. and Neal Adams Firefighters.

CONCLUSIONS

1. Estimation of a Realistic Worst Case Blowout Scenario is an extremely complex task involving the interrelationship of many factors and the use of substantial engineering judgement. However, by using the methodology presented in this report, it is feasible to develop an estimate, on a site specific basis, in which a reasonable level of confidence can be placed.

2. Worst Case Blowout Scenarios will be well and field specific and their development should be left to the individual operator.

3. Oil Blowouts on exploration wells are an extremely infrequent event, especially when drilling in a known geological environment involving a sand/shale sequence with experienced crews and modern drilling equipment.

4. The results of this study agree with previous findings by others that, even with high permeability and thick pay zones, the 1 in 10,000 well event is unlikely to result in a spill of more than 20,000 m^3 and will probably be substantially less.

5. Two worst case blowout scenarios should be examined:

   i) A high rate, short duration event controlled from surface or by formation collapse.

   ii) A low rate, long duration event requiring a relief well.

   In the hypothetical example considered in this report, the first was found to result in the more significant spill

6. In normal pressured, 9 - 11 kPa/m (0.4 - 0.5 psi/ft), sandstone formations, the most probable cause of a severe well kick is swabbing gas in during a trip. With modern fluid metering systems, such swabbing will normally be detected before a significant hydrocarbon influx can occur, and can be handled with standard well control techniques.

7. In sandstone formations, the greatest risk with respect to a long duration blowout is posed by:

   i) Fracturing below the shoe of the surface casing.

   ii) A leak through the blowout preventor (BOP) or wellhead.

Both of these events involve the drill string being in the hole, and will impose a natural choking of the resultant flow.

8. Higher rate events may occur as a result of a combination of surface equipment failures, but these are likely to be of short duration, because either they can be controlled or capped from surface; or they lead to natural bridging due to downhole collapse.

9. In evaluating the blowout potential, it is important to consider not only the pay zones but also all permeable formations open to the wellbore in order to develop an estimate of the inflow capacity of the combined zones, the resulting water cut and the free gas influx rate.

10. The behaviour of the gas is critical in modelling blowouts. The rapid expansion of the gas near surface creates a substantial back-pressure that chokes the flow.

11. Gas bearing intervals are much more likely to lead to blowouts than oil or water zones.

12. The only plausible scenario leading to a completely hydrocarbon filled casing with no drill pipe in the well is a kick-loss situation in high permeability fractured formations or vugular carbonates. The vast majority of wells drilled in the Beaufort Sea will not encounter this type of lithology; and, therefore, unrestricted flow up open casing is not relevant in defining the Worst Case Blowout Scenario for this area.

13. There are many factors which may naturally limit the blowout rate and duration including:

    - Formation damage or plugging.
    - Formation collapse.
    - Hydrate or wax deposition in low rate flows.
    - Piping configurations and surface choking.

14. In thick, high permeability formations, the well outflow performance will limit the blowout rate; and liquid production rates will be controlled by the volume and velocity of the gas at surface.

15. Even in high permeability thick pay zones, the most probable blowouts will likely involve extended flow rates of less than 2000 m^3/d of total fluids (oil and water). Lower rates can be expected from wells that have:

- Poorly developed sands.
- Blowouts through fractures around the surface casing.

16. The time required to cap a well blowing out at surface is needed to estimate the maximum probable oil spill from a blowout. This will be location and well specific, but will likely take less than a week.

17. For a specific well location, where the pay thickness and permeability trends can be defined, it is possible to develop typical blowout rate expectations for various reservoir pressures using the methodology presented in this report.

18. The use of offset well test results to determine the oil zone inflow performance is quite acceptable, provided that the results are adjusted for variations in permeability and pay thickness. However, this approach may overestimate the blowout rates possible from well developed oil zones.

RECOMMENDATIONS

1. Individual operators should prepare well or field specific Worst Case Blowout Scenarios based on well prognosis, casing scheme and local geological conditions.

2. At least two scenarios should be evaluated:

    i) A high rate, short duration event controlled from surface or by formation collapse.

    ii) A low rate, long duration event requiring a relief well.

    Both can involve an element of choking by the flow conduit.

3. Worst Case Blowout Scenarios need not address flow through unrestricted casing unless fractured carbonates are expected within the open hole section.

4. The methodology used to develop the inflow performance of a well should be left to the operator and will depend on the available well and geological data; but should consider all permeable zones that may be open to the wellbore at the time of the blowout.

5. In developing a Worst Case Blowout Scenario, the operator may consider the effects of:

    - Formation damage or plugging.

    - Partial penetration of a zone.

    - Rate dependent, non-Darcy skin.

    - Drawdown dependent relative permeability and oil viscosity effects (i.e. Vogel curvature or two phase skin).

    - Free gas influx and the additional friction caused by the rapid expansion of the gas near surface.

    - Friction in and around the drill string; and at the leak point (e.g. at a hole in the wellhead, or along a fissure through the cement or formation).

- Formation collapse anywhere in the open hole section and, especially in any weak zones below the casing shoe.

- Hydrate or wax deposition at low flow rates.

- Piping configurations and surface choking.

6. In estimating the maximum possible oil spill, the operator needs to define the time required to cap a well from surface, as well as relief well drilling times.

EXECUTIVE SUMMARY

This study forms part of the Beaufort Sea Steering Committee Task Group Number 1's effort "to create a generally acceptable procedure for developing and estimating the potential cost of a "worst case" scenario".

Previous studies had shown that the probability of an uncontrolled oil well blowout involving more than 20,000 m^3 (125,800 bbls) of oil in the Beaufort Sea is significantly less than the 1 in 10,000 wells implied from historical data. While potential blowout rates in the Beaufort had been estimated at between 1000 m^3/d and 6500 m^3/d, duration was expected to be limited by hole collapse, or by control from surface.

Updating these studies with more recently published data indicates that the trend of a decreasing frequency of exploration well blowouts is continuing; and confirms that oil well blowouts are much less common than gas well blowouts.

On a worldwide basis, the majority of blowouts have commenced during drilling operations, as a result of unexpected high pressure kicks, abnormal pressures or lost circulation. These factors are unlikely to cause kicks during the drilling of sandstones in a relatively well known geological and depositional environment, such as the Beaufort. The most probable scenario for a well control situation getting out of hand in the Beaufort is, therefore, an equipment failure after swabbing in a gas zone during a trip. This implies that the drillpipe will still be in the hole, at least to the depth of the gas zone.

Since most Beaufort wells involve normal pressured sandstone reservoirs with shallow dips and relatively short hydrocarbon columns, they should be classified as having a low blowout risk. Even the deeper wells, which penetrate the overpressures, would only be ranked as a moderate risk, especially since permeability deteriorates rapidly with depth. High risk features (such as fractured carbonates; extreme pressures and temperatures; and sour gas) are rarely encountered in the Beaufort, significantly reducing the probability and complexity of any blowout.

Most blowouts are quickly controlled from surface, many in less than 1 day. A substantial number of wells kill themselves by bridging-off or by increasing water production. Less than 5% of oil blowouts require the drilling of a relief well. Therefore, it seemed logical to examine two blowout scenarios:

i) A high rate, short duration event controlled from surface or by formation collapse.

ii) A low rate, long duration event requiring a relief well.

In the hypothetical example considered in this report, the first was found to result in the more significant spill volume.

In a drilling well, the open hole, the mudcake, the cement around the casing shoe, the casing string, the wellhead and the blowout preventors (BOP's) form a pressure vessel to contain the well pressures involved with circulating-out a kick. The critical area in this system is usually the shoe strength, which determines the optimum casing setting depth.

In sandstone formations, the greatest risk with respect to a long duration blowout is posed by:

i) Fracturing below the shoe of the surface casing.

ii) A leak through the BOP or wellhead.

Both of these events impose a natural choking of the resultant flow, but may require a relief well to be drilled.

The length of the open hole section and the type formations encountered are critical in assessing blowout behaviour, since they will determine the inflow performance and fluid types; the probability of hole collapse; and the shoe strength.

Once well control has been lost, the well will behave in a similar manner to any flowing well and is analyzed using the principles of Well Deliverability Prediction. Each well has its own unique capabilities depending on reservoir properties, depth, piping configurations and surface choking. Since the well is part of an interdependent system, well deliverability prediction involves separately evaluating the Inflow and Outflow Performance and then finding the common operating conditions, where the two curves intersect.

Although the theoretical inflow performance of a single zone can be described reasonably well using the Darcy Radial Flow Equation, there is considerable uncertainty over the estimation of certain key terms, such as effective permeability (k), the contributing net pay zone thickness (h), and total Darcy and Non-Darcy Skin (S'). The degree of Formation Damage (or Skin) to be expected in a drilling well is critical, and it will certainly be higher than that seen in a well test.

To develop a realistic model of a blowout, the inflow performance relationship (IPR) for each fluid type in each permeable zone must be estimated and combined to define not only the total inflow potential but also the expected water cut and gas liquid ratio.

Review of the gas zones is critical in modelling blowouts because of:

- the higher mobility of gas within the reservoir rock
- the high density contrast between the gas and well fluids
- the friction effects caused by the rapid expansion of the gas at surface

In fact, the gas expansion near surface will control not only the well rate but also the back-pressure on the formation. Thus, oil wells producing at the solution gas oil ratio could achieve higher oil and water blowout rates than the higher risk wells that contain gas zones.

Because of the complexity and the number of assumptions involved in developing a theoretical inflow model, a pragmatic approach using the summation of the offset well tests, adjusted for the anticipated open hole interval, is quite reasonable for the poorer zones. However, this approach will tend to underestimate the influence of non-Darcy skin and overestimate the capacity of the better wells.

The outflow performance during a hydrocarbon blowout is dominated by the friction effects and will, therefore, depend on the piping configuration and the leak path geometry. It is unrealistic to assume that a well would blowout through unrestricted casing, in a Beaufort type environment. Therefore, the highest flow rates will likely be associated with a blowout through the drill pipe, or through a damaged side-outlet to the wellhead or BOP.

The flowing bottom hole pressure, achieved during the blowout, will also determine the tendency for the formations to collapse and bridge-off the well. This may occur not only in the pay zone, but also, more probably, in the weak formations further uphole. Other studies have shown that most Beaufort sands will collapse at drawdowns of 3 MPa. High drawdowns may occur at the start of a blowout because of the high degree of drilling damage caused by the mudcake and filtrate; and will occur in wells with less developed pay zones. Thus, the key issue in developing a worst case blowout scenario is NOT the determination of a minimum bottomhole pressure or an Absolute Open Flow Potential (AOF), but the definition of plausible cases where the drawdown will be less than that which will induce formation collapse.

Low rate blowouts, especially those around the outside of the casing, or through a restricted flow path, may also plug themselves off by hydrate formation or wax deposition.

Hypothetical field studies developed in this report suggest that:

- Even in high permeability, thick pay zones, the most probable blowouts will likely involve flow rates of less than 2000 m^3/d of total fluids (probably a combination of oil and water); and much lower rates would be expected from poorer intervals, or if the blowout path was through fractures around the well.

- The time required for a surface kill or capping operation may be needed to estimate the maximum possible oil spill from a blowout. This is likely to be location and well specific, but, in most cases, will be less than a week.

- The 1:10,000 well event will likely involve an oil spill of significantly less than 20,000 m^3.

Estimation of a Realistic Worst Case Blowout Scenario is, therefore, an extremely complex task involving the interrelationship of many factors and the use of substantial engineering judgement, which will be well and field specific; and their development should be left to the individual operator. Nevertheless, using the methodology presented in this report, it is possible to develop, with a reasonable level of confidence, a site specific, worst case oil spill estimate.

1.0 INTRODUCTION

An operator wishing to drill an exploration well in the Beaufort Sea may be required to assess the effects of a blowout, often termed "A Worst Case Scenario". There are presently no guidelines for a methodology to calculate the flow rate and duration of such an event. This has caused some inconsistency regarding this issue, and lead to this becoming a major concern with respect to exploration drilling in this area.

As part of an effort to resolve this, and other major issues concerning drilling operations in the Beaufort, the Beaufort Sea Steering Committee was formed in September, 1990 (Reference 1.1). The committee, chaired by Mr. Robert Hornal reporting to the Federal Minister of Indian Affairs and Northern Development, appointed 7 major task groups to address the specific issues. The various stakeholders were represented on each task group as required. The key operators in the area were represented through the Canadian Petroleum Association (CPA).

The aspect of Blowout flowrate analysis was tabled under Task Group #1 which was asked *"to create a generally acceptable procedure for developing, and estimating the potential cost of a 'worst case scenario".*

As part of this effort, the CPA representatives on this Committee requested Adams Pearson Associates Inc. to prepare a study on "A Recommended Philosophy for Development of a Worst Case Blowout Scenario for Wells Drilled in the Beaufort Sea". The objectives of this study, discussed with the CPA Task Force members on January 16th, 1991 were :

1. To develop a methodology for determining scenarios for worst case blowouts in the Beaufort Sea, including factors that may limit the rate and duration. Two scenarios will be considered - a maximum rate short duration event and a long term limited rate event. Geological and reservoir factors controlling the probability and magnitude of a blowout will be discussed.

2. To prepare example calculations to illustrate the method and to quantify the risks.

3. To prepare a discussion document providing the technical background to the proposed approach and the problems in developing such a scenario.

4. To prepare an executive summary.

The study was formally commissioned on January 23rd, 1991; the draft report was submitted on March 1st, 1991 for review by the CPA task group; and a final report was issued on March 19th, 1991.

Both industry and government had previously completed a number of reports on the subject of the probability and contingency plans for a blowout in the Beaufort Sea. These are reviewed and extended in Chapter 2, and had previously been summarized in a discussion paper issued by COGLA in August 1990: "The Prospect of an Oil Well Blowout in the Beaufort Sea" (Reference 1.2). This paper concluded that:

> *"It is COGLA's contention that the requirements for a high standard of equipment, personnel, and regulatory compliance suggest that the probability of an uncontrolled oil well blowout occurring in the Beaufort Sea is significantly less than. that implicated by the incidence of 1 in 10,000 developed from historical data bases."*

The discussion paper also points out that most oil blowouts are very short in duration and involve the release of less than 20,000 m^3 of oil.

These previous studies clearly show how risks are mitigated by the Canadian operators using the very best equipment, personnel and practices; and operating under strict regulatory requirements and inspections. Implicitly, the reports also identify the geological differences between the Beaufort and those areas where the most severe blowouts have occurred. This is a significant factor, which is discussed in more detail in Chapter 3 of this report. On this basis, **most Beaufort Sea wells should be classified as having a low blowout risk.**

Chapter 4 discusses the theory controlling well behaviour during a blowout, including mitigative factors such as flow path friction, surface choking, hole collapse, hydrate formation and wax deposition. However, it must be emphasized from the outset that the development of a worst case blowout scenario is an extremely complex and site specific issue. Although the industry has a basic theoretical description for the mechanisms involved, much of the required input data is unknown, especially during the exploration drilling phase. The process, therefore, must rely heavily on engineering judgement. Moreover, given the complexity and uncertainties, there is considerable room for a pragmatic approach that uses available offset well test data to quickly define an upper limit.

It is apparent that one reasonable mitigative provision that can be assumed in analyzing a worst case blowout is that the flow conduit will be restricted, so that friction will limit the maximum blowout rate. It will also be shown that, while the existence of gas zones will increase the blowout risks, the high velocities resulting from gas expansion will limit the resultant oil rates and spill potential.

Chapter 5, discusses the data sources that can be used to develop a reasonable reservoir-geological prognosis for building a field or well specific worst case scenario.

The recommended approach is illustrated in Chapter 6 for a completely hypothetical field with two major, well developed reservoirs both containing an oil rim below a gas cap. The results showed that quantification of the maximum oil spill depended more on the time required to cap a high rate blowout from surface, than on the time needed to kill a more complex, low rate blowout with a relief well.

The blowout volumes estimated in Chapter 6 are in agreement with earlier estimates that the 1:10,000 well event is likely to involve an oil spill of less than 20,000 m^3 (126,000 bbls) even in a highly productive formation; and that, in less well developed or shallower zones, the blowout rates and spill volumes are likely to be substantially lower.

2.0 BACKGROUND

2.1 Summary of Previous Environmental Submissions

To date, there have been two submissions made to the Environmental Impact Review Board, under the terms of the Inuvialut Final Agreement (IFA) (Reference 1.3).

1) Esso Resources Canada Ltd. submission in 1989 to drill Esso Chevron et al Isserk I-15.

2) Gulf Canada Resources Ltd. submission in 1990 for the Kulluk Drilling Program 1990-1992.

Both of these submissions highlighted the remote probability of an uncontrolled flow to surface on the grounds that:

a) the geology was well known and defined by good well control.

b) severe overpressures were not expected in the well developed sands. (The Gulf wells would penetrate the deeper overpressured zones; however, their flow potential would be limited by "significant loss in reservoir porosity, permeability and sand quality that occurs with depth".)

c) dips were low and no long gas columns could be expected.

d) the depth pressure trends were well defined.

The major difference between the two submissions was in the estimation of the maximum possible hydrocarbon flow rates during a worst case blowout:

1) Esso selected 1000 m^3/d (6300 b/d), a rate that was twice as large as the test results in nearby offset wells.

2) Gulf selected a stabilized oil rate after 24 hours of 6500 m^3/d (40,900 b/d) based on theoretical simulation model studies of a blowout from the Lower Pullen at Amauligak prior to setting the 178 mm (7") liner. However, Gulf maintained that this

> was a purely hypothetical number and that, for the purposes of assessing the risk of the project, a "more realistic case" would be 320 m^3/d (2000 b/d), based on historical data from the Gulf of Mexico.

In their comments on areas of concern with the Gulf submission, the Environmental Impact Review Board (EIRB) implied a willingness to consider a "more probable case" provided that it was based on the deliverability potential of the Pullen Delta wells (Reference 1.4).

As discussed by COGLA in Reference 1.2, and the EIRB in Reference 1.4, Gulf had also provided studies showing that this rate could not be sustained, not only because of reservoir depletion, but also because it would lead to natural bridging as a result of sand collapse.

Since the COGLA Reservoir and Production Division support the conclusion that "a well drilled through one or more of these (Pullen Delta) formations will shut itself off, should a blowout occur", the key issue appears to be the estimation of a sustainable blowout rate that has a definable probability of occurrence. To address this, it is pertinent to look at the probability of having an oil well blowout.

2.2 Review of Previous Reports on Blowout Frequency

2.2.1 Overview

Several studies have been conducted in the last 13 years to predict the probability of a blowout, including blowouts during exploration drilling. The three main data banks utilized are the ERCB data covering land drilling in Alberta (1900-1989), world-wide offshore data (1955-1980), and Norwegian Continental Shelf Data (1976-1980). The ERCB data has been broken up into several periods and utilized in several different studies. In addition, the MMS (1956 - 1986) Gulf Coast data bank, which combined blowouts during drilling, completions, workovers and production, was used in a limited sense to determine the probable duration of a blowout in a sand prone, offshore area.

Although there are many problems with existing worldwide data, such as non-standardization, incompleteness, and discrepancies among different sources in the same area, the data does provide some useful statistics for blowouts. Data collection and analysis has improved significantly over the past 10 years thus making the recent data more informative. Modern database computer programs allow quick analysis of blowout trends.

The following studies have been summarized below:

Author	Date	Wells Covered	Years Covered	Reference
F.G. Bercha	1978	ERCB (land)	1900-1978	-
Gulf R&D	1981	Offshore Worldwide	1955-1980	2.3
SRI Norway	1983	Offshore Norway	1976-1980	2.4
Manadrill	1985	All of above	All of above	2.7
Manadrill	1985	Canada Lands**	1962-1984	2.7
MMS (USA)	1988	Gulf Coast	1956 - 1986	2.8
CPA/IPAC	1989	Summary of Above	1955-1989	2.9
COGLA	1990	Summary of Above	Summary	2.12
W.W. Wylie	1990	ERCB (land)	1979-1988	2.11
ERCB Rep. 90-B	1990	ERCB (land)	1975-1988	2.13
Neal Adams	1991	Worldwide	1966-1990	2.14

** Canada Lands roughly includes Government owned lands in the northern territories as well as subsea lands 200 nautical miles from Canada's coasts.

The following parameters have been cited as being important in affecting blowout frequency:

- gas vs. oil
- kick frequency
- exploratory vs. development well
- well depth
- experience in the region
- lithology
- state of technology
- offshore vs. onshore
- regulatory requirements
- environmental conditions

It is important to keep in mind the assumptions that underlie the statistical information provided by the various studies as presented below. Also, note that a blowout can include spills ranging from a few hundred barrels of crude oil to several million barrels.

2.2.2 Manadrill Study (1985)

The Manadrill study (Reference 2.7) provides a good summary of the three previous studies, Bercha (1978), Gulf R&D (1983), and SRI Norway (1983), as well as an analysis of the relatively few wells drilled on Canada Lands (COGLA's jurisdiction).

A summary of **blowouts during exploration drilling** is as follows:

	ERCB Land 1974-1983	Gulf Offshore 1955-1980	Norway Offshore 1976-1980
# exploration wells	20,000	11,737	4,175
# blowouts	14	96	32
frequency	1/1430	1/120	1/130

Historically, the frequency of offshore blowouts is about 10 times higher than onshore. Explanations offered include: (1) higher abnormal pressures offshore, (2) drilling units change areas and, therefore, crews more frequently offshore, (3) remote location of subsea well control equipment, (4) the higher level of experience in the Western Canada basin given the larger number of wells, (5) the effect of sea state on floating rig kick detection equipment.

Also, the blowout frequency on an exploration well is about 3 times that of a development well. Drilling a well into an unknown area definitely increases the risk of a blowout. However, it is important to note that exploration wells tend to be deeper than development wells and blowout frequency increases with depth, as will be shown at the end of this section. Also, many of the development wells in the ERCB data are shallow heavy oil or bitumen wells which have negligible risk of blowout.

Since oil blowouts are of far more environmental concern than gas blowouts, a summary of the **oil well blowouts** is provided below.

	ERCB Land 1900-1983	Gulf Offshore 1955-1980	Manadrill Interpretation of Gulf Offshore Data 1955-1980
# wells	97,000	36,633	36,633
# blowouts	63	162	162
# oil blowouts	8	N/A	12
% blowouts that are oil	12.7%	N/A	7.4%
oil blowout occurrence	1/12125	N/A	1/3052
# major oil blowouts	1	N/A	5
major oil blowout freq.	1/97000	N/A	1/7325
major oil blowout as a % of total blowouts (>7950 m^3)	1.6%	N/A	3.1%

Manadrill had to amalgamate data from two offshore studies to obtain an interpreted estimate of oil well blowouts. Overall, the results indicate that a very small percentage (7.4 -> 12.7%) of blowouts actually release oil. Furthermore, only an extremely small percentage (1.6 -> 3.1 %) of blowouts release a large amount (>7950 m^3) of oil. It is important to note that 4 out of 5 of the offshore oil blowouts occurred in Mexico, Nigeria, Iran and Saudi Arabia, countries which do not have the high safety standards, nor the expertise, that exist in Canada.

Another important consideration is the **well kill mechanism** used to control the blowout. A summary is provided below.

	ERCB Landwells Alberta 1900-1983	Gulf Offshore Worldwide 1955-1980
# of wells	97,000	36,633
# of blowouts	63	162
Wellkill Mechanism		
self-bridging	87%	35%
surface killed		58%
relief wells	13%	7%
Relief Wells: oil blowouts		
requiring relief wells	2	2
% of total blowouts	3%	1%

The results indicate that 35% of offshore blowouts will bridge off due to caving in of the formation. It is important to note that self-bridging is very dependent on the formation types encountered in the well that experiences the blowout. Poorly consolidated sands tend to cave-in easily and hard carbonates do not. Hence, the 35 % could indicate the fraction of wells that happened to have poorly consolidated sands.

The percentage of relief wells required to stop blowouts is quite low, ranging from 7 to 13 %. For oil blowouts, it is even lower, 1 to 3 %, indicating that oil blowouts are easier than gas blowouts to bring under control from surface.

Manadrill also presented some data on <u>blowout frequency on Canada Lands</u> since 1962. The number of wells is relatively small. The data is summarized as follows:

	ERCB Landwells Alberta 1974-1983	Canada Lands Landwells 1962-1984	Gulf Offshore 1955-1980	Norwegian Offshore 1976-1980	Canada Lands Offshore 1966-1984
# wells	51,000	453	36,633	11,116	293
# blowouts	20	2	162	46	3
blowout freq.	1/2550	1/226	1/225	1/240	1/98

It is important to note that three of the Canada Lands blowouts produced gas and water, and the other two produced water. Two of the offshore blowouts in the Beaufort, which produced water, occurred during the first season of floating drilling systems when experience was lacking. Also, the two land blowouts occurred early in the frontier exploration era. Taking these factors into consideration, along with the relatively small sample size, the Canada Lands blowout statistics are similar to worldwide, but not the Alberta data.

The Manadrill data is summarized in Table 2.1. It is interesting to note that Bercha and Associates indicated that, based on their estimation and from their contacts, the Alberta blowout statistics generally reflect blowout incidence on a world basis.

2.2.3 Norwegian Ship Research Institute (NSRI) (Dahl et al) Study (1983)

In addition to the data incorporated into the Manadrill report, the NSRI study (Reference 2.4) contains some useful statistics for 172 offshore blowouts, of which 49 % occurred during exploratory drilling. Note that the statistics provided below include blowouts during drilling, completions and workovers.

Regarding the **cause of blowouts**, the following statistics were provided:

unexpected high pressure kicks	50%
swabbing	28%
lost circulation	9%
other	13%

Regarding the **path taken by fluids**, the following statistics were provided for 61 of the offshore blowouts:

	# blowouts	%
thru drillpipe/tubing	17	28%
thru BOP/inner annulus	27	44%
thru wellhead	5	8%
outside casing	12	20%
totals	61	100%

No breakdown was given on the number that were oil wells nor on amount of oil released. Failure of the BOP to close is recorded as the main factor (50%) responsible for BOP/inner annulus blowouts.

A major issue is the role of human error in causing blowouts. The NSRI defines human error in the broad sense to include improper planning, inadequate testing of equipment, and poor maintenance. The following statistics summarizes their findings:

1.	Inattention to operations	18%
2.	Inadequate supervision/work performance	12%
3.	Improper maintenance of equipment	31%

4. Improper installation/inspection 6%
5. Inadequate testing 2%
6. Inadequate documentation 2%
7. Improper method/procedure 6%
8. Improper planning 12%
9. Sabotage -
10. No direct human error involved 10%

Hence, improper maintenance of equipment and inattention to operations are cited as the main causes of offshore blowouts.

2.2.4 MMS Gulf Coast (1986)

The U.S. Department of the Interior Minerals Management Service (MMS) published details on 145 US Gulf Coast blowouts from 1956 - 1986 (Reference 2.8). Unfortunately, the data combined blowouts during drilling, completions, workovers and production. However, the report provides some useful statistics on self-bridging, since, like the Beaufort, the Gulf Coast reservoirs are mostly poorly consolidated sands. Also, the report provides some interesting data on blowout duration and the time required to kill the well.

The statistics regarding blowout duration are as follows:

	Frequency	%
≥ 1 month	13/145	9
1 week to 1 month	15/145	10
1 day to 1 week	31/145	21
≤ 1 day	86/145	60

Hence, 81% of blowouts are controlled within one week and 91% were controlled within one month. The report also shows that only 4% of all blowouts released significant quantities of oil (100 and 10,000 m^3) into the environment.

With regards to the mechanism by which the well was killed, the following statistics were compiled from the report:

Kill Mechanism	Frequency (%)	Blowout Duration (Days)	
		Mean	Standard Deviation
Relief Wells	6.2	64.7	48
Pumping Kill Fluid	20.7	6.8	11.3
Installing Valves/Capping	7.6	5.5	11.7
Closing Valves or BOP	9.0	0.4	0.4
Died Due to Pressure Loss	4.8	6.5	6.2
Self-Bridged	46.2	4.9	18.1
Miscellaneous	5.5	-	-

Hence, 46% of the wells self-bridged, while 6.2% of the blowouts required relief wells. **The vast majority of blowouts (81 - 94%) are killed within one week from surface or by self bridging, while the average time to kill a well using relief wells is 65 days.** These durations are in agreement with other estimates elsewhere, and have therefore been used in Section 6 for the blowout duration in the hypothetical field worst case scenarios.

2.2.5 CPA/IPAC (1989)

In a report entitled "Oil Preparedness in the Upstream Petroleum Industry" (Reference 2.9), blowout probabilities for large offshore oil spills (>1600 m^3) were estimated based on worldwide offshore data. The report indicated that only three large oil spills occurred offshore worldwide during exploration drilling and that Canada has never experienced a major offshore oil spill (>24,000 m^3). The three spills are as follows:

1.	Mexico	477,000 m^3	1979
2.	Saudi Arabia	9,500 m^3	1980
3.	Mexico	8,900 m^3	1987

Note that two of these spills occurred in Mexico, a country which does not have the same quality of standards as Canada. All three of these wells likely involved high permeability and relatively stable carbonates that pose much more severe well control problems than the poorly consolidated sandstones that exist in the Beaufort, as discussed in Section 4.5.

This report indicated that, based on worldwide offshore statistics and a drilling rate of 24 wells per year, the chances for a large oil spill range from 1 in 300 years to 1 in 1000 years. This indicates that the chance for a large oil spill in the Beaufort is negligible.

2.2.6 COGLA (1990)

The COGLA report (Reference 2.12) is an overview of the previous reports to estimate the chances of a major oil blowout in the Beaufort Sea. The report concludes that the probability of a major offshore oil blowout in the Beaufort Sea is 1/10,000. This is obtained by taking the ERCB statistic of 1/97,000 for a major oil blowout for land wells and multiplying it by 10 to account for the factor of 10 higher probability of a blowout offshore. The offshore data discussed by Manadrill indicated that there is an order of magnitude greater chance of a blowout offshore than on land. The COGLA reasoning is discussed in more detail in Section 2.3

2.2.7 Wylie et al (ERCB) Study (1990)

Wylie et al recently published an SPE paper (Reference 2.11) which presents kick and blowout statistics on ERCB data (land wells) for the years 1979-1988. There were 22 blowouts during this period, 12 occurring on exploratory wells.

A summary of the **blowout and kick frequencies** are as follows:

	ERCB 1979 - 1988	
	Exploration Wells	**Development Wells**
# wells	18,947	43,685
# blowouts	12	10
# blowouts/well	1/1580	1/4370
# blowouts/kick	1/90	1/138
# kicks/100 wells	5.7	3.2

Hence, the frequency of an exploratory well kick is 1.8 times greater than a development well kick, but the frequency for an exploration well blowout is 2.8 times greater than for a development well blowout. This factor of 2.8 is lower than the 3.6 suggested by the

Manadrill (1985) report. The reason for this is that the heavy oil and bitumen development wells were not included in this study, but were included in the Manadrill study.

The **kick rate versus depth statistics** are provided below.

	Based on Depth of Kick (#kicks/100 wells)		Based on Depth of Well (# kicks/100 wells)		Well Depth Distribution (%)	
Depth	**Exploration**	**Development**	**Exploration**	**Development**	**Exploration**	**All**
0-1000 m	1.9	1.8	2.6	2.3	39.4	51.5
1001-2000 m	3.0	2.3	5.3	4.3	41.5	35.5
2001-3000 m	5.5	5.0	6.8	6.1	14.0	10.9
3001-4000 m	12.8	11.3	23.2	19.9	4.7	2.1
>4000 m	24.5	22.9	54.0	54.0		

These results indicate that well depth and kick depth play a major role in kick frequency and therefore blowout frequency. It is interesting to note that exploration wells are usually deeper than development wells and this partially explains the higher blowout rate for exploration wells. However, the lack of experience in an area is the primary reason exploratory wells have a higher blowout frequency.

The **cause of the 12 exploration blowouts** are summarized below.

	# blowouts	**%**
during drilling	6	50
lost circulation	4	33
abnormal pressure	1	8
improper use of equipment	1	8
totals	12	99

2.2.8 ERCB Updates (1989)

The ERCB publishes yearly updates on all blowouts and kicks and each report contains a summary for the past decade. However, the same results are presented more systematically in a special report prepared by ERCB, as summarized in the next section.

2.2.9 ERCB 90-B (1990)

A special study was performed by the ERCB entitled "Risk Approach: An Approach for Estimating Risk to Public Safety for Uncontrolled Sour Gas Releases" (Reference 2.13). A part of this study was dedicated to risk assessment of blowouts and a detailed analysis of ERCB data for Alberta land wells for 1975-1988.

A **summary of the blowout data** is provided below.

# wells	83,786
# blowouts	28
blowout frequency	1/2992
# kicks	2918
# kicks/100 wells	3.48
# blowouts/kick	1/13

A breakdown between **development and exploration** wells is provided below:

Depth (m)	Development	Exploration	Exploration/Development
0 - 1000	57%	28%	-
1001-2000	33%	50%	-
2001-3000	9.2%	17%	-
3000-4000	4%	0.7%	-
>4000	1%	0.1%	-
kick frequency	1/26	1/19	1.4
blowout frequency	1/3610	1/1698	2.1

Again we see that exploration wells are drilled deeper and have a greater blowout frequency. However, because the shallow heavy oil and bitumen wells were left out, the ratio is not as large as indicated in the Manadrill report.

2.2.10 Neal Adams Firefighters - Blowout Control Database

Neal Adams Firefighters, Houston (Reference 2.14), a company experienced in the causes and control of oil and gas well blowouts, was canvassed during the preparation of this report and provided statistics from their database.

The statistics have been separated into the past decade (1981 - 1990) and the 15 years preceding (1966 - 1980) to analyze for any trend changes which may be attributable to factors such as improved training and technology.

Neal Adams Firefighters Blowout Control Database	Exploration Wells	
	1966 - 1980	1981 - 1990
# of blowouts	140	74
# of blowouts/year	9.3	7.4
# of oil blowouts	3	4
percentage of blowouts that were oilwells	2%	5.4%

The frequency of exploration well blowouts has declined from 9.3 wells per year during the period 1966 - 1980 to 7.4 wells per year during the period 1981 - 1990.

During the past decade, 5.4% of the exploration well blowouts have been oilwells. **The flow duration for each of the four oilwell blowouts was one day or less.**

Neal Adams Firefighters are also currently preparing the study "Joint Industry Program For Floating Vessel Blowout Control", DEA-63. This project currently involves some 14 oil operating companies and four governments as participants.

2.3 Discussion of Blowout Statistics

The prime objective of this section to provide the reader with a proper perspective of the risks of blowouts. Applying the statistical data from previous wells from different operating theatres to a specific operating theatre, such as the Beaufort, raises some legitimate concerns. These concerns are:

1) The worldwide offshore blowout statistics include countries where drilling practices are inferior to those applied in Canada, particularly in the Arctic. The statistics are heavily weighted by blowouts in such countries.

2) Considerable drilling experience already exists in the Beaufort, thus reducing the risk associated with a lack of data.

3) Technology is improving at a rapid pace, particularly with weather forecasting, measurement while drilling, early kick detection, fluid loss control, expert systems, automation, redundant back-up systems, improved training facilities and quality control. The older statistics do not reflect these trends.

4) The worldwide and Alberta data do not reflect the specific characteristics of the Beaufort reservoirs that will restrict release rates, such as wax and hydrate formation due to cold surface temperatures, or poorly consolidated reservoir rock which will likely self-bridge, or abundant high permeability water sands.

5) The statistics do not isolate key factors such as the separate effects of depth and experience in the area, both of which seem to increase the blowout risk in exploration wells.

6) The statistics do not fully account for volumes released. Most of the blowouts cited resulted in small releases.

In light of these concerns, the blowout probabilities given in the previous section are likely to be upper bound or conservative predictions.

A significant improvement in blowout prediction will occur as the contributing factors are more accurately quantified with better risk analysis tools. The ERCB report 90-B (1990) provides an initial step in this direction. The ERCB Fault Tree Analysis (FTA) technique focuses on one particular event and provides a logical method for determining potential causes and probabilities of the event occurring. However, accurate historical data is still required in order to perform the risk calculations.

In absence of such a model, blowout frequency must be predicted using the most current methods as discussed in the next sections.

2.3.1 Predicting a Gas Well Blowout

To predict the upper bound on the probability of a gas blowout in the Beaufort, one should use the Norwegian offshore worldwide data (1976-1980) since the North Sea probably best represents the Beaufort, although it has a high frequency of severe overpressures. The following statistics should be used.

Probability of a blowout	1/240 wells
Percent which are gas blowouts	92.6%
Probability of a gas blowout	1/260 wells
Percent that require relief wells	7%
Probability of a relief well	1/3700 wells

This indicates that the chances of having to drill a relief well in the Beaufort to control a gas well are quite low.

2.3.2 Predicting a Large Oil Spill

To predict an upper bound on the probability of a large oil spill (20,000 m^3) due to a blowout during exploratory drilling, the method employed by the CPA/IADC (1989) is recommended. The following statistics should be used.

probability of a blowout	1/240 wells
percent that are oil blowouts	7.4%
probability of an oil blowout	1/3243 wells
percent that require a relief well	1%
probability of a relief well	1/324300 wells
probability of an oil blowout leading to a large spill	1/10,600 wells

Hence, even for an increased drilling rate of 10 wells/year, the chances of an oil blowout leading to a large spill are less than 1 in 1000 years. This indicates that **it is very unlikely that a significant oil spill will occur in the Beaufort. Moreover, even if a blowout does occur it is highly probable that self-bridging hydrates and wax will help in restricting flow.**

2.3.3 Predicting Blowout Duration

Using the MMS US Gulf Coast data, it is apparent that most blowouts are short duration events that are controlled from surface or by self-bridging. The following estimates can therefore be used for duration:

Short Duration Blowouts	< 7 days
Long Duration Blowouts	< 65 days

3.0 REVIEW OF POTENTIAL BLOWOUT SITUATIONS

Blowouts occur as a result of a loss of well control, while the well is "live". The well can only become "live" if there is a permeable section within the open hole and if the head of fluid in the well is less than the reservoir pressure. This is done to induce flow during testing or production. However, here, we are concerned with situations where the well inadvertently becomes live. These are termed "well kicks", and are handled with normal well control procedures through the BOP's.

"Good Oilfield Practices" ensure a secondary line of defence against hydrocarbon emission on all wells at all times! In a drilling situation, the secondary line of defence consists of four sub-systems:

1) the blowout preventors (BOP's)
2) the casing string
3) the cementation at the casing shoe
4) the formation strength between the casing shoe and the permeable zone.

