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

- VOLUME II -

(PENINSULAR MALAYSIA)

JANUARY 1978

JAPAN INTERNATIONAL COOPERATION AGENCY

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Page

Vol. II PENINSULAR MALAYSIA AREA

PART A EVALUATION OF OIL AND GAS FIELD AND PERFORMANCE PREDICTION

Page

PART B SURFACE FACILITIES

Page

PART C COST ESTIMATE AND ECONOMIC ANALYSIS

PART A EVALUATION OF OIL AND GAS FIELD AND PERFORMANCE PREDICTION

1. GENERAL

Sixteen oil and gas fields in the offshore of Peninsular Malaysia were studied. This area can be divided into two, southern and northern areas.

In the northern area where there exist five gas fields, which are Pilong, Bintang, Jerneh, Sepat and Bujang fields. Among the fields, the biggest is Jerneh field, whose original gas in place is estimated to be more than four trillion standard cubic feet, while hydrocarbon accumulations for the other four fields were estimated to be comparatively poor.

In the southern area, there are four oil fields for development, which are Bekok, Pulai, Seligi and Tapis fields. Bekok field is estimated to have the biggest reserves and will play an important role in the development of this area. Pulai and Seligi fields are recommended to be developed in conjunction with Bekok field.

Although there exist some uncertain factors in estimating original hydrocarbon in place for Tapis field, the field has possibility of having big reserves, and its development schedule is recommended to be made separately from the other three fields. The case studies for the development of these four fields were made in this report.

The other fields fall under the category of the potential field or undeveloped field. Among the fields in this category, Sotong field has different characteristics. According to the preliminary performance prediction of the field, producing gas oil ratio was estimated to be very high. From the viewpoint of the petroleum conservation, the development of the field is recommended to be postponed until confirmation is obtained as to the reserves and productivity of Duyong field. Duyong field has possibility of having huge reserves and more exploratory works are required to establish development schedule. Combined field development of Sotong, Duyong and Anding fields will be the most recommendable ways.

As for Peta, Belumut, Angsi and Besar fields, there exist some uncertainties in defining reservoirs and more exploratory works are recommended. Therefore, those fields were discarded from the short term field development schedule.

In general, oil with high API gravity was anticipated to be produced from this area, and in many reservoirs, high producing gas oil ratio was estimated from the early production stage. The field development schedule is required for efficient utilization of associated gas from the view point of petroleum resources conservation.

It should be reminded, however, that there always exist some uncertainties in establishing associated gas deliverability schedule. The gas volume is always much influenced by the field capability of oil production. The schedule, therefore, should be reviewed and revised with the advent of new information after completing the oil production system and by periodical field observation.

The original hydrocarbon in place of Peninsular Malaysia was shown on Tables A-1 - 2.

2. GEOLOGY

2.1 Stratigraphy and Reservoirs

The 16 structures of Peninsular area are located in the offshore 100 to 250 km of the eastern coast of the Malay Peninsula and in the central part of the Malay Basin which are developed during probably Cretaceous and Tertiary time. Sedimentary sections penetrated in wells exceed 10,000 ft in thickness and the basement is not reached in most of the fields.

Although geological age of the sediments is not always conclusive, a stratigraphic summary made up using well data is given in Fig. 1-2-1. The studied area seems divided into the northern area in which thick sedimentary rocks of Pliocene age are known and the southern area in which most of Pliocene sediments are lacking and sediments of Miocene and older age are known as main rocks in wells.

In the Peninsular area there is a regional unconformity below marine Pleistocene sediments. Hydrocarbons are accumulated in thick sections below the unconformity consisting of Pliocene, Miocene, and older sediments. Especially in the southern fields hydrocarbons are accumulated in formations which are developed in Group J and below Trengganu Shale and, therefore, the tops of Group J and Trengganu Shale are given in the correlation tables as geological time references (Tables 1-2-1, 2-2-1, 3-2-1, 4-2-1, 5-2-1, 6-2-1, 7-2-1, 8-2-1, 14-2-1, 15-2-1, 16-2-1).

Hydrocarbon reservoirs are sandstones sealed by shale beds which are more developed than those in the Sarawak and Sabah fields. Reservoir rocks including potential ones are picked up individually and named alphabetically as a_1, a_2, ..., b_1, b_2.. and so on (Tables 1-2-1 - 16-2-1). These hydrocarbon-bearing formations are sediments deposited in fresh or brackish environments.

2.2 Geologic Structure

Structures of the Peninsular fields are anticline or domal anticline which are frequently cut into blocks by normal fault systems. The anticlines are considerably large and have closures which are 10 to 20 km across in general and some of them reach even more than 2,000 ft in height.

Structural type of the anticlines varies in different localities but most of them have a trend of E-W or NW-SE. N-S trending fault systems dominate the Pilong and Bintang structures, whereas an E-W element dominates Jerneh, Sepat, and Bujang structures. Structures of Tapis, Bekok, Seligi, Pulai, Belumut, and Peta possess E-W trending anticlinal axes associated with a N-S fault trend. Further to the south, structures such as Angsi, Besar, Duyong, Sotong, and Anding are WNW-ESE or NW-SE trending anticlinal highs of which axes are generally intersected obliquely by a NNW-SSE trending fault system.

3. FIELDS FOR DEVELOPMENT

3.1 Bekok Field

3.1.1 Geology

(1) Reservoir Beds

In the Bekok field reservoirs were picked up as zones a_1 - a_5 above Trengganu Shale and as b_1 - b_6 below it (Table 1-2-1) and no essential sandstone beds are found above Group J. The reservoir sandstones show fairly good continuity and tend to be thicker with lower structural position for the beds. In case of zones a_5, b_3, and b_4, the intercalation of shale beds is only in well No. 1, the structurally highest well. That is, a sandstone reservoir of the field generally indicates better development with depth. Thickness of a single sandstone bed does not exceed 270 ft and the average thicknesses of zones a_2, a_5, b_3, and b_4 are 124 ft, 163 ft, 214 ft, and 199 ft, respectively.

(2) Geologic Structure

Structure contour maps of tops of zones a_2, b_3 and b_4 are shown in Figs. 1-2-2, 1-2-3, 1-2-4 and a structural cross-section is shown in Fig. 1-2-5. The central part of the structure was drilled by well No.1, the north and east parts were drilled by the rest five wells, and the west and south parts remain not drilled by wells. The structure is an E-W trending anticline which shows an asymmetric N-S cross-section with gentler north flanks of 7 to 13 - degree dips. The western tip of the anticline is a fault block upthrown by a N-S trending normal fault. In shallower horizons, minor faults trending N-S are developed on the southern limb of the anticline. The extent of a main oil zone in a_2 is 8 km in long diameter and 5 km in short diameter.

[Seismic Interpretation]

Interpreted horizons were the top of zone a_3 and top of zone b_3. Quality of reflections from the top of zone a_3 is usually fairly good except in surroundings of faults. However, reflections associated with the top of zone b_3 are not so good as the above ones. Besides, they are considerably poor in the crestal part of the structure and in surrounding of faults. Well shooting data of Bekok Nos. 3 thru 6 were available, but Bekok No.6 did not penetrate to the top of zone b_3. Interpretation result and representative seismic section are shown in Fig. 1-1-1, Fig. 1-1-2 and Fig. 1-1-3.

