GEOLOGICAL SURVEY OF CANADA
COMMISSION GEOLOGIQUE DU CANADA

Open File 814

AN ANALYSIS OF HEAVY OIL SUPPLY - LLOYDMINSTER AREA, ALBERTA

M. Raicar and R.M. Procter

Geological Survey of Canada (Calgary)
3303 - 33 Street N.W.
Calgary, Alberta T2L 2A7

June 6, 1980

CONTENTS

LIST OF FIGURES

Page

LIST OF TABLES

SUMMARY

(1) An estimate of the heavy oil resources of the Lloydminster type in Alberta was prepared by McCrossan et al (1979) which indicated a total resource of approximately 25 billion barrels of heavy oil in-place with possible recoverable resources in the range of 2.5 to 3.5 billion barrels. This oil is contained in approximately 9000 segments of varying quality in more than 600 individual pools. This estimate should be considered an inventory of the total resource most of which will not be developed in the immediate future for a variety of reasons.

(2) In order to estimate the quantities of oil that may actually form a part of supply in the next 25 year period, a more pragmatic approach to the development of these resources was required. The present study has limited the future development to the most promising parts of the resource including only rich oil* saturation in beds greater than five feet thick with no appreciable underlying water or overlying gas. This part of the resource is estimated to contain approximately 10 billion barrels of oil in-place at the 50% probability level.

(3) Of the various tertiary processes available, wet-combustion was identified as the most appropriate method of enhanced recovery in the Lloydminster area. Optimum development using wet-combustion over the next 24 years could recover 1.5 billion barrels of oil at the 50% probability level. Corresponding production period for this recovery would be 35 years. Maximum recovery from the same resource by conventional means (primary plus waterflood) would be 700 million barrels in the same time period.

* Rich oil saturation is defined as oil saturation of equal to or more than 1500 barrels per acre foot.

(4) The maximum potential rate of production by wet-combustion is estimated to be 240 thousand barrels per day and could be achieved by the year 2000 whereas production by conventional means would reach approximately 115 thousand barrels per day by the year 1995.

(5) The development of these resources using wet-combustion would require an investment of approximately 8 billion 1980 Canadian dollars over the next 24 year period.

(6) Economic evaluations indicate that under the currently existing techno-economic conditions only deposits having more than 20 feet (6 meters) of net oil pay would marginally qualify for wet-combustion recovery processes.

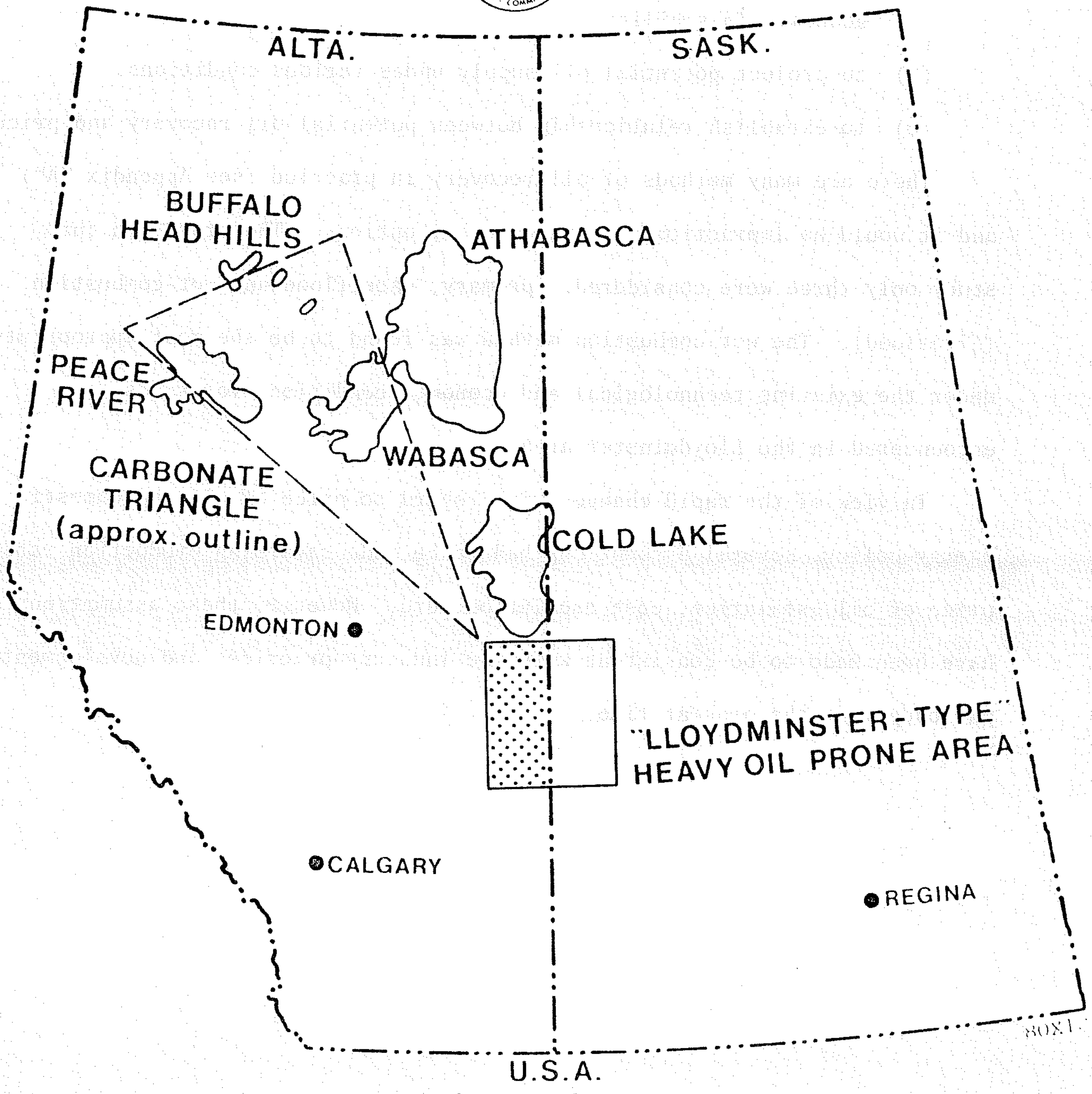
1. INTRODUCTION

The heavy oil deposits in the Lloydminster area have been known to exist for many decades (Fig. 1.1). However, the magnitude and extent of these resources have not been established with detailed studies. Various estimates put the in-place-oil between 10 to 40 x 10^9 bbls (1.6 - 6.4 x $10^9 m^3$) in the Alberta part and at least as much and probably greater on the Saskatchewan side (1,2). In 1978 the Geological Survey of Canada contracted MacCallum, Stewart and Associates Consulting Geologists Ltd.[1] to prepare a systematic geological study of this heavy oil resource in two stages. The first stage was to cover approximately 4300 square miles (11,000 sq. km) in Alberta between Rg. 1 through Rg. 8 and Twp. 39 through Twp. 56 (excluding the military reserves in Wainwright area) and in the second stage to cover the area in Saskatchewan. The Alberta component of this study was completed in late 1978 and the Saskatchewan part is due for completion by late 1981. The data obtained from the first report have been partially digitized and stored on an in-house computer file to facilitate access by various government agencies.

This file was used to generate an estimate of in-place and recoverable oil based on preliminary criteria for recovery techniques in June, 1979 [McCrossan et al. (2)]. This paper attempted to treat all the resources on the Alberta side and identified an average in-place estimate of approximately 25 x 10^9 bbls. The present study is an attempt to examine the possible supply and cost considerations of the high grade component of the same base, restricted to rich oil in beds with more than 5 feet net oil pay, with negligible or no bottom water, no gas cap and using a wet-combustion process.

---

[1] DSS-EMR Contract Numbers 08SB.23294-9-0771 and 22SQ.23294-8-0833



ALBERTA-SASKATCHEWAN AREA

SHOWING APPROXIMATE OUTLINE OF OIL SANDS AND HEAVY OIL DEPOSIT AREAS

INDEX MAP

Figure 1·1

The present report was prepared using the work by McCallum, Stewart and Associates as data base. The main objectives of this report are:

(a) to identify the appropriate recovery process and evaluate its economic feasibility.

(b) to project potential oil supply under various conditions.

(c) to establish relationship between potential oil recovery and price.

There are many methods of oil recovery in practice (see Appendix "A") and it would be impractical to evaluate all options. Therefore, in this study only three were considered: primary, waterflood and wet-combustion (fireflood). The wet-combustion method was found to be the most appropriate under the existing technological and economic conditions for sands as encountered in the Lloydminster area.

In view of the rapid changes with regard to price of oil and domestic energy-policy, several assumptions had to be made regarding production rate, price of oil escalation, cost escalation, etc. However, these assumptions have been made to be consistent with the industry practices and development philosophy at the present time.

2. GENERAL BACKGROUND

Although the heavy oil deposits in the Lloydminster area have been recognized for several decades as one of the largest petroleum reserves in the world, it has always been a major challenge to economically transform these vast resources into usable energy. During the early 1930's, repeated attempts toward serious exploitation were mostly unsuccessful primarily because economic viability was discouraging or at best marginal. Some of the main reasons were:

(a) the heavy oil was much more capital and manpower intensive than conventional light and medium gravity oils.

(b) the market for heavy oil was mostly local and seasonal and the oil had to be supplied by trucks or railroad.

(c) the production and treating facilities were relatively inefficient.

Confronted with these problems, large scale operations seemed to be unattractive. In addition, at that time, there was a widespread notion that the supply of easily accessible light oil would be unlimited for several decades to come, and as a result, the accelerated development of heavy oil resources was not required.

In the early 1960's the oils were diluted with lighter petroleum products obtained from gas plants and rendered transportable through pipelines thereby opening additional markets. The first pipeline connecting Lloydminster to the interprovincial system was constructed in 1963 carrying approximately 8000 bbls. per day (3). This was expanded to over 50,000 bbls. per day during the subsequent years. The new facility created renewed interest in the heavy oil industry and increased the pace of development which also resulted in the relocation of a refinery to process the oil locally.

The early production relied exclusively on primary depletion methods, yielding approximately 5 per cent of the oil-in-place. By any standard, this was only a small portion of the vast potential. Therefore, a method had to be devised to improve the recovery efficiency, and the application of a conventional waterflood method seemed to be a logical approach. In 1963, a pilot project was initiated in Lone Rock Pool to evaluate the feasibility of application of this technique for Lloydminster heavy oil. The results obtained were encouraging and consequently waterflood was tried on other pools in this area. By the end of the 1960's, most of these major pools were on waterflood. Available data to date indicates that by waterflood process the average recoverable portion of oil can be increased to approximately 8 to 10 per cent. Some more successful projects are expected to yield up to 12 to 15 per cent.

The early 1970's brought revolutionary changes throughout the oil industry. The price of oil increased manyfold in a short span of time, and contrary to previous beliefs, acute shortages of oil were anticipated within the foreseeable future. As a result, much attention was focused on hitherto unattractive tertiary recovery technology that could also increase the recovery potential of heavy oils in the Lloydminster area. Among the various methods considered, the application of thermal recovery processes, such as in-situ-combustion (fireflood), steamflood or steam-stimulation, seemed most attractive.

By thermal recovery methods, recovery factors approaching 50 per cent of the original oil-in-place can be realized. In some projects recoveries as high as 80 percent are anticipated (4). It should, however, be noted that many of the projects with poor successes have not been reported and therefore, an average recovery factor of 25 per cent of the original oil-in-place seems more realistic [the 25 per cent recovery factor corresponds to approximately 50 per cent average probability expectations (5)].

Thermal recovery techniques are, at current stage of development, far from satisfactory and major problems still remain to be solved. However, continued research indicates that new recovery methods will be developed and the available technology can be improved. Implicit in these expectations, of course, are the existence of favourable economic conditions.

Thermal recovery projects can contribute significantly to Canadian energy needs. However, the extent to which these projects become reality are highly dependent on a favourable economic climate which will also encourage additional research and improvement in technology. It is, therefore, imperative to examine the large scale development of Lloydminster heavy oil in light of reasonable economic benefits to the prospective developers. In Chapters 3, 4 and 5 some of the aspects related to this evaluation are discussed. The economic considerations and their impact on supply is discussed in Chapters 6 and 7.

3. GEOLOGY

Heavy oils in Lloydminster area are found mainly in the upper part of the Mannville Formation of Lower Cretaceous age. The reservoirs consist of fine to very-fine grained, well-sorted and essentially unconsolidated sandstone. Porosity reaches 35 to 36 per cent (6) and averages approximately 30 per cent. The average initial water saturation in productive zones is approximately 15 per cent. The reservoir is encountered at an average depth of about 2000 feet (610 m). The hydrocarbons are contained in stratigraphic traps, the maximum closure of which is 40 to 50 feet (12 to 15 m).

MacCallum, Stewart and Associates conducted a detailed study of this area (7). Some of the important findings of this study are given below.

In their study 19 separate zones were identified with several hundred individual pools with considerable overlaps. In addition, a complex network of relatively thin, shoestring-like deposits called channel-sands were detected (Fig. 3.1). These channel-sands generally surround the main pools and frequently cut through one or more zones. A typical log showing most of these deposits is shown in Figure 3.2.

For the purpose of evaluation, all these deposits were divided into two main categories called rich oil pools and lean oil pools[1]. Each of these pools was further classified into various segments according to following criteria:

(a) Oil saturation

(b) Net oil-pay-thickness

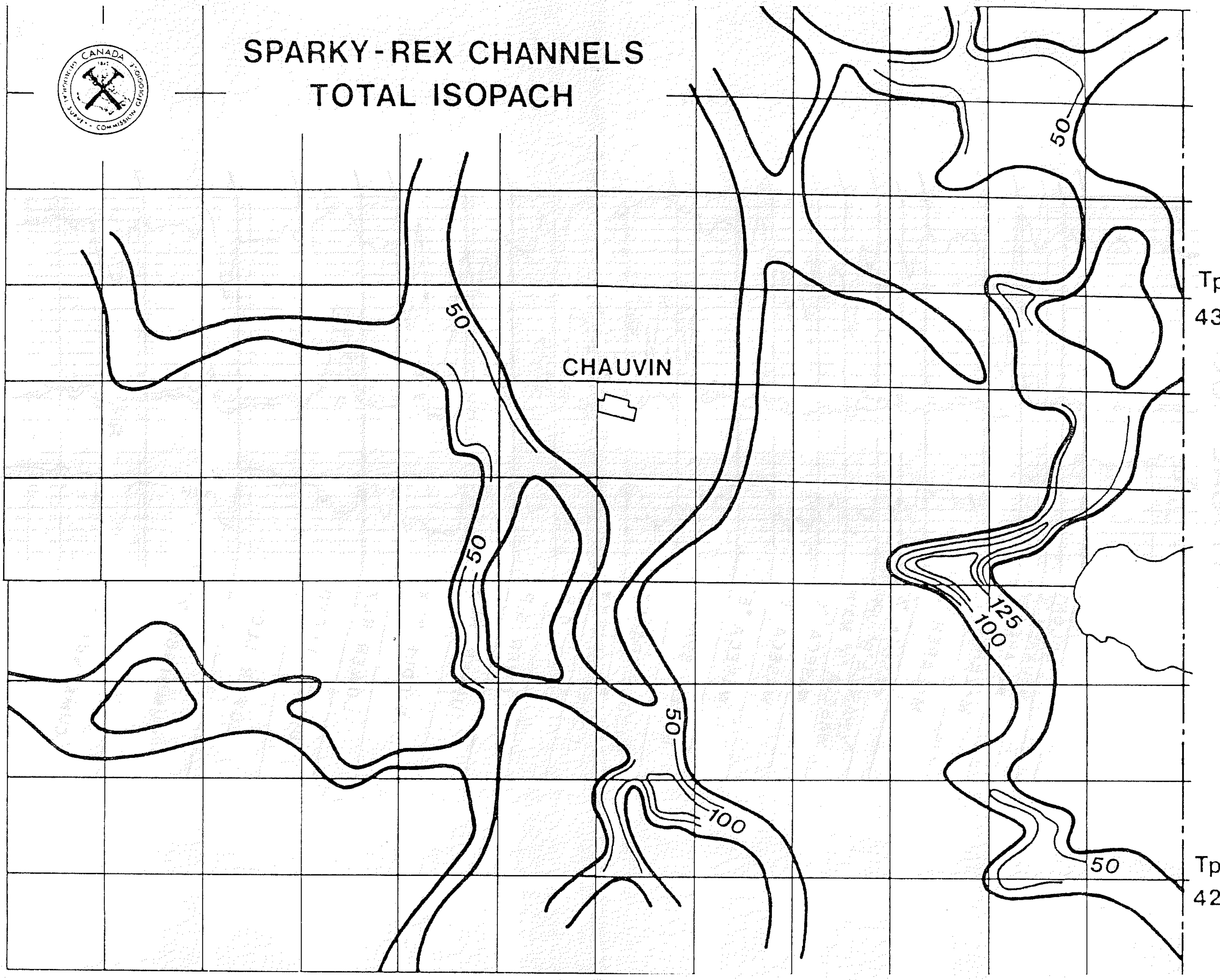
(c) Extent of bottom-water

(d) Extent of gas cap

(e) Size of the segment

---

[1]Lean oil is defined as oil saturation between 1250-1500 barrels per acre-foot.


SPARKY - REX CHANNELS
TOTAL ISOPACH
CHAUVIN
50
50
50
50
50
125
100
100
50
Tp
43
Tp
42

TYPICAL LOG

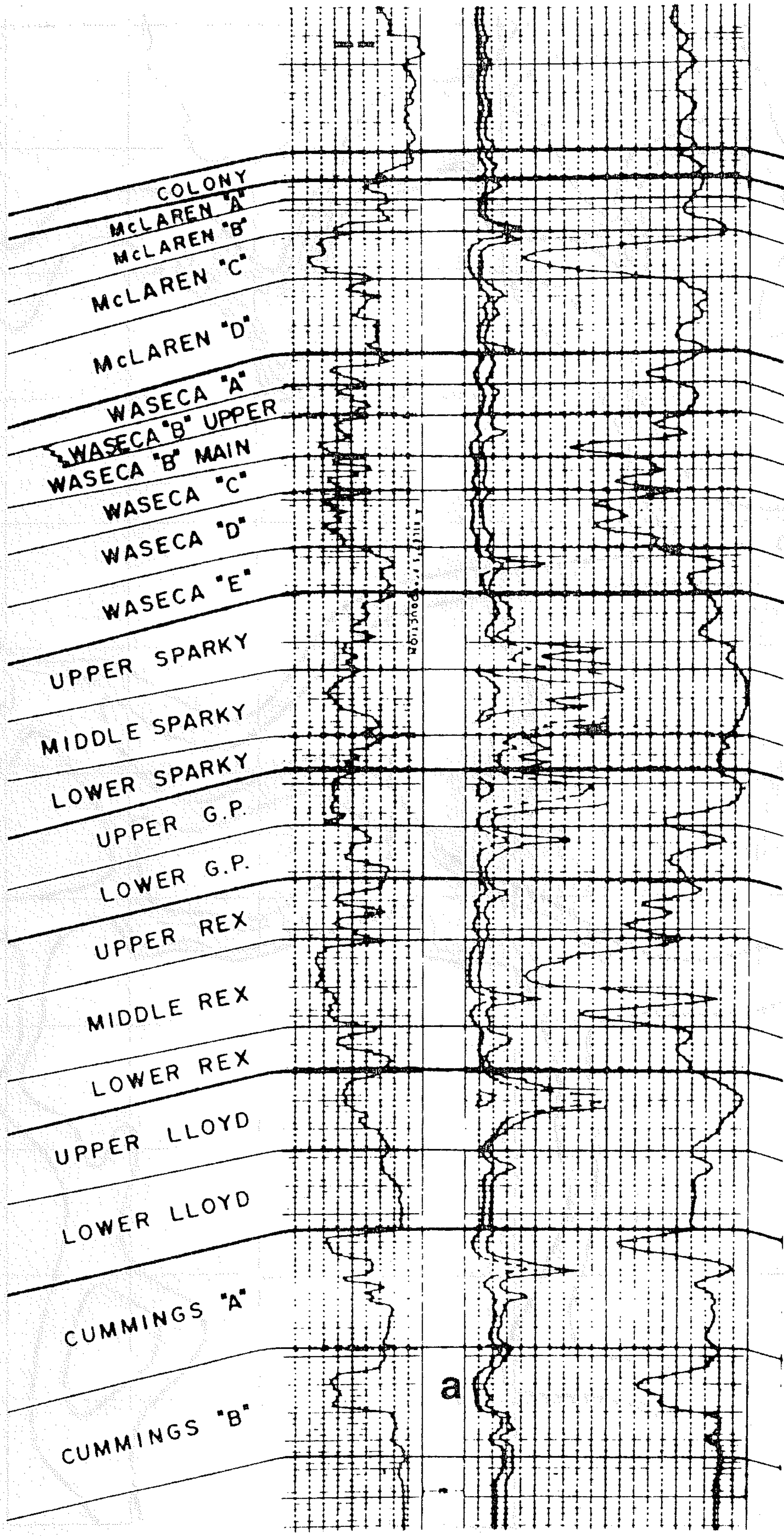
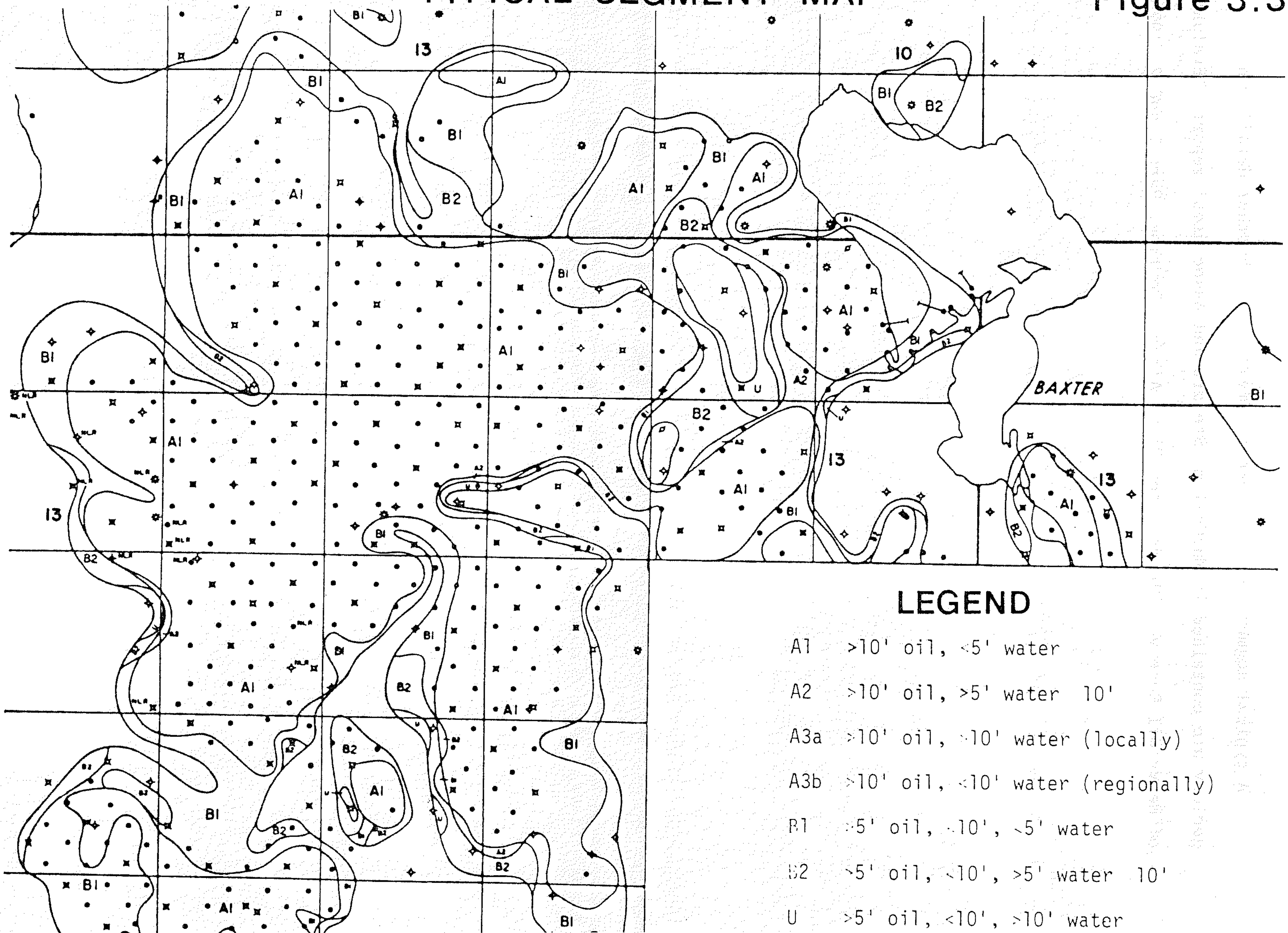


Figure 3.2

A typical segment map is shown in Figure 3.3. Further details on geology are contained in MacCallum, Stewart and Associates' report, "Evaluation of Heavy Oil Reserves Lloydminster Play, Alberta Portion, Part 1 and 2, 1978".

TYPICAL SEGMENT MAP

Figure 3.3



4. RESERVOIR AND FLUID PROPERTIES

4.1 General

In any reservoir engineering study, the minimum prerequisite for evaluation is adequate knowledge of oil and reservoir properties. In this study the task was slightly different in that it did not deal with a single reservoir with well-defined properties, but rather with several hundred pools having varied characteristics. To evaluate each of these reservoirs individually was almost impossible and to circumvent these difficulties statistical analysis based on data from the study by MacCallum, Stewart and Associates was used. Some of the more important properties utilized in this evaluation are given below.

4.2 Reservoir and Fluid Properties

4.2.1 Net Pay Thickness: The net oil-pay-thickness on the Alberta side of the Lloydminster field varies between 0 to 35 feet (0-11 m) with most frequent value between 5 to 10 feet (1.5-3 m). The net oil pay distribution of rich oil segments is shown in Figure 4.1. The in-place-oil contained in these segments is shown in Figure 4.2. As may be seen, only a small portion (7.5%) of the total area underlain by oil sands has over 20 feet (6 m) net oil-pay thickness and the major portion falls within 5 to 10 feet (1.5-3 m) range. This is particularly important, because economic evaluation indicates that under the currently existing techno-economic conditions only greater than 20 feet (6 m) thick net-pay-segments qualify even marginally for tertiary recovery schemes.

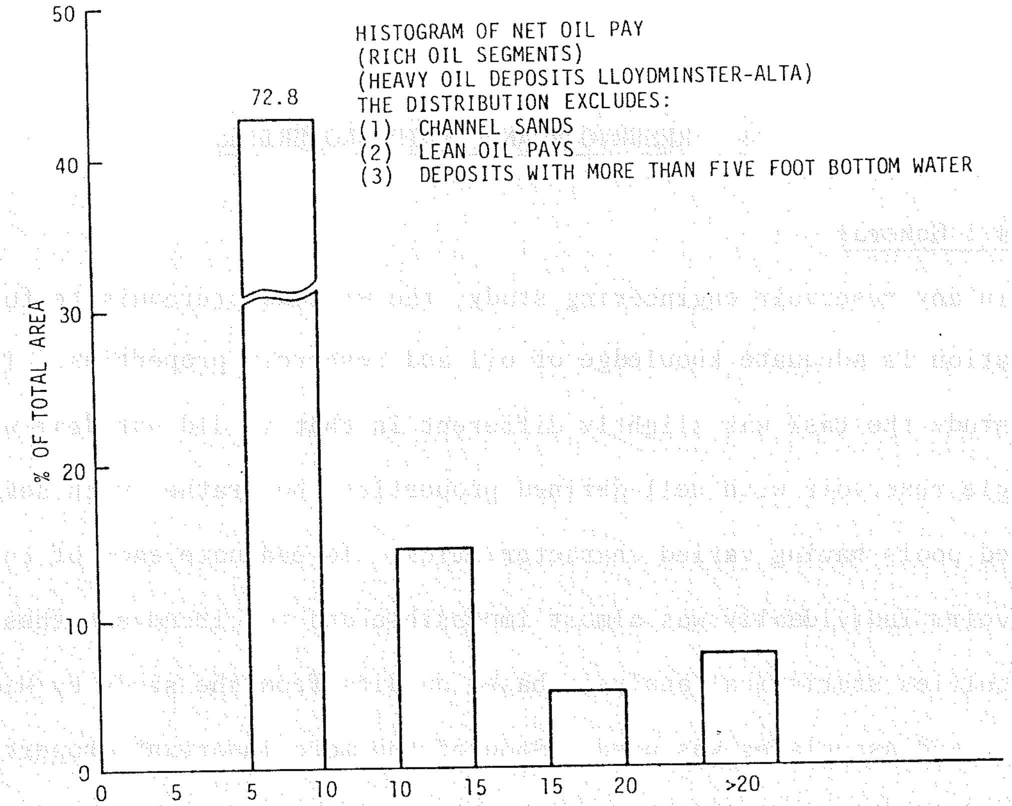


FIGURE 4.1

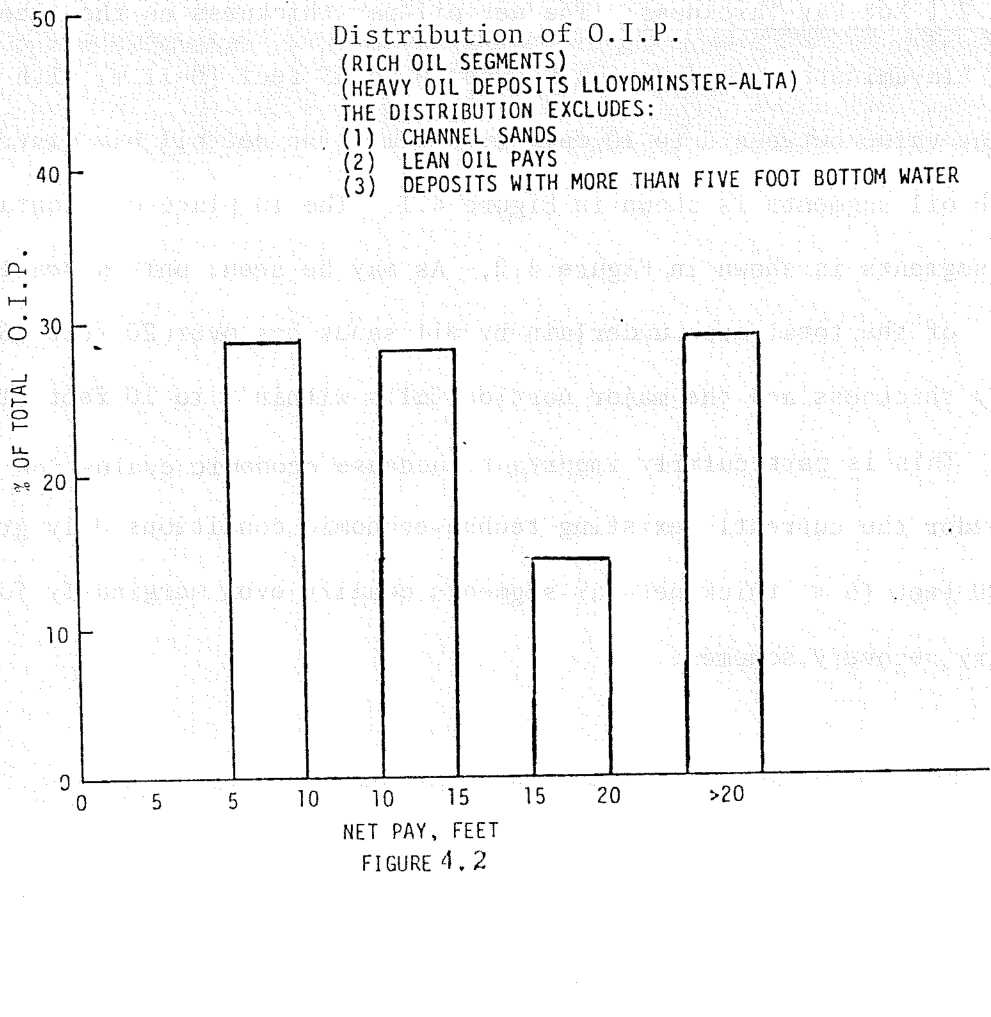


FIGURE 4.2

4.2.2 Gravity of Oil: The gravity of oil in Lloydminster area varies between 10° and 26° API with most frequent gravities as between 15° and 17° API (8). The distribution of gravities is illustrated in Figure 4.3.

Gravity of oil in itself does not play a significant role in thermal recovery processes. However, there is a definite relationship established between gravity and fuel deposit (9) which is of major importance in the design and implementation of in-situ-combustion processes (Appendix "A). The relationship between gravity and fuel deposit is shown graphically in Figure 4.4.

4.2.3 Viscosity: As is well known, viscosity of oil has substantial effect on oil recovery especially in primary and waterflood processes. It is also closely related to gravity. Figure 4.5 and 4.6 show the relationship between gravity and viscosity for oils in the Lloydminster area (10). Figure 4.5 shows viscosities measured on gas-free samples obtained from all the Lloydminster area, whereas those shown in Figure 4.6 were obtained from samples from Wildmere Pool under original reservoir conditions (11). As may be seen the viscosities of gas-free samples are considerably higher than those of comparable oils under reservoir conditions. The main reasons for these higher viscosities is the reduction in dissolved gas, a phenomenom that takes place during primary depletion. Increase in viscosity is highly detrimental to recovery and has to be avoided whenever possible. Therefore, it is advisable to implement secondary or tertiary recovery schemes at the early stages of depletion to keep the viscosity at an acceptable level.

The viscosity of oil is also highly temperature dependent, a property which is more pronounced in heavy oils. Raising the temperature of oil as

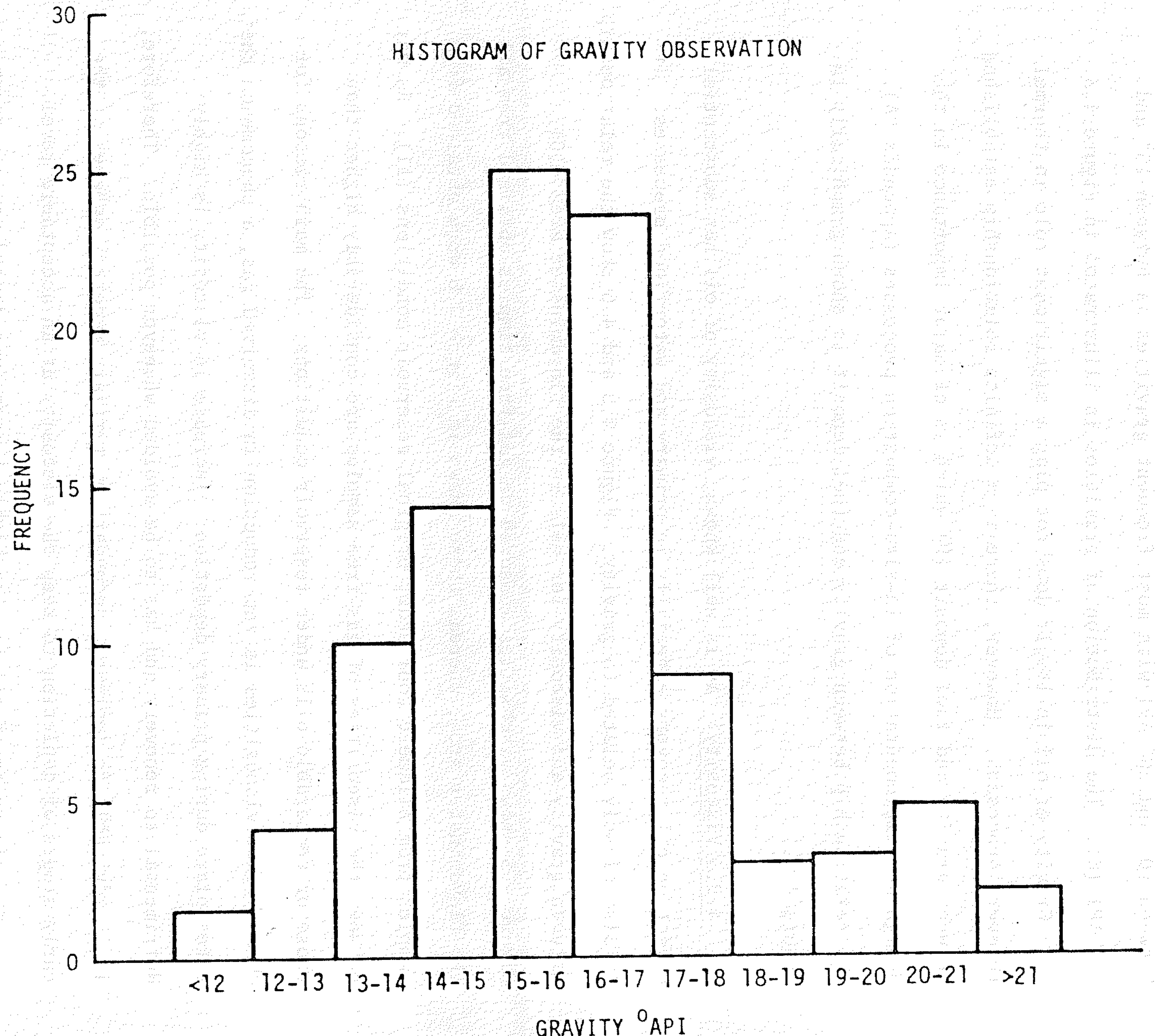

HISTOGRAM OF GRAVITY OBSERVATION
FREQUENCY
30
25
20
15
10
5
0
<12
12-13
13-14
14-15
15-16
16-17
17-18
18-19
19-20
20-21
>21
GRAVITY ^{o}API

FIGURE 4.3

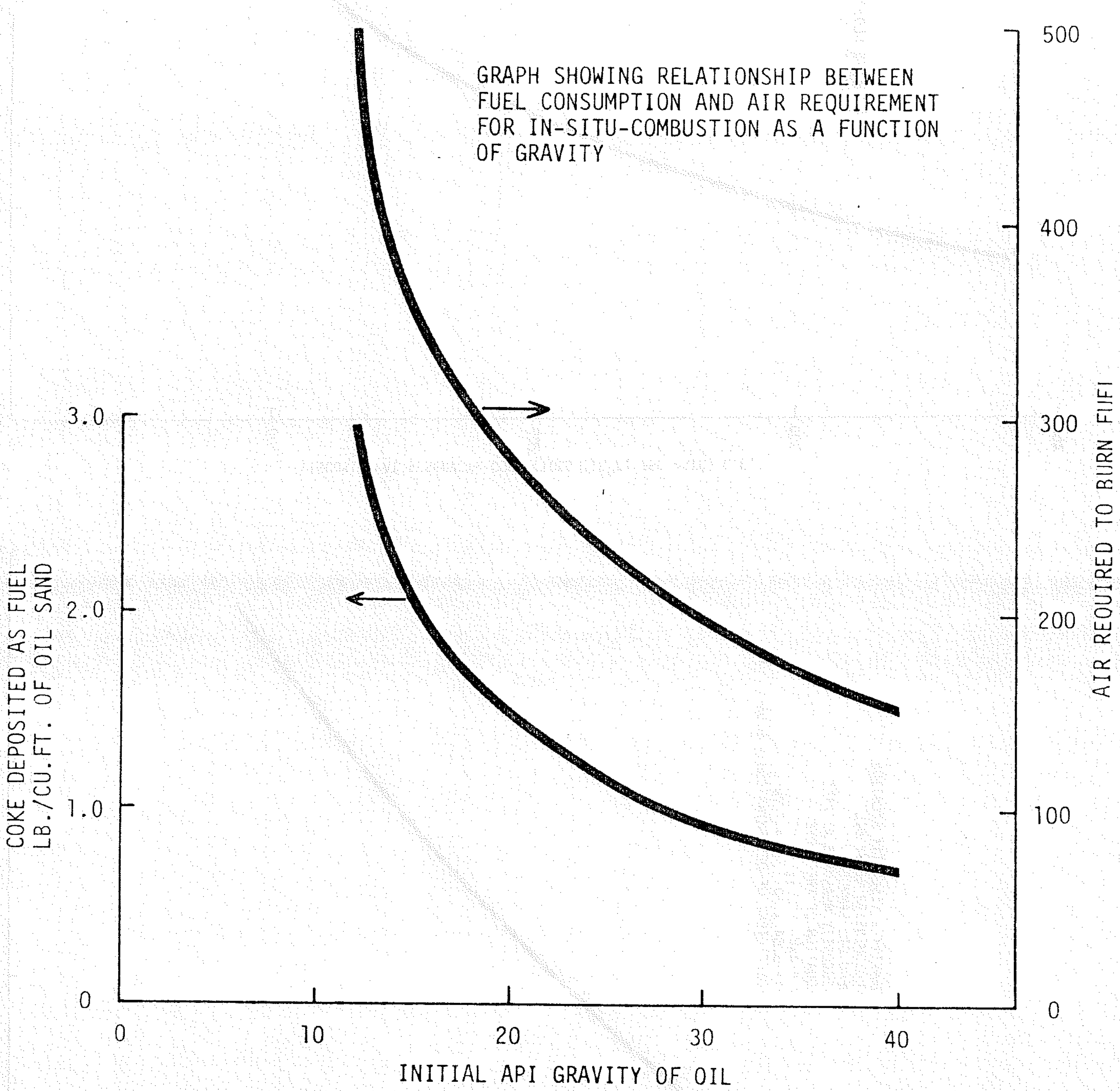
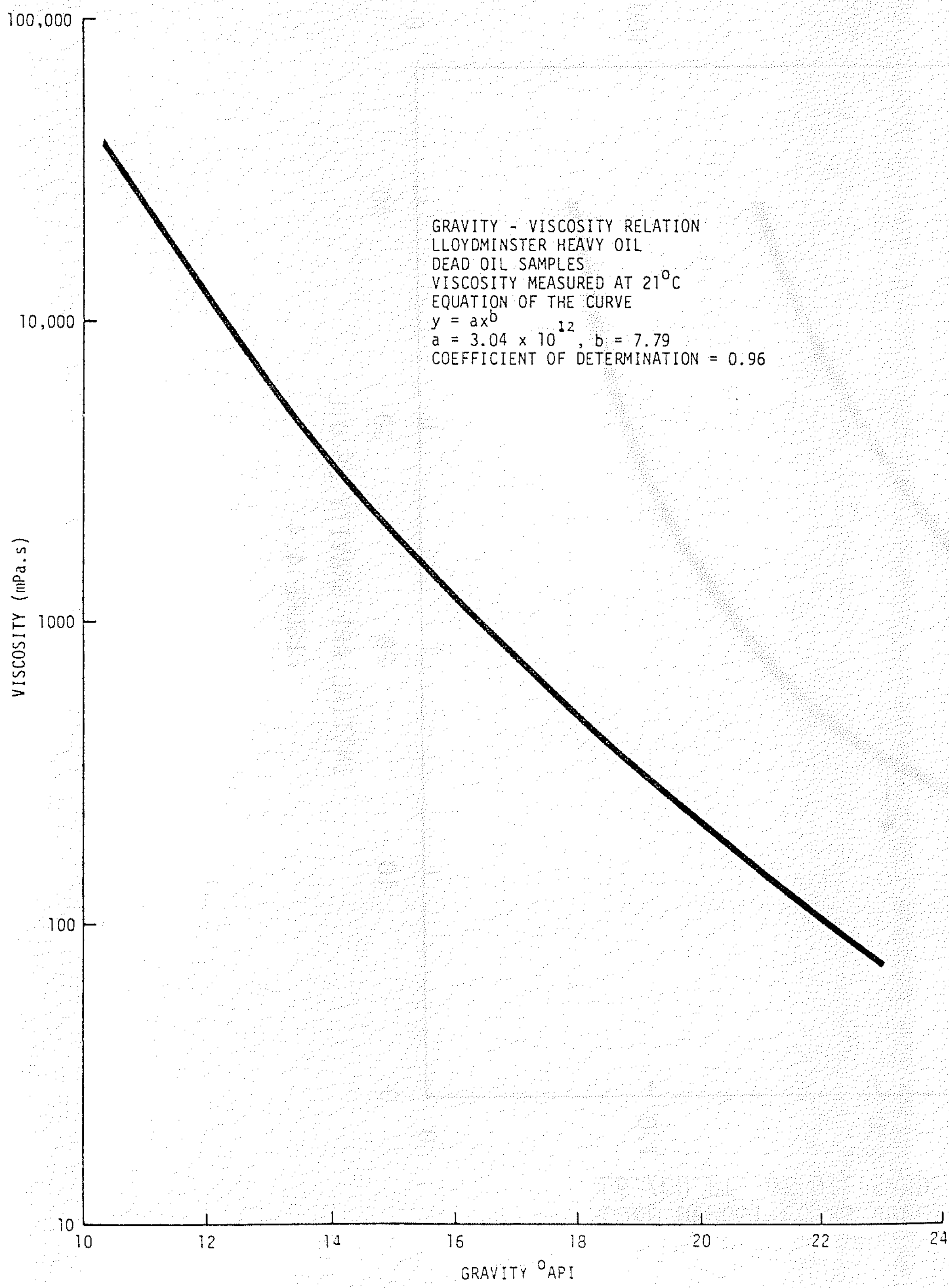
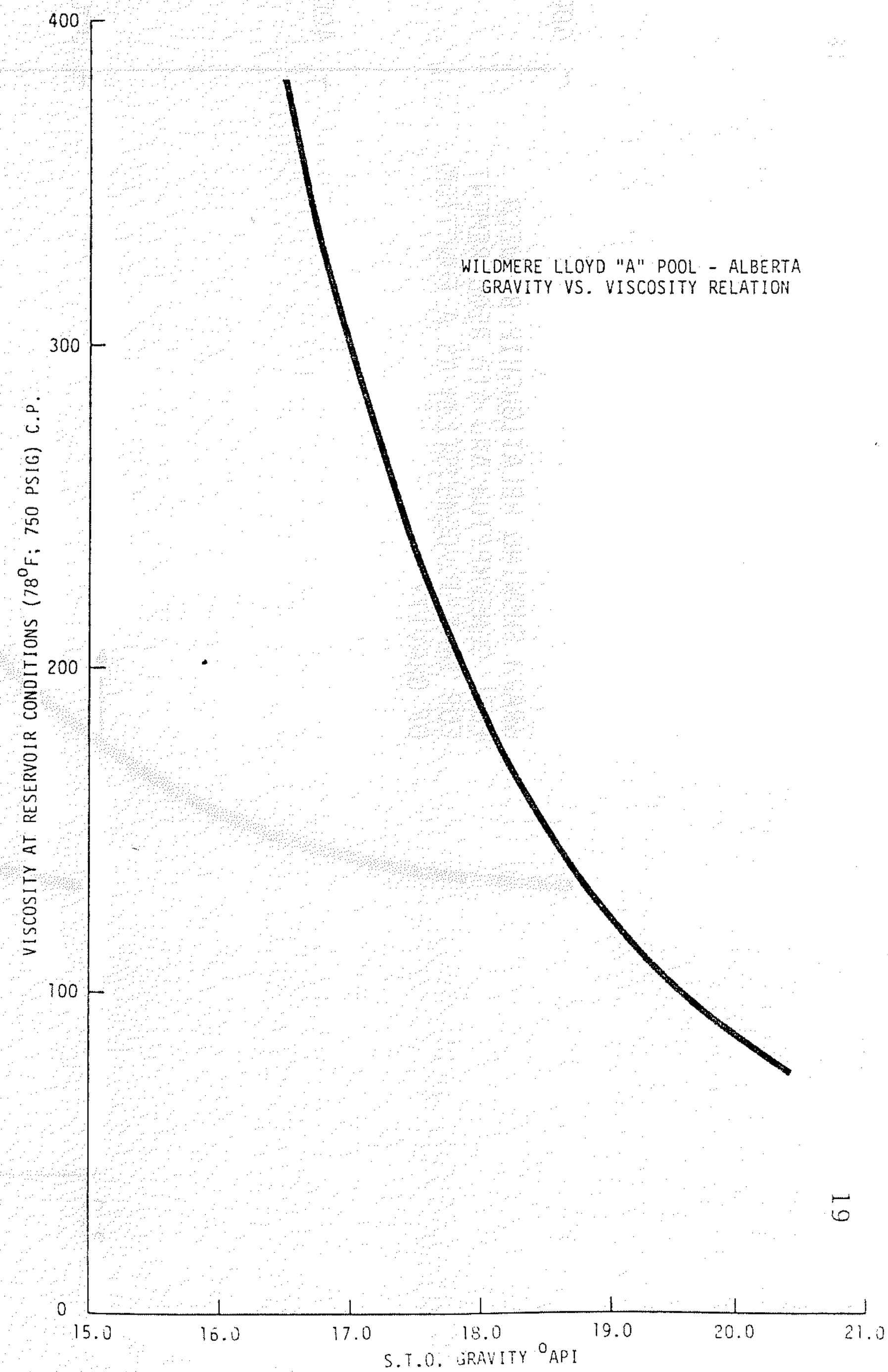

GRAPH SHOWING RELATIONSHIP BETWEEN FUEL CONSUMPTION AND AIR REQUIREMENT FOR IN-SITU-COMBUSTION AS A FUNCTION OF GRAVITY
COKE DEPOSITED AS FUEL LB./CU.FT. OF OIL SAND
AIR REQUIRED TO BURN FUEL
0
1.0
2.0
3.0
0
100
200
300
400
500
0
10
20
30
40
INITIAL API GRAVITY OF OIL

FIGURE 4.4


GRAVITY - VISCOSITY RELATION
LLOYDMINSTER HEAVY OIL
DEAD OIL SAMPLES
VISCOSITY MEASURED AT 21°C
EQUATION OF THE CURVE
y = ax^b
a = 3.04 x 10^12 , b = 7.79
COEFFICIENT OF DETERMINATION = 0.96
VISCOSITY (mPa.s)
100,000
10,000
1000
100
10
10
12
14
16
18
20
22
24
GRAVITY °API


WILDMERE LLOYD "A" POOL - ALBERTA
GRAVITY VS. VISCOSITY RELATION
VISCOSITY AT RESERVOIR CONDITIONS (78°F; 750 PSIG) C.P.
400
300
200
100
0
15.0
16.0
17.0
18.0
19.0
20.0
21.0
S.T.O. GRAVITY °API

in thermal recovery process reduces its viscosity and facilitates fluid flow. Therefore, adequate knowledge of viscosity-temperature relations is essential for evaluating the process properly (12). Figure 4.7 illustrates the viscosities of various oils in Canada including Lloydminster oil at various temperatures . As may be seen, the viscosities of heavier oils decrease more rapidly with the increase in temperature suggesting that recovery methods involving increase in temperature are more advantageous than other tertiary recovery methods for exploitation of heavy oils.

4.2.4 Others: The average values of other pertinent parameters used in the evaluation are given below:

(a)	initial reservoir pressure	500 PSI (3500 KPa)
(b)	permeability	350 md (350 μm^2)
(c)	porosity	30 per cent
(d)	initial water saturation	15 per cent
(e)	oil formation volume factor	1.018 B/STB
(f)	reservoir depth	2000 feet (610 m)

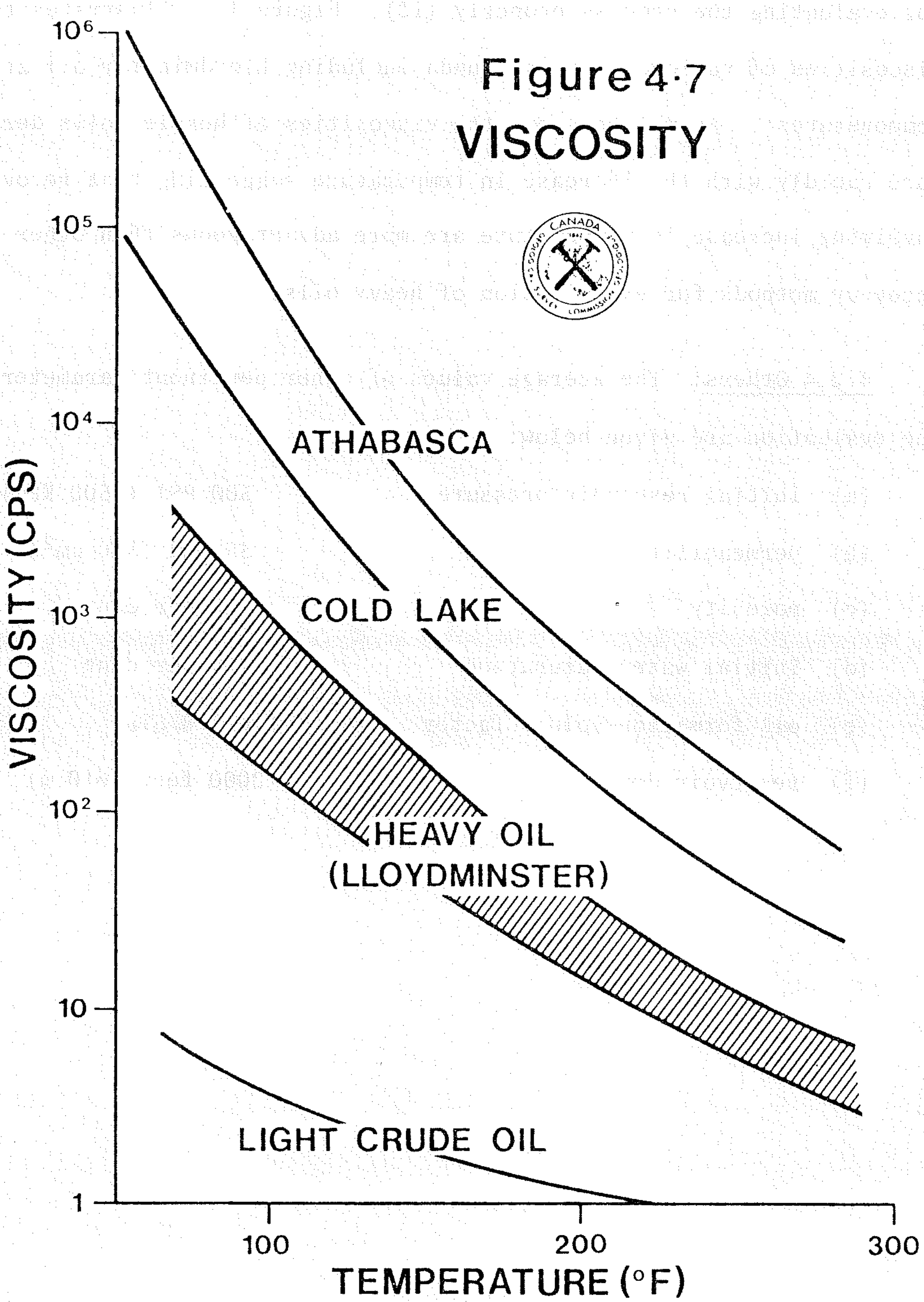


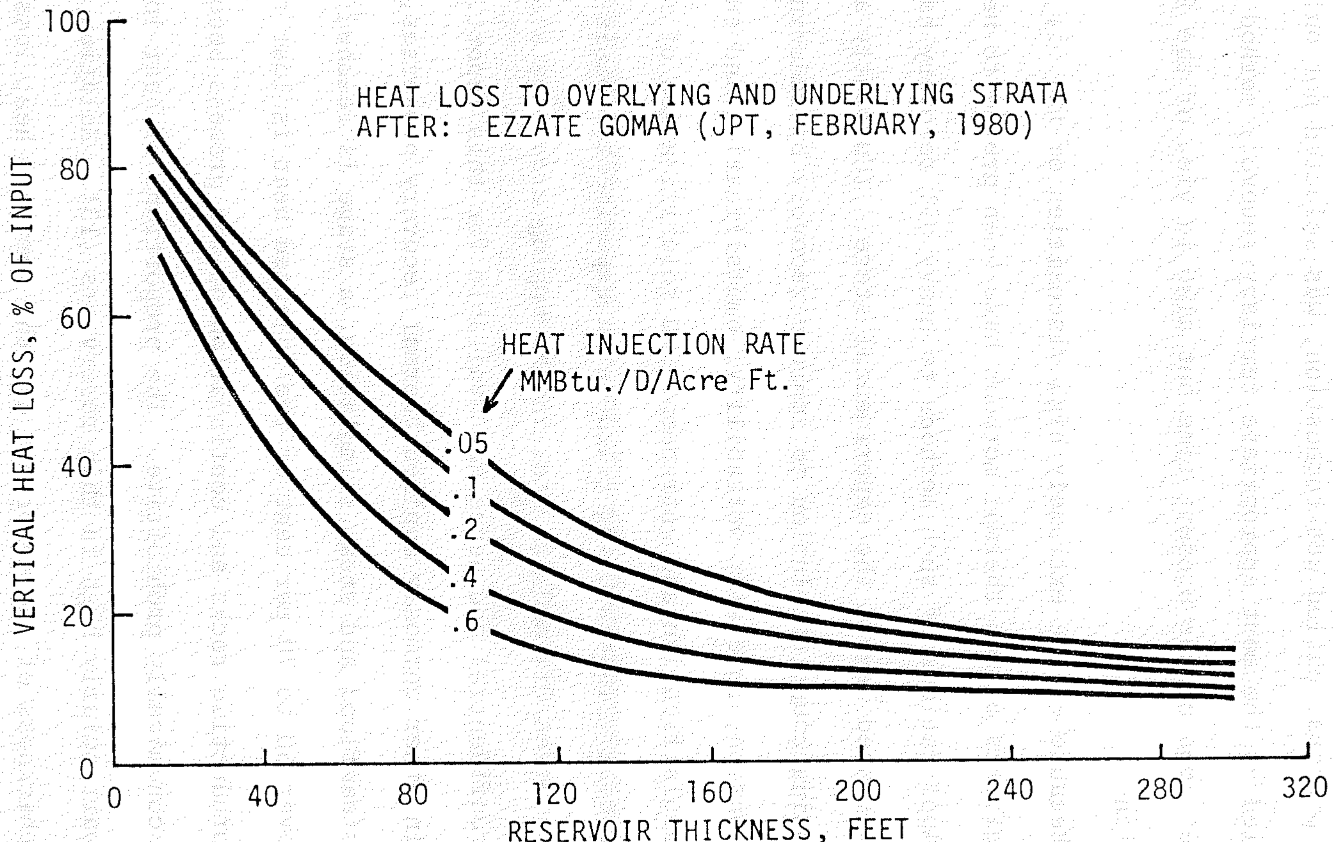
Figure 4·7
VISCOSITY
ATHABASCA
COLD LAKE
HEAVY OIL
(LLOYDMINSTER)
LIGHT CRUDE OIL
VISCOSITY (CPS)
TEMPERATURE (°F)
10⁶
10⁵
10⁴
10³
10²
10
1
100
200
300

5. SELECTION OF THE RECOVERY METHOD

For the purpose of this evaluation, a modification of the in-situ-combustion process, called wet-combustion, was selected not only because it is identified as the most appropriate tertiary recovery method in the Lloydminster area at the present time but also in view of the following considerations:

(a) Because of the extremely high viscosities of the oil, the beneficial effects of non-thermal methods have been proved to be marginal. Applications of such methods to heavy oil recovery have not yet advanced beyond the experimental stage. (Currently a process using caustic solution to improve recovery by reducing interfacial tension, reversing wettability, emulsification and entrainment, emulsification and entrapment and solubilization of rigid interfacial films is being tried on an experimental basis by Canadian Reserves Oil and Gas Ltd. in the Epping area. Data obtained are confidential and hence not available for this report.)

(b) In other commonly applied thermal recovery processes, such as steamflood and steam stimulation, a stage is reached beyond which over 60 to 70 per cent of the injected heat is lost to non-productive rocks and continuation of the process becomes economically prohibitive. The proportions of heat lost are particularly high in thin reservoirs (13). Relation between the thickness of the reservoir and the vertical heat loss is shown in Figure 5.1 (E. Gomaa, 1980).



HEAT LOSS TO OVERLYING AND UNDERLYING STRATA
AFTER: EZZATE GOMAA (JPT, FEBRUARY, 1980)
HEAT INJECTION RATE
MMBtu./D/Acre Ft.
.05
.1
.2
.4
.6
VERTICAL HEAT LOSS, % OF INPUT
0
20
40
60
80
100
0
40
80
120
160
200
240
280
320
RESERVOIR THICKNESS, FEET

FIGURE 5.1

6. ECONOMIC EVALUATION

6.1 General

For the purpose of economic evaluation a computer program owned by PSI Energy Software (POGO) was used. Some of the important elements of this evaluation are given below.

6.2 Physical Limitations to Development

Field development and an operation of the magnitude we are confronted with deserves special attention regarding physical limitations. The most important of these limitations include:

(a) availability of drilling equipment,

(b) availability of trained field personnel,

(c) availability of technical personnel,

(d) availability of other hardware required to put projects on stream,

(e) financing,

(f) other miscellaneous limitations, such as legal, access to site, ecology, etc.

As may be seen, there are various factors that can hamper the development process substantially. It would be very laborious, if not impossible, to evaluate the effect of each of these factors on development individually and express them as simple and useful functions. To simplify the procedure, drilling activity, the parameter which reflects most of the essential elements of the above limitations, was used. Extrapolation of heavy oil drilling during the last few years is felt to be the best indicator for future drilling activity. Figure 6.1 shows the drilling from 1950 to 1978 in Lloydminster. It can be reasonably assumed that during the last 4 to 5 years the drilling capacity in this area was almost fully utilized and the same trend is assumed to continue during the next few years. Figure 6.1 shows three drilling trends, i.e. high case, medium case and low case, which in turn correspond to approximately 10 per cent, 7.5 per cent and 5 per cent annual increase respectively in drilling activity in the 1980's and 1990's. For the purpose of evaluation any of these trends could be used. However, only one drilling scenario representing the high case is used in this report, and other options will be evaluated in future for additional flexibility.

Historically, the drilling activity in the Lloydminster area has frequently shifted across the border between Alberta and Saskatchewan depending upon the financial incentives offered. It would, therefore, be difficult to estimate reliably the future activity on each side of the border. For the purpose of this evaluation it is assumed that approximately 40 per cent of the drilling would be on the Alberta side (the proportion of in-place resources on the Alberta side is roughly estimated to be 40 per cent). It is also assumed that all the newly drilled wells would be successful except in exploration cases where success ratio is assumed to be 70 per cent. These assumptions are based on currently available statistics.

