REPORT
ON
MASTER PLAN STUDY
FOR
THE DEVELOPMENT OF PETROLEUM AND NATURAL GAS RESOURCES
IN
MALAYSIA

- VOLUME IV -

(SARAWAK)

JANUARY 1978

JAPAN INTERNATIONAL COOPERATION AGENCY

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PART A EVALUATION OF OIL AND GAS FIELD AND PERFORMANCE PREDICTION

1. GENERAL

Sarawak area is the center of petroleum industry in Malaysia at present, with six oil producing fields, the total daily average production rate of which during the month of June 1976 amounts to 116,743 STB.

West Lutong field has the longest production history among the Malaysia oil fields. The field is composed of many sands layers. The production performance of its main zone was and will be very stable.

The biggest oil field in Malaysia is Baronia field, which is thought to have long and stable production performance. Special care should be taken for its field observation.

Baram has two different reservoir structures, that are Baram A and Baram B. Both structures are divided into several blocks and their oil displacement energy is interpreted to be poor. As for Baram B, the reservoir is confirmed in the highly limited portion of the structure.

Bakau field has only 3 wells drilled to the Bakau structure and is producing from 3 different blocks. In this field also, only partial area is confirmed by actual well log. Judging from their production performance, however, the size of the field is estimated to be very small.

Tukau field, which is also composed of many thin sand layers, is estimated to be medium sized oil field with comparatively poor oil displacement energy.

Fairly Baram field bestrides the national boundary between Malaysia and Brunei with its crestal part in Brunei. The field is medium sized oil field with comparatively good reservoir characteristics.

Original hydrocarbons in place for above 6 fields are shown on Table A-1 and the daily average oil production rates during the month of June 1976 are listed as follows.

Baronia Field	51,707	STB/D
Fairly Baram Field	2,952	STB/D
West Lutong Field	14,549	STB/D
Baram Field	30,995	STB/D
Bakau Field	4,034	STB/D
Tukau Field	12,506	STB/D

In addition to these producing fields, there exist three fields for development, which are Betty, Bokor and Temana, and potential fields that are Beryl and Siwa fields. There remains problem as to oil displacement mechanism in Bokor and Temana fields because of its heavy oil characteristics and poor recovery is estimated.

In Betty field, only one well has been drilled so far into the objective oil reservoir and good reservoir characteristics are estimated, although the size of the field is small.

Beryl field is still in the exploration stage and requires more wells to define the reservoir. In Siwa field, where one well is drilled at the crestal area, reservoir limits are confirmed at this location in some zone, but still requires more information to characterize the reservoir.

Original hydrocarbons in place are shown on Table A-2 for the development fields, Table A-3 for the potential fields and A-4 for Central Luconia fields.

2. GEOLOGY

2.1 Stratigraphy

It is known that a vast offshore and onshore area of Sarawak was a place of sedimentation of Tertiary time. On the coastal area of Sarawak between 2.5°N and 5°N deltaic and shallow water marine deposits which consist predominantly of arenaceous materials crop out and the corresponding strata continue to the northwest under the sea. All of the study fields in the Sarawak area are located in the offshore area, but the most off Central Luconia fields are dealt with in other chapter because they have common characteristics that hydrocarbons are accumulated in carbonate rocks of the reef origin.

In most fields palynologic interpretation is available and a regional stratigraphy is established by Shell in the form of sedimentary cycles. The cycle boundaries can be made use of as a regional time reference and Fig. 1-2-1 is such a summary which shows geologic time and cycles of sedimentary sections penetrated in each field. The sedimentary sequences penetrated in the area are considered as conformable except the recent sediments. However, Temana structure, which is located in the southernmost part of the area, has a different tectonic history from the other northern structures and suffered from subareal erosion of formations in Middle and Late Miocene time.

Since Shell adopted a number system to classify fossil pollen, scientific specific names of the fossil were not clarified. It is impossible to make clear the floral assemblages and to check the correlation by them. Therefore, it is desirable for Petronas to conduct palynological study for samples to be collected from surface and subsurface in future exploration activity.

2.2 Correlation of Reservoir Beds

Sedimentary rocks of the Sarawak fields consist mainly of sandstones intercalated with shale beds. Most of hydrocarbon accumulations are found in these sandstone beds mainly of Upper Miocene age which were deposited in shallow marine and deltaic environments.

Since argillaceous rocks are not predominant, it was difficult to know exactly the continuity of a great number of reservoir sandstones on the scale of a unit bed, especially at the early stage of the study. Therefore, the reservoir rocks were grouped into several zones to which alphabetical names were given as a, b, ... from a stratigraphical viewpoint and in consideration of the relative size and the vertical communication of them. However, since a detailed correlation of the reservoirs between the fields or structures was generally impossible and meaningless, the alphabetical names given to them are not identical with each other between any fields; for example, the horizon of reservoir d_2 of Baronia field does not correspond to that of d_2 of Baram field. Owing to a frequent difficulty of defining the lower limit of the reservoir zones, only top of the zone is given in the correlation tables.

2.3 Geologic Structure

Geologic structures of most of the producing fields were determined through stratigraphic correlation but seismic interpretation was made for the fields in which well control is very poor or correlation cannot be the only means for structural mapping.

For some fields such as Baram field very detailed correlation was required even in horizons in which hydrocarbons are not bearing because structures of such fields are intensely faulted into blocks.

It is concluded that a general characteristics of the petroleum fields of Sarawak area is a close relation of the hydrocarbon accumulation to the structural development accompanied by growth faulting which occurred during sedimentation. Hydrocarbons are trapped in anticlinal structural highs associated with such faulting. These growth faults are north-dipping normal ones with E-W or NE-SW strikes.

The correlation of zones to the Shell nomenclature for producing fields was shown on Appendix I.

3. EXISTING PRODUCING FIELDS

3.1 Baronia Field

3.1.1 Field Status

Baronia field is located approximately 31 km north-west of the mouth of Baram River. Production started May 1972 and the cumulative production as of October 1976 amounts to 30 MMSTB by 15 producing wells. During the 4 years' production history, maximum record of 50 MSTB/D was reported since the start of production. The field has the largest original in place with the highest productivity among the existing oil fields in Malaysia.

3.1.2 Geology

(1) Reservoir Beds

Sedimentary sections penetrated by wells in the Baronia field consist of the uppermost Miocene and Pliocene clastics where formations of the lower part of cycle VI and the upper part of cycle V are hydrocarbon bearing. Reservoir zones are named as a - g (Table 1-2-1).

Continuity of reservoirs is so good that there is no difficulty in correlation of them. Main oil bearing zones are $a_2 - {}_3$ and $d_2 - {}_4$. Although there are intercalations of 20 to 30 ft thick shale between zones a_2 and a_3, and between zones d_2, d_3, and d_4, depths of OWC and GOC seem to be common for zones a_2 and a_3 and for zones d_2, d_3, and d_4, respectively.

(2) Geologic Structure

Figs. 1-2-2 - 5 show geologic structure of the field in horizons of zones a_2, c_2, d_2, and f_1 and Fig. 1-2-6 shows a north - south structural cross-section.

The structure is a very gentle domal anticline of which the north and south limits are two growth faults ENE-striking and north-dipping. The north fault is crossed by well No.2 in the zone b_2 horizon with a throw of about 150 ft. The anticlinal axis is ENE-WSW trending and dips of formations are less than 5 degrees at most.

3.1.3 Reservoir Analysis

Objective reservoir is classified and grouped into 6 zones which are A, C, D, E, F1 and F2 Zones from shallower to deeper horizon. They correspond to geological correlation names of Table 1-2-1 in the following ways.

Reservoir Model	Geological Code
A Zone	Zone a2 - a3
C	c2
D	d2 - d4
E	e
F1	f1
F2	f2

In reservoir analysis, the three-phase three-dimensional model is applied to A and C Zones, while D to F2 Zones are analysed by the use of the block model.

The field total reservoir performance derived from simulation study is presented in the graphical form on Fig. 1-3-9 and in the tabular form on Table 1-3-1.

(a) Baronia A Zone

Reservoir Status

The reservoir was interpreted to be combination drive of gas cap and aquifer water. Oil water contact is observed at almost all wells penetrated the reservoir except for the few wells drilled at the crestal part.

Vertical reservoir permeability was supposed to be very poor due to shale breaks developed in the oil and gas zones. Reservoir net oil thickness, porosity and water saturation range from 23 to 65 ft, 0.20 to 0.28 and 0.35 to 0.50, respectively. Gas oil and oil water contacts derived from log interpretation are 5,590 and 5,665 ft s.s. depth, respectively.

Production started July 1973 at BN-Well No.5. Gas oil ratio increased remarkably from 1000 to 4000 SCF/STB within only a few months, while with the commencement of production by other wells, the field total gas oil ratio got stabilized down to 1500 SCF/STB. Peak oil rate of 17.8 MSTB/D was recorded after 3 years from the start of production.

Cumulative oil production during the history stage was 9.2 MMSTB, which was 4.53% of original oil in place. Water production was comparatively low during the period and cumulative water oil ratio was 0.017% only.

Original oil in place calculated by volumetric method is 202.7 MMSTB and gas cap gas in place is 287.32 MMMSCF.

Reservoir Parameter and Modeling

Reservoir oil properties were estimated based on the Baram Well No.12 data by modifying the API and other factor through history match calculation, as no fluid analysis is available for this zone. Gas properties were determined by laboratory analysis of FIT sample. Those are summarized on Figs. 1-3-35 and 41.

Gas oil relative permeability relation is assumed at first by the use of general relation of representative sample, modified and established later by history match calculation. This is due to the lack of actually measured data.

Water oil relative permeability was established by manipulating the actually measured data of BN-Well No.4 D Zone through history match calculation. Those relations are summarized on Fig. 1-3-25.

In addition to the above relations, pseudo-relative permeability relation was established for cell by cell to obtain well performance by taking into account the perforation interval, producing gas oil, water oil ratio, and average water saturation.

In-put data for absolute permeability for oil zone were based on the Build-up Curve analyses for individual wells, and vertical/horizontal permeability ratio was assumed to be 0.1.

Porosity and saturation data for individual cells were derived from the distribution map illustrated on Figs. 1-3-3 and 5.

Original reservoir pressure was determined to be 2470 psig at the datum plane of 5630 ft subsea from FIT and BHP survey data. The pressure distribution at the end of October 1976 is shown as an isobaric map on Fig. 1-3-7. Simulation calculation was made by the Grid Model as illustrated on Fig. 1-3-1 utilizing aforementioned reservoir parameters.

Computation Results

History match calculation was made for the interval from May 1972 to October 1976, and revised reservoir parameter through the matching calculation was used to make extension for the subsequent 12 years' prediction.

Reservoir performance for A Zone is illustrated on Fig. 1-3-10, tabulated on Table 1-3-2 and individual well behaviors are shown on Figs. 1-3-11 - 14, and Tables 1-3-3 - 6.

Reservoir pressure match was made by changing aquifer size, horizontal and vertical permeability and vertical permeability of gas cap zone. Water oil and gas oil ratio are matched satisfactorily through the calculation.

As shown on the predicted results, producing gas oil ratio of the block for BN-11, 13 and 16 and the block for BN-17, 18 will increase to be 11000 and 12000 after 10 and 9 years, respectively.

(b) Baronia C Zone

Production started August 1974. Cumulative production as of October 1976 amounts to 6.384 MMSTB which is equivalent to 18.75 per cents of original oil in place. Average daily oil production rate of the zone during the month was 10.17 MSTB/D by five producers.

According to the log interpretation and FIT results, free gas zone was detected over the oil zone. Due to shale breaks developing between oil and gas zones, the gas zone is interpreted to have little contribution for oil displacement. The C Zone is regarded as water drive type reservoir with oil water contact at 6487 feet s.s.

Reservoir Analysis

Reservoir performance was calculated by the three dimensional model with the grid pattern shown on Fig. 1-3-2. Water saturation, porosity and effective thickness are obtained from log analysis for each well. Sw and øh for each cell was derived from the distribution maps illustrated on Figs. 1-3-4, 6. Horizontal permeability KH was calculated for each cell by using the relation $\log K_H = 21.47\phi - 0.87$. This relation was obtained from core analysis at BN-Well No.8. Vertical permeability was assumed to be 30 per cent of horizontal permeability.

Gas oil relative permeability relation was assumed at first by the use of general relation of representative sample, modified and established later by history match calculation. This is due to the lack of actually measured data. Water oil relative permeability was established by manipulating the actually measured data of BN-Well No.4 D Zone through history match calculation. Those relations are summarized on Fig. 1-3-26. In addition to the above relations, pseudo-relative permeability relation was established for well by well to obtain well performance by taking into account the perforation interval, producing gas oil ratio, water oil ratio, and average water saturation.

For oil properties, the result of fluid study at Baram field was revised. Gas properties were obtained from the gas analysis at BW-Well No.4. Oil and gas properties are shown on Fig. 1-3-36 and Fig. 1-3-42, respectively. The premise was made in the model that well is to be shut-in when producing gas-oil ratio comes up to 10,000 SCF/STB or water oil ratio is more than 2.0. The performance is shown on Fig. 1-3-15 and Table 1-3-7. Individual well performances are shown on Figs. 1-3-16 - 20 and Tables 1-3-8 - 12. Reservoir pressure is decided to 2840 psig at datum level of 6450 feet s.s. from FIT and BHP survey. The pressure is corrected to the pressure at mid point depth for each cell. The pressure distribution at the end of October 1976 is shown as the isobaric map on Fig. 1-3-8.

(c) Baronia D Zone

This zone was interpreted to be combination drive of large gas cap and aquifer water. The fluid levels are estimated by the log analysis. Gas oil contact and oil water contact are 7200 feet s.s. and 7290 feet s.s., respectively. The results of log interpretation are shown on Appendix II. Average water saturation and porosity are 0.35 to 0.75 and 0.16 to 0.25, respectively. Production started

October 1974 at BN-Well No.8 and eight wells are currently producing.

Average API gravity of oil is 42.3°, and solution gas oil ratio was assumed to be about 900 SCF/STB, however, producing gas oil ratio increased rapidly to 3600 SCF/STB at the end of October 1976 when recovery reached to only 2.11% of original oil in place. The increase of gas oil ratio is interpreted to be brought about by gas coning. Gas oil ratio of BN-Well No.11, 13, 16 and 17 situated at upper part of the structure reached to 4600 - 6100 SCF/STB, accordingly it is considered that the gas cap gas is being produced.

At BN-Well No.8, 12, 14 and 15, situated at lower part of the structure, water production has started, especially, at BN-Well 14, whose water oil ratio reached to 0.66 at the end of October 1976. Cumulative water oil ratio of the zone is 0.1. The reservoir was interpreted to have strong water drive. Original oil in place and gas in place were estimated to be 271.222 MMSTB and 843.267 MMMSCF, respectively.

Reservoir Analysis

Datum level was decided to be 7250 feet s.s. and initial pressure was obtained to be 3170 psig from FIT and BHP survey.

In Baronia field, as PVT analysis was not available, the fluid data of Baram field was used by minor modification. Gas properties were obtained from gas analysis by FIT Sampling. Oil and gas properties are shown on Fig. 1-3-37 and Fig. 1-3-43, respectively.

As no special core analysis was available, the average trend of gas oil relative permeability relation was revised based on fluid properties and producing gas oil ratio of history stage. Calculation result is shown on Fig. 1-3-21 and Table 1-3-13, used reservoir parameters are shown on Figs. 1-3-27 and 31.

Gas cap volume was calculated to be 4.259 MMMCF whose original in place is 843 MMMSCF, and gas cap volume ratio is 1.83.

Gas cap drive was interpreted to be not so much effective due to several shale breaks in gas cap zone, and gas cap volume ratio was assumed to be 0.3 for the estimation of reservoir performance.

Assuming the gas cap volume ratio to be 0.3, cumulative gas production of 88 MMMSCF is to be produced by gas expansion and 755 MMMSCF gas in D zone was calculated to be remained unproduced. The water encroachment is 90 MMBBL at the pressure stage of 1200 psig and each phase saturation distribution can be summarized as follows.

	initial condition	at 1200 psig
water saturation	30%	44%
oil saturation	70%	46%
gas saturation	0%	10%

The volume of water enchroachment at that reservoir condition corresponds to 63% volume of the void space produced by the oil production. Because of strong water enchroachment, the gas saturation will be only 10% at the final stage.

(d) Baronia E Zone

The form of this structure is similar to the other zones of Baronia field, but reservoir extent of oil zone is small. Oil was found at only 6 wells completed at the crestal part. Three of these 6 wells are producing. Gas cap is absent and aquifer is thought to be prevailing. Oil water contact, average water saturation and porosity were estimated by the log interpretation to be 7390 feet s.s., 41 - 52% and 16 - 23%, respectively.

Production started September 1974 at BN-Well No.7 and numbers of producer are 3 as of October 1976. Average API gravity of oil is 40.7°. Producing gas oil ratio was 900 - 1000 SCF/STB in the early stage and rised up gradually and reached to 1700 SCF/STB in October 1976.

Water production started July 1975 at BN-Well 9 and March 1976 at BN-Well 7. Water oil ratio for the wells reached to 0.88 and 0.6, respectively. Cumulative water oil ratio of zone total was 0.12.

Pressure decline of 250 psig was observed when recovery of original oil in place reached to 10%, while the increase of gas oil ratio was not remarkable, so that strong water drive can be anticipated. Original oil in place and history stage recovery is as follows.

Original oil in place = 16.779 MMSTB
History stage recovery = 11.76%

Reservoir Analysis

Datum level was decided to be 7370 feet s.s. and initial pressure was obtained to be 3220 psig from FIT and BHP survey. Fluid level is different from Baronia D Zone by 120 feet and fluid properties of D Zone were used for performance estimation.

Average trend of gas oil relative permeability curve was assumed and revised based on rock parameters, fluid properties and producing gas oil ratio. Fluid properties are summarized on Figs. 1-3-38 and 44, and relative permeability curve is summarized on Figs. 1-3-28 and 32.

Calculation result is shown on Fig. 1-3-22 and 1-3-14. After 16.75 years, oil production rate is 0.1 MSTB/D, and prediction calculation is terminated. At this time reservoir pressure is 1285 psig and recovery is 24.19%.

Cumulative water encroachment reached to 6 MMBBL when reservoir pressure is 1300 psig and this volume corresponds to 65% of void space under the reservoir condition.

(e) Baronia F1 Zone

Mid-point depth of oil zone is about 7650 feet s.s. and 7 wells are drilled to this depth. Four of these 7 wells are producer. Gas cap is absent and aquifer is existent. Oil water contact is 7704 feet s.s. Average water saturation and porosity are 42 to 73% and 13 to 20%, respectively.

Production started September 1974 at BN-Well No.7 and there were 4 producers as of October 1976. Average API gravity of oil is 40.3°. Producing gas oil ratio was 900 - 1000 SCF/STB in the early stage and increased gradually and reached to 1400 SCF/STB in October 1976. Water production started April 1975 at BN-Well No.6 and for BN-Well Nos.6, 7 and 9, October 1976. Water oil ratios for the three wells are 0.25, 0.99 and 0.66, respectively. Cumulative water oil ratio of zone total was 0.14. Original oil in place and history stage recovery are

Original oil in place = 34.651 MMSTB

History stage recovery = 8.24%

Reservoir Analysis

Datum level was decided to 7660 feet s.s. and initial reservoir pressure is 3350 psig from FIT and BHP Survey.

Oil properties of Baram field were used for performance estimation. Gas properties are obtained by gas analysis of FIT sampling. They are shown on Figs. 1-3-39 and 45. Average trend of gas oil relative permeability curve was revised based on rock parameters, fluid properties and producing gas oil ratio of history stage. Relative permeability relation is shown on Figs. 1-3-29 and 33.

Calculation result is shown on Fig. 1-3-23 and Table 1-3-15. After 20 years, reservoir pressure is 1664 psig, with the recovery of 23.18% and production rate is estimated to be 0.2 MSTB/D.

Cumulative water encroachment amounts to 8 MMBBL when reservoir pressure is 1700 PSIG and the volume corresponds to 45% of void space under reservoir condition.

(f) Baronia F2 Zone

The zone is the deepest one among the Baronia producing zones. No gas cap is detected while water bearing zone is confirmed at BN-Well No.2 which was drilled in the most down dip location. The oil displacement mechanism was thought to be edge water encroachment. Oil water contact was estimated to be between 7909 feet s.s. (bottom of BN-Well No.5) and 7920 feet s.s. (top of BN-Well No.2). Average water saturation and porosity range from 46 to 59 and from 11 to 15%, respectively.

Production started May 1972 at BN-Well No.4 and there were 4 producers in October 1976. Average API gravity of oil is 40.6° and solution gas oil ratio was estimated to be from 900 to 1000 SCF/STB, while producing gas oil ratio changed from 400 to 1200

SCF/STB during the 3 months and increased to be 2600 SCF/STB after 1.25 years and then declined to 1400 SCF/STB in October 1976. In spite of low permeability, oil production rate was high and the pressure around the well bore declined rapidly. This free gas is the cause of high gas oil ratio in the early stage.

As no oil water contact was detected in the individual producer, the start of water production was comparatively later stage of production. The fact is questionable that the water production is reported to start at BN-Well No.7 from the beginning of 1976 and remarkable increase of water oil ratio of 1.12 is reported. During the month, the water oil ratios of E and F zones of BN-Well No.7 are reported to be same value. Production split of commingled completion should be reviewed again.

Original Oil in Place and History Recovery

As no oil water contact was confirmed by well data, proven oil in place was calculated by setting 7901 feet s.s. as lower limit.

Original oil in place = 44.033 MMSTB

History stage recovery = 8.84%

Reservoir Analysis

Datum level was decided to be 7830 feet s.s. and initial reservoir pressure was estimated to be 3420 psig from the results of FIT and BHP survey. Oil properties of Baram field were used for the performance estimation of Baronia F2 Zone. Gas properties were obtained by gas analysis of FIT sample.

Average trend of gas oil relative permeability curve was revised based on rock parameters, fluid properties and producing gas oil ratio of history stage. Relative permeability relation is shown on Figs. 1-3-30 and 34. Fluid properties are shown on Figs. 1-3-40 and 46.

Calculation result for 20 years performance is shown on Fig. 1-3-24 and Table 1-3-16. Reservoir pressure is 915 psig and recovery is 31.38%. Active water drive was anticipated from history match calculation.

Cumulative water encroachment reached to 22 MMBBL when reservoir pressure declined to 900 psig, and the value corresponds to 59% of void space at reservoir condition.

(g) Additional Wells Case

The performance projections described in (a) to (f) were conducted on the basis of existing wells.

Additional wells case was studied from the view point of defining maximum allowable production rate.

Additionally required wells in this case are as follows.

Baronia A and	D	Zone	BN-A 1, 2, 3, 4, 5, 6
	C	Zone	BN-A 7, 9
	E	Zone	BN-A 7, 8, 9, 10
	F1	Zone	BN-A 7, 8, 9
	F2	Zone	BN-A 7, 8, 9

The proposed locations for the additional wells are shown on Fig. 1-3-53. The reservoir performance prediction was made by the use of total 10 additional wells and such assumption was made that the wells start to produce from November 1976.

The locations of the additional wells were determined for the purpose of increasing areal sweep efficiency, while the primary recovery increased slightly from 26.9% of existing condition to 29.5% (Fig. 1-3-9 and Table 1-3-17). More enhanced production rate will shorten the economic life of the field and decrease the recovery factor.

Under the current PS Agreement, it is difficult to define the most efficient rate for PETRONAS. The above-mentioned enhanced rate is technically allowable maximum production rate.

The control of producing gas oil ratio is the most important factor in attaining good recovery. The allowable producing gas oil ratio is described for zone by zone as a function of cumulative oil production.

The relation is summarized on the following figures for individual zones.

Baronia	A Zone	Fig. 1-3-47
	C	Fig. 1-3-48
	D	Fig. 1-3-49
	E	Fig. 1-3-50
	F1	Fig. 1-3-51
	F2	Fig. 1-3-52

3.2 Fairley-Baram Field

3.2.1 Field Status

Fairley-Baram field is located about 25 km north of Baram River. The structure is an anticlinal high which is developed in the northern downthrown block of an ENE-trending growth fault. The field bestrides the boundary between Malaysia and Brunei.

The reservoir consists of 9 sand layers developed from approximately 7500 feet to 8800 feet s.s. No gas cap is detected but light oil of API 38° to 40° exists. Each sand has aquifer.

Production started July 1975 by FB-11 and 29. The number of current producers is 5 and cumulative oil production amounts to 4.56 MMSTB.

3.2.2 Geology

(1) Reservoir Beds

Hydrocarbons are accumulated in sandstones probably of the uppermost part of cycle V and the lower part of cycle VI. Reservoir sandstones show very stable continuity and were picked up as zones a, b, and c (Table 2-2-1), main oil-producing zones being a_{2-3}, b_{2-3} and c.

(2) Geologic Structure

Structural maps of zones a_3, b_2, and c are shown in Figs. 2-2-1 - 3, and structural cross-sections cut in the both countries are shown in Fig. 2-2-4. The structure is an anticlinal high which was developed in the northern downthrown side as a rollover of an ENE-WSW trending growth fault. The anticline has a culmination in the west, Brunei, side but extends into the Malaysian area with gentler slopes than in the Brunei side.

The central part of the anticline develops a few minor faults dipping southward antithetically, of which throws are observed to be less than 60 ft in well Nos.1, 2. Besides another larger fault occurs from the west but appears not to cross the crestal area. Dips of the northern slope are 6 or 7°N in the zone b horizon in well No.11 and 3°NW in well No.29.

Formations south of the growth fault limiting the south of the field are uniformly north-dipping, that is, open toward the south and is not expected to have hydrocarbon accumulations.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone b. Quality of reflections of the horizon is very good and faults appear clearly in seismic sections. Migrated seismic sections were available mainly in Malaysia area, but most sections in Brunei area were unmigrated ones. Time contours based on the unmigrated sections in the latter area were migrated. After that, the contours in both areas were combined. The relation of reflection time versus depth was based on the well shooting data of Fairley No.11. Interpretation result and representative seismic section are shown in Fig. 2-1-1 and 2-1-2.

3.2.3 Reservoir Analysis

The sand layers were grouped into 3 zones and three models are used for performance analysis.

A, B and C Zones in reservoir analysis correspond to zones a, b and c in geological code.

(a) Fairley-Baram A Zone

This zone consists of 4 oil bearing sands of zone a_1, a_2, a_3 and a_4 completed in Well FB-1 to 3 and FB-29.

No vertical reservoir continuity between each zone was supposed to exist due to shale breaks, while the wells are produced by commingle production system.

Original reservoir pressure was determined to be 3390 psig at datum plane of 7800 feet s.s. from Figs. 2-3-1 and 2 which were obtained from FIT and BHP survey data.

Reservoir oil properties were estimated from laboratory analysis of Well FB-11 by modifying the API and other factors, as no fluid analysis was available for this zone. Permeability data were assumed at first by the use of special core analysis data of Well FB-2, modified and established later by history match calculation. Those are summarized on Figs. 2-3-35, 36, 39 and 40. Original oil in place calculated by volumetric method is 19.63 MMSTB as proved and 7.57 MMSTB as probable.

Water production increased from the later stage of history. This is due to the production from Well FB-1 and FB-2. Those wells, however, were completed near the crestal area. The high water oil ratio is thought to be caused by high water saturation zone in lower part of zone a_2 of Well FB-1 and zone a_3 of Well FB-2. Workover will be required for this well in some near future to shut off water. The calculated performance is shown on Fig. 2-3-13 and Table 2-3-3.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the zone as a function of cumulative oil production and summarized on Fig. 2-3-45.

(b) Fairley-Baram B Zone

Reservoir fluid properties were obtained from laboratory analysis of Well FB-11 as shown on Figs. 2-3-41 and 42. Porosity, water saturation and effective thickness were obtained from log analysis.

Permeability data was estimated at first by the use of special core analysis data of Well FB-2, modified and established finally by history match calculation. The relation is summarized on Fig. 2-3-37.

The grid model is composed of 90 cells (9x5x2) as illustrated on Fig. 2-3-3. Water saturation and effective thickness data for the grid model were obtained from the distribution map as illustrated on Figs. 2-3-5, 7.

Based on the history match calculation, isobaric map for October 1976 is illustrated on Fig. 2-3-9. Reservoir performance predictions were made for two cases.

Case 1 is the extension of existing condition and illustrated on Fig. 2-3-14 and Table 2-3-4. The predicted performance for individual wells are described as follows.

Producing gas oil ratio for Well FB-2 is estimated to be increasing rapidly and the well is obliged to be shut-in at the stage when gas oil ratio comes up to 10000 SCF/STB as shown on Fig. 2-3-18, and Table 2-3-8. Water oil ratio and producing gas oil ratio for Well FB-3 are predicted to be increasing gradually and will be shut-in at the time when water oil ratio and gas oil ratio come up to 2.0 STB/STB and 7000 SCF/STB, respectively, as shown on Fig. 2-3-19 and Table 2-3-9. Well FB-29, which was shut-in about 4 months in 1976, started production again and it is estimated to have good performance as illustrated on Fig. 2-3-20 and Table 2-3-10.

Case 2 is the additional well case. One well is drilled in the crestal area where poor recovery is estimated by Case 1, whose location is I=6, J=4 in Fig. 2-3-3. The results are described on Fig.

2-3-24 and Table 2-3-14 and the well is anticipated to have good performance. In this case, as illustrated on Figs. 2-3-15, 21 - 23 and Tables 2-3-5, 11 - 13, no serious well interferences are estimated on existing wells FB-2 and 3, and slight effect on Well FB-29.

(c) Fairley Baram C Zone

The reservoir fluid properties were determined based on the results by PVT study of Well FB-11, initial production tests of Well FB-2 and FB-29, and sample analysis of FIT at Well FB-29. The fluid properties are shown on Figs. 2-3-43 and 44. Rock parameters such as porosity, water saturation and effective thickness are interpreted by log analysis, and permeability estimated from log analysis is checked and revised through history match calculation. Permeability data are summarized on Fig. 2-3-38.

As shown on Fig. 2-3-4, the objective reservoir is divided into 286 cells (13x11x2) in the model. The individual parameters in the cells were investigated and corrected through history match calculation. Water saturation and effective thickness data for the grid model were obtained from the distribution map as illustrated on Figs. 2-3-6 and 8.

The isobaric map for October 1976 is illustrated on Fig. 2-3-10.

This reservoir has short production history and no sufficient data was available for history matching. The history performance could be match by the minor change of each parameter in the cell and the future performance will be much influenced in the later stage. It should be emphasized therefore, that the accuracy of reservoir information in the early exploration stage has a great influence upon the future performance.

Results of the future performance on the basis of history matching are shown as Fig. 2-3-16 and Table 2-3-6 and individual well performance is shown on Figs. 2-3-25 - 28 and Tables 2-3-15 - 18. Case 1 is the extension of existing condition.

Apart from international boundary problem, investigation was made by Case 2 for increasing oil recovery by having 2 additional wells.

The study was made based on the computation results of Case 1. Additional wells are to be drilled in the area of poor recovery, the locations of which are (8,8) and (9,7) in Fig. 2-3-4. In this case additional 10% recovery is anticipated.

Performance for this case is shown on Fig. 2-3-17 and Table 2-3-7, and individual well performance is shown on Figs. 2-3-29 - 34 and Tables 2-3-19 - 24.

Field total performance for Case 1 and Case 2 is shown on Fig. 2-3-11, Table 2-3-1 and Fig. 2-3-12, Table 2-3-2, respectively.

(d) International Boundary Problem

Sample illustration is made for the main productive zones of b and c to describe the oil recoveries in the Malaysia and Brunei Area.

Existing Well Conditions

		Malaysia	Brunei	Total
Cumulative	zone b	1.093	0.643	1.736
Production (MMSTB)	zone c	6.283	7.527	13.810
		7.376	8.170	15.546

Under the existing wells condition, the field total recovery is 26.56%. In order to increase the recovery, a trial was made to have additional wells in the crestal area where there still remains unrecovered oil. The case is to have 3 additional wells, one is for zone b and two for zone c. The case is made only for the purpose of increasing field total recovery.

(e) Additional Wells Case

		Malaysia	Brunei	Total
Cumulative	zone b	1.059	1.552	2.611
Production (MMSTB)	zone c	5.787	13.026	18.813
		6.846	14.578	21.424

As illustrated on the table, the differences of areal recoverable oil depend on the numbers of wells.

The results show that the increased oil production rates in Brunei Side will cause decrease of cumulative oil production of Malaysia Side, and vice versa. As shown on the results, ratio of recoverable oil for Malaysia and Brunei is much influenced by the numbers of wells drilled in the individual areas.

As no remarkable difference is observed between the two areas, such an effort is recommended as to increase the field base total recovery.

		MALAYSIA SIDE		BRUNEI SIDE		FIELD TOTAL	
		B Zone	C Zone	B Zone	C Zone	B Zone	C Zone
Original Oil in Place		7.76	23.47	10.30	28.45	18.06	51.92
End of History	Cumulative Oil Production (MMSTB)	0.184	0.774	0.214	1.695	0.398	2.469
	Recovery (%)	2.37	3.30	2.08	5.96	2.20	4.75
End of Prediction CASE 1	Cumulative Oil Production (MMSTB)	1.093	6.283	0.643	7.527	1.736	13.810
	Recovery (%)	14.09	26.77	6.24	26.46	9.61	26.56
End of Prediction CASE 2	Cumulative Oil Production (MMSTB)	1.059	5.787	1.552	13.026	2.611	18.813
	Recovery (%)	13.65	24.66	15.07	45.79	14.46	36.18

3.3 West Lutong Field

3.3.1 Field Status

West Lutong field, located approximately 10 km north of Sarawak western shore, has the longest production history among the producing fields in Malaysia.

In the past 8 years' history, it recorded maximum rate of more than 50,000 STB/D. Although it declined to be 15,000 STB/D under the current stage, the production performance is very stable and reservoir is thought to be in quite stabilized condition.

The reservoir is composed of approximately 50 sand layers and commingled production system is widely used.

3.3.2 Geology

(1) Reservoir Beds

In the West Lutong field hydrocarbons are found in sandstones which are predominant in deltaic sediments of the upper part of sedimentary cycle V. Correlation of reservoirs is very good and zones of a - e are recognized (Table 3-2-1), b_2, c_1, and c_2

containing main oil zones.

(2) Geologic Structure

Geologic structure of zones a_1, b_2, c_2, and e_1 is shown in Figs. 3-2-1 - 4 and a structural cross section in Fig. 3-2-5. The W. Lutong structure is a NE-SW trending anticline of which size is 6 km long and 1.5 km wide in the c_2 oil zone. The anticline is symmetric with flanks of a maximum 7 degree dip in shallower horizons than zone c_2 but is asymmetric in the deeper part where a north-dipping growth fault is developed to run parallel to the anticlinal axis.

The upthrown south part of the fault is reached by well Nos.3, 4, 7, 8, 23 and the north side is penetrated by well Nos.1, 2, 14, but this growth fault is not recognized on the seismic record sections which were available for the study.

3.3.3 Reservoir Analysis

The reservoir is composed of more than 50 sand layers developed from 4000 feet to 8000 feet s.s. Reservoir analysis was made by grouping and classifying the sand layers into 3 zones, taking into account geological correlation results and existing production system.

A Zone consists of zone $a_1 - a_3$ and b_1, developed from the depth of 4000 feet to 5200 feet s.s. It has 6 years' production history. Remarkable increase in gas oil and water oil ratios were observed soon after the start of production, and oil production rate decreased rapidly.

B Zone consists of zone b_2, c_1 and c_2, developed in the depth interval from 5200 feet to 5800 feet s.s. The zone is the main producing reservoir in the West Lutong field with constant rate of production even after 8 years of history. Water oil ratio increased gradually during the early depletion stage but came to be stabilized and almost constant after 6 years of production.

C Zone is composed of zone $c_3 - e_3$, the depth interval for which ranges from 6300 feet to 7300 feet s.s. The zone has 8 years of production history. The producing gas oil ratio for the zone was almost constant, while water oil ratio was observed to be increasing gradually.

Field total performance is shown on Fig. 3-3-2 and Table 3-3-1. Initial reservoir pressure at datum plane depth for individual zone is decided based on Fig. 3-3-1.

(a) West Lutong A Zone

A Zone consists of many gas rich sand reservoirs. Most of the produced oil is condensate or light oil.

The reservoir fluid properties were determined on the basis of results analyzed by PVT study of WL Well No.19 from zone a_2 as shown on Figs. 3-3-12 and 15. Relative permeability data are shown on Figs. 3-3-6 and 9. Reservoir performance as derived from Model study is shown on Fig. 3-3-3 and Table 3-3-2. According to this results, rapid decrease of reservoir pressure was estimated.

Although water drive can be anticipated to some extent, there exists so many gas rich reservoir and it is next to impossible to produce oil by refraining gas oil ratio.

(b) West Lutong B Zone

B Zone, which includes 6 reservoirs, consists of zone b_2, b_3, c_1 and c_2. The oil properties produced is 35° to 41° API gravity and average producing gas oil ratio is shown as follows.

zones with gas cap	1600 - 3000 SCF/STB
zones without gas cap (zone c_{1-3}, c_{2-1})	1000 - 1100 SCF/STB

The reservoir fluid properties were determined by PVT studies of fluid samples from WL Well No.1 in zone c_2 and WL Well No.2 in zone c_1. They are shown in Figs. 3-3-13 and 16. Relative permeability data is shown on Figs. 3-3-7 and 10.

The oil production started on August 1968 by 24 wells (WL Well No.1 - 25) except for WL No.5, and the cumulative oil production was 67.08 MMSTB and the recovery to original oil in place was estimated to be 37.4% during history stage.

In the model study the reservoir parameter was so adjusted as to match the past 8 years' production history by taking into account oil displacement mechanism. Based on this model, prediction of reservoir performance was made, which is summarized on Fig. 3-3-4 and Table 3-3-3.

Judging from this computed results (Fig. 3-3-4 and Table 3-3-3), producing gas oil ratio is kept constant while water oil ratio is increasing gradually. The reservoir energy was interpreted to be supplied by strong water drive.

The abandonment condition of the reservoir will be determined not from production decrease due to pressure decline but from increased water oil ratio, while the reservoir pressure will be kept comparatively high level.

The current reservoir condition is quite stable and no increased production rate is recommended in order to expect good sweep efficiency.

(c) West Lutong C Zone

The zone is composed of 25 sand layers from zone c_3 to e_3.

In the area below zone c_3, there developed a big fault from north east to south west and no detailed information has been obtained for the northern part of the fault. The objective area in this study was for the southern block of the fault where there developed a small fault parallel to the above fault, which was interpreted to have little effects on this reservoir group.

The API gravity of the oil accumulating in the thin sand layers ranges from API 38° to 50° and the average producing gas oil ratio was from 1500 to 2000 SCF/STB.

No PVT analysis was available for this zones, the fluid properties were estimated from the average trend of Malaysia crude oil. Fluid properties are shown on Figs. 3-3-14 and 17. Relative permeability relation is shown on Figs. 3-3-8 and 11.

The past reservoir performance of the zone shows comparatively mild reservoir pressure decline with no remarkable change in the producing gas oil ratio, however gradual increase of water oil ratio is noticed.

In comparison with the aforementioned B Zone, the zone is composed of many thin and gas rich sands, and the operation problems are difficulties in controlling of production of gas and water.

The predicted reservoir performance is shown on Fig. 3-3-5 and Table 3-3-4.

(d) Additional Wells Case

Two wells are recommended to be drilled in the undeveloped portion of the field, which are zone d3-6, 7, 9, 10 and e2-1, 2, 3. The location of the wells are illustrated on Fig. 3-3-22.

The anticipated reservoir performance for this case is described on Fig. 3-3-23 and Table 3-3-5. In this calculation, reservoir rock and fluid parameter were assumed to be identical to that of Model C.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual zones as a function of cumulative oil production and summarized on Figs. 3-3-18 - 21.

3.4 Baram Field

3.4.1 Field Status

The field is composed of two different structures. Baram A, which is eastern structure, is located approximately 13 km north-northwest of Baram River. The western structure Baram B is located 17 km north-west of the river.

A and B fields started production from July 1970 and October 1972, and their peak oil rates are reported to be 40 and 20 MSTB/D, respectively.

Current production rates for A and B fields declined to 21.5 and 9.5 MSTB/D. The production was estimated to decline continuously.

3.4.2 Geology

(1) Reservoir Beds

The field is divided into two fields about 7 km apart, A to the east and B to the west. Sedimentary sections are clastics consisting of alternations of sandstone and shale, occurring half and half as a whole. Hydrocarbons are accumulated chiefly in deltaic sediments of cycle V with reservoirs named as zones a - g for the two fields (Tables 4-2-1, 2). It is noted that the horizon of zone d_2 in A field is equivalent to that of zone c_4 in B field.

(2) Geologic Structure

As shown in Fig. 4-2-1 indicating the location of the two fields in the corresponding horizons, they are anticlinal highs which are developed along the same growth fault running in the ENE-WSW direction. Figs. 4-2-2 - 4 show structural maps of the A structure for zones c_1, d_2, and f_2, and Figs. 4-2-6 - 9 show those of the B structure for zones b_3, c_4, e_1 and e_3.

As known from the structural maps and structural cross-sections in Figs. 4-2-5, 10, the both structures are extremely divided into blocks by faulting and then fluid levels are also different in block to block. Naturally the calculation of volumetric oil or gas-in-place carried out for each of blocks which are named I to VIII in A and I to V in B.

3.4.3 Reservoir Analysis, Baram A

The oil reservoir consists of more than 100 sand layers developed from the depth of 3700 feet to 9600 feet s.s. The structure is divided into 11 blocks (I1, I2, II, III, IV1, IV2, V, VI, VII, VIII, upper block) by many faults.

In the vertical direction, the sand layers can be divided into 15 groups from zone a_2 to zone g_3 and no dominant productive zone was found. The sand zones, whose cumulative oil production exceed 10% of field total cumulative production, are zones b, e_1 and g_{2-3} only.

Block III and IV2 contain no hydrocarbon, and I1 and I2 are combined, and reservoir performances are estimated for 8 blocks (Block I, II, IV, V, VI, VII, VIII and upper Block).

Reservoir Parameter and Modeling for Baram A Block I - VIII and Upper Block

Each Block consists of several or dozens of thin sand layers. Confirmed area is highly limited and reservoir limit such as gas oil and oil water contact can not be defined for all of the reservoir sands. The reserves calculation, therefore, by volumetric method is apt to be underestimated.

In this reservoir, the oil and gas reserves are estimated by the production decline curve method based on the reservoir performance and production history. Based on this estimated reserves, production performance is recalculated. The procedure is repeated until satisfactory results are obtained.

It is possible that the assumed oil in place by the Trial & Error Method is sometimes less than volumetrically calculated value. (Block VII)
At Block VII, it is considered that all the reserves calculated by the volumetric method do not contribute to the production performance.

Reservoir oil properties were estimated based on the BA-Well No.12 data by modifying the API gravity and other factors through history match calculation.

Gas properties were determined by laboratory analysis of FIT sample. Those are summarized on Figs. 4-3-26 - 41. Relative permeability relation was estimated by revising the general relation to match history performance. This relation is shown on Figs. 4-3-10 - 25. Field total reservoir performance is illustrated on Fig. 4-3-1, tabulated on Table 4-3-1, and performances for the individual block are shown on Figs. 4-3-2 - 9, tabulated on Tables 4-3-2 - 9. No additional case was considered for this field.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual Blocks as a function of cumulative oil production and summarized on Figs. 4-3-53 - 60.

3.4.4 Reservoir Analysis, Baram B

The oil zone of this field consists of dozens of sand layers that develop from the depth of 4000 ft. to 9600 ft. s.s. The field is divided into 6 blocks (I, II, III1, III2, III3 and south Block) by several faults and most of the reservoirs are interpreted to be combination drive of gas cap and aquifer water. The continuities between the blocks are indistinct. Reservoir performance calculation was made for Block I, II and South Block by Model 1, and Block III1 and III3 are combined by Model 2. No calculation was made for Block III2, as no hydrocarbon is observed.

In this field same problem as in Baram A was encountered in defining the gas oil contact and lower limit of the reservoir.

The most suitable proved and probable oil in place is obtained by the Trial & Error method in the same ways as in Baram A. Fluid properties and relative permeability were obtained by the same way as Baram A field. Relative permeability is shown on Figs. 4-3-45 - 48, and fluid properties are shown on Figs. 4-3-49 - 52. The production performance of Baram B field is shown on Fig. 4-3-42 and Table 4-3-10 and the production performances of Model 1 and 2 are shown on Figs. 4-3-43, 44 and Tables 4-3-11, 12. No additional well case was considered for this field.

The most important factor to attain maximum recovery is the control of producing gas oil ratio.

The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual Blocks as a function of cumulative oil production and summarized on Figs. 4-3-61, 62.

3.5 Bakau Field

3.5.1 Field Status

Bakau field is located approximately 20 km west of Baram river. Production started February 1972 by well BK-3, and average daily rate of production during the month of June 1976 was 4.03 MSTB/D and cumulative oil production as of June 1976 amounts to 3.33 MSTB by 3 wells.

The field is divided into three blocks by faults.

Each well is drilled into independent block and commingled production system has been adopted.

Confirmed areas by three existing wells are highly limited and more delineation wells are required to be drilled for future development.

Only one well is completed in the individual blocks and performance analysis is made block by block using one well data.

3.5.2 Geology

(1) Reservoirs and Geologic Structure

In the Bakau field the upper part of sedimentary cycle V is hydrocarbon bearing. Only three wells, well Nos. 3, 4, and 5 are drilled in this field to produce oil, since Bakau well Nos.1 and 2 are considered out of the study object because of their locations being on a different structure in the distance 15 km southwest of the field.

The Bakau structure is a northeast-plunging nose-like one cut by several growth faults trending E-W or ENE-WSW. Especially a major fault which separates the south area drilled by well No.3 and the north area including well Nos.4 and 5 is presumed the most important, making correlation between the two areas impossible for some reservoir levels.

As shown in the correlation table (Table 5-2-1), zones a and b are common to the three wells, that is, the occurrence of identical strata over the field is down to the horizon of zone b_2, whereas zones c and lower of well No.3 and zones c' and lower of well Nos.4 and 5 have no relation to each other in the alphabetical names. Therefore, in Figs. 5-2-1, 2 and Figs. 5-2-3, 4 structural maps are independently given of the two areas.

(2) Hydrocarbon Trapping

Hydrocarbon trapping of the Bakau field is considered of a fault type in a nose-shaped anticline. Although it is inferred from Figs.5-2-1 - 2 that this is open southward, variable extents of faulting may make possible further distributions of hydrocarbons to the south. There is still two undrilled blocks in the area of well Nos.4 and 5, for which original hydrocarbons-in-place could not be estimated.

It is necessary to study structurally and stratigraphically the way in which the reservoirs are in contact across faults, since there is a possibility that the main growth fault does not always act as a seal, as suggested in Fig. 5-2-5.

[Seismic Interpretation]

In the southern area a target horizon of the seismic interpretation was the top of zone c_1 and in the northern area, the top of zone c'_4. These horizons have the best quality in each area. However, correlation of reflections across faults was not always possible. The relation of reflection time versus depth was based on well shooting data of Bakau No.3. Interpretation result and representative seismic section are shown in Figs. 5-1-1 - 3.

3.5.3 Reservoir Analysis

(a) Well BK-3

Well BK-3 is completed for 3 zones, which are zone c_1, upper and lower parts of zone c_3.

Original reservoir pressure was determined from Fig. 5-3-1 to be 3196 psig at datum plane of 7400 ft s.s. Average reservoir porosity is 0.2 and water saturation range from 0.47 to 0.67. Fluid properties and permeability data were established as shown on Figs. 5-3-6, 9, 12 and 15. Produced API gravity is 40 degrees.

As confirmed reserves by volumetric method are only for highly limited area the value is apt to be underestimated. The reserves calculation, therefore, was made by Decline Curve method and several trial and errors were made to match actual well performance. Estimated original oil in place is 6.993 MMSTB.

Based on this reserves, performance prediction was made, which is illustrated on Fig. 5-3-3 and tabulated on Table 5-3-2.

(b) Well BK-4

Well BK-4 is completed for 3 zones of zone a_1, zone c_1, upper part of zone c_4. Reservoir porosity and water saturation range from 0.44 to 0.70 and 0.22 to 0.17, respectively. Original reservoir pressure was determined to be 3325 psig at datum plane of 7700 ft s.s. from Fig. 5-3-1. Fluid properties and permeability data were established as shown on Figs. 5-3-7, 10, 13 and 16.

The production started May 1975 and cumulative oil production by June 1976 is 1.158 MMSTB that is 28% of oil volume detected by volumetric method. However production performance during the history stage seems to be prospective and original oil in place was determined by trial and error method in the same ways with Well BK-3. Estimated original oil in place is 14.475 MMSTB.

Computed result based on the above reserves is shown on Fig. 5-3-4 and Table 5-3-3.

(c) Well BK-5

Well BK-5 is completed for 4 zones of zone b_1, c_1, c_3 and c_4. Reservoir porosity ranges from 0.15 to 0.11 and water saturation was interpreted to be very high and exceeding 60%. Original reservoir pressure was determined to be 3497 psig from Fig. 5-3-1. Fluid properties and permeability data were determined as shown on Figs. 5-3-8, 11, 14 and 17.

Production started February 1976. As illustrated on Fig. 5-3-5, remarkable production decline was observed even in the short period of history stage.

Original oil in place was determined by trial and error method due to bad quality of log survey results. Original oil in place was estimated to be 0.834 MMSTB by that method.

Estimation of future performance was made using the aforementioned reserves, the results of which are shown on Fig. 5-3-5 and Table 5-3-4.

Field total performance is shown on Fig. 5-3-2 and Table 5-3-1.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual wells as a function of cumulative oil production and summarized on Figs. 5-3-18 - 20.

3.6 Tukau Field

3.6.1 Field Status

In this field, 21 wells have been drilled so far, and 13 wells are producing.

The oil reservoir is composed of approximately 60 sand layers. Heavy and light oil with API gravity ranging from 22° to 39° accumulates in the reservoir in the depth from 2650 ft to 7550 ft s.s.

Production started June 1975 and average daily production rate during the month of June 1976 was 12.5 MSTB/D and cumulative oil production as of June 1976 amounts to 2.97 MMSTB.

3.6.2 Geology

(1) Reservoir Beds

The Tukau field has hydrocarbon accumulations in sandstones, occurring in depths below 2000 ft, which were deposited in deltaic environments of cycle V. Correlation of horizons of reservoirs is relatively good but below zone d it becomes extremely poor between the northern main wells and the southern wells because of the affect of growth faulting to the sedimentation below the horizon of zone b_3 (Table 6-2-1).

(2) Geologic Structure

The Tukau structure is a N-S trending anticlinal one which is transected by an ESE-WNW striking fault system, divided into the unfaulted northern half and the extremely faulted southern half, as shown in Figs. 6-2-1 - 4.

The fault system is probably rooted in a growth fault which occurs in greater depths than approximately 3000 ft. The growth fault, northward dipping, runs in the WNW direction between well Nos.2 and 11 to be the boundary between the northern and southern halves, but its exact location is difficult to know on account of intense tectonic disturbance of strata.

The southern half of the structure is cut into many parts by step-like faulting but the available seismic sections have so bad record quality below the zone d horizon in the area that accurate mapping was avoided in the present study.

3.6.3 Reservoir Analysis

The field is classified into 11 groups by blocking and zoning, and reservoir performance calculation was made for the individual group. The groups correspond to Models 1 - 11, respectively. The each Model defined by blocking and the original oil in place calculated by volumetric method are summarized on the following table. The each reservoir performance calculated by the Model is shown as Figs. 6-3-3 - 13 and Tables 6-3-2 - 12. The field total performance is shown on Fig. 6-3-2 and Table 6-3-1. Original reservoir pressure is determined from Fig. 6-3-1.

In the model calculation, well production behaviors such as the change of production rate, producing gas oil ratio and water oil ratio were matched, as no sufficient pressure information was available in this field.

Utilized fluid properties and rock characteristics are shown on Figs. 6-3-14 - 41.

The blocks analysed in the models are as follows, respectively.

Model	Block Zone	Producer	Sub Sea Depth	API Gravity	O.O.I.P. (MMSTB)
Model-1	Block-I zone b1,b2, b3	4	2650'-3250'	21°-24°	20.16
Model-2	Block-I zone c1,c2	2	3250'-3800'	26°-38°	4.30
Model-3	Block-I zone d1,d2, d3	4	3800'-4350'	27°-30°	13.45
Model-4	Block-I zone d4	2	4350'-4600'	31°-32°	1.07
Model-5	Block-I zone d5,e	1	5500'-7550'	36°-37°	20.50
Model-6	Block-II zone b1,b2, b3	1	2700'-3200'	23°	2.36
Model-7	Block-III zone d1,d2, d3	2	3700'-4200'	30°	0.98
Model-8	zone f	2	6200'-6600'	36°-38°	9.77
Model-9	Block-III zone b1,b2, b3	0(2)	2600'-3100'		48.49
Model-10	Block-IV zone b1,b2, b3	0(2)	2750'-3000'		19.88
Model-11	Block-IV zone d4	0(1)	3600'-4200'		2.66

* The figures in the parenthesis are required numbers of wells in the additional wells case.

Additional wells case study was made for the development of undeveloped portion of the field. In this field, total 5 wells are required to develop zone b of Block III, zone b of Block IV and zone d of Block IV which correspond to Model 9, 10 and 11, respectively. The well location was shown on Fig. 6-3-53.

The anticipated reservoir performance for this case is shown on Figs. 6-3-11 - 13 and Tables 6-3-10 - 12. The performance of Model 9, 10 and 11 was shown on Table 6-3-13.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual Models as a function of cumulative oil production and summarized on Figs. 6-3-42 - 52.

4. FIELDS FOR DEVELOPMENT (I)

4.1 Betty Field

4.1.1 Geology

(1) Reservoir Beds

The Betty field has been drilled by four wells in the order of well Nos.1, 2, 3, and 4 from east to west. Correlation of well data indicates that formations decrease in thickness to the west both in cycle V and in the lower part of cycle VI. Hydrocarbons are accumulated in cycle V sediments of Upper Miocene age. Reservoirs are sandstones, named as zones a - c (Table 7-2-1), of varied thicknesses up to 190 ft generally intercalated with shale beds less than 10 ft or so. Well No.1 proved oil in zones a and b and gas in zones b and c, while well No.3 proved only gas in zones b and c and well Nos.2 and 4 were dry.

(2) Geologic Structure and Hydrocarbon Trapping

As shown in structural maps of zones a_1 and b_2 in Figs. 7-2-1, 2, the Betty structure is the roll-over that formed on the north side of a nearly east-west running growth fault, having structural highs both on the east and the west about 10 km apart. The depressed area between the both highs has depth differences ranging from 300 to 500 ft and lower than the OWC levels encountered in the east by well No.1 (Figs. 7-2-1, 2). Since well No.2 was dry, the gas zones that were proved to exist in the both highs are considered to have no connection. There is an undrilled block faulted between well Nos.3 and 4 in the west area.

[Seismic Interpretation]

An interpreted horizon was the top of zone a_1. Data quality of the interpreted horizon is partly poor in the western part of the structure, but very good, in the other part. Faults also appear clearly in the seismic sections. The relation of reflection time versus depth was based on well shooting data of all wells, Betty Nos.1 - 4. Interpretation result and representative seismic section are shown in Fig. 7-1-1 and Fig. 7-1-2.

4.1.2 Reservoir Analysis

Two wells have been drilled in the eastern and western structure. Well No.1 drilled in the eastern structure confirmed oil accumulation in the zones a_1, a_3 and a_2, the API of which are 34.4°, 39.9° and 39°, respectively. Gas or gas condensate accumulation was observed in zones b_1 and c_1. In the Well No.3 of western structure, small amounts of gas are observed in zones b_2 and c.

No gas cap was confirmed in oil zone of Well No.1 but aquifer was detected in zones a_1 and a_3.

The reservoir seems to have good characteristics from qualitative log interpretation but reservoir extent seems to be comparatively small.

Proved oil reserves calculated from volumetric method is listed on Table 1-1-2 and log analysis is shown on Appendix.

The main production reservoirs are interpreted to be zones a_1 and a_3, but DST and production test has not been made so far and productivity for individual zone is still unknown.

As special core analysis and PVT data is not available, general trend of fluid characteristic was used for reservoir performance prediction of main zone. Reservoir parameters used in this sample calculation are listed on Tables 7-3-1 - 3 and computed results are summarized on Tables 7-3-4 - 6.

It should be reminded that the computed results as shown above are much influenced by the assumed and utilized parameters.

According to the study results, total proved oil reserved are estimated to be 54.2 MMSTB and the field belongs to medium to small sized reservoir in Malaysia. Although the results are much influenced by the assumed data, the field is anticipated to have the production ability of maximum 15 MSTB/D at initial condition. No delineation well is thought to be required, however, the first requisite is to confirm maximum allowable production rate on well basis and to obtain reservoir transmissibility by build up curve analysis. After the start of production, periodical pressure survey is required especially for the evaluation of water drive.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual zones as a function of cumulative oil production and summarized on Figs. 7-3-1 - 3.

4.2 Bokor Field

4.2.1 Geology

(1) Reservoir Beds

The Bokor structure is located about 4 km south-southwest of Betty well No.1 and has been drilled by four wells. Hydrocarbons are found in sediments of cycle V and lower cycle VI, of which non-deltaic sediments of cycle VI contain heavy oil of 19.5° API in 10 to 50 ft thick sandstones (zones a_1 - a_3, Table 8-2-1).

(2) Geologic Structure and Hydrocarbon Trapping

Figs. 8-2-1, 2 show structural maps of zones a_1 and b_3. The structure is an anticlinal high, the south half of which is blocked by several east-west trending faults. The main, north block of the structure was drilled at and below zone b_1 by well No.3 on the crestal part, and well Nos.1 and 2 on the western flank. Well No.4 drilled on one of the fault blocks of the south half. As seen in a north-south cross-section of Fig. 8-2-3 hydrocarbon accumulations have been proved to exist only in the north block. No hydrocarbons were found in zones a_1 - a_3 of two minor blocks penetrated through these horizons by well No.3 and well No.4, respectively (Fig. 8-2-1).

For horizons of zone b and lower, however, a central horst-like block is not explored as to the hydrocarbon accumulation since well No.3 enters the north block across the bounding fault at the top of zone b_1.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone a. Quality of reflections associated with the horizon is partly poor in the crestal part of the structure and around faults, but in the other part it is fair to good. In the marginal area it was possible to correlate reflections across faults. The relation of reflection time versus depth was based on well shooting data of Bokor Nos.1 and 2. Interpretation result and representative seismic section are shown in Fig. 8-1-1 and Fig. 8-1-2.

4.2.2 Reservoir Analysis

Four wells have been drilled in this structure and oil accumulation was confirmed by Well No.2 and 3.

In the northern block divided by the main fault crossing the central part of the structure, accumulation of heavy oil with API 19.5° was confirmed in the depth interval from 2000 ft to 3000 ft s.s.

While in the well No.1, 300 ft structurally in down dip location, all the zones are completely wet.

In the central block of the structure, hydrocarbon accumulation was confirmed by log analysis in the sand layers with total thickness of more than 190 ft, while discrimination of oil and gas can be made only at 4 points by FIT results. In this block, production test was conducted for a part of zone b, and API gravity of 21.5° and gas oil ratio of 330 SCF/STB were obtained. Hydrocarbon accumulation is widely distributed in the interval from 3100 ft to 5000 ft s.s.

In the southern block, only slight hydrocarbon was observed in zone b but all the other zones are water wet.

Zone a in northern block and zone b in central block are main productive reservoirs. Estimation of original reserves using log analysis results were made by volumetric method as listed on Table 1-1-2.

Sample calculations of performance prediction were made for zone a in northern block and for zone b in central block by using proved and probable in place. Reservoir parameters used in the computation are shown on Tables 8-3-1 - 3 and predicted performances are shown on Tables 8-3-4 - 6. As PVT data and special core analysis were not available in this reservoir, general trend of Malaysia field was used in the calculation.

Computed results exhibit poor performance. This is primarily brought about from insufficient reservoir energy caused by poor reservoir mobility and low solution gas oil ratio. However, probable hydrocarbon in place is not so small and further confirmation works are required.

First of all, confirmation of productivity and mobility should be checked zone by zone through production test or DST. High reservoir oil viscosity was thought to be the cause of poor reservoir mobility and strict production control should be made. In order to make this feasible, stabilized production rate should be determined through long term production test.

Relative permeability data should also be indispensable in designing future probable secondary recovery operation. The reservoir depth is comparatively shallow and drilling of appraisal wells is required for this reservoir.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual zones as a function of cumulative oil production and summarized on Figs. 8-3-1 - 3.

4.3 Temana Field

4.3.1 Stratigraphy and Geologic Structure

The Temana field is divided into two structures, "East" and "West"; Temana East has been drilled by well Nos.1 - 4 and Temana West by well Nos.5 - 10. Correlation of reservoirs and seismic interpretation were carried out separately for the two structures (Tables 9-2-1, 2). In the Temana field it is a difference from other Sarawak fields that there are unconformities between Pliocene and Middle-Lower Miocene sequences.

For the west structure there are two unconformities between Pliocene and Middle Miocene sediments and between Middle Miocene and Lower Miocene sediments. The middle Miocene consists of shaly beds of sedimentary cycle V ranging from 250 to 300 ft in thickness. Important hydrocarbon bearing rocks are of non-deltaic sediments of cycle II and especially sandstones of zones c and d are heavy oil bearing, though their continuity being extremely bad. The west structure in the cycle II horizons is almost circular and dome-like and is associated with many small faults as shown in Fig. 9-2-1. It is interpreted that the structural high is dropped down relatively to the east because a fault located east of well No.10 in the figure is considered to be penetrated by the well at 2720 ft with a 650 ft throw.

As passing eastward from the west structure, sediments of cycles II and III occur in shallower depths, while the unconformity between them and Pliocene beds become deeper.

In the area of Temana East, Middle Miocene formations are lost and instead Pliocene sediments overlie directly the lower part of the cycle II with obviously angular unconformity (Fig. 9-2-2). The east structure in the cycle III horizons indicates an E-W elongate dome shape, transected by a number of faults originated before the formation of the unconformity. Well Nos.1, 3, 4, which encountered hydrocarbon accumulations, have been drilled on separate fault blocks. Lateral variations in rock facies of reservoirs are smaller than in the west structure to give relatively good correlation. A heavy oil bearing zone, found also in the east structure in well No.3 (zone a), has a limited distribution in a peripheral area of the structure due to erosion of cycle II sediments in the crestal area.

[Seismic Interpretation]

A target horizon of the interpretation was the top of zone c_1 for Temana (West). Quality of reflections from the target horizon is partly poor, but mostly poor. Especially, in the eastern part of the structure quality becomes very poor. Well shooting data of Temana Nos.5 and 7 were available. Interpretation result and representative seismic section are shown in Fig. 9-1-3 and Fig. 9-1-4.

A selected horizon for the seismic interpretation was the top of zone c for Temana (East). Quality of reflections associated with the interpreted horizon is fair to poor. In the southern part of the structure quality is mostly poor. The locations of most of faults are ambiguous in the seismic sections and correlation of reflections across faults is quite difficult. Well shooting data of only Temana No.4 were available in this structure.

Interpretation result and representative seismic section are shown in Fig. 9-1-1 and Fig. 9-1-2.

4.3.2 Reservoir Analysis

Oil properties and its distribution are quite different in the east and west structure.

In the east structure, accumulation of oil with API gravity ranging from 31° to 35° was confirmed in zone b to c in the depth interval from 3000 ft to 5000 ft and productivity for individual zones was confirmed by DST. The structure is subdivided into several blocks and no well has been drilled in the central block. Total 10 DSTs have been conducted. DSTs No.6 to 8 were conducted for main zone. Average productivities for the zones are about 300 to 400 STB/D with productivity index approximately 1 B/D/psi, which are regarded as very poor value. Production test conducted at Well No.4 shows the productivity of 310 STB/D, while well head pressure declined to as low as 30 psig during 2.5 hours flowing period. Both zones are estimated to have extremely low productivities. According to the production test for zone c at Well No.4, the well is reported to be killed itself and no productivity is obtained.

According to the log analysis as shown in Appendix II, oil accumulation is confirmed, while actual productivity is extremely low in the confirmed area. The east structure will not be worth while unless high productivity zone exists in the undrilled central and its surrounding area.

In the west structure, heavy oil with API 18° to 23° accumulates in the depth interval from 1500 ft to 2200 ft s.s. and light oil with API 40° to 42° exists in the interval from 2500 ft to 3200 ft s.s. The light oil, however, is confirmed to exist only 10 ft in Well No.5. In Well No.5, oil and gas showings are observed in the interval from 5400 ft to 7000 ft, however, the zones were estimated to be poor permeable and tight according to the FIT results.

In the western structure, the field is divided into 4 blocks by fault. The block which includes Well No.5 shows high productivity. Production tests were conducted for zone e and f, which have light hydrocarbon, however, no report is made for productivity. Productivity for the zones may well be estimated to be very poor.

Main reservoir sands for the field are thought to be zone c and d which produce heavy oil. Assuming reservoir parameter to be as listed in Table 9-3-1, reservoir performance was predicted as shown on Table 9-3-2.

Estimated poor performance is not only due to poor reservoir mobility but due to poor water drive as the producing area is in a completely closed area.

As a result of the study, poor reservoir quality was estimated for eastern structure, while in western structure, confirmation of the reservoir extent of the productive zone observed in Well No.5 is required together with relative permeability information. The information is necessary to conduct feasibility study on secondary recovery as poor recovery was estimated by natural depletion.

5. POTENTIAL FIELDS

5.1 Beryl Field

5.1.1 Geology and Hydrocarbon Occurrence

A large area, amounting to 600 km^2 in area, is drilled by six wells under the name of Beryl, of which well data indicate that there had been sedimentation till Pleistocene. Sedimentary sections penetrated by wells consist of sandstones and shales of cycles ranging from V to VIII, increasing in thickness toward the north as a whole (Table 10-2-1). The area is tectonically characteristic of the development of many growth faults which trend east-west and throw their north sides down to give a step-like appearance. Fig. 10-2-1 shows a depth contour on the top horizon of cycle VI.

The most significant hydrocarbon occurrence is a net 55 ft of gas in well No.6 at 4405 ft in a sandstone bed of cycle VI. Taking account of good continuity of this regressive sandstone and of the location of well No.6 being a few hundreds feet lower than the highest point of the block to which the well belongs, it is desirable to drill in a mid-point among well Nos.1, 4 and 6 to make further exploration. Other hydrocarbon occurrences of the Beryl area are as follows; oil shows or indications were found in sediments of cycle V in well No.2, of cycle VI in well No.4, and of cycle VII in well No.3, while there was no hydrocarbon indication in well Nos.1 and 5.

It should also be reminded that GWC of the gas zone is obtained at well No.6. The field is still in the early stage of exploration and the objective area should be decided by more exploratory work.

[Seismic Interpretation]

An interpreted horizon of the seismic interpretation was the top of upper cycle VI. In general, quality of reflections associated with the target horizon is good. Several faults running east-west are clearly recognized in the seismic sections, but reflections are not always correlative across faults. In a fault block where no well has been drilled, reflections were correlated across the fault by the reliable seismic sections. The relation of reflection time versus depth was based on well shooting data of Beryl Nos.3, 4, 5 and 6. Interpretation result and representative seismic section are shown in Fig. 10-1-1 and Fig. 10-1-2.

5.2.1 Siwa Field

5.2.1 Geology and Hydrocarbon Occurrences

There is an east-west trending fault zone between Siwa well Nos.3 and 4 and this gives different structural characteristics to the north and south.

The south structure drilled by well Nos.1, 2 and 3 is a nose-like anticline pluging southward with considerably steep wings. It is suggested from seismic record sections that, after monotonous sedimentation continued till an early Pliocene time, a sudden tectonic movement happened to cause the uplift in the south area. The three wells drilled on the south structure all encountered undersompacted shale at about 5000 ft, which suggests the possibility of the structural origin in shale diapir movement.

Hydrocarbons were discovered only on the north structure in well No.4. Study was made for the northe structure in part because correlation was not possible between the two structures. The north structure is an east-west elongate high downthrown relative to the south (Figs. 11-2-1, 2). Well No.4, located near the crest of the anticline, contains hydrocarbons in mainly deltaic sediments of cycle V. It is considered that the south structure was formed after the migration of hydrocarbons had finished, if any.

[Seismic Interpretation]

Near the top of zone d_1 was a target horizon of the seismic interpretation. In the interpreted area quality of reflections arising from the target horizon is partly poor, but mostly fair to good. The relation of reflection time versus depth is based on well shooting data of Siwa No.4. Interpretation result and representative seismic section are shown in Fig. 11-1-1 and Fig. 11-1-2.

5.2.2 Reservoir Analysis

Four wells have been drilled, however, only the Siwa Well No.4 is drilled into the objective structure.

In the location of Well No.4, where the well is drilled into the crestal part of the structure, hydrocarbon accumulation is observed in the depth interval from 1380 ft to 6700 ft BDF. Shallow horizon above the depth of 2000 ft is an alternation of shale and thin sand, and poor reservoir characteristics is anticipated.

Main reservoir is sand zone below 4000 ft depth, however, water levels are confirmed in many sand layers and wide reservoir extent can not be anticipated.

Areal extent should be confirmed and productivity should be evaluated by DST or production test.

6. FIELD FOR DEVELOPMENT (II) - CENTRAL LUCONIA FIELDS

6.1 Geology

6.1.1 Stratigraphy

Central Luconia area is a sedimentary basin off Sarawak and has an about 6,000 km^2 area with water depths of 100 to 500 ft. This basin is characterized by reefal carbonate buildups which were developed in Middle to Late Miocene age. Each of the 14 studied structures was drilled by generally one or two walls, which penetrated the carbonate buildups. The structure which was drilled by the deepest well is B12 with a total depth of 12,225 ft and other structures were drilled by wells of total depths of 4,500 to 7,500 ft (Fig. 12-2-1, Table 12-2-1).

Sedimentary sections known in Central Luconia area are composed of sediments of sedimentary cycles III to VIII. The beginning of the carbonate buildup development is considered to be at times of cycles III to IV in Middle to Late Miocene age, but the termination of their development appears to be younger toward the north or northwest (Fig. 12-2-1). That is to say, times of termination of reefal development were probably within the cycle V time for fields of the southern side of a line connecting K4 and F23, at almost the same time as top of cycle V for fields of the northern side to M5 area, and then within the cycle VI time for M3 and M1 in the northernmost area.

6.1.2 Structure of Reefal Carbonates

Fig. 12-2-2 shows areal size and shape of reefal structures at hydrocarbon bearing levels. The largest fields reach about 50 km^2 in area in F6 and F9. Most structures elongate N-S and NE-SW but F13 structure has a mixture of the two directions. Structural cross-sections shown in Figs. A75, 78, 81, 85, 90 indicate that carbonate buildups such as F13 and F14 have flat tops and others such as E11 and F22 have steep flanks.

The basements of the carbonate buildups were encountered in wells only in two fields of E11 and F13, but all of interfaces between water and hydrocarbons are proved to be within the carbonates as shown in Fig. 12-2-1. Gas columns confirmed in wells attain a maximum of 1,660 ft in E8 and a minimum of 220 ft in M1. The number of wells drilled on each structure is one to three. Correlation was not effective to know the internal structure or stratification of the carbonate reservoirs because of an insufficient number of wells fully penetrated the carbonates. However, some fields can be subdivided into a few zones in vertical sections.

6.1.3 Seismic Interpretation and Geology of Each Fields

In this section, (a) the explanation of seismic interpretation and (b) geologic comments on structure and reservoirs are given to each field.

B12 Field

(a) A target horizon of the seismic interpretation was the top of carbonates. Quality of reflections is partly a little poor in the seismic sections shot in 1968, but generally good in the other sections. Well shooting data of B12 No.1 was available. Interpretation result and representative seismic section are shown in Fig. 12-1-1 and Fig. 12-1-2.

(b) The B12 structure is the deepest carbonate buildup in the Central Luconia objective fields. Well No.1 penetrated carbonate rocks between 10,564 and 12,225 feet without reaching the basement. This reefal structure is NNE-SSE elongate, dome-like, and 6 km long and 2 km wide at the level of GWC and was drilled by well No.B12. 1X on the crest (Figs. 12-2-3, 6). Gas bearing reservoirs are limestones argillaceous to a considerable extent and of an average effective porosity of 14%.

E6 Field

(a) An interpreted horizon was the top of carbonates. In general, quality of reflections associated with the interpreted horizon is fair to good, but partly a little poor in the eastern and western flanks of this carbonate buildup. The well shooting data of E6 No.1X was used for time-depth conversion. Interpretation result and representative seismic section are shown in Fig. 12-1-3 and Fig. 12-1-4.

(b) The E6 structure is very elongate in the north-south direction and 10 km long and 1.5 km wide at the OWC level. It has two crests with similar heights in the north and the south, on the north of which well E6.1X was drilled (Figs. 12-2-4, 6). Reservoir rocks are limestones which show good characteristics for gas and oil bearing intervals except a shaly part of the uppermost several tens feet; namely, the interval of 5300 to 5600 ft consists of wackestone and packstone with an average effective porosity of 25%, and the interval of 5600 to 5830 ft is of wackestone with that of 19%. However, reservoir rocks deteriorate downward just below the OWC level at 5938 ft.