For a well to blowout, there must be a failure of one of these secondary lines of defence, during a well control operation.

It is, therefore, pertinent to consider how well kicks occur and the causes of failures in the secondary line of defence.

3.1 Causes of Well Kicks

The well can inadvertently become live for two reasons:

1) Insufficient Fluid Density
   - Drilling into overpressured zones with insufficient mud weight.
   - Loss of mud properties allowing settlement of weighting materials.
   - Thermal expansion of the well fluid reducing the average density.
   - Deliberate use of low density drilling completion or treating fluids.

2) Insufficient Fluid Column Height
   - Massive loss of drilling fluid to either natural or induced fractures in the formation.
   - Swabbing of the wellbore fluids from the well during tripping.
   - Loss of clear fluids into permeable zones.

Obviously, the most serious problems occur if a well kick and losses occur simultaneously. **The potential for a kick-loss situation is greatest in vugular or highly fractured carbonates**, where the fractures or vugs are so large (1 mm - 100 mm) that it is difficult to bridge them. This was the situation in the Ixtoc-1, Atlantic No. 3, Lodgepole, Arun and probably several of the Middle East blowouts. However, this type of lithology is rarely encountered in the Beaufort Sea.

In sand/shale sequences, the mud particles are unable to migrate far into the formation due to bridging effects, because the pore throats are only 0.001 to 0.1 mm in diameter (and usually < 0.03 mm). Therefore, a kick-loss situation usually involves losses into fractures at the casing shoe or a highly depleted zone. The casing scheme and well control plan are designed to avoid such situations. Thus, this type of serious problem generally only develops as a result of mishandling a kick or as a result of a poor well design. (The latter being unlikely in the Canadian Frontier context with experienced operators and strict regulatory supervision).

In normal pressured 9 - 11 kPa/m (0.4 - 0.5 psi/ft) sandstone formations, the most probable cause of a severe well kick is swabbing gas in during a trip. With modern fluid metering systems, such swabbing will normally be detected before a significant hydrocarbon influx can occur. If the influx is so small that it is not detected until logging or casing running is in progress, the resulting shut-in pressures are generally low, allowing pipe to be striped into the well.

A blowout will, therefore, only occur if a routine well kick is mishandled by poor control of circulating pressures; attempts to run to bottom before closing in the well and circulating the kick out; or mishandling of an internal blowout (where fluids are cross-flowing between zones). As has been discussed previously (References 2.7, 2.12), this is unlikely with the highly trained, well supervised crews and sophisticated monitoring systems used in Canadian Frontier operations.

However, it is possible to develop high wellhead pressures from the annulus becoming partially gas filled during the well control operation and equipment failures or human errors may occur at that point. Therefore, blowouts are feasible, but are improbable and highly infrequent events in sand-shale sequences.

Gas kicks and blowouts are much more frequent than those from oil zones, especially if the system is overpressured. This is because the gas is much more mobile than other reservoir fluids because of its low viscosity; and, once in the wellbore, there is a much greater density difference between the gas and water (> 8 kPa/m) than between live oil and water (< 4 kPa/m).

3.2 Causes of Blowouts

There are essentially six common causes for blowouts:

1) Unexpected Well Conditions, such as a sudden change in pressure regime (at an unconformity for example), or lithology (e.g. penetrating a fractured carbonate). This is usually restricted to rank wildcat exploration wells.

2) Design Errors, such as having too much open-hole for the shoe strength; or non-sour spec materials exposed to H_2S.

3) Equipment Failures, such as valves becoming plugged by solids or hydrates, control system malfunctions or manufacturing defects. The industry tries to minimize these by the inclusion of redundant back-ups and strict QA/QC procedures. For example, historically very few blowouts have been caused by burst or worn casing.

4) Human Errors, such as the operation of the incorrect valve, or a decision to try something that involves a high risk without fully assessing the consequences. These are minimized by training and close supervision.

5) War or Sabotage, unlikely in the context of exploration drilling.

6) Natural Disasters, such as earthquakes, landslides, forest fires, or ice impacts. In the exploration drilling phase, it is almost impossible to imagine this occurring simultaneously with a critical well situation. In the production phase, downhole safety valves are used to protect against such occurrences.

It is important to emphasize that, for a well kick to develop into a blowout, there must be a coincidental failure in the secondary line of defence, primarily caused either by human error or by equipment failure.

3.3 Classification of Risk Based on Well Type

Based on the above discussion, exploration well risks can be ranked as shown in Table 3.1. In this analysis, Level I represents the highest risk and Level VIII the lowest.

Typically, the normally pressured sand shale sequences that are the prime target for Beaufort exploration would classify in lower risk categories V to VIII.

3.4 Opportunities to Regain Well Control

As discussed in Section 2, very few blowouts result in substantial oil spills or are out of control for long periods of time.

The majority of blowouts (50 - 60%) are killed from surface. There are a number of mechanisms by which this can be achieved:

- Pumping into the drillpipe.
- Pumping into the casing.
- Repair of the malfunctioning equipment.
- Capping of the leak with a valve.
- Freezing of the wellhead area.
- Snubbing small diameter pipe into the well against the flow and killing the well by circulation.

A substantial number of blowouts (35%) kill themselves by natural bridging. This is particularly common in semi-consolidated formations, especially when there is a substantial section of open hole between the casing shoe and the blowout zone. The causes of this type of collapse will be discussed in detail in Section 4.

Reservoir pressure depletion terminates many shallow gas blowouts, but is not a significant consideration for deep blowouts from developable hydrocarbon accumulations.

Some 5 - 15% of blowouts require relief wells to be drilled in order to regain well control. This may occur when a fire has damaged the original drilling unit and prevents wellhead access, or when surface capping operations are not feasible. Although infrequent, the long duration of a blowout requiring a relief well clearly represents one of the worst cases that is of concern to the public and industry.

3.5 Definition of Two Probable Worst Cases

In sandstone formations, the greatest risk with respect to a long duration blowout is posed by:

i) Fracturing below the shoe of the surface casing.

ii) a leak through the BOP or wellhead.

Both of these events impose a natural choking of the resultant flow, but may require a relief well to be drilled. Other studies have considered the duration of a relief well drilling operation and concluded that, in the worst case operating period, 45 to 66 days might be needed (Reference 3.1). This is consistent with the 65 day average relief well kill estimate developed from the MMS data, which is discussed in Section 2.

Higher rate events may occur as a result of a combination of surface equipment failures, but these are likely to be of short duration, because either they can be controlled or capped from surface; or they lead to natural bridging due to downhole collapse. Events involving the simultaneous or sequential failure of two independent well control functions have a very low probability of occurrence.

Data from the DEA-63 data bank maintained by Neal Adams Firefighters (Reference 3.2) suggests most oil blowouts occurring on exploration wells in the last five years have been killed within less than 1 day. However, for planning purposes we have assumed that a surface capping operation may involve the mobilization of a team of well kill experts and, therefore, a high rate event could last up to a week.

4.0 DRILLING AND RESERVOIR MECHANICS

4.1 Characterization of a Drilling Well

A drilling well consists of four elements:

1) The Wellhead and BOP's
2) The Cased Section
3) The Open Hole Section
4) The Drill String

This general arrangement is illustrated in Figure 4.1. In this case, the drill bit is shown to be off bottom for a trip out of the hole, and to have swabbed in gas at the top of the pay zone. As discussed in the previous section, this is the most probable kick scenario for normal pressured sandstone formations.

The open hole, the mudcake, the cement around the casing shoe, the casing string, the wellhead and BOP form a pressure vessel to contain the well pressures involved with circulating out the kick. The critical area in this system is usually the shoe strength, which determines the optimum casing setting depth, and is the reason for performing leak-off tests.

The casing also isolates upper formations from becoming involved in the blowout by:

1) producing additional fluids
2) collapsing into the wellbore
3) acting as thief zones leading to an internal blowout
4) fracturing around the cement

The first two are potentially beneficial in restricting the rate and duration of the flow; and are the major cause of most blowouts killing themselves. The third and fourth effects potentially complicate the well control process and are a major concern in the casing design process and well control plan.

The existence of the drillpipe not only provides the main means of controlling a kick by circulating out the hydrocarbons, but also differentiates the two possible blowout paths as discussed in the preceding section. Modelling the flow during a blowout therefore involves evaluation of the hydraulics within the open hole section and either the annulus or drill string, both of which have variable diameters.

It is important to remember that, **while a kick is initiated from a single zone, once a blowout starts, all permeable zones placed under drawdown will contribute to the flow.** Therefore, the greater the open hole interval the larger the inflow capacity.

However, since most permeable zones are water bearing, this also results in a tendency for the well with a long open hole section to kill itself, provided it is in a normal pressured environment.

Overpressured zones (> 11 kPa/m), on the other hand, have the capacity to flow water to surface at substantial rates. Figure 4.2 is a typical depth-pressure plot showing how formation strength varies with pore pressure; and how casing is normally set before penetrating overpressures and to isolate underpressured or weak zones.

Because overpressures are more common at depth and are more difficult to control, there is a greater frequency of blowouts from overpressured zones. Moreover, the higher rock strength and compaction and the extensively cased section permit much greater drawdowns to be sustained on overpressured zones during a blowout. **As discussed in Section 3, the risks associated with drilling in severe overpressures is at least an order of magnitude greater than in normal pressured zones.**

To maintain well control, the wellbore pressure normally overbalances the formation pressure. This is feasible because the mudcake and filtrate (and casing) are designed to seal-off the near wellbore permeability. However, if the well pressure becomes too high, the resultant hoop stress in the borehole wall can become tensile. Rock is inherently weak in tension and, therefore, will "break down", allowing a vertical fracture to be initiated at right angles to the least principal stress. The drilling fluid will flow into the fracture and, because of the large surface area, may leak-off into the formation. This is the major cause of loss circulation in sand/shale sequences.

Lost circulation can also occur where the pore throats, vugs or fractures are so large that they are difficult to bridge with mud solids. This only occurs in carbonates, conglomerates, fractured basement and very high permeability sands (> 5D).

Since the maximum wellbore pressure occurs while circulating out a kick, lost circulation is not an uncommon complication to well control operations. However, this is most apparent in high permeability fractured or vuggy carbonates and when drilling through highly depleted zones which have reduced rock strength (Figure 4.2).

If a kick-loss situation is mishandled, it is feasible for the annulus to become hydrocarbon filled and for an internal or external blowout to develop as discussed in Section 3.

Once well control has been lost, the well will behave in a similar manner to any flowing well and is analyzed using the principles of Well Deliverability prediction. Each well has its own unique capabilities depending on reservoir properties, depth, piping configurations and surface choking.

In order to predict well deliverability, it is necessary to consider the well as a system. Each element of this system is related to the others and its performance is a function of both its own design and of the performance of other elements. Analysis and design work must consider the system as a whole, as well as the specific elements. With the ability to program these inter-dependencies into a computer, it has become vogue to term the process "Nodal Analysis" and to use simulation techniques to try and analyze production problems. If properly applied and analyzed, these techniques are enormously valuable and powerful.

The concept is based on the classic work by W.E. Gilbert and involves overlaying the **inflow performance relationship (IPR)**, or reservoir capability, with the **outflow performance capacity.**

These two performance capabilities are irrevocably coupled at the bottom of the hole. **Overall, well deliverability is predicted by calculating both the inflow performance and the outflow performance and then finding the intersection of the two performance curves.**

Further, more extensive background material can be obtained from the following textbooks and classic papers:

1. K.E. Brown, "The Technology of Artificial Lift Methods", PPC, Tulsa, 1980.

2. M. Golan and C.H. Whitson, "Well Performance" IHRDC, Boston, 1986.

3. IHRDC Production Video Modules (PE 102, 103, 104, and 301).

4. T.E.W. Nind, "Principles of Oil Well Production" McGraw-Hill, 1964.

5. W.E. Gilbert, "Flowing and Gaslift Well Performance", API 801-30H, 1954.

6. J.V. Vogel, "Flow Performance Relationships for Solution - Gas Drive Wells", JPT, January 1968.

7. K.E. Brown, "Nodal System Analysis of Oil and Gas Wells", JPT, October, 1985.

4.2 Principles Controlling Inflow

All producing wells, including wells with artificial lift, flow fluids through the reservoir and into the bottom of the well. Therefore, we define the bottom hole pressure under producing conditions as the **flowing bottom hole pressure** (FBHP or P_{wf}).

The **average reservoir pressure** (P_{avg}, $\overline{P}$ P_R) will be the **stabilized pressure after a prolonged shut-in** and is, therefore, often referred to as the **shut-in bottom hole pressure** (P_{ws}, SIBHP) or the closed-in bottom hole pressure (CIBHP). Under virgin conditions, this may also be called the Initial Reservoir Pressure (P_i, P*).

The difference between the flowing pressure and the reservoir pressure is termed the drawdown and is one of the parameters that determines the amount of production that will be achieved.

$$\text{DRAWDOWN} = \text{SIBHP} - \text{FBHP} = (P_R - P_{wf})$$

Production is a function of drawdown. The relationship between production and drawdown is called the **inflow performance relationship (IPR).**

Oilwell inflow performance can be calculated in several ways, depending on what information is available to the engineer. If a well test is available, extrapolation of the measured rates and pressures (or the calculated productivity index) can be used to predict well performance at other conditions. If reservoir parameters are known, theoretical calculations can be made using Darcy's law.

In any case, **an inflow calculation consists of predicting stabilized flow rate at given bottom hole flowing pressures.** The calculated points are then connected to provide curves, sometimes referred to as the Inflow Performance Relationship, or IPR curves.

Figure 4.3 illustrates how, in general, **an oilwell IPR will be a straight line relationship to the bubble point pressure, and approximately straight to a FBHP of 75% of the bubble point pressure (P_b). If the average reservoir pressure (P_R) is at or below the bubble point, the entire IPR will be curved,** although curvature is still minimal at low drawdowns. This curvature is caused by relative permeability effects; the compressibility of gas, the change in oil viscosity with pressure as gas comes out of solution; and the fact that gas easily reaches turbulent conditions within the pores.

The shape of the IPR varies with the fluid produced, primarily as a function of the amount of gas present at the sandface.

VARIATION OF IPR WITH WELL TYPE	
Straight Line IPR's (Defined PI)	• Oilwells with FBHP ≥ Bubble Point
	• Oilwells with high water cuts
	• Oilwells with limited drawdown
	• Oilwells with high skin or formation damage
	• Water zones
Curved IPR's	• Gaswells
	• Oilwells with FBHP << Bubble Point
	• Oilwells with high GLR's

Inflow of oil into a wellbore is governed by the radial flow equation, whereby the rate is controlled by Darcy's law:

$$q_o = \frac{k_o h}{1866\ \mu_o B_o} \frac{\left(P_R - P_{wf}\right)}{\left[\ln\left(.472\ \frac{r_e}{r_w}\right)\right]}$$

(Equation 4.1)

where	q_o	=	oil rate, m^3/d
	P_R	=	volumetric average reservoir pressure, kPa
	P_{wf}	=	flowing bottom hole pressure, kPa
	k_o	=	effective oil permeability, md
	h	=	net pay, m
	μ_o	=	live oil viscosity at reservoir conditions, mPa•s
	B_o	=	formation volume factor, rm^3/sm^3
	r_e	=	drainage radius, m
	r_w	=	well bore drainage radius, m

Equation (4.1) applies to pseudo-steady state flow conditions (i.e., no pressure maintenance). For steady state flow, the constant ".472" should be replaced by ".607".

See Section 2.2 of Golan (Reference 4.1) for a detailed discussion of these equations.

The concept of a productivity index (PI) to describe an oilwell IPR is derived directly from Equation 4.1:

$$J = \frac{q_o}{\left(P_R - P_{wf}\right)}$$

(Equation 4.2)

where: $$J_o = \frac{k_o h}{1866\, \mu_o\, B_o \left[\ln\left(.472\, \frac{r_e}{r_w}\right)\right]}$$

J_o = ideal productivity index with zero skin, $m^3/d/kPa$

Estimating the Permeability Thickness, $k_o h$

The main problem in applying Equation 4.1 to describe the potential influx to be expected during a blowout is in the development of reasonable estimates for the key **permeability thickness ($k_o h$)** parameter prior to core, log and well test results being available.

The permeability of a reservoir is a measure of the ease with which fluid flows through a rock. It is a function of the degree of interconnection between pores in the rock which is determined by the size of the openings between pores, known as pore throats.

Permeability is normally measured from well tests and core plugs, but care must be taken that cores have been handled properly. More often, permeability must be implied from porosity estimates. In general, the higher the porosity the better the permeability. In sandstone reservoirs, an empirical relationship can often be found between porosity and permeability. This usually has the form of:

$$k = a\phi^b$$

where:	k	=	permeability, md
	ϕ	=	porosity, fraction
	a, b	=	empirical constants

It is, therefore, convenient to have a plot of ϕ vs log k to estimate how a zone will produce and to identify the "cut-off porosity" at which effective productivity of an unstimulated formation is negligible.

Figure 4.4 is a porosity vs permeability plot for a Beaufort Sea field. This plot shows the relatively high cut-off at 15% porosity and how the very high permeabilities (>1000 md) correspond to very high porosities (> 27%). These high porosities imply that there can be very little cementing materials between the grains and that the high permeability sands must, therefore, be relatively weak (unconsolidated to friable) and have a tendency to collapse under high drawdowns.

Porosity (ϕ) is defined as the ratio of the pore space in a rock sample to the total volume. Porosity is either expressed as a percentage or as a fraction. Total porosity includes non-connected pore space and also pore space taken-up by conate and shale water.

However, the petroleum engineer is primarily interested in effective porosity, which is defined as the interconnected pores that contain hydrocarbons and connate water. The porosity of a rock is independent of grain size but is a function of how the grains are packed together. Porosity is measured by the Density Neutron or Sonic logs or from cores.

In the exploration phase, the porosity has to be estimated based on geological interpretation and regional trends. For a particular depositional environment, a porosity versus depth trend can often be established (Refer Figure 4.5). Obviously, for poorly cemented granular type rocks, such as sand, porosity tends to decrease with depth because of the increasing compaction caused by the overburden.

By combining the porosity-depth, porosity-permeability, and depth-blowout frequency trends (as discussed in Section 2.2), it is apparent that, in a given field area:

- while blowout frequency increases with depth, blowout flow rates will decrease;

- there is a depth below which oil flow rates are primarily a function of well stimulation efficiency, because the natural permeability is below the cut-off (4000 m in the examples shown in Figures 4.4 and 4.5). This is one of the criteria used to define the optimum depth of exploration wells;

- the worst case blowout is likely to involve a moderate depth well in which the weakest, highest permeability sands have been cased-off, but the open hole section is moderately permeable and strong.

Obviously, we must also be concerned with the fluid saturations in the open sands. Gas zones are the most difficult to control because of the low viscosity and density of the gas and its ability to transport liquids out of the wellbore (Refer Section 4.3). Oil zones present the greatest pollution risks and are the main focus of this report.

Open water zones, on the other hand, tend to be beneficial in ameliorating blowouts. The high density fluid reduces both the flow rate and wellhead pressures and decreases the risk of a catastrophic fire.

Moreover, evaluation of the fluid saturations within the reservoirs is also important because there will be a greater resistance to the flow of one fluid in the presence of others, since the second (and possible third) fluid(s) will block part of the flow channel. Since this situation exists in the majority of hydrocarbon reservoirs, the ease with which oil moves in the presence of connate water and perhaps free gas is defined as the relative oil permeability. Relative permeabilities are frequently expressed as functions of total liquid saturations (S_w + S_o) (Reference Figure 4.6). By looking at these curves, we can see how a reservoir is likely to behave.

There is a critical saturation at which the second (or third) phase becomes mobile. As its saturation further increases, it becomes easier and easier for that phase to flow, and harder for the first phase to flow.

This is one of the reasons why **uncorrected air permeability data from core analysis cannot be used to estimate the effective permeability** used in Equation 4.1. All reservoir rocks contain an irreducible water saturation known as the interstitial or connate water saturation. It is held in place by capillary forces and its magnitude is a function of porosity, where lower porosity rocks have larger connate water saturations. The magnitude of the water saturation determines the oil permeability.

Therefore, if the high drawdowns associated with a blowout cause water or gas to cusp or cone into the oil zone, the oil permeability and production rate will decrease.

Similarly, the release of solution gas out of the oil under high drawdown conditions will cause a gas saturation to build-up in the near wellbore area inhibiting oil flow. This, in combination with the resultant increase in oil viscosity, causes oilwell IPR's to roll over at high drawdowns below that predicted by the Darcy radial flow equation. This effect will be discussed later.

The **net pay (h)** used in Equation 4.1 should be the average isopach of net pay over the drainage area. It is usually selected based on an analysis of a combination of open hole logs or from geological mapping.

Use of oversimplified methods of selecting net pay can lead to substantial errors in the productivity estimates. For example, suppose an 80 API unit gamma ray cut-off was used to pick net pay in a sandstone reservoir, without consulting the porosity logs; the procedure would eliminate shale streaks from the pay count, but tight zones would be counted as "clean sand"; however, these would probably not contribute to flow.

Moreover, it is unlikely that all of the net pay will be opened up even under blowout conditions. Unless special procedures are adopted in cleaning-up a well, many of the perforations, or much of the sandface in the case of an open hole, will remain plugged with solids. Once one or two intervals within the pay start to flow, the drawdown is decreased and the rest will likely remain plugged. In theory, the most permeable intervals will open up first but production logs show that this is not always true. **Thus, the use of the total net pay for h is definitely an unrealistic worst case.**

In deviated wells or steeply dipping formations, net pay must be corrected to remove the apparent thickening caused by not penetrating the pay perpendicular to the bedding. Figure 4.7 displays the concept of net pay applied to a deviated well showing how the effects of shale, tight streaks, deviation and dip are eliminated from kh.

Effect of Skin Damage

Equation 4.1 gives the ideal inflow performance, or IPR, of the well. Only rarely does a well produce under the conditions of the ideal radial flow equation and, to achieve this, it must be carefully completed. Generally, the permeability of the formation near the wellbore is altered during the drilling. Moreover, penetration of only part of the total net pay also reduces productivity. The sum of these effects has been defined as the **total skin**, and causes an additional pressure drop near the well bore, as shown in Figure 4.8.

The additional pressure loss ΔP_{skin}, was defined by Hurst (Reference 4.2) and Van Everdingen (Reference 4.3), such that the radial flow equation is modified as follows:

$$q_o = \frac{k_o h}{1866\ \mu_o B_o} \frac{\left(P_R - P_{wf}\right)}{\left[\ln \frac{0.472\ r_e}{r_w} + S'\right]}$$

(Equation 4.3)

where: S' = total skin effect

From this equation, it is apparent that a positive skin term will reduce well productivity.

Typically, skin factors can be expected to be as follows:

Situation	Typical Skin Factor
Very Poorly Completed Well	+20 to +500
Damaged Well	+2 to +20
Good Initial, Unstimulated Completion	+2 to -1

Understanding Skin Effect and its components is fundamental to the prediction of Blowout Rates. The magnitude of the various components of the skin term can be estimated, using empirical and analytical techniques, however, these calculations require numerous assumptions which can have large ranges of possible values. Therefore, the most widely used method of determining the well IPR is analysis of test results in nearby wells. By adjusting those components of the tested skin that relate to the completion methods, which can be estimated theoretically, the degree and cause of the open hole damage can be estimated.

A total skin measured in a well test is the sum of all the Darcy (or non rate dependent) skin components (S) and the non-Darcy (or rate dependent) skin so that:

$$S' = S + DQ$$

(Equation 4.4)

where:	Q	=	rate, m^3/d
	D	=	non-Darcy skin coefficient $(m^3/d)^{-1}$
	S	=	Darcy skin

The factors which determine the skin can be summarized as follows:

Formation damage (S_d) caused by influx of fluids and solids from the wellbore into the formation.

Perforation skin (S_p) caused as the radial flow of reservoir fluid deviates to spherical/cylindrical flow into the perforations and crosses any crushed zone around the perforation tunnel.

Completion skin (S_c) which includes the effects of partial completion (caused by flow converging to enter an open interval that is less than the total formation net pay) and wellbore deviation.

Multiphase flow effects (S_m) caused by saturation changes around the wellbore. In oil wells, this would be gas break-out below the bubble point (the Vogel effect, Reference 4.4). In gaswells, condensate dropout around the wellbore can cause a similar effect.

Gravel pack skin (S_g) caused by additional pressure drops through the gravel that fills the perforations in an internal gravel pack. Formation sand filling collapsed perforation, or infiltrating the gravel, will cause a similar and even more marked effect.

Non-Darcy skin (D) caused by additional pressure drops due to high velocity flow through the reservoir (D_R), damaged zone (D_d), and or gravel filled perforations (D_g).

Certain completion techniques and reservoir factors can cause productivity enhancement or negative skin effects. These can be summarized as follows:

- **Fracture Stimulation**, (S_s) which increases the contact area (or the effective size) of the wellbore.

- **Natural Fractures and Vugular Carbonates**, (S_h) which increase the contact area (or the effective size) of the wellbore.

- **Well Deviation or TCP Perforation with high power guns**, can also cause the completion skin component (S_c) to be negative.

The total skin determined from well test is a composite of these individual near wellbore effects.

When trying to estimate the open hole skin components from well test data the method of Karakas & Tariq (Reference 4.5) can be used to evaluate the combined effect of perforation skin and near wellbore formation damage.

Partial penetration will magnify near wellbore skin effects and cause more distant skin effects due to flow convergence.

Total Darcy Skin, (S) = near wellbore skin + more distant skin effects

(Equation 4.5)

The effect on the near wellbore skin can be accounted for by using the h/h_p multiplier proposed by Jones and Watts (Reference 4.6). The flow convergence effects can be estimated using the equations published by Brons and Marting (Reference 4.7) or Odeh (Reference 4.8). These are incorporated into the completion skin component and added to these near wellbore effects.

Thus, in a perforated completion:

$$S = \frac{h}{h_p}\left(S_{dp}\right) + S_c + \left[S_m\right] + \left[S_h\right]$$

(Equation 4.6)

where:

S	=	total Darcy skin
S_{dp}	=	perforation skin including effect of formation damage
S_c	=	completion skin including the effect of partial completion and deviation
S_m	=	effects of multiphase flow on measured skin
S_h	=	effect of heterogeneities, fractures or vugular carbonates on the measured skin
h	=	net pay thickness (isopach)
h_p	=	along hole length of the perforated net pay

As discussed later, multiphase flow effects are normally dealt with outside of the radial flow equation by adjusting the shape of the IPR curve, in which case S_m is ignored in Equation 4.6. However, when a well test is performed at high drawdown, the calculated skin will include an apparent skin component due to multiphase flow effects in the near wellbore area.

Depending on how the well test is interpreted, reservoir heterogeneities may also cause an apparent skin effect (S_h), however, there are no generally applicable equations for estimating the effect of layering, natural fracturing or other stochastic features on the skin factor. If no field data is available, this component is generally ignored when developing theoretical estimates of the expected Darcy skin.

Because drilling and testing operations are carried out under overbalanced conditions, they result in an influx of solids and fluids into the formation. Assuming the well is open over the entire net pay, the effect of formation damage in an uncased open hole can be estimated by the Hawkins (Reference 4.9) equation, where:

$$S_d = \frac{k_u - k_s}{k_s} \ln \frac{r_s}{r_w}$$

(Equation 4.7)

where:

	S_d	=	formation damage skin
	k_u	=	undamaged formation permeability
	k_s	=	skin zone permeability
	r_s	=	radius of damaged zone

Since k_s and r_s are generally unknown, S_d is best determined by subtracting all the skin components attributable to all other effects from the total skin measured in a well test. However, the Hawkin's equation does clearly show that as k_s approaches zero, skin in an open hole completion will rapidly approach infinity irrespective of how small the damaged zone is (r_s). **It is this factor that most severely limits the rate at which wells blowout from sandstone reservoirs.** From the analysis of perforated well tests, many test analysts have concluded that even after clean-up, drilling damage often results in a 50 to 100 mm zone with k_s:k_u ratio of around 0.4; and that substantially more damage occurs in many zones.

If the non-Darcy skin component is expected to dominate the IPR, as in high rate or high GLR oilwells and gaswells, evaluation of the relative contribution of the various skin components is extremely difficult, due to the interdependence of the Darcy and non-Darcy skin components. The only reliable way to quantify the non-Darcy skin components is to perform a multi-rate test, and to use numerical simulation to develop a theoretical estimate of the relative importance of the various components.

Despite the difficulties and uncertainties involved in trying to understand the causes of the total skin factor measured in a well test, **estimation of the magnitude of the various skin components can be used to show that the flow capacity of an open hole section will be much lower than that seen during cased hole DST's.**

High positive skins are not the only cause of low productivity; consideration of the radial flow equation (Equation 4.1) shows that limited production can also be caused by other effects.

Low Effective Permeability, k_o

The effective oil permeability, k_o, is a function of both the absolute permeability of the rock, k, and the relative permeability to the fluid being considered, in this example oil (k_{ro}), so that:

$$k_o = k_{ro} \times k$$

The absolute permeability (k) is a function of rock structure and, to some extent, the confining stress. These are generally considered constant over the life of the reservoir, although the confining stress will increase as the reservoir pressure decreases. Estimation of the in-situ permeability of the relatively weak formations found in the Beaufort from core data should, however, include a stress correction.

The relative permeability, k_{ro}, will be reduced as the saturation of oil (in this case) decreases around the wellbore. In a blowout situation, these saturation changes will be caused by increased gas saturation, and increasing GOR, as the flowing bottom hole pressure falls below the bubble point. The effect is more pronounced around the wellbore because of the high drawdowns (see Figure 4.8).

The same effect is caused by increasing water saturations as a result of coning. Drilling operations may also cause serious water blocking if the mud filtrate (usually water based) is not cleaned-up or bypassed by perforation. In tight rock, the filtrate can completely saturate the near wellbore region thereby reducing the oil relative permeability to zero.

Reservoir Pressure Depletion

Some Beaufort Sea reservoirs produce under solution gas drive, such that reservoir pressure (P_R) would decline relatively quickly as the fluid is produced, causing a rapid decline in well production. In reservoirs where there is strong gas cap drive or natural water drive, this effect is reduced but would still be apparent if the reservoir extent was limited or the blowout were to continue for a long period.

Fluid Viscosity, μ

The lower the viscosity of the produced reservoir fluid, the better the productivity of the well. Since oil viscosity increases with decreasing gas saturation, this effect can become important during a high drawdown flow condition, such as a blowout.

Heavy oil wells, with high reservoir fluid viscosities, will have relatively poor inflow performance, especially at low reservoir temperatures, and, therefore, will have low blowout rates.

IPR Curvature

For oil wells, the theoretical IPR is a straight line when bottom hole flowing pressures are above the bubble point. The slope of this line is increased by increasing Darcy skin components. Below the bubble point, two phase flow effects, which are rate dependent, become dominant and introduce a curvature in the actual IPR. In high productivity and high GLR oil wells, non-Darcy flow effects can often dominate the total skin and degree of IPR curvature.

For gas wells, the ideal IPR is already curved, because the formation volume factor and gas viscosity are pressure dependent. Darcy skin effects reduce the already curved IPR; and the non-Darcy terms will both reduce productivity and increase the degree of curvature of the IPR.

Variation of Flow Rate with Time

When a well is initially opened, the flow is said to be transient (or infinite acting) until the pressure disturbance encounters a boundary. During this time, the flowing rate decreases rapidly with time. The high initial flow rates experienced during the transient period are often referred to as "flush" production (Figure 4.9).

Most DST's and many well tests are conducted under transient flow conditions and, consequently, the observed productivity will usually be greater than that which will be seen under pseudo-steady state, or long term production conditions. It is important, therefore, in estimating the long term blowout rate from a well to correct transient productivities.

Vogel's IPR for Low Rate, High Drawdown Wells

A straight line IPR or PI only applies to undersaturated oil wells. Below the bubble point pressure, liberated solution gas increases the gas saturation around the wellbore, thereby reducing the oil relative permeability and causing the IPR to curve downwards from the straight line. In a single rate well test, this effect will be seen as skin, causing the apparent PI(J') to be less than the ideal PI(J_o).

The most commonly used equation to describe the entire curved IPR is the one developed by Vogel (Reference 4.4) (Figure 4.10) where:

$$q_o/q_{max} = 1 - 0.2\ (P_{wf}/P_R) - 0.8\ (P_{wf}/P_R)^2$$

(Equation 4.8)

where: q_{max} = maximum oil rate when the flowing pressure is zero, m^3/d

P_R = reservoir pressure at the bubble point, kPa

In an undamaged well, the maximum rate (q_{max}) can be predicted from the theoretical straight line PI with zero skin (J_o):

$$q_{max} = \frac{J_o\ P_R}{1.8}$$

(Equation 4.9)

In order to account for skin effects, the Vogel curve should be modified using Standing's curves (Reference 4.10). For further discussion of these effects, the reader should refer to Golan and Whitson (Reference 4.1) or Brown et al (Reference 4.10).

Fetkovich's IPR for High Rate, High GLR Wells

The Vogel equation does not account for high velocity effects that can exist in high rate or high GLR oilwells. A better expression of the IPR is an empirical equation substantiated by Fetkovich (Reference 4.12) where:

$$q_o/q_{max} = \left[1 - \left(P_{wf}/P_R\right)^2\right]^n$$

(Equation 4.10)

However, there is unfortunately no theoretical method to predict the exponent (n) so that this equation can only be used with well test data.

Blount-Jones Generalized IPR

An even better method to describe non-Darcy flow effects is the extension of the Forcheimer equation, published by Blount and Jones (Reference 4.13)

$$P_R - P_{wf} = aq + bq^2$$

(Equation 4.11)

where: a = Darcy flow coefficient, $kPa/m^3/d$

b = non-Darcy flow coefficient, $kPa/(m^3/d)^2$

If no well tests are available, these coefficients can be estimated theoretically as discussed by Golan (Reference 4.1).

Gaswell Radial Flow Equation

The pseudo-steady state radial flow equation describing gas production from a reservoir can be written as:

$$Q = \frac{k_g h \left(m\left(P_R\right) - m\left(P_{wf}\right)\right)}{1.295\left[\ln\left(.472\,\frac{r_e}{r_w}\right) + S'\right]}$$

(Equation 4.12)

where the real gas pseudo pressure, m(P) is defined by Al-Hussainy* et al, (Reference 4.14) as:

$$m(P) = 2 \int_{o}^{P} \frac{P}{\mu z}\, dp$$

(Equation 4.13)

and where: Q = gas rate, m^3/d

k_g = effective permeability, md

T = reservoir temperature, ^{o}k

z = gas deviation factor

μ = gas viscosity, μPa.s

$m(P)$ = pseudo pressure, $kPa^2/\mu Pa \cdot s$

The radial flow equation is sometimes presented in terms of p^2, as developed by Russell et al (Reference 4.15):

$$Q = \frac{k_g h \left(P_R^2 - P_{wf}^2\right)}{1.295\ \mu z T \left(\ln\left(.472\ \frac{r_e}{r_w}\right) + S'\right)}$$

(Equation 4.14)

However, because of the pressure dependency of μ and z, the pressure squared equation is only a valid approximation at low pressures (<2000 psi); and it becomes increasingly inaccurate at higher pressures.

As discussed by the ERCB (Reference 4.16), since the pseudo pressure parameter rigorously accounts for the pressure dependence of gas properties, Equation 4.12 is valid for the entire range of pressures applicable to a given well. Calculation of the pseudo pressure integral can be done by numerical integration for which computer software is readily available.

The apparent skin term, S', in these gaswell equations, nearly always contains a rate dependent, or non-Darcy, skin term, where:

$$S' = S + DQ$$

(Equation 4.4)

Consequently, Equation 4.12 can be written as:

$$m(P_R) - m(P_{wf}) = 1.295 \frac{QT}{kh} \left(\ln \left(\frac{0.472\ r_e}{r_w} \right) + S + DQ \right)$$

(Equation 4.15)

This can be simplified to the following quadratic:

$$m(P_R) - m(P_{wf}) = AQ + BQ^2$$

(Equation 4.16)

Thus, gaswell IPR's are always curved.

In Equation 4.16, A is referred to as the Darcy flow coefficient, and is comprised of the rock and fluid properties and Darcy skin. The value of A will vary with time until the well reaches pseudo-steady state flow conditions. Many well tests may not have been produced long enough to reach pseudo-steady state conditions. Adjustments of the value derived from well tests is, therefore, essential in estimating long term gas blowout rates.

Similarly, B is referred to as the non-Darcy flow coefficient. It is related to the rate dependent skin, DQ, as follows:

$$D = \frac{B\ kh}{1.295T} \qquad (m^3/d)^{-1}$$

(Equation 4.17)

The non-Darcy coefficient (B) is best estimated by multi-rate testing, but it can also be estimated theoretically if the effective productive interval can be estimated. However, the value of B depends not only on the reservoir permeability but also on the degree of formation damage, heterogeneity and partial penetration effects.

The AOF (absolute open flow potential) of a gaswell refers to the theoretical blowout capacity, if there is no friction or liquids in the wellbore. It is determined from the root of equation 4.16, so that:

$$AOF = \frac{-A + \sqrt{A^2 + 4 \times B \times m\ (P_R)}}{2B} \quad m^3/d$$

(Equation 4.18)

Back Pressure Equation

Historically, gaswell productivity was described by the U.S. Bureau of Mines back pressure equation developed by Rawlins and Schellhardt (Reference 4.17), where:

$$Q = C(P_R^2 - P_{wf}^2)^n$$

(Equation 4.19)

where: C = deliverability coefficient, $m^3/d/(kPa)^2$

n = deliverability exponent, varying between 1.0 for laminar flow conditions and 0.5 for fully turbulent conditions (high velocity flow)

n and C are derived from a plot of $P_R^2 - P_{wf}^2$ against Q on a log/log scale (Figure 4.11).

The AOF, using this IPR method, is read directly from the plot or calculated from

$$AOF = C\ (P_R^2)^n \quad m^3/d$$

(Equation 4.20)

It should be emphasized that the back pressure equation is purely empirical and, although still widely used, can lead to erroneous results. At low rates, n tends towards 1 and, since it is not possible to define the effect of higher rates on n, it is important to test wells close to their intended offtake rates if the backpressure equation is used to describe the IPR. Moreover, the coefficient C varies with time until pseudo-steady state conditions are reached, and can only be estimated theoretically when n = 1. **Thus the extrapolation**

of well test data and AOF's tends to overestimate the actual rates to be expected in a blowout.