3.1.2 Reservoir Analysis

The field is currently estimated to be the biggest one among the fields in the Peninsular Malaysia area. The original oil and gas in place estimated by volumetric method and primary recoverable reserves for the main productive zones are tabulated on Table A-1.

The main productive zones for the field are a_2 for zone a, b_3 and b_4 for zone b. The field is predicted to have high producing gas oil ratio from comparatively early production stage, and efficient utilization of the associated gas should be considered in the oil production from this field.

A few alternative development plans were investigated and reservoir performances were studied. Restricted gas production case is finally recommended, where associated gas is controlled and efficiently produced.

Cap gas is confirmed to exist in the individual zones by FIT and production test results, while it is difficult to define the gas oil contact clearly from well log analysis.

The contact is defined tentatively from the pressure traverse relation and API gravity distribution as illustrated on Fig. 1-3-3 and 1-3-4, respectively. Oil water contact was determined from log analysis. Reservoir parameters such as net oil thickness, porosity and water saturation were obtained from log analysis. (Appendix).

As special fluid analysis data are not available at present, estimation of the fluid properties was made on the basis of general characteristics of Malaysia crude oil (Appendix) and results are summarized on Table 1-3-1 - 3.

Special core analysis results for Bekok No.2 were utilized in establishing relative permeability relation for estimating the reservoir performance. The relation is tabulated on Table 1-3-1 - 3.

Anticipated reservoir performances for individual zones were estimated for natural depletion case by material balance method, and the results are tabulated on Table 1-3-4 - 6. and illustrated on Fig. 1-3-1.

As for gas utilization, the condition of constant rate of supply during a certain long period is the first requisite in establishing the deliverability schedule. Not only for increasing the recovery of reservoir but for efficient utilization of overall petroleum resources, oil production schedule should be established.

Recommended is the restricted gas production case, where associated gas is to be controlled at the rate of 150 MMSCF/D for the time duration of 20 years.

In order to make this feasible, the fields adjacent to Bekok field such as Pulai and Seligi fields are to be developed simultaneously. Anticipated performance of Bekok field for this case is tabulated on Table 1-3-7 - 9 and illustrated on Fig. 1-3-2. Facilities design and economic analysis are made for this case in Part B and Part C, respectively.

Recommendable initial oil production rates for the individual zones were estimated as follows.

Zone Name	Initial Oil Prod. Rate (MSTB/D)	Oil Gravity (°API)
A2	25.0	48
B3	25.0	47
B4	10.0	48
Total	60.0	

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. 1-3-5 - 7.

Discussion is made for several uncertain factors which have profound influence on future reservoir performance.

The most important factor among the unforeseeable parameters at current stage is the degree of natural water drive, which is specific to individual reservoirs. It is difficult to predict the degree of water drive at current stage when no production is initiated. This can be evaluated quantitatively only after the start of production, by periodical pressure survey on the field basis.

Sample calculations of reservoir performance were made for reference to obtain the effect of water drive by assuming water influx rate to be 20 per cents of oil production rate.

Another important factor is producing gas oil ratio, which is, on the one hand, inherent in individual reservoirs (reservoir fluid characteristics and relative permeability) but, on the other hand, is subject to artificial factor, which are well completion condition (the relation of perforation depth and gas oil contact level) and production control. Once production is initiated, establishment of field base gas oil relative permeability relation should be made by observing producing gas oil ratio and reservoir pressure.

Maximum allowable field base production rate should, therefore, be re-evaluated by (a) confirming gas oil contact, (b) obtaining productivity index by production test at the time of well completion and (c) sample analysis for reservoir fluid and rock sample.

3.2 Pulai Field

3.2.1 Geology

(1) Reservoir Beds

In the Pulai field reservoirs are selected as a, b, ..., e (Table 2-2-1), where zone a corresponds to the reservoirs of zones a_1 - a_5 of the Bekok field. Zone a is a single bed of well developed sandstone as much as 453 ft in average thickness, being gas-bearing. Zone b_1 is generally shaly and 73 ft thick in average, zone b_2 is 105 ft thick, and zone b_3 is 179 ft thick, but all of these lessen approximately 10% in thickness on the highest point of the structure. Zones b_1, b_2, and b_3 are separated by 30 to 90 ft thick shales but appear to have a common level as to OWC and GOC.

(2) Geologic Structure

Structural maps of zones a and b_1 are shown in Figs. 2-2-1, 2 and an east-west cross-section is shown in Fig. 2-2-3. The structure is an E-W trending anticline and has oil and gas distribution areas less than about 4 km across. On the western part a N-S trending normal fault with the west side thrown down runs the anticline to form a minor block which is not drilled yet.

[Seismic Interpretation]

Only records shot in 1974 were used for the seismic interpretation of the Pulai structure, because the horizontal scale of the other seismic sections was too small.

A target horizon of the interpretation was the top of zone b. Data quality is generally fair, but poor in surroundings of fault. It was possible to correlate reflections across the fault in the eastern part of the structure, but it was difficult in the western part of the structure. Well velocity surveys have been conducted in all wells in this field. Interpretation result and representative seismic section are shown in Fig. 2-1-1 and Fig. 2-1-2.

3.2.2 Reservoir Analysis

The field has two main oil productive zones, which are b_2 and b_3 of zone b. The original oil and gas in place estimated by volumetric method and primary recoverable reserves for the main productive zones are tabulated on Table A-1.

Estimated gas oil contact depth for zone b_3 is 3884 ft s.s. which is confirmed by pressure vs depth relation obtained by FIT results, as illustrated on Fig. 2-3-2.

As no well has been drilled through the gas oil contact for zone b_2, the same value estimated for zone b_3 was applied to zone b_2, because the fluid characteristics of the two zones can be regarded to be identical, both zones have common oil water contact (4004 ft s.s.) and identical pressure profile through the reservoir is observed. Special core analysis is available for Pulai Well No.1 and the data used in the performance calculation is tabulated on Tables 2-3-1, 2.

Reservoir performance prediction was made for main productive zones of b_2 and b_3 by the material balance method, and illustrated on Fig. 2-3-1. Water drive is anticipated to be existing but quantitative estimation is difficult to be made under current stage. The degree was, therefore, assumed in two cases, those are 20 and 40 per cents of oil production rate, and the results are tabulated on Tables 2-3-3 - 6.

In case of strong water drive, gas injection is sometimes not effective at all for the purpose of increasing recovery. At current stage, sufficient data are not available for justifying the necessity of gas injection.

Natural depletion case is illustrated here, which is the basis for obtaining the other relevant cases. Gas injection for enhancing recovery may or may not be required, depending on the field characteristics, which should be determined at comparatively earlier stage when production is started.

The field seems to have good characteristics and efficient field maintenance is required by periodical pressure survey.

Recommended production schedule is based on the natural depletion case, where associated gas is collected and transferred to Bekok Field for gas utilization purpose.

Recommendable initial oil production rates for the individual zones were estimated as follows.

Zone Name	Initial Oil Prod. Rate (MSTB/D)	Oil Gravity (°API)
B2	7.0	42
B3	5.9	42
Total	12.9	

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 summerized on Figs. 2-3-3 - 6.

3.3 Seligi Field

3.3.1 Geology

(1) Reservoir Beds

The Seligi field is located 15 km east of Bekok and 15 km northwest of Pulai and has been drilled by 4 wells. Hydrocarbon reservoirs are named as zones a_1 - a_2, b_1 - b_3, and c (Table A-26). Zone a_2 has an average thickness of 369 ft, but contains several highly argillaceous parts, which means that the Seligi field lies halfway between the Bekok and Pulai fields concerning the development of zone a. Sandstones of zones b and c indicate very intense lateral change in lithology from sandstones to shale. Zone b_2 contains two beds of shale reaching a maximum 50 ft in thickness which have no field-wide distributions and zone c has a transition of sand to shale in the lower half in the order of well Nos. 4, 1, 2, 3.

(2) Geologic Structure

Structural maps of zones a_2, b_2, and c are shown in Figs. 3-2-1 - 3 and a cross-section in Fig. 3-2-4. The structure is composed of two anticlinal highs of E-W trending axes, on the south one (A block) of which well Nos. 1, 2, and 4 were drilled and on the north (B block) well No.3.

However, there is some uncertainty as to the separation of the two sub-structures at levels of fluid interfaces owing to the large lateral lithologic changes and even to suspicious well data. It is to be desired that delineation wells should be drilled on the synclinal part between the two anticlines and on the northern flank of the north anticline.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone b_2. Quality of reflections from the interpreted horizon is fair to good, but partly poor in the eastern part of the structure. Geologically the interpreted horizon is the highest in well No.3 but reflection time in this well is not the least. It may be considered that this is caused by velocity increase around well No.3, which could not be checked directly because well shooting data of this well were not available. Because well shooting data only of wells No.1 and No.4 were available, average velocities for well Nos. 2 and 3 were decided using seismic reflection time and actual depth. It was assumed that the average velocity increases linearly with distance to the north along the meridian. Interpretation result and representative seismic section are shown in Fig. 3-1-1 and Fig. 3-1-2.

3.3.2 Reservoir Analysis

The reservoir analysis is made for individual productive zones for Block A and B, where A and B are western and eastern structures, respectively. Main productive zones for Block A are zone a_2, b_2 and c, while b_2 and c are productive in Block B. Well Nos.1, 2 and 4 are drilled in Block A and only one well, Well No.3, is drilled in Block B. Reservoir structure is comparatively small but existences of cap gas and edge water and/or bottom water are confirmed.

Fluid contact level was obtained for individual zone from log analysis. The problem is the oil water contact for zone b_2. Three different values were obtained as 5264 ft, 5234 ft and 5244 ft s.s. for Well Nos.1, 2 and 4, respectively. In the reserves calculation by volumetric method, average of these 3 values was used. Probable misinformation as to derrick floor elevation can be thought of.

Pressure traverse relation as obtained from FIT and production test was utilized to determine original reservoir pressure for individual reservoirs. Special core analysis data are available for zone c of Well No.1, which were used to calculate reservoir performance. The applied relative permeability relation is tabulated on Tables 3-3-1 - 5. Oil production test data are available for zone b_2 for A block and zone c for A and B block. Estimated fluid properties are tabulated on Tables 3-3-1 - 5, as no actual PVT data are available for this field.

The original oil and gas in place estimated by volumetric method and primary recoverable reserves for the main productive zones are tabulated on Table A-1.

Reservoir performance calculation was made for individual reservoirs of each block and tabulated on Tables 3-3-6 - 10 and field total performance is illustrated of Fig. 3-3-1.

Recommendable initial oil production rates for the individual zones were estimated as follows.

Zone Name	Initial Oil Prod. Rate (MSTB/D)	Oil Gravity (°API)
A2 (A-Block)	7.0	48
B2 (A-Block)	6.0	48
C (A-Block)	2.0	45
B2 (B-Block)	6.0	48
C (B-Block)	15.0	45
Total	36.0	

There is some uncertainty as to the fluid contacts of this reservoir, which should be clarified, and original oil and gas in place is recommended to be calculated once again.

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. 3-3-3 - 7.

3.4 Tapis Field

3.4.1 Geology

(1) Reservoir Beds

The Tapis field is located 20 km north-northwest of the Bekok field. Hydrocarbon occurrence is found in formations of Group J, named here as a_1 - a_5 in Table 4-2-1. Reservoir rocks are sandstones of a maximum thickness of 110 ft. It is considered that lateral continuity of them is not so bad, though argillaceous parts are contained in zones a_3 and a_5.

(2) Geologic Structure

Figs. 4-2-1, 2 show structural contours of zones a_1 and a_3 and Fig. 4-2-3 shows a structural cross-section. The Tapis structure is an E-W trending anticline which is transected by several faults trending N-S or NNW-SSE. Two of the faults cross the anticlinal high completely, dividing into the central (A) block drilled by well Nos.1 and 3, the east (B) block drilled by well Nos.2 and 4, and the west, undrilled block.

The crestal part of A block seems very flat, through seismic reflections being obscure, and is

Block A includes Well Nos.1 and 3, and Block B includes Well Nos.2 and 4.

Main productive zones for Block A are a_3 and a_5, while in Block B, those are a_3, a_4 and a_5. In both blocks, the shale develops in the reservoir in the crestal area, and the reservoir characteristics are comparatively poor. Oil zone resistivity is not so high, while good productivity is observed by production tests.

As no gas oil contact has been drilled through by existing wells, the contact was estimated by conventional pressure traverse relation as illustrated on Fig. 4-3-2. Rock and fluid properties required for performance calculation are tabulated on Table 4-3-1 - 5.

As remarkable reservoir heterogeneity is estimated to exist even in the confirmed area, the hydrocarbon in place should be reevaluated by confirming reservoir characteristics, and reservoir continuity and transmissibility should be checked again by the production tests.

Main displacement mechanism is supposed to be solution gas and cap gas expansion with little drilled by well No.1 on the highest point. This anticline is asymmetric with dips of 10 or 12 degrees on the north limb and of 25 degrees on the south limb in the reservoir horizons. A and B blocks, separated by a 150 ft throw fault with A block throwndown, can be regarded as probably different structures as to the hydrocarbon accumulations.

[Seismic Interpretation]

A mapped horizon was the top of J. Quality of reflections of the horizon is fair in the marginal area of the structure, but poor in the crestal part and in surroundings of faults. Well shooting data of Tapis Nos.2, 3 and 4 were available. Interpretation result and representative seismic section are shown in Fig. 4-1-1 and Fig. 4-1-2.

3.4.2 Reservoir Analysis

The reservoir extent was interpreted to be huge, while the reservoir heterogeneity was supposed to be prevailing. Net oil thickness was interpreted to be comparatively poor. Only four wells have been drilled so far. The productive area is divided into two Blocks by the fault, that are A and B, where effect by edge water, but more information is required to confirm the fact.

Performance prediction was made tentatively for individual productive zones for the natural depletion case, and the results are illustrated on Fig. 4-3-1 for field total and tabulated on Tables 4-3-6 - 10.

Recommendable initial oil production rates for the individual zones were estimated as follows.

Zone Name	Initial Oil Prod. Rate (MSTB/D)	Oil Gravity (°API)
A3 (A-Block)	20.0	45.4
A5 (A-Block)	8.0	45.4
A3 (B-Block)	6.5	45.4
A4 (B-Block)	13.0	45.4
A5 (B-Block)	6.75	45.4
	54.25	

It is still premature to think about secondary recovery planning for this reservoir as the hydrocarbon in place and oil displacement mechanism are still not confirmed yet, therefore general discussion is made here.

First of all, the reservoir pressure is supposed to be decreasing rapidly due to poor reservoir transmissibility. Especially in the crestal area, the reservoir pressure is difficult to be maintained at higher level as the distance to aquifer area is long enough and the reservoir transmissibility seems to be poor.

Gas cap expansion also is thought to be insufficient to maintain this huge area. Therefore, time will come when additional energy is required to produce oil.

The methods that can be thought of at current stage to maintain reservoir pressure are gas injection into crestal area and water injection into the aquifer.

In order to establish the most efficient development schedule, the followings are required to be conducted.

(1) to evaluate productivity of individual zones at the time of well completion,

(2) to obtain detailed special core and fluid analysis for representative core and fluid sample,

(3) to conduct reservoir base periodical pressure survey and to evaluated productivity of oil and gas for individual zones once production started.

Sufficient field data should be collected before conducting feasibility study on the secondary recovery by observing actual field performance.

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. 4-3-3 - 7.

4. POTENTIAL FIELDS

4.1 Peta Field

4.1.1 Geology

The Peta field proved a slight occurrence of gas zones (zone b) below a 5000 ft depth in an alternation of sand and shale beds less than 20 ft thick each presumably of turbiditic origin.

The Peta structure is an ENE-WSW trending anticline. Many normal faults trending N-S or NNW-SSE are found, but all of them do not traverse the anticline completely. The anticline is asymmetric with the north flank dipping at 5 degrees and the south at 13 degrees in the horizon of zone a_3, as shown in Fig. 5-2-1. Well No.1 is drilled on the south flank near the anticlinal crest. Although well No.1 was water bearing in zone a, it is pointed out that the east block is structurally higher than the area of well No.1.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone a_3. Quality of reflections associated with the target horizon is fair except in the southern flank of the structure. Correlation of reflections across faults is partly possible, but mostly difficult. Well velocity survey results of Peta No.1 were available. Interpretation result and representative seismic section are shown in Fig. 5-1-1 and Fig. 5-1-2.

4.1.2 Reservoir Analysis

Hydrocarbon showings are observed in the interval from the depth of 3190 ft to 4300 ft s.s. at the location of Well No.1, however, water saturation obtained from log analysis exceed more than 70 per cents except for a part of zone b. Proved oil reserves for zone b is also not so much, as listed on Table 1-1-2. The field is subdivided into several blocks by faults and exploration wells are required for the crestal part of central block.

The field has so many unconfirmed area, for which more exploratory works are required. The gas zone detected at Well No.1 has still some possibility to be gas cap of oil zone. Exploration for unconfirmed central block is also required.

4.2 Belumut Field

4.2.1 Geology

The Belumut structure has been drilled by two wells, the both of which reached the basement granitic rocks probably of Cretaceous in age. Sedimentary sections from the basement up to Group J consist of clastic sediments which are so sandstone predominant that Trengganu Shale does not occur or is poorly developed. Hydrocarbon reservoirs are very fine grained sandstones found in an interval 2000 ft from the basement. Well No.1 was dry but Well No.2 discovered gas accumulations.

Fig. 6-2-1 shows a structural map of zone a_1 and Fig. 6-2-2 a structural cross-section. The structure is an east-west trending, very gentle anticline of which central part is crossed by a NE-SW striking fault to divide into two areas. This fault is normal with a 500 to 650 ft throw. The east, upthrown, half of the structure was drilled by well No.2 and the west, downthrown, half was drilled by well No.1.

[Seismic Interpretation]

An interpreted horizon was the top of zone a_1. Data quality of the target horizon is fair to poor. Correlation of reflections across faults is partly possible. Well shooting data of Belumut Nos.1 and 2 were available. Interpretation result and representative seismic section are shown in Fig. 6-1-1 and Fig. 6-1-2.

4.2.2 Reservoir Analysis

Oil is confirmed to exist in zone b of eastern side of the fault crossing NE to SW. In this block hydrocarbon showings are detected in the interval from the depth of 2923 ft to 4596 ft BDF. According to the log analysis, however, the interval is estimated to have high water saturation except for zone a_1 and b_2.

Four production tests have been conducted. PT No.4 was made for gas cap or gas zone and PT No.1 to 3 were for oil zone. Water cut for PT No.2 and 4 is comparatively high and oil water contact is supposed to be close to the tested interval. It is not possible to define reservoir limit only by one well especially for this type of reservoir which has extremely flat structure.

The first requisite is to confirm how the zone develops over the eastern part of the structure. As the field seems to have quite flat structure, wide reservoir extent can be anticipated.

4.3 Angsi Field

4.3.1 Geology

The Angsi structure is a NW-SE elongate dome-like anticline which is seemingly unfaulted (Figs. 7-2-1, 2). Well No.1 was drilled on the crestal part of the structure. Zone b underlying Trengganu Shale is oil bearing sandstones, argillaceous in general and less than 60 feet thick.

[Seismic Interpretation]

A target horizon of the seismic interpretation was near the top of zone b. Quality of reflections associated with the horizon is fair to poor, but generally poor. Well shooting data of Angsi No.1 was available. Interpretation result and representative seismic section are shown in Fig. 7-1-1 and Fig. 7-1-2.

4.3.2 Reservoir Analysis

At the location of Well No.1 drilled in the crestal area, oil is found in the interval from

7885 ft to 8980 ft BDF but log analysis results show very poor porosity. Although production tests have been conducted for zone b_1 and b_2, the productivity is considered to be extremely low.

Appraisable wells are required to be drilled in the flank of the structure to confirm whether the poor reservoir characteristics is limited to crestal area or not.

4.4 Besar Field

4.4.1 Geology

The Besar structure is a WNW-ESE trending anticline partly transected by several NNW-SSE striking normal faults (Figs. 8-2-1, 2). Well No.1 was drilled a little down on the crestal part and proved the gas occurrence in sandstones of zone b. Main reservoir is zone b_1 which is a total 200 ft sand-shale alternation including eight sandstone beds 5 to 15 ft in thickness.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone b_1. Data quality of the target horizon is fair in the marginal area of the structure, but poor in the crestal part and in surroundings of faults. Correlation of reflections across faults is difficult. Well velocity survey data of Besar No.1 was available. Interpretation result and representative seismic section are shown in Fig. 8-1-1 and Fig. 8-1-2.

4.4.2 Reservoir Analysis

Main reservoir is thought to be the upper part of zone b where gas and gas condensate are found.

There remains some possibility of the gas zone to be gas cap of oil reservoir, and exploratory works are required. Data of one well are not sufficient to define the reservoir.

4.5 Jerneh Field

4.5.1 Geology

The Jerneh field proved the occurrence of many gas bearing zones in an anticline. The anticline is approximately east-west elongated and is traversed by a NE-SW trending normal fault at the northeastern end (Fig. 9-2-1).

Pliocene sandstone beds occurring from 4000 to 7000 ft in depth compose reservoirs named as zones

$a_1 - {}_3$, b, and $c_1 - {}_5$ (Table 9-2-1). This formation is interpreted to be marsh to lagoonal sediments in the transition from regression to transgression. Reservoir sandstones have generally good continuity and a maximum thickness of 150 ft. Especially, zone c_1, Jerneh sandstone, consists of fine grained sandstone which is well developed with an average thickness of 138 ft and an average effective porosity of 25%. Zones c_2 through c_5 are composed of sandstones 20 to 70 ft thick which have large lateral variations in lithology.

[Seismic Interpretation]

An interpreted horizon was the top of zone c_1. In general, quality of reflections arising from the horizon is fair to good, but partly a little poor. Correlation of reflections across a fault is relatively easy. Well velocity survey data of Jerneh No.1A was used for time-depth conversion. Interpretation result and representative seismic section are shown in Fig. 9-1-1 and Fig. 9-1-2.

4.5.2 Reservoir Analysis

Many gas zones are detected in the interval from 4000 to 6600 ft BDF, and zone c_1 (Jerneh sand) was interpreted to be the main productive zone in this field.

Three wells have been drilled in the proper location to delineate the reservoir. Estimated original gas in place is 5640 MMMSCF.

One production test was conducted at Well No.1 and high gas productivity was confirmed in zone c_1. In this zone, gas water contact has not been drilled through. At the location of Well No.2, the zone is completely water wet, while in Well No.3, the zone is gas bearing.

The estimation of the gas water contact for the zone was made by the pressure traverse of the three wells and the contact was determined to be 5780 ft S.S.D. The contacts for the other zones were directly obtained from the log analysis except for zones c_4 and c_5.

Production test is recommended to be conducted for all the gas bearing zones. At present it is still unknown whether all the gas zones except for zone c_1 are highly productive or not.

Tentative development schedule for zone c_1 is made in this report based on the estimated proved original gas in place. However, confirmation is required as to the productivity of the upper and the lower layers of zone c_1 together with the existence of gas field near by, and decision should be made whether Jerneh field should be developed by itself or in combination with the other fields.

Bintang field is located in the convenient place to be jointly developed with Jerneh field, but the reservoir characteristics and gas productivity of the field have not been confirmed yet. No exploratory well has been drilled in the vicinity of Jerneh field.

The production schedule of 230 MMSCF/D and its production facilities design as described in Part B, are just tentative ones, which should be revised when additional information become available.

4.6 Pilong Field

4.6.1 Geology

The Pilong structure was proved gas bearing at well No.1 in Pliocene sandstones. The interval from 3700 to 9000 ft consists of sandstones and mudstones with intervening coal beds. Reservoir sandstones are selected as zones $a_1 - {}_3$ and $b_1 - {}_7$ (Table

10-2-1). The sandstones are very fine grained and friable or unlithified.

As shown in Fig. 10-2-1, a system of approximately N-S trending normal faults is developed in this area. Well No.1 was drilled on one of such fault blocks. Other undrilled blocks which form closures are also found in the figure.

[Seismic Interpretation]

An interpreted horizon was the top of zone b_1. Quality of reflections of the horizon is generally poor. In this structure many faults running roughly east-west are recognized in the seismic sections. Correlation of reflections across the faults is partly possible, but mostly difficult. Well shooting data of Pilong No.1 was available. Interpretation result and representative seismic section are shown in Fig. 10-1-1 and Fig. 10-1-2.

4.6.2 Reservoir Analysis

One well is drilled in the crestal area. In the interval from 3760 ft to 8690 ft BDF, partial gas accumulation is observed. Oil and gas are found in the interval from 5762 ft to 5785 ft BDF with gas oil contact at 5770 ft BDF. The oil zone is only 8 ft with aquifer below. The reservoir is interpreted to be highly limited.

Gas zones are scattered widely in zone a and b, and gas water contact are not confirmed yet except for a part of zone a. Additional exploratory wells are required, of course, to define the reservoir, however, the field is not much prospective.

4.7 Bintang Field

4.7.1 Geology

In the Bintang field hydrocarbons are accumulated in deltaic sediments of Pliocene age. Gas reservoirs are sandstones of a maximum thickness of 70 ft found below 4000 ft and have very poor continuity because of a large facies change for all zones.

As structural maps of zones a and b_4 are shown in Figs. 11-2-1, 2 and a cross-section in Fig. 11-2-3 the orientation of the structural high is not obvious but N-S trending faults are developed very evidently.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone b_4. Generally, quality of reflections associated with the horizon is fair, but partly poor. Correlation of reflections across faults is mostly possible. Well shooting data of Bintang Nos. 2 and 3 were used for time-depth conversion. Interpretation result and representative seismic section are shown in Fig. 11-1-1 and Fig. 11-1-2.

4.7.2 Reservoir Analysis

Original gas in place calculated by volumetric method is 2025 MMMSCF.

Production tests have been conducted for many intervals at Well No.2. Among the tested intervals, zones b_1 and b_2 have comparatively high productivities.

At the location of Well No.3 which was drilled in the crestal area, all the sand zones are completely wet.

Recommended is to drill the exploratory well in the location between Well No.2 and No.3 for the purpose of confirming the reservoir limit. Simultaneously productivity data and pressure continuity information should be collected by the production test.

Based on this information, decision should be made whether appraisal wells are additionally required or not.

Judging from the large facies change and probable poor reservoir continuity, more exploratory wells are required.

4.8 Sepat Field

4.8.1 Geology

In the Sepat field gas was found in Pliocene sediments between 3000 and 6000 ft and reservoirs are very fine grained sandstones of 10 to 90 ft in thickness. Fig. 12-2-1 gives a structure contour map of gas zone a_5, and Fig. 12-2-2 a structural cross-section. The structure is an E-W trending anticline of which east-sided crestal part was drilled by well No.1.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone a_5. Data quality of the interpreted horizon is fair to poor, but generally poor. Good reflections are seen at much lower levels. Well shooting data of Sepat No.1 was available.

Interpretation result and representative seismic section are shown in Fig. 12-1-1 and Fig. 12-1-2.

4.8.2 Reservoir Analysis

Total 40 ft of net gas column is found in the interval from 4173 ft to 4588 ft BDF. However, priority for the field exploration is extremely low judging from high water saturation even in the crestal location.

Additional exploratory walls are required, of course, to define the reservoir, however, the field is not prospective.

4.9 Bujang Field

4.9.1 Geology

In the Bujang field, Pliocene sediments between 3000 and 6000 ft contain gas accumulations in fine grained sandstones intercalated with thin coal beds. Reservoirs have thicknesses less than 100 ft and are muddy in general. Figs. 13-2-1, 2 show structure maps of zones a_1 and b_2, and Fig. 13-2-3 shows a structural cross-section. The structure is a roughly circular high with a significantly flat top where well No.1 was drilled. There is the occurrence of a few faults trending ENE-WSE.

[Seismic Interpretation]

An interpreted horizon was the top of zone a_1. Quality of reflections from the interpreted horizon is poor in the crestal part and eastern part of the structure, but it is fair in the other part. Correlation of reflections across faults is partly possible, but mostly difficult. Since no well shooting data was available in this field, time-depth curve was constructed from the sonic log of Bujang No.1. Interpretation result and representative seismic section are shown in Fig. 13-1-1 and Fig. 13-1-2.

4.9.2 Reservoir Analysis

At the location of Well No.1 drilled in the crestal area, gas accumulation is found in the sands from the depth of 4000 ft to 5220 ft BDF. Individual zones, however, have gas water contact and gas in place is estimated to be very small. Additional exploratory work is not recommendable.

4.10 Sotong Field

4.10.1 Geology

The Sotong structure has been drilled by 6 wells, all of which penetrated probably to the basement rocks of Paleogene and Jurassic ages. Hydrocarbons are trapped in Tapis Sandstone below Trengganu Shale, where ten zones are picked up as a_1 - a_{10} (Table 14-2-1). Zone a_2 is a main reservoir of the field and is considered as a channel-fill sand which probably has a limited distribution only in an area drilled by well Nos.1 and 3 (A block). All other reservoir sandstones indicate very intense variations in rock facies to die out laterally and to give a very irregular distribution of hydrocarbon bearing zones.

Geochemical analyses have been carried out on samples from a few wells and the results of well No.1 for which the analysis was made most extensively are summarized as follows. The Pliocene unconformity at the Sotong location is about 3000 ft deep and the overlying sediments are organically immature and have the ability to source only limited amounts of gas. The section down to 7150 ft contains sediments sufficiently rich to realise their potential as source rocks. The interval 3000 to 6500 ft falls in the gas zone and that 6500 to 7150 ft is a transition zone within which the sediments have a potential for gas with oil. The lignite-coaly beds should be particularly good gas sources. The sediments below 7150 ft, i.e., below Trengganu Shale, and down to 9030 ft are in the oil with gas zone but have fairly low organic carbon contents. The basement rocks of limestone have very low organic carbon contents and fall within the zone of destruction of the oil source rock potential.

Structure maps of the Sotong field in zones a_2 and a_4 are shown in Figs. 14-2-1, 2 and a structural cross-section through well No.4 and well No.6 is shown in Fig.14-2-3. The structure is a gentle anticlinal high trending NNW-SSE. Well No.4 was off structure and well No.6 is drilled at the northern edge of the structure. The anticline is traversed in the central part by a WNW-ESE trending normal fault and on the northeast side by a NNW-SSE trending one. It is regarded, therefore, that the structure comprises three areas, named as A block (well Nos.1, 3), B block (well No.2), and C block (well No.5).

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone a_4. Quality of reflections arising from the target horizon is fair to poor, but generally poor. In addition, the continuity of reflections is also poor. Since correlation of reflections across faults is difficult, identification of reflection with gaslogical horizon was made based on well data in each fault block. Well shooting data of 6 wells (Sotong Nos.1 thru 6) were available. Interpretation result and representative seismic section are shown in Fig. 14-1-1 and Fig. 14-1-2.

4.10.2 Reservoir Analysis

Productive area for this field is divided by the faults into three blocks, which are A, B and C. Wells No.1 and 3 belong to A, No.2 to B and No.5 to C.

Detailed drill stem tests have been made for each productive zones of individual blocks and their productivities were confirmed through the tests.

Although the productivities of the tested intervals are comparatively high, the estimated original oil in place is not so big as listed on Table A-2.

In this field, zone a_2 in Block A is the main productive zone. The gross sand thickness of the zone is more than 100 ft, with the following fluid levels.

gas oil contact	7104 ft s.s.
oil water contact	7139 ft s.s.

The oil displacement energy for this reservoir is the combination of gas cap expansion and bottom water drive.

Among the other zones, zone a_3 at the location of Well No.1 has comparatively high productivity (27 B/D/psi) and production rate of 2570 STB/D was confirmed, while at the location of Well No.3 the zone has poor reservoir characteristics due to the shale development in the sand, and no fluid level was confirmed.

Based on the currently available information, reservoir performance calculation was made for zone a_2 of Block A. In this reservoir, production is to be made from 35 ft oil sand between gas zone and acquifer, and the gas and water coning problems will be encountered. Computation is made for ideal case of refraining gas and water production, and the predicted results are tabulated on Table 14-3-4 - 6. The reservoir parameters used in this calculation are summarized on Table 14-3-1 - 3. Even in this ideal case, high producing gas oil ratio is anticipated.

For the other zones, the summation of proved and probable oil reserves are 113.2 MMSTB. In addition to the above value, there exist hydrocarbons, which can not be defined to be oil or gas. The volume was estimated to be 221.56 MMBBL under the reservoir condition.

Sample calculation was made for gross estimate of probable future performance for the two cases, assuming all hydrocarbons to be gas and oil.

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. 14-3-1 - 3.

Although performance prediction was made based on the several assumption, it is not recommended here to develop the field right now from view-point of gas utilization. As described in the sample calculation, the reservoir will have high producing gas oil ratio, while injection of associated gas into gas cap zone is not suitable at all, judging from the type of the reservoir, and the volume of gas is not sufficient enough for planning some gas utilization project.

The field should be developed together with adjacent gas fields, especially with Duyong field which has possibility of being big gas reservoir.

4.11 Duyong Field

4.11.1 Geology

Sandstone reservoirs just above and below Trengganu Shale were discriminated as zones a and b (Table 15-2-1). Zones a_1 and a_2 are in good continuity, 26 - 30 ft and 30 - 50 ft in thickness, respectively. Sandstones of zones b_1 - b_5 have generally poor continuity; zone b_1 is of two sand beds in well No.1, a single muddy sandstone in well No.2, but die out in well No.3; also zone b_2 shows much lateral change in lithology to coalesce and separate sand bodies; zone b_3 is muddy in well No.1, and zones b_4 and b_5 are thin with a thickness of some 20 ft.

A study has been carried out on the source rock potential and the thermal maturity of sediments for samples of the well No.2 section. The interval 5500 to 6370 feet is considered to be mature to give rise to oil and gas, or oil alone, accumulations which could be commercial in case there were good source-trap situations. The potential of major oil accumulation is low in view of a very low average organic carbon content. But coal encountered in this interval could represent a prolific gas source. The interval 7100 to 8268 feet is mature but from 7600 feet falls in the oil phase-out zone. Throughout this lower interval it has been concluded that major accumulations will not occur because of a low average organic carbon content. It must be noted, however, that mudstones at 7100 - 7150 feet contain unusually high hydrocarbon contents of which 50% are alkanes and if this mudstone occurred more frequently or occurred within a very extensive geological structure the possibility of a major hydrocarbon accumulation becomes possible.

A structure map of zone b_2 is shown in Fig. 15-2-1 and a structural cross-section in Fig. 15-2-2. Well No.1 is drilled on the crest and well Nos.2 and 3 are midway and down on the south flank, respectively. The Duyong structure is of a large scale with a closure more than 1400 ft high and more than 20 km across. A fault is suggested to limit the west side of the field, trending NNW-SSW.

[Seismic Interpretation]

An interpreted horizon was near the top of zone b_5. Quality of reflections from the target horizon is fair to good, but partly poor in Exxon's area. Well shooting data of Duyong Nos.1, 2 and 3 were available. Interpretation result and representative seismic section are shown in Fig. 15-1-1 and Fig. 15-1-2.

Duyong structure extends over from CONOCO's area to Exxon's area. And some Exxon's seismic lines have been prolonged to CONOCO's area. The shotpoint locations of these lines in CONOCO's map do not coincide with those in Exxon's map. Therefore, CONOCO's area was interpreted without Exxon's seismic sections. After interpreting both areas separately, the results were combined.

4.11.2 Reservoir Analysis

Based on the geological correlation study, the results of drill stem tests and FITs are tabulated on Table 15-2-2.

According to the table, the pressure continuity comes into question. The pressure gradients between the adjacent wells are quite unreasonable. In addition to this fact, gravity of the fluid sample from the well in shallower location in the same zone is slightly heavier than that of from the deeper location, which suggests no pressure communication among the wells.

However, the problem should be reviewed from the reasons described hereunder.

First of all, the reliability and accuracy of pressure gauge should be checked. The pressure gauge usually used for drill stem test is stout enough against several type of shocks at the time of field operation. When it comes to accuracy, however, accuracy is poor. Wide pressure range gauge is also usually used in such high pressure zone like this field, which inevitably decreases the accuracy.

The characteristics of bottom hole sample also depend on the sampling conditions, which are flow condition at the time of sampling, well cleaning status and preserving ways of the sample.

Therefore, it is not proper to make pessimistic decision as to the reservoir continuity.

There is uncertainty as to the pressure communication through the reservoir as stated before.

However, the field is expected to have huge areal extent, and more exploratory works are required to define the reservoir.

Three wells are recommended to be drilled additionally for the further exploration purpose. The coordinates of locations for the wells are as follows.

Well No.4	E520000	N554000
No.5	E529000	N553000
No.6	E534000	N555000

Production test should be conducted for the representative zones of individual wells and the pressure build up data should be collected. Bottom hole sample data are helpful to determine the distribution of fluid characteristics.

4.12 Anding Field

4.12.1 Geology

The Anding field is the southernmost of the sixteen fields, located 20 km southeast of the Sotong Field. Below Trengganu Shale sandstones are developed which are hydrocarbon bearing and were discriminated as zones a and b (Table 16-2-1). As in the

Sotong field, zone a sandstones are considered to have deposited in deltaic environments and are muddy as well as in a large lithologic variation. Sandstones of zone b has uncertain continuity probably because of being close to the basement, and lies as a single bed 20 ft thick in well No.1 but is recognized as muddy sand interbedded with shale, 10 ft thick each.

A geochemical analysis has been made with the narrow sample spacing for the well No.1 section. The well section is generally organically lean and the character of the organic matter seems unsuitable for major oil generation. Olive grey clays down to 3540 feet would be predicted to be immature but have been affected by oil-like hydrocarbons from down-dip into some parts. The only interval which is rich to provide oil in commercial amounts is from 3900 to 4680 feet but as it is probably prospective for gas, it could have the potential for major oil generation by an additional burial of more than 1000 or 1500 feet. From 4680 to 8090 feet the sediments become leaner with depth with organic carbon contents less than 1%. In addition the type of organic matter present in this interval is unfavourable for major oil generation, in spite of being within the oil-prone mature zone.

A structural map of zone a_2 is shown in Fig. 16-2-1 and a north-south cross-section in Fig. 16-2-2. In the horizons of zone a, well No.1 is structurally lower than well No.2 where a closure 2 km long and 1 km wide is found. However, the basement rocks of Jurassic age are reached in well No.1 at a depth 240 ft higher than in well No.2 and accordingly oil zone b is shallower in well No.1 than in well No.2.

[Seismic Interpretation]

A target horizon of the seismic interpretation was the top of zone a_2. Only seismic sections processed by Petty-Ray were used for the interpretation, because the other seismic sections have much poorer quality. Quality of reflections associated with the target horizon is fair to poor. Well shooting data of Anding Nos.1 and 2 were available. Interpretation result and representative seismic section are shown in Fig. 16-1-1 and Fig. 16-1-2.

4.12.2 Reservoir Analysis

From drill stem test results conducted at Well No.2 drilled at the crestal part of the reservoir, productive zone was interpreted to be zones a_1 to a_5. Zone a_1 has 10 ft net thickness and oil productive, while zones a_2 to a_5 produce gas/gas condensate.

Among these five zones, the thinnest one is zone a_3 with only 8 ft net thickness. Except for this a_3, oil/gas water contacts for all the other zones are confirmed. Even for zone a_3, high water cut is observed during the short time of drill stem test at Well No.2. The actual water level, therefore, is estimated to be close to the confirmed level.

Judging from the fact that all the five sands are non-productive at Well No.1, the reservoir extents are limited to the surrounding area of Well No.2. Estimated reserves are tabulated on Table A-2.

The reservoir has small extent with proved reserves of 4.35 MMMSCF. No additional exploratory work is required. The field is recommended to be developed in connection with the high productive field.

5. CONCLUSIONS AND RECOMMENDATIONS

1. Bekok, Pulai, Seligi and Tapis fields fall into the category of "the fields for development" in the short term development schedule.

2. Combined fields development was recommended for Bekok, Pulai and Seligi fields, while Tapis field was recommended to be developed independently from the other fields.

3. The recommendable maximum daily production rates at the initial stage for the individual fields were estimated as follows.

Bekok field	60	MSTB/D
Pulai field	12.9	
Seligi (A) field	15	
(B) field	21	
Tapis field	54.75	

There are uncertain factors in estimating original hydrocarbon in places for Seligi (B) and Tapis fields. Reevaluation should be made when additional data become available.

4. Restricted gas production case was applied for Bekok field from the view point of associated gas utilization. The average rate of 150 MMSCF/D was estimated to be produced from Bekok-Pulai fields.

5. Duyong field will play an important role in establishing the combined fields development for Sotong, Duyong and Anding fields. Additional three exploratory wells were recommended to be drilled in the Duyong field for obtaining reservoir continuity information. Producing gas oil ratio for Sotong field was estimated to be high from the early depletion stage and combined fields development with the other gas fields will be the most recommendable development ways.

6. Jerneh field was estimated to have the biggest gas in place among the fields in the northern part of the Peninsular Malaysia Area. Judging from the costs required for the gas handling facilities, decision should be made whether the field is to be developed independently from or jointly with the other fields by conducting more exploratory works. Bintang field is located in a favorable location to be jointly developed with Jerneh field, however, no data has been collected so far as to gas productivities. Production Test for the other zones than the Jerneh sand has not been conducted so far and production test is also required for them. Gas production schedule was tentatively established for the development of Jerneh sand in this report.

Followings are recommended in the actual field operation.

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

The data are indispendable for establishing the most effective secondary recovery method, to say nothing of the performance prediction.

(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 conditions (the separator pressure and temperature) and resultantly increase recoverable oil.

Analysis for the separator liquid together with liberated gas is indispensable 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 chokes 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) At current stage, it is not possible to estimate quantitatively water drive or oil displacement mechanism.

It is indispensable to observe the field average rservoir pressure periodically and the analysis is required for the pressure performance in relation to the cumulative produced oil and gas.

(5) It is still premature to mention about the secondary recovery techniques to be applied in future, however, following data syould be collected in the early depletion stages.

(a) Special core analysis

(b) Special fluid analysis

(c) Pressure performance

(d) Water source or gas availability

PART B SURFACE FACILITIES

1. PROPOSED FACILITIES

There are many offshore oil and gas fields scattered in the east of Peninsular Malaysia. Among these fields the following fields classified into four categories were selected as the objective fields for this study, in accordance with the results of the reservoir study.

- Bekok, Pulai and Seligi for combined development oil fields
- Tapis for individual development oil field
- Bekok and Pulai for combined gas utilization fields
- Tapis and Jerneh for individual gas utilization fields.

The latter two categories are for gas utilization. Tapis and Jerneh fields are different from the other fields in the stage of exploration and so these fields are treated as those in different category. This is the reason why these two fields are not considered for the possibility of combined production system with other fields. Therefore, this possibility is to be studied when the exploration stage for the fields advances in future. It should be noted that the conceptual design for these fields is tentative one based on the design bases with lower grade of informations than those for the other fields and so only facilities arrangements have been prepared for reference.

1.1 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.

1.1.1 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)
Bekok	234
Pulai	245
Seligi	248
Tapis	225
Jerneh	205

(4) Soil Data at Sea Bed

The soil character under offshore structures is taken into consideration in the conceptual design in accordance with the soil data received from Petronas. For the offshore structures, typical soil data considered to be average are tentatively used.

1.1.2 Assumed Design Conditions

(1) Gas Utilization

Gas utilization case for Bekok and Pulai fields has been studied to supply 150 MMSCFD gas for 20 years to power plant(s) and a fertilizer plant. Battery limit is the shore line near Dungun 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

1.1.3 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 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

A 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.

1.2 Conceptual Design

1.2.1 Bekok, Pulai and Seligi Fields

(1) Design Bases

1) Oil Production Rate and Number of Wells

Field	Oil Production Rate (BPD)	No. of Wells
Bekok	60,000	30
Seligi 'A'	15,000	8
'B'	21,000	11
Pulai	15,000	8

2) Fluid Property

Field	API Gravity	Viscosity (60°F) cp	Max. GOR (SCF/STB)
Bekok	47	3	1,500
Seligi	45	4	800
Pulai	42	5	300

3) Consideration for Gas Injection Facilities

At this stage it is difficult to determine the future requirement of gas injection for the pressure maintenance. However, there might be a possibility of gas injection for Bekok field in course of crude production.

The deck space for gas injection compressors, slots of wells, etc. on Production Platform is considered for use in future.

(2) Conceptual Design

Location of Bekok, Pulai and Seligi fields is shown in Fig. 30-9-1. Bekok field which will become a base for the operation and maintenance of these fields is located approximately 144 miles away to the east from Dungun area.

For designing the combined development plan of fields in offshore Peninsular area, the following case setting has been adopted taking into consideration results of reservoir study, geographical location, economics and operation, after screening other alternatives which were considered obviously pessimistic.

In each case, conceptual design of production facilities has been performed and investment and operating costs have been estimated based on the unit costs so that input data for economic analysis could be prepared to select an optimum alternative for this oil production scheme.

1) Case Setting

The following four cases were selected as alternative development plans for these three fields. Major difference of production systems is that of loading system.

a. Case IA - Bekok, Pulai and Seligi (A, B), Offshore Storage Case

This is the case of floating storage with tanker loading facilities in Bekok field. Objective fields for this case are as follows:

- Bekok
- Seligi 'A' Block and 'B' Block
- Pulai

The crude oil produced at each field will be pumped to Bekok central field after oil and gas separation. The oil, then, will be stored in an Offshore Storage Barge which will be moored in Bekok field and connected with one of Well Production Platforms by a submarine pipeline. The crude will be loaded to a visiting tanker by means of SALM. Facilities arrangement and block flow diagram are shown in Fig. 17-5-1 and Fig. 17-5-2 respectively.

b. Case IB - Bekok, Pulai and Seligi (A, B),
Onshore Terminal Case

This is the case to install a pipeline to shore where conventional onshore storage will be adopted with conventional loading facilities using SBM. The objective fields for this case are as follows:

- Bekok
- Seligi 'A' Block and 'B' Block
- Pulai

The crude oil produced at the above fields will be gathered to Bekok central field after oil and gas separation. Then the oil will be transported to an onshore terminal in Dungun area, and will be loaded to a visiting tanker by means of SBM. Facilities arrangement and block flow diagram are shown in Fig. 17-5-3 and Fig. 17-5-4 respectively.

c. Case II - Bekok, Pulai and Seligi (A),
Offshore Storage Case

This case is almost the same as Case IA except for objective fields. The objective fields for this case are as follows:

- Bekok
- Seligi 'A' Block
- Pulai

Facilities arrangement and block flow diagram are shown in Fig. 17-5-5 and Fig. 17-5-6 respectively.

d. Case III - Bekok and Pulai, Offshore Storage Case

This case is nearly the same as Case IA except for objective fields. The objective fields for this case are as follows:

- Bekok
- Pulai

Facilities arrangement and block flow diagram are shown in Fig. 17-5-7 and Fig. 17-5-8 respectively.

2) Facilities Description

The selection of a suitable case among all alternatives had to be made after obtaining the results of economic evaluation, as the capital investment costs, operating costs and crude oil production rates are different for each case and so the simple comparison of capital investment is not suitable for the selection of an optimum case. Estimates of capital investment and operating costs were carried out for all of the alternative cases and the economic evaluation was performed as described in Part C.

As the result of the economic analysis, Case IA is the most profitable. So the field facilities are described below for this case which also covers the field facilities for all fields.

a. Case IA - Bekok, Pulai and Seligi (A, B),
Offshore Storage Case

Crude oil production system in these three fields consists of the following facilities;

Bekok Field

1 ... 6-leg Riser Platform	BER-A
1 ... 8-leg Well Platform	BEW-A
1 ... 8-leg Production Platform	BEP-A
1 ... 8-leg Well and Production Platform	BEWP-A
2 ... 3-leg Flare Jacket	BEV-A & B
1 ... Offshore Storage and Loading Facilities	
Submarine Pipelines	

Seligi Field

2 ... 8-leg Well and Production Platform	SEWP-A & B
2 ... 3-leg Flare Jacket	SEV-A & B
Submarine Pipelines	

Pulai Field

1 ...	8-leg Well and Production Platform	PUWP-A
1 ...	3-leg Flare Jacket	PUV-A

Submarine Pipelines

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

(i) Bekok Field

(a) 6-leg Riser Platform

A 6-leg Riser Platform (BER-A) will be located next to the Production Platform. It will be equipped with sphere receivers, launchers and the related facilities which are required for pigging operation of incoming and outgoing oil and gas lines.

(b) 8-leg Well Platform

The Well Platform (BEW-A) will be an 8-leg, 20-slