HOD FIELD
DEVELOPMENT AND OPERATING PLAN

SUPPLEMENT

APRIL 1988

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A. INTRODUCTION

This Supplement to the Hod Field Development and Operating Plan (FDOP) was prepared in response to certain questions and comments raised by the Norwegian Petroleum Directorate (hereinafter referred to as "The Directorate") concerning chapters 3 and 4, Geological Conditions and Reservoir Engineering, of the Hod FDOP.

By way of introduction, outlined below is a synopsis of the correspondence between Amoco Norway and the Directorate regarding the contents of these Chapters.

1. Amoco Norway submitted a draft version of Chapters 3 and 4 of the Hod FDOP to the Directorate on 22 January 1988. This was transmitted under cover letter from R.D. Erickson to F. Al-Kasim, reference NO L 308 413.64 LH.

2. Amoco Norway received a letter from the Directorate dated 14 March 1988, reference OD/8 PEØ/THe, which contained a request for additional information on nineteen (19) questions or comments related to the Geological and Reservoir Engineering aspects of the Hod FDOP. In this letter, the Directorate requested that the additional information be included in the final version of the FDOP or, if this was not possible, be submitted separately and as soon as possible.

3. On 6 April 1988 a meeting was held between members of the Directorate's Reservoir Technology and Production Geology Sections, and Amoco Norway Chief Engineer, M.D. Drennon. The purpose of the meeting was to clarify the nature of some of the questions and comments contained in the Directorate's letter of 14 March 1988.

4. As a consequence of this meeting, Amoco Norway sent a telex to the Directorate dated 7 April 1988, reference NO T 659 413.64 MA. In this telex, Amoco Norway stated that answers to the questions and comments contained in the Directorate's letter, except those relating to reservoir uncertainty, would be provided to the Directorate by the end of April 1988. Amoco Norway also provided, in this telex, a summary of the ranges of oil-in-place and reserves that were calculated for development planning purposes in the Hod FDOP. Amoco Norway expressed the opinion that "these ranges are considered to be sufficiently extensive to cover any reasonable outcome of the development of the Hod Field".

5. On 7 April 1988, the final version of the Hod FDOP was signed by all members of the Amoco/NOCO Group and formally submitted to the Ministry of Petroleum and Energy. A copy of the finalized FDOP was submitted to the Directorate on 8 April 1988.

6. The Directorate sent a telex dated 11 April 1988 in response to Amoco Norway's telex. In this telex, reference AUB/INS no. 518/88, the Directorate requested a qualitative evaluation of variations in certain parameters used to calculate oil-in-place and reserves. It was stated that this evalua-

tion should be provided, if possible, by the end of April this year.

7. Finally, Amoco Norway replied in a telex dated 15 April 1988, reference NO T 716 413.64 MA, wherein it was stated that the Directorate's request was being handled with the aim of providing the evaluation requested by the end of April 1988.

Copies of the correspondence outlined above are included in Section B of this Supplement.

B. AMOCO/NPD CORRESPONDENCE

Attached are copies of all correspondence entered into between Amoco Norway and the Directorate on the subject of Hod Field Geological Conditions and Reservoir Engineering since January, 1988.

1. Letter from Amoco Norway to Norwegian Petroleum Directorate

Date: 22 January 1988

From: R. D. Erickson

To : F. Al-Kasim

Ref : NO L 308 413.64 LH

Subj: Draft Hod Field Development and Operating Plan
Geology, Geophysics and Reservoir Engineering

Version: English

Amoco Norway Oil Company
(Utenlandsk Aksjeselskap)
Bergjelandsgata 25
P.O. Box 388
4001 Stavanger, Norway
Tel.: (04) 50 20 00
Telex: 42780
Telefax: (04) 50 22 18

Robert D. Erickson
President and General Manager

22 January 1988

Norwegian Petroleum Directorate
P.O. Box 600
4004 Stavanger

Attn.: F. Al-Kasim

File : NO L 308 413.64 LH
Subj.: Draft Hod Field Development and Operating Plan
Geology, Geophysics and Reservoir Engineering

Dear Sir,

As requested in our informal meetings with your M. Marable, Ø. Dretvik and other staff on 16 October and 3 December 1987, please find attached for your information a draft copy of the Geological Conditions and Reservoir Engineering chapters for the Hod Field Development and Operating Plan (FD&OP). A description of the proposed installations and facilities (Hod Development Study) was submitted to the NPD on 20 November 1987, and has been followed by communication with your Ø. Tuntland in particular.

The FD&OP is a compilation of input from several sources. The document is currently in a draft form and we are continuing to work on it to incorporate comments from various reviews.

Amoco will be pleased to meet with your staff to discuss and clarify any issues required. Please revert to Amoco Norway's Chief Engineer, Mike Drennon at your earliest convenience should you have any further enquiries. We hope this should assist in accelerating, smoothing the approval process for the Hod FD&OP which we envision will be submitted by Mid February.

Yours truly,

R. D. Erickson
Ø

cc: M. Marable
P.E. Øverli

2. Letter from Norwegian Petroleum Directorate to Amoco Norway

Date: 14 March 1988

From: Else Ormaasen, Leif Hinderaker

To : -

Ref : OD/8'PEØ/THe

Subj: Comments regarding Hod Development and Operating Plan - Geology and Production

Version: Norwegian and English

OLJEDIREKTORATET

PROF. OLAV HANSSENSVEI 10, BOKS 600, 4001 STAVANGER - TELEFON (04) 87 60 00 TELEFAX (04) 55 15 71 TELEX 42863 NOPED

AMOCO NORWAY
DATE RECEIVED: 15/3-88
LOG NO: 4677
ANSWER DUE DATE: asap.
ACTION BY: M. D. Drennon ~~A. Tansø~~
RESP. DEPARTM: ~~Eng. Constr.~~
COPY TO: RDE, JAB, AT, AB, ASE, MDD, KA
FILE NO: 413-64

Amoco Norway Oil Company
Postboks 388

4001 STAVANGER

Offentlig

Deres ref. | Vår ref. (bes oppgitt ved svar) OD/88/4642 PEØ/THe | Dato 14 MARS 1988

KOMMENTARER VEDRØRENDE PUD FOR HOD - GEOLOGI OG UTVINNING

Oljedirektoratet har mottatt en foreløpig utgave av PUD for Hod. Dette utkastet omfatter kapittel 3 og 4, GEOLOGISKE, RESERVOARTEKNISKE OG UTVINNINGSMESSIGE FORHOLD. Oljedirektoratet ønsker på denne måten å kommentere noen av punktene knyttet til den geologiske modellen og utvinningen av feltet. Dersom den etterspurte tilleggsdokumentasjon ikke kan inkluderes i endelig utgave av PUD, vil en be om å få dokumentasjonen separat og så snart som mulig. Oljedirektoratet vil gjerene vite når dokumentasjonen kan mottas.

OMRÅDETS STRATIGRAFI OG AVSETNINGSMILJØ (Kap. 3.1.2.2). Amoco skriver at det er betydelige mineralogiske forskjeller mellom Tor- og Hod-formasjonen. Oljedirektoratet ønsker dokumentasjon på undersøkelser som er utført på Hodkjerner.

I følge Amoco's sin tolkning har Vest Hod strukturen beveget seg nordover også etter migrasjon av hydrokarboner inn i strukturen. Erfaringer fra andre krittfelt med strukturell bevegelse etter oljemigrasjon tilsier ulik utvikling av porøsitet og permeabilitet over feltet. For Hod vil en slik tolkning medføre en bedre por/perm på sørflanken enn ellers på feltet. Oljedirektoratet ber om at plasseringen av produksjonsbrønner blir vurdert med hensyn til dette.

FORMASJONSPARAMETRE (Kap. 3.2...). Oljedirektoratet har ikke mottatt tolkede resultater fra RFT fra brønnene 2/11-3, 3A og 6(ST-1).

BEREGNING AV VANNMETNING (Kap.3.2.1.1). Det foreligger ingen vannanalyser fra Hod. Erfaringer fra nabofeltene viser at Rw varierer med en faktor på opp til 2 i reservoarer over saltstrukturer. Oljedirektoratet ønsker utredet hvilke konsekvenser endringer i Rw vil fører for ressursgrunnlaget og produksjonsstrategien.

TILSTEDEVÆRENDE HYDROKARBONER (Kap. 3.3). Oljedirektoratet ønsker en vurdering av usikkerheter i STOOIP.

BRØNNTESTER (Kap. 4.2). Oljedirektorater ønsker at Amoco redegjør for sine erfaringer forbundet med DST-prosedyrer.

BERGARTSEGENSKAPER - KJERNEBORING I FRAMTIDIGE BRØNNER (Kap. 4.3...). Oljedirektoratet ønsker å bli informert om TD og planlagte intervall for kjerneboring i de brønner som er omtalt i den foreløpige utgaven av PUD. Oljedirektoratet er spesielt opptatt av muligheten av å kjerneta reservoaret i det antatte graben området.

VÆSKE EGENSKAPER (Kap. 4.4). Synes det å være noen korrelasjoner angående kokepunkt og oppløsningsgass mot dyp?

DRIVMEKANISMER (Kap. 4.5.2). Ble det dannet noen overliggende adskilte gass sone i simulerings tilfeller? Oljedirektoratet ønsker at Amoco kommenterer konsekvenser med og uten danning av adskilte gass sone.

INNGANGSDATA TIL SIMULERING (Kap. 4.5.3). Oljedirektoratet ber Amoco om å få en tape med inngangsdata til base case og hoved sensitivitets tilfellene. Det bør følge med nok opplysninger for å kunne omdanne inngangsfilene til inngangsfiler til ECLIPSE 100 simulerings program.

Usikkerheter i inngangsdata bør vurderes og rapporteres.

Erfaringer fra andre felt tilsier at Ekofisk- og Tor formasjonen har ulike reservoaregenskaper. Er det utført studier på hva effekten av slike forskjeller vil føre til m.h.t. utvinning? I Hod er disse formasjonene simulert i samme enhet. Hvor store er volumene av hver formasjon i reservoarnivå? (Tor og Ekofisk fm)

RESSURSER (Kap. 4.5.4. og 4.5.5). Oljedirektoratet ønsker en vurdering av usikkerheter for både tekniske utvinnbar ressurser og økonomisk utvinnbar ressurser.

PRODUKSJONSSTRATEGI - KOMPLETERINGSSTRATEGI (Kap. 4.6.1). Oljedirektoratet ønsker at Amoco redegjør for den planlagte kompleteringsstrategi i Hod feltet utfra sine erfaringer i Valhall feltet.

4.6.2 RESERVOAROVERVÅKNING. En reservoar overvåkningsplan med estimerert regularitet i datainnsamling bør være med i PUD.

4.6.3 PROSESSKAPASITETER. Platforms separator og måle system skal brukes for måling av feltets produksjon og for allokering av produksjon til de enkelte brønnene. Oljedirektoratet ønsker en nærmere beskrivelse.

PUNKTER SOM IKKE ER NEVNT I DEN FORELAGTE UTGAVE AV PUD
Oljedirektoratet har utarbeidet et utkast til innhold i

Plan for utbygging og Drift (PUD) i henhold til forskrifter i petroleumsloven. Avsnittene nevnt nedenfor refererer seg til dette utkastet.

TIDSPLAN FOR UTBYGGING (AVS. NR. 5.8). Planen bør omfatte en beskrivelse og fremgangsmåte for forboring og innsamling av reservoar/geologiske data.

RISIKOANALYSER/SAMORDNING (AVS. NR. 6.3). Planen må inneholde alternative produksjonsprofiler som kan gjenspeile den reservoarmessige usikkerhet samt en vurdering av utbyggingsløsningens fleksibilitet med hensyn på endrede ressursanslag.

JURAPROSPEKTER. Hvordan oppfatter Amoco potensialet for tilleggsressurser i jura? Amoco bes vurdere en mulig plan for eventuell påvisning av slike ressurser.

Med hilsen

Else Ormaasen

Else Ormaasen
Seksjonssjef

Leif Hinderaker

Leif Hinderaker
Seksjonssjef

TRANSLATION

LETTER FROM : Norwegian Petroleum Directorate

DATED : 14.03.88

REF. : OD/8 PEØ/THe (ANOC Log No. 4677)

ADDRESSED TO : Amoco Norway Oil Company

COMMENTS REGARDING HOD PLAN FOR DEVELOPMENT AND PRODUCTION - GEOLOGY AND PRODUCTION

The Petroleum Directorate has received a preliminary version of the Hod Plan for Development and Production. This draft covers chapters 3 and 4, GEOLOGICAL, RESERVOIR-TECHNICAL AND PRODUCTION-RELATED ASPECTS. The Petroleum Directorate in this manner wishes to comment on some of the items in connection with the geological model and production from the field.
If the requested additional documentation cannot be included in the final version of the Development and Production Plan, one requests that the documentation be submitted separately and as soon as possible.
The Petroleum Directorate would like to know when one can expect to receive the documentation.

THE STRATIGRAPHY AND DEPOSIT ENVIRONMENT (Chapter 3.1.2.2). Amoco writes that there are important mineralogical differences between the Tor- and Hod formations. The Petroleum Directorate would like to have documentation of analyses performed on Hod cores.

According to Amoco's interpretation, the West Hod structure has moved northward also after migration of hydrocarbons into the structure. Experience from other chalk fields with structural movement after oil migration indicates different development of porosity and permeability over the field. For Hod such an interpretation will result in better porosity/permeability on the southern flank than elsewhere in the field. The Petroleum Directorate requests that this be taken into consideration when selecting locations for the production wells.

FORMATION PARAMETERS (Chapter 3.2...). The Petroleum Directorate has not received analyzed results from RFT from wells 2/11-3, 3A and 6 (ST-1).

CALCULATION OF WATER SATURATION (Chapter 3.2.1.1). There are no water analyses from Hod. Experience from the neighboring fields indicates that Rw varies with a factor of up to 2 in reservoirs above salt structures. The Petroleum Directorate would like a report on what consequences changes in Rw will have for the resource basis and the production strategy.

HYDROCARBONS IN PLACE (Chapter 3.3). The Petroleum Directorate would like to have an evaluation of uncertainties in STOOIP.

WELL TESTS (Chapter 4.2). The Petroleum Directorate would like Amoco to report on its experiences in connection with DST-procedures.

ROCK PROPERTIES - CORE DRILLING IN FUTURE WELLS (Chapter 4.3...). The Petroleum Directorate would like to be informed of TD and scheduled interval for core drilling in those wells that are mentioned in the preliminary version of the Development and Production Plan. The Petroleum Directorate is particularly interested in the possibility of coring the reservoir in the assumed graben area.

FLUID PROPERTIES (Chapter 4.4). Does there appear to be any, correlation regarding boiling point and solution gas towards depths?

DRIVE MECHANISMS (Chapter 4.5.2) Did any overlying separate gas zone develop in simulation cases? The Petroleum Directorate would like Amoco to comment on consequences with and without formation of separate gas zone.

ENTRY DATA FOR SIMULATION (Chapter 4.5.3). The Petroleum Directorate requests a tape from Amoco with entry data for base case and main sensitivity cases. Sufficient information should be included in order to convert the entry files to entry files for the ECLIPSE 100 simulation program.

Uncertainties in entry data should be analyzed and reported.

Experience from other fields indicate that the Ekofisk- and Tor formations have different reservoir properties. Have studies been performed on the effect of such differences in terms of production? In Hod, these formations have been simulated in the same unit: How large are the volumes in each formation on reservoir level? (Tor and Ekofisk formations.)

RESERVES (Chapter 4.5.5 and 4.5.5). The Petroleum Directorate would like to have an evaluation of uncertainties both concerning technically recoverable reserves and economically recoverable reserves.

PRODUCTION STRATEGY - COMPLETION STRATEGY (Chapter 4.6.1). The Petroleum Directorate requests that Amoco report on the planned completion strategy in the Hod Field based on its experience from the Valhall Field.

4.6.2 RESERVOIR MONITORING. A reservoir monitoring plan with estimated data collection regularity should be included in the Development and Production Plan.

4.6.3 PROCESS CAPACITIES. Platform separator and measuring system to be used for measuring production from the field and for allocation of production between the individual wells. The Petroleum Directorate would like a further description.

ITEMS NOT MENTIONED IN THE PLAN PRESENTED.
The Petroleum Directorate has prepared a draft for the contents of a Plan for Development and Production pursuant to the regulatio in the Petroleum Act. The paragraphs below refer to this draft.

TIME SCHEDULE FOR DEVELOPMENT (PARAGRAPH NO. 5.6(. The plan should include a description and procedure for test drilling and collection of reservoir/geological data.

RISK ANALYSES/COORDINATION (PARAGRAPH NO. 6.3). The plan must contain alternative production profiles that can reflect the reservoir-related uncertainty plus an evaluation of the flexibilit of the development concept in terms of revised reserves estimates.

JURASSIC PROSPECTS. What are Amoco's views on the potential for additional jurassic deposits. Amoco is asked to consider a possible plan for detection of such possible deposits.

Best regards,

Else Ormaasen (sign.)

Leif Hinderaker (sign.)

3. Telex from Amoco Norway to Norwegian Petroleum Directorate

Date: 7 April 1988

From: R. D. Erickson

To : F. Al-Kasim
Attn: M. Marable/L. Hinderaker/A. Bergo

Ref : NO T 659 413.64 MA

Subj: Hod Field Development and Operating Plan

Version: English

7 APR. 1988

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42863A NOPED N
42780Z AMOCO N

FROM: AMOCO NORWAY OIL COMPANY APRIL 7, 1988

TO: F. AL-KASIM
NORWEGIAN PETROLEUM DIRECTORATE

ATTN: M. MARABLE/L. HINDERAKER/A. BERGO

FILE: NO T 659 413.64 MA
SUBJ: HOD FIELD DEVELOPMENT AND OPERATING PLAN

REFERENCE IS MADE TO YOUR LETTER DATED 14 MARCH 1988, REF. OD/8 PEOE/THE, COMMENTING ON THE PRELIMINARY GEOLOGY AND RESERVOIR ENGINEERING SECTIONS OF THE SUBJECT PLAN, AND TO YOUR SUBSEQUENT MEETING WITH M. D. DRENNON, AMOCO NORWAY CHIEF ENGINEER, ON 6 APRIL 1988. AMOCO NORWAY WISHES TO EXPRESS ITS APPRECIATION FOR THE CONSIDERABLE EFFORT THE DIRECTORATE HAS GIVEN TO EXPEDITING EVALUATION OF THE PLANNED HOD DEVELOPMENT.

REGARDING THE CONTENTS OF YOUR LETTER, WE WILL BE ABLE TO PROVIDE ANSWERS TO THE MAJORITY OF THE QUESTIONS AND COMMENTS, EXCEPT FOR THOSE CONCERNING UNCERTAINTY IN OIL-IN-PLACE AND RESERVES, BY THE END OF APRIL 1988. WE WILL PROVIDE PRINTOUTS OF THE SIMULATION INPUT DATA IMMEDIATELY, TO BE FOLLOWED BY A TAPE OF THE DATA BY 15 APRIL.

ON THE ISSUE OF RESERVOIR UNCERTAINTY, THE DIRECTORATE REQUESTED THAT THIS BE FURTHER ASSESSED IN TERMS OF :

- CALCULATION OF WATER SATURATION (CHAPTER 3.2.1.1)
- HYDROCARBONS IN PLACE (CHAPTER 3.3)
- ENTRY DATA FOR SIMULATION (CHAPTER 4.5.3)
- RESERVES (CHAPTERS 4.5.4 AND 4.5.5)

AS DISCUSSED IN THE REFERENCED MEETING, AMOCO NORWAY IS INTERESTED IN MAINTAINING THE LEVEL OF DETAIL IN DEFINING UNCERTAINTY COMMENSURATE WITH THE SCALE OF THE HOD DEVELOPMENT. IN VARIOUS DISCUSSIONS BETWEEN OUR STAFFS, THE DIRECTORATE'S INTENT IN THIS REGARD HAS BEEN CLARIFIED TO BE A DESIRE TO OBTAIN A VERY RIGOROUS ASSESSMENT OF THE POTENTIAL IMPACT OF REASONABLE VARIATIONS IN A LARGE NUMBER OF RESERVOIR PARAMETERS. OUR UNDERSTANDING IS THAT THE DIRECTORATE DESIRES THAT THE OIL COMPANIES TAKE A FAIRLY STANDARDIZED, STATISTICAL APPROACH IN EVALUATING UNCERTAINTY. WE ACKNOWLEDGE THAT MOST OF THE PARAMETERS CONSIDERED IN DETERMINING OIL-IN-PLACE AND RESERVES HAVE A RANGE OF UNCERTAINTY, AND WE CAN SEE MERIT IN USING A STATISTICAL APPROACH FOR EVALUATING UNCERTAINTY IN CERTAIN SITUATIONS. HOWEVER, WE CONSIDER SUCH A RIGOROUS APPROACH TO BE INAPPROPRIATE FOR THE HOD FIELD, FOR THE FOLLOWING REASONS :

1. THE VALIDITY OF A STATISTICAL ASSESSMENT OF UNCERTAINTY IS INFLUENCED BY THE SIZE OF THE DATA BASE USED FOR THE STATISTICAL ANALYSIS. FOR HOD, WHICH COMPRISES TWO SEPARATE STRUCTURES, THIS DATA BASE IS VERY SMALL. IT IS BELIEVED THAT A STATISTICAL ANALYSIS BASED ON SUCH LIMITED DATA WOULD NOT NECESSARILY RESULT IN A MORE PRECISE DEFINITION OF RESERVOIR UNCERTAINTY.

2. IN CONSIDERING THE APPROPRIATE LEVEL OF DETAIL, I.E. HOW RIGOROUS AN APPROACH TO TAKE IN EVALUATING UNCERTAINTY, IT IS FIRST OF ALL ESSENTIAL TO CONSIDER THE POSSIBLE OUTCOMES. IT SHOULD BE CONSIDERED WHETHER ANY SIGNIFICANT CHANGES TO THE DEVELOPMENT PLAN WOULD RESULT FROM ANY INCREASED PRECISION IN DEFINING THE PROBABLE RANGE OF OIL-IN-PLACE AND RESERVES. HOD IS A VERY SMALL DEVELOPMENT BY NORWEGIAN STANDARDS TO DATE, AND EVEN VERY SIGNIFICANT VARIATIONS IN STOOIP AND RESERVES ARE ACTUALLY VERY SMALL IN ABSOLUTE TERMS, AS ILLUSTRATED IN POINT 3 BELOW.

3. WE BELIEVE THAT THE ISSUE OF RESERVOIR UNCERTAINTY, AS IT COULD IMPACT ANY DEVELOPMENT PLANNING AND DECISIONS, HAS ALREADY BEEN ADEQUATELY ADDRESSED IN THE RESERVOIR ENGINEERING SECTION OF THE FIELD DEVELOPMENT PLAN. OUR SECTION 4.5.5.8 ENTITLED 'SENSITIVITIES' DEALS WITH VARIATIONS BOTH IN THE NUMBER OF WELLS AND IN THE RESERVOIR DESCRIPTION. FOR THE OIL-IN-PLACE, THREE CASES HAVE BEEN CONSIDERED, VIZ.

<u>BASE CASE</u> : THE BASE CASE OIL-IN-PLACE AND RESERVES WERE CALCULATED BASED ON THE PRESENCE OF EKOFISK/TOR AND HOD FORMATIONS OVER THE WHOLE OF THE EAST HOD STRUCTURE, AND OF THE HOD FORMATION ONLY OVER THE WHOLE OF THE WEST HOD STRUCTURE. THE BASE CASE STOOIP IS 187.4 MMSTBO AND ECONOMICALLY-RECOVERABLE RESERVES ARE 25.4 MMSTBO.

<u>HIGH CASE</u> : THIS IS ON THE SAME BASIS FOR EAST HOD AS THE BASE CASE, BUT FOR WEST HOD ASSUMES THE ADDITIONAL PRESENCE OF PRODUCIBLE OIL IN THE TOR FORMATION. THIS RESULTS IN A STOOIP OF 262.8 MMSTBO, AN INCREASE OF 40 O/O OVER THE BASE CASE STOOIP. THE ECONOMICALLY-RECOVERABLE RESERVES ARE 37.1 MMSTBO, AN INCREASE OF 46 O/O (BUT LESS THAN 12 MMSTBO) OVER THE BASE CASE RESERVES. FROM A DEVELOPMENT PERSPECTIVE, THIS APPARENTLY LARGE UNCERTAINTY IS ACCOUNTED FOR BY AN INCREASE OF ONLY ONE WELL, FROM FIVE TO SIX. THIS POSSIBLE OUTCOME IS PROVIDED FOR IN OUR DEVELOPMENT CONCEPT, AS EIGHT WELL SLOTS ARE INCLUDED IN THE PLATFORM DESIGN.

<u>LOW CASE</u> : THIS IS ON THE SAME BASIS FOR EAST HOD AS THE BASE CASE, BUT FOR WEST HOD ASSUMES NO HYDROCARBONS ARE PRESENT TO THE WEST OF THE MAJOR NORTH-SOUTH FAULT ON THE STRUCTURE. THIS RESULTS IN A STOOIP OF 152.7 MMSTBO, A DECREASE OF 19 O/O FROM THE BASE CASE. THE ECONOMICALLY RECOVERABLE RESERVES ARE 21.6 MMSTBO, A DECREASE OF 15 O/O COMPARED TO THE BASE CASE.

THE ECONOMIC ANALYSIS PERFORMED ON THESE CASES FOUND ALL THREE TO BE ECONOMIC, WITH INTERNAL RATES OF RETURN OF 20 O/O, 31 O/O AND 16 O/O IN ADDITION, ECONOMIC SENSITIVITIES WERE ALSO RUN ASSUMING AN ARBITRARY VARIATION IN RESERVES OF +/- 25 O/O VERSUS THE BASE CASE.. THESE TWO CASES RESULTED IN INTERNAL RATES OF RETURN OF 26 O/O AND 12 O/O RESPECTIVELY.

THEREFORE THE ECONOMIC EVALUATION IN THE FIELD DEVELOPMENT PLAN ENCOMPASSES LARGE RANGES, FOR OIL-IN-PLACE OF -19 O/O TO +40 O/O, AND FOR RESERVES OF -25 O/O TO +46 O/O, COMPARED TO THE BASE CASE. THESE RANGES ARE CONSIDERED TO BE SUFFICIENTLY EXTENSIVE TO COVER ANY REASONABLE OUTCOME OF THE DEVELOPMENT OF THE HOD FIELD. ALL THE CASES CONSIDERED HERE RESULTED IN AN ECONOMIC DEVELOPMENT, WITH INTERNAL RATES OF RETURN IN THE RANGE 12 TO 31 O/O.

THE DESIGN OF THE HOD PLATFORM AND FACILITIES PROVIDES THE FLEXIBILITY TO ACCOMMODATE A WIDE RANGE OF PRODUCTION RATES AND RESERVES. IT IS THEREFORE OUR OPINION THAT AN ADEQUATE AND PRUDENT EVALUATION OF THE UNCERTAINTIES IN OIL-IN-PLACE AND RESERVES HAS BEEN BRACKETED, AS PRESENTLY DOCUMENTED IN THE PRELIMINARY FIELD DEVELOPMENT AND OPERATING PLAN.

ONCE DEVELOPMENT DRILLING IS UNDERTAKEN AND NEW DATA BECOME AVAILABLE, ESTIMATES OF OIL-IN-PLACE AND RESERVES WILL BE UPDATED AS A MATTER OF COURSE.

WE WOULD HOPE THAT THE PETROLEUM DIRECTORATE SHARE OUR VIEW ON THIS MATTER AND ACCEPT THE ABOVE DISCUSSION AS CONFIRMATION OF THE VIABILITY AND COMMERCIALITY OF THE HOD FIELD.

ALTHOUGH WE DO NOT CONSIDER THE MORE RIGOROUS ASSESSMENT OF UNCERTAINTY APPROPRIATE OR MEANINGFUL TO THE EVENTUAL DEVELOPMENT OF HOD, GIVEN THE SMALL SCALE OF THE CONCEPT ENVISAGED, WE HAVE EVALUATED WHAT WOULD BE REQUIRED TO PERFORM SUCH AN ASSESSMENT. WE ESTIMATE THAT SUCH A STUDY, IF COMMENCED IMMEDIATELY, WOULD NOT BE FINISHED UNTIL OCTOBER 1988 AT THE EARLIEST.

WE TRUST THAT THIS CLARIFIES OUR POSITION REGARDING THE EVALUATION OF RESERVOIR UNCERTAINTY IN THE HOD DEVELOPMENT PLAN, AND THAT THE PETROLEUM DIRECTORATE CONCUR WITH OUR CONCLUSION, SO THAT WE MAY PROCEED WITH THE HOD PROJECT DEVELOPMENT AS SOON AS POSSIBLE. ONCE AGAIN, WE APPRECIATE THE EXPEDITIOUS MANNER IN WHICH THE DIRECTORATE HAS REVIEWED AND COMMENTED ON OUR PRELIMINARY DOCUMENT.

WE LOOK FORWARD TO AN EARLY AND FAVORABLE RESPONSE TO THIS TELEX. MEANWHILE WE ARE PROCEEDING TO ADDRESS THE OTHER POINTS IN THE REFERENCED LETTER.
IF YOU HAVE ANY FURTHER QUESTIONS, OR REQUIRE CLARIFICATION OF ANY ISSUE, PLEASE CONTACT M.D. DRENNON.

REGARDS,

R.D. ERICKSON
PRESIDENT AND GENERAL MANAGER

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4. Telex from Norwegian Petroleum Directorate to Amoco Norway

Date: 11 April 1988

From: Arild N. Nystad, Anna AAbø

To: R.D. Erickson/M.D. Drennon

Ref: 518/88 AUB/INS

Subj: Hod - Development and Operating Plan

Version: Norwegian and English

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428632 NOPED N
REF: 1126 DATE: 880411 TIME: 15:15
TLX NO 518/88 STAVANGER 11.4.88 AUB/INS
UNNTATT OFF

AMOCO NORWAY	
DATE RECEIVED: 12/4 -88	
ANSWER DUE DATE: 30/4	LOG NO: 4393
RESP. DEPARTM: Eng.	ACTION BY: MDD
COPY TO: KA, RDE, AT, MDD, AB, ASE	
FILE NO: 413.63	

TIL: AMOCO NORWAY OIL COMPANY - STAVANGER
ATT: R.D. ERICKSON / M.D. DRENNON

KOPI: TB, LEH, MM, AUB, AN

HOD - PLAN FOR UTBYGGGING OG DRIFT

VI VISER TIL MØTE HOS OLJEDIREKTORATET 6.4 OG TELEX FRA AMOCO 7.4 ANGAENDE OLJEDIREKTORATETS FORESPØRSEL OM AMOCOS VURDERING AV USIKKERHET KNYTTET TIL RESSURSANSLAG.

OLJEDIREKTORATET SETTER VANLIGVIS SOM KRAV AT OPERATØREN VURDERER USIKKERHETEN I RESSURSANSLAGENE SOM PRESENTERES I EN PLAN FOR UTBYGGING OG DRIFT.

OLJEDIREKTORATET HAR IMIDLERTID MERKET SEG AT UTBYGGINGS LØSNINGEN HAR KAPASITET FOR EN EVT ØKNING I RESERVENE UTOVER BASIS-ANSLAGET.

VI ØNSKER LIKEVEL DERSOM MULIG EN KVALITATIV VURDERING INNEN UTGANGEN AV APRIL D.A., AV HVILKE VARIASJONER I NEDENFORSTAENDE PARAMETRE SOM AMOCO MENER KAN VÆRE REALISTISKE.

STOOIP PARAMETRE

1. BRUTTO BERGARTSVOLUM (BBV) SOM FUNKSJON AV USIKKERHET I SEISMISK STRUKTUR.

2. BBV SOM FUNKSJON AV OLJE/VANN KONTAKTEN.
3. NETTO/BRUTTO FORHOLD
4. PORØSITET
5. OLJEMETNING
6. FORMASJONS VOLUMFAKTOR

USIKKERHET I RESERVOAR UTVINNINGSPARAMETRE

1. VARIASJONER I RELATIVE PERMEABILITETER
2. VARIASJONER I HORISONTALE PERMEABILITETER
3. VARIASJONER I VERTIKALE PERMEABILIATETER
4. VARIASJONER I VÆSKE EGENSKAPER

MED HILSEN
ARILD N NYSTAD / AVDELINGSDIREKTØR
ANNA AABØ / FUNGERENDE SEKSJONSSJEF
OLJEDIREKTORATET

428632 NOPED N+
427808 AMOCO N

TRANSLATION

TELEX FROM : Norwegian Petroleum Directorate

DATED : 11.04.88

REF. : AUB/INS - Tlx. NO. 518/88

ADDRESSED TO: Amoco Norway Oil Company

HOD - PLAN FOR DEVELOPMENT AND PRODUCTION

We refer to meeting in the Petroleum Directorate on 6.4 and to telex from Amoco on 7.4. regarding the Petroleum Directorate's inquiry about Amoco's evaluation of uncertainty associated with reserves estimate.

The Petroleum Directorate normally requires that the operator evaluates the uncertainty in the reserves estimates that are presented in a plan for development and production.

The Petroleum Directorate has noted, however, that the development concept has capacity for a possible increase in the reserves beyond the basic estimate.

We nevertheless request, if possible, a qualitative evaluation by the end of April this year concerning which variations in the parameters below may be realistic in Amoco's opinion.

STOOIP PARAMETERS

1. Gross rock volume (BBV) as a function of uncertainty in seismic structure.
2. BBV as a function of the oil/water contact.
3. Net/gross ratio
4. Porosity.
5. Oil saturation
6. Formation volume factor

UNCERTAINTY IN RESERVOIR PRODUCTION PARAMETERS

1. Variations in relative permeabilities
2. Variations in horizontal permeabilities
3. Variations in vertical permeabilities
4. Variations in fluid properties.

Best Regards,
Arild N. Nystad
Anna AAbø
Petroleum Directorate

5. Telex from Amoco Norway to Norwegian Petroleum Directorate

Date: 15 April 1988

From: R. D. Erickson

To: F. Al-Kasim
Attn: Arild N. Nystad/Anna AAbø

Ref: NO T 716 413.64 MA

Subj: Hod Field Development and Operating Plan

Version: English

16.05 42863+

42863B NOPED N
42780Z AMOCO N

15 APR.

15 APRIL 1988

TO: F. AL-KASIM
NORWEGIAN PETROLEUM DIRECTORATE

ATTN: ARILD N NYSTAD/ANNA AABOE

FROM: AMOCO NORWAY OIL COMPANY

FILE: NO T 716 413.64 MA
SUBJ: HOD FIELD DEVELOPMENT AND OPERATING PLAN

REFERENCE IS MADE TO YOUR TELEX DATED 11 APRIL 1988, REF. NO. 518/88 AUB/INS ON THE ABOVE SUBJECT.

WE HAVE TAKEN NOTE OF YOUR COMMENTS AND OF YOUR REQUEST FOR A QUALITATIVE EVALUATION OF VARIATIONS IN OIL-IN-PLACE PARAMETERS AND RESERVE PARAMETERS FOR THE HOD FIELD. WE ARE WORKING IN ACCORDANCE WITH YOUR REQUEST WITH THE AIM OF PROVIDING YOU WITH THIS EVALUATION BY THE END OF APRIL 1988.
MEANWHILE WE ARE ALSO CONTINUING TO ADDRESS THOSE ITEMS LISTED IN YOUR LETTER DATED 14 MARCH 1988 WHICH DO NOT RELATE TO RESERVOIR UNCERTAINTY. REPLIES TO THESE COMMENTS AND QUERIES WILL ALSO BE PROVIDED TO YOU BY THE END OF APRIL 1988 IN ORDER TO FACILITATE YOUR TIMELY HANDLING OF THE DEVELOPMENT EVALUATION.

WE TRUST THAT YOU WILL FIND THIS SATISFACTORY. IF YOU HAVE ANY FURTHER QUESTIONS, PLEASE CONTACT M. D. DRENNON.

REGARDS,

R.D. ERICKSON

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C. DISCUSSION

The Amoco/NOCO Group's response to the questions and comments raised by the Directorate are discussed herein.

Section I addresses those items raised in the Directorate's letter of 14 March 1988, except for the following items relating to reservoir uncertainty:

- Calculation of Water Saturation (Chapter 3.2.1.1)
- Hydrocarbons in Place (Chapter 3.3)
- Entry Data for Simulation (Chapter 4.5.3)
- Reserves (Chapters 4.5.4 and 4.5.5)

A meeting was held on 6 April 1988 between members of the Directorate and Amoco Norway Chief Engineer, M.D. Drennon, to discuss these items. Amoco Norway then sent a telex to the Directorate on 7 April 1988, stating the opinion that the issue of uncertainty in oil-in-place and reserves had been adequately covered by the High Reserve and Low Reserve Cases studied and described in the Field Development and Operating Plan.

The Directorate replied in a telex dated 11 April 1988, requesting a qualitative evaluation of realistic variations in parameters relating to oil-in-place and reserves. This evaluation is provided in Section II of this Supplement.

Relevant Exhibits are included in each section.

SECTION I

This section provides answers to the questions and comments raised by the Directorate in their letter dated 14 March 1988, reference OD/8 PEØ/The. Some of these questions or comments are addressed in Section II of this Discussion, and these are marked with an asterisk (*) in the table below.

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1. STRATIGRAPHY AND DEPOSITIONAL ENVIRONMENT (Chapter 3.1.2.2)

Question/Comment :

Amoco writes that there are important mineralogical differences between the Tor and the Hod Formations. The Petroleum Directorate would like to have documentation of analyses performed on Hod cores.

Answer :

X-ray diffraction analyses of the mineralogy of the Hod Field formations were performed on cores from wells 2/11-3, 2/11-3A and 2/11-6. The results are tabulated in Exhibit 1.1, and show that the main difference between the Tor and the Hod Formations is the higher quartz content of the Hod rock. Typically the Hod rock comprises 5 to 8% quartz, with values as high as 15% in the Upper Hod and 22% in the Middle Hod being recorded. The Tor rock, on the other hand, shows typical quartz content of only 2%, with 5% being the highest value recorded.

2. STRUCTURAL MOVEMENT (Chapter 3.1.2.3.2)

Question/Comment:

According to Amoco's interpretation, the West Hod structure has moved northward also after migration of hydrocarbons into the structure. Experience from other chalk fields with structural movement after oil migration indicates different development of porosity and permeability over the field. For Hod such an interpretation will result in better porosity/permeability on the southern flank than elsewhere in the field. The Petroleum Directorate requests that this be taken into consideration when selecting locations for the production wells.

Answer:

Further explanation of our interpretation of the structural history of Hod Field is perhaps in order. In the West Hod structure we do not envisage that the paleocrest shifted northward after migration of hydrocarbon into the structure, but rather, that this occurred prior to migration. During deposition of the Hod Formation the paleocrest apparently was close to the Lindesnes Ridge, near the 2/11-5 well. This is evidenced by the 45 meters of Hod Formation in that well as opposed to the 98.5 meters in the 2/11-2 well. At the time of Tor Formation deposition, or soon after this time, the paleocrest shifted northward to its current location near the 2/11-2 well. This is shown by the total absence of Tor and Ekofisk Formations in that well due to non-deposition or erosion. We are thus interpreting the improved porosity in 2/11-2 in contrast to 2/11-5 as the result of more abundant, redeposited, high porosity chalks in the 2/11-2 paleoflank area.

Certainly, it is possible that a percentage of the total porosity seen in the chalks is related to the preservation of pore space by infill of hydrocarbons. This can be seen in a comparison of the porosity in the 2/11-3 well, located in the present day water column, and the 2/11-2 or 2/11-3A wells located in the oil column. The significant reduction in porosity in well 2/11-3 is thought to be related to continuing diagenesis and destruction of porosity in the water column. The preservation of porosity by hydrocarbons replacing pore waters is, however, thought to have started only in Upper Eocene time, by which time the Hod Field structures had already formed much as we see them today. Little re-structuring is thought to have occurred after the initial migration of hydrocarbons into the Hod Field area.

For this reason, we don't necessarily see the probability of better porosity/permeability on the present day southern flank of the field, and the lower porosities observed in Well 2/11-5 would seem to support our contention for West Hod. Further well data from the development drilling stage will naturally be invaluable in further refining the structural history and porosity distribution in the Hod Field. Early drilling results will guide our thinking at that time.

3. FORMATION PARAMETERS (Chapter 3.2)

Question/Comment:

The Petroleum Directorate has not received analyzed RFT results from wells 2/11-3, 2/11-3A and 2/11-6(ST-1).

Answer:

In Well 2/11-3 an RFT log was run and 19 measurements were attempted. Only five resulted in reasonable formation pressure readings. Of these, four were at the same depth, i.e. 2790.5 meters RKB (2755 m TVD SS) in the Upper Hod Formation. The measured pressure was between 7000 and 7030 psig, averaged 7020 psig. One reading, ten meters up the hole at 2745m TVD SS, indicated the pressure to be approximately 6910 psig. At the other stations, communication with the formation was not established. The RFT tool eventually experienced a hydraulic failure.

An RFT log was not run in Well 2/11-3A due to well control problems.

The RFT measurements taken in Well 2/11-6(ST-1) are available in the RDRS report.

4. CALCULATION OF WATER SATURATION (Chapter 3.2.1.1)

Question/Comment:

There are no water analyses from Hod. Experience from the neighboring fields indicates that Rw varies with a factor of up to 2 in reservoirs above salt structures. The Petroleum Directorate would like a report on what consequences changes in Rw will have for the resources basis and the production strategy.

Answer:

This item is addressed in Section II of this Discussion, which is a separate reply to the telex from the Directorate dated 11 April 1988, ref. 518/88 AUB/INS.

5. HYDROCARBONS IN PLACE (Chapter 3.3)

Question/Comment:

The Petroleum Directorate would like to have an evaluation of uncertainties in STOOIP.

Answer:

This item is addressed in Section II of this Discussion, which is a separate reply to the telex from the Directorate dated 11 April 1988, ref. 518/88 AUB/INS.

6. WELL TESTS (Chapter 4.2)

Question/Comment :

The Petroleum Directorate would like Amoco to report on its experiences in connection with DST procedures.

Answer :

This question was further clarified in telephone conversations between members of Amoco Norway and the Directorate's staff. Certain questions were asked as to the reasoning behind the procedure followed in testing the Hod appraisal wells, and how this may impact future testing plans.

The testing of the Hod appraisal wells was performed in 1974, 1978 and 1982. The objectives of these tests were to determine the production rates that could be achieved by Hod wells, and to quantify reservoir and wellbore parameters such as permeability, skin factor, initial reservoir pressure and other data which would assist in an evaluation of the rates and ultimate reserves which could be obtained by developing the field. A total of fourteen individual tests were conducted in the three wells that were tested. These tests provided much information regarding the production rates that could be achieved from each of the productive formations in Hod. A large amount of reservoir and wellbore data for individual zones was also collected including permeability, skin factor, initial reservoir pressure and productivity index. Fluid samples were also taken during these tests, and PVT properties were measured on these samples for later use in estimating oil-in-place and reserves. Amoco Norway believes that these tests provided sufficient proof of the productivity of the Hod reservoirs, and provided sufficient reservoir data to enable a proper engineering and geological evaluation of the field to be made.

As regards future well tests, there are as yet no firm plans to test the individual zones in the Hod development wells. However, should it be deemed necessary to perform such tests in any well, the objectives of the tests would be clearly defined and the appropriate testing procedure would be prepared for achieving these objectives. The test procedure would be described in the drilling program for the well, and submitted to the Directorate for their review and approval.

7. ROCK PROPERTIES - CORE DRILLING IN FUTURE WELLS (Chapter 4.3)

Question/Comment:

The Petroleum Directorate would like to be informed of TD and scheduled interval for core drilling in those wells that are mentioned in the preliminary version of the Field Development and Operating Plan. The Petroleum Directorate is particularly interested in the possibility of coring the reservoir in the assumed graben area.

Answer:

The initial development wells in the Hod Field include four new wells and one recompletion (well 2/11-6 (ST-1)). Details of these planned wells including total depths are shown in Exhibit 5.35 of the Hod Field Development and Operating Plan. Specific coring plans for the new wells have not yet been formulated. The following list of current core data indicates the sections of interest, i.e. Ekofisk/Tor and Hod Formations, which have been sampled by coring the exploration and appraisal wells.

HOD FIELD
(Cored intervals)

WELL	NO. OF CORES	CORED INTERVAL (MD)	CORED FORMATION
West Hod			
2/11-2	1	2661.5-2671 m	U. Hod
2/11-5	0		
East Hod			
2/11-3	3	2777-2811 m	U. Hod
2/11-3A	7	3192-3250 m	Ekofisk,Tor,U. Hod
2/11-6	7	3693-3741 m	Tor,U.Hod
2/11-6 (ST-1)	0		

East Hod, with a total of 17 cores from the 2/11-3, 2/11-3A, and 2/11-6 wells is particularly well covered by the existing core data. Further coring may be required in the West Hod structure, particularly if the Tor Formation is present. The possible need for further coring will be addressed when the actual drilling programs for these wells are prepared.

8. FLUID PROPERTIES (Chapter 4.4)

Question/Comment :

Does there appear to be any correlation regarding bubble point and solution gas versus depth?

Answer :

Based on the available fluid property database for the Hod Field, it is difficult to determine whether there are variations in bubble point pressure or solution gas-oil ratio with depth.

On West Hod, only Well 2/11-2 has penetrated and tested hydrocarbon-bearing formation and therefore a correlation with depth cannot be formulated for this structure.

On East Hod, Wells 2/11-3A and 2/11-6(ST-1) have penetrated and tested hydrocarbon bearing Hod and Tor Formations. Bottomhole fluid samples were collected from Well 2/11-6(ST-1) while surface recombination samples were collected from 2/11-3A. The results of the PVT analyses performed are detailed in Exhibit 1.2 and are shown plotted in Exhibits 1.3a and 1.3b.

As can be seen from the Exhibits, these test results are not directly comparable since the 2/11-3A tests were conducted in the Upper Hod and Tor Formations while the 2/11-6(ST-1) results were conducted in the Lower Hod and the commingled Upper Hod/Tor Formations. Even if the Tor Formation results from Well 2/11-3A are directly compared to the Upper Hod/Tor Formation results from Well 2/11-6(ST-1), it is difficult to formulate a relationship between either the bubble point pressure or the gas-oil ratio with depth. This is mainly due to the spread in bubble point pressure observed from the Well 2/11-3A PVT results. For this reason it has been concluded that insufficient data currently exist to substantiate a variation in fluid properties with depth.

9. DRIVE MECHANISMS (Chapter 4.5.2)

Question/Comment :

Did any overlying separate gas zone develop in the simulation cases? The Petroleum Directorate would like Amoco to comment on the consequences with and without the formation of a separate gas zone.

Answer :

Based on the results of the modelling runs, no significant gas cap was formed in any of the simulation cases. Gas saturations in the Tor Formation rose to around 20% in the crestal part of the structure. This result is not surprising since the reservoir simulator used was a single porosity black oil model. Each formation was modelled by a single layer. As such, the model was not designed to define accurately the formation of a gas cap in the reservoir layers. A multi-layer model would be needed to describe this occurrence adequately. Our approach was to model the field on a gross basis since only a limited amount of reservoir data is available at this time.

As presently mapped, none of the development wells are located in the highest structural elevations of either East or West Hod. We therefore do not anticipate substantial rises in gas-oil ratio (GOR) for any of the development wells.

If a substantial rise in produced GOR is actually experienced in the field during the production phase, the potential for remedial action, such as recompletion or sidetracking, may be evaluated at that time.

10. ENTRY DATA FOR SIMULATION (Chapter 4.5.3)

Question/Comment:

The Petroleum Directorate requests a tape from Amoco with entry data for base case and main sensitivity cases. Sufficient information should be included in order to convert the entry files to entry files for the ECLIPSE 100 simulation program.

Answer:

A paper printout of all the reservoir simulation entry data was forwarded to the Directorate on 13 April 1988, and a tape containing these data was forwarded on 15 April 1988. This tape is in IBM CMS Format - Density 6250 BPI.

Amoco Norway does not use the ECLIPSE 100 simulation program in any of its reservoir simulation applications. Consequently, it is regretted that no information is available in-house regarding conversion of the Black Oil Model entry files to similar files for the ECLIPSE 100 program.

The RDRS tape containing a listing of reservoir data from each well was also forwarded on 15 April.

11. UNCERTAINTIES IN ENTRY DATA

Question/Comment:

Uncertainties in entry data should be analyzed and reported.

Answer:

This item is addressed in Section II of this Discussion, which is a separate reply to the telex from the Directorate dated 11 April 1988, ref. 518/88 AUB/INS.

12. EKOFISK/TOR PROPERTIES (Chapter 4.5.3)

Question/Comment:

Experience from other fields indicates that the Ekofisk and Tor Formations have different reservoir properties. Have studies been performed on the effect of such differences in terms of production? In Hod, these formations have been simulated in the same unit. How large are the volumes in each formation on a reservoir level? (Tor and Ekofisk Formations.)

Answer:

In Hod Field, the Ekofisk Formation has only been encountered in two wells. The 2/11-5 well on West Hod had 17.5 meters of Ekofisk, based on paleontological evidence, and on East Hod the 2/11-3A well had 9 meters of Ekofisk Formation. These representative thicknesses are all below the seismic resolution capabilities which exist in the Hod area. As such, we are unable to map seismically the thickness or extent of the Ekofisk Formation, and with well control limited to one well on each of the East and West Hod structures, little can be extrapolated from the available data.

The Ekofisk and Tor Formation parameters can be compared on the basis of the available data obtained from the 2/11-3A core material. The core analysis results (Exhibit 4.13 of the Field Development and Operating Plan) show little change in porosity/permeability measurements between the Ekofisk and Tor intervals. Likewise, the X-ray diffraction analysis shows little mineralogical difference between the two formations.

Owing to the similarity in reservoir parameters, the limited thickness of the Ekofisk, and the inability to map the extent of the Ekofisk Formation, this was combined with the Tor Formation for the purpose of calculating oil-in-place and reserves. In other fields such as Ekofisk Field, which has significantly thicker Ekofisk and Tor Formations, it may be possible to differentiate between the two formations based on reservoir parameters. That does not seem to be the case in the Hod Field, however.

The Directorate also requested an estimate of the relative volumes of oil-in-place in the Ekofisk and Tor Formations. Assuming that the reservoir parameters are similar, a comparison of the average thickness of the Ekofisk and Tor reveals that the Ekofisk Formation on the average is 25 % of the combined Ekofisk/Tor thickness. Based on this rough comparison it could be concluded that in East Hod, approximately 25 % of the base case oil in place estimated for the Ekofisk/Tor Formation as a unit (9.2 million Sm^3) is contained in the Ekofisk Formation alone.

13. RESERVES (Chapter 4.5.4 and 4.5.5)

<u>Question/Comment:</u>

The Petroleum Directorate would like to have an evaluation of uncertainties both concerning technically recoverable reserves and economically recoverable reserves.

<u>Answer</u>:

This item is addressed in Section II of this Discussion, which is a separate reply to the telex from the Directorate dated 11 April 1988, ref. 518/88 AUB/INS.

14. PRODUCTION STRATEGY-COMPLETION STRATEGY (Chapter 4.6.1)

Question/Comment:

The Petroleum Directorate requests that Amoco report on the planned completion strategy in the Hod Field based on its experience in the Valhall Field.

Answer:

As stated in the Chapter 4.6.1 of the Field Development and Operating Plan, the completion strategy for Hod wells is expected to be similar to that currently used on Valhall, since the formations in both fields are believed to be similar. However, alternative completion methods will also be considered when the wells are drilled.

On Valhall, the Lower Hod Formation is completed by hydraulic fracturing, whereas the Tor Formation is completed by hydraulic fracturing followed by gravel packing. In wells where both formations are productive, the Lower Hod is completed first by hydraulic fracturing, and isolated by means of a sand plug. The Tor Formation is then perforated and hydraulically-fractured. The wellbore is then cleaned out of excess proppant using a snubbing unit, and the Tor Formation is then gravel packed. The well is then placed on production, the fluid from both zones being commingled in the wellbore and produced up the same tubing string. Production from individual zones can be determined by running a wireline-conveyed flowmeter to the bottom of the gravel pack screens, where the Lower Hod flowrate is measured, and then measuring the combined flow above the screens. The Tor flowrate can then be obtained by subtraction.

In Hod wells, the situation is somewhat different in that the Upper Hod Formation has been proven productive over the whole field. In West Hod, if no Tor Formation is discovered, the wells would be single zone Upper Hod completions via hydraulic fracturing. The possibility of gravel packing the Upper Hod would also be considered, depending on an evaluation of the risk of solids production from this formation. If the Tor were discovered to the west of the main fault, the well(s) in this area would be commingled dual-zone Upper Hod/Tor completions. In this case the completion scheme selected would be similar to the one used on Valhall dual-zone completions.

In the case of East Hod, it is currently intended to treat the Ekofisk and the Tor Formations as a single reservoir unit due to their similarity in formation properties, unless drilling results dictate otherwise. The well to be drilled in the northern part of the structure is expected to encounter productive pay only in the Ekofisk/Tor Formation, in which case it would be completed as a single zone producer via hydraulic fracturing and gravel packing. Of the other two wells on the structure, one is planned to be drilled in the vicinity of 2/11-3A, and is expected to encounter productive Ekofisk/Tor, Upper Hod and Lower Hod Formations. This well would most likely be completed with separate fracture stimulations in each formation. The Tor Formation would be gravel packed, and the necessity and feasibility of gravel packing the Upper Hod Formation would also be investigated.

In the case of well 2/11-6(ST-1), it is presently intended to re-enter, tie back and complete the current wellbore for production. The completion procedure is expected to be similar to that for the 2/11-3A clone well, with the Tor, and possibly the Upper Hod Formation if desirable, being gravel packed. For these two wells, it may not be feasible to gravel pack both the Tor and the Upper Hod, as there is too little distance between these formations to perform a separate gravel pack on each. A single gravel pack job in both zones appears at first glance to have a high risk of failure due to possibly different permeabilities and due to the presence of a Dense Zone between these formations. The possibilities for the different methods of completion need to be studied much more thoroughly before a final procedure can be decided upon. An evaluation of potential completion schemes will be performed prior to the commencement of development drilling, and the optimum scheme will then be recommended for implementation.

Regarding the feasibility of performing reservoir monitoring programs in Hod Field completions, most of the anticipated data collection procedures should be possible. The size of the tubing string will allow passage of wireline-run pressure gauges to just above the top of the reservoir for bottomhole pressure surveys. For production logging, this should always be possible in commingled dual zone completions, as the logging tool can be run to the bottom of the gravel pack screens across the top (Tor) Formation. This procedure has recently been successfully implemented in a dual zone gravel packed well in the Valhall Field.

In wells with three productive zones, such as are expected in two of the East Hod wells, the ability to measure the flowrate from each individual zone will depend on the gravel pack configuration. Assuming that the Tor Formation will be gravel packed, and the Lower Hod Formation will not be gravel packed, then the ability to measure the individual rates from the Upper and Lower Hod Formations will depend on whether the Upper Hod is gravel packed or not. If the Upper Hod is gravel packed in conjunction with the Tor, then it should be possible to measure individual zonal rates. However, as stated above, it may not be desirable or even feasible to gravel pack the Upper Hod Formation. In this case, the ability to differentiate between Upper and Lower Hod production would have to be sacrificed, since current gravel pack equipment does not allow enough clearance to run wireline tools below the bottom of the screens owing to the presence of a small-diameter O-ring seal sub. However, it should be noted that these formations contain only about 17 percent of total reserves in the field, so strict monitoring of production from each zone is not as critical as, say, for the Tor Formation. Estimates of the productivity of each zone, and of relative production rates, can be made using values of permeability measured in the drill stem tests conducted on the Hod appraisal wells, and values of skin factor derived from a post-frac analysis of each fracture stimulation job performed in the development wells. It should also be noted that the possibility of not gravel packing the Tor Formation also exists. If this were the case, then there would be no restriction to prevent measurement of flowrates from each of the three zones.

To conclude, Amoco Norway is committed to completing the Hod Field wells in the optimum manner, i.e. one that results in a stable, long-life completion and has the least risk of being damaged or plugged, but also one which results in optimum production rates and depletion of the reservoir. To this end, all the potential completion schemes applicable to the formations in Hod will be considered, and the ability to monitor reservoir parameters and production rates will be taken into account and accommodated as much as possible when planning these completions.

15. RESERVOIR MONITORING (Chapter 4.6.2)

Question/Comment:

A reservoir monitoring plan with estimated data collection regularity should be included in the Field Development and Operating Plan.

Answer:

As stated in Chapter 4.6.2, monitoring of the Hod reservoir will be undertaken to ensure optimum depletion and reservoir management. Reservoir monitoring will take the following forms :

15.1 Well performance will be closely monitored by means of monthly production tests. These tests can be performed more frequently if warranted by well performance.

15.2 Engineering analyses of reservoir and wellbore performance will be made and updated continuously.

15.3 Irregular bottomhole surveys : Should a well give cause for concern, consideration will be given at that time to collecting downhole data by means of pressure transient tests, flow profile surveys or other applicable methods in order to determine the cause of the problem.

15.4 Regular bottomhole surveys : Besides the irregular surveys, it is envisaged that full use will be made of regular maintenance shutdowns at Ekofisk to collect pressure buildup, flow profile or other data required on key Hod wells. These maintenance shutdowns are expected to occur once every two years.

15.5 Other shutdowns : Should other planned shutdowns be scheduled either on Ekofisk, on Valhall or on Hod itself, then the requirement for bottomhole data will be evaluated at that time and such data collected if deemed to be necessary for optimizing reservoir management.

16. PROCESS CAPACITIES (Chapter 4.6.3)

Question/Comment:

The platform separator and metering system will be used for metering field production and for allocating production to the individual wells. The Petroleum Directorate would like further clarification of this statement.

Answer:

A single combination production/test separator will be provided at Hod with gas and liquid metering suitable for either full production flow or single well measurement. In the normal unmanned mode, all wells will flow through the separator for the measurement of full field production. It is planned that a team of operators and maintenance personnel will be flown to Hod from Valhall one to two times per week and will be available to perform well tests. To do this, the operators will switch all of the producing wells, except the one to be tested, out of the separator and into the bypass header. The operator will then select the correct orifice plate and turbine meter for the flow rate of the well to be tested. Once well test measurements are initiated, the computer system will automatically record flows, temperatures and pressures and display them on request at Hod, Valhall or Amoco's Stavanger Office. The operator at Hod will collect samples for BS&W determination as per current practice at Valhall. At the conclusion of the well test, another well may be put into the separator for test purposes or all wells may be put through the separator to return to full production measurement mode.

In the "Hod Development Study" Amoco concluded that it would take a total of 24 "test hours" to test all of the Hod wells once. Forty-eight hours per month of testing were assumed in the production allocation uncertainty calculations since additional or extended tests beyond the normal monthly test may sometimes be advantageous. Using the manning frequency in the Hod Development Study of one and a half 12-hour visits to Hod per average week, operators should be on board Hod 78 hours per month. Thus, 48 hours of testing per month should be easily achievable at Hod within the anticipated visiting schedule. Consequently, one to two well tests per well per month can be performed at Hod with the current arrangement.

The well tests themselves will benefit by the high accuracy of the metering installed at Hod. The Hod metering will meet the Directorate's requirements for fiscal metering, with the only notable exception being the lack of an installed back-up flow computer. At the Directorate's suggestion, there will be duplicate meter runs on the separator gas and liquid lines to assure reliability. Well tests at Hod therefore shall exhibit an accuracy and reliability beyond those usually provided for simple test separators, and will meet or exceed those normally supplied for reservoir monitoring.

The metering facilities and method of allocating total production from the Hod Field is described in more detail in the "Hod Development Study" (presented to the Directorate in November 1987), reference Chapter 7, Sections 7.1.2.3 and 7.1.2.4 and Appendix 1, Sections 6 and 7. The Directorate commented on this study in a letter dated 23 December 1987. Metering equipment additions resulting from the Directorate's comments are described in the "Supplement" to the Hod Development Study, dated March 1988 and submitted 18 April 1988.

ITEMS NOT MENTIONED IN THE PLAN PRESENTED

The Petroleum Directorate has prepared a draft for the contents of a Field Development and Operating Plan pursuant to the regulations in the Petroleum Act. The following discussions under items 17, 18 and 19 refer to this draft.

17. TIME SCHEDULE FOR DEVELOPMENT (Paragraph no. 5.6)

Question/Comment:

The Plan should include a description and procedure for pre-drilling and collection of reservoir/geological data.

Answer:

Section 5.4 of the Field Development and Operating Plan describes the drilling and completion considerations for the Hod development wells. It is stated that the Hod wells may be pre-drilled prior to jacket installation, or post-drilled after the platform is installed. Pre-drilling would be performed in the second half of 1989, whereas post-drilling would take place in the second half of 1990.

An evaluation of the economics of pre- vs. post-drilling has been performed. This showed that the economics of post-drilling are slightly better than those for pre-drilling. However, the decision whether to pre-drill or post-drill the wells need not be taken now, and this has been postponed until early 1989 when another evaluation will be performed and a final decision taken at that time.

Regarding the collection of reservoir/geologic data, consideration will be given to coring any of the development wells when the drilling plan is prepared. It is intended to run a full suite of open-hole logs on each well. As stated in item 6, there are as yet no firm plans to test individual zones in the Hod wells, but the possibility of doing this will be considered when preparing the drilling program for the well.

18. RISK ANALYSES/COORDINATION (Paragraph no.6.3)

Question/Comment:

The plan must contain alternative production profiles that can reflect the reservoir-related uncertainty plus an evaluation of the flexibility of the development concept with respect to revised reserve estimates.

Answer:

Alternative production profiles, reflecting reservoir-related uncertainty, are included as Exhibits 1.4 and 1.5 (Low Reserve Case) and Exhibits 1.6 and 1.7 (High Reserve Case).

The ability of the installation to accommodate a larger number of wells and higher reserves and production rates is discussed in Sections 4.5.5.10 and 5.2.4.1 of the Hod Field Development and Operating Plan. The pressure rating of the separator will be more than three times above normal operating pressure and hence the throughput capacity can be increased by increasing the separator operating pressure, e.g. by opening the chokes on the wells. While six wells are predicted for the High Reserve case, eight well slots are provided. Space has also been reserved for additional wells, as indicated on Exhibit 5.12, Drawing P-5000. The manifold and control systems would have to be expanded should such wells be required, but this would not be expected to pose any problems. In reality the performance of the wells initially planned will be monitored and analyzed before a potential recommendation for drilling additional wells is made. The production from the initial wells will most likely have declined by the time any additional wells may be ready for production. This will tend to extend the plateau production period rather than increase the plateau level.

The economic aspect of varying the number of wells is included in the sensitivities shown in the Economic Evaluation section of the Field Development and Operating Plan, Chapter 7, Section 7.4, and Exhibits 7.6 and 7.7. If oil price or other developments dictate that more wells than those assumed in the Field Development Plan would be economically desirable, these can be accommodated within the flexibility of the planned concept.

19. JURASSIC PROSPECTS

Question/Comment:

What are Amoco's views on the potential for additional Jurassic deposits. Amoco is asked to consider a possible plan for detection of such possible deposits.

Answer:

The Amoco/NOCO Group considers the Jurassic potential of the License 006, 032, 033 area to be of great interest. Currently the partner group is mapping the Jurassic in Blocks 2/5 and 2/8. Although the Jurassic potential of the Bloc 2/11 area is less well known, further work is planned to better define any possible leads.

Jurassic reservoir potential in the Hod Field area may exist at two levels. First is the Middle Jurassic Bryne Formation equivalent which was proven productive in the 2/12-1 well. Second is the Upper Jurassic, Eldfisk Formation equivalent, turbiditic sandstone seen in wells in block 2/7. Previous mapping has indicated, however, that structural closures are limited, particularly at the Middle Jurassic level. A small closure is possible below the East Hod structure but salt may have pierced the Jurassic section. The same interval may be faulted out below West Hod by the Lindesnes Fault. In any case, the extreme depth of the Middle Jurassic section of interest raises questions about whether sufficient porosity and permeability have been preserved to make a productive reservoir.

The Upper Jurassic, located at higher depths, suffers from a lack of proven reservoirs in the 2/11 area. Although turbidite sands are possible, having been shed north of the Grensen High into the 2/7 area, the lack of sands in the equivalent section of the 2/11-1 and 2/8-3 wells indicates that limited sands were shed eastwards into the Hod area. The recent Phillips' 2/7-20 discovery may be of importance to the 2/11 area but too little is known at this time to determine its impact.

The Amoco/NOCO Group is in the process of mapping Jurassic leads and prospects in the 2/5, 2/8 and 2/9 blocks. Based on this mapping we see several Jurassic prospects which could each hold 100 MMBO or more. The Amoco/NOCO Group hopes to drill the first of these prospects in Block 2/8 later this year. This planned well will yield valuable data which can then be related to the 2/11 area. Planned reprocessing of the existing seismic data in the Hod Field area may result in better definition of the Jurassic potential below the known hydrocarbon-bearing chalk structures. Any prospect which may emerge from further evaluation would be judged on its merits relative to the other Jurassic prospects in Blocks 2/5, 2/8, 2/9 and 2/11.

The Hod facilities were designed with the uncertainties of the chalk reservoir at Hod in mind and as such extra well-slots are provided.

Should a drillable prospect in the Jurassic emerge from the above described geologic effort it can be incorporated into the existing Hod facilities design provided it can be developed with three wells or less. The expected Jurassic pressure will only require Christmas trees and Manifold with higher pressure rating than that needed for the Hod chalk reservoir but space is available on the planned platform to install such equipment should it become desired.

Should a larger Jurassic prospect emerge which would require more than three wells, then such a reservoir can be developed by another low cost, stand alone Hod Development similar to that proposed for the chalk.

Based on the above discussion Amoco feels the potential for a Jurassic prospect is adequately accommodated by the existing facilities proposed for Hod and as such no change in the Hod Development Concept is proposed.

SECTION I

LIST OF EXHIBITS

1.1a Hod Field X-ray Diffraction Analyses, Well 2/11-3

1.1b Hod Field X-ray Diffraction Analyses, Well 2/11-3A

1.1c Hod Field X-ray Diffraction Analyses, Well 2/11-6

1.2 East Hod Fluid Properties

1.3a East Hod - Bubble Point v. Depth Plot

1.3b East Hod - Gas-oil Ratio v. Depth Plot

1.4 Production Profiles - Low Reserve Case (English Units)

1.5 Production Profiles - Low Reserve Case (Metric Units)

1.6 Production Profiles - High Reserve Case (English Units)

1.7 Production Profiles - High Reserve Case (Metric Units)

SECTION II

This section provides a response to the telex from the Norwegian Petroleum Directorate dated 11 April 1988, ref. 518/88 AUB/INS.

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STOOIP PARAMETERS

1. Variations in Gross Rock Volume (GRV) as a Function of Uncertainty in Seismic Structure.

The seismic mapping is tied into the available well control and at such points the uncertainty is zero. Away from well control, the accuracy of the time-depth conversion becomes more uncertain and could vary up to +/- 20 meters on East Hod. On West Hod the accuracy is less, due to the gas cloud effects, and as a result could be as much as +/- 50 meters.

In order to obtain an accurate estimate of the potential variation in gross rock volume as a function of seismic uncertainty, a new set of structure maps would have to be developed. This procedure would be time-consuming and would require a significant manpower effort. As a result, a simplistic technique was applied to scope out the possible variations. This technique involved adjusting the structural horizons higher and lower at the contours of maximum distance away from well control. Thus the difference in top structure depth varied from zero at the wells to +/- 20 meters (East Hod) or +/- 50 meters (West Hod) at the oil water contact. In each case the possible high and low values of gross rock volume were calculated for each horizon, and summed up to give a minimum and maximum value for each of the two structures.

The variations in Gross Rock Volume are tabulated below, in million of cubic meters:

		West Hod			East Hod	
	Min	Base	Max	Min	Base	Max
Ekofisk/Tor	-	-	-	64.8	101.6	157.2
Upper Hod - H1	47.1	81.2	169.0	87.2	107.5	143.8
Middle Hod - H2	3.7	25.3	86.0	73.6	115.3	159.1
Lower Hod - H3	NP	NP	NP	6.6	9.4	17.3
- H4	NP	NP	NP	14.3	20.8	32.9
Total	50.8	106.5	255.0	246.5	354.6	510.3

NP = Not present

2. Variations in Gross Rock Volume as a Function of the Oil Water Contact

In the Hod Field Development and Operating Plan, the oil water contacts (OWC) for the reservoir units of East and West Hod are defined by statistically derived equations. As a result, the OWC's for each reservoir unit are different. However in defining possible variations in gross rock volume as a function of OWC uncertainty, the following were used:

i: East Hod
Minimum gross rock volume: - All Hod reservoir units are oil saturated down to the lowest penetrated oil in the H1 formation at a depth of 2759 m SS. The Ekofisk/Tor formation, due to its better reservoir quality is oil saturated down to the East Hod spill point of 2766.5 m SS.

Maximum gross rock volume: - All units are oil saturated down to the lowest observed oil in the H4 formation. This equates to a depth of 2840 m SS.

ii: West Hod
Minimum gross rock volume: - All reservoir units are oil saturated down to the lowest observed oil in Well 2/11-2. This equates to a depth of 2638 m SS.

Maximum gross rock volume: - The H2 and H3 layers were wet at a depth of 2638 m SS, therefore the OWC for these units was fixed at 2638 m SS. However since an OWC has not been observed for the H1 layer of West Hod, it is assumed that this layer is oil saturated down to a depth of 2766.5 m SS, equivalent to the spill point of the West Hod structure.

The resultant variations in Gross Rock Volume as a function of these assumptions are summarized below (all values in million of cubic meters):

		West Hod			East Hod	
	Min	Base	Max	Min	Base	Max
Ekofisk/Tor	-	-	-	101.6	101.6	215.3
Upper Hod - H1	21.4	81.2	164.3	107.5	107.5	292.8
Middle Hod - H2	25.3	25.3	25.3	57.9	115.3	274.6
Lower Hod - H3	NP	NP	NP	*	9.4	18.3
- H4	NP	NP	NP	*	20.8	20.8
Total	46.7	106.5	189.6	267.0	354.6	821.7

NOTES:

* Highest OWC is above structural closure
NP = Not present

3. Variations in Net-to-Gross Ratio

In order to arrive at what, in our opinion, are realistic variations in net-to gross ratio in the Hod Field, we examined the net-to-gross ratio maps provided as Exhibits 3.73 to 3.78 in Volume 2 of the Hod Field Development and Operating Plan. These Exhibits show the distribution of net-to-gross ratio for each formation in the field. The maps were carefully checked against the actual values of net-to-gross ratio measured from the individual well logs to ensure that these were consistent with each other. Having ensured that these were consistent, a range of net-to-gross ratio for each formation in each of the two structures was determined qualitatively. This range was evaluated for each formation in which oil-in-place has been identified for the Base Case scenario, i.e. with no oil present in the Ekofisk or Tor Formations in West Hod.

These ranges for net-to-gross ratio are tabulated below:

		West		East	
		Min	Max	Min	Max
Ekofisk/Tor		-	-	1.0	1.0
Upper Hod	H1	0.75	1.0	0.75	1.0
Middle Hod	H2	0.4	0.9	0.4	0.8
Lower Hod	- H3	NP	NP	0.5	0.9
	- H4	NP	NP	0.5	1.0
	- H5/6	NP	NP	0.1	0.6

NP = Not present

4. Variations in Porosity

Exhibits 3.55 to 3.60 in Volume 2 of the Hod Field Development and Operating Plan show the distribution of net porosity for each formation in the field. The maps were carefully checked against the actual values of net porosity measured from the individual well logs to ensure that these were consistent with each other. Having ensured that these were consistent, a range of net porosity for each formation in each of the two structures was determined. This range was evaluated for each formation in which oil-in-place has been identified for the Base Case scenario, i.e. with no oil present in the Ekofisk or Tor Formations in West Hod.

These ranges for net porosity are tabulated below, in percent porosity units:

	West		East	
Formation	Min	Max	Min	Max
Ekofisk/Tor	-	-	30	40
Upper Hod - H1	28	35	26	31
Middle Hod- H2	24	30	20	26
Lower Hod - H3	NP	NP	26	30
- H4	NP	NP	24	30
- H5/6	NP	NP	22	26

NP = Not present

The uncertainties in the above numbers are considered low, a substantial log and core data base exists and each porosity estimate is anticipated to be within 2 porosity units (PU).

5. Variations in Oil Saturation

Exhibits 3.67 to 3.72 in Volume 2 of the Hod Field Development and Operating Plan show the distribution of net water saturation for each formation in the field. The maps were carefully checked against the actual values of net water saturation measured from the individual well logs to ensure that these were consistent with each other. Having ensured that these were consistent, a range of net oil saturation for each formation in each of the two structures was determined by the following equation:

$$\text{Net oil saturation (\%)} = 100 - \text{net water saturation (\%)}$$

These ranges for net oil saturation for the Base Case scenario, i.e. with no oil present in the Ekofisk or Tor Formations in West Hod, are tabulated below, in percent saturation units:

	West		East	
Formation	Min	Max	Min	Max
Ekofisk/Tor	-	-	60	90
Upper Hod - H1	40	80	30	70
Middle Hod- H2	25	50	25	35
Lower Hod - H3	NP	NP	25	50
- H4	NP	NP	25	60
- H5/6	NP	NP	20	30

NP = Not present

The uncertainties in the oil saturations are mainly a function of uncertainties in porosity and formation water resistivity (Rw). Based on a 2 porosity units (PU) uncertainty in the porosity estimates and an assumed 10% uncertainty in the Rw value, the oil saturation uncertainties were calculated for average formation properties as follows:

	Average values(1)		Range of Oil Saturation(2)	
Formation	Oil Saturation(%)	Porosity(%)	Min (%)	Max(%)
H1 (West Hod)	60	32	55	64
H2 (West Hod)	38	27	29	45
Tor (East Hod)	75	35	73	78
H1 (East Hod)	50	29	44	55
H2 (East Hod)	30	23	20	39
H3 (East Hod)	38	28	30	45
H4 (East Hod)	43	26	35	49
H5/6(East Hod)	25	24	14	34

As can be seen from the above table the uncertainty in high porosity rock with high oil saturation the uncertainty is estimated to only a few percent. In poorer rock however, the uncertainty is up to 10 percent units.

(1) Arithmetic average of porosity and oil saturation as given previously.
(2) Using the above discussed uncertainties for the average formation properties.

6. Variation in Formation Volume Factor

In the Hod Field Development and Operating Plan, values of 1.57 and 1.44 bbl/stb were assigned to the formation volume factor (FVF) of the West and East Hod fluids respectively. These figures were assumed based on PVT data from Wells 2/11-2, 2/11-3A and 2/11-6(ST-1) corrected for separator effects. However, a spread in data does exist from the available PVT data base for the Hod Field. These data are shown in Exhibits 2.1 and 2.2.

As can be seen from Exhibit 2.1, the FVF for the Tor Formation of East Hod varies between 1.36 and 1.44, bbl/stb for separator adjusted data. The differential vaporization data varies between 1.47 and 1.58 bbl/stb. The separator-adjusted FVF for the Lower Hod Formation is estimated at between 1.438 and 1.439 bbl/stb. Since this spread in the data is very small, it has been assumed that 1.44 bbl/stb is a reasonable estimate to use for both the Tor and Hod Formations. However, as can be seen from Exhibit 2.1, the FVF for the Tor Formation may be as low as 1.36 bbl/stb. This figure may therefore be used as the minimum possible FVF for East Hod. In determining the maximum possible FVF, it is suggested that the differential vaporization data be used. This means that a value of 1.58 bbl/stb may be assigned for East Hod fluids.

Only a limited amount of data exists for West Hod from Well 2/11-2. These data are detailed in Exhibit 2.2. In addition to PVT laboratory measurements, FVF's were estimated using fluid compositions and the Amoco Redlich-Kwong Equation of State. These factors range between 1.555 and 1.705 bbl/stb. For the Hod Field Development and Operating Plan the most likely FVF was considered to be 1.572 bbl/stb, which lies within this range. The figure of 1.555 may be considered as the minimum value of the FVF, while the maximum value may be considered to be 1.705 bbl/stb.

UNCERTAINTIES IN RESERVOIR RECOVERY PARAMETERS

1. Variation in Relative Permeabilities

1.1 Gas-Oil Relative Permeability

The gas-oil relative permeability raw data obtained by testing core samples from wells 2/11-2, 2/11-3A and 2/11-6 were shown in Volume 2, Exhibits 4.20 to 4.34 of the Hod Field Development and Operating Plan (FDOP) submitted 7 April 1988.

Water-oil relative permeability testing was not possible on Hod Field cores, because the core plugs had permeabilities below the low end of the range necessary for performing such tests. Therefore data from the Valhall field Wells 2/11-4 and 2/8A-1 were used in the Hod Field reservoir simulator. Well 2/11-4 is located on the southern flank of Valhall and is the well which is geographically closest to Hod and bears most resemblance to Hod with respect to rock properties. To be consistent, the corresponding gas-oil relative permeability curves from these two wells were also used in the model.

The following analysis illustrates the potential variation as a result of using the Valhall gas-oil relative permeability data rather than the Hod data.

The effect of different connate water saturation for each core was compensated for by normalizing the gas saturation to a zero connate water saturation. This allows consistent averaging and "re-normalizing" to the water saturation levels used in the reservoir model. The four sets of gas-oil relative permeability curves for Well 2/11-2, normalized to zero water saturation, are presented in Exhibit 2.3. Oil and gas relative permeabilities (Kro and Krg) were then averaged and the gas saturation normalized to correspond to connate water saturations (Swc) of 20, 50 and 70 percent as shown in Exhibit 2.4. These water saturations have been used to normalize the curves for the crestal Tor (20%), crestal Upper Hod (50%) and other Hod and flank (70%) blocks in the reservoir model. These normalized curves from the 2/11-2 data result in slightly higher relative permeabilities to oil and gas than those input into the reservoir model (Exhibit 2.5).

Similar calculations have been performed for Well 2/11-3A. Exhibit 2.6 shows the different sets of relative permeability curves for this well, normalized to a zero connate water saturation. These curves were averaged and re-normalized to water saturations of 20, 50 and 70 percent, as shown in Exhibit 2.7. These Kro curves essentially overlay those developed from Well 2/11-2 data and hence show slightly higher Kro values than those used in the reservoir model for the same saturations. The relative permeabilities to gas (Krg) estimated from Well 2/11-3A data are somewhat lower than those used in the reservoir simulation.

The relative permeability curves prepared for the core sample obtained from Well 2/11-6 are shown in Exhibit 2.8. These curves plot within the spread of the corresponding curves for Well 2/11-3A. This core was cut in the Tor Formation as was the core from Well 2/11-3A.

Overall the variation indicated in the relative permeability to oil (Kro) is marginal. More variation is indicated in the relative permeability to gas.

1.2 Water-Oil Relative Permeability

Water-oil relative permeability curves (Kro and Krw) curves prepared for Tor Formation core samples from Well 2/11-4 are presented in Exhibit 2.9. The two sets of curves to the right (representing cores cut at 2603.4 and 2604.4 meters) have Krw/Kro = 1 at a water saturation (Sw) of approximately 70 percent, indicating flow behaviour normally associated with water-wet rock. The third curve set (intersection at about 50 percent) is typical for intermediate wettability rock. The strong "water-wet" flow behaviour, although consistent with previously measured restored state flow behaviour, is not consistent with the oil-wetting preference indicated by contact angle measurement tests on samples from Well 2/11-3A. Hence, these two sets of curves have not been included in the data base used for the model.

The three sets of curves prepared for Valhall Field Well 2/8A-1 are shown in Exhibit 2.10. Geometric average curves have been created from these in combination with the one set from Well 2/11-4, from 2585.4 meters depth, as shown on Exhibit 2.11. One factor illustrating an element of uncertainty is the one set of curves plotted at the extreme left, measured on the sample taken at 2491.65 meters. The other curves show only minor variations from the average.

A similar group of water-oil relative permeability curves for the Hod Formation is shown in Exhibit 2.12.

The geometric average curves described above were used to create the curves normalized to 20, 50 and 70 percent connate water saturation used in the reservoir model for crestal Tor, Upper Hod crest and Lower Hod plus flanks, respectively, as shown in Exhibit 2.13 (Exhibit 4.45 of the FDOP).

2. Variations in Horizontal Permeabilities

A qualitative evaluation of realistic variations in horizontal permeabilities was made by using the permeability vs. porosity relationships shown in Exhibits 4.46 to 4.49 in the Field Development and Operating Plan (FDOP). These exhibits are plots of log permeability vs. porosity from the Valhall Field, incorporating permeabilities measured both from core analysis and from pressure buildup (PBU) test analysis. The values obtained from the Hod well tests are also included for comparison in the plots for the Tor and Upper Hod Formations.

Tor Formation

The permeability vs. porosity relationship is shown in Exhibit 4.46 of the Hod FDOP. Two straight lines are plotted, one for core data and one for pressure buildup data. The core data line represents values of matrix permeability, i.e. excluding the influence of natural fractures, whereas the influence of natural fractures in observed in the pressure buildup data. In the reservoir model, the core data was used at lower porosities up to the intersection point with the pressure buildup line. Thereafter, at higher porosities, the pressure buildup data is used since this is more representative of the actual formation permeability. Most of the productive Ekofisk/Tor sections in the Hod Field have porosities greater than 30% and therefore fall on the pressure buildup line.

The test data points for Wells 2/11-3A and 2/11-6(ST-1) show higher permeabilities than the pressure buildup line for equivalent porosities. Thus Well 2/11-6(ST-1) shows permeability of 7 md whereas the equivalent straight line permeability is only 1-2 md. Similarly, Well 2/11-3A shows a permeability of 17 md compared to an equivalent straight line permeability of 5 md. However, owing to the much larger data base available from Valhall wells, it was considered prudent to use the Valhall straight line in the Hod reservoir model.

Since the Hod well permeabilities were higher than the equivalent straight line permeabilities, the highest permeability measured in a Hod PBU test was chosen to be the high value of the range of permeability variation. This value is 17 md, as measured in DST no.2 in Well 2/11-3A. The equivalent Valhall straight line permeability is 5 md. Since this value is lower than that measured in the 2/11-6(ST-1) DST, the value of 5md was chosen to be the low value of the reange. The arithmetic average of those two values, i.e. 11 md may be considered as the average permeability of the Ekofisk/Tor Formation in East Hod. The range of permeability variation for this formation is therefore 5 to 17 md.

Exhibit 2.14 shows this range on the permeability-porosity plot.

Upper Hod Formation

The Upper Hod permeability - porosity relationship (Exhibit 4.47 of the Hod FDOP) is similar to that for the Tor Formation in that two straight lines are included. The lower line represents the core data obtained from this formation in the Valhall Field. The upper line represents the core data from Hod Well 2/11-2 and includes the pressure buildup point from this well. The data from 2/11-2 shows significantly higher permeabilities than those from the Valhall Field, by up to an order of magnitude. This is due to the much better quality of the Upper Hod Formation in the Hod Field, compared to the same formation in the Valhall Field. For this reason, the Valhall data is not included in the qualitative evaluation of permeability variation.

As can be seen in the above mentioned exhibit, the values of Upper Hod permeability range between 1 and 5 md depending on porosity. If the four points representing less than 30 percent porosity are excluded as not being representative of Upper Hod average porosity, then most of the points lie in the 2-5 md range. The range of permeability variation for this formation may therefore be chosen as 2 to 5 md, with an average value of 3.5 md. Exhibit 2.15 shows this range on the permeability-porosity plot.

Middle Hod Formation

This formation is of poor reservoir quality both in Valhall and in Hod Fields. Exhibit 4.48 in the Hod FDOP shows a plot of permeability vs. porosity for this formation based on core analysis data. The majority of the points on this plot lie in the porosity range of 20-30 percent. Therefore, the permeability variation can be taken as the range of permeabilities corresponding to those porosities, i.e. a range of 0.05 to 0.2 md.

Exhibit 2.16 shows the permeability - porosity plot for this formation.

Lower Hod Formation

This formation is of better reservoir quality than the Middle Hod, and the H4 horizon of this formation is expected to be productive in East Hod. Exhibit 4.49 of the Hod FDOP shows a plot of permeability vs. porosity data for this formation. This is mostly based on core analysis data but some pressure buildup data is also included. All the points fall fairly close to a single straight line, with most of the points concentrated in the porosity range of 25-35 percent. However, the pressure buildup data indicates permeabilities in the higher end of this range. Since the pressure buildup permeability is considered to be more representative with respect to well productivity prediction, the range of permeability variation may be chosen as the range of pressure buildup-measured permeabilities. This range is 0.8 to 2.0 md, with an average value of 1.4 md.

Exhibit 2.17 shows the permeability - porosity plot for this formation.

Summary

The ranges of permeabilities determined for each formation in the Hod Field are summarized in the following table, in millidarcies:

	Min.	Max.
Ekofisk/Tor	5	17
Upper Hod	2	5
Middle Hod	0.05	0.2
Lower Hod	0.8	2.0

3. Variations in Vertical Permeabilities

A qualitative evaluation of variations in vertical permeabilities can be made by using the percentage of horizontal permeability as used in the Hod reservoir simulation model. These percentages are based on experience from the Valhall Field, and take into account the lithology of each formation.

Vertical permeabilities were calculated as follows:

Ekofisk/Tor Formation	= 10%	of horizontal permeability
Upper Hod Formation	= 1%	of horizontal permeability
Middle Hod Formation	= 2.5%	of horizontal permeability
Lower Hod Formation	= 2.5%	of horizontal permeability

The variation in vertical permeabilities may be obtained by multiplying the minimum and maximum values of horizontal permeability determined under Item 2 by the above percentages.
The range of values thus calculated for each formation in the Base Case scenario is listed below, in millidarcies:

	Min	Max
Ekofisk/Tor	0.5	1.7
Upper Hod	0.02	0.05
Middle Hod	0.0013	0.005
Lower Hod	0.02	0.05

4. Variations in Fluid Properties

A number of PVT analyses have been conducted on samples of reservoir fluid collected from the Hod Field wells. These analyses show some degree of scatter in the various fluid properties. A summary of the PVT results for East Hod is given in Exhibit 2.18, and for West Hod in Exhibit 2.19. It should be noted that insufficient fluid data exist for West Hod from which to draw conclusions with respect to uncertainties. For East Hod, the variations in fluid properties can be detailed as follows:

4.1 Reservoir Fluid Viscosity

This parameter shows significant scatter, ranging from 0.43 to 0.73 cP at initial reservoir conditions. The most likely value used for East Hod in the Hod Field Development and Operating Plan was 0.66 cP which lies in the "conservative" end of the range. The range from 0.43 cP to 0.73 cP may be considered as the possible variation in this property.

4.2 Oil Density

The data do not show a significant variation in oil density values. These range from 0.681 g/cc to 0.707 g/cc at initial reservoir conditions. This represents a scatter of around 4%. The most likely value used in the Hod Field Development and Operating Plan was 0.681 g/cc which represents the results from the Well 2/11-3A Tor Formation test. The range from 0.681 g/cc to 0.707 g/cc may be considered as the possible variation in this property.

4.3 Gas-Oil Ratio

Using separator-adjusted data, the gas-oil ratio ranges between 820 scf/stb and 876 scf/stb. The differential vaporization data yield a range between 927 scf/stb and 1131 scf/stb. It is believed that separator-adjusted data would more closely represent producing conditions in the Hod Field, and for this reason a value of 876 scf/stb was used in the Hod Field Development and Operating Plan. The range from 820 scf/stb to 1131 scf/stb may be considered as the possible variation in this property.

4.4 Oil Formation Volume Factor

Using separator-adjusted data, the oil formation volume factor at initial reservoir conditions ranges between 1.36 bbl/stb and 1.44 bbl/stb. Differential vaporization data yield a range from 1.47 bbl/stb to 1.583 bbl/stb. Again, separator-adjusted data are considered to be more representative for the Hod Field, and a value of 1.44 bbl/stb was considered as the most likely and used in the Hod Field Development and Operating Plan. The range from 1.36 bbl/stb to 1.583 bbl/stb may be considered as the possible variation in this property.

4.5 Bubble Point Pressure

Bubble point pressures range from 3314 psig to 4000 psig for the East Hod fluid. The well 2/11-3A Tor Formation test value of 3912 psig was used as the most likely value in the Hod Field Development and Operating Plan. However, the range 3314 psig to 4000 psig may be considered as the possible variation in this property.

4.6 Gas Viscosity

Gas viscosity values measured at pressures just below the bubble point pressure show no major variations. All values lie in the range 0.020 cP to 0.023 cP. The assumptions used in the Hod Field Development and Operating Plan are therefore considered most likely with no major variation based on the available database.

SECTION II

LIST OF EXHIBITS

2.1 Formation Volume Factors, East Hod

2.2 Formation Factors, West Hod

2.3 Gas-Oil Relative Permeabilities, Well 2/11-2

2.4 Average Gas-Oil Relative Permeabilities, Well 2/11-2

2.5 Gas-Oil Relative Permeabilities used in Reservoir Model

2.6 Gas-Oil Relative Permeabilities, Well 2/11-3A

2.7 Average Gas-Oil Relative Permeabilities, Well 2/11-3A

2.8 Gas-Oil Relative Permeabilities, Well 2/11-6

2.9 Water-Oil Relative Permeabilities, Well 2/11-4

2.10 Water-Oil Relative Permeabilities, Well 2/8A-1

2.11 Water-Oil Relative Permeabilities, Tor Formation

2.12 Water-Oil Relative Permeabilities, Hod Formation

2.13 Water-Oil Relative Permeabilities used in Reservoir Model

2.14 Permeability vs. Porosity Plot, Tor Formation

2.15 Permeability vs. Porosity Plot, Upper Hod Formation

2.16 Permeability vs. Porosity Plot, Middle Hod Formation

2.17 Permeability vs. Porosity Plot, Lower Hod Formation

2.18 Fluid Properties, East Hod

2.19 Fluid Properties, West Hod

SECTION I

LIST OF EXHIBITS

1.1a Hod Field X-ray Diffraction Analyses, Well 2/11-3

1.1b Hod Field X-ray Diffraction Analyses, Well 2/11-3A

1.1c Hod Field X-ray Diffraction Analyses, Well 2/11-6

1.2 East Hod Fluid Properties

1.3a East Hod - Bubble Point v. Depth Plot

1.3b East Hod - Gas-oil Ratio v. Depth Plot

1.4 Production Profiles - Low Reserve Case (English Units)

1.5 Production Profiles - Low Reserve Case (Metric Units)

1.6 Production Profiles - High Reserve Case (English Units)

1.7 Production Profiles - High Reserve Case (Metric Units)

EXHIBIT 1.1a

-WELL 2/11-3 PETROLOGY

Core Depth (Metres)	X-Ray Diffraction Mineral Percentages Calcite	Quartz	Kaolinite	Illite	Others	Zone
2778	97	3	---	trc		Hod
2789	94	6	trc	---		Hod
2808	76	22	trc	trc	Halite 2	Hod

EXHIBIT 1.1b

WELL 2/11-3A PETROLOGY

Core Depth (Metres)	X-Ray Diffraction Mineral Percentages Calcite	Quartz	Kaolinite	Illite	Others	Zone
3193.0	41	36	6	6	11	Ekofisk/Shale
3195.0	83	11	trc	2	2 Dolo 2 Bari	Ekofisk
3196.3	95	5	trc			Ekofisk
3197.9	93	5	2		trc	Ekofisk
3201.7	100	trc	trc	trc	trc	Ekofisk
3203.4	100	trc	trc			Ekofisk
3205.1	100	trc				Tor
3207.0	100	trc		trc		Tor
3226.71	100	trc	trc	trc	Bari trc	Tor
3228.61	98	2	trc	trc		Tor
3229.46	100	trc				Tor
3232.65	100	trc	trc			Tor
3236.65	98	2	trc			Tor
3241.4	94	4	2	trc		Tor
3245.4	93	5	trc	trc	2 Bari	Tor
3247.8	97	3	trc	trc	Sidr trc	Tor

WELL 2/11-6 PETROLOGY

Core Depth (Metres)	X-Ray Diffraction Mineral Percentages Calcite	Quartz	Kaolinite	Illite	Others	Core Porosity %	Zone
3693.1	99	1	trc			33.1	Tor
3693.25							Tor
3694.1	99	1				33.1	Tor
3694.55	98	2	trc				Tor
3694.8							Tor
3694.85	98	2	trc			32.0	Tor
3695.1	94	5		1		32.9	Tor
3695.35	97	3				29.4	Tor
3696.1							Tor
3696.6	98	2	trc			28.8	Tor
3697.2						28.8	Tor
3697.4	97	3	trc			24.2	Tor
3702.2	98	2				32.3	Tor
3702.4	98	2	trc			29.1	Tor
3702.65	98	2	trc			31.0	Tor
3702.85	98	2	trc			41.9	Tor
3703.1	98	2				32.7	Tor
3703.35	98	2				32.8	Tor
3703.6	98	2		trc		34.4	Tor
3703.85	98	2	trc			34.9	Tor
3704.1	98	2				34.6	Tor
3704.35	98	2				34.4	Tor
3704.6	89	3	3		4 Smectite 1 Pyrite		Tor
3705.0	96	2	2			38.9	Tor
3705.1	97	3	trc	trc		38.6	Tor
3705.6	98	2				37.2	Tor
3705.8	93	5	2	trc		38.2	Tor
3705.85	97	3	trc			39.4	Tor
3708.1	98	2				35.7	Tor
3708.6	98	2	trc			33.5	Tor

WELL 2/11-6 PETROLOGY (contined)

Core Depth (Metres)	Calcite	Quartz	Kaolinite	Illite	Others	Core Porosity %	Zone
	X-Ray Diffraction Mineral Percentages						
3709.6	98	2	trc			33.5	Tor
3710.05	100	trc	trc			13.0	Tor
3710.1	98	2				15.7	Tor
3710.35	97	1		2		23.8	Tor
3712.0							Tor
3716.05	98	2				32.7	Tor
3716.35	99	1				30.0	Tor
3717.6							Dense
3717.85	97	2			Fluorite 1	13.6	Dense
3720.1	97	3				9.3	Dense
3720.35	97	3				8.2	Dense
3720.7	98	2	trc			5.8	Dense
3721.0							Dense
3721.1	98	2				4.8	Dense
3721.35	98	1	1			4.3	Dense
3721.7	98	1				4.8	Dense
3735.1	93	5	2			33.1	Upper Hod
3736.1	97	3				29.4	Upper Hod
3737.35	93	5	2		Halite trc	37.1	Upper Hod
3737.6	92	6	2		Halite trc	34.4	Upper Hod
3738.3	94	5	1		Halite trc Dolomite trc		Upper Hod
3738.85	91	7	2		Halite trc Smectite trc	38.4	Upper Hod
3739.3	85	15				38.3	Upper Hod
3739.35	90	8	2		Halite trc	37.9	Upper Hod

EXHIBIT 1.2

EAST HOD FLUID PROPERTIES

Well	Formation	Mid-pt of Formation (m-SS)	Bubble pt Pressure (psig)	Gas-oil Ratio (scf/stb)
2/11-3A	Upper Hod	2736	3842	970
	Upper Hod	2736	4000	1054
	Tor	2695	3912	1131
	Tor	2695	3314	927
2/11-6(ST-1)	Lower Hod	2841.5	3455	1017
	Lower Hod	2841.5	3430	1017
	Upper Hod/Tor*	2728.3**	3323	1021
	Upper Hod/Tor*	2728.3**	3475	1028

* Well was perforated in both the Upper Hod and Tor Formations.

** Mid-point depth is assumed to be the mid-point of the Tor/Upper Hod interval.

EXHIBIT 1.3a

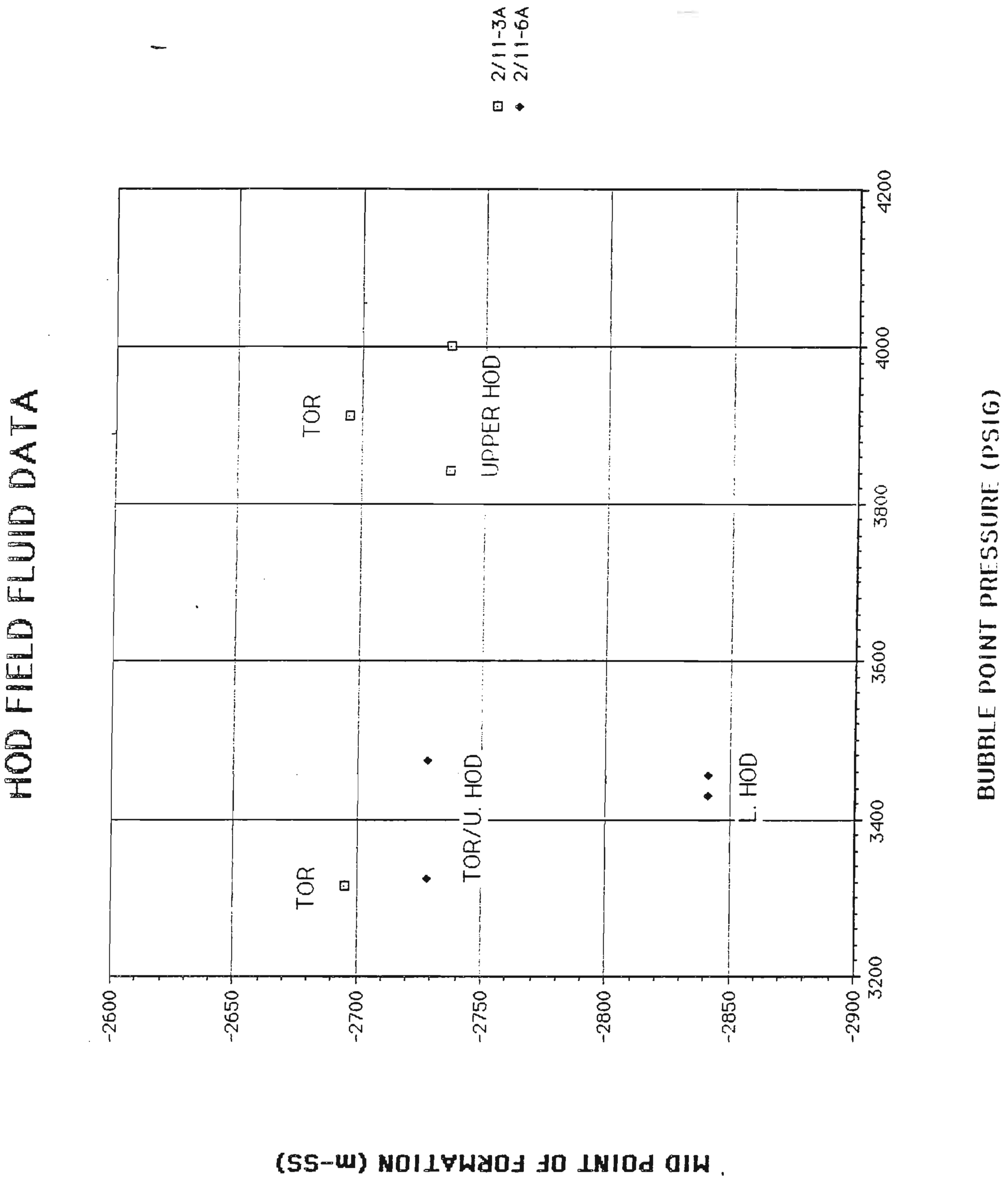

HOD FIELD FLUID DATA
2/11-3A
2/11-6A
TOR
UPPER HOD
TOR
TOR/U. HOD
L. HOD
-2600
-2650
-2700
-2750
-2800
-2850
-2900
3200
3400
3600
3800
4000
4200
BUBBLE POINT PRESSURE (PSIG)
MID POINT OF FORMATION (m-SS)

EXHIBIT 1.3b

HOD FIELD FLUID DATA

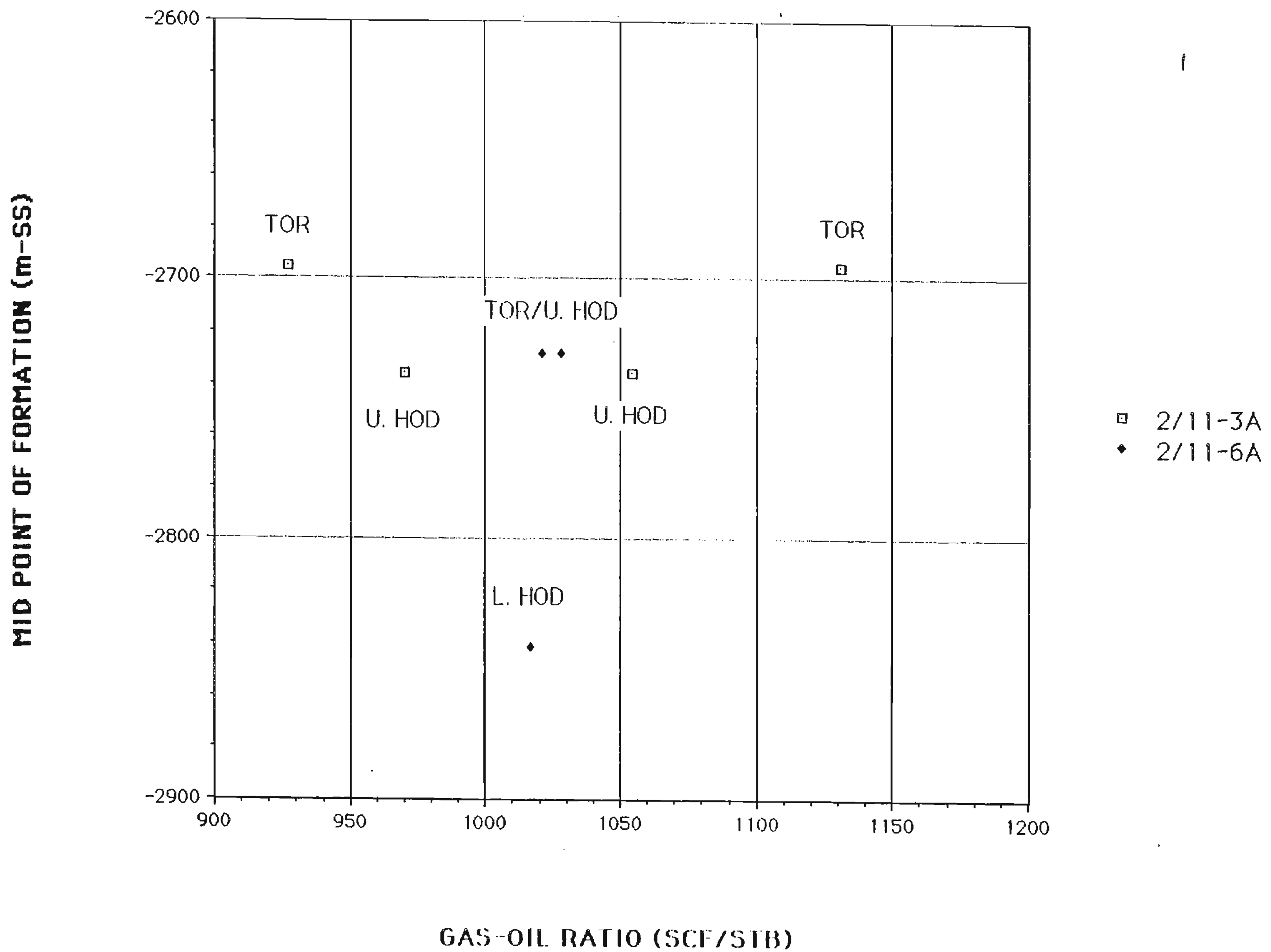


EXHIBIT 1.4

HOD FIELD

PRODUCTION PROFILES

LOW RESERVE CASE, CASE A4
(No reserves to west of fault in West Hod)

Year	SALES OIL (STBOPD)	SALES GAS (MSCFD)	SALES NGL (BLPD)
1990	4,883	3,893	409
1991	12,154	16,098	1,690
1992	7,200	8,031	843
1993	5,666	6,175	648
1994	4,614	5,388	566
1995	3,862	4,859	510
1996	3,337	4,419	464
1997	2,947	4,070	427
1998	2,640	3,774	396
1999	2,397	3,524	370
2000	2,199	3,305	347
2001	2,030	3,112	327
2002	1,887	2,947	310
2003	1,764	2,796	294
2004	1,638	2,620	275
CUMULATIVE PRODUCTION	21,615,453 STB	27,378,919 MSCF	2,875,252 BBL

HOD FIELD

PRODUCTION PROFILES

LOW RESERVE CASE, CASE A4
(No reserves to west of fault in West Hod)

YEAR	SALES OIL (Sm^3/D)	SALES GAS ($10^3Sm^3/D$)	SALES NGL (TONNES/D)
1990	776	110	32
1991	1,932	456	134
1992	1,145	227	67
1993	901	175	51
1994	733	153	45
1995	614	138	40
1996	530	125	37
1997	468	115	34
1998	420	107	31
1999	381	100	29
2000	350	94	28
2001	323	88	26
2002	300	83	25
2003	280	79	23
2004	260	74	22
CUMULATIVE PRODUCTION	3,436 10^3Sm^3	775 10^6Sm^3	228 10^3 Tonnes

CONVERSION FACTORS USED

OIL	1 STB	= 0.15897	Cubic meters
GAS	1 SCF	= 0.02832	Cubic meters
NGL	1 BBL	= 0.07937	Tonnes

EXHIBIT 1.6

HOD FIELD

PRODUCTION PROFILES

HIGH RESERVE CASE, CASE B1
(With Tor Formation in West Hod)

Year	SALES OIL (STBOPD)	SALES GAS (MSCFD)	SALES NGL (BLPD)
1990	8,602	7,744	813
1991	24,731	28,266	2,968
1992	13,663	16,079	1,688
1993	10,039	13,155	1,381
1994	7,869	11,798	1,239
1995	6,435	10,785	1,133
1996	5,434	9,985	1,049
1997	4,661	9,220	968
1998	4,050	8,558	899
1999	3,562	7,966	837
2000	3,168	7,428	780
2001	2,846	6,916	726
2002	2,590	6,463	679
2003	2,175	5,635	592
2004	1,917	5,119	538
CUMULATIVE PRODUCTION	37,135,933 STB	56,618,031 MSCF	5,945,785 BBL

EXHIBIT 1.7

HOD FIELD

PRODUCTION PROFILES

HIGH RESERVE CASE, CASE B1
(With Tor Formation in West Hod)

YEAR	SALES OIL (Sm^3/D)	SALES GAS (10^3Sm^3/D)	SALES NGL (TONNES/D)
1990	1,367	219	65
1991	3,931	800	236
1992	2,172	455	134
1993	1,596	373	110
1994	1,251	334	98
1995	1,023	305	90
1996	864	283	83
1997	741	261	77
1998	644	242	71
1999	566	226	66
2000	503	210	62
2001	452	196	58
2002	411	183	54
2003	346	160	47
2004	304	145	43
CUMULATIVE PRODUCTION	5,903 10^3Sm^3	1,603 10^6Sm^3	472 10^3 Tonnes

CONVERSION FACTORS USED

OIL 1 STB = 0.15897 Cubic meters
GAS 1 SCF = 0.02832 Cubic meters
NGL 1 BBL = 0.07937 Tonnes

SECTION II

LIST OF EXHIBITS

2.1 Formation Volume Factors, East Hod

2.2 Formation Factors, West Hod

2.3 Gas-Oil Relative Permeabilities, Well 2/11-2

2.4 Average Gas-Oil Relative Permeabilities, Well 2/11-2

2.5 Gas-Oil Relative Permeabilities used in Reservoir Model

2.6 Gas-Oil Relative Permeabilities, Well 2/11-3A

2.7 Average Gas-Oil Relative Permeabilities, Well 2/11-3A

2.8 Gas-Oil Relative Permeabilities, Well 2/11-6

2.9 Water-Oil Relative Permeabilities, Well 2/11-4

2.10 Water-Oil Relative Permeabilities, Well 2/8A-1

2.11 Water-Oil Relative Permeabilities, Tor Formation

2.12 Water-Oil Relative Permeabilities, Hod Formation

2.13 Water-Oil Relative Permeabilities used in Reservoir Model

2.14 Permeability vs. Porosity Plot, Tor Formation

2.15 Permeability vs. Porosity Plot, Upper Hod Formation

2.16 Permeability vs. Porosity Plot, Middle Hod Formation

2.17 Permeability vs. Porosity Plot, Lower Hod Formation

2.18 Fluid Properties, East Hod

2.19 Fluid Properties, West Hod

FORMATION VOLUME FACTORS

EAST HOD FLUIDS

Well	Formation	Formation Volume Factor (bbl/stb)	Comment
2/11-3A	Upper Hod	1.51	Differential Vaporization
	Upper Hod	1.56	Differential Vaporization
	Tor	1.47	Differential Vaporization
	Tor	1.58	Differential Vaporization
	Tor	1.36	Separator adjusted
	Tor	1.44	Separator adjusted
2/11-6(ST-1)	Lower Hod	1.548	Differential Vaporization
	Lower Hod	1.548	Differential Vaporization
	Lower Hod	1.439	Separator adjusted
	Lower Hod	1.438	Separator adjusted
	Upper Hod/Tor	1.551	Differential Vaporization
	Upper Hod/Tor	1.535	Differential Vaporization
	Upper Hod/Tor	1.435	Separator adjusted
	Upper Hod/Tor	1.402	Separator adjusted

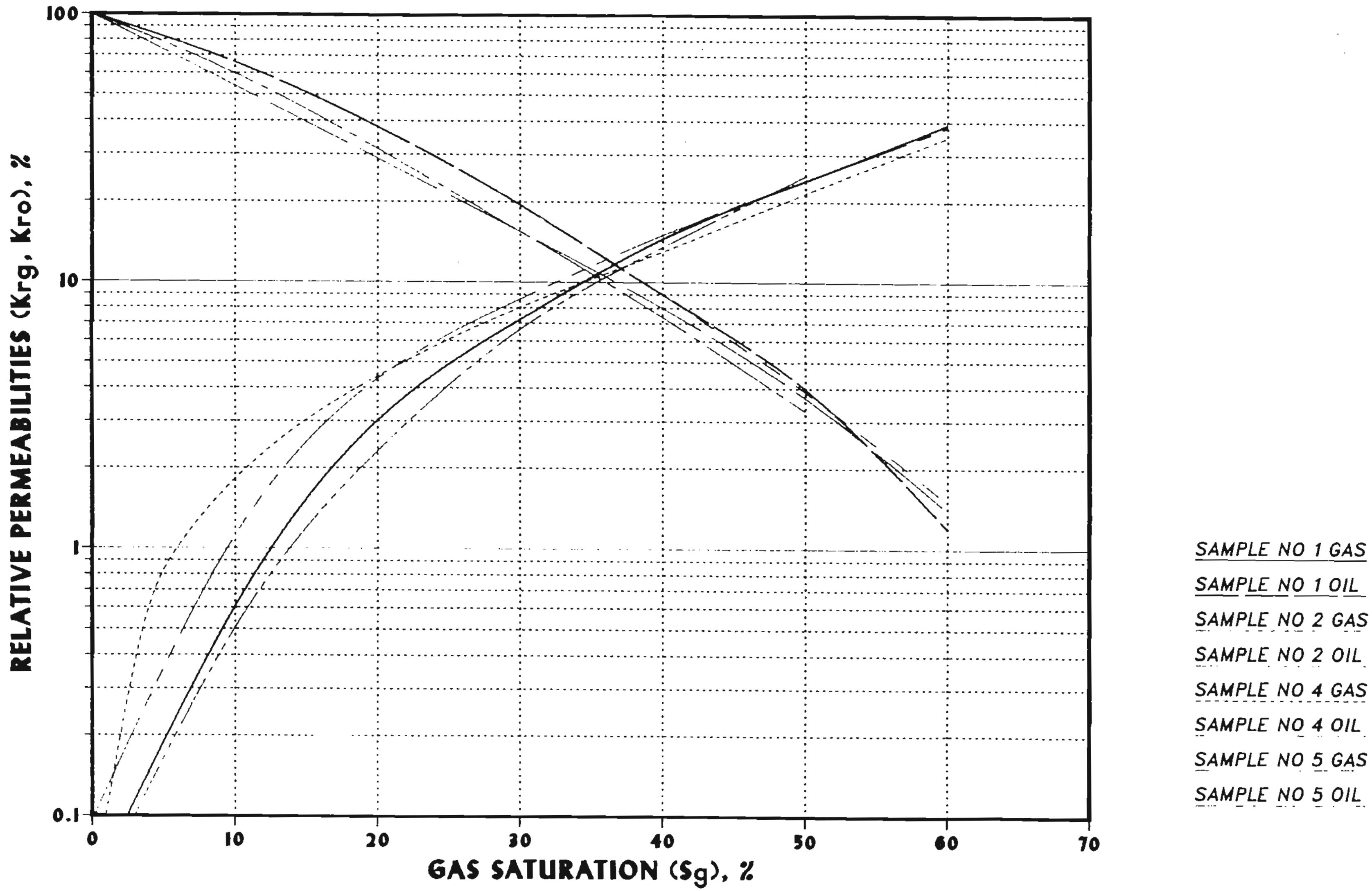
FORMATION VOLUME FACTORS

WEST HOD

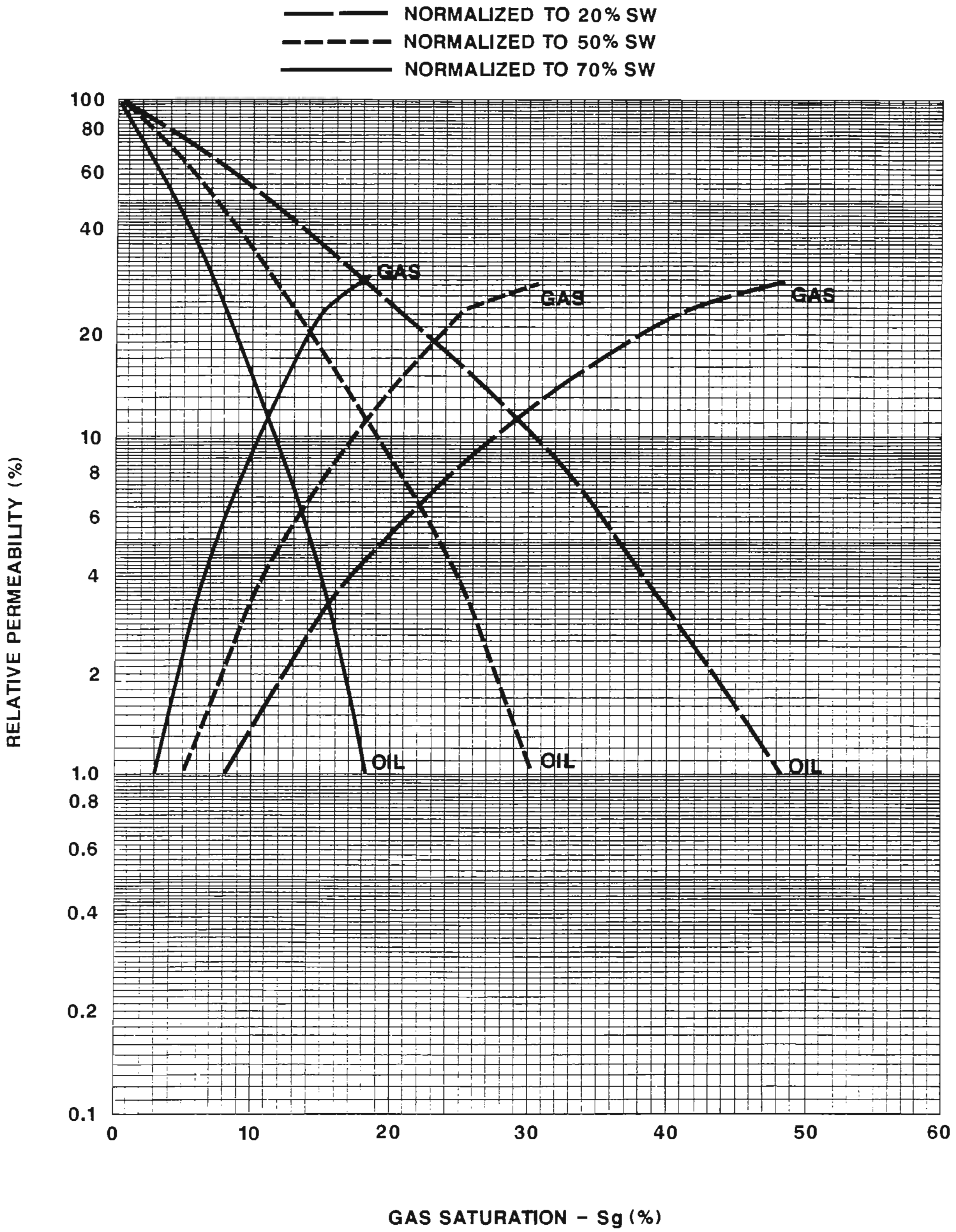
Well	Formation	Formation Volume Factor (bbl/stb)	Comment
2/11-2	Upper Hod	1.688	Differential Vaporization
	Upper Hod	1.572	Separator adjusted
	Upper Hod	1.555	Separator adjusted
	Upper Hod	1.585	Simulated differential vaporization using Redlich Kwong Equation of State
	Upper Hod	1.705	Simulated differential vaporization using Redlich Kwong Equation of State

EXHIBIT 2.3

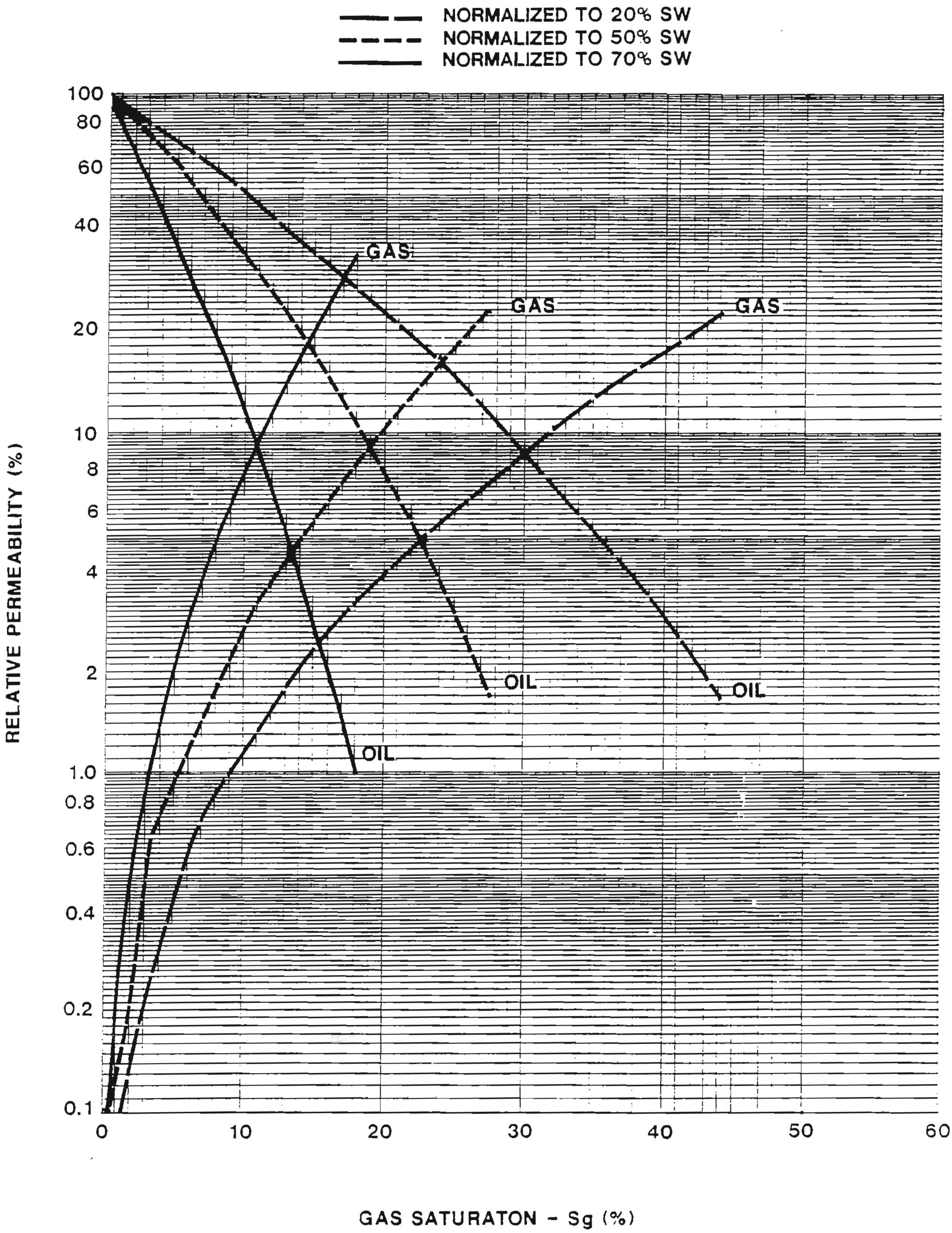
HOD FIELD, GAS-OIL REL. PERM., NORMALIZED TO 0% Sw
WELL 2/11-2, UPPER HOD FORMATION CORE TESTS

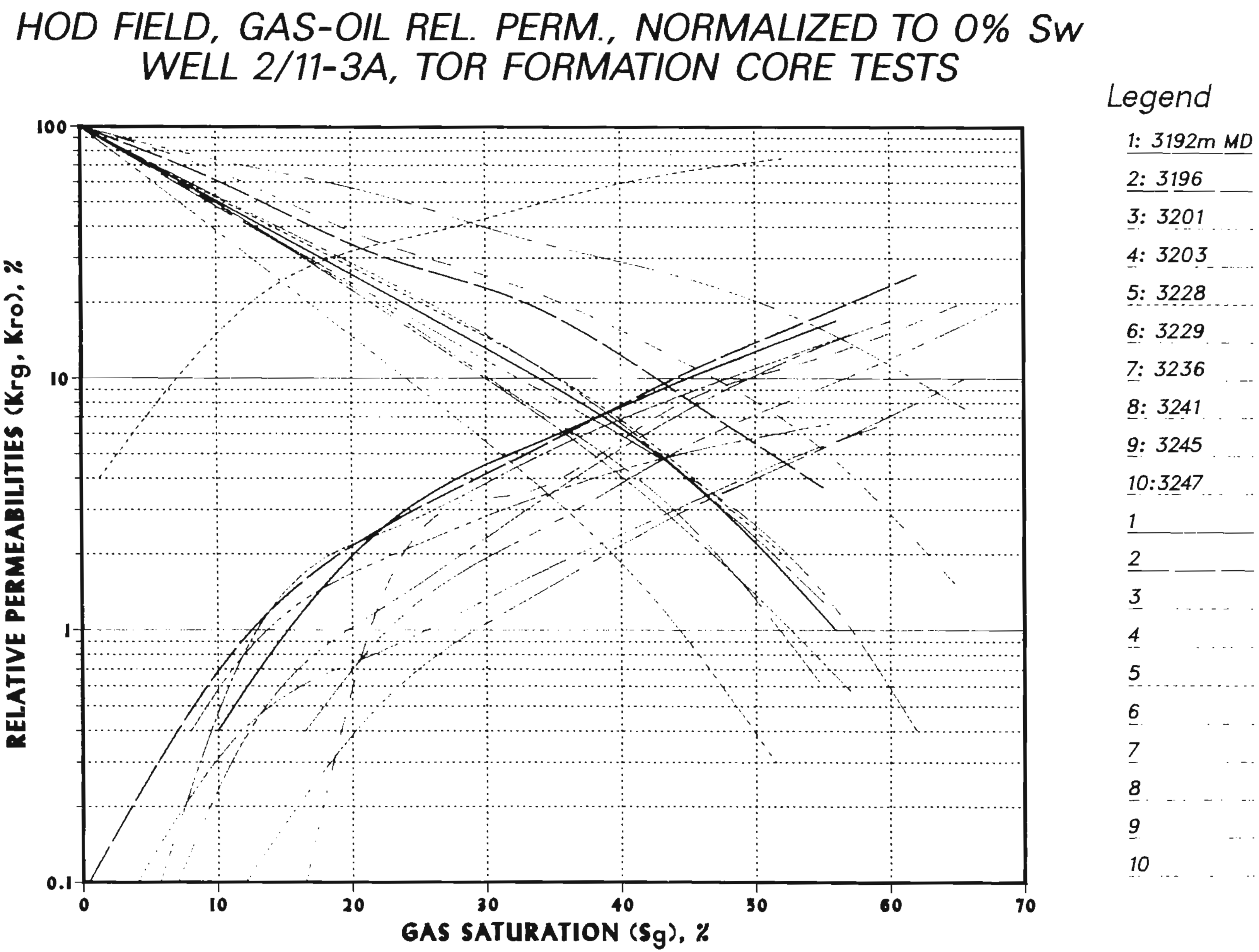


GAS OIL RELATIVE PERMEABILITIES
WEST HOD WELL 2/11-2
(BASED ON UPPER HOD FORMATION CORE)

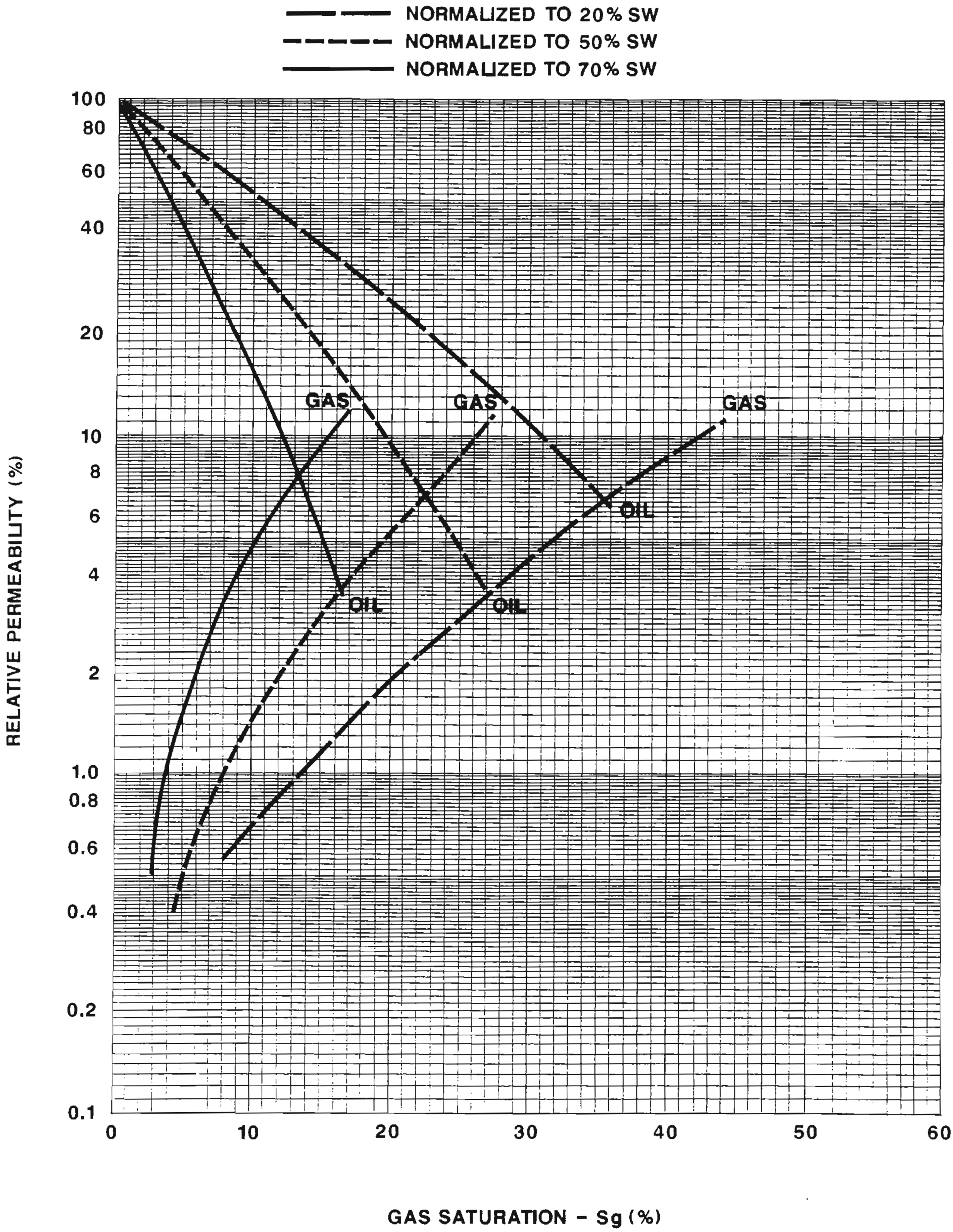


GAS OIL RELATIVE PERMEABILITIES
USED IN MODEL

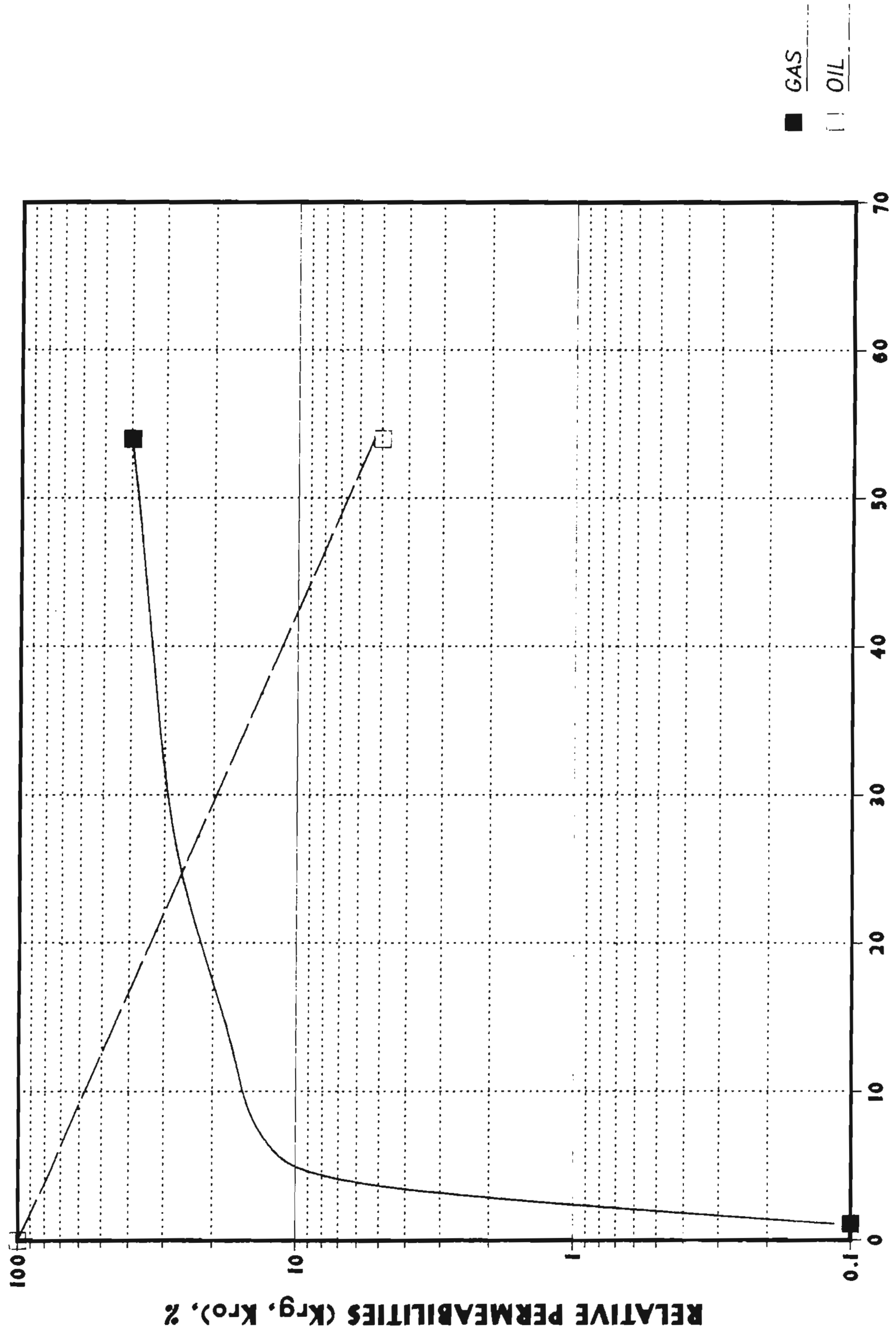



HOD FIELD, GAS-OIL REL. PERM., NORMALIZED TO 0% Sw
WELL 2/11-3A, TOR FORMATION CORE TESTS
Legend
1: 3192m MD
2: 3196
3: 3201
4: 3203
5: 3228
6: 3229
7: 3236
8: 3241
9: 3245
10:3247
1
2
3
4
5
6
7
8
9
10
RELATIVE PERMEABILITIES (Krg, Kro), %
100
10
1
0.1
GAS SATURATION (Sg), %
0
10
20
30
40
50
60
70

GAS OIL RELATIVE PERMEABILITIES
EAST-HOD WELL 2/11-3A
(BASED ON TOR FORMATION CORE TESTS)



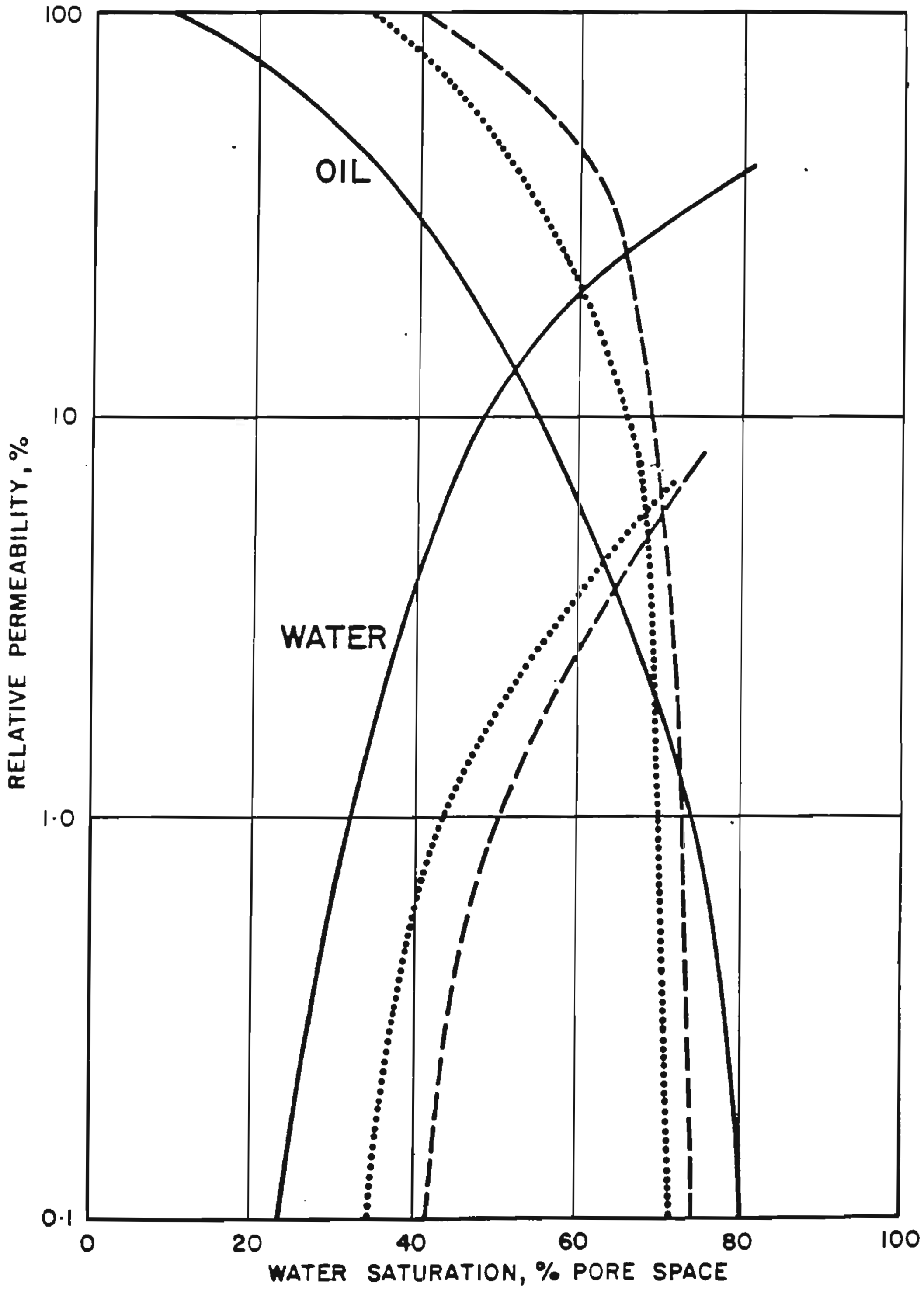
HOD FIELD, GAS-OIL REL. PERM., NORMALIZED TO 0% Sw
WELL 2/11-6, TOR FORMATION CORE TEST



VALHALL FIELD

WATER-OIL RELATIVE PERMEABILITIES - TOR FORMATION
WELL 2/11-4 — NATIVE STATE SAMPLES

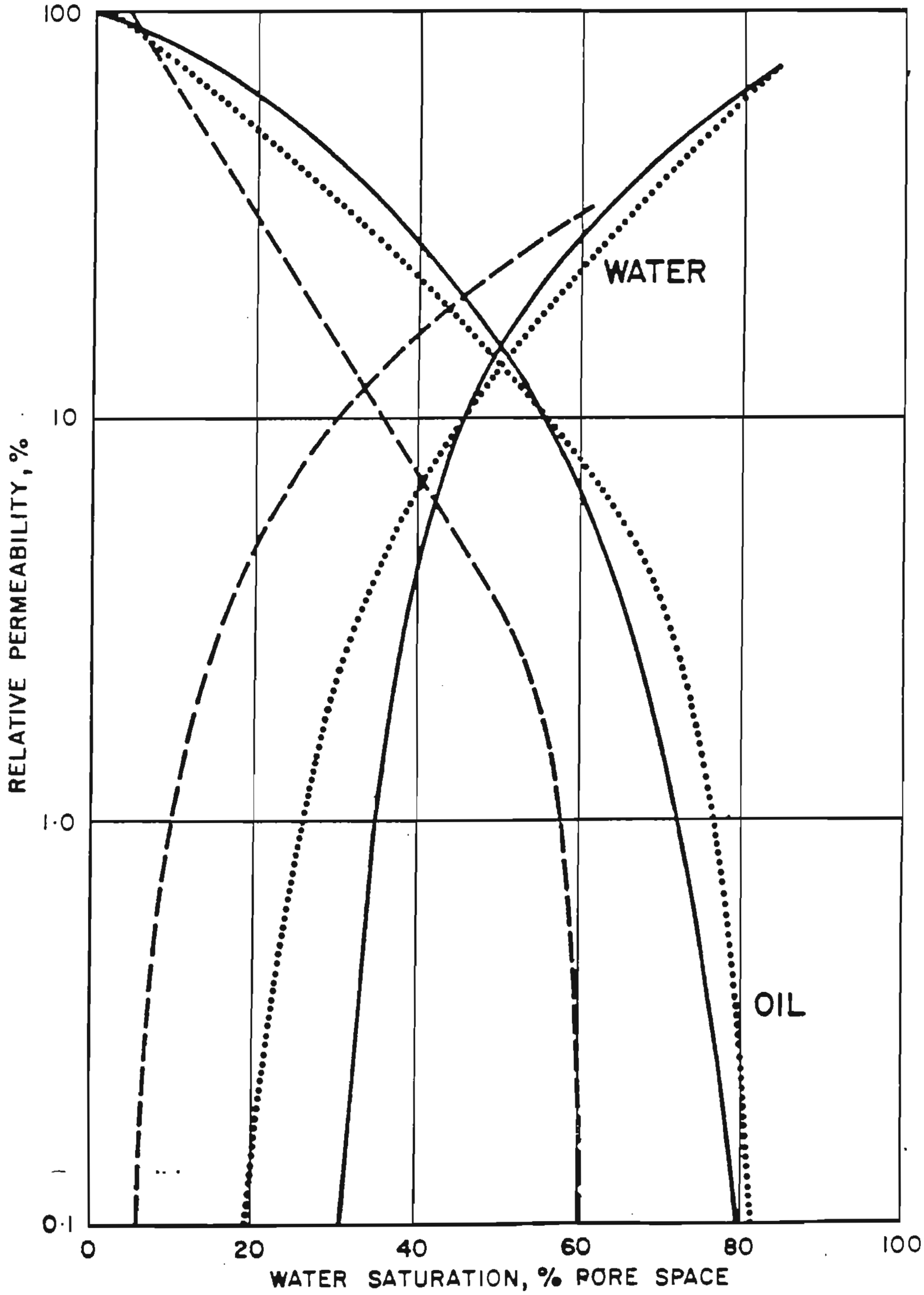
	Depth, ft.	Porosity, %	Sw, %	Oil Permeability, md
————————	2585.4	35.2	9.6	1.15
— — — — —	2603.4	29.5	40.0	0.183
•••••••••••••••	2604.4	33.9	33.0	1.32



VALHALL FIELD

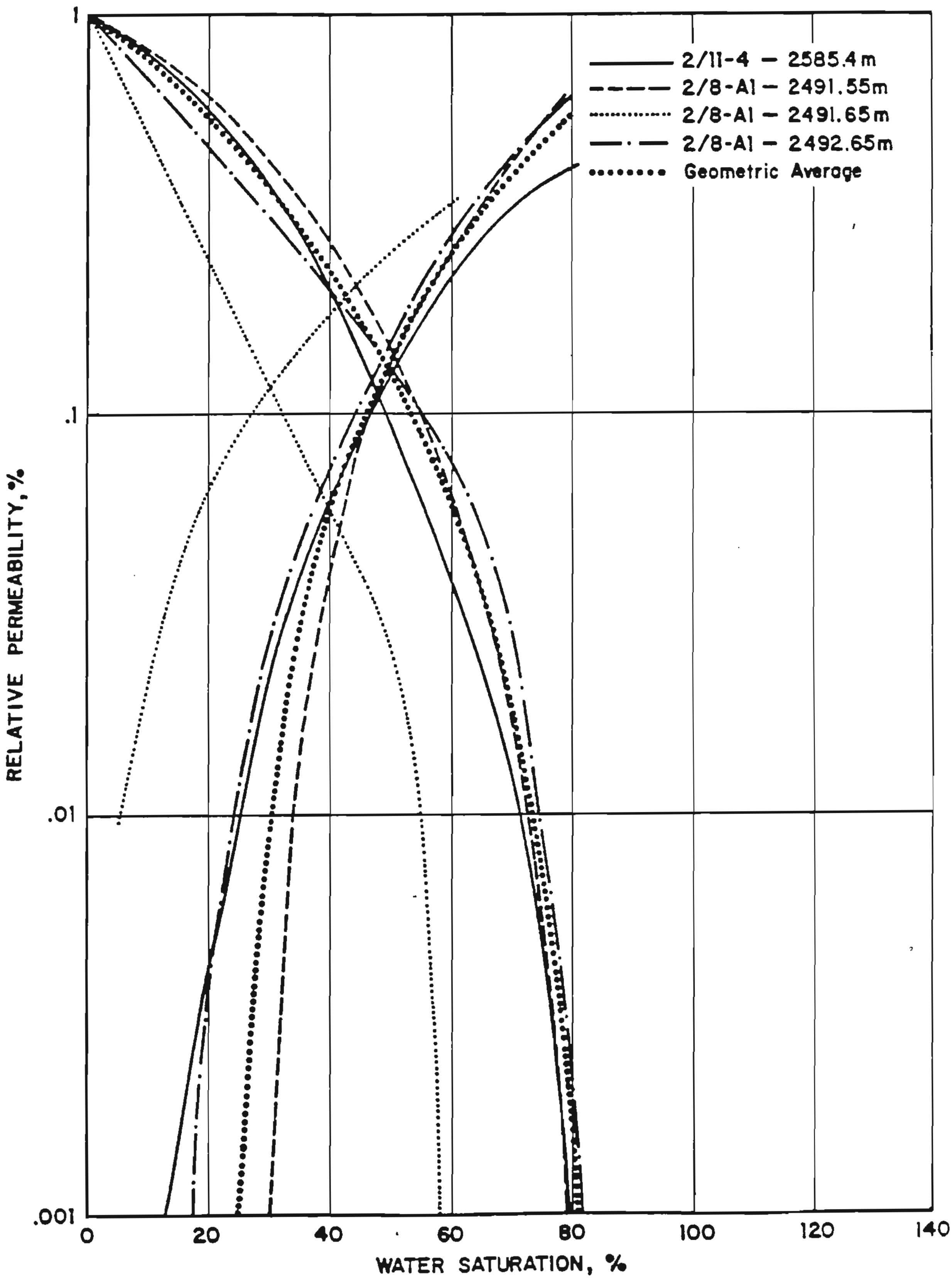
WATER-OIL RELATIVE PERMEABILITIES - TOR FORMATION
WELL 2/8-A1 — NATIVE STATE SAMPLES

	Depth, ft.	Porosity, %	Sw, %	Oil Permeability, md
————————	2491.55	40.4	0.0	4.5
— — — — —	2491.65	40.6	4.9	6.65
················	2492.65	38.4	2.3	4.0



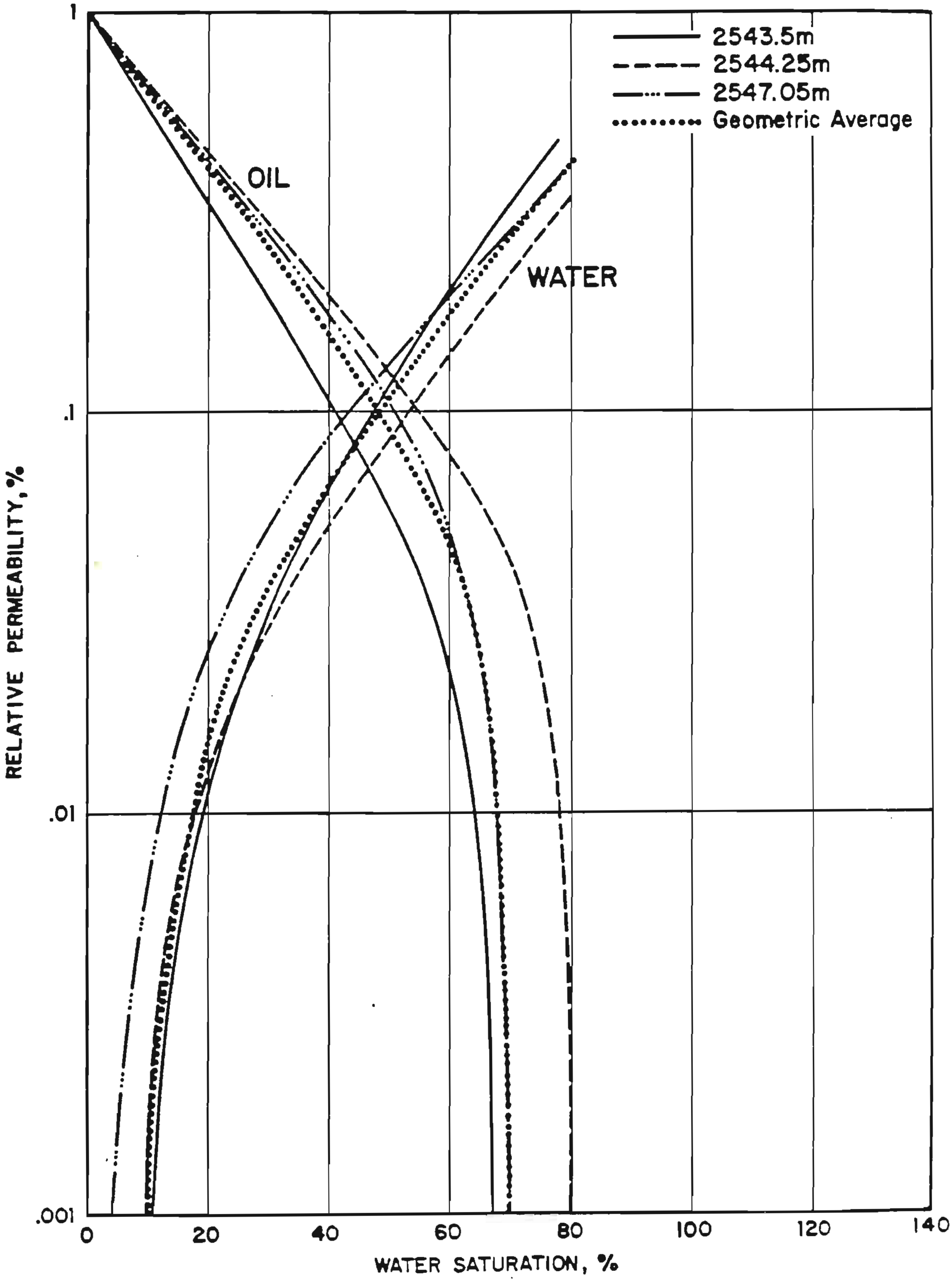
VALHALL FIELD

WATER-OIL RELATIVE PERMEABILITY - NORMALISED - TOR FORMATION
NATIVE STATE CORES

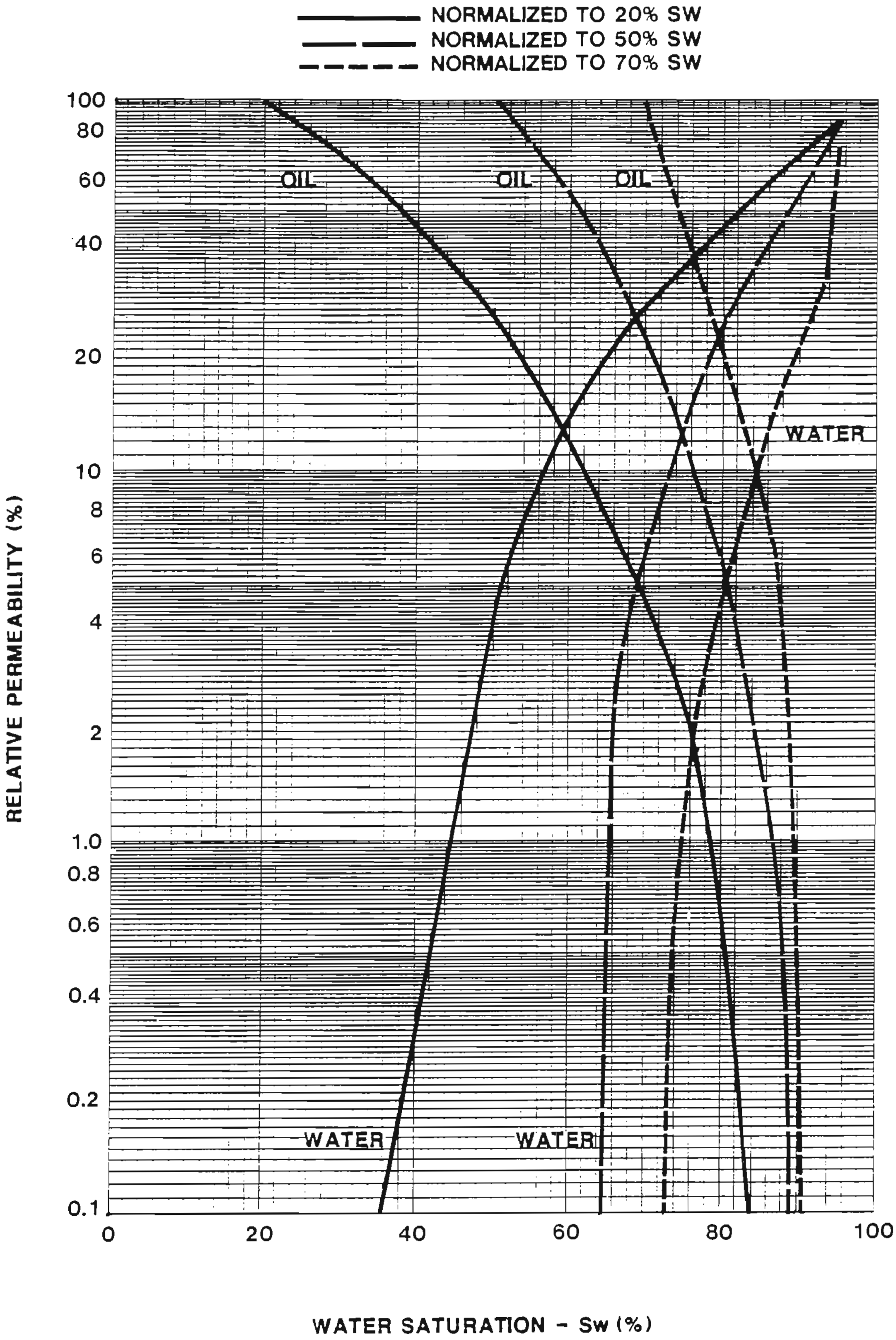


VALHALL FIELD

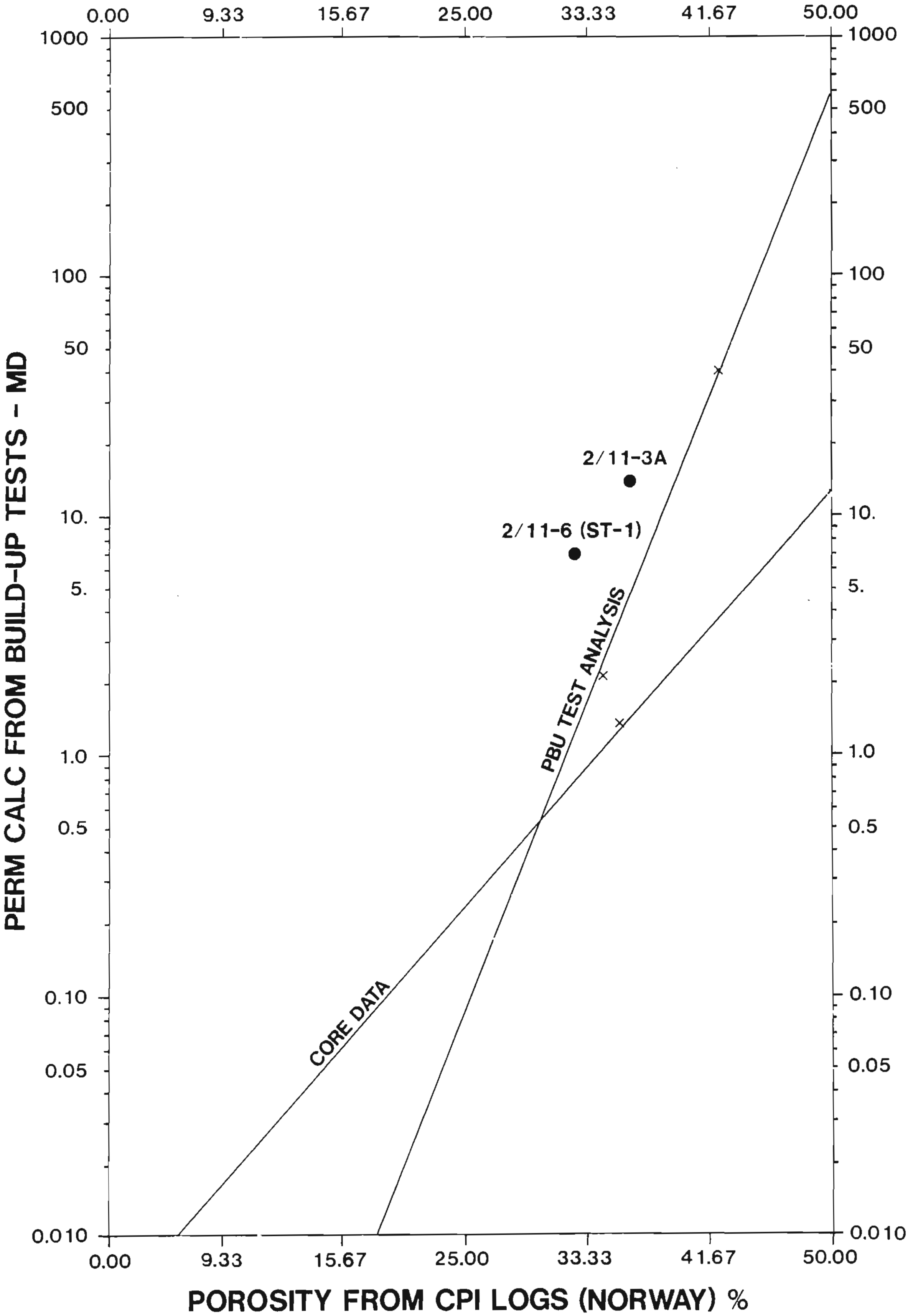
WATER-OIL RELATIVE PERMEABILITY
SAMPLES FROM WELL 2/8-A1 — HOD FORMATION
NATIVE STATE CORES



WATER OIL RELATIVE PERMEABILITIES USED IN MODEL



POROSITY VS PERMEABILITY RELATIONSHIP
VALHALL FIELD TOR FORMATION CORE AND PBU DATA
(SHOWING HOD FIELD DATA)



POROSITY VS PERMEABILITY RELATIONSHIP

VALHALL AND HOD FIELDS - UPPER HOD FORMATION

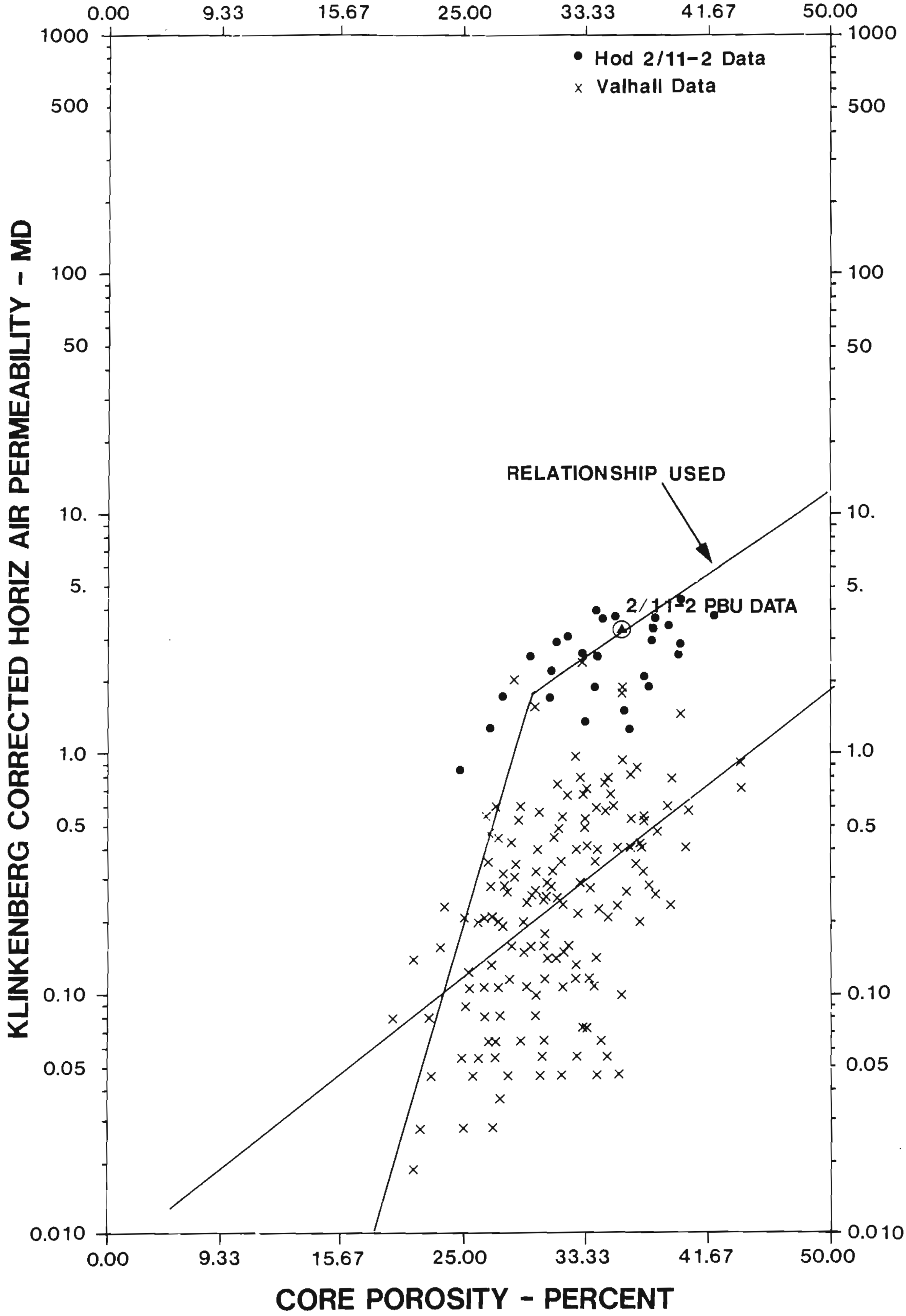
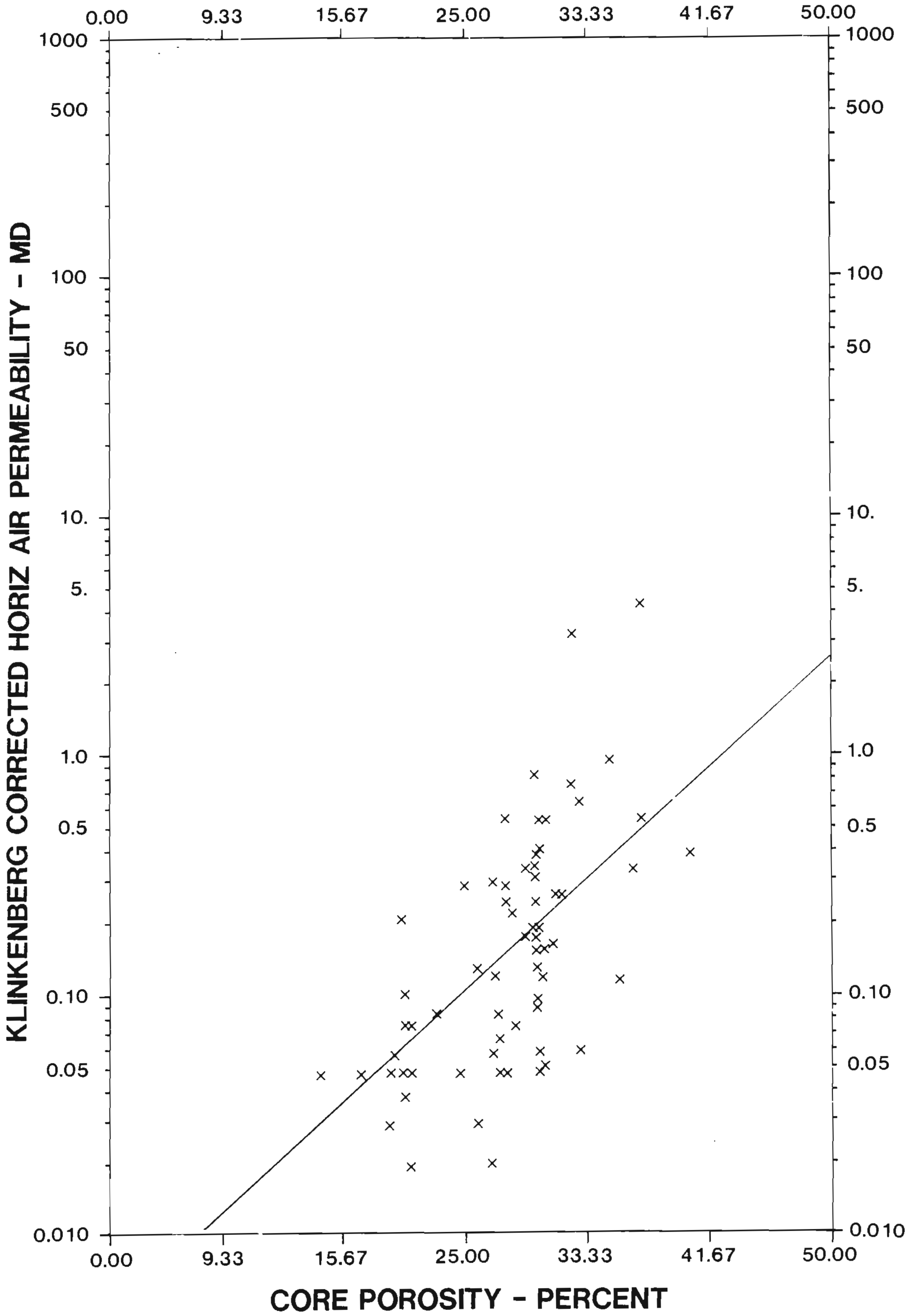


EXHIBIT 2.16

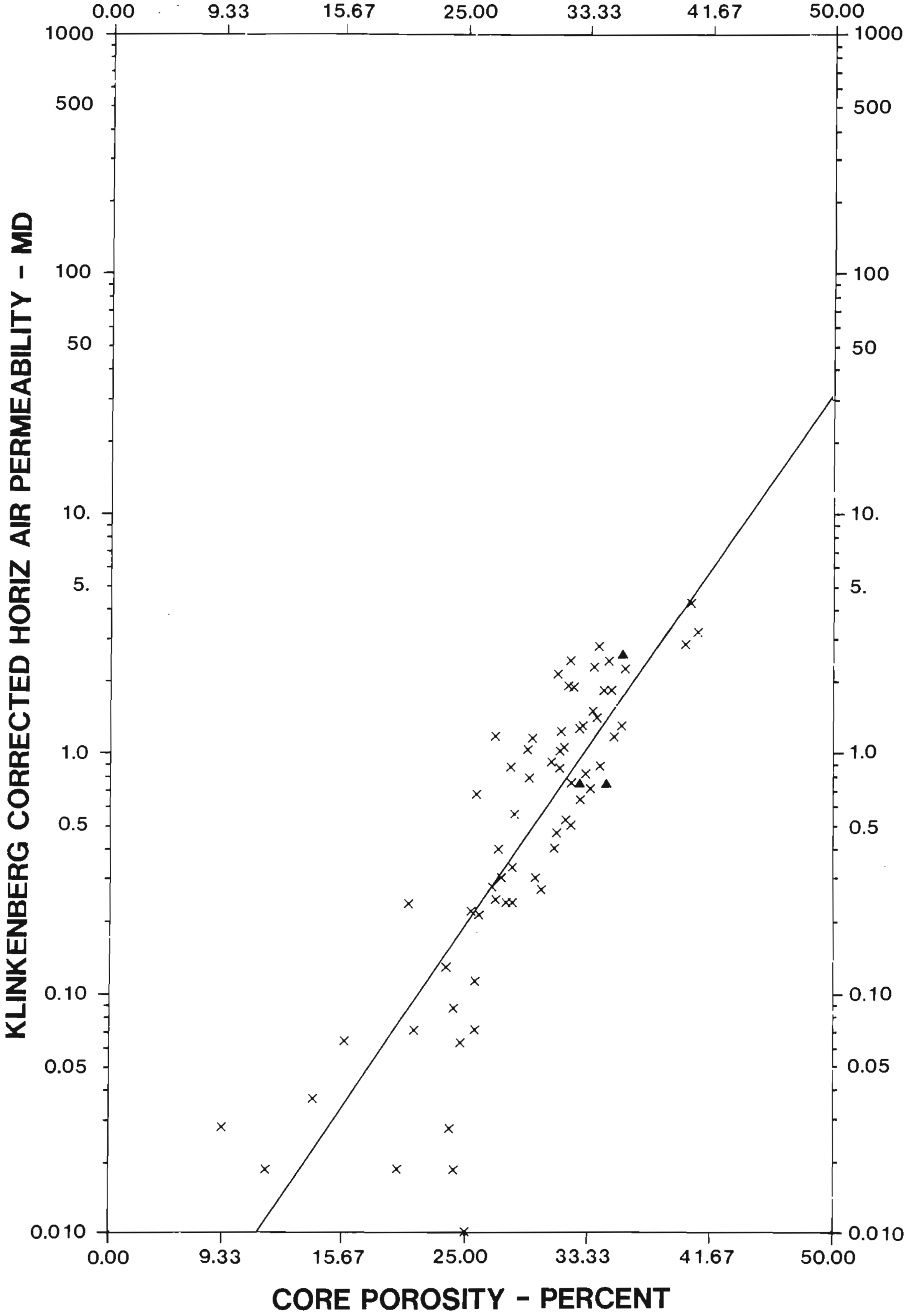
POROSITY VS PERMEABILITY RELATIONSHIP

VALHALL FIELD MIDDLE HOD FORMATION



POROSITY VS PERMEABILITY RELATIONSHIP

VALHALL FIELD LOWER HOD FORMATION



FLUID PROPERTIES - EAST HOD

	Tor Formation				U. Hod Formation		L. Hod Formation	
	2/11-6 (ST-1)		2/11-3A		2/11 -3A		2/11-6 (ST-1)	
DIFFERENTIAL VAPORIZATION AT RESERVOIR TEMP.								
Bubble Point Pressure (psig)	3323	3475	3912	3314	3842 -	4000	3455	3430
Oil Density (g/cc) at BPP	0.675	0.668	0.657	0.674	0.681 -	0.673	0.662	0.663
Oil Density (g/cc) at Pi	0.707	0.697	0.681	-	0.703 -	0.693	0.693	0.693
Oil Viscosity (cp) at BPP	0.36	0.35	0.55	0.427	0.61 -	0.62	0.32	0.31
Oil Viscosity (cp) at Pi	0.49	0.47	0.66	-	0.73 -	0.71	0.49	0.46
GOR (SCF/STB) at BPP	1021	1028	1131	927	970	1054	1017	1017
Oil Formation Volume Factor (RB/STB) at BPP	1.607	1.617	1.639	1.560	1.512	1.604	1.619	1.616
Oil Formation Volume Factor (RB/STB) at Pi	1.535	1.551	1.583	1.547	1.561	1.559	1.548	1.548
Oil Compressibility $(psi^{-1}) * 10^{-6}$	12.06	10.6	10.72	-	10.17	9.32	11.34	11.34
Gas Viscosity at BPP (cp)	-	0.0201	0.022	0.022	0.021	0.023	0.021	-
SEPARATOR TEST RESULTS								
GOR (SCF/STB)	836	876	-	820	-	-	861	865
Oil Formation Volume Factor (RB/STB) at Pi	1.402	1.435	-	1.36	-	-	1.439	1.438

Note: 1. BPP = Bubble Point Pressure
2. Pi = Initial Reservoir Pressure

FLUID PROPERTIES - WEST HOD

	Upper Hod Formation
	2/11-2
DIFFERENTIAL VAPORIZATION AT RESERVOIR	
Bubble Point Pressure (psig)	4648
Oil Density (g/cc) at BPP	0.642
Oil Density (g/cc) at Pi	0.661
Oil Viscosity (cp) at BPP	0.36
Oil Viscosity (cp) at Pi	0.41
GOR (SCF/STB) at BPP	1398
Oil Formation Volume Factor (RB/STB) at BPP	1.738
Oil Formation Volume Factor (RB/STB) at Pi	1.688
Oil Compressibility (psi^{-1})* 10^{-6}	15.3
Gas Viscosity at BPP (cp)	-
SEPARATOR TEST RESULTS	
GOR (SCF/STB)	1207
Oil Formation Volume Factor (RB/STB) at Pi	1.572