6.3 Development Allocation to Various Groups

In the development schedule it is assumed that the drilling spacing unit for the purpose of primary and waterflood schemes would be 40 acres and that for wet-combustion, 10 acres. The wells allocated to Alberta in the various net pay classifications are shown in Table 6.1. There are several ways in which the total drilling efforts could be expected to be assigned to different parts of the

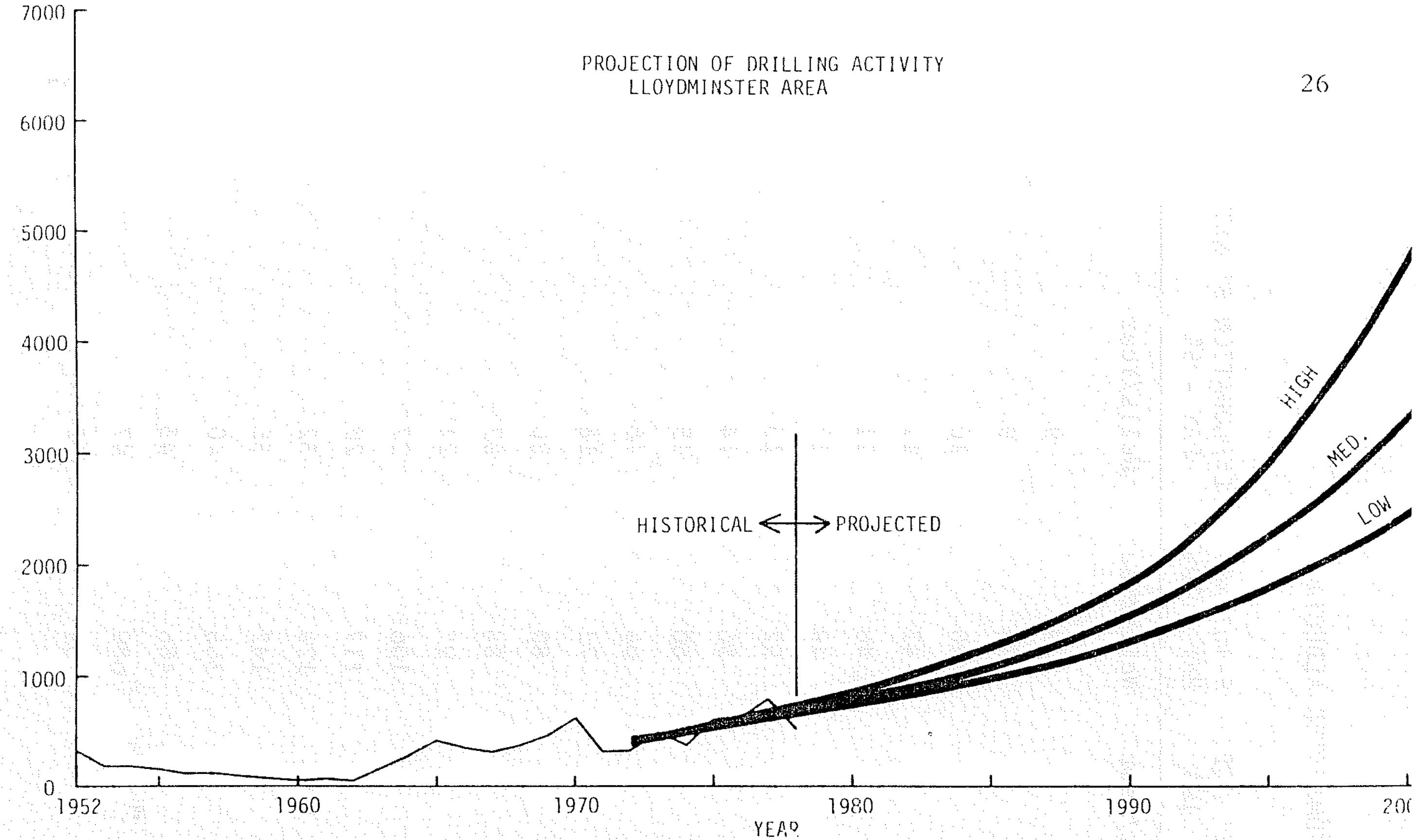


FIGURE 6.1

SCHEMATIC OF A FIREFLOOD PROJECT DEVELOPMENT

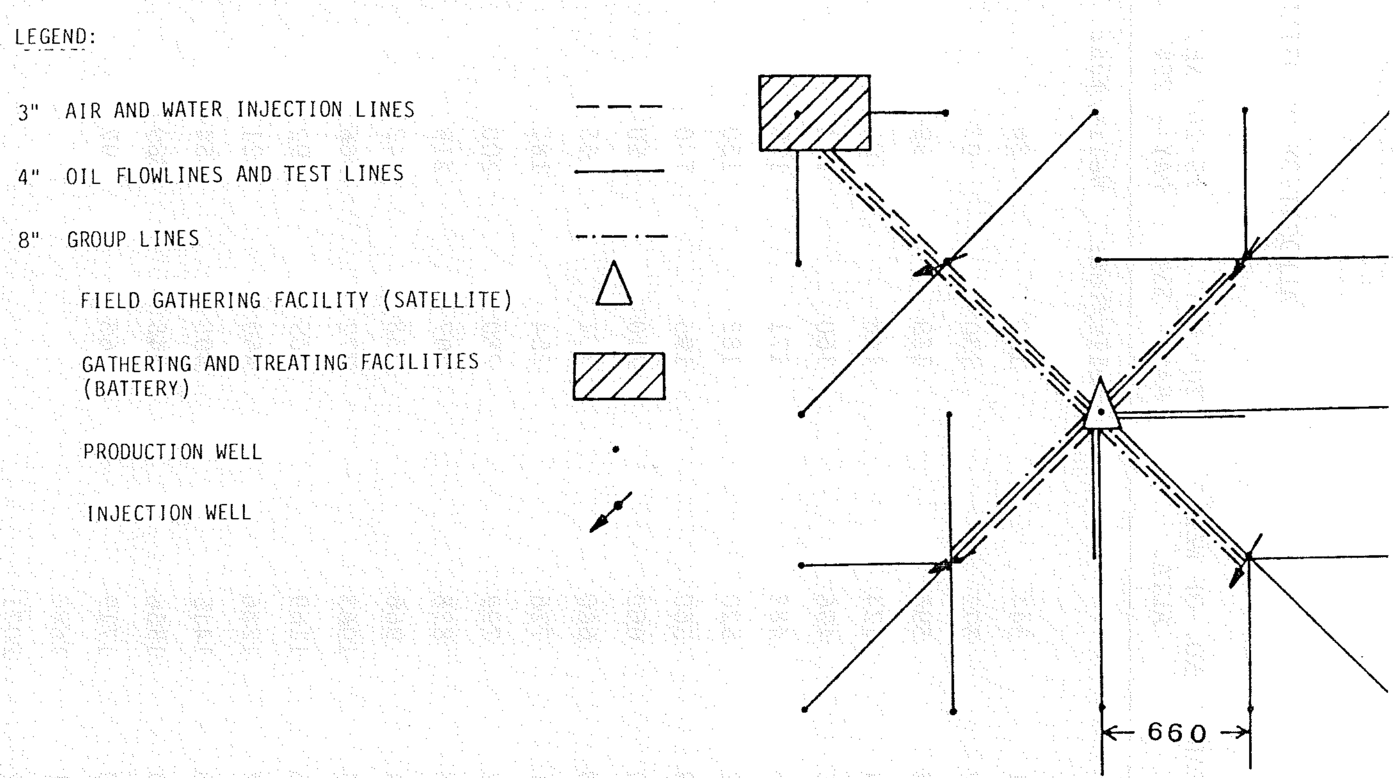


FIGURE 6.2

TABLE 6.1

ALLOCATION OF DRILLING ACTIVITY IN LLOYDMINSTER ALBERTA
(Optimum Case)

YEAR	NO. OF WELLS ALTA.	>20' NET PAY - 35%	15-20' NET PAY - 25%	10-15' NET PAY - 15%	10-15' NET PAY - 10%	5-10' NET PAY - 10%	EXPLORATION 8' NET PAY - 5%
		Wells/Year	Wells/Year	Wells/Year	Wells/Year	Wells/Year	Wells/Year
1	344	120	86	52	34	34	9
2	372	130	93	56	37	37	9
3	396	139	99	59	40	40	10
4	424	148	106	64	42	42	11
5	456	160	114	68	46	46	11
6	488	171	122	73	49	49	12
7	520	182	130	78	52	52	13
8	560	196	140	84	56	56	14
9	600	210	150	90	60	60	15
10	660	231	165	99	66	66	16
11	726	254	181	109	73	73	18
12	799	280	200	120	80	80	20
13	878	307	219	132	88	88	22
14	966	338	242	145	97	97	24
15	1063	372	266	159	106	106	27
16	1169	409	292	175	117	117	29
17	1286	450	321	193	129	129	32
18	1415	495	354	212	142	142	35
19	1556	545	389	233	156	366	40
20	1719	363	97	258	172	486	43
21	1883			143	188	689	47
22	2071					759	52

resource. In this study the assumption is made that:[1]

35 per cent of activity will be directed to beds greater than 20 feet pay-thickness for wet-combustion projects;

40 per cent to beds between 10 to 20 feet for wet-combustion; and that the remaining 25 per cent will be used for primary and secondary techniques (pay-thickness of 5 to 10 feet).

It is also assumed that all development except in 5 to 10 feet net pay area will be completed in about 22 years (considered most accelerated rate) and thus approximately 20,000 wells would be drilled during this period. These assumptions are based on good engineering practice and judgement expressed by industry engineers as personal communication.

6.4 Selection of a Module

For this study, a module area comprising of 550 acres has been selected as a basis for detailed economic evaluation. The areas under each classification (net oil-pay-thickness - 20 feet; 15-20 feet; 10-15 feet; 5-10 feet) were assumed to be developed as described previously. The area of the module was chosen with the consideration that in a wet-combustion scheme it would enclose ten complete, inverted-nine-spot patterns requiring two average size compressors. A development scenario for a wet-combustion project is schematically shown in Figure 6.2. Further details are contained in Appendix "B".

6.5 Time Sensitivity of Economic Evaluations

If we consider the limitations as mentioned previously and the recent changes with respect to price of oil, the development costs, and the rapid increase in the operating costs, one cannot ignore the time related changes likely to influence the economic evaluation substantially. The involved time

---

[1]This assumption is made so that all the area underlain by net-oil-pay of greater than 10 feet would be completely drilled within the next 20 to 25 years.

factor extends to over 20 years even if the developments were to proceed at high rate. To incorporate the time related elements, it was assumed that the development of the module area would be consistent with the development pace of the entire area under each net pay classification. In other words, the time required for development of a module area is the same as that required to develop the entire area in that particular net pay classification. Evaluation of a project on this basis, together with its application for overall development, would take into account all the anticipated changes in drilling and other related costs during the entire life of the project. On the other hand, evaluation of a project developed over a limited period of 4 to 5 years, and its subsequent generalized application would be tantamount to development of the whole area within this limited period. Using good engineering practices under the existing conditions, such an accelerated pace of development is considered impractical. Moreover, this type of approach would not yield realistic information on production rates beyond 15 to 16 years. The attached evaluations are, therefore, based on a development schedule spread out over approximately 22 years, the time span considered necessary to develop the major portion of the subject area under assumed conditions.

6.6 Screening Criteria

As described under "Geology", there are approximately 9000 segments containing over 25 billion barrels of oil-in-place in the Alberta part of Lloydminster area. However, oil-in-place is one thing and to economically recover it is another. Analysis of segments with various characteristics shows that under the currently existing techno-economic conditions segments with less than 5 feet net oil-pay are of little importance and hence were not considered for evaluation. Also, segments with excessively thick bottom water zones, lean oil segments, segments with gas caps, and the channel sands were not considered likely to contribute significantly to reserves at the present time, and therefore were excluded from evaluation. The screening criteria used for selection of the segments that would qualify for evaluation are shown in Table 6.2. Results of the screening show that only 2507 segments should be considered appropriate for recovery processes at the present time. The oil-in-place contained in these segments is estimated to be approximately 10 billion barrels at the 50 per cent probability level.

6.7 Escalation of Oil Price

The price of oil is a major factor in an economic evaluation. Among other things it determines whether certain deposits should be exploited, what recovery process should be used, and how long production may be continued. One of the objectives of the present evaluation is to determine the minimum basic price of oil[3] required to make wet-combustion projects economically viable under predetermined conditions.

Economic evaluation based on a single price projection does not allow adequate flexibility to analyze the impact of price changes. Therefore, for the purpose of this study three different price projections were utilized. In the price projection of this report the prices were assumed to escalate from three 1980 base prices of \$16/B, \$20/B and \$22/B as follows:

1980 to 1987	12 per cent per year
1987 to 1995	8 per cent per year
1995 and thereafter	constant at 1995 level

The basic prices and the escalations only serve to determine the minimum price of oil and the effect of price changes on various projects. In the present study, it is also assumed that the existing royalty and tax

[3]The basic price of oil is defined as price of oil in 1980.

TABLE 6.2

TOTAL SEGMENTS

Rich Oil

Lean Oil
(Rejected)

Channel Sand
(Rejected)

>5 Feet Net Pay

<5 Feet Net Pay
(Rejected)

<20% Bottom Water

>20% Bottom Water
(Rejected)

Gas Caps
(Rejected)

>20 Feet Net Pay
(Prim; W.F.; F.F.)

15-20 Feet Net Pay
(Prim; W.F.; F.F.)

10-15 Feet Net Pay
(Prim; W.F.; F.F.)

5-10 Feet Net Pay
(Prim; W.F.)

Legend

Prim - Primary
W.F. - Waterflood
F.F. - Fireflood

structure remain unchanged throughout the life of the projects. The price escalations as used are shown in Figure 6.3 which also include a probable international price trend for comparison.

6.8 Capital and Operating Cost

The capital requirements for the development and the operating costs are assumed to escalate from the 1980 base costs as follows:

1980 to 1987	10 per cent per year
1987 to 1995	7 per cent per year
1995 and thereafter	constant at 1955 level

The capital and the operating costs for the year 1979 are obtained from various industry sources. It should be noted that the cost estimates used in this study to evaluate wet-combustion projects correspond to costs incurred for pilots and, therefore, are likely to be higher than necessary in commercial operations.

The capital cost estimates associated with wet-combustion processes and used in this evaluation are shown in Table 6.3A. The operating costs are shown in Table 6.3B.

6.9 Profitability

There are several criteria that can be used to assess profitability of a project. In this evaluation the DCF-rate-of-return has been chosen as an economic indicator. It has been a matter of debate for some time as to what rate of return on investment can be considered reasonable and values from 10 per cent to as high as 40 per cent have been suggested. Projects with high risk factors, such as tertiary recovery in Lloydminster area, probably require above average return on investments and increased flexibility to make decisions. Evaluations using a single discount rate may

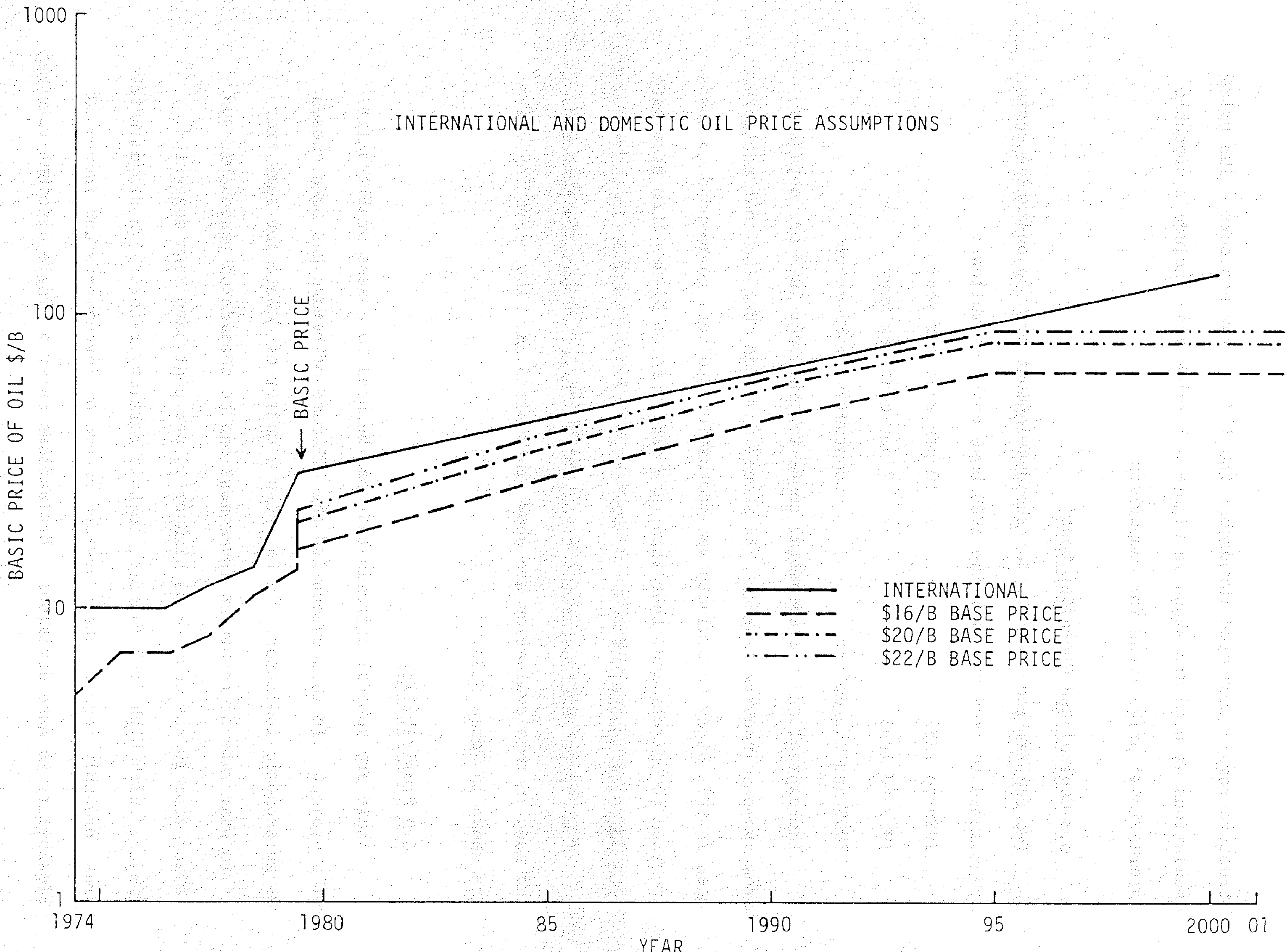

INTERNATIONAL AND DOMESTIC OIL PRICE ASSUMPTIONS
BASIC PRICE OF OIL $/B
1000
100
10
1
BASIC PRICE
INTERNATIONAL
$16/B BASE PRICE
$20/B BASE PRICE
$22/B BASE PRICE
1974
1980
85
1990
95
2000
01
YEAR

FIGURE 6-3

TABLE 6.3A

COST ESTIMATES
DEVELOPMENT OF FIREFLOOD
HEAVY OIL - LLOYD-ALBERTA

Year	Drilling and Completion Cost M$/W	Other Development Cost M$/W	Total Cost M$/W
1980	198	136	334
1981	218	151	369
1982	240	166	406
1983	263	183	446
1984	290	201	491
1985	319	221	540
1986	351	243	594
1987	375	268	643
1988	402	287	689
1989	430	307	737
1990	460	328	788
1991	492	351	843
1992	526	376	902
1993	563	402	965
1994	602	430	1032
1995	644	460	1104
1996	644	460	1104
1997	644	460	1104
1998	644	460	1104
1999	644	460	1104
2000	644	460	1104
2001	644	460	1104
2002	644	460	1104
2003	644	460	1104
2004	644	460	1104

Table 6.3B

OPERATING COST OF A FIREFLOOD WELL
(costs include compressor operating costs)

Year	Operating Cost $/W/month
1980	6,000
1981	6,600
1982	7,300
1983	8,000
1984	8,800
1985	9,700
1986	10,600
1987	11,700
1988	12,500
1989	13,400
1990	14,300
1991	15,300
1992	16,400
1993	17,600
1994	18,800
1995	constant at 1994 level until the end of the project

not provide adequate information for this purpose. Therefore, this analysis used two discount rates of 10 and 15 per cent. Values outside these limits can reasonably be extrapolated if necessary and will still lie within an acceptable margin of error.

6.10 Production Performance Profile

Table 6.4 and 6.5 show the performance profiles of an average well used in the evaluation. These profiles are based on recovery factors anticipated at a 50 per cent probability level and are consistent with the average performance of a Lloydminster well.

TABLE 6.4

PRODUCTION PROFILE
FIREFLOOD PROJECT
DEVELOPMENT SPACING - 10 ACRES
RESOURCE PROBABILITY - 50 PERCENT

YEAR	22.5 FEET NET OIL PAY		17.5 FEET NET OIL PAY		12.5 FEET NET OIL PAY	
	B/W/Y	Cum. bbls	B/W/Y	Cum. bbls	B/W/Y	Cum. bbls
1	9000	9000	7300	7300	6600	6600
2	9000	18000	7300	14600	6600	13200
3	9000	27000	7300	21900	6600	19800
4	9000	36000	7300	29200	6600	26400
5	9000	45000	7300	36500	6600	33000
6	9000	54000	7300	43800	6600	39600
7	9000	63000	7300	51100	6600	46200
8	9000	72000	7300	58400	6600	52800
9	9000	81000	7300	65700	4900	57700
10	9000	90000	6600	75300	3300	61000
11	7000	97000	6000	78300		
12	5500	102500	4300	82600		
13	4300	106800	3200	85800		
14	3200	110000				

TABLE 6.5

PRODUCTION PROFILE
HEAVY OIL LLOYDMINSTER
DEVELOPMENT SPACING - 40 ACRES
RESOURCE PROBABILITY - 50 PERCENT

YEAR	WATERFLOOD						PRIMARY	
	22.5 Feet NP		17.5 Feet NP		12.5 Feet NP		8 Feet NP	
	B/W/Y	Cum. bbls	B/W/Y	Cum. bbls	B/W/Y	Cum. bbls	B/W/Y	Cum. bbls
1	9000	9000	7300	7300	6600	6600	5500	5500
2	9000	18000	7300	14600	6600	13200	4700	10200
3	9000	27000	7300	21900	6600	19800	4000	14200
4	9000	36000	7300	29200	6600	26400	3400	17600
5	9000	45000	7300	36500	6600	33000	3100	20700
6	9000	54000	7300	43800	6600	39600	2600	23300
7	9000	63000	7300	51100	5900	45500	2200	25500
8	9000	72000	7300	58400	5300	50800	2000	27500
9	9000	81000	6600	65000	4800	55600	1800	29300
10	8100	89100	5900	70900	4300	59900	1700	31000
11	7300	96400	5300	76200	3900	63800		
12	6600	103000	4800	81000	3500	67300		
13	5900	108900	4300	85300	3200	70500		
14	5300	114200	3900	89200	2800	73300		
15	4800	119000	3500	92700	2600	75900		
16	4300	123300	3100	95800	2300	78200		
17	3900	127200	2900	98600	2100	80300		
18	3500	130700	2500	101100	1900	82200		
19	3100	133800	2300	103400	1800	84000		
20	2800	136600	2100	105500				
21	2500	139100	1800	107300				
22	2300	141400	1700	109000				
23	2000	143400						
24	1800	145200						
25	1800	147000						

7. RESULTS

7.1 Sensitivity of Price on Profitability

One of the main objectives of this study is to determine the minimum basic price of oil that would make a wet-combusion recovery process economically viable. In order to study the impact of oil price on profitability, an assumed wet-combustion project covering 550 acres and drilled on 10 acre spacing is evaluated. Using three price schedules the resulting present values, discounted at 15 and 20 per cent, were determined and plotted against the basic price of oil. These values were then extrapolated (if necessary) to intersect the zero present value coordinate. The point of intersection gives the minimum basic price of oil necessary to generate the corresponding rate of return. The process is repeated for all the four net pay classifications at 50 per cent recovery probability level as shown in Figures 7.1 through 7.4 and for three net pay classifications at 90 per cent recovery probability level as shown in Figure 7.5 through 7.7.

The procedure is explained with the following example taken from Figure 7.3.

Example:

Recovery Process	wet-combustion
Net oil-pay-thickness	17.5 feet
Recovery factor	25 per cent oil-in-place at 50 per cent probability
Basic oil price	\$16/B, \$20/B, \$22/B
Discount rates	15 per cent
Present values:	
@\$16/B - 15% D.R.	-0.5 MM\$
@\$20/B - 15% D.R.	3.26 MM\$
@\$22/B - 15% D.R.	5.15 MM\$

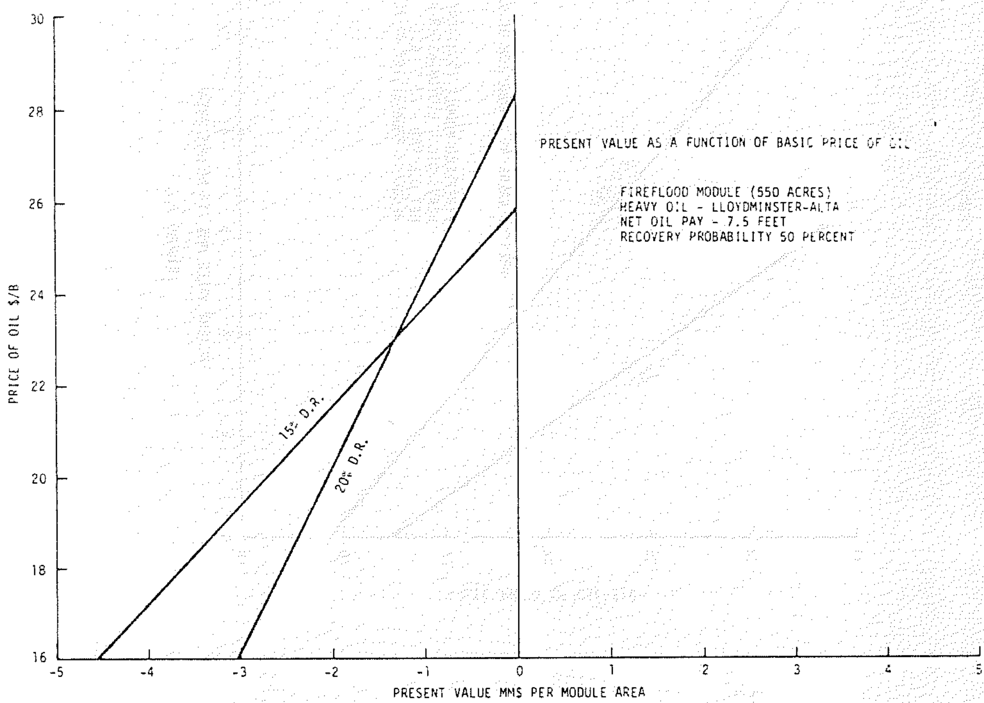


FIGURE 7.1

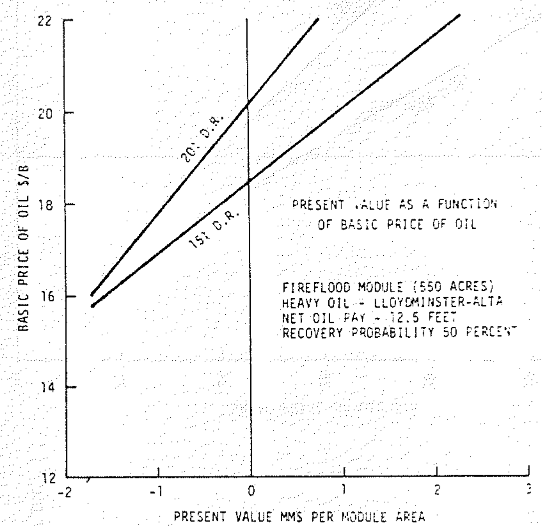
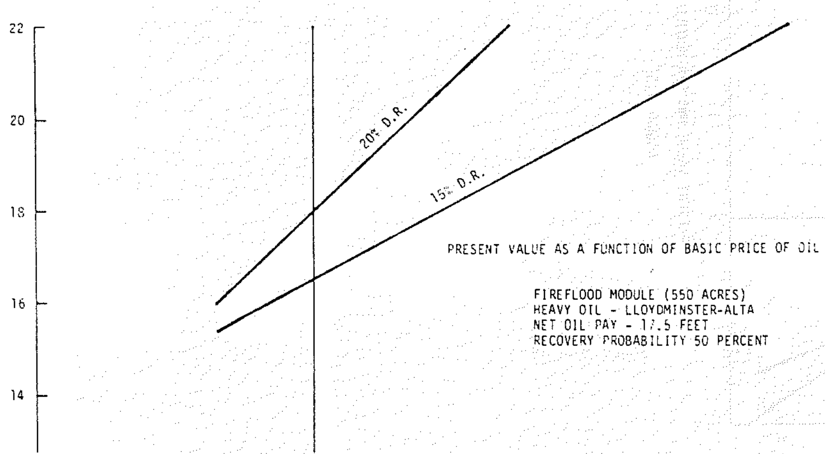
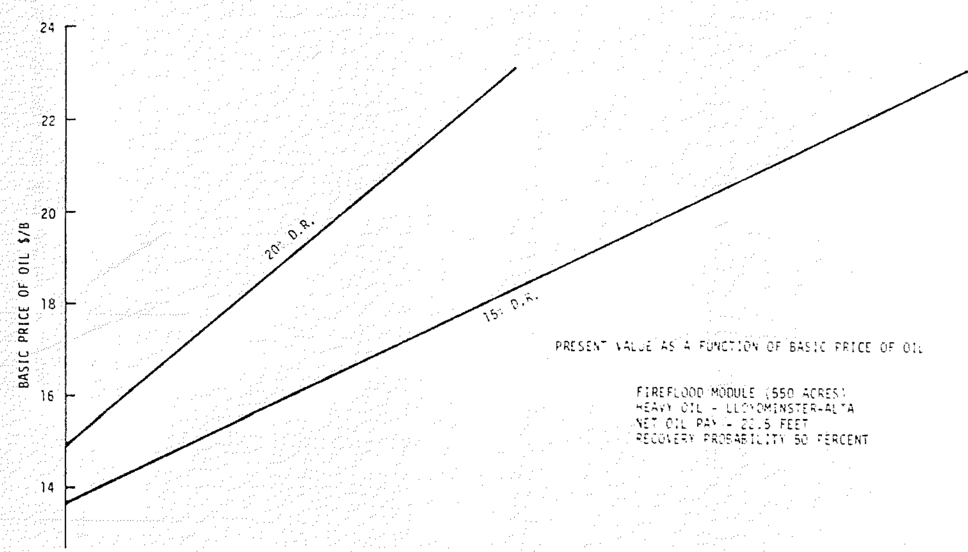


FIGURE 7.2





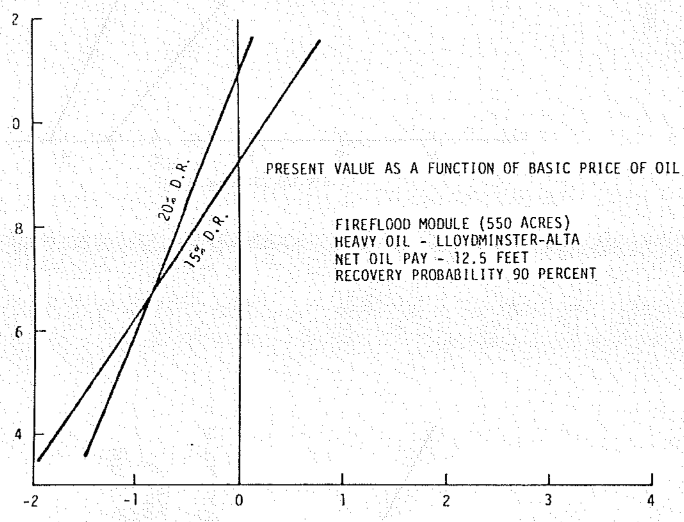


FIGURE 7.5

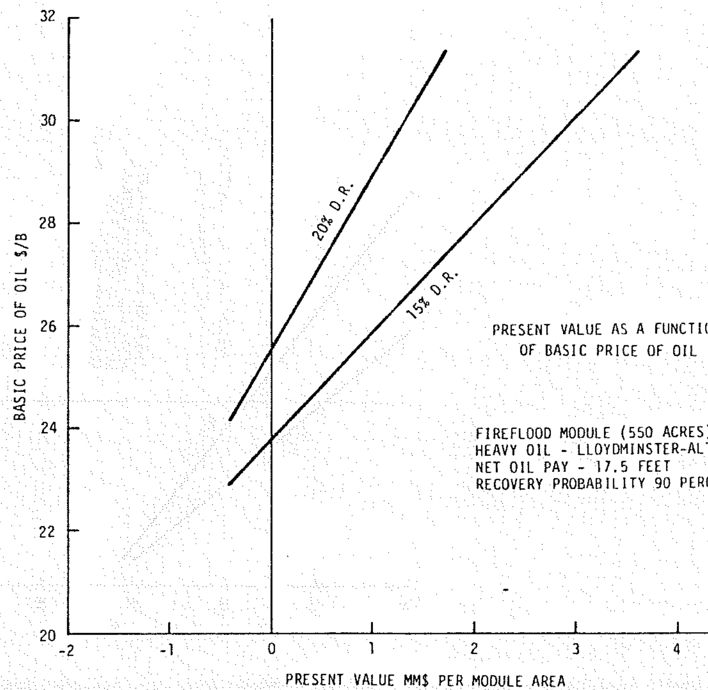


FIGURE 7.6

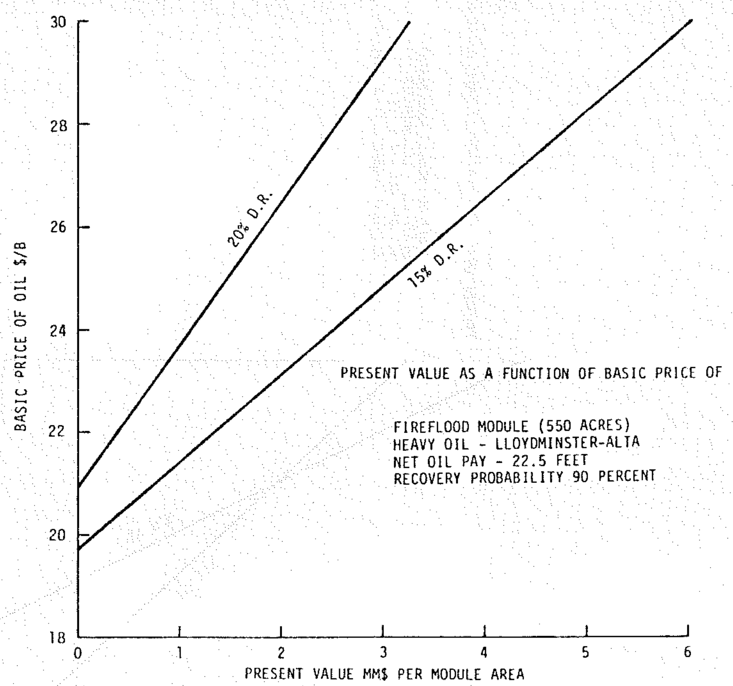


FIGURE 7.7

The minimum basic price required is \$16.50/B. These minimum basic prices, corresponding to 50 per cent and 90 per cent probability levels, were then plotted against the net oil pay thicknesses as illustrated in Figures 7.8 and 7.9.

7.2 Potential Oil Supply

The potential oil supply projections shown in Figures 7.10 and 7.11 are based on recovery levels corresponding to 50 per cent probability, which compares with the performance of an average well in the Lloydminster area. These projections are arrived at assuming a 22 year development period, the high case drilling rate, and the corresponding period of production extending to 35 years. The study indicates that if wet-combustion recovery schemes are used, the cumulative supply could be roughly twice that expected when using only primary and waterflood in the next 35 year period (Fig. 7.11). The study also indicates that a production rate of 240 thousand barrels per day could be achieved by the year 2000 (Fig. 7.10). The period of 20 years that would be required to achieve peak rates reflects the lead time necessary to put these projects into operation. The maximum recoverable oil by conventional means is estimated to be 700 million barrels, and the peak production rate of 115 thousand barrels per day could be reached by 1995 (Fig. 7.10).

7.3 Capital Requirements

Figures 7.12 and 7.13 show the capital investment necessary for the development of the area during the next 22 year period. No attempt has been made to estimate the portion of this capital that may be internally generated. As may be seen, a total of approximately 8 billion in 1980 Canadian dollars.

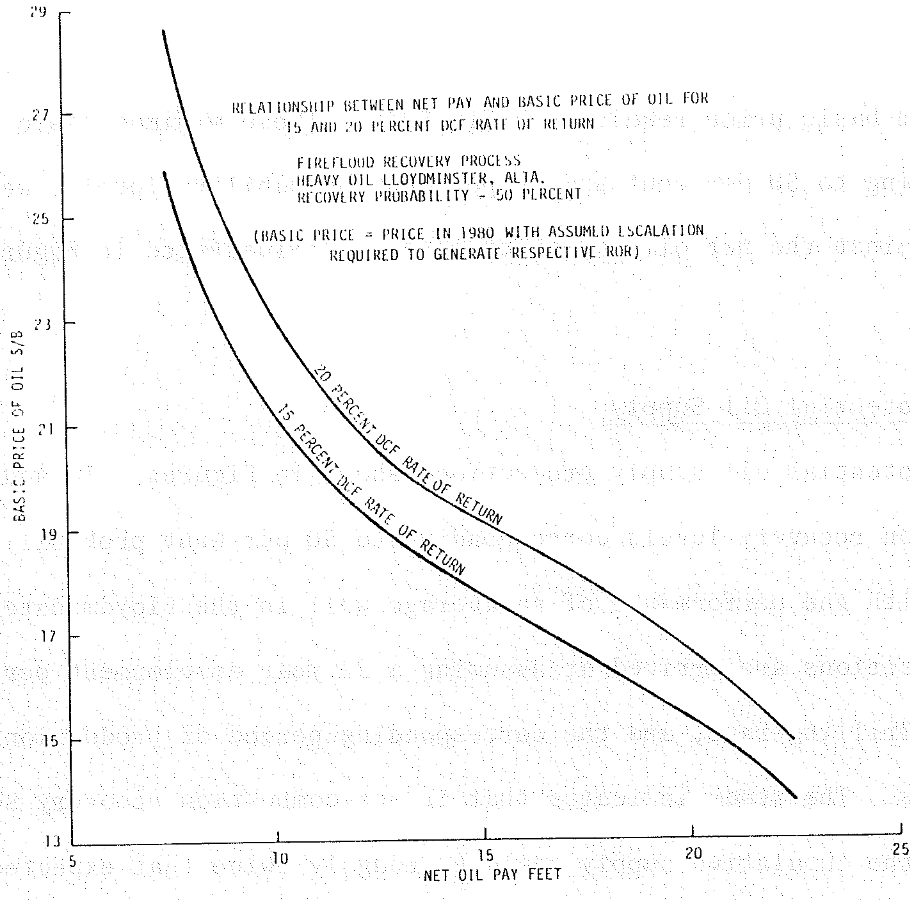


FIGURE 7.8

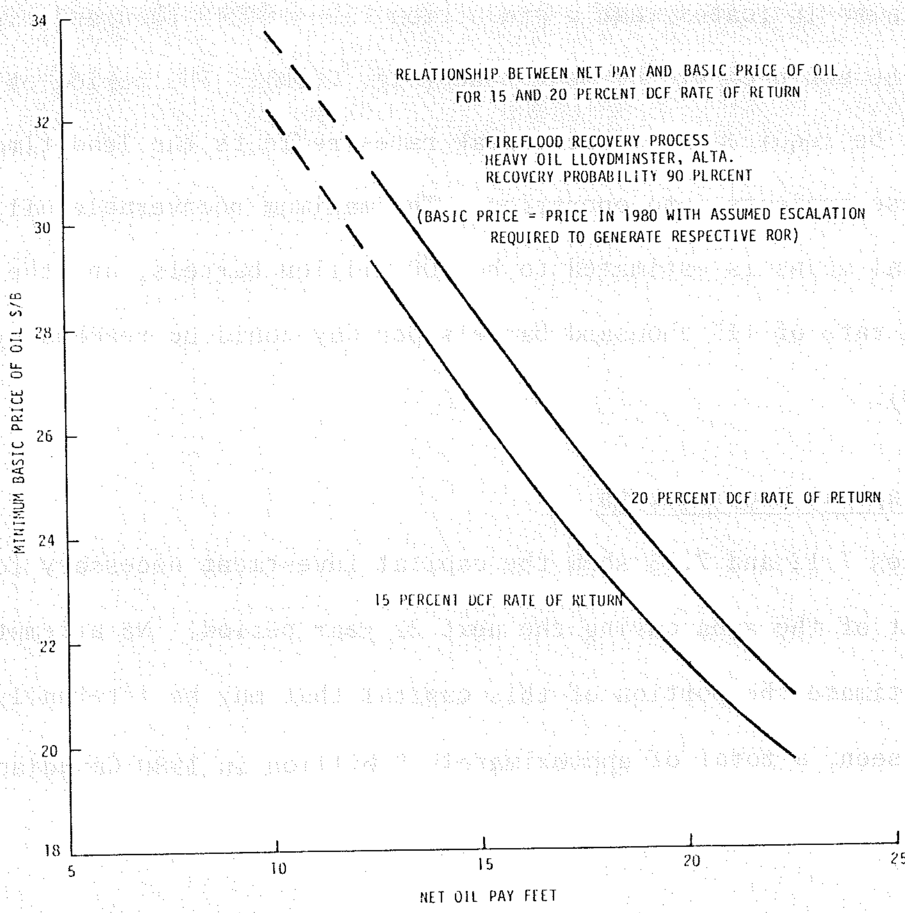


FIGURE 7.9

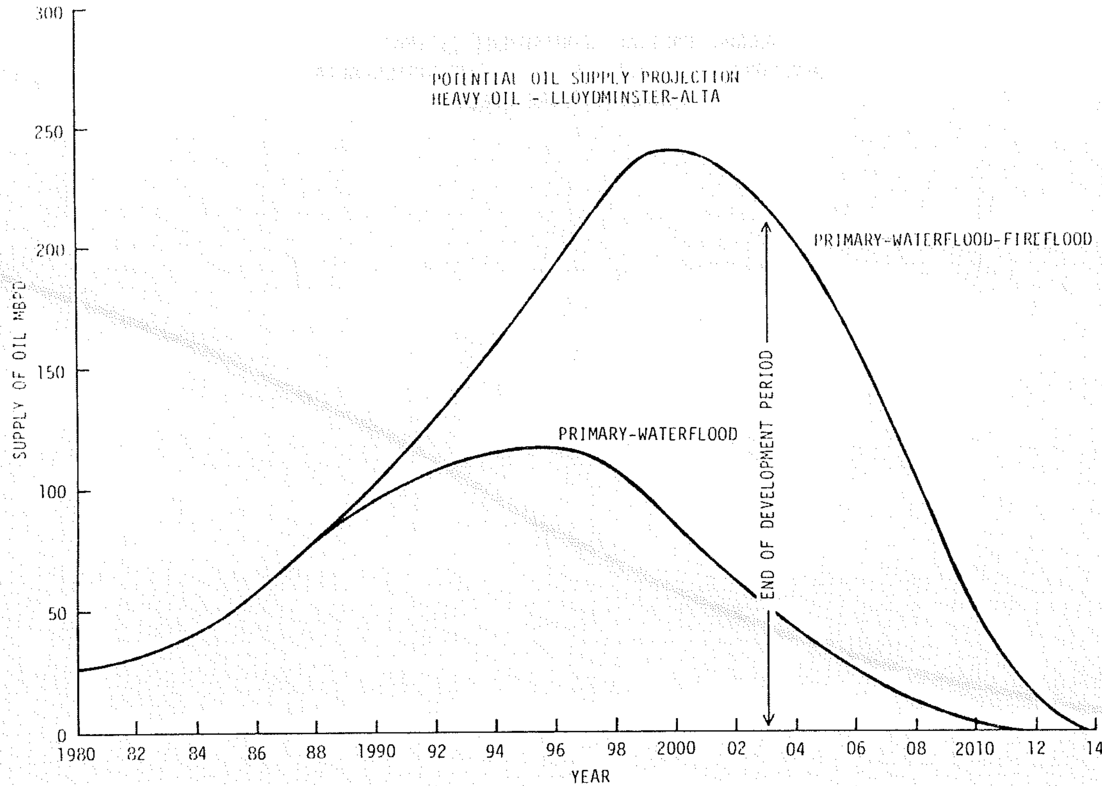


FIGURE 7.10

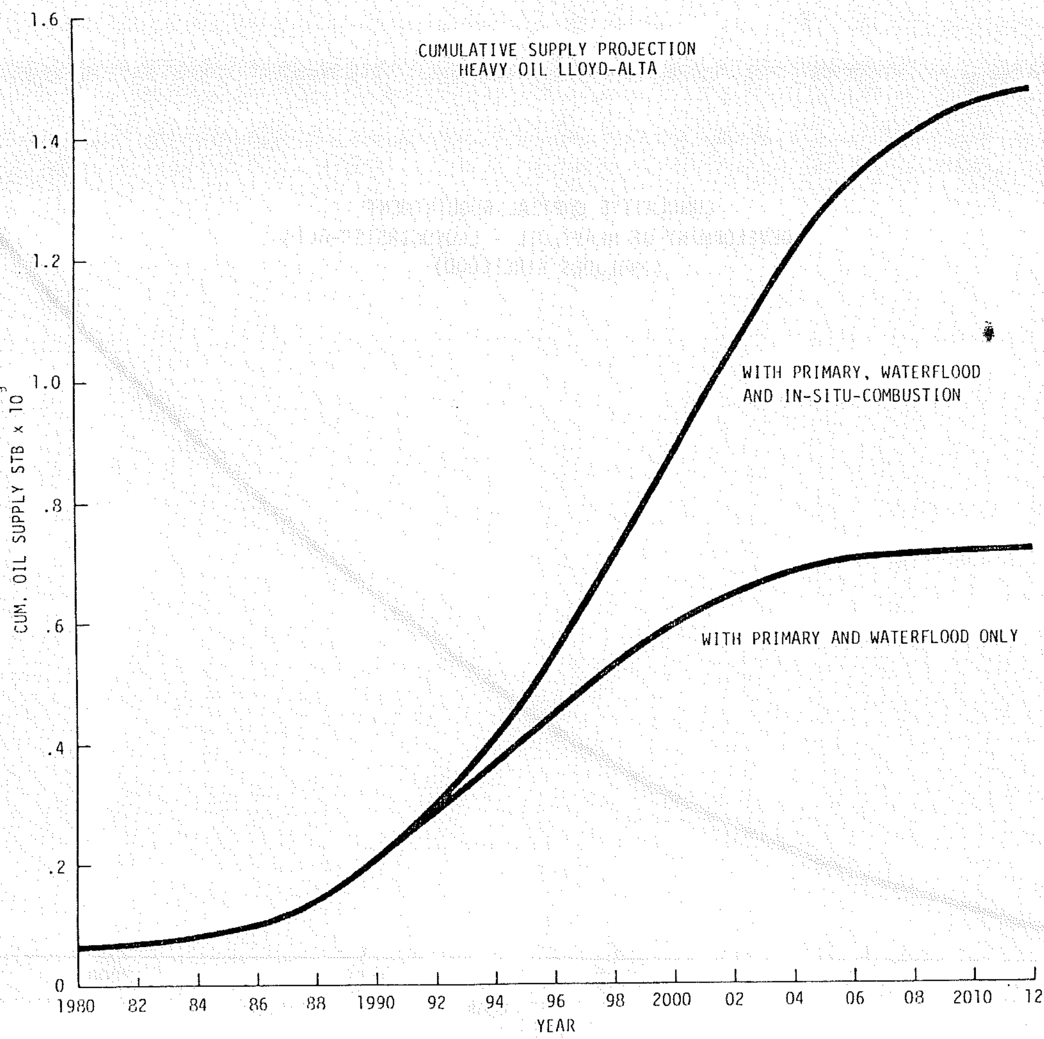


FIGURE 7.11

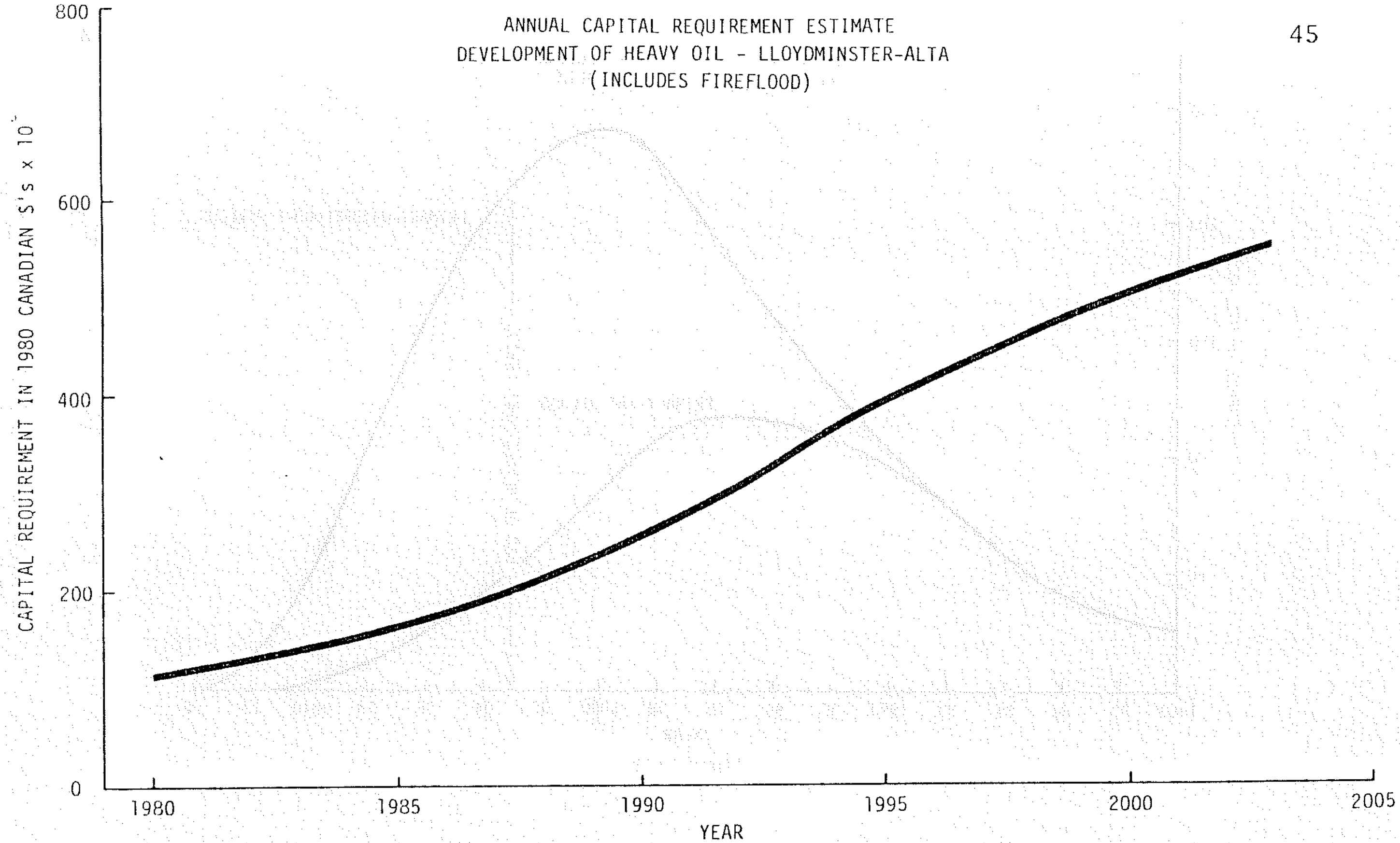


FIGURE 7.12

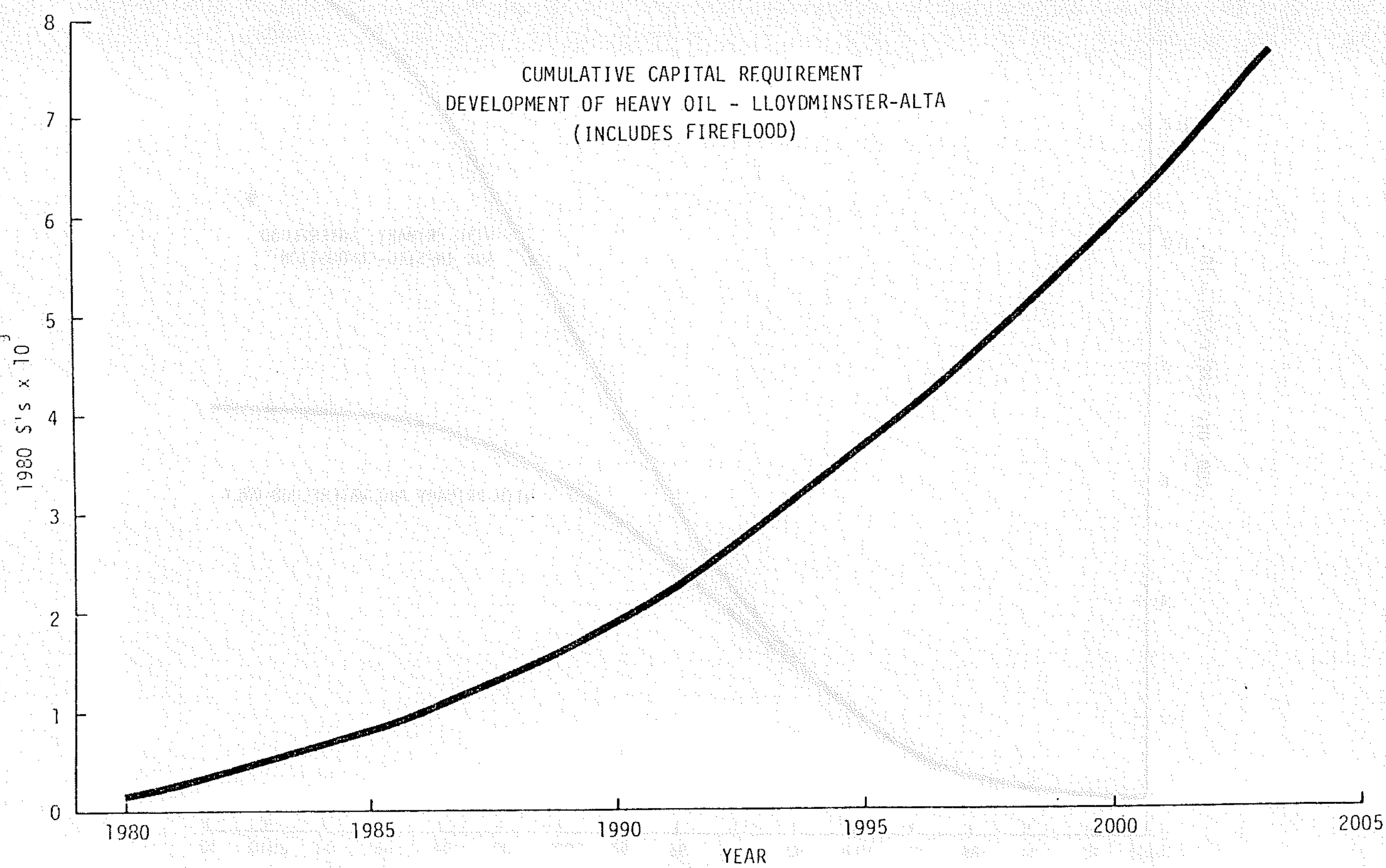


FIGURE 7.13

would be needed for optimum development which would result in approximately 800 million barrels of additional oil over the 700 million recoverable by conventional means.

7.4 Potential Reserves

The total quantity of oil that may be added to reserves from the Alberta part of the Lloydminster heavy oil deposits is illustrated in Figure 7.14. This illustration indicates the quantities of oil that may be available at different basic oil prices using four probability levels of recovery. These projections assume only the primary, waterflood, and wet-combustion recovery technologies. The illustration suggest that starting from an average estimated in-place oil resource of 10×10^9 bbls and considering the average recovery at 50 per cent probability level about 700 MM bbls of recoverable oil would be available at a base price of \$14/B increasing to 2.5×10^9 bbls at \$22/B and 2.5×10^9 at \$30/B.

The impact of base price on quantities of oil that may become recoverable is also illustrated as a family of cumulative frequency distribution curves in Figure 7.15. This illustration indicates the estimate of total in-place oil (curve to the extreme right) as well as the part of that resource that may be added to reserves as base price increases. It is apparent that the bands converge as the price increases indicating that there will be a limit beyond which additional price increase will not add to significant reserves.

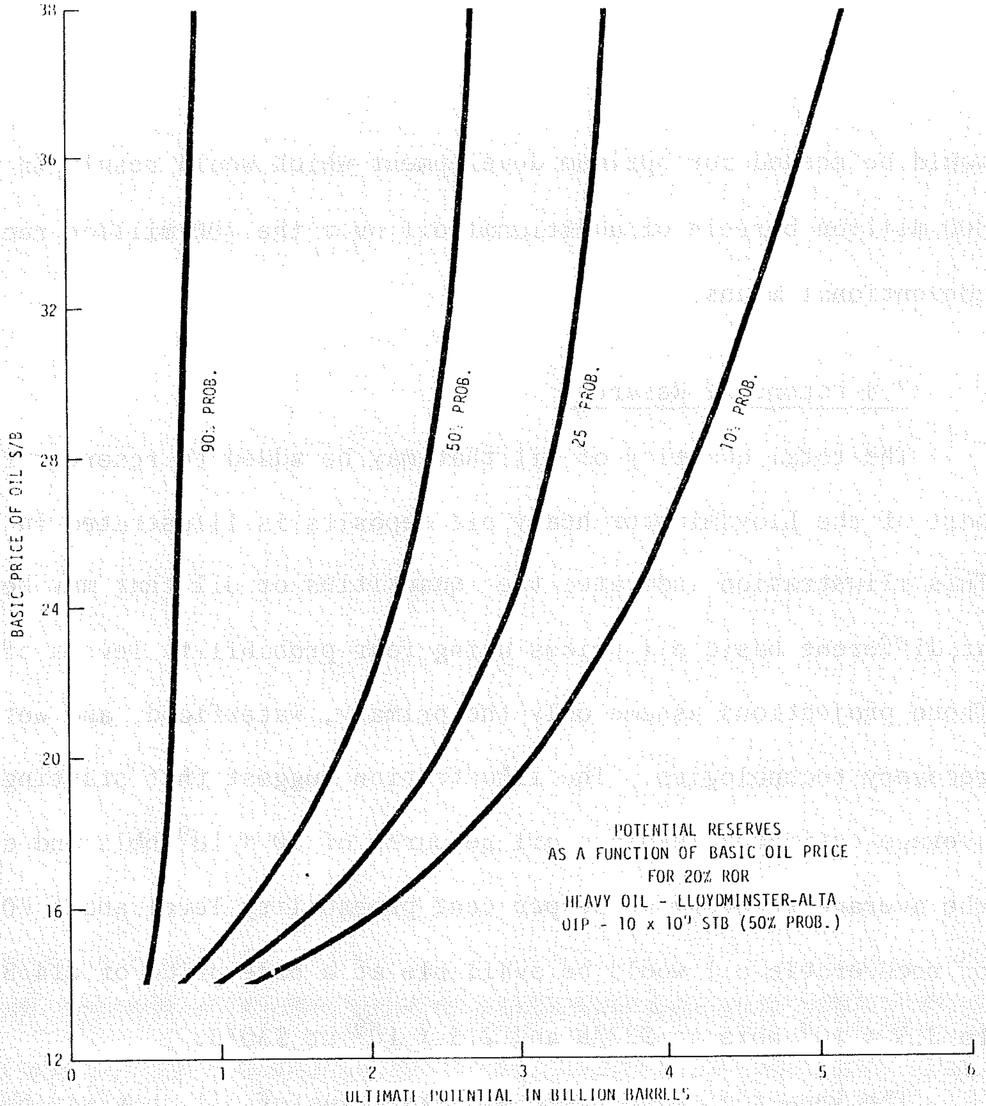


FIGURE 7.14

POTENTIAL OF HEAVY OIL AVAILABLE AT DIFFERENT BASIC OIL PRÎCE LEVELS - LLOYDMINSTER AREA
BASIC OIL PRICE = PRICE IN 1980 WITH ASSUMED ESCALATION
(ASSUMED DCF RATE OF RETURN - 20%)

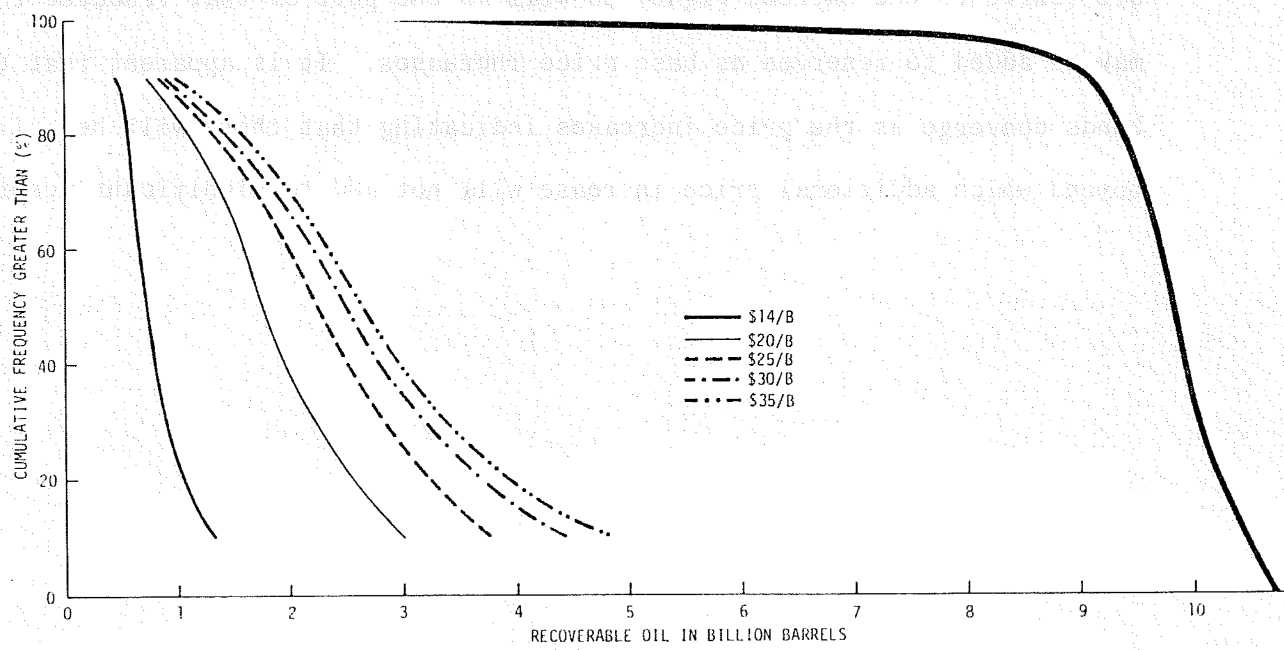


FIGURE 7.15

REFERENCES

Ref. 1 Heavy Crude Oil Potential of Saskatchewan - J. E. Christopher, R. H. Knudsen, in The Future of Heavy Crude Oils and Tar Sands: International Conference - sponsored by the United Nations Institute for Training and Research (UNITAR) and the United States Department of Energy, Edmonton, Alberta, June 1979. R. F. Meyer and C. T. Steele, editors. McGraw-Hill Mining Informational Services, New York, 1980.

Ref. 2 Estimate of Oil Resources, Lloydminster Area, Alberta - R. G. McCrossan, R. M. Procter, W. J. Ward, in The Future of Heavy Crude Oils and Tar Sands: International Conference - sponsored by the United Nations Institute for Training and Research (UNITAR) and the United States Department of Energy, Edmonton, Alberta, June 1979. R. F. Meyer and C. T. Steele, editors. McGraw-Hill Mining Informational Services, New York, 1980.

Ref. 3 40 Years of Heavy Oil Exploration and Production - James A. William, in The Future of Heavy Crude Oils and Tar Sands: International Conference - sponsored by the United Nations Institute for Training and Research (UNITAR) and the United States Department of Energy, Edmonton, Alberta, June 1979. R. F. Meyer and C. T. Steel, editors. McGraw-Hill Mining Informational Services, New York, 1980.

Ref. 4 A Current Appraisal of In-Situ-Combustion Field Tests - S. M. Farouq Ali, Journal of Petroleum Technology, Vol. 24, Apr. 1972, p. 477.

Ref. 5 Preliminary Analysis of Heavy Oil, Lloydminster Alberta Database, Internal Report - D. N. Skibo, K. N. Nairn, EMR, Calgary, 1978.

Ref. 6 Operating Practices to Improve Profitability of Conventional Heavy Oil Production - D. O. Gurel, in The Future of Heavy Crude Oils and Tar Sands: International Conference - sponsored by the United Nations Institute for Training and Research (UNITAR) and the United States Department of Energy, Edmonton, Alberta, June 1979. R. F. Meyer and C. T. Steele, editors. McGraw-Hill Mining Informational Services, New York, 1980.

Ref. 7 Evaluation of Heavy Oil Reserves, Lloydminster Play Alberta - MacCallum, Stewart and Associates Consulting Geologists Inc., 1978. Contract Study to: Geological Survey of Canada, Dept. EMR, Calgary, Canada.

Ref. 8 Log and Gravity Data from Lloydminster Area - Husky Oil Ltd. Internal Report.

Ref. 9 Fundamentals of Tertiary Oil Recovery, Pt. 9: Thermal Recovery by In-Situ-Combustion - E. F. Herbeck, R. C. Heintz and J. R. Hastings, Petroleum Engineer International, Vol. 49, No. 2, p. 46-56, February 1977.

Ref. 10 Analysis of Lloydminster Heavy Oil - A. A. Amundrud, Husky Oil Ltd. (Personal Communication).

Ref. 11 Technical Feasibility of Waterflood - Wildmere Lloydminster "A" Pool, August 1976, M. Raicar, Internal Report Husky Oil Ltd.

Ref. 12 Factors Influencing Selection of Oil Reservoir and Design Considerations for Production by In-Situ-Combustion and the Combination Thermal Process (Thermal Recovery Course) - Tejas Petroleum Engineers, April 1973, 2809-B Allen St., Dallax, Texas, 75204.

Ref. 13 Simplified Method for Predicting Oil Recovery by Steamflood - Ezzat E. Gomaa, Paper No. SPE 6169, 1976. Paper presented 51st Annual Techn. Conf., New Orleans, Oct. 1976. Improved Oil Recovery Symposium Proceedings, Society of Petroleum Engineers of AIME.