Multizone IPR's

As has been discussed earlier, a blowout will involve the commingled production of all zones open to the wellbore. This will result in rather strange looking composite IPR's (Refer Figure 4.12).

If there is no vertical communication between the zones, except through the wellbore, production will be drawn primarily from the highest permeability zone with the result that the static pressure in this interval will decline more rapidly than the pressures in other zones. Conversely, the lowest permeability section will maintain the highest reservoir pressure due to its limited production. This phenomenon is referred to as differential depletion. In this situation, the relative contribution from each zone will be a function of drawdown and of the IPR's of the individual layers.

Moreover, if there are any gas zones in the wellbore, the producing **Gas-Liquid-Ratio (GLR) will depend not only on the Solution GOR but also the free gas production rate.** Free gas may also be produced from the oil zones at high drawdowns. Once the reservoir pressure drops below the bubble point, high GOR can be expected because of the diversion of gas libérated in the immediate wellbore area before it can reach the secondary gas cap. Under these conditions, the GOR is often a function of drawdown.

In some instances, a high producing GOR may also be indicative of gas coning or cusping. Coning is a vertical distortion of the GOC near the wellbore, which develops when the drawdown exceeds the existing gravity forces. Coning occurs most frequently under conditions where vertical permeability is enhanced due to vertical fracturing (either natural or hydraulic) or uniform isotropic sands without shale barriers. Cusping or tonguing is a lateral distortion of the GOC down-dip in high permeability streaks.

In these situations, separate IPR's must be generated for the oil, water and gas zones in each area of the wellbore. The flowing bottom hole pressure (FBHP) at that point (P_{wfx}) will determine the relative contribution of each fluid and, hence, the GLR and Water Cut (WC) (Refer Figure 4.13). However, the process is obviously iterative since the FBHP depends heavily on the GLR, WC and depth.

Simulation Programs

It can be seen from the above discussion that description of the theoretical inflow capacity to a blowout is extremely complex and will vary as the well is deepened and is progressively cased.

If theoretical calculations are to be made, it is obviously advantageous to use a reservoir simulator to develop the composite inflow performance curves.

However, during exploration drilling, the reservoir-geological model is generally insufficient to permit meaningful reservoir simulation; although this may be feasible in the delineation phase, as shown by Gulf at Amauligak.

Alternatively, a somewhat simpler single well model, such as the WEM model used in this study (Reference 4.18) or Neotechnology Consultant's WELLFLO Program (Reference 4.19) could be used.

Pragmatic Approach

It should also be obvious from the above discussion that:

- Many of the parameters needed for a theoretical description of the well IPR will not be available during the exploration drilling phase.

- Use of properly combined IPR's from well tests in offset wells should, generally, overestimate the inflow potential of a drilling well, since they would likely exclude the effect of:

    - flowing through the drilling damage (as opposed to having it by-passed by perforations)

    - the high rate non-Darcy flow effects

    - high drawdowns on absolute and relative permeability and oil viscosity

    - having water zones open to the wellbore

Provided that both gas and oil zones are considered.

Therefore, many operators feel that a somewhat simpler approach can be adopted, particularly if the offset well production has been disappointing, so that the wells were tested at high drawdowns. **In situations of this type, it is quite reasonable to define the maximum oil inflow capacity as the sum of the q_{max} values for each of the oil zones tested in the best offset well; provided that the resultant sum is corrected proportionately for any higher kh values predicted for the drilling well.**

An even more optimistic estimate would result from simply summing and grossing up the productivity indices (J).

However, while these simple approaches are a convenient short-cut for low productivity areas, they are not recommended for the high productivity reservoirs, because they will grossly over-estimate the inflow performance and apparent blowout capacity.

4.3 Principles Controlling Outflow

Calculation of the **outflow or tubing performance** is complex because most wells produce under conditions of **multiphase flow** (Gas, Oil and Water) with varying phase distributions and slippage within the wellbore.

The relationship between pressure and temperature drop in the well and the PVT behaviour involves combining the fundamentals of mass, momentum and energy conservation with mass transfer phenomena for multicomponent hydrocarbon mixtures. The pressure drop is then determined using empirical and semi-empirical correlations with all calculations being performed on a computer. Sub-routines within the program calculate:

1) The phase behaviour and physical properties of the fluids.
2) The flowing temperature.
3) The flow regime and liquid hold-up fraction.
4) The frictional pressure loss.

By numerical integration, a steady state pressure gradient along the string is estimated.

In a flowing oilwell or gaswell, the resulting **pressure traverse is dominated by the rapid expansion of free gas near surface causing a steepening of the slope** (Figure 4.14). With the low surface pressures associated with a blowout this gas expansion can cause an almost vertical line approaching the residual gas density. The occurrence of increasing volumes of free gas in the wellbore will also affect the phase velocities and, therefore, the flow pattern.

Most investigators, who have flow regime dependent correlations, identify four major regimes which may all occur in different places along the wellbore (Figure 4.15). In order of increasing gas volume, or velocity, and decreasing depth in an oilwell, they are:

Bubble Flow

The pipe is almost completely filled with liquid and the free gas phase is present in small bubbles. The bubbles move at approximately the same velocity as the liquid and, except for their density, have little effect on the pressure gradient. The wall of the pipe is always contacted by the liquid phase.

Piston/Slug Flow

The gas phase is more pronounced. Although the liquid phase is still continuous, the gas bubbles coalesce and form plugs or slugs which almost fill the pipe cross section. The gas bubble velocity is greater than that of the liquid. The liquid in the film around the bubble may move downward at low velocities. Both the gas and liquid have significant effects on the pressure gradient.

Transition Flow (Slug/Churn/Annular Flow)

The change from a continuous liquid phase to a continuous gas phase occurs. The gas bubbles may join and liquid may be entrained in the bubbles. Although the liquid effects are significant, the gas phase affects dominate the pressure gradient and frictional pressure loses.

Mist Flow

The gas phase is continuous and the bulk of the liquid is entrained as droplets in the gas phase. The pipe wall is coated with a liquid film, but the gas phase predominantly controls the pressure gradient.

The pressure gradient at each point in the well, and thus the total pressure drop, is very dependent on the flow pattern. Typical pressure gradients in an oilwell for the different flow regimes are:

- Single-phase oil = 7 to 8 kPa/m
- Bubble flow = 5 to 7 kPa/m
- Slug flow = 3 to 5 kPa/m
- Mist flow = 2 to 6 kPa/m

Consequently, prediction of pressure drop in multiphase systems is complex and has led to the development of several different pressure drop correlations. Although many of these correlations have been used with some degree of success, *no single method is universally applicable.*

All of the major companies have worked on this subject and each has its own proprietary in-house correlations and programs, which are generally more accurate than those in the public domain. Several software developers offer programs providing a selection of public domain correlations (Reference 4.18, 4.19).

The computer program calculates the bottom hole flowing pressure (FBHP) associated with a given flow rate, gas liquid ratio and surface tubing pressure. A series of FBHP values are generated for each surface tubing pressure by assuming a series of flow rates. The results are then plotted and a curve is drawn through the points as shown in Figure 4.16. The curve can be divided into three regions:

- An area to the left of the minimum where the static density effects from liquid hold-up dominate and flow is unstable.

- The area of the minimum, where the FBHP depends primarily on the mixture density and the dominant flow regime. (This is a function of the GLR and surface pressure.)

- The area to the right of the minimum, which is dominated by friction. The frictional pressure drop is highly dependent upon the velocity and the effective diameter of the flow conduit (Q^2/d^5). Thus, as shown in Figures 6.3 and 6.4, a blowout through a crack around the cement (Case II) will have much higher friction effects than flow through the drillpipe (Case I).

The flowing bottom hole pressure (FBHP) will also depend heavily upon the surface pressure of the escaping fluids. The effect of increasing Wellhead Pressure (WHP) is magnified downhole because of the resulting reduction in gas density, break-out and volume. It is therefore essential to develop a realistic estimate of any flow restrictions or chokes in the flow path.

Expansion of the gas across a choke may lead to the formation of gas hydrates, ice and wax (Refer Section 4.6) which may further inhibit the flow and accelerate deposition.

Ultimately, a small restriction may result in critical choking, where the gas reaches sonic velocity. Under these conditions, the flow rate is independent of the downstream pressure. A number of equations have been developed to describe the critical flow of multiphase fluids, which all have the form of:

$$Q = \frac{P_{wh}^{n} \, d^{t}}{C \, R^{m}}$$

(Equation 4.21)

where: P_{wh} = Wellhead Pressure (kPa)

d = Choke Size (mm)

R = Gas Liquid Ratio (m^3/m^3)

The empirical constants commonly recommended are:

	Gilbert Reference 4.20	Nind Reference 4.21
n	1	1
t	1.89	2
C	195	308
m	0.546	0.5

Experience has shown that critical choking occurs when the wellhead pressure is more than 170 to 200% of the downstream pressure.

Under these conditions, the flow stream is extremely erosive and the hole size will rapidly increase unless made of a corrosion resistant material. Where velocities are in the range of 100 to 200 m/sec, erosion rates of 0.1 mm/min may occur, whereas they will be negligible at rates of 10 m/sec.

Thus, while critical choking provides an opportunity for the well to plug itself off, or for the crew to quickly regain control, it is unlikely to limit the rate for an extended period of time.

On the other hand, the sub-critical choking associated with a flow restriction will likely limit the blowout rate once the surface velocity drops below 100 m/sec, unless substantial quantities of sand are being produced.

The problem in modelling the outflow performance is, therefore, to select:

- A realistic wellhead pressure and stable choke configuration.

- The effective Gas Liquid Ratio, which will depend not only on the solution GOR, but also the number of gas zones open, the effective drawdown on the oil zones and the number of water zones open.

- The effective water-cut which depends on the number of water sands open.

- The wellbore piping configuration.

- The best flow correlation for the flow conditions.

- A wellhead temperature, which is appropriate for the production rates and the environmental conditions.

4.4 Theoretical Flow Capacity

In order to predict the actual blowout rates, the Inflow and Outflow Performance Curves are plotted on the same graph, as shown in Figure 4.17. **The only condition that actually exists is that at which the two curves intersect.** In the case of a well producing 35% water cut against a 345 kPa wellhead pressure, the following rates could be expected:

Skin Damage	Liquid Rate m^3/d*		
	Gas Liquid Ratio m^3/m^3		
	88	500	1250
2	1900	1660	1350
20	1820	1620	1300
200	1260	1225	1050

* 35% water 65% oil.

The importance of properly establishing the gas rate is readily apparent from this example. It is also apparent that where the damage is low and the IPR is high, the outflow capacity limits the rate; while when the IPR is poor, the inflow capacity will limit the rate, and it is under these conditions that the formation may collapse.

The effects of the very high gas velocities at surface during a blowout are very interesting and result in a well response that is contrary to normal expectations. **Because the friction from the expanding gas controls the back pressure, a decrease in GLR due to a well not penetrating the gas cap or from an increase in water cut results in an increase in inflow rate!** This is because the decrease in friction is greater than the increase in the head effects. This can be seen from the way the curves cross-over from low to high rates.

Thus, while wells which penetrate high permeability gas have the greatest blowout potential, the resultant rates are self limiting and may be lower than the less probable oil blowout. However, even at solution GOR, the blowout rates are primarily controlled by the surface gas velocity.

The problems in establishing the dynamic water cut and GLR during a multizone blowout have been discussed in Section 4.2. It is an iterative process in which the FBHP determines the relative contributions from each of the zones, which in turn determines the FBHP.

By finding the intersection point of the IPR and OPC for a variety of pressures, the computer programs can also be used to generate a wellhead deliverability curve of rate versus wellhead pressure (Figure 4.18).

Typically, in a high GLR blowout situation, it is found that rate is limited by the friction of the expanding gas and therefore the maximum rate is independent of wellhead pressure at the limits. At high GLR, the rate may be cut off even sooner by the flow reaching sonic velocity as determined by the critical choke equation (4.21). This is illustrated in Figure 4.18.

Looking at the bottom hole curves, it is interesting to note that with the restricted outflow scenarios we have adopted, very little drawdown may be achieved on the sand face unless the formation is damaged or the permeability thickness is low. This will limit the tendency for hole collapse and sand production discussed in the next section. **However, as discussed in Section 4.2, we believe that many drilling wells will be severely damaged, or have a limited amount of pay effectively open, resulting in a poor IPR and a high probability of hole collapse.**

4.5 Borehole Stability Considerations

Basic Rock Mechanics

An appreciation of basic rock mechanics principles is useful in trying to understand and predict hole collapse and sand problems. Borehole instability and sand failure are formation collapse phenomena, while fracturing and mud losses result from an induced tensional failure. The following material is taken from a text on "Sand Production" that the authors prepared for IHRDC (Ref. 4.22).

In-situ stresses

In the ground, undisturbed rock materials are in a state of triaxial compression because of the weight of the overburden. This overburden creates vertical and horizontal stresses, and it is these compressive stresses that holds unconsolidated material together.

In tectonically relaxed areas, where normal faulting predominates, **the weight of the overburden material can be assumed to be the major principal stress.** It can be calculated by integration of the formation density log from the surface down to the point of interest.

Various correlations of overburden gradient against depth have been published, showing a rapid increase from around 19 kPa/m near the surface and approaching 25 kPa/m at depths in excess of 3000 m. An average value of around 23 kPa/m is frequently used as a first approximation.

Effective matrix compressive stress is reduced when the formation has porosity and contains fluid because part of the overburden load is supported by the pressured fluid.

In a deltaic sedimentary basin, such as the Beaufort, **the effective horizontal stress is a resultant of the overburden load** so that, simplistically, effective horizontal compressive stress may be approximated by

$$\sigma_h \approx \frac{\gamma}{1 - \gamma} (S_v - P_p)$$

(Equation 4.22)

Since: $S_h = \sigma_h + P_p$

(Equation 4.23)

$$S_h \approx \left[\frac{\gamma}{1 - \gamma}\right] S_v + \left[\frac{1 - 2\gamma}{1 - \gamma}\right] P_p$$

(Equation 4.24)

$$S_h \approx 11.5 + 0.5 \left(\frac{P_p}{D}\right) \qquad \text{kPa/m}$$

(Equation 4.25)

where:

γ	=	Poisson's ratio (0.33)
S_v	=	total vertical stress (23 kPa/m)
P_p	=	pore pressure ($P_p = P_R$ in pay zones)
σ_h	=	effective grain to grain horizontal stress
S_h	=	total horizontal stress
D	=	depth

Poisson's ratio may have a value of from 0.1 to 0.4, depending on the type of formation. A U.S. Gulf Coast sandstone would typically have a value of 0.33, while a mid-continent limestone may have a value of 0.27 (Reference 4.23). It follows that in a relaxed tectonic area, the effective horizontal matrix stress will be about one-half to one-third the effective vertical stress.

It is important to note the gross generalizations used in deriving this expression and to apply the results with appropriate caution.

The approach is also particularly useful to illustrate the effect that reservoir depletion will have on the minimum horizontal stress. The total vertical stress (S_v), being the overburden gradient, remains constant so that:

$$\Delta\sigma_H = \left[\frac{1 - 2\gamma}{1 - \gamma}\right] \Delta Pr \approx 0.5\ \Delta Pr$$

(Equation 4.26)

Strictly speaking, in looking at a specific zone, the above relationships should be corrected for the effects of rock and bulk compressibility by multiplying by (1 - Cr/Cb), which Schlumberger terms as α in the Mecprolog computations. However, for practical purposes, this can be ignored when an average basin wide value of poisson's ratio, such as 0.33, is used.

Wellbore Area Stresses

The introduction of a borehole into the undisturbed rock distorts the stress field in the general vicinity of the wellbore. Hubert and Willis (Reference 4.24) have shown that classic elastic theory can be applied to estimate the magnitude of the resulting stress, provided corrections are made for pore pressure.

Most failure prediction programs are based on the use of this technique to predict the radial, tangential, and axial stresses at the borehole, or cavity wall, for various geometrical configurations. The simplest form of such equations for a vertical well with non-penetrating wellbore fluids is

$$\text{radial stress} = \sigma_r = P_w - P_o$$

(Equation 4.27)

$$\text{tangential stress} = \sigma_\theta = 3S_h - S_H - P_w - \alpha P_o$$

(Equation 4.28)

$$\text{axial stress} = \sigma_z = S_v + 2\gamma\left(S_h - S_H\right) - \alpha P_o$$

(Equation 4.29)

where:	γ	=	Poisson's ratio
	α	=	1 - (rock matrix compressibility/bulk compressibility) This is omitted in some texts
	S_h	=	minor horizontal total stress (least principal stress)
	S_H	=	major horizontal total stress (intermediate principal stress)
	S_v	=	vertical total stress (maximum principal stress)
	P_o	=	reservoir (pore) pressure
	P_w	=	wellbore pressure

From these equations, it can be seen that as the wellbore pressure decreases, (1) the support of the grains in the radial direction decreases, (2) the tangential grain-to-grain compressive stress increases, and (3) the difference between the maximum and minimum principal stresses on the sand face, therefore, increases. These effects tend to destabilize the sand and cause shear-type failure.

In reality, of course, the situation is more complex, since the pore pressure and effective stresses in the wellbore area vary radially form the wellbore and are not independent of the wellbore pressure, as assumed in this simplified case.

Failure Criteria

Although a number of failure criteria have been proposed for rocks under stress, by far the most universally accepted is the Mohr-Coulomb concept that failure occurs predominantly as a result of shear.

As indicated in Figure 4.19, the Mohr's circle is a convenient way of presenting how the stresses vary on a plane intersecting the maximum and minimum principal stresses.

The radius of the Mohr's circle is equal to the maximum shear stress (ς max):

$$\varsigma_{max} = \frac{\sigma_1 - \sigma_3}{2} = R_M$$

(Equation 4.30)

where: ζ = shear stress
σ_1 = maximum principal stress
σ_3 = minimum principal stress
R_M = radius of Mohr's circle

If a series of Mohr's circles are constructed to represent the failure conditions of similar materials under varying triaxial loads, then it should be possible to construct a failure envelope tangential to these circles.

The Mohr failure envelope is an empirically derived curvo-linear function that is not represented by any general mathematical formula. Typically, it has a parabolic shape that rapidly increases from a low tensional strength and levels off as the compressional loading increases. The **Coulomb failure criteria** is just a special case of the Mohr's envelope that defines the critical shear stress in a cohesive rock in terms of the angle of internal friction (ϕ) and natural cohesion (C):

$$\zeta_{crit} = \sigma \tan\phi + C$$

(Equation 4.31)

The failure envelope for a given reservoir can be determined by laboratory measurements on core material or triaxially loaded formation sand. From such measurements, **it has been found that the angle of internal friction (ϕ) is normally very close to 30°**, particularly at high confining stresses.

Correlations are available relating uniaxial compressive strength of a given lithology to Young's modulus (e.g., Coates and Denoo Reference 4.25). Similarly, several correlations are available for estimating Young's modulus based on sonic transit time measurements, or Brinell hardness measurements on the core material. Thus a first estimate of the failure envelope can be developed based on log data and/or simple core tests, using these correlations and assumptions.

It should be recognized, however, that the failure envelope itself may vary with the rock condition and be affected by the coring and handling process. In particular, changes in the water saturation will affect the rock strength. If the core is allowed to dry out, the cementation will often deteriorate and the rock may crumble. Increasing water saturation may also decrease the rock strength by reducing internal friction coefficients and/or by dissolution of the cementing material.

Application of These Rock Mechanics Concepts

In theory, stress analysis techniques can be used to predict the loading conditions at the wellbore wall, and these can be compared with the rock failure envelope. A set of stress conditions falling inside of this failure envelope can be considered to be safe, and those outside to represent increasing risk of a failure.

This theory is the basis of the Mechanical Properties Log or sand-strength log. The sonic and density logs are used to calculate the elastic moduli of the formation, and hence a failure envelope. This is compared with the computed critical wellbore stresses to develop a prediction of the maximum allowable drawdown prior to sand failure (Reference 4.25). (The formulas used by Schlumberger assume a penetrating fluid, and are, therefore, slightly more complex and theoretically sound than the simplified analysis presented above.)

Several other investigators have used similar concepts. However, as with other strength-of-materials situations, there is confusion between the use of the yield, ultimate strength, and actual failure points in defining the boundary of safe operating conditions. From soil mechanics, it is well known that unconsolidated sand, under triaxial compression, will deform plastically prior to failure. It is also commonly accepted that consolidated rocks, under high confining stresses and temperatures, show considerably increased ductility compared with surface conditions. It is, therefore, not surprising that, as Geertsma points out (Reference 4.26), in collapse situations, "substantial yielding around the borehole is required before actual borehole failure materializes." Thus, the theory of elasticity, as applied to porous rocks (poroelasticity), is too conservative for defining sand failure. Even where failure does occur, the production of the loose sand is controlled by natural bridging and arching at the cavity wall.

In semi-consolidated rocks, mining experience shows that arching not only occurs in the loose material that forms the zone of disturbance at the inner boundary of the plastic zone, but also within the plastic and elastic regions, thereby reducing the effective load on the weakened rock. Thus, unless the initial failure results in total hole collapse, it is not unusual to have a short burst of sand production, which rapidly decreases as natural arching limits the growth of the cavity.

This phenomenon of post-failure stabilization is frequently observed in the field. Although a joint industry project at the Colorado School of Mines has examined the stability of arches in unconsolidated sands, we do not have an adequate theory for predicting the post-failure stabilization of partially consolidated and friable rocks, or the conditions at which the cavity reaches a state of incipient failure. This places a limitation on the application of the rock mechanical theory in a quantitative manner, especially for partially cemented sands.

The principles are, however, useful in developing other predictive tools:

1. Increasing drawdown and depletion will increase the shear loading, due to an increasing difference between the maximum and minimum principal stresses.

2. Higher rock strengths and/or higher average initial stress conditions will result in a greater region of stability (safe region) below the failure envelope. The two effects are sometimes termed the **cementation** or **formation strength index**, and are correlated with sonic transit time data in the formation and/or surrounding shales (lower sonic transit times indicating stronger and/or more compacted rock).

3. In addition to the safe and failure regions, there is likely to be a risk region in which some zones produce sand while others do not (or show intermittent, minor sanding).

4. Water production will probably increase the area of the risk and failure regions (i.e., a downward displacement of the failure envelope).

Figure 4.20 shows the type of relationship that can be expected between cementation indicator (e.g., rock type, hardness, sonic transit time, log-derived strength index) and drawdown. This concept was first proposed by N. Stein of Mobil in 1972 (Reference 4.27/8) and has subsequently been used by several other experts.

Despite considerable research on this subject since 1970, our capabilities in this area are not well developed, and rely heavily on qualitative judgment and local experience. Some success has been achieved on a regional basis in poorly consolidated sands (e.g., on the U.S. Gulf Coast and in the Niger Delta), but no universally applicable criteria can yet be considered proven.

In general, borehole stability and sand prediction specialists still have to rely on a combination of

- analogy
- core inspection and testing
- log interpretation
- special well tests
- field experience

The first step is to consider the field characteristics, including

- geological age
- depth of zones
- environment of deposition
- pressure regime
- development concept
- fluid type and viscosity
- porosity and permeability
- primary cementation material

These are reviewed and compared with similar fields elsewhere in the region and/or the world.

It is well known that severe sand production and borehole collapse tendencies can be expected from

- young, shallow, poorly cemented, dirty, deltaic sandstones, especially under depletion drive conditions

- heavy oil wells

- highly overpressured, poorly cemented sands

Poor conventional core recoveries are often an early indication of the potential for borehole collapse, provided good coring techniques were used. Similarly, if the core falls apart as it is retrieved, the risks of sand production is substantial. Mechanical properties can also be measured on the core.

A great deal of work has been done on the prediction of sand strength from logs, especially by the major companies, some of whom have proprietary in-house techniques. Schlumberger has developed its mechanical properties log (MPL) and MECPRO logs, or, more correctly, computer analysis techniques, in an attempt to predict sand failure. Various papers have been published on the use of the borehole-compensated sonic, full wave train sonic, and sonic/density combinations for this purpose.

Such log analysis techniques are sometimes reduced to a simple rule of thumb that sand production can be expected from any zone with a sonic transit time in excess of some locally determined threshold, usually ranging from 310 to 360 μs/m (95 to 110 μs/ft.).

Of the other sand production indicators, the most commonly used is that developed by Tixier (Reference 4.29) using log-derived factors of shear modulus (G) divided by bulk compressibility (C_b):

$$G = 1.34 \times 10^{10} \frac{A\rho_b}{t_c^2} \quad \text{(psi)}$$

(Equation 4.32)

$$\frac{1}{C_b} = 1.34 \times 10^{10} \frac{B\rho_b}{t_c^2} \quad \text{(psi)}$$

(Equation 4.33)

where:

where:	G	=	shear modulus (psi)
	C_b	=	bulk compressibility (psi^{-1})
	ρ_b	=	bulk density (gm/cm^3)
	t_c	=	compressional transit time (μs/ft)

The constants A and B are related to Poisson's ratio by the following equations:

$$A = \frac{1 - 2\gamma}{2\ (1 - \gamma)}$$

(Equation 4.34)

$$B = \frac{1 + \gamma}{3\ (1 - \gamma)}$$

(Equation 4.35)

where: γ = Poisson's ratio

Several techniques have been proposed for estimating Poisson's ratio from log response. However, G/C_b is not very sensitive to this factor.

γ	=	.2	.3	.4
A	=	.38	.29	.17
B	=	.5	.62	.78
AB	=	.19	.18	.13

For the U.S. Gulf Coast, the threshold above which sand production should not be expected has been variously stated at between 0.7 and 0.98 x 10^{12} psi^2 (Reference 4.24). Initially, this was claimed to have fairly universal application; however, further experience showed this to only be true if the depth versus sonic trend was similar to the U.S. Gulf Coast.

Schlumberger now utilizes a modification of the technique to estimate the sand failure envelope, and applies this in a wellbore area stress model to estimate the maximum drawdown and/or depletion that could occur without inducing sand failure. The industry is still in the process of evaluating this technique, but it appears to work for some areas while being too conservative for others.

Properly conducted well tests with effective surface, and possibly downhole, sand-detection equipment are the best method for proving the conditions at which continuous sand production occurs.

Using techniques of this type, several operators have conducted borehole stability predictions for their Beaufort Sea discoveries (Reference 4.30). From these, it is concluded that the:

- Pullen Delta sands are generally semi-consolidated to friable with poor cementation, often only localized.

- Drill cuttings indicate most sections are unconsolidated or poorly consolidated.

- Sand strength increases with depth.

- All zones will collapse at drawdowns exceeding 7 MPa and most will collapse at drawdowns of around 3 MPa.

- At Amauligak, the Upper and Middle Pullen Sands will definitely collapse during a blowout and the Lower Pullen will likely collapse.

The Reservoir and Production Division at COGLA have examined these reports and support the conclusion that:

> "In light of current knowledge of these formation and reservoir properties, there is a high probability that a well drilled through one or more of these formations will shut itself off, should a (severe 1600 - 3000 m^3/d) blowout occur". (Reference 4.31)

A recent paper from the US Gulf Coast suggests that the maximum drawdown predictions made by Schlumberger are reliable within about 1.4 MPa in unconsolidated deltaic sands (Reference 4.32). Other recent papers (References 4.33/4) indicate that fluctuating drawdowns, typical in blowouts, can significantly weaken friable sandstones due to plastic deformation causing tensile loading; and that brittle rocks increase the tendency for shear failure. This supports the conclusion that even the deeper sands may rapidly fail during a blowout.

Although not specifically discussed elsewhere, it is apparent, by implication, that the shallow sands around the shoe of the surface casing will be even weaker than the reservoir rocks and will, therefore, collapse even sooner.

Moreover, we believe that the predominant failure mode during a blowout is likely to be catastrophic failure of an entire sand section, as observed by Vriezen (References 4.35/6) or rapid bridging due to large pieces of debris falling into the wellbore, rather than a cavity enlargement process.

Thus, the key issue in developing a worst case blowout scenario is NOT the determination of a minimum bottom hole pressure or an Absolute Open Flow Potential (AOF) but the definition of plausible cases where the drawdown is less than some 4.4 MPa. (3 + 1.4 MPa).

4.6 Theoretical Factors Limiting Flow Capacity or Duration

Hydrates

Hydrates are solid crystalline substances resembling snow or ice in appearance with densities between 950 and 970 kg/m^3. Hydrates can form when CO_2, H_2S, or light hydrocarbon gas molecules, C1 to C4, are dissolved in water in the vicinity of 0 °C. Liquid water must be present and gas must be dissolved in the water. Hydrate forming temperatures increase with increasing pressure and can be as high as 25 °C. At high pressures, above 10 MPa, the hydrate temperature is quite sensitive to the composition of butanes and propanes, and relatively insensitive to pressure. A typical hydrate curve is provided in Figure 4.21, presented as pressure versus temperature. Hydrate curves usually do not vary much from one reservoir to the next. Hydrates which form at high pressures can be re-melted by lowering the pressure.

For practical purposes, if hydrate forming conditions prevail then the amount of hydrates formed can be assumed to be equal to the amount of liquid water present. Salinity inhibits hydrate formation to some degree. For example, adding NaCl to make a 3% solution could lower the hydrate temperature by 2 °C. Amauligak formation brines are apparently not very saline, typically 3%.

One of main production problems in subsea wells is hydrates forming around restrictions and valves (Reference 4.38). Many cases have been recorded where hydrates damaged valves and plugged off chokes. Also, hydrates have been known to plug off subsea flowlines, requiring depressurization to remove the plug (Reference 4.39).

Hydrate Plugging of Gas Blowouts

Low rate gas blowouts in cold surroundings offer ideal conditions for hydrate plugging. It can be assumed that the gas is saturated with water at reservoir conditions. As the gas cools, the water will condense out on the walls of the flow channel. If hydrate conditions prevail and gas velocity is low or moderate (e.g. a restricted rate blowout scenario), then hydrates will form and build-up on the walls of the flow channel, thus restricting flow.

The upper part of the Amauligak reservoir is about 70 °C and 30,000 kPa. Assuming that the reservoir gas is saturated with water vapour, every kg of gas produced will carry roughly

1 gram of water vapour. Most of this water will condense out at the cold surface temperatures and likely form hydrate deposits or possibly ice. In the event of a low rate gas blowout, these deposits will restrict flow and, eventually, will likely shut off flow.

Since pressure, temperature and flow rate are key parameters affecting hydrate deposition, a thermal-hydraulic simulator is required to estimate hydrate deposition rates during a gas blowout.

Hydrate Effects in Oil Blowouts

The role of hydrates during an oil blowout is not as predictable. If hydrate conditions prevail and sufficient quantities of low molecular weight gas (C1-C4) is dissolved in the water, the amount of hydrates that form can be estimated roughly as the amount of water present. However, the hydrates that form won't necessarily deposit on surfaces or restrict flow. It is likely that much of the hydrates will be carried to the surface by the flowstream.

If the water cut is high, and if there are restrictions in the flow path, it is likely that hydrates or ice will plug off the flow stream. For example, if there is an external blowout then the narrow flow channel through the rock or cement channel will likely plug off due to hydrates or ice, especially given the cold temperatures at the surface. In such cases, one can assume that the fluid temperature will be equal to the surrounding rock temperature. For a blowout up the wellbore, the likelihood of plugging due to hydrates will depend on the temperature and pressure of the fluid in the wellbore, and the presence of flow restrictions. At high flow rates, the temperature will likely be above the hydrate temperature. If flow rates can be reduced then hydrates could kill the well.

Wax

Waxy crudes can become extremely viscous at cold temperatures thus resisting flow. Furthermore, waxy crudes can form deposits on the walls of the flow channel thus restricting or plugging off flow. The key parameter is temperature, since temperature affects the solubility of the wax. Hence, waxy crudes may play a role in restricting oil releases during a blowout.

A major waxy crude study was performed for Gulf on Amauligak crudes in 1989 (Reference 4.37). This study indicated that the Upper and Middle Pullen crudes are relatively wax-free but the Lower Pullen crude is extremely waxy. A 50:50 crude blend of Lower:Upper and Lower:Middle were also found to be very waxy. The 50:50 blend was considered to be a base case for the total production life of the reservoir. The maximum wax deposition temperature was determined to be 25 °C for the Lower Pullen and the 50:50 blends. The pour point of the Lower Pullen is 9 °C, indicating that the crude behaves as a solid gel below this temperature. However, the effect of wax will depend on the fraction of Lower Pullen crude in the crude blend. Below 50 % by volume of Lower Pullen in a blend, the effect of wax diminishes.

For a high-rate oil blowout up the wellbore, wax will not play a role in restricting flow since the wellhead temperatures will be higher than the wax appearance temperature. However, if flow rates are low, thus allowing wellhead temperatures to fall below 25 °C, then wax could help plug off the well.

For an external oil blowout, wax will likely play a significant role in reducing surface releases since crude temperatures will likely fall far below 25 C.

5.0 DEVELOPING INPUT ASSUMPTIONS FOR BLOWOUT PREDICTION

From the above discussions, it is apparent that the development of a Worst Case Blowout Scenario is extremely complex, and case specific. It should therefore be done by the individual operators on a field-by-field or area-by-area basis, and may involve special considerations for specific wells (e.g. wells penetrating a gas cap or overpressured zone).

The following is a list of the factors that we would recommend be considered in developing such a scenario. It is not intended to be either exhaustive or a check list detailing the minimum considerations, but rather a general discussion of typical data sources, not all of which will be applicable to all wells.

5.1 Regional Information

The reason that delineation drilling and exploration of a known basin are less-risky than rank wildcats is availability of regional data. The Canadian regulatory authorities and operator associations have done an excellent job in making sure that this information is in the public domain and available to other operators in the region.

As discussed in Chapter 3, the key parameters are:

1) the depth-pressure trends and the occurrence and type of abnormal pressures.

2) the lithology, particularly the occurrence of fractured formations and carbonates.

3) the formation fluids, particularly with respect to the probability of encountering gas or sour fluids.

4) the regional extent of a particular problem type (e.g. overpressures below 3500 m).

5.2 Offset Well Information

Relevant offset well information is obviously the best indication of the type of formation and drilling problems to be expected.

As discussed in Chapter 4, the parameters required to develop a well IPR are:

- Net thickness of the permeable zones exposed in the open hole.
- The expected porosity-depth trend.
- The expected permeability-porosity trend.
- The oil density and GOR.
- The tested permeability, skin and IPR.

These can be obtained from the logs, cores and well test results.

This information must be integrated into the geological prognosis for the well being drilled. Some offset wells will obviously be totally irrelevant, since they may not have gone deep enough, or have been drilled in an area with a totally different depositional setting.

Where clear regional trends exist (e.g. a sand shaling out to the North), it is obviously better to select parameters based on the trend rather than some averaged value. Similarly, where there is no clear trend, the maximum value should probably be used to establish a worst case rather than an average of the surrounding wells. However, the permeability and porosity data across an individual zone should be averaged.

5.3 Geophysical, Geological and Prognosis Data

Obviously, the worst case blowout scenario for a specific well must reflect the geological prognosis for that well and the hydrocarbon expectations.

It is apparent from Equation 4.1 that thinning or thickening of the sands will have a proportionate effect on the expected IPR. Similarly, the hydrocarbon expectations will vary depending on where the well is located on the structure. Crestal wells are much more likely to encounter gas, unless there is clear evidence that the downdip oil zones were significantly undersaturated. Gas may also be identifiable as seismic bright spots.

Seismic data can also sometimes be used to identify the probable top of overpressures or where the penetration of a fault, or unconformity, may lead to a change in pressure regime or fluids.

The casing scheme and length of open hole will determine what zones can be expected to contribute to a blowout. Of particular importance are:

i) Any expected gas zones.

ii) Shallow water bearing zones which may collapse or significantly increase the producing water cut.

iii) The expected shoe strength during penetration of the hydrocarbon bearing zones.

5.4 General Assumptions

The operator should develop at least two plausible blowout scenarios for a short duration high rate event that would likely kill itself or be controlled from surface; and a long duration low rate event that would require a relief well. The scenario should discuss the sequence of events that might lead to the blowout, the blowout path and the time frame under which the well could be brought back under control.

The scenario should also discuss the well configuration, the IPR assumptions and the outflow potential as illustrated in the next section.

6.0 TYPICAL WORST CASE PREDICTIONS

The approach discussed above is illustrated in this chapter **for a completely hypothetical field** described in Figures 6.1, 6.2 and Table 6.1.

6.1 Hypothetical Field Data

The hydrocarbons are located in two reservoirs between 2740 and 3050 m both of which contain a gas cap, oil rim and water leg. A perfectly located delineation well is planned to prove up some 15.9 x 10^6 m^3 (100 MMbbls) of oil and 115 x 10^6 m^3 (41 BCF) of gas, by penetrating both contacts in both zones.

The upper pay zone is extremely well developed having an average permeability of 1 D., while the lower pay zone is somewhat better cemented and has a permeability of 250 mD.

Both zones are quite thick but include substantial shale layers to give a net to gross ratio of 0.2.

Two casing schemes have been considered, as shown in Figure 6.1, one where the pay is drilled with only the surface casing set at 914 m; and a second where the intermediate casing is set at 2743 m before drilling the pay.

The well control situation leading to the hypothetical blowout is also illustrated in Figure 6.1. While tripping out of the well for logging, gas from the upper high permeability gas zone is swabbed in behind the bit, with flow being detected and shut-in when the bit is at the top of the pay at 2743 m.

Normally, this type of kick would be handled quite satisfactorily by routine well control procedures. However, the blowout scenarios consider what could happen in the very unlikely event that something went seriously wrong during these operations.

It is important to remember that, as discussed in Section 2, we are investigating a 1 in 10,000 well event that has an expected occurrence frequency of less than 1 in 1000 years at foreseeable exploration activity levels!

6.2 Blowout Scenarios

Four blowout scenarios have been considered for this well, two for each casing scheme, as shown in Tables 6.2, 6.3, 6.4 and 6.5 and Figures 6.3 and 6.4.

CASE 1 (Table 6.2 and Figure 6.3)
Short Duration, High Rate Event with Shallow Casing

- Internal BOP was cross threaded and blown off when well was shut-in.
- Shear rams fail to operate or to cut the pipe.
- Blowout Duration: < 7 days.
- Well is capped from surface by installation of a valve on the drill pipe or repair of the shear ram function.

CASE 2 (Table 6.3 and Figure 6.4)
Long Duration, Low Rate Event with Shallow Casing

- Internal BOP was cross threaded and blown off when well was shut-in.
- Shear rams operate and successfully cut the pipe.
- An attempted squeeze kill inadvertently results in breakdown at the shoe.
- Vertical fracturing in the vicinity of the borehole, or between the cement and formation, allows the hydrocarbons to flow to surface through a 3.8 mm circumferential crack, along the wall of the original borehole.
- Blowout Duration: < 65 days.
- The well is brought under control either through the original borehole or by drilling a relief well.

CASE 3 (Table 6.4 and Figure 6.3)
Short Duration, High Rate Event with Deep Casing

- While circulating out the kick, sand erodes a hole in the kill valve body.
- An attempt is made to kill the well by pumping mud from the reserve pit.
- Barite settlement during pumping of heavy mud to control the well plugs off the bit or dart sub.
- Hydrocarbons flow to surface through the side outlet.
- Blowout Duration: < 7 days.
- The well is brought under control by perforating the drill pipe above the hold up point and circulating the well dead. (With a shallow set casing, the well would probably kill itself even sooner by collapse of the upper zones.)

CASE 4 (Table 6.5 and Figure 6.4)
Long Duration, Low Rate Event with Deep Casing

- Gas was swabbed in while tripping out the hole with a plugged bit.
- During an attempt to run the drill pipe to bottom, the string was inadvertently dropped into hole and the well shut-in on the blind rams.
- During an attempted squeeze kill, the casing burst at a weak point near surface caused by wear, or by a mill defect.
- The surface casing could not contain the resulting pressure and also burst.
- The split casing acts as a choke.
- Blowout Duration: < 65 days.
- A relief well has to be drilled to control the well.

6.3 IPR Modelling

All immediate offset wells had been wet and were not tested; therefore, theoretical IPR's were developed using Darcy's Radial Flow Equation. The simulation work was done on the Well Evaluation Model (WEM) simulator developed by P.E. Moseley (Reference 4.18).

The calculated liquid IPR's, including skin and non-Darcy flow effects from 76 mm of damage to 40% of the initial permeability, are shown in Figure 6.5 and are dominated by the oil and water influx from the Upper Pay Zone. The sensitivity of the Upper Oil Zone IPR to the damage assumptions is shown in Figure 6.6. As discussed in Section 4.2, we believe that 40% damage is a minimum expectation and that much more extensive damage can be expected from an uncompleted well. The IPR's are therefore a worst case, and represent the conditions where flow has caused substantial clean-up.

The Oil IPR's are then corrected for the relative permeability effects of gas breakout at high drawdown using the Vogel equation (Figure 6.7).

The Oil and Water IPR's were then combined to develop a total IPR (Figure 6.8). This shows that the sandface AOF could theoretically be as high as 50,000 m^3/d of total fluid with an oil rate of 28,300 m^3/d and a water cut of 43%.

Of course, this AOF could not actually be achieved because atmospheric pressure can never reach the bottom of a flowing well at these rates.

The combined IPR was then back-loaded into the simulator as a multi-rate test. Analysis showed the minimum resultant total skin (S') to be +7.5. In reality, we would expect higher skin values to further limit the rate.

Similarly, the free gas rates from the two zones was estimated (Figure 6.9) and is dominated by the influx from the high permeability upper sand where there is 12 m of net gas pay in a 1 D. sand. **From this, it is easy to see why gas kicks and blowouts are much more common.**

As discussed in Chapter 4.6, it seems improbable that drawdowns in excess of 3 MPa can be sustained on the weaker upper sand. Therefore, the expected Gas and Fluid Influx at

27.6 MPa was used to approximate a Worst Case GLR (1205 m^3/m^3) and water cut (35%), resulting in an equivalent GOR of 1854 m^3/m^3.

6.4 Outflow Modelling

The blowout paths discussed in Section 6.2 were also modelled on WEM (Figure 6.10) as outflow performance curves, using 0% Water Cut and Solution GOR of 135 m^3/m^3 as a worst case (minimum gas velocity at surface). A modified Duns and Ross flow correlation suitable for high rate wells was selected.

The results show that the Maximum Outflow Performance Capacity will limit the blowout capabilities in all four cases. Even with an infinite IPR, the outflow capacities would be less than:

Case	Maximum Theoretical Outflow Rate m^3/d
I	2050
II	110
III	2150
IV	1060

6.5 Blowout Rate Predictions

The combined IPR and OPC for CASE I is given in Figure 6.11. This shows that the maximum expected blowout rate for the case of a high GLR and 35% water cut is 1350 m^3/d; and that it is insensitive to wellhead pressure. In fact, because of the gas expansion effects, lower pressure will further reduce the rates.

Figure 6.12 shows the sensitivity to GOR and average combined zone formation permeability. As expected, lower kh values will significantly reduce the blowout capacity and increase the probability of formation collapse.

As discussed in Chapter 4, it is interesting to see how the lower GLR's result in higher maximum rates; while for high drawdown blowouts on low permeability zones, free gas production increases the rates.

The effect of water cut is illustrated in Figure 6.13 for a HGOR well (1854 m^3/m^3) and Figure 6.14 for well producing at SGOR. As expected, the trends are significantly different. At high gas rates, reducing the GLR allows more liquid to be produced because of the reduction in surface velocity and resulting friction. At low GOR's, the increasing head of the water dominates and reduces the overall rate, so that the well would quit as the water cut approached 100%.

The velocity effects at the maximum predicted rate are clearly illustrated in Figure 6.15. This shows how the velocity rapidly increases over the upper 200 m of the well. It is also apparent that this rate is not actually attainable, since the calculated surface velocity exceeds the sonic velocity. The high velocities result in rapid pressure losses near surface, as illustrated in Figure 6.16.

The stabilized flowing temperatures predicted by WEM are illustrated in Figure 6.17. This shows how even in with a cold ground temperature (-2°C), high liquid rates create high wellhead temperatures (> 60°C). Actually, the Enertech program WT-PROD (Reference 4.40) is a much better thermal simulator and can show how the wellhead temperature will increase with time (Figures 6.18/19).

A wellhead deliverability plot (Figure 6.20) is often used to show how blowouts are self-limiting and the effects on flow of choking back the wellhead pressure. The conditions under which sonic velocities can be expected can be plotted across this, as shown in Figure 6.21, to determine the maximum practical rate. In this case, it is 1325 m^3/d fluid at 35% water cut and 1854 m^3/m^3 GOR; or 861 m^3/d (5417 BOPD) of oil and 1.6 x 10^6 m^3/d (56.7 MM Scf/d) of gas. In seven days, the total volume of oil that might be spilt is some 6000 m^3 (38000 bbls). If not capped from surface, this blowout rate could continue for an extended period without significant pressure depletion (estimated at less than 2% in 65 days). Moreover, the drawdowns are very low (<0.5 MPa) indicating that sand collapse may not occur. **Therefore, determination of the worst case blowout is a matter of estimating the probability of being able to cap the well from surface and the time that will be required.** We rate this as high and expect the maximum duration of such a blowout to be less than seven days, based on the MMS data base (Reference 2.8) but this is a judgement call that must be made by the operator.

Where the blowout path is even more restrictive, as in Case II, where the well is flowing outside of the casing, the friction effects will be even more dramatic. Figure 6.22 shows how the maximum expected rates for this case would be less than 84 m^3/d at a GOR of 1854 m^3/m^3, or only 54.5 m^3/d (343 BOPD) of oil and 0.1 x 10^6 m^3/d (3.6 MM Scf/d) of gas. However, this is a case that might be expected to flow for the full 65 days resulting in a total spill of some 3540 m^3 (22,300 bbls), assuming that the flow path did not bridge-off in the meantime. This is less than that expected in the high rate short duration event.

Similar curves can be generated for the other scenarios, but this has not been undertaken since this was only a hypothetical case.

The effect of depth on the blowout capacity for Case I at Solution GOR is presented in Figure 6.32. From this it can be seen that the reservoir pressure has a more significant effect than the shorter flow path.

Depth Mid-Pay (m)	Maximum Fluid Rate (m^3/d)
2896	1900
2396	1700
1896	1450

The blowout volumes estimated above are in agreement with earlier estimates that the 1:10,000 well event is likely to involve an oil spill of less than 20,000 m^3 (126,000 bbls) even in a highly productive formation (Reference 2.7, 2.8 and 2.11).

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8.0 GLOSSARY OF TERMS

8.1 Abbreviations

AOF:	Absolute Open Flow Potential, the maximum theoretical flow capacity of a well with atmospheric pressure at the surface
API:	American Petroleum Institute, an industry funded body that publishes standards, specifications and recommended practices commonly used by the oil industry
ASL/AGL:	Above Sea Level/Above Ground Level
ATDW:	Authority to Drill A Well, granted by the Canada Oil and Gas Lands Administration
BEARP:	Beaufort Sea Environment Assessment and Review Process
BHA:	Bottom Hole Assembly, the equipment on the bottom of the drill pipe or tubing
BHP:	Bottom Hole Pressure
BOP:	Blowout Preventor, which is a series of valves and closing devices (rams) on top of the casing strings. These valves can be closed to prevent a release of oil or gas when other means of well control have proven ineffective.
BSB:	Below Seabed
CHP:	Casing Head Pressure or pressure in the casing at surface
COGLA:	Canada Oil and Gas Lands Administration
CPA:	Canadian Petroleum Association
DEA:	Drilling Engineering Association
DIAND:	Federal Government Department of Indian Affairs and Northern Development, also referred to as INAC
DP:	Drill Pipe

DPA:	Drilling Program Approval granted by the Canada Oil and Gas Lands Administration
DST:	Drill Stem Test, which is a procedure for evaluating the well by flowing well fluids into the wellbore
FBG:	Formation Breakdown Gradient
FBHP:	Flowing Bottom Hole Pressure
FGLR:	Formation Gas Liquid Ratio
FPP:	Fracture Propagation Pressure
FTHP:	Flowing Tubing Head Pressure/system back pressure
GIIP:	Gas Initially In Place
GLR:	Gas Liquid Ratio expressed as m^3/m^3 (scf/b)
GOR:	Gas to Oil Ratio expressed as m^3/m^3 (scf/b)
HWDP:	Heavy Weight Drill Pipe
ID:	Inside Diameter (d)
IFA:	Inuvialuit Final Agreement on the Western Arctic Land Claim, 1985
IPR:	Inflow Performance Relationship or how flow rate changes with bottom hole pressure
JCPT:	Journal of Canadian Petroleum Technology, the technical publication of the Petroleum Section of the Canadian Institute of Mining
JPT:	Journal of Petroleum Technology, the technical publication for the Society of Petroleum Engineers (SPE)
KBE:	Kelly Bushing Elevation or rig floor elevation
kh:	Formation Permeability Thickness which determines a well's ability to flow
MODU:	Mobile Offshore Drilling Unit

MPP:	Mid-point of perforations/producing interval
MSL:	Mean Sea Level
MWD:	Measurement While Drilling System, which is a downhole tool that collects engineering and geological data to surface while drilling
NaCl:	Sodium Chloride (salt)
RFT:	Repeat Formation Tester, which is a tool that can repeatedly take pressure readings of the formation fluids
SIBHP:	Shut-in Bottom Hole Pressure
SITHP:	Shut-in Tubing Head Pressure
SPE:	Society of Petroleum Engineers
TCP:	Tubing Conveyed Perforating
TGLR:	Total Gas Liquid Ratio
TGOR:	Total (output) gas oil ratio
THP:	Tubing Head Pressure
THIP:	Tubing Head Injection Pressure
TPC:	Tubing Performance Curve
TVD:	True Vertical Depth
WEM:	Well Evaluation Model (PC Program by P.E. Moseley and Associates Ltd.)
WHP:	Well Head Pressure

8.2 Technical Terms

d:	Internal Diameter (ID)
D:	Depth
D:	Non-Darcy rate dependent skin coefficient
G:	Gas Gravity (Air = 1) or liquid specific gravity
h:	Net productive interval
h_o:	Net oil pay being drained
H_L:	Measured length of the perforated interval along hole
h_p:	Perforated length of completed interval
J:	Productivity Index (PI) of a well in $m^3/d/kPa$ (b/d/psi)
J_f:	PI of a fracture stimulated well
J_o:	PI with no damage or zero mechanical/geometric skin
K:	Permeability of a rock in mili-Darcies
K_g:	Effective gas permeability
Kh:	Permeability thickness
K_H:	Horizontal permeability
K_o:	Effective oil permeability
K_p:	Permeability in the perforated interval or near wellbore
K_{ro}:	Relative oil permeability
K_{rw}:	Relative water permeability
K_s:	Permeability of skin zone
K_u:	Undamaged zone permeability

K_v:	Vertical permeability
M(P):	Gas pseudo pressure
MW:	Mud weight
P:	Pressure
P_b:	Bubble point
P_e:	Reservoir pressure at the drainage boundary (re)
P_i:	Initial reservoir pressure
P_R:	Reservoir pressure
P_{tb}:	Tubing intake pressure
P_{wf}:	Bottom hole flowing pressure
P_{wfs}:	Flowing pressure at sandface
PI:	Productivity index (J)
PT:	Pressure test
PVT:	Pressure - volume - temperature relationship of hydrocarbons
q:	Flow rate
q_{max}:	Maximum theoretical flow rate of an oilwell with atmospheric pressure at sandface
q_g:	Gross production rate
q_o:	Oil rate
q_w:	Water rate
Q_T:	Total gas rate
r_e:	Systems external radius
r_s:	Radius of skin

r_w:	Well radius of the opening hole prior to casing in
R_s:	Solution gas oil ratio (SGOR)
S:	Skin, which is a petroleum engineering concept used to describe variations from the Darcy Ideal Radial Flow Equation. It is usually caused by a combination of formation damage, flow and geometric effects.
S':	Total skin due to Darcy and Non-Darcy Effects
S_a:	Skin due to partial completions
S_p:	Skin due to perforations
S_s:	Skin due to fracturing/stimulation
S_t:	Skin due to formation damage (true skin)
S_{tp}:	Skin due to two phase flow
S_w:	Water saturation
SG:	Specific gravity of a liquid (water = 1)
T_R:	Reservoir temperature
W_f:	Propped frac width after closure
x_f:	Length of one wing of a fracture
Z:	Gas deviation factor
Zm:	Distance from top of pay to middle of perforated interval
ΔP_{Total}:	Total pressure drop
ΔP_f:	Frictional losses
ΔP_s:	Pressure drop due to skin effect
ß:	Turbulent factor
δ:	Pressure drop per unit length

ρ:	Density
σ:	Effective stress
μ:	Viscosity
ϕ:	Porosity

8.3 Definitions

Abnormal Pressure:	A formation pressure that is significantly different from the normal hydrostatic gradient of 10 kPa/m (0.44 psi/ft) (i.e. more than 11 kPa/m (0.5 pis/ft) or less than 9 kPa/m (0.4 psi/ft).
Blowout:	An uncontrolled release of reservoir fluids from the well.
Casing String:	A length of steel pipe that extends from the surface or seabed to some depth in the hole and which is used to contain well pressure and support the hole.
Choke Manifold:	An arrangement of valves and chokes designed to regulate the flow of reservoir fluids at surface.
Conductor Pile:	The first string of pipe (casing) that is run as a foundation for future casing strings and blowout preventor loads. This is normally 762 mm (30 inch) in diameter.
Drawdown:	The difference between the flowing bottom hole pressure and the reservoir or formation pore pressure.
Drilling Prediction Curve:	A chart that is derived from surface seismic data of underlying formation pressure gradients.
Gas Diverter:	A piece of equipment designed to redirect a flow of gas out to one side of the rig.
Gas Hydrates:	A solid mixture of water and gas, most often methane, that may be found under certain low temperature and high pressure conditions. They are found in Beaufort sediments and can form in the flow stream.
Gas Influx:	Formation gas entering the wellbore as a result of reservoir pressures greater than those of the column of the mud in the hole.
Geophysical Logs:	Profiles obtained using acoustic reflection and refraction techniques to define the subsurface lithology and structure.
Inflow Performance:	The rate at which a permeable formation will flow fluid at a specified drawdown.

Kill Muds:	Drilling mud held in reserve or specifically mixed to counter balance overpressure formations if they are not controlled by the normal drilling mud.
Kill Operation:	Pumping fluids into a live or blowing well to regain control.
Logging:	The process of using recording instruments to monitor and/or measure the properties of the material surrounding the recording device. This may include rock formations, their contents, or other materials.
Normal Pressures:	Hydrostatically pressured formations with a pressure gradient between 9 and 11 kPa/m (0.4 - 0.5 psi/ft).
Outflow Performance:	The bottom hole pressure required to lift fluids through the wellbore or tubing at a specified rate.
Overpressured Zone:	A zone that has a pore pressure exceeding 11 kPa/m (0.5 psi/ft).
Overpressuring:	The change of a normal pressured zone to an overpressured zone.
Packer:	A rubber element and holding device that can be expanded downhole to seal between various pipe sizes to prevent flow.
Permafrost:	Sediments where the pore fluids are permanently ice.
Physiographic:	Within the context of this report, this term defines a geographic area having a similar depositional environment. In the general context, it is a geographic area having some similar elements of nature.
Productivity Index:	Amount of liquid production expected for each increment of drawdown, expressed as $m^3/d/kPa$ (b/d/psi).
Relief Well:	A well drilled beside a well that has a blowout. The relief well is drilled at an angle so that it intersects the original wellbore. The new well is then used to regain control of the blowout.
Riser:	A length of steel pipe used to connect the wellhead and/or blowout preventor on the seabed to an offshore drilling rig.

Risk Operations:	Drilling operations which have formations below the risk threshold depth open to the wellbore (i.e. not behind casing).
Risk Threshold Depth:	The depth at which there is a risk of a blowout from an oil reservoir.
Same Season Capability:	The capability of drilling a relief well within the same drilling season.
Shallow Casing:	Casing set at a shallow depth to provide a foundation for future loads and allow venting of shallow gas.
Sonic/Resistivity Logs:	Sonic Logs are downhole readings which measure and record the ability of the rock to transmit sound waves. This ability can indicate the rock formation density. Resistivity logs are downhole readings which measure and record the ability of the formation to resist an electrical current. This can indicate the type of fluid found in the formation.
Stratigraphy:	The different rock types encountered in an area.
Surface Casing:	The first string of casing upon which a full set of blowout preventors are effective (usually the 340 mm (13.375") pipe in offshore wells and the 244 mm (9.625") pipe in onshore wells).
Surface Kill:	Bringing a blowout under control by accessing the blowout well itself (i.e. by closing a valve on surface)
Test String:	The steel tubing, packer, and valve assembly that is run in the hole to flow test a formation.
Tubing:	A small diameter steel pipe that is used for testing purposes. It is inside the casing.
Well Logs:	A log of the wellbore which indicate the properties of the wellbore, the surrounding formation, or the formations contents.
Worst Case Blowout:	One that will result in a significant oil spill. (It has an occurrence frequency of less than 1 in 10,000 wells.)

TABLE 2.1

SUMMARY OF MANADRILL DATA

	ERCB Landwells Alberta 1900-1983	Worldwide Offshore Drilling 1955-1980
# wells	97,000	36,633
blowout frequency	1/1540	1/225
oil blowout frequency	1/12125	1/3055
major oil blowout frequency	1/97000	1/7325
relief well frequency	1/12125	1/3330
relief well on oil blowouts	1/48500	1/18320

TABLE 3.1

BLOWOUT RISK CLASSIFICATION FOR EXPLORATION WELLS
(Ranked in Order of Decreasing Risk)

Risk	Wildcat	Carbonates	Gas Zones	Over-Presures	H_2S	Modern Rigs	Experienced Crews	>3000 m
I	Y	Y	Y	Y	Y	N	N	Y
II	Y	Y	Y	Y	Y	Y	Y	Y
	Y	Y	Y	Y	N	N	N	Y
	N	Y	Y	Y	Y	N	N	Y
III	Y	Y	Y	N	N	Y	Y	Y
	Y	N	Y	Y	Y	N	N	N
	N	Y	Y	Y	Y	Y	Y	N
	N	Y	Y	Y	N	Y	Y	Y
IV	Y	Y	N	N	Y	Y	Y	N
	Y	N	Y	Y	N	Y	Y	N
	N	Y	Y	N	Y	Y	Y	N
V	Y	N	Y	N	Y	Y	Y	N
	N	Y	N	N	Y	Y	Y	N
	N	N	Y	N	N	Y	Y	Y
VI	N	Y	N	N	N	Y	Y	N
	N	N	Y	N	Y	Y	Y	N
	N	N	N	Y	N	Y	Y	Y
	N	N	Y	N	N	Y	Y	Y
VII	N	N	N	N	Y	Y	Y	N
	N	N	Y	N	N	Y	N	N
VIII	N	N	N	N	N	Y	Y	N

I High Risk Wells typical of Arabian Gulf.
VIII Low Risk Wells typical of Alberta Oil Sands.

TABLE 6.1

BEAUFORT SEA WORST CASE BLOWOUT SCENARIOS

HYPOTHETICAL FIELD MODEL

Upper Zone	Total Isopach	=	135 m
	Porous Sand	=	27 m
	Net:Gross	=	0.2
	k	=	1000 md
	ϕ	=	0.25
	S_w	=	0.2
	GOC	=	2804 mTV
	OWC	=	2850 mTV
	Grad	=	9.9 kPa/m
	P_R	=	28,520 kPa
	G	=	0.6
	API	=	30°
	GOR	=	135 m^3/m^3
	BHT	=	75°C
	μ_o	=	0.55 MPa·s at reservoir conditions
	B_o	=	1.38 m^3/m^3
Lower Zone	Total Isopach	=	122 m
	Porous Sand	=	24 m
	Net:Gross	=	0.2
	k	=	250 md
	ϕ	=	0.25
	S_w	=	0.2
	GOC	=	2941 mTV
	OWC	=	3039 mTV
	Grad	=	9.9 kPa/m
	P_R	=	30940 kPa
	G	=	0.6
	API	=	30°
	GOR	=	135 m^3/m^3
	BHT	=	80°C
	μ_o	=	0.55 MPa·s
	B_o	=	1.38 m^3/m^3
Ground Temperatures	Surface	=	0°C
	120 m	=	-2°C
	490 m	=	-2°C

TABLE 6.2

BEAUFORT SEA WORST CASE BLOWOUT SCENARIOS

CASE: I	**Short Duration, High Rate Event.**
CASING:	Surface Pipe: 340 mm (13 3/8") at 914.4 m (3000') ID: 314 mm (12.347")
OPEN HOLE:	311 mm (12 1/4") to 3048 m (10,000') TVD
STANDARD DRILL PIPE:	2353 m of 140 mm (5.5") DP ID: 109 mm (4.276")
HEAVY WEIGHT DRILL PIPE:	200 m of HWDP at 2353 mTVD (7720' TVD) ID: 71.4 mm (2 13/16")
DRILL COLLARS:	190 m of 210 mm (8.25") ID: 71.4 mm (2 13/16")
BIT:	At 2743 mTVD (9000') Tripping out 3 x 12.7 mm (0.5") nozzles. Equivalent area 380 mm^2. Equivalent ID: 22 mm
BLOWOUT PATH:	Through the drill pipe.
BLOWOUT DURATION:	< 7 days.
SCENARIO:	• Gas was swabbed in while tripping out of the hole. • Internal BOP was cross threaded and blown off when well was shut-in. • Shear rams fail to operate or to cut the pipe. • Well is capped from surface by installation of a valve on the drill pipe or repair of the shear ram function.

TABLE 6.3

BEAUFORT SEA WORST CASE BLOWOUT SCENARIOS

CASE: II	**Long Duration, Low Rate Event.**
CASING:	Surface Pipe: 340 mm (13 3/8") at 914.4 m (3000') ID: 314 mm (12.347")
OPEN HOLE:	311 mm (12 1/4") to 3048 m (10,000') TVD
STANDARD DRILL PIPE:	2353 m (7720') of 140 mm (5.5") DP ID: 109 mm (4.276")
HEAVY WEIGHT DRILL PIPE:	200 m of HWDP at 2353 mTVD (7720' TVD) ID: 71.4 mm (2 13/16")
DRILL COLLARS:	190 m of 210 mm (8.25") ID: 71.4 mm (2 13/16")
BIT:	At 2743 mTVD (9000') Tripping out 3 x 12.7 mm (0.5") nozzles. Equivalent area 380 mm^2. Equivalent ID: 22 mm
BLOWOUT PATH:	Through a 3.8 mm (0.15") circumferential crack around the surface pipe, or through an imperfect cement bond.
BLOWOUT DURATION:	< 65 days.
SCENARIO:	• Gas was swabbed in while tripping out the hole. • Internal BOP was cross threaded and blown off when well was shut-in. • Shear rams operate and successfully cut the pipe. • An attempted squeeze kill inadvertently results in breakdown at the shoe. • Vertical fracturing in the vicinity of the borehole, or between the cement and formation, allows the hydrocarbons to flow to surface through a 3.8 mm circumferential crack, along the wall of the original borehole. Because of simulator model limitations, this has had to be treated as an annular area of 4.0 sq. ins. between (12" and 12.21") from the centre of the well. • The 914.4 m (3000') crack has a high degree of roughness (1 mm, 0.004") which gives a high level of friction. • The well is brought under control either through the original borehole or by drilling a relief well.

TABLE 6.4

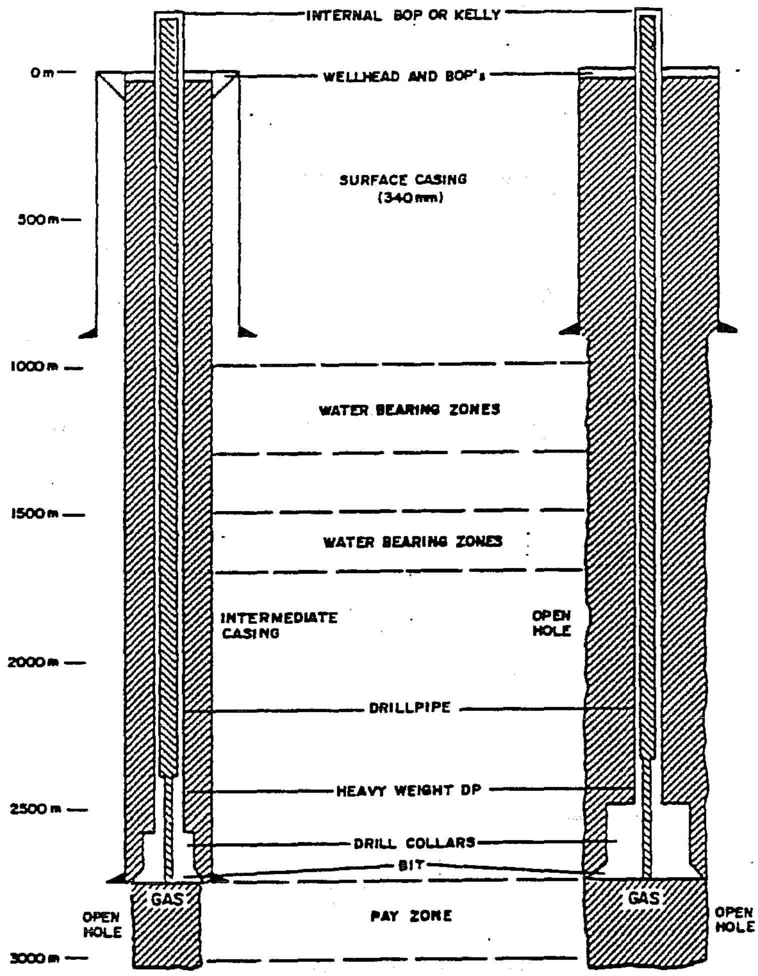
BEAUFORT SEA WORST CASE BLOWOUT SCENARIOS

CASE: III	**Short Duration, High Rate Event.**
CASING:	Intermediate Pipe: 244 mm (9.625") at 2743 m (9000') TVD ID: 217 mm (8.535")
OPEN HOLE:	216 mm (8.5") to 3048 mTVD (10,000') TVD
STANDARD DRILL PIPE:	2393 m of 140 mm (5.5") DP ID: 109 mm (4.276")
HEAVY WEIGHT DRILL PIPE:	200 m of HWDP at 2393 mTVD (7851' TVD) ID: 71.4 mm (2 13/16")
DRILL COLLARS:	150 m of 165 mm (6.5") ID: 71.4 mm (2 13/16")
BIT:	At 2743 mTVD (9000' TVD) Tripping out 3 x 12.7 mm (0.5") nozzles. Equivalent area 380 mm^2. Equivalent ID: 22 mm
BLOWOUT PATH:	Through the annulus and a 38 mm (1.5") hole in the kill line access to the BOP or casing head spool.
BLOWOUT DURATION:	< 7 days.
SCENARIO:	• Gas was swabbed in while tripping out of the hole. • While circulating out the kick, sand erodes a hole in the valve body. • An attempt is made to kill the well by pumping mud from the reserve pit. • Barite settlement during pumping of heavy mud to control the well plugs off the bit or dart sub. • Hydrocarbons flow to surface through the side outlet. • The well is brought under control by perforating the drill pipe above the hold up point and circulating the well dead. (With a shallow set casing, the well would probably kill itself even sooner by collapse of the upper zones.)

TABLE 6.5

BEAUFORT SEA WORST CASE BLOWOUT SCENARIOS

CASE: IV	**Long Duration, Low Rate Event.**
CASING:	Intermediate Pipe: 244 mm (9.625") at 2743 m (9000') TVD ID: 217 mm (8.535")
OPEN HOLE:	216 mm (8.5") to 3048 mTVD (10,000') TVD
STANDARD DRILL PIPE:	2393 m of 140 mm (5.5") DP at 305 m (1000') TVD
HEAVY WEIGHT DRILL PIPE:	200 m of HWDP at 2698 m (8852') ID: 71.4 mm (2 13/16")
DRILL COLLARS:	150 m of 165 mm (6.5") ID: 71.4 mm (2 13/16")
BIT:	At 3048 mTVD (10000' TVD) On Bottom 3 x 12.7 mm (0.5") nozzles. Equivalent area 380 mm^2. Equivalent ID: 22 mm
BLOWOUT PATH:	Through the drill pipe and annulus to 305 m (1000') and then up the open casing to surface. 152 mm x 6.4 mm (6" x 0.25") splits in the surface and intermediate casings allow hydrocarbon to escape the wellbore.
BLOWOUT DURATION:	< 65 days.
SCENARIO:	• Gas was swabbed in while tripping out the hole with a plugged bit. • During an attempt to run the drill pipe to bottom, the string was inadvertently dropped into hole and the well shut in on the blind rams. • During an attempted squeeze kill, the casing burst at a weak point near surface caused by wear, or by a mill defect. • The surface casing could not contain the resulting pressure and also burst. • The split casing acts as a choke. This is modelled with an equivalent area of 968 mm^2 (1.5 in^2), or an equivalent ID of 35 mm (1.375"). • While operating at sonic velocity, the walls of the cracks are eroded away so that the width of the split increases. • A relief well has to be drilled to control the well.



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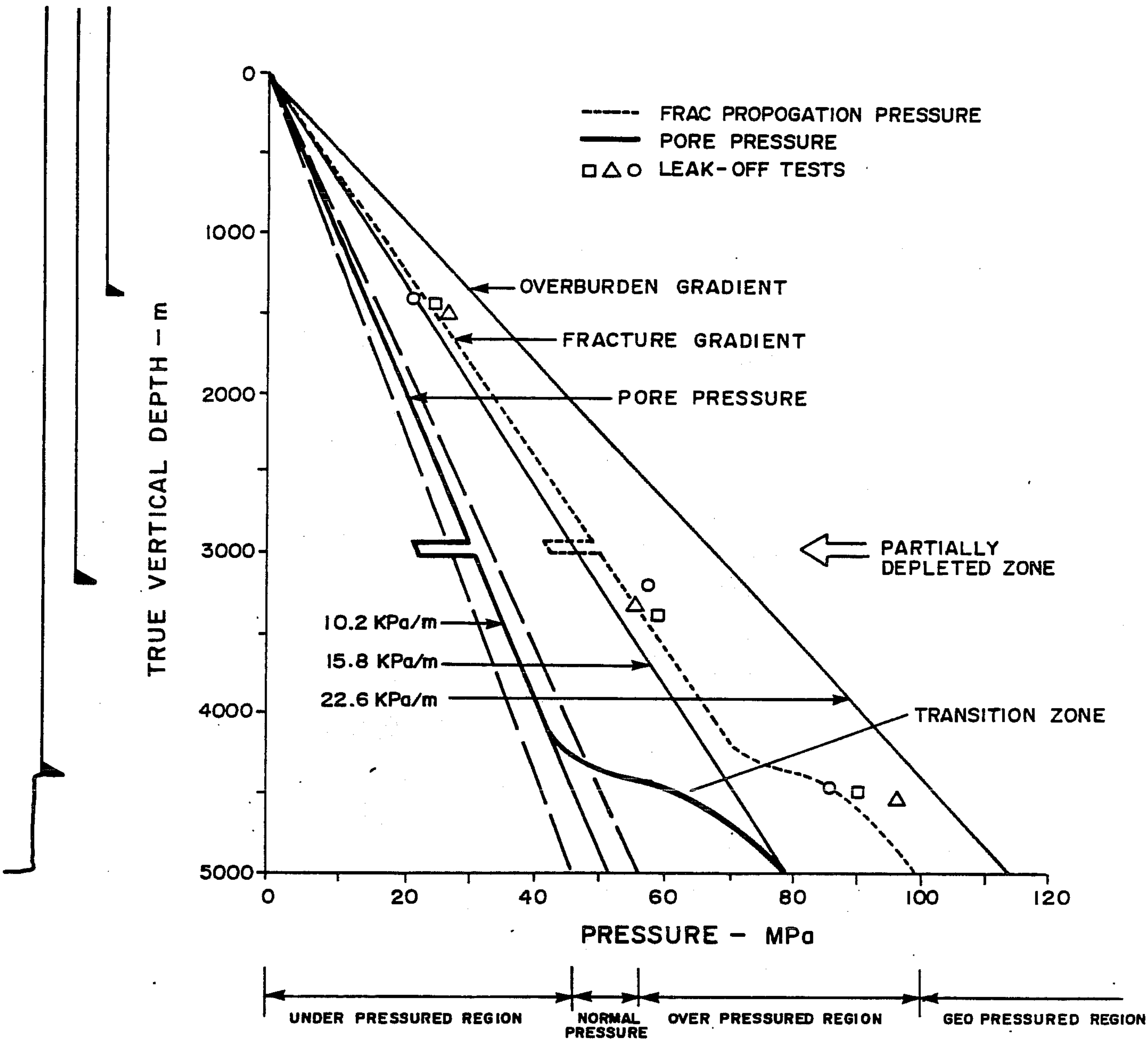
WELL CONFIGURATION
DURING INITIAL GAS KICK

Date: February, 1991	Figure: 4.1



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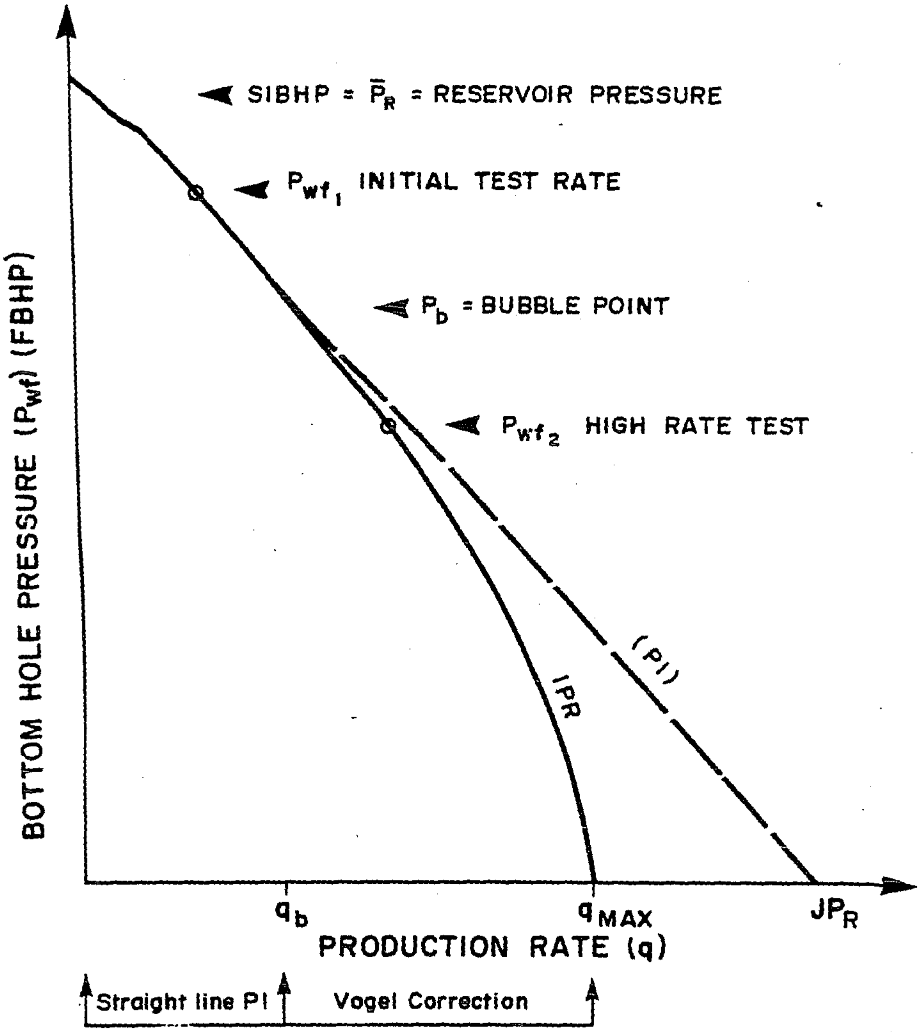
DEPTH PRESSURE PLOT