E8 Field

(a) A target horizon of the seismic interpretation was the top of carbonates. In the crestal part of this carbonate buildup, quality of reflections from the target horizon is fair, but in the marginal area it is generally poor. Well shooting data of E8 Nos.1X and 2 was available. Interpretation result and representative seismic section are shown in Fig. 12-1-5 and Fig. 12-1-6.

(b) The E8 structure is a NNW-SSE slightly elongate reef with a flat top and steep flanks, 3.5 km long and 2.5 km wide at the GWC level (Figs. 12-2-5, 6). Two wells have been drilled without reaching the basement. Limestones are good in reservoir characteristics, except for the topmost 150 ft in well No.E8.1X and 280 ft in well No.E8.2, and consist mainly of packstone with minor intercalations of grainstone and wackestone, showing an average effective porosity of around 20%. However, reservoir rocks decrease in porosity below the GWC level.

E11 Field

(a) The top of carbonates was a target horizon of the seismic interpretation. Quality of reflections associated with the top of carbonate is generally good to fair, but partly poor in the marginal area of the carbonate buildup. Time-depth conversion was made by the well shooting data of E11 Nos.1 and 2. Interpretation result and representative seismic section are shown in Fig. 12-1-7 and Fig. 12-1-8.

(b) The E11 structure does not have a flat crest but steep slopes with dips of as much as 35 degrees, and is 8 km long and 4 km wide at the GWC level. The structure has been drilled by two wells, well No.E11.1X on the crest and well No.E11.2X on the east flank (Figs. 12-2-7, 9). The reefal limestones are vertically divided into the upper and lower parts with the boundary at depths of about 5900 to 6100 ft by the occurrence of shaly and low porosity intervention through which vertical communication of reservoir fluids are considered impossible. Reservoir rocks are mainly of wackestone and packstone and have an average effective porosity of about 20%. The basement of the carbonate buildup is reached at 6583 ft in well No.E11.1X. Beside of the reefal reservoir, for a shallower interval between it and a 2600 ft depth there are gas accumulations in a number of sandstone beds of cycle V though being in a much lesser amount.

F6 Field

(a) An interpreted horizon was the top of carbonates. Quality of reflections arising from the interpreted horizon is good. The relation of reflection time versus depth was based on well shooting data of F6 No.2. T-z graph of F6 No.1 was not used because it was not clear whether this graph had been constructed based on the well shooting data, for lack of check shot marks in the graph. Interpretation result and representative seismic section are shown in Fig. 12-1-9 and Fig. 12-1-10.

(b) The F6 structure is one of the largest reef fields in Central Luconia and has a gas bearing area 20 km long and 4 km wide at the GWC level. It is an ENE-WSW elongate structure the crest of which was drilled by well No.F6.1X and the north-east flank by well No.F6.2 (Figs. 12-2-8, 9). The carbonates in well No.F6.1X become better upward with increasing proportions of grainstones to wackestones. At about 3960 to 4090 ft in well No.F6.1X there is a reservoir deterioration caused by a marine transgression which may divide the reservoir into the upper and lower parts, but this is doubtful to be applied to the whole area of the large field.

F9 Field

(a) A target horizon of the seismic interpretation was the top of carbonates. Quality of reflections associated with the top of carbonates is generally good to fair, but partly a little poor in the northern flank of the structure. Well shooting data of F9 No.1X were used for time-depth conversion. Interpretation result and representative seismic section are shown in Fig. 12-1-11 and Fig. 12-1-12.

(b) The F9 structure is located 10 km north of the F6 structure. It is an ENE-WSW elongate structure with extremely flat surfaces, hollowed in the central portion, and has a gas bearing area 13 km long and 6 km wide (Figs. 12-2-10, 12). Well No.F6.1X was drilled nearly on the crest biassed in the north-east. Reefal carbonates mainly consist of wackestones and not good as reservoir rocks. The gas bearing interval of 232 ft has also a low net-gross ratio of as low as 0.29.

F13 Field

(a) A target horizon of the seismic interpretation was the top of carbonates. Quality of reflection arising from the target horizon is generally good to fair, but partly poor. Well shooting data of F13 Nos.1X and 2 were used for time-depth convertion. Interpretation result and representative seismic section are shown in Fig. 12-1-13 and Fig. 12-1-14.

(b) The F13 field is in a reefal structure 10 km north of the E11 structure. It indicates two structural orientations which perhaps results from the basement movement and configuration; namely they are the NE-SW trend over the area and the N-S trend dividing the structure east-west. The "sub-structure" of the northeast was drilled by well No.F13.1X and that of the southwest by well No.F13.2 (Figs. 12-2-11, 12). Well No.F13.1X reached the basement of the reef complex at 6860 ft in well No.F13.2. Reservoir limestones consist of packstones and wackestones and give an average effective porosity of 22%.

F14 Field

(a) An interpreted horizon of this field was the top of carbonates. Well shooting data of F14 No.1X was available. Interpretation result and representative seismic section are shown in Fig. 12-1-15 and Fig. 12-1-16.

(b) The F14 structure is a reef complex with extremely flat top surfaces and was drilled by well No.F14.1X in the center. The field is restricted by an E-W trending fault in the north (Figs. 12-2-13, 16). Proved gas column is only 223 ft but the gas bearing interval has an average effective porosity of 27% indicating relatively good reservoirs.

F22 Field

(a) The top of carbonates was interpreted in this field. Quality of reflections from the interpreted horizon is good to fair. Areal extent of this field is very small and since only three survey lines cover this field, detailed configuration of this structure is not definite. Well shooting data of F22 No.1 was used for time-depth conversion. Interpretation result and representative seismic section are shown in Fig. 12-1-17 and Fig. 12-1-18.

(b) The F22 structure is a relatively small, NE-SW elongate reef of a gas bearing area of 3 km in length and 1 km in width with slopes dipping as steeply as 37 degrees (Figs. 12-2-14, 16). Reservoir rocks are tight for the uppermost 80 ft interval, but below this, increase in effective porosity from 12% to 25% downward.

F23 Field

(a) A target horizon of the seismic interpretation was the top of carbonates. Quality of reflections associated with the top of carbonates is good and the reflections were easily followed. Well shooting data of F23 No.1 was available. Interpretation result and representative seismic section are shown in Fig. 12-1-9 and Fig. 12-1-20.

(b) The F23 structure indicates an oval shape in a gas bearing area of 7 km in length and 3.7 km in width (Figs. 12-2-15, 16). It has dips varying from 40 degrees near the GWC level to gradually small values toward the top. Well No.F23.1 is on the topmost part of the structure, where a gas column attains 1,060 ft. The net-gross ratio of the gas bearing interval is 0.95 and the average effective porosity is as high as 25%. The core data of well No.F23.1 indicate that the rocks are of principally vuggy reefoid for the interval between 4150 and 5000 ft.

K4 Field

(a) An interpreted horizon of this field was the top of carbonates. Quality of reflections arising from the interpreted horizon is generally fair, but partly poor. Well shooting data of K4 No.1 was available. Interpretation result and representative seismic section are shown in Fig. 12-1-21 and Fig. 12-1-22.

(b) The K4 field is located in the westernmost part of Central Luconia area. It is a small reef structure elongated in the north-south direction and has a gas bearing area of 3.5 km in length and 1.5 km in width. Well No.K4.1 was drilled on the crest with only a 238 ft gas column. Limestones of the gas interval have an average effective porosity of 28%.

M1 Field

(a) A target horizon of the seismic interpretation was the top carbonates. Reflections arising from the top of carbonates appear clearly in the marginal area of this buildup, but do not in the main area. However, as reflections of different pattern appear in the main area, these reflections were assumed to be associated with the top of carbonates. Well shooting data of M1 No.1 was available. Interpretation result and representative seismic section are shown in Fig. 12-1-23 and Fig. 12-1-24.

(b) The M1 field has a ring-like, NE-SW elongate, reef structure with hollow parts at some places. The overall size of the structure is 8.5 km long and 5 km wide at the GWC level. The highest part of the ring is on the west and was drilled by well No.M1.1X (Figs. 12-2-18, 21). The gas column is 220 ft in a maximum and probably less than 100 ft in the most parts of the ring.

M3 Field

(a) An interpreted horizon in this field was the top of carbonates. Quality of reflections arising from the top of carbonates is good. Well shooting data of M3 No.1 was available. Interpretation result and representative seismic section are shown in Fig. 12-1-25 and Fig. 12-1-26.

(b) The M3 structure is a platform type reef of an E-W elongate oval shape, 6.5 km in length and 4 km in width (Figs. 12-2-19, 21). The gas column is 390 feet in well No.M3.1X which was drilled somewhat downflank. A tight part of 30 feet or so is found in the middle of the gas zone.

M5 Field

(a) The top of carbonates was a target horizon of the seismic interpretation. Quality of reflections from the interpreted horizon is good. Well shooting data of M5 No.1X was available. Interpretation result and representative seismic section are shown in Fig. 12-1-27 and Fig. 12-1-28.

(b) The M5 structure is a platform type reef 7 km long and 4 km wide. The highest point is biassed in the southeast of the field (Figs. 12-2-20, 21). It is regarded that the gas bearing interval does not have effective porosities for the most part since the upper part of limestones is mostly tight.

6.2 Reservoir Analysis

6.2.1 Analytical Procedure

For all of the reservoirs in the fourteen fields, the hydrocarbon accumulation was confirmed by FIT and log analysis results. Volumetrically calculated gas in place for the individual fields is tabulated on Table 1-1-4.

In this reserves calculation, the gas formation volume factor was estimated for representative sample of the fields as listed on Tables 12-3-1 - 8, based on the mole fraction of each components by Standing and Katz method.

For the objective gas fields for development, which are E8, E11, F6, F13, F14 and F23, the relations of

Reservoir Pressure/Gas Deviation Factor vs Cumulative Production

were calculated at first by regarding all the reservoir as complete volumetric reservoirs. Based on the relations, the instantaneous static reservoir pressures were described as a function of cumulative production.

Finally bottom hole flowing pressures were described as a function of cumulative gas production for variable daily production rates cases of 30, 20 and 10 MMSCF/D by the turbulent steady-state flow equation. The computed results are described on Figs. 12-3-7 - 12 and on Tables 12-3-9, 12 - 18.

In the estimation of ultimate recoveries and deliverabilities required for establishing suitable production facilities design, the relations of Well Head Flowing Pressure vs Cumulative Production as a function of individual well production rates are required.

The well head pressures for variable production rates cases were estimated from Cullender & Smith method. The relations are described in Part B.

The application of the above procedures is due to the fact that no production potential test has been conducted so far for the Central Luconia fields except for E11.2 and F13.3.

The exceptional field among the fields for development in the Central Luconia Area is E6, which can be interpreted to be an oil field with a huge gas cap.

Oil production is scheduled on this field, however, with the progress of the depletion stage, a lot of associated gas is anticipated to be produced. In the recommended gas production schedule, consideration was also made for the efficient utilization of the associated gas from E6.

The reservoir performance predictions for E6 obtained by material balance method for the volumetric reservoir with gas cap were made for two cases, one was for natural depletion and the other was for restricted gas production case. The cases are presented on Figs. 12-3-5, 6, tabulated on Tables 12-3-10, 11 and rock and fluid characteristics are shown on Figs. 12-3-1 - 4.

The most important factor to attain maximum recovery is the control of producing gas oil ratio. The value changes with the progress of the depletion stage.

The most recommendable producing gas oil ratio was described for the individual zones as a function of cumulative oil production and summarized on Fig. 12-3-13.

6.2.2 Test Required in Future

Reserves and reservoir performances were calculated based on the aforementioned procedure for the individual fields, which were estimated to have sufficient deliverability for anticipated gas production schedule.

What are required from now on for those fields are

(1) to evaluate the gas properties accurately by analysing the samples obtained under stabilized reservoir condition, collected through the recombine method of separator fluid and liberated gas, and

(2) to confirm maximum allowable production rate determined from the modified Isochronal Test, and

(3) to review the proposed schedule presented in this report.

Especially, the required numbers of wells to be allocated for individual fields are much influenced by the potential test results.

The computed results presented in this report are, with all several assumptions and premise, thought to have sufficient capability for proceeding the gas production project.

It should be reminded, however, that the reservoir heterogeneity of the limestone reservoir is supposed to exist always, even though the areal extents of the fields are clearly obtained. The reservoir parameter, therefore, should be obtained in the sufficient points in the reservoir through the above tests. The biggest point that is quite different from the sandstone reservoir is this heterogeneity.

The degrees of draw down imposed on the reservoir are much influenced by the skin factors at well bore. Instead of conducting conventional acidizing, recommended are to select the most suitable acid by laboratory analysis for the representative sample and to conduct acid fracturing. Gas productivity for the individual wells will often be much increased.

6.2.3 Recoverable Gas and Condensate Reserves

In the gas reservoir, the recoverable gas volume depends on the well head restriction. Based on the relation of bottom hole pressure us cumulative production for variable rates of production, well head pressure was estimated by Cullender & Smith method. The point when the estimated well head pressure corresponds to the utilized facilities restriction is the abandonment time.

Recoverable reserves for the proposed deliberability shcedule are as follows.

	Original in Place (MMMMSCF)	Recoverable Volume (MMMMSCF)	Recovery (%)
E8	1.25	0.69	55.2
E11	3.45	2.08	60.3
F6	5.61	2.46	43.9
F13	1.47	0.71	48.3
F14	1.25	0.62	49.6
F23	5.75	3.37	58.6

(Offshore Compressor Installation Case)

As for the condensate recovery, it is not possible to estimate the value, because no sample analysis has been conducted for the combined sample of liberated gas and separator fluid. Phase equilibrium calculation should be conducted based on the sample collected under stabilized reservoir condition.

The estimation based on liberated gas analysis obtained during short time production test will lead to serious error.

7. CONCLUSIONS AND RECOMMENDATIONS

1. Baronia field has the largest original hydrocarbon in place with the highest productivity among the existing producing oil fields in Malaysia.

The reservoir energy was interpreted to be combination drive of aquifer water, solution gas and gas cap expansion. High production rate was recorded so far, however, production control, especially strict control for the producing gas oil raatio is required for efficient utilization of the reservoir energy.

Optimum producing gas oil ratio is illustrated in this report as a function of cumulativeproduced oil. The relation, however, should be reviewed and revised year by year by observing actual field performance.

Reservoir performance predictions were made for two cases. One is the case for the extension of the existing conditions and the other is for the additional wells case. The additional wells case was made from the view point of enchancing production rate and increasing areal sweep efficiencies. The estimated production rate can be defined as technically allowable maximum production rate.

The reservoir has only short production history. Survey of well behaviors at the crest and down flank of the structure is required to confirm what is the dominant reservoir energy.

Special core analysis data are required for the main producing zones to decide most suitable secondary recovery method. Commingled production system is widely applied in the well completion of stratified reservoir. In this system, periodical production test is required to make suitable production allocation to individual zones.

2. The Fairley-Baram field bestrides the international boundary between Malaysia and Brunei with its crestal part in Brunei. Well interference was expected when additional wells are drilled and produced, which means that increased oil production rate in one area will cause the production decline in the other area.

Such efforts are recommended in this report as to increase the field total recovery by mutual agreement between Malaysia and Brunei.

Unit operation based on the original oil in place seems to be the most suitable ways in developing this field.

3. West Lutong field has the longest production history among the fields in Malaysia. The main producing zone is B Zone, which is supported by strong water drive.

The reservoir will be abandoned not from pressure decline but from increased water oil ratio, while the reservoir pressure will be kept comparatively high. The reservoir is in quite stable condition and WOR and GOR control are required. The lower part of the field has still undeveloped area.

Additional wells are recommended to be drilled and expected performances were illustrated.

4. Among the Central Luconia fields, six gas fields and one oil field were selected for establishing the short term fields development schedule.

The gas deliverability schedule of 1340 MMSCF/D with the project life of 20 years was recommended and the required production facilities were designed. In this area, only one or two wells have been drilled for individual fields, and no detailed production test has been conducted so far. The reservoir is composed of carbonate build-up and reservoir heterogeneity was anticipated to exist. Detailed reservoir information should be collected every time when new well is completed.

FIT sample analysis data are available, however, the results qre quite insufficient to estimate anticipated fluid characteristics. Recommended are to conduct gas and liquid analyses for the recombined sample of liberated gas and separator liquid, collected under stabilized reservoir condition, and to make phase-equilibrium calculation. Modified isochronal test is recommended to decide the optimum well base gas deliberability.

Followings are recommended in the actual field operation.

(1) Special core analysis data should be collected for the main productive zones of individual fields.

The data will be helpful in establishing the most effective secondary recovery method, to say nothing of performance analysis.

(2) Special fluid analysis should be made for the samples collected through the actually applied well completion system.

The data will be helpful in establishing the most optimum operating conditons (separator pressure and temperature) and resultantly increase recoverable oil.

Analysis for the separator liquid together with liberated gas is indispendable for the estimation of fluid characteristics under any operating conditions by phase equilibrium calculation.

(3) Detailed production test is required at the time of well completion.

Minimum three sizes of choke are recommended to be used for the test, and draw-down, productivity and producing gas oil ratio data should be obtained. The data will be helpful in deciding the most optimum production rate.

(4) Control of producing gas oil ratio is required for the producing field.

In order to preserve the reservoir energy, it is recommended to make production control to restrict producing gas oil ratio for the fields whose main displacement energy is the gas cap expansion and solution gas. The maximum allowable producing gas oil ratio is not constant, depending on the progress of reservoir depletion stage.

For individual producing fields, recommendable producing gas oil ratio is descibed as a function of cumulative oil production.

(5) Countermeasures for High Producing Gas Oil Ratio

The cause of high producing gas oil ratio should be detected by the use of Combination Production

Log survey, if necessary.

Control of producing gas oil ratio should be made not only by the use of reduced choke at well head but also by the shut-off of high gas saturation zone through the work over or by closing the sliding side door.

(6) Commingled Production System and Well Test

The commingled production system by the use of the sliding side door is efficient ways in completing highly stratified reservoirs, but production profile information by the periodical production test and profile survey is indispendable for the proper field operation.

PART B SURFACE FACILITIES

1. EXISTING FACILITIES

1.1 Present Status of the Existing Production Facilities

The Lutong Stream will be further classified into the following three offshore oil streams which consist of six oil fields as shown in Fig. 13-4-1.

1) Baronia, West Lutong, Bakau and Tukau Fields Stream
2) Fairley-Baram Field Stream
3) Baram Field Stream

Table 13-4-1 shows the oil and gas production rate of each field as of May, 1976.

Produced oil is transferred to shore after separation of gas at the offshore Production Platforms and dehydrated and stored at the Lutong Terminal. Then the oil is sent to offshore loading facilities or to Lutong Refinery.

Field facilities adopted here are conventional and rather simple with several characteristic points such as underwater well completion, standard modular concept for production platform design and reciprocating oil transfer pump driven by gas expansion on the Production Platforms.

1.1.1 Offshore Production Facilities

(1) Oil Gathering Scheme

The oil gathering scheme for the following three streams is shown on Figs. 13-4-2, 3, 4, 5, 6, 7 and 8. The production rates described below in this article are the figures as of May, 1976.

1) Baronia, West Lutong, Bakau and Tukau Fields Stream

In Baronia field total oil plus formation water of 51,977 BPD is collected at Production Platform A (BNP-A) and this oil is transferred to Bakau Production Platform A(BKP-A).

In West Lutong field major portion of the oil water mixture produced in the field is collected at Production Platform A(WLP-A) and this mixture is sent to Lutong Terminal by a 10" submarine transmission line after combined with Baronia and Bakau production.

In Bakau field total oil plus formation water of 5,316 BPD is gathered into Production Platform A(BKP-A) and this production combined with that of Baronia field is transmitted to West Lutong Production Platform A(WLP-A).

In Tukau field total oil production with some formation water of 13,411 BPD is gathered at Production Platform A(TKP-A) and is transferred to West Lutong Production Platform C(WLP-C) where the other portion of West Lutong production is gathered. The combined production is transferred to Lutong Terminal by another 12" transmission line.

From WLDP-A, 11.2 MMSCFD separated gas at the platform is sent to the Lutong Terminal through 8" pipeline for the utilization as fuel gas mainly for the refinery.

2) Fairley-Baram Stream

A detailed oil gathering scheme for this stream is not clear because the stream is being gathered in Brunei.

3) Baram Field Stream

Produced oil with formation water of 14,358 BPD is collected at Production Platform B(BAP-B) and delivered to Production Platform A(BAP-A). The production combined with that of 33,503 BPD produced at BAP-A is sent to the mouth of Baram River through 12" transmission line and then transferred to Lutong Terminal by 10" onshore line.

(2) Facilities

Offshore production facilities mainly consist of Drilling Platforms, Production Platforms and submarine pipelines.

1) Drilling Platforms

The following three kinds of drilling platforms are used in this area:

<u>Well Head Protection Jacket</u>

- 3-leg/1 Well Jacket
- 3-leg/2 Well Jacket
- 3-leg/3 Well Jacket
- 4-leg/4 Well Jacket

<u>Tender Assisted Drilling Platform</u>

- 6-leg/10 Well Platform
- 6-leg/12 Well Platform
- 8-leg/12 Well Platform

<u>Self-contained Drilling Platform</u>

- 4 x 4-leg/17 Well Platform

Most production wells are completed on multiwell drilling platforms and well production is transferred to bridge-connected Production Platforms, while produced oil at the satellite platforms is transmitted through individual flowlines. Exceptionally, there are two underwater completion wells in Baronia field. Individual flowline connects each well with the production platform.

Summary of offshore structures for five oil fields in this area is shown in Table 28-4-1.

2) Production Platforms

Each oil field has one or two Production Platforms where oil and gas separation equipment, transmission pumps and associated equipment are equipped to handle the well effluent from an adjacent Drilling Platform together with that brought from satellite well platforms by flowlines.

The Production Platform is a 4-leg structure with the deck dimension 50' x 62' and is installed separate from Drilling Platform due to a safety reason. Major equipment arrangement of that Production Platform is shown on Fig. 13-4-9.

This platform has two major distinctive features as follows:

- Standard modular concept adopted for the processing equipment and platform design

- Reciprocating oil transfer pumps driven by expansion of high pressure separator gas

Fig. 30-4-1 shows typical mechanical flow diagram of standard Production Platform.

The standard Production Platform is basically designed at nominal gross (oil plus formation water) throughput of 30,000 BPD together with 90 MMSCFD associated gas. The throughput can be increased to 60,000 BPD by adding the second bank separators. Transmission pumps whose capacity is 13,000 BPD each can be installed up to 5 units on the deck. There were eight standard Production Platforms in the five oil fields as of December, 1976. The design oil handling capacity for each platform is as follows.

Design Capacity of Each Production Platform

Field	Production Platform	No. of Separator Banks	Design Gross Oil Throughput	No. of Transfer Pumps (Capacity)
Baronia	BNP-A	2	60,000 BPD	5 (65,000 BPD)
West Lutong	WLP-A	1	30,000 BPD	3 (39,000 BPD)
	WLP-C	1	30,000 BPD	3 (39,000 BPD)
Baram	BAP-A	2	60,000 BPD	5 (65,000 BPD)
	BAP-B	1	30,000 BPD	3 (39,000 BPD)
Bakau	BKP-A	1	30,000 BPD	3 (39,000 BPD)
Tukau	TKP-A	1	30,000 BPD	3 (39,000 BPD)
	TKP-B	1	30,000 BPD	3 (39,000 BPD)

Most wells are produced without artificial lift but portion of wells in West Lutong field are produced by either gas lift or fluid lift. Fluid lift is the artificial lift using well fluid of high GOR well without any processing. Production from wells is directed into a manifold system leading to a production separator bank on each Production Platform and generally separated in three stages under following conditions.

1st Stage	250 psig in HP Separator
2nd Stage	50 psig in LP Separator
3rd Stage	Near Atom. in Surge Vessel

In some cases, the pressure of 1st stage varies depending on flowing wellhead pressure. HP Separator was operated at 200 psig in the West Lutong Production Platform (WLP-A) at the time of site survey performed in January, 1977. In addition, HHP Separator is installed on the West Lutong Drilling Platform (WLDP-A) and the separator operating pressure was 700 psig at the time of our site survey. Some wells of comparatively low wellhead pressure are connected to LP (low pressure) manifold which leads the well fluid directly to LP Separator. After separation of gas at a Surge Vessel, oil is delivered to Lutong Terminal by gas expansion driven transfer pumps through submarine transmission line.

Production ability of each well is measured by a Test Separator twice a month which is accommodated on each Production Platform, while the total fluid production cannot be measured as there are no metering facilities on the platform.

Separated gas at separators is vented at a Vent Structure which is located 2,000' apart from a Production Platform and connected with it by a submarine vent line. The 250 psig gas from HP Separator is utilized to drive oil transfer pumps and then led to the vent line. The utilized gas corresponds to above 16% of total separated gas which ranges 250 to 300 MMSCFD in these five fields in 1976. Separated gas by HHP Separator at WLDP-A is used for gas lift gas and also for the fuel gas to be sent to the Lutong Terminal through 8" pipeline for the utilization as fuel gas mainly for the refinery.

Produced formation water is transported to Lutong Terminal together with the oil without any separation at the platform. However, oily deck drains are collected and treated by a submerged caisson type oil-water separator.

Major equipment lists with simple specifications of the Production Platforms are attached as Tables 13-4-2, 3, 4, 5, 6, 7, 8 and 9.

3) Submarine Pipelines

Submarine pipelines except loading lines consist of the following;

a. Oil Lines

(i) to transfer well fluids from satelline Drilling Platforms to Production Platforms

(ii) to transfer gas-separated oil with formation water to another platform

(iii) to transfer combined oil water mixture to Lutong Terminal

b. Gas Lines

(i) to transfer separated gas from Production Platform to Vent Structure

(ii) to transfer separated gas from WLP-A to Lutong Terminal

(iii) to transfer gas lift gas to satellite platform wells

Summary of the above-mentioned pipelines is shown in Table 28-4-2 and the general layout of the offshore pipelines is shown in Figs. 13-4-2, 3, 4, 5, 6, 7 and 8.

1.1.2 Lutong Terminal

(1) Storage Facilities

The layout of Lutong Terminal facilities is shown on Fig. 13-4-10. Gross production (oil plus formation water) gathered from five fields flows into storage tanks and is settled for about 24 hours to separate water then stored in appropriate tanks. The gross storage capacity of Lutong Terminal is 161,000 long tons or about 1,252,000 barrels. Tanks are classified into three groups which are crude, products and Brunei natural gas liquid.

The last group tanks are to be converted to those for Miri light crude. Natural gas liquid was transported from Brunei by an onshore pipeline.

As the soil condition is very bad as shown on Fig. 13-4-11 which is a typical example, the height of storage tanks is limited rather small, accordingly all tanks are cone roof type except only one gasoline storage tank which has a floating roof.

The official gauging for sale is carried out by manual dipping at a storage tank after 24 hours settling. Measuring of water separated at the tanks is not carried out. Estimation of total water production is made based on the analysis results of samples taken from incoming crude and water mixture.

Combined waste water is gathered into two drain pits connected each other in series and the latter is a 3-channel gravity type oil separator. The both pits have oil skimmers and skimmed oil is sent to a slop tank in which crude, emulsion and water are separated. Crude is injected into crude filling line and water is returned to the former pit. Emulsion is then treated with heater treater at 250°F and separated crude and water are also sent to crude filling line and pit respectively. Oil content of final effluent to the sea is to be around 50 ppm.

(2) Loading Facilities

Route and size of loading lines are shown on Fig. 13-4-12. Loading of crude and products to tankers is carried out at the following berths all of which are SBM type.

Berth No. 1 (for white products *1)

LINE NO.	RATE	
1A	630 BPH	(100 M^3/HR)
1B	4,410	(700)
1C	4,410	(700)
1D	1,130	(180)

Berth No. 2 (for black products *2)

2 lines	7,560	(1,200)
4 lines	13,860	(2,200)
3B LFO	630	(100)

Berth No. 4 (for black products *2)

2 lines	7,560	(1,200)
3 lines	13,860	(2,200)
4 lines	15,120	(2,400)
5 lines	19,530	(3,100)

Notes *1 Topped naphtha, kerosene, gas oil, etc.

*2 SWR (Sarawak Waxy Residue)

MLC (Miri Light Crude)

BNGL (Brunei Natural Gas Liquid)

Bunker

Simultaneous loading operations for tankers at two or three SBMs are not performed due to miscellaneous reasons in relation to tank combination, customs, third party inspection of tank dipping, etc.

Maximum size of tankers to be moored will be 90,000 DWT and possibly 100,000 DWT at good sea conditions such as wave, tide and current. Anchor chains are fixed at the sea bottom by anchors and not by piles.

Available draft for each berth is as follows;

No. 1	41'
No. 2	41'
No. 3	44'

1.2 Review on the Capacity of the Existing Production Facilities

Review was performed to evaluate the capacity of the existing production facilities and to proceed to the subsequent assessment of the capacity compared with the predicted production performance. The major facilities and items for reviewing are as follows and these are considered to dominate the capacity of total facilities. For the execution of the study several assumptions have been made in accordance with the availability of the data.

<u>Facility Items for Review</u>

1) Offshore Production Facilities
   - Oil and gas separator
   - Gas venting line
   - Oil gathering line
   - Oil transmission line

2) Onshore Production Facilities
   - Storage tank
   - Loading system

Study Items

1) Separator

- Liquid capacity or retention time for proper oil-gas separation and for absorbing possible surge
- Gas capacity to handle separated gas

2) Vent or Flare Line

- Gas capacity to handle separated gas

3) Oil Gathering and Transmission Line

- Pressure balance for present oil production rate and for maximum oil handling capacity of production platforms

4) Storage Tank

- Storage capacity to meet maximum visiting tanker and enough allowance for daily production

5) Loading System

- Pressure loss and flow speed in loading line

1.2.1 Offshore Production Facilities

Standard modular concept is adopted on offshore production platform design in this oil field and separation system on the platform is basically designed at a nominal gross liquid (oil plus formation water) throughput of 30,000 BPD together with 90 MMSCFD associated gas. Throughput is designed to be increased to 60,000 BPD by adding second bank of separator. Platform space is available for transmission pumps to be installed up to 5 units.

(1) Separator

<u>Calculation Bases</u>

Flow Rate 30,000 BPD

	H.P. Separator	L.P. Separator	Surge Vessel
Operating Pressure	250 PSIG	50 PSIG	10 PSIG
Operating Temperature	123°F	113°F	110°F
Separator Dimension	72"I.D.x20'	72"I.D.x20'	126"I.D.x32'
Specific Gravity (Assumed)			
Gas	0.671	0.764	1.077
Oil	0.830	0.830	0.830
Gas Velocity Factor	0.40	0.40	0.40

Calculated Results

	Retention Time	Gas Capacity
H.P. Separator	2.7 minutes	61.5 MMSCFD
L.P. Separator	2.7 minutes	28.9 MMSCFD
Surge Vessel	13.6 minutes	46.4 MMSCFD

(2) Vent Line

Calculation Bases

Same as those for separator calculation.

Calculated Results

	Size and Length	Maximum Gas Flow Rate
High Pressure Vent Line	10" x 2,000'	167 MMSCFD
Low Pressure Vent Line	10" x 2,000'	36 MMSCFD
Low Pressure Vent Line	10" x 2,000'	11 MMSCFD

(3) Oil Gathering and Transmission Line

Figs. 13-4-13 and 13-4-14 show pressure balance of gathering and transmission lines under present production rate and design maximum liquid handling capacity of Production Platforms.

1.2.2 Lutong Terminal

(1) Storage Tank

The following is analysis on storage tank capacity made by the operating company:

Gross Tankage	1,252,000	BBLS
Unpumpable	(-) 210,000	
Pumpable	1,042,000	
One Tank for Emulsion Service	(-) 47,000	
Max. Operating Ullage	995,000	
Receiving, Settling & Drainage	(-) 93,000	
1-1/2 Day Safeguard to Delay	(-) 156,000	
Balance	746,000	

This balance of 746,000 barrels is about equal to cargo volume of 100,000 DWT tanker or additional daily production for one week.

(2) Loading System

The loading system at Lutong Terminal is complex due to presence of many pipelines and pumps for many products transferred to three sea berths. The operating company indicated us the following operational target loading rates for the combination of lines at each sea berth. Berth No. 1 was omitted from the review as it is especially for the loading of white products.

Berth No. 2

2 lines	7,560 BPH
4 lines	13,860 BPH

Berth No. 4

2 lines	7,560 BPH
3 lines	13,860 BPH
4 lines	15,120 BPH
5 lines	19,530 BPH

The above data was only available to review the capability of the existing loading system. Therefore, analysis has been carried out as the following.

<u>Calculation Bases</u>

- For Berth No. 2

Combination of loading lines	As shown in Fig. 13-4-15
Loading capacity	13,860 BPH

- For Berth No. 4

Combination of loading lines

Case 1	As shown in Fig. 13-4-16
Case 2	As shown in Fig. 13-4-17

Loading capacity

Case 1	13,860 BPH
Case 2	19,530 BPH

Calculated Results

Results of the calculated pressure loss and flow velocity are as shown in Table 13-4-10 and Table 13-4-11.

- For Berth No. 2

  The indicated loading rate by the operating company, 13,860 BPH, is considered a maximum allowable rate according to the limitation of flow velocity, though the existing loading pump units have enough capacity for larger flow rate.

- For Berth No. 4

  The loading rate of Case 1 is acceptable from both aspects of flow velocity and pressure loss.
  Case 2 is not desirable from the viewpoint of excess flow velocity in rubber hoses.

1.2.3 Conclusion

- Specified design capacity of the existing vent lines and separation system with two banks of separators is reasonable and sufficient. The design capacity is 60,000 BPD gross liquid production and 180 MMSCFD separated gas.

- Gathering and transmission lines will cover maximum oil handling capacity of the existing Production Platforms in hydraulic design aspects including transmission pumps which have a design capacity of 13,000 BPD/unit.

- Storage tank capacity seems to have only small allowance if the existing production rate continues or increases. More storage capacity for safe guard to delay, say, for 3-day additional production is desirable.

1.3 Assessment of the Facilities Capacity for the Predicted Production Scheme

The assessment of the facilities capacity was executed from a viewpoint of handling capacity of major production facilities by comparing the predicted maximum production rate with the facilities capacity on which the evaluation was made in the previous section. Therefore the study does not cover the capability of the facilities to adopt unforeseen additional facilities or modifications which have no relation with the predicted production performance of each field.

The additional well development case is described later for reference.

The maximum production rate of gross liquid and gas for each field and its occurrence year after 1976 are shown below based on the reservoir study in previous sections.

Predicted Maximum Production Rate after 1976

Oil Field	Gross Liquid (year) BPD	Oil BPD	Water BPD	Gas (year) MMSCFD
Baronia	55,150 (1978)	48,680	6,470	164.5 (1983)
West Lutong	30,230 (1980)	14,500	15,730	58.3 (1979)
Baram	40,670 (1977)	25,440	15,230	137.8 (1977)
Bakau	2,830 (1977)	2,530	300	4.7 (1977)
Tukau	12,930 (1977)	12,380	550	34.5 (1978)

As shown in the above table, predicted maximum gross liquid production rates will not exceed the production rates in 1976 except Baronia field where some 3,150 BPD of increase is expected. When new fields such as Betty and Bokor would be joined in future, the total handling rate would not increase due to the decline of the existing fields before the start-up of the new fields.

1.3.1 Offshore Production Platform

Table 28-4-3 shows the comparison of the present production rates versus the evaluated capacity of Production Platforms for each field. While, the comparisons of the predicted maximum production rates after 1976 versus the evaluated capacity of them for each field are shown on Table 28-4-4 for gross liquid and on Table 28-4-5 for gas.

As shown in the tables referred to above, the Production Platforms in West Lutong, Baram, Bakau and Tukau have the liquid handling capacity of 60,000 BPD, 90,000 BPD, 30,000 BPD and 60,000 BPD respectively, whereas the present gross liquid production rates are 33,130 BPD, 47,861 BPD, 5,316 BPD, and 13,411 BPD respectively with no increase after 1976. For Baronia field present gross liquid production is 51,977 BPD and predicted maximum gross liquid production will surpass this figure to 55,150 BPD in 1978. But this rate still lies within the handling capacity of 60,000 BPD. Therefore all of the platforms have enough liquid handling capacity throughout the life of the fields as well as the capacity for gas.

1.3.2 Offshore Gathering and Transmission Pipelines

Fig. 13-4-18 shows the pressure balance for the present and predicted maximum gross liquid production rate. As known from this figure, the existing gathering and transmission network will have enough capacity to handle the maximum production rate predicted after 1976. On the other hand, so far as the present transmission pump system is used, high pressure power gas will be required for each transmission pump at the volume corresponding to its transmission rate. Based on the predicted gas production rate for each oil field, the required gas will be available without a problem.

1.3.3 Storage and Loading Facilities

(1) Storage Facilities

As evaluated in the previous section concerning review on the storage capacity, the capacity seems to have only small allowance from the view point of operation flexibility or to be said rather short. However, the conditions related to storage capacity will be improved year after year due to the decline of the predicted production rates.

(2) Loading Facilities

At present maximum size of tankers to be moored is 90,000 DWT from the limitation of the available draft. Although the data on the average size of incoming tankers and operation efficiency of the berths depending on bad weather, etc. are required for the detailed evaluation of the berths capacity, the conditions from now will be anyway improved from the same reason as above.

1.3.4 Conclusion

In accordance with the assessment of key components of the producing, storage and loading facilities for each field, the existing field facilities will basically cover the predicted future oil production, as well as associated gas and formation water, for all fields without any bottleneck. This conclusion, of course, results from the decline of oil production from the existing fields except gas and water and the time lag due to the necessity of lead time even if new field(s) will be tied in. In case of the adoption of gas lift, possible artificial lifting method, gas source will be available from high pressure gas reservoirs or high GOR wells and the addition of a high pressure separator and simple modification of the existing facilities are only the work required for it.

1.3.5 Additional Well Development Case

The additional well development case of Baronia, West Lutong and Tukau fields is described below for reference. The predicted maximum gross liquid and gas production rate for each field and its occurence year after 1976 are shown below based on the reservoir study in Part A. West Lutong and Tukau fields are not decided the starting year of production, therefore it is assumed that the starting year of those two fields is 1976.

Predicted Maximum Production Rate after 1976

Oil Field	Gross Liquid (year) BPD	Oil BPD	Water BPD	Gas (year) MMSCFD
Baronia	86,980 (1978)	74,130	12,850	250.3 (1981)
West Lutong	33,010 (1980)	15,570	17,440	67.4 (1979)
Tukau	18,680 (1977)	18,080	600	40.8 (1978)

Production Facilities to be required in additional well case are as follows;

(1) Offshore Drilling and Production Platform

a. Baronia Field

Ten (10) additional wells will be drilled for this case. As ten (10) wells have ever been drilled from the existing BNDP-A (8P/12W), the new drilling platform (8P/12W) will be required. And also the predicted liquid production rates (86,980 BPD) at 1978 will exceed the handling capacity of existing facilities (60,000 BPD), therefore the new production platform having the capacity of 30,000 BPD will be required.

b. West Lutong Field

Two (2) additional wells will be drilled for this case. Five (5) wells and six (6) wells have been drilled from existing WLDP-B (6P/10W) and WLDP-C (6P/10W) respectively, so two (2) wells in addition can be drilled from these two platforms. The predicted maximum production rate is 33,010 BPD at 1980, therefore there is no need of the new production platform compared with the handling capacity of existing facilities. Consequently the existing platforms will basically cover the predicted future oil production without any problem.

c. Tukau Field

Five (5) additional wells will be drilled for this case. Twelve (12) wells have been drilled from existing TKDP-A (6P/12W), so this platform can't afford to drill any more. And also existing TKDP-B will not be able to drill the wells because TKDP-B is far from the new development wells, therefore the new drilling platform (6P/10W) will be required for the additional two wells. The predicted maximum production rate will not exceed the handling capacity of the existing facilities.

(2) Offshore Gathering and Transmission Pipelines

a. Baronia Field

The 10" x 1,500 ft submarine gathering pipeline will be installed between existing BNP-A and new production platform. There is no need of the new transmission line from the viewpoints of the pressure balance as shown on Fig. 13-4-18.

b. West Lutong Field

The existing gathering and transmission pipelines will basically cover the predicted future oil production without any problem.

c. Tukau Field

The 10" x 4,000 ft submarine flow pipeline will be installed between existing TKP-A and new drilling platform. There is no need of the new transmission line from the viewpoints of the pressure balance as shown on Fig. 13-4-18.

(3) Storage Facilities

The predicted maximum production rate after 1976 in this case will exceed by present production rate but the present storage capacity will absorb its increase without installation of new additional tanks. And also the conditions related to storage capacity will be improved year after year due to the decline of the predicted production rate.

(4) Loading Facilities

The conditions from now will be improved from the same reason as above, therefore the expansion of loading facilities will not be required for this case.

1.4 Assessment on Present Production Practices

In this section assessment and recommendation are made on the topics related to present production practices which have been noticed during the course of the study on the review and assessment of the existing oil production facilities including site survey.

1.4.1 Associated Gas Utilization

As shown in Table 28-4-6, total separated gas at offshore platforms in Baronia, West Lutong, Baram, Bakau and Tukau fields was about 290 MMSCFD. The utilization status of this gas was as follows:

	MMSCFD	%
Pump Driving	46.8	16.3
To Shore	11.2	3.9
Venting	228.8	79.8
Total	286.8	100.0

In the above table the gas used for driving the transfer pumps is ultimately vented, therefore only 4% of the total gas is actually utilized. As for the utilization of this associated gas, the following will be considered:

(1) Industrial or Town Use

The downstream team of the Master Plan study is to study about this utilization based on the predicted availability of future associated gas. The transferred cost of the gas to shore is studied in the subsequent section of this report.

(2) Underground Storage

Detailed feasibility study will be required to appraise whether the underground storage of the gas is feasible or not. The study will include the confirmation of the presence of suitable reservoirs with enough capacity. Forecast of gas price with the possibility of gas requirement will also be a key factor. At present the detailed discussion on this matter based on assumptions will have little meaning, as there are only few reliable informations.

1.4.2 Metering System

(1) Offshore Platforms

As there are no metering facilities of liquid at offshore Production Platforms, allocation of crude and water production to each field and each well will be inevitably inaccurate.

Many informations should be checked such as fluctuation of flow and pressure and space limitation to select optimum metering system to be applied on the platform because conventional method may not be applied due to the existing pumps of reciprocating type. However, it is recommended to install a flow meter at inlet of transmission line to measure the total liquid flow produced at each platform to achieve more accurate allocation of production. At present, if it should be selected, there are two kinds of flow meter which are positive displacement type meter (PD meter) and turbine type meter for this purpose. A PD meter is just little better than a turbine meter from the following technical viewpoints.

- No need of electrical power
- More proven meter for this purpose
- More reliable
- More little occupied space on a platform

(2) Lutong Terminal

Measurement of produced oil to be transmitted from offshore and exported crude is carried out by hand dipping at storage tank, and official measurement of exported oil is also being made by hand dipping at storage tanks. This is not a conventional method at modern facilities but a conservative method which is adopted in fields in Saudi Arabia, etc. Flow meter method can save personnel cost, can improve accuracy and makes it possible to control and monitor operations from a control room.

1.4.3 Waste Water Treatment System

Produced formation water, which is major waste water source on all offshore platforms, is transported with oil to Lutong Terminal by submarine pipelines and combined oil and water is dehydrated by being settled in storage tanks for 24 hours. This concept is more preferable to prevent oil pollution to the sea near offshore platforms compared with the method adopted in Tembungo platform. However, pipeline efficiency will be improved as shown in Fig. 13-4-19 in case waste water is treated at offshore platforms. In spite of this demerit the existing system is not necessary to be changed judging from the predicted production rate of all fields.

1.4.4 Crude Oil Dehydration System

Conventional storage tanks are used to cut the associated water at Lutong Terminal. The tank capacity used for dehydration purpose occupies about 11% of total operating tank capacity. Moreover, the temperature of incoming crude becomes 90°F to 93°F in cooler months and dehydration efficiency becomes lower.

Judging from the above-mentioned status, the existing storage tanks would be utilized more efficiently with the application of more effective dehydration method if any is applicable.

Although detailed evaluation will be required for the selection of treating method including a laboratory test and/or a pilot plant test to study the properties of oil-water emulsion, effect on the oil properties by treatment, etc., a wash tank method will be an alternative with the use of a direct fired heater because of simple method and simple operation. Fig. 13-4-20 shows a simplified flow diagram of this system and Table 13-4-12 shows a preliminary cost estimate.

1.4.5 Tank Size at Lutong Terminal

The form of structures to be installed and the properties of soil are important factors in investigaing the bearing capacity of foundation, and so the detailed investigation on these matters will be required prior to final conclusion on the possibility to enlarge a tank size in Lutong Terminal. In the study at this time, as there are many unclear points on the soil conditions, a general explanation is made for the possible tank foundation plans suitable for the area.

Design and investigation of the tank foundation are generally based on the following factors:

a. Bearing capacity of foundation

b. Foundation settlement

It is a general method to decide the possible tank capacity from the above investigation factors but the soil data available at present are only the result of cone test, and its testing method is also unclear. However, when assuming those data as the resistance values "qc" of Holland style test and comparing them with the distributed stress below the ground of tank load with the oil in it, the comparison between bearing capacity and distributed stress is shown in Fig. 13-4-21. As for Labuan Terminal, the bearing capacity of ground is strong enough to support the tank with the capacity of 400,000 barrels or even more. Fig. 13-4-11 shows the typical cone test data for the tank area. But as for Lutong Terminal, although the bearing capacity value at the points 6' - 9' below the ground level ranges from 4,000 - 6,000 lb/ft^2, it ranges from 250 - 400 lb/ft^2 at 20' - 40' below the ground level as shown in Fig. 13-4-21 and it can be said that the foundation is very weak. Therefore, in case of constructing a tank on the present foundation, the effective height of the tank must be within 40', but even in this case, it is desirable to proceed with the construction with continuous checking about the degree of settlement.

If the foundation could be improved down to about 60' under the ground level by any of the following methods, tanks with 200,000 - 400,000 barrels capacity and 70' effective height would be constructed.

Improvement methods for the clayey soil

a. Preloading
b. Sand drain or paper drain
c. Sand compaction pile
d. Replacement by excavation
e. Others

Improvement methods for the sandy soil

a. Water binding
b. Compaction by blasting
c. Compaction pile, sand compaction pile
d. Vibro-floatation method

It is the combined method of vibro-floatation and preloading that seems the most useful for Lutong Terminal among these methods from the viewpoints of construction term and construction cost, although the detailed evaluation must be made about the properties of soil prior to the final selection of the suitable method.

1.4.6 Control and Monitoring System

In offshore operations for Lutong Stream, no monitoring system at the onshore terminal is applied on. It will be worthy to take into consideration the adoption of telemetering system to monitor the operating conditions of offshore facilities to add more safety. This is because nobody can watch offshore facilities at night without the installation of an accommodation platform in addition and it takes time to find out any accident and to reach the location. Efficiency and safety of oil production operation will be improved by the adoption of the system by which working conditions can be monitored at an onshore control room. At least the following status had better be monitored with alarm function.

a. Emergency shut-down valve closed
b. Low pressure of each separator
c. High pressure of each separator
d. High level of each separator
e. Fire
f. Transmission pump stopped

2. PROPOSED FACILITIES

2.1 General Design Bases

All data and informations collected mainly in data collection and site survey phases have been reviewed, and accurate and realistic data required for conceptual design have been selected out of those data and informations.

However some of collected data and informations are imperfect or not clarified to adopt as design data. So some of design bases are assumed so as to be realistic and reasonable taking into consideration the purpose of this study.

Only common design bases to all fields have been described in this section and specified design bases for each field are mentioned in the subsequent sections for each field.

2.1.1 Basic Design Data from Collected Data

(1) Fields Location

As shown in Fig. 30-9-1.

(2) Meteorological and Oceanographical Data

Atmospheric Temperature

Max.	110°F
Min.	65°F

Sea Water Temperature at Sea Bottom

Min.	60°F

Relative Humidity

Max.	90%

(3) Hydrographic and Topographic Data

Sea Water Depth

Sea water depths for offshore structures in new fields are maximum water depths obtained from drilling reports in each field. Design water depth for each field is summarized below.

Field	Sea Water Depth (feet)
Baronia	254
Betty	247
Bokor	228
Temana	99

Field	Sea Water Depth (feet)
(Central Luconia)	
B-12	298
E-6	239
E-8	207
E-11	230
F-6	285
F-13	250
F-14	347
F-23	280

(4) Soil Data at Sea Bed

Offshore structures especially in Temana field, where sea bed soil is very soft, are taken into consideration the soil character in the conceptual design in accordance with the soil data received from Petronas. For the offshore structures in the other areas, typical soil data considered to be average are tentatively used.

2.1.2 Assumed Design Conditions

(1) Gas Utilization

1) Miri Fertilizer Plant

Gas utilization case has been studied to supply 37 MMSCFD gas for 20 years to a fertilizer plant at Miri area. Battery limit is the shore line near the mouth of Baram river where a gas transmission line will terminate and any onshore facilities are not included.

2) Central Luconia

Studied is the case to develop Central Luconia gas fields and to transport the gas to Bintulu for 20 years. Battery limit is the shore of Bintulu area and any onshore facilities are not included.

(2) Development Well

Development wells are assumed to be drilled by the following two types of rig.

- Rig on self-contained platform
- Rig on tender assisted platform

2.1.3 Determination of Facilities Capacity

(1) Onshore Storage Tank

Storage tank capacity is assumed in accordance with the following formula.

Total Gross Capacity

= {Design Production Capacity (BPD) x 6 days

+ Full Cargo of 100,000 DWT Tanker (724,500 barrels)}

÷ Pumpable Factor (0.9)

As for the required number of tanks, minimum three tanks are required for the purpose of receiving, settling and loading.

(2) Offshore Storage Barge

An oil storage barge which is to be newly built is adopted as an offshore storage facility and its capacity is assumed in accordance with the following formula.

Storage Capacity

= Design Production Capacity (BPD) x 6 days

+ Full Cargo of 100,000 DWT Tanker (724,500 barrels)

(3) Loading Pump

Loading pumps and a loading line are sized to complete the full cargo loading to a visiting tanker of 100,000 DWT (724,500 barrels) within 24 hours.

(4) Loading Line

Flowing velocity of crude oil in pipeline is limited to within 10 ft/sec to prevent static electricity generation and maximum internal pressure in hose line is limited within allowable pressure of 150 psig.

(5) Mooring Facilities

An SBM system which is popular all over the world at present is adopted in Malaysia. But in deep sea water (over approximately 200') a SALM system is adopted. In case of offshore storage and loading, two SBMs (or SALMs) are to be installed, one for an oil storage barge and the other for a visiting tanker. The system to moor a visiting tanker alongside the oil storage barge was not adopted at this time for safety reason.

2.2 Conceptual Design

2.2.1 Baronia Oil Field and B-12 Gas Field Gas Utilization

B-12 field comes within the category of Central Luconia field, however this field should be considered for stand by capacity of Baronia associated gas utilization.

(1) Design Bases

Utilization of Baronia associated gas and B-12 free gas was considered in response to the demand from downstream team for the gas supply to a fertilizer plant. Field facilities in these fields have been designed in accordance with the following bases.

1) Requirements of Fertilizer Plant

Gas Supply Rate	:	41 MMSCFD
Annual Operating Hour	:	8,000 Hrs
Gas Supply Period	:	20 Years
Gas Supply Pressure	:	150 psig or 570 psig at Plant Inlet
Plant Location	:	Miri area, Sarawak
Gas Composition	:	CH_4>64%, C_4+< 5%

2) Gas Sources

Baronia: Associated Gas at Separation Pressure of 250 psig

B-12 : Free Gas Dehydrated at 1,500 psig

Supply rate of Baronia associated gas is changeable dependent on oil production conditions. So B-12 field gas backs up just in case of shutdown or drop below 41 MMSCFD of Baronia associated gas production to supply the gas continuously to the fertilizer plant for 20 years.

3) Gas Properties

Offshore gas production and gathering facilities to supply the gas to the fertilizer plant have been designed based upon the following gas components. The gas analysis was obtained from the data of wireline formation test.

Component	Baronia Associated Gas	B-12 Field Gas
Hydrogen Sulfide	0.0	0.0
Carbon Dioxide	0.6	3.2
Oxygen	0.0	0.0
Nitrogen	0.6	1.3
Hydrogen	0.0	0.1
Methane	84.4	90.5
Ethane	7.5	2.9
Propane	4.3	1.1
i-Butane	0.6	0.2
n-Butane	1.1	0.3
i-Pentane	0.3	0.1
n-Pentane	0.3	0.1
Hexane	0.2	0.1
Heptane plus	0.1	0.1
Total	100.0	100.0

4) Gas Wells in B-12 Gas Field

Drilling Rig Type: Tender Assisted Drilling Rig

No. of Wells : 2

Max. Prod. Rate, MMSCFD : 41

(2) Conceptual Design

Location of Baronia oil field and B-12 gas field is shown in Fig. 30-9-1. Based upon the above design bases, several cases were compared and examined from economic points of view.

As the result, the following two cases were selected as alternative development cases out of several cases.

1) Case Setting

a. Case IA - Natural Flow Case

This is a case that Baronia associated gas and/or B-12 field gas is transported by natural flow to the onshore fertilizer plant at supply pressure of 150 psig. Facilities arrangement for this case is shown in Fig. 14-5-1. Block flow diagram of produced gas is shown in Fig. 14-5-2.

b. Case IB - Offshore Compression Case

This is a case that Baronia associated gas and/or B-12 field gas which will be transferred to Baronia field is compressed up to 1,200 psig at an offshore Compressor Platform installed adjacent to Baronia Production Platform A and then compressed gas is transported to the onshore fertilizer plant at supply pressure of 570 psig. Facilities arrangement for this case is shown in Fig. 14-5-3. Block flow diagram of produced gas is shown in Fig. 14-5-4.

2) Preliminary Selection

Well and offshore facility capital investment costs for the above two cases have been estimated and are summarized below.

	Case IA	Case IB
Production Wells	M$25,400,000	M$25,400,000
Offshore Platforms	23,899,000	27,930,000
Offshore Production Equipment	5,080,000	11,430,000
Submarine Pipelines	34,796,000	29,515,000
Total	M$89,175,000	M$94,275,000

As shown above, well and offshore facility costs for Case IA are lower than that for Case IB and also operating costs for Case IA are considered to be obviously lower than that for Case IB. From the above-mentioned reasons Case IA is selected at this stage, although there is small discrepancy in the basis of comparison. Therefore, field facilities are described for Case IA.

3) Facilities Description of Selected Scheme

Gas production system of Case IA for the development of Baronia and B-12 fields consists of the following facilities:

Baronia Field

1 ... 4-leg Riser Platform	BNR-A
Submarine Pipelines	

B-12 Field

1 ... 6-leg Well and Production Platform	B12WP-A
Submarine Pipelines	

Facilities arrangement of these facilities is shown in Fig. 14-5-1. Major equipment to be installed are tabulated with simple specification in Table 14-5-1.

a. Baronia Field

(i) 4-leg Riser Platform

One 4-leg Riser Platform will be installed at approximately 254' water depth adjacent to Baronia Production Platform A and connected with the Production Platform by a bridge. A gas line branched from HP vent header at BNP-A and 8" gas Gathering Line from B-12 will be combined into 16" Transmission Line to the onshore fertilizer plant. A sphere launcher and receiver will be also provided on this platform.

b. B-12 Field

(i) 6-leg Well and Production Platform

This platform will be installed at 298' water depth in B-12 field and maximum 4 wells can be drilled from this platform and process equipment with the capacity of 41 MMSCFD shown in Table 14-5-1 are also installed on this platform. Typical mechanical and utility flow diagrams are shown in Figs. 30-5-5 and 30-5-10. A heliport is provided on this platform for air transportation. Typical plan and elevation is shown in Fig. 30-5-20.

2.2.2 Betty and Bokor Oil Fields

(1) Design Bases

1) Production Rate and Number of Wells

Field	Production Rate (BPD)	No. of Wells
Betty	16,000	10
Bokor	5,000	8

2) Fluid Property

Field	API Gravity	Viscosity (60°F) cp	MAX. GOR (SCF/STB)
Betty	39	6	2,000
Bokor	19.5	220	800

(2) Conceptual Design

Location of Betty and Bokor oil fields is shown in Fig. 30-9-1. On the development of Betty and Bokor fields, two cases were considered. One is to develop both Betty and Bokor fields. The other is to develop Betty only. Because the reservoir pressure at Bokor field is low and the produced oil has relatively heavy gravity and high viscosity, gas lift will be required from the beginning of the production.

And in any case, the existing Lutong stream is to be utilized for oil gathering scheme of Betty and Bokor fields from the viewpoints of geographical location and relatively low oil production rate of these two fields. And then, two oil gathering schemes were considered for each case.

One scheme is that the production from Betty and Bokor fields are transported to the Bakau Production Platform (BKP-A), and the other is that the production is transferred to the Tukau Production Platform (TKP-A). On the above two schemes, a conclusive difference is not recognized on the initial capital investments estimated.

But the distance between Betty and Bakau is shorter than that between Betty and Tukau and, according to the available data, the existing transmission network is originally planned and designed to connect the pipeline from the Bakau Production Platform at the development phase of Betty and Bokor fields. Therefore, the oil gathering scheme for the former was selected. The following two cases were set for this scheme.

1) Case Setting

a. Case I - Betty and Bokor, Bakau Gathering System Case

Betty and Bokor fields will be developed and their production will be transferred to the Bakau Production Platform. Facilities arrangement and block flow diagram are shown in Fig. 15-5-1 and Fig. 15-5-2 respectively.

b. Case II - Betty, Bakau Gathering System Case

Betty field will be developed and its production will be transported to the Bakau Production Platform. Facilities arrangement and block flow diagram are shown in Fig. 15-5-3 and Fig. 15-5-4 respectively.

2) Study on Lutong Stream Capability to Receive the Production from Betty and Bokor Fields

The study on capability is conducted fundamentally for the relation between the maximum oil production rate predicted for Betty and Bokor fields and the overall capacity of the existing offshore transmission network and storage capacity of the Lutong stream at starting time of production from Betty and Bokor. Starting time of production is assumed to be 1981 based on the prepared project schedule.

a. Transmission Network

Fig. 15-5-5 and Fig. 15-5-6 show the pressure balance of overall transmission network for the two cases under the expected maximum flow rates which are flow rates from the existing oil fields at 1981 plus maximum production rate from Betty and Bokor fields or Betty only. As shown in the pressure balance, Transmission Line inlet pressure at each Production Platform for the above two cases increases slightly in comparison with that for the existing oil fields only shown in Fig. 15-5-7 but this increase does not have an important effect on the existing facilities because they have enough design pressure of Transmission Lines, and design head and displacement capacity of transmission pump.

b. Storage Capacity

At the stage of development of Betty and Bokor fields, oil production rate to be handled in the Lutong Terminal will additionally increase to 21,000 BPD in maximum. On the other hand, net oil production from the existing fields in 1981 declines to 77,630 BPD, and so even if produced oil of 21,000 BPD from Betty and Bokor add to the Lutong Terminal, the storage capacity will have more allowance compared with the production of 136,880 BPD in 1977. From the above consideration, additional storage capacity will not be required for Betty and

Bokor development.

3) Facilities Description

For the above-mentioned two cases, capital investment costs and operating costs have been estimated and then economic analysis has been performed as described in Part C. As the result of the economic analysis, Case II is a more profitable case. However, as Case I is a case to cover the required facilities for both fields, the facilities for both Case I and Case II are described below.

a. Case I - Betty and Bokor, Bakau Gathering System Case

Crude oil production system for the development of Betty and Bokor fields consists of the following facilities;

Betty Field

1 ... 6-leg Well and Production Platform	BTWP-A
1 ... 3-leg Vent Jacket	BTV-A
Submarine Pipelines	

Bokor Field

2 ... 4-leg Well Platform	BOW-A & B
2 ... 6-leg Well and Production Platform	BOWP-A
1 ... 3-leg Vent Jacket	BOV-A
Submarine Pipelines	

General arrangement of these facilities is shown in Fig. 15-5-1. Major equipment to be installed are tabulated with simple specification in Table 15-5-1.

(i) Betty Field

(a) 6-leg Well & Production Platform

One 6-leg Well and Production Platform, BTWP-A, will be installed and ten directional wells will be drilled from this platform by a tender assisted drilling rig. On the other half of the platform, production equipment will be laden. Typical mechanical flow, utility flow diagrams and typical plan and elevation are shown in Fig. 30-5-2, Fig. 30-5-10 and Fig. 30-5-16 respectively. Well fluids from BTWP-A will be separated into liquid and gas in three-stage separators. Separated liquid from BOWP-A will be transferred to BTWP-A and combined with that from BTWP-A, and then sent through 12" Transmission Line to Bakau platform by means of transmission pumps. And separated gases will be sent through 8" and 6" Vent Lines to Vent Jacket (BTV-A).

(ii) Bokor Field

(a) 4-leg Well Platform

Two 4-leg Well Platforms (BOW-A & BOW-B) will be installed and two or three directional wells will be drilled from each Well Platform by a tender assisted drilling rig. Manifolds and a test separator will be mounted on each Well Platform. Also those two Well Platforms will have enough space so that the workover rig can be mounted after well completion. Typical mechanical flow diagram and typical plan and elevation are shown in Fig. 30-5-1 and Fig. 30-5-13 respectively. Well fluids from these two platforms will be sent through 6" respective flow lines to Well and Production Platform (BOWP-A).

(b) 6-leg Well and Production Platform

One 6-leg Well and Production Platform (BOWP-A) will be installed and three directional wells will be drilled from this platform by a tender assisted drilling rig. On the other half of the platform, production equipment will be laden. Typical mechanical flow, utility flow diagrams and typical plan and elevation are shown in Fig. 30-5-2, Fig. 30-5-10 and Fig. 30-5-16 respectively. And then, for the reason of high viscosity of the production oil and low reservoir pressure in Bokor field as shown in the result of reservoir study, a gas lift operation will have to be adopted to maintain the oil production. Source gas will be derived from a gas reservoir in Bokor field. The gas from the reservoir will be flowed into the high pressure separator on this platform and sent through 4" gas lines to BOW-A and BOW-B respectively to be used for a gas lift operation. Well fluids from Well and Production Platform (BOWP-A) will be combined with those from BOW-A and BOW-B in the three-stage separators. And separated liquid will be sent through 8" Gathering Line to Well and Production Platform (BTWP-A). On the other hand, separated gas will be sent through 6" and 4" Vent Lines to Vent Jacket (BOV-A).

b. Case II - Betty, Bakau Gathering System Case

Crude oil production system for the development of Betty field only consists of the following facilities:

1 ... 6-leg Well and Production Platform		BTWP-A
1 ... 3-leg Vent Jacket		BTV-A
Submarine Pipelines		

Description of above facilities is almost the same as that of Betty field in Case I. Only 12" Transmission Line is altered to 10" because of lower production rate due to no development of Bokor field.

2.2.3 West Temana and E-6 Oil Fields

Originally, E-6 field comes within the category of Central Luconia fields, however this oil field has been considered for posibility of combined production system with neighbouring oil field.

(1) Design Bases

1) Production Rate and Number of Wells

Field	Production Rate (BPD)	No. of Wells
West Temana	4,000	6
E-6	30,000	15

2) Fluid Property

Field	API Gravity	Viscosity (60°F) cp	Max. GOR (SCF/STB)
West Temana	20	200	4,700
E-6	35	10	30,000

3) Others

Soil condition

Soil condition at sea bottom in West Temana field is expected to be not stable enough. For this reason, type of jackets to be installed in West Temana field is considered to be 3- or 4-leg jackets.

Gas lift

For the reason of low reservoir pressure in West Temana field as described in the result of reservoir study, a gas lift operation will be adopted to maintain the oil production rate. Source gas for the gas lift operation is assumed to be derived from a gas reservoir which exists beneath the oil reservoir. The gas flows upward in a tubing of the production well to the reservoir level and is injected into the oil produced through annulus at an appropriate point through gas lift valves. This is so-called "auto-lift" system.

(2) Conceptual Design

Location of West Temana field and E-6 field is shown in Fig. 30-9-1. West Temana field is located approximately 24 miles away from Bintulu Terminal to the west of Sarawak and E-6 field is located approximately 85 miles away from Bintulu Terminal to the northwest.

For designing the development plans of these fields, the following case setting was adopted taking into consideration geographical, economic and operational factors. As for West Temana field, it is evident that the independent development of this field is not profitable at all considering high capital investment and low production rate. High investment costs are due to the difficulty of recovering oil, i.e. requirement of gas lift facilities to produce from low pressure reservoir and larger size pipelines to transfer high viscosity oil, and more offshore structures with smaller size to stand on bad sea bottom soil condition.

In each case, production facilities are conceptually designed and capital investment of facilities is estimated based on the basic cost data so that optimum case might be found among the alternatives.

1) Case Setting

The following three cases have been selected as alternatives for the development of these fields.

a. Case I - West Temana and E-6, Bintulu Terminal Case

Produced crude oil in both West Temana and E-6 fields will be gathered and transported to onshore storage terminal which will be constructed at Bintulu, and will be loaded to a tanker by means of SBM. Facilities arrangement and block flow diagram in this case are shown in Fig. 16-5-1 and Fig. 16-5-2.

b. Case IIA - E-6, Offshore Storage Case

Produced crude oil in E-6 field will be gathered and transported to an Offshore Storage Barge and will be loaded to a tanker by means of SALM. Facilities arrangement and block flow diagram in this case are shown in Fig. 16-5-3 and Fig. 16-5-4.

c. Case IIB - E-6, Onshore Terminal

Produced crude oil in E-6 field will be gathered and transported to Bintulu Terminal, and will be loaded to a tanker by means of SBM. Facilities arrangement and block flow diagram in this case are shown in Fig. 16-5-5 and Fig. 16-5-6.

2) Facilities Description

For the above-mentioned three cases, capital investment costs and operating costs have been estimated and then economic analysis has been performed as described in Part C. As the result of the economic analysis, Case IIB is the most profitable case among the above three cases. Production facilities for

Case I, however, are described below because those for Case I cover the required facilities for the development of both fields. The difference is that all of the offshore facilities related to West Temana are excluded in Case IIB. There is only small difference in onshore facilities due to small production rate of West Temana field compared with E-6 field.

The production system in Case I will consist of the following facilities:

West Temana Field

2 ... 4-leg Well Platform	WTW-A & B
1 ... 4-leg Production Platform	WTP-A
1 ... 3-leg Flare Jacket	WTV-A
Submarine Pipelines	

E-6 Field

2 ... 6-leg Well and Production Platform	E6WP-A & B
2 ... 3-leg Flare Jacket	E6V-A & B
1 ... 4-leg Accommodation Platform	E6A-A
Submarine Pipelines	

Bintulu Terminal

Tankage and Loading Facilities

Onshore Support Facilities

Facilities arrangement of these facilities is shown in Fig. 16-5-1. Major equipment to be installed are tabulated with simple specification in Table 16-5-1.

a. West Temana Field

(i) 4-leg Well Platform

Two 4-leg Well Platforms (WTW-A & B) will be installed and three directional wells will be drilled from each Well Platform by a tender assisted drilling rig. For the purpose of gas lift operation, each well will be dual completion. Test separator and other wellhead equipment will be mounted on an isolated Well Platform. Well Platforms will have enough space so that the workover rig can be mounted after well completion. Typical mechanical flow diagram and typical plan and elevation are shown in Fig. 30-5-1 and Fig. 30-5-13. Production from wellhead will be sent through an 8" flow line to a Production Platform.

(ii) 4-leg Production Platform

A 4-leg Production Platform (WTP-A) will be installed and a Well Platform (WTW-A) will be connected with a bridge to it. After degassing, combined production from two Well Platforms (WTW-A & B) will be transferred to Bintulu Terminal through 6", 140,200' length Transmission Line. Typical mechanical flow diagram, typical utility flow diagram and typical plan and elevation are shown in Fig. 30-5-2, Fig. 30-5-10 and Fig. 30-5-15 respectively.

(iii) 3-leg Flare Jacket

A 3-leg Flare Jacket will be installed. The Flare Jacket will be located 2,000' apart from the Production Platform.

b. E-6 Field

(i) 6-leg Well and Production Platform

Two 6-leg Well and Production Platforms will be installed and located approximately 3 miles away from each other. Fifteen directional wells will be drilled from these two platforms by tender assisted drilling rig. On the other half area of the platform, production equipment will be laden. Typical mechanical flow diagram, typical utility flow diagram and typical plan and elevation are shown in Fig. 30-5-2, Fig. 30-5-10 and Fig. 30-5-16 respectively. Production from the Well and Production Platform (E6WP-B) will be transferred to the other (E6WP-A) and combined with that from E6WP-A. Then the combined production will be sent to Bintulu Terminal through 12", 492,000' length Transmission Line.

(ii) 3-leg Flare Jacket

Two 3-leg Flare Jackets will be installed. Each Flare Jacket will be located 2,000' apart from corresponding Production Platform. Separated gas from production separators will be led through two submarine pipelines (one for HP gas, the other for LP gas) to the Flare Jacket and flared out at the top of it.

(iii) 4-leg Accommodation Platform

An Accommodation Platform (E6A-A) with helideck, whose typical plan and elevation is shown in Fig. 30-5-31, will be built next to the Well and Production Platform (E6WP-A) and a bridge will connect these two platforms. Also, a Utility Platform and a Compressor Platform, the outline of which is described in the item of Central Luconia gas fields, will be connected with bridges to E6WP-A. This Accommodation Platform will accommodate the operating personnel who are working for E-6 field production facilities.

c. Tankage and Loading Facilities

Three 410,000 BBLS storage tanks will be installed at Bintulu Terminal. Production from offshore will be stored and loaded to a visiting tanker through 30", 15,000' length submarine Loading Line and a single buoy mooring (SBM).

d. Onshore Support Facilities

To support offshore operation and maintenance activities, the following facilities will be constructed at Bintulu Terminal;

Jetty
Material Yard
Office Buildings
Heliport, etc.

General layout for Bintulu Terminal is shown in Fig. 30-5-19.

2.2.4 Central Luconia Gas Fields

(1) Case Setting

Conceptual design for Central Luconia gas fields is for the collection, treating and transportation of hydrocarbons produced at offshore platforms to supply them to a shore-based gas plant to be located at Bintulu area. An oil field E-6 in this area was discussed in the previous section of this report.

The objective gas fields in this study are the fields with rather large reserves such as E-8, E-11, F-6, F-13, F-14 and F-23, and the other fields with smaller reserves have not been considered in the facilities design at this time but regarded as a portion of standby capacity which will be required enough at this phase of a project.

With regard to the gas production from the above-mentioned fields, the following alternatives of the development scheme were considered:

1) Case IA - Natural Flow Case, Six Fields Development

The produced gas will be treated at each field, collected into E-11 field and then flow by natural energy to Bintulu with required arrival pressure to feed the onshore plant. The objective fields are E-8, E-11, F-6, F-13, F-14 and F-23. Facilities arrangement and block flow diagram in this case are shown in Fig. 17-5-1 and Fig. 17-5-2.

2) Case IB - Onshore Compression Case, Six Fields Development

The produced gas will be treated at each field, collected into E-11 field and then delivered to shore with required compressor suction pressure by natural flow. Gas will be compressed at onshore to meet the feed pressure to the plant. The objective fields are the same as Case IA. Facilities arrangement and block flow diagram in this case are shown in Fig. 17-5-3 and Fig. 17-5-4.

3) Case IC - Offshore Compression Case, Six Fields Development

The produced gas will be treated at each field, collected into E-11 field and compressed there. Then, the gas will be delivered to shore with required arrival pressure to feed the plant. The objective fields are E-8, E-11, F-6, F-13, F-14 and F-23. Facilities arrangement and block flow diagram in this case are shown in Fig. 17-5-5 and Fig. 17-5-6.

4) Case II - Offshore Compression Case, Five Fields Development

This is the same gathering system as that of Case IC. The objective fields are E-8, E-11, F-6, F-13 and F-23. Facilities arrangement and block flow diagram in this case are shown in Fig. 17-5-7 and Fig. 17-5-8.

5) Case III - Offshore Compression Case, Four Fields Development

This is the same gathering system as that of Case IC. The objective fields are E-11, F-6, F-13 and F-23. Facilities arrangement and block flow diagram in this case are shown in Fig. 17-5-9 and Fig. 17-5-10.

6) Case IV - Offshore Compression Case, Three Fields Development

This is also the same gathering system as that of Case IC. The fields for development are E-11, F-6 and F-23. Facilities arrangement and block flow diagram in this case are shown in Fig. 17-5-11 and Fig. 17-5-12.

(2) Selection of Optimized Scheme

The purpose of this study is to find out the optimum development and gathering scheme to maintain constant supply of the gas to the onshore gas plant at Bintulu, although the final selection will be made by a more detailed feasibility study when more well data are available as the field development advances. At this stage only a few basic data were available.

1) Study on Deliverability

Reservoir sizes, deliverabilities, tubing diameters, gathering line lengths and diameters, transmission line length and diameter and delivery pressure all interact to establish flow rates from an individual field and total fields. All of the above-mentioned elements of the entire system affecting deliverability have to be evaluated by changing various parameters. Therefore, the following procedure was taken to establish the alternative schemes as the basis of conceptual design:

a. To prepare a performance curve for each field to show wellhead pressure vs. cumulative gas production, taking into consideration the deliverability of each well.

b. To investigate the transmission line pressure loss according to the changes of the line size for various production rates of total fields, and to determine the optimum transmission line diameter considering recoverable reserves in connection with size and cost of required compressors and pipelines and various technical aspects.

c. To sum up the recoverable reserves or daily gas production rate of each field using its performance curve for the gathering lines which are selected to meet minimum pressure drop at reasonable pipeline costs and gathering line routes.

d. To draw the curve of transmission line inlet pressure vs. gas production rate to be prepared based on the results of step b. and also the curve of transmission line inlet pressure vs. recoverable gas reserves or daily gas production rate to be prepared based on the results of step c. The intersection of the above-mentioned curves shows the total deliverability of all fields. Then, the deliverability of each field can be calculated.

This procedure from b. to d. has been iterated to establish the optimum plan for each alternative case.

2) Bases for Conceptual Design

The bases for conceptual design and the study results for them are shown as follows.

a. Design Bases

(i) Fluid Property

The composition of the reservoir fluids used in the design of gas gathering system is as follows:

(Volume %)

Field	E-11	F-23	F-6	F-13	E-8	F-14	E-6
Component							
Hydrogen Sulfide	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	6.60	2.20	1.80	15.00	2.00	1.80	1.30
Oxygen	0.00	0.00	0.00	0.10	0.20	0.10	0.40
Nitrogen	1.80	0.90	0.70	3.60	0.80	3.30	2.90
Methane	83.70	88.20	88.70	74.60	88.40	84.70	89.10
Ethane	5.50	3.70	4.10	4.80	4.20	4.20	3.10
Propane	1.30	2.80	2.80	1.10	2.50	3.50	1.90
i-Butane	0.20	0.80	0.70	0.20	0.40	0.70	0.30
n-Butane	0.30	0.70	0.60	0.20	0.60	0.80	0.50
i-Pentane	0.10	0.30	0.20	0.10	0.20	0.30	0.10
n-Pentane	0.10	0.10	0.10	0.10	0.20	0.20	0.10
Hexane	0.20	0.20	0.20	0.10	0.30	0.30	0.20
Heptane Plus	0.20	0.10	0.10	0.10	0.20	0.10	0.10
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00

In all cases the gas is assumed to be saturated with water vapor.

(ii) Production Performance of Each Field

Curves of wellhead pressure vs. cumulative gas production for each field, taking into consideration the pressure loss in tubing are shown in Fig. 17-5-13 and Fig. 17-5-14.

Deliverability of each well is assumed 30 MMSCFD.

(iii) Gas Supply Pressure

The gas supply pressure at the entrance of the onshore gas plant is assumed to be 750 psig minimum. This is common to each of the above cases except the onshore compression case. In the onshore compression case, the pressure at the entrance of the plant is assumed to be 240 psig minimum.

(iv) Wellhead Flowing Pressure

Initial and final wellhead flowing pressure is assumed as follows:

Initial Wellhead Flowing Pressure (I.W.F.P.)

Field Name	E-11	F-23	F-6	F-13	E-8	F-14
I.W.F.P. (psia)	2,280	2,060	1,720	1,140	2,000	1,920

These are common to all cases.

Final Wellhead Flowing Pressure (psia)

Case Number	IA	IB	IC	II	III	IV
Field						
E-11	880	910	460	440	420	400
F-23	1,030	1,060	610	590	570	550
F-6	1,130	1,160	710	690	670	650
F-13	930	960	510	490	470	-
E-8	930	960	510	490	-	-
F-14	1,130	1,160	710	-	-	-

(v) Wellhead Flowing Temperature

Wellhead temperature is assumed to be same throughout project years. Only the well test data of E-11 was available for the estimate of wellhead temperature, therefore the validity of the following wellhead flowing temperature, which is assumed for this conceptual design, is to be confirmed by a subsequent test and study:

Wellhead Flowing Temperature (W.F.T.)

Field Name	E-11	F-23	F-6	F-13	E-8	F-14
W.F.T.(°F)	132	116	113	136	124	114

These are common to all cases.

(vi) Dew Point of Dehydrated Gas

Water dew point at dehydrator outlet: 55°F

(vii) Utilities

Electric power is assumed to be generated at both platforms of E-11 and F-23 and distributed to outlying platforms by submarine cables. Other utilities such as instrument air and water are also considered at each platform as required.

b. Calculation Results

(i) Production Rate

Production rate throughout the project life of 20 years from an individual field is governed by deliverability of a well, size of tubings, gathering lines through which the gas flows, and the required pressure at the onshore delivery point. The following figures are the results of a preliminary study to obtain high deliverability by keeping minimum pressure drop at reasonable costs while maintaining operational flexibility, although a detailed study will be required to confirm or modify these figures when more complete data are available by future drilling of delineation and production wells.
In the alternatives using compressors the requirements of fuel consumption for compressors have been estimated tentatively and described in the following table.

Production Rate (MMSCFD)

Case Number	IA	IB	IC	II	III	IV
Field						
E-11	230	240	290	290	290	290
F-23	350	340	460	470	470	470
F-6	240	210	340	340	340	350
F-13	80	80	100	100	100	-
E-8	70	70	90	90	-	-
F-14	60	60	80	-	-	-
Total	1,030	1,000	1,360	1,290	1,200	1,110
Fuel Consumption	0	20	20	20	20	20
Net Gas Rate	1,030	980	1,340	1,270	1,180	1,090

(ii) Number of Wells

The number of producing wells is shown below based on the condition that each well produces 30 MMSCFD throughout the project life of 20 years, although the number is increased by about 10% for allowance. This condition may not be realistic for the actual development of gas fields, as recoverable reserves will be increased by additional drilling of producing wells with less production rate. However, the above condition is considered to be allowed at this time taking into the consideration the purpose of this study, the extent of data availability and the requirement of sizable allowance as back-up capacity at this phase of the project.

Number of Wells

Case Number	IA	IB	IC	II	III	IV
Field						
E-11	9	9	11	11	11	11
F-23	13	13	17	17	18	18
F-6	9	8	13	13	13	13
F-13	3	3	4	4	4	-
E-8	3	3	4	4	-	-
F-14	2	2	3	-	-	-
Total	39	38	52	49	46	42

(iii) Condensate Production

A slight amount of condensate will be expected to drop out at offshore separators outlet. Expected condensate quantity has been calculated based on assumed properties of heavy hydrocarbons and is summarized as follows:

Condensate Production (bbls/day)

Case Number	IA	IB	IC	II	III	IV
Field						
E-11	863	849	1,021	1,025	1,032	1,035
F-23	933	914	1,225	1,238	1,246	1,256
F-6	471	450	705	713	722	730
F-13	76	75	92	93	94	-
E-8	338	333	434	438	-	-
F-14	208	205	300	-	-	-
Total	2,889	2,826	3,777	3,507	3,094	3,021

(iv) Free Water Production

Free water production is assumed based on the condition that all produced gas is saturated with water.

c. Discussion

There are several points to be considered in selecting the gas gathering system as described below under the following headings:

- Gas standby capacity
- Heavy hydrocarbon condensation
- Comparison of alternative schemes

(i) Gas Standby Capacity

As F-9, F-22, K-4, M-1, M-3 and M-5 fields have rather small gas in place and/or are in remote locations, these fields have been excluded from the development schemes in this study at this stage mainly from the economic viewpoint. These fields, however, could be considered to provide standby capacity when required during the course of the development of other fields. Enough standby capacity in addition to the estimated deliverability must be taken into consideration at this stage of data availability for the subject fields, because it is the most important responsibility to keep constant feed rate during the project life of the onshore gas plant.

Recoverable reserves may be somewhat improved by drilling additional wells in the course of reservoir depletion. The detailed study on the expected allowance should be performed at the time when more data become available, taking into consideration the standby capacity requirements as mentioned above.

We assumed that the compression ratio of offshore compressor is three to one. In further engineering stage, recoverable reserves may be also improved, if the compressors with higher compressibility ratio are adopted.

Associated gas produced from E-6 oil field is supposed to be fed to the onshore gas plant as the first priority by adjusting gas production from other fields, especially E-8 field. This amount of gas should be considered to increase standby capacity at this stage and should not be considered to affect the deliverability of gas fields.

(ii) Heavy Hydrocarbon Condensation

Molecular weight and specific gravity of heptane plus in well effluent fluids are very sensitive to the quantity of hydrocarbon condensation estimated by equilibrium calculation. Although those data were not available, the following condensation quantity was estimated based on the assumed properties.

In gathering lines : about 7 bbls/MMSCF

In transmission line: about 4 bbls/MMSCF

The detailed study on this matter should be carried out when useful data become available. If hydrocarbon condensation is several times over the above figures, the configuration of gas gathering system will have to be changed into the system to install independent condensate gathering lines and transmission line.

(iii) General Comparison of Alternative Schemes

The general advantages and disadvantages of the Natural Flow Case are as follows:

Advantage:

- Simplicity of operation

Disadvantage:

- Low gas deliverability due to required high wellhead pressure

The advantages and disadvantages of Onshore Compression Case are;

Advantage:

- Simplicity of operation and major rotating equipment is onshore with minimum equipment offshore.

Disadvantages:

- Low gas deliverability
- Gas velocity will be high in transmission line due to low pressure level

The advantages and disadvantages of Offshore Compression Case are;

Advantages:

- High gas deliverability
- High operational flexibility

Disadvantages:

- Complicated operation
- Many equipment at offshore

3) Selection of Optimum Scheme

The final selection of the optimum scheme among all alternatives had to be made after the performance of economic evaluations, as the deliverabilities as well as the investment costs and operating costs are different for each case and so the simple comparison of costs is not suitable for the selection in this case. Therefore, estimates of capital investment and operating costs were carried out for all of the alternative schemes and the economic evaluation was performed based on them. The evaluation procedure and results are described in Part C.2, Economic Analysis. Consequently offshore compression case, Case IC, is recommended as the optimum gas gathering system from economic and technical viewpoints.

(3) Facilities Description of Optimum Scheme

Outline of facilities and process has been described below for the selected Case IC, Offshore Compression Case.

1) Outline of the Facilities

The separation, dehydration and reinjection equipment will be installed on each Well Production Platform or Production Platform. The design pressure of separators on each platform is tentatively set at 1000 psig.

The separated gas will go to the dehydration system to remove water. The dehydrated gas from glycol contactor and the condensate from separator will be then combined into common pipeline. The combined fluids from F-6 and F-14 fields will be also combined into fluid from the F-23 after terminating at the header on lower deck of the Utility Platform in F-23 field. The fluid will be then delivered to the Riser Platform in E-11 field.

The gases from E-8, E-11 and F-13 fields will be treated quite same method as F-6, F-14 and F-23. All of the gases will be received at the Riser Platform, and transferred to the Compressor Platform. These gases will be separated again there to remove liquid by centrifugal separators before going to the compressor station in E-11 field.

There are also liquid knockout drum and scrubbers on the Compressor Platform to protect the compressor. The compressed gas will go back to the Riser Platform, and knockout liquid will be also transferred to flash tanks on the Riser Platform. At that point, all liquid will be pumped and reinjected into the 36" Transmission Line to Bintulu Terminal.

a. Well Platform

Well Platform (F23W-A) is located in F-23 field. It will be an eight-leg, 17-well structure with 18 slots. This structure will accommodate one removable drilling rig and its support facilities. Typical plan and elevation for F23W-A is shown in Fig. 30-5-24.

b. Production Platform

Production Platform (F23P-A) is located in F-23 field. This platform will be installed to produce and treat natural gas and condensate. It will be an eight-leg structure and equipped with high pressure separator and dehydration unit to achieve a water dew-point less than 55°F. Typical mechanical flow diagram, typical utility flow diagram and typical plan and elevation for F23P-A are shown in Fig. 30-5-3, Fig. 30-5-10 and Fig. 30-5-23 respectively.

c. Well and Production Platform

Well and Production Platforms (F13WP-A, F6WP-A, F6WP-B, F14WP-A, E11WP-A and E8WP-A) will be installed to drill wells and to produce and treat the gas. There are two types of them in Central Luconia fields. One is an eight-leg structure and the other is a six-leg according to the capacity to be treated. Six-leg platforms will be installed in F-13, F-6, E-8 and F-14 fields respectively. Eight-leg platforms will be installed in E-11 and F-6 fields. Typical mechanical flow diagram, typical utility flow diagram and typical plan and elevation for F13WP-A, F6WP-B, E8WP-A and F14WP-A are shown in Fig. 30-5-5, Fig. 30-5-10 and Fig. 30-5-20 respectively. The same for E11WP-A are also shown in Fig. 30-5-4, Fig. 30-5-10 and Fig. 30-5-22 respectively. And those for F6WP-A are shown in Fig. 30-5-5, Fig. 30-5-10 and Fig. 30-5-21 respectively.

d. Utilities Platform

Utilities Platforms (E11U-A, F23U-A and E6U-A) are located in E-11, F-23 and E-6 fields which are bases for operation and maintenance of all offshore facilities. On the platform in F-23 field, the two gas turbine driven package type generator sets will be installed on the upper deck. The gas gathering lines will terminate at the lower deck of this platform and start from here to E-11 field. Manifold, sphere receivers and launchers will be installed on this lower deck. The platform in E-11 field is about same as that in F-23 although there are no gathering lines coming in on it. Typical plan and elevation for E11U-A is shown in Fig. 30-5-30. And typical plan and elevation for F23U-A and E6U-A are shown in Fig. 30-5-29.

e. Compressor Platform

Compressor Platforms (E11C-A, E11C-B and E6C-A) are located in E-11 and E-6 fields. The platform in E-6 oil field is for the associated gas which is to be considered as supplemental gas supply source to Central Luconia gas fields. It will be a six-leg structure and accommodate four gas turbine driven compressors. The two eight-leg structures will be installed in E-11 field. These are equipped with four gas turbine driven compressors and its related facilities. Typical mechanical flow diagram, typical utility flow diagram and typical plan and elevation for E11C-A and E11C-B are shown in Fig. 30-5-7, Fig. 30-5-11 and Fig. 30-5-26 respectively. Those for E6C-A are also shown in Fig. 30-5-8, Fig. 30-5-12 and Fig. 30-5-27 respectively.

f. Accommodation Platform

Accommodation Platforms (E11A-A and F23A-A) are located in both E-11 and F-23 fields. They will accommodate operation and maintenance personnel at normal operation time and also in case of emergency. They will be four-leg structures with heliport on the top of the platform. Safety and escape devices will be also equipped. Typical plan and elevation for E11A-A and F23A-A are shown in Fig. 30-5-31.

g. Riser Platform

Riser Platform (E11R-A) is located in E-11 field. It will be a six-leg structure and equipped with liquid handling facilities which are required for pigging operating of incoming gathering lines. Typical mechanical flow diagram and typical plan and elevation for E11R-A are shown in Fig. 30-5-9 and Fig. 30-5-28 respectively.

Major equipment to be installed for this case are tabulated with simple specification in Table 17-5-1.

2.2.5 East Temana Oil Field

At this time East Temana field is not considered to be developed with West Temana and E-6 fields at the same time, because further exploration for the field is considered to be required for the determination whether to proceed to development or not. Facilities study on this field, however, is briefly discussed below.

Location of East Temana field is shown in Fig. 30-9-1 and is located approximately 18 miles away from Bintulu Terminal. Soil conditions at sea bottom in East Temana field are expected not stable enough as West Temana field. For this reason, type of jackets to be installed in East Temana field is considered to be 3- or 4-leg jackets.

As the information on the production performance is not available, production rate of East Temana is assumed to be 8,000 BPD and maximum GOR figure 5,000 ft^3/bbl. Using the information of the fluid properties such as 34° API gravity and 11 cp of viscosity at 60°F, and of others mentioned above, facilities arrangement is tentatively designed and shown in Fig. 18-5-1 considering geographical, economic and operational factors. Block flow diagram is shown in Fig. 18-5-2.

Main facilities are as follows:

2 ... 4-leg Well Platform	ETW-A & B
1 ... 4-leg Production Platform	ETP-A
1 ... 3-leg Flare Jacket	ETV-A
Submarine Pipelines	

Four directional wells will be drilled from each Well Platform. Production from Well Platforms will be gathered to the Production Platform and after separating gas, oil will be sent to Bintulu Terminal through 6", 92,000' length Transmission Line.

Estimated cost for these facilities is shown below;

Development Wells	M$22,758,000
Offshore Platforms	49,337,000
Offshore Production Equipment	3,797,000
Submarine Pipelines	12,814,000
Others	19,604,000
Total	M$108,310,000

Note: Others consist of engineering, pre-start-up expenses and contingencies.

3. CONCLUSIONS AND RECOMMENDATIONS

3.1 Existing Facilities

(1) Present Status of the Existing Production Facilities

At present six offshore fields are producing oil in Sarawak area. Data collection and site survey were executed to investigate the present status of these existing production facilities at September, 1976 and January, 1977 respectively. Operating Company names, field names and oil production rates as of May, 1976 are shown below for each field.

Field	Oil Production Rate (BPD)	Major Facilities
Baronia	49,162	Drilling Platforms
West Lutong	14,333	Production Platforms
Baram	30,683	Lutong Terminal
Bakau	5,203	Single Buoy Mooring System
Tukau	13,031	Submarine Pipelines
(Sarawak Shell Berhad)		
Fairley Baram	11,705*	Drilling Platforms
		Submarine Pipelines
		Production Facilities in Brunei

* Note: Total for Sarawak and Brunei

(2) Review on the Capacity of the Existing Production Facilities

Review and evaluation on the capacity of the existing production facilities have been carried out for the above-mentioned fields. These results are to be used for the assessment of the ability of those facilities to meet the predicted production performance of the relevant fields. The major objective facilities for reviewing are as follows and these are basic items to evaluate the capacity of whole production facilities.

Oil and Gas Separator
Vent or Flare Line
Oil and Gas Gathering Pipeline
Storage Tank
Loading System

As a result of review, it was confirmed that the processing facilities have sufficient capacity to handle the initial design rate. As for storage tank and loading system, storage capacity of Lutong Terminal is considered to be a little short.

The handling capacity of the offshore production facilities is shown below.

Field	Capacity of Offshore Production Facilities (BPD)
Baronia	60,000
West Lutong	60,000
Baram	90,000
Bakau	30,000
Tukau	60,000

(3) Assessment of the Facilities Capacity for the Predicted Production Scheme

Based upon the review described above, assessment of capacity of the existing production facilities was performed based on the predicted maximum production rate of well fluids for each field.

As a result of the study, it has been confirmed that any bottlenecks on the capacity of the production facilities will not basically occur even if the changes of production rate of associated gas and formation water are considered, because the oil production rates from each field will decline gradually and predicted maximum production rate of oil plus formation water will not generally exceed the present production rate as shown below.

Field	Production Rate as of May, 1976 (BPD) Crude Oil + Formation Water	Crude Oil	Formation Water	Predicted Max. Prod. Rate after 1976 (BPD) Crude Oil + Formation Water (Year)	Crude Oil	Formation Water
Baronia	51,977	49,162	2,815	55,150('78)	48,680	6,470
West Lutong	33,130	14,333	18,797	30,230('80)	14,500	15,730
Baram	47,861	30,638	17,178	40,670('77)	25,440	15,230
Bakau	5,316	5,203	113	2,830('77)	2,530	300
Tukau	13,411	13,031	380	12,930('77)	12,380	550

Note: The oil production facilities of Fairley Baram are mostly located in Brunei area and the site survey was not performed.

(4) Assessment on Present Production Practices

Related to the evaluation study on the existing oil production facilities including site survey, the study on the following items was performed, although these items have no direct relation to the handling capacity of the production facilities.

- Associated Gas Utilization
- Metering System
- Waste Water Treatment System
- Crude Oil Dehydration System
- Tank Size at Lutong Terminal
- Control and Monitoring System

And the items shown below about existing facilities are recommended to be improved.

1) Metering System

There are no metering facilities of produced liquids at offshore Production Platforms in Lutong Stream. It is recommended to install a positive displacement meter at the inlet of pipeline to measure the total liquid flow produced at each platform to achieve more accurate allocation of production from the viewpoint of accurate field control. However, detailed study will be required to select an optimum metering system due to the existing pumps of reciprocating type.

2) Crude Oil Dehydration System

Conventional storage tanks are used to cut the associated water at Lutong Terminal. The tank capacity used for dehydration purpose occupies about 11% of total operating tank capacity. Moreover, the temperature of incoming crude becomes 90°F to 93°F in cooler months and dehydration efficiency becomes lower.

Judging from the above-mentioned status, the existing storage tanks would be utilized more efficiently with the application of more effective dehydration method if any is applicable.

Although detailed evaluation will be required for the selection of treating method including a laboratory test and/or a pilot plant test to study the properties of oil-water emulsion, effect on the oil properties by treatment, etc., a wash tank method will be attractive alternative with the use of a direct fired heater because of simple method and simple operation.

3) Tank Size at Lutong Terminal

The size of the tanks at Lutong Terminal is relatively small due to the weak soil. The possibility to enlarge a tank size was studied. The form of structures to be installed and the properties of soil are important factors in investigating the bearing capacity of foundation, and so the detailed investigation on these matters together with economic evaluation will be required prior to final conclusion on the possibility. It is the combined method of vibro-flotation and pre-loading that seems to be the most applicable to Lutong Terminal among various methods from the viewpoints of construction term and cost.

4) Control and Monitoring System

In offshore operations for Lutong Stream, no monitoring system at the onshore terminal is applied on. It will be worthy to take into consideration the adoption of telemetering system to monitor the operating conditions of offshore facilities to add more safety.

This is because nobody can watch offshore facilities at night without the installation of an accommodation platform in addition and it takes time to find out any accident and to reach the location. Efficiency and safety of oil production operation will be improved by the adoption of the system by which working conditions can be monitored at an onshore control room.

3.2 Proposed Facilities

Several alternative cases for the development of oil and gas fields in Sarawak area as shown below have been established including the cases for single field development and for the combined development of several fields. Conceptual design for the alternative cases has been carried out in accordance with the production performance predicted in Part A. As a result of the conceptual design, flow diagrams, facilities layouts and so on have been prepared.

Baronia and B-12 group (gas)
Betty and Bokor group (crude oil)
West Temana and E-6 group (crude oil)
Central Luconia (gas)
East Temana (crude oil)

(1) Field Development Schemes

1) Baronia and B-12 Fields (gas)

Utilization of Baronia associated gas together with B-12 free gas was considered for the gas supply to a possible fertilizer plant. The gas delivery rate is 41 MMSCFD and is kept constant for 20 years. Other usage of the associated gas produced in this area will be considered for the injection into the underground for secondary recovery, while current reservoir performance information is not sufficient enough to establish pressure maintenance by gas injection.

The facilities mainly consist of well and production platform, riser platform and submarine pipelines.

2) Betty Field (crude oil)

The combined development scheme of Betty and Bokor was considered in the established alternative schemes. However, the scheme for Betty single field development with the connection to the existing Bakau production platform has been selected from the economic viewpoint.

The maximum production rate is predicted as 15,330 BPD.

The facilities mainly consist of well and production platforms and submarine pipelines.

3) E-6 Field (crude oil)

E-6 Field in Central Luconia Fields is divided as an oil field because it is built-up with huge capacity.

The combined development scheme of E-6 and West Temana was considered in the established alternative schemes. However, the scheme for E-6 single field development has been selected from the economic viewpoint.

The maximum production rate is predicted as 30,000 BPD.

The facilities mainly consist of well and production platforms, accommodation platform, submarine pipelines and onshore terminal with tankage and loading facilities.

4) Central Luconia Fields (gas)

The scheme for the development of six gas fields such as E-8, E-11, F-6, F-13, F-14 and F-23 with the offshore compression stations has been selected.

The gas delivery rate is predicted as 1,340 MMSCFD for 20 years.

The facilities mainly consist of well and production platforms, utilities platforms, compressor platforms, accommodation platforms and submarine pipelines.

PART C COST ESTIMATE AND ECONOMIC ANALYSIS

1. COST ESTIMATE

1.1 General Cost Estimate Bases

1.1.1 Basic Cost Data

Cost data on materials and services, which are required for the estimate of cost for drilling, facilities construction and operation and maintenance, have been collected and tabulated as the values as of middle of 1976.

The following basic cost data tables and figures have been prepared;

- Basic cost data for wells and facilities cost -

  Development wells .... Fig. 31-6-1
  Offshore structures .... Table 29-6-1 to 29-6-10
  Submarine pipelines .... Table 29-6-11, 29-6-12
  Gas production equipment .... Table 29-6-13
  Oil production equipment .... Table 29-6-14
  Other production equipment .. Table 29-6-15
  Offshore storage barge ...... Table 29-6-16
  Onshore support facilities .. Table 29-6-17

- Basic cost data for operating cost -

  Operating personnel .... Table 29-6-18
  Chemicals .... Table 29-6-19
  Service contractors .... Table 29-6-20

Computation for cost estimation has been performed in the currency of U.S. dollars, and then the results are converted into Malaysian dollars (M$) with the shown exchange rate.

U.S.$1 = M$2.54

1.1.2 Estimate of Other Cost Items

The following items of capital investment cost and operating cost have been computed in accordance with the following formulas using some of the above-mentioned basic cost data:

Capital Investment Cost

Engineering Fee (C_1)	:	10% of (C_2 + C_3)
Pre-start-up Expenses	:	1% of (C_1 + C_2 + C_3)
Contingency	:	10% of (C_1 + C_2 + C_3)

Annual Operating Cost

Operation Management (C_4)	:	10% of C_5
Repair and Maintenance		
Pipelines	:	0.1% of C_6
Others	:	2% of (C_7 + C_8) (in case of onshore storage)
		3% of (C_7 + C_8) (in case of offshore storage)
Operating Supplies	:	0.3% of (C_6 + C_7 + C_8)
Indirect Personnel	:	50% of (C_4 + C_5)

Insurance

Pipelines : 0.5% of C_6

Others : 1.5% of $(C_7 + C_8)$

where,

C_1: Engineering Fee

C_2: Development Well Cost from Basic Cost Data

C_3: Facilities Cost from Basic Cost Data

C_4: Operation Management Cost

C_5: Operation Personnel Cost from Basic Cost Data

C_6: Pipeline Cost including Miscellaneous Cost

C_7: Development Well Cost including Miscellaneous Cost

C_8: Facilities Cost except Pipeline Cost including Miscellaneous Cost.

Note: Miscellaneous costs include engineering, pre-start-up expenses and contingency.

1.1.3 Estimate of Past Investment

Only exploration wells cost has been counted in capital investment and other past investment is not included in this study.

1.1.4 Estimate of Annual Operating Cost

Annual operating costs for each field have been counted only for its oil or gas production life span when two or more fields are produced in the combined production system.

1.2 Cost Estimate

1.2.1 Baronia Oil Field and B-12 Gas Field Gas Utilization

(1) Bases of Cost Estimate

Capital investment costs and operating costs for Baronia and B-12 fields have been estimated based upon the basic cost data and method of cost estimation which are described in 1.1, taking into consideration the following.

- It is assumed that all existing facilities in Miri will be utilized as onshore support facilities for these fields. Therefore onshore base cost is not included.

- Operating personnel costs include only the minimum required for offshore operation as estimated below.

  Foreman : 6
  Operator: 9

- It is assumed that Baronia associated gas is available cost free at offshore Production Platform (BNP-A) in Baronia.

- Offshore gas gathering facilities will be installed as the same time for both Baronia and B-12 fields.

(2) Capital Investment Cost Estimate

Capital investment costs for the development of these fields are summarized in Table 14-6-1. Total amount becomes M$113,027,000.

(3) Annual Operating Cost Estimate

Annual operating costs for these fields are summarized in Table 14-6-2. Total amount becomes M$4,809,000.

(4) Project and Investment Schedules

The project schedule for the development of Baronia and B-12 fields is tabulated as shown in Fig. 14-6-1, based upon the availability of following construction equipment.

Tender Assisted Drilling Rig 1
Derrick Barge (500 ton) 1
Lay Barge (up to 16" ϕ) 1

Subsequently based on the above project schedule, the investment schedule has been made as shown in Table 14-6-3.

1.2.2 Betty and Bokor Oil Fields

(1) Bases of Cost Estimate

Capital costs and operating costs in these fields have been estimated based upon the basic cost data in 1.1, taking into consideration the following.

- It is assumed that all existing facilities at Lutong Terminal could be utilized for these fields.

- Operation of these fields is considered to be performed linking with the Lutong Terminal as well as the existing fields. And an operation organization for these fields and existing fields is tentatively assumed as shown in Fig. 31-6-3, and operating personnel cost of Betty and Bokor fields is distributed according to the ratio of oil production rates of these two fields to those of the existing fields.

(2) Capital Investment Cost Estimate

Capital investment costs in each case have been estimated and are summarized in Table 15-6-1. Total amount becomes M$232,200,000 for Case I and M$122,166,000 for Case II respectively.

(3) Annual Operating Cost Estimate

Annual operating costs for each case have been estimated and are summarized in Table 15-6-2 and 15-6-3.

(4) Project and Investment Schedules

The project and investment schedules for Case II (optimum case) have been made and are shown in Fig. 15-6-1 and Table 15-6-5 respectively. For reference, the investment schedule for Case I is shown in Table 15-6-4.

The following construction equipment are assumed to be available.

Tender Assisted Drilling Rig 1
Derrick Barge (500 ton) 1
Lay Barge (12" - 30") 1
Lay Barge (4" - 10") 1

1.2.3 West Temana and E-6 Oil Fields

(1) Bases of Cost Estimate

Capital costs and operating costs for West Temana and/or E-6 fields have been estimated based upon the basic cost data and computation method which are described in 1.1. Besides, the following considerations are taken into:

- Extra piling cost is considered for jackets to be installed in West Temana field because of bad soil conditions.
- It is assumed that sufficient excavated areas are available at Bintulu for terminal construction.
- Operation organizations for Case I and Cases IIA and IIB are tentatively assumed as shown in Fig. 31-6-4 and Fig. 31-6-3 respectively.

(2) Capital Investment Cost Estimate

Capital investment costs in each case have been estimated and are summarized in Table 16-6-1. Total amount becomes M$416,583,000 for Case I, M$285,366,000 for Case IIA and M$299,134,000 for Case IIB respectively.

(3) Annual Operating Cost Estimate

Annual operating costs for each case have been estimated and are summarized in Table 16-6-2, Table 16-6-3 and Table 16-6-4.

(4) Project and Investment Schedules

The project schedule for Case IIB (optimum case) is shown in Fig. 16-6-1. Investment schedule based upon the above-mentioned project schedule has been made and is shown in Table 16-6-7. Investment schedules for other cases have also been made in accordance with each project schedule and are shown in Table 16-6-5 and Table 16-6-6 for reference.

The following construction equipment are assumed to be available:

Tender Assisted Drilling Rig 1
Derrick Barge (500 ton) 1
Lay Barge (12" - 30") 1
Lay Barge (4" - 10") 1

1.2.4 Central Luconia Gas Fields

(1) Bases of Cost Estimate

Capital investment and operating cost for Central Luconia fields have been estimated based on the basic cost data and computation method described in 1.1, taking into account the following assumptions.

- It is assumed that the facilities which consist of buildings such as residence, office, warehouse, etc. and jetty will be newly installed at Bintulu Terminal.

- Compressors are assumed to be replaced at the end of the tenth year after initial installations.

- Operating personnel costs have been estimated based on the tentative operating organization as shown in Fig. 31-6-5.

(2) Capital Investment Cost Estimate

As for these fields there are six cases and the estimated capital investments are summarized below. The breakdowns are shown in Table 17-6-1.

Case IA	M$1,271,003,000
Case IB	M$1,384,640,000
Case IC	M$1,658,253,000
Case II	M$1,565,995,000
Case III	M$1,461,356,000
Case IV	M$1,369,979,000

(3) Annual Operating Cost Estimate

Estimated annual operating costs are summarized below. These costs are all the same throughout the project life for each case. The breakdowns are shown in Table 17-6-2.

Case IA	M$42,912,000
Case IB	M$46,529,000
Case IC	M$56,008,000
Case II	M$52,775,000
Case III	M$49,555,000
Case IV	M$46,188,000

(4) Project and Investment Schedules

The project schedule for Case IC selected as an optimum case is shown in Fig. 17-6-1. The investment schedule for Case IC has been prepared based on the above project schedule and is shown in Table 17-6-5.

The investment schedules for other cases are shown in Tables 17-6-3, 4, 6, 7 and 8 respectively.

The following construction equipment are assumed to be available.

Tender Assisted Drilling Rig 3

Derrick Barge (500 ton) 3

Lay Barge 2

2. ECONOMIC ANALYSIS

2.1 General Economic Analysis Bases

2.1.1 Oil

(1) Method of Economic Analysis

Necessary items and formulas for the calculation of profitability of both Petronas and Operating Company in accordance with PS Agreements are shown in Appendix II.

(2) Profitability Yardsticks

The following profitability yardsticks are used for profitability analysis and for comparison of alternative schemes which are settled at conceptual design phase;

- Cumulative Net Cash Flow
- DCF ROR
- Cumulative Present Worth
- Payout Time

(3) Production Schedule

Annual oil production is obtained from calendar days (365) multiplied by daily oil production which has been estimated in Part A. Table 30-6-1 shows annual oil production for each field. Starting time of production is to be at the completion of all of the drilling and installation of facilities.

(4) Oil Sales Price

The method to establish oil sales price has been presented from downstream team as follows;

1) As for the oil, of which the actual price at the middle of 1976 is known, the following actual prices are to be adopted.

Labuan Crude	M$31.88 (US$12.55)/BBL
Miri Crude	M$32.00 (US$12.60)/BBL

2) As for the oil, of which the actual price at that time does not exist or can not be obtained, the price is to be established by making adjustment for API premium based on the price of the above-mentioned crudes or actual price of other oils.

The method to adjust oil price for API premium of each oil is to be made as follows;

a. As for the oil exceeding API 40.3°, M¢7.62 (US¢3)/° API is to be added to the standard price, M$32.00 (US$12.60)/BBL.

b. As for the oil under API 36.4°, M¢7.62 (US¢3)/° API is to be reduced from the standard price M$31.88 (US$12.55)/BBL.

c. As for the oil between API 36.4° and 40.3°, price is to be established in proportion calculation based on the above standard price.

And as for the oil produced from several combined fields, establishment of sales price is to be made by calculating the weighted average of oil production per year from each field. The prices established by this method are shown in Table 30-6-1, with oil production per year from each field.

(5) Investment Schedule

Capital investment schedules based on alternative schemes are shown in Table 31-6-1.

(6) Annual Operating Costs

Annual operating costs based on alternative schemes are shown in Table 31-6-2.

(7) Common Input Data

Common input data for economic analysis to all cases of alternative schemes are as follows;

• Royalty Rate		10%
• Maximum Cost Recovery Ratio - Oil		20%
	(Gas	25%)
• Profit Oil Share	Petronas	70%
	Operating Company	30%
• Rate of Payment for Research Fund		0.5%
• Initial Basic Price (at 1976 Base)		M$32.31 (US$12.72)/BBL
• Rate of Increase for Basic Price		5%/year
• Rate of Payment for Profit Oil above Basic Price		70%
• Production Bonus above 50,000 BPD		M$5,000,000
• Discovery Bonus*		M$2,500,000
• Income Tax Rate		45%
• Discount Rate		5%, 10%, 15%

Note: * It is assumed that the value of M$2,500,000 as discovery bonus is applied to even combined production fields case.

2.1.2 Gas

(1) Calculation Formula for Gas Cost

For the purpose of selection of the optimum case by comparing alternative schemes, the following formula is used for the calculation of net gas cost;

$$\sum_{i=1}^{n} \frac{GQ_i - (C_i + O_i)}{(1 + r)^{i-0.5}} = 0$$

where,

G = Gas Cost

Q_i = Gas Rate by Year

C_i = Capital Investment by Year

O_i = Operating Cost by Year

r = Discount Rate

n = Project Life

It should be noted that sales profit conception is not included in this gas cost calculation formula and, therefore, cash outflow factors such as tax, royalty, bonus and research fund are excluded. And as for the influence by these factors for cash flow, the attached calculated example in accordance with PS Agreements could be referred.

(2) Production Schedule

Annual gas production rate is obtained from the daily gas production rate multiplied by 365 calendar days. Daily gas production rate is shown in Table 31-6-3. Production life of all gas projects is twenty years and starting time of production is to be at the time of completion of drilling and installation of production facilities.

(3) Investment Schedule

Capital investment schedules based on the alternative schemes are shown in Table 31-6-4.

(4) Annual Operating Costs

Annual operating costs based on alternative schemes are shown in Table 31-6-5.

(5) Common Input Data

Discount Rate	0, 5, 10, 15, 20%

2.2 Profitability Analysis on Oil

The production rate and the production life of each field have important effect upon its profitability. As the result of analysis, it can be said that more advantageous case by comparison of investment cost based on the same production rate is not always advantageous for Operating Company in view of profitability when operating costs are not the same. In the various cases selected in the conceptual design phase, included are the cases for developing fields as a group by combining them or for developing them individually and also the alternative cases for developing the same field or the same group of fields by offshore storage and loading or onshore storage and loading. In this part C.2.2, a comparative study on the results of profitability analysis of each case and selection of a more profitable case in view of profitability are made for the above alternatives taking into consideration technical viewpoints. Detailed explanation of the facilities is made for the case(s) selected considering these results in Part B.2. And as for the selection standard of the alternative cases in the conceptual design, we adopted the value of DCF ROR of the year when that of the Operating Company is the largest, because the case of the largest oil production is most profitable for Petronas at all times, which cannot be the selection standard.

In this area the following two cases for the development of Betty and Bokor oil fields and three cases for the development of West Temana and E-6 oil fields have been selected as alternative schemes, and profitability analysis for each case has been carried out.

2.2.1 Betty and Bokor Oil Fields

Case I : Betty and Bokor, Bakau Gathering System Case

Case II: Betty, Bakau Gathering System Case

Each of the profitability yardsticks obtained for each case is shown in Table 31-6-6. Cash Flow Tables for each of Petronas and Operating Company are shown in Tables 15-6-6 and 7. Descriptions for each case are as follows;

Case I: As Bokor field is connected to Betty field in this case, oil production rate increases. However, capital investment cost is higher due to the installation of a submarine pipeline to connect both fields. In this case Operating Company will not be able to recover the investment cost even at the time of project end and the cash flow conditions for Operating Company are very bad. At the same time, for the reason of low production rate, short production year, heavy oil (19.5° API) and necessity of artificial lift for low well head pressure in Bokor field, capital investment cost is too high for this low oil production rate at the level of present sales price from the viewpoint of economics.

Case II: The profit will become a peak in the eighth year after the project start (in the fifth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR is 12.62% in this year.

In comparison of the above two cases, profitability of Case II will be better than that of Case I. However, even if Case II is adopted, as oil production rate in the ninth year after the project start is extremely low, it will be better for Operating Company to stop the project at eighth year.

2.2.2 West Temana and E-6 Oil Fields

Case I : West Temana and E-6, Bintulu Terminal Case

Case IIA: E-6, Offshore Storage Case

Case IIB: E-6, Onshore Terminal Case

Each of the profitability yardsticks obtained for each case is shown in Table 31-6-6. Cash Flow Tables for Petronas and Operating Company are shown in Tables 16-6-8, 9 and 10. Descriptions for each case are as follows;

Case I: For the reason of low production rate, very short production life, bad soil condition and high investment cost of jackets in gathering scheme of West Temana field, profitability of combined development case of both fields as well as the development case of only the West Temana field is worse than the other alternative cases. The profit will become a peak in the fourteenth year after the project start (in the eleventh year after the production start) as shown in Cash Flow Table for Operating Company. As maximum DCF ROR is 7.88% in this year, this case cannot be said to be profitable.

Case IIA: In this case, capital investment cost is lower but operating cost is higher compared with Case IIB. The profit will become a peak in the thirteenth year after the project start (in the tenth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR is 15.48% in this year. Profitability after this year will become worse because of declining oil production rate.

Case IIB: In this case, capital investment cost is higher and operating cost is lower compared with Case IIA. The profit will become a peak in the sixteenth year after the project start (in the thirteenth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR in this year is 16.75%. Profitability after this year will become worse because of declining oil production rate.

In comparison of the above three cases, Case I is less profitable due to the high capital investment cost. And in comparison of Case IIA with Case IIB the latter can be said to be more profitable, because its profitability is better when the profit for Operating Company in Case IIA will become a peak in the thirteenth year after the project start and this tendency continuous throughout the project life as shown in Cash Flow Table for Operating Company. However, even if Case IIB is adopted, as the profitability of Operating Company after the fifteenth year will become worse, it will be better for Operating Company to stop the project in this year.

2.3 Gas Cost Estimate

The gas costs calculated based on the formula mentioned above in the section of economic analysis bases are shown below. For reference, Table 14-6-4 and Tables 17-6-9 thru 14 show the analyzed results based on the PS Agreements under the condition to obtain 10% DCF ROR.

2.3.1 Baronia Oil Field and B-12 Gas Field Gas Utilization

For these fields the gas costs have been estimated for Case IA which was selected at the conceptual design phase.

Case IA: Natural Flow Case

The followings are gas costs for each discount rate;

Unit: M¢/1,000 SCF

	Discount Rate				
	0%	5%	10%	15%	20%
Gas Cost	77.4	103.8	137.0	175.6	218.2

2.3.2 Central Luconia Gas Fields

For Central Luconia gas fields in this area, the six cases of gas production scheme are selected corresponding to different gas production, investment and annual operating costs and the gas costs for each case have been calculated and analyzed.

Case IA :	Natural Flow Case - Six Fields Development
Case IB :	Onshore compression Case - Six Fields Development
Case IC :	Offshore Compression Case - Six Fields Development
Case II :	Offshore Compression Case - Five Fields Development
Case III:	Offshore Compression Case - Four Fields Development
Case IV :	Offshore Compression Case - Three Fields Development

The followings are the gas costs of each case for each discount rate;

Unit: M¢/1,000 SCF

	Discount Rate				
	0%	5%	10%	15%	20%
Case IA	28.3	39.4	53.8	71.3	91.5
Case IB	32.4	43.6	58.1	75.6	95.8
Case IC	28.4	38.6	52.1	68.6	87.9
Case II	28.3	38.5	51.9	68.4	87.6
Case III	28.2	38.3	51.5	67.8	86.9
Case IV	28.8	38.9	52.0	67.8	86.2

As known from the above table, a relative order of each case varies in accordance with the discount rate. Gas costs of Case IA and Case IB are higher in comparison with other cases. In the other cases, the gas cost in Case III is comparatively low, but the difference from other cases is small.

Case IC has been selected at this time in spite of the above-mentioned results and in spite that in this case there are many offshore facilities which will require more or less complicated operation. The reasons are described below, although final selection should be made based on the profitability analysis for the combined scheme of both gas gathering and a gas plant.

(1) In general the project for large scale gas utilization will become more advantageous with the increase of supply gas rate due to the "merit of size" in spite of small increase in gas cost. Gas production rate is the largest in Case IC.

(2) Gas recovery is relatively high, therefore this case has the merit to utilize gas reserves effectively.

2.4 Sensitivity Analysis

The sensitivity analysis has been carried out on the profitability yardstick for the optimum case of the production schemes as described in Part B.2 and the sensitivity curve is shown in Fig. 31-6-8. The results of sensitivity analysis for each case are as follows;

2.4.1 Betty and Bokor Oil Fields (Case II)

Production Rate Change	-20%	-10%	0%
DCF ROR (%)	3.58	8.30	12.62

Sales Price Change	-20%	-10%	0%	10%	20%
DCF ROR (%)	3.58	8.30	12.62	16.62	19.44

Investment Change	-20%	-10%	0%	10%	20%
DCF ROR (%)	20.02	16.36	12.62	9.36	6.50

2.4.2 West Temana and E-6 Oil Fields (Case IIB)

Production Rate Change	-20%	-10%	0%
DCF ROR (%)	9.99	13.99	16.75

Sales Price Change	-20%	-10%	0%	10%	20%
DCF ROR (%)	9.99	13.99	16.75	18.90	20.87

Investment Change	-20%	-10%	0%	10%	20%
DCF ROR (%)	21.36	18.87	16.75	14.87	12.62

3. CONCLUSIONS AND RECOMMENDATIONS

3.1 Cost Estimate

Capital investment and annual operating cost have been estimated for each of the alternative cases for which the conceptual design of production facilities of the oil and gas fields has been performed. As a result, capital investment schedules have been prepared to be used as basic data for subsequent economic analysis.

The capital investment cost estimate has been performed for the drilling of production wells, offshore platforms, submarine pipelines, oil and gas processing equipment, offshore storage and loading facilities or onshore storage and loading facilities, support facilities, etc. The operating cost has been estimated for operating personnel, chemicals, service contractors, repair and maintenance, insurance and so on required for the field operation of the above-mentioned facilities.

Estimated capital investment cost in each case is summarized and shown below with design capacity of the production facilities.

Baronia and B-12 group (gas)

	41 MMSCFD	M$ 113,027,000

Betty and Bokor group (crude oil)

Case I	21,000 BPD	M$ 232,200,000
Case II	16,000 BPD	M$ 122,166,000

West Temana and E-6 group (crude oil)

Case I	34,000 BPD	M$ 416,583,000
Case IIA	30,000 BPD	M$ 285,366,000
Case IIB	30,000 BPD	M$ 299,134,000

Central Luconia (gas)

Case IA	1,200 MMSCFD	M$ 1,271,003,000
Case IB	1,100 MMSCFD	M$ 1,384,640,000
Case IC	1,500 MMSCFD	M$ 1,658,253,000
Case II	1,400 MMSCFD	M$ 1,565,995,000
Case III	1,300 MMSCFD	M$ 1,461,356,000
Case IV	1,200 MMSCFD	M$ 1,369,979,000

East Temana (crude oil)

	8,000 BPD	M$ 108,310,000

3.2 Economic Analysis

The economic analysis has been performed regarding various production schemes for both oil and gas fields selected in the conceptual design phase. Regarding oil, the profitability of each production scheme is analyzed based on Production Sharing Agreements in Malaysia from the standpoint of Petronas and Operating Company respectively. Sales price of crude was given by the down-stream team of the Master Plan study.

Regarding gas, gas costs have been calculated based on the proper formula which was prepared for the purpose to select the lowest cost scheme of gas production and gathering. Gas utilization projects of large scale are generally difficult to decide the execution of them without the consideration of overall profitability for both gas production scheme and utilization scheme. And it is difficult to obtain such a general sales price for gas as sales price for oil. Therefore, it is not realistic to analyze profitability only for the objective gas production scheme without that for gas utilization scheme and this is the reason to use the above-mentioned formula. Consequently, the following have been selected as more profitable cases:

- Betty single field development case with connection to the existing Bakau facilities.

- E-6 single field development case with onshore storage facilities.

The cost of net gas delivered to a shore point has been estimated for the following two fields:

- Baronia and B-12 fields
- Central Luconia fields.

The summary of the results is shown below. For the cases of crude oil the indicated figures belong to the year when the profitability indexes become maximum, and for the cases of gas the indicated figures are the gas costs throughout 20 producing years.

- Crude Oil -

	Petronas	Operating Company		
Name of Field	Cumulative Net Cash Flow (M$ 1,000)	DCF ROR (%)	Cumulative Net Cash Flow (M$ 1,000)	Payout Time (year)
Betty	188,132	12.6	58,526	5.7
E-6	697,320	16.8	282,672	6.2

- Gas -

Gas Cost by Discount Factors
(M¢/1,000 CF)

Name of Field(s)	Discount Factor (%)				
	0	5	10	15	20
Baronia and B-12	77.4	103.8	137.0	175.6	218.2
Central Luconia	28.4	38.6	52.1	68.6	87.9

TABLE

TABLE

TABLE LIST VOL. IV SARAWAK AREA

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Vol. IV Table A-1

ORIGINAL HYDROCARBONS IN PLACE - PRODUCING FIELDS OF SARAWAK

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.G.I.P. (MMMSCF)	PRODUCED RESVS. OIL (MMSTB)	PRODUCED RESVS. GAS (MMMSCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
BARONIA	A Zone	202.70	362.10	7.354	13.696	72.462	321.788
	C Zone	33.62	42.48	5.171	8.647	11.213	26.171
	D Zone	271.22	377.94	4.231	11.368	66.473	288.802
	E Zone	16.78	15.16	1.652	2.067	4.651	11.368
	F1 Zone	34.65	31.70	2.402	2.935	8.883	16.802
	F2 Zone	44.03	40.29	3.368	5.097	14.246	31.900
	TOTAL	603.00	869.67	24.158	43.819	177.928	696.831
	PROVED RESVS.	630.00	869.67				
	PROBABLE RESVS.						
FAIRLEY BARAM	A Zone	27.20	36.99	1.306	2.190	7.992	26.463
	B Zone	18.06	21.09	0.318	0.640	2.611	7.228
	C Zone	51.92	63.74	1.663	2.360	18.813	35.765
	TOTAL	97.18	121.82	3.287	5.190	29.416	69.456
	PROVED RESVS.	97.18	121.82				
	PROBABLE RESVS.						
WEST LUTONG	A Zone	23.30	80.30	2.142	18.810	4.390	63.363
	B Zone	179.36	169.40	67.080	100.860	105.163	129.988
	C Zone	45.64	129.38	7.030	20.350	21.959	91.570
	ADD. WELL	8.67	31.43	0.0	0.0	4.149	17.237
	TOTAL	256.97	410.51	76.252	140.02	135.661	302.158
	PROVED RESVS.	256.97	410.51				
	PROBABLE RESVS.						

Vol. IV Table A-1 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - PRODUCING FIELDS OF SARAWAK

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.G.I.P. (MMMSCF)	PRODUCED RESVS. OIL (MMSTB)	PRODUCED RESVS. GAS (MMMSCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
BARAM A	BLOCK I	110.00	215.00	16.501	47.982	31.761	134.172
	BLOCK II	8.60	16.03	2.495	11.498	2.738	13.580
	BLOCK IV	18.00	30.71	4.687	18.980	5.199	22.424
	BLOCK V	64.00	142.08	16.082	78.597	19.784	107.620
	BLOCK VI	46.41	59.63	10.110	41.532	12.519	51.854
	BLOCK VII	19.38	18.54	3.875	14.578	4.201	9.102
	BLOCK VIII	29.21	30.08	4.382	12.518	6.673	20.576
	UPPER BLOCK	12.91	7.03	0.728	0.895	2.918	5.003
	TOTAL	308.51	519.10	58.860	226.580	85.793	364.331
	PROVED RESVS.	179.05	375.99				
	PROBABLE RESVS.	129.46	143.11				
BARAM B	MODEL-1	25.23	47.77	6.651	19.845	9.992	30.556
	MODEL-2	56.18	140.22	11.729	49.426	21.613	97.996
	TOTAL	81.41	195.21	18.380	69.271	31.605	128.552
	PROVED RESVS.	74.66	187.45				
	PROBABLE RESVS.	6.75	7.76				
BAKAU	BK-3	6.99	8.84	2.098	4.721	2.557	6.308
	BK-4	14.48	7.63	1.158	1.524	4.222	5.473
	BK-5	0.83	1.25	0.072	0.366	0.155	0.838
	TOTAL	22.30	17.72	3.328	6.611	6.934	12.619
	PROVED RESVS.	6.35	5.30				
	PROBABLE RESVS.	15.95	12.42				

Vol. IV Table A-1 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - PRODUCING FIELDS OF SARAWAK

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.G.I.P. (MMMSCF)	PRODUCED RESVS. OIL (MMSTB)	PRODUCED RESVS. GAS (MMMSCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
TUKAU	MODEL-1	20.16	4.43	0.726	0.334	5.405	2.586
	MODEL-2	4.30	1.93	0.430	0.337	1.102	1.217
	MODEL-3	13.45	18.14	0.460	1.026	3.128	13.775
	MODEL-4	1.07	0.53	0.136	0.172	0.246	0.366
	MODEL-5	20.50	40.93	0.252	0.877	3.901	31.385
	MODEL-6	2.36	1.98	0.026	0.021	0.505	1.142
	MODEL-7	6.98	4.19	0.362	0.243	2.153	2.966
	MODEL-8	9.77	11.26	0.710	0.672	3.955	7.033
	MODEL-9	48.49	10.67	0.0	0.0	5.742	6.076
	MODEL-10	19.88	4.37	0.0	0.0	2.222	2.440
	MODEL-11	2.66	2.24	0.0	0.0	1.126	1.672
	TOTAL	149.62	100.67	3.102	3.682	29.485	70.658
	PROVED RESVS.	149.62	100.67				
	PROBABLE RESVS.						
GRAND TOTAL	PROVED RESVS.	1366.83	2071.41	187.367	495.173	496.822	1644.605
	PROBABLE RESVS.	152.16	163.29				

Vol. IV Table A-2

ORIGINAL HYDROCARBONS IN PLACE - DEVELOPMENT FIELDS OF SARAWAK

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	O.H.I.P. (MMCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
BETTY (E)	a1	41.09	0.0	19.31	181.0	16.02	14.95
	a3	11.57	0.0	6.36	56.0	6.44	5.36
	b1	0.0	14.27	0.0	0.0		
	b2	1.55	0.0	0.85	12.0	1.00	0.85
	c1	0.0	47.75	0.0	0.0		
	TOTAL	54.21	62.02	26.52	249.0	23.46	21.16
	PROVED RESVS.	13.51	47.72	6.61			
	PROBABLE RESVS.	40.70	14.30	19.91			
	POSSIBLE RESVS.						
TEMANA (W)	c1	7.77	0.0	1.79	44.0		
	c2	10.03	0.0	2.31	33.0		
	d1	30.03	2.31	6.91	1.0		
	d2	8.50	2.83	1.96	8.0		
	d3	0.34	0.0	0.08	9.0		
	e	1.08	0.0	0.73	11.0		
	f1	0.81	1.23	0.55	0.0		
	f2	0.0	0.92	0.0	0.0		
	f3	0.47	0.05	0.32	1430.0		
	g	0.14	0.58	0.09	810.0		
	i	0.0	2.64	0.0	0.0		
	TOTAL	59.15	10.56	14.72	2346.0	2.47	5.15
	PROVED RESVS.	50.93	10.56	12.67			
	PROBABLE RESVS.	8.22		2.05			
	POSSIBLE RESVS.						

Vol. IV Table A-2 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - DEVELOPMENT FIELDS OF SARAWAK

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	O.H.I.P. (MMCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
BOKOR	a1	12.30	0.0	1.43	76.0	0.91	0.60
	a2	24.20	0.0	3.05	20.0	1.77	1.09
	a3	3.80	0.0	0.48	55.0		
	b1	0.0	0.0	0.0	12.0		
	b2	8.60	0.0	2.84	16.0	1.37	0.99
	b3	0.0	0.0	0.0	137.0		
	c	0.0	0.0	0.0	79.0		
	d	0.0	0.0	0.0	2.0		
	TOTAL	48.90	0.0	7.79	398.0	4.05	2.68
	PROVED RESVS.	48.90		7.79			
	PROBABLE RESVS.						
	POSSIBLE RESVS.						

Vol. IV Table A-3

ORIGINAL HYDROCARBONS IN PLACE - POTENTIAL FIELDS OF SARAWAK

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	O.H.I.P. (MMCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
BETTY (W)	b2	0.0	0.24	0.0	0.0		
	c1	0.0	0.06	0.0	0.0		
	c2	0.0	1.90	0.0	0.0		
	TOTAL	0.0	2.20	0.0	0.0		
	PROVED RESVS.		2.20				
	PROBABLE RESVS.						
	POSSIBLE RESVS.						
TEMANA (E)	a2	0.0	1.22	0.0	0.0		
	b1	0.0	6.25	0.0	0.0		
	b2	0.0	1.03	0.0	0.0		
	d2	0.93	0.0	0.37	8.6		
	TOTAL	0.93	8.51	0.37	8.6		
	PROVED RESVS.	0.93	8.51	0.37			
	PROBABLE RESVS.						
	POSSIBLE RESVS.						
SIWA	a	0.49	0.23	0.12	0.0		
	b	0.50	0.34	0.12	0.0		
	c	1.55	0.0	0.36	0.0		
	d1	5.38	0.0	1.18	0.0		
	d2	0.97	0.0	0.29	0.0		
	d3	0.0	0.0	0.0	4.9		
	e1	0.0	39.06	0.0	0.0		
	e2	0.0	27.23	0.0	0.0		
	e4	3.33	1.57	1.13	0.0		
	f	0.0	1.02	0.0	0.0		

Vol. IV Table A-3 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - POTENTIAL FIELDS OF SARAWAK

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	O.H.I.P. (MMCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
	TOTAL	12.22	69.45	3.20	4.9		
	PROVED RESVS.	4.00	69.45	1.05			
	PROBABLE RESVS.	8.22		2.15			
	POSSIBLE RESVS.						

Vol. IV Table A-4

ORIGINAL HYDROCARBONS IN PLACE - CENTRAL LUCONIA FIELDS

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.G.I.P. (MMMSCF)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
B12	TOTAL		409.				
	PROVED RESVS.		161.				
	PROBABLE RESVS.		248.				
	POSSIBLE RESVS.						
E6	TOTAL	226.		1165.	99.44	Case1 82.96	737.31
						Case2 83.32	759.57
	PROVED RESVS.	10.		331.	4.40		
	PROBABLE RESV.	216.		834.	95.04		
	POSSIBLE RESV.						
E8	TOTAL		1253.				690
	PROVED RESVS.		1253.				
	PROBABLE RESVS.						
	POSSIBLE RESVS.						
E11	TOTAL		3454.				2080
	PROVED RESVS.		1405.				
	PROBABLE RESVS.		2409.				
	POSSIBLE RESVS.						
F6	TOTAL		5609.				2460
	PROVED RESVS.		670.				
	PROBABLE RESVS.		4939.				
	POSSIBLE RESVS.						

Vol. IV Table A-4 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - CENTRAL LUCONIA FIELDS

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.G.I.P. (MMMSCF)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
F9	TOTAL		350.				
	PROVED RESVS.		28.				
	PROBABLE RESVS.		322.				
	POSSIBLE RESVS.						
F13	TOTAL		1475.				710
	PROVED RESVS.		1143.				
	PROBABLE RESVS.		332.				
	POSSIBLE RESVS.						
F14	TOTAL		1252.				620
	PROVED RESVS.		166.				
	POSSIBLE RESVS.		-				
F22	TOTAL		284.				
	PROVED RESVS.		284.				
	PROBABLE RESVS.						
	POSSIBLE RESVS.						
F23	TOTAL		5750.				3370
	PROVED RESVS.		904.				
	PROBABLE RESVS.		4846.				
	POSSIBLE RESVS.						
K4	TOTAL		197.				
	PROVED RESVS.		197.				
	PROBABLE RESVS.						
	POSSIBLE RESVS.						

Vol. IV Table A-4 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - CENTRAL LUCONIA FIELDS

FIELD NAME	BLOCK & ZONE	O.O.I.P. (MMSTB)	O.G.I.P. (MMMSCF)	O.C.G.I.P. (MMMSCF)	O.S.G.I.P. (MMMSCF)	RECOVERABLE RESVS. OIL (MMSTB)	RECOVERABLE RESVS. GAS (MMMSCF)
M1	TOTAL		840.				
	PROVED RESVS.		214.				
	PROBABLE RESVS.		626.				
	POSSIBLE RESVS.						
M3	TOTAL		2043.				
	PROVED RESVS.		172.				
	PROBABLE RESVS.		1871.				
	POSSIBLE RESVS.						
M5	TOTAL		517.				
	PROVED RESVS.		90.				
	PROBABLE RESVS.		427.				
	POSSIBLE RESVS.						
GRAND TOTAL	TOTAL	226.	24598.		99.44	Case1 82.96	10267.
	PROVED RESVS.	10.	6207.		4.40	Case2 83.32	10290.
	PROBABLE RESVS.	216.	18391.		95.04		
	POSSIBLE RESVS.						

Table 1-2-1 CORRELATION TABLE
Vol. IV BARONIA FIELD

Well No.	1		2		4		5		6		7	
D.F.E.	111		110		41		41		78		78	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Middle VI	4120	4009	4927	4817	4083	4042	4070	4029	4246	4025	4102	4012
Lower VI	5421	5310	(5633)	(5523)	5353	5312	5375	5334	5633	5296	5444	5289
V	8047	7936	8233	8123	7996	7955	8018	7977	8494	7932	8269	7912
Top a_1	5421	5310	(5633)	(5523)	5353	5312	5375	5344	5633	5296	5444	5289
a_2	5549	5438	(5755)	(5645)	6478	5437	5514	5473	5775	5425	5581	5418
a_3	5671	5560	5866	5756	5590	5549	5634	5593	5906	5544	5702	5534
Top b	6007	5896	6239	6129	5924	5883	5980	5939	6283	5884	6064	5874
Top c_1	6461	6350	6551	6441	6385	6344	6427	6387	6791	6342	6547	6327
c_2	6512	6401	6602	6492	6437	6396	6489	6448	6858	6401	6610	6386
Top d_1	6961	6850	7078	6977	6880	6839	6940	6899	7336	6840	7084	6824
d_2	7011	6900	7139	7029	6927	6886	6986	6945	7388	6887	7137	6876
d_3	7100	6989	7234	7124	7022	6981	7079	7038	7488	6983	7236	6966
d_4	7228	7117	7373	7263	7158	7113	7202	7161	7622	7113	7373	7093
Top e	7458	7347	7617	7507	7389	7348	7432	7391	7860	7335	7623	7324
Top f_1	7714	7603	7903	7793	7663	7622	7693	7652	8146	7605	7913	7589
f_2	7857	7746	8030	7920	7800	7759	7834	7793	8294	7146	8065	7722
Top g	8047	7936	8233	8123	7996	7955	8018	7977	8494	7932	8269	7912
T.D.	9001	8890	8510	8400	8200	8159	8227	8186	8575	8009	8330	7967

Table 1-2-1 (Continued) CORRELATION TABLE
Vol. IV BARONIA FIELD

Well No.	8		9		10		11		12		13	
D.F.E.	78		78		78		78		78		78	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Middle VI	4933	4039	4236	4029	4335	4012	4730	4034	4623	4003	4723	4011
Lower VI	6945	5357	5653	5299	5790	5285	6499	5317	6354	5323	6508	5297
V			8491	7951	8534	7920						
Top a_1	6945	5357	5653	5299	5790	5285	6499	5317	6354	5323	6508	5927
a_2	7163	5489	5790	5422	5927	5411	6672	5448	6514	5455	6696	5424
a_3	7362	5611	5923	5541	6055	5331	6826	5566	6665	5580	6862	5537
Top b	8000	5980	6305	5883	6433	5886	7263	5914	7100	5928	7388	5886
Top c_1	8717	6455	6822	6343	6887	6313	7799	6375	7690	6390	8051	6350
c_2	8806	6516	6882	6398	6942	6365	7864	6432	7784	6465	8120	6401
Top d_1	9472	6988	7364	6843	7408	6816	8340	6875	8345	6926	8723	6859
d_2	9539	7037	7414	6890	7458	6865	8390	6922	8405	6979	8792	6912
d_3	9674	7138	7510	6985	7552	6956	8484	7013	8515	7073	8913	7012
d_4	9838	7263	7638	7110	7684	7085	8620	7145	8666	7205	9081	7146
Top e	-	-	7879	7347	7927	7323	8862	7382	-	-	(9383)	(7390)
Top f_1			8155	7617	8197	7588	-	-			-	-
f_2			8297	7759	8341	7731						
Top g_1			8491	7951	8534	7920						
T.D.	10100	7463	8550	8009	8610	7995	8965	7483	8930	7432	9500	7486

Table 1-2-1 (Continued) Vol. IV

CORRELATION TABLE
BARONIA FIELD

Well No.	14		15		16		17		18	
D.F.E.	111		78		78		78		78	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Middle VI	4712	4027	4586	4020	4816	4035	4702	4000	5138	3989
Lower VI	6651	5404	6188	5320	6506	5305	6434	5301	7258	5314
V										
Top a_1	6651	5404	6188	5320	6506	5305	6434	5301	7258	5314
a_2	6852	5543	6356	5454	6676	5433	6605	5432	7479	5449
a_3	7037	5669	6509	5571	6828	5547	6768	5556	7702	5581
Top b	7581	6032	6977	5931	7322	5894	7231	5898	-	-
Top c_1	8294	6511	7578	6390	8017	6367	7859	6358		
c_2	8376	6575	7666	6457	8091	6419	7946	6422		
Top d_1	9009	7049	8257	6921	8683	6870	8557	6879		
d_2	9079	7105	8317	6972	8754	6924	8627	6932		
d_3	9199	7201	8430	7069	8879	7023	8754	7028		
d_4	9386	7349	8572	7194	9053	7159	8928	7161		
Top e	-	-	-	-	9368	7402	-	-		
Top f_1										
f_2										
Top g										
T.D.	9604	7521	8907	7494	9484	7492	9318	7457	7754	5600

Vol. IV Table 1-3-1

PREDICTED PERFORMANCE OF BARONIA FIELD

PRODUCTION START : May 1972
PRODUCTION END : Oct.1994

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jan.1973	0.09	2.05	1.87	912	0.0	0.561	0.512	0.0
1974	0.35	4.22	4.31	1021	0.002	2.100	2.085	0.004
1975	0.92	9.41	11.54	1226	0.023	5.534	6.297	0.083
1976	2.79	30.95	42.79	1383	0.054	16.830	21.916	0.693
1977	5.72	48.36	95.24	1969	0.083	34.480	56.678	2.154
1978	8.67	48.68	133.43	2741	0.133	52.251	105.380	4.513
1979	11.26	42.60	139.57	3276	0.148	67.875	156.324	6.826
1980	13.56	38.11	152.86	4011	0.183	81.789	212.118	9.366
1981	15.54	32.66	158.32	4848	0.182	93.733	269.904	11.533
1982	17.28	28.74	162.12	5641	0.182	104.224	329.077	13.466
1983	18.85	25.79	164.51	6379	0.225	113.639	389.123	15.564
1984	20.24	23.11	159.43	6899	0.279	122.075	447.316	17.916
1985	21.50	20.67	147.85	7153	0.344	129.621	501.283	20.509
1986	22.61	17.54	123.18	7023	0.432	136.023	546.243	23.273
1987	23.61	15.32	85.70	5594	0.482	141.614	577.525	25.966
1988	24.51	13.70	55.10	4022	0.449	146.614	597.637	28.210

Vol. IV Table 1-3-1 (Continued)

PREDICTED PERFORMANCE OF BARONIA FIELD

PRODUCTION START : May 1972
PRODUCTION END : Oct.1994

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jan.1989	25.30	12.16	44.37	3649	0.454	151.052	613.833	30.226
1990	25.73	6.22	25.94	4171	0.303	153.323	623.302	30.915
1991	26.04	4.22	19.47	4613	0.162	154.865	630.408	31.165
1992	26.32	3.90	17.83	4572	0.155	156.287	636.916	31.386
1993	26.55	3.65	16.40	4493	0.143	157.621	642.902	31.576
1994	26.75	3.45	15.52	4500	0.142	158.881	648.568	31.755
Oct.1994	26.90	3.14	14.06	4479	0.148	159.740	652.418	31.882

Vol. IV Table 1-3-2

PREDICTED PERFORMANCE OF A ZONE,

BARONIA FIELD

PRODUCTION START : Jul. 1973
PRODUCTION END : Apr. 1989

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2351	4.53	17.48	27.67	1583	0.01	9.175	12.01	0.062
Jan.1977	2334	5.31	17.50	29.81	1705	0.02	10.772	14.73	0.089
1978	2220	8.62	18.38	37.67	2050	0.04	17.479	28.48	0.347
1979	2075	11.82	17.75	52.19	2941	0.07	23.957	47.53	0.786
1980	1893	14.84	16.79	68.06	[illegible]054	0.10	30.085	72.37	1.413
1981	1688	17.71	15.94	85.84	5386	0.15	35.902	103.7	2.266
1982	1449	20.44	15.15	101.92	6727	0.21	41.432	140.9	3.413
1983	1190	22.97	14.04	111.23	7925	0.28	46.555	181.5	4.862
1984	929	25.27	12.79	112.05	8762	0.38	51.223	222.4	6.622
1985	685	27.35	11.54	105.75	9166	0.49	55.434	261.0	8.704
1986	490	29.20	10.29	88.77	8628	0.62	59.189	293.4	11.039
1987	400	30.84	9.10	55.89	6142	0.70	62.51	313.8	13.36
1988	377	32.30	8.10	28.49	3517	0.65	65.467	324.2	15.289
1989	361	33.58	7.10	20.55	2894	0.67	68.058	331.7	17.013
Apr.1989	357	33.87	6.50	17.53	2698	0.70	68.651	333.3	17.43

Vol. IV Table 1-3-3

PREDICTED PERFORMANCE OF A ZONE,

WELL 1, BARONIA FIELD

PRODUCTION START : Jul. 1973
PRODUCTION END : Apr. 1989

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Oct.1976	2315	6.00	11.17	1862	0.029	3.856	6.536	0.046
Jan.1977	2298	6.25	12.17	1948	0.036	4.426	7.646	0.067
1978	2180	6.25	13.55	2167	0.068	6.708	12.59	0.222
1979	2037	6.19	16.30	2634	0.109	8.966	18.54	0.468
1980	1854	5.93	19.92	3359	0.154	11.13	25.81	0.802
1981	1646	5.70	24.14	4235	0.208	13.21	34.62	1.235
1982	1406	5.47	28.30	5174	0.282	15.207	44.95	1.799
1983	1142	5.15	31.56	6128	0.377	17.088	56.47	2.508
1984	873	4.76	33.07	6947	0.497	18.826	68.54	3.372
1985	616	4.34	32.82	7563	0.670	20.411	80.52	4.433
1986	406	3.95	28.36	7179	0.589	21.854	90.87	5.671
1987	376	3.56	14.00	3933	0.936	23.154	95.98	6.887
1988	356	3.12	9.37	3003	0.848	24.293	99.40	7.853
1989	322	2.73	7.67	2810	0.920	25.291	102.20	8.770
Apr.1989	310	2.54	1.64	2657	1.067	25.523	102.80	9.014

Vol. IV Table 1-3-4

PREDICTED PERFORMANCE OF A ZONE,

WELL 2, BARONIA FIELD

PRODUCTION START : Jan. 1975
PRODUCTION END : Apr. 1989

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2327	4.99	7.77	1556	0.0	3.119	3.101	0.0
Jan.1977	2312	4.74	8.55	1800	0.008	3.551	3.881	0.0003
1978	2192	4.69	10.88	2320	0.028	5.263	7.852	0.049
1979	2042	4.44	15.58	3510	0.064	6.882	13.54	0.153
1980	1849	4.19	20.96	5002	0.111	8.412	21.19	0.322
1981	1637	3.93	26.11	6644	0.174	9.848	30.72	0.571
1982	1394	3.71	30.49	8219	0.257	11.203	41.85	0.919
1983	1135	3.35	32.16	9601	0.358	12.427	53.59	1.357
1984	878	2.95	30.19	10504	0.476	13.502	64.90	1.870
1985	638	2.55	27.70	10862	0.603	14.434	75.01	2.431
1986	451	2.15	21.97	10220	0.733	15.219	83.03	3.006
1987	386	1.75	14.11	8063	0.852	15.857	88.18	3.550
1988	358	1.35	5.07	3754	0.881	16.350	90.03	3.984
1989	349	0.95	2.66	2797	0.960	16.696	91.00	4.317
Apr.1989	350	0.70	1.94	2772	0.988	16.760	91.18	4.381

Vol. IV Table 1-3-5

PREDICTED PERFORMANCE OF A ZONE,

WELL 3, BARONIA FIELD

PRODUCTION START : Apr. 1975
PRODUCTION END : Apr. 1989

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2354	4.52	7.63	1689	0.014	1.799	2.152	0.016
Jan.1977	2340	3.50	7.48	2138	0.020	2.119	2.835	0.022
1978	2221	3.44	9.66	2808	0.043	3.373	6.361	0.076
1979	2070	3.19	13.73	4302	0.076	4.536	11.37	0.164
1980	1886	2.98	17.51	5875	0.115	5.623	17.76	0.289
1981	1676	2.88	22.14	7686	0.163	6.672	25.84	0.460
1982	1432	2.78	26.52	9540	0.230	7.685	35.52	0.693
1983	1170	2.60	28.71	11043	0.321	8.635	46.00	0.998
1984	908	2.39	28.38	11876	0.438	9.509	56.36	1.380
1985	660	2.20	26.05	11843	0.573	10.312	65.87	1.840
1986	465	2.00	20.99	10493	0.715	11.043	73.53	2.362
1987	386	1.80	12.96	7199	0.854	11.700	78.26	2.923
1988	376	1.60	5.86	3664	0.906	12.284	80.40	3.452
1989	365	1.40	4.63	3307	0.924	12.795	82.09	3.924
Apr.1989	361	1.30	4.05	3119	0.935	12.913	82.46	4.034

Vol. IV Table 1-3-6

PREDICTED PERFORMANCE OF A ZONE,

WELL 4, BARONIA FIELD

PRODUCTION START : Feb. 1976
PRODUCTION END : Apr. 1989

TIME	RESERVOIR PRESSURE	OIL PROD. RATE	GAS PROD. RATE	G.O.R.	W.O.R.	CUMULATIVE PRODUCTION		
						OIL	GAS	WATER
(YEAR)	(PSIG)	(MSTB/D)	(MMSCF/D)	(SCF/STB)	(STB/STB)	(MMSTB)	(MMMSCF)	(MMSTB)
Oct.1976	2386	1.95	1.07	550	0.0	0.401	0.221	0.0
Jan.1977	2364	3.00	1.64	546	0.0	0.675	0.370	0.0
1978	2253	4.00	3.59	899	0.0	2.136	1.682	0.0
1979	2113	3.94	6.56	1666	0.0	3.572	3.078	0.0
1980	1935	3.68	9.69	2634	0.0	4.918	7.616	0.0
1981	1735	3.44	13.33	3874	0.0	6.173	12.48	0.0
1982	1501	3.19	16.58	5196	0.0	7.336	18.53	0.0
1983	1244	2.94	18.82	6402	0.0	8.408	25.40	0.0
1984	983	2.69	19.84	7374	0.0	9.390	32.64	0.0
1985	747	2.44	19.17	7860	0.0	10.279	39.64	0.0
1986	559	2.19	17.29	7894	0.0	11.078	45.95	0.0
1987	405	2.00	14.90	7452	0.0	11.807	51.39	0.0
1988	381	2.00	8.03	4014	0.0	12.537	54.32	0.0
1989	369	2.00	5.48	2740	0.0	13.267	56.32	0.0
Apr.1989	366	2.00	5.12	2558	0.0	13.451	56.78	0.0

Vol. IV Table 1-3-7

PREDICTED PERFORMANCE OF C ZONE,

BARONIA FIELD

PRODUCTION START : Aug. 1974
PRODUCTION END : Oct. 1980

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2394	18.75	9.73	19.19	1973	0.08	6.384	9.160	0.229
Jan.1977	2319	20.76	7.49	16.46	2198	0.39	7.067	10.662	0.494
1978	1906	27.80	6.54	21.94	3356	0.41	9.453	18.670	1.468
1979	1621	31.76	3.68	11.15	3026	0.61	10.798	22.740	2.285
1980	1400	34.01	2.10	7.56	3596	1.25	11.565	25.499	3.245
Oct.1980	1324	34.80	0.98	5.13	5241	1.74	11.832	26.904	3.711

Vol. IV Table 1-3-8

PREDICTED PERFORMANCE OF C ZONE,

WELL BN-6, BARONIA FIELD

PRODUCTION START : Nov. 1974
PRODUCTION END : Jan. 1978

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2322	1.65	3.52	2131	0.0	0.969	1.450	0.0
Jan.1977	2225	1.62	4.09	2523	0.81	1.117	1.823	0.119
Jan.1978	1872	1.27	4.78	3760	1.50	1.579	3.566	0.814

Vol. IV Table 1-3-9

PREDICTED PERFORMANCE OF C ZONE,

WELL BN-7, BARONIA FIELD

PRODUCTION START : Aug.1974
PRODUCTION END : Jul.1980

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2333	3.90	8.02	2055	0.05	2.225	3.347	0.017
Jan.1977	2276	1.78	4.26	2394	0.06	2.387	3.736	0.027
1978	1845	1.78	7.24	4066	0.12	3.037	6.378	0.106
1979	1565	1.71	6.27	3669	0.49	3.662	8.668	0.413
1980	1364	0.79	2.64	3340	1.18	3.950	9.631	0.754
Jul.1980	1319	0.31	0.78	2528	1.80	4.006	9.774	0.856

Vol. IV Table 1-3-10

PREDICTED PERFORMANCE OF C ZONE,

WELL BN-9, BARONIA FIELD

PRODUCTION START : Nov. 1974
PRODUCTION END : Jul. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Oct.1976	2348	1.10	1.18	1069	0.36	1.716	1.905	0.188
Jan.1977	2266	1.08	1.19	1106	0.41	1.815	2.014	0.228
1978	1869	0.98	1.25	1278	0.51	2.173	2.471	0.410
1979	1587	0.54	1.10	2045	0.84	2.372	2.874	0.576
Jul.1979	1506	0.17	0.43	2514	1.64	2.403	2.952	0.627

Vol. IV Table 1-3-11

PREDICTED PERFORMANCE OF C ZONE,

WELL BN-10, BARONIA FIELD

PRODUCTION START : Dec. 1974
PRODUCTION END : Oct. 1980

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2376	2.04	4.10	2010	0.0	1.144	1.692	0.0
Jan.1977	2303	1.73	4.15	2401	0.0	1.302	2.071	0.0
1978	1871	1.61	6.13	3805	0.0	1.888	4.307	0.0
1979	1573	1.42	7.82	5508	0.39	2.408	7.162	0.202
1980	1351	1.23	7.38	6003	1.27	2.857	9.857	0.770
Oct.1980	1278	1.17	6.92	5915	1.70	3.071	11.12	1.133

Vol. IV Table 1-3-12

PREDICTED PERFORMANCE OF C ZONE,

WELL BN-13, BARONIA FIELD

PRODUCTION START : Jun. 1975
PRODUCTION END : Oct. 1977

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2397	1.30	2.69	2066	0.16	0.331	0.766	0.024
Jan.1977	2318	1.27	2.77	2183	0.23	0.447	1.019	0.051
Oct.1977	1979	1.20	3.35	2795	0.58	0.776	1.937	0.242

Vol. IV Table 1-3-13

PREDICTED PERFORMANCE OF D ZONE,

BARONIA FIELD

PRODUCTION START : Oct. 1974
PRODUCTION END : Oct. 1994

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3046	2.11	12.29	44.48	3632	0.12	5.722	14.937	0.571
Jan.1977	3003	2.61	15.00	54.29	3619	0.12	7.091	19.891	0.731
1978	2819	4.63	15.00	58.29	3718	0.12	12.567	41.167	1.415
1979	2624	6.65	15.00	62.35	4159	0.13	18.042	63.937	2.140
1980	2428	8.61	14.55	65.28	4488	0.14	23.352	87.766	2.856
1981	2261	10.27	12.34	58.07	4705	0.14	27.857	108.960	3.488
1982	2115	11.68	10.50	50.78	4838	0.14	31.688	127.496	4.031
1983	1983	12.90	9.08	44.86	4942	0.15	35.001	143.869	4.521
1984	1866	13.98	7.96	39.85	5006	0.15	37.906	158.414	4.954
1985	1767	14.92	7.03	35.28	5017	0.14	40.473	171.292	5.324
1986	1674	15.77	6.26	31.32	5001	0.15	42.759	182.725	5.666
1987	1591	16.52	5.63	28.00	4975	0.15	44.813	192.944	5.976
1988	1521	17.21	5.07	25.01	4930	0.14	46.665	202.07	6.236
1989	1455	17.82	4.59	22.40	4876	0.15	48.342	210.251	6.480
1990	1394	18.39	4.19	20.28	4844	0.15	49.870	217.652	6.708
1991	1337	18.91	3.85	18.33	4753	0.15	51.278	224.344	6.919
1992	1287	19.39	3.57	16.82	4715	0.14	52.580	230.483	7.107
1993	1245	19.84	3.36	15.84	4613	0.13	53.805	236.134	7.266
1994	1205	20.27	3.18	14.65	4615	0.13	54.964	241.483	7.416
Oct.1994	1174	20.57	3.03	13.51	4454	0.13	55.774	245.180	7.529

Vol. IV Table 1-3-14

PREDICTED PERFORMANCE OF E ZONE,

BARONIA FIELD

PRODUCTION START : Sep. 1974
PRODUCTION END : Jul. 1994

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2729	11.76	1.7	3.03	1815	0.15	1.974	2.571	0.239
Jan.1977	2686	12.47	1.30	2.39	1832	0.16	2.093	2.789	0.259
1978	2449	15.13	1.22	2.75	2253	0.25	2.539	3.794	0.372
1979	2251	17.07	0.89	2.60	2908	0.29	2.865	4.742	0.466
1980	2077	18.49	0.65	2.26	3471	0.35	3.103	5.568	0.549
1981	1926	19.58	0.50	1.95	3912	0.40	3.285	6.280	0.621
1982	1806	20.45	0.40	1.63	4075	0.39	3.431	6.875	0.678
1983	1705	21.17	0.33	1.35	4108	0.40	3.551	7.368	0.726
1984	1619	21.77	0.28	1.12	4020	0.40	3.653	7.778	0.767
1985	1548	22.29	0.24	0.95	4012	0.40	3.739	8.123	0.801
1986	1487	22.73	0.20	0.80	3959	0.39	3.813	8.416	0.830
1987	1434	23.10	0.18	0.68	3760	0.38	3.877	8.663	0.855
1988	1388	23.43	0.15	0.59	3909	0.40	3.932	8.877	0.877
1989	1348	23.72	0.13	0.50	3857	0.40	3.980	9.060	0.896
1990	1314	23.97	0.12	0.44	3667	0.37	4.022	9.221	0.912
1991	1285	24.19	0.10	0.38	3781	0.38	4.059	9.359	0.926
1992	1261	24.39	0.09	0.33	3714	0.34	4.092	9.481	0.937
1993	1239	24.57	0.08	0.30	3801	0.38	4.122	9.592	0.948
1994	1219	24.73	0.07	0.27	3914	0.35	4.149	9.692	0.957
Jul.1994	1209	24.80	0.07	0.25	3601	0.39	4.161	9.738	0.962

Vol. IV Table 1-3-15

PREDICTED PERFORMANCE OF F1 ZONE,

BARONIA FIELD

PRODUCTION START : Aug. 1974
PRODUCTION END : Jul. 1994

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2855	8.24	3.59	4.94	1387	0.17	2.857	3.261	0.417
Jan.1977	2793	9.19	3.59	5.04	1402	0.18	3.185	3.721	0.475
1978	2537	12.77	3.40	5.48	1615	0.19	4.425	5.723	0.715
1979	2382	14.90	2.02	3.88	1923	0.19	5.162	7.140	0.860
1980	2275	16.30	1.33	2.83	2126	0.21	5.648	8.173	0.961
1981	2191	17.35	0.99	2.24	2257	0.22	6.010	8.990	1.039
1982	2120	18.19	0.80	1.90	2377	0.23	6.302	9.684	1.106
1983	2056	18.91	0.69	1.69	2458	0.24	6.553	10.301	1.166
1984	2000	19.55	0.61	1.51	2489	0.24	6.774	10.851	1.219
1985	1948	20.11	0.53	1.39	2619	0.25	6.968	11.359	1.267
1986	1902	20.60	0.47	1.23	2617	0.25	7.140	11.808	1.310
1987	1863	21.05	0.42	1.14	2714	0.24	7.292	12.224	1.347
1988	1828	21.44	0.37	1.02	2755	0.24	7.428	12.596	1.380
1989	1797	21.79	0.33	0.91	2756	0.24	7.550	12.928	1.409
1990	1767	22.10	0.30	0.84	2804	0.26	7.658	13.235	1.437
1991	1741	22.38	0.27	0.76	2801	0.25	7.755	13.511	1.462
1992	1717	22.63	0.24	0.68	2820	0.25	7.842	13.758	1.484
1993	1695	22.86	0.22	0.61	2790	0.25	7.921	13.982	1.504
1994	1674	23.07	0.20	0.59	2973	0.27	7.995	14.199	1.524
Jul.1994	1667	23.18	0.20	0.59	2932	0.25	8.032	14.306	1.533

Vol. IV Table 1-3-16

PREDICTED PERFORMANCE OF F2 ZONE,

BARONIA FIELD

PRODUCTION START : Oct. 1976
PRODUCTION END : Apr. 1985

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3079	8.84	4.18	6.13	1467	0.05	3.890	4.282	0.087
Jan.1977	3032	9.70	4.18	6.60	1578	0.05	4.272	4.884	0.106
1978	2805	13.14	4.15	7.29	1757	0.06	5.788	7.546	0.196
1979	2570	16.01	3.46	7.37	2129	0.07	7.051	10.235	0.289
1980	2372	18.25	2.70	6.87	2544	0.08	8.036	12.742	0.367
1981	2194	20.09	2.22	6.38	'873	0.09	8.847	15.070	0.438
1982	2023	21.66	1.90	5.89	3097	0.10	9.539	17.218	0.506
1983	1866	23.04	1.67	5.38	3220	0.12	10.147	19.181	0.577
1984	1727	24.27	1.48	4.90	3310	0.12	10.687	20.969	0.642
1985	1595	25.38	1.34	4.48	3345	0.12	11.175	22.605	0.702
1986	1474	26.39	1.22	4.07	3336	0.13	11.621	24.093	0.758
1987	1361	27.33	1.13	3.70	3271	0.13	12.034	25.444	0.811
1988	1259	28.20	1.05	5.37	3197	0.12	12.419	26.675	0.858
1989	1168	29.02	0.99	3.06	3097	0.12	12.780	27.793	0.901
1990	1081	29.80	0.93	2.79	2991	0.12	13.120	28.810	0.941
1991	1000	30.53	0.88	2.56	2904	0.12	13.442	29.745	0.979
1992	932	31.22	0.83	2.28	2752	0.10	13.745	30.579	1.010
Apr.1992	915	31.38	0.80	2.18	2726	0.11	13.818	30.778	1.018

Vol. IV TABLE 1-3-17

PREDICTED PERFORMANCE OF BARONIA FIELD

- ADDITIONAL WELL CASE -

PRODUCTION START : May.1972
PRODUCTION END : Oct.1994

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jan.1973	0.09	2.05	1.87	912	0.0	0.561	0.512	0.0
1974	0.35	4.22	4.31	1021	0.002	2.100	2.085	0.004
1975	0.92	9.41	11.54	1226	0.023	5.534	6.297	0.083
1976	2.79	30.95	42.79	1383	0.054	16.830	21.916	0.693
1977	6.13	55.16	112.54	2040	0.088	36.962	62.992	2.473
1978	10.99	74.13	220.36	2973	0.173	64.019	143.422	7.161
1979	14.54	58.92	224.23	3806	0.138	85.525	225.266	10.126
1980	17.43	48.23	233.45	4840	0.156	103.130	310.475	12.877
1981	19.86	41.32	250.31	6058	0.190	118.212	401.837	15.748
1982	22.59	32.99	213.72	6478	0.243	130.254	479.844	18.672
1983	23.34	29.08	193.83	6666	0.371	140.868	550.593	22.609
1984	24.89	25.65	121.51	4737	0.575	150.230	594.945	27.995
1985	26.26	22.69	72.92	3214	0.626	158.511	621.561	33.176
1986	27.12	14.22	48.84	3435	0.483	163.703	639.389	35.684
1987	27.50	6.29	27.27	4337	0.143	165.998	649.338	36.013
1988	27.83	5.48	23.58	4305	0.149	167.998	657.945	36.311

Vol. IV TABLE 1-3-17 (CONTINUED)

PREDICTED PERFORMANCE OF BARONIA FIELD

- ADDITIONAL WELL CASE -

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1989	28.14	5.06	21.04	4162	0.151	169.843	665.624	36.589
1990	28.42	4.69	19.21	4101	0.147	171.553	672.637	36.841
1991	28.68	4.31	16.85	3909	0.128	173.126	678.785	37.043
1992	28.92	3.94	15.39	3903	0.129	174.566	684.403	37.229
1993	29.14	3.62	13.55	3744	0.136	175.886	689.347	37.409
1994	29.34	3.34	12.23	3656	0.139	177.107	693.810	37.579
Oct.1994	29.48	3.00	11.04	3680	0.134	177.928	696.831	37.689

Table 2-2-1 CORRELATION TABLE
Vol. IV FAIRLEY BARAM FIELD

Well No.	1		2		3		11		29	
D.F.E.	76		76		111		112		111	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Lower VI(?)	6793	6400	6947	6565	6766	6340	6683	6571	6585	6474
V (?)	9186	8573	9109	8576	9485	8655	8823	8711	8753	8642
Top a_1	6793	6400	6947	6565	6766	6340	6683	6571	6585	6474
a_2	8084	7600	8072	7617	8299	7672	7884	7772	7801	7690
a_3	8204	7711	8183	7718	8430	7783	7988	7876	7905	7794
a_4	8268	7770	8247	7778	8498	7839	8045	7933	7962	7851
Top b_1	8915	8334	8847	8333	9186	8410	8585	8473	8516	8405
b_2	8979	8391	8909	8390	9256	8469	8640	8528	8584	8473
b_3	9054	8457	8980	8456	9337	8534	8706	8594	8637	8526
Top c	9186	8573	9109	8576	9485	8655	8823	8711	8753	8642
Top d	-	-	-	-	-	-	9146	9034	9075	8964
T.D.	9580	8926	9519	8960	9830	8935	10368	10156	9240	9129

Vol. IV Table 2-3-1

PREDICTED PERFORMANCE OF FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1975	1.46	7.79	10.83	1391	0.01	1.421	1.977	0.007
1976	5.32	10.26	15.87	1547	0.08	5.167	7.771	0.312
1977	8.93	9.62	16.98	1766	0.30	8.677	13.970	1.368
1978	12.14	8.56	19.31	2255	1.34	11.802	21.017	5.567
1979	14.82	7.12	17.25	2422	2.26	14.401	27.313	11.445
1980	16.92	5.59	13.88	2482	3.44	16.443	32.380	18.473
1981	18.67	4.67	13.26	2839	4.40	18.148	37.221	25.968
1982	20.16	3.96	12.50	3158	4.98	19.593	41.785	33.161
1983	21.41	3.32	11.49	3459	5.30	20.805	45.978	39.580
1984	22.51	2.94	10.98	3739	5.44	21.877	49.986	45.410
1985	23.50	2.63	10.34	3927	5.79	22.838	53.760	50.971
Oct.1986	24.22	2.30	9.60	4175	6.09	23.538	56.681	55.232

Vol. IV Table 2-3-2

PREDICTED PERFORMANCE OF FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1975	1.46	7.79	10.83	1391	0.01	1.421	1.977	0.007
1976	5.50	10.76	16.49	1533	0.08	5.349	7.997	0.313
1977	10.21	12.52	20.64	1649	0.26	9.919	15.532	1.490
1978	14.41	11.20	22.95	2048	1.16	14.008	23.908	6.245
1979	18.10	9.82	21.29	2168	1.99	17.592	31.679	13.363
1980	21.04	7.83	18.00	2299	3.23	20.450	38.249	22.596
1981	23.51	6.56	17.47	2663	4.42	22.844	44.625	33.171
1982	25.56	5.48	21.99	4014	5.37	24.843	52.650	43.910
1983	27.24	4.47	10.47	2341	6.09	26.475	56.471	53.846
1984	28.27	3.54	14.46	4082	7.09	27.768	61.748	63.015
1985	29.60	2.75	12.70	4628	7.80	28.770	66.385	70.832
Oct.1986	30.27	2.12	10.10	4754	7.71	29.416	69.456	75.814

Vol. IV Table 2-3-3

PREDICTED PERFORMANCE OF A ZONE,

FAIRLEY BARAM FIELD

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3049	6.24	2.82	2.99	2122	0.12	1.696	3.017	0.207
Dec.1976	3007	6.78	2.80	6.21	2218	0.21	1.866	3.395	0.242
1977	2743	10.59	2.78	6.81	449	0.22	2.879	5.880	0.462
1978	2480	13.83	2.42	7.43	3070	0.19	3.762	8.592	0.630
1979	2224	16.69	2.13	7.51	3527	0.21	4.538	11.334	0.794
1980	1964	19.22	1.89	7.43	3928	0.24	5.228	14.044	0.961
1981	1718	21.45	1.67	7.21	4318	0.26	5.836	16.676	1.119
1982	1498	23.44	1.48	6.69	4522	0.26	6.376	19.119	1.260
1983	1284	25.22	1.33	6.16	4653	0.28	6.860	21.369	1.397
1984	1116	26.82	1.19	5.50	4621	0.25	7.295	23.376	1.505
1985	948	28.27	1.09	4.83	4426	0.27	7.691	25.137	1.613
Oct.1986	808	29.38	0.99	4.36	4403	0.30	7.992	26.463	1.702

Vol. IV Table 2-3-4

PREDICTED PERFORMANCE OF B ZONE, FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Jul. 1975
PRODUCTION END : Jun. 1985

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2.20	0.80	1.60	2000	0.27	0.398	0.739	0.021
Dec.1976	2.58	1.12	2.32	2069	0.22	0.466	0.880	0.036
1977	4.69	1.04	2.90	2785	0.41	0.847	1.937	0.190
1978	6.59	0.94	4.99	5310	0.84	1.190	3.759	0.478
1979	7.58	0.49	3.29	6721	0.89	1.369	4.961	0.637
1980	8.05	0.23	0.78	3395	0.31	1.453	5.246	0.663
1981	8.46	0.21	0.69	3288	0.39	1.528	5.498	0.693
1982	8.84	0.19	0.66	3446	0.56	1.596	5.737	0.732
1983	9.17	0.17	0.65	3820	0.84	1.657	5.974	0.784
1984	9.48	0.15	0.68	4548	1.37	1.712	6.223	0.859
Jun.1985	9.62	0.14	0.72	5166	1.84	1.737	6.355	0.906

Vol. IV Table 2-3-5

PREDICTED PERFORMANCE OF B ZONE,

FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1984

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	2.20	0.80	1.60	2000	0.27	0.398	0.739	0.021
Dec.1976	2.58	1.12	2.32	2073	0.22	0.466	0.88	0.036
1977	4.69	1.04	2.90	2774	0.40	0.847	1.937	0.190
1978	6.79	1.04	5.07	4874	0.78	1.227	3.789	0.485
1979	8.94	1.06	3.76	3549	0.57	1.614	5.162	0.707
1980	10.44	0.74	1.15	1554	0.41	1.885	5.583	0.817
1981	11.78	0.67	0.99	1485	0.58	2.128	5.944	0.957
1982	13.00	0.60	0.91	1517	0.81	2.347	6.276	1.135
1983	14.09	0.54	1.44	2663	1.14	2.544	6.801	1.360
Oct.1984	14.46	0.22	1.40	6382	1.58	2.611	7.228	1.466

Vol. IV Table 2-3-6

PREDICTED PERFORMANCE OF C ZONE,

FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	4.76	6.45	7.99	1238	0.03	2.469	3.044	0.019
Dec.1976	5.46	6.02	7.43	1235	0.04	2.835	3.496	0.034
1977	9.54	5.80	7.28	1256	0.32	4.951	6.153	0.716
1978	13.19	5.20	6.89	1323	1.97	6.850	8.666	4.459
1979	16.36	4.50	6.44	1431	3.38	8.494	11.018	10.014
1980	18.80	3.47	5.68	1634	5.39	9.762	13.090	16.849
1981	20.77	2.80	5.36	1915	7.15	10.784	15.047	24.156
1982	22.39	2.30	5.16	2243	8.36	11.623	16.929	31.169
1983	23.67	1.82	4.68	2567	9.37	12.288	18.636	37.399
1984	24.79	1.60	4.80	3008	9.70	12.870	20.387	43.046
1985	25.83	1.48	5.16	3492	10.02	13.410	22.272	48.453
Oct.1986	26.60	1.31	5.23	3987	10.45	13.809	23.863	52.624

Vol. IV Table 2-3-7

PREDICTED PERFORMANCE OF C ZONE,

FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	4.76	6.45	7.99	1238	0.03	2.469	3.044	0.019
Dec.1976	5.81	9.01	11.15	1237	0.03	3.017	3.722	0.035
1977	11.93	8.70	10.94	1257	0.25	6.193	7.715	0.838
1978	17.37	7.74	10.44	1349	1.52	9.019	11.527	5.130
1979	22.03	6.63	10.02	1510	2.78	11.440	15.183	11.862
1980	25.69	5.20	9.42	1813	4.72	13.337	18.622	20.818
1981	28.66	4.23	9.27	2193	6.66	14.880	22.005	31.095
1982	31.05	3.40	8.90	2621	8.40	16.120	25.255	41.515
1983	32.88	2.61	8.35	3203	10.07	17.071	28.301	51.089
1984	34.40	2.17	8.34	3845	11.32	17.862	31.344	60.044
1985	35.57	1.66	7.33	4417	12.72	18.468	34.020	67.753
Oct.1986	36.23	1.13	5.74	5056	14.19	18.813	35.765	72.646

Vol. IV Table 2-3-8

PREDICTED PERFORMANCE OF B ZONE,

WELL FB-2, FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Sep. 1975
PRODUCTION END : Jun. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3354	0.51	1.30	2521	0.1	0.214	0.393	0.012
Dec.1976	3322	0.51	1.30	2546	0.13	0.245	0.472	0.016
1977	3009	0.47	1.55	3305	0.39	0.417	1.039	0.082
1978	2543	0.42	2.63	6256	1.08	0.572	1.998	0.248
Jun.1979	2301	0.39	3.44	8809	1.70	0.644	2.625	0.369

Vol. IV Table 2-3-9

PREDICTED PERFORMANCE OF B ZONE,

WELL FB-3, FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Oct. 1976
PRODUCTION END : Feb. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3392	0.28	0.31	1084	0.57	0.017	0.019	0.010
Dec.1976	3355	0.28	0.28	1002	0.59	0.034	0.036	0.020
1977	3031	0.26	0.28	1094	0.93	0.128	0.139	0.108
1978	2564	0.23	1.03	4491	1.44	0.212	0.516	0.229
Feb.1979	2474	0.23	1.63	7076	1.72	0.226	0.615	0.253

Vol. IV Table 2-3-10

PREDICTED PERFORMANCE OF B ZONE,

WELL FB-29, FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Jul.1975
PRODUCTION END : Jun.1985

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3406	0.0	0.0	0.0	0.0	0.167	0.328	0.0
Dec.1976	3337	0.33	0.72	2192	0.0	0.187	0.372	0.0
1977	3011	0.32	1.06	3313	0.0	0.302	0.759	0.0
1978	2539	0.29	1.33	4591	0.01	0.406	1.245	0.001
1979	2269	0.26	1.30	5016	0.15	0.499	1.721	0.015
1980	2218	0.23	0.78	3395	0.31	0.583	2.006	0.041
1981	2165	0.21	0.69	3288	0.39	0.658	2.258	0.071
1982	2117	0.19	0.66	3446	0.56	0.726	2.497	0.110
1983	2068	0.17	0.65	3820	0.84	0.787	2.734	0.162
1984	2012	0.15	0.68	4548	1.37	0.842	2.983	0.237
Jun.1985	1981	0.14	0.72	5166	1.84	0.867	3.115	0.284

Vol. IV Table 2-3-11

PREDICTED PERFORMANCE OF B ZONE,

WELL FB-2, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Sep. 1975
PRODUCTION END : Jun. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Oct.1976	3354	0.51	1.30	2521	0.10	0.214	0.393	0.012
Dec.1976	3322	0.51	1.30	2546	0.13	0.245	0.472	0.016
1977	3009	0.47	1.55	3305	0.39	0.417	1.039	0.082
1978	2534	0.42	2.63	6256	1.08	0.572	1.998	0.248
Jun.1979	2266	0.39	3.44	8809	1.73	0.644	2.625	0.371

Vol. IV Table 2-3-12

PREDICTED PERFORMANCE OF B ZONE,

WELL FB-3, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Oct. 1976
PRODUCTION END : Feb. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Oct.1976	3392	0.28	0.31	1084	0.57	0.017	0.019	0.010
Dec.1976	3355	0.28	0.28	1002	0.59	0.034	0.036	0.020
1977	3046	0.26	0.28	1094	0.93	0.128	0.139	0.108
1978	2559	0.23	1.03	4491	1.44	0.212	0.516	0.229
Feb.1979	2464	0.23	1.63	7076	1.72	0.226	0.615	0.254

Vol. IV Table 2-3-13

PREDICTED PERFORMANCE OF B ZONE,

WELL FB-29, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1984

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3406	0.0	0.0	0.0	0.0	0.167	0.328	0.0
Dec.1976	3337	0.33	0.72	2192	0.0	0.187	0.372	0.0
1977	3011	0.32	1.06	3312	0.0	0.302	0.759	0.0
1978	2533	0.29	1.33	4591	0.01	0.406	1.245	0.001
1979	2209	0.26	1.36	5216	0.16	0.499	1.740	0.016
1980	2117	0.23	0.82	3550	0.32	0.583	2.038	0.043
1981	2030	0.21	0.70	3314	0.42	0.658	2.292	0.075
1982	1944	0.19	0.66	3461	0.65	0.726	2.532	0.120
1983	1833	0.17	0.68	4013	1.05	0.787	2.781	0.185
Oct.1984	1735	0.15	0.72	5119	1.07	0.833	2.999	0.261

Vol. IV Table 2-3-14

PREDICTED PERFORMANCE OF B ZONE,

WELL FB-A1, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Nov. 1978
PRODUCTION END : Feb. 1984

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1978	2591	0.61	0.49	810	0.19	0.037	0.030	0.007
1979	2250	0.57	0.42	731	0.29	0.245	0.182	0.067
1980	2142	0.51	0.34	661	0.45	0.432	0.305	0.150
1981	2056	0.46	0.29	637	0.64	0.600	0.412	0.258
1982	1971	0.41	0.25	615	0.89	0.751	0.504	0.391
1983	1840	0.37	0.76	2044	1.19	0.887	0.780	0.551
Feb.1984	1779	0.35	3.44	9816	1.41	0.908	0.989	0.581

Vol. IV Table 2-3-15

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-2, FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Sep. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Oct.1976	3659	1.93	2.42	1253	0.04	0.769	0.952	0.010
Dec.1976	3658	1.51	1.91	1263	0.05	0.861	1.068	0.015
1977	3613	1.45	1.87	1291	0.16	1.390	1.751	0.100
1978	3503	1.30	1.80	1383	0.67	1.865	2.407	0.419
1979	3339	1.15	1.77	1537	1.52	2.284	3.052	1.058
1980	3132	1.00	1.76	1764	2.13	2.649	3.696	1.837
1981	2909	0.85	1.76	2073	2.52	2.959	4.339	2.620
1982	2693	0.70	1.69	2415	2.73	3.216	4.956	3.317
1983	2499	0.55	1.57	2854	2.70	3.416	5.529	3.858
1984	2322	0.50	1.77	3545	2.54	3.598	6.176	4.321
1985	2155	0.50	2.12	4230	2.88	3.781	6.948	4.846
Oct.1986	2024	0.50	2.40	4793	3.42	3.933	7.677	5.366

Vol. IV Table 2-3-16

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-3, FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Oct. 1976
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3694	0.09	0.11	1208	0.01	0.005	0.007	0.0
Dec.1976	3683	1.51	1.79	1187	0.01	0.097	0.116	0.0
1977	3631	1.45	1.75	1204	0.04	0.626	0.753	0.019
1978	3531	1.30	1.58	1218	0.23	1.100	1.331	0.127
1979	3365	1.15	1.47	1282	1.04	1.520	1.869	0.563
1980	3149	1.00	1.43	1430	2.83	1.885	2.391	1.595
1981	2918	0.85	1.43	1686	5.02	2.195	2.914	3.153
1982	2698	0.70	1.36	1945	6.58	2.452	3.411	4.833
1983	2504	0.55	1.22	2217	7.48	2.652	3.856	6.335
1984	2325	0.50	1.30	2592	7.97	2.834	4.329	7.789
1985	2160	0.48	1.51	3139	8.85	3.010	4.879	9.340
Oct.1986	2037	0.40	1.43	3567	9.70	3.131	5.313	10.520

Vol. IV Table 2-3-17

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-11, FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3682	2.37	2.86	1203	0.04	0.926	1.124	0.009
Dec.1976	3682	1.50	1.81	1205	0.11	1.017	1.234	0.019
1977	3626	1.45	1.78	1230	1.08	1.546	1.885	0.589
1978	3483	1.30	1.75	1342	6.81	2.022	2.522	3.820
1979	3321	1.08	1.61	1489	9.97	2.417	3.109	7.751
1980	3116	0.85	1.43	1676	12.92	2.728	3.629	11.760
1981	2896	0.66	1.21	1839	16.11	2.969	4.072	15.640
1982	2681	0.52	1.16	2229	18.97	3.159	4.495	19.240
1983	2489	0.41	0.95	2312	21.72	3.308	4.841	22.490
1984	2319	0.33	0.81	2466	24.08	3.429	5.138	25.390
1985	2160	0.27	0.69	2567	26.28	3.527	5.391	27.980
Oct.1986	2036	0.22	0.60	2720	28.69	3.594	5.573	29.900

Vol. IV Table 2-3-18

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-29, FAIRLEY BARAM FIELD, CASE 1

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Oct.1976	3674	2.06	2.61	1267	0.0	0.769	0.961	0.0
Dec.1976	3672	1.50	1.92	1282	0.0	0.860	1.078	0.0
1977	3629	1.45	1.88	1296	0.02	1.389	1.764	0.008
1978	3526	1.30	1.76	1353	0.18	1.863	2.406	0.093
1979	3357	1.12	1.60	1424	1.34	2.273	2.988	0.642
1980	3151	0.62	1.06	1706	4.49	2.500	3.374	1.657
1981	2924	0.44	0.95	2167	6.79	2.661	3.722	2.743
1982	2705	0.37	0.95	2555	7.67	2.796	4.067	3.779
1983	2509	0.32	0.94	2937	8.02	2.912	4.410	4.716
1984	2334	0.27	0.92	3389	8.42	3.009	4.744	5.546
1985	2171	0.23	0.85	3693	8.83	3.092	5.054	6.287
Oct.1986	2046	0.19	0.81	4257	9.53	3.151	5.300	6.838

Vol. IV Table 2-3-19

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-2, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Sep. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Oct.1976	3659	1.93	2.42	1253	0.04	0.769	0.952	0.010
Dec.1976	3654	1.51	1.91	1263	0.05	0.861	1.068	0.015
1977	3585	1.45	1.89	1300	0.20	1.390	1.756	0.121
1978	3432	1.30	1.86	1429	0.93	1.865	2.434	0.560
1979	3205	1.15	1.90	1656	2.05	2.284	3.129	1.422
1980	2920	1.00	1.99	1992	3.01	2.649	3.856	2.521
1981	2606	0.85	2.04	2401	3.97	2.959	4.601	3.751
1982	2293	0.70	2.00	2861	4.95	3.216	5.332	5.015
1983	2001	0.55	1.93	3517	5.84	3.416	6.038	6.187
1984	1724	0.50	2.17	4345	6.70	3.598	6.831	7.409
1985	1506	0.41	2.10	5112	8.09	3.749	7.596	8.619
Oct.1986	1369	0.28	1.58	5624	9.03	3.835	8.075	9.388

Vol. IV Table 2-3-20

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-3, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Oct. 1976
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Oct.1976	3694	0.09	0.11	1208	0.01	0.005	0.007	0.0
Dec.1976	3681	1.51	1.79	1187	0.01	0.097	0.116	0.001
1977	3608	1.45	1.74	1202	0.03	0.626	0.752	0.019
1978	3469	1.30	1.58	1218	0.23	1.100	1.330	0.128
1979	3243	1.15	1.49	1294	1.02	1.520	1.873	0.556
1980	2955	1.00	1.49	1493	2.73	1.885	2.418	1.551
1981	2639	0.85	1.53	1802	4.72	2.195	2.977	3.016
1982	2328	0.70	1.58	2250	5.95	2.452	3.552	4.537
1983	2039	0.54	1.69	3135	6.30	2.650	4.170	5.778
1984	1779	0.39	1.58	4039	5.98	2.792	4.745	6.629
1985	1562	0.26	1.33	5121	5.04	2.886	5.231	7.107
Oct.1986	1417	0.18	1.23	6831	3.84	2.942	5.605	7.317

Vol. IV Table 2-3-21

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-11, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3682	2.37	2.86	1203	0.04	0.926	1.124	0.009
Dec.1976	3680	1.50	1.81	1205	0.11	1.017	1.234	0.019
1977	3597	1.45	1.79	1232	1.25	1.546	1.886	0.681
1978	3415	1.25	1.72	1374	7.74	2.001	2.513	4.211
1979	3193	0.94	1.50	1597	11.92	2.345	3.061	8.301
1980	2916	0.68	1.29	1902	16.66	2.594	3.533	12.435
1981	2610	0.50	1.06	2121	21.17	2.770	3.920	16.299
1982	2302	0.30	0.81	2712	31.53	2.889	4.217	19.752
1983	2014	0.23	0.63	2728	36.28	2.972	4.446	22.798
1984	1750	0.15	0.46	3068	47.16	3.028	4.614	25.380
1985	1532	0.10	0.32	3205	58.08	3.066	4.731	27.500
Oct.1986	1393	0.07	0.23	3335	70.26	3.088	4.802	28.996

Vol. IV Table 2-3-22

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-29, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Jul. 1975
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Oct.1976	3674	2.06	2.61	1267	0.0	0.769	0.961	0.0
Dec.1976	3670	1.50	1.92	1282	0.0	0.860	1.078	0.0
1977	3604	1.45	1.89	1306	0.02	1.389	1.769	0.008
1978	3461	1.30	1.81	1395	0.21	1.863	2.431	0.107
1979	3231	1.09	1.62	1488	1.60	2.261	3.023	0.743
1980	2952	0.52	1.00	1913	5.40	2.449	3.386	1.767
1981	2638	0.35	0.90	2561	9.08	2.576	3.713	2.927
1982	2327	0.26	0.85	3267	11.48	2.671	4.023	4.016
1983	2035	0.19	0.78	4095	13.06	2.739	4.307	4.922
1984	1770	0.13	0.71	5479	14.84	2.788	4.567	5.626
1985	1550	0.10	0.64	6438	13.89	2.823	4.802	6.133
Oct.1986	1407	0.07	0.55	7843	14.06	2.844	4.969	6.431

Vol. IV Table 2-3-23

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-A1, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Nov. 1976
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1976	3633	1.50	1.86	1238	0.0	0.091	0.113	0.0
1977	3587	1.45	1.82	1256	0.02	0.621	0.778	0.006
1978	3441	1.30	1.76	1353	0.24	1.095	1.420	0.094
1979	3205	1.15	1.79	1558	1.39	1.515	2.074	0.676
1980	2914	1.00	1.87	1866	3.30	1.880	2.755	1.882
1981	2596	0.85	1.90	2234	4.79	2.190	3.448	3.368
1982	2279	0.70	1.83	2611	6.44	2.446	4.115	5.013
1983	1987	0.55	1.63	2954	8.22	2.647	4.708	6.664
1984	1709	0.50	1.68	3353	9.91	2.828	5.320	8.472
1985	1498	0.39	1.46	3744	11.78	2.972	5.853	10.149
Oct.1986	1365	0.27	1.09	4018	12.62	3.053	6.183	11.185

Vol. IV Table 2-3-24

PREDICTED PERFORMANCE OF C ZONE,

WELL FB-A2, FAIRLEY BARAM FIELD, CASE 2

PRODUCTION START : Nov. 1976
PRODUCTION END : Oct. 1986

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1976	3633	1.50	1.86	1238	0.0	0.091	0.113	0.0
1977	3587	1.45	1.81	1248	0.01	0.621	0.774	0.003
1978	3441	1.30	1.71	1317	0.06	1.095	1.399	0.030
1979	3216	1.15	1.71	1487	0.32	1.515	2.023	0.164
1980	2928	1.00	1.78	1784	1.36	1.880	2.674	0.662
1981	2606	0.85	1.84	2166	3.46	2.190	3.346	1.734
1982	2287	0.70	1.84	2622	5.67	2.446	4.016	3.182
1983	1993	0.55	1.69	3068	7.76	2.647	4.632	4.740
1984	1715	0.50	1.74	3479	9.80	2.828	5.267	6.528
1985	1500	0.40	1.48	3699	11.76	2.972	5.807	8.245
Oct.1986	1366	0.26	1.07	4097	14.72	3.051	6.131	9.409

Table 3-2-1 CORRELATION TABLE
Vol. IV WEST LUTONG FIELD

Well No.	1		2		3		4		5		6	
D.F.E.	83		83		81		82		114		65	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V	3131	3048										
Top a_1	4147	4054	4375	4111	4767	4085	4153	4071	4300	4184	4465	4089
a_2	4437	4344	4682	4407	5167	4398	4447	4364	4595	4479	4809	4390
a_3	4849	4756	5117	4824	5743	4858	4853	4771	5080	4964	5269	4806
Top b_1	5024	4931	5311	5006	5969	5040	5040	4958	5229	5113	5471	4988
b_2	5335	5242	5647	5321	6384	5375	5335	5251	5583	5467	5811	5295
Top c_1	5453	5360	5779	5440	6558	5518	5463	5380	5715	5598	5959	5427
c_2	5732	5638	6085	5735	6915	5812	5736	5652	6012	5894	6281	5715
c_3	6162	6068	6561	6175	7325	6148	6195	6110	6413	6293		
Top d_1	6591	6470	7043	6616	7763	6502	6483	6398	6897	6775	-	-
d_2	6977	6841	7461	7004	8178	6848	6820	6734	7347	7224		
d_3	7322	7223	7849	7372	8518	7138	7093	7007	7696	7571		
Top e_1	8021	7923	8576	8057	8971	7524	7440	7353	8553	8425		
e_2	8214	8116	8745	8213	9159	7683	7568	7481	8749	8621		
e_3	8455	8357	9039	8489	9465	7940	7788	7700	9019	8890		
T.D.	9500	9400	9122	8566	9598	8055	9110	9020	9534	9403	6392	5814

Table 3-2-1 (Continued) CORRELATION TABLE
Vol. IV *WEST LUTONG FIELD*

Well No.	7		8		9		10		11		12	
D.F.E.	65		65		65		65		65		65	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V												
Top a_1	4120	4053	4500	4071	4234	4060	4621	4078	4827	4053	4271	4058
a_2	4420	4353	4824	4368	4547	4365	4950	4369	5154	4358	4580	4352
a_3	4835	4769	5267	4781	4984	4792	5413	4782	5603	4774	5005	4759
Top b_1	5014	4949	5461	4965	5171	4975	5617	4965	5811	4968	5190	4935
b_2	5318	5252	5785	5275	5490	5290	5971	5267	6167	5300	5503	5235
Top c_1	5447	5382	5921	5406	5623	5422	6135	5402	6305	5429	5637	5364
c_2	5726	5661	6211	5689	5915	5711	6484	5686	6617	5712	5925	5640
c_3	6164	6099	6551	6019	-	-	-	-	-	-	-	-
Top d_1	6424	6358	6903	6363								
d_2	6766	6699	7241	6693								
d_3	7058	6991	7525	6969								
Top e_1	7447	7380	7923	7361								
e_2	7603	7536	8083	7518								
e_3	7858	7791	8323	7754								
T.D.	8827	8160	8650	8076	6215	6008	6755	5907	7065	6125	6315	6014

Table 3-2-1 (Continued) CORRELATION TABLE
Vol. IV WEST LUTONG FIELD

Well No.	13		14		15		16		17		18	
D.F.E.	65		65		65		71		71		71	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V												
Top a_1	4836	4063	4120	4052	4617	4046	4173	4102	4421	4083	4387	4123
a_2	5209	4365	4422	4348	4975	4338	4469	4398	4739	4373	4707	4422
a_3	5739	4785	4845	4762	5463	4739	4888	4817	5179	4778	5150	4841
Top b_1	5976	4970	5025	4939	5695	4921	5075	5004	5375	4963	5347	5028
b_2	6379	5281	5336	5244	6092	5215	5400	5329	5715	5282	5690	5357
Top c_1	6553	5416	5461	5366	6263	5344	5534	5463	5842	5402	5817	5479
c_2	6919	5694	5743	5637	6609	5621	5805	5735	6137	5680	(6114)	(5763)
c_3	-	-	6204	6062	-	-	-	-	-	-	-	-
Top d_1			6719	6495								
d_2			7195	6893								
d_3			7599	7234								
Top e_1			8549	8027								
e_2			8758	8197								
e_3			9085	8486								
T.D.	7100	5830	11040	9975	7033	5960	5981	5910	6433	5967	6230	5874

Table 3-2-1 (Continued) Vol. IV

CORRELATION TABLE
WEST LUTONG FIELD

Well No.	19		20		21		22		23		24	
D.F.E.	71		71		73		73		73		73	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V												
Top a_1	4442	4123	4392	4094	4167	4094	4951	4146	4212	4092	4503	4127
a_2	4761	4421	4730	4398	4456	4384	5346	4440	4521	4379	4840	4420
a_3	5196	4835	5192	4826	4864	4791	5909	4854	4962	4787	5295	4828
Top b_1	5407	5038	5397	5020	5053	4980	6153	5035	5169	4977	5503	5018
b_2	5750	5368	5746	5354	5348	5275	6579	5347	5490	5274	5827	5316
Top c_1	5881	5494	5883	5485	5478	5405	6748	5471	5631	5405	5965	5445
c_2	6174	5775	(6170)	(5762)	5748	5675	7121	5735	5926	5680	6253	5713
c_3	-	-	-	-	-	-	-	-	6315	6045	-	-
Top d_1									6707	6413		
d_2									6988	6678		
d_3									7279	6956		
Top e_1									7678	7337		
e_2									7845	7498		
e_3									8082	7723		
T.D.	6270	5866	6220	5810	6130	6057	7160	5763	8400	8029	6450	5898

Table 3-2-1 (Continued) CORRELATION TABLE
Vol. IV WEST LUTONG FIELD

Well No.	25		26	
D.F.E.	73		73	
Cycle/Zone	Log	Subsea	Log	Subsea
Top V				
Top a_1	4407	4105	4345	4127
a_2	4709	4390	4652	4410
a_3	5129	4792	-	-
Top b_1	5323	4980		
b_2	5620	5269		
Top c_1	5752	5398		
c_2	6027	5668		
c_3	-	-		
Top d_1				
d_2				
d_3				
Top e_1				
e_2				
e_3				
T.D.	6171	5809	4790	4539

Vol. IV Table 3-3-1

PREDICTED PERFORMANCE OF WEST LUTONG FIELD

PRODUCTION START : Jul. 1968
PRODUCTION END : Jun. 1992

TIME	RECOVERY	OIL PROD. RATE	GAS PROD. RATE	G.O.R.	W.O.R.	CUMULATIVE PRODUCTION		
						OIL	GAS	WATER
(YEAR)	(%)	(MSTB/D)	(MMSCF/D)	(SCF/STB)	(STB/STB)	(MMSTB)	(MMMSCF)	(MMSTB)
Dec.1968	0.50	4.50	5.00	1103	0.02	1.235	1.362	0.028
1969	1.56	7.24	7.72	1066	0.03	3.877	4.178	0.099
1970	3.19	11.10	12.06	1087	0.04	7.928	8.580	0.175
1971	9.60	43.58	63.51	1457	0.08	23.833	31.761	1.441
1972	17.46	53.46	76.97	1440	0.27	43.346	59.854	6.646
1973	23.77	42.97	74.74	1739	0.54	59.029	87.134	15.122
1974	27.07	22.45	46.74	2082	0.67	67.225	104.195	20.588
1975	29.59	17.15	31.18	1818	0.68	73.483	115.575	24.846
1976	32.04	16.66	38.39	2304	0.76	79.563	129.586	29.461
1977	34.33	15.56	49.24	3164	0.80	85.243	147.557	34.023
1978	36.59	15.40	54.04	3509	0.74	90.864	167.281	38.193
1979	38.83	15.20	58.27	3828	0.92	96.421	188.551	43.304
1980	40.96	14.50	57.01	3930	1.08	101.715	209.359	49.045
1981	42.86	12.93	47.28	3657	0.90	106.433	226.615	53.279
1982	44.60	11.80	38.77	3286	0.85	110.739	240.765	56.944
1983	46.13	10.44	20.56	1969	0.82	114.550	248.270	60.085
1984	47.62	10.11	19.37	1916	0.78	118.241	255.341	62.960
1985	49.07	9.88	18.18	1841	0.81	121.846	261.977	65.895
1986	50.49	9.67	17.27	1787	0.83	125.374	268.281	68.873
1987	51.89	9.49	16.28	1715	0.87	128.838	274.222	71.850
1988	52.38	3.33	9.05	2716	1.07	130.054	277.525	73.148
1989	52.56	1.24	6.33	5126	1.48	130.505	279.837	73.817
1990	52.73	1.16	5.86	5066	1.60	130.927	281.975	74.491
1991	52.89	1.08	5.46	5035	1.70	131.323	283.969	75.164
Jun.1992	52.96	1.04	5.22	5037	1.70	131.512	284.921	75.485

Vol. IV Table 3-3-2

PREDICTED PERFORMANCE OF A ZONE

WEST LUTONG FIELD

PRODUCTION START : Mar. 1971
PRODUCTION END : Dec. 1982

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1717	9.19	0.11	1.46	14367	0.320	2.140	18.690	0.445
Dec.1976	1647	9.97	1.00	15.3	15224	0.492	2.323	21.476	0.535
1977	1496	11.54	1.00	15.8	15797	0.359	2.688	27.242	0.666
1978	1309	13.10	1.00	19.2	19145	0.340	3.053	34.230	0.790
1979	1091	14.67	1.00	22.2	22203	0.397	3.418	42.334	0.935
1980	863	16.18	0.96	22.6	23504	0.430	3.769	50.584	1.086
1981	666	17.56	0.88	19.3	21839	0.406	4.092	57.638	1.217
1982	522	18.84	0.82	15.7	19211	0.322	4.390	63.363	1.313

Vol. IV Table 3-3-3

PREDICTED PERFORMANCE OF B ZONE

WEST LUTONG FIELD

PRODUCTION START : Jul. 1968
PRODUCTION END : Mar. 1989

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1476	37.40	12.99	18.02	1386	0.67	67.080	80.869	20.913
Dec.1976	1473	38.64	12.15	16.87	1388	0.667	69.298	83.947	22.393
1978	1378	40.58	9.56	13.19	1380	0.573	72.788	88.762	24.393
1979	1325	42.49	9.40	12.86	1369	0.430	76.218	93.457	25.869
1980	1267	44.37	9.22	12.56	1361	0.684	79.585	98.040	28.171
1981	1205	46.20	9.00	12.19	1354	0.905	82.871	102.489	31.146
1982	1145	48.00	8.82	11.76	1333	0.726	86.092	106.782	33.485
1983	1087	49.77	8.71	11.47	1317	0.689	89.271	110.968	35.674
1984	1036	51.52	8.57	10.89	1271	0.624	92.398	114.942	37.625
1985	985	53.23	8.41	10.52	1250	0.635	95.468	118.780	39.575
1986	932	54.91	8.29	9.99	1197	0.664	98.494	122.403	41.583
1987	879	56.58	8.18	9.53	1166	0.678	101.479	125.883	43.608
1988	824	58.22	8.08	9.01	1115	0.701	104.430	129.172	45.677
Mar.1989	811	58.63	8.03	8.94	1113	0.701	105.163	129.988	46.191

Vol. IV Table 3-3-4

PREDICTED PERFORMANCE OF C ZONE

WEST LUTONG FIELD

PRODUCTION START : Jul. 1968
PRODUCTION END : Jun. 1992

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	2614	15.40	1.30	4.73	3716	1.16	7.030	20.689	5.401
Dec.1976	2533	17.40	5.00	19.04	3809	1.24	7.942	24.163	6.533
1977	2360	21.40	5.00	20.25	4049	1.332	9.767	31.553	8.964
1978	2176	25.40	5.00	22.03	4404	1.407	11.593	39.594	11.534
1979	1986	29.40	5.00	23.52	4703	1.460	13.418	48.177	14.198
1980	1799	33.03	4.54	22.22	4894	1.578	15.075	56.286	16.813
1981	1673	35.60	3.22	16.19	5033	1.503	16.249	62.195	18.577
1982	1574	37.42	2.27	11.61	5113	1.665	17.078	66.434	19.957
1983	1490	38.92	1.87	9.67	5162	1.740	17.762	69.965	21.147
1984	1423	40.28	1.70	8.86	5206	1.490	18.383	73.198	22.072
1985	1357	41.55	1.59	8.25	5204	1.601	18.962	76.211	22.999
1986	1292	42.74	1.49	7.74	5201	1.689	19.505	79.035	23.916
1987	1224	43.86	1.41	7.27	5170	1.840	20.018	81.687	24.860
1988	1168	44.92	1.32	6.81	5149	1.623	20.501	84.174	25.644
1989	1120	45.91	1.24	6.33	5126	1.483	20.952	86.486	26.313
1990	1072	46.83	1.16	5.86	5066	1.597	21.374	88.624	26.987
1991	1024	47.70	1.08	5.46	5035	1.699	21.770	90.618	27.660
Jun.1992	1001	48.12	1.04	5.22	5037	1.698	21.959	91.570	27.981

Vol. IV TABLE 3-3-5

PREDICTED PERFORMANCE OF WEST LUTONG FIELD

- ADDITIONAL WELL CASE -

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.00	2889	8.42	2.00	5.13	2563	0.404	0.730	1.891	0.295
2.00	2554	16.84	2.00	6.93	3466	1.221	1.460	4.401	1.186
3.00	2180	25.26	2.00	8.38	4189	1.366	2.190	7.459	2.183
4.00	1786	33.23	1.89	9.05	4783	1.517	2.881	10.764	3.231
5.00	1551	37.74	1.07	5.42	5056	1.596	3.272	12.741	3.855
6.00	1399	40.69	0.70	3.62	5160	1.578	3.528	14.062	4.259
7.00	1257	43.23	0.60	3.12	5177	2.718	3.748	15.201	4.637
8.00	1138	45.46	0.53	2.72	5119	1.634	3.942	16.194	4.954
9.00	1036	47.40	0.46	2.33	5024	1.604	4.111	17.043	5.225
9.25	1011	47.85	0.42	2.13	5105	1.737	4.149	17.237	5.291

Table 4-2-1 CORRELATION TABLE
Vol. IV BARAM FIELD
A-AREA

Well No.	1		2		3		5		6		8	
D.F.E.	38		65		39		114		102		110	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top a_0												
a_1	5034	4996	5258	5193	5218	5179	5615	5501	5385	5283	5372	5262
a_2	5288	5250	5491	5426	5477	5438	5852	5738	5539	5437	5554	5444
Top b	5542	5504	5744	5679	5693	5654	6112	5998	5808	5706	5780	5670
Top c_1	6076	6038	6236	6171	6232	6193	6644	6530	6318	6216	6354	6244
c_2	6400	6362	6578	6513	6410	6371	6994	6880	6673	6571	6707	6597
Top d_1	7123	7085	7263	7198	7000	6961	7699	7585	7394	7292	7359	7249
d_2	7300	7262	7439	7374	7188	7149	7860	7746	7566	7464	7535	7425
Top e_1	-	-	7721	7656	7518	7479	8207	8093			7900	7790
e_2			8042	7977	7621	7582	8476	8362			8057	7947
Top f_1			8295	8230			8744	8630			8326	8216
f_2			8497	8432			8938	8824			8534	8424
Top g_1			-	-			9358	9244			8975	8865
g_2							9602	9488			9253	9143
g_3							-	-			9447	9337
T.D.	7617	7579	9879	9814	9619	8580	9626	9512	8840	8738	9772	9662

Table 4-2-1 (Continued)
Vol. IV

CORRELATION TABLE
BARAM FIELD
A-AREA

Well No.	9		10		11		12		13		14	
D.F.E.	71		71		71		72		72		72	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top a_0												
a_1	5188	5115	5800	5176	5393	5031	5440	5086	5596	5217	5248	5067
a_2	5442	5369	6098	5439	5651	5275	5749	5362	5863	5465	5515	5330
Top b	5672	5599	6351	5663	5905	5517	6015	5604	6040	5628	5754	5565
Top c_1	6128	6055	6844	6100	6456	6045	6651	6097	6438	5996	6312	6115
c_2	6472	6398	7256	6459	6809	6386	6769	6296	6826	6350	6562	6361
Top d_1	7176	7102	8096	7198	7541	7090	7602	7049	7646	7095	7204	6990
d_2	7349	7252	8251	7330	7726	7267	7813	7236	7860	7285	7390	7171
Top e_1	7488	7414	8526	7562	-	-	8248	7617	8160	7549	7756	7530
e_2	7522	7448	8877	7869	7774	7312	8614	7939	8480	7832	8060	7828
Top f_1	7703	7629	9183	8143	7953	7481	8779	8085	8805	8118	8342	8105
f_2	7820	7746	9407	8347	8092	7612	9024	8304	9038	8322	8547	8307
Top g_1	7992	7918	9884	8793	8371	7877	9532	8767	9556	8776	8993	8747
g_2	8159	8085	10107	9004	-	-	9842	9054	9850	9035	9264	9014
g_3	-	-	10323	9211			10055	9251	10080	9238	9398	9147
T.D.	8586	8512	10473	9354	8660	8151	10220	9405	10250	9388	9782	9526

Table 4-2-1 (Continued)
Vol. IV

CORRELATION TABLE
BARAM FIELD
A-AREA

Well No.	15		16		17		18		19		20	
D.F.E.	72		72		72		111		72		72	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top a_0							3879	3768				
a_1	5843	5130	5869	5142	5630	5186	5331	5220	5584	5237	6165	5216
a_2	6127	5376	6191	5423	5938	5462	5575	5463	5653	5292	6499	5477
Top b	6417	5629	6475	5670	6125	5629	5855	5743	5904	5540	6774	5696
Top c_1	7024	6156	6885	6019	6562	6020	6413	6301	6359	5975	7367	6176
c_2	7439	6514	7332	6597	6969	6383	6777	6664	6722	6320	7800	6539
Top d_1	8133	7097	8258	7177	7860	7167	7335	7222	7485	7036	8422	7053
d_2	8300	7239	8495	7371	8087	7364	7500	7387	7674	7213	8660	7246
Top e_1	8734	7612	8787	7608	8321	7564	7860	7747	8057	7569	9145	7627
e_2	9092	7914	9179	7931	8701	7884	8146	8033	8374	7866	9432	7852
Top f_1	9444	8207	9520	8219	9053	8177	8420	8306	8665	8139	9773	8124
f_2	9600	8339	9770	8436	9312	8392	8610	8496	8858	8321	10028	8327
Top g_1	10143	8802	10263	8877	9830	8831	8985	8871	9261	8702	10610	8778
g_2	10470	9083	10579	9167	10165	9121	9224	9110	9557	8982	11004	9079
g_3	10703	9285	10798	9369	10400	9324	9412	9298	9770	9183	11271	9289
T.D.	10850	9412	10950	9510	10560	9465	10044	9930	10205	9582	11608	9565

Table 4-2-1 (Continued)
Vol. IV

CORRELATION TABLE
BARAM FIELD
A-AREA

Well No.	21		22		25		26		27		28	
D.F.E.	71		71		72		72		72		72	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top a_0												
a_1	5499	4910	5773	4887	5401	5235	7034	5300	5261	5189	6433	5353
a_2	5756	5151	5995	5104	5680	5491	7377	5566	5510	5437	6758	5613
Top b	5990	5375	6194	5301	5943	5730	7436	5613	5793	5720	7136	5917
Top c_1	6428	5805	6722	5827	6578	6303	7757	5870	6275	6202	7828	6503
c_2	6757	6132	7054	6158	6996	6682	8147	6188	6635	6562	8230	6858
Top d_1	7411	6785	7716	6820	7592	7220	8982	6795	7352	7279	8756	7327
d_2	7557	6930	7867	6871	7780	7390	9192	6939	7516	7443	8955	7506
Top e_1	7836	7209	8158	7262	8190	7754	9576	7201	7794	7720	9357	7865
e_2	8056	7429	8390	7494	8498	8022	9876	7420	8013	7939	9701	8175
Top f_1	8249	7622	-	-	8836	8316	-	-	8276	8202	9875	8334
f_2	8375	7748			8970	8433			8460	8386	10074	8516
Top g_1	8644	8017			9418	8831			8876	8802	10528	8934
g_2	-	-			9695	9083			9140	9066	10805	9189
g_3					9893	9267			9329	9255	10995	9456
T.D.	8806	8179	8398	7502	10250	9600	10080	7567	9505	9431	11159	9515

Table 4-2-1 (Continued)
Vol. IV

CORRELATION TABLE
BARAM FIELD
A-AREA

Well No.	30		31		31 SDTR	
D.F.E.	72		72		72	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea
Top a_0			4226	3811	3997	3773
a_1	5820	5319				
a_2	6103	5573				
Top b	6404	5851				
Top c_1	6641	6074				
c_2	7006	6431				
Top d_1	7718	7138				
d_2	7882	7302				
Top e_1	8228	7648				
e_2	8512	7932				
Top f_1	8791	8211				
f_2	8979	8401				
Top g_1	9400	8820				
g_2	9667	9087				
g_3	9852	9272				
T.D.	10040	9460	4964	4382	4300	4069

Table 4-2-2 CORRELATION TABLE
Vol. IV BARAM FIELD
B-AREA

Well No.	7		24		32		33		34		35	
D.F.E.	111		110		72		72		72		72	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V	5686	5576	5881	5770	5271	5199	5892	5407	6393	5478	5677	5032
Top a_0											4777	4198
a_1	5474	5364	5692	5581	5081	5009	5650	5202	6213	5270	5524	4893
a_2	5930	5820	6128	6017	5529	5457	6216	5677	6869	5762		
Top b_1	6200	6090	6393	6282	5812	5740	6312	5756	7130	5964		
b_2	6463	6353	6659	6548	6090	6018	6555	5979	7208	6025		
b_3	6618	6508	6810	6699	6244	6172	6740	6145	7427	6195		
Top c_1	6939	6829	7098	6987	6604	6532	7128	6494	7905	6568		
c_2	7160	7050	7221	7110			7376	6717	8197	6796		
c_3	7332	7222	7405	7294			7595	6919	8440	6990		
c_4	7552	7442	7628	7517			7870	7171	8740	7235		
Top d_1	7943	7833	7978	7867			8323	7591	9245	7649		
d_2	8187	8077	8211	8100			8598	7848	9553	7898		
Top e_1	8510	8400	8537	8426			8955	8180	9956	8225		
e_2	8719	8609	8746	8635			9178	8388	10202	8435		
e_3	8876	8766	8902	8791			9343	8542	10366	8581		
Top f	9125	9015	9149	9038			9576	8759	10606	8799		
Top g_1	9451	9341	9452	9341			9878	9040	10900	9076		
g_2	9747	9637	-	-			10230	9366	11257	9418		
T.D.	10034	9924	9739	9628	8480	8408	10360	9487	11424	9578	8150	7501

Table 4-2-2 (Continued)
Vol. IV

CORRELATION TABLE
BARAM FIELD
B-AREA

Well No.	36		37		38		39		40		41	
D.F.E.	72		72		72		72		72		72	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V	5278	5169	7288	5687	-	-	6550	5707	6852	5640	6610	5708
Top a_0												
a_1	5090	4990	7007	5491	6032	5537	6340	5527	6591	5458	6369	5533
a_2	5560	5429	7486	5826	6226	5708	6821	5943	7187	5886	6924	5940
Top b_1	5877	5715	7617	5918	6525	5970	7118	6201	7557	6164	7270	6198
b_2	6177	5984	7996	6195	6828	6232	7421	6459	-	-	7606	6456
b_3	6351	6138	8202	6349	6998	6381	7591	6605	7825	6369	7786	6599
Top c_1	6759	6475	8650	6698	7381	6714	7967	6925	8216	6668	8020	6787
c_2	7053	6713	8966	6923	7623	6927	8029	6978	8524	6901	8170	6909
c_3	7293	6903	9232	7102	7843	7128	8202	7124	8781	7092	8416	7105
c_4	7605	7145	9630	7343	8098	7362	8477	7356	9114	7341	8700	7330
Top d_1	8120	7558	10342	7765	8373	7602	8952	7752	9717	7774	9231	7732
d_2	8423	7813	10766	8019	8690	7861	9252	7998	10112	8040	9580	7990
Top e_1	8818	8134	-	-	9141	8214	9692	8351	10667	8383	10059	8335
e_2	-	-			9440	8441	9972	8575	10994	8593	10348	8557
e_3					9705	8632	10184	8744	11258	8771	10561	8724
Top f					10141	8920	10509	9003	11617	9020	10902	8995
Top g_1					-	-	-	-	-	-	-	-
g_2												
T.D.	8900	8200	11953	8729	10350	9055	10720	9173	11705	9081	11050	9115

Vol. IV Table 4-3-1

PREDICTED PERFORMANCE OF BARAM A FIELD

PRODUCTION START : Apr. 1969
PRODUCTION END : Mar. 1991

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1969	0.14	1.57	2.3	1465	0.13	0.43	0.63	0.056
1970	0.75	5.18	9.09	1755	0.09	2.32	3.95	0.234
1971	3.77	25.53	53.44	2093	0.18	11.64	23.46	1.895
1972	8.01	35.78	99.6	2784	0.21	24.7	59.81	4.668
1973	12.22	35.62	129.13	3625	0.29	37.7	106.94	8.448
1974	15.61	28.63	133.76	4672	0.33	48.15	155.76	11.943
1975	17.89	19.32	101.77	5268	0.33	55.2	192.91	14.26
1976	20.19	19.42	105.35	5425	0.35	62.29	232.48	16.71
1977	22.03	15.53	86.87	5594	0.33	67.96	264.29	18.588
1978	23.50	12.41	71.26	5742	0.36	72.49	290.30	20.197
1979	24.66	9.81	55.96	5704	0.36	76.07	310.72	21.502
1980	25.53	7.4	40.15	5426	0.44	78.77	325.38	22.696
1981	26.15	5.18	25.89	4998	0.32	80.66	335.13	23.305
1982	26.62	4.03	20.21	5015	0.37	82.13	342.21	23.842
1983	26.93	2.58	14.26	5527	0.42	83.07	347.30	24.241
1984	27.15	1.86	10.77	5790	0.31	83.75	351.22	24.449

Vol. IV Table 4-3-1 (Continued)

PREDICTED PERFORMANCE OF BARAM A FIELD

PRODUCTION START : Apr. 1969
PRODUCTION END : Mar. 1991

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1985	27.30	1.32	8.47	6417	0.12	84.23	354.32	24.507
1986	27.43	1.09	7.02	6440	0.12	84.63	356.88	24.553
1987	27.54	0.94	5.98	6362	0.1	84.97	359.06	24.587
1988	27.64	0.81	5.18	6395	0.1	85.26	360.95	24.616
1989	27.72	0.8	4.49	6414	0.1	85.52	362.59	24.642
1990	27.79	0.61	3.89	6377	0.1	85.74	364.01	24.664
Mar.1991	27.81	0.56	3.54	6321	0.1	85.79	364.33	24.669

Vol. IV Table 4-3-2

PREDICTED PERFORMANCE OF BLOCK I, BARAM A FIELD

PRODUCTION START : Apr. 1971
PRODUCTION END : Mar. 1991

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	2396	15.0	9.19	41.16	4609	0.07	16.501	45.494	0.822
Dec.1976	2293	16.53	9.19	43.74	4759	0.08	18.178	53.476	0.952
1977	2079	19.26	8.23	42.73	5191	0.09	21.183	69.071	1.220
1978	1895	21.28	6.10	34.74	5695	0.10	23.410	81.751	1.452
1979	1765	22.84	4.70	28.30	6022	0.10	25.124	92.082	1.615
1980	1654	24.07	3.70	22.92	6194	0.10	26.475	100.447	1.755
1981	1562	25.05	2.95	18.65	6321	0.11	27.553	107.253	1.870
1982	1490	25.84	2.38	15.19	6381	0.10	28.423	112.796	1.961
1983	1427	26.48	1.94	12.44	6410	0.11	29.132	117.335	2.040
1984	1372	27.01	1.59	10.22	6427	0.12	29.713	121.065	2.109
1985	1326	27.45	1.32	8.47	6416	0.12	30.194	124.156	2.167
1986	1289	27.81	1.09	7.01	6435	0.12	30.593	126.716	2.213
1987	1262	28.12	0.94	5.98	6365	0.10	30.935	128.900	2.247
1988	1239	28.39	0.81	5.18	6399	0.10	31.231	130.792	2.276
1939	1219	28.63	0.70	4.49	6411	0.10	31.488	132.430	2.302
1990	1201	28.83	0.61	3.89	6373	0.10	31.710	133.849	2.324
Mar.1991	1197	28.87	0.56	3.54	6321	0.10	31.761	134.172	2.329

Vol. IV Table 4-3-3

PREDICTED PERFORMANCE OF BLOCK II,

BARAM A FIELD

PRODUCTION START : Apr. 1971
PRODUCTION END : Jun. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	866	29.01	0.22	1.96	8865	0.50	2.495	11.670	0.675
Dec.1976	796	29.48	0.22	1.95	8867	0.50	2.536	12.026	0.695
1977	663	30.43	0.22	1.83	8331	0.47	2.617	12.695	0.733
1978	560	31.37	0.22	1.66	7547	0.37	2.698	13.301	0.763
Jun.1979	504	31.84	0.22	1.53	6949	0.40	2.738	13.580	0.779

Vol. IV Table 4-3-4

PREDICTED PERFORMANCE OF BLOCK IV,

BARAM A FIELD

PRODUCTION START : Jul. 1970
PRODUCTION END : Jun. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1202	26.04	0.50	4.09	8249	0.09	4.687	18.160	0.245
Dec.1976	1134	26.51	0.47	3.88	8266	0.10	4.772	18.869	0.254
1977	991	27.46	0.47	3.92	8336	0.11	4.943	20.299	0.273
1978	869	28.41	0.47	3.90	8295	0.09	5.114	21.722	0.288
Jun.1979	806	28.88	0.47	3.85	8184	0.10	5.199	22.424	0.297

Vol. IV Table 4-3-5

PREDICTED PERFORMANCE OF BLOCK V,

BARAM A FIELD

PRODUCTION START : Jul. 1970
PRODUCTION END : Sep. 1980

TIME	RESERVOIR PRESSURE	RECOVERY	OIL PROD. RATE	GAS PROD. RATE	G.O.R.	W.O.R.	CUMULATIVE PRODUCTION		
							OIL	GAS	WATER
(YEAR)	(PSIG)	(%)	(MSTB/D)	(MMSCF/D)	(SCF/STB)	(STB/STB)	(MMSTB)	(MMMSCF)	(MMSTB)
Jun.1976	1524	25.13	4.42	38.16	8649	0.59	16.082	75.950	4.902
Dec.1976	1371	26.31	4.15	36.19	8720	0.66	16.839	82.554	5.400
1977	1166	27.98	2.92	25.63	8777	0.62	17.906	91.908	6.066
1978	996	29.28	2.27	19.53	8602	0.67	18.736	99.035	6.618
1979	888	30.30	1.80	14.91	8282	0.60	19.392	104.476	7.009
Sep.1980	814	30.91	1.43	11.48	8031	1.23	19.784	107.620	7.490

Vol. IV Table 4-3-6

PREDICTED PERFORMANCE OF BLOCK VI,

BARAM A FIELD

PRODUCTION START : Apr. 1969
PRODUCTION END : Mar. 1983

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1126	21.79	2.42	12.10	4967	0.40	10.111	41.563	3.003
Dec.1976	1021	22.52	1.87	9.16	4898	0.41	10.452	43.234	3.143
1977	915	23.39	1.10	5.23	4752	0.36	10.855	45.142	3.286
1978	816	24.18	1.00	4.51	4510	0.36	11.220	46.788	3.418
1979	720	24.90	0.92	3.94	4285	0.38	11.555	48.227	3.546
1980	652	25.57	0.85	3.41	4006	0.29	11.865	49.470	3.637
1981	592	26.21	0.82	3.15	3839	0.27	12.163	50.619	3.718
1982	529	26.82	0.78	2.72	3484	0.29	12.449	51.611	3.801
Mar.1983	514	26.98	0.77	2.66	3458	0.28	12.519	51.854	3.821

Vol. IV Table 4-3-7

PREDICTED PERFORMANCE OF BLOCK VII,

BARAM A FIELD

PRODUCTION START : Jan. 1971
PRODUCTION END : Sep. 1980

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1429	20.00	0.24	0.75	3120	0.49	3.875	8.059	1.897
Dec.1976	1407	20.23	0.24	0.73	3042	0.48	3.919	8.103	1.918
1977	1365	20.63	0.21	0.68	3238	0.52	3.997	8.443	1.958
1978	1323	21.02	0.21	0.67	3190	0.52	4.073	8.687	1.998
1979	1287	21.41	0.20	0.65	3260	0.49	4.147	8.925	2.034
Sep.1980	1267	21.68	0.20	0.65	3233	0.40	4.201	9.102	2.056

Vol. IV Table 4-3-8

PREDICTED PERFORMANCE OF BLOCK VIII,

BARAM A FIELD

PRODUCTION START : Jun. 1971
PRODUCTION END : Jun. 1982

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1601	15.00	1.71	6.28	3730	0.75	4.382	11.921	3.451
Dec.1976	1491	16.03	1.64	6.16	3759	0.70	4.681	13.046	3.662
1977	1298	17.68	1.32	5.06	3836	0.77	5.163	14.894	4.033
1978	1160	19.08	1.12	4.35	3885	0.64	5.573	16.482	4.296
1979	1028	20.31	0.99	3.77	3808	0.70	5.933	17.858	4.550
1980	929	21.41	0.87	3.28	3773	0.60	6.252	19.056	4.740
1981	840	22.39	0.79	2.86	3624	0.59	6.540	20.101	4.911
Jun.1982	797	22.85	0.73	2.60	3565	0.62	6.673	20.576	4.993

Vol. IV Table 4-3-9

PREDICTED PERFORMANCE OF UPPER BLOCK,

BARAM A FIELD

PRODUCTION START : Jul. 1973
PRODUCTION END : Sep. 1984

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
							OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jun.1976	1543	5.64	1.03	1.64	1601	0.83	0.728	0.868	0.523
Dec.1976	1462	7.10	1.03	1.69	1639	0.87	0.916	1.176	0.686
1977	1297	10.01	1.03	1.80	1748	0.89	1.293	1.833	1.019
1978	1125	12.89	1.02	1.91	1869	0.93	1.664	2.529	1.364
1979	973	15.37	0.88	1.71	1943	0.96	1.985	3.152	1.672
1980	843	17.46	0.74	1.45	1966	0.97	2.254	3.683	1.934
1981	737	19.21	0.62	1.23	1984	0.94	2.481	4.132	2.147
1982	649	20.64	0.50	1.01	2011	0.97	2.665	4.499	2.324
1983	567	21.88	0.42	0.84	1990	1.07	2.819	4.804	2.488
Sep.1984	511	22.60	0.36	0.73	2019	1.17	2.918	5.003	2.603

Vol. IV Table 4-3-10

PREDICTED PERFORMANCE OF BARAM B FIELD

PRODUCTION START : Sep.1972
PRODUCTION END : Jun.1982

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
						OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Dec.1972	0.62	5.5	10.09	1835	0.34	0.502	0.92	0.173
1973	5.39	10.65	17.53	1646	0.34	4.39	7.32	0.877
1974	14.04	19.29	53.76	2788	0.28	11.43	26.94	2.866
1975	20.67	14.79	53.87	3642	0.59	16.829	46.6	6.054
1976	25.31	10.35	44.98	4348	0.59	20.270	61.802	8.291
1977	29.75	9.91	50.96	5142	1.02	23.961	80.491	11.971
1978	33.18	7.65	44.61	5831	0.94	26.831	97.066	14.597
1979	35.48	5.13	33.03	6442	0.77	28.884	109.967	16.035
1980	37.00	3.39	23.35	6888	0.62	30.122	118.490	16.799
1981	38.26	2.8	19.12	6822	0.59	31.147	125.470	17.407
Jun.1982	38.82	2.51	16.89	6729	0.67	31.605	128.552	17.716

Vol. IV Table 4-3-11

PREDICTED PERFORMANCE OF MODEL-1,

BARAM B FIELD

PRODUCTION START : Aug. 1973
PRODUCTION END : Sep. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
							OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jun.1976	1989	26.36	3.64	12.39	3437	1.11	6.651	16.627	3.784
Dec.1976	1826	28.99	3.64	12.75	3503	0.78	7.315	18.954	4.302
1977	1449	34.05	3.50	13.96	3988	1.82	8.592	24.048	6.627
1978	1186	37.60	2.46	11.06	4495	1.89	9.488	28.084	8.321
Sep.1979	1020	39.60	1.84	9.03	4908	1.84	9.992	30.556	9.247

Vol. IV Table 4-3-12

PREDICTED PERFORMANCE OF MODEL-2,

BARAM B FIELD

PRODUCTION START : Sep. 1972
PRODUCTION END : Jun. 1982

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
							OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jun.1976	2406	20.88	6.72	31.19	4789	0.34	11.729	36.696	3.085
Dec.1976	2270	23.06	6.72	33.81	5016	0.39	12.955	42.848	3.567
1977	1939	27.36	6.61	37.25	5635	0.51	15.369	56.443	4.792
1978	1662	30.87	5.41	34.35	6350	0.55	17.343	68.982	5.881
1979	1431	33.63	4.24	28.57	6739	0.59	18.892	79.411	6.788
1980	1237	35.83	3.39	23.35	6888	0.62	20.130	87.934	7.552
1981	1082	37.66	2.81	19.12	6805	0.59	21.155	94.914	8.160
Jun.1982	1004	38.47	2.51	16.89	6728	0.68	21.613	97.996	8.469

Table 5-2-1 CORRELATION TABLE
Vol. IV BAKAU FIELD

Well No.	3	
D.F.E.	110	
Cycle/Zone	Log	Subsea
Top VI	1400	1290
V	4325	4215
Top a	6780	6670
Top b_1	7089	6979
b_2	7145	7035
Top c_1	7346	7236
c_2	7463	7353
c_3	7785	7675
c_4	8218	8108
Top d	8459	8349
Top e	9570	9460
T.D.	10239	10129

Well No.	4		5	
D.F.E.	112		111	
Cycle/Zone	Log	Subsea	Log	Subsea
Top VI				
V	5001	4311	4397	4286
Top a	8520	6911	7590	7170
Top b_1	9018	7265	8170	7686
b_2	9131	7342	8273	7775
Top c_1'	9276	7443	8438	7919
c_2'	9467	7581	8650	8096
c_3'	9640	7708	8854	8265
c_4'	9840	7858	9096	8471
Top d'	10702	8490	10113	9322
T.D.	11300	8901	10993	10017

Vol. IV Table 5-3-1

PREDICTED PERFORMANCE OF BAKAU FIELD

PRODUCTION START : Feb. 1972
PRODUCTION END : Mar. 1982

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1972	3.56	2.18	3.81	1749	0.0	0.794	1.389	0.0
1973	6.65	1.89	4.17	2210	0.025	1.483	2.912	0.017
1974	8.69	1.25	3.41	2726	0.055	1.939	4.155	0.042
1975	12.35	2.24	3.32	1485	0.032	2.755	5.367	0.068
1976	18.33	3.66	7.35	2010	0.058	4.089	8.049	0.145
1977	22.47	2.53	4.70	1858	0.120	5.012	9.764	0.256
1978	25.61	1.92	3.38	1761	0.200	5.712	10.997	0.396
1979	27.95	1.43	2.35	1644	0.301	6.234	11.855	0.553
1980	29.48	0.93	1.05	1129	0.097	6.574	12.239	0.586
1981	30.78	0.80	0.84	1059	0.124	6.865	12.547	0.622
Mar.1982	31.09	0.76	0.79	1044	0.131	6.934	12.619	0.631

Vol. IV Table 5-3-2

PREDICTED PERFORMANCE OF WELL BK-3,

BAKAU FIELD

PRODUCTION START : Feb. 1972
PRODUCTION END : Sep. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1332	30.06	0.42	1.34	3227	0.30	2.098	4.646	0.077
Dec.1976	1236	31.09	0.42	1.39	3301	0.34	2.174	4.899	0.103
1977	1014	33.28	0.42	1.50	3558	0.50	2.327	5.446	0.179
1978	895	35.25	0.38	1.43	3764	0.65	2.465	5.968	0.269
Sep.1979	804	36.56	0.25	1.24	4968	1.36	2.557	6.308	0.362

Vol. IV Table 5-3-3

PREDICTED PERFORMANCE OF WELL BK-4,

BAKAU FIELD

PRODUCTION START : May 1975
PRODUCTION END : Mar.1982

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	2360	8.00	3.75	5.18	1421	0.02	1.158	1.504	0.015
Dec.1976	1906	12.31	3.41	5.10	1496	0.03	1.781	2.435	0.036
1977	1529	17.48	2.05	2.86	1395	0.05	2.530	3.480	0.071
1978	1237	21.36	1.54	1.95	1265	0.09	3.092	4.191	0.121
1979	1003	24.33	1.18	1.42	1203	0.15	3.522	4.709	0.185
1980	914	26.68	0.93	1.05	1131	0.10	3.862	5.093	0.218
1981	831	28.69	0.80	0.84	1055	0.12	4.153	5.401	0.254
Mar.1982	810	29.17	0.76	0.79	1038	0.13	4.222	5.473	0.263

Vol. IV Table5-3-4

PREDICTED PERFORMANCE OF WELL BK-5,

BAKAU FIELD

PRODUCTION START : Mar. 1976
PRODUCTION END : Mar. 1977

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1973	8.62	0.52	3.36	6847	0.06	0.072	0.345	0.004
Dec.1976	1286	16.03	0.34	2.03	5963	0.03	0.134	0.715	0.006
Mar.1977	980	18.54	0.23	1.35	5861	0.03	0.155	0.838	0.006

Table 6-2-1 CORRELATION TABLE
Vol. IV TUKAU FIELD

Well No.	1		2		3		4		5		6	
D.F.E.	39		110		110		112		112		111	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Upper V	2480	2441										
Lower V	5450	5411										
Top a	2151	2112	2229	2119	2237	2125	2149	2037				
Top b_1	2782	2743	2735	2625	2781	2669	2735	2623	2699	2587	2827	2716
b_2	2910	2871	2831	2721	2910	2798	2862	2750	2819	2707	2953	2842
b_3	3080	3041	2973	2863	3077	2965	3033	2921	2972	2860	3107	2996
Top c_1	3448	3409					3388	3276				
c_2	3631	3592					3557	3445				
Top d_1	4096	4057	3980	3870	3747	3637	4002	3890	3841	3729	3866	3755
d_2	4209	4170	4055	3945	3820	3710	4117	4005	3920	3808	3950	3839
d_3	4449	4410	4296	4186	4061	3949	4348	4236	4151	4039	4194	4083
d_4	4621	4582	4465	4355	4224	4114	4511	4399	4314	4202	4365	4254
Top e_1	5711	5672					5551	5439			-	-
e_2	6266	6227					6078	5966				
e_3	6634	6595					6431	6319				
e_4	6889	6850					6658	6546				
Top f_1	7329	7290					7117	7005				
f_2	7620	7581					7413	7301				
T.D.	9186	9147	7554	7443	7093	6982	8781	8670	7000	6889	5110	4999

Table 6-2-1 (Continued)
Vol. IV

CORRELATION TABLE
TUKAU FIELD

Well No.	7		8		9		10		11		16	
D.F.E.	111		111		64		64		64		64	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Upper V												
Lower V												
Top a	2231	2120	2154	2043	2063	1981	2101	2005	2055	1991	-	-
Top b_1	2822	2711	2761	2650	2683	2554	2766	2607	2641	2577	2730	2600
b_2	2951	2840	2889	2778	2814	2675	2901	2730	2763	2699	2877	2723
b_3	3115	3004	3071	2960	2986	2833	3093	2903	2928	2864	3085	2897
Top c_1			3430	3319	3378	3192	3502	3274	3281	3217		
c_2			3599	3488	3549	3349	3695	3449	3447	3383	3742	3456
Top d_1	3949	3838	4053	3942	4008	3777	4185	3900	-	-	4251	3906
d_2			4162	4051	4121	3883	4305	4011			4383	4025
d_3	-	-	4395	4284	4357	4104	4560	4248			4653	4268
d_4	4401	4290	4563	4452	4532	4268	4734	4411			4830	4428
Top e_1	-	-	-	-			5916	5485			-	-
e_2							6586	6086				
e_3							7037	6487				
e_4							7304	6721				
Top f_1							7875	7220				
f_2							8267	7563				
T.D.	5110	4999	5000	4889	7961	7361	8263	7560	3495	3431	5176	4743

Table 6-2-1 (Continued)
Vol. IV

CORRELATION TABLE
TUKAU FIELD

Well No.	17		18		19		20		21		22	
D.F.E.	64		64		64		64		73		73	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Upper V												
Lower V												
Top a	2415	2124			-	-	2425	2101	2145	2030	-	-
Top b_1	3244	2655	-	-	3353	2697	3169	2647	2852	2623	2814	2609
b_2	3423	2767	2818	2710	3530	2808	3327	2768	3016	2750	2968	2734
b_3	3656	2912	2996	2878	3774	2958	3515	2917	3217	2905	3150	2883
Top c_1	4248	3287	3370	3238	-	-	3967	3268	3728	3287	3604	3255
c_2	4497	3450	3557	3419			4180	3424	3961	3462	3820	3430
Top d_1	4895	3715	3994	3844			4650	3717	4554	3927	4492	3893
d_2	5005	3789	4106	3952			4786	3798	4698	4045	4681	4003
d_3	5377	4038	4335	4175			5151	4019	4973	4277	5091	4247
d_4	5609	4198	-	-			-	-	5177	4453	-	-
Top e_1									6424	5530		
e_2									7100	6105		
e_3									7550	6477		
e_4									7873	6744		
Top f_1									8424	7214		
f_2									8770	7517		
T.D.	6757	5008	4465	4301	4268	3250	5235	4071	8882	7617	5239	4265

Table 6-2-1 (Continued) CORRELATION TABLE
Vol. IV TUKAU FIELD

Well No.	23		24		25		26		27		28	
D.F.E.	73		73		73		73		73		73	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Upper V												
Lower V												
Top a	-	-	-	-	-	-	-	-	-	-	-	-
Top b_1	2805	2619	2783	2602	3005	2599	2956	2581	2753	2626	2751	2609
b_2	2944	2745	2927	2726	3205	2722	3116	2699	2887	2752	2898	2734
b_3	3134	2915	3107	2879	3487	2886	3330	2860	3068	2924	3093	3899
Top c_1	3553	3290	3560	3247	-	-	3801	3212	3465	3301	3532	3272
c_2	3729	3448	3784	3423			4024	3375	3641	3469	3712	3427
Top d_1	4226	3893	4355	3874			-	-	4117	3926	4218	3858
d_2	4357	4010	4500	3988					4237	4042	4348	3970
d_3	4614	4239	4803	4224					-	-	4604	4190
d_4	4811	4415	5017	4393							4796	4360
Top e_1	-	-	-	-							-	-
e_2												
e_3												
e_4												
Top f_1												
f_2												
T.D.	5124	4701	5382	4686	3687	2995	4222	3518	4505	4300	5275	4795

Table 6-2-1 (Continued) CORRELATION TABLE
Vol. IV TUKAU FIELD

Well No.	29	
D.F.E.	73	
Cycle/Zone	Log	Subsea
Top Upper V Lower V		
Top a	-	-
Top b_1 b_2 b_3	2715 2843 3016	2603 2724 2888
Top c_1 c_2	3394 3565	3245 3408
Top d_1 d_2 d_3 d_4	4032 4147 4380 4554	3854 3964 4187 4354
Top e_1 e_2 e_3 e_4	5601 6147 6508 6738	5361 5885 6230 6451
Top f_1 f_2	7229 7503	6923 7187
T.D.	7947	7615

Vol. IV Table 6-3-1

PREDICTED PERFORMANCE OF TUKAU FIELD

TUKAU FIELD

PRODUCTION START : Aug. 1975
PRODUCTION END : Dec. 1983

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Dec.1975	0.45	3.66	3.99	1091	0.013	0.667	0.728	0.009
1976	3.73	13.44	20.23	1505	0.036	5.573	8.119	0.184
1977	6.74	12.38	30.08	2430	0.044	10.091	19.089	0.382
1978	9.39	10.86	34.47	3174	0.040	14.056	31.669	0.539
1979	11.37	8.09	30.30	3745	0.044	17.007	42.730	0.670
1980	12.75	5.66	21.67	3829	0.050	19.071	50.638	0.774
1981	13.29	2.22	13.07	5887	0.041	19.882	55.408	0.807
1982	13.49	0.83	8.58	10337	0.013	20.184	58.539	0.811
1983	13.62	0.58	5.15	8871	0.014	20.395	60.417	0.814

Vol. IV Table 6-3-2

PREDICTED PERFORMANCE OF MODEL-1

TUKAU FIELD

PRODUCTION START : Aug. 1975
PRODUCTION END : Mar. 1981

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1116	3.60	3.19	1.64	524	0.08	0.726	0.338	0.043
Dec.1976	1063	6.32	3.00	1.49	496	0.117	1.274	0.610	0.107
1977	952	11.75	3.00	1.45	484	0.098	2.369	1.140	0.226
1978	797	17.05	2.93	1.38	472	0.073	3.437	1.644	0.304
1979	662	21.74	2.59	1.25	481	0.072	4.382	2.099	0.372
1980	547	25.86	2.28	1.08	477	0.070	5.213	2.495	0.430
Mar.1981	521	26.81	1.58	0.75	474	0.068	5.405	2.586	0.443

Vol. IV Table 6-3-3

PREDICTED PERFORMANCE OF MODEL-2

TUKAU FIELD

PRODUCTION START : Aug. 1975
PRODUCTION END : Jun. 1978

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1138	10.01	2.50	2.36	1027	0.02	0.430	0.362	0.006
Dec.1976	980	14.26	1.00	1.10	1098	0.02	0.613	0.563	0.010
1977	646	22.44	0.96	1.26	1311	0.02	0.964	1.023	0.018
Jun.1978	514	25.65	0.76	1.06	1406	0.02	1.102	1.217	0.021

Vol. IV Table 6-3-4

PREDICTED PERFORMANCE OF MODEL-3

TUKAU FIELD

PRODUCTION START : Oct. 1975
PRODUCTION END : Jun. 1980

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1666	3.42	1.87	5.06	3156	0.00	0.460	0.945	0.002
Dec.1976	1558	6.13	2.00	7.14	3570	0.00	0.825	2.248	0.002
1977	1298	11.56	2.00	8.72	4358	0.03	1.555	5.429	0.004
1978	960	16.89	1.96	10.34	5270	0.04	2.271	9.202	0.007
1979	665	21.37	1.65	8.92	5398	0.03	2.874	12.457	0.009
Jun.1980	542	23.26	1.39	7.22	5189	0.04	3.128	13.775	0.010

Vol. IV Table 6-3-5

PREDICTED PERFORMANCE OF MODEL-4

TUKAU FIELD

PRODUCTION START : Oct. 1975
PRODUCTION END : Mar. 1976

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
							OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jun.1976	1332	12.73	0.53	0.82	1687	0.04	0.136	0.164	0.004
Dec.1976	866	19.56	0.40	0.73	1836	0.04	0.209	0.298	0.007
Mar.1977	625	22.98	0.40	0.75	1838	0.05	0.246	0.366	0.009

Vol. IV Table 6-3-6

PREDICTED PERFORMANCE OF MODEL-5

TUKAU FIELD

PRODUCTION START : Aug. 1975
PRODUCTION END : Dec. 1983

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	3070	1.23	0.65	2.91	4420	0.01	0.252	0.779	0.004
Dec.1976	2990	2.12	2.00	9.10	4560	0.011	0.434	1.609	0.006
1977	2617	5.68	2.00	11.25	5616	0.011	1.165	5.714	0.014
1978	2187	9.19	1.97	14.85	7552	0.011	1.883	11.136	0.022
1979	1767	12.10	1.47	15.00	10236	0.017	2.481	16.612	0.031
1980	1412	14.37	1.27	13.18	10344	0.015	2.946	21.422	0.038
1981	1174	16.20	1.02	11.08	10812	0.013	3.320	25.467	0.043
1982	969	17.73	0.86	9.13	10578	0.013	3.635	28.799	0.047
1983	749	19.03	0.73	7.08	9722	0.015	3.901	31.385	0.051

Vol. IV Table 6-3-7

PREDICTED PERFORMANCE OF MODEL-6

TUKAU FIELD

PRODUCTION START : Mar. 1976
PRODUCTION END : Mar. 1982

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1179	1.09	0.24	0.19	1128	0.01	0.026	0.019	0.000
Dec.1976	1087	2.94	0.24	0.35	1488	0.00	0.069	0.083	0.000
1977	1040	6.64	0.24	0.40	1690	0.01	0.156	0.230	0.001
1978	982	10.35	0.24	0.42	1761	0.00	0.244	0.385	0.001
1979	841	14.05	0.24	0.59	2494	0.00	0.331	0.602	0.001
1980	682	17.69	0.24	0.69	2930	0.00	0.417	0.854	0.001
1981	537	20.76	0.20	0.61	3264	0.01	0.489	1.089	0.002
Mar.1982	504	21.44	0.18	0.58	3345	0.00	0.505	1.142	0.002

Vol. IV Table 6-3-8

PREDICTED PERFORMANCE OF MODEL-7

TUKAU FIELD

PRODUCTION START : Jan. 1976
PRODUCTION END : Mar. 1979

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
Jun.1976	1640	5.18	3.01	2.08	752	0.01	0.362	0.243	0.005
Dec.1976	1445	12.33	2.73	2.65	970	0.02	0.861	0.727	0.013
1977	976	22.58	1.96	3.10	1580	0.03	1.576	1.857	0.032
1978	597	29.47	1.32	2.55	1929	0.03	2.058	2.787	0.048
Mar.1979	527	30.84	1.05	1.96	1841	0.03	2.153	2.966	0.051

Vol. IV Table 6-3-9

PREDICTED PERFORMANCE OF MODEL-8

TUKAU FIELD

PRODUCTION START : Aug. 1975
PRODUCTION END : Jun. 1981

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
							OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
Jun.1976	2650	7.35	2.12	2.09	1006	0.04	0.718	0.670	0.019
Dec.1976	2508	11.31	2.12	2.22	1049	0.05	1.105	1.076	0.037
1977	2204	19.22	2.12	2.75	1298	0.05	1.878	2.079	0.076
1978	1820	27.14	2.12	3.96	1871	0.06	2.651	3.525	0.124
1979	1430	33.89	1.81	4.40	2436	0.08	3.310	5.130	0.174
1980	1121	38.56	1.25	3.65	2925	0.09	3.766	6.464	0.213
Jun.1981	1009	40.49	1.02	3.02	2952	0.08	3.955	7.033	0.227

Vol. IV Table 6-3-10

PREDICTED PERFORMANCE OF MODEL-9

TUKAU FIELD

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.00	1111	2.26	3.00	2.70	900	0.01	1.095	0.984	0.007
2.00	962	4.52	3.00	3.34	1113	0.01	2.190	2.202	0.014
3.00	819	6.72	2.92	3.19	1092	0.01	3.257	3.366	0.021
4.00	690	8.73	2.68	2.95	1101	0.01	4.234	4.443	0.027
5.00	577	10.57	2.45	2.66	1086	0.01	5.124	5.414	0.033
5.75	500	11.84	2.26	2.42	1071	0.01	5.742	6.076	0.037

Vol. IV Table 6-3-11

PREDICTED PERFORMANCE OF MODEL-10

TUKAU FIELD

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION		
							OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
1.0	1005	3.67	2.00	2.01	1005	0.01	0.730	0.733	0.005
2.0	757	7.30	1.98	2.24	1131	0.01	1.451	1.550	0.010
3.0	548	10.46	1.72	2.00	1163	0.01	2.080	2.278	0.014
3.25	503	11.18	1.56	1.78	1141	0.01	2.222	2.440	0.015

Vol. IV Table 6-3-12

PREDICTED PERFORMANCE OF MODEL-11

TUKAU FIELD

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.0	1534	13.19	0.96	0.82	854	0.01	0.351	0.298	0.003
2.0	1250	23.13	0.72	1.10	1528	0.02	0.615	0.699	0.008
3.0	964	30.93	0.57	1.07	1877	0.02	0.823	1.089	0.013
4.0	716	37.21	0.46	0.90	1957	0.02	0.990	1.419	0.017
5.0	513	42.35	0.37	0.69	1865	0.02	1.126	1.672	0.020

Vol. IV TABLE 6-3-13

PREDICTED PERFORMANCE OF TUKAU FIELD

- ADDITIONAL WELL CASE -

TIME (YEAR)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
1.00	3.06	5.96	5.52	926	0.007	2.176	2.015	0.015
2.00	5.99	5.70	6.59	1157	0.008	4.256	4.421	0.032
3.00	8.67	5.22	6.33	1214	0.008	6.160	6.733	0.048
4.00	10.48	3.52	4.30	1221	0.009	7.445	8.302	0.059
5.00	11.93	2.81	3.35	1192	0.009	8.472	9.526	0.068
5.75	12.80	2.26	2.42	1071	0.006	9.090	10.188	0.072

Table 7-2-1 CORRELATION TABLE
Vol. IV BETTY FIELD

Well No.	1		2		3		4	
D.F.E.	110		110		112		111	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Upper VI			1385	1275	1450	1338		
Middle VI	2270	2160	2670	2560	2760	2648	2800	2689
Lower VI	3645	3535	4220	4110	4340	4228	4330	4219
V	5000	4890	5415	5305	5492	5380	5446	5335
Top a_1	7559	7449	7621	7511	7492	7380	6892	6781
a_2	7786	7675	7828	7718	7652	7540	6950	6839
a_3	7892	7782	7916	7806	7765	7653	7012	6901
Top b_1	8100	7990	8100	7990	7867	7755	7122	7011
b_2	8290	8180	8261	8151	8000	7888	7217	7106
Top c_1	8483	8373	8438	8328	8140	8029	7327	7216
c_2	8867	8757	8812	8702	8455	8343	7609	7498
T.D.	8943	8833	9436	9326	8803	8691	9485	9374

RESERVOIR DATA

FIELD NAME; BETTY   RESERVOIR NAME; A1 (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.029	0.	0.907080	1.1400	0.01190
200.	1.048	31.	0.081441	1.0200	0.01214
400.	1.060	64.	0.041214	0.9400	0.01238
600.	1.071	96.	0.027164	0.8800	0.01262
1000.	1.092	162.	0.015764	0.7700	0.01354
1400.	1.114	226.	0.010898	0.6800	0.01458
1800.	1.135	292.	0.008288	0.6100	0.01576
2900.	1.194	470.	0.005109	0.4700	0.01963
3260.	1.186	470.	0.004631	0.4730	0.02094

SL	KG/KO	KRO
0.65	12.0000	0.0707
0.70	3.6000	0.1229
0.75	1.0000	0.1962
0.80	0.3000	0.2938
0.85	0.0800	0.4195
0.90	0.0230	0.5768
0.95	0.0056	0.7691
1.00	0.0020	1.0000

BUBLE POINT PRESSURE (PSIG) = 2900.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 3260.0000
EFFECTIVE COMPRESSIBILITY = 0.0000030
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.4033
FINAL PRESSURE (PSIG) = 1000.0000
ORIGINAL OIL IN PLACE (MMSTB) = 68.0400
OIL PRODUCTION RATE (MSTB/D) = 2.5000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0000

Vol. IV Table 7-3-1

RESERVOIR PARAMETERS USED IN PERFORMANCE CALCULATION

RESERVOIR DATA

FIELD NAME; BETTY RESERVOIR NAME; A3 (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.061	0.	0.912830	0.8170	0.01197
200.	1.085	35.	0.082000	0.7100	0.01220
400.	1.010	67.	0.041520	0.6480	0.01244
1000.	1.133	167.	0.015910	0.5350	0.01358
2000.	1.173	333.	0.007483	0.4400	0.01634
2600.	1.197	433.	0.005699	0.4100	0.01846
3300.	1.225	550.	0.004632	0.3900	0.02099
3420.	1.223	550.	0.004508	0.3905	0.02142

SL	KG/KO	KRO
0.65	12.7040	0.0270
0.70	3.3750	0.0640
0.75	1.0000	0.1250
0.80	0.2963	0.2160
0.85	0.0787	0.3430
0.90	0.0220	0.5120
0.95	0.0056	0.7290
1.00	0.0000	1.0000

BUBLE POINT PRESSURE (PSIG) = 3300.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 3420.0000
EFFECTIVE COMPRESSIBILITY = 0.0000030
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.5084
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 19.6900
OIL PRODUCTION RATE (MSTB/D) = 2.5000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0000

Vol. IV Table 7-3-2

RESERVOIR PARAMETERS USED IN PERFORMANCE CALCULATION

RESERVOIR DATA

FIELD NAME; BETTY RESERVOIR NAME; B2 (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.054	0.	0.918583	0.9500	0.01203
200.	1.074	36.	0.082560	0.7900	0.01226
400.	1.089	73.	0.041827	0.7200	0.01250
1000.	1.126	184.	0.016057	0.5500	0.01362
2000.	1.176	366.	0.007566	0.4300	0.01634
3000.	1.226	550.	0.005074	0.3800	0.01981
3640.	1.219	550.	0.004354	0.3810	0.02211

SL	KG/KO	KRO
0.65	5.3594	0.0481
0.70	1.7280	0.0939
0.75	0.5787	0.1623
0.80	0.1866	0.2577
0.85	0.0527	0.3847
0.90	0.0230	0.5477
0.95	0.0056	0.7510
1.00	0.0001	1.0000

BUBLE POINT PRESSURE (PSIG) = 3000.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 3640.0000
EFFECTIVE COMPRESSIBILITY = 0.0000030
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.4453
FINAL PRESSURE (PSIG) = 1000.0000
ORIGINAL OIL IN PLACE (MMSTB) = 3.2800
OIL PRODUCTION RATE (MSTB/D) = 0.2500
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0000

Vol. IV Table 7-3-3

RESERVOIR PARAMETERS USED IN PERFORMANCE CALCULATION

FIELD NAME: BETTY RESERVOIR NAME: A1 (A-BLOCK)

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	PRODUCTION RATE GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.50	2651.	2.68	10.00	5.21	521.	1.825	0.950	0.30
1.00	2447.	5.37	10.00	5.23	528.	3.650	1.905	0.65
1.50	2264.	8.05	10.00	5.41	563.	5.476	2.893	1.01
2.00	2085.	10.73	10.00	6.04	654.	7.301	3.994	1.38
2.50	1892.	13.41	10.00	7.31	822.	9.126	5.328	1.75
3.00	1714.	15.94	9.43	8.84	1050.	10.848	6.942	2.08
3.50	1555.	18.19	8.38	9.75	1293.	12.377	8.722	2.40
4.00	1386.	20.19	7.45	10.72	1595.	13.737	10.679	2.68
4.50	1242.	21.97	6.62	11.44	1870.	14.946	12.767	2.93
5.00	1078.	23.55	5.90	11.97	2207.	16.023	14.952	3.16

Vol. IV Table 7-3-4
PREDICTED PERFORMANCE

FIELD NAME; BETTY RESERVOIR NAME; A3 (A-BLOCK)

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	PRODUCTION RATE GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.50	2872.	4.63	5.00	2.57	487.	0.913	0.469	0.13
1.00	2559.	8.94	4.65	2.31	539.	1.761	0.891	0.29
1.50	2332.	12.67	4.02	2.33	610.	2.495	1.317	0.43
2.00	2137.	15.94	3.53	2.27	685.	3.139	1.732	0.56
2.50	1972.	18.83	3.12	2.31	789.	3.708	2.153	0.67
3.00	1864.	21.41	2.78	2.34	894.	4.216	2.580	0.75
3.50	1758.	23.74	2.52	2.38	1004.	4.675	3.015	0.85
4.00	1648.	25.87	2.30	2.44	1128.	5.094	3.461	0.94
4.50	1532.	27.81	2.10	2.50	1266.	5.476	3.917	1.03
5.00	1410.	29.59	1.91	2.55	1419.	5.825	4.382	1.11
5.50	1279.	31.21	1.75	2.63	1591.	6.145	4.862	1.18
6.00	1136.	32.70	1.61	2.72	1792.	6.438	5.359	1.25

Vol. IV Table 7-3-5

PREDICTED PERFORMANCE

FIELD NAME; BETTY

RESERVOIR NAME; B2 (A-BLOCK)

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	PRODUCTION RATE GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE OIL (MMSTB)	PRODUCTION GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.50	2782.	2.78	0.50	0.27	521.	0.091	0.049	0.01
1.00	2599.	5.56	0.50	0.26	516.	0.183	0.096	0.03
1.50	2431.	8.35	0.50	0.27	574.	0.274	0.146	0.04
2.00	2265.	11.13	0.50	0.30	628.	0.365	0.201	0.06
2.50	2097.	13.91	0.50	0.33	710.	0.456	0.261	0.08
3.00	1947.	16.69	0.50	0.39	833.	0.548	0.333	0.10
3.50	1826.	19.48	0.50	0.44	924.	0.639	0.413	0.11
4.00	1697.	22.26	0.50	0.48	1011.	0.730	0.501	0.13
4.50	1551.	25.04	0.50	0.54	1124.	0.821	0.598	0.15
5.00	1381.	27.82	0.50	0.60	1321.	0.913	0.708	0.17
5.50	1160.	30.61	0.50	0.75	1693.	1.004	0.845	0.19

Vol. IV Table 7-3-6

PREDICTED PERFORMANCE

Table 8-2-1 CORRELATION TABLE
Vol. IV BOKOR FIELD

Well No.	1		2		3		4	
D.F.E.	111		111		111		111	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Lower VI	2832	2721						
Upper V	3850	3739						
Top a_1	2496	2385	2220	2109	2328	2217	2242	2131
a_2	2832	2721	2494	2383	2615	2504	2540	2429
a_3	3084	2973	2857	2746	2976	2865	2902	2791
Top b_1	3590	3479	3322	3211	3230	3119	3360	3249
b_2	3697	3586	3420	3309	3340	3229	3464	3353
b_3	3850	3739	3580	3469	3530	3419	3636	3525
Top c	4559	4448	4304	4193	4246	4135	4329	4218
Top d	5042	4931	4776	4665	4733	4622	4770	4659
T.D.	7885	7774	8974	8863	5500	5389	7273	7162

RESERVOIR DATA

FIELD NAME; BOKOR RESERVOIR NAME; A1

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.021	0.	0.811065	9.5800	0.01218
100.	1.026	12.	0.138331	9.0800	0.01229
200.	1.029	23.	0.073355	8.7700	0.01240
400.	1.036	47.	0.037412	8.2800	0.01262
600.	1.042	70.	0.024858	7.9500	0.01284
800.	1.048	94.	0.018501	7.6900	0.01319
990.	1.055	116.	0.014711	7.4500	0.01354

SL	KG/KO	KRO
0.65	12.0000	0.0707
0.70	3.6000	0.1230
0.75	1.0000	0.1965
0.80	0.3000	0.2939
0.85	0.0800	0.4196
0.90	0.0230	0.5768
0.95	0.0056	0.7691
1.00	0.0020	1.0000

BUBLE POINT PRESSURE (PSIG) = 1035.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 991.0000
EFFECTIVE COMPRESSIBILITY = 0.0000030
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3805
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 12.3000
OIL PRODUCTION RATE (MSTB/D) = 0.5000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0500

Vol. IV Table 8-3-1

RESERVOIR PARAMETERS USED IN PERFORMANCE CALCULATION

RESERVOIR DATA

FIELD NAME; BOKOR RESERVOIR NAME; A2

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.020	0.	0.815376	9.8000	0.01223
100.	1.025	12.	0.139078	9.4000	0.01234
200.	1.029	24.	0.073758	9.1000	0.01245
400.	1.035	48.	0.037625	8.5600	0.01267
800.	1.049	96.	0.018619	7.6400	0.01323
1048.	1.057	126.	0.014075	7.2000	0.01367
1080.	1.054	126.	0.013604	7.2200	0.01373

SL	KG/KO	KRO
0.65	12.0000	0.0480
0.70	3.6000	0.0939
0.75	1.0000	0.1623
0.80	0.3000	0.2577
0.85	0.0800	0.3847
0.90	0.0230	0.5477
0.95	0.0056	0.7513
1.00	0.0020	1.0000

BUBLE POINT PRESSURE (PSIG) = 1048.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 1082.0000
EFFECTIVE COMPRESSIBILITY = 0.0000030
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.4548
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 24.2000
OIL PRODUCTION RATE (MSTB/D) = 1.2500
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0000

Vol. IV Table 8-3-2
RESERVOIR PARAMETERS USED IN PERFORMANCE CALCULATION

RESERVOIR DATA

FIELD NAME; BOKOR RESERVOIR NAME; B2

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.026	0.	1.116201	4.8500	0.01175
100.	1.032	23.	0.141511	4.7000	0.01187
200.	1.036	46.	0.074776	4.6000	0.01199
400.	1.043	91.	0.037860	4.4100	0.01222
600.	1.050	137.	0.024966	4.2300	0.01245
1000.	1.061	228.	0.014482	3.9000	0.01330
1450.	1.074	330.	0.009631	3.5800	0.01442

SL	KG/KO	KRO
0.65	12.0000	0.0010
0.70	3.6000	0.0700
0.75	1.0000	0.0710
0.80	0.3000	0.1228
0.85	0.0800	0.2000
0.90	0.0230	0.4200
0.95	0.0056	0.7000
1.00	0.0020	1.0000

BUBLE POINT PRESSURE (PSIG)	= 3400.0000
INITIAL RESERVOIR PRESSURE (PSIG)	= 1452.0000
EFFECTIVE COMPRESSIBILITY	= 0.0000030
WATER FORMATION VOLUME FACTOR	= 1.0250
IREDUCIBLE WATER SATURATION	= 0.6236
FINAL PRESSURE (PSIG)	= 860.0000
ORIGINAL OIL IN PLACE (MMSTB)	= 8.6000
OIL PRODUCTION RATE (MSTB/D)	= 0.5000
FRACTION OF RESERVOIR GAS AND OIL VOL.	= 0.0000

Vol. IV Table 8-3-3

RESERVOIR PARAMETERS USED IN PERFORMANCE CALCULATION

FIELD NAME; BOKOR RESERVOIR NAME; A1

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	PRODUCTION RATE GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	WATER. ENCROACH. (MMBBL)
0.50	904.	1.48	1.00	0.58	598.	0.183	0.105	0.03
1.00	815.	2.97	1.00	0.62	644.	0.365	0.218	0.07
1.50	731.	4.45	1.00	0.66	679.	0.548	0.339	0.11
2.00	644.	5.94	1.00	0.70	720.	0.730	0.467	0.14
2.50	560.	7.42	1.00	0.74	744.	0.913	0.601	0.18

Vol. IV Table 8-3-4
PREDICTED PERFORMANCE

FIELD NAME; BOKOR RESERVOIR NAME; A2

NATURAL DEPLETION CASE

			PRODUCTION RATE		GAS OIL	CUMULATIVE PRODUCTION		WATER
TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL (MSTB/D)	GAS (MMSCF/D)	RATIO (SCF/STB)	OIL (MMSTB)	GAS (MMMSCF)	ENCROACH. (MMBBL)
0.50	918.	1.89	2.50	1.42	604.	0.456	0.259	0.08
1.00	791.	3.77	2.50	1.57	646.	0.913	0.545	0.17
1.50	686.	5.60	2.42	1.55	638.	1.355	0.828	0.26
2.00	590.	7.30	2.26	1.45	652.	1.766	1.092	0.34

Vol. IV Table 8-3-5
PREDICTED PERFORMANCE

FIELD NAME; BOKOR RESERVOIR NAME; B2

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	PRODUCTION RATE GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.50	1332.	3.18	1.50	0.97	663.	0.274	0.178	0.05
1.00	1217.	6.37	1.50	1.02	696.	0.548	0.363	0.10
1.50	1099.	9.55	1.50	1.08	744.	0.821	0.560	0.16
2.00	979.	12.73	1.50	1.16	795.	1.095	0.772	0.21
2.50	871.	15.92	1.50	1.21	836.	1.369	0.993	0.27

Vol. IV Table 8-3-6

PREDICTED PERFORMANCE

Table 9-2-1 CORRELATION TABLE
Vol. IV TEMANA (EAST) FIELD

Well No.	1		2		3		4	
D.F.E.	67		66		64		41	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top VI	450	383						
II	1870	1803	1764	1698	1900	1836	1990	1949
I?							2170	2129
Top a_1	-	-	2150	2084	1900	1836	-	-
a_2	1870	1803	2450	2384	2190	2126	1990	1949
Top b_1	2207	2140	2785	2719	2546	2482	2220	2179
b_2	2734	2667	3295	3229	3025	2961	2861	2820
Top c	3390	3323	3980	3914	3718	3654	3500	3459
Top d_1	4213	4146	4965	4899	4760	4696	4258	4217
d_2	4440	4373	5200	5134	4990	4926	4545	4504
Top e	5103	5036	5710	5644	5525	5461	5303	5262
T.D.	10013	9946	8072	8006	7610	7546	7204	7163

Table 9-2-2 CORRELATION TABLE
Vol. IV TEMANA (WEST) FIELD

Well No.	5		6		7		8		9		10	
D.F.E.	41		41		41		41		41		41	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top V	796	755	-	-	834	793			995	954	906	865
III	1094	1053	1240	1199	1123	1082			1246	1205	1140	1099
II	1630	1589	1465	1424	2004	1963	2936	2895	1690	1649	1704	1663
I?	4590	4549										
Top a	796	755	-	-	834	793			995	954	906	865
Top b	1094	1053	1240	1199	1123	1082			1246	1205	1140	1099
Top c_1	1630	1589	1465	1424	2004	1963	2936	2895	1690	1649	1704	1663
c_2	1750	1709	1567	1526	2080	2039	3085	3044	1807	1766	1771	1730
Top d_1	2023	1978			2743	2702	3346	3305	2088	2047	2041	2000
d_2	2140	2099			2848	2807	3494	3453	2175	2134	2126	2085
d_3	2365	2324			3042	3001	3724	3682	-	-	2288	2247
Top e	2660	2519			3420	3379	4295	4254			2638	2597
Top f_1	3616	3575			-	-	5384	5343			2980	2939
f_2	3718	3677					-	-			3095	3054
f_3	3925	3884									3300	3259
Top g	4098	4057									3560	3519
Top h	5005	4965									4435	4394
Top i	5786	5745										
T.D.	7020	6979	3281	3240	3617	3576	5456	5415	2515	2474	5047	5006

RESERVOIR DATA

FIELD NAME; TEMANA RESERVOIR NAME;

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.031	0.	1.125825	8.2000	0.01184
200.	1.041	51.	0.075330	7.6200	0.01208
400.	1.048	102.	0.038093	7.1600	0.01232
600.	1.054	153.	0.025087	6.7300	0.01256
900.	1.063	230.	0.016290	6.1600	0.01316

SL	KG/KO	KRO
0.65	80.0000	0.1517
0.70	28.0000	0.2160
0.75	9.5000	0.2963
0.80	2.8500	0.3944
0.85	0.8500	0.5120
0.90	0.2000	0.6510
0.95	0.0380	0.8130
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2420.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 901.0000
EFFECTIVE COMPRESSIBILITY = 0.0000115
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.2360
FINAL PRESSURE (PSIG) = 300.0000
ORIGINAL OIL IN PLACE (MMSTB) = 36.2180
OIL PRODUCTION RATE (MSTB/D) = 2.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0000

Vol. IV Table 9-3-1

RESERVOIR PARAMETERS USED IN PERFORMANCE CALCULATION

FIELD NAME; TEMANA RESERVOIR NAME;

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	PRODUCTION RATE GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.25	877.	1.01	4.00	1.83	532.	0.365	0.167	0.0
0.50	846.	2.02	4.00	2.55	766.	0.730	0.400	0.0
0.75	803.	3.02	4.00	3.83	1192.	1.095	0.749	0.0
1.00	737.	4.03	4.00	6.18	1977.	1.460	1.313	0.0
1.25	633.	5.03	3.95	10.27	3353.	1.820	2.250	0.0
1.50	480.	5.97	3.73	15.65	4686.	2.161	3.678	0.0
1.75	326.	6.83	3.42	16.08	4623.	2.473	5.145	0.0

Vol. IV Table 9-3-2
PREDICTED PERFORMANCE

Table 10-2-1 CORRELATION TABLE
Vol. IV BERYL FIELD

Well No.	1		2		3		4		5		6	
D.F.E.	112		112		112		112		112		41	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top Upper VI	3300	3188	2739	2627	6891	6779	3967	3855	3241	3129	3930	3889
Middle VI	5104	4992	3682	3570			5900	5788	4897	4785	5850	5809
Lower VI	7166	7054	5121	5009			8175	8063	6883	6771	8095	8054
V	8929	8817	6435	6323			10297	10185	8701	8589		
T.D.	11583	11471	10304	10192	9208	9096	11814	11702	9700	9588	12077	12036

Table 11-2-1 CORRELATION TABLE
Vol. IV SIWA FIELD

Well No.	4	
D.F.E.	109	
Cycle/Zone	Log	Subsea
Top Upper V Lower V		
Top a	1388	1279
Top b	1892	1783
Top c	2918	2809
Top d_1 d_2 d_3	3760 4011 4311	3651 3902 4202
Top e_1 e_2 e_3 e_4	4383 4662 4922 5391	4274 4553 4813 5282
Top f	6680	6571
T.D.	7579	7470

Table 12-2-1 CORRELATION TABLE
Vol. IV CENTRAL LUCONIA FIELD

Well No.	B12-1		E6-1		E8-1		E8-2		E8-3		E11-1	
D.F.E.	112		112		112		112		41		112	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top VI	3412	3300										
V	7019	6907	3372	3260	2242	2130	2350	2238	2140	2099	2725	2613
IV - III							6395	6283			6690	6578
Top "Carbonate Buildup"	10676	10564	5375	5263	4655	4543	4680	4568	-	-	4856	4744
T.D.	12337	12225	6267	6155	6300	6188	6432	6320	8792	8751	7238	7126

Table 12-2-1 (Continued)
Vol. IV

CORRELATION TABLE
CENTRAL LUCONIA FIELD

Well No.	E11-2		F6-1		F6-2		F9-1		F13-1		F13-2	
D.F.E.	112		112		112		112		112		112	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top VI			1530	1418	1719	1607	1918	1806				
V	2738	2626	-	-	-	-	-	-	2765	2653	2842	2730
IV - III	6825	6713							6940	6828	6814	6702
Top "Carbonate Buildup"	5590	5478	3636	3524	4149	4037	4416	4304	6339	6227	6180	6068
T.D.	6864	6752	4615	4503	5662	5550	5319	5207	7182	7070	7645	7533

Table 12-2-1 (Continued)
Vol. IV

CORRELATION TABLE
CENTRAL LUCONIA FIELD

Well No.	F13-3		F14-1		F22-1		F23-1		K4-1		M1-1	
D.F.E.	111		40		112		112		41		112	
Cycle/Zone	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top VI			1763	1696	1999	1887	1642	1530	1255	1214	4220	4108
V	2753	2642	-	-	4450	4338	-	-	3820	3779	-	-
IV - III												
Top "Carbonate Buildup"	6324	6213	4305	4265	6439	6327	3941	3829	4118	4077	4867	4755
T.D.	6476	6365	4845	4805	7550	7438	5123	5011	4686	4645	5527	5415

Table 12-2-1 (Continued) CORRELATION TABLE
Vol. IV CENTRAL LUCONIA FIELD

Well No.	M3-1		M5-1	
D.F.E.	112		111	
Cycle/Zone	Log	Subsea	Log	Subsea
Top VI	3589	3477	3319	3208
V	-	-	-	-
IV - III				
Top "Carbonate Buildup"	5652	5540	6468	6357
T.D.	6523	6411	7000	6889

Vol. IV Table 12-3-1

GAS COMPONENTS AND Z-FACTOR

CENTRAL LUCONIA B 12

Gas Component	MOL %
Methane	92.1
Ethane	3.0
Propane	1.2
Iso-Butane	0.2
N-Butane	0.3
Iso-Pentane	0.1
N-Pentane	0.1
Hexanes	0.1
Heptanes Plus	0.1
Hydrogen	
Helium	
Oxeygen	0.6
Nitrogen	1.6
Carbon Monoxide	
Carbon Dioxido	0.6
Hydrogen Sulphide	

Static Reservoir Pressure (PSIG)	Cumulative Production (10^{12} SCF)	Z-factor
5030.	0.0	1.0363
5000.	0.0018	1.0347
4800.	0.0140	1.0240
4600	0.0264	1.0133
4400.	0.0392	1.0025
4200.	0.0521	.9917
4000.	0.0653	.9807
3800.	0.0788	.9698
3600.	0.0926	.9589
3400.	0.1067	.9480
3200.	0.1229	.9424
3000.	0.1396	.9383
2800.	0.1564	.9342
2600.	0.1737	.9311
2400.	0.1913	.9293
2200.	0.2092	.9278
2000.	0.2278	.9304
1800.	0.2464	.9332
1600.	0.2649	.9360
1400.	0.2835	.9402
1200.	0.3019	.9449
1000.	0.3206	.9534
800.	0.3388	.9615
600.	0.3568	.9699
400.	0.3745	.9799
200.	0.3919	.9900
100.	0.4005	.9950

Reservoir Temperature (°F)	240.
Reservoir Pressure (PSIG)	5030.
Original Gas In Place (10^{12} SCF)	0.4089
Original Gas Formation Volume Factor (SCF/CFT)	245.81

Vol. IV Table 12-3-2

GAS COMPONENTS AND Z-FACTOR

CENTRAL LUCONIA E8

Gas Component	MOL %
Methane	88.4
Ethane	4.2
Propane	2.5
Iso-Butane	0.4
N-Butane	0.6
Iso-Pentane	0.2
N-Pentane	0.2
Hexanes	0.3
Heptanes Plus	0.2
Hydrogen	
Helium	0.2
Oxygen	0.2
Nitrogen	0.8
Carbon Monoxide	
Carbon Dioxido	2.0
Hydrogen Sulphide	

Static Reservoir Pressure (PSIG)	Cumulative Production (10^{12} SCF)	Z-factor
2545.	0.00	.8603
2400.	0.07	.8614
2200.	0.17	.8630
2000.	0.28	.8678
1800.	0.38	.8733
1600.	0.48	.8804
1400.	0.59	.8893
1200.	0.69	.9021
1000.	0.79	.9167
800.	0.89	.9314
600.	0.98	.9471
400.	1.08	.9647
200.	1.17	.9824
100.	1.21	.9912

Reservoir Temperature (°F)	162
Reservoir Pressure (PSIG)	2545
Original Gas In Place (10^{12} SCF)	1.25
Original Gas Formation Volume Factor (SCF/CFT)	656.5

Vol. IV Table 12-3-3

GAS COMPONENTS AND Z-FACTOR

CENTRAL LUTONIA F11

Gas Component	MOL %
Methane	83.7
Ethane	5.5
Propane	1.3
Iso-Butane	0.2
N-Butane	0.3
Iso-Pentane	0.1
N-Pentane	0.1
Hexanes	0.2
Heptanes Plus	0.2
Hydrogen	
Helium	
Oxygen	
Nitrogen	1.8
Carbon Monoxide	
Carbon Dioxido	6.6
Hydrogen Sulphide	

Static Reservoir Pressure (PSIG)	Cumulative Production (10^{12} SCF)	Z-factor
2890.	0.00	.8577
2800.	0.10	.8548
2600.	0.34	.8557
2400.	0.58	.8574
2200.	0.83	.8604
2000.	1.08	.8651
1800.	1.34	.8715
1600.	1.59	.8786
1400.	1.84	.8882
1200.	2.09	.9025
1000.	2.34	.9170
800.	2.57	.9316
600.	2.80	.9476
400.	3.03	.9651
200.	3.25	.9825
100.	3.35	.9915

Reservoir Temperature (°F)	177
Reservoir Pressure (PSIG)	2890
Original Gas In Place (10^{12} SCF)	3.45
Original Gas Formation Volume Factor (SCF/CFT)	187.0

Vol. IV Table 12-3-4

GAS COMPONENTS AND Z-FACTOR

CENTRAL LUCONIA F6

Gas Component	MOL %
Methane	88.7
Ethane	4.1
Propane	2.8
Iso-Butane	0.7
N-Butane	0.6
Iso-Pentane	0.2
N-Pentane	0.1
Hexanes	0.2
Heptanes Plus	0.1
Hydrogen	
Helium	
Oxygen	
Nitrogen	0.7
Carbon Monoxide	
Carbon Dioxido	1.8
Hydrogen Sulphide	0.9

Static Reservoir Pressure (PSIG)	Cumulative Production (10^{12} SCF)	Z-factor
2195.	0.00	.8204
2000.	0.53	.8261
1800.	1.09	.8348
1600.	1.64	.8454
1400.	2.18	.8571
1200.	2.73	.8738
1000.	3.26	.8908
800.	3.77	.9105
600.	4.26	.9319
400.	4.73	.9546
200.	5.18	.9773
100.	5.40	.9887

Reservoir Temperature (°F)	144
Reservoir Pressure (PSIG)	2195
Original Gas In Place (10^{12} SCF)	5.61
Original Gas Formation Volume Factor (SCF/CFT)	156.5

Vol. IV Table 12-3-5

GAS COMPONENTS AND Z-FACTOR

CENTRAL LUCONIA F13

Gas Component	MOL %
Methane	74.6
Ethane	4.8
Propane	1.1
Iso-Butane	0.2
N-Butane	0.2
Iso-Pentane	0,1
N-Pentane	0.1
Hexanes	0.1
Heptanes Plus	0.1
Hydrogen	
Helium	
Oxygen	0.1
Nitrogen	3.6
Carbon Monoxide	
Carbon Dioxido	15.0
Hydrogen Sulphide	

Static Reservoir Pressure (PSIG)	Cumulative Production (10^{12}SCF)	Z-factor
2950.	0.00	.8413
2800.	0.07	.8406
2600.	0.18	.8424
2400.	0.28	.8441
2200.	0.38	.8489
2000.	0.49	.8542
1800.	0.60	.8622
1600.	0.70	.8708
1400.	0.81	.8820
1200.	0.91	.8968
1000.	1.01	.9114
800.	1.11	.9274
600.	1.21	.9449
400.	1.30	.9632
200.	1.39	.9816
100.	1.43	.9908

Reservoir Temperature (°F)	182
Reservoir Pressure (PSIG)	2950
Original Gas In Place (10^{12}SCF)	1.48
Original Gas Formation Volume Factor (SCF/CFT)	679.1

Vol. IV Table 12-3-6

GAS COMPONENTS AND Z-FACTOR

CENTRAL LUCONIA F14

Gas Component	MOL %
Methane	84.7
Ethane	4.2
Propane	3.5
Iso-Butane	0.7
N-Butane	0.8
Iso-Pentane	0.3
N-Pentane	0.2
Hexanes	0.3
Heptanes Plus	0.1
Hydrogen	
Helium	
Oxygen	0.1
Nitrogen	3.3
Carbon Monoxide	
Carbon Dioxido	1.8
Hydrogen Sulphide	

Static Reservoir Pressure (PSIG)	Cumulative Production (10^{12} SCF)	Z-factor
2470.	0.00	.8266
2400.	0.04	.8273
2200.	0.14	.8296
2000.	0.25	.8353
1800.	0.36	.8426
1600.	0.47	.8525
1400.	0.57	.8635
1200.	0.68	.8790
1000.	0.78	.8957
800.	0.89	.9143
600.	0.98	.9346
400.	1.08	.9564
200.	1.17	.9782
100.	1.21	.9891

Reservoir Temperature (°F)	147
Reservoir Pressure (PSIG)	2470
Original Gas In Place (10^{12} SCF)	1.25
Original Gas Formation Volume Factor (SCF/CFT)	174.0

Vol. IV Table 12-3-7

GAS COMPONENTS AND Z-FACTOR

CENTRAL LUCONIA F23

Gas Component	MOL %
Methane	88.2
Ethane	3.7
Propane	2.8
Iso-Butane	0.8
N-Butane	0.7
Iso-Pentane	0.3
N-Pentane	0.1
Hexanes	0.2
Heptanes Plus	0.1
Hydrogen	
Helium	
Oxygen	
Nitrogen	0.9
Carbon Monoxide	
Carbon Dioxido	2.2
Hydrogen Sulphide	

Static Reservoir Pressure (PSIG)	Cumulative Production (10^{12}SCF)	Z-factor
2510.	0.00	.8310
2400.	0.26	.8321
2200.	0.73	.8346
2000.	1.22	.8401
1800.	1.71	.8475
1.600	2.20	.8569
1400.	2.68	.8677
1200.	3.16	.8831
1000.	3.63	.8993
800.	4.09	.9173
600.	4.53	.9369
400.	4.96	.9579
200.	5.36	.9790
100.	5.56	.9895

Reservoir Temperature (°F)	150
Reservoir Pressure (PSIG)	2510
Original Gas In Place (10^{12} SCF)	5.75
Original Gas Formation Volume Factor (SCF/CFT)	175.0

Vol. IV Table 12-3-8

GAS COMPONENTS AND Z-FACTOR

CENTRAL LUCONIA M 1

Gas Component	MOL %
Methane	87.5
Ethane	4.5
Propane	2.7
Iso-Butane	0.5
N-Butane	0.6
Iso-Pentane	0.2
N-Pentane	0.2
Hexanes	0.4
Heptanes Plus	0.2
Hydrogen	
Helium	
Oxeygen	
Nitrogen	0.4
Carbon Monoxide	
Carbon Dioxido	2.8
Hydrogen Sulphide	

Static Reservoir Pressure (PSIG)	Cumulative Production (10^{12} SCF)	Z-factor
3450.	0.0	.8697
3400.	0.0091	.8665
3200.	0.0513	.8592
3000.	0.0943	.8519
2800.	0.1380	.8446
2600.	0.1867	.8428
2400.	0.2383	.8446
2200.	0.2901	.8471
2000.	0.3431	.8523
1800.	0.3963	.8590
1600.	0.4494	.8673
1400.	0.5022	.8774
1200.	0.5552	.8921
1000.	0.6067	.9076
800.	0.6567	.9240
400.	0.7520	.9612
100.	0.8187	.9903

Reservoir Temperature (°F)	167.
Reservoir Pressure (PSIG)	3450.
Original Gas In Place (10^{12} SCF)	0.8401
Original Gas Formation Volume Factor (SCF/CFT)	224.59

Vol. IV Table 12-3-9

ESTIMATING BOTTOM HOLE FLOWING PRESSURE VS.
CUMULATIVE PRODUCTION

CENTRAL LUCONIA B 12

Cumulative Production (MMMMSCF)	Production Rate (MMSCF/D) Q=30	Q=20	Q=15	Q=10
	Bottom Hole Flowing Pressure (PSIG)			
0.0	4997.	5008.	5013.	5019.
0.0018	4967.	4978.	4983.	4989.
0.0140	4766.	4778.	4783.	4789.
0.0264	4566.	4577.	4583.	4589.
0.0392	4365.	4377.	4383.	4389.
0.0521	4165.	4177.	4183.	4188.
0.0653	3964.	3976.	3982.	3988.
0.0788	3764.	3776.	3782.	3788.
0.0926	3563.	3575.	3582.	3588.
0.1067	3362.	3375.	3381.	3387.
0.1229	3161.	3174.	3181.	3187.
0.1396	2959.	2973.	2980.	2987.
0.1564	2757.	2772.	2779.	2786.
0.1737	2555.	2570.	2578.	2585.
0.1913	2353.	2369.	2377.	2385.
0.2092	2149.	2167.	2175.	2183.
0.2278	1945.	1964.	1973.	1982.
0.2464	1740.	1761.	1771.	1781.
0.2649	1534.	1557.	1568.	1579.
0.2835	1362.	1351.	1364.	1376.
0.3019	1114.	1144.	1158.	1173.
0.3206	897.	933.	950.	967.
0.3388	668.	716.	738.	759.
0.3568	412.	484.	516.	545.
0.3745		193.	261.	314.
0.3919				

Vol. IV Table 12-3-10

PREDICTED PERFORMANCE CASE 1

CENTRAL LUCONIA E6

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	GAS (MMMSCF)	WATER (MMSTB)
1.00	2628	4.85	30.00	14.49	483	0.0	10.951	5.289	0.0
2.00	2595	9.69	30.00	16.50	550	0.0	21.902	11.310	0.0
3.00	2552	14.54	30.00	27.57	919	0.0	32.854	21.374	0.0
4.00	2493	19.38	30.00	49.06	1635	0.0	43.805	39.280	0.0
5.00	2392	23.80	27.38	106.23	3880	0.0	53.797	78.055	0.0
6.00	2267	27.29	21.56	166.73	7733	0.0	61.667	138.913	0.0
7.00	2082	30.05	17.08	225.56	13206	0.0	67.902	221.242	0.0
8.00	1881	32.17	13.15	281.09	21376	0.0	72.702	323.841	0.0
9.00	1637	33.90	10.73	319.37	29764	0.0	76.620	440.410	0.0
10.00	1406	35.34	8.89	354.24	39847	0.0	79.865	569.708	0.0
11.00	1136	36.47	6.99	369.36	52841	0.0	82.417	704.523	0.0
11.25	1082	36.71	5.93	359.33	60596	0.0	82.958	737.312	0.0

Vol. IV Table 12-3-11

PREDICTED PERFORMANCE CASE 2

CENTRAL LUCONIA E6

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	OIL PROD. RATE (MSTB/D)	GAS PROD. RATE (MMSCF/D)	G.O.R. (SCF/STB)	W.O.R. (STB/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	CUMULATIVE PRODUCTION WATER (MMSTB)
1.00	2628	4.85	30.00	14.49	483	0.0	10.951	5.289	0.0
2.00	2595	9.69	30.00	16.50	550	0.0	21.902	11.310	0.0
3.00	2552	14.54	30.00	27.57	919	0.0	32.854	21.374	0.0
4.00	2493	19.38	30.00	49.06	1635	0.0	43.805	39.280	0.0
5.00	2392	23.80	27.38	106.24	3880	0.0	53.798	78.057	0.0
6.00	2267	27.29	21.56	166.73	7733	0.0	61.667	138.913	0.0
7.00	2104	29.80	15.55	200.27	12879	0.0	67.344	212.013	0.0
8.00	1950	31.46	10.27	200.02	19476	0.0	71.091	285.021	0.0
9.00	1815	32.73	7.89	200.02	25351	0.0	73.972	358.029	0.0
10.00	1658	33.78	6.50	200.02	30773	0.0	76.343	431.037	0.0
11.00	1524	34.66	5.44	200.02	36769	0.0	78.327	504.045	0.0
12.00	1392	35.41	4.66	200.02	42923	0.0	80.027	577.052	0.0
13.00	1229	36.05	3.95	200.02	50638	0.0	81.469	650.060	0.0
14.00	1106	36.60	3.44	200.02	58146	0.0	82.724	723.068	0.0
14.50	1041	36.86	3.24	200.02	61735	0.0	83.315	759.572	0.0

Vol. IV Table 12-3-12

ESTIMATING BOTTOM HOLE FLOWING PRESSURE VS. CUMULATIVE PRODUCTION

CENTRAL LUCONIA E8

Cumulative Production (MMMMSCF)	Production Rate (MMSCF/D) Q=30	Q=20	Q=15	Q=10
	Bottom Hole Flowing Pressure (PSIG)			
0.00	2527.	2533.	2536.	2539.
0.07	2382.	2388.	2391.	2394.
0.17	2181.	2187.	2190.	2194.
0.28	1979.	1986.	1990.	1993.
0.38	1778.	1785.	1789.	1793.
0.48	1575.	1584.	1588.	1592.
0.59	1373.	1382.	1387.	1391.
0.69	1169.	1179.	1185.	1190.
0.79	963.	975.	982.	988.
0.89	754.	770.	777.	785.
0.98	544.	563.	573.	582.
1.08	342.	362.	372.	382.
1.17	135.	160.	171.	182.
1.21	11.	57.	20.	82.

Vol. IV Table 12-3-13

ESTIMATING BOTTOM HOLE FLOWING PRESSURE VS. CUMULATIVE PRODUCTION

CENTRAL LUCONIA E11

Cumulative Production (MMMMSCF)	Production Rate (MMSCF/D) Q=30	Q=20	Q=15	Q=10
	Bottom Hole Flowing Pressure (PSIG)			
0.00	2839.	2857.	2865.	2873.
0.10	2749.	2766.	2775.	2783.
0.34	2546.	2565.	2574.	2583.
0.58	2344.	2363.	2372.	2382.
0.83	2140.	2161.	2171.	2181.
1.08	1936.	1958.	1968.	1979.
1.34	1730.	1754.	1766.	1777.
1.59	1523.	1550.	1563.	1575.
1.84	1314.	1344.	1358.	1372.
2.09	1100.	1135.	1152.	1168.
2.34	879.	922.	942.	962.
2.57	646.	702.	728.	753.
2.80	410.	483.	515.	545.
3.03	174.	273.	310.	343.
3.25		161.	92.	138.
3.35				21.

Vol. IV. Table 12-3-14

ESTIMATING BOTTOM HOLE FLOWING PRESSURE VS.
CUMULATIVE PRODUCTION

CENTRAL LUCONIA F6

Cumulative Production (MMMMSCF)	Q=30	Q=20	Q=15	Q=10
	Production Rate (MMSCF/D)			
	Bottom Hole Flowing Pressure (PSIG)			
0.00	2094.	2129.	2146.	2163.
0.53	1893.	1930.	1948.	1966.
1.09	1683.	1724.	1744.	1763.
1.64	1471.	1516.	1538.	1559.
2.18	1254.	1306.	1331.	1355.
2.73	1029.	1091.	1120.	1148.
3.26	792.	869.	905.	938.
3.77	524.	633.	680.	723.
4.26	205.	389.	452.	507.
4.73		133.	233.	300.
5.18				73.
5.40				

Vol. IV Table 12-3-15

ESTIMATING BOTTOM HOLE FLOWING PRESSURE VS. CUMULATIVE PRODUCTION

CENTRAL LUCONIA F13

Cumulative Production (MMMMSCF)	Production Rate (MMSCF/D) Q=30	Q=20	Q=15	Q=10
	Bottom Hole Flowing Pressure (PSIG)			
0.00	2735.	2812.	2849.	2884.
0.07	2578.	2658.	2696.	2732.
0.18	2367.	2451.	2491.	2529.
0.28	2153.	2243.	2285.	2325.
0.38	1935.	2033.	2078.	2121.
0.49	1712.	1819.	1868.	1914.
0.60	1481.	1601.	1656.	1707.
0.70	1239.	1378.	1440.	1497.
0.81	978.	1146.	1218.	1284.
0.91	671.	896.	985.	1064.
1.01	175.	611.	733.	835.
1.11		168.	433.	586.
1.21				337
1.30				
1.39				
1.43				

Vol. IV •Table 12-3-16

ESTIMATING BOTTOM HOLE FLOWING PRESSURE VS.
CUMULATIVE PRODUCTION

CENTRAL LUCONIA F14

Cumulative Production (MMMMSCF)	Production Rate (MMSCF/D) Q=30	Q=20	Q=15	Q=10
	Bottom Hole Flowing Pressure (PSIG)			
0.00	2366.	2403.	2420.	2437.
0.04	2295.	2331.	2349.	2367.
0.14	2089.	2128.	2147.	2165.
0.25	1881.	1923.	1943.	1963.
0.36	1671.	1717.	1738.	1760.
0.47	1457.	1508.	1532.	1556.
0.57	1238.	1297.	1324.	1350.
0.68	1010.	1080.	1112.	1143.
0.78	767.	855.	895.	932.
0.89	487.	614.	667.	715.
0.98	62.	355.	432.	496.
1.08		38.	204.	287.
1.17				39.
1.21				

Vol. IV Table 12-3-17

ESTIMATING BOTTOM HOLE FLOWING PRESSURE VS. CUMULATIVE PRODUCTION

CENTRAL LUCONIA F23

Cumulative Production (MMMMSCF)	Production Rate (MMSCF/D) Q=30	Q=20	Q=15	Q=10
	Bottom Hole Flowing Pressure (PSIG)			
0.00	2497.	2561.	2504.	2506.
0.26	2387.	2391.	2393.	2396.
0.73	2186.	2191.	2193.	2195.
1.22	1985.	1990.	1993.	1985.
1.71	1784.	1789.	1792.	1795.
2.20	1582.	1588.	1591.	1594.
2.68	1380.	1387.	1390.	1394.
3.16	1177.	1185.	1189.	1193.
3.63	973.	982.	987.	991.
4.09	767.	778.	784.	789.
4.53	561.	574.	581.	587.
4.96	359.	373.	380.	387.
5.36	156.	172.	180.	187.
5.56	48.	71.	79.	87.

Vol. IV Table 12-3-18

ESTIMATING BOTTOM HOLE FLOWING PRESSURE VS. CUMULATIVE PRODUCTION

CENTRAL LUCONIA M 1

Cumulative Production (MMMMSCF)	Q=30	Q=20	Q=15	Q=10
	Bottom Hole Flowing Pressure (PSIG)			
0.0	3406.	3421.	3428.	3436.
0.0091	3356.	3371.	3378.	3386.
0.0513	3155.	3170.	3178.	3185.
0.0943	2954.	2970.	2977.	2985.
0.1380	2753.	2769.	2777.	2785.
0.1867	2551.	2568.	2576.	2584.
0.2383	2349.	2366.	2375.	2383.
0.2901	2146.	2164.	2173.	2182.
0.3431	1942.	1962.	1972.	1981.
0.3963	1737.	1759.	1769.	1780.
0.4494	1530.	1555.	1566.	1578.
0.5022	1322.	1349.	1362.	1375.
0.5552	1110.	1141.	1157.	1171.
0.6067	892.	930.	948.	966.
0.6567	663.	713.	736.	758.
0.7052	403.	479.	513.	544.
0.7520		180.	254.	311.
0.7969				

Production Rate (MMSCF/D)

Table 13-4-1
(Vol. IV)

OIL AND GAS PRODUCTION RATE

OF

EACH FIELD IN LUTONG STREAM

FIELD	OIL (BPD)	GAS (MMSCFD)
BARONIA	49,162	106.1
FAIRLEY-BARAM	11,705	21.6
WEST LUTONG	14,333	35.2
BARAM	30,683	117.4
BAKAU	5,203	10.5
TUKAU	13,031	17.6
TOTAL	124,117	308.4

NOTE

* AVERAGE PRODUCTION IN MAY, 1976

Table 13-4-2 (Vol. IV) MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION BNP-A

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100 & 101	2	Hori.	72"øx20'	30,000	385/250
LP Separator V-200 & 201	2	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300 & 301	2	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	Vert.	72"øx20'		385

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 805	5	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 13-4-3 (Vol. IV) MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION BAP-A

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100 & 101	2	Hori.	72"øx20'	30,000	385/250
LP Separator V-200 & 201	2	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300 & 301	2	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	Vert.	72"øx20'		385

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 805	5	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 13-4-4 (Vol. IV)

MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION BAP-B

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100	1	Hori.	72"øx20'	30,000	385/250
LP Separator V-200	1	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300	1	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	Vert.	72"øx20'		385

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 803	3	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 13-4-5 (Vol. IV) MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION BKP-A

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100	1	Hori.	72"øx20'	30,000	385/250
LP Separator V-200	1	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300	1	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	ditto	60"øx15'		385

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 803	3	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 13-4-6 (Vol. IV) MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION WLP-A

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100	1	Hori.	72"øx20'	30,000	385/250
LP Separator V-200	1	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300	1	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	N/A	N/A		385
Gas Lift Separator V-500	1	ditto (installed on WLDP-A)	36"øx10.'		1,440/950

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 803	3	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 13-4-7 (Vol. IV) **MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION WLP-C**

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100	1	Hori.	72" øx20'	30,000	385/250
LP Separator V-200	1	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300	1	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	Vert.	70"øx20'		385

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 803	3	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 13-4-8 (Vol. IV)

MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION TKP-A

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100	1	Hori.	72"øx20'	30,000	385/250
LP Separator V-200 &	1	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300 &	1	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	ditto	60"øx15'		385
Gas Lift Separator V-500	1	ditto	42"øx15'		1,440/950

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 803	3	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 13-4-9 (Vol. IV) MAJOR EQUIPMENT SPECIFICATIONS OF PRODUCTION STATION TKP-B

SEPARATOR

Name & Tag No.	No.	Type	Size	Design Capacity BPD	Pressure Design/ Operation PSIG
HP Separator V-100	1	Hori.	72"øx20'	30,000	385/250
LP Separator V-200	1	ditto	72"øx20'	30,000	125/50
Surge Vessel V-300	1	ditto	126"øx32'	30,000	85/10
Test Separator V-400	1	N/A	N/A		385

PUMP

Name & Tag No.	No.	Capacity BPD	Type	Header Suction/ Discharge
Crude Oil Transfer Pump P-801 - 803	3	13,000	Recipro. Gas Expansion Driven	20" 150# ANSI/ 8" 600# ANSI

ELECTRICAL GENERATOR

No.	Type	Voltage volts	Phase	Frequency Hz	Capacity Kw	Speed RPM	Service
1	Gas Expansion Turbine-driven	415	3	50	20	1,500	Lighting, Instr., etc.

Table 13-4-10
(Vol. IV)

PRESSURE LOSS AND FLOW VELOCITY IN LOADING LINES FOR BERTH NO. 2

Flow Rate : 13,860 BPH

Section		Pressure Loss	Max. Velocity in This
From	To	PSI	Section, FT/SEC
Lutong Terminal	Manifold Platform	100	7.0
Manifold Platform	SBM	76	13.9
SBM	Hose End	20	13.7

Table 13-4-11
(Vol. IV)

PRESSURE LOSS AND FLOW VELOCITY IN LOADING LINES FOR BERTH NO. 4

Flow Rate Case 1: 13,860 BPH
Case 2: 19,530 BPH

Section		Pressure Loss PSI		Max. Velocity in This Section, FT/SEC	
From	To	Case 1	Case 2	Case 1	Case 2
Lutong Terminal	Manifold Platform	55	59	6.3	6.6
Manifold Platform	SBM	13	24	6.3	8.9
SBM	Hose End	22	41	13.7	19.4

Table 13-4-12
(Vol. IV)

PRELIMINARY CAPITAL INVESTMENT COST
AND UTILITIES REQUIREMENTS FOR WASH TANK SYSTEM

I. CAPITAL INVESTMENT

		M$
FREE WATER KNOCKOUT	100,000BPD	203,000
DIRECT FIRED HEATER	100,000BPD	381,000
WASH TANK	100,000BBLS	2,032,000
PUMPS		178,000
PIPING		559,000
ELECTRICAL EQUIPMENT		279,000
INSTRUMENT EQUIPMENT		381,000
TOTAL		4,013,000

II. UTILITIES REQUIREMENTS

1.	FUEL	MMBTU/HR	13
	EQUIVALENT TO NATURAL GAS	SCFPD	40,000
2.	ELECTRICAL POWER	KW	200

Table 14-5-1 (Vol. IV)

MAJOR EQUIPMENT LIST

FOR BARONIA OIL FIELD AND B-12 GAS FIELD GAS UTILIZATION-CASE IA

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V - 101 PRODUCTION SEPARATOR	B12WP-A	1	SIZE: 5'-0" I.D. x 15'-0" S-S DESIGN PRESS.: 1,500 PSIG @ 150°F TYPE: HORIZONTAL
V- 102 TEST SEPARATOR	B12WP-A	1	SIZE: 5'-0" I.D. x 15'-0" S-S DESIGN PRESS.: 1,500 PSIG @ 150°F TYPE: HORIZONTAL
V - 103 LIQUID KNOCKOUT DRUM	B12WP-A	2	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 1,500 PSIG @ 150°F TYPE: VERTICAL
V - 104 GLYCOL CONTACTOR	B12WP-A	1	SIZE: 4'-9" I.D. x 27'-6" S-S DESIGN PRESS.: 1,500 PSIG @ 150°F TYPE: VERTICAL
V - 105 CONDENSATE SURGE VESSEL	B12WP-A	1	SIZE: 4'-6" I.D. x 15'-0" S-S DESIGN PRESS.: 1,500 PSIG @ 150°F TYPE: HORIZONTAL
GR - 101 GLYCOL REGENERATOR	B12WP-A	1	REBOILER: 36" DIA. x 17'-6" L STILL COLUMN: 24" DIA. x 11'-0" L SURGE TANK: 36" DIA. x 17'-6" L
H - 101 START-UP HEATER	B12WP-A	1	SIZE: 24" DIA. x 7'-6" L
C - 151 INSTRUMENT AIR COMPRESSOR	B12WP-A	2	CAPACITY: 35 SCFM
P - 152 FIRE WATER PUMP	B12WP-A	1	CAPACITY: 1,500 GPM TYPE: VERTICAL
TK - 101 CORROSION INHIBITOR TANK	B12WP-A	1	CAPACITY: 20 BBL SIZE: 5'-0" I.D. x 8'-0" H
TK - 102 GLYCOL STORAGE TANK	B12WP-A	1	CAPACITY: 20 BBL SIZE: 5'-0" I.D. x 8'-0" H
M - 101 INLET MANIFOLD	B12WP-A	1	PRODUCTION HEADER AND TEST HEADER
G - 152 GAS TURBINE GENERATOR	B12WP-A	2	CAPACITY: 1,000 KVA

Table 14-6-1 (Vol. IV) **CAPITAL INVESTMENT COST ESTIMATION**

BARONIA OIL FIELD AND B-12 GAS FIELD
GAS UTILIZATION

(M$ 1,000)

		CASE I A
1.	Exploration & Appraisal Wells	4,145
2.	Engineering	8,918
3.	Development Wells	25,400
4.	Facilities	
	a. Offshore Platforms	23,899
	b. Offshore Production Equipment	5,080
	c. Submarine Pipelines	34,796
	d. Offshore Storage & Loading Facilities .	-
	e. Onshore Terminal & Loading Facilities .	-
	f. Support Facilities	-
	Sub Total	63,775
5.	Pre-start up Expense	980
6.	Contingencies	9,809
	TOTAL	113,027

Table 14-6-2 (Vol. IV)

ANNUAL OPERATION COST ESTIMATION

(M$ 1,000/Year)

BARONIA OIL FIELD AND B-12 GAS FIELD
GAS UTILIZATION

	CASE I A
1. Direct Cost	
a. Operating Personnel	48
b. Operating Management	5
c. Repair & Maintenance	1,359
d. Operating Supplies	324
e. Chemical	69
f. Service Contract	1,778
Sub Total	3,583
2. Indirect Cost	
a. Indirect Personnel	28
b. Insurance	1,198
Sub Total	1,226
TOTAL	4,809

Table 14-6-3 (Vol. IV) INVESTMENT SCHEDULE

BARONIA OIL FIELD AND B-12 GAS FIELD GAS UTILIZATION CASE I A

(M$ 1,000)

Item / Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	4,145	-		
2. Engineering	8,918	-		
3. Development Wells	-	25,400		
4. Offshore Platforms	15,227	8,672		
5. Offshore Production Equipment	-	5,080		
6. Submarine Pipelines	3,988	30,808		
7. Offshore Storage & Loading Facilities	-	-		
8. Onshore Terminal & Loading Facilities	-	-		
9. Support Facilities	-	-		
10. Pre-start up Expense	281	699		
11. Contingencies	2,813	6,996		
Total	35,372	77,655		

****
* E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T *
****

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS

VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* P R E M I S E S *

PRODUCTION LIFE	: 20 YEARS
PRE-STARTUP PERIOD	: 2 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C   T E R M S   O F   P/S   A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 25.00 %
PROFIT GAS SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	35372.	77655.	0.	0.	0.	0.	0.	0.	0.	0.	113027.
GAS PRODUCTION (MMSCF/DAY)	0.	0.	37.	37.	37.	37.	37.	37.	37.	37.	296.
SALES PRICE OF GAS (M¢/MSCF)	0.0	0.0	430.0	430.0	430.0	430.0	430.0	430.0	430.0	430.0	

TERM	11	12	13	14	15	16	17	18	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	113027.
GAS PRODUCTION (MMSCF/DAY)	37.	37.	37.	37.	37.	37.	37.	37.	37.	37.	666.
SALES PRICE OF GAS (M¢/MSCF)	430.0	430.0	430.0	430.0	430.0	430.0	430.0	430.0	430.0	430.0	

* E C O N O M I C A N A L Y S I S F O R M A L A Y S I A P R O J E C T *

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS

VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* INPUT DATA BY YEAR *

TERM	21	22	22YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	113027.
GAS PRODUCTION (MMSCF/DAY)	37.	37.	740.
SALES PRICE OF GAS (M¢/MSCF)	430.0	430.0	

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS

VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 3

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	26423.	26423.	26423.	26423.	26423.	26423.	26423.	26423.	211380.
2 BONUS FROM OIL COMPANY	0.	0.	2500.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	2500.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	0.	0.	129.	129.	129.	129.	129.	129.	129.	129.	1034.
4 TOTAL CASH INFLOW	0.	0.	29052.	26552.	26552.	26552.	26552.	26552.	26552.	26552.	214914.
5 INCOME TAX	0.	0.	13073.	11948.	11948.	11948.	11948.	11948.	11948.	11948.	96711.
6 NET CASH FLOW	0.	0.	15978.	14603.	14603.	14603.	14603.	14603.	14603.	14603.	
7 CUMULATIVE NET CASH FLOW	0.	0.	15978.	30582.	45185.	59789.	74392.	88996.	103599.	118203.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	26423.	26423.	26423.	26423.	26423.	26423.	26423.	26423.	26423.	26423.	475605.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	129.	129.	129.	112.	81.	81.	81.	81.	81.	81.	2017.
4 TOTAL CASH INFLOW	26552.	26552.	26552.	26534.	26503.	26503.	26503.	26503.	26503.	26503.	480122.
5 INCOME TAX	11948.	11948.	11948.	11940.	11926.	11926.	11926.	11926.	11926.	11926.	216055.
6 NET CASH FLOW	14603.	14603.	14603.	14594.	14577.	14577.	14577.	14577.	14577.	14577.	
7 CUMULATIVE NET CASH FLOW	132806.	147409.	162013.	176607.	191184.	205760.	220337.	234914.	249491.	264067.	

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS

VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

TERM	21	22	22YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	26423.	26423.	528450.
2 BONUS FROM OIL COMPANY	0.	0.	2500.
DISCOVERY BONUS	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	81.	81.	2178.
4 TOTAL CASH INFLOW	26503.	26503.	533129.
5 INCOME TAX	11926.	11926.	239907.
6 NET CASH FLOW	14577.	14577.	
7 CUMULATIVE NET CASH FLOW	278644.	293221.	

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS

VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

** PRESENT WORTH OF NET CASH FLOW FOR PETRONAS **
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	14144.	12311.	11725.	11166.	10635.	10128.	9646.	9187.
CUMULATIVE PRESENT WORTH	0.	0.	14144.	26455.	38179.	49346.	59981.	70109.	79755.	88942.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	12591.	10461.	9510.	8646.	7860.	7145.	6496.	5905.
CUMULATIVE PRESENT WORTH	0.	0.	12591.	23052.	32562.	41208.	49068.	56213.	62708.	68613.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	11267.	8954.	7786.	6770.	5887.	5119.	4452.	3871.
CUMULATIVE PRESENT WORTH	0.	0.	11267.	20220.	28006.	34777.	40664.	45784.	50235.	54106.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	8749.	8333.	7936.	7553.	7185.	6843.	6517.	6207.	5911.	5630.
CUMULATIVE PRESENT WORTH	97691.	106024.	113959.	121512.	128697.	135540.	142057.	148263.	154174.	159804.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	5368.	4880.	4437.	4031.	3660.	3327.	3025.	2750.	2500.	2273.
CUMULATIVE PRESENT WORTH	73982.	78862.	83298.	87329.	90989.	94316.	97341.	100091.	102590.	104863.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	3366.	2927.	2545.	2212.	1921.	1671.	1453.	1263.	1098.	955.
CUMULATIVE PRESENT WORTH	57473.	60400.	62945.	65157.	67078.	68748.	70201.	71464.	72562.	73517.

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS

VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	21	22
PRESENT WORTH		
5.00% DISCOUNT RATE	0.37	0.35
PRESENT WORTH	5362.	5106.
CUMULATIVE PRESENT WORTH	165166.	170272.
10.00% DISCOUNT RATE	0.14	0.13
PRESENT WORTH	2066.	1878.
CUMULATIVE PRESENT WORTH	106929.	108807.
15.00% DISCOUNT RATE	0.06	0.05
PRESENT WORTH	831.	722.
CUMULATIVE PRESENT WORTH	74348.	75070.

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS
VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	11324.	11324.	11324.	11324.	11324.	11324.	11324.	11324.	90592.
2 SALES REVENUE FROM COST GAS	0.	0.	14518.	14518.	14518.	14518.	14518.	14518.	14518.	14518.	116143.
3 SALES REVENUE FROM ROYALTY GAS	0.	0.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	46457.
4 TOTAL CASH INFLOW	0.	0.	31649.	31649.	31649.	31649.	31649.	31649.	31649.	31649.	253192.
5 ROYALTY	0.	0.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	46457.
6 BONUS	0.	0.	2500.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	2500.	0.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	0.	0.	129.	129.	129.	129.	129.	129.	129.	129.	1034.
OPERATING EXPENSES	0.	0.	14518.	14518.	14518.	14518.	14518.	14518.	14518.	14518.	116143.
8 OPERATING COST	0.	0.	4809.	4809.	4809.	4809.	4809.	4809.	4809.	4809.	38472.
CAPITAL COST RECOVERY	0.	0.	9709.	9709.	9709.	9709.	9709.	9709.	9709.	9709.	77671.
INCOME BEFORE TAX	0.	0.	8695.	11195.	11195.	11195.	11195.	11195.	11195.	11195.	87058.
9 INCOME TAX	0.	0.	3913.	5038.	5038.	5038.	5038.	5038.	5038.	5038.	39176.
10 CAPITAL INVESTMENT	35372.	77655.	0.	0.	0.	0.	0.	0.	0.	0.	113027.
11 TOTAL CASH OUTFLOW	35372.	77655.	17158.	15783.	15783.	15783.	15783.	15783.	15783.	15783.	240666.
12 NET CASH FLOW	-35372.	-77655.	14491.	15866.	15866.	15866.	15866.	15866.	15866.	15866.	
13 CUMULATIVE NET CASH FLOW	-35372.	-113027.	-98536.	-82670.	-66804.	-50938.	-35072.	-19206.	-3340.	12526.	
14 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.21	
15 CORPORATE CAPITAL	35372.	77655.	0.	0.	0.	0.	0.	0.	0.	0.	113027.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.2 YEARS

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS
VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 8

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	11324.	11324.	11324.	11324.	11324.	11324.	11324.	11324.	11324.	11324.	203831.
2 SALES REVENUE FROM COST GAS	14518.	14518.	14518.	11039.	4809.	4809.	4809.	4809.	4809.	4809.	199588.
3 SALES REVENUE FROM ROYALTY GAS	5807.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	104529.
4 TOTAL CASH INFLOW	31649.	31649.	31649.	28170.	21940.	21940.	21940.	21940.	21940.	21940.	507949.
5 ROYALTY	5807.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	5807.	104529.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	129.	129.	129.	112.	81.	81.	81.	81.	81.	81.	2017.
OPERATING EXPENSES	14518.	14518.	14518.	11039.	4809.	4809.	4809.	4809.	4809.	4809.	199589.
8 OPERATING COST	4809.	4809.	4809.	4809.	4809.	4809.	4809.	4809.	4809.	4809.	86562.
CAPITAL COST RECOVERY	9709.	9709.	9709.	6230.	0.	0.	0.	0.	0.	0.	113027.
INCOME BEFORE TAX	11195.	11195.	11195.	11212.	11243.	11243.	11243.	11243.	11243.	11243.	199313.
9 INCOME TAX	5038.	5038.	5038.	5045.	5059.	5059.	5059.	5059.	5059.	5059.	89691.
10 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	113027.
11 TOTAL CASH OUTFLOW	15783.	15783.	15783.	15773.	15756.	15756.	15756.	15756.	15756.	15756.	398325.
12 NET CASH FLOW	15866.	15866.	15866.	12396.	6184.	6184.	6184.	6184.	6184.	6184.	
13 CUMULATIVE NET CASH FLOW	28392.	44258.	60124.	72520.	78704.	84888.	91071.	97255.	103439.	109623.	
14 DCF ROR OF NET CASH FLOW (%)	4.39	6.05	7.35	8.16	8.51	8.81	9.07	9.29	9.49	9.67	
15 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	113027.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.2 YEARS

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS
VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	22YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	11324.	11324.	226479.
2 SALES REVENUE FROM COST GAS	4809.	4809.	209206.
3 SALES REVENUE FROM ROYALTY GAS	5807.	5807.	116143.
4 TOTAL CASH INFLOW	21940.	21940.	551829.
5 ROYALTY	5807.	5807.	116143.
6 BONUS	0.	0.	2500.
DISCOVERY BONUS	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	81.	81.	2178.
OPERATING EXPENSES	4809.	4809.	209207.
8 OPERATING COST	4809.	4809.	96180.
CAPITAL COST RECOVERY	0.	0.	113027.
INCOME BEFORE TAX	11243.	11243.	221800.
9 INCOME TAX	5059.	5059.	99810.
10 CAPITAL INVESTMENT	0.	0.	113027.
11 TOTAL CASH OUTFLOW	15756.	15756.	429838.
12 NET CASH FLOW	6184.	6184.	
13 CUMULATIVE NET CASH FLOW	115806.	121990.	
14 DCF ROR OF NET CASH FLOW (%)	9.82	9.95	
15 CORPORATE CAPITAL	0.	0.	113027.
16 INTEREST	0.	0.	0.
17 BANK BORROWING	0.	0.	0.
18 REPAYMENT	0.	0.	0.
19 BORROWING BALANCE	0.	0.	

20 PAYOUT TIME 9.2 YEARS

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS

VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-34520.	-72175.	12827.	13375.	12738.	12132.	11554.	11004.	10480.	9981.
CUMULATIVE PRESENT WORTH	-34520.	-106694.	-93867.	-80492.	-67754.	-55622.	-44067.	-33064.	-22584.	-12603.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-33726.	-67310.	11419.	11366.	10332.	9393.	8539.	7763.	7057.	6416.
CUMULATIVE PRESENT WORTH	-33726.	-101036.	-89617.	-78252.	-67919.	-58526.	-49987.	-42224.	-35167.	-28751.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-32985.	-62968.	10218.	9728.	8459.	7356.	6396.	5562.	4837.	4206.
CUMULATIVE PRESENT WORTH	-32985.	-95953.	-85735.	-76007.	-67548.	-60192.	-53796.	-48234.	-43397.	-39192.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	9506.	9053.	8622.	6416.	3048.	2903.	2765.	2633.	2508.	2388.
CUMULATIVE PRESENT WORTH	-3097.	5956.	14578.	20994.	24042.	26945.	29709.	32342.	34850.	37238.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	5832.	5302.	4820.	3424.	1553.	1411.	1283.	1167.	1060.	964.
CUMULATIVE PRESENT WORTH	-22919.	-17617.	-12797.	-9373.	-7820.	-6409.	-5126.	-3959.	-2899.	-1935.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	3657.	3180.	2765.	1879.	815.	709.	616.	536.	466.	405.
CUMULATIVE PRESENT WORTH	-35534.	-32354.	-29589.	-27710.	-26895.	-26187.	-25570.	-25034.	-24568.	-24163.

TABLE 14-6-4 CASH FLOW TABLE FOR GAS BARONIA OIL FIELD AND B-12 GAS FIELD GAS

VOL.IV UTILIZATION CASE I A : NATURAL FLOW CASE

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22
PRESENT WORTH		
5.00% DISCOUNT RATE	0.37	0.35
PRESENT WORTH	2274.	2166.
CUMULATIVE PRESENT WORTH	39512.	41679.
10.00% DISCOUNT RATE	0.14	0.13
PRESENT WORTH	876.	797.
CUMULATIVE PRESENT WORTH	-1058.	-261.
15.00% DISCOUNT RATE	0.06	0.05
PRESENT WORTH	352.	306.
CUMULATIVE PRESENT WORTH	-23811.	-23505.

Table 15-5-1 (Vol. IV)

MAJOR EQUIPMENT LIST

FOR BETTY AND BOKOR OIL FIELDS-CASE I

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V - 1 1ST STAGE PRODUCTION SEPARATOR	BTWP-A	1	SIZE: 5'-6" I.D. x 16'-6" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
	BOWP-A	1	SIZE: 4'-0" I.D. x 12'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
V - 2 2ND STAGE PRODUCTION SEPARATOR	BTWP-A	1	SIZE: 5'-6" I.D. x 16'-6" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
	BOWP-A	1	SIZE: 4'-0" I.D. x 12'-0" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
V - 3 3RD STAGE PRODUCTION SEPARATOR	BTWP-A	1	SIZE: 12'-0" I.D.x 24'-0" S-S DESIGN PRESS.: 50 PSIG @150°F TYPE: HORIZONTAL
	BOWP-A	1	SIZE: 9'-0" I.D. x 18'-0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
V - 4 TEST SEPARATOR	BTWP-A BOWP-A BOW-A BOW-B	1 1 1 1	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
C - 151 INSTRUMENT AIR COMPRESSOR	BTWP-A BOWP-A	2 2	CAPACITY: 35 SCFM
P - 2 CRUDE TRANSFER PUMP	BTWP-A	2	CAPACITY: 470 GPM TYPE: HORIZONTAL
	BOWP-A	2	CAPACITY 150 GPM TYPE: HORIZONTAL
P - 152 FIRE WATER PUMP	BTWP-A BOWP-A	1 1	CAPACITY: 1,500 GPM TYPE: VERTICAL
TK - 1 DEEMULSIFIER TANK	BTWP-A BOWP-A	1 1	SIZE: 6'-0" I.D. x 15'-6" H
TK - 2 DEFOAMANT TANK	BTWP-A BOWP-A	1 1	SIZE: 6'-0" I.D. x 15'-6" H
TK - 152 DIESEL STORAGE TANK	BTWP-A BOWP-A	1 1	CAPACITY: 500 BBL SIZE: 15'-6" I.D. x 16'-0" H
M - 1 INLET MANIFOLD	BTWP-A BOWP-A	1 1	HIGH PRESSURE HEADER LOW PRESSURE HEADER TEST HEADER
G - 151 DIESEL DRIVEN GENERATOR	BTWP-A BOWP-A	2 2	CAPACITY: 300 KVA
FM - 1 FLOW METER	BTWP-A	1	DESIGN RATE: 500 GPM (MAX.)
	BOWP-A	1	DESIGN RATE: 180 GPM (MAX.)

Table 15-6-1 (Vol. IV) **CAPITAL INVESTMENT COST ESTIMATION**

(M$ 1,000)

BETTY AND BOKOR OIL FIELDS	CASE I	CASE II
1. Exploration & Appraisal Wells	26,711	11,821
2. Engineering	16,830	9,037
3. Development Wells	76,543	53,009
4. Facilities		
a. Offshore Platforms	61,783	22,951
b. Offshore Production Equipment	7,940	3,970
c. Submarine Pipelines	22,029	10,444
d. Offshore Storage & Loading Facilities .	-	-
e. Onshore Terminal & Loading Facilities .	-	-
f. Support Facilities	-	-
Sub Total	91,752	37,365
5. Pre-start up Expense	1,852	993
6. Contingencies	18,512	9,941
TOTAL	232,200	122,166

ANNUAL OPERATION COST ESTIMATION

Table 15-6-2 (Vol.IV)

BETTY AND BOKOR OIL FIELDS CASE I

(M$ 1,000)

	1	2	3	4	5	6	7	8	9
1. Direct Cost									
a. Operating Personnel				607	607	607	607	607	455
b. Operating Management				61	61	61	61	61	46
c. Repair & Maintenance				3,772	3,772	2,896	2,019	2,019	1,514
d. Operating Supplies				617	617	473	328	328	246
e. Chemical				843	792	620	399	279	15
f. Service Contract				2,159	2,159	2,159	1,778	1,778	1,334
Sub Total				8,059	8,008	6,816	5,192	5,072	3,610
2. Indirect Cost									
a. Indirect Personnel				335	335	335	335	335	251
b. Insurance				2,903	2,903	2,229	1,554	1,554	1,166
Sub Total				3,238	3,238	2,564	1,889	1,889	1,417
TOTAL				11,297	11,246	9,380	7,081	6,961	5,027

ANNUAL OPERATION COST ESTIMATION

Table 15-6-3 (Vol.IV)　　BETTY AND BOKOR OIL FIELDS CASE II　　(M$ 1,000)

	1	2	3	4	5	6	7	8	9
1. Direct Cost									
a. Operating Personnel				490	490	490	490	490	368
b. Operating Management				49	49	49	49	49	37
c. Repair & Maintenance				2,019	2,019	2,019	2,019	2,019	1,514
d. Operating Supplies				328	328	328	328	328	246
e. Chemical				632	589	544	399	279	15
f. Service Contract				1,778	1,778	1,778	1,778	1,778	1,334
Sub Total				5,296	5,253	5,208	5,063	4,943	3,514
2. Indirect Cost									
a. Indirect Personnel				269	269	269	269	269	202
b. Insurance				1,554	1,554	1,554	1,554	1,554	1,166
Sub Total				1,823	1,823	1,823	1,823	1,823	1,368
TOTAL				7,119	7,076	7,031	6,886	6,766	4,882

Table 15-6-4 (Vol. IV) INVESTMENT SCHEDULE

BETTY AND BOKOR OIL FIELDS CASE I

(M$ 1,000)

Year / Item	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	26,711	-	-	
2. Engineering	16,830	-	-	
3. Development Wells	-	10,754	65,789	
4. Offshore Platforms	6,568	44,412	10,803	
5. Offshore Production Equipment	1,270	5,438	1,232	
6. Submarine Pipelines	-	-	22,029	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	-	-	-	
10. Pre-start up Expense	247	606	999	
11. Contingencies	2,467	6,060	9,985	
Total	54,093	67,270	110,837	

Table 15-6-5 (Vol. IV) <u>INVESTMENT SCHEDULE</u>

BETTY AND BOKOR OIL FIELDS CASE II

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	11,821	-	-	
2. Engineering	9,037	-	-	
3. Development Wells	-	10,754	42,255	
4. Offshore Platforms	6,568	16,383	-	
5. Offshore Production Equipment	1,257	2,713	-	
6. Submarine Pipelines	-	-	10,444	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	-	-	-	
10. Pre-start up Expense	168	298	527	
11. Contingencies	1,686	2,985	5,270	
Total	30,537	33,133	58,496	

* E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T *

TABLE 15-6-6 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS

 CASE I : BETTY & BOKOR, BAKAU GATHERING SYSTEM CASE

* P R E M I S E S *

PRODUCTION LIFE	: 6 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C   T E R M S   O F   P/S   A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 20.00 %
PROFIT OIL SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
INITIAL BASIC PRICE (AT 1976 BASE)	: M$ 32.31 /BBL
RATE OF INCREASE FOR BASIC PRICE	: 5.00 %
RATE OF PAYMENT FOR PROFIT OIL ABOVE BASIC PRICE	: 70.00 %
PRODUCTION BONUS ABOVE 50000BBL/DAY	: M$ 5000000.
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	9YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	54093.	67270.	110837.	0.	0.	0.	0.	0.	0.	232200.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	7421.	6972.	5456.	3526.	2467.	136.	25978.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	31.70	31.70	31.88	31.95	31.95	31.95	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	52.63	

TABLE 15-6-6 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS

VOL.IV CASE I : BETTY & BOKOR, BAKAU GATHERING SYSTEM CASE

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 2

TERM	1	2	3	4	5	6	7	8	9	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	115270.	108296.	85229.	55201.	38622.	2129.	404748.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	482.	453.	357.	231.	162.	9.	1693.
5 TOTAL CASH INFLOW	0.	0.	0.	118253.	108749.	85586.	55432.	38784.	2138.	408941.
6 INCOME TAX	0.	0.	0.	53214.	48937.	38514.	24945.	17453.	962.	184023.
7 NET CASH FLOW	0.	0.	0.	65039.	59812.	47072.	30488.	21331.	1176.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	65039.	124851.	171923.	202411.	223742.	224918.	

TABLE 15-6-6 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS

VOL.IV CASE I : BETTY & BOKOR, BAKAU GATHERING SYSTEM CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9
PRESENT WORTH									
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66
PRESENT WORTH	0.	0.	0.	54829.	48022.	35994.	22202.	14794.	777.
CUMULATIVE PRESENT WORTH	0.	0.	0.	54829.	102851.	138844.	161047.	175841.	176618.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44
PRESENT WORTH	0.	0.	0.	46591.	38951.	27868.	16409.	10437.	523.
CUMULATIVE PRESENT WORTH	0.	0.	0.	46591.	85542.	113410.	129819.	140256.	140779.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30
PRESENT WORTH	0.	0.	0.	39878.	31890.	21824.	12291.	7478.	358.
CUMULATIVE PRESENT WORTH	0.	0.	0.	39878.	71767.	93591.	105882.	113360.	113718.

TABLE 15-6-6 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS
VOL.IV CASE I : BETTY & BOKOR, BAKAU GATHERING SYSTEM CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	49402.	46413.	36527.	23658.	16552.	912.	173463.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	47049.	44202.	34787.	22531.	15764.	869.	165203.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	23525.	22101.	17394.	11266.	7882.	435.	82602.
4 TOTAL CASH INFLOW	0.	0.	0.	119975.	112716.	88708.	57454.	40199.	2216.	421268.
5 ROYALTY	0.	0.	0.	23525.	22101.	17394.	11266.	7882.	435.	82602.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	482.	453.	357.	231.	162.	9.	1693.
OPERATING EXPENSES	0.	0.	0.	47049.	44202.	34787.	22531.	15764.	5027.	169361.
(M$/BBL)	0.0	0.0	0.0	6.34	6.34	6.38	6.39	6.39	36.96	6.52
9 OPERATING COST	0.	0.	0.	11297.	11246.	9380.	7081.	6961.	5027.	50992.
CAPITAL COST RECOVERY	0.	0.	0.	35752.	32956.	25407.	15450.	8803.	0.	118369.
INCOME BEFORE TAX	0.	0.	0.	46419.	45960.	36170.	23427.	16391.	904.	169270.
10 INCOME TAX	0.	0.	0.	20889.	20682.	16277.	10542.	7376.	407.	76171.
11 CAPITAL INVESTMENT	54093.	67270.	110837.	0.	0.	0.	0.	0.	0.	232200.
12 TOTAL CASH OUTFLOW	54093.	67270.	110837.	58693.	54482.	43407.	29120.	22380.	5877.	446158.
13 NET CASH FLOW	-54093.	-67270.	-110837.	61283.	58234.	45301.	28335.	17818.	-3661.	
14 CUMULATIVE NET CASH FLOW	-54093.	-121363.	-232200.	-170917.	-112683.	-67382.	-39047.	-21229.	-24890.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
16 CORPORATE CAPITAL	54093.	67270.	110837.	0.	0.	0.	0.	0.	0.	232200.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	146.	146.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	3807.	3807.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	3807.	

21 PAYOUT TIME 0.0 YEARS

TABLE 15-6-6 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS

VOL.IV CASE I : BETTY & BOKOR, BAKAU GATHERING SYSTEM CASE

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9
PRESENT WORTH									
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66
PRESENT WORTH	-52789.	-62523.	-98110.	51663.	46755.	34639.	20634.	12358.	-2418.
CUMULATIVE PRESENT WORTH	-52789.	-115312.	-213422.	-161759.	-115004.	-80365.	-59730.	-47373.	-49791.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44
PRESENT WORTH	-51576.	-58309.	-87338.	43900.	37924.	26819.	15250.	8718.	-1628.
CUMULATIVE PRESENT WORTH	-51576.	-109884.	-197222.	-153322.	-115398.	-88579.	-73329.	-64611.	-66239.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30
PRESENT WORTH	-50442.	-54547.	-78152.	37575.	31048.	21003.	11423.	6246.	-1116.
CUMULATIVE PRESENT WORTH	-50442.	-104989.	-183141.	-145567.	-114518.	-93516.	-82093.	-75846.	-76962.

*** E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T ***

TABLE 15-6-7 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS

VOL.IV CASE II : BETTY, BAKAU GATHERING SYSTEM CASE

* P R E M I S E S *

PRODUCTION LIFE	: 6 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C   T E R M S   O F   P/S   A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 20.00 %
PROFIT OIL SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
INITIAL BASIC PRICE (AT 1976 BASE)	: M$ 32.31 /BBL
RATE OF INCREASE FOR BASIC PRICE	: 5.00 %
RATE OF PAYMENT FOR PROFIT OIL ABOVE BASIC PRICE	: 70.00 %
PRODUCTION BONUS ABOVE 50000BBL/DAY	: M$ 5000000.
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	9YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	30537.	33133.	58496.	0.	0.	0.	0.	0.	0.	122166.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	5595.	5206.	4805.	3526.	2467.	136.	21735.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	31.95	31.95	31.95	31.95	31.95	31.95	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	52.63	

TABLE 15-6-7 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS

VOL.IV CASE II : BETTY, BAKAU GATHERING SYSTEM CASE

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 2

TERM	1	2	3	4	5	6	7	8	9	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	87593.	81503.	75225.	55201.	38622.	2129.	340272.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	366.	341.	315.	231.	162.	9.	1424.
5 TOTAL CASH INFLOW	0.	0.	0.	90459.	81843.	75539.	55432.	38784.	2138.	344196.
6 INCOME TAX	0.	0.	0.	40707.	36830.	33993.	24945.	17453.	962.	154888.
7 NET CASH FLOW	0.	0.	0.	49752.	45014.	41547.	30488.	21331.	1176.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	49752.	94766.	136313.	166801.	188132.	189308.	

TABLE 15-6-7 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS

VOL.IV CASE II : BETTY, BAKAU GATHERING SYSTEM CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9
PRESENT WORTH									
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66
PRESENT WORTH	0.	0.	0.	41942.	36141.	31768.	22202.	14794.	777.
CUMULATIVE PRESENT WORTH	0.	0.	0.	41942.	78083.	109851.	132054.	146848.	147625.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44
PRESENT WORTH	0.	0.	0.	35640.	29314.	24597.	16409.	10437.	523.
CUMULATIVE PRESENT WORTH	0.	0.	0.	35640.	64955.	89551.	105960.	116397.	116920.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30
PRESENT WORTH	0.	0.	0.	30505.	24000.	19262.	12291.	7478.	358.
CUMULATIVE PRESENT WORTH	0.	0.	0.	30505.	54505.	73767.	86058.	93536.	93894.

TABLE 15-6-7 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS
VOL.IV CASE II : BETTY, BAKAU GATHERING SYSTEM CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	1	2	3	4	5	6	7	8	9	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	37540.	34930.	32239.	23658.	16552.	912.	145831.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	35752.	33266.	30704.	22531.	15764.	869.	138887.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	17876.	16633.	15352.	11266.	7882.	435.	69443.
4 TOTAL CASH INFLOW	0.	0.	0.	91168.	84829.	78295.	57454.	40199.	2216.	354161.
5 ROYALTY	0.	0.	0.	17876.	16633.	15352.	11266.	7882.	435.	69443.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	366.	341.	315.	231.	162.	9.	1424.
OPERATING EXPENSES	0.	0.	0.	35752.	33266.	30704.	22531.	15764.	4882.	142900.
(M$/BBL)	0.0	0.0	0.0	6.39	6.39	6.39	6.39	6.39	35.90	6.57
9 OPERATING COST	0.	0.	0.	7119.	7076.	7031.	6886.	6766.	4882.	39760.
CAPITAL COST RECOVERY	0.	0.	0.	28633.	26190.	23673.	15645.	8998.	0.	103140.
INCOME BEFORE TAX	0.	0.	0.	34673.	34589.	31924.	23427.	16391.	904.	141907.
10 INCOME TAX	0.	0.	0.	15603.	15565.	14366.	10542.	7376.	407.	63858.
11 CAPITAL INVESTMENT	30537.	33133.	58496.	0.	0.	0.	0.	0.	0.	122166.
12 TOTAL CASH OUTFLOW	30537.	33133.	58496.	43464.	39615.	37064.	28925.	22185.	5732.	299151.
13 NET CASH FLOW	-30537.	-33133.	-58496.	47703.	45214.	41231.	28530.	18013.	-3516.	
14 CUMULATIVE NET CASH FLOW	-30537.	-63670.	-122166.	-74463.	-29249.	11983.	40513.	58526.	55010.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	3.49	9.80	12.62	12.16	
16 CORPORATE CAPITAL	30537.	33133.	58496.	0.	0.	0.	0.	0.	0.	122166.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	141.	141.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	3657.	3657.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	3657.	

21 PAYOUT TIME 5.7 YEARS

TABLE 15-6-7 CASH FLOW TABLE FOR OIL BETTY AND BOKOR OIL FIELDS

VOL.IV CASE II : BETTY, BAKAU GATHERING SYSTEM CASE

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9
PRESENT WORTH									
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66
PRESENT WORTH	-29801.	-30795.	-51779.	40215.	36301.	31527.	20776.	12493.	-2322.
CUMULATIVE PRESENT WORTH	-29801.	-60596.	-112375.	-72160.	-35858.	-4331.	16445.	28938.	26616.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44
PRESENT WORTH	-29116.	-28719.	-46094.	34172.	29445.	24410.	15355.	8813.	-1564.
CUMULATIVE PRESENT WORTH	-29116.	-57835.	-103929.	-69757.	-40312.	-15902.	-547.	8266.	6703.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30
PRESENT WORTH	-28476.	-26867.	-41246.	29249.	24107.	19116.	11502.	6315.	-1072.
CUMULATIVE PRESENT WORTH	-28476.	-55343.	-96589.	-67340.	-43233.	-24118.	-12616.	-6301.	-7373.

Table 16-5-1 (Vol. IV)

MAJOR EQUIPMENT LIST

FOR WEST TEMANA AND E-6 OIL FIELDS-CASE I

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V - 1 1ST STAGE PRODUCTION SEPARATOR	WTP-A	1	SIZE: 4'-0" I.D. x 12'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
	E6WP-A E6WP-B	1 1	SIZE: 5'-6" I.D. x 16'-6" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
V - 2 2ND STAGE PRODUCTION SEPARATOR	WTP-A	1	SIZE: 4'-0" I.D. x 12'-0" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
	E6WP-A E6WP-B	1 1	SIZE: 5'-6" I.D. x 16'-6" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
V - 3 3RD STAGE PRODUCTION SEPARATOR	WTP-A	1	SIZE: 9'-0" I.D. x 18'-0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
	E6WP-A E6WP-B	1 1	SIZE: 12'-0" I.D. x 24'-0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
V - 4 TEST SEPARATOR	WTP-A WTW-B E6WP-A E6WP-B	1 1 1 1	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
C - 151 INSTRUMENT AIR COMPRESSOR	WTP-A E6WP-A E6WP-B	2 2 2	CAPACITY: 35 SCFM
P - 2 CRUDE TRANSFER PUMP	WTP-A	2	CAPACITY: 120 GPM TYPE: HORIZONTAL
	E6WP-A E6WP-B	2 2	CAPACITY: 400 GPM TYPE: HORIZONTAL
P - 152 FIRE WATER PUMP	WTP-A E6WP-A E6WP-B	1 1 1	CAPACITY: 1,500 GPM TYPE: VERTICAL
TK - 1 DEEMULSIFIER TANK	WTP-A E6WP-A E6WP-B	1 1 1	SIZE: 6'-0" I.D. x 15'-6" H
TK - 2 DEFOAMANT TANK	WTP-A E6WP-A E6WP-B	1 1 1	SIZE: 6'-0" I.D. x 15'-6" H
TK - 152 DIESEL STORAGE TANK	WTP-A E6WP-A E6WP-B	1 1 1	CAPACITY: 500 BBL SIZE: 15'-6" I.D. x 16'-0" H
M - 1 INLET MANIFOLD	WTP-A E6WP-A E6WP-B	1 1 1	HIGH PRESSURE HEADER LOW PRESSURE HEADER TEST HEADER
G - 151 DIESEL DRIVEN GENERATOR	WTP-A E6WP-B	2 2	CAPACITY: 300 KVA
FM - 1 FLOW METER	WTP-A	1	DESIGN RATE: 150 GPM (MAX.)
	E6WP-A E6WP-B	1 1	DESIGN RATE: 500 GPM (MAX.)

Table 16-6-1 (Vol. IV) **CAPITAL INVESTMENT COST ESTIMATION**

(M$ 1,000)

WEST TEMANA AND E-6 OIL FIELDS	CASE I	CASE II A	CASE II B
1. Exploration & Appraisal Wells	14,841	4,397	4,397
2. Engineering	32,903	23,012	24,140
3. Development Wells	76,076	62,865	62,865
4. Facilities			
a. Offshore Platforms	99,024	39,756	49,688
b. Offshore Production Equipment	26,129	13,980	20,213
c. Submarine Pipelines	66,383	3,345	52,575
d. Offshore Storage & Loading Facilities	-	96,990	56,048
e. Onshore Terminal & Loading Facilities	38,936	-	-
f. Support Facilities	22,478	13,178	-
Sub Total	252,950	167,249	178,524
5. Pre-start up Expense	3,620	2,531	2,655
6. Contingencies	36,193	25,312	26,553
TOTAL	416,583	285,366	299,134

ANNUAL OPERATION COST ESTIMATION

Table 16-6-2 (Vol.IV) WEST TEMANA AND E-6 OIL FIELDS CASE I (M$ 1,000)

	1	2	3	4	5	6	7	8	9	10
1. Direct Cost										
a. Operating Personnel				2,276	2,276	2,276	2,276	2,276	2,276	2,27
b. Operating Management				228	228	228	228	228	228	22
c. Repair & Maintenance				6,494	5,652	4,806	4,806	4,806	4,806	4,80
d. Operating Supplies				1,204	1,054	904	904	904	904	90
e. Chemical				1,430	1,346	1,262	1,262	1,151	907	65
f. Service Contract				4,054	4,054	4,054	4,054	4,054	4,054	4,05
Sub Total				15,686	14,610	13,530	13,530	13,419	13,175	12,92
2. Indirect Cost										
a. Indirect Personnel				1,252	1,252	1,252	1,252	1,252	1,252	1,25
b. Insurance				5,217	4,547	3,876	3,876	3,876	3,876	3,87
Sub Total				6,469	5,799	5,128	5,128	5,128	5,128	5,12
TOTAL				22,155	20,409	18,658	18,658	18,547	18,303	18,05

(M$ 1,000)

	6	7	8	9	10	11	12	13	14	15	16	17	18
76	2,276	2,276	2,276	2,276	2,276	2,276	2,276	2,276	2,276	2,276	2,276	2,276	1,138
28	228	228	228	228	228	228	228	228	228	228	228	228	114
52	4,806	4,806	4,806	4,806	4,806	4,806	4,806	4,806	4,806	4,806	4,806	4,806	2,403
54	904	904	904	904	904	904	904	904	904	904	904	904	452
46	1,262	1,262	1,151	907	655	432	333	274	229	196	165	145	69
54	4,054	4,054	4,054	4,054	4,054	4,054	4,054	4,054	4,054	4,054	4,054	4,054	2,027
10	13,530	13,530	13,419	13,175	12,923	12,700	12,601	12,542	12,497	12,464	12,433	12,413	6,203
52	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	627
47	3,876	3,876	3,876	3,876	3,876	3,876	3,876	3,876	3,876	3,876	3,876	3,876	1,938
99	5,128	5,128	5,128	5,128	5,128	5,128	5,128	5,128	5,128	5,128	5,128	5,128	2,565
09	18,658	18,658	18,547	18,303	18,051	17,828	17,729	17,670	17,625	17,592	17,561	17,541	8,768

ANNUAL OPERATION COST ESTIMATION

Table 16-6-3 (Vol.IV) WEST TEMANA AND E-6 OIL FIELDS CASE IIA (M$ 1,000)

	1	2	3	4	5	6	7	8	9	10
1. Direct Cost										
a. Operating Personnel				1,801	1,801	1,801	1,801	1,801	1,801	1,80
b. Operating Management				180	180	180	180	180	180	180
c. Repair & Maintenance				8,313	8,313	8,313	8,313	8,313	8,313	8,31
d. Operating Supplies				843	843	843	843	843	843	84
e. Chemical				1,262	1,262	1,262	1,262	1,151	907	65
f. Service Contract				3,962	3,962	3,962	3,962	3,962	3,962	3,96
Sub Total				16,361	16,361	16,361	16,361	16,250	16,006	15,75
2. Indirect Cost										
a. Indirect Personnel				991	991	991	991	991	991	99
b. Insurance				4,173	4,173	4,173	4,173	4,173	4,173	4,17
Sub Total				5,164	5,164	5,164	5,164	5,164	5,164	5,16
TOTAL				21,525	21,525	21,525	21,525	21,414	21,170	20,918

(M$ 1,000)

	6	7	8	9	10	11	12	13	14	15	16	17	18
801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	902
180	180	180	180	180	180	180	180	180	180	180	180	180	90
313	8,313	8,313	8,313	8,313	8,313	8,313	8,313	8,313	8,313	8,313	8,313	8,313	4,155
843	843	843	843	843	843	843	843	843	843	843	843	843	422
262	1,262	1,262	1,151	907	655	432	333	274	229	196	165	145	69
962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	1,981
361	16,361	16,361	16,250	16,006	15,754	15,531	15,432	15,373	15,328	15,295	15,264	15,244	7,619
91	991	991	991	991	991	991	991	991	991	991	991	991	495
73	4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,173	4,173	2,088
64	5,164	5,164	5,164	5,164	5,164	5,164	5,164	5,164	5,164	5,164	5,164	5,164	2,583
25	21,525	21,525	21,414	21,170	20,918	20,695	20,596	20,537	20,492	20,459	20,428	20,408	10,202

ANNUAL OPERATION COST ESTIMATION

Table 16-6-4 (Vol.IV) WEST TEMANA AND E-6 OIL FIELDS CASE IIB (M$ 1,000)

	1	2	3	4	5	6	7	8	9	10
1. Direct Cost										
a. Operating Personnel				1,801	1,801	1,801	1,801	1,801	1,801	1,801
b. Operating Management				180	180	180	180	180	180	180
c. Repair & Maintenance				4,686	4,686	4,686	4,686	4,686	4,686	4,686
d. Operating Supplies				884	884	884	884	884	884	884
e. Chemical				1,262	1,262	1,262	1,262	1,151	907	655
f. Service Contract				3,962	3,962	3,962	3,962	3,962	3,962	3,962
Sub Total				12,775	12,775	12,775	12,775	12,664	12,420	12,168
2. Indirect Cost										
a. Indirect Personnel				991	991	991	991	991	991	991
b. Insurance				1,490	1,490	1,490	1,490	1,490	1,490	1,490
Sub Total				2,481	2,481	2,481	2,481	2,481	2,481	2,481
TOTAL				15,256	15,256	15,256	15,256	15,145	14,901	14,649

(M$ 1,000)

	6	7	8	9	10	11	12	13	14	15	16	17	18
01	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	1,801	902
80	180	180	180	180	180	180	180	180	180	180	180	180	90
86	4,686	4,686	4,686	4,686	4,686	4,686	4,686	4,686	4,686	4,686	4,686	4,686	2,344
84	884	884	884	884	884	884	884	884	884	884	884	884	442
62	1,262	1,262	1,151	907	655	432	333	274	229	196	165	145	69
62	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	3,962	1,982
75	12,775	12,775	12,664	12,420	12,168	11,945	11,846	11,787	11,742	11,709	11,678	11,658	5,829
91	991	991	991	991	991	991	991	991	991	991	991	991	495
90	1,490	1,490	1,490	1,490	1,490	1,490	1,490	1,490	1,490	1,490	1,490	1,490	1,892
81	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,481	2,387
56	15,256	15,256	15,145	14,901	14,649	14,426	14,327	14,268	14,223	14,190	14,159	14,139	8,216

Table 16-6-5 (Vol. IV) INVESTMENT SCHEDULE

WEST TEMANA AND E-6 OIL FIELDS CASE I

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	14,841	-	-	
2. Engineering	32,903	-	-	
3. Development Wells	-	32,070	44,006	
4. Offshore Platforms	37,249	59,964	1,811	
5. Offshore Production Equipment	5,062	17,435	3,632	
6. Submarine Pipelines	-	27,186	39,197	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	-	14,041	24,895	
9. Support Facilities	3,459	10,373	8,646	
10. Pre-start up Expense	787	1,611	1,222	
11. Contingencies	7,867	16,107	12,219	
Total	102,168	178,787	135,628	

Table 16-6-6 (Vol. IV) INVESTMENT SCHEDULE

WEST TEMANA AND E-6 OIL FIELDS CASE II A

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	4,397	-	-	
2. Engineering	23,012	-	-	
3. Development Wells	-	17,960	44,905	
4. Offshore Platforms	13,030	26,726	-	
5. Offshore Production Equipment	3,378	10,602	-	
6. Submarine Pipelines	-	3,099	246	
7. Offshore Storage & Loading Facilities	-	87,859	9,131	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	-	8,786	4,392	
10. Pre-start up Expense	394	1,550	587	
11. Contingencies	3,942	15,503	5,867	
Total	48,153	172,085	65,128	

Table 16-6-7 (Vol. IV) INVESTMENT SCHEDULE

WEST TEMANA AND E-6 OIL FIELDS CASE II B

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	4,397	-	-	
2. Engineering	24,140	-	-	
3. Development Wells	-	18,860	44,005	
4. Offshore Platforms	11,725	36,152	1,811	
5. Offshore Production Equipment	3,406	13,175	3,632	
6. Submarine Pipelines	-	13,378	39,197	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	3,043	22,103	30,902	
9. Support Facilities	-	-	-	
10. Pre-start up Expense	423	1,037	1,195	
11. Contingencies	4,231	10,367	11,955	
Total	51,365	115,072	132,697	

* ECONOMIC ANALYSIS FOR MALAYSIA PROJECT *

TABLE 16-6-8 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

* P R E M I S E S *

PRODUCTION LIFE	: 15 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C T E R M S O F P/S A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 20.00 %
PROFIT OIL SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
INITIAL BASIC PRICE (AT 1976 BASE)	: M$ 32.31 /BBL
RATE OF INCREASE FOR BASIC PRICE	: 5.00 %
RATE OF PAYMENT FOR PROFIT OIL ABOVE BASIC PRICE	: 70.00 %
PRODUCTION BONUS ABOVE 50000BBL/DAY	: M$ 5000000.
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	102168.	178787.	135628.	0.	0.	0.	0.	0.	0.	0.	416583.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	12411.	11681.	10951.	10951.	9993.	7869.	5677.	69533.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	31.47	31.52	31.57	31.57	31.57	31.57	31.57	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	52.63	55.26	

TERM	11	12	13	14	15	16	17	18	18YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	0.	0.	0.	0.	0.	416583.
OIL PRODUCTION (M BBL/YEAR)	3747.	2881.	2371.	1984.	1700.	1442.	1255.	591.	85504.
SALES PRICE OF OIL (M$/BBL)	31.57	31.57	31.57	31.57	31.57	31.57	31.57	31.57	
BASIC PRICE OF OIL (M$/BBL)	58.02	60.92	63.97	67.17	70.53	74.05	77.76	81.64	

TABLE 16-6-8 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE I : WEST TEMANA & E-6, BINTULU TERMINAL CASE

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 2

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	191381.	180411.	169404.	169404.	154585.	121728.	87819.	1074731.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	801.	755.	709.	709.	647.	509.	367.	4496.
5 TOTAL CASH INFLOW	0.	0.	0.	194682.	181165.	170113.	170113.	155231.	122237.	88187.	1081727.
6 INCOME TAX	0.	0.	0.	87607.	81524.	76551.	76551.	69854.	55007.	39684.	486777.
7 NET CASH FLOW	0.	0.	0.	107075.	99641.	93562.	93562.	85377.	67230.	48503.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	107075.	206716.	300278.	393840.	479217.	546448.	594950.	

TERM	11	12	13	14	15	16	17	18	18YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	57963.	44567.	36678.	30691.	26298.	22307.	19414.	9142.	1321787.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	243.	186.	153.	128.	110.	93.	81.	38.	5530.
5 TOTAL CASH INFLOW	58206.	44753.	36831.	30819.	26408.	22400.	19495.	9181.	1329817.
6 INCOME TAX	26193.	20139.	16574.	13869.	11884.	10080.	8773.	4131.	598419.
7 NET CASH FLOW	32013.	24614.	20257.	16951.	14524.	12320.	10722.	5049.	
8 CUMULATIVE NET CASH FLOW	626964.	651578.	671835.	688786.	703310.	715630.	726352.	731402.	

TABLE 16-6-8 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE I : WEST TEMANA & E-6, BINTULU TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	90267.	79999.	71542.	68135.	59214.	44408.	30512.
CUMULATIVE PRESENT WORTH	0.	0.	0.	90267.	170266.	241808.	309943.	369157.	413565.	444077.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	76703.	64889.	55391.	50356.	41773.	29904.	19613.
CUMULATIVE PRESENT WORTH	0.	0.	0.	76703.	141592.	196984.	247339.	289113.	319017.	338629.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	65652.	53125.	43377.	37719.	29930.	20494.	12857.
CUMULATIVE PRESENT WORTH	0.	0.	0.	65652.	118777.	162154.	199873.	229803.	250298.	263155.

TERM	11	12	13	14	15	16	17	18
PRESENT WORTH								
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43
PRESENT WORTH	19180.	14045.	11008.	8773.	7159.	5783.	4794.	2150.
CUMULATIVE PRESENT WORTH	463257.	477301.	488310.	497082.	504241.	510025.	514818.	516968.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19
PRESENT WORTH	11768.	8226.	6154.	4682.	3647.	2812.	2225.	953.
CUMULATIVE PRESENT WORTH	350397.	358623.	364777.	369459.	373106.	375918.	378142.	379095.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09
PRESENT WORTH	7379.	4934.	3531.	2569.	1914.	1412.	1069.	438.
CUMULATIVE PRESENT WORTH	270534.	275467.	278998.	281567.	283481.	284893.	285961.	286399.

TABLE 16-6-8 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS
VOL.IV CASE I : WEST TEMANA & E-6, BINTULU TERMINAL CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	82021.	77319.	72602.	72602.	66251.	52169.	37637.	460599.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	78115.	73637.	69145.	69145.	63096.	49685.	35845.	438666.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	39057.	36818.	34572.	34572.	31548.	24842.	17922.	219333.
4 TOTAL CASH INFLOW	0.	0.	0.	199193.	187774.	176319.	176319.	160894.	126696.	91404.	1118598.
5 ROYALTY	0.	0.	0.	39057.	36818.	34572.	34572.	31548.	24842.	17922.	219333.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	801.	755.	709.	709.	647.	509.	367.	4496.
OPERATING EXPENSES	0.	0.	0.	78115.	73637.	69145.	69145.	63096.	49685.	35845.	438666.
(M$/BBL)	0.0	0.0	0.0	6.29	6.30	6.31	6.31	6.31	6.31	6.31	6.31
9 OPERATING COST	0.	0.	0.	22155.	20409.	18658.	18658.	18547.	18303.	18051.	134781.
CAPITAL COST RECOVERY	0.	0.	0.	55960.	53228.	50487.	50487.	44549.	31382.	17794.	303885.
INCOME BEFORE TAX	0.	0.	0.	78720.	76564.	71893.	71893.	65604.	51660.	37269.	453603.
10 INCOME TAX	0.	0.	0.	35424.	34454.	32352.	32352.	29522.	23247.	16771.	204121.
11 CAPITAL INVESTMENT	102168.	178787.	135628.	0.	0.	0.	0.	0.	0.	0.	416583.
12 TOTAL CASH OUTFLOW	102168.	178787.	135628.	99937.	92436.	86291.	86291.	80263.	66902.	53112.	981815.
13 NET CASH FLOW	-102168.	-178787.	-135628.	99256.	95338.	90028.	90028.	80631.	59795.	38292.	
14 CUMULATIVE NET CASH FLOW	-102168.	-280955.	-416583.	-317327.	-221989.	-131962.	-41934.	38697.	98492.	136784.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.35	5.27	6.74	
16 CORPORATE CAPITAL	102168.	178787.	135628.	0.	0.	0.	0.	0.	0.	0.	416583.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

21 PAYOUT TIME 7.5 YEARS

TABLE 16-6-8 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS
VOL.IV CASE I : WEST TEMANA & E-6, BINTULU TERMINAL CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	11	12	13	14	15	16	17	18	18YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	24841.	19100.	15719.	13153.	11270.	9560.	8320.	3918.	566482.
2 SALES REVENUE FROM COST OIL	23659.	18191.	14970.	12527.	10734.	9105.	7924.	3732.	539507.
3 SALES REVENUE FROM ROYALTY OIL	11829.	9095.	7485.	6263.	5367.	4552.	3962.	1866.	269753.
4 TOTAL CASH INFLOW	60329.	46386.	38175.	31944.	27371.	23217.	20206.	9516.	1375739.
5 ROYALTY	11829.	9095.	7485.	6263.	5367.	4552.	3962.	1866.	269753.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	243.	186.	153.	128.	110.	93.	81.	38.	5530.
OPERATING EXPENSES	23659.	18191.	17670.	17625.	17592.	17561.	17541.	8768.	577272.
(M$/BBL)	6.31	6.31	7.45	8.88	10.35	12.18	13.98	14.84	6.75
9 OPERATING COST	17828.	17729.	17670.	17625.	17592.	17561.	17541.	8768.	267095.
CAPITAL COST RECOVERY	5831.	462.	0.	0.	0.	0.	0.	0.	310177.
INCOME BEFORE TAX	24599.	18914.	15566.	13025.	11160.	9467.	8239.	3880.	558452.
10 INCOME TAX	11070.	8511.	7005.	5861.	5022.	4260.	3708.	1746.	251303.
11 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	416583.
12 TOTAL CASH OUTFLOW	40969.	35522.	32313.	29878.	28091.	26467.	25292.	12418.	1212761.
13 NET CASH FLOW	19360.	10864.	5862.	2066.	-720.	-3250.	-5085.	-2902.	
14 CUMULATIVE NET CASH FLOW	156144.	167008.	172869.	174935.	174215.	170965.	165880.	162977.	
15 DCF ROR OF NET CASH FLOW (%)	7.37	7.68	7.83	7.88	7.86	7.79	7.70	7.64	
16 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	416583.
17 INTEREST	0.	0.	0.	0.	29.	190.	538.	901.	1658.
18 BANK BORROWING	0.	0.	0.	0.	749.	3439.	5624.	3804.	13616.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	749.	4188.	9812.	13616.	

21 PAYOUT TIME 7.5 YEARS

TABLE 16-6-8 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE I : WEST TEMANA & E-6, BINTULU TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-99706.	-166170.	-120054.	83675.	76545.	68839.	65561.	55922.	39496.	24088.
CUMULATIVE PRESENT WORTH	-99706.	-265876.	-385930.	-302255.	-225710.	-156871.	-91310.	-35388.	4109.	28197.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-97413.	-154970.	-106873.	71102.	62087.	53299.	48454.	39451.	26597.	15484.
CUMULATIVE PRESENT WORTH	-97413.	-252383.	-359256.	-288154.	-226067.	-172768.	-124315.	-84864.	-58267.	-42783.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-95272.	-144974.	-95632.	60857.	50831.	41739.	36295.	28266.	18228.	10150.
CUMULATIVE PRESENT WORTH	-95272.	-240246.	-335878.	-275021.	-224190.	-182451.	-146157.	-117890.	-99663.	-89512.

TERM	11	12	13	14	15	16	17	18
PRESENT WORTH								
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43
PRESENT WORTH	11599.	6199.	3185.	1069.	-355.	-1525.	-2274.	-1236.
CUMULATIVE PRESENT WORTH	39796.	45995.	49181.	50250.	49895.	48369.	46096.	44860.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19
PRESENT WORTH	7117.	3631.	1781.	571.	-181.	-742.	-1055.	-548.
CUMULATIVE PRESENT WORTH	-35667.	-32036.	-30255.	-29685.	-29865.	-30607.	-31662.	-32210.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09
PRESENT WORTH	4463.	2178.	1022.	313.	-95.	-372.	-507.	-252.
CUMULATIVE PRESENT WORTH	-85050.	-82872.	-81851.	-81537.	-81632.	-82005.	-82511.	-82763.

ECONOMIC ANALYSIS FOR MALAYSIA PROJECT

TABLE 16-6-9 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE II A : E-6, OFFSHORE STORAGE CASE

* PREMISES *

PRODUCTION LIFE	: 15 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* BASIC TERMS OF P/S AGREEMENTS *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 20.00 %
PROFIT OIL SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
INITIAL BASIC PRICE (AT 1976 BASE)	: M$ 32.31 /BBL
RATE OF INCREASE FOR BASIC PRICE	: 5.00 %
RATE OF PAYMENT FOR PROFIT OIL ABOVE BASIC PRICE	: 70.00 %
PRODUCTION BONUS ABOVE 50000BBL/DAY	: M$ 5000000.
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	48153.	172085.	65128.	0.	0.	0.	0.	0.	0.	0.	285366.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	10951.	10951.	10951.	10951.	9993.	7869.	5677.	67343.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	31.57	31.57	31.57	31.57	31.57	31.57	31.57	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	52.63	55.26	

TERM	11	12	13	14	15	16	17	18	18YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	0.	0.	0.	0.	0.	285366.
OIL PRODUCTION (M BBL/YEAR)	3747.	2881.	2371.	1984.	1700.	1442.	1255.	591.	83314.
SALES PRICE OF OIL (M$/BBL)	31.57	31.57	31.57	31.57	31.57	31.57	31.57	31.57	
BASIC PRICE OF OIL (M$/BBL)	58.02	60.92	63.97	67.17	70.53	74.05	77.76	81.64	

TABLE 16-6-9 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE II A : E-6, OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 2

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	169404.	169404.	169404.	169404.	154585.	121728.	87819.	1041748.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	709.	709.	709.	709.	647.	509.	367.	4358.
5 TOTAL CASH INFLOW	0.	0.	0.	172613.	170113.	170113.	170113.	155231.	122237.	88187.	1048606.
6 INCOME TAX	0.	0.	0.	77676.	76551.	76551.	76551.	69854.	55007.	39684.	471873.
7 NET CASH FLOW	0.	0.	0.	94937.	93562.	93562.	93562.	85377.	67230.	48503.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	94937.	188499.	282061.	375624.	461001.	528231.	576734.	

TERM	11	12	13	14	15	16	17	18	18YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	57963.	44567.	36678.	30691.	26298.	22307.	19414.	9142.	1288804.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	243.	186.	153.	128.	110.	93.	81.	38.	5392.
5 TOTAL CASH INFLOW	58206.	44753.	36831.	30819.	26408.	22400.	19495.	9181.	1296696.
6 INCOME TAX	26193.	20139.	16574.	13869.	11884.	10080.	8773.	4131.	583515.
7 NET CASH FLOW	32013.	24614.	20257.	16951.	14524.	12320.	10722.	5049.	
8 CUMULATIVE NET CASH FLOW	608747.	633361.	653618.	670569.	685093.	697413.	708136.	713185.	

TABLE 16-6-9 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE II A : E-6, OFFSHORE STORAGE CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 3

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	80034.	75119.	71542.	68135.	59214.	44408.	30512.
CUMULATIVE PRESENT WORTH	0.	0.	0.	80034.	155153.	226695.	294830.	354044.	398452.	428964.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	68008.	60930.	55391.	50356.	41773.	29904.	19613.
CUMULATIVE PRESENT WORTH	0.	0.	0.	68008.	128939.	184330.	234686.	276459.	306363.	325976.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	58210.	49884.	43377.	37719.	29930.	20494.	12857.
CUMULATIVE PRESENT WORTH	0.	0.	0.	58210.	108093.	151471.	189190.	219120.	239615.	252471.

TERM	11	12	13	14	15	16	17	18
PRESENT WORTH								
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43
PRESENT WORTH	19180.	14045.	11008.	8773.	7159.	5783.	4794.	2150.
CUMULATIVE PRESENT WORTH	448144.	462188.	473197.	481969.	489128.	494912.	499705.	501855.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19
PRESENT WORTH	11768.	8226.	6154.	4682.	3647.	2812.	2225.	953.
CUMULATIVE PRESENT WORTH	337744.	345969.	352124.	356805.	360452.	363264.	365489.	366441.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09
PRESENT WORTH	7379.	4934.	3531.	2569.	1914.	1412.	1069.	438.
CUMULATIVE PRESENT WORTH	259850.	264784.	268315.	270884.	272798.	274210.	275278.	275716.

TABLE 16-6-9 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS
VOL.IV CASE II A : E-6, OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	72602.	72602.	72602.	72602.	66251.	52169.	37637.	446464.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	69145.	69145.	69145.	69145.	63096.	49685.	35845.	425203.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	34572.	34572.	34572.	34572.	31548.	24842.	17922.	212602.
4 TOTAL CASH INFLOW	0.	0.	0.	176319.	176319.	176319.	176319.	160894.	126696.	91404.	1084268.
5 ROYALTY	0.	0.	0.	34572.	34572.	34572.	34572.	31548.	24842.	17922.	212602.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	709.	709.	709.	709.	647.	509.	367.	4358.
OPERATING EXPENSES	0.	0.	0.	69145.	69145.	69145.	69145.	63096.	49685.	35845.	425203.
(M$/BBL)	0.0	0.0	0.0	6.31	6.31	6.31	6.31	6.31	6.31	6.31	6.31
9 OPERATING COST	0.	0.	0.	21525.	21525.	21525.	21525.	21414.	21170.	20918.	149602.
CAPITAL COST RECOVERY	0.	0.	0.	47620.	47620.	47620.	47620.	41682.	28515.	14927.	275601.
INCOME BEFORE TAX	0.	0.	0.	69393.	71893.	71893.	71893.	65604.	51660.	37269.	439605.
10 INCOME TAX	0.	0.	0.	31227.	32352.	32352.	32352.	29522.	23247.	16771.	197822.
11 CAPITAL INVESTMENT	48153.	172085.	65128.	0.	0.	0.	0.	0.	0.	0.	285366.
12 TOTAL CASH OUTFLOW	48153.	172085.	65128.	90533.	89158.	89158.	89158.	83130.	69769.	55979.	852250.
13 NET CASH FLOW	-48153.	-172085.	-65128.	85786.	87161.	87161.	87161.	77764.	56928.	35425.	
14 CUMULATIVE NET CASH FLOW	-48153.	-220238.	-285366.	-199580.	-112420.	-25259.	61902.	139666.	196594.	232018.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	5.90	10.98	13.57	14.78	
16 CORPORATE CAPITAL	48153.	172085.	65128.	0.	0.	0.	0.	0.	0.	0.	285366.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

21 PAYOUT TIME 6.3 YEARS

TABLE 16-6-9 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS
VOL.IV CASE II A : E-6, OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 5

TERM	11	12	13	14	15	16	17	18	18YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	24841.	19100.	15719.	13153.	11270.	9560.	8320.	3918.	552346.
2 SALES REVENUE FROM COST OIL	23659.	18191.	14970.	12527.	10734.	9105.	7924.	3732.	526044.
3 SALES REVENUE FROM ROYALTY OIL	11829.	9095.	7485.	6263.	5367.	4552.	3962.	1866.	263022.
4 TOTAL CASH INFLOW	60329.	46386.	38175.	31944.	27371.	23217.	20206.	9516.	1341409.
5 ROYALTY	11829.	9095.	7485.	6263.	5367.	4552.	3962.	1866.	263022.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	243.	186.	153.	128.	110.	93.	81.	38.	5392.
OPERATING EXPENSES	23659.	20596.	20537.	20492.	20459.	20428.	20408.	10202.	581984.
(M$/BBL)	6.31	7.15	8.66	10.33	12.03	14.17	16.26	17.26	6.99
9 OPERATING COST	20695.	20596.	20537.	20492.	20459.	20428.	20408.	10202.	303419.
CAPITAL COST RECOVERY	2964.	0.	0.	0.	0.	0.	0.	0.	278565.
INCOME BEFORE TAX	24599.	18914.	15566.	13025.	11160.	9467.	8239.	3880.	544454.
10 INCOME TAX	11070.	8511.	7005.	5861.	5022.	4260.	3708.	1746.	245004.
11 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	285366.
12 TOTAL CASH OUTFLOW	43836.	38389.	35180.	32745.	30958.	29334.	28159.	13852.	1104701.
13 NET CASH FLOW	16493.	7997.	2995.	-801.	-3587.	-6117.	-7952.	-4336.	
14 CUMULATIVE NET CASH FLOW	248511.	256508.	259503.	258702.	255115.	248998.	241045.	236709.	
15 DCF ROR OF NET CASH FLOW (%)	15.24	15.42	15.48	15.47	15.42	15.34	15.25	15.20	
16 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	285366.
17 INTEREST	0.	0.	0.	32.	210.	615.	1227.	1817.	3901.
18 BANK BORROWING	0.	0.	0.	833.	3797.	6732.	9180.	6153.	26695.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	833.	4630.	11362.	20542.	26695.	

21 PAYOUT TIME 6.3 YEARS

TABLE 16-6-9 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE II A : E-6, OFFSHORE STORAGE CASE

** PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY **
(X M$ 1000)

(CONT'D)
PAGE 6

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-46993.	-159941.	-57649.	72319.	69979.	66647.	63473.	53934.	37603.	22285.
CUMULATIVE PRESENT WORTH	-46993.	-206933.	-264583.	-192264.	-122284.	-55637.	7836.	61770.	99373.	121657.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-45912.	-149161.	-51320.	61453.	56762.	51601.	46910.	38048.	25321.	14324.
CUMULATIVE PRESENT WORTH	-45912.	-195073.	-246393.	-184940.	-128178.	-76577.	-29666.	8382.	33703.	48028.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-44903.	-139539.	-45922.	52598.	46471.	40410.	35139.	27261.	17354.	9390.
CUMULATIVE PRESENT WORTH	-44903.	-184442.	-230364.	-177766.	-131295.	-90885.	-55747.	-28485.	-11132.	-1741.

TERM	11	12	13	14	15	16	17	18
PRESENT WORTH								
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43
PRESENT WORTH	9881.	4563.	1627.	-415.	-1768.	-2871.	-3555.	-1846.
CUMULATIVE PRESENT WORTH	131539.	136102.	137729.	137314.	135546.	132675.	129120.	127273.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19
PRESENT WORTH	6063.	2673.	910.	-221.	-901.	-1396.	-1650.	-818.
CUMULATIVE PRESENT WORTH	54091.	56763.	57673.	57452.	56551.	55155.	53505.	52687.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09
PRESENT WORTH	3802.	1603.	522.	-121.	-473.	-701.	-792.	-376.
CUMULATIVE PRESENT WORTH	2060.	3663.	4185.	4064.	3591.	2890.	2097.	1722.

* E C O N O M I C A N A L Y S I S F O R M A L A Y S I A P R O J E C T *

TABLE 16-6-10 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE II B : E-6, ONSHORE TERMINAL CASE

* P R E M I S E S *

PRODUCTION LIFE	: 15 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C T E R M S O F P/S A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 20.00 %
PROFIT OIL SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
INITIAL BASIC PRICE (AT 1976 BASE)	: M$ 32.31 /BBL
RATE OF INCREASE FOR BASIC PRICE	: 5.00 %
RATE OF PAYMENT FOR PROFIT OIL ABOVE BASIC PRICE	: 70.00 %
PRODUCTION BONUS ABOVE 50000BBL/DAY	: M$ 5000000.
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	51365.	115072.	132697.	0.	0.	0.	0.	0.	0.	0.	299134.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	10951.	10951.	10951.	10951.	9993.	7869.	5677.	67343.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	31.57	31.57	31.57	31.57	31.57	31.57	31.57	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	52.63	55.26	

TERM	11	12	13	14	15	16	17	18	18YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	0.	0.	0.	0.	0.	299134.
OIL PRODUCTION (M BBL/YEAR)	3747.	2881.	2371.	1984.	1700.	1442.	1255.	591.	83314.
SALES PRICE OF OIL (M$/BBL)	31.57	31.57	31.57	31.57	31.57	31.57	31.57	31.57	
BASIC PRICE OF OIL (M$/BBL)	58.02	60.92	63.97	67.17	70.53	74.05	77.76	81.64	

TABLE 16-6-10 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE II B : E-6, ONSHORE TERMINAL CASE

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 2

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	169404.	169404.	169404.	169404.	154585.	121728.	87819.	1041748.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	709.	709.	709.	709.	647.	509.	266.	4257.
5 TOTAL CASH INFLOW	0.	0.	0.	172613.	170113.	170113.	170113.	155231.	122237.	88085.	1048505.
6 INCOME TAX	0.	0.	0.	77676.	76551.	76551.	76551.	69854.	55007.	39638.	471827.
7 NET CASH FLOW	0.	0.	0.	94937.	93562.	93562.	93562.	85377.	67230.	48447.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	94937.	188499.	282061.	375624.	461001.	528231.	576678.	

TERM	11	12	13	14	15	16	17	18	18YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	57963.	44567.	36678.	30691.	26298.	22307.	19414.	9142.	1288804.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 RESEARCH FUND FROM OIL CO.	196.	167.	150.	128.	110.	93.	81.	38.	5221.
5 TOTAL CASH INFLOW	58160.	44734.	36828.	30819.	26408.	22400.	19495.	9181.	1296526.
6 INCOME TAX	26172.	20130.	16572.	13869.	11884.	10080.	8773.	4131.	583438.
7 NET CASH FLOW	31988.	24604.	20255.	16951.	14524.	12320.	10722.	5049.	
8 CUMULATIVE NET CASH FLOW	608666.	633269.	653525.	670475.	685000.	697320.	708042.	713091.	

TABLE 16-6-10 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE II B : E-6, ONSHORE TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	80034.	75119.	71542.	68135.	59214.	44408.	30477.
CUMULATIVE PRESENT WORTH	0.	0.	0.	80034.	155153.	226695.	294830.	354044.	398452.	428928.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	68008.	60930.	55391.	50356.	41773.	29904.	19590.
CUMULATIVE PRESENT WORTH	0.	0.	0.	68008.	128939.	184330.	234686.	276459.	306363.	325953.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	58210.	49884.	43377.	37719.	29930.	20494.	12842.
CUMULATIVE PRESENT WORTH	0.	0.	0.	58210.	108093.	151471.	189190.	219120.	239615.	252457.

TERM	11	12	13	14	15	16	17	18
PRESENT WORTH								
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43
PRESENT WORTH	19165.	14039.	11007.	8773.	7159.	5783.	4794.	2150.
CUMULATIVE PRESENT WORTH	448093.	462132.	473139.	481912.	489071.	494854.	499648.	501798.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19
PRESENT WORTH	11759.	8222.	6154.	4682.	3647.	2812.	2225.	953.
CUMULATIVE PRESENT WORTH	337712.	345934.	352088.	356769.	360416.	363228.	365453.	366405.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09
PRESENT WORTH	7373.	4931.	3530.	2569.	1914.	1412.	1069.	438.
CUMULATIVE PRESENT WORTH	259830.	264761.	268292.	270861.	272775.	274187.	275255.	275693.

TABLE 16-6-10 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS
VOL.IV CASE II B : E-6, ONSHORE TERMINAL CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	72602.	72602.	72602.	72602.	66251.	52169.	37637.	446464.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	69145.	69145.	69145.	69145.	63096.	49685.	15494.	404853.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	34572.	34572.	34572.	34572.	31548.	24842.	17922.	212602.
4 TOTAL CASH INFLOW	0.	0.	0.	176319.	176319.	176319.	176319.	160894.	126696.	71053.	1063918.
5 ROYALTY	0.	0.	0.	34572.	34572.	34572.	34572.	31548.	24842.	17922.	212602.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	709.	709.	709.	709.	647.	509.	266.	4257.
OPERATING EXPENSES	0.	0.	0.	69145.	69145.	69145.	69145.	63096.	49685.	15494.	404853.
(M$/BBL)	0.0	0.0	0.0	6.31	6.31	6.31	6.31	6.31	6.31	2.73	6.01
9 OPERATING COST	0.	0.	0.	15256.	15256.	15256.	15256.	15145.	14901.	14649.	105719.
CAPITAL COST RECOVERY	0.	0.	0.	53889.	53889.	53889.	53889.	47951.	34784.	845.	299134.
INCOME BEFORE TAX	0.	0.	0.	69393.	71893.	71893.	71893.	65604.	51660.	37371.	439707.
10 INCOME TAX	0.	0.	0.	31227.	32352.	32352.	32352.	29522.	23247.	16817.	197868.
11 CAPITAL INVESTMENT	51365.	115072.	132697.	0.	0.	0.	0.	0.	0.	0.	299134.
12 TOTAL CASH OUTFLOW	51365.	115072.	132697.	84264.	82889.	82889.	82889.	76861.	63500.	49654.	822079.
13 NET CASH FLOW	-51365.	-115072.	-132697.	92055.	93430.	93430.	93430.	84033.	63197.	21399.	
14 CUMULATIVE NET CASH FLOW	-51365.	-166437.	-299134.	-207079.	-113650.	-20220.	73210.	157243.	220440.	241839.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	7.05	12.40	15.15	15.86	
16 CORPORATE CAPITAL	51365.	115072.	132697.	0.	0.	0.	0.	0.	0.	0.	299134.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

21 PAYOUT TIME 6.2 YEARS

TABLE 16-6-10 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS
VOL.IV CASE II B : E-6, ONSHORE TERMINAL CASE

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

(CONT'D)
PAGE 5

TERM	11	12	13	14	15	16	17	18	18YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	24841.	19100.	15719.	13153.	11270.	9560.	8320.	3918.	552346.
2 SALES REVENUE FROM COST OIL	14426.	14327.	14268.	12527.	10734.	9105.	7924.	3732.	491895.
3 SALES REVENUE FROM ROYALTY OIL	11829.	9095.	7485.	6263.	5367.	4552.	3962.	1866.	263022.
4 TOTAL CASH INFLOW	51097.	42522.	37472.	31944.	27371.	23217.	20206.	9516.	1307260.
5 ROYALTY	11829.	9095.	7485.	6263.	5367.	4552.	3962.	1866.	263022.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.
8 RESEARCH FUND TO PETRONAS	196.	167.	150.	128.	110.	93.	81.	38.	5221.
OPERATING EXPENSES	14426.	14327.	14268.	14223.	14190.	14159.	14139.	8216.	512801.
(M$/BBL)	3.85	4.97	6.02	7.17	8.35	9.82	11.27	13.90	6.16
9 OPERATING COST	14426.	14327.	14268.	14223.	14190.	14159.	14139.	8216.	213667.
CAPITAL COST RECOVERY	0.	0.	0.	0.	0.	0.	0.	0.	299134.
INCOME BEFORE TAX	24645.	18933.	15569.	13025.	11160.	9467.	8239.	3880.	544625.
10 INCOME TAX	11090.	8520.	7006.	5861.	5022.	4260.	3708.	1746.	245081.
11 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	299134.
12 TOTAL CASH OUTFLOW	37542.	32109.	28909.	26476.	24689.	23065.	21890.	11866.	1028625.
13 NET CASH FLOW	13555.	10413.	8563.	5468.	2682.	152.	-1683.	-2350.	
14 CUMULATIVE NET CASH FLOW	255394.	265807.	274370.	279837.	282519.	282672.	280988.	278638.	
15 DCF ROR OF NET CASH FLOW (%)	16.23	16.46	16.62	16.71	16.75	16.75	16.73	16.71	
16 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	299134.
17 INTEREST	0.	0.	0.	0.	0.	0.	67.	234.	301.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	1751.	2585.	4335.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	1751.	4335.	

21 PAYOUT TIME 6.2 YEARS

TABLE 16-6-10 CASH FLOW TABLE FOR OIL WEST TEMANA AND E-6 OIL FIELDS

VOL.IV CASE II B : E-6, ONSHORE TERMINAL CASE

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-50127.	-106951.	-117460.	77604.	75013.	71441.	68039.	58282.	41743.	13462.
CUMULATIVE PRESENT WORTH	-50127.	-157078.	-274538.	-196934.	-121921.	-50481.	17558.	75840.	117583.	131045.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-48975.	-99743.	-104563.	65944.	60844.	55313.	50285.	41116.	28110.	8653.
CUMULATIVE PRESENT WORTH	-48975.	-148717.	-253281.	-187337.	-126493.	-71180.	-20896.	20220.	48330.	56983.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-47898.	-93309.	-93566.	56442.	49813.	43316.	37666.	29459.	19265.	5672.
CUMULATIVE PRESENT WORTH	-47898.	-141207.	-234773.	-178330.	-128517.	-85201.	-47535.	-18076.	1189.	6861.

TERM	11	12	13	14	15	16	17	18
PRESENT WORTH								
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43
PRESENT WORTH	8121.	5942.	4653.	2830.	1322.	72.	-753.	-1001.
CUMULATIVE PRESENT WORTH	139166.	145108.	149761.	152591.	153913.	153984.	153232.	152231.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19
PRESENT WORTH	4983.	3480.	2601.	1510.	673.	35.	-349.	-443.
CUMULATIVE PRESENT WORTH	61966.	65446.	68047.	69557.	70231.	70265.	69916.	69473.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09
PRESENT WORTH	3124.	2087.	1492.	829.	353.	17.	-168.	-204.
CUMULATIVE PRESENT WORTH	9985.	12073.	13565.	14394.	14747.	14765.	14597.	14393.

Table 17-5-1 (Vol. IV)

MAJOR EQUIPMENT LIST

FOR CENTRAL LUCONIA GAS FIELDS-CASE IC

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V-101 PRODUCTION SEPARATOR	E8WP-A F13WP-A F14WP-A	1 1 1	SIZE: 7'-0" I.D. x 21'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
	E11WP-A F6WP-A F6WP-B F23P-A	2 1 1 3	SIZE: 8'-0" I.D. x 24'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
V-102 TEST SEPARATOR	E8WP-A F13WP-A F14WP-A	1 1 1	SIZE: 7'-0" I.D. x 21'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
	E11WP-A F6WP-A F6WP-B F23P-A	1 1 1 1	SIZE: 8'-0" I.D. x 24'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
V-103 LIQUID KNOCKOUT DRUM	E8WP-A E11WP-A F6WP-A F6WP-B F13WP-A F14WP-A F23W-A	4 11 7 6 4 3 17	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150 °F TYPE: VERTICAL
V-104 GLYCOL CONTACTOR	E8WP-A F13WP-A F14WP-A	1 1 1	SIZE: 6'-0" I.D. x 27'-6" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: VERTICAL
	F6WP-A F6WP-B	1 1	SIZE: 8'-0" I.D. x 28'-6" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: VERTICAL
	E11WP-A E23P-A	2 3	SIZE: 7'-6" I.D. x 28'-6" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: VERTICAL
V-105 CONDENSATE SURGE VESSEL	E8WP-A E11WP-A F6WP-A F6WP-B F13WP-A F14WP-A F23P-A	1 1 1 1 1 1 1	SIZE: 4'-6" I.D. x 15'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
GR - 101 GLYCOL REGENERATOR	E8WP-A F13WP-A F14WP-A	1 1 1	REBOILER: 42" DIA. x 21'-6" L STILL COLUMN: 22" DIA. x 12'-0" L SURGE TANK: 42" DIA. x 21'-6" L
	E11WP-A F6WP-A F6WP-B F23P-A	2 1 1 3	REBOILER: 48" DIA. x 24'-0" L STILL COLUMN: 28" DIA. x 13'-0" L SURGE TANK: 48" DIA. x 22'-0" L
H - 101 START-UP HEATER	E8WP-A E11WP-A F6WP-A F6WP-B F13WP-A F14WP-A F23W-A	1 1 1 1 1 1 1	SIZE: 24" DIA. x 7'-6" L

Table 17-5-1 (Vol. IV)

MAJOR EQUIPMENT LIST

FOR CENTRAL LUCONIA GAS FIELDS - CASE IC (Cont'd)

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
C - 151 INSTRUMENT AIR COMPRESSOR	E8WP-A E11WP-A F6WP-A F6WP-B F13WP-A F14WP-A F23P-A	2 2 2 2 2 2 2	CAPACITY: 35 SCFM
P - 152 FIRE WATER PUMP	E8WP-A E11WP-A F6WP-A F6WP-B F13WP-A F14WP-A F23P-A	1 1 1 1 1 1 1	CAPACITY: 1,500 GPM TYPE: VERTICAL
TK - 101 CORROSION INHIBITOR TANK	E8WP-A F13WP-A F14WP-A	1 1 1	CAPACITY: 20 BBL SIZE: 5'-0" I.D. x 8'-0" H
	F6WP-A F6WP-B	1 1	CAPACITY: 50 BBL SIZE: 6'-6" I.D. x 10'-0" H
	E11WP-A	1	CAPACITY: 70 BBL SIZE: 8'-0" I.D. x 10'-0" H
	F23P-A	1	CAPACITY: 90 BBL SIZE: 9'-6" I.D. x 12'-0" H
TK - 102 GLYCOL STORAGE TANK	E8WP-A F13WP-A F14WP-A	1 1 1	CAPACITY: 20 BBL SIZE: 5'-0" I.D. x 8'-0" H
	F6WP-A F6WP-B	1 1	CAPACITY: 50 BBL SIZE: 6'-6" I.D. x 10'-0" H
	E11WP-A	1	CAPACITY: 70 BBL SIZE: 8'-0" I.D. x 10'-0" H
	F23P-A	1	CAPACITY: 90 BBL SIZE: 9'-6" I.D. x 12'-0" H
M - 101 INLET MANIFOLD	E8WP-A E11WP-A F6WP-A F6WP-B F13WP-A F14WP-A F23W-A	1 1 1 1 1 1 1	PRODUCTION HEADER TEST HEADER
C - 111 GAS TURBINE COMPRESSOR	E6C-A	3	CAPACITY: 100 MMSCFD
	E11C-A E11C-B	4 4	CAPACITY: 230 MMSCFD
V - 111 KNOCKOUT DRUM	E6C-A	1	SIZE: 5'-0" I.D. x 15'-0" S-S TYPE: VERTICAL
	E11C-A E11C-B	1 1	SIZE: 10'-0" I.D. x 20'-0" S-S TYPE: VERTICAL

Table 17-5-1 (Vol. IV)

MAJOR EQUIPMENT LIST

FOR CENTRAL LUCONIA GAS FILEDS-CASE IC (Cont'd)

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V - 112 UNIT SUCTION SCRUBBER	E6C-A	3	SIZE: 3'-6" I.D. x 10'-0" S-S TYPE: VERTICAL
	E11C-A E11C-B	4 4	SIZE: 5'-6" I.D. X 16'-0" S-S TYPE: VERTICAL
E - 111 AFTERCOOLER	E6C-A E11C-A E11C-B	6 16 16	TYPE: SHELL AND TUBE
P - 153 SEA WATER PUMP	E6C-A	3	CAPACITY: 650 GPM TYPE: VERTICAL
	E11C-A E11C-B	4 4	CAPACITY: 3,000 GPM TYPE: VERTICAL
V - 108 CENTRIFUGAL SEPARATOR	E11R-A	4	SIZE: 6'-6" I.D. x 16'-0" S-S TYPE: VERTICAL
G - 152 GAS TURBINE GENERATOR	E6U-A E11U-A F23U-A	2 2 2	CAPACITY: 1,000 KVA

Table 17-6-1
(Vol. IV)

CAPITAL INVESTMENT COST ESTIMATION

(M$ 1,000)

CENTRAL LUCONIA GAS FIELDS	CASE IA	CASE IB	CASE IC	CASE II	CASE III	CASE IV
1. Exploration & Appraisal Wells	66,957	66,957	66,957	66,957	66,957	66,957
2. Engineering	98,032	107,919	130,328	122,770	114,201	106,718
3. Development Wells	148,209	145,034	196,088	186,573	173,863	155,575
4. Facilities						
a. Offshore Platforms	232,921	210,168	314,763	293,108	277,157	259,152
b. Offshore Production Equipment	175,603	316,364	474,742	444,285	413,890	383,062
c. Submarine Pipelines	390,657	250,813	278,374	264,444	237,800	230,084
d. Offshore Storage & Loading Facilities .	-	-	-	-	-	-
e. Onshore Terminal & Loading Facilities .	-	117,500	-	-	-	-
f. Support Facilities	39,304	39,304	39,304	39,304	39,304	39,304
Sub Total	838,485	934,149	1,107,183	1,041,141	968,151	911,602
5. Pre-start up Expense	10,847	11,871	14,336	13,505	12,562	11,738
6. Contingencies	108,473	118,710	143,361	135,049	125,622	117,389
TOTAL	1,271,003	1,384,640	1,658,253	1,565,995	1,461,356	1,369,979

Table 17-6-2 (Vol. IV)

ANNUAL OPERATION COST ESTIMATION

(M$ 1,000/Year)

CENTRAL LUCONIA GAS FIELDS

	CASE IA	CASE IB	CASE IC	CASE II	CASE III	CASE IV
1. Direct Cost						
a. Operating Personnel	2,545	2,545	2,545	2,545	2,545	2,545
b. Operating Management	254	254	254	254	254	254
c. Repair & Maintenance	14,145	16,713	21,120	19,774	18,512	17,094
d. Operating Supplies	3,470	3,373	4,128	3,879	3,597	3,358
e. Chemical	2,535	2,477	3,345	3,170	2,957	2,733
f. Service Contract	5,944	5,944	5,944	5,563	5,182	4,801
Sub Total	28,893	31,306	37,336	35,185	33,047	30,785
2. Indirect Cost						
a. Indirect Personnel	1,400	1,400	1,400	1,400	1,400	1,400
b. Insurance	12,619	13,823	17,272	16,190	15,108	14,003
Sub Total	14,019	15,223	18,672	17,590	16,508	15,403
TOTAL	42,912	46,529	56,008	52,775	49,555	46,188

Table 17-6-3 (Vol. IV) INVESTMENT SCHEDULE

CENTRAL LUCONIA GAS FIELDS CASE I A

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	13TH
1. Exploration & Appraisal Wells	66,957	-	-	-
2. Engineering	94,070	-	-	3,962
3. Development Wells	-	60,452	87,757	-
4. Offshore Platforms	59,510	153,558	19,853	-
5. Offshore Production Equipment	36,548	91,859	7,572	39,624
6. Submarine Pipelines	-	155,227	235,430	-
7. Offshore Storage & Loading Facilities	-	-	-	-
8. Onshore Terminal & Loading Facilities	-	-	-	-
9. Support Facilities	11,791	19,652	7,861	-
10. Pre-start up Expense	2,019	4,807	3,585	436
11. Contingencies	20,192	48,075	35,847	4,359
Total	291,087	533,630	397,905	48,381

Table 17-6-4 (Vol. IV) INVESTMENT SCHEDULE

CENTRAL LUCONIA GAS FIELDS CASE I B

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	13TH
1. Exploration & Appraisal Wells	66,957	-	-	-
2. Engineering	92,054	-	-	15,865
3. Development Wells	-	60,452	84,582	-
4. Offshore Platforms	60,183	132,624	17,361	-
5. Offshore Production Equipment	36,515	114,605	6,596	158,648
6. Submarine Pipelines	-	88,034	162,779	-
7. Offshore Storage & Loading Facilities	-	-	-	-
8. Onshore Terminal & Loading Facilities	-	-	117,500	-
9. Support Facilities	11,791	19,652	7,861	-
10. Pre-start up Expense	2,005	4,154	3,967	1,745
11. Contingencies	20,054	41,537	39,668	17,451
Total	289,559	461,058	440,314	193,709

Table 17-6-5 (Vol. IV) INVESTMENT SCHEDULE

CENTRAL LUCONIA GAS FIELDS CASE I C

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	13TH
1. Exploration & Appraisal Wells	66,957	-	-	-
2. Engineering	112,695	-	-	17,633
3. Development Wells	-	83,820	112,268	-
4. Offshore Platforms	121,298	176,848	16,617	-
5. Offshore Production Equipment	115,253	175,679	7,483	176,327
6. Submarine Pipelines	-	156,820	121,554	-
7. Offshore Storage & Loading Facilities	-	-	-	-
8. Onshore Terminal & Loading Facilities	-	-	-	-
9. Support Facilities	11,791	19,652	7,861	-
10. Pre-start up Expense	3,609	6,129	2,657	1,941
11. Contingencies	36,104	61,283	26,579	19,395
Total	467,707	680,231	295,019	215,296

Table 17-6-6 (Vol. IV) INVESTMENT SCHEDULE

CENTRAL LUCONIA GAS FIELDS CASE II

(M$ 1,000)

Item / Year	1ST	2ND	3RD	13TH
1. Exploration & Appraisal Wells	66,957	-	-	-
2. Engineering	105,869	-	-	16,901
3. Development Wells	-	83,830	102,743	-
4. Offshore Platforms	121,300	160,604	11,204	-
5. Offshore Production Equipment	108,605	161,072	5,596	169,012
6. Submarine Pipelines	-	156,822	107,622	-
7. Offshore Storage & Loading Facilities	-	-	-	-
8. Onshore Terminal & Loading Facilities	-	-	-	-
9. Support Facilities	11,791	19,652	7,861	-
10. Pre-start up Expense	3,476	5,820	2,350	1,859
11. Contingencies	34,757	58,198	23,503	18,591
Total	452,755	645,998	260,879	206,363

Table 17-6-7 (Vol. IV) INVESTMENT SCHEDULE

CENTRAL LUCONIA GAS FIELDS CASE III

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	13TH
1. Exploration & Appraisal Wells	66,957	-	-	-
2. Engineering	98,199	-	-	16,002
3. Development Wells	-	75,692	98,171	-
4. Offshore Platforms	99,205	161,732	16,220	-
5. Offshore Production Equipment	85,443	163,063	5,364	160,020
6. Submarine Pipelines	-	126,126	111,674	-
7. Offshore Storage & Loading Facilities	-	-	-	-
8. Onshore Terminal & Loading Facilities	-	-	-	-
9. Support Facilities	11,791	19,652	7,861	-
10. Pre-start up Expense	2,946	5,463	2,393	1,760
11. Contingencies	29,464	54,627	23,929	17,602
Total	394,005	606,355	265,612	195,384

Table 17-6-8 (Vol. IV) INVESTMENT SCHEDULE

CENTRAL LUCONIA GAS FIELDS CASE IV

(M$ 1,000)

Item / Year	1ST	2ND	3RD	13TH
1. Exploration & Appraisal Wells	66,957	-	-	-
2. Engineering	91,661	-	-	15,057
3. Development Wells	-	52,324	103,251	-
4. Offshore Platforms	57,117	178,725	23,310	-
5. Offshore Production Equipment	34,354	180,525	17,612	150,571
6. Submarine Pipelines	-	35,215	194,869	-
7. Offshore Storage & Loading Facilities	-	-	-	-
8. Onshore Terminal & Loading Facilities	-	-	-	-
9. Support Facilities	11,791	19,652	7,861	-
10. Pre-start up Expense	1,949	4,664	3,469	1,656
11. Contingencies	19,492	46,644	34,690	16,563
Total	283,321	517,749	385,062	183,847

* E C O N O M I C A N A L Y S I S F O R M A L A Y S I A P R O J E C T *

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

* P R E M I S E S *

PRODUCTION LIFE	: 20 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C T E R M S O F P/S A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 25.00 %
PROFIT GAS SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	291087.	533630.	397905.	0.	0.	0.	0.	0.	0.	0.	1222622.
GAS PRODUCTION (MMSCF/DAY)	0.	0.	0.	1030.	1030.	1030.	1030.	1030.	1030.	1030.	7210.
SALES PRICE OF GAS (M¢/MSCF)	0.0	0.0	0.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	

TERM	11	12	13	14	15	16	17	18	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	48381.	0.	0.	0.	0.	0.	0.	0.	1271003.
GAS PRODUCTION (MMSCF/DAY)	1030.	1030.	1030.	1030.	1030.	1030.	1030.	1030.	1030.	1030.	17510.
SALES PRICE OF GAS (M¢/MSCF)	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	174.0	

*** E C O N O M I C A N A L Y S I S F O R M A L A Y S I A P R O J E C T ***

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR. TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	1271003.
GAS PRODUCTION (MMSCF/DAY)	1030.	1030.	1030.	20600.
SALES PRICE OF GAS (M¢/MSCF)	174.0	174.0	174.0	

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 3

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	297639.	297639.	297639.	297639.	297639.	297639.	297639.	2083474.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1455.	1455.	1455.	1455.	1455.	1455.	1455.	10188.
4 TOTAL CASH INFLOW	0.	0.	0.	301595.	299095.	299095.	299095.	299095.	299095.	299095.	2096161.
5 INCOME TAX	0.	0.	0.	135718.	134593.	134593.	134593.	134593.	134593.	134593.	943273.
6 NET CASH FLOW	0.	0.	0.	165877.	164502.	164502.	164502.	164502.	164502.	164502.	
7 CUMULATIVE NET CASH FLOW	0.	0.	0.	165877.	330379.	494881.	659384.	823886.	988388.	1152889.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	297639.	297639.	297639.	297639.	297639.	297639.	297639.	297639.	297639.	297639.	5059864.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	1455.	1455.	1455.	1176.	852.	852.	852.	852.	852.	852.	20845.
4 TOTAL CASH INFLOW	299095.	299095.	299095.	298815.	298492.	298492.	298492.	298492.	298492.	298492.	5083204.
5 INCOME TAX	134593.	134593.	134593.	134467.	134321.	134321.	134321.	134321.	134321.	134321.	2287442.
6 NET CASH FLOW	164502.	164502.	164502.	164349.	164170.	164170.	164170.	164170.	164170.	164170.	
7 CUMULATIVE NET CASH FLOW	1317391.	1481893.	1646395.	1810743.	1974913.	2139083.	2303253.	2467423.	2631593.	2795763.	

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	297639.	297639.	297639.	5952781.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	852.	852.	852.	23402.
4 TOTAL CASH INFLOW	298492.	298492.	298492.	5978677.
5 INCOME TAX	134321.	134321.	134321.	2690405.
6 NET CASH FLOW	164170.	164170.	164170.	
7 CUMULATIVE NET CASH FLOW	2959933.	3124103.	3288273.	

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	139838.	132075.	125786.	119796.	114092.	108659.	103485.
CUMULATIVE PRESENT WORTH	0.	0.	0.	139838.	271913.	397699.	517495.	631587.	740246.	843730.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	118826.	107129.	97390.	88536.	80487.	73170.	66519.
CUMULATIVE PRESENT WORTH	0.	0.	0.	118826.	225955.	323345.	411881.	492368.	565538.	632057.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	101706.	87706.	76267.	66319.	57669.	50147.	43606.
CUMULATIVE PRESENT WORTH	0.	0.	0.	101706.	189412.	265678.	331997.	389666.	439812.	483418.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	98557.	93864.	89394.	85058.	80920.	77067.	73397.	69902.	66573.	63403.
CUMULATIVE PRESENT WORTH	942287.	1036151.	1125545.	1210602.	1291521.	1368587.	1441983.	1511884.	1578457.	1641859.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	60471.	54974.	49977.	45391.	41220.	37472.	34066.	30969.	28154.	25594.
CUMULATIVE PRESENT WORTH	692528.	747502.	797479.	842870.	884089.	921562.	955628.	986596.	1014750.	1040344.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	37918.	32972.	28671.	24908.	21636.	18814.	16360.	14226.	12371.	10757.
CUMULATIVE PRESENT WORTH	521336.	554308.	582980.	607888.	629524.	648338.	664698.	678924.	691295.	702051.

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	60384.	57509.	54770.
CUMULATIVE PRESENT WORTH	1702242.	1759750.	1814520.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	23267.	21152.	19229.
CUMULATIVE PRESENT WORTH	1063611.	1084763.	1103992.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	9354.	8134.	7073.
CUMULATIVE PRESENT WORTH	711405.	719539.	726612.

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	127560.	127560.	127560.	127560.	127560.	127560.	127560.	892919.
2 SALES REVENUE FROM COST GAS	0.	0.	0.	163538.	163538.	163538.	163538.	163538.	163538.	163538.	1144767.
3 SALES REVENUE FROM ROYALTY GAS	0.	0.	0.	65415.	65415.	65415.	65415.	65415.	65415.	65415.	457907.
4 TOTAL CASH INFLOW	0.	0.	0.	356513.	356513.	356513.	356513.	356513.	356513.	356513.	2495591.
5 ROYALTY	0.	0.	0.	65415.	65415.	65415.	65415.	65415.	65415.	65415.	457907.
6 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	0.	0.	0.	1455.	1455.	1455.	1455.	1455.	1455.	1455.	10188.
OPERATING EXPENSES	0.	0.	0.	163538.	163538.	163538.	163538.	163538.	163538.	163538.	1144767.
8 OPERATING COST	0.	0.	0.	42912.	42912.	42912.	42912.	42912.	42912.	42912.	300384.
CAPITAL COST RECOVERY	0.	0.	0.	120626.	120626.	120626.	120626.	120626.	120626.	120626.	844383.
INCOME BEFORE TAX	0.	0.	0.	123604.	126104.	126104.	126104.	126104.	126104.	126104.	880230.
9 INCOME TAX	0.	0.	0.	55622.	56747.	56747.	56747.	56747.	56747.	56747.	396104.
10 CAPITAL INVESTMENT	291087.	533630.	397905.	0.	0.	0.	0.	0.	0.	0.	1222622.
11 TOTAL CASH OUTFLOW	291087.	533630.	397905.	167905.	166530.	166530.	166530.	166530.	166530.	166530.	2389700.
12 NET CASH FLOW	-291087.	-533630.	-397905.	188609.	189984.	189984.	189984.	189984.	189984.	189984.	
13 CUMULATIVE NET CASH FLOW	-291087.	-824717.	-1222622.	-1034013.	-844030.	-654046.	-464063.	-274079.	-84096.	105888.	
14 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.71	
15 CORPORATE CAPITAL	291087.	533630.	397905.	0.	0.	0.	0.	0.	0.	0.	1222621.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.4 YEARS

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 8

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	127560.	127560.	127560.	127560.	127560.	127560.	127560.	127560.	127560.	127560.	2168510.
2 SALES REVENUE FROM COST GAS	163538.	163538.	163538.	107654.	42912.	42912.	42912.	42912.	42912.	42912.	2000500.
3 SALES REVENUE FROM ROYALTY GAS	65415.	65415.	65415.	65415.	65415.	65415.	65415.	65415.	65415.	65415.	1112059.
4 TOTAL CASH INFLOW	356513.	356513.	356513.	300629.	235887.	235887.	235887.	235887.	235887.	235887.	5281080.
5 ROYALTY	65415.	65415.	65415.	65415.	65415.	65415.	65415.	65415.	65415.	65415.	1112059.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	1455.	1455.	1455.	1176.	852.	852.	852.	852.	852.	852.	20845.
OPERATING EXPENSES	163538.	163538.	163538.	107654.	42912.	42912.	42912.	42912.	42912.	42912.	2000507.
8 OPERATING COST	42912.	42912.	42912.	42912.	42912.	42912.	42912.	42912.	42912.	42912.	729504.
CAPITAL COST RECOVERY	120626.	120626.	120626.	64742.	0.	0.	0.	0.	0.	0.	1271003.
INCOME BEFORE TAX	126104.	126104.	126104.	126384.	126707.	126707.	126707.	126707.	126707.	126707.	2145167.
9 INCOME TAX	56747.	56747.	56747.	56873.	57018.	57018.	57018.	57018.	57018.	57018.	965327.
10 CAPITAL INVESTMENT	0.	0.	48381.	0.	0.	0.	0.	0.	0.	0.	1271003.
11 TOTAL CASH OUTFLOW	166530.	166530.	214911.	166376.	166198.	166198.	166198.	166198.	166198.	166198.	4101225.
12 NET CASH FLOW	189984.	189984.	141603.	134253.	69689.	69689.	69689.	69689.	69689.	69689.	
13 CUMULATIVE NET CASH FLOW	295872.	485855.	627458.	761711.	831400.	901089.	970778.	1040467.	1110155.	1179844.	
14 DCF ROR OF NET CASH FLOW (%)	4.15	6.00	7.08	7.93	8.30	8.62	8.90	9.14	9.36	9.54	
15 CORPORATE CAPITAL	0.	0.	48381.	0.	0.	0.	0.	0.	0.	0.	1271002.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.4 YEARS

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

(CONT'D)
PAGE 9

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	127560.	127560.	127560.	2551187.
2 SALES REVENUE FROM COST GAS	42912.	42912.	42912.	2129233.
3 SALES REVENUE FROM ROYALTY GAS	65415.	65415.	65415.	1308304.
4 TOTAL CASH INFLOW	235887.	235887.	235887.	5988741.
5 ROYALTY	65415.	65415.	65415.	1308304.
6 BONUS	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	852.	852.	852.	23402.
OPERATING EXPENSES	42912.	42912.	42912.	2129243.
8 OPERATING COST	42912.	42912.	42912.	858240.
CAPITAL COST RECOVERY	0.	0.	0.	1271003.
INCOME BEFORE TAX	126707.	126707.	126707.	2525288.
9 INCOME TAX	57018.	57018.	57018.	1136381.
10 CAPITAL INVESTMENT	0.	0.	0.	1271003.
11 TOTAL CASH OUTFLOW	166198.	166198.	166198.	4599816.
12 NET CASH FLOW	69689.	69689.	69689.	
13 CUMULATIVE NET CASH FLOW	1249533.	1319222.	1388911.	
14 DCF ROR OF NET CASH FLOW (%)	9.70	9.85	9.97	
15 CORPORATE CAPITAL	0.	0.	0.	1271002.
16 INTEREST	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	

20 PAYOUT TIME 9.4 YEARS

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-284072.	-495972.	-352214.	159001.	152534.	145270.	138353.	131765.	125490.	119515.
CUMULATIVE PRESENT WORTH	-284072.	-780043.	-1132257.	-973256.	-820722.	-675452.	-537100.	-405335.	-279845.	-160331.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-277540.	-462543.	-313544.	135110.	123723.	112475.	102250.	92955.	84505.	76822.
CUMULATIVE PRESENT WORTH	-277540.	-740083.	-1053626.	-918516.	-794793.	-682318.	-580067.	-487113.	-402608.	-325786.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-271440.	-432707.	-280566.	115643.	101292.	88080.	76592.	66601.	57914.	50360.
CUMULATIVE PRESENT WORTH	-271440.	-704147.	-984713.	-869070.	-767777.	-679697.	-603106.	-536504.	-478590.	-428230.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	113823.	108403.	76950.	69482.	34350.	32714.	31156.	29673.	28260.	26914.
CUMULATIVE PRESENT WORTH	-46507.	61896.	138846.	208328.	242678.	275392.	306548.	336221.	364481.	391395.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	69839.	63490.	43020.	37079.	17497.	15907.	14461.	13146.	11951.	10865.
CUMULATIVE PRESENT WORTH	-255947.	-192458.	-149438.	-112359.	-94862.	-78955.	-64494.	-51348.	-39397.	-28533.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	43792.	38080.	24680.	20347.	9184.	7986.	6945.	6039.	5251.	4566.
CUMULATIVE PRESENT WORTH	-384438.	-346358.	-321678.	-301331.	-292147.	-284160.	-277215.	-271177.	-265925.	-261359.

TABLE 17-6-9 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I A : NATURAL FLOW CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	25632.	24412.	23249.
CUMULATIVE PRESENT WORTH	417027.	441439.	464688.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	9877.	8979.	8163.
CUMULATIVE PRESENT WORTH	-18656.	-9677.	-1514.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	3971.	3453.	3002.
CUMULATIVE PRESENT WORTH	-257388.	-253936.	-250933.

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

 CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* P R E M I S E S *

PRODUCTION LIFE	: 20 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C T E R M S O F P/S A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 25.00 %
PROFIT GAS SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	289559.	461058.	440314.	0.	0.	0.	0.	0.	0.	0.	1190931.
GAS PRODUCTION (MMSCF/DAY)	0.	0.	0.	980.	980.	980.	980.	980.	980.	980.	6860.
SALES PRICE OF GAS (M¢/MSCF)	0.0	0.0	0.0	181.0	181.0	181.0	181.0	181.0	181.0	181.0	

TERM	11	12	13	14	15	16	17	18	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	193709.	0.	0.	0.	0.	0.	0.	0.	1384640.
GAS PRODUCTION (MMSCF/DAY)	980.	980.	980.	980.	980.	980.	980.	980.	980.	980.	16660.
SALES PRICE OF GAS (M¢/MSCF)	181.0	181.0	181.0	181.0	181.0	181.0	181.0	181.0	181.0	181.0	

*** E C O N O M I C A N A L Y S I S F O R M A L A Y S I A P R O J E C T ***

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	1384640.
GAS PRODUCTION (MMSCF/DAY)	980.	980.	980.	19600.
SALES PRICE OF GAS (M¢/MSCF)	181.0	181.0	181.0	

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 3

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	294584.	294584.	294584.	294584.	294584.	294584.	294584.	2062084.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1441.	1441.	1441.	1441.	1441.	1441.	1441.	10084.
4 TOTAL CASH INFLOW	0.	0.	0.	298524.	296024.	296024.	296024.	296024.	296024.	296024.	2074669.
5 INCOME TAX	0.	0.	0.	134336.	133211.	133211.	133211.	133211.	133211.	133211.	933602.
6 NET CASH FLOW	0.	0.	0.	164188.	162813.	162813.	162813.	162813.	162813.	162813.	
7 CUMULATIVE NET CASH FLOW	0.	0.	0.	164188.	327002.	489815.	652629.	815442.	978255.	1141068.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	294584.	294584.	294584.	294584.	294584.	294584.	294584.	294584.	294584.	294584.	5007914.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	1441.	1441.	1441.	1441.	1441.	867.	864.	864.	864.	864.	21609.
4 TOTAL CASH INFLOW	296024.	296024.	296024.	296024.	296024.	295451.	295448.	295448.	295448.	295448.	5032028.
5 INCOME TAX	133211.	133211.	133211.	133211.	133211.	132953.	132951.	132951.	132951.	132951.	2264408.
6 NET CASH FLOW	162813.	162813.	162813.	162813.	162813.	162498.	162496.	162496.	162496.	162496.	
7 CUMULATIVE NET CASH FLOW	1303881.	1466694.	1629507.	1792320.	1955133.	2117631.	2280127.	2442623.	2605119.	2767615.	

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	294584.	294584.	294584.	5891663.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	864.	864.	864.	24201.
4 TOTAL CASH INFLOW	295448.	295448.	295448.	5918369.
5 INCOME TAX	132951.	132951.	132951.	2663261.
6 NET CASH FLOW	162496.	162496.	162496.	
7 CUMULATIVE NET CASH FLOW	2930111.	3092607.	3255103.	

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

** PRESENT WORTH OF NET CASH FLOW FOR PETRONAS **
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	138414.	130719.	124495.	118566.	112920.	107543.	102422.
CUMULATIVE PRESENT WORTH	0.	0.	0.	138414.	269133.	393628.	512194.	625115.	732658.	835080.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	117617.	106029.	96390.	87627.	79661.	72419.	65836.
CUMULATIVE PRESENT WORTH	0.	0.	0.	117617.	223645.	320035.	407663.	487324.	559743.	625579.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	100670.	86806.	75484.	65638.	57076.	49632.	43158.
CUMULATIVE PRESENT WORTH	0.	0.	0.	100670.	187476.	262960.	328598.	385674.	435306.	478464.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	97545.	92900.	88476.	84263.	80251.	76281.	72648.	69189.	65894.	62756.
CUMULATIVE PRESENT WORTH	932626.	1025526.	1114002.	1198265.	1278515.	1354796.	1427444.	1496632.	1562526.	1625282.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	59851.	54410.	49463.	44967.	40879.	37091.	33718.	30653.	27867.	25333.
CUMULATIVE PRESENT WORTH	685429.	739839.	789302.	834269.	875148.	912239.	945957.	976610.	1004477.	1029810.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	37529.	32634.	28377.	24676.	21457.	18622.	16193.	14081.	12244.	10647.
CUMULATIVE PRESENT WORTH	515993.	548626.	577003.	601679.	623136.	641759.	657952.	672033.	684277.	694924.

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	59768.	56922.	54211.
CUMULATIVE PRESENT WORTH	1685050.	1741972.	1796183.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	23030.	20937.	19033.
CUMULATIVE PRESENT WORTH	1052840.	1073776.	1092809.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	9258.	8051.	7001.
CUMULATIVE PRESENT WORTH	704183.	712234.	719234.

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 7

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	126250.	126250.	126250.	126250.	126250.	126250.	126250.	883751.
2 SALES REVENUE FROM COST GAS	0.	0.	0.	161859.	161859.	161859.	161859.	161859.	161859.	161859.	1133014.
3 SALES REVENUE FROM ROYALTY GAS	0.	0.	0.	64744.	64744.	64744.	64744.	64744.	64744.	64744.	453205.
4 TOTAL CASH INFLOW	0.	0.	0.	352853.	352853.	352853.	352853.	352853.	352853.	352853.	2469971.
5 ROYALTY	0.	0.	0.	64744.	64744.	64744.	64744.	64744.	64744.	64744.	453205.
6 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	0.	0.	0.	1441.	1441.	1441.	1441.	1441.	1441.	1441.	10084.
OPERATING EXPENSES	0.	0.	0.	161859.	161859.	161859.	161859.	161859.	161859.	161859.	1133014.
8 OPERATING COST	0.	0.	0.	46529.	46529.	46529.	46529.	46529.	46529.	46529.	325703.
CAPITAL COST RECOVERY	0.	0.	0.	115330.	115330.	115330.	115330.	115330.	115330.	115330.	807311.
INCOME BEFORE TAX	0.	0.	0.	122310.	124810.	124810.	124810.	124810.	124810.	124810.	871167.
9 INCOME TAX	0.	0.	0.	55039.	56164.	56164.	56164.	56164.	56164.	56164.	392025.
10 CAPITAL INVESTMENT	289559.	461058.	440314.	0.	0.	0.	0.	0.	0.	0.	1190931.
11 TOTAL CASH OUTFLOW	289559.	461058.	440314.	170252.	168878.	168878.	168878.	168878.	168878.	168878.	2374445.
12 NET CASH FLOW	-289559.	-461058.	-440314.	182600.	183975.	183975.	183975.	183975.	183975.	183975.	
13 CUMULATIVE NET CASH FLOW	-289559.	-750617.	-1190931.	-1008331.	-824355.	-640380.	-456404.	-272429.	-88453.	95522.	
14 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.60	
15 CORPORATE CAPITAL	289559.	461058.	440314.	0.	0.	0.	0.	0.	0.	0.	1190930.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.5 YEARS

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

(CONT'D)
PAGE 8

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	126250.	126250.	126250.	126250.	126250.	126250.	126250.	126250.	126250.	126250.	2146251.
2 SALES REVENUE FROM COST GAS	161859.	161859.	161859.	161859.	161859.	47208.	46529.	46529.	46529.	46529.	2175628.
3 SALES REVENUE FROM ROYALTY GAS	64744.	64744.	64744.	64744.	64744.	64744.	64744.	64744.	64744.	64744.	1100641.
4 TOTAL CASH INFLOW	352853.	352853.	352853.	352853.	352853.	238202.	237523.	237523.	237523.	237523.	5422525.
5 ROYALTY	64744.	64744.	64744.	64744.	64744.	64744.	64744.	64744.	64744.	64744.	1100641.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	1441.	1441.	1441.	1441.	1441.	867.	864.	864.	864.	864.	21609.
OPERATING EXPENSES	161859.	161859.	161859.	161859.	161859.	47208.	46529.	46529.	46529.	46529.	2175633.
8 OPERATING COST	46529.	46529.	46529.	46529.	46529.	46529.	46529.	46529.	46529.	46529.	790993.
CAPITAL COST RECOVERY	115330.	115330.	115330.	115330.	115330.	679.	0.	0.	0.	0.	1384640.
INCOME BEFORE TAX	124810.	124810.	124810.	124810.	124810.	125383.	125386.	125386.	125386.	125386.	2122139.
9 INCOME TAX	56164.	56164.	56164.	56164.	56164.	56422.	56424.	56424.	56424.	56424.	954964.
10 CAPITAL INVESTMENT	0.	0.	193709.	0.	0.	0.	0.	0.	0.	0.	1384640.
11 TOTAL CASH OUTFLOW	168878.	168878.	362587.	168878.	168878.	168562.	168560.	168560.	168560.	168560.	4255341.
12 NET CASH FLOW	183975.	183975.	-9734.	183975.	183975.	69640.	68962.	68962.	68962.	68962.	
13 CUMULATIVE NET CASH FLOW	279498.	463473.	453739.	637715.	821690.	891330.	960292.	1029255.	1098216.	1167178.	
14 DCF ROR OF NET CASH FLOW (%)	4.07	5.93	5.84	7.20	8.26	8.59	8.87	9.12	9.34	9.53	
15 CORPORATE CAPITAL	0.	0.	193709.	0.	0.	0.	0.	0.	0.	0.	1384638.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.5 YEARS

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

(CONT'D)
PAGE 9

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	126250.	126250.	126250.	2525001.
2 SALES REVENUE FROM COST GAS	46529.	46529.	46529.	2315212.
3 SALES REVENUE FROM ROYALTY GAS	64744.	64744.	64744.	1294870.
4 TOTAL CASH INFLOW	237523.	237523.	237523.	6135091.
5 ROYALTY	64744.	64744.	64744.	1294870.
6 BONUS	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	864.	864.	864.	24201.
OPERATING EXPENSES	46529.	46529.	46529.	2315220.
8 OPERATING COST	46529.	46529.	46529.	930580.
CAPITAL COST RECOVERY	0.	0.	0.	1384640.
INCOME BEFORE TAX	125386.	125386.	125386.	2498297.
9 INCOME TAX	56424.	56424.	56424.	1124234.
10 CAPITAL INVESTMENT	0.	0.	0.	1384640.
11 TOTAL CASH OUTFLOW	168560.	168560.	168560.	4761021.
12 NET CASH FLOW	68962.	68962.	68962.	
13 CUMULATIVE NET CASH FLOW	1236140.	1305102.	1374064.	
14 DCF ROR OF NET CASH FLOW (%)	9.69	9.83	9.96	
15 CORPORATE CAPITAL	0.	0.	0.	1384638.
16 INTEREST	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	

20 PAYOUT TIME 9.5 YEARS

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-282581.	-428521.	-389753.	153936.	147710.	140676.	133977.	127598.	121522.	115735.
CUMULATIVE PRESENT WORTH	-282581.	-711102.	-1100855.	-946919.	-799209.	-658533.	-524556.	-396958.	-275437.	-159702.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-276084.	-399638.	-346961.	130806.	119810.	108918.	99017.	90015.	81832.	74393.
CUMULATIVE PRESENT WORTH	-276084.	-675722.	-1022683.	-891877.	-772067.	-663149.	-564132.	-474117.	-392284.	-317892.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-270015.	-373860.	-310469.	111959.	98089.	85295.	74169.	64495.	56083.	48768.
CUMULATIVE PRESENT WORTH	-270015.	-643875.	-954344.	-842385.	-744296.	-659001.	-584832.	-520337.	-464254.	-415486.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	110224.	104975.	-5289.	95216.	90682.	32691.	30831.	29363.	27965.	26633.
CUMULATIVE PRESENT WORTH	-49478.	55497.	50208.	145423.	236105.	268796.	299627.	328990.	356956.	383589.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	67630.	61482.	-2957.	50811.	46192.	15895.	14310.	13009.	11826.	10751.
CUMULATIVE PRESENT WORTH	-250262.	-188780.	-191737.	-140925.	-94733.	-78838.	-64528.	-51519.	-39692.	-28941.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	42407.	36875.	-1696.	27883.	24246.	7981.	6872.	5976.	5196.	4519.
CUMULATIVE PRESENT WORTH	-373079.	-336204.	-337900.	-310017.	-285771.	-277790.	-270918.	-264942.	-259746.	-255227.

TABLE 17-6-10 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I B : ONSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	25365.	24157.	23007.
CUMULATIVE PRESENT WORTH	408954.	433111.	456118.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	9774.	8885.	8078.
CUMULATIVE PRESENT WORTH	-19167.	-10282.	-2204.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	3929.	3417.	2971.
CUMULATIVE PRESENT WORTH	-251298.	-247881.	-244910.

* E C O N O M I C A N A L Y S I S F O R M A L A Y S I A P R O J E C T *

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* P R E M I S E S *

PRODUCTION LIFE	: 20 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C T E R M S O F P/S A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 25.00 %
PROFIT GAS SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	467707.	680231.	295019.	0.	0.	0.	0.	0.	0.	0.	1442957.
GAS PRODUCTION (MMSCF/DAY)	0.	0.	0.	1340.	1340.	1340.	1340.	1340.	1340.	1340.	9380.
SALES PRICE OF GAS (M¢/MSCF)	0.0	0.0	0.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	

TERM	11	12	13	14	15	16	17	18	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	215296.	0.	0.	0.	0.	0.	0.	0.	1658253.
GAS PRODUCTION (MMSCF/DAY)	1340.	1340.	1340.	1340.	1340.	1340.	1340.	1340.	1340.	1340.	22780.
SALES PRICE OF GAS (M¢/MSCF)	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	

* E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T *

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

(CONT'D)

VOL.IV   CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	1658253.
GAS PRODUCTION (MMSCF/DAY)	1340.	1340.	1340.	26800.
SALES PRICE OF GAS (M¢/MSCF)	165.0	165.0	165.0	

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	367192.	367192.	367192.	367192.	367192.	367192.	367192.	2570339.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1796.	1796.	1796.	1796.	1796.	1796.	1796.	12569.
4 TOTAL CASH INFLOW	0.	0.	0.	371487.	368987.	368987.	368987.	368987.	368987.	368987.	2585409.
5 INCOME TAX	0.	0.	0.	167169.	166044.	166044.	166044.	166044.	166044.	166044.	1163434.
6 NET CASH FLOW	0.	0.	0.	204318.	202943.	202943.	202943.	202943.	202943.	202943.	
7 CUMULATIVE NET CASH FLOW	0.	0.	0.	204318.	407261.	610204.	813147.	1016090.	1219033.	1421976.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	367192.	367192.	367192.	367192.	367192.	367192.	367192.	367192.	367192.	367192.	6242249.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	1796.	1796.	1796.	1796.	1342.	1067.	1067.	1067.	1067.	1067.	26428.
4 TOTAL CASH INFLOW	368987.	368987.	368987.	368987.	368534.	368259.	368259.	368259.	368259.	368259.	6271180.
5 INCOME TAX	166044.	166044.	166044.	166044.	165840.	165716.	165716.	165716.	165716.	165716.	2822030.
6 NET CASH FLOW	202943.	202943.	202943.	202943.	202694.	202542.	202542.	202542.	202542.	202542.	
7 CUMULATIVE NET CASH FLOW	1624919.	1827862.	2030805.	2233748.	2436441.	2638983.	2841525.	3044067.	3246609.	3449151.	

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	367192.	367192.	367192.	7343822.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	1067.	1067.	1067.	29629.
4 TOTAL CASH INFLOW	368259.	368259.	368259.	7375954.
5 INCOME TAX	165716.	165716.	165716.	3319178.
6 NET CASH FLOW	202542.	202542.	202542.	
7 CUMULATIVE NET CASH FLOW	3651693.	3854235.	4056777.	

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 5

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	172244.	162938.	155180.	147790.	140753.	134050.	127667.
CUMULATIVE PRESENT WORTH	0.	0.	0.	172244.	335183.	490362.	638153.	778905.	912956.	1040623.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	146364.	132162.	120148.	109225.	99296.	90269.	82063.
CUMULATIVE PRESENT WORTH	0.	0.	0.	146364.	278526.	398674.	507899.	607195.	697464.	779526.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	125275.	108202.	94089.	81816.	71145.	61865.	53796.
CUMULATIVE PRESENT WORTH	0.	0.	0.	125275.	233477.	327565.	409381.	480526.	542391.	596186.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	121588.	115798.	110284.	105032.	99908.	95079.	90552.	86240.	82133.	78222.
CUMULATIVE PRESENT WORTH	1162210.	1278007.	1388290.	1493322.	1593229.	1688308.	1778859.	1865098.	1947231.	2025453.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	74602.	67821.	61655.	56050.	50892.	46231.	42028.	38207.	34734.	31576.
CUMULATIVE PRESENT WORTH	854129.	921949.	983604.	1039654.	1090546.	1136776.	1178804.	1217011.	1251745.	1283321.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	46779.	40677.	35371.	30758.	26713.	23211.	20184.	17551.	15262.	13271.
CUMULATIVE PRESENT WORTH	642965.	683642.	719014.	749771.	776484.	799696.	819880.	837431.	852693.	865964.

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	74497.	70950.	67571.
CUMULATIVE PRESENT WORTH	2099950.	2170900.	2238471.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	28706.	26096.	23724.
CUMULATIVE PRESENT WORTH	1312026.	1338122.	1361845.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	11540.	10035.	8726.
CUMULATIVE PRESENT WORTH	877504.	887539.	896265.

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	157368.	157368.	157368.	157368.	157368.	157368.	157368.	1101575.
2 SALES REVENUE FROM COST GAS	0.	0.	0.	201754.	201754.	201754.	201754.	201754.	201754.	201754.	1412275.
3 SALES REVENUE FROM ROYALTY GAS	0.	0.	0.	80701.	80701.	80701.	80701.	80701.	80701.	80701.	564910.
4 TOTAL CASH INFLOW	0.	0.	0.	439823.	439823.	439823.	439823.	439823.	439823.	439823.	3078761.
5 ROYALTY	0.	0.	0.	80701.	80701.	80701.	80701.	80701.	80701.	80701.	564910.
6 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	0.	0.	0.	1796.	1796.	1796.	1796.	1796.	1796.	1796.	12569.
OPERATING EXPENSES	0.	0.	0.	201754.	201754.	201754.	201754.	201754.	201754.	201754.	1412275.
8 OPERATING COST	0.	0.	0.	56008.	56008.	56008.	56008.	56008.	56008.	56008.	392056.
CAPITAL COST RECOVERY	0.	0.	0.	145746.	145746.	145746.	145746.	145746.	145746.	145746.	1020220.
INCOME BEFORE TAX	0.	0.	0.	153072.	155572.	155572.	155572.	155572.	155572.	155572.	1086505.
9 INCOME TAX	0.	0.	0.	68883.	70008.	70008.	70008.	70008.	70008.	70008.	488928.
10 CAPITAL INVESTMENT	467707.	680231.	295019.	0.	0.	0.	0.	0.	0.	0.	1442957.
11 TOTAL CASH OUTFLOW	467707.	680231.	295019.	209888.	208513.	208513.	208513.	208513.	208513.	208513.	2903916.
12 NET CASH FLOW	-467707.	-680231.	-295019.	229935.	231310.	231310.	231310.	231310.	231310.	231310.	
13 CUMULATIVE NET CASH FLOW	-467707.	-1147938.	-1442957.	-1213021.	-981711.	-750400.	-519090.	-287779.	-56469.	174842.	
14 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.27	
15 CORPORATE CAPITAL	467707.	680231.	295019.	0.	0.	0.	0.	0.	0.	0.	1442955.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.2 YEARS

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

(CONT'D)
PAGE 8

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	157368.	157368.	157368.	157368.	157368.	157368.	157368.	157368.	157368.	157368.	2675245.
2 SALES REVENUE FROM COST GAS	201754.	201754.	201754.	201754.	111061.	56008.	56008.	56008.	56008.	56008.	2610382.
3 SALES REVENUE FROM ROYALTY GAS	80701.	80701.	80701.	80701.	80701.	80701.	80701.	80701.	80701.	80701.	1371922.
4 TOTAL CASH INFLOW	439823.	439823.	439823.	439823.	349130.	294077.	294077.	294077.	294077.	294077.	6657568.
5 ROYALTY	80701.	80701.	80701.	80701.	80701.	80701.	80701.	80701.	80701.	80701.	1371922.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	1796.	1796.	1796.	1796.	1342.	1067.	1067.	1067.	1067.	1067.	26428.
OPERATING EXPENSES	201754.	201754.	201754.	201754.	111061.	56008.	56008.	56008.	56008.	56008.	2610388.
8 OPERATING COST	56008.	56008.	56008.	56008.	56008.	56008.	56008.	56008.	56008.	56008.	952136.
CAPITAL COST RECOVERY	145746.	145746.	145746.	145746.	55053.	0.	0.	0.	0.	0.	1658253.
INCOME BEFORE TAX	155572.	155572.	155572.	155572.	156026.	156301.	156301.	156301.	156301.	156301.	2646323.
9 INCOME TAX	70008.	70008.	70008.	70008.	70212.	70335.	70335.	70335.	70335.	70335.	1190845.
10 CAPITAL INVESTMENT	0.	0.	215296.	0.	0.	0.	0.	0.	0.	0.	1658253.
11 TOTAL CASH OUTFLOW	208513.	208513.	423809.	208513.	208263.	208112.	208112.	208112.	208112.	208112.	5202078.
12 NET CASH FLOW	231310.	231310.	16014.	231310.	140867.	85965.	85965.	85965.	85965.	85965.	
13 CUMULATIVE NET CASH FLOW	406152.	637463.	653477.	884787.	1025655.	1111619.	1197584.	1283549.	1369514.	1455479.	
14 DCF ROR OF NET CASH FLOW (%)	4.59	6.36	6.46	7.71	8.33	8.65	8.93	9.17	9.38	9.57	
15 CORPORATE CAPITAL	0.	0.	215296.	0.	0.	0.	0.	0.	0.	0.	1658251.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.2 YEARS

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 9

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	157368.	157368.	157368.	3147346.
2 SALES REVENUE FROM COST GAS	56008.	56008.	56008.	2778403.
3 SALES REVENUE FROM ROYALTY GAS	80701.	80701.	80701.	1614025.
4 TOTAL CASH INFLOW	294077.	294077.	294077.	7539799.
5 ROYALTY	80701.	80701.	80701.	1614025.
6 BONUS	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	1067.	1067.	1067.	29629.
OPERATING EXPENSES	56008.	56008.	56008.	2778412.
8 OPERATING COST	56008.	56008.	56008.	1120160.
CAPITAL COST RECOVERY	0.	0.	0.	1658253.
INCOME BEFORE TAX	156301.	156301.	156301.	3115226.
9 INCOME TAX	70335.	70335.	70335.	1401850.
10 CAPITAL INVESTMENT	0.	0.	0.	1658253.
11 TOTAL CASH OUTFLOW	208112.	208112.	208112.	5826411.
12 NET CASH FLOW	85965.	85965.	85965.	
13 CUMULATIVE NET CASH FLOW	1541444.	1627409.	1713374.	
14 DCF ROR OF NET CASH FLOW (%)	9.73	9.87	9.99	
15 CORPORATE CAPITAL	0.	0.	0.	1658251.
16 INTEREST	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	

20 PAYOUT TIME 9.2 YEARS

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-456436.	-632227.	-261142.	193840.	185714.	176871.	168448.	160427.	152788.	145512.
CUMULATIVE PRESENT WORTH	-456436.	-1088662.	-1349804.	-1155963.	-970249.	-793379.	-624930.	-464503.	-311715.	-166203.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-445941.	-589614.	-232471.	164715.	150636.	136942.	124493.	113175.	102887.	93533.
CUMULATIVE PRESENT WORTH	-445941.	-1035555.	-1268026.	-1103311.	-952675.	-815733.	-691240.	-578065.	-475178.	-381645.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-436139.	-551582.	-208020.	140982.	123326.	107240.	93252.	81089.	70512.	61315.
CUMULATIVE PRESENT WORTH	-436139.	-987721.	-1195741.	-1054758.	-931432.	-824192.	-730939.	-649850.	-579338.	-518023.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	138583.	131984.	8703.	119714.	69434.	40355.	38433.	36603.	34860.	33200.
CUMULATIVE PRESENT WORTH	-27620.	104365.	113067.	232781.	302214.	342569.	381002.	417605.	452465.	485665.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	85030.	77300.	4865.	63885.	35369.	19622.	17838.	16216.	14742.	13402.
CUMULATIVE PRESENT WORTH	-296615.	-219314.	-214449.	-150564.	-115195.	-95573.	-77735.	-61519.	-46777.	-33375.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	53317.	46363.	2791.	35057.	18565.	9852.	8567.	7449.	6478.	5633.
CUMULATIVE PRESENT WORTH	-464705.	-418342.	-415551.	-380494.	-361929.	-352077.	-343511.	-336061.	-329584.	-323951.

TABLE 17-6-11 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE I C : OFFSHORE COMPRESSION CASE - SIX FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	31619.	30113.	28680.
CUMULATIVE PRESENT WORTH	517284.	547397.	576077.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	12184.	11076.	10069.
CUMULATIVE PRESENT WORTH	-21191.	-10115.	-46.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	4898.	4259.	3704.
CUMULATIVE PRESENT WORTH	-319053.	-314794.	-311090.

*** E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T ***

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* P R E M I S E S *

PRODUCTION LIFE	: 20 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C   T E R M S   O F   P/S   A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 25.00 %
PROFIT GAS SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	452755.	645998.	260879.	0.	0.	0.	0.	0.	0.	0.	1359632.
GAS PRODUCTION (MMSCF/DAY)	0.	0.	0.	1270.	1270.	1270.	1270.	1270.	1270.	1270.	8890.
SALES PRICE OF GAS (M¢/MSCF)	0.0	0.0	0.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	

TERM	11	12	13	14	15	16	17	18	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	206363.	0.	0.	0.	0.	0.	0.	0.	1565995.
GAS PRODUCTION (MMSCF/DAY)	1270.	1270.	1270.	1270.	1270.	1270.	1270.	1270.	1270.	1270.	21590.
SALES PRICE OF GAS (M¢/MSCF)	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	

*** E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T ***

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV   CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	1565995.
GAS PRODUCTION (MMSCF/DAY)	1270.	1270.	1270.	25400.
SALES PRICE OF GAS (M¢/MSCF)	164.0	164.0	164.0	

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV   CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 3

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	345901.	345901.	345901.	345901.	345901.	345901.	345901.	2421303.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1691.	1691.	1691.	1691.	1691.	1691.	1691.	11840.
4 TOTAL CASH INFLOW	0.	0.	0.	350092.	347592.	347592.	347592.	347592.	347592.	347592.	2435645.
5 INCOME TAX	0.	0.	0.	157542.	156417.	156417.	156417.	156417.	156417.	156417.	1096040.
6 NET CASH FLOW	0.	0.	0.	192551.	191176.	191176.	191176.	191176.	191176.	191176.	
7 CUMULATIVE NET CASH FLOW	0.	0.	0.	192551.	383727.	574902.	766078.	957254.	1148429.	1339604.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	345901.	345901.	345901.	345901.	345901.	345901.	345901.	345901.	345901.	345901.	5880303.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	1691.	1691.	1691.	1691.	1285.	1005.	1005.	1005.	1005.	1005.	24917.
4 TOTAL CASH INFLOW	347592.	347592.	347592.	347592.	347186.	346906.	346906.	346906.	346906.	346906.	5907723.
5 INCOME TAX	156417.	156417.	156417.	156417.	156233.	156108.	156108.	156108.	156108.	156108.	2658472.
6 NET CASH FLOW	191176.	191176.	191176.	191176.	190952.	190798.	190798.	190798.	190798.	190798.	
7 CUMULATIVE NET CASH FLOW	1530779.	1721954.	1913129.	2104304.	2295256.	2486054.	2676852.	2867650.	3058448.	3249246.	

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	345901.	345901.	345901.	6918003.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	1005.	1005.	1005.	27932.
4 TOTAL CASH INFLOW	346906.	346906.	346906.	6948438.
5 INCOME TAX	156108.	156108.	156108.	3126793.
6 NET CASH FLOW	190798.	190798.	190798.	
7 CUMULATIVE NET CASH FLOW	3440044.	3630842.	3821640.	

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	162324.	153491.	146182.	139221.	132591.	126278.	120265.
CUMULATIVE PRESENT WORTH	0.	0.	0.	162324.	315815.	461997.	601218.	733809.	860087.	980351.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	137934.	124499.	113181.	102892.	93538.	85035.	77304.
CUMULATIVE PRESENT WORTH	0.	0.	0.	137934.	262433.	375615.	478507.	572045.	657080.	734384.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	118060.	101928.	88633.	77072.	67019.	58278.	50676.
CUMULATIVE PRESENT WORTH	0.	0.	0.	118060.	219988.	308621.	385693.	452713.	510990.	561667.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	114538.	109084.	103889.	98942.	94120.	89566.	85301.	81240.	77371.	73687.
CUMULATIVE PRESENT WORTH	1094889.	1203972.	1307861.	1406803.	1500923.	1590489.	1675790.	1757029.	1834400.	1908086.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	70277.	63888.	58080.	52800.	47944.	43550.	39591.	35992.	32720.	29746.
CUMULATIVE PRESENT WORTH	804661.	868549.	926629.	979429.	1027373.	1070923.	1110514.	1146506.	1179226.	1208971.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	44066.	38319.	33321.	28974.	25166.	21866.	19014.	16533.	14377.	12502.
CUMULATIVE PRESENT WORTH	605733.	644051.	677372.	706346.	731512.	753377.	772391.	788924.	803301.	815803.

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

** PRESENT WORTH OF NET CASH FLOW FOR PETRONAS **
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	70178.	66836.	63654.
CUMULATIVE PRESENT WORTH	1978263.	2045099.	2108752.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	27041.	24583.	22348.
CUMULATIVE PRESENT WORTH	1236012.	1260595.	1282943.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	10871.	9453.	8220.
CUMULATIVE PRESENT WORTH	826674.	836127.	844347.

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	148243.	148243.	148243.	148243.	148243.	148243.	148243.	1037703.
2 SALES REVENUE FROM COST GAS	0.	0.	0.	190055.	190055.	190055.	190055.	190055.	190055.	190055.	1330387.
3 SALES REVENUE FROM ROYALTY GAS	0.	0.	0.	76022.	76022.	76022.	76022.	76022.	76022.	76022.	532155.
4 TOTAL CASH INFLOW	0.	0.	0.	414321.	414321.	414321.	414321.	414321.	414321.	414321.	2900242.
5 ROYALTY	0.	0.	0.	76022.	76022.	76022.	76022.	76022.	76022.	76022.	532155.
6 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	0.	0.	0.	1691.	1691.	1691.	1691.	1691.	1691.	1691.	11840.
OPERATING EXPENSES	0.	0.	0.	190055.	190055.	190055.	190055.	190055.	190055.	190055.	1330387.
8 OPERATING COST	0.	0.	0.	52775.	52775.	52775.	52775.	52775.	52775.	52775.	369425.
CAPITAL COST RECOVERY	0.	0.	0.	137280.	137280.	137280.	137280.	137280.	137280.	137280.	960963.
INCOME BEFORE TAX	0.	0.	0.	144052.	146552.	146552.	146552.	146552.	146552.	146552.	1023362.
9 INCOME TAX	0.	0.	0.	64823.	65948.	65948.	65948.	65948.	65948.	65948.	460513.
10 CAPITAL INVESTMENT	452755.	645998.	260879.	0.	0.	0.	0.	0.	0.	0.	1359632.
11 TOTAL CASH OUTFLOW	452755.	645998.	260879.	197812.	196437.	196437.	196437.	196437.	196437.	196437.	2736059.
12 NET CASH FLOW	-452755.	-645998.	-260879.	216509.	217884.	217884.	217884.	217884.	217884.	217884.	
13 CUMULATIVE NET CASH FLOW	-452755.	-1098753.	-1359632.	-1143123.	-925239.	-707355.	-489471.	-271587.	-53703.	164181.	
14 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.25	
15 CORPORATE CAPITAL	452755.	645998.	260879.	0.	0.	0.	0.	0.	0.	0.	1359630.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.2 YEARS

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

(CONT'D)
PAGE 8

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	148243.	148243.	148243.	148243.	148243.	148243.	148243.	148243.	148243.	148243.	2520133.
2 SALES REVENUE FROM COST GAS	190055.	190055.	190055.	190055.	108687.	52775.	52775.	52775.	52775.	52775.	2463163.
3 SALES REVENUE FROM ROYALTY GAS	76022.	76022.	76022.	76022.	76022.	76022.	76022.	76022.	76022.	76022.	1292376.
4 TOTAL CASH INFLOW	414321.	414321.	414321.	414321.	332952.	277040.	277040.	277040.	277040.	277040.	6275674.
5 ROYALTY	76022.	76022.	76022.	76022.	76022.	76022.	76022.	76022.	76022.	76022.	1292376.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	1691.	1691.	1691.	1691.	1285.	1005.	1005.	1005.	1005.	1005.	24917.
OPERATING EXPENSES	190055.	190055.	190055.	190055.	108687.	52775.	52775.	52775.	52775.	52775.	2463169.
8 OPERATING COST	52775.	52775.	52775.	52775.	52775.	52775.	52775.	52775.	52775.	52775.	897175.
CAPITAL COST RECOVERY	137280.	137280.	137280.	137280.	55912.	0.	0.	0.	0.	0.	1565995.
INCOME BEFORE TAX	146552.	146552.	146552.	146552.	146959.	147238.	147238.	147238.	147238.	147238.	2492715.
9 INCOME TAX	65948.	65948.	65948.	65948.	66131.	66257.	66257.	66257.	66257.	66257.	1121722.
10 CAPITAL INVESTMENT	0.	0.	206363.	0.	0.	0.	0.	0.	0.	0.	1565995.
11 TOTAL CASH OUTFLOW	196437.	196437.	402800.	196437.	196213.	196059.	196059.	196059.	196059.	196059.	4904674.
12 NET CASH FLOW	217884.	217884.	11521.	217884.	136739.	80981.	80981.	80981.	80981.	80981.	
13 CUMULATIVE NET CASH FLOW	382065.	599949.	611469.	829353.	966093.	1047073.	1128054.	1209034.	1290014.	1370994.	
14 DCF ROR OF NET CASH FLOW (%)	4.57	6.32	6.40	7.66	8.29	8.61	8.89	9.13	9.35	9.53	
15 CORPORATE CAPITAL	0.	0.	206363.	0.	0.	0.	0.	0.	0.	0.	1565992.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.2 YEARS

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	148243.	148243.	148243.	2964862.
2 SALES REVENUE FROM COST GAS	52775.	52775.	52775.	2621485.
3 SALES REVENUE FROM ROYALTY GAS	76022.	76022.	76022.	1520442.
4 TOTAL CASH INFLOW	277040.	277040.	277040.	7106794.
5 ROYALTY	76022.	76022.	76022.	1520442.
6 BONUS	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	1005.	1005.	1005.	27932.
OPERATING EXPENSES	52775.	52775.	52775.	2621494.
8 OPERATING COST	52775.	52775.	52775.	1055500.
CAPITAL COST RECOVERY	0.	0.	0.	1565995.
INCOME BEFORE TAX	147238.	147238.	147238.	2934429.
9 INCOME TAX	66257.	66257.	66257.	1320493.
10 CAPITAL INVESTMENT	0.	0.	0.	1565995.
11 TOTAL CASH OUTFLOW	196059.	196059.	196059.	5492851.
12 NET CASH FLOW	80981.	80981.	80981.	
13 CUMULATIVE NET CASH FLOW	1451974.	1532954.	1613934.	
14 DCF ROR OF NET CASH FLOW (%)	9.69	9.83	9.96	
15 CORPORATE CAPITAL	0.	0.	0.	1565992.
16 INTEREST	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.

20 PAYOUT TIME 9.2 YEARS

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-441844.	-600410.	-230923.	182522.	174934.	166604.	158671.	151115.	143919.	137066.
CUMULATIVE PRESENT WORTH	-441844.	-1042254.	-1273176.	-1090654.	-915720.	-749116.	-590445.	-439330.	-295411.	-158345.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-431685.	-559941.	-205569.	155097.	141892.	128993.	117267.	106606.	96915.	88104.
CUMULATIVE PRESENT WORTH	-431685.	-991626.	-1197195.	-1042098.	-900206.	-771213.	-653947.	-547341.	-450426.	-362322.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-422196.	-523823.	-183948.	132750.	116168.	101015.	87840.	76382.	66419.	57756.
CUMULATIVE PRESENT WORTH	-422196.	-946019.	-1129967.	-997217.	-881050.	-780034.	-692195.	-615812.	-549393.	-491637.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	130539.	124323.	6261.	112765.	67399.	38015.	36205.	34481.	32839.	31275.
CUMULATIVE PRESENT WORTH	-27806.	96517.	102778.	215543.	282942.	320957.	357161.	391642.	424481.	455756.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	80095.	72814.	3500.	60177.	34332.	18484.	16804.	15276.	13887.	12625.
CUMULATIVE PRESENT WORTH	-282227.	-209414.	-205913.	-145737.	-111405.	-92920.	-76117.	-60840.	-46953.	-34328.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	50223.	43672.	2008.	33022.	18021.	9280.	8070.	7017.	6102.	5306.
CUMULATIVE PRESENT WORTH	-441414.	-397742.	-395734.	-362712.	-344691.	-335411.	-327341.	-320323.	-314221.	-308915.

TABLE 17-6-12 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE II : OFFSHORE COMPRESSION CASE - FIVE FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	29786.	28367.	27017.
CUMULATIVE PRESENT WORTH	485541.	513909.	540925.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	11477.	10434.	9485.
CUMULATIVE PRESENT WORTH	-22851.	-12417.	-2932.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	4614.	4012.	3489.
CUMULATIVE PRESENT WORTH	-304301.	-300289.	-296800.

* E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T *

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV   CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* P R E M I S E S *

PRODUCTION LIFE	: 20 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C   T E R M S   O F   P/S   A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 25.00 %
PROFIT GAS SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	394005.	606355.	265612.	0.	0.	0.	0.	0.	0.	0.	1265972.
GAS PRODUCTION (MMSCF/DAY)	0.	0.	0.	1180.	1180.	1180.	1180.	1180.	1180.	1180.	8260.
SALES PRICE OF GAS (M¢/MSCF)	0.0	0.0	0.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	

TERM	11	12	13	14	15	16	17	18	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	195384.	0.	0.	0.	0.	0.	0.	0.	1461356.
GAS PRODUCTION (MMSCF/DAY)	1180.	1180.	1180.	1180.	1180.	1180.	1180.	1180.	1180.	1180.	20060.
SALES PRICE OF GAS (M¢/MSCF)	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	

* E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T *

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

(CONT'D)

VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	1461356.
GAS PRODUCTION (MMSCF/DAY)	1180.	1180.	1180.	23600.
SALES PRICE OF GAS (M¢/MSCF)	164.0	164.0	164.0	

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 3

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	321388.	321388.	321388.	321388.	321388.	321388.	321388.	2249717.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1572.	1572.	1572.	1572.	1572.	1572.	1572.	11001.
4 TOTAL CASH INFLOW	0.	0.	0.	325460.	322960.	322960.	322960.	322960.	322960.	322960.	2263216.
5 INCOME TAX	0.	0.	0.	146457.	145332.	145332.	145332.	145332.	145332.	145332.	1018448.
6 NET CASH FLOW	0.	0.	0.	179003.	177628.	177628.	177628.	177628.	177628.	177628.	
7 CUMULATIVE NET CASH FLOW	0.	0.	0.	179003.	356631.	534259.	711887.	889515.	1067142.	1244769.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	321388.	321388.	321388.	321388.	321388.	321388.	321388.	321388.	321388.	321388.	5463597.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	1572.	1572.	1572.	1572.	1256.	936.	936.	936.	936.	936.	23227.
4 TOTAL CASH INFLOW	322960.	322960.	322960.	322960.	322645.	322325.	322325.	322325.	322325.	322325.	5489316.
5 INCOME TAX	145332.	145332.	145332.	145332.	145190.	145046.	145046.	145046.	145046.	145046.	2470193.
6 NET CASH FLOW	177628.	177628.	177628.	177628.	177455.	177279.	177279.	177279.	177279.	177279.	
7 CUMULATIVE NET CASH FLOW	1422396.	1600023.	1777650.	1955277.	2132731.	2310009.	2487287.	2664565.	2841843.	3019121.	

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	321388.	321388.	321388.	6427761.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	936.	936.	936.	26036.
4 TOTAL CASH INFLOW	322325.	322325.	322325.	6456288.
5 INCOME TAX	145046.	145046.	145046.	2905331.
6 NET CASH FLOW	177279.	177279.	177279.	
7 CUMULATIVE NET CASH FLOW	3196399.	3373677.	3550955.	

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	150903.	142614.	135823.	129355.	123195.	117329.	111742.
CUMULATIVE PRESENT WORTH	0.	0.	0.	150903.	293517.	429339.	558694.	681889.	799218.	910960.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	128229.	115676.	105160.	95601.	86910.	79009.	71826.
CUMULATIVE PRESENT WORTH	0.	0.	0.	128229.	243906.	349066.	444666.	531576.	610585.	682411.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	109753.	94705.	82352.	71610.	62270.	54148.	47085.
CUMULATIVE PRESENT WORTH	0.	0.	0.	109753.	204458.	286810.	358420.	420690.	474838.	521923.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	106421.	101353.	96527.	91931.	87468.	83220.	79257.	75483.	71889.	68465.
CUMULATIVE PRESENT WORTH	1017381.	1118734.	1215261.	1307191.	1394658.	1477877.	1557134.	1632617.	1704505.	1772970.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	65297.	59361.	53964.	49058.	44555.	40464.	36786.	33442.	30402.	27638.
CUMULATIVE PRESENT WORTH	747708.	807068.	861032.	910091.	954646.	995110.	1031896.	1065337.	1095738.	1123375.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	40944.	35603.	30959.	26921.	23387.	20316.	17666.	15362.	13358.	11616.
CUMULATIVE PRESENT WORTH	562867.	598470.	629429.	656350.	679737.	700053.	717719.	733081.	746439.	758055.

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

 CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	65205.	62100.	59143.
CUMULATIVE PRESENT WORTH	1838175.	1900275.	1959418.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	25125.	22841.	20765.
CUMULATIVE PRESENT WORTH	1148500.	1171341.	1192105.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	10101.	8783.	7638.
CUMULATIVE PRESENT WORTH	768156.	776939.	784577.

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 7

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	137738.	137738.	137738.	137738.	137738.	137738.	137738.	964165.
2 SALES REVENUE FROM COST GAS	0.	0.	0.	176587.	176587.	176587.	176587.	176587.	176587.	176587.	1236107.
3 SALES REVENUE FROM ROYALTY GAS	0.	0.	0.	70635.	70635.	70635.	70635.	70635.	70635.	70635.	494443.
4 TOTAL CASH INFLOW	0.	0.	0.	384960.	384960.	384960.	384960.	384960.	384960.	384960.	2694714.
5 ROYALTY	0.	0.	0.	70635.	70635.	70635.	70635.	70635.	70635.	70635.	494443.
6 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	0.	0.	0.	1572.	1572.	1572.	1572.	1572.	1572.	1572.	11001.
OPERATING EXPENSES	0.	0.	0.	176587.	176587.	176587.	176587.	176587.	176587.	176587.	1236107.
8 OPERATING COST	0.	0.	0.	49555.	49555.	49555.	49555.	49555.	49555.	49555.	346885.
CAPITAL COST RECOVERY	0.	0.	0.	127032.	127032.	127032.	127032.	127032.	127032.	127032.	889224.
INCOME BEFORE TAX	0.	0.	0.	133666.	136166.	136166.	136166.	136166.	136166.	136166.	950663.
9 INCOME TAX	0.	0.	0.	60150.	61275.	61275.	61275.	61275.	61275.	61275.	427798.
10 CAPITAL INVESTMENT	394005.	606355.	265612.	0.	0.	0.	0.	0.	0.	0.	1265972.
11 TOTAL CASH OUTFLOW	394005.	606355.	265612.	184411.	183036.	183036.	183036.	183036.	183036.	183036.	2548599.
12 NET CASH FLOW	-394005.	-606355.	-265612.	200548.	201923.	201923.	201923.	201923.	201923.	201923.	
13 CUMULATIVE NET CASH FLOW	-394005.	-1000360.	-1265972.	-1065423.	-863500.	-661576.	-459653.	-257730.	-55806.	146117.	
14 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.17	
15 CORPORATE CAPITAL	394005.	606355.	265612.	0.	0.	0.	0.	0.	0.	0.	1265971.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.3 YEARS

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 8

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	137738.	137738.	137738.	137738.	137738.	137738.	137738.	137738.	137738.	137738.	2341535.
2 SALES REVENUE FROM COST GAS	176587.	176587.	176587.	176587.	113562.	49555.	49555.	49555.	49555.	49555.	2303782.
3 SALES REVENUE FROM ROYALTY GAS	70635.	70635.	70635.	70635.	70635.	70635.	70635.	70635.	70635.	70635.	1200789.
4 TOTAL CASH INFLOW	384960.	384960.	384960.	384960.	321934.	257928.	257928.	257928.	257928.	257928.	5846119.
5 ROYALTY	70635.	70635.	70635.	70635.	70635.	70635.	70635.	70635.	70635.	70635.	1200789.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	1572.	1572.	1572.	1572.	1256.	936.	936.	936.	936.	936.	23227.
OPERATING EXPENSES	176587.	176587.	176587.	176587.	113562.	49555.	49555.	49555.	49555.	49555.	2303788.
8 OPERATING COST	49555.	49555.	49555.	49555.	49555.	49555.	49555.	49555.	49555.	49555.	842435.
CAPITAL COST RECOVERY	127032.	127032.	127032.	127032.	64007.	0.	0.	0.	0.	0.	1461356.
INCOME BEFORE TAX	136166.	136166.	136166.	136166.	136481.	136801.	136801.	136801.	136801.	136801.	2315813.
9 INCOME TAX	61275.	61275.	61275.	61275.	61417.	61561.	61561.	61561.	61561.	61561.	1042117.
10 CAPITAL INVESTMENT	0.	0.	195384.	0.	0.	0.	0.	0.	0.	0.	1461356.
11 TOTAL CASH OUTFLOW	183036.	183036.	378420.	183036.	182863.	182687.	182687.	182687.	182687.	182687.	4572419.
12 NET CASH FLOW	201923.	201923.	6539.	201923.	139072.	75241.	75241.	75241.	75241.	75241.	
13 CUMULATIVE NET CASH FLOW	348040.	549964.	556503.	758426.	897498.	972738.	1047979.	1123219.	1198459.	1273699.	
14 DCF ROR OF NET CASH FLOW (%)	4.51	6.28	6.33	7.60	8.30	8.62	8.90	9.14	9.36	9.54	
15 CORPORATE CAPITAL	0.	0.	195384.	0.	0.	0.	0.	0.	0.	0.	1461355.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.3 YEARS

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	137738.	137738.	137738.	2754746.
2 SALES REVENUE FROM COST GAS	49555.	49555.	49555.	2452444.
3 SALES REVENUE FROM ROYALTY GAS	70635.	70635.	70635.	1412691.
4 TOTAL CASH INFLOW	257928.	257928.	257928.	6619900.
5 ROYALTY	70635.	70635.	70635.	1412691.
6 BONUS	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	936.	936.	936.	26036.
OPERATING EXPENSES	49555.	49555.	49555.	2452453.
8 OPERATING COST	49555.	49555.	49555.	991100.
CAPITAL COST RECOVERY	0.	0.	0.	1461356.
INCOME BEFORE TAX	136801.	136801.	136801.	2726216.
9 INCOME TAX	61561.	61561.	61561.	1226797.
10 CAPITAL INVESTMENT	0.	0.	0.	1461356.
11 TOTAL CASH OUTFLOW	182687.	182687.	182687.	5120477.
12 NET CASH FLOW	75241.	75241.	75241.	
13 CUMULATIVE NET CASH FLOW	1348939.	1424179.	1499419.	
14 DCF ROR OF NET CASH FLOW (%)	9.70	9.85	9.97	
15 CORPORATE CAPITAL	0.	0.	0.	1461355.
16 INTEREST	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	

20 PAYOUT TIME 9.3 YEARS

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-384510.	-563564.	-235112.	169066.	162120.	154400.	147048.	140045.	133377.	127026.
CUMULATIVE PRESENT WORTH	-384510.	-948074.	-1183186.	-1014120.	-852000.	-697600.	-550553.	-410507.	-277130.	-150105.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-375669.	-525579.	-209299.	143663.	131498.	119544.	108676.	98797.	89815.	81650.
CUMULATIVE PRESENT WORTH	-375669.	-901248.	-1110547.	-966884.	-835386.	-715842.	-607165.	-508368.	-418553.	-336903.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-367412.	-491677.	-187285.	122964.	107658.	93616.	81405.	70787.	61554.	53525.
CUMULATIVE PRESENT WORTH	-367412.	-859089.	-1046374.	-923411.	-815753.	-722137.	-640732.	-569945.	-508391.	-454865.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	120977.	115216.	3554.	104505.	68548.	35320.	33638.	32037.	30511.	29058.
CUMULATIVE PRESENT WORTH	-29128.	86088.	89642.	194146.	262695.	298015.	331653.	363690.	394200.	423259.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	74228.	67480.	1987.	55768.	34918.	17174.	15613.	14193.	12903.	11730.
CUMULATIVE PRESENT WORTH	-262675.	-195195.	-193209.	-137440.	-102522.	-85349.	-69736.	-55542.	-42639.	-30909.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	46544.	40473.	1140.	30603.	18328.	8623.	7498.	6520.	5670.	4930.
CUMULATIVE PRESENT WORTH	-408322.	-367849.	-366709.	-336106.	-317778.	-309155.	-301657.	-295137.	-289468.	-284538.

TABLE 17-6-13 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE III : OFFSHORE COMPRESSION CASE - FOUR FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	27674.	26357.	25102.
CUMULATIVE PRESENT WORTH	450933.	477289.	502391.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	10664.	9694.	8813.
CUMULATIVE PRESENT WORTH	-20246.	-10551.	-1739.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	4287.	3728.	3242.
CUMULATIVE PRESENT WORTH	-280251.	-276523.	-273281.

* E C O N O M I C   A N A L Y S I S   F O R   M A L A Y S I A   P R O J E C T *

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

  CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

* P R E M I S E S *

PRODUCTION LIFE	: 20 YEARS
PRE-STARTUP PERIOD	: 3 YEARS
EQUITY RATIO OF OIL COMPANY	: 100.00 %
INTEREST RATE	: 8.00 %

* B A S I C   T E R M S   O F   P/S   A G R E E M E N T S *

ROYALTY RATE	: 10.00 %
MAXIMUM COST RECOVERY RATIO	: 25.00 %
PROFIT GAS SHARE	
PETRONAS	: 70.00 %
OPERATING COMPANY	: 30.00 %
RATE OF PAYMENT FOR RESEARCH FUND	: 0.50 %
DISCOVERY BONUS	: M$ 2500000.
INCOME TAX RATE	: 45.00 %

* INPUT DATA BY YEAR *

TERM	1	2	3	4	5	6	7	8	9	10	10YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	283321.	517749.	385062.	0.	0.	0.	0.	0.	0.	0.	1186132.
GAS PRODUCTION (MMSCF/DAY)	0.	0.	0.	1090.	1090.	1090.	1090.	1090.	1090.	1090.	7630.
SALES PRICE OF GAS (M¢/MSCF)	0.0	0.0	0.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	

TERM	11	12	13	14	15	16	17	18	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	183847.	0.	0.	0.	0.	0.	0.	0.	1369979.
GAS PRODUCTION (MMSCF/DAY)	1090.	1090.	1090.	1090.	1090.	1090.	1090.	1090.	1090.	1090.	18530.
SALES PRICE OF GAS (M¢/MSCF)	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	

****
* E C O N O M I C A N A L Y S I S F O R M A L A Y S I A P R O J E C T *
****

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	1369979.
GAS PRODUCTION (MMSCF/DAY)	1090.	1090.	1090.	21800.
SALES PRICE OF GAS (M¢/MSCF)	163.0	163.0	163.0	

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 3

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	295065.	295065.	295065.	295065.	295065.	295065.	295065.	2065455.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1443.	1443.	1443.	1443.	1443.	1443.	1443.	10100.
4 TOTAL CASH INFLOW	0.	0.	0.	299008.	296508.	296508.	296508.	296508.	296508.	296508.	2078056.
5 INCOME TAX	0.	0.	0.	134554.	133429.	133429.	133429.	133429.	133429.	133429.	935125.
6 NET CASH FLOW	0.	0.	0.	164455.	163080.	163080.	163080.	163080.	163080.	163080.	
7 CUMULATIVE NET CASH FLOW	0.	0.	0.	164455.	327534.	490614.	653693.	816773.	979852.	1142931.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	295065.	295065.	295065.	295065.	295065.	295065.	295065.	295065.	295065.	295065.	5016105.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	1443.	1443.	1443.	1443.	1337.	863.	863.	863.	863.	863.	21525.
4 TOTAL CASH INFLOW	296508.	296508.	296508.	296508.	296402.	295928.	295928.	295928.	295928.	295928.	5040129.
5 INCOME TAX	133429.	133429.	133429.	133429.	133381.	133168.	133168.	133168.	133168.	133168.	2268052.
6 NET CASH FLOW	163080.	163080.	163080.	163080.	163021.	162761.	162761.	162761.	162761.	162761.	
7 CUMULATIVE NET CASH FLOW	1306010.	1469089.	1632168.	1795247.	1958268.	2121028.	2283788.	2446548.	2609308.	2772068.	

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

 CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	295065.	295065.	295065.	5901300.
2 BONUS FROM OIL COMPANY	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	863.	863.	863.	24114.
4 TOTAL CASH INFLOW	295928.	295928.	295928.	5927913.
5 INCOME TAX	133168.	133168.	133168.	2667553.
6 NET CASH FLOW	162761.	162761.	162761.	
7 CUMULATIVE NET CASH FLOW	2934828.	3097588.	3260348.	

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

 CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	0.	0.	0.	138639.	130933.	124698.	118760.	113105.	107719.	102590.
CUMULATIVE PRESENT WORTH	0.	0.	0.	138639.	269572.	394270.	513030.	626135.	733854.	836444.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	0.	0.	0.	117807.	106202.	96547.	87770.	79791.	72538.	65943.
CUMULATIVE PRESENT WORTH	0.	0.	0.	117807.	224009.	320557.	408327.	488118.	560656.	626599.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	0.	0.	0.	100833.	86948.	75607.	65745.	57170.	49713.	43229.
CUMULATIVE PRESENT WORTH	0.	0.	0.	100833.	187781.	263388.	329133.	386303.	436016.	479245.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	97705.	93052.	88621.	84401.	80353.	76405.	72766.	69301.	66001.	62859.
CUMULATIVE PRESENT WORTH	934148.	1027200.	1115821.	1200222.	1280575.	1356979.	1429745.	1499046.	1565047.	1627905.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	59949.	54499.	49544.	45040.	40931.	37151.	33773.	30703.	27912.	25374.
CUMULATIVE PRESENT WORTH	686548.	741047.	790591.	835631.	876562.	913713.	947486.	978189.	1006101.	1031475.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	37590.	32687.	28424.	24716.	21485.	18652.	16219.	14104.	12264.	10665.
CUMULATIVE PRESENT WORTH	516835.	549522.	577945.	602661.	624146.	642798.	659018.	673122.	685386.	696050.

** PRESENT WORTH OF NET CASH FLOW FOR PETRONAS **
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	59865.	57015.	54300.
CUMULATIVE PRESENT WORTH	1687770.	1744784.	1799083.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	23068.	20971.	19064.
CUMULATIVE PRESENT WORTH	1054542.	1075512.	1094576.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	9274.	8064.	7012.
CUMULATIVE PRESENT WORTH	705324.	713388.	720400.

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)
PAGE 7

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	0.	0.	0.	126457.	126457.	126457.	126457.	126457.	126457.	126457.	885196.
2 SALES REVENUE FROM COST GAS	0.	0.	0.	162124.	162124.	162124.	162124.	162124.	162124.	162124.	1134866.
3 SALES REVENUE FROM ROYALTY GAS	0.	0.	0.	64850.	64850.	64850.	64850.	64850.	64850.	64850.	453947.
4 TOTAL CASH INFLOW	0.	0.	0.	353430.	353430.	353430.	353430.	353430.	353430.	353430.	2474005.
5 ROYALTY	0.	0.	0.	64850.	64850.	64850.	64850.	64850.	64850.	64850.	453947.
6 BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	0.	0.	0.	1443.	1443.	1443.	1443.	1443.	1443.	1443.	10100.
OPERATING EXPENSES	0.	0.	0.	162124.	162124.	162124.	162124.	162124.	162124.	162124.	1134866.
8 OPERATING COST	0.	0.	0.	46188.	46188.	46188.	46188.	46188.	46188.	46188.	323316.
CAPITAL COST RECOVERY	0.	0.	0.	115936.	115936.	115936.	115936.	115936.	115936.	115936.	811551.
INCOME BEFORE TAX	0.	0.	0.	122514.	125014.	125014.	125014.	125014.	125014.	125014.	872595.
9 INCOME TAX	0.	0.	0.	55131.	56256.	56256.	56256.	56256.	56256.	56256.	392668.
10 CAPITAL INVESTMENT	283321.	517749.	385062.	0.	0.	0.	0.	0.	0.	0.	1186132.
11 TOTAL CASH OUTFLOW	283321.	517749.	385062.	170112.	168737.	168737.	168737.	168737.	168737.	168737.	2368659.
12 NET CASH FLOW	-283321.	-517749.	-385062.	183318.	184693.	184693.	184693.	184693.	184693.	184693.	
13 CUMULATIVE NET CASH FLOW	-283321.	-801070.	-1186132.	-1002814.	-818121.	-633427.	-448734.	-264041.	-79348.	105346.	
14 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.75	
15 CORPORATE CAPITAL	283321.	517749.	385062.	0.	0.	0.	0.	0.	0.	0.	1186131.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.4 YEARS

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

(CONT'D)

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	126457.	126457.	126457.	126457.	126457.	126457.	126457.	126457.	126457.	126457.	2149757.
2 SALES REVENUE FROM COST GAS	162124.	162124.	162124.	162124.	140874.	46188.	46188.	46188.	46188.	46188.	2155166.
3 SALES REVENUE FROM ROYALTY GAS	64850.	64850.	64850.	64850.	64850.	64850.	64850.	64850.	64850.	64850.	1102441.
4 TOTAL CASH INFLOW	353430.	353430.	353430.	353430.	332180.	237494.	237494.	237494.	237494.	237494.	5407365.
5 ROYALTY	64850.	64850.	64850.	64850.	64850.	64850.	64850.	64850.	64850.	64850.	1102441.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	1443.	1443.	1443.	1443.	1337.	863.	863.	863.	863.	863.	21525.
OPERATING EXPENSES	162124.	162124.	162124.	162124.	140874.	46188.	46188.	46188.	46188.	46188.	2155172.
8 OPERATING COST	46188.	46188.	46188.	46188.	46188.	46188.	46188.	46188.	46188.	46188.	785196.
CAPITAL COST RECOVERY	115936.	115936.	115936.	115936.	94686.	0.	0.	0.	0.	0.	1369979.
INCOME BEFORE TAX	125014.	125014.	125014.	125014.	125120.	125593.	125593.	125593.	125593.	125593.	2125732.
9 INCOME TAX	56256.	56256.	56256.	56256.	56304.	56517.	56517.	56517.	56517.	56517.	956581.
10 CAPITAL INVESTMENT	0.	0.	183847.	0.	0.	0.	0.	0.	0.	0.	1369979.
11 TOTAL CASH OUTFLOW	168737.	168737.	352584.	168737.	168678.	168418.	168418.	168418.	168418.	168418.	4238213.
12 NET CASH FLOW	184693.	184693.	846.	184693.	163502.	69076.	69076.	69076.	69076.	69076.	
13 CUMULATIVE NET CASH FLOW	290039.	474732.	475579.	660272.	823774.	892850.	961926.	1031002.	1100078.	1169154.	
14 DCF ROR OF NET CASH FLOW (%)	4.19	6.04	6.04	7.37	8.30	8.62	8.91	9.15	9.37	9.56	
15 CORPORATE CAPITAL	0.	0.	183847.	0.	0.	0.	0.	0.	0.	0.	1369977.
16 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	

20 PAYOUT TIME 9.4 YEARS

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS
VOL.IV CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	126457.	126457.	126457.	2529125.
2 SALES REVENUE FROM COST GAS	46188.	46188.	46188.	2293727.
3 SALES REVENUE FROM ROYALTY GAS	64850.	64850.	64850.	1296988.
4 TOTAL CASH INFLOW	237494.	237494.	237494.	6119844.
5 ROYALTY	64850.	64850.	64850.	1296988.
6 BONUS	0.	0.	0.	2500.
DISCOVERY BONUS	0.	0.	0.	2500.
7 RESEARCH FUND TO PETRONAS	863.	863.	863.	24114.
OPERATING EXPENSES	46188.	46188.	46188.	2293736.
8 OPERATING COST	46188.	46188.	46188.	923760.
CAPITAL COST RECOVERY	0.	0.	0.	1369979.
INCOME BEFORE TAX	125593.	125593.	125593.	2502511.
9 INCOME TAX	56517.	56517.	56517.	1126130.
10 CAPITAL INVESTMENT	0.	0.	0.	1369979.
11 TOTAL CASH OUTFLOW	168418.	168418.	168418.	4743464.
12 NET CASH FLOW	69076.	69076.	69076.	
13 CUMULATIVE NET CASH FLOW	1238230.	1307306.	1376382.	
14 DCF ROR OF NET CASH FLOW (%)	9.72	9.86	9.99	
15 CORPORATE CAPITAL	0.	0.	0.	1369977.
16 INTEREST	0.	0.	0.	0.
17 BANK BORROWING	0.	0.	0.	0.
18 REPAYMENT	0.	0.	0.	0.
19 BORROWING BALANCE	0.	0.	0.	

20 PAYOUT TIME 9.4 YEARS

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

** PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY **
(X M$ 1000)

TERM	1	2	3	4	5	6	7	8	9	10
PRESENT WORTH										
5.00% DISCOUNT RATE	0.98	0.93	0.89	0.84	0.80	0.76	0.73	0.69	0.66	0.63
PRESENT WORTH	-276493.	-481211.	-340846.	154541.	148286.	141225.	134500.	128095.	121996.	116187.
CUMULATIVE PRESENT WORTH	-276493.	-757704.	-1098550.	-944009.	-795723.	-654498.	-519998.	-391902.	-269907.	-153720.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44	0.40
PRESENT WORTH	-270136.	-448777.	-303424.	131320.	120278.	109343.	99403.	90367.	82151.	74683.
CUMULATIVE PRESENT WORTH	-270136.	-718913.	-1022337.	-891016.	-770739.	-661395.	-561992.	-471626.	-389474.	-314791.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30	0.27
PRESENT WORTH	-264198.	-419829.	-271510.	112399.	98472.	85628.	74459.	64747.	56302.	48958.
CUMULATIVE PRESENT WORTH	-264198.	-684027.	-955538.	-843138.	-744667.	-659039.	-584580.	-519834.	-463532.	-414574.

TERM	11	12	13	14	15	16	17	18	19	20
PRESENT WORTH										
5.00% DISCOUNT RATE	0.60	0.57	0.54	0.52	0.49	0.47	0.45	0.43	0.41	0.39
PRESENT WORTH	110654.	105385.	460.	95587.	80590.	32426.	30882.	29412.	28011.	26677.
CUMULATIVE PRESENT WORTH	-43066.	62318.	62778.	158365.	238955.	271382.	302264.	331676.	359687.	386364.
10.00% DISCOUNT RATE	0.37	0.33	0.30	0.28	0.25	0.23	0.21	0.19	0.17	0.16
PRESENT WORTH	67894.	61722.	257.	51010.	41052.	15767.	14334.	13030.	11846.	10769.
CUMULATIVE PRESENT WORTH	-246897.	-185176.	-184919.	-133909.	-92857.	-77090.	-62757.	-49726.	-37880.	-27111.
15.00% DISCOUNT RATE	0.23	0.20	0.17	0.15	0.13	0.11	0.10	0.09	0.08	0.07
PRESENT WORTH	42572.	37019.	147.	27992.	21548.	7916.	6884.	5986.	5205.	4526.
CUMULATIVE PRESENT WORTH	-372002.	-334983.	-334835.	-306843.	-285295.	-277379.	-270495.	-264510.	-259305.	-254778.

TABLE 17-6-14 CASH FLOW TABLE FOR GAS CENTRAL LUCONIA GAS FIELDS

VOL.IV CASE IV : OFFSHORE COMPRESSION CASE - THREE FIELDS DEVELOPMENT

* * PRESENT WORTH OF NET CASH FLOW FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	25407.	24197.	23045.
CUMULATIVE PRESENT WORTH	411771.	435969.	459014.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	9790.	8900.	8091.
CUMULATIVE PRESENT WORTH	-17321.	-8421.	-330.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	3936.	3422.	2976.
CUMULATIVE PRESENT WORTH	-250843.	-247420.	-244444.

Table 28-4-1 SUMMARY OF OFFSHORE STRUCTURES
(Vol. IV)

FIELD/ FACILITY NAME	W.D. FT MSL	PLATFORM TYPE	PLATFORM OVERALL DIMENSION	FACILITY LOCATION				DATE INSTALLED
				BORNEO GRID		GEOGRAPHICAL		
				NORTH	EAST	LAT.-N	LONG.-E	
BARAM		18 Miles off Lutong						
BARAM A	118			1,707,000 FT	1,550,000 FT	4° 42' 11"	113° 56' 17"	
BARAM B	203			1,696,000	1,519,000	4 40 23	113 51 11	
BADP-A	118	4x4P/17W Self-Cont. Drill. P/F		1,706,990	1,549,970	4 42 10	113 56 17	May '69
BADP-B	203	6P/10W Tender-Ass. Drill. P/F		1,696,410	1,519,180	4 40 26	113 51 12	Mar. '73
BADP-C	110	6P/10W Tender-Ass. Drill. P/F		1,710,620	1,557,090	4 42 47	113 57 27	Nov. '72
BA-8	180	3P/1W WHPJ		1,709,170	1,544,393	4 32 32.889	113 55 21.9	Aug. '68
BA-18	130	3P/1W WHPJ		1,711,436	1,556,150	4 42 55.161	113 57 18.3	May '71
BA-24	212	3P/1W WHPJ		1,700,113	1,517,216	4 41 3.717	113 50	May '72
BAP-A	118	4P Prod. P/F	50'-0" x 62'-0"	1,706,856	1,549,976			Jun. '69
BAP-B	203	4P Prod. P/F	50'-0" x 62'-0"					Feb. '73
BAV-A	118	3P Vent Structure		1,705,853	1,551,720			May '69
BAV-B	205	3P Vent Structure		1,698,830	1,518,880			Feb. '73

Table 28-4-1 SUMMARY OF OFFSHORE STRUCTURES (Cont'd)
(Vol. IV)

FIELD/ FACILITY NAME	W.D. FT MSL	PLATFORM TYPE	PLATFORM OVERALL DIMENSION	FACILITY LOCATION				DATE INSTALLED
				BORNEO GRID		GEOGRAPHICAL		
				NORTH	EAST	LAT.-N	LONG.-E	
BARONIA	250	27 Miles off Lutong		1,721,000 FT	1,479,000 FT	4° 41' 31"	113° 44' 35"	
BNDP-A	249	8P/12W Tender-Ass. Drill. P/F	49'-0" x 98'-0"	1,721,280	1,479,380	4 44 34	113 44 39	Feb. '74
BNJT-D		3P/3W WHPJ						
BN-4		Subsea Completion						
BN-5		Subsea Completion						
BN-14	251	3p/1W WHPJ		1,720,099	1,473,626	4 44 34	113 44	Jul. '75
BNP-A	254	4P Prod. P/F	50'-0" x 62'-0"	1,721,146	1,479,270			
BNV-A	250	3P Vent Structure		1,720,360	1,477,390			Sep. '73
BAKAU	180	14 Miles off Lutong		1,660,000	1,510,000	4 34 26	113 49 41	
BKJT-A	175	4P/4W WHPJ		1,660,254	1,508,393	4 34 27.971	113 49 25.08	Aug. '74
BK-3	176	3P/1W WHPJ		1,659,306	1,510,080	4 34 20.689	113 49 40.6	Oct. '71
BKP-A	180	4P Prod. P/F	50'-0" x 62'-0"	1,660,380	1,508,466			Dec. '71
BKV-A	179	3P Vent Structure	17'-17" Triangular	1,660,380	1,510,510			Oct. '74

Table 28-4-1 (Vol. IV) SUMMARY OF OFFSHORE STRUCTURES (Cont'd)

FIELD/ FACILITY NAME	W.D. FT MSL	PLATFORM TYPE	PLATFORM OVERALL DIMENSION	FACILITY LOCATION				DATE INSTALLED
				BORNEO GRID		GEOGRAPHICAL		
				NORTH	EAST	LAT.-N	LONG.-E	
WEST LUTONG	90	9 Miles off Lutong		1,632,000 FT	1,539,000 FT	4° 29' 47"	113° 54' 27"	
WLDP-A	90	6P/10W Tender-Ass. Drill. P/F		1,632,000	1,538,570	4 29 51	113 54 23	Apr. '70
WLDP-B	90	6P/10W Tender-Ass. Drill. P/F		1,632,270	1,541,750	4 30 29.5	113 54 54.5	Apr. '71
WLDP-C	104	6P/10W Tender-Ass. Drill. P/F		1,628,600	1,534,450	4 13 38.9	114 9 10	Mid. '72
WL-(1,2,3)	101	3P/3W WHPJ		1,633,920	1,539,020			Apr. '68
WL-4	101	3P/1W WHPJ		1,629,528	1,535,581	4 29 22.763	113 53 53	Apr. '68
WLP-A	90	4P Prod. P/F	50'-0" x 62'-0"	1,632,306	1,538,467			Aug. '68
WLP-C	104	4P Prod. P/F	50'-0" x 62'-0"					Mid. '72
WLV-A	90	3P Vent Structure		1,631,854	1,536,450			Aug. '68
WLV-C	107	3P Vent Structure		1,630,600	1,534,290			Mid. '72
TUKAU	158	20 Miles off Lutong		1,600,000	1,470,000	4 24 31	113 43 4	
TKDP-A	156	6P/12W Tender-Ass. Drill. P/F		1,601,793	1,472,782			Oct. '74
TKDP-B	159	6P/12W Tender-Ass. Drill. P/F		1,604,890	1,472,150			Jun. '75
TK-3	157	3P/1W WHPJ		1,598,018	1,470,712			Dec. '75
TKP-A	156	4P Prod. P/F	50'-0" x 62'-0"					Mar. '75
TKP-B	160	4P Prod. P/F	50'-0" x 62'-0"					Jun. '75
TKV-A	155	3P Vent Structure		1,603,000	1,474,550			Mar. '75
TKV-B	159	3P Vent Structure						Jul. '75

Table 28-4-1 SUMMARY OF OFFSHORE STRUCTURES (Cont'd)
(Vol. IV)

FIELD/ FACILITY NAME	W.D. FT MSL	PLATFORM TYPE	PLATFORM OVERALL DIMENSION	FACILITY LOCATION				DATE INSTALLED
				BORNEO GRID		GEOGRAPHICAL		
				NORTH	EAST	LAT.-N	LONG.-E	
LUTONG TERMINAL								
WL-M.P.	50	4P Manifold P/F				40° 29' 33"	113° 56' 37"	Mid. '66
SBM-1		Single Buoy Mooring System						
SBM-2		ditto						
SBM-4		ditto						

Table 28-4-2 SUMMARY OF SUBMARINE PIPELINES
(Vol. IV)

ORIGIN	TERMINAL	DIAMETER (IN.)	LENGTH (FT.)	SERVICE	NOS.	REMARKS
BARONIA FIELD						
BN-4	BNP-A	6	3,000	WELL FLUID	1	
BN-5	BNP-A	6	3,200	WELL FLUID	1	
BN-14	BNP-A	8	6,000	WELL FLUID	1	
BNP-A	BKP-A	12	67,847	CRUDE	1	
BNP-A	BNV-A	10	2,000	VENT	3	
BNJT-D	BNP-A	6	6,000	WELL FLUID	3	
BNP-A	BNJT-D	6	6,000	GAS LIFT	1	
BARAM FIELD						
BA-18	BADP-C	6	2,560	WELL FLUID	1	
BA-18	BAP-A	6	9,145	WELL FLUID	1	
BADP-C	BAP-A	8	8,320	WELL FLUID	2	
BA-8	BAP-A	6	6,000	WELL FLUID	1	

Table 28-4-2 (Vol. IV) SUMMARY OF SUBMARINE PIPELINES (Cont'd)

ORIGIN	TERMINAL	DIAMETER (IN.)	LENGTH (FT.)	SERVICE	NOS.	REMARKS
BARAM FIELD (cont'd)						
BA-24	BAP-B	6		WELL FLUID	1	
BA-24	BAP-A	8	33,447	WELL FLUID	1	
BAP-A	SHORE	12	44,516	CRUDE	1	
BADP-C	BA-18		2,560		1	
BAP-A	BAV-A	10	2,000	VENT	3	
BAP-B	BAV-B	10	2,000	VENT	3	
BAP-B	BA-24	8		CRUDE	1	
BAKAU FIELD						
BK-3	BKP-A	6	2,000	WELL FLUID	1	
BKP-A	WLP-A	16	40,904	CRUDE	1	
BKP-A	BKV-A	10	2,000	VENT	3	

Table 28-4-2 (Vol. IV) SUMMARY OF SUBMARINE PIPELINES (Cont'd)

ORIGIN	TERMINAL	DIAMETER (IN.)	LENGTH (FT.)	SERVICE	NOS.	REMARKS
WEST LUTONG FIELD						
WLDP-B	WLDP-A	6		WELL FLUID	4	
WL-1,2,3	WLP-A	6		WELL FLUID	3	
WLP-A	WLDP-C	10		CRUDE	1	
WL-4	WLP-A	6		WELL FLUID	1	
WL-4	WLP-C	6		WELL FLUID	1	
WLP-A	LUTONG T.	10	40,185	CRUDE	1	
WLDP-C	LUTONG T.	12	41,500	CRUDE	1	
WLDP-A	WLDP-B	6		GAS LIFT	1	VIA WL-1, 2, 3
WLP-A	WL-4	6		GAS LIFT	1	
WLP-C	WL-4	6		GAS LIFT	1	
WLP-A	LUTONG T.	8	40,436	GAS	1	
WLP-A	WLV-A	10	2,000	VENT	3	
WLP-C	WLV-C	10	2,000	VENT	3	

Table 28-4-2 (Vol. IV) SUMMARY OF SUBMARINE PIPELINES (Cont'd)

ORIGIN	TERMINAL	DIAMETER (IN.)	LENGTH (FT.)	SERVICE	NOS.	REMARKS
TUKAU FIELD						
TK-3	TKP-A	6	4,910	WELL FLUID	1	
TKP-B	TKP-A	10	3,000	CRUDE	1	
TKP-A	WLDP-C	10	67,970	CRUDE	1	
TKP-B	TKV-B	10	2,000	VENT	3	
TKP-A	TKV-A	10	2,000	VENT	3	
TKP-A	TKDP-B	6	3,000	GAS LIFT	1	
LABUAN TERMINAL						
LABUAN T.	SBM	48	15,000	CRUDE	1	
LUTONG TERMINAL						
LUTONG T.	SBM NO. 1	12	20,454		1	1B
LUTONG T.	SBM NO. 1	12	20,700		1	1C
LUTONG T.	M.P.	6	26,550	GAS OIL	1	1A
LUTONG T.	M.P.	12	19,212		1	2B
LUTONG T.	M.P.	12	19,630		1	2C

Table 28-4-2 (Vol. IV) SUMMARY OF SUBMARINE PIPELINES (Cont'd)

ORIGIN	TERMINAL	DIAMETER (IN.)	LENGTH (FT.)	SERVICE	NOS.	REMARKS
LUTONG TERMINAL (Cont'd)						
LUTONG T.	M.P.	12"	19,065'	BUNKER	1	3B
LUTONG T.	M.P.	12	20,085		1	4B
LUTONG T.	M.P.	12	19,890		1	4C
LUTONG T.	M.P.	20	26,200		1	4D
M.P.	SBM NO. 1	6	7,400	GAS OIL	1	1A
M.P.	SBM NO. 2	12	4,533		1	2B
M.P.	SBM NO. 2	12	4,340		1	2C
M.P.	SBM NO. 2	6	4,446	BUNKER	1	3B
M.P.	SBM NO. 4	6	4,447	BUNKER	1	3B
M.P.	SBM NO. 4	12	4,440		1	4B
M.P.	SMB NO. 4	16	4,431		1	4C
M.P.	SMB NO. 4	16	4,431		1	4D

NOTE:

M.P. = MANIFOLD PLATFORM

Table 28-4-3
(Vol. IV)

COMPARISON OF PRESENT PRODUCTION RATE VS. PLATFORM CAPABILITY

OIL FIELD	PRODUCTION PLATFORM	PRESENT PRODUCTION RATE @ MAY, 1976				PRODUCTION PLATFORM CAPABILITY			
		GROSS LIQUID (BPD)	NET OIL (BPD)	GAS (MMSCFD)	WATER (BPD)	NO. OF SEPARATION BANKS	GROSS LIQUID THROUGHPUT (BPD)	GAS (MMSCFD)	EFFICIENCY* (%)
TEMBUNGO	A	5,294	4,983	3.7	311	1	20,000	16	26.5
BARONIA	BNP-A	51,977	49,162	106.1	2,815	2	60,000	180	86.6
WEST LUTONG	WLP-A	23,191	10,033	24.6	13,158	1	30,000	90	77.3
	WLP-C	9,939	4,300	10.6	5,639	1	30,000	90	33.1
		33,130	14,333	35.2	18,797	2	60,000	180	55.2
BARAM	BAP-A	33,503	21,478	82.2	12,025	2	60,000	180	55.8
	BAP-B	14,358	9,205	35.2	5,153	1	30,000	90	47.9
		47,861	30,683	117.4	17,178	3	90,000	270	53.2
BAKAU	BKP-A	5,316	5,203	10.5	113	1	30,000	90	17.7
TUKAU	TKP-A	6,706	6,516	8.8	190	1	30,000	90	22.4
	TKP-B	6,705	6,515	8.8	190	1	30,000	90	22.4
		13,411	13,031	17.6	380	2	60,000	180	22.4
SAMARANG	SMP-A	65,000**				2	60,000	180	108.3
	SMP-B	5,000**				1	30,000	90	16.7
		70,000**				3	90,000	270	77.8

NOTE: * EFFICIENCY = GROSS LIQUID/GROSS LIQUID THROUGHPUT

** ROUNDED FIGURE IN DECEMBER, 1976

Table 28-4-4 (Vol. IV)

COMPARISON OF MAXIMUM PREDICTED PRODUCTION RATE VS. PLATFORM CAPABILITY, GROSS LIQUID BASE

		PREDICTED PRODUCTION RATE BASED ON MAX. GROSS LIQUID RATE				PRODUCTION PLATFORM CAPABILITY			
OIL FIELD	PRODUCTION PLATFORM	GROSS LIQUID (BPD)	NET OIL (BPD)	GAS (MMSCFD)	WATER (BPD)	NO. OF SEPARATION BANKS	GROSS LIQUID THROUGHPUT (BPD)	GAS (MMSCFD)	EFFICIENCY* (%)
TEMBUNGO	A	4,060 [9,770]	3,470 [8,460]	4.8 [15.7]	590 [1,310]	1	20,000	16	20.3 [48.9]
BARONIA	BNP-A	55,150 [86,980]	48,680 [74,130]	133.5 [220.4]	6,470 [12,850]	2	60,000	180	91.9 [145.0]
WEST LUTONG	WLP-A					1	30,000	90	
	WLP-C					1	30,000	90	
		30,230 [33,010]	14,500 [15,570]	57.0 [62.5]	15,730 [17,440]	2	60,000	180	50.4 [55.0]
BARAM	BAP-A					2	60,000	180	
	BAP-B					1	30,000	90	
		40,670	25,440	137.8	15,230	3	90,000	270	45.2
BAKAU	BKP-A	2,830	2,530	4.7	300	1	30,000	90	9.4
TUKAU	TKP-A					1	30,000	90	
	TKP-B					1	30,000	90	
		12,930 [18,680]	12,380 [18,080]	30.1 [36.7]	550 [600]	2	60,000	180	21.6 [31.2]
SAMARANG	SMP-A					2	60,000	180	
	SMP-B					1	30,000	90	
		38,530 [49,150]	38,230 [48,650]	47.7 [66.0]	300 [500]	3	90,000	270	42.8 [54.6]

NOTE * EFFICIENCY = GROSS LIQUID/GROSS LIQUID THROUGHPUT

[.] = ADDITIONAL WELL DEVELOPMENT CASE

Table 28-4-5 (Vol. IV)

COMPARISON OF MAXIMUM PREDICTED PRODUCTION RATE VS. PLATFORM CAPABILITY, GAS BASE

OIL FIELD	PRODUCTION PLATFORM	PREDICTED PRODUCTUIN RATE BASED ON MAX. GAS RATE				PRODUCTION PLATFORM CAPABILITY			
		GROSS LIQUID (BPD)	NET OIL (BPD)	GAS (MMSCFD)	WATER (BPD)	NO. OF SEPARATION BANKS	GROSS LIQUID THROUGHPUT (BPD)	GAS (MMSCFD)	EFFICIENCY* (%)
TEMBUNGO	A	4,060 [9,770]	3,470 [8,460]	4.8 [15.7]	590 [1,310]	1	20,000	16	20.3 [48.9]
BARONIA	BNP-A	31,540 [49,190]	25,790 [41,320]	164.6 [250.3]	5,750 [7,870]	2	60,000	180	52.6 [82.0]
WEST LUTONG	WLP-A					1	30,000	90	
	WLP-C					1	30,000	90	
		29,200 [33,960]	15,200 [17,090]	58.3 [67.4]	14,000 [16,870]	2	60,000	180	48.7 [56.6]
BARAM	BAP-A					2	60,000	180	
	BAP-B					1	30,000	90	
		40,670	25,440	137.8	15,230	3	90,000	270	45.2
BAKAU	BKP-A	2,830	2,530	4.7	300	1	30,000	90	9.4
TUKAU	TKP-A					1	30,000	90	
	TKP-B					1	30,000	90	
		11,290 [16,560]	10,860 [16,080]	34.5 [40.8]	430 [480]	2	60,000	180	18.8 [27.6]
SAMARANG	SMP-A					2	60,000	180	
	SMP-B					1	30,000	90	
		28,910 [39,160]	28,410 [38,530]	56.6 [73.1]	500 [630]	3	90,000	270	32.1 [43.5]

NOTE: *EFFICIENCY = GROSS LIQUID/GROSS LIQUID THROUGHPUT

[ ] = ADDITIONAL WELL DEVELOPMENT CASE

Table 28-4-6
(Vol. IV)

SUMMARY OF GAS UTILIZATION (UNIT: MMSCFD)

LUTONG STREAM	PUMP DRIVE GAS	GAS TO SHORE	VENT GAS	TOTAL
BARONIA	23.3		82.8	106.1
WEST LUTONG	7.3	11.2	16.7	35.2
BARAM	11.4		106.0	117.4
BAKAU	1.8		8.7	10.5
TUKAU	3.0		14.6	17.6
TOTAL	46.8	11.2	228.8	286.8
LABUAN STREAM				
SAMARANG	10.2		30.9	41.1

* Figures are as of May, 1976

Table 29-6-1 (Vol. IV)

4-LEG OFFSHORE PLATFORM COST

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	3,618,000	682,000 (852)	546,000	2,390,000
E-11	230'	3,805,000	772,000 (965)	618,000	2,415,000
F-6	285'	4,289,000	962,000 (1,202)	790,000	2,537,000
F-13	250'	4,054,000	864,000 (1,080)	691,000	2,499,000
F-14	347'	4,899,000	1,272,000 (1,590)	1,018,000	2,609,000
F-23	280'	4,239,000	958,000 (1,197)	760,000	2,521,000
Temana	99'	3,261,000	426,000 (532)	341,000	2,494,000
E-6	239'	3,910,000	819,000 (1,023)	655,000	2,436,000
Betty	247'	3,998,000	853,000 (1,066)	683,000	2,462,000
Bokor	228'	3,788,000	765,000 (956)	612,000	2,411,000
Baronia	254'	4,086,000	880,000 (1,100)	705,000	2,501,000
B-12	298'	4,425,000	1,025,000 (1,281)	830,000	2,570,000
Sabah Area					
South Furious	188'	3,481,000	610,000 (762)	485,000	2,386,000
Erb West	252'	4,070,000	872,000 (1,090)	698,000	2,500,000
Peninsular Area					
Bekok	234'	3,849,000	793,000 (991)	634,000	2,422,000
Pulai	245'	3,981,000	844,000 (1,055)	675,000	2,462,000
Seligi	248'	4,003,000	856,000 (1,070)	685,000	2,462,000
Tapis	225'	3,767,000	754,000 (942)	604,000	2,409,000
Jerneh	205'	3,590,000	668,000 (835)	534,000	2,388,000

Table 29-6-2 (Vol. IV) **6-LEG OFFSHORE PLATFORM COST**

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	5,011,000	1,339,000 (1,673)	1,071,000	2,601,000
E-11	230'	5,347,000	1,504,000 (1,880)	1,203,000	2,640,000
F-6	285'	6,063,000	1,820,000 (2,275)	1,452,000	2,791,000
F-13	250'	5,781,000	1,680,000 (2,100)	1,344,000	2,757,000
F-14	347'	7,204,000	2,400,000 (3,000)	1,920,000	2,884,000
F-23	280'	5,915,000	1,736,000 (2,170)	1,397,000	2,782,000
Temana	99'	3,955,000	744,000 (930)	593,000	2,618,000
E-6	239'	5,451,000	1,551,000 (1,938)	1,241,000	2,659,000
Betty	247'	5,655,000	1,649,000 (2,061)	1,319,000	2,687,000
Bokor	228'	5,329,000	1,495,000 (1,868)	1,197,000	2,637,000
B-12	298'	6,631,000	2,103,000 (2,628)	1,702,000	2,826,000
Sabah Area					
South Furious	188'	4,827,000	1,241,000 (1,551)	997,000	2,589,000
Erb West	252'	5,831,000	1,706,000 (2,132)	1,364,000	2,761,000
Peninsular Area					
Bekok	234'	5,396,000	1,525,000 (1,906)	1,220,000	2,651,000
Pulai	245'	5,595,000	1,618,000 (2,022)	1,295,000	2,682,000
Seligi	248'	5,669,000	1,655,000 (2,068)	1,324,000	2,690,000
Tapis	225'	5,260,000	1,466,000 (1,832)	1,173,000	2,621,000
Jerneh	205'	4,980,000	1,322,000 (1,652)	1,058,000	2,600,000

Table 29-6-3 (Vol. IV) **8-LEG OFFSHORE PLATFORM COST**

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	7,459,000	2,518,000 (3,147)	2,015,000	2,926,000
E-11	230'	8,180,000	2,864,000 (3,580)	2,291,000	3,025,000
F-6	285'	9,805,000	3,683,000 (4,603)	2,947,000	3,175,000
F-13	250'	8,688,000	3,120,000 (3,900)	2,496,000	3,072,000
F-14	347'	12,251,000	4,960,000 (6,200)	3,968,000	3,323,000
F-23	280'	9,596,000	3,574,000 (4,467)	2,857,000	3,165,000
Temana	99'	5,568,000	1,447,000 (1,808)	1,158,000	2,963,000
E-6	239'	8,419,000	2,990,000 (3,737)	2,392,000	3,037,000
Betty	247'	8,613,000	3,086,000 (3,857)	2,468,000	3,059,000
Bokor	228'	8,125,000	2,837,000 (3,546)	2,269,000	3,019,000
B-12	298'	10,139,000	3,839,000 (4,798)	3,085,000	3,215,000
Sabah Area					
South Furious	188'	7,012,000	2,280,000 (2,850)	1,824,000	2,908,000
Erb West	252'	8,740,000	3,149,000 (3,936)	2,519,000	3,072,000
Peninsular Area					
Bekok	234'	8,283,000	2,920,000 (3,650)	2,336,000	3,027,000
Pulai	245'	8,563,000	3,062,000 (3,827)	2,450,000	3,051,000
Seligi	248'	8,644,000	3,097,000 (3,871)	2,477,000	3,070,000
Tapis	225'	8,032,000	2,796,000 (3,495)	2,237,000	2,999,000
Jerneh	205'	7,413,000	2,496,000 (3,120)	1,997,000	2,920,000

Table 29-6-4 (Vol. IV) **3-LEG VENT AND FLARE JACKET COST**

UNIT: US $

Water Depth	Total Cost	Breakdown		
		Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
20'	343,000	100,000 (125)	80,000	163,000
40'	395,000	120,000 (150)	96,000	179,000
60'	447,000	140,000 (175)	112,000	195,000
100'	595,000	204,000 (255)	163,000	228,000
160'	660,000	240,000 (300)	192,000	228,000
180'	696,000	260,000 (325)	208,000	228,000
200'	764,000	280,000 (350)	224,000	260,000
220'	800,000	300,000 (375)	240,000	260,000
240'	869,000	320,000 (400)	256,000	293,000
260'	905,000	340,000 (425)	272,000	293,000
280'	973,000	360,000 (450)	288,000	325,000

Table 29-6-5 (Vol. IV) COST OF 3 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	571,000	128,000 (160)	38,000	405,000
E-11	230'	581,000	135,000 (168)	41,000	405,000
F-6	285'	609,000	152,000 (190)	46,000	411,000
F-13	250'	587,000	140,000 (175)	42,000	405,000
F-14	347'	627,000	166,000 (207)	50,000	411,000
F-23	280'	606,000	150,000 (187)	45,000	411,000
Temana	99'	411,000	92,000 (115)	28,000	291,000
E-6	239'	584,000	138,000 (172)	41,000	405,000
Betty	247'	587,000	140,000 (175)	42,000	405,000
Bokor	228'	580,000	135,000 (168)	40,000	405,000
B-12	298'	614,000	156,000 (195)	47,000	411,000
Sabah Area					
South Furious	188'	546,000	150,000 (187)	36,000	360,000
Erb West	252'	588,000	141,000 (176)	42,000	405,000
Peninsular Area					
Bekok	234'	582,000	136,000 (170)	41,000	405,000
Pulai	245'	587,000	140,000 (175)	42,000	405,000
Seligi	248'	587,000	140,000 (175)	42,000	405,000
Tapis	225'	579,000	134,000 (167)	40,000	405,000
Jerneh	205'	569,000	126,000 (157)	38,000	405,000

Table 29-6-6 (Vol. IV) COST OF 4 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown: Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	778,000	171,000 (213)	51,000	556,000
E-11	230'	791,000	181,000 (226)	54,000	556,000
F-6	285'	841,000	204,000 (255)	61,000	576,000
F-13	250'	802,000	189,000 (236)	57,000	556,000
F-14	347'	868,000	225,000 (281)	67,000	576,000
F-23	280'	839,000	202,000 (252)	61,000	576,000
Temana	99'	534,000	122,000 (152)	36,000	376,000
E-6	239'	795,000	184,000 (230)	55,000	556,000
Betty	247'	800,000	188,000 (235)	56,000	556,000
Bokor	228'	790,000	180,000 (225)	54,000	556,000
B-12	298'	846,000	208,000 (260)	62,000	576,000
Sabah Area					
South Furious	188'	658,000	162,000 (202)	48,000	448,000
Erb West	252'	803,000	190,000 (237)	57,000	556,000
Peninsular Area					
Bekok	234'	793,000	182,000 (227)	55,000	556,000
Pulai	245'	800,000	188,000 (235)	56,000	556,000
Seligi	248'	802,000	189,000 (236)	57,000	556,000
Tapis	225'	789,000	179,000 (223)	54,000	556,000
Jerneh	205'	777,000	170,000 (212)	51,000	556,000

Table 29-6-7 (Vol. IV) COST OF 6 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	1,269,000	256,000 (320)	77,000	936,000
E-11	230'	1,286,000	269,000 (336)	81,000	936,000
F-6	285'	1,378,000	312,000 (390)	94,000	972,000
F-13	250'	1,308,000	286,000 (357)	86,000	936,000
F-14	347'	1,422,000	346,000 (432)	104,000	972,000
F-23	280'	1,367,000	304,000 (380)	91,000	972,000
Temana	99'	919,000	182,000 (227)	55,000	682,000
E-6	239'	1,300,000	280,000 (350)	84,000	936,000
Betty	247'	1,306,000	285,000 (356)	85,000	936,000
Bokor	228'	1,284,000	268,000 (335)	80,000	936,000
B-12	298'	1,386,000	318,000 (397)	96,000	972,000
Sabah Area					
South Furious	188'	1,087,000	242,000 (302)	73,000	772,000
Erb West	252'	1,309,000	287,000 (358)	86,000	936,000
Peninsular Area					
Bekok	234'	1,290,000	272,000 (340)	82,000	936,000
Pulai	245'	1,302,000	282,000 (352)	84,000	936,000
Seligi	248'	1,306,000	285,000 (356)	85,000	936,000
Tapis	225'	1,284,000	268,000 (335)	80,000	936,000
Jerneh	205'	1,266,000	254,000 (317)	76,000	936,000

Table 29-6-8 (Vol. IV) COST OF 8 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown		
			Material Cost (Weight: ton)	Fabrication Cost	Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	1,903,000	384,000 (480)	115,000	1,404,000
E-11	230'	1,934,000	408,000 (510)	122,000	1,404,000
F-6	285'	2,061,000	464,000 (580)	139,000	1,458,000
F-13	250'	1,955,000	424,000 (530)	127,000	1,404,000
F-14	347'	2,130,000	517,000 (646)	155,000	1,458,000
F-23	280'	2,051,000	456,000 (570)	137,000	1,458,000
Temana	99'	1,234,000	275,000 (343)	77,000	882,000
E-6	239'	1,945,000	416,000 (520)	125,000	1,404,000
Betty	247'	1,952,000	422,000 (527)	126,000	1,404,000
Bokor	228'	1,934,000	408,000 (510)	122,000	1,404,000
B-12	298'	2,080,000	478,000 (597)	144,000	1,458,000
Sabah Area					
South Furious	188'	1,643,000	364,000 (455)	109,000	1,170,000
Erb West	252'	1,958,000	426,000 (532)	128,000	1,404,000
Peninsular Area					
Bekok	234'	1,942,000	414,000 (517)	124,000	1,404,000
Pulai	245'	1,950,000	420,000 (525)	126,000	1,404,000
Seligi	248'	1,953,000	422,000 (527)	127,000	1,404,000
Tapis	225'	1,926,000	402,000 (502)	120,000	1,404,000
Jerneh	205'	1,901,000	382,000 (477)	115,000	1,404,000

Table 29-6-9 (Vol. IV) COST OF 12 CONDUCTORS

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown: Material Cost (Weight: ton)	Breakdown: Fabrication Cost	Breakdown: Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	2,442,000	512,000 (640)	154,000	1,776,000
E-11	230'	2,478,000	540,000 (675)	162,000	1,776,000
F-6	285'	2,649,000	616,000 (770)	185,000	1,848,000
F-13	250'	2,514,000	568,000 (710)	170,000	1,776,000
F-14	347'	2,737,000	684,000 (855)	205,000	1,848,000
F-23	280'	2,638,000	608,000 (760)	182,000	1,848,000
Temana	99'	1,748,000	366,000 (457)	110,000	1,272,000
E-6	239'	2,494,000	552,000 (690)	166,000	1,776,000
Betty	247'	2,512,000	566,000 (707)	170,000	1,776,000
Bokor	228'	2,473,000	536,000 (670)	161,000	1,776,000
B-12	298'	2,678,000	638,000 (797)	192,000	1,848,000
Sabah Area					
South Furious	188'	1,978,000	488,000 (610)	146,000	1,344,000
Erb West	252'	2,517,000	570,000 (712)	171,000	1,776,000
Peninsular Area					
Bekok	234'	2,483,000	544,000 (680)	163,000	1,776,000
Pulai	245'	2,504,000	560,000 (700)	168,000	1,776,000
Seligi	248'	2,512,000	566,000 (707)	170,000	1,776,000
Tapis	225'	2,468,000	532,000 (665)	160,000	1,776,000
Jerneh	205'	2,439,000	510,000 (637)	153,000	1,776,000

Table 29-6-10 <u>COST OF 18 CONDUCTORS</u>
(Vol. IV)

UNIT: US$

Field Name	Water Depth	Total Cost	Breakdown: Material Cost (Weight: ton)	Breakdown: Fabrication Cost	Breakdown: Installation Cost
Sarawak Area					
Central Luconia					
E-8	207'	3,600,000	762,000 (952)	228,000	2,610,000
E-11	230'	3,681,000	824,000 (1,030)	247,000	2,610,000
F-6	285'	3,914,000	920,000 (1,150)	276,000	2,718,000
F-13	250'	3,733,000	864,000 (1,080)	259,000	2,610,000
F-14	347'	4,018,000	1,000,000 (1,250)	300,000	2,718,000
F-23	280'	3,893,000	904,000 (1,130)	271,000	2,718,000
Temana	99'	2,615,000	544,000 (680)	163,000	1,908,000
E-6	239'	3,702,000	840,000 (1,050)	252,000	2,610,000
Betty	247'	3,723,000	856,000 (1,070)	257,000	2,610,000
Bokor	228'	3,671,000	816,000 (1,020)	245,000	2,610,000
B-12	298'	3,945,000	944,000 (1,180)	283,000	2,718,000
Sabah Area					
South Furious	188'	2,962,000	728,000 (910)	218,000	2,016,000
Erb West	252'	3,738,000	868,000 (1,085)	260,000	2,610,000
Peninsular Area					
Bekok	234'	3,692,000	832,000 (1,040)	250,000	2,610,000
Pulai	245'	3,702,000	840,000 (1,050)	252,000	2,610,000
Seligi	248'	3,723,000	856,000 (1,070)	257,000	2,610,000
Tapis	225'	3,650,000	800,000 (1,000)	240,000	2,610,000
Jerneh	205'	3,598,000	760,000 (950)	228,000	2,610,000

Table 29-6-11
(Vol. IV)

UNIT COST OF SUBMARINE PIPELINE (PER 1,000 FEET)

UNIT: US $

Size	Total	Breakdown		
		Materials	Corrosion & Weight Coating*	Installation
6"	31,000	7,000	2,000	22,000
8"	33,000	8,000	3,000	22,000
10"	36,000	11,000	3,000	22,000
12"	39,000	13,000	4,000	22,000
14"	46,000	14,000	4,000	28,000
16"	50,000	17,000	5,000	28,000
18"	53,000	20,000	5,000	28,000
20"	61,000	20,000	6,000	35,000
24"	68,000	25,000	8,000	35,000
28"	76,000	31,000	10,000	35,000
30"	94,000	34,000	13,000	47,000
32"	99,000	37,000	15,000	47,000
36"	106,000	41,000	18,000	47,000
42"	172,000	48,000	29,000	95,000
48"	204,000	69,000	40,000	95,000

* Pipelines of size from 6" to 10" exclude weight coating cost.

Table 29-6-12
(Vol. IV)

UNIT COST OF RISER PIPE (PER ONE RISER)

UNIT: US $

Size	Total	Breakdown		
		Materials	Prefabrication	Riser Installation & Tie-in
6"	190,000	7,000	2,000	181,000
8"	194,000	11,000	2,000	181,000
10"	198,000	15,000	2,000	181,000
12"	203,000	20,000	2,000	181,000
14"	299,000	24,000	3,000	272,000
16"	303,000	28,000	3,000	272,000
18"	308,000	33,000	3,000	272,000
20"	404,000	38,000	4,000	362,000
24"	409,000	43,000	4,000	362,000
28"	414,000	48,000	4,000	362,000
30"	508,000	50,000	5,000	453,000
32"	513,000	55,000	5,000	453,000
36"	518,000	60,000	5,000	453,000
42"	614,000	65,000	6,000	543,000
48"	619,000	70,000	6,000	543,000

Table 29-6-13 (Vol. IV)

GAS PRODUCTION EQUIPMENT COST

UNIT : US$

CASE 65MMSCFD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	1,042,000	538,000	1,580,000
Electrical Equipment	1,008,000	253,000	1,261,000
Instrument Equipment	227,000	57,000	284,000
Total Cost	2,277,000	848,000	3,125,000

CASE 95MMSCFD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	1,255,000	648,000	1,903,000
Electrical Equipment	1,099,000	275,000	1,374,000
Instrument Equipment	261,000	66,000	327,000
Total Cost	2,615,000	989,000	3,604,000

CASE 110MMSCFD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	1,341,000	692,000	2,033,000
Electrical Equipment	1,135,000	284,000	1,419,000
Instrument Equipment	276,000	69,000	345,000
Total Cost	2,752,000	1,045,000	3,797,000

Table 29-6-13 (Vol. IV) GAS PRODUCTION EQUIPMENT COST (Cont'd)

UNIT : US$

CASE 265MMSCFD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	2,135,000	1,100,000	3,235,000
Electrical Equipment	1,472,000	368,000	1,840,000
Instrument Equipment	405,000	102,000	507,000
Total Cost	4,012,000	1,570,000	5,582,000

CASE 320MMSCFD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	2,658,000	1,370,000	4,028,000
Electrical Equipment	1,694,000	424,000	2,118,000
Instrument Equipment	492,000	123,000	615,000
Total Cost	4,844,000	1,917,000	6,761,000

CASE 390MMSCFD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	2,844,000	1,466,000	4,310,000
Electrical Equipment	1,772,000	444,000	2,216,000
Instrument Equipment	522,000	131,000	653,000
Total Cost	5,138,000	2,041,000	7,179,000

Table 29-6-13 (Vol. IV)

GAS PRODUCTION EQUIPMENT COST (Cont'd)

UNIT : US$

CASE 520MMSCFD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	3,442,000	1,774,000	5,216,000
Electrical Equipment	2,026,000	507,000	2,533,000
Instrument Equipment	620,000	155,000	775,000
Total Cost	6,088,000	2,436,000	8,524,000

Table 29-6-14
(Vol. IV)

OIL PRODUCTION EQUIPMENT COST

UNIT : US$

CASE 10,000BPD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	593,000	322,000	915,000
Electrical Equipment	320,000	80,000	400,000
Instrument Equipment	105,000	27,000	132,000
Total Cost	1,018,000	429,000	1,447,000

CASE 20,000 BPD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	664,000	340,000	1,004,000
Electrical Equipment	336,000	84,000	420,000
Instrument Equipment	113,000	29,000	142,000
Total Cost	1,113,000	453,000	1,566,000

CASE 30,000BPD

	Material Cost	Installation Cost	Total Cost
Process Equipment (including Piping)	795,000	400,000	1,195,000
Electrical Equipment	368,000	93,000	461,000
Instrument Equipment	128,00	32,000	160,000
Total Cost	1,291,000	525,000	1,816,000

Table 29-6-15
(Vol. IV)

UNIT COST OF

OTHER PRODUCTION EQUIPMENT

UNIT : US$

1.	ONSHORE TANKAGE	5 / BBL
2.	PUMP WITH ELEC.MOTER & ACCESSORIES	650 / HP
3.	GAS COMPRESSOR WITH GAS TURBINE	600 / HP

Table 29-6-16
(Vol. IV)

NEWLY BUILT
STORAGE BARGE COST

UNIT : US$

STORAGE CAPACITY	STORAGE BARGE COST
940,000 BBLS	19,000,000
1,100,000 BBLS	23,000,000
1,200,000 BBLS	25,000,000
1,270,000 BBLS	27,000,000
1,400,000 BBLS	32,000,000

Table 29-6-17
(Vol. IV)

ONSHORE SUPPORT FACILITIES COST

(IN CASE OF 30,000BPD)

UNIT : US$

	OFFSHORE STORAGE CASE	ONSHORE STORAGE CASE
SITE PREPARATION	50,000	173,000
BUILDING	1,960,000	2,000,000
JETTY	2,000,000	2,000,000
OTHERS	1,203,000	1,252,000
AUXILIARY FACILITIES FOR TANKAGE	—	2,360,000
TOTAL	5,213,000	7,785,000

* Cost for the other capacity case is estimated based on above shown table considering scale factor.

Table 29-6-18 (Vol. IV) OPERATING PERSONNEL COST

US$/Person/Year

1.	Manager	72,000
2.	Superintendent	44,000
3.	Supervisor	28,800
4.	Engineer	19,200
5.	Geologist	19,200
6.	Clerk	4,800
7.	Officer	4,800
8.	Mechanician	1,800
9.	Electrician	1,800
10.	Instrument	1,800
11.	Foreman	1,800
12.	Field Operator	1,500
13.	Store Keeper	960
14.	Laborer	1,200

Table 29-6-19
(Vol. IV)

UNIT COST

OF

VARIOUS CHEMICALS

UNIT : US$

1.	Tri-Ethylene-Glycol	3.30/ gal.
2.	Corrosion Inhibitor for Gas	20.0/ gal.
3.	Deemulsifier	0.74/lb
4.	Defoamant	o.73/lb

Table 29-6-20
(Vol. IV)

UNIT COST
OF
SERVICE CONTRACTORS

UNIT: US$

1.	One Work Boat	30,000 per year
2.	One Crew Boat	10,000 per year
3.	One Tug Boat Fleet*	18,000 for each berthing and unberthing operation
4.	One Helicopter	150,000 per year assuming one flight a day
5.	Catering Service Personnel	
	a. Cook	8,760 per year
	b. Waiter	6,570 per year
	c. Room Boy	4,380 per year

* Consisting of one tug boat, one hose handling boat and one mooring line handling boat.

Table 30-6-1 (Vol. IV) ANNUAL OIL PRODUCTION AND FOB PRICE PER BARREL

SARAWAK AREA

FIELD	West Temana & E-6 Fields						Betty & Bokor Fields					
CASE	Case I (West Temana & E-6)			Case IIA, IIB (E-6)			Case I (Betty & Bokor)			Case II (Betty)		
YEAR	Annual Production (M BBLS)	F.O.B. Price (M$)	F.O.B. Price (US$)	Annual Production (M BBLS)	F.O.B. Price (M$)	F.O.B. Price (US$)	Annual Production (M BBLS)	F.O.B. Price (M$)	F.O.B. Price (US$)	Annual Production (M BBLS)	F.O.B. Price (M$)	F.O.B. Price (US$)
1												
2												
3												
4	12,411	31.47	12.39	10,951	31.57	12.43	7,421	31.70	12.48	5,595	31.95	12.58
5	11,681	31.52	12.41	10,951	31.57	12.43	6,972	31.70	12.48	5,206	31.95	12.58
6	10,951	31.57	12.43	10,951	31.57	12.43	5,456	31.88	12.55	4,805	31.95	12.58
7	10,951	31.57	12.43	10,951	31.57	12.43	3,526	31.95	12.58	3,526	31.95	12.58
8	9,993	31.57	12.43	9,993	31.57	12.43	2,467	31.95	12.58	2,467	31.95	12.58
9	7,869	31.57	12.43	7,869	31.57	12.43	136	31.95	12.58	136	31.95	12.58
10	5,677	31.57	12.43	5,677	31.57	12.43						
11	3,747	31.57	12.43	3,747	31.57	12.43						
12	2,881	31.57	12.43	2,881	31.57	12.43						
13	2,371	31.57	12.43	2,371	31.57	12.43						
14	1,984	31.57	12.43	1,984	31.57	12.43						
15	1,700	31.57	12.43	1,700	31.57	12.43						
16	1,442	31.57	12.43	1,442	31.57	12.43						
17	1,255	31.57	12.43	1,255	31.57	12.43						
18	591	31.57	12.43	591	31.57	12.43						

Note: Crude price is as of middle of 1976

Table 31-6-1
(Vol. IV)

INVESTMENT SCHEDULE FOR OIL

UNIT: M$1,000

AREA	SARAWAK AREA					SABAH AREA			PENINSULAR AREA					
FIELD	West Temana & E-6 Fields			Betty & Bokor Fields		South Furious & Erb West Fields			Bekok, Pulai & Seligi Fields				Tapis Field	
YEAR	CASE I	CASE IIA	CASE IIB	CASE I	CASE II	CASE I	CASE IIA	CASE IIB	CASE IA	CASE IB	CASE II	CASE III	CASE IA	CASE IB
1	102,168	48,153	51,365	54,093	30,537	96,956	102,689	108,517	201,002	240,976	179,848	150,020	72,691	80,694
2	178,787	172,085	115,072	67,270	33,133	61,615	77,320	102,291	275,415	305,619	262,407	205,658	148,355	197,443
3	135,628	65,128	132,697	110,837	58,496	147,695	81,863	61,426	259,019	241,490	193,549	153,643	186,690	175,568
4						100,048								
5														
6														
7														
8														
9														
10														
11														
12														
13														
14														
15														
16														
17														
18														
19														
20														
21														
22														
23														

Table 31-6-2
(Vol. IV)

ANNUAL OPERATING COST FOR OIL

UNIT: M$1,000

AREA / FIELD	SARAWAK AREA					SABAH AREA			PENINSULAR AREA					
	West Temana & E-6 Fields			Betty & Bokor Fields		South Furious & Erb West Fields			Bekok, Pulai & Seligi Fields				Tapis Field	
YEAR	CASE I	CASE IIA	CASE IIB	CASE I	CASE II	CASE I	CASE IIA	CASE IIB	CASE IA	CASE IB	CASE II	CASE III	CASE IA	CASE IB
1														
2														
3														
4	22,155	21,525	15,256	11,297	7,119		13,328	13,538	44,319	36,097	38,158	31,560	27,486	22,276
5	20,409	21,525	15,256	11,246	7,076	19,051	13,328	13,538	44,241	36,019	38,120	31,523	27,318	22,108
6	18,658	21,525	15,256	9,380	7,031	19,051	13,328	13,538	43,885	35,663	37,904	31,286	27,095	21,885
7	18,658	21,525	15,256	7,081	6,886	13,005	13,328	13,538	43,000	34,778	37,166	30,487	26,655	21,445
8	18,547	21,414	15,145	6,961	6,766	13,005	13,135	13,345	40,430	32,208	31,277	29,184	26,305	21,095
9	18,303	21,170	14,901	5,027	4,882	12,812			39,165	30,943	30,347	28,286	25,654	20,444
10	18,051	20,918	14,649						30,408	23,799	29,688	27,636		
11	17,828	20,695	14,426						29,897	23,288	29,182	27,151		
12	17,729	20,596	14,327						28,917	22,308	28,203	22,917		
13	17,670	20,537	14,268						24,861	18,662	24,066	22,221		
14	17,625	20,492	14,223						24,617	18,418	23,822	21,987		
15	17,592	20,459	14,190						24,399	18,200	23,626	21,780		
16	17,561	20,428	14,159						24,241	18,042	23,456	21,603		
17	17,541	20,408	14,139						24,119	17,920	23,324	21,512		
18	8,768	10,202	8,216						24,000	17,801	23,211	21,396		
19									23,913	17,714	23,108	21,316		
20									23,824	17,625	23,018	21,227		
21									23,738	17,539	22,963	21,148		
22									23,694	17,495	22,899	21,108		
23									23,372	17,173	22,582	20,796		

Table 31-6-3 (Vol. IV)

DAILY GAS PRODUCTION

MMSCFD

AREA / FIELD / YEAR	SARAWAK AREA							PENINSULAR AREA
	Central Luconia Fields						Baronia & B-12 Fields	Bekok & Pulai Fields
	Case IA	Case IB	Case IC	Case II	Case III	Case IV	Case IA	
1								
2								
3							37	
4	1,030	980	1,340	1,270	1,180	1,090		150
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								

Table 31-6-4 (Vol. IV) **INVESTMENT SCHEDULE FOR GAS**

UNIT: M$1,000

AREA	SARAWAK AREA							PENINSULAR AREA
FIELD	Central Luconia Fields						Baronia & B-12 Fields	Bekok & Pulai Fields
YEAR	Case IA	Case IB	Case IC	Case II	Case III	Case IV	Case IA	
1	291,087	289,559	467,707	452,755	394,005	283,321	35,372	32,878
2	533,630	461,058	680,231	645,998	606,355	517,749	77,655	109,440
3	397,905	440,314	295,019	260,879	265,612	385,062		149,410
4								
5								
6								
7								
8								
9								
10								
11								
12								
13	48,381	193,709	215,296	206,363	195,384	183,847		
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								

Table 31-6-5
(Vol. IV)

ANNUAL OPERATING COST FOR GAS

UNIT: M$1,000

AREA / FIELD / YEAR	SARAWAK AREA							PENINSULAR AREA
	Central Luconia Fields						Baronia & B-12 Fields	Bekok & Pulai Fields
	Case IA	Case IB	Case IC	Case II	Case III	Case IV	Case IA	
1								
2								
3							4,809	
4	42,912	46,529	56,008	52,775	49,555	46,188		7,285
5								7,303
6								7,376
7								7,587
8								8,507
9								9,162
10								9,708
11								10,048
12								10,755
13								11,309
14								11,504
15								11,683
16								11,808
17								11,906
18								12,006
19								12,068
20								12,150
21								12,225
22								12,260
23								12,531

Table 31-6-6 (Vol. IV) PROFITABILITY YARDSTICKS OF OIL

AT THE YEAR OF MAX. R.O.R. FOR OPERATING COMPANY

UNIT : M$1,000

AREA	FIELD	CASE \ YARDSTICK	PETRONAS Cumulative Net Cash Flow	PETRONAS Cumulative Present Worth at Discount Rate 10%	OPERATING COMPANY Maximum ROR Year (*)	OPERATING COMPANY Maximum ROR ROR (%)	OPERATING COMPANY Maximum Cumulative Net Cash Flow	OPERATING COMPANY Maximum Cumulative Present Worth at Discount Rate 10%	OPERATING COMPANY Payout Time (year)
Sarawak Area	West Temana & E-6 Fields	CASE I	688,786	369,459	14	7.88	174,935	-29,685	7.5
		CASE IIA	653,618	352,124	13	15.48	259,503	57,673	6.3
		CASE IIB	697,320	363,228	16	16.75	282,672	70,265	6.2
	Betty & Bokor Fields	CASE I	223,742	140,256	8	-	-21,229	-64,611	-
		CASE II	188,132	116,397	8	12.62	58,526	8,266	5.7
Sabah Area	Erb West & South Furious Fields	CASE I	385,924	218,331	9	-	-37,904	-124,962	-
		CASE IIA	297,213	179,263	8	1.31	13,964	-63,044	7.7
		CASE IIB	297,213	179,263	8	0.23	2,552	-74,768	7.9
Peninsular Area	Bekok, Pulai & Seligi Fields	CASE IA	1,770,974	1,015,256	14	21.04	727,775	252,866	5.1
		CASE IB	1,826,413	1,028,039	17	19.42	748,844	239,115	5.2
		CASE II	1,529,282	858,248	15	19.78	622,606	202,485	5.2
		CASE III	1,337,232	738,332	15	20.77	547,063	184,618	5.2
	Tapis Field	CASE IA	702,728	428,202	9	15.05	239,153	53,873	5.6
		CASE IB	702,728	428,202	9	12.51	224,444	30,337	5.8

Note: (*) - In the case that cumulative net cash flow is not positive, the year shown above is a peak year of cumulative net cash.