Adjunct to the Report

An Analysis of Heavy Oil Supply

Lloydminster Area, Alberta

In 1980, the Petroleum Energy Assessment Secretariat of the Geological Survey of Canada prepared a report evaluating the potential of heavy oil resources on the Alberta side of the Lloydminster area titled "An Analysis of Heavy Oil Supply - Lloydminster Area, Alberta" by M. Raicar and R.M. Procter, dated June 6, 1980.

This report, which is based on geological study by MacCallum, Stewart and Associates, was initially intended to be used as an internal document. The economic evaluation in this report arbitrarily assumed escalating oil price and costs as follows:

Escalation in Oil Price		
1980 to 1987	-	12 per cent per year
1987 to 1995	-	8 per cent per year
1995 to thereafter	-	Constant at 1995 level
Escalation in Capital and Operating Costs		
1980 to 1987	-	10 per cent per year
1987 to 1995	-	7 per cent per year
1995 to thereafter	-	Constant at 1995 level

In order to properly incorporate the effect of escalating price and cost over a long period of time, the development of the assumed 550 acres wet-combustion module was spread out over approximately 20 years which is also the time required to develop a major part of the field at the prespecified rate of drilling (high case drilling activity).

The above conditions adequately reflect some of the expected future changes. However, upon consultation with the various groups or agencies within Energy, Mines and Resources, it was suggested that an evaluation of these resources assuming shorter development period of approximately three years for the wet-combustion module and based on constant 1980 dollars would contribute substantially to the original report. The latter approach may be useful for comparison of economic evaluations of a specific pool developed for a wet-combustion recovery process over a short period of time, with a more general evaluation reflecting changes over a period of time and covering a variety of pools, as expressed in the report.

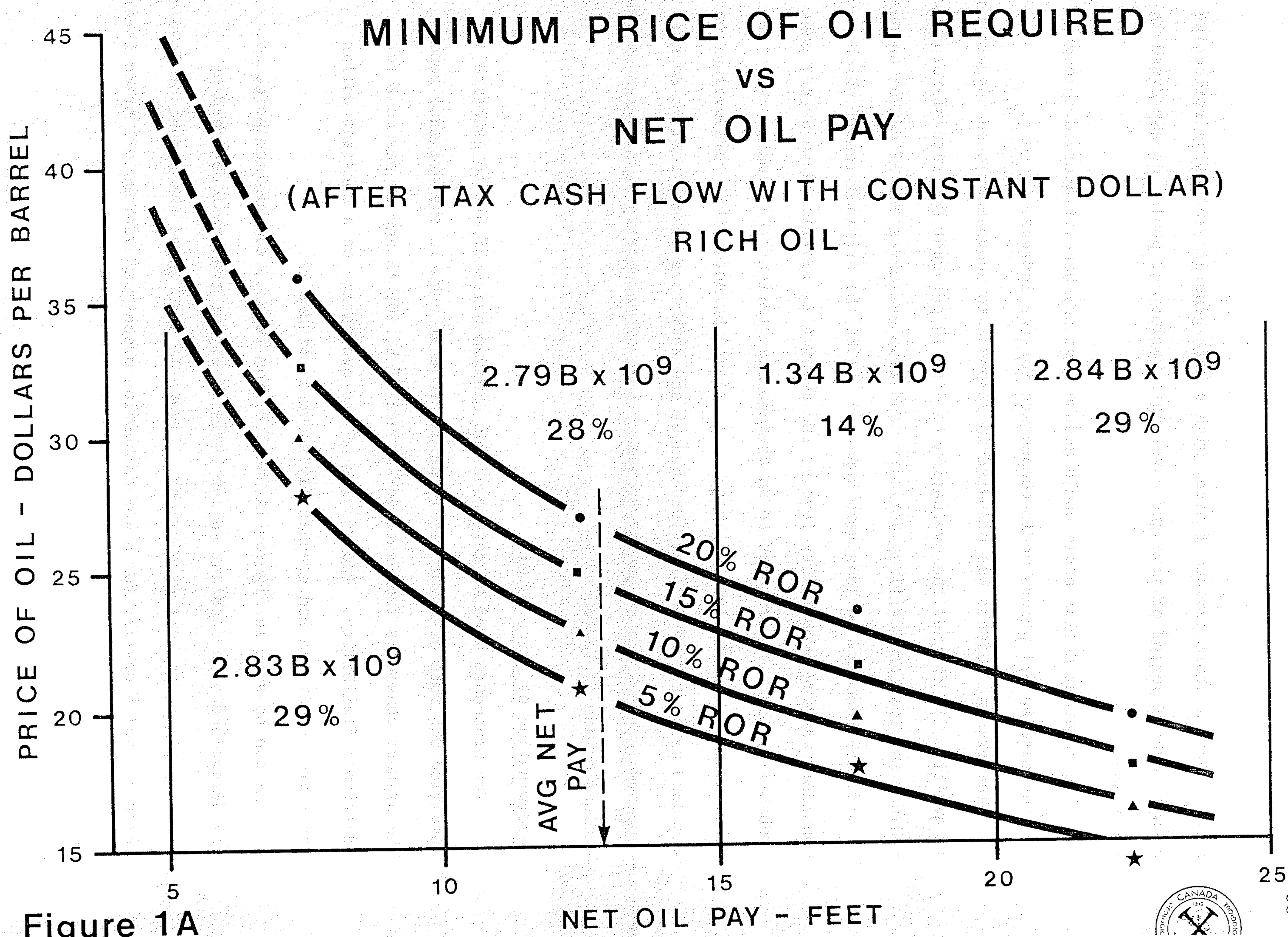
The constant dollar basis would assume that any benefit accrued through the increase in oil prices would compensate for the increase in cost.

The present adjunct was prepared in response to above-mentioned suggestions. In addition, it extends the evaluation to 5 to 10 per cent DCF rate-of-return, medium- and low-case drilling activity, and also evaluates the effect of changes in ultimate recovery on long term supply. Unlike the original report which considers varying probability levels, the adjunct is restricted to 50 per cent probability which corresponds to an average expectation or estimate. All the other assumptions are left unchanged. It should be noted that this evaluation was done prior to the October 1980 budget and therefore do not reflect changes proposed in the National Energy Program. Some of the pertinent findings of the evaluation are as follows:

Determination of Price of Oil

The procedure used to determine the minimum price of oil to generate a specified DCF rate-of-return is identical to that used in the original report. The adjunct considers four rates-of-return of 5, 10, 15 and 20 per cent for additional flexibility. The results of the evaluation on a constant dollar basis are summarized and graphically shown in Figure 1A.

As can be seen in Figures 1A and 7.8 from report, the minimum price of oil determined on a constant dollar basis is higher than that obtained by assuming price and cost escalations. Figure 1A also shows the amount of in-place resources which qualify for a wet-combustion process at various oil price levels.



MINIMUM PRICE OF OIL REQUIRED
VS
NET OIL PAY
(AFTER TAX CASH FLOW WITH CONSTANT DOLLAR)
RICH OIL
PRICE OF OIL - DOLLARS PER BARREL
45
40
35
30
25
20
15
5
10
15
20
25
NET OIL PAY - FEET
2.83 B x 10^9
29%
2.79 B x 10^9
28%
1.34 B x 10^9
14%
2.84 B x 10^9
29%
20% ROR
15% ROR
10% ROR
5% ROR
AVG NET PAY

Figure 1A

Figure 2A shows a relation between the price of oil and the ultimately available oil resources at 10 per cent rate-of-return. The dotted line indicates that an unspecified amount of oil will be available from sources other than considered for this evaluation. This oil could come from lean oil segments, segments with less than five feet net oil pay, segments with gas cap, segments with bottom water and channel sand segments.

Figure 3A illustrates a potential future rate of oil supply corresponding to the medium case drilling rate. This figure also shows the effect of lower recovery factor of 20 per cent of the oil-in-place on supply (bottom curve). The upper curve assumes a recovery factor of 25 per cent of the oil-in-place.

Figure 4A shows supply projections corresponding to a low case drilling rate. As in 3A, the upper curve assumes an ultimate recovery factor of 25 per cent and the lower 20 per cent of the oil-in-place.

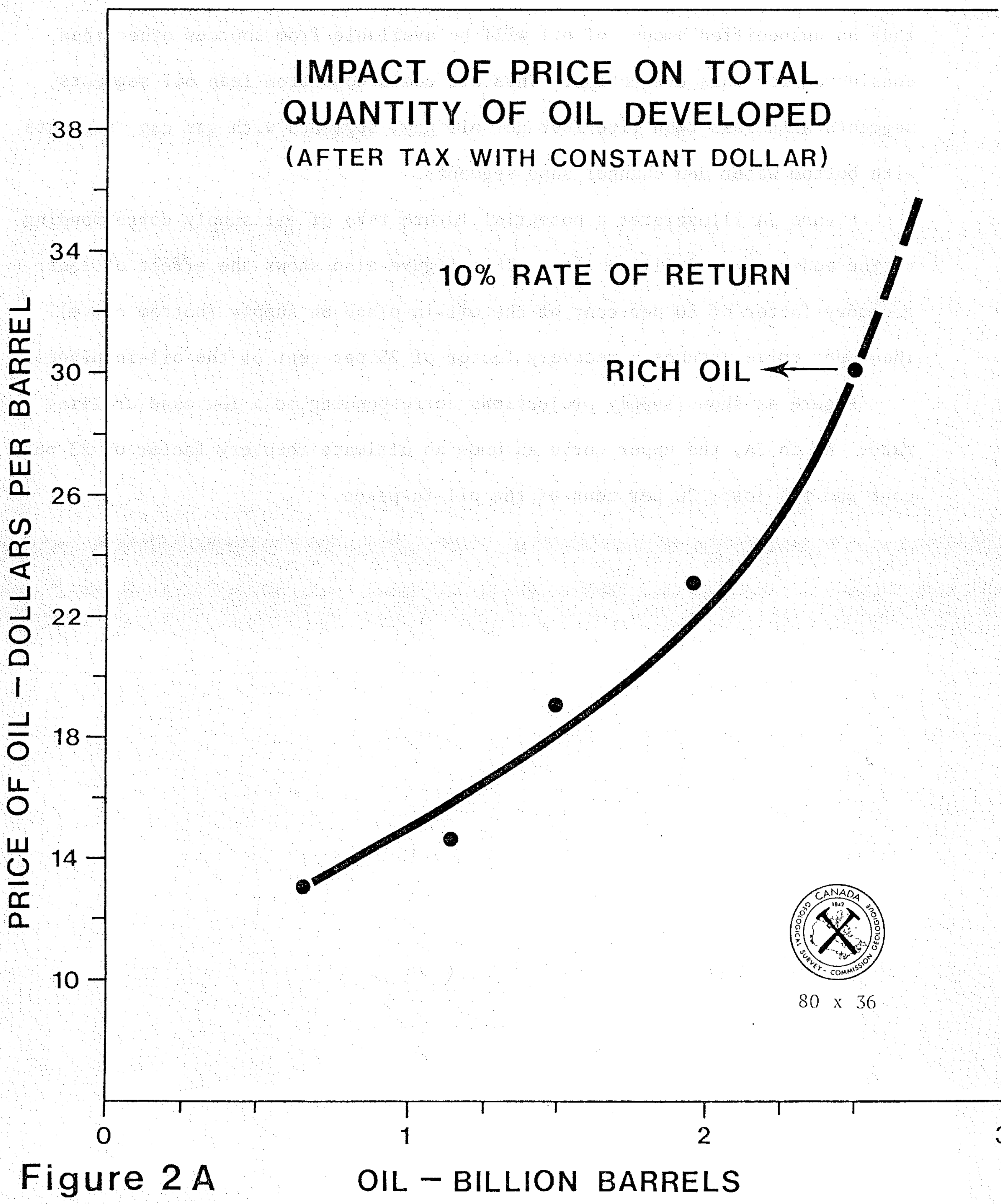

IMPACT OF PRICE ON TOTAL
QUANTITY OF OIL DEVELOPED
(AFTER TAX WITH CONSTANT DOLLAR)
10% RATE OF RETURN
RICH OIL
PRICE OF OIL – DOLLARS PER BARREL
38
34
30
26
22
18
14
10
0
1
2
3
OIL – BILLION BARRELS
80 x 36

Figure 2A

Figure 3 A

MEDIUM CASE SUPPLY PROJECTION

HEAVY OIL – LLOYDMINSTER, ALTA.
RICH OIL ONLY

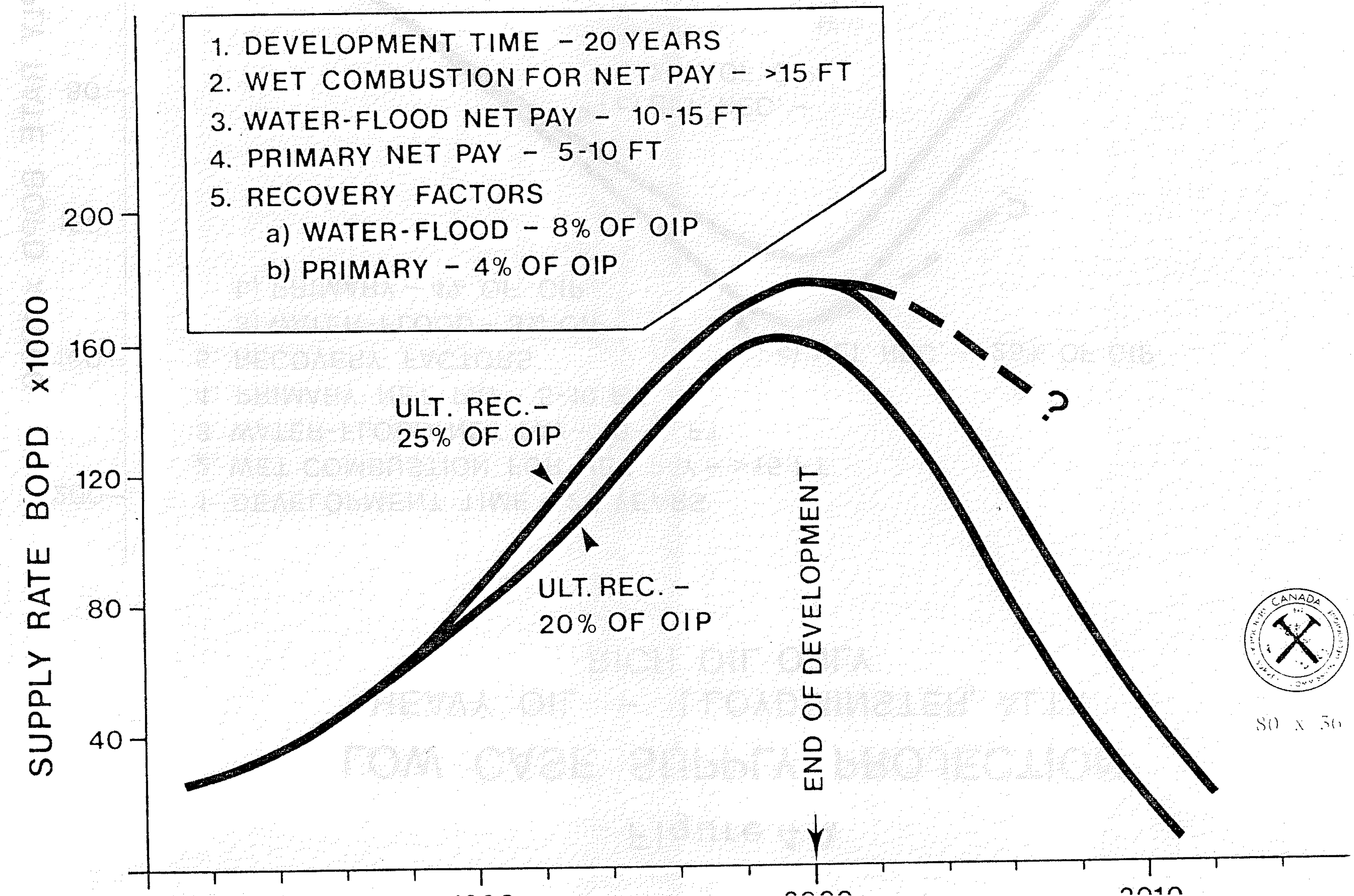
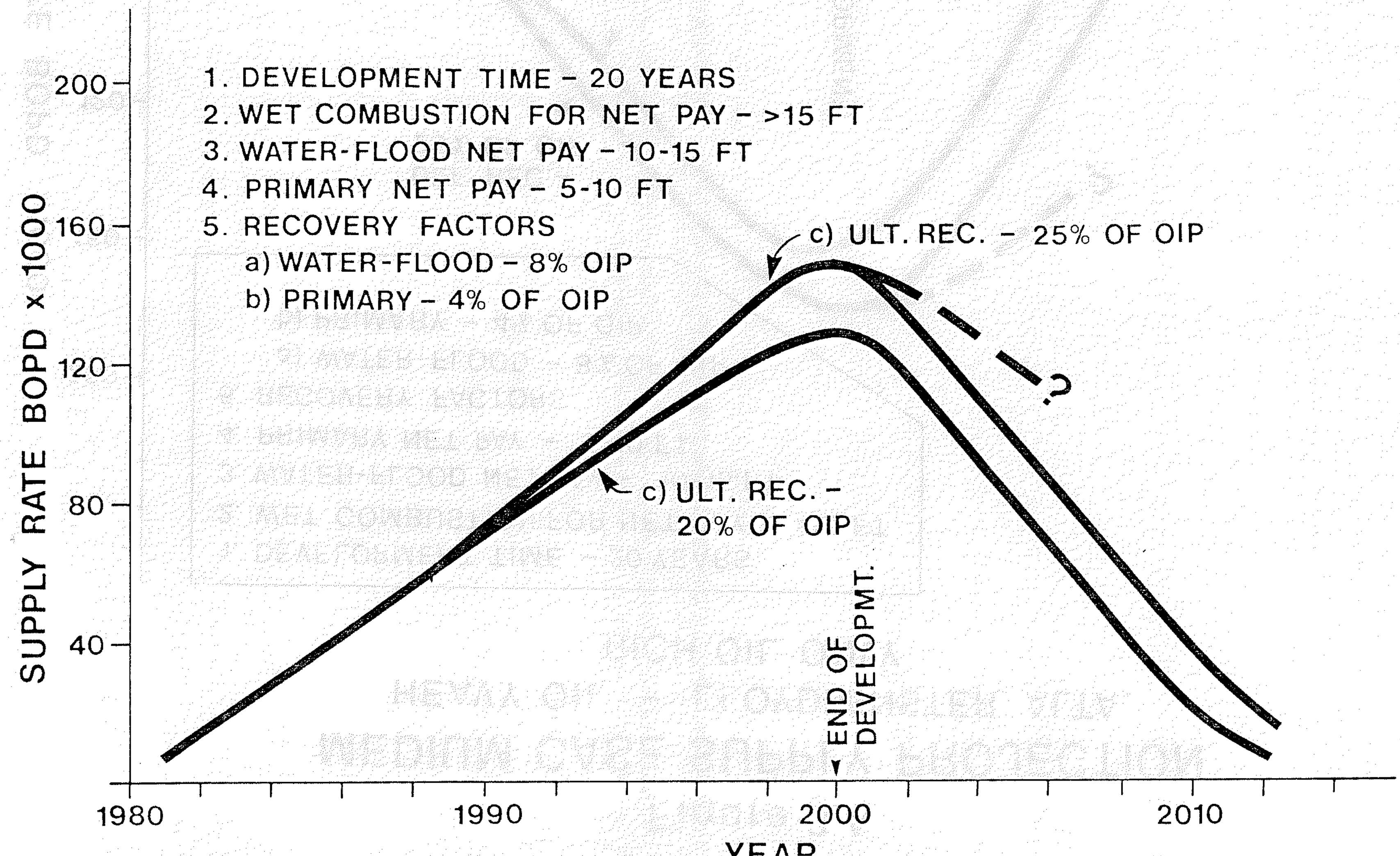


Figure 4 A

LOW CASE SUPPLY PROJECTION

HEAVY OIL – LLOYDMINSTER, ALTA
RICH OIL ONLY



APPENDIX "A"

METHODS OF OIL RECOVERY

by

M. Raicar

Institute of Sedimentary and Petroleum Geology,
Geological Survey of Canada,
3303 - 33 Street N.W., Calgary, Alberta, Canada

METHODS OF OIL RECOVERY

1. General

Methods of oil recovery can be classified in three groups: primary, secondary and tertiary. Generally speaking, this grouping represents the order in which a reservoir is depleted. It is important to know that there are no universally accepted definitions of these recovery methods. Therefore, for this report these three groups are defined as follows:

(a) Primary - Depletion in which oil is produced exclusively by utilizing the internal energy of the reservoir

(b) Secondary - Depletion in which water or natural gas is injected to supplement the internal energy of the reservoir

(c) Tertiary - All other methods of depletion such as chemical, thermal, etc.

In addition, the term enhanced recovery will be used to represent methods of recovery beyond primary depletion.

2. Primary Depletion of Oil

During the earliest phase of the petroleum industry, oil was recovered by primary depletion. This method involves utilization of the internal reservoir energy such as dissolution of gas, expansion of gas cap, expansion of fluids, compaction of overburden, etc. as a driving force to enable the oil to migrate to the well-bore.

As the oil production continues, the reservoir pressure declines unless replenished by some moving aquifer or compacting overburden. Only a few reservoirs are fortunate enough to have a large and mobile aquifer which is able to supply water to the reservoir as fast as the oil is normally produced or to have fast enough compaction to replace the energy lost through production. The decline in reservoir pressure adversely affects the oil production in several ways. Among the most important are:

(a) it diminishes the driving force which is essential to push the oil to the well-bore,

(b) it releases some of the gas previously in solution and impedes the flow of oil while increasing flow of gas.

Primary recovery is an inefficient method especially in reservoirs having little solution gas. In the case of light oil reservoirs, it may yield a maximum of 20 to 30 percent of the original oil-in-place. For heavy oil reservoirs such as encountered in the Lloydminster area the recovery efficiency usually ranges between 0 and 6 percent averaging approximately 4 percent. However, in some cases, expected recovery factors as high as 8 to 10 percent have been reported.

Consequently, primary depletion leaves a substantial portion of the oil in the formation which may never be recovered. It is also recognized that if the reservoir pressure is allowed to decline to a sufficiently low level, oil which might otherwise be considered recoverable by secondary or tertiary means could also be lost permanently. It is therefore necessary to implement enhanced recovery schemes at the early stages of depletion.

3. Secondary Recovery

A traditional method of increasing oil recovery by supplementing the reservoir energy is through injection of water or gas into the reservoir. These methods are briefly explained below.

3.1 Water Injection: The basic idea in a waterflood recovery process is to inject water into the reservoir and supplement the energy lost through production and force the oil towards the producing well. The process is schematically shown in Figure 1.

The benefits of water injection on oil recovery were recognized accidentally when disposal water was inadvertently injected into a formation through abandoned wellsin 1880, in the Pithole City area in Pennsylvania. Since then remarkable improvement has been made in the technique resulting in severalfold increases in oil recovery, especially in light oil reservoirs.

Waterflood technique on a large scale was first applied during the early 1920's. These initial flooding methods were inefficient because of the lack of adequate knowledge of fluid movements within the reservoir. In subsequent years through extensive laboratory research and field pilot studies the concept of pattern-flooding was introduced. Some of the patterns commonly used are shown in Figure 2.

One of the most important aspects of reservoir engineering is to predict fluid behavior and the impact of operational changes on production rates and the ultimate recovery. The methods of prediction at the early stages of development of waterflood technique were cumbersome and inaccurate. During the mid 1960s, due to the widespread use of computer technology, the behaviour of fluid in the reservoir could be more accurately predicted. By calculating the fluid saturation and pressure distribution as a function of time, and by simulating the effect of operational changes on reservoir performance most of the costly errors in design and implementation could be identified and to a large extent eliminated. The new technology also had much impact on industry in that the manpower needed for lengthy calculations could be greatly reduced.

Injection of water into the reservoir as a rule increases the rate of production which is more pronounced in light oil reservoirs. Therefore, besides improving ultimate recovery it also increases the rate of production. Through careful planning of waterfloods, the recoverable portion of oil can be increased to as much as 50 percent of the original oil-in-place in light oil reservoirs. For heavy oil it is much lower but may reach 20 percent under suitable conditions.

Waterflooding in the Lloydminster area was first initiated in the late 1950s with the injection of water into the Lone Rock pool as a pilot project. This pilot study proved the feasibility of waterflooding the heavy oils in the area, and as a result, water injection started in major pools during the 1960s.

The ultimate recovery of oil in the Lloydminster area through waterflooding generally varies between 6 and 12 percent of the original oil-in-place with an average value of approximately 8 percent. However, in some cases recoveries as high as 20 percent have been anticipated.

Research and field experience indicate that it is advisable to initiate water injection at an early stage of primary depletion. However, the long time span required for the development of a pool and economic considerations do not always permit a timely implementation. The ensuing delay reduces recovery efficiency in many projects. To date, almost all the light oil pools in Canada are on enhanced recovery schemes although much remains to be accomplished in the case of heavy oil pools where the economic incentives have been less attractive.

3.2 Gas Injection: As in waterflood, injection of natural gas adds energy to the reservoir resulting in an increase in the ultimate recovery.

However, the mechanism of fluid movements using gas injection is considerably different than that of waterfloods. Gas injection is generally more applicable to reservoirs with large primary gas caps or where waterflooding is suspected to produce detrimental effects. Since this method is not applied to the pools in the Lloydminster area, its detailed explanation is considered beyond the scope of this report.

4. Tertiary Methods of Oil Recovery

Tertiary methods of oil recovery cover a wide range of technological applications designed to improve oil recovery efficiency. Although many of these technological advances have been and are effectively applied to commercial exploitation, there are a few others that are still only of academic importance under the current state of development.

The tertiary recovery methods may be broadly classified into two groups:

(a) non-thermal, and

(b) thermal.

4.1 Non-Thermal Recovery Processes: The non-thermal methods make use of the beneficial changes in physical and chemical properties of rock and oil. The most important of these methods include: chemical floods, CO_2 flood, micellar flood, polymer flood, and solvent extraction. Results of laboratory and field pilot projects indicate that non-thermal methods are more suited for light oil reservoirs whereas thermal processes have distinct advantage in heavy oils. Since the non-thermal methods have only limited applicability in Lloydminster area their detailed explanations will not be covered in this report.

4.2 Thermal Recovery Processes: In a thermal recovery process heat is applied to a reservoir to raise its temperature above the ambient temperature and reduce viscosity of oil which is highly temperature dependent (especially in heavy oils (Fig. 3)). This decrease in viscosity increases the mobility of oil resulting in a higher productivity and recovery. In addition other phenomena that favour the recovery processes are:

(a) steam stimulation,

(b) hydrocarbon cracking of heavier molecules into light components,

(c) alteration of rock properties that reduce the capillary restrictive forces to the fluid flow at the displacing end.

The increase in temperature can be accomplished in two ways:

(1) heat may be generated at the surface or in the well-bore and then injected into the formation as in hot waterflood, steamflood, steam stimulation, etc. or

(2) it may be generated within the reservoir by burning a portion of the oil in the formation.

The latter process is called in-situ-combustion (fireflood). Currently a method of heating the reservoir by electric energy is being studied but has not yet been commercially applied (1).

Generating heat on the surface and then injecting it into the formation has some disadvantages in that a substantial amount of this heat is lost to the surface and downhole equipment. To minimize this loss specially insulated equipment is needed resulting in higher initial capital costs. However, the process is relatively simple to operate and under suitable conditions yields high recovery.

Recovery processes in which heat is generated at the surface are favoured in reservoirs with more than 30 feet net pay thicknesses. Wilson and Roots (2) studied the relative merits of fireflood and steamflood with regard to reservoir and oil properties. Some of their findings, established by comparing nine fireflood and ten steamflood cases that are known to be both technically and economically successful, show that following criteria may be used for selection:

	Net Pay Feet	Permeability (md)	Gravity °API
Fireflood	10 to 120	> 100	10 - 40
Steamflood	30 to 400	>1000	10 to 16 and >40

The net pay thicknesses in Lloydminster area generally vary between 0-25 feet. The above criteria as well as the results of several other studies indicate that, in Lloydminster area, fireflood should be the preferred thermal method of tertiary recovery and hence it is dealt with in some detail. Some of the other more common methods are also briefly explained.

4.2.1. Hot Waterflooding

The process seems to be best adapted to reservoirs that require only mild heating. The sweep efficiency of hot waterflooding may not be as high as in other thermal recovery methods, especially for high viscosity oils.

In some areas, where the reservoirs do not have adequate steam injectivity, and where fracturing might be detrimental, injection of hot water may be used in preference to steam. Another possibility would be to start the recovery process (steam injection) with hot water until adequate injectivity to steam is established.

Hot waterfloods have been tried on experimental basis in some reservoirs. However, as tertiary recovery methods, they have not been found very promising.

4.2.2 Recovery by Steam Injection

Recovery of oil by steam injection can be achieved in two ways:

(a) steam stimulation, or

(b) steam drive.

(a) Steam Stimulation

Steam stimulation, also called "cyclic steam injection" or "huff and puff" has established its widespread application in thick heavy oil reservoirs. In this process, steam (generally 70-80% quality) is injected down a well to raise the temperature of the reservoir around the well-bore. After injecting a specified amount of steam, usually for three to four weeks at some specific rate depending on net pay thickness and other reservoir characteristics, the well is returned to production. In some cases the well is shut in for a certain period of time called "soak period". The hot steam raises the temperature of the reservoir and decreases oil viscosity thus increasing the oil mobility and thus production rates. After the oil production has declined to a predetermined limit, a new cycle may be initiated. The process is repeated until any additional cycle would not heat incremental reservoir volume sufficiently to make the process economically viable. At this stage the well may be converted to a steam injection conduit and production of oil continued from the adjacent wells. This latter process is called steam drive which generally follows steam stimulation.

(b) Steam Drive

In this process, also, steam is injected into the well, but here the injected steam not only serves to reduce the viscosity of oil but also supplies the energy needed to move the oil towards the production well. In many respects steam drive is analogous to waterflooding. As steam is injected into the formation, an expanding steam zone as well as a hot water zone is formed. The latter creates a hot waterflood effect and further ahead of the hot water zone gives rise to a cold waterfront. The most important part of a steam drive is the steam zone where maximum displacement of oil takes place. The displacement efficiency in this zone is almost 100 percent.

As is previously mentioned, the main disadvantage of a steam drive is the loss of heat in transit. Also, there is a considerable heat loss to unproductive over and underburden which at some stage in the life of the project makes the process economically prohibitive. This becomes all the more significant with increase in fuel costs. The distribution of injected heat and the fractional heat loss with time is shown in Figure 4.

The steam drive or steam stimulation processes are more suitable to heavy oil formations with net pay thicknesses in excess of 30 feet as in the Cold Lake area. In the past, numerous steam injection tests have been carried out in the Lloydminster area. However, the results obtained have not been published. It is suspected that these tests have not been successful. Currently there are some four projects in various stages of development which involve steam injection (3) in the Llodyminster area. Three of these projects are partially funded by the Government of Canada.

5. Thermal Recovery by In-Situ-Combustion

5.1 General: The in-situ-combustion is a thermal recovery technique in which heat is generated within the reservoir by burning a portion of the reservoir oil. The amount of oil normally consumed by combustion is approximately 14 percent (4).

In-situ-combustion originated in the early part of the century when underground combustion accidentally occurred when air was injected to drive oil towards the producing well. This combustion increased the production rate and raised the oil temperatures. However, neither of these observations was then attributed to the subsurface fire. Only at a much later date was spontaneous combustion acknowledged as the cause of those unexpected phenomena.

The idea of recovering oil by the in-situ-combustion process was first published during the early 1920's in a patent issued to Edson Wolcott and Frank Howard. The first known attempt to put the process into practice was made in 1952 in Oklahoma. Since then, through extensive laboratory research and field pilot studies, the process has developed to the extent, that today, it can be applied commercially to many reservoirs. The process is not quite perfect and many problems still remain to be solved. However, the vigorous interest shown by industry and other institutions will undoubtedly prove it to be one of the most viable methods of oil recovery in the near future.

In an in-situ-combustion process the burning front continuously moves within the reservoir. The movement of this front may be imagined to resemble the movement of the burning tip of a cigarette. Basically there are two variations of this process, namely: (a) reverse combustion and

(b) forward combustion, depending upon the direction of advancement of the burning front and the direction of air and fluid flow. Of the two, the forward combustion is most widely pursued and hence explained in greater details.

5.2 Reverse Combustion: In a forward combustion method, hot oil flows ahead of the burning front into a cold zone. When applying forward combustion to very viscous oils or tar sands there is a tendency for the hydrocarbons to flow forward while still warm and solidify in the cooler part of the formation sometimes reducing permeability to an extent that the process becomes inoperable. To overcome this difficulty a unique process was designed in which oil flows from the cold into the heated zone. This process is known as reverse combustion. In this process, the formation is ignited at the producing well, and the air required to sustain this combustion is supplied through the injection well. Thus the burning front moves counter current to the injected air (Fig. 5).

Reverse combustion makes it possible to produce oil which is too viscous to flow under reservoir conditions. However, the reservoir must have adequate permeability for the process to work. Since the oil flows towards the burning front, in this process, a part of the moving oil is burnt and the air requirement is often excessive. The process also has low efficiency and is expected to have only limited applications.

5.3 Forward Combustion

5.3.1 General: Forward combustion is the most widely pursued in-situ-combustion method at the present time. The method has two variations namely (a) dry combustion and (b) wet combustion. Some of the important aspects of forward combustion are:

5.3.1.1 Ignition: Ignition of the reservoir is the first prerequisite for in-situ-combustion. In some reservoirs the composition of oil is such that ignition occurs spontaneously by merely injecting air, sometimes within as short a period as eight hours. However, in most reservoirs an external source of heat is needed. Some of the most commonly used methods of igniting a reservoir are (a) downhole electric or gas heaters, (b) injecting of pre-heated air and (c) preceding air injection by an easily oxidizable chemical such as linseed oil to induce spontaneous combustion.

Once the reservoir is ignited, air injection is continued at a predetermined rate to sustain and control the advance of the burning front. The rate of injection is carefully calculated since higher rates tend to burn excessive amounts of the oil in the reservoir and may cause the burning front to override the oil whereas too low rates tend to quench the fire.

5.3.1.2 The Fuel Deposit: The amount of fuel contained in a given volume of reservoir is the most basic parameter in designing a fireflood. If these deposits are too low, combustion cannot be supported without injecting supplemental fuel and if they are too high, the advancement of flood front is too slow since all the fuel must be consumed before the burning zone moves forward. Figure 6 shows fuel deposits as a function of oil gravity. For Lloydminster crude the fuel deposit averages approximately 2 lbs./cu. ft. (5) which is high enough to sustain combustion reasonable well.

5.3.2 Recovery Mechanism of Forward Combustion: In a reservoir undergoing forward combustion a number of zones with varied characteristics are created. Some of the more important of these are: behind the burning front is the clean reservoir with no residual oil. At the burning front the temperature of the reservoir increases to anywhere from 600° to 1500° F depending on the physical characteristics of the reservoir and the operating conditions. Immediately ahead of the burning front, the high temperature cracks the oil into lighter components. These along with other volatile fractions (inherent in the oil) are distilled away leaving a heavy deposit behind, which is generally referred to as coke. It is this coke that serves as fuel to the advancing burning front. Next to it is the vaporized zone consisting of combustion products, vaporized light hydrocarbons and steam. The temperatures across this zone vary from high combustion temperatures to those just necessary to boil water under prevailing pressures. The region in front of this vaporized zone is called the condensing zone, where the volatile products turn into liquid state. From this region oil is displaced by several means: (1) condensed light hydrocarbons displace the oil as in miscible flood, (2) condensed steam causes hot waterflood, (3) the CO_2 in the combustion gases gets dissolved in oil and effects the CO_2 flood, and (4) the remaining undissolved gases provide a driving force to displace oil as in gas drive. The temperatures of this zone range from 100 to 200° F above the initial reservoir temperature. The oil displaced from the condensing zone tends to accumulate in a region ahead of it and forms an oil bank. The temperature of this region is close to the ambient temperature. Further ahead lies the part of the reservoir unaffected by combustion. An idealized forward combustion process is schematically shown in Figure 7.

5.3.3 Dry Combustion: In a dry combustion process air is injected into the reservoir to sustain and propagate the burning front. At the burning front heat is created of which only about 20% is carried forward by the incoming cold air (6). The heat left behind is eventually dissipated to the unproductive over- and underburden. If a greater portion of this lost heat can be salvaged and carried forward where it is needed, the amount of air required for the propagation of the burning front can be reduced resulting in substantial economic benefits. This could be accomplished by injecting water into the reservoir, a modification known as wet combustion.

5.3.4 Wet Combustion: There are two variations of this method that have been proposed: (1) simultaneous air and water injection, (2) alternate air and water injection. The process in which air and water are injected alternately is termed the COFCAW process (combination of forward combustion and waterflood).

The injected water is converted into steam by the high temperatures at the burnt zone. This steam then flows through the burning front and heats the reservoir ahead. Idealized temperature profiles of a wet combustion process is shown in Figure 8. For comparison a temperature profile of a dry combustion is also included.

The in-situ-combustion process has been effectively applied to reservoirs with high viscosity oils where conventional processes such as primary or waterflood are not very effective, and the residual oil saturation is very high. Although the process is preferred in heavy oils it has also been used in reservoirs with oil gravities as high as 40° API. Given below are the criteria that may be used in the selection of this process.

1. Reservoir thickness should be 10 feet or more.
2. Oil content should be greater than 700 bbls./ac. ft. for the process to be economic (in heavy oils this limit should be much higher). In other words, both porosity and oil saturation should be relatively high.

3. The gravity of oil should be in the 10 to 40° API range. Very heavy oils tend to deposit excessive amounts of coke thus requiring higher air injection rates.

4. Permeability of rock should be greater than 100 md. to allow adequate flow of viscous oil.

5. Reservoir depths of between 300 to 4000 feet are suitable. Shallow reservoirs limit injection pressures whereas deep reservoirs involve excessive air compression costs.

6. Current Status of Thermal Recovery Process

The thermal recovery process can be a viable tertiary method of oil recovery especially in heavy oil reservoirs with thick formations. The technology has advanced significantly since its first application in the early 1920's. Hundreds of technical papers have been published describing field projects and providing greater understanding of the mechanism. Some of the projects are several years old whereas some are in earliest stages of development. Unfortunately, however, valuable data obtained from many of the projects has been considered confidential and hence is not published. Also information from many of the projects which have not been considered economically or technologically successful have been ignored. It is hoped that during the coming years the data obtained from the pilot projects and the results of research will be published to the benefit of all concerned.

REFERENCES

Ref. 1 The Electric Pre-heat Recovery Process - D. E. Towson, in The Future of Heavy Crude Oils and Tar Sands: International Conference - sponsored by the United Nations Institute for Training and Research (UNITAR) and the United States Department of Energy, Edmonton, Alberta, June 1979. R. F. Meyer and C. T. Steele, editors. McGraw-Hill Mining Informational Services, New York, 1980.

Ref. 2 Cost and Comparison of Reservoir Heating Using Steam or Air - L. A. Wils and P. J. Root, Journal of Petroleum Technology, vol. 18, February 1976, p. 233.

Ref. 3 Field Pilot Project Optimization Through Single Well Pre-Pilot Test - P. J. Jespersen, in The Future of Heavy Crude Oils and Tar Sands: International Conference - sponsored by the United Nations Institute for Training and Research (UNITAR) and the United States Department of Energy, Edmonton, Alberta, June 1979. R. F. Meyer and C. T. Steele, editors. McGraw-Hill Mining Informational Services, New York, 1980.

Ref. 4 In-Situ Combustion in the Tulare Formation, South Belrdige Field, Kern County, California - C. F. Gates, K. D. Jung and R. A. Surface, 47th Annual California Regional Meeting of the Society of Petroleum Engineers of AIME, April 13-15, 1977 (SPE.6554)

Ref. 5 Factors Influencing Selection of Oil Reservoirs and Design Considerations for Production by In-Situ-Combustion and the Combination Thermal Process (Thermal Recovery Course) - Tejas Petroleum Engineers, April 1973.

Ref. 6 Thermal Recovery by In-Situ-Combustion - E. F. Herbeck, R. C. Heinz and J. R. Hastings, Part 9 of Fundamentals of Tertiary Recovery Course, Petroleum Engineer, February 1977, p. 46.

SCHEMATIC DIAGRAM OF WATERFLOOD

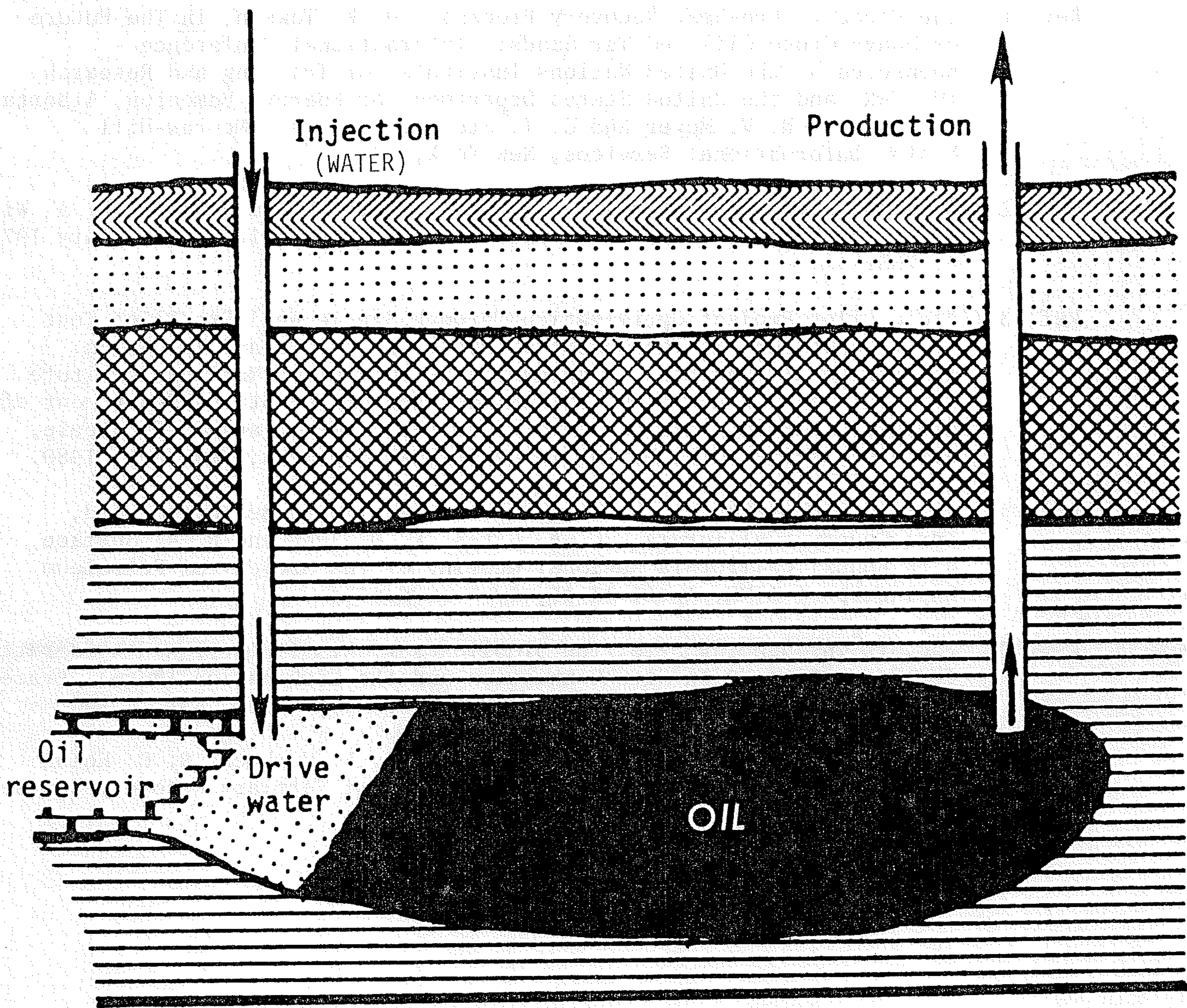
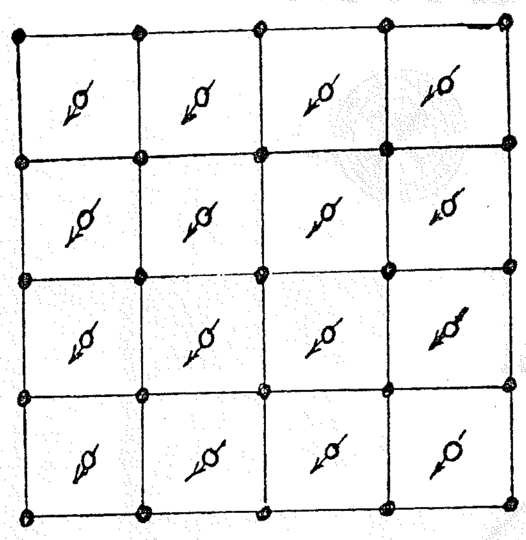


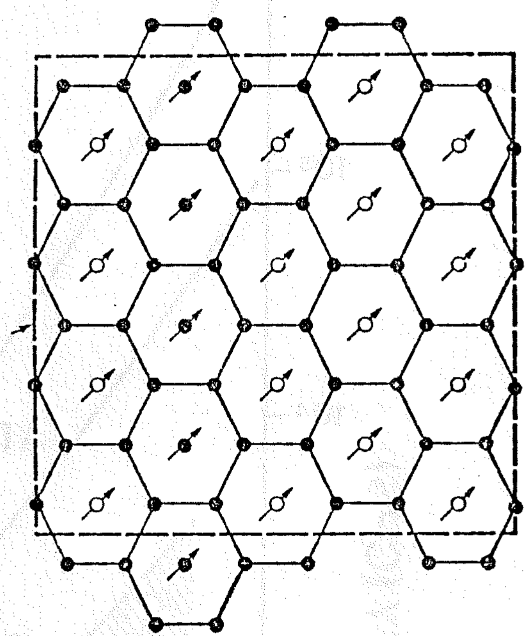
FIGURE 1

Figure 2

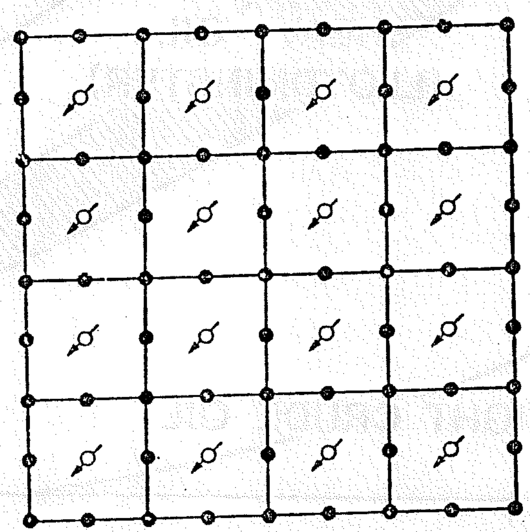
INJECTION PATTERNS



5-Spot



7-Spot (Inverted)



9-Spot (Inverted)

Legend

● Production Well

Injection Well

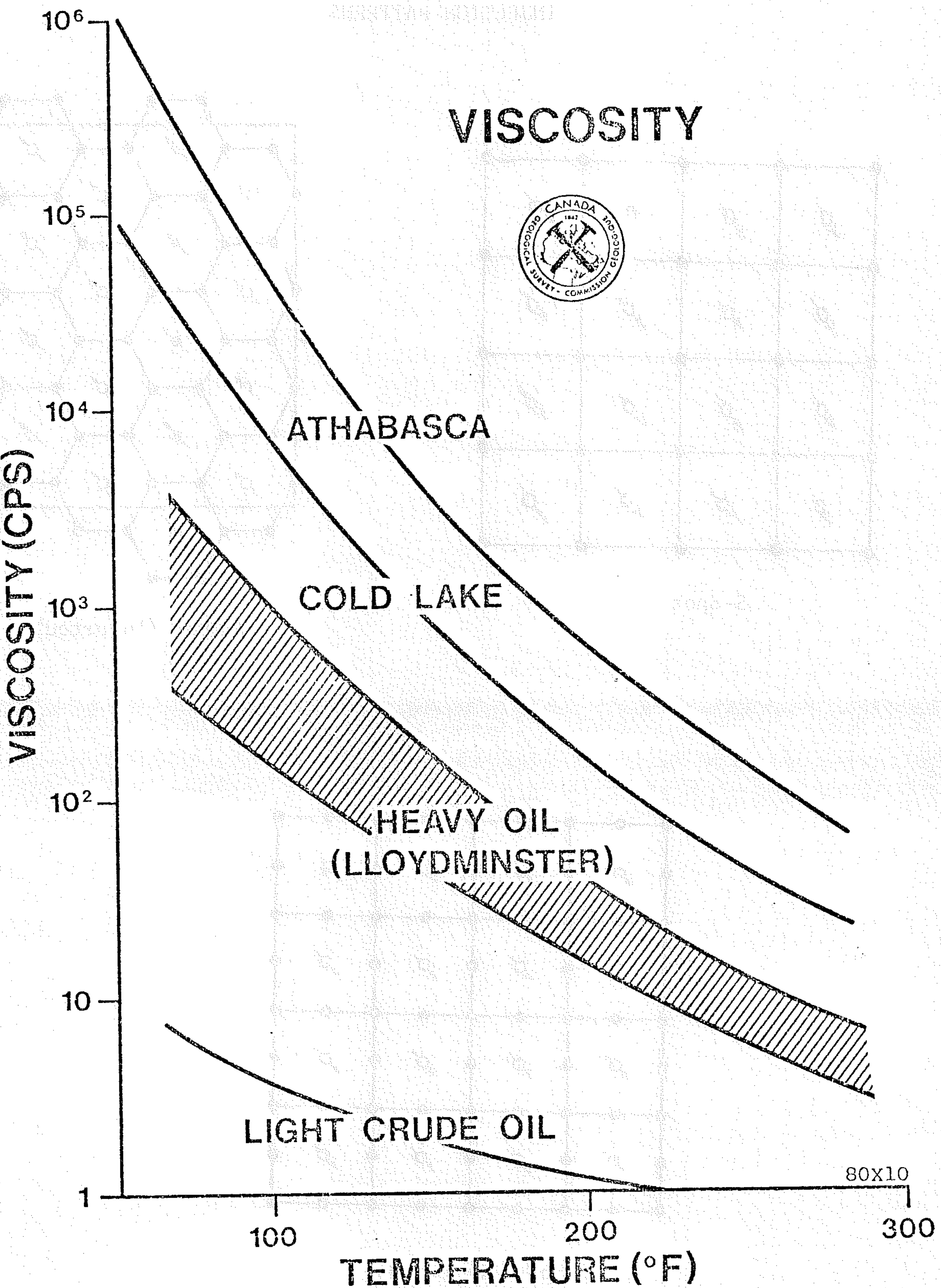

VISCOSITY
CANADA
GEOLOGICAL SURVEY · COMMISSION GEOLOGIQUE
ATHABASCA
COLD LAKE
HEAVY OIL
(LLOYDMINSTER)
LIGHT CRUDE OIL
VISCOSITY (CPS)
10^6
10^5
10^4
10^3
10^2
10
1
100
200
300
TEMPERATURE (°F)
80X10

FIG. 3

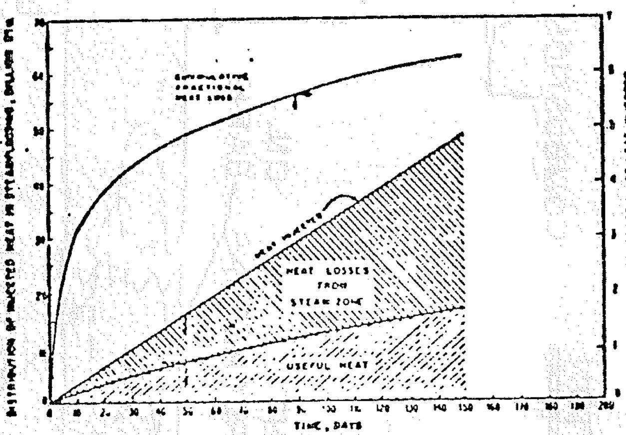


Fig. 4—Distribution of injected heat and fractional heat loss vs time.

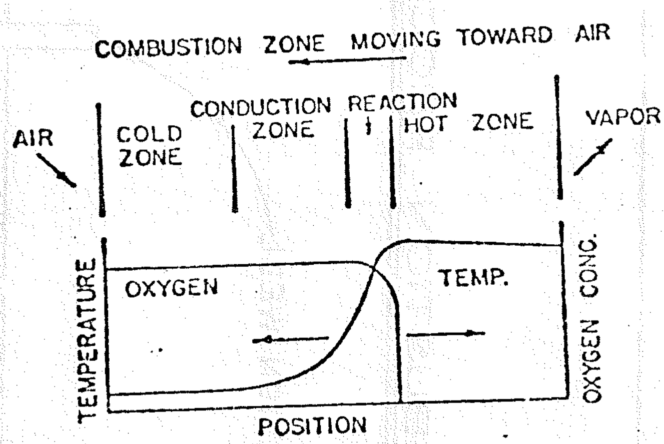


Fig. 5—Schematic diagram of reverse combustion (aft Berry and Parrish[14]).

FIGURE 6

RELATIONSHIP BETWEEN FUEL DEPOSIT AND CRUDE GRAVITY

(AFTER ALEXANDER ET AL, JOURNAL OF PETROLEUM TECHNOLOGY OCT. 1962)

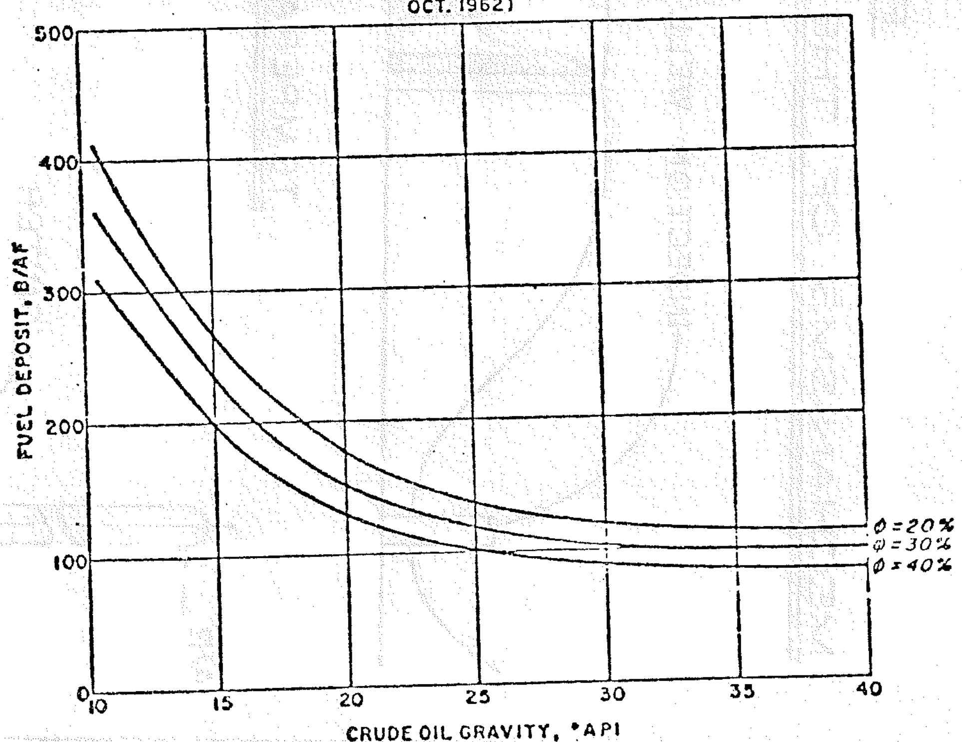
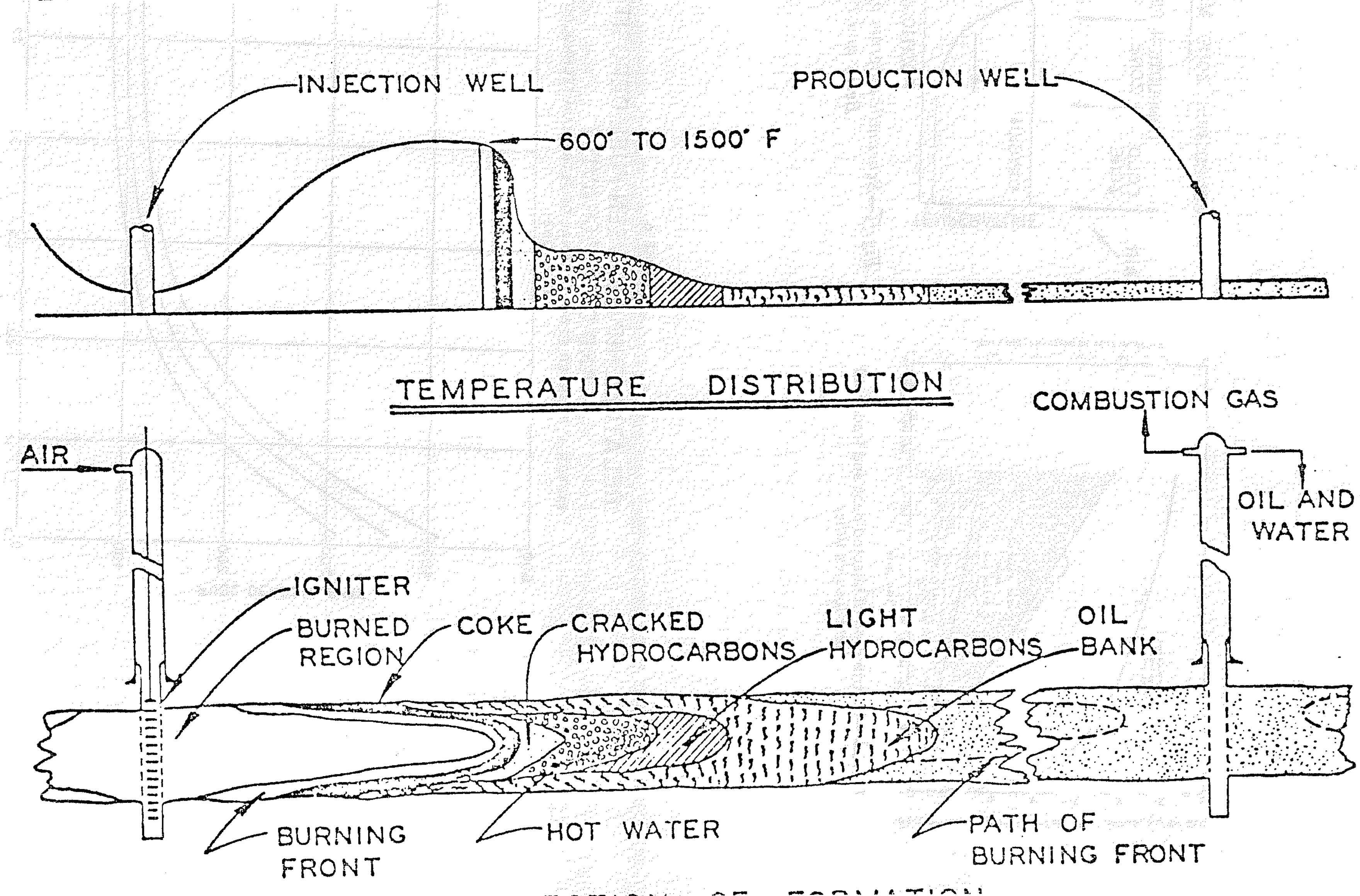


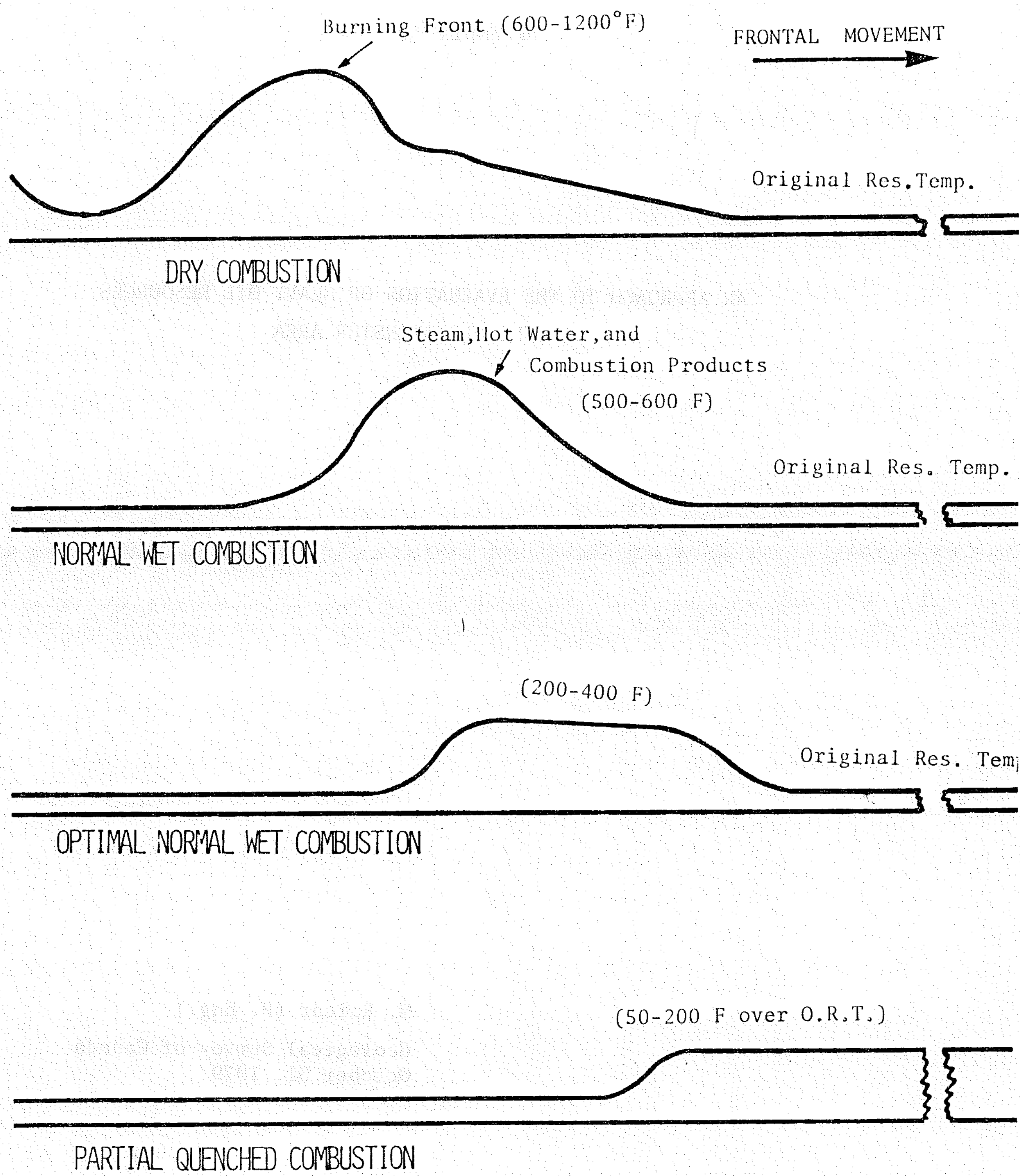
FIGURE 7

MECHANISMS OF THE IN-SITU COMBUSTION PROCESS



FIG·8

SCHEMATIC DIAGRAM OF TEMPERATURE PROFILE



APPENDIX "B"

AN APPROACH TO THE EVALUATION OF HEAVY OIL RESOURCES IN THE LLOYDMINSTER AREA

M. Raicar (P. Eng.)
Geological Survey of Canada
October 31, 1979

INTRODUCTION

On the 24th and 25th of September, 1979 a meeting involving representatives from GSC, EPS and EPA sectors was called to co-ordinate the efforts of various groups within EMR involved in the ongoing heavy oil study in the Lloydminster area. In this meeting several figures and tables were presented by M. Raicar (GSC) to illustrate a methodology that can be used to achieve collective objectives. Attached is a refined version of the material presented, plus explanatory notes. To eliminate undue confusion the report does not include some of the previously presented figures. Also, all the tabulated data are regrouped and retitled for improved clarity.

It should be noted that this report is primarily intended to exemplify and illustrate the different concepts that can be used to evaluate the application of various methods used to recover heavy oil. The assumptions made in this report are based on practical experience and are consistent with industry practices. Most of the data used in the evaluations are obtained from industry and are modified wherever necessary to account for anticipated future changes.

This report should be read in conjunction with the previously presented documentation titled "Evaluation of heavy oil potential in the Lloydminster area".

Gravities and distribution of heavy oil

The gravity of oil in the Lloydminster area varies between 10° and 26° API, the most frequent of which is between 15° and 17° API. The gravity distribution is illustrated in figures 1 and 2. Figure 1, also shows the gravity distributions of heavy oil in the whole of Alberta for comparison. Gravity in itself does not play a significant role in recovery mechanism; however its close association with viscosity makes its consideration imperative in certain recovery processes.

Gravity-viscosity relation

Figures 3 and 4 show the relation between gravity and viscosity. Figure 3 shows viscosities that were measured on gas-free oil samples obtained from the entire Lloydminster area whereas those shown in Figure 4 were determined on samples from the Wildmere pool under original reservoir conditions. The viscosity values of the gas-free oil samples are considerably higher than those of comparable samples under reservoir conditions. The main reason for this increase is the release of gas with the decrease of pressure, a phenomenon that takes place during primary depletion.

In the case of thermal recovery processes the effect of increased temperatures on the reduction of viscosities is remarkable and, since the thermal recovery processes involve high temperatures, the initial viscosity considerations are of little importance. Because of the drastic reduction in viscosity, thermal recovery methods are favoured over other tertiary recovery schemes.

Net pay distributions

The net oil pay thickness of the Lloydminster field varies from 0 to approximately 30 feet. Reservoirs with less than five feet of net oil pay, under the existing techno-economic conditions, are of little importance and therefore not included in this distribution. Figure 5 shows the areal extent of the rich oil accumulations under each group expressed as a per-cent of the total area. (The rich oil herein referred to, means reservoirs with low water saturations as specified in the report by McCallum & Stewart Consulting Geologists Ltd.). For the purpose of this illustration the area covering more than 20 feet net oil pay is selected. (For screening criteria see previous documentation under Evaluation of heavy oil potential in the Lloydminster area by M. Raicar.) This area will hereinafter be referred to as area A. As may be seen in Figure 5, only a small portion of the total area falls under this category and the major portion of the field has between five and ten feet net oil pay. Under the currently existing conditions, this latter category is of little significance for tertiary recovery operations. However, it could be considered for primary and waterflood recovery assessments.

Selection of a module

Figure 6 shows a module for the tertiary recovery project used for economic evaluation as a basis for development of the field. This module comprises 45 producing wells and 10 injection wells and includes 10 invert nine spot injection patterns. The wells are assumed to be drilled on a 10-acre spacing which is considered most economical in this area. The module area will hereinafter be referred to as area B.

Physical limitations to development

Field development and an operation of the magnitude we are confronted with deserves special attention regarding physical limitations. The most important of these limitations can be divided as follows:

(A) Availability of drilling equipment

(B) Availability of trained manpower

(C) Availability of technical personnel

(D) Availability of other hardware required to put projects on stream

(E) Financing

(F) Other miscellaneous limitations, such as legal, access to site, ecology, etc.

As may be seen, there are various factors that can hamper the development process. It would be very laborious to evaluate the effect of each of these factors individually and express them as a simple function. Therefore, to simplify the procedure it is felt necessary to consider only the most important factor which takes into account the essential elements of limitations to the greatest extent.

In this study, extrapolation of drilling activities during the last few years is felt to be the best indicator for future development. Figure 7 shows the drilling activities in the Lloydminster area since 1950. It can reasonably be assumed that during the last four to five years the drilling capacity in the Lloydminster area was almost fully utilized and therefore the same trend is likely to continue during the next few years. Figure 7 illustrates three different projections; optimistic, most probable and pessimistic. In this report only the most probable projection is utilized. These projections would be re-evaluated in the light of any additional information or developments.

Historically, the drilling activity in the Lloydminster area is frequently shifted across the border between Alberta and Saskatchewan depending upon the financial incentives offered. It would therefore be difficult to estimate reliably the future activities on each side of the border. For the purpose of our evaluation it is assumed that approximately 40 per cent of the drillings would be on the Alberta side. It is also assumed that all the newly drilled wells would be successful.

Time sensitivity of economic evaluations

If we consider the aforesaid limitations and the current changes with respect to price of oil, the cost for development and the rapid increase in the operating costs, one cannot ignore the time related changes that are likely to influence the economic evaluation substantially. The time factor, we are concerned with, is likely to extend to over 20 years even if the development were to proceed at the optimum rate. For example, to develop the area A on a ten-acre spacing, with all the drilling activity in the Alberta side of Lloydminster concentrated in this area, it would still take approximately 18 years for complete development.

To incorporate the time related elements, it is assumed that the development of the area B would be consistent with the development pace of the area A. Tables 1 and 2 show the development of the areas A and B over an 18 year period. The expected enhanced drilling activity during the successive years is appropriately accounted for and the fractional values rounded up. Evaluation of a project on this basis together with its application for overall development would take into account all the anticipated changes. On the other hand, development of a project over a limited period, of four to five years, and its subsequent application to overall evaluation would be tantamount to development of the entire area A within this limited period. By any stretch of imagination and under the existing conditions, such a pace of development is impossible. Moreover, it would not reveal adequate information on production rates beyond 15 to 16 years. The attached evaluations are therefore based on spread out development schedule.

Costs and price escalation

As an example case, the capital and the operating costs shown in Tables 2 and 3 are based on existing market values and escalated as follows:

1980 - 1985 - 8.0 per cent per year

1985 - 1990 - 5.0 per cent per year

1990 - 1995 - 4.0 per cent per year

From 1995 and thereafter until the end of the project the costs are left constant at 1995 level.

The price of oil is supposed to escalate from the two assumed 1981 base prices of 17.60 $/b and 21.0 $/b follows:

1981 - 1984 - 10.0 per-cent per year

1984 - 1989 - 6.0 per cent per year

1989 - 1995 - 5.0 per cent per year

The price of oil is kept constant thereafter at 1995 level. The prices of oil are graphically presented in Figure 8.

Gathering, treating and flow lines

In order to estimate the flow line costs, approximately half of the module area comprised of 25 wells is selected. Figure 9 shows the locations of the wells, the flow line lay-out and the surface installations. The criteria used for the lay-out are consistent with the general industry practice.

The estimated costs are equally divided between all the enclosed wells. The cost-per-well is then multiplied by the incremental number of wells during the respective years to estimate the total flow line costs. These costs are then adjusted to account for inflation. The final estimates are shown in Table 2.

Production Forecast

Based on experience, the initial production rate of an average fire-flood well is assumed to be 25 bbls per day per well. This rate is assumed to remain constant over a period of ten years and decline during the subsequent three years to the abandonment rate. During the life of the well it is assumed to produce a total of 110 MSTB from the ten-acre drainage area, which in terms of the original oil in place amounts to approximately 25 per cent. The yearly production rate schedule on an individual well basis is shown in Table 4. The total production rate of the project (module area) is estimated by integrating the production rate of the individual wells in their respective years as shown in Table 1, column 3. Table 1 also shows (1) the average production rate on a per well basis over the entire life of the project, (2) the probable number of wells drilled in area A, (3) the probable number of active wells and (4) the total production rate therefrom. It should be emphasized that the estimated production rate from this area is the maximum rate that can be realized under favourable economic conditions.

Presentation of results

The main objective of this evaluation is to determine the appropriate economic parameters for evaluating the feasibility of various methods and to project some trend of future oil supply under various economic conditions. One of the most important factors that influences the economic feasibility is the price of oil.

For the purpose of our study, a method is shown in Figure 10 to determine the minimum basic price required to generate a specified rate of return. The after tax present values at 15 and 20 per cent discount rates are plotted against the assumed basic prices of oil. The two lines shown in Figure 10 are obtained by joining the respective calculated points, which are then extrapolated to intersect the oil price axis. The points of intersection give the minimum price of oil required to generate the respective rates of return. It should be noted that for the sake of simplicity the relation between present value and oil price is assumed to be linear, which may not be the case in actual practice. Figure 11 presents the present values corresponding to various discount rates for one of the two assumed price schedule cases. Figure 11 also shows the same relation for different net pay thicknesses (hypothetical).

Figure 12 shows the relation between minimum oil prices required to generate a specified rate of return for various net oil pay thicknesses. The data required to generate these curves may be obtained from Figure 10.

Figure 13 illustrates the maximum oil supply projection for over 20 feet net pay, rich oil pools. It should be noted that the supply projection considers that all the drilling activity on the Alberta side of the Lloydminster area will be used to develop this specific area. However, in actual practice the drilling activity will be divided between several different categories and therefore, the final curve obtained by integration of these various curves will have different characteristics.

DRILLING AND PRODUCTION FORECAST
Hypothetical Fire-flood Project
(Lloydminster Alberta)

	AREA "B"			AREA "A"			
Year	Cum. no. of wells in Area B	Prod. rate Mb/y	Prod. rate Mb/w/y	No. of wells drilled in Area A	Cum. of wells in Area A	Prod. rate M bbls/y	Prod. rate M bbls/d
1981	1	9	9	270	270	2430	6.7
1982	2	18	9	290	560	5040	13.8
1983	3	27	9	308	868	7812	21.7
1984	4	36	9	326	894	8046	22.0
1985	6	54	9	346	1240	11160	30.6
1986	8	72	9	366	1606	14454	39.6
1987	10	90	9	388	1994	17946	49.2
1988	12	108	9	410	2404	21636	59.3
1989	15	135	9	432	2836	25524	69.9
1990	18	162	9	456	3292	29628	81.2
1991	21	188.1	8.9	480	3772	33571	92.0
1992	25	222.4	8.9	510	4282	38110	104.4
1993	29	254.0	8.9	542	4824	42934	117.6
1994	32	281.0	8.8	576	5130	45144	123.7
1995	36	316.1	8.8	612	5452	47978	131.4
1996	40	350.4	8.8	651	5795	50996	139.7
1997	45	391.0	8.7	692	6161	63601	146.8
1998	49	427.0	8.7	736	6551	56994	156.1
1999	47	408.1	8.7		6185	53810	147.4
2000	45	388.4	8.6		5797	49854	136.6
2001	43	366.0	8.5		5387	45789	125.4
2002	40	338.1	8.4		4955	41622	114.0
2003	37	309.4	8.4		4499	37792	103.5
2004	34	278.0	8.2		4019	32956	90.3
2005	30	241.1	8.0		3509	28072	76.9
2006	26	203.4	7.8		2967	23143	63.4
2007	22	162.1	7.4		2391	17693	48.5
2008	17	115.4	6.8		1779	12097	33.1
2009	12	71.4	6.0		1128	6768	18.5
2010	6	27.6	4.6		436	2006	5.5

Note: (a) The above forecast considers only the area with more than 20 feet net oil pay with less than 20% water zone referred to as Area A.

(b) The forecast assumes that all the available drilling will be concentrate in this area.

Table 1

(c) The forecast is primarily intended to illustrate an example.

(d) The Area "A" means total area with 22.5 feet average net oil pay (rich oil).

(e) Area B means module area.

CAPITAL EXPENDITURE REQUIRED TO DEVELOP THE MODULE
Hypothetical Fire-flood Project

		Drilling Cost M$[3]					Other Costs[4]					
1	2	3a	3b	3c	3d	3e	4a	4b	4c	4d	4e	5
1981	1	198	198	109	89	40	35	25	76	14	79	119
1982	1	214	214	118	96	44	38	26	82	15	89	133
1983	1	231	231	127	104	48	41	29	89	16	98	146
1984	1	250	250	138	112	51	44	31	96	17	105	156
1985	2	269	538	296	242	56	96	67	208	37	228	284
1986	2	282	564	310	254	58	100	70	218	39	239	297
1987	2	297	594	327	267	61	106	73	229	41	251	312
1988	2	311	622	342	280	64	111	77	240	43	273	337
1989	3	327	981	539	442	68	175	121	379	68	415	483
1990	3	343	1029	566	463	71	183	127	398	71	436	507
1991	3	357	1071	589	482	74	191	132	414	74	454	528
1992	4	371	1484	816	668	77	264	183	573	102	628	705
1993	4	386	1544	849	695	80	275	190	596	104	653	733
1994	4	402	1608	884	724	83	286	198	620	110	679	762
1995	5	418	2090	1150	940	86	372	257	806	143	883	969
1996	5	418	2090	1150	940	86	372	257	806	144	883	969
1997	6	418	2508	1379	1129	103	446	308	968	172	1061	1164
1998	6	418	2508	1379	1129	103	446	308	968	172	1061	1164
1999												
2000												

1 Year
2 Probable no. of wells drilled in the module area
3 Capital Expenditure for drilling and completions
3a Cost per well M$
3b Total cost M$
3c Tangible cost M$
3d Intangible cost M$
3e Additional drill cost over water flood
4 Capital expenditures for producing treating and disposal facilities M$
4a Battery and other gathering and treating facilities M$
4b Flow lines (oil, water and air) M$
4c Compressor and disposal facilities M$
4d Miscellaneous
4e Additional costs over water flood
5 Total additional costs over water flood M$

Table 3

OPERATING COST AND OIL PRICE SCHEDULE
Hypothetical Fire-flood Project

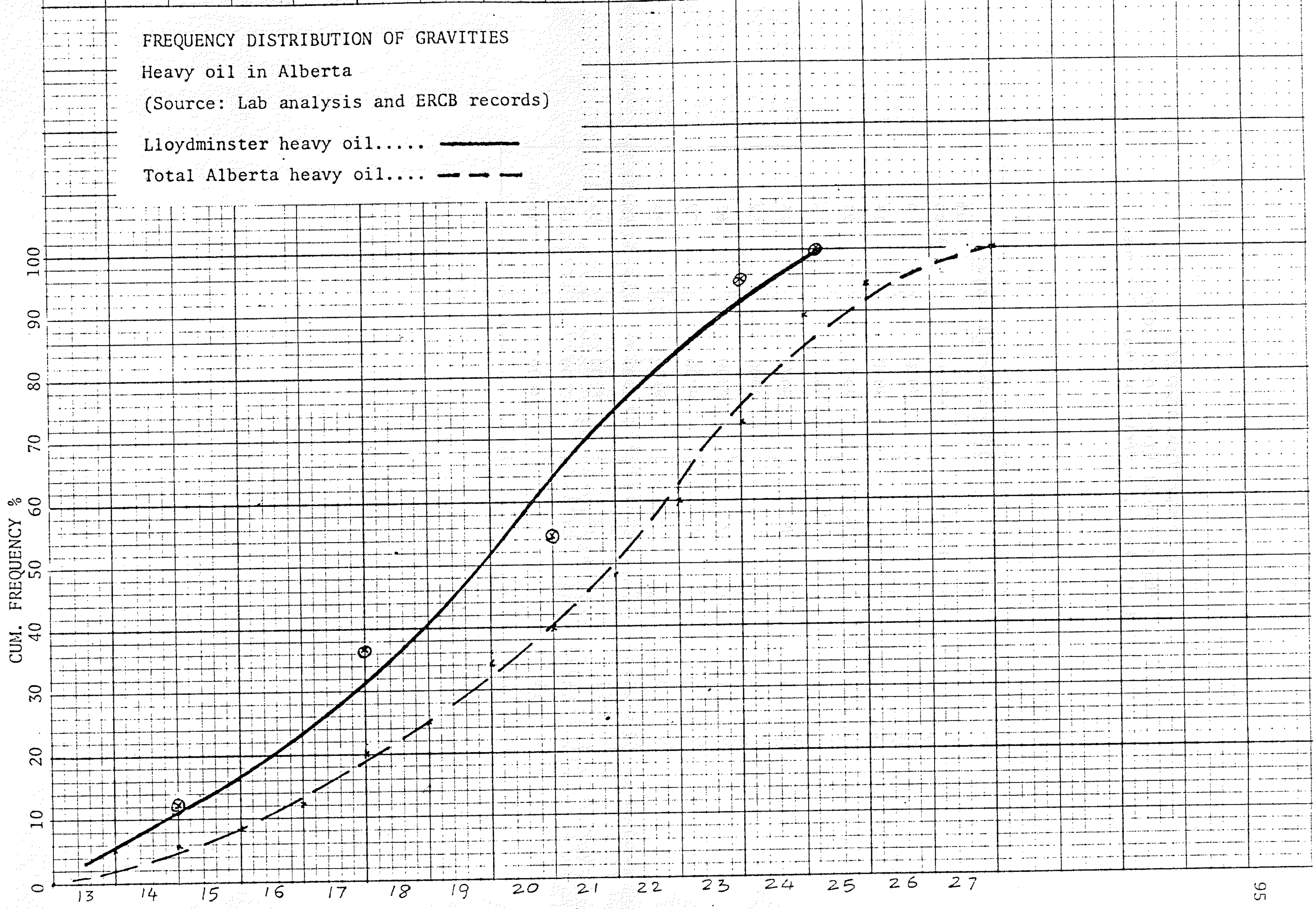
Year	Operating Cost M$/w/y	Basic Price of Oil $/b	
		Schedule I	Schedule II
1981	84	17.6	19.0
1982	91	19.4	20.0
1983	98	21.3	21.0
1984	105	23.4	23.0
1985	114	24.8	25.2
1986	120	26.3	27.8
1987	126	27.9	29.5
1988	132	29.5	32.4
1989	139	31.3	35.7
1990	146	34.9	39.2
1991	152	36.6	43.2
1992	158	38.4	47.5
1993	164	40.4	49.3
1994	177	42.3	51.3
1995	177	44.6	53.4
1996	"	"	"
1997	"	"	"
1998	"	"	"
1999	"	"	"
2000	"	"	"
2001	"	"	"
2002	"	"	"
2003	"	"	"
2004	"	"	"
2005	"	"	"
2006	"	"	"
2007	"	"	"
2008	"	"	"
2009	"	"	"
2010	"	"	"

Table 4

PRODUCTION SCHEDULE
Hypothetical Fire-flood Project
(Net oil pay 22.5 feet; spacing 10 acres)

Year	Oil production rate		
	b/d/w	b/y/w	Cum. M bbls
1	25	9000	9
2	25	9000	18
3	25	9000	27
4	25	9000	36
5	25	9000	45
6	25	9000	54
7	25	9000	63
8	25	9000	72
9	25	9000	81
10	25	9000	90
11	22	8100	98.1
12	20	7300	105.4
13	13	4600	110.0

FIG 1



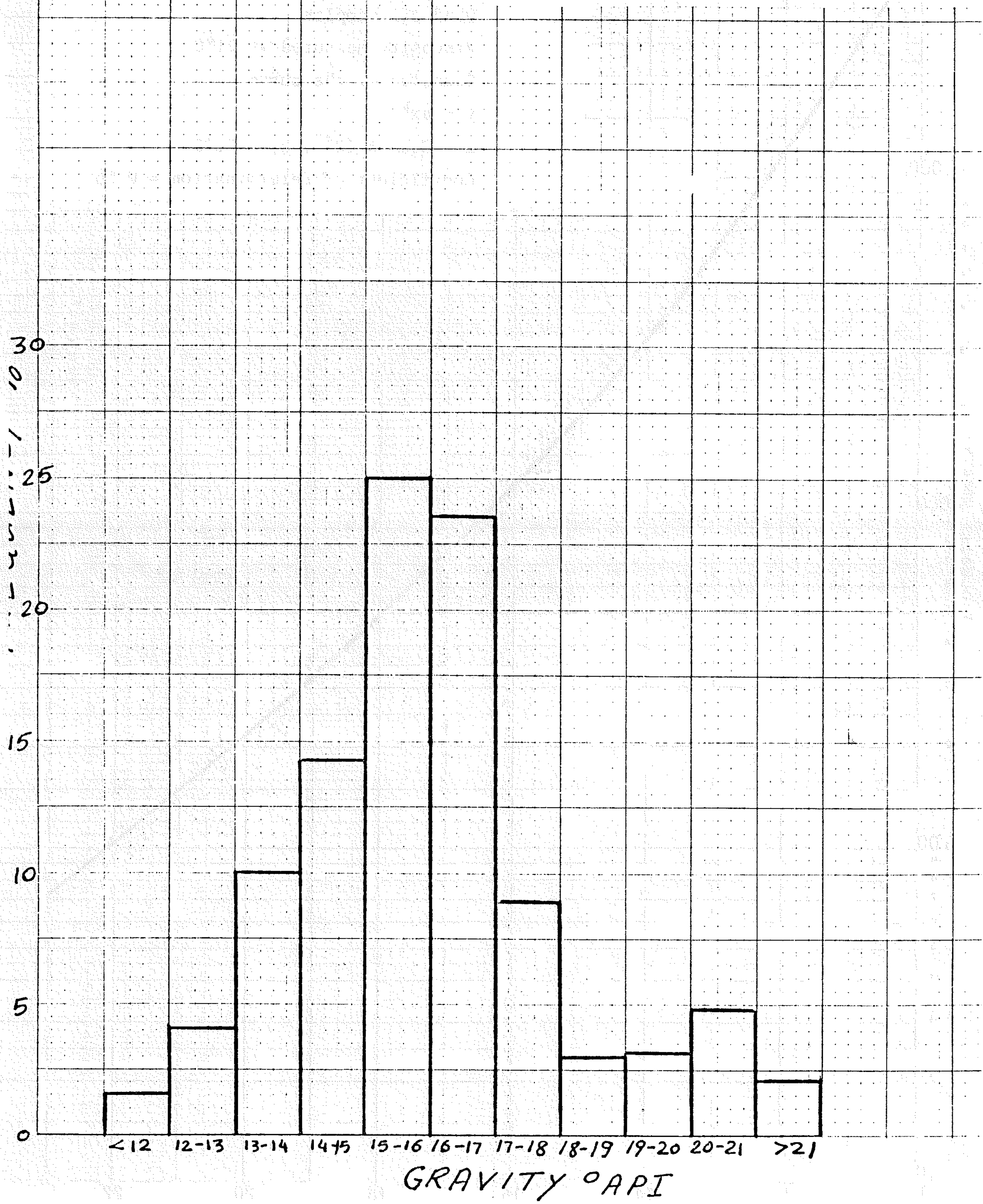
FREQUENCY DISTRIBUTION OF GRAVITIES
Heavy oil in Alberta
(Source: Lab analysis and ERCB records)
Lloydminster heavy oil.....
Total Alberta heavy oil....
CUM. FREQUENCY %
0
10
20
30
40
50
60
70
80
90
100
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

FIG 2

FREQUENCY DISTRIBUTION OF GRAVITIES

Heavy oil Lloydminster area

(Source: Geological log books; heavy c



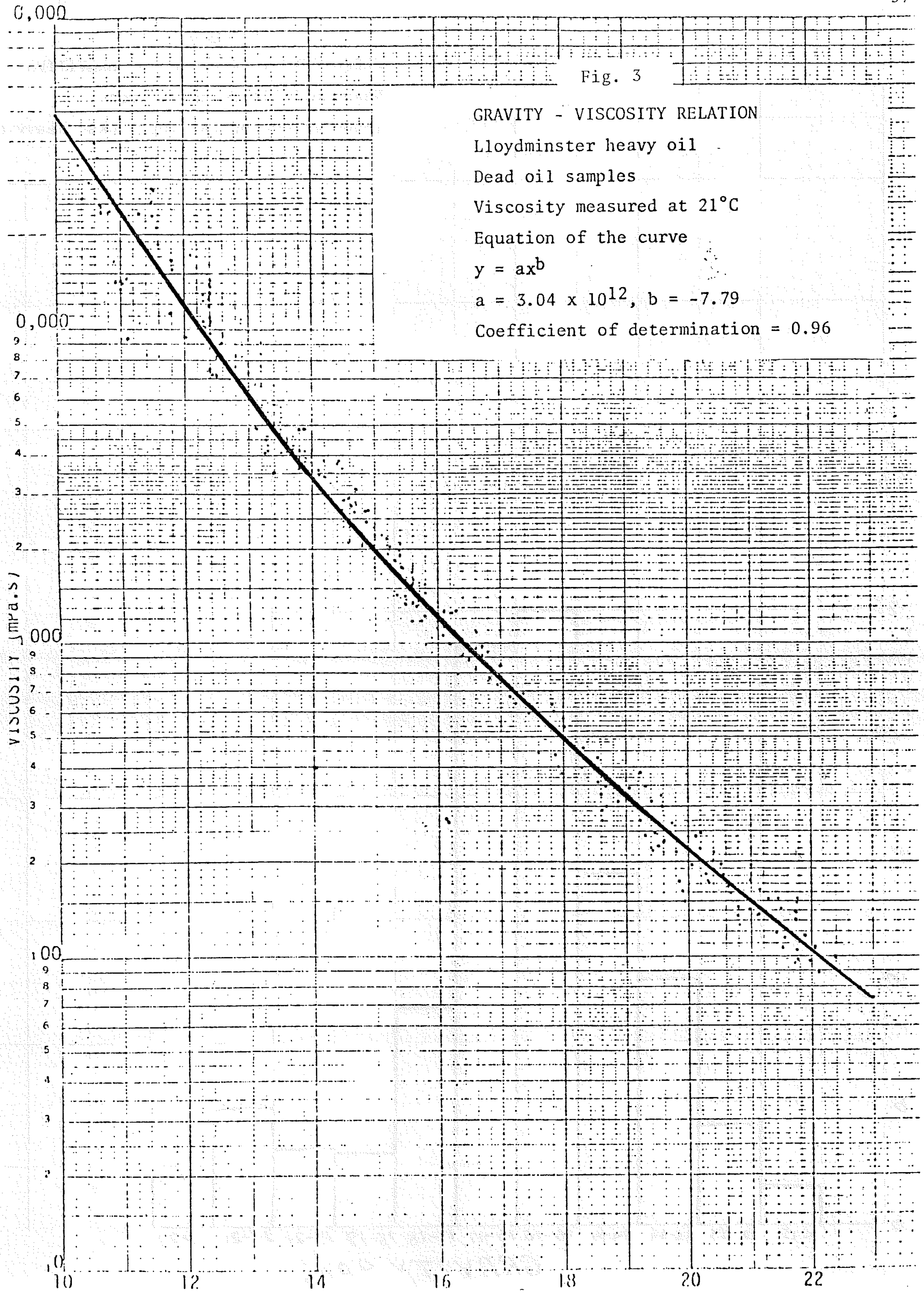
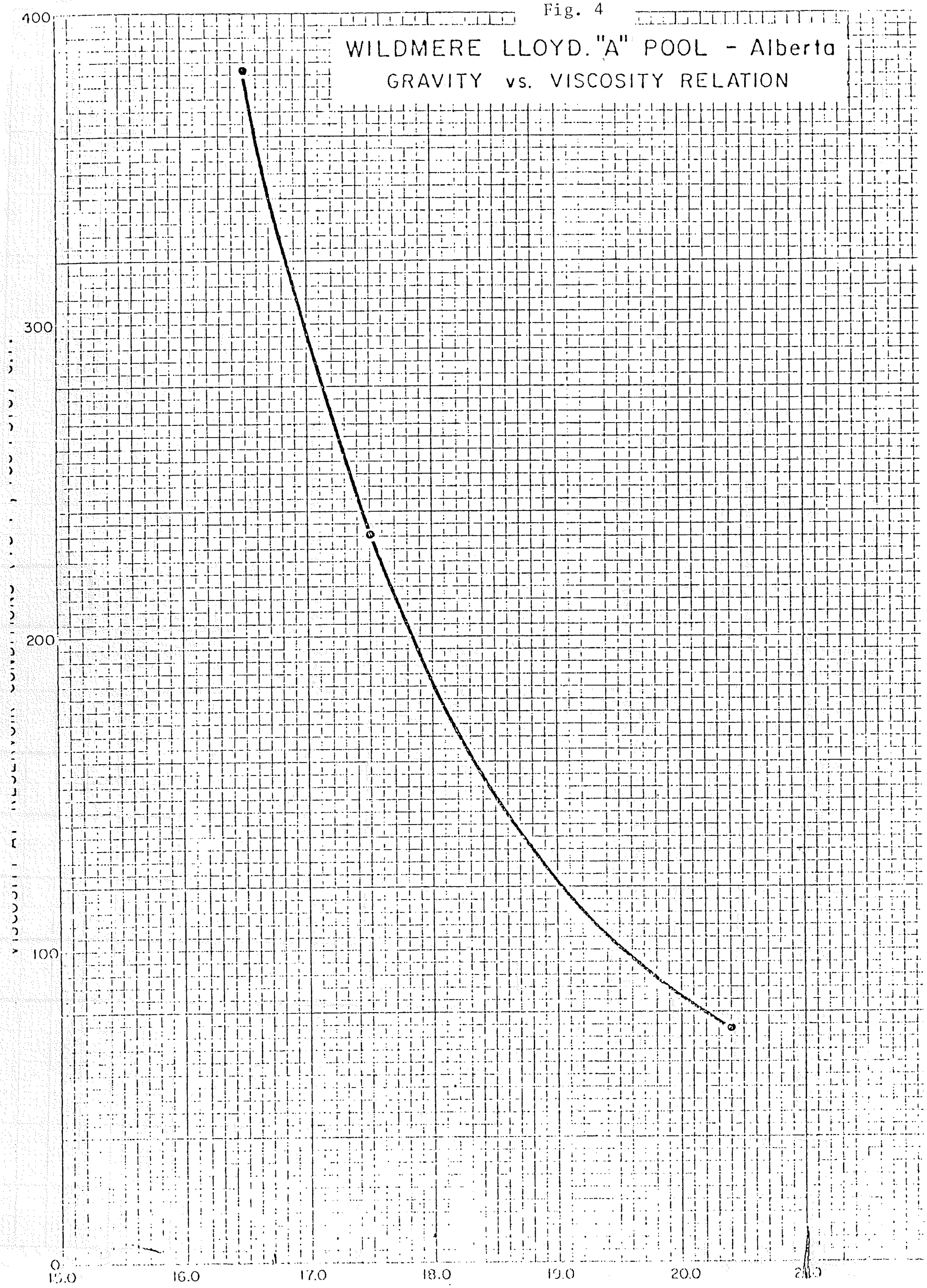


Fig. 3
GRAVITY - VISCOSITY RELATION
Lloydminster heavy oil
Dead oil samples
Viscosity measured at 21°C
Equation of the curve
$y = ax^b$
$a = 3.04 \times 10^{12}$, $b = -7.79$
Coefficient of determination = 0.96
VISCOSITY (mPa.s)
10
12
14
16
18
20
22

Fig. 4


WILDMERE LLOYD. "A" POOL - Alberta
GRAVITY vs. VISCOSITY RELATION
400
300
200
100
0
15.0
16.0
17.0
18.0
19.0
20.0

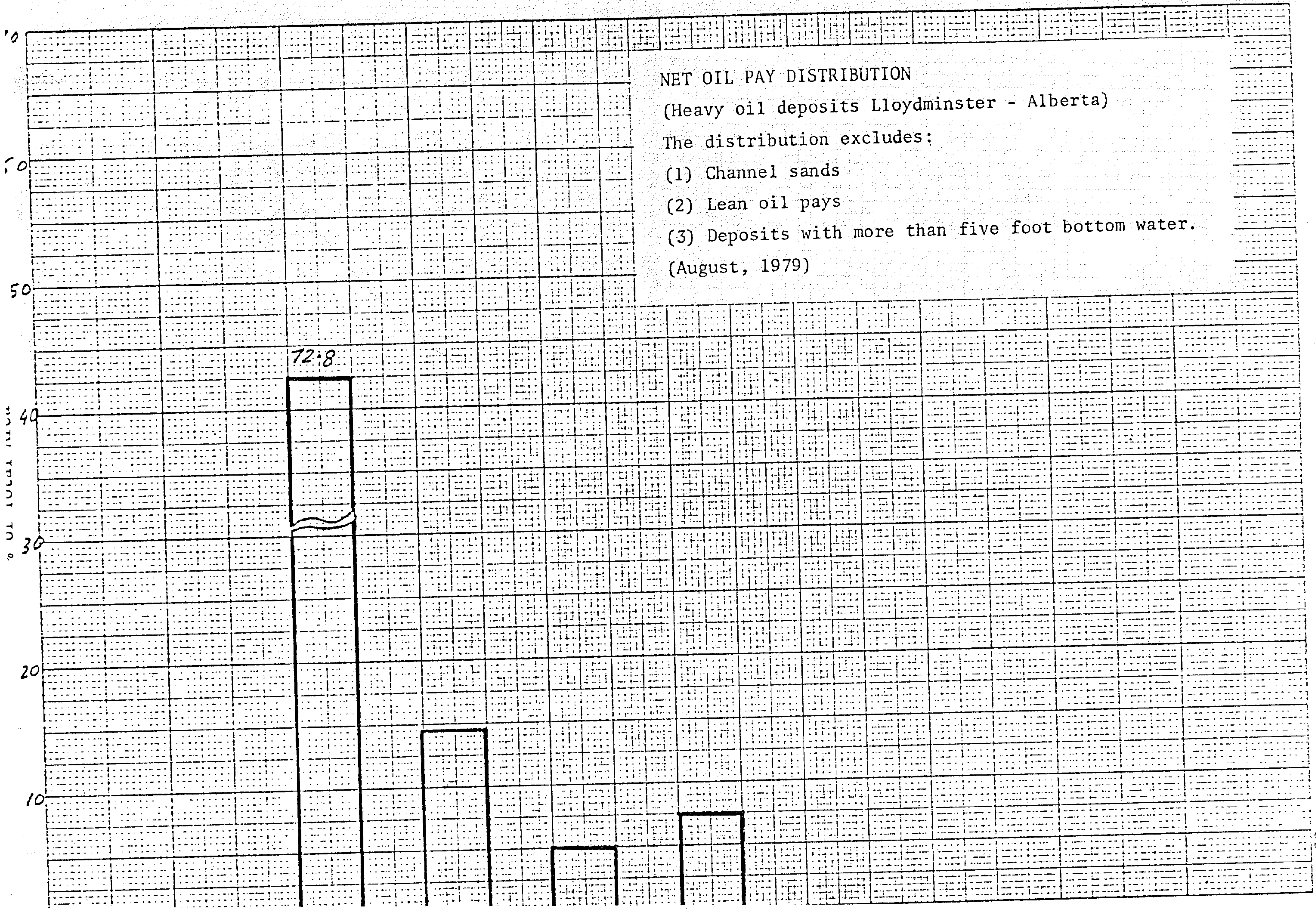
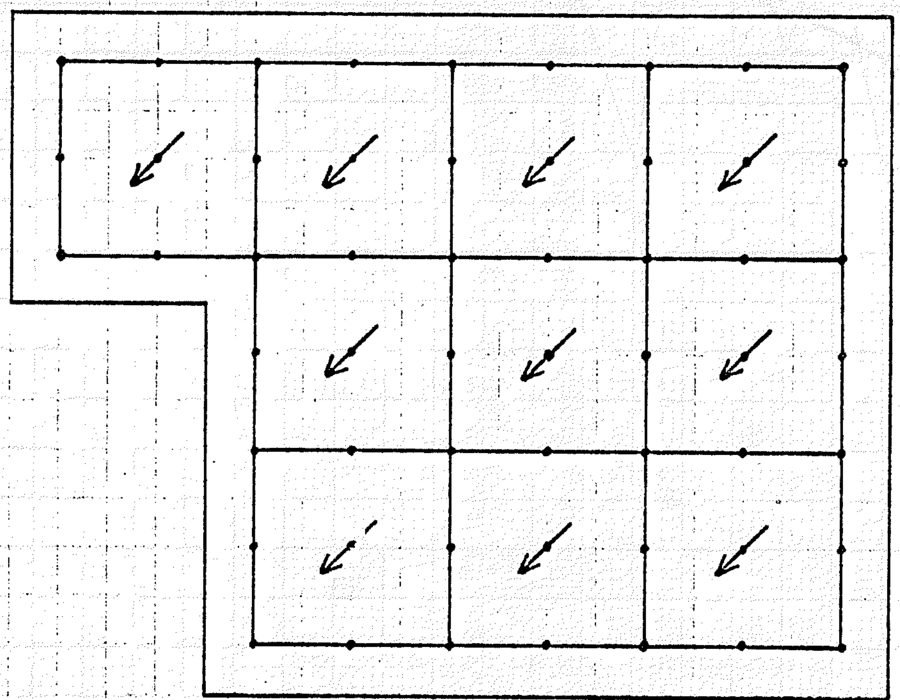

NET OIL PAY DISTRIBUTION
(Heavy oil deposits Lloydminster - Alberta)
The distribution excludes:
(1) Channel sands
(2) Lean oil pays
(3) Deposits with more than five foot bottom water.
(August, 1979)
72·8
10
20
30
40
50
60
70
% of Total Area

Fig. 6

DEVELOPMENT MODULE

Thermal recovery projects



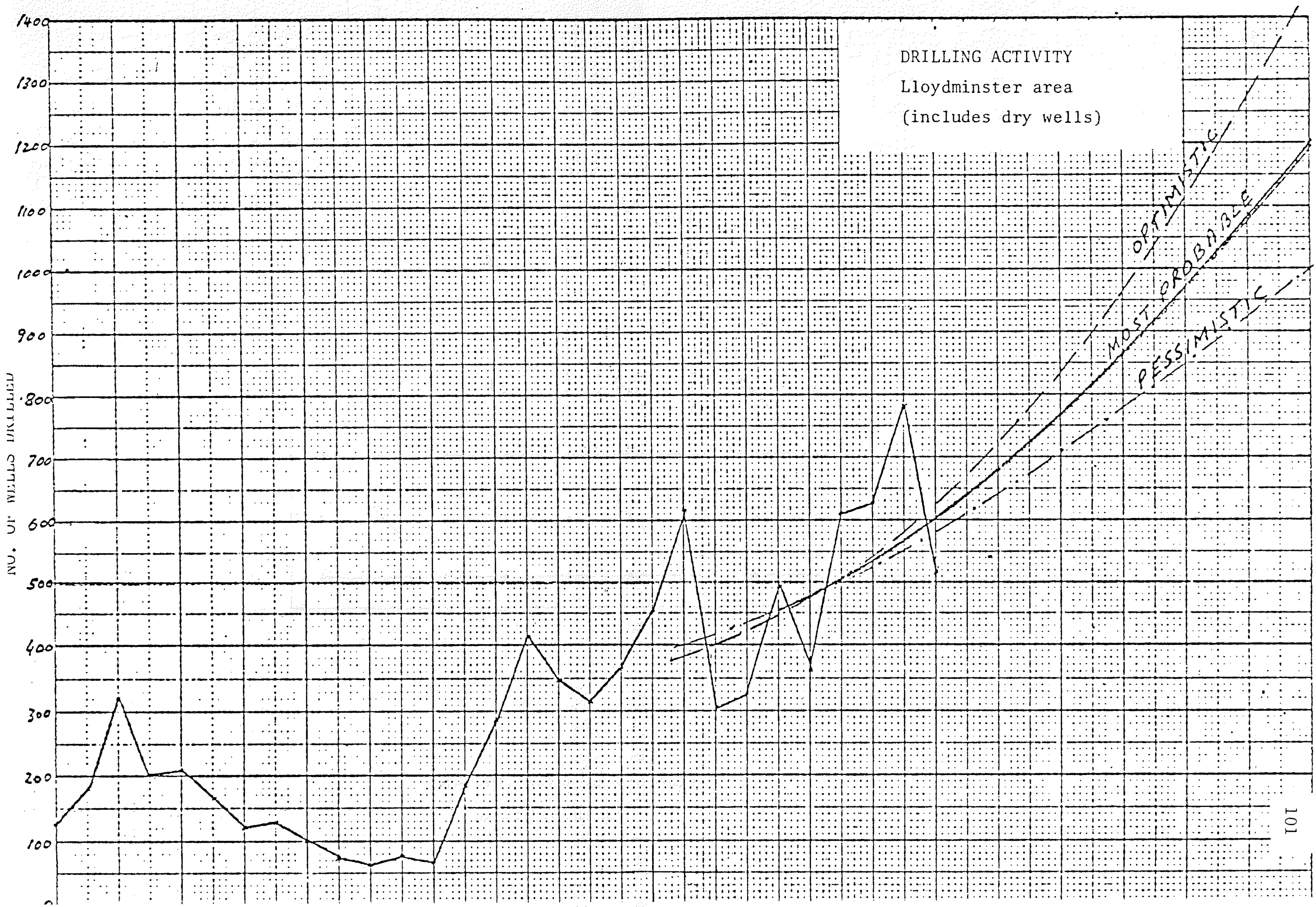
Project - Firewood

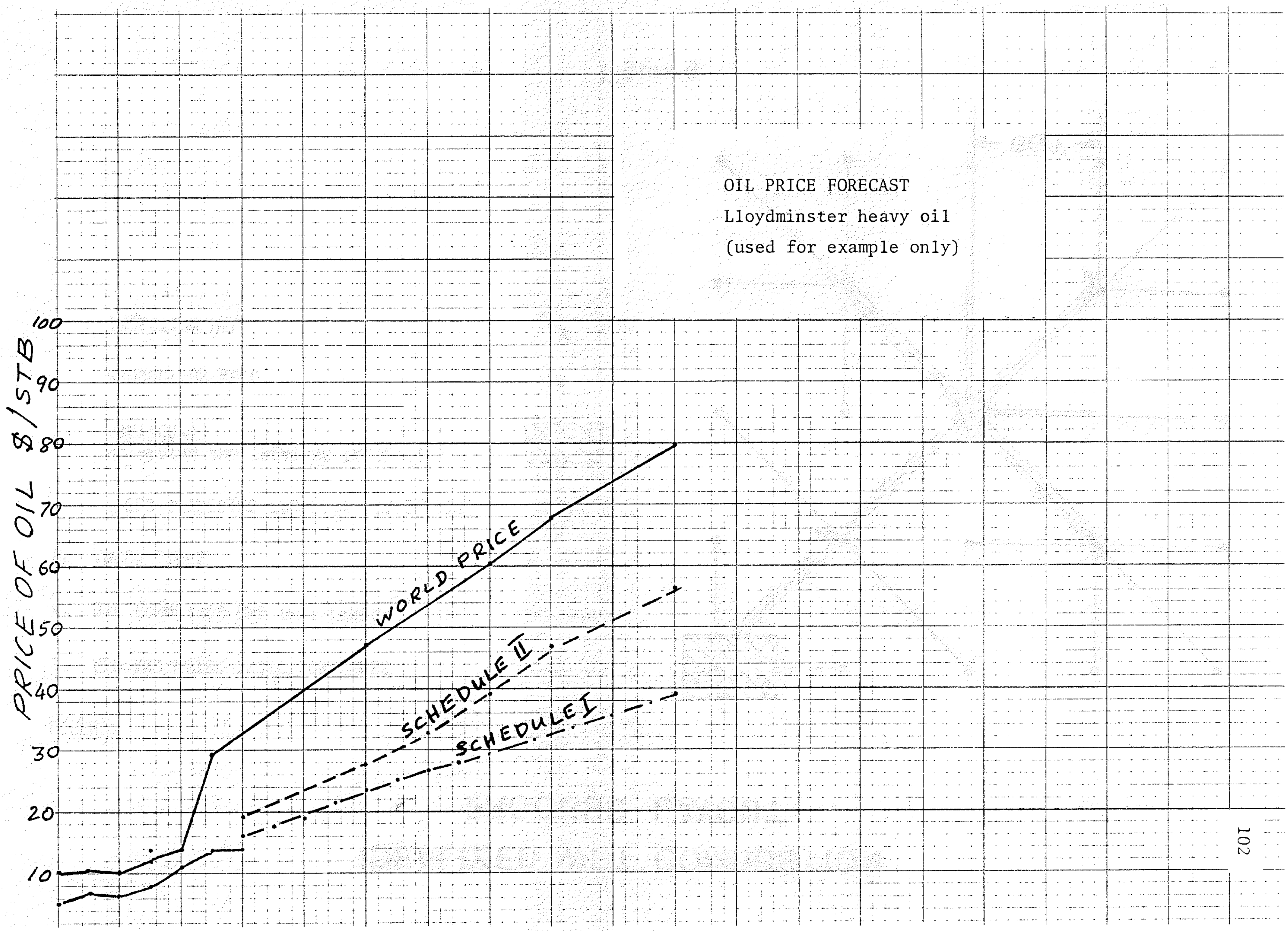
No. of producing wells - 45

No. of air injection wells - 10

Drilling spacing - 10 acres/well

Total area - 550 acres


DRILLING ACTIVITY
Lloydminster area
(includes dry wells)
NO. OF WELLS DRILLED
1400
1300
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
OPTIMISTIC
MOST PROBABLE
PESSIMISTIC


OIL PRICE FORECAST
Lloydminster heavy oil
(used for example only)
PRICE OF OIL $/STB
100
90
80
70
60
50
40
30
20
10
WORLD PRICE
SCHEDULE II
SCHEDULE I

IDEALIZED WET COMBUSTION PROCESS LAYOUT

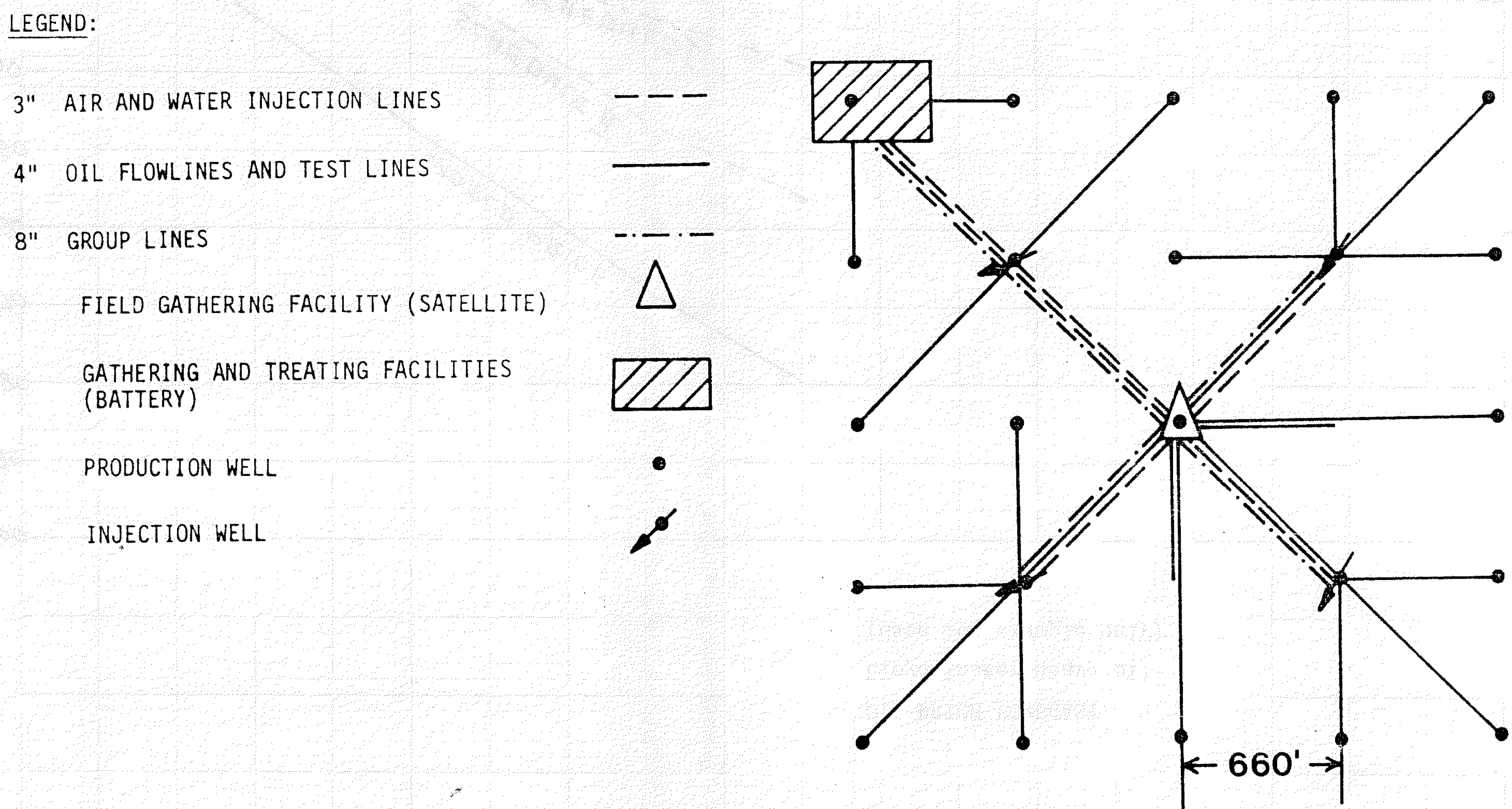
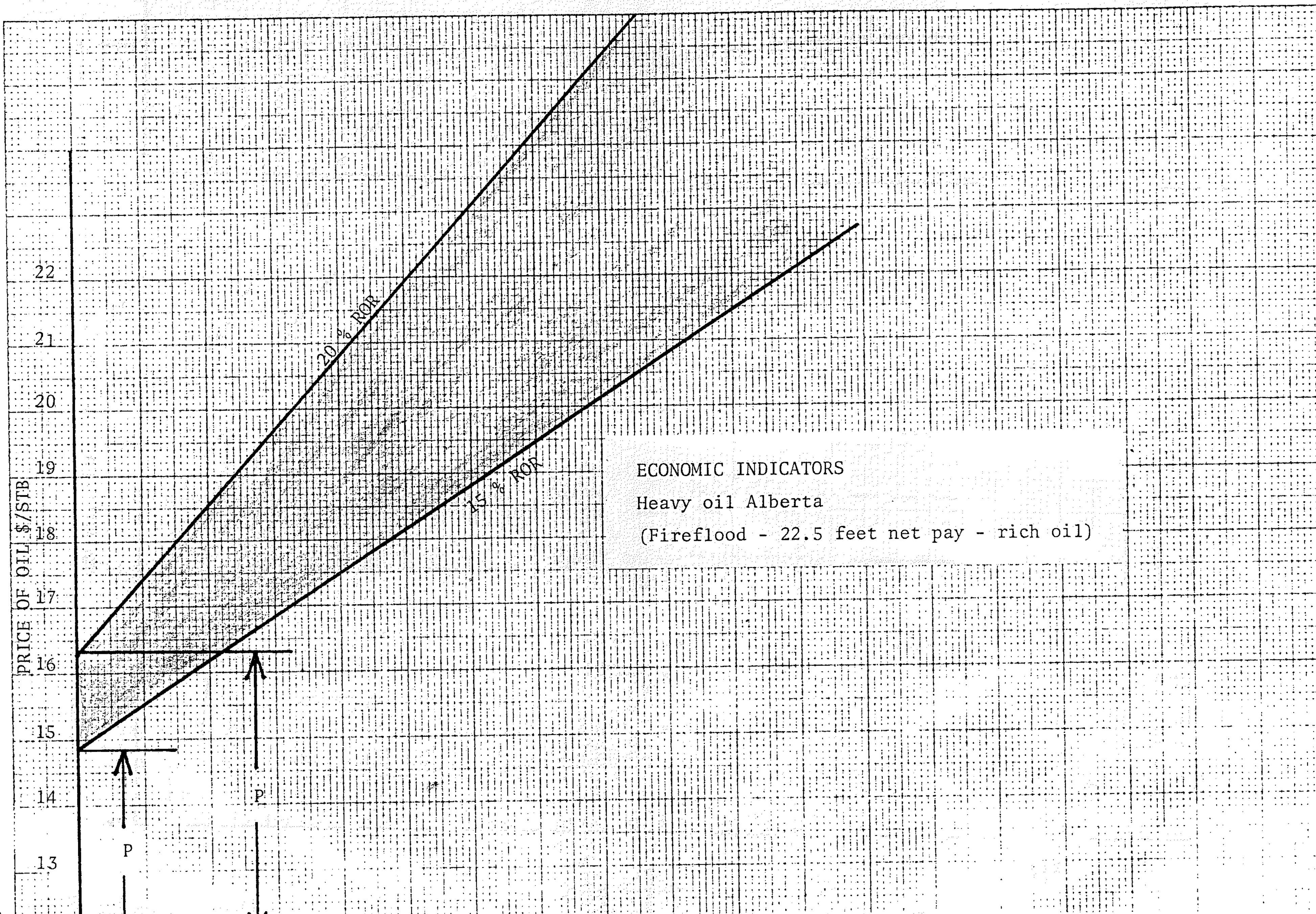


Figure 9

Fig. 10



ECONOMIC INDICATORS
Heavy oil Alberta
(Fireflood - 22.5 feet net pay - rich oil)
PRICE OF OIL $/STB
22
21
20
19
18
17
16
15
14
13
20 % ROR
15 % ROR
P
P

Fig. 11

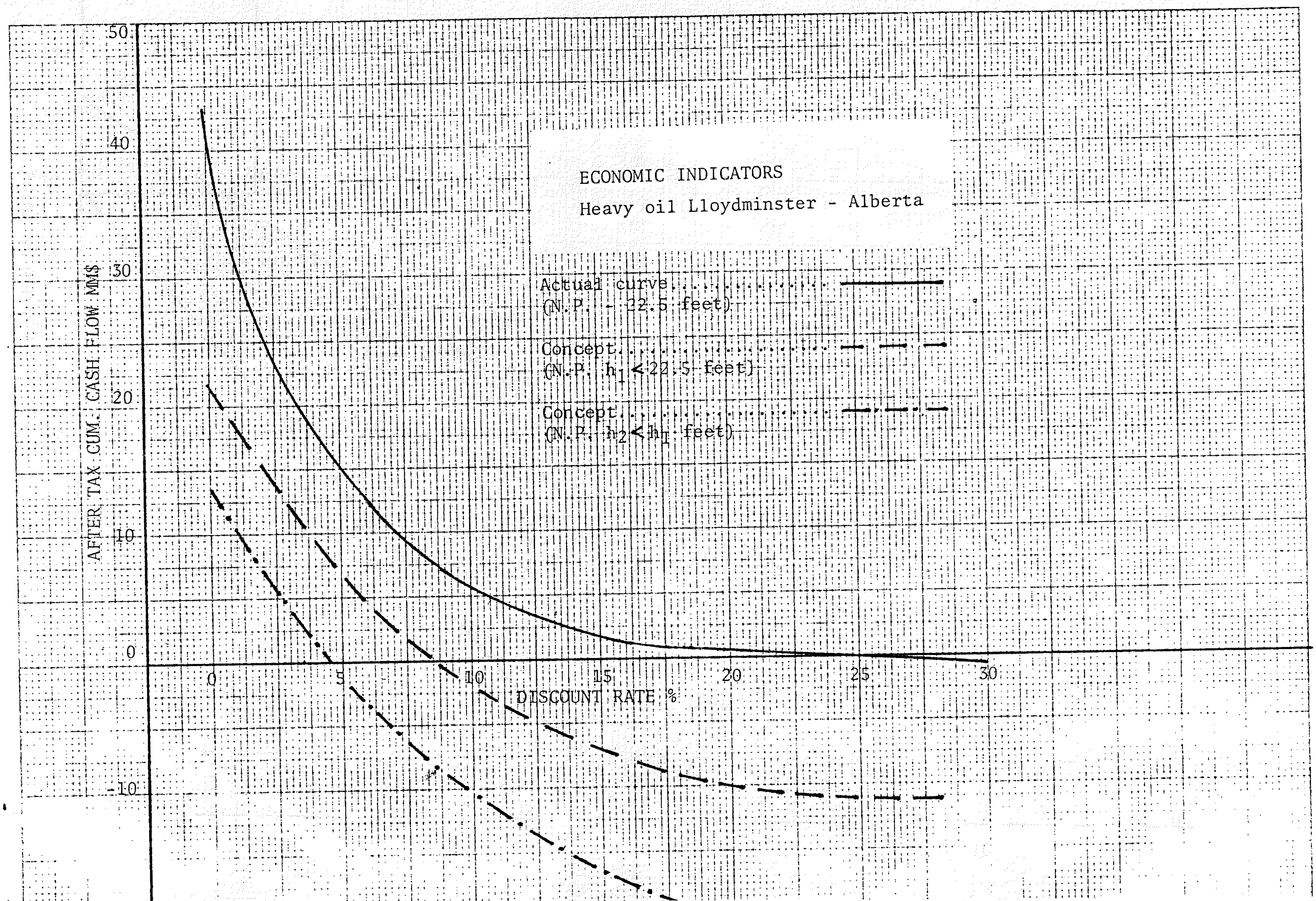

ECONOMIC INDICATORS
Heavy oil Lloydminster - Alberta
Actual curve
(N.P. - 22.5 feet)
Concept
(N.P. h1 < 22.5 feet)
Concept
(N.P. h2 < h1 feet)
AFTER TAX CUM. CASH FLOW MM$
DISCOUNT RATE %
50
40
30
20
10
0
-10
0
5
10
15
20
25
30

Fig. 12

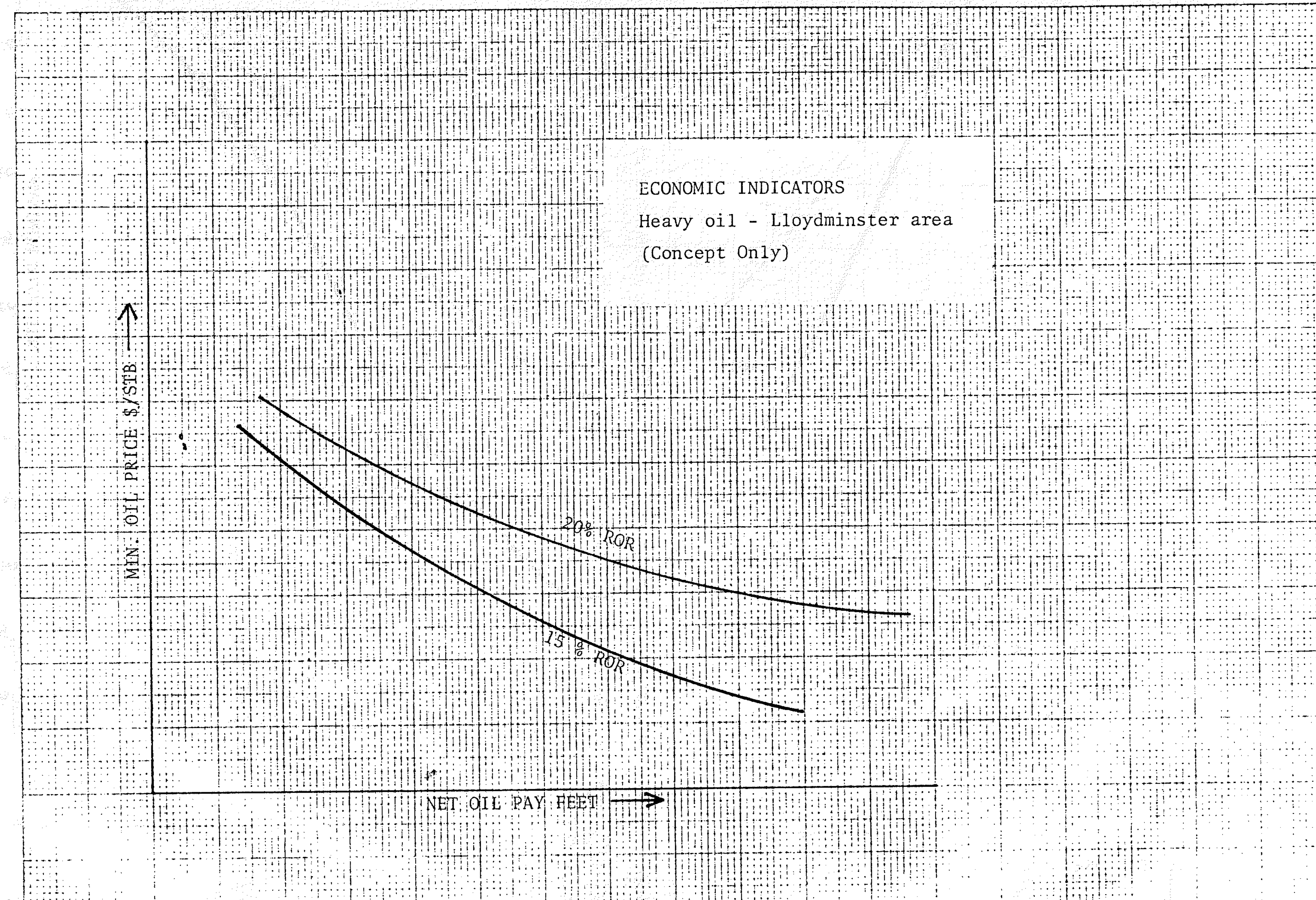
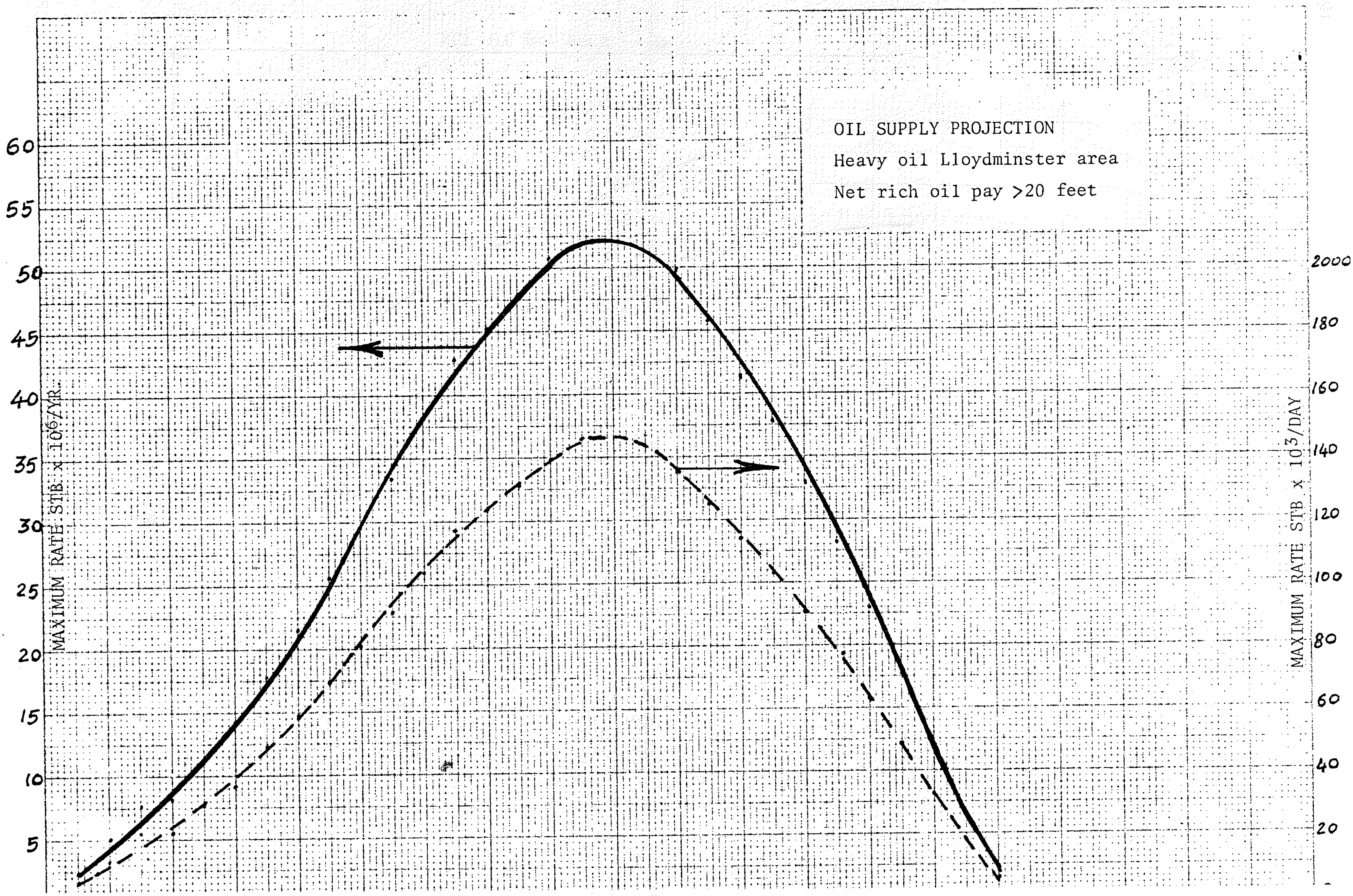

ECONOMIC INDICATORS
Heavy oil - Lloydminster area
(Concept Only)
MIN. OIL PRICE $/STB
NET OIL PAY FEET
20% ROR
15 % ROR

Fig. 13


OIL SUPPLY PROJECTION
Heavy oil Lloydminster area
Net rich oil pay >20 feet
MAXIMUM RATE STB x 10^6/YR.
MAXIMUM RATE STB x 10^3/DAY
60
55
50
45
40
35
30
25
20
15
10
5
2000
180
160
140
120
100
80
60
40
20