Date: February, 1991 | Figure: 4.2



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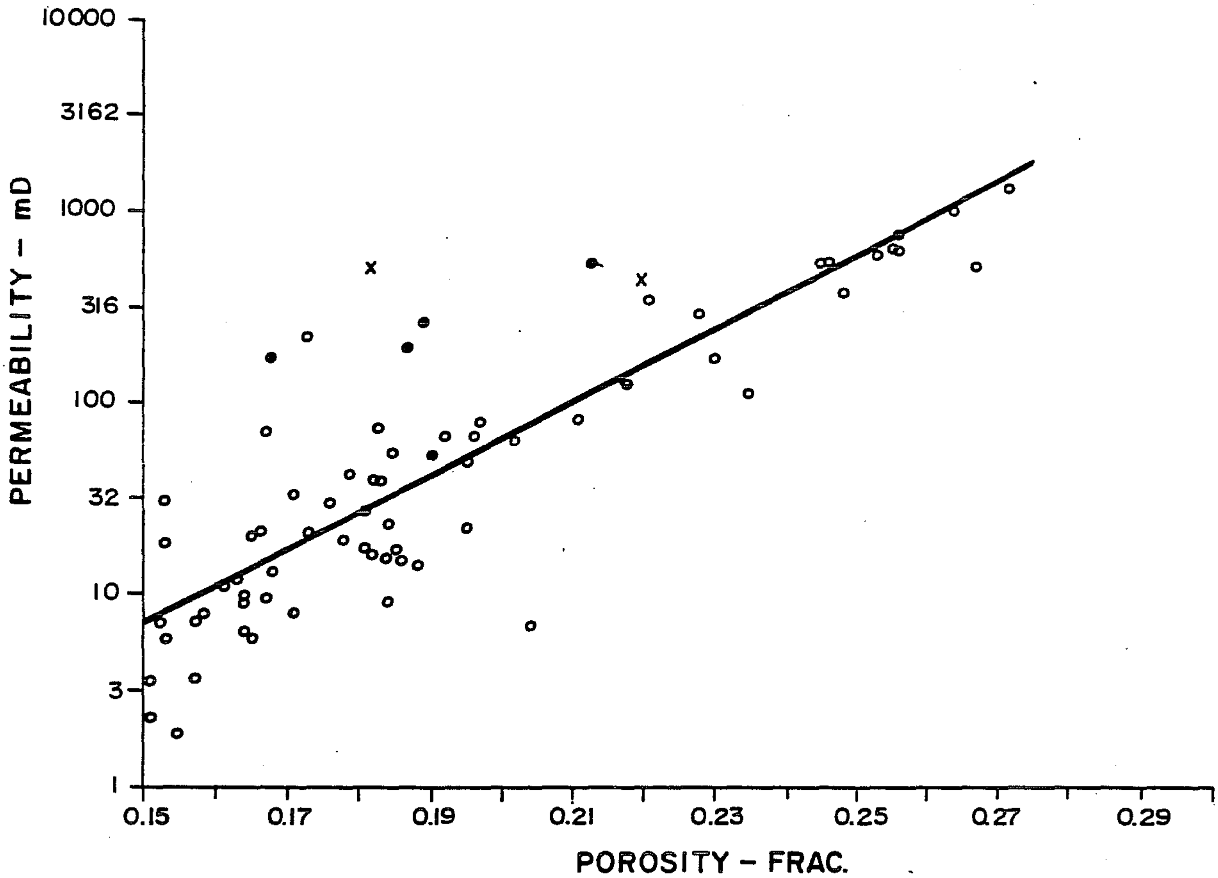
OILWELL INFLOW PERFORMANCE RELATIONSHIPS

Date : February, 1991 | Figure : 4.3



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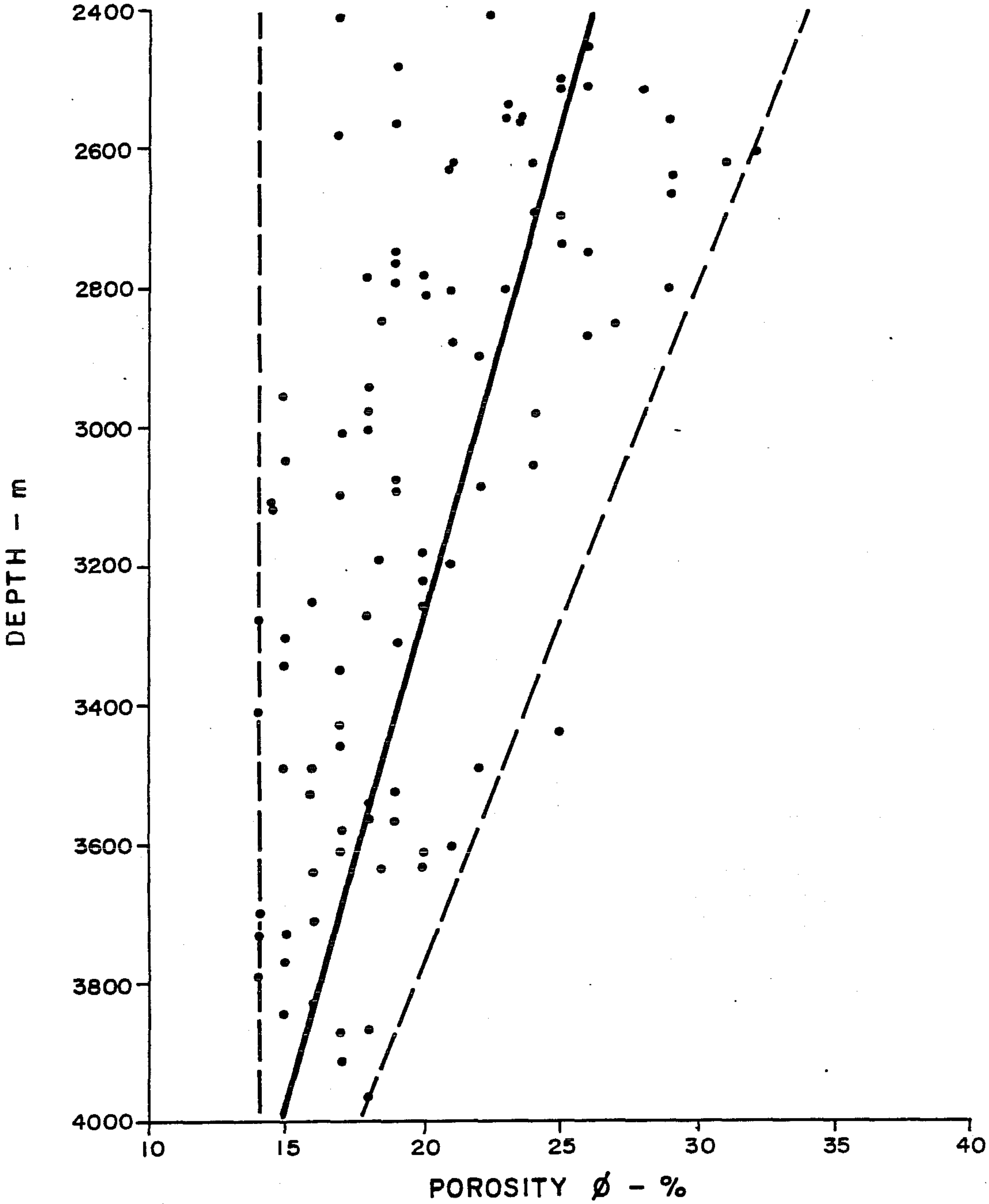
PERMEABILITY VERSUS POROSITY
CROSS PLOT

Date : February, 1991	Figure : 4.4



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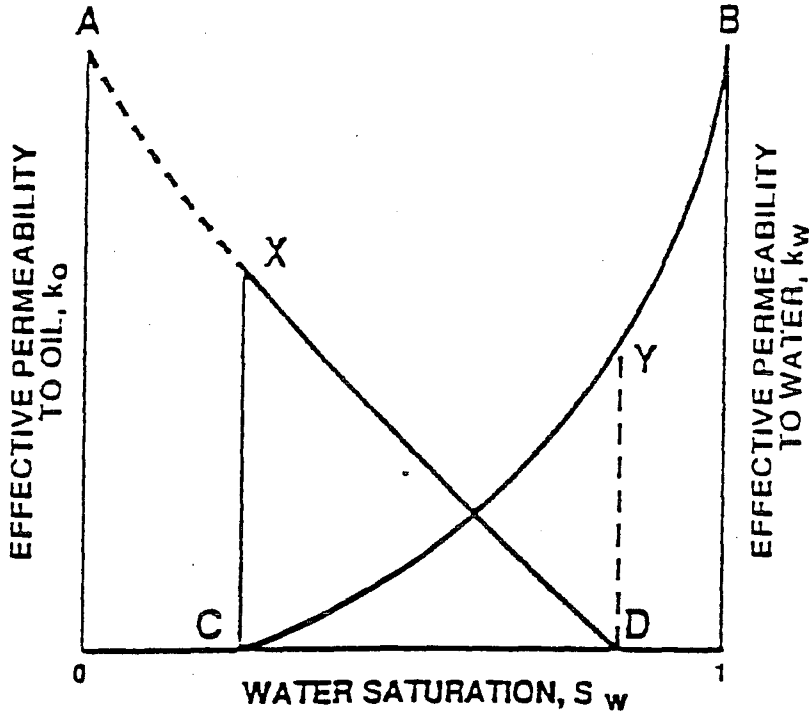
TYPICAL DEPTH POROSITY TREND

Date: February, 1991 | Figure: 4.5



Where:

A = k_o at $S_w = 0$ absolute permeability of the rock (k)

B = Connate water saturation S_{wc} (usually 0.1 to 0.5)

X = k_w at $S_w = S_{wc}$ effective permeability of oil at connate water saturation. Frequently referred to as the end point relative permeability to oil. Notice that the effective permeability of water at this point is zero.

D = Residual oil saturation S_{or} (usually 0.1 to 0.5)

Y = k_w at $S_w = (1-S_{or})$ effective permeability of water at residual oil saturation. Frequently referred to as the end point relative permeability to water. Notice that the effective permeability of oil at this point is zero.

At any value of S:

$$k_o + k_w = k_e < k$$

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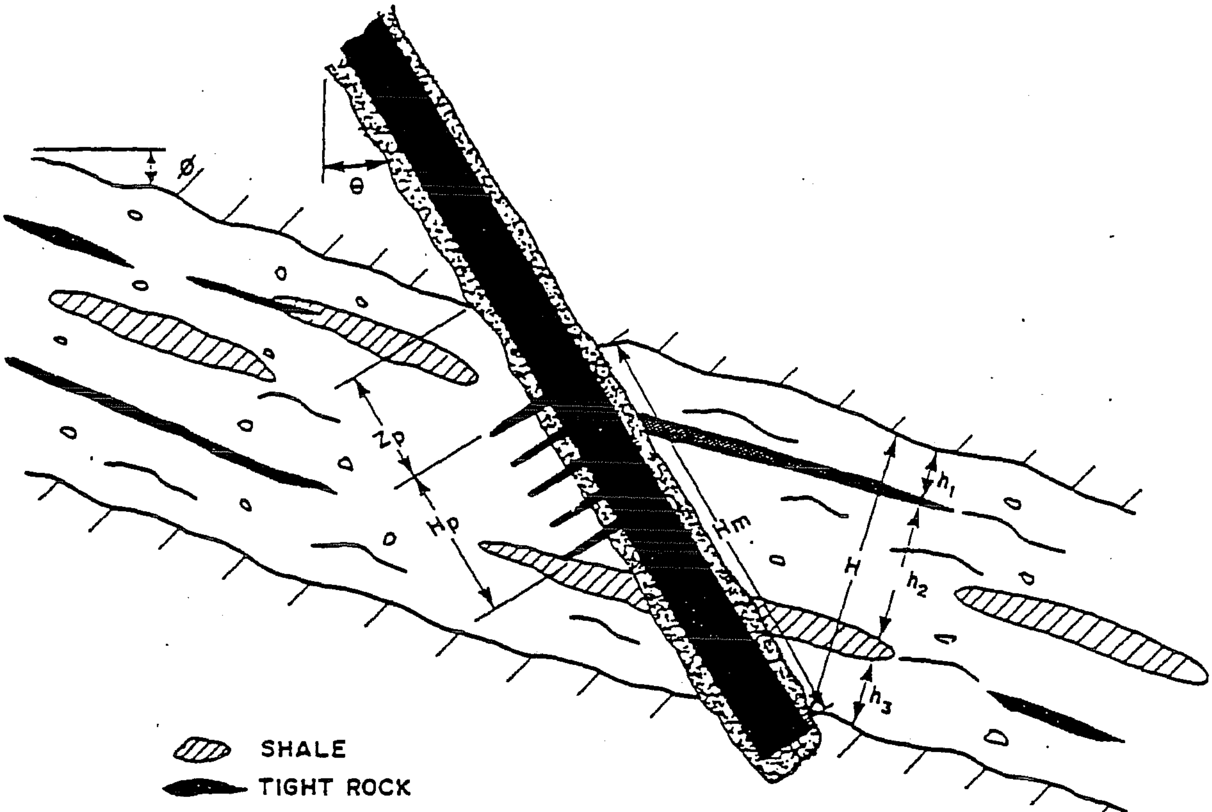
OIL / WATER
RELATIVE PERMEABILITY CURVE

Date: February, 1991 | Figure: 4.6



SHALE

TIGHT ROCK

θ WELLBORE DEVIATION

ø FORMATION DIP

Zp DISTANCE TO TOP PERFORATION

H_m MEASURED GROSS PAY

h_p MEASURED PERFORATED INTERVAL

H GROSS ISOPACH $H_m \cos(\theta + \phi)$

h NET PAY THICKNESS $= h_1 + h_2 + h_3 = H \times \frac{h_m}{H_m}$

h_m MEASURED NET PAY

$\frac{h_m}{H_m} =$ NET TO GROSS RATIO

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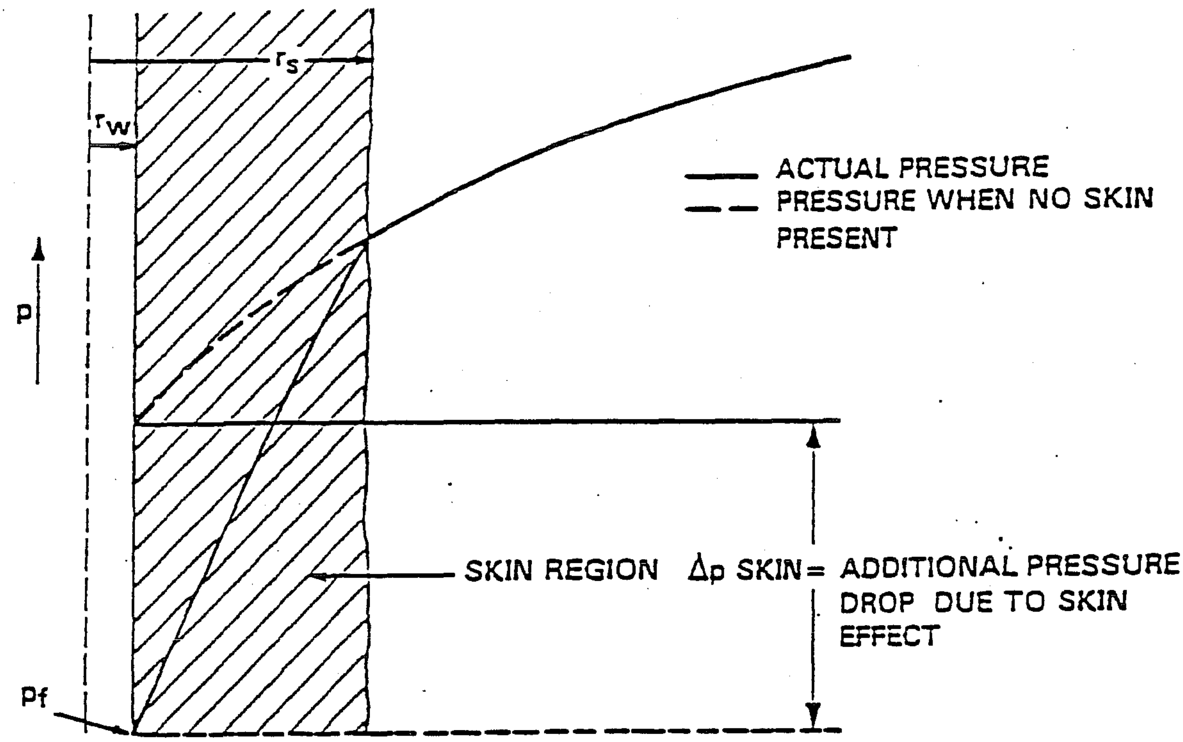
NET PAY CONCEPT

Date : February, 1991	Figure : 4.7



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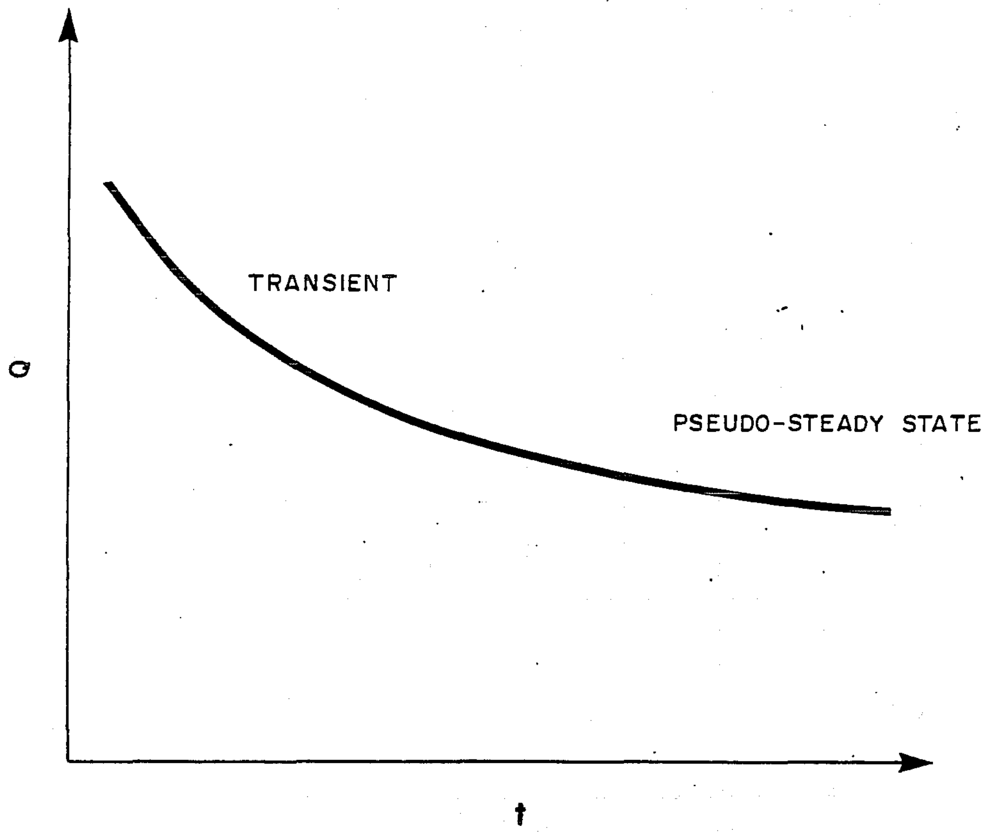
SKIN EFFECT

EFFECT OF SKIN
ON PRESSURE TRANSIENTS

Date: February 1991	Figure: 4.8



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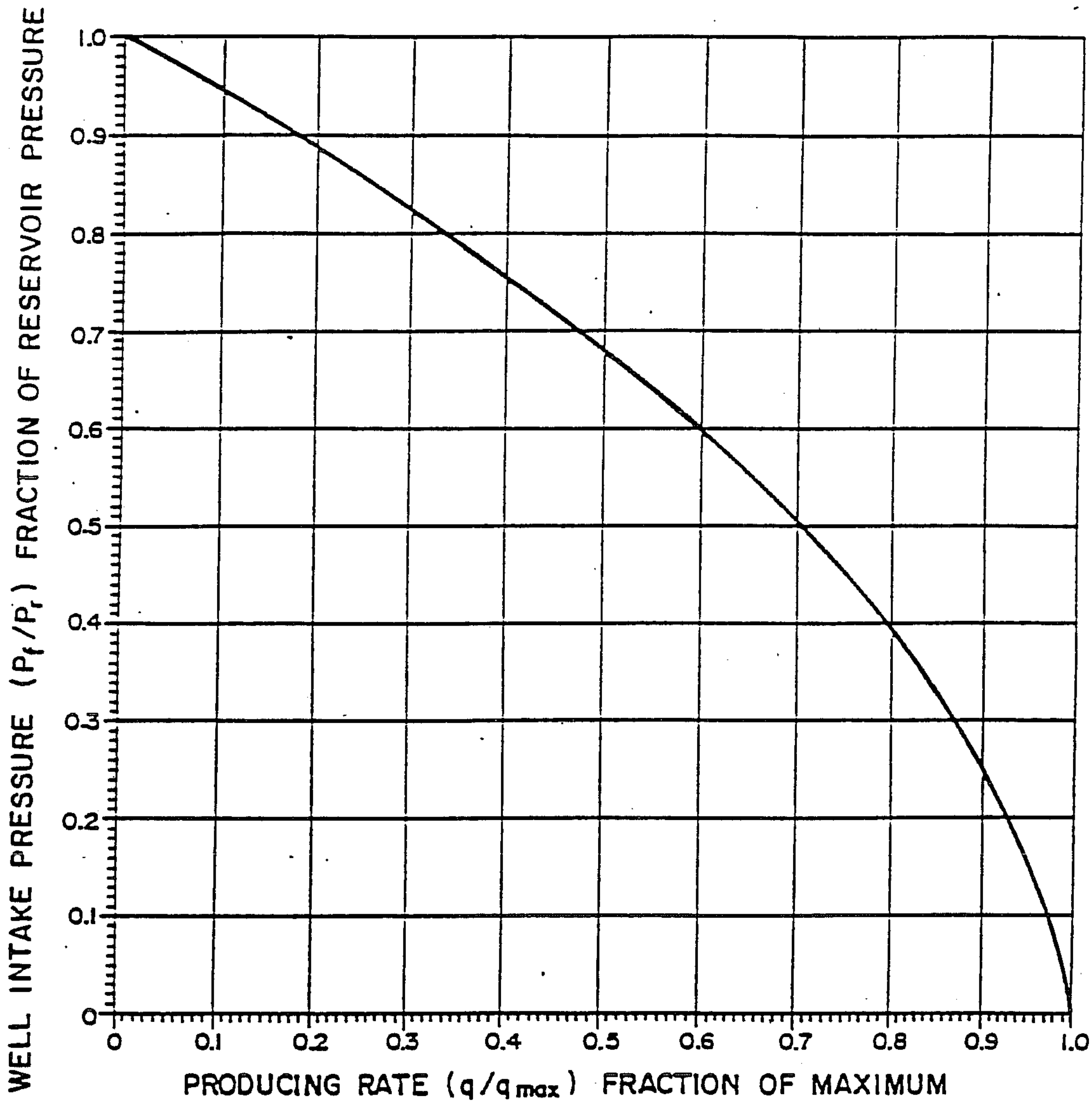
VARIATION OF FLOWRATE WITH TIME

Date : February, 1991 | Figure : 4.9



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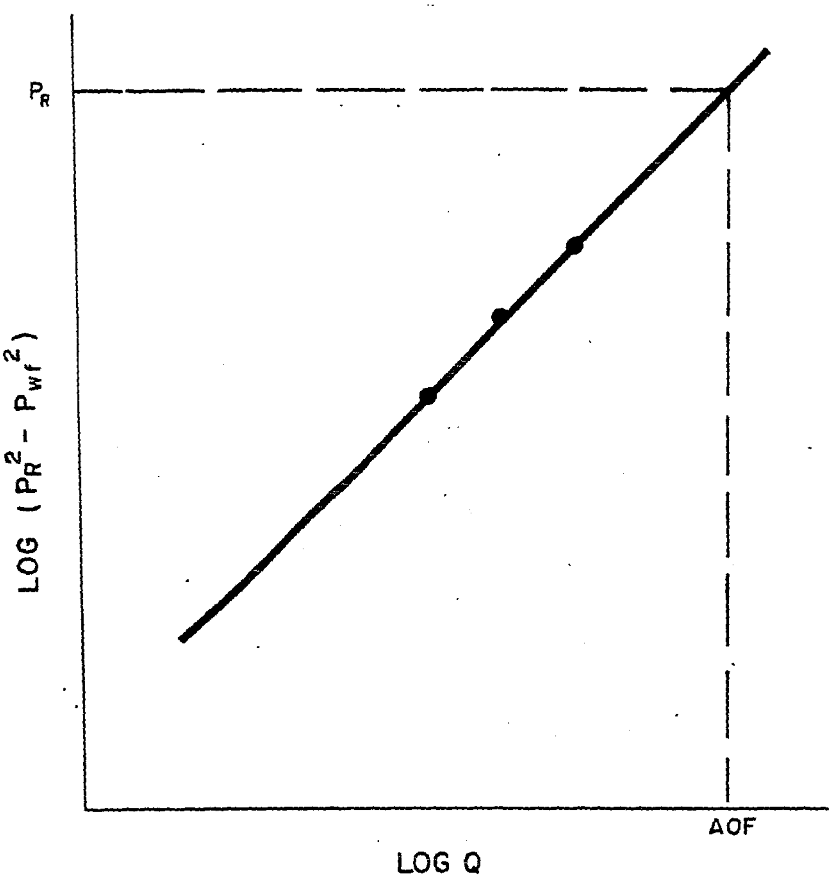
VOGEL REFERENCE CURVE

INFLOW PERFORMANCE RELATIONSHIP FOR SOLUTION GAS DRIVE RESERVOIRS

Date : February, 1991	Figure : 4.10



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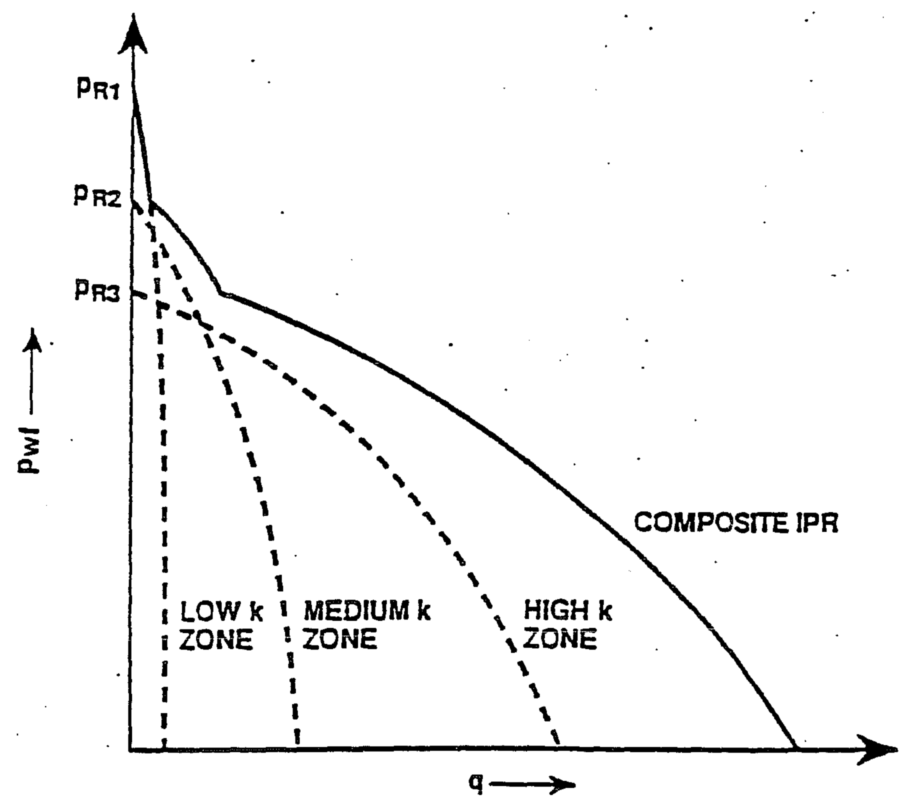
AOF BACK PRESSURE PLOT

Date : February, 1991	Figure : 4.11



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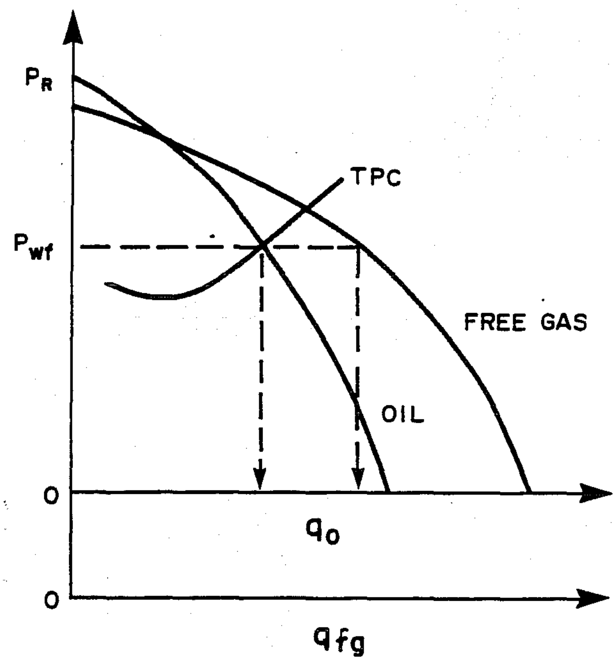
MULTIZONE IPR'S

Date: February, 1991 | Figure: 4.12



$$\text{EQUIVALENT GOR} = \frac{\text{FREE GAS PRODUCTION + SOLUTION GAS PRODUCTION}}{\text{OIL PRODUCTION}}$$

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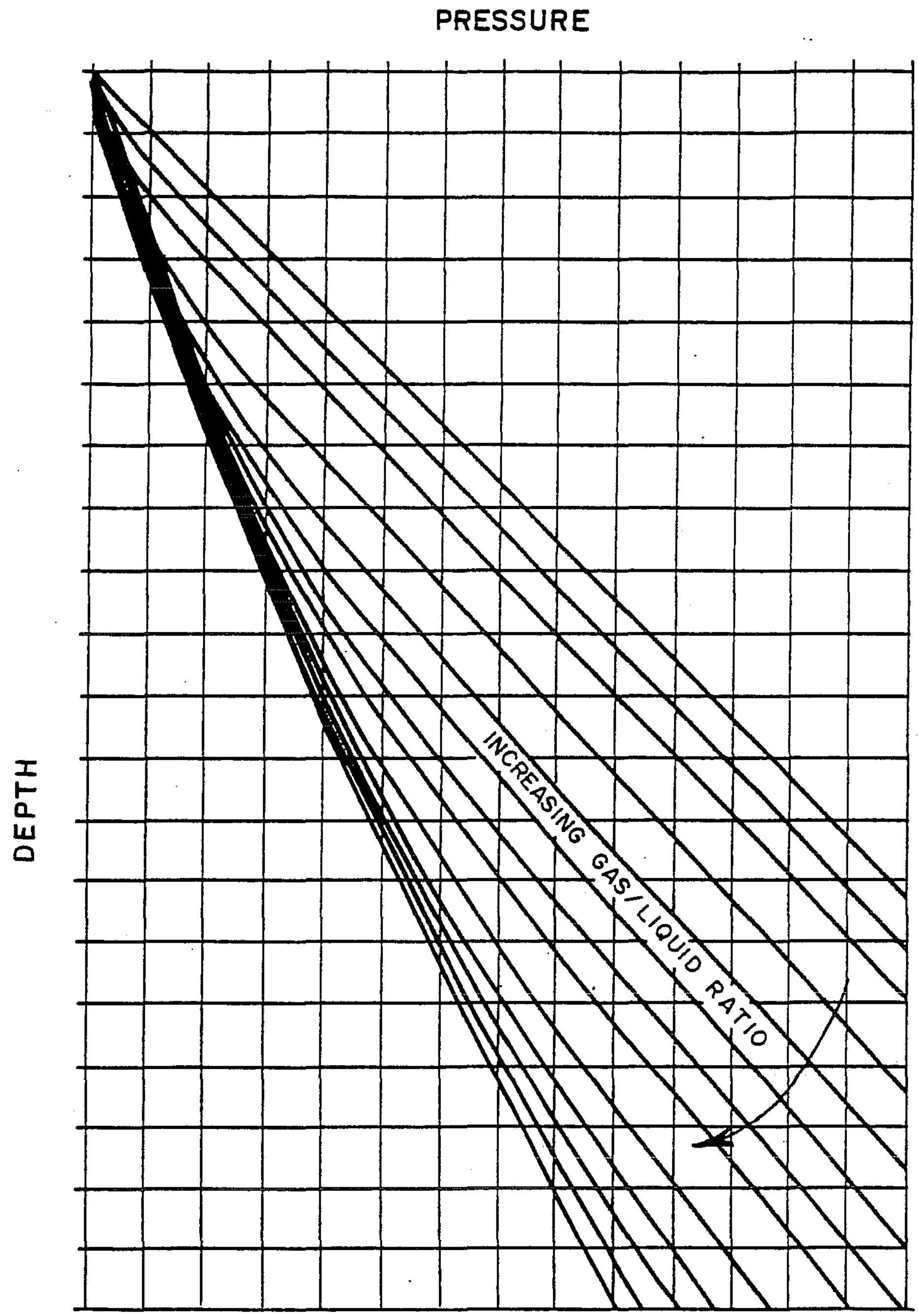
IPR OF AN OIL WELL PRODUCING FREE GAS.

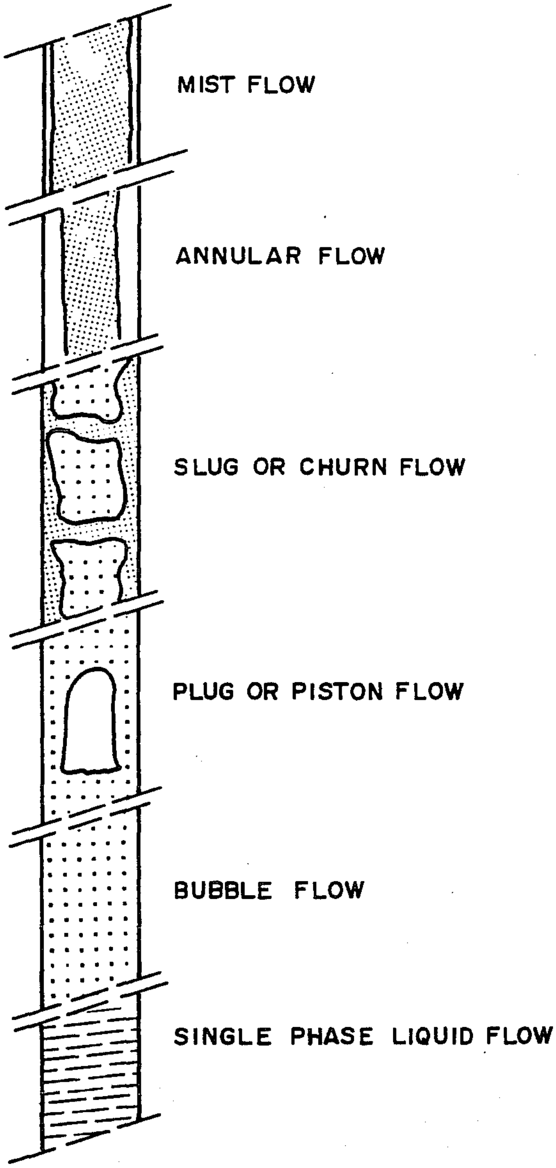
Date : February, 1991	Figure : 4.13



ADAMS PEARSON ASSOCIATES

PRESSURE TRAVERSE

Date : February, 1991 | Figure : 4.14



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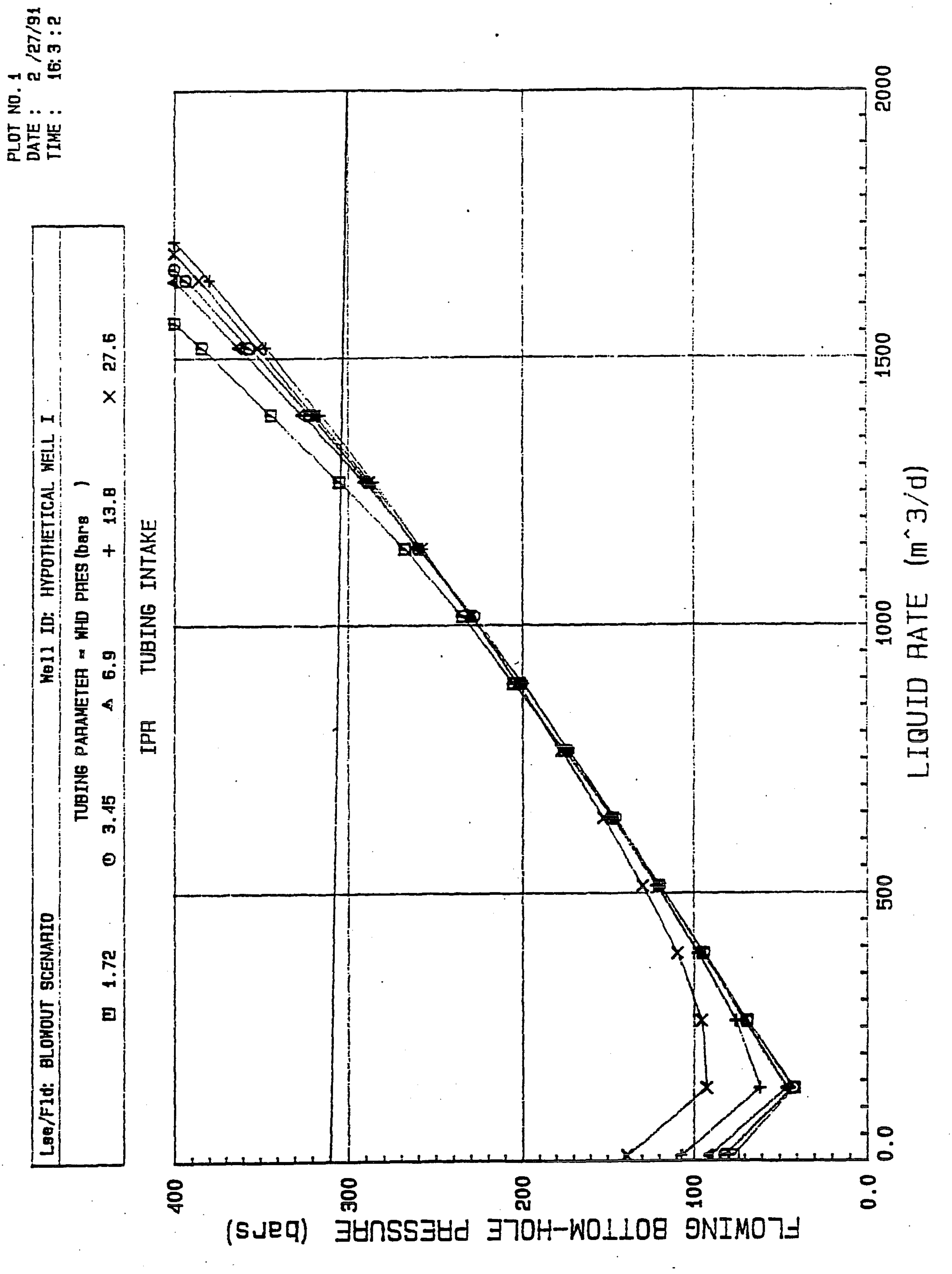
PATTERN OF
TWO PHASE VERTICAL FLOW
(AFTER DUNS AND ROS)

Date : February, 1991 | Figure : 4.15



PLOT NO. 1
DATE : 2 /27/91
TIME : 16:3 :2
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
TUBING PARAMETER = WHD PRES (bars)
1.72
3.45
6.9
13.8
27.6
IPR
TUBING INTAKE
FLOWING BOTTOM-HOLE PRESSURE (bars)
400
300
200
100
0.0
LIQUID RATE (m^3/d)
0.0
500
1000
1500
2000

Figure 4.16

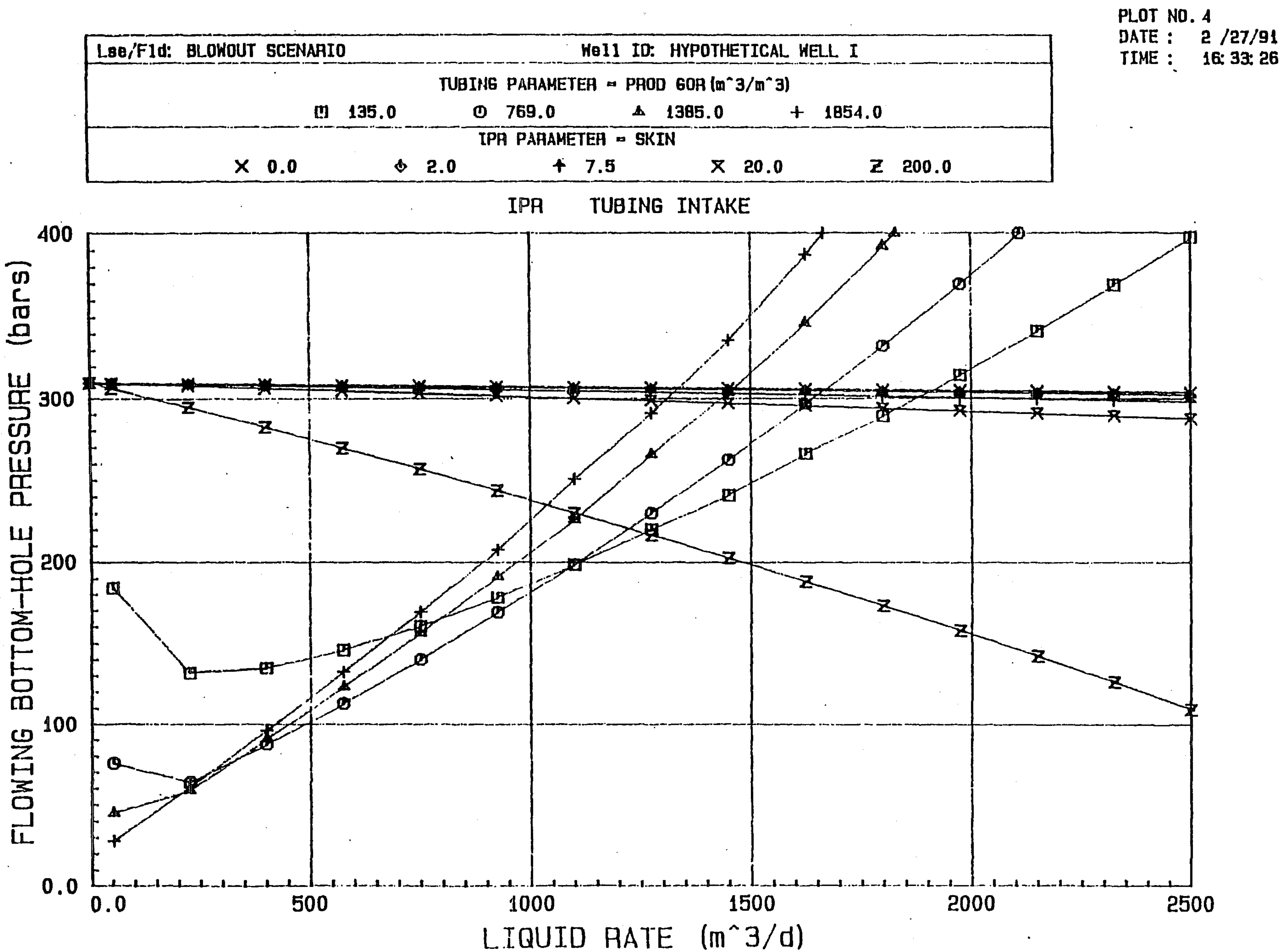
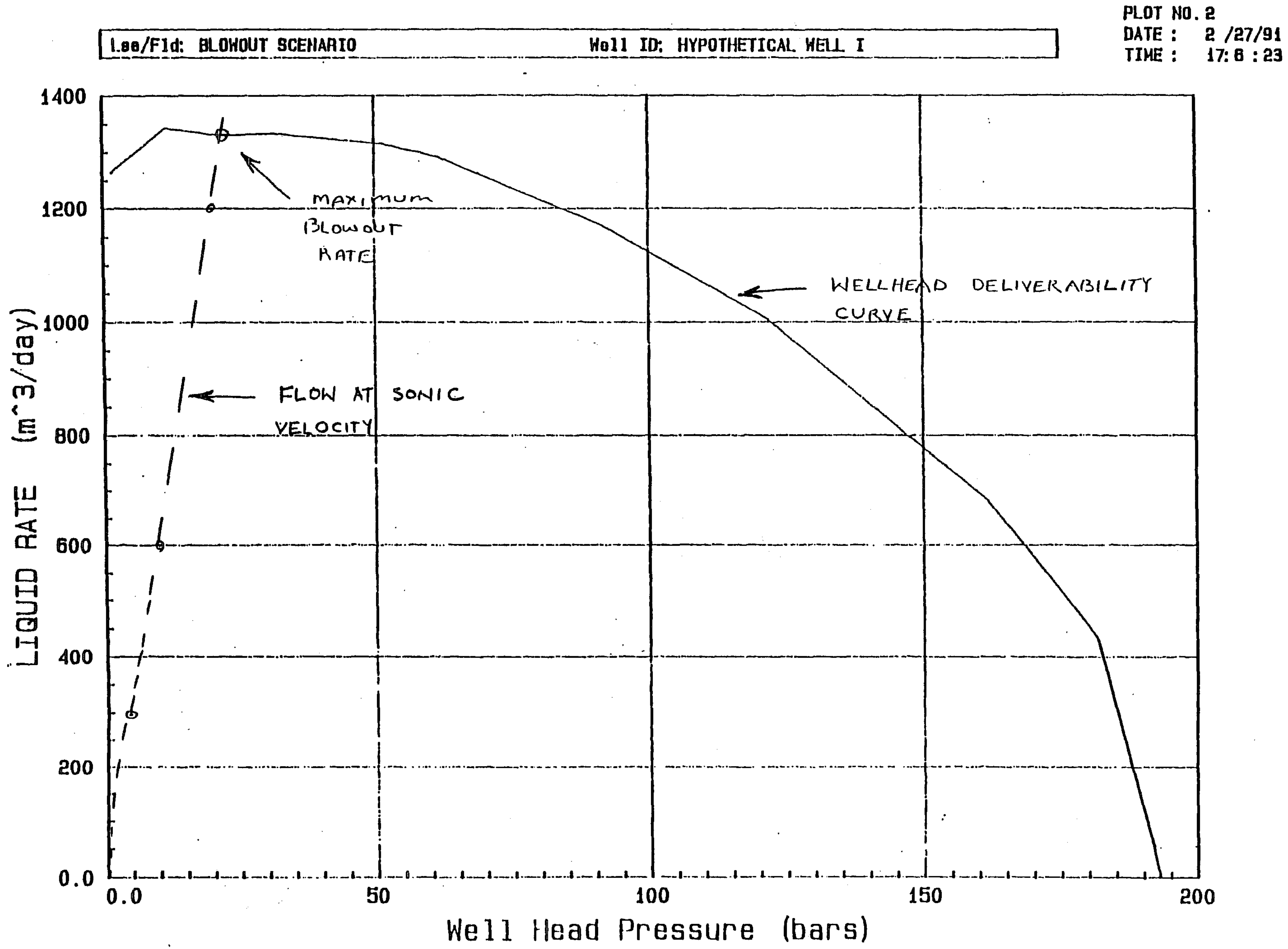
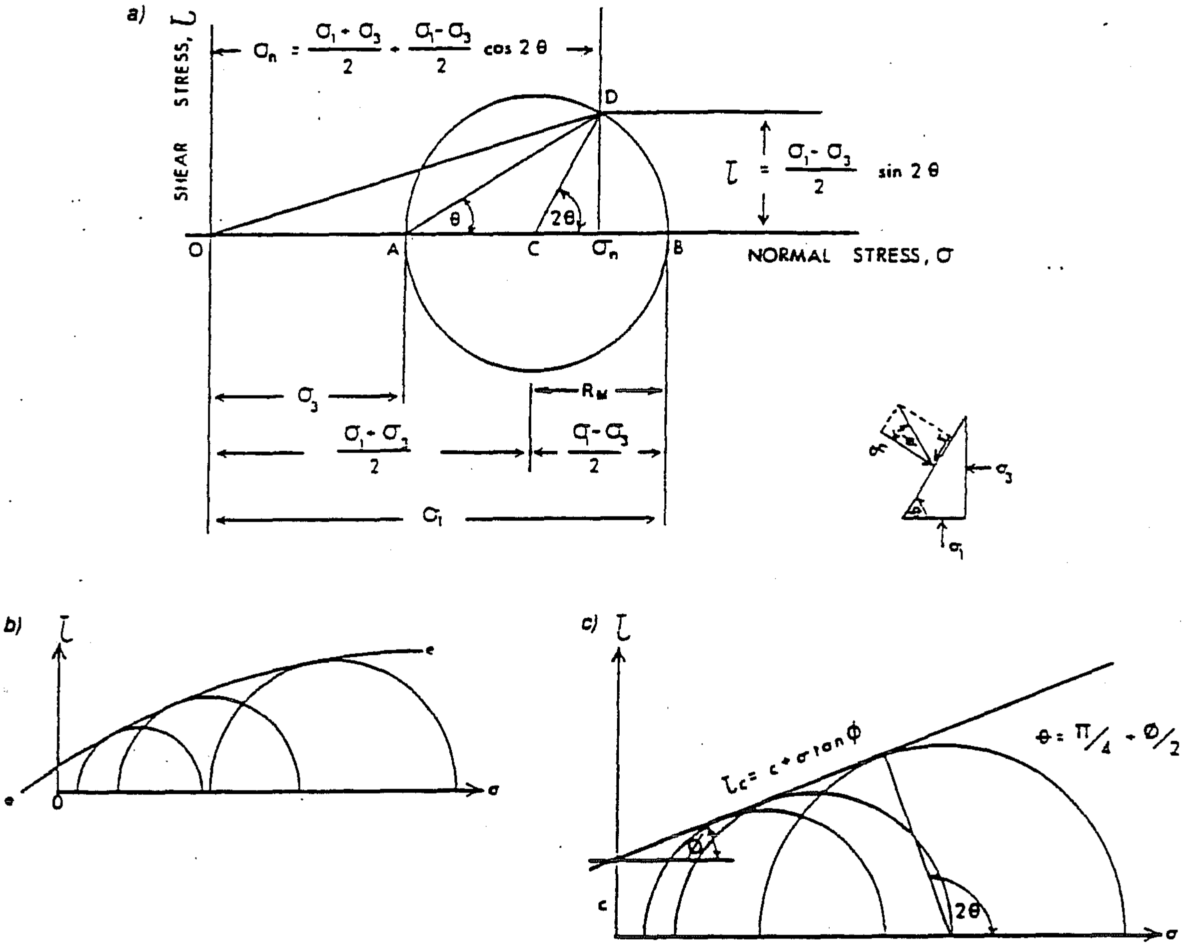

PLOT NO. 4
DATE : 2 /27/91
TIME : 16:33:26
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
TUBING PARAMETER = PROD GOR (m^3/m^3)
135.0
769.0
1385.0
1854.0
IPR PARAMETER = SKIN
0.0
2.0
7.5
20.0
200.0
IPR TUBING INTAKE
FLOWING BOTTOM-HOLE PRESSURE (bars)
LIQUID RATE (m^3/d)
0.0
100
200
300
400
500
1000
1500
2000
2500

Figure 4.17


PLOT NO. 2
DATE : 2 /27/91
TIME : 17: 6 : 23
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
LIQUID RATE (m^3/day)
1400
1200
1000
800
600
400
200
0.0
Well Head Pressure (bars)
0.0
50
100
150
200
MAXIMUM BLOWOUT RATE
WELLHEAD DELIVERABILITY CURVE
FLOW AT SONIC VELOCITY

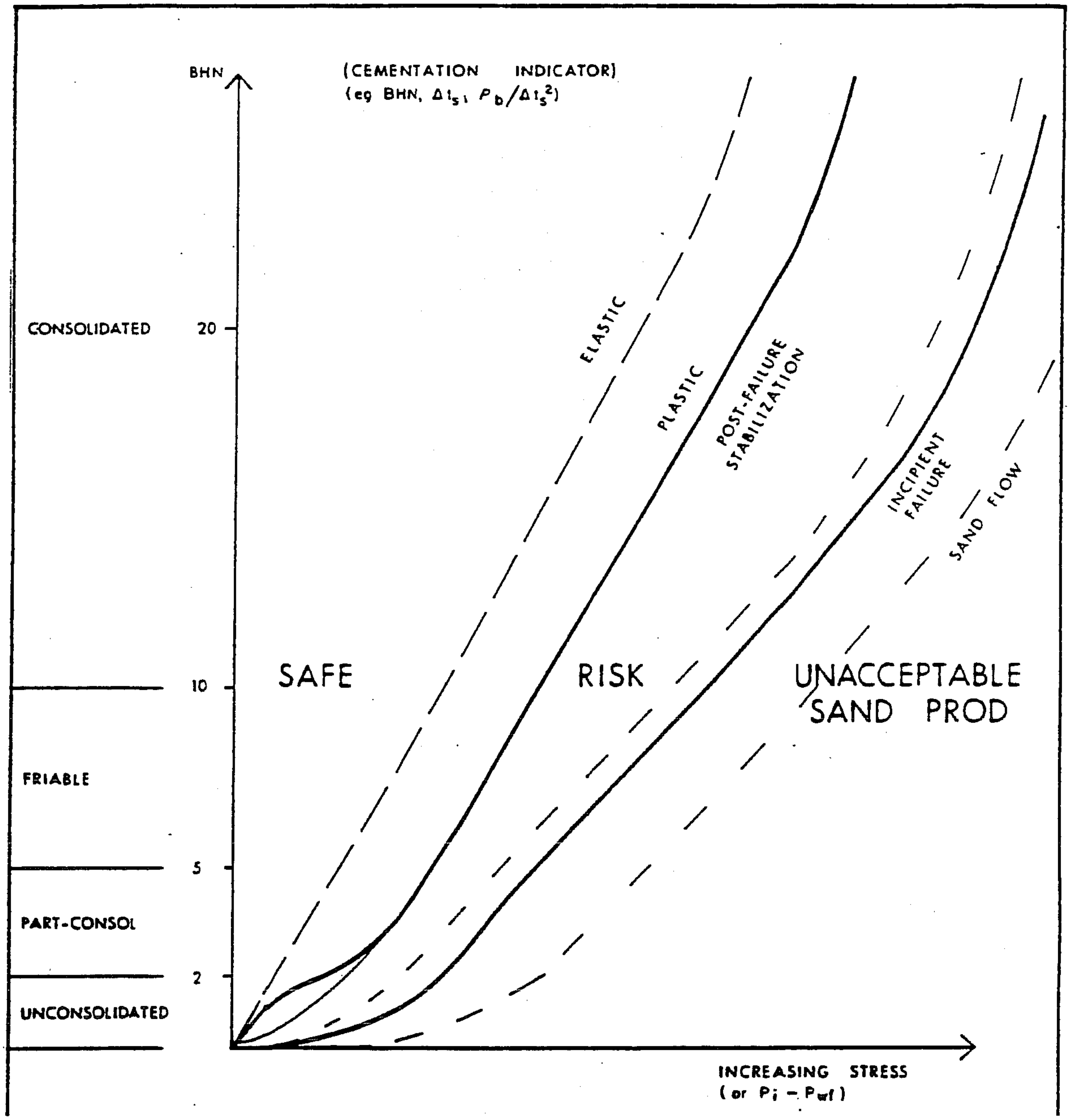


Stress analysis (a) using Mohr's circle; failure envelope (b) based on Mohr's circles; and Coulomb failure envelope (c).

ADAMS PEARSON ASSOCIATES

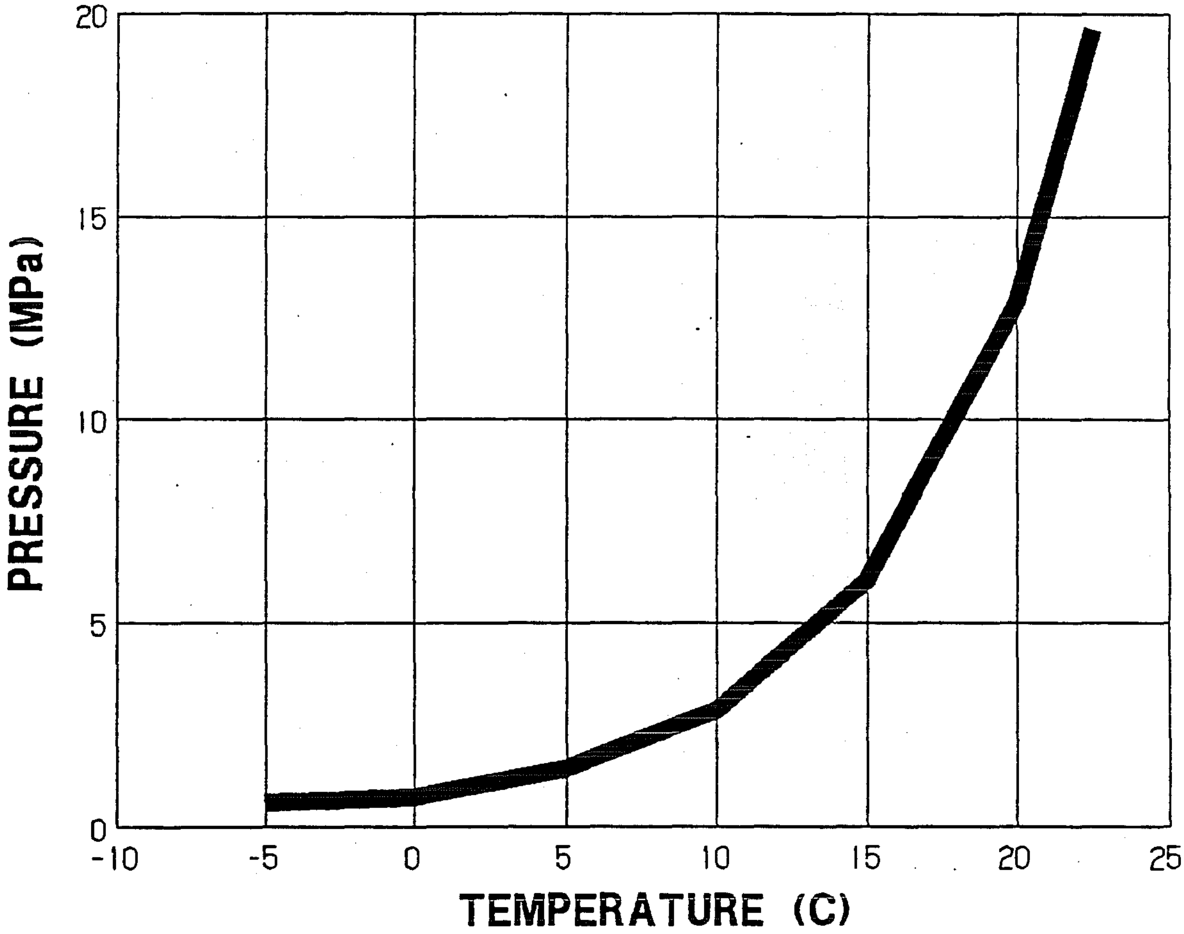
MOHR'S CIRCLE

Date : February 1991



ADAMS PEARSON ASSOCIATES

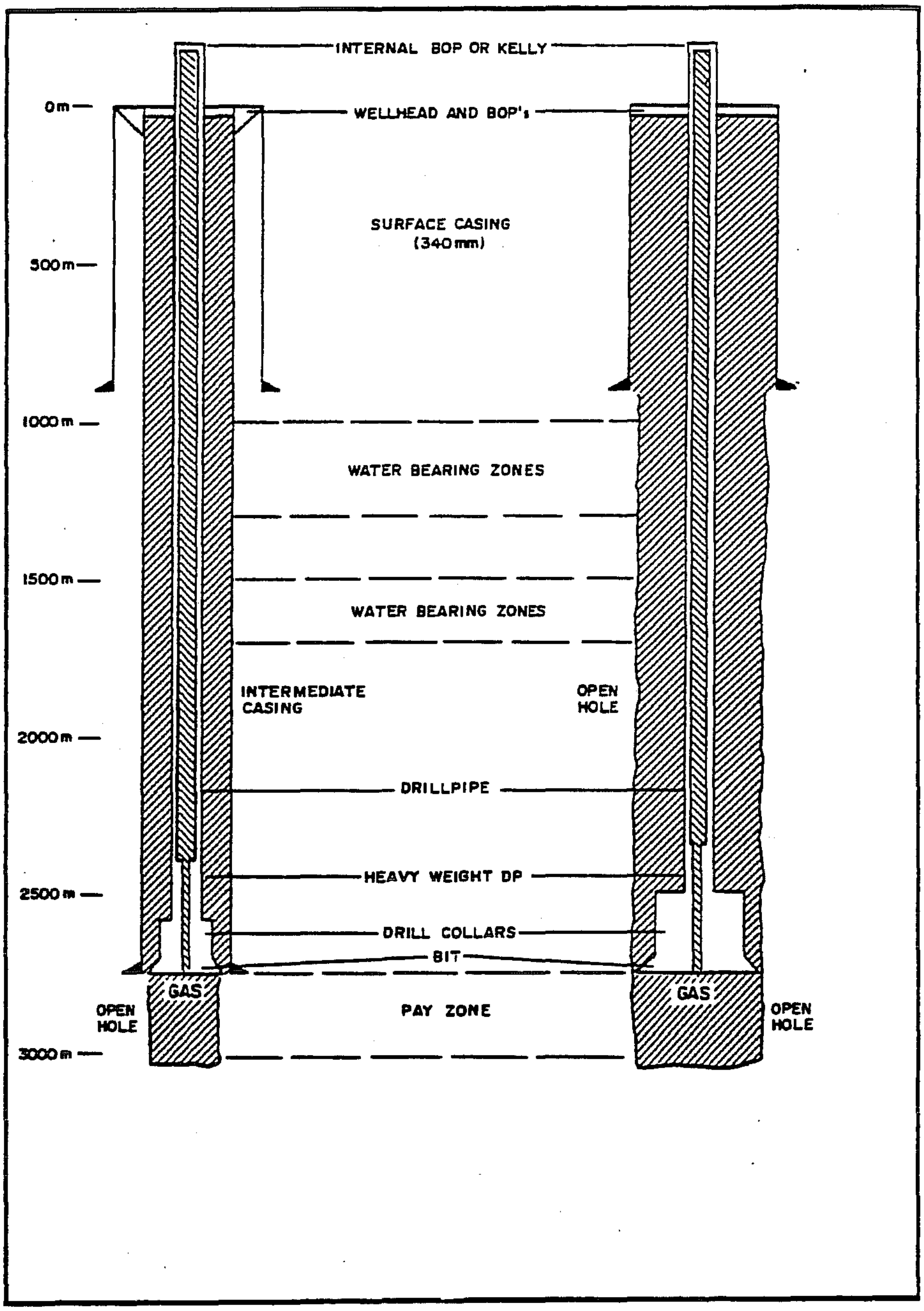
CEMENTATION INDICATOR VERSUS DRAWDOWN



ADAMS PEARSON ASSOCIATES

TYPICAL HYDRATE CURVE

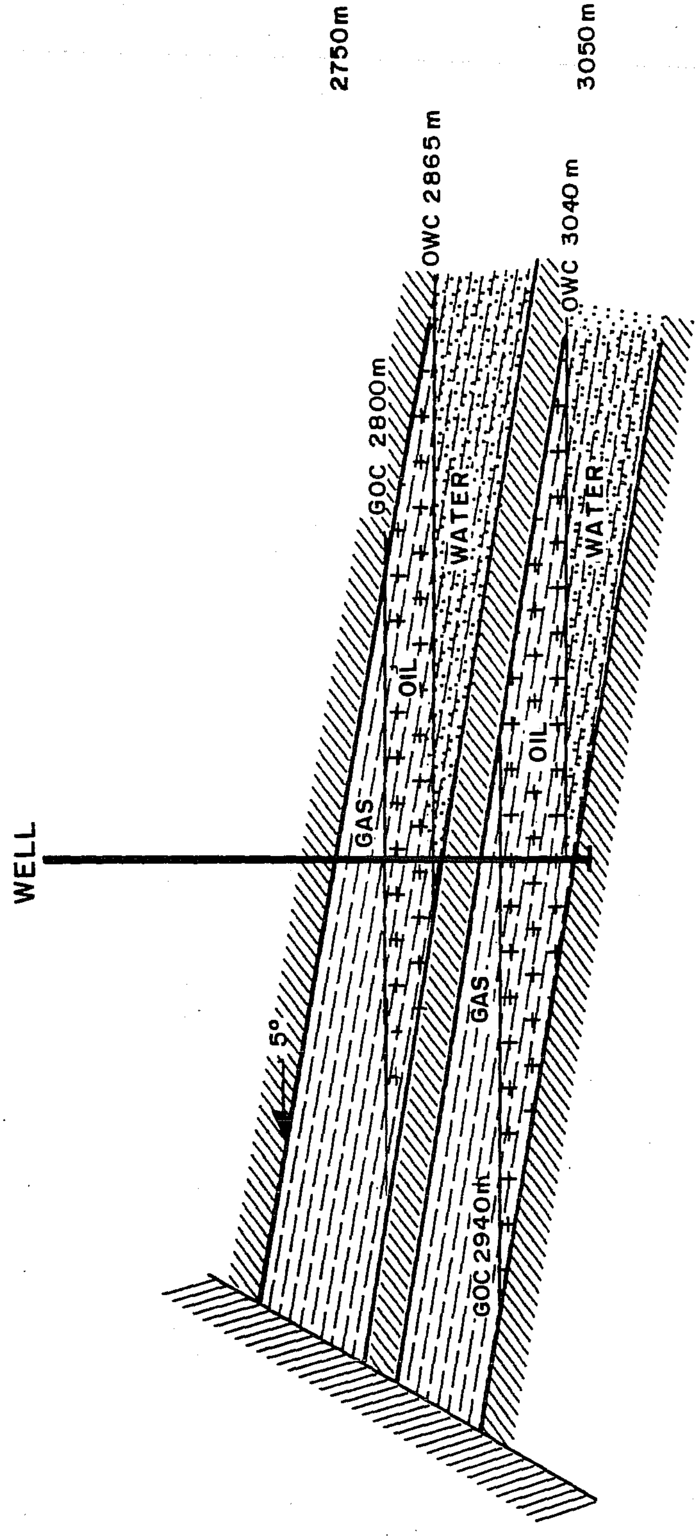
Date: February 1991 | Figure: 4.21



ADAMS PEARSON ASSOCIATES

WELL CONFIGURATION
DURING INITIAL GAS KICK

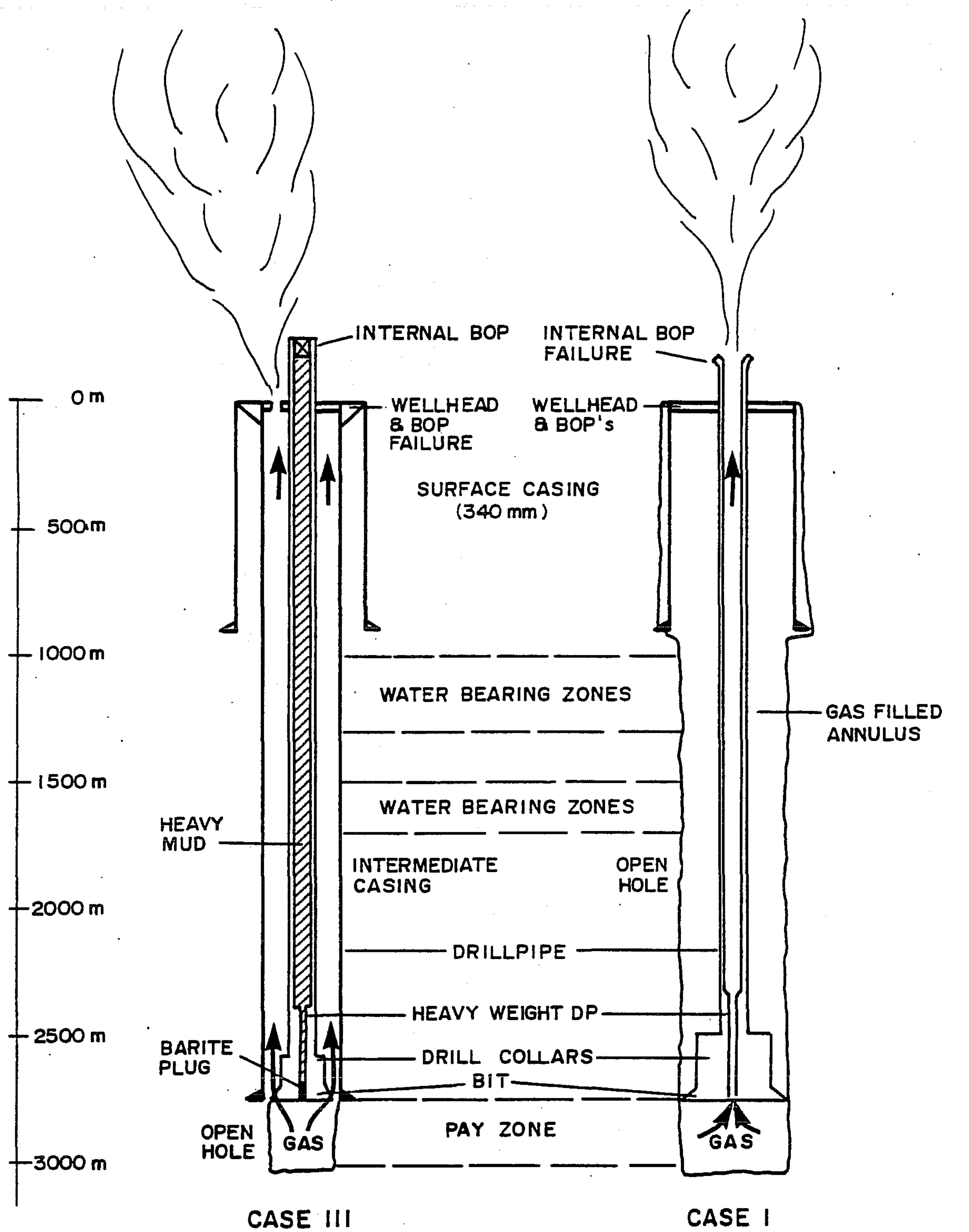
Date: February, 1991	Figure: 6.1



ADAMS PEARSON ASSOCIATES

CROSS SECTION
OF HYPOTHETICAL FIELD

Date : February, 1991	Figure : 6.2



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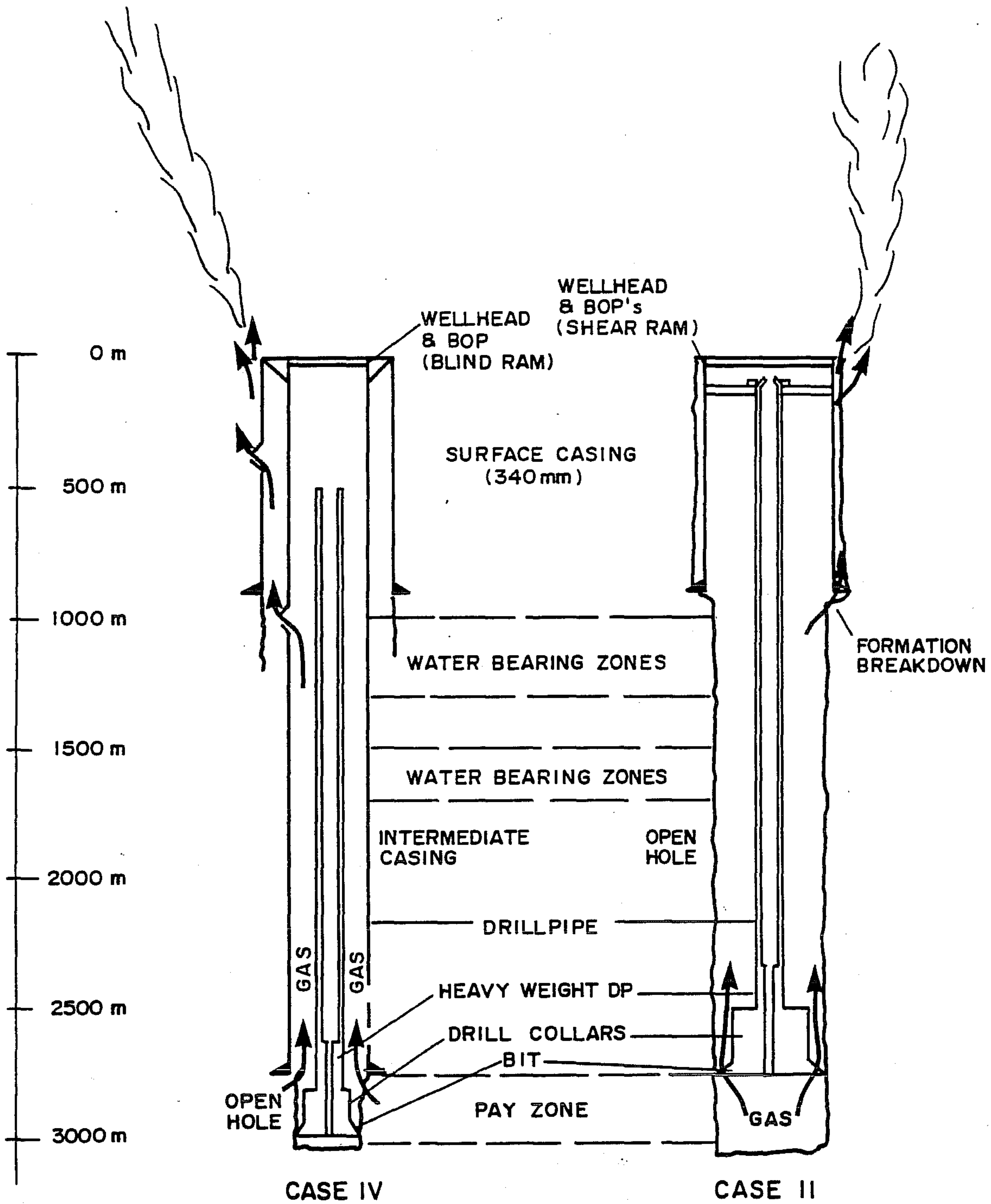
SHORT DURATION HIGH RATE BLOWOUT

Date : February, 1991	Figure : 6.3



ADAMS PEARSON ASSOCIATES

LONG DURATION
LOW RATE BLOWOUT

Date: February, 1991	Figure: 6.4

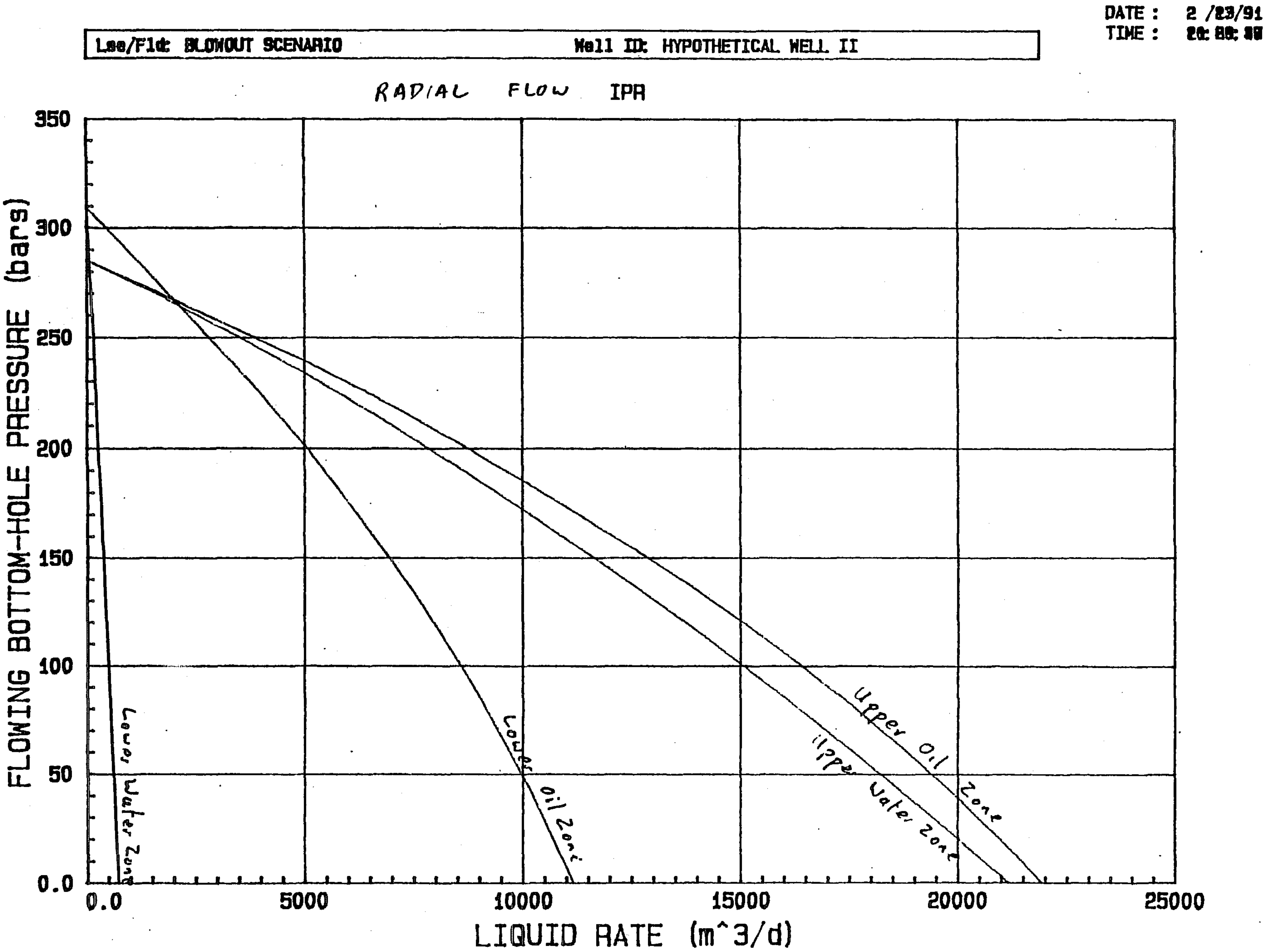

DATE : 2 /23/91
TIME :
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL II
RADIAL FLOW IPR
FLOWING BOTTOM-HOLE PRESSURE (bars)
350
300
250
200
150
100
50
0.0
0.0
5000
10000
15000
20000
25000
LIQUID RATE (m^3/d)
Lower Water Zone
Lower Oil Zone
Upper Oil Zone
Upper Water Zone

Figure 6.5

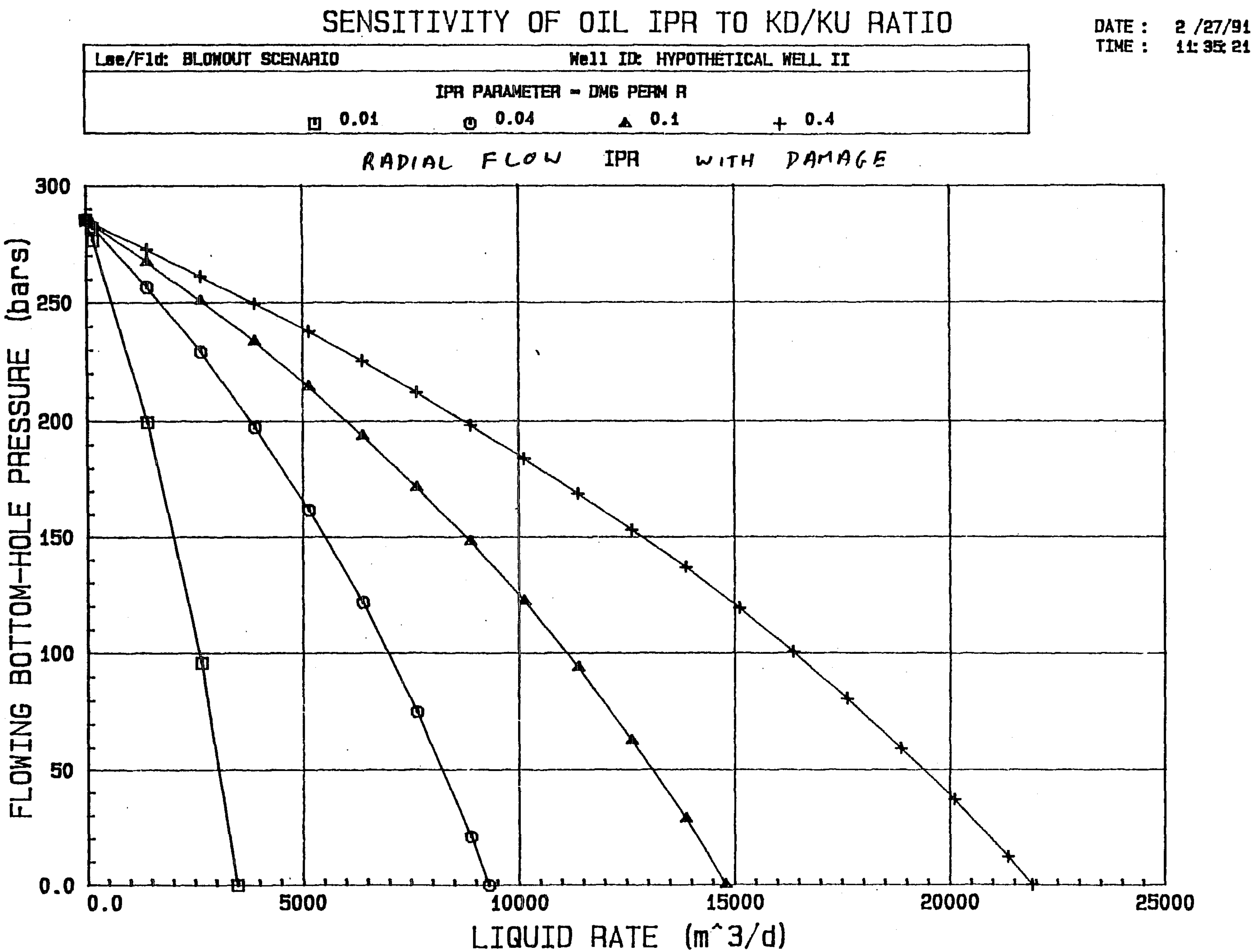
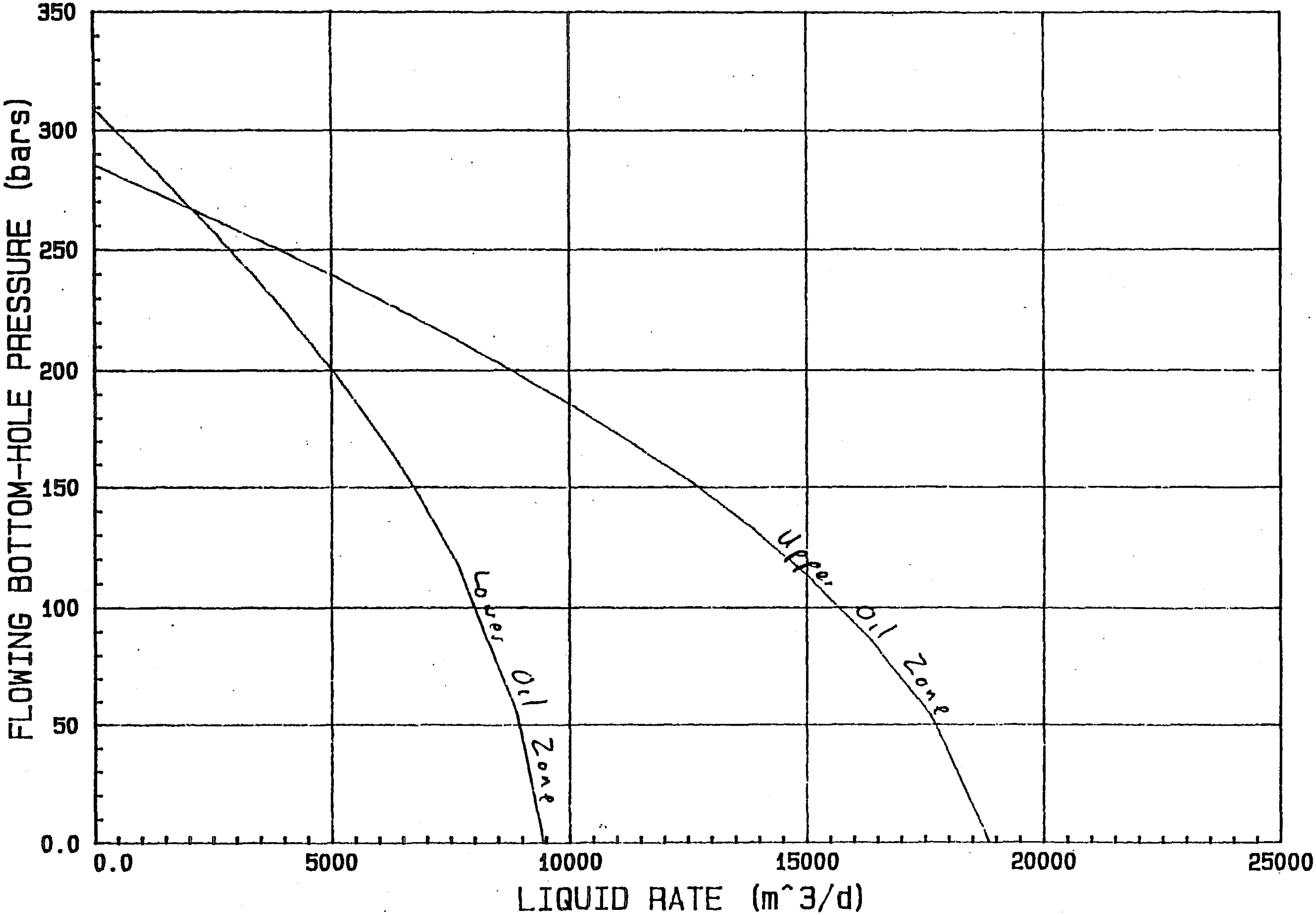

SENSITIVITY OF OIL IPR TO KD/KU RATIO
DATE : 2 /27/91
TIME : 11:35:21
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL II
IPR PARAMETER = DMG PERM R
0.01
0.04
0.1
0.4
RADIAL FLOW IPR WITH DAMAGE
FLOWING BOTTOM-HOLE PRESSURE (bars)
300
250
200
150
100
50
0.0
0.0
5000
10000
15000
20000
25000
LIQUID RATE (m^3/d)

Figure 6.6

DATE : 2 /27/91
TIME : 12 28 94

Lse/Fld: BLOWOUT SCENARIO   Well ID: HYPOTHETICAL WELL II

IPR VOGEL CORRECTIONS



BEAUFORT AREA BLOWOUT SCENARIO
COMBINED IPR'S

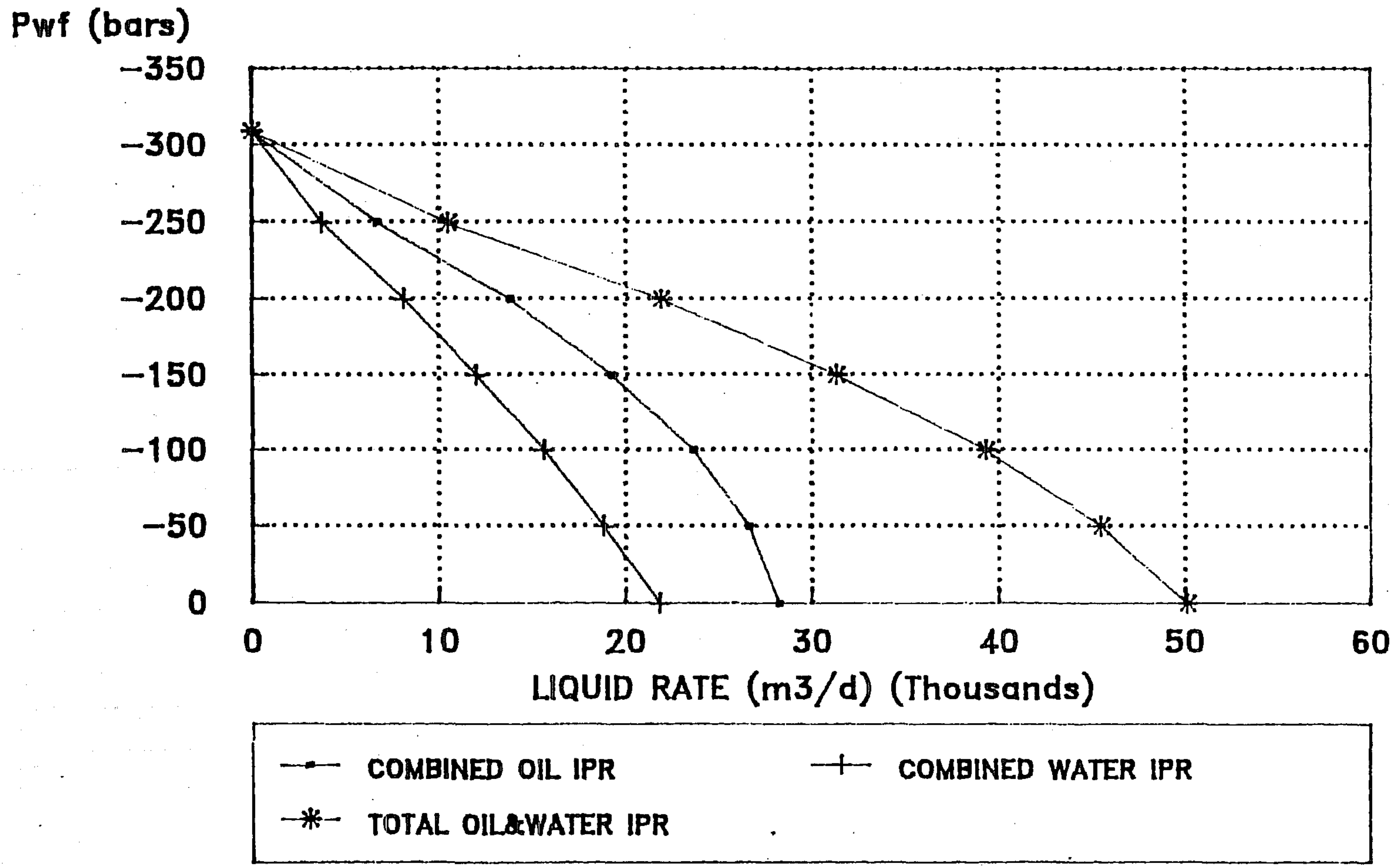
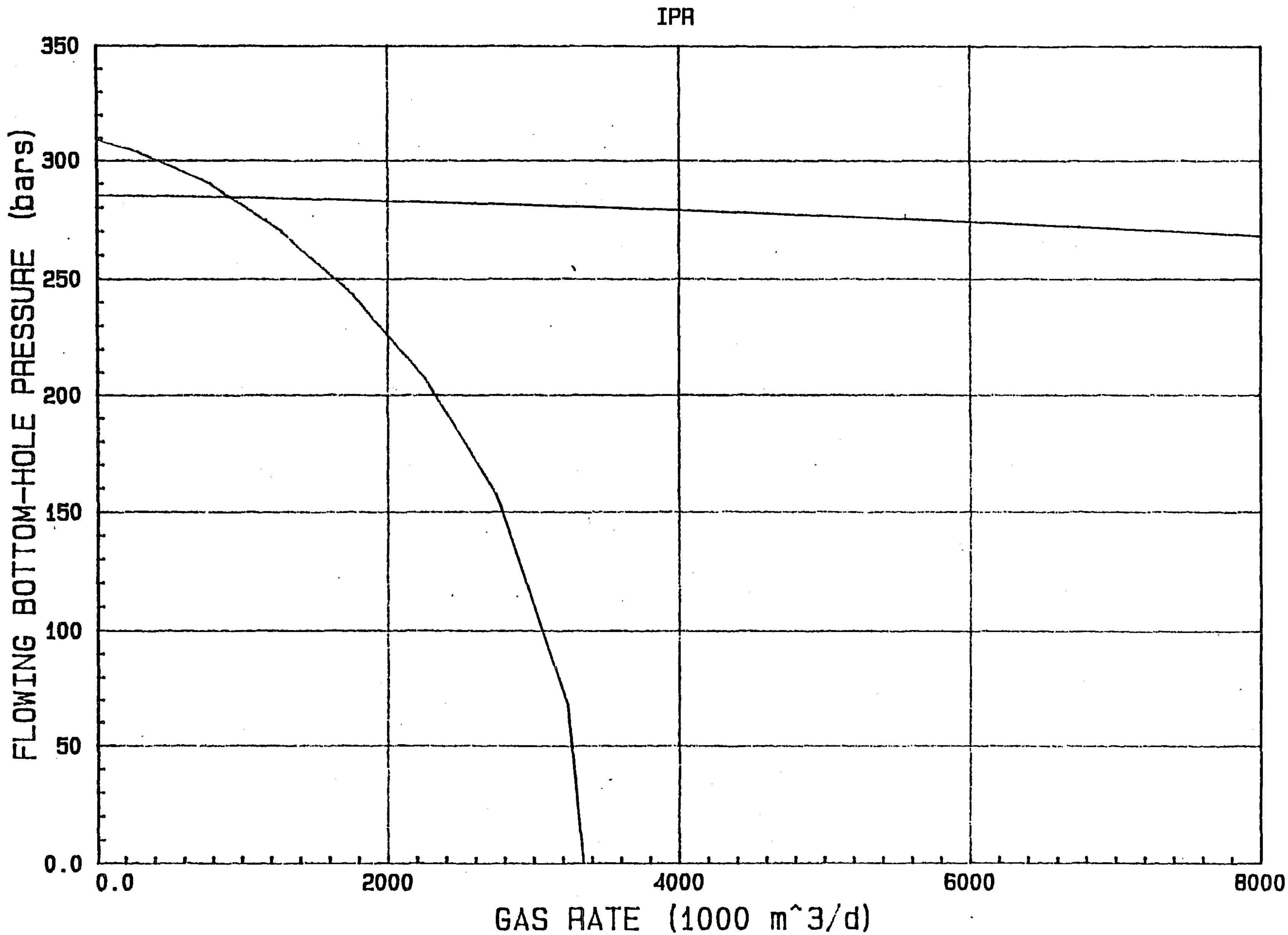


Figure 6.8

DATE : 2 /27/91
TIME : 02:06:00

Lse/Fld: BLOWOUT SCENARIO   Well ID: HYPOTHETICAL WELL II



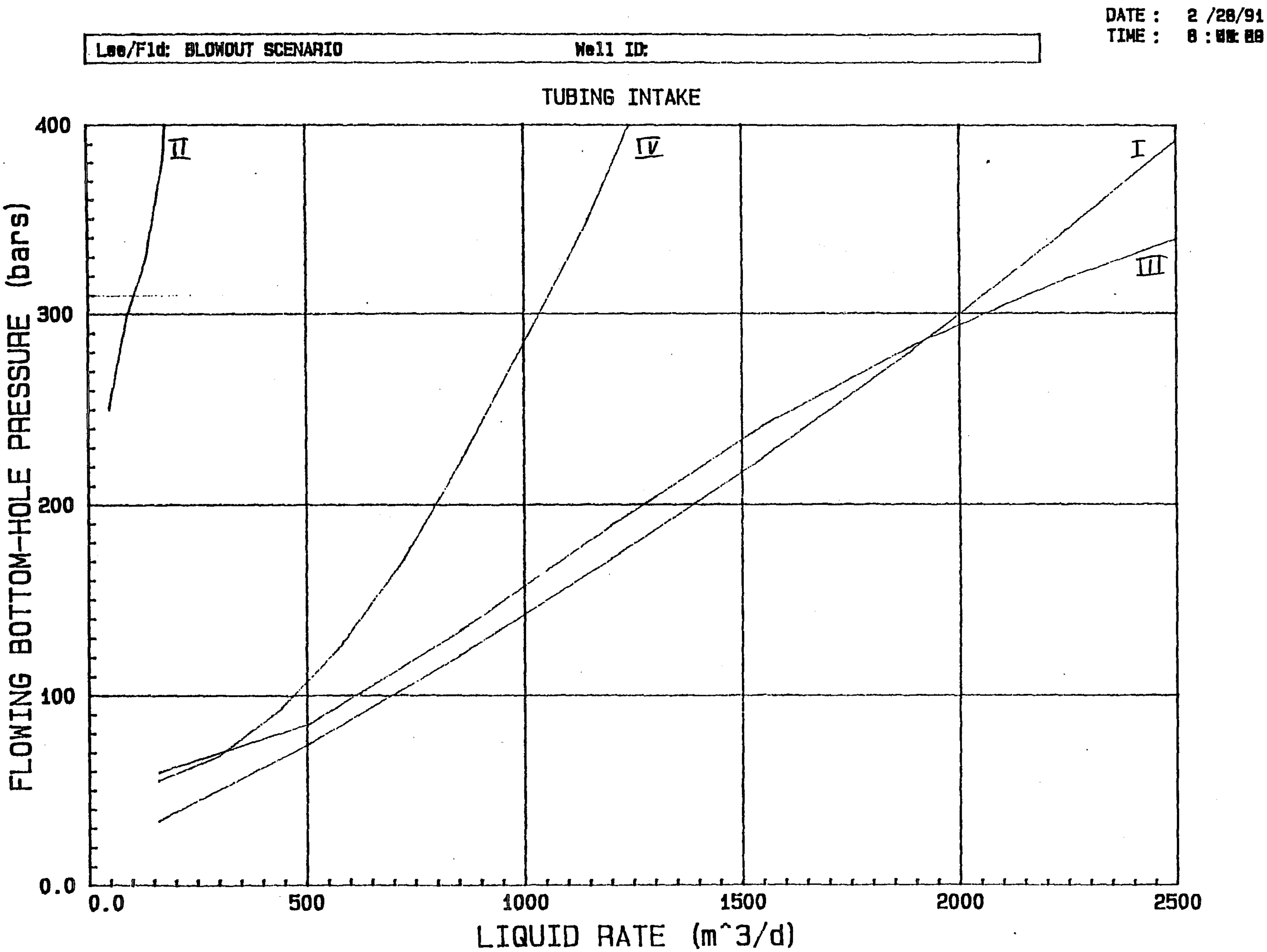
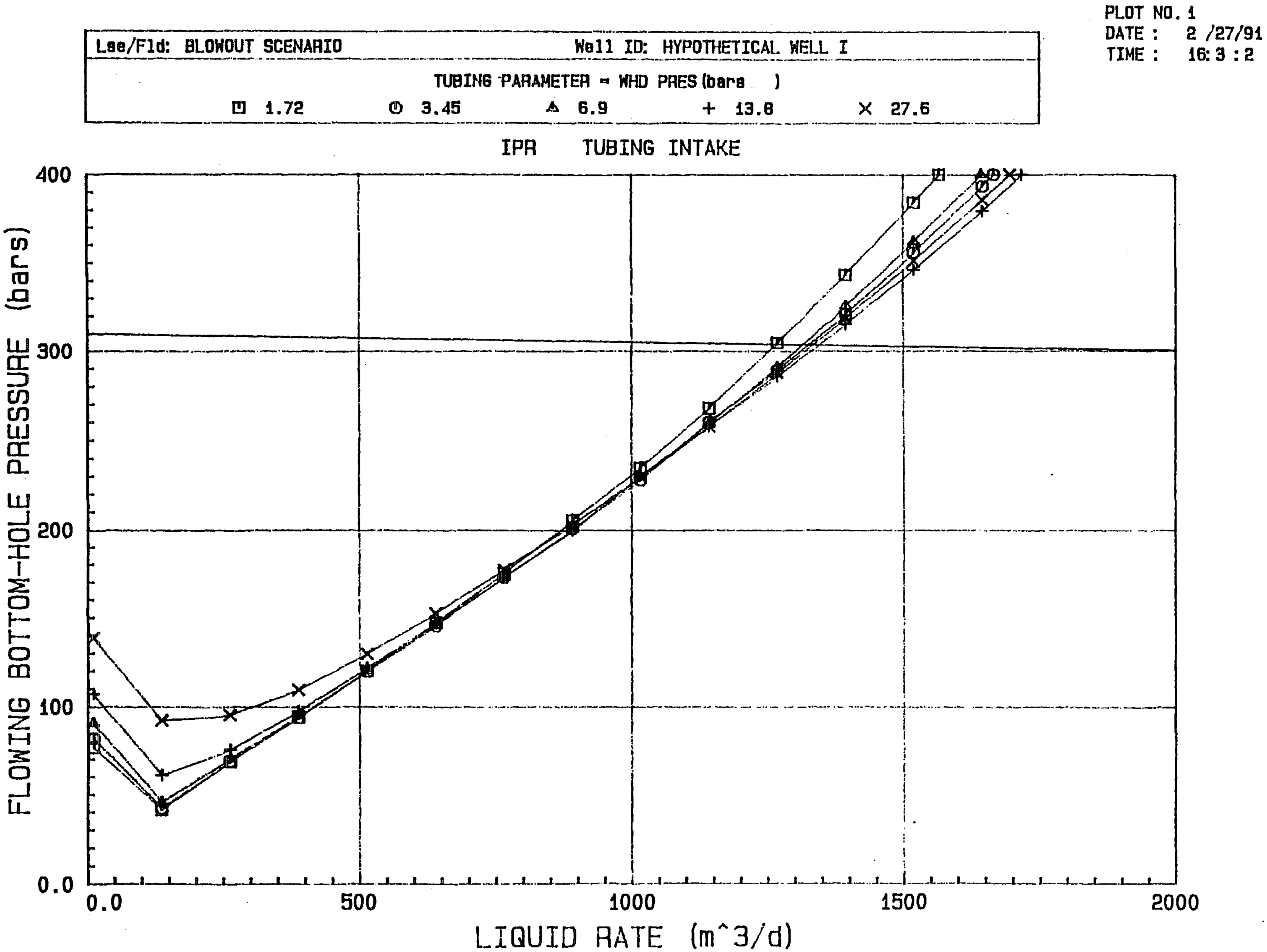

DATE : 2 /28/91
TIME :
Lse/Fld: BLOWOUT SCENARIO
Well ID:
TUBING INTAKE
I
II
III
IV
FLOWING BOTTOM-HOLE PRESSURE (bars)
400
300
200
100
0.0
0.0
500
1000
1500
2000
2500
LIQUID RATE (m^3/d)

Figure 6.10



PLOT NO. 1
DATE : 2 /27/91
TIME : 16: 3 : 2
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
TUBING PARAMETER = WHD PRES (bars)
1.72
3.45
6.9
13.8
27.6
IPR TUBING INTAKE
FLOWING BOTTOM-HOLE PRESSURE (bars)
400
300
200
100
0.0
0.0
500
1000
1500
2000
LIQUID RATE (m^3/d)

Figure 6.11

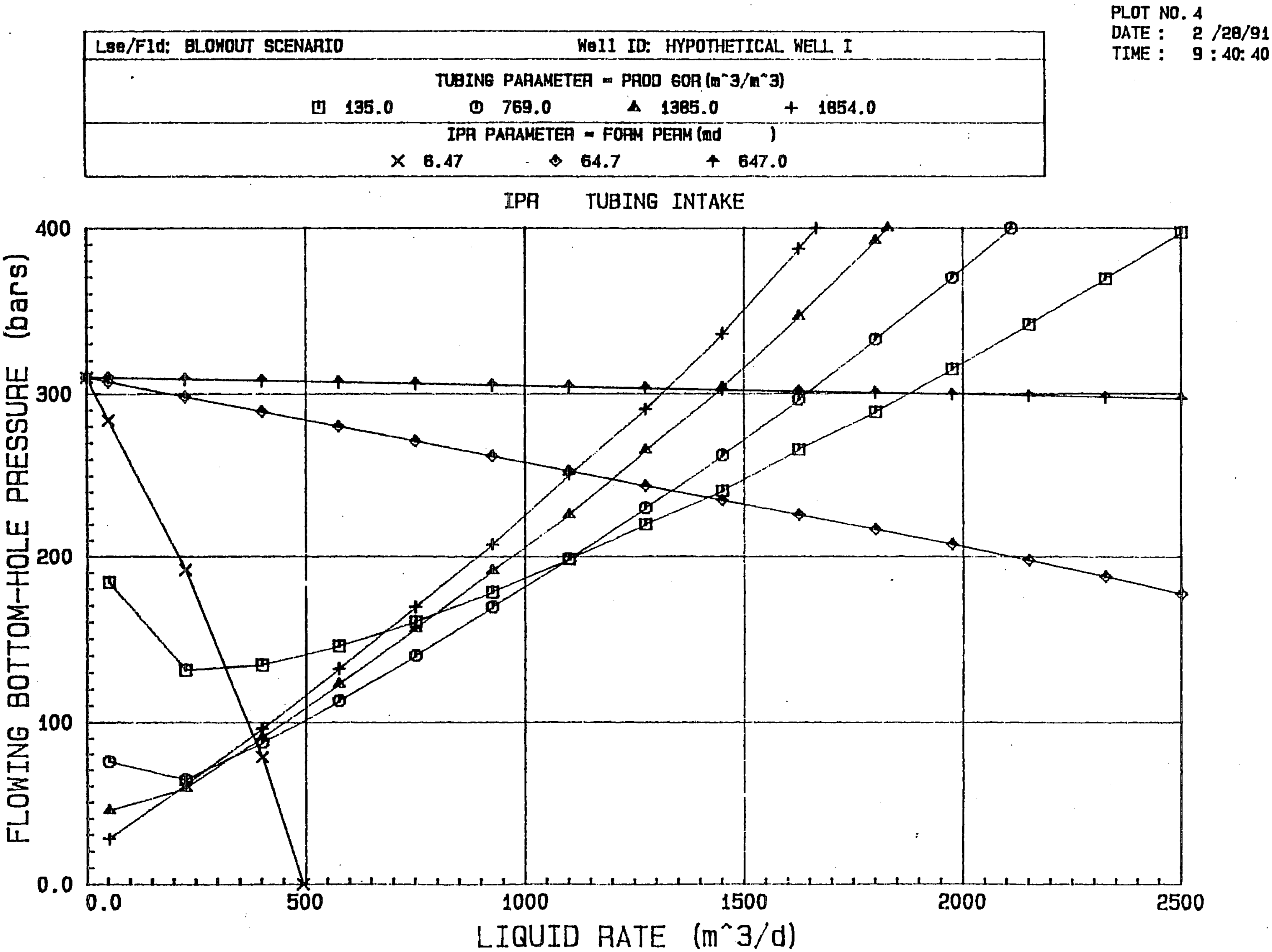
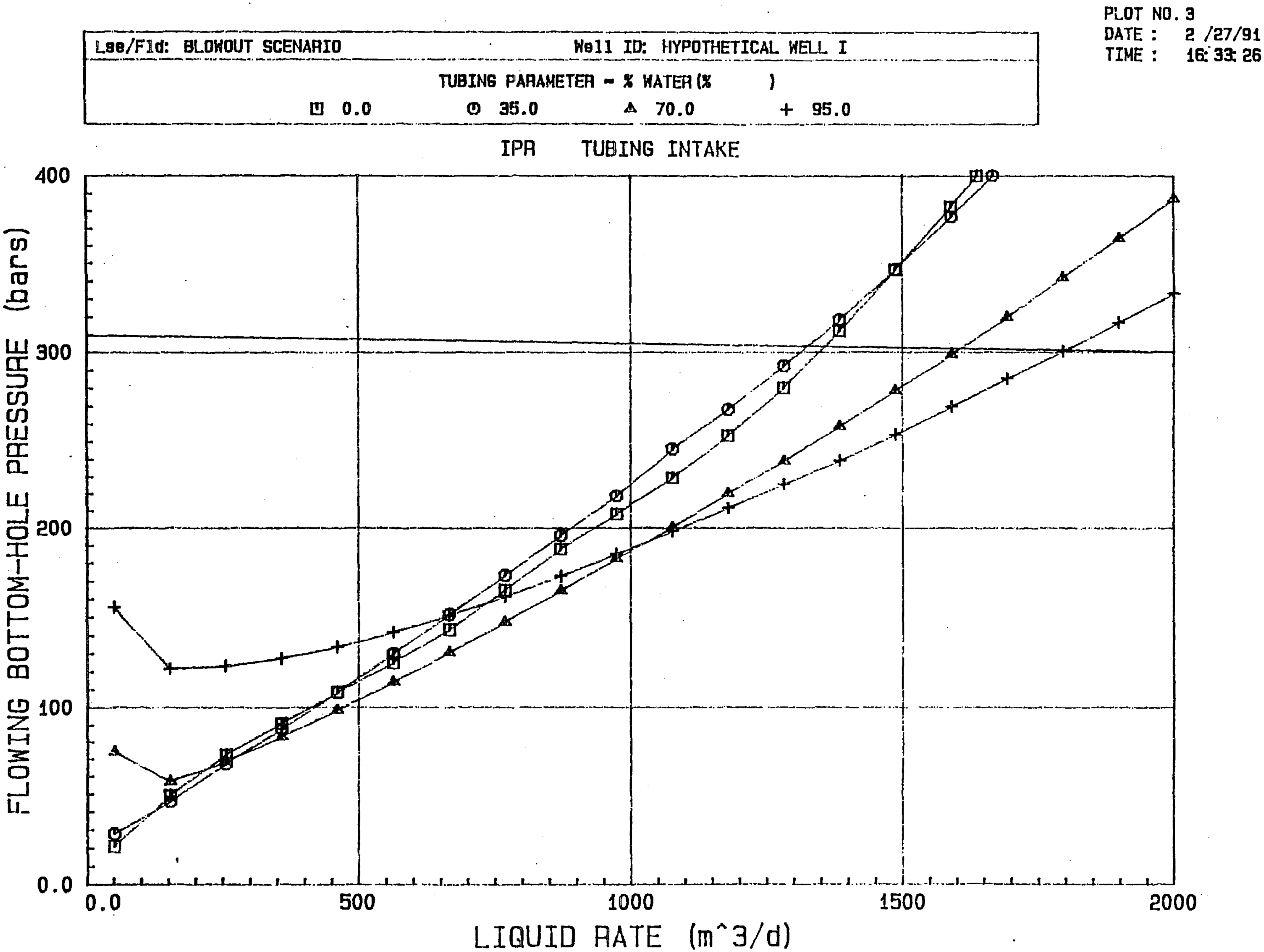

PLOT NO. 4
DATE : 2 /28/91
TIME : 9 : 40: 40
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
TUBING PARAMETER = PROD GOR (m^3/m^3)
135.0
769.0
1385.0
1854.0
IPR PARAMETER = FORM PERM (md)
6.47
64.7
647.0
IPR TUBING INTAKE
FLOWING BOTTOM-HOLE PRESSURE (bars)
400
300
200
100
0.0
500
1000
1500
2000
2500
LIQUID RATE (m^3/d)

Figure 6.12



PLOT NO. 3
DATE : 2 /27/91
TIME : 16:33:26
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
TUBING PARAMETER - % WATER (%)
0.0
35.0
70.0
+ 95.0
IPR TUBING INTAKE
FLOWING BOTTOM-HOLE PRESSURE (bars)
400
300
200
100
0.0
500
1000
1500
2000
LIQUID RATE (m^3/d)

Figure 6.13

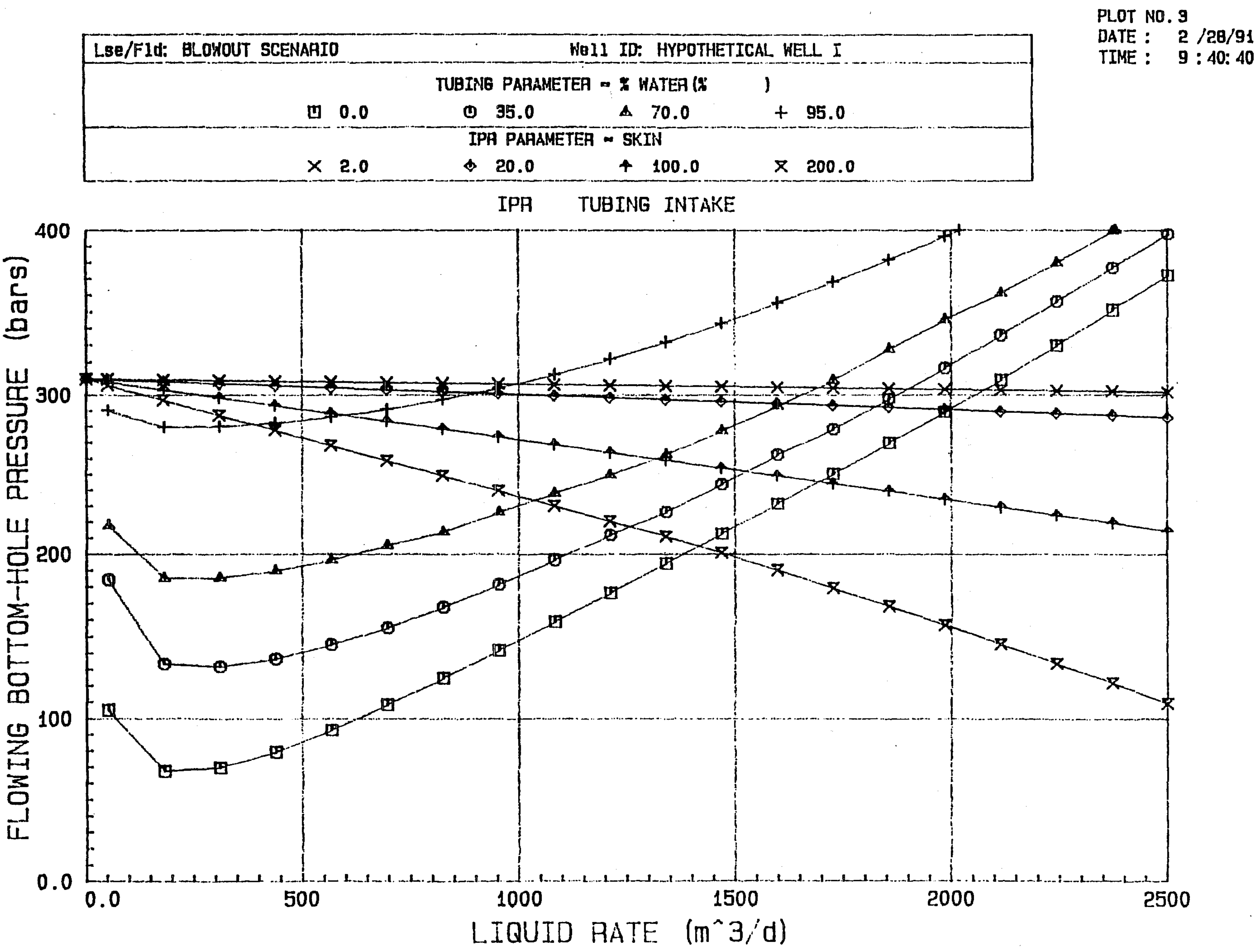
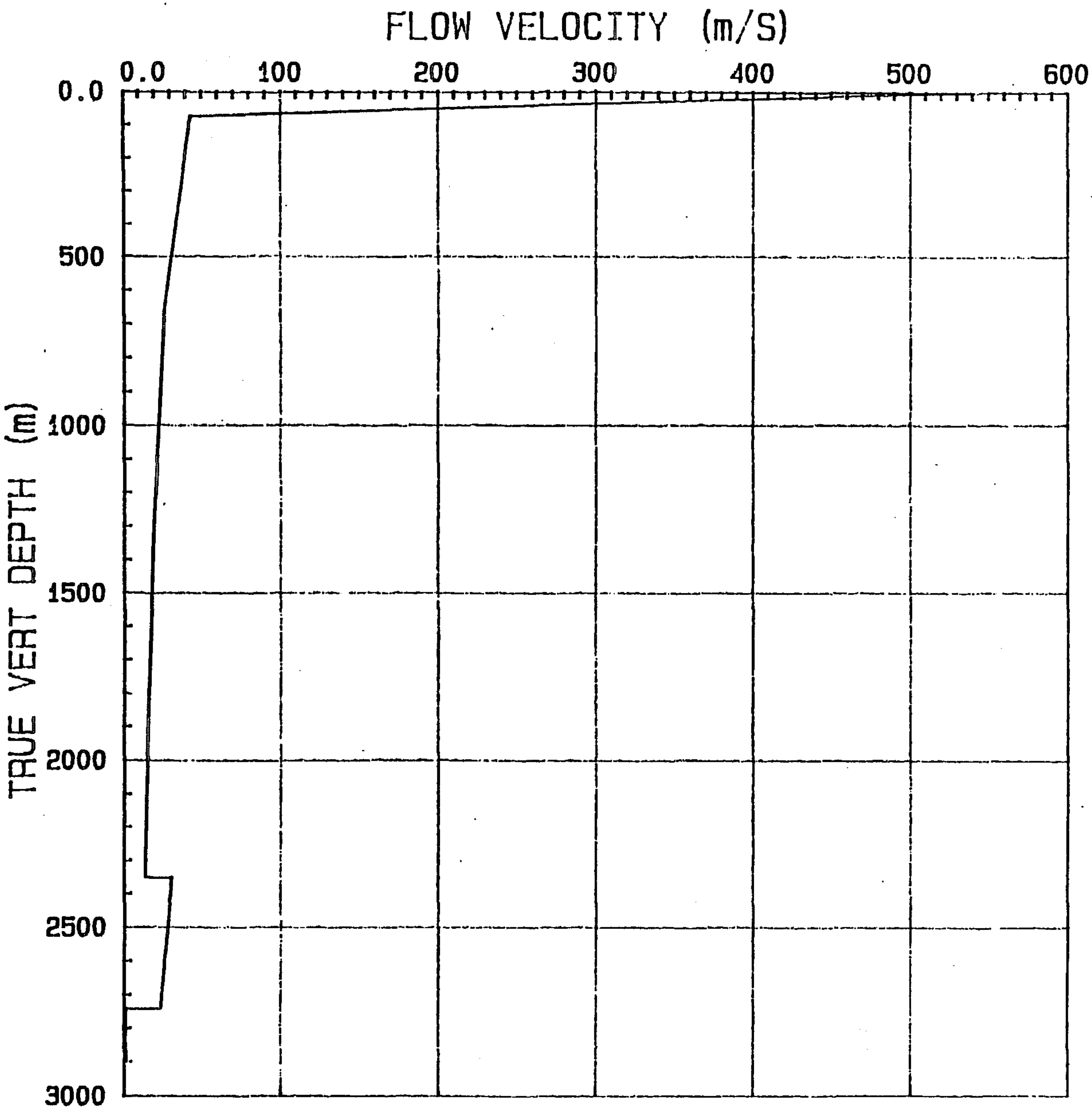

PLOT NO. 9
DATE : 2 /28/91
TIME : 9 : 40: 40
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
TUBING PARAMETER ~ % WATER (%)
0.0
35.0
70.0
95.0
IPR PARAMETER ~ SKIN
2.0
20.0
100.0
200.0
IPR TUBING INTAKE
FLOWING BOTTOM-HOLE PRESSURE (bars)
LIQUID RATE (m^3/d)
0.0
100
200
300
400
0.0
500
1000
1500
2000
2500

Figure 6.14

DATE : 2 /27/91
TIME : 17:20:13



BLOWOUT SCENARIO
HYPOTHETICAL WELL I

PRODUCTION WELL

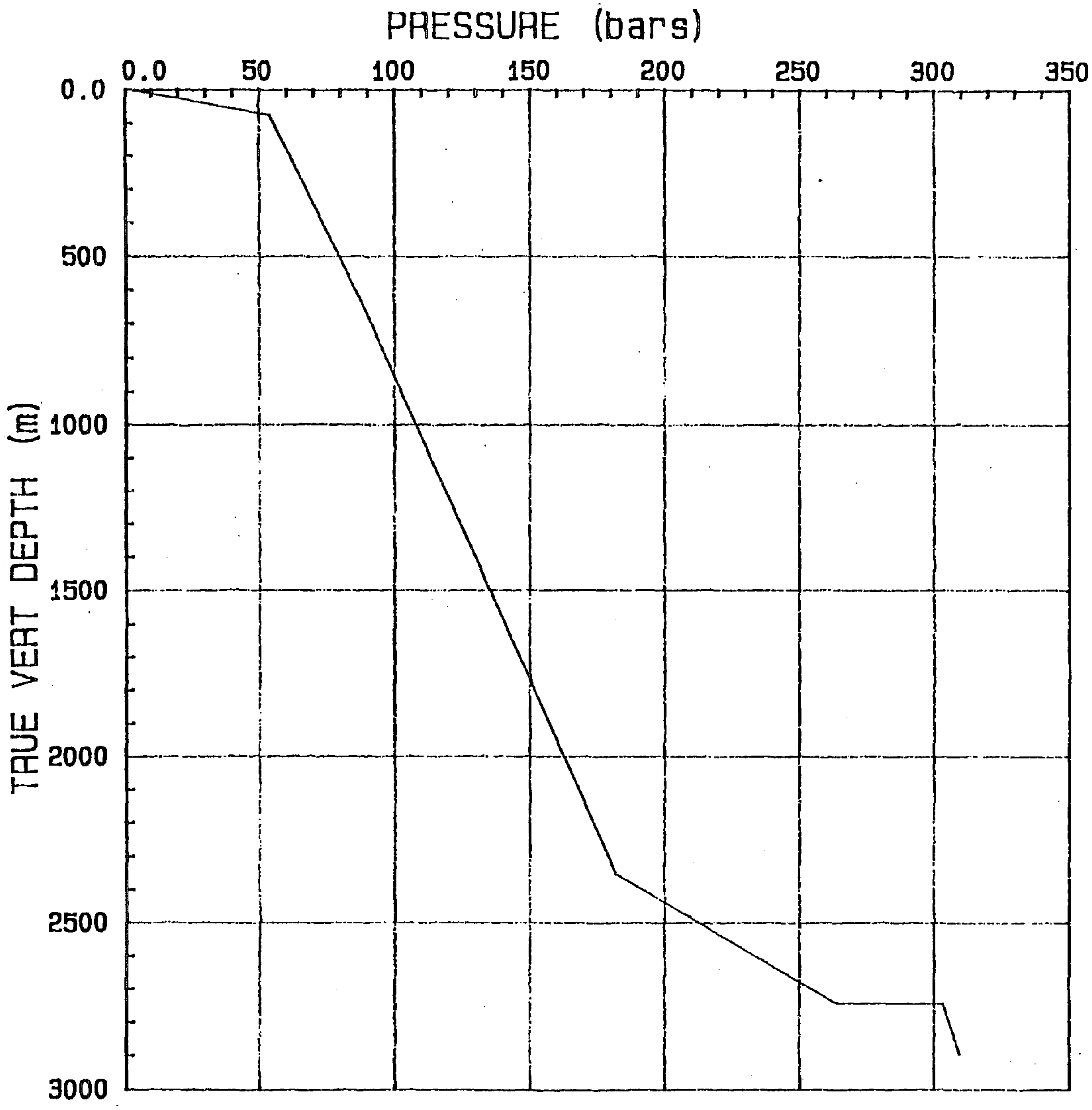
0.104 WATER GRAD (bars/m)
0.861 OIL DENSITY (g/cm^3)
0.60 GAS REL DEN (FORM)
35 PERCENT WATER
1854. FORM GOR (m^3/m^3)

CASING 33.972 - 2896
TUBULAR 13.970 - 2743
TUBULAR 13.970 - 2353

FLOW CORRELATION = M/S

RATE = 1350.0 m^3/d
68 WHD TEMP (deg C)

DATE : 2 /27/91
TIME : 17: 20: 13



BLOWOUT SCENARIO
HYPOTHETICAL WELL I

PRODUCTION WELL

0.104 WATER GRAD (bars/m)
0.861 OIL DENSITY (g/cm^3)
0.60 GAS REL DEN (FORM)
35 PERCENT WATER
10293.FORM GOR (m^3/m^3)

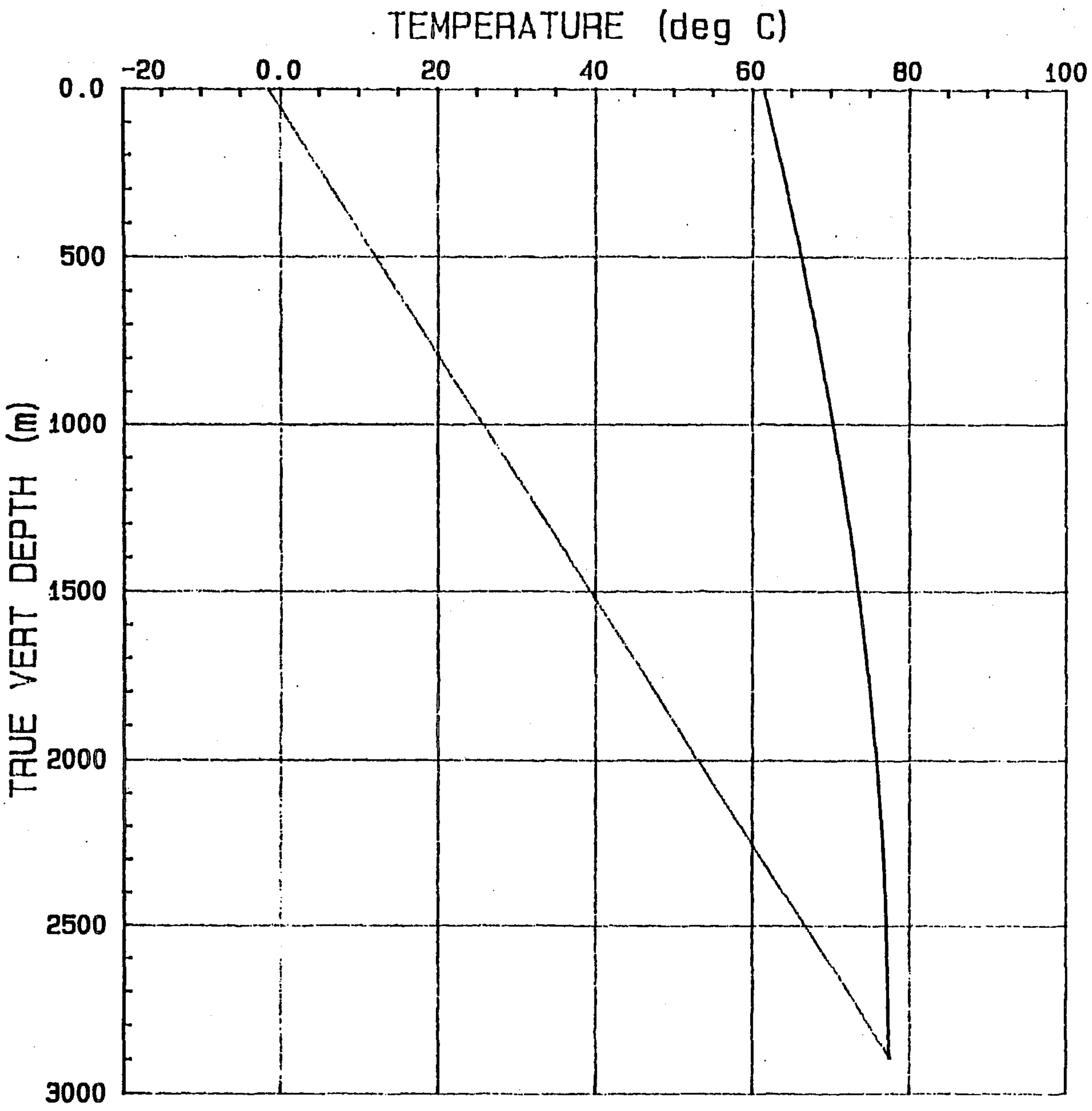
CASING 33.972 - 2896
TUBULAR 13.970 - 2743
TUBULAR 13.970 - 2353

FLOW CORRELATION = M/S

RATE = 1350.0 m^3/d
68 WHD TEMP (deg C)

Figure 6.16

DATE : 2 /27/91
TIME : 17: 27: 57



BLOWOUT SCENARIO
HYPOTHETICAL WELL I

PRODUCTION WELL

0.104 WATER GRAD (bars/m)
0.861 OIL DENSITY (g/cm^3)
0.60 GAS REL DEN (FORM)
35 PERCENT WATER
334. FORM GOR (m^3/m^3)

CASING 33.972 - 2896
TUBULAR 13.970 - 2743
TUBULAR 13.970 - 2353

FLOW CORRELATION = M/S

RATE = 1350.0 m^3/d
61 WHD TEMP (deg C)

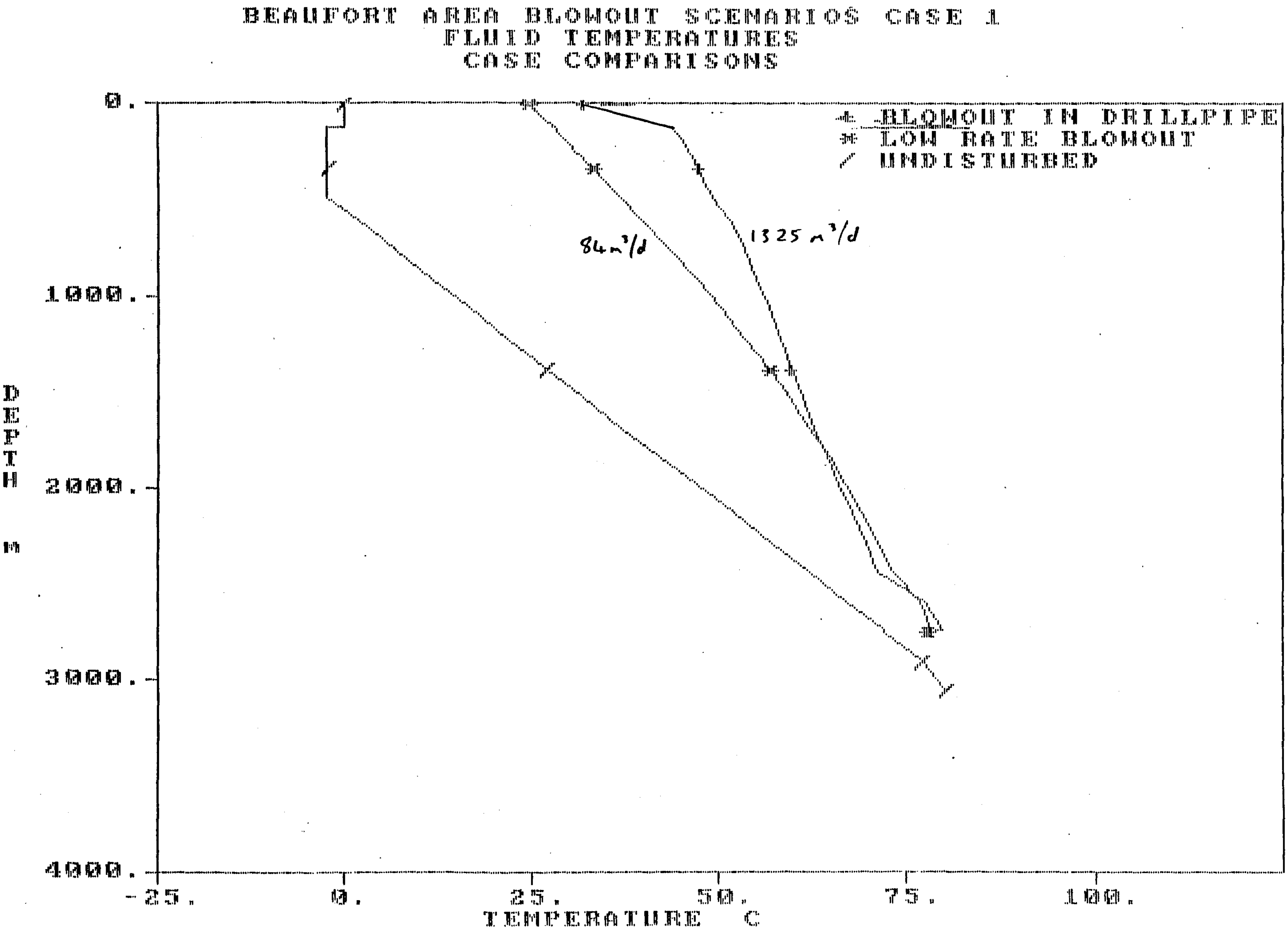
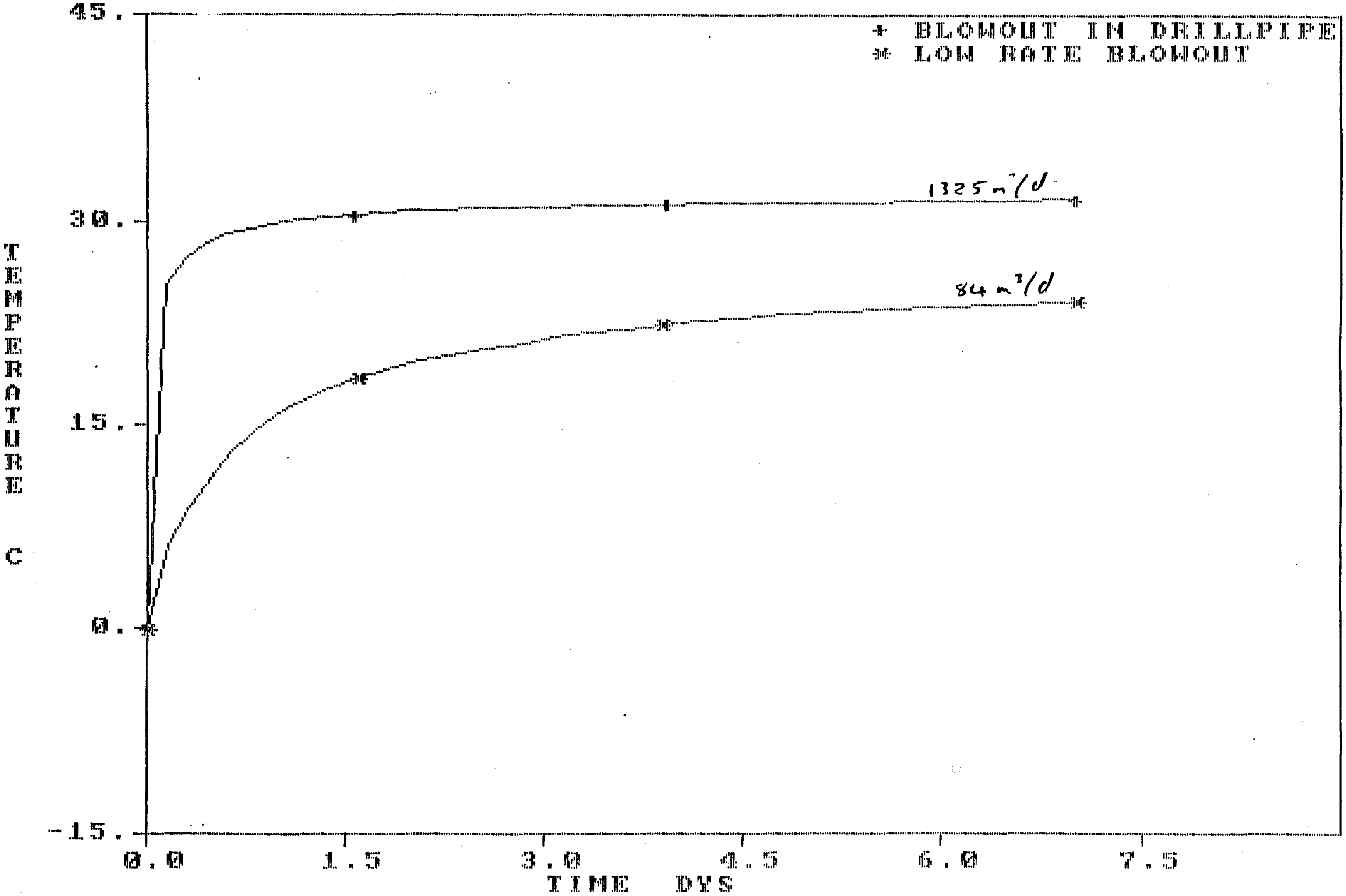
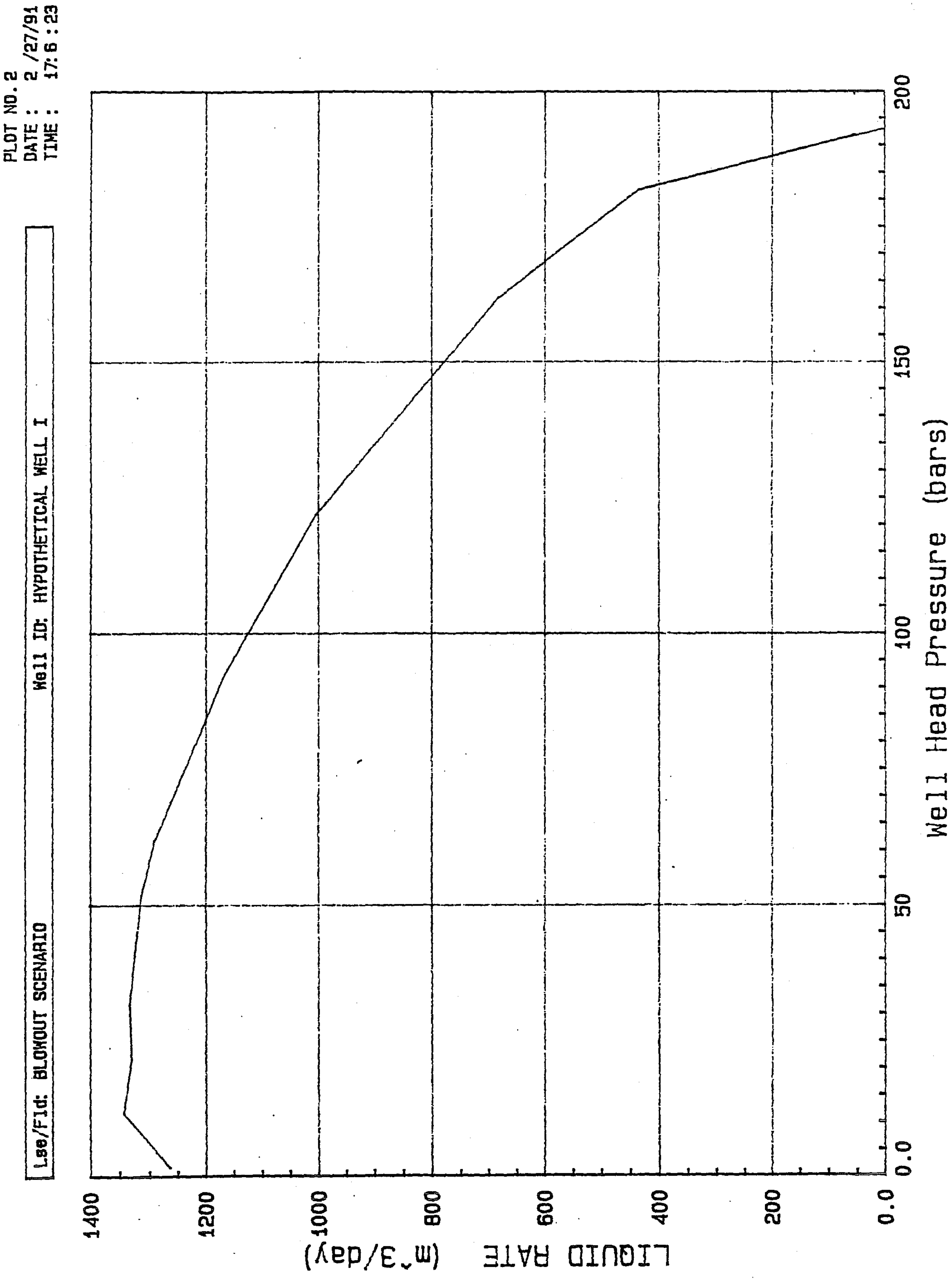

BEAUFORT AREA BLOWOUT SCENARIOS CASE 1
FLUID TEMPERATURES
CASE COMPARISONS
+ BLOWOUT IN DRILLPIPE
* LOW RATE BLOWOUT
/ UNDISTURBED
84 m³/d
1325 m³/d
0.
1000.
2000.
3000.
4000.
DEPTH
m
-25.
0.
25.
50.
75.
100.
TEMPERATURE C

Figure 6.18

BEAUFORT AREA BLOWOUT SCENARIOS CASE 1
WELLHEAD TEMPERATURES VS. TIME
CASE COMPARISONS





PLOT NO. 2
DATE : 2 /27/91
TIME : 17:6 :23
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
LIQUID RATE (m^3/day)
0.0
200
400
600
800
1000
1200
1400
Well Head Pressure (bars)
0.0
50
100
150
200

Figure 6.20

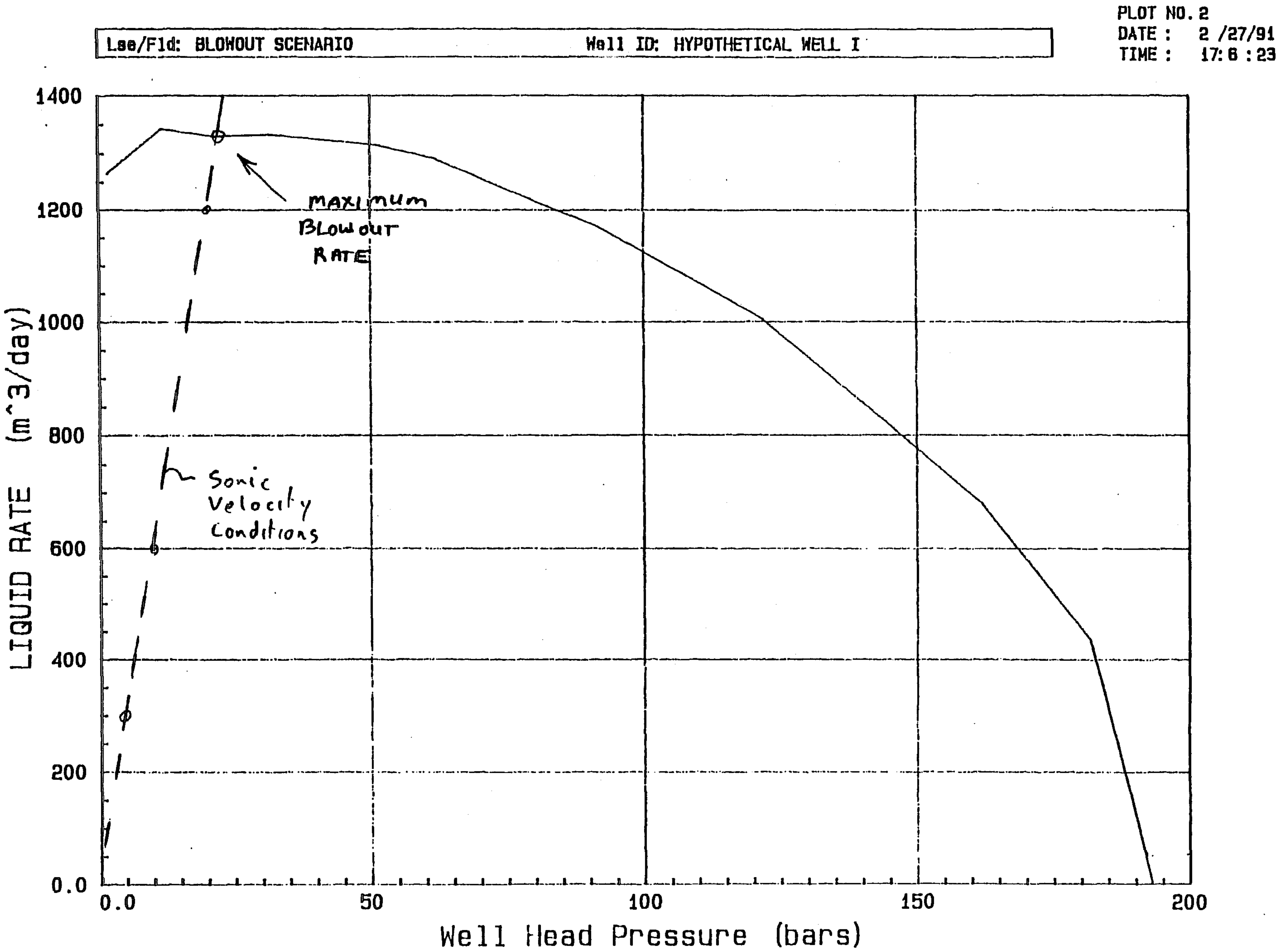
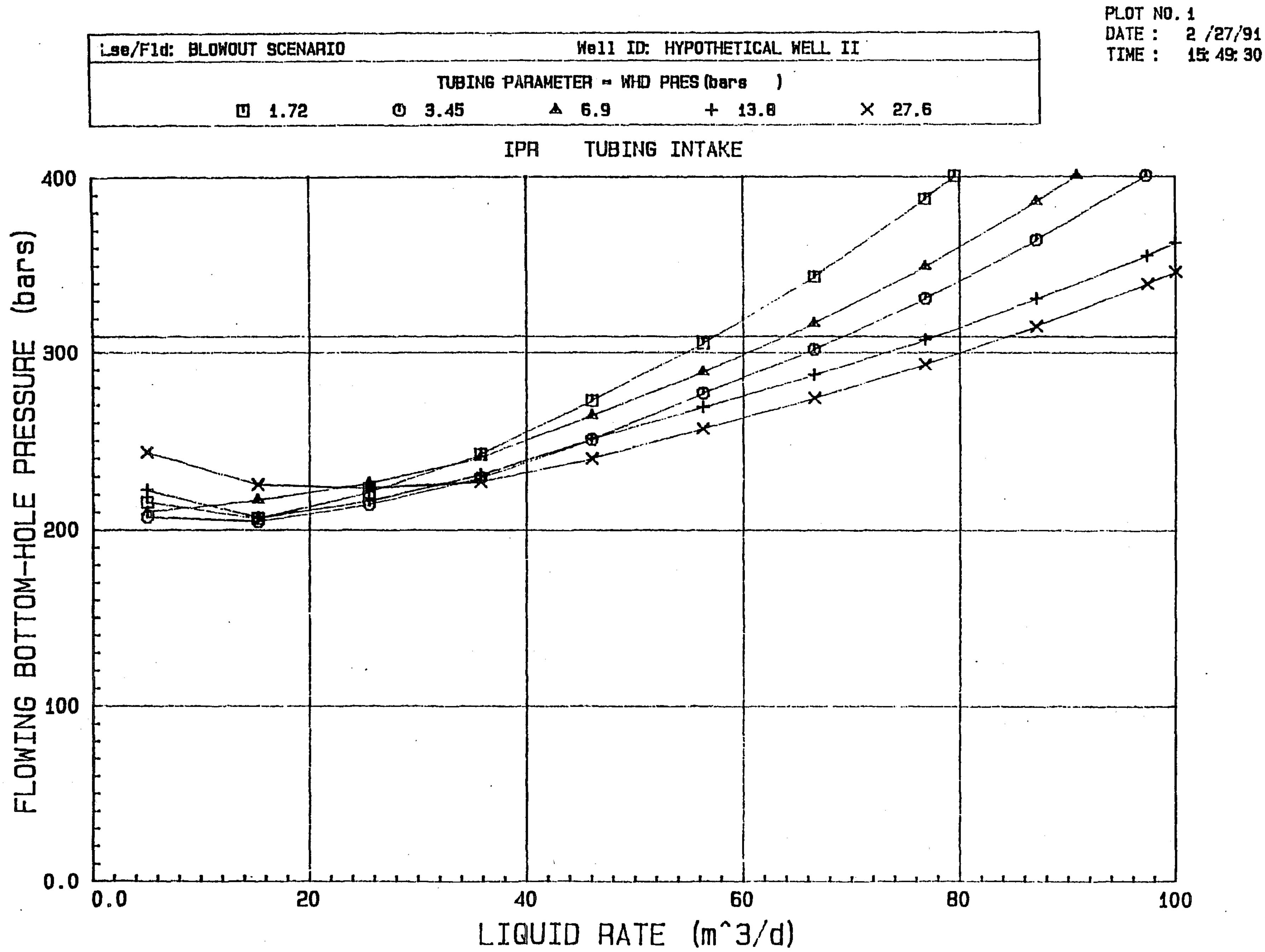
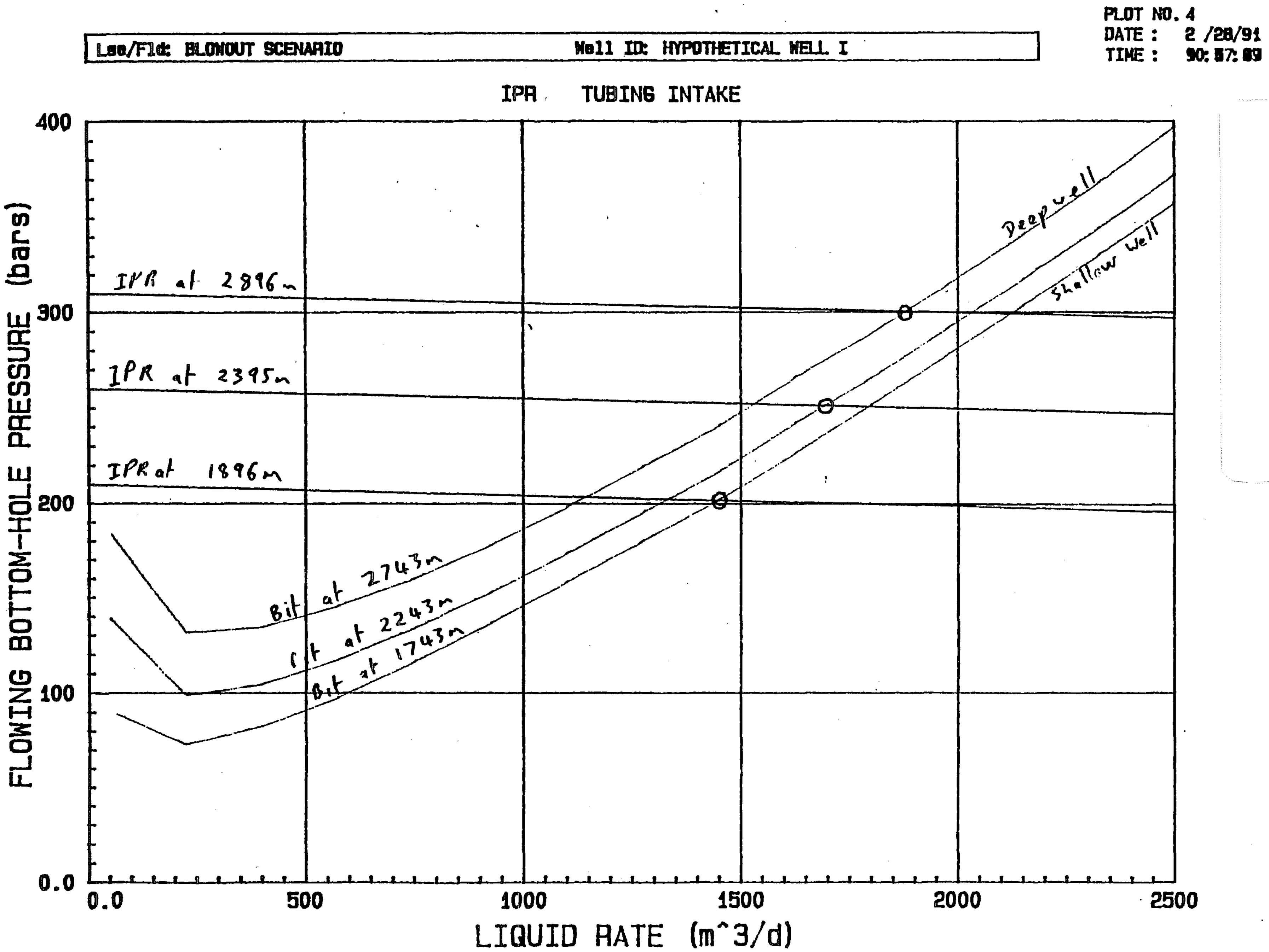

Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
PLOT NO. 2
DATE : 2 /27/91
TIME : 17:6 :23
1400
1200
1000
800
600
400
200
0.0
LIQUID RATE (m^3/day)
0.0
50
100
150
200
Well Head Pressure (bars)
MAXIMUM
BLOWOUT
RATE
Sonic
Velocity
Conditions

Figure 6.21


PLOT NO. 1
DATE : 2 /27/91
TIME : 15:49:30
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL II
TUBING PARAMETER = WHD PRES (bars)
1.72
3.45
6.9
13.8
27.6
IPR TUBING INTAKE
FLOWING BOTTOM-HOLE PRESSURE (bars)
400
300
200
100
0.0
20
40
60
80
100
LIQUID RATE (m^3/d)



PLOT NO. 4
DATE : 2 /28/91
TIME : 90:57:09
Lse/Fld: BLOWOUT SCENARIO
Well ID: HYPOTHETICAL WELL I
IPR TUBING INTAKE
IPR at 2896m
IPR at 2395m
IPR at 1896m
Bit at 2743m
Bit at 2243m
Bit at 1743m
Deep well
Shallow well
FLOWING BOTTOM-HOLE PRESSURE (bars)
400
300
200
100
0.0
500
1000
1500
2000
2500
LIQUID RATE (m^3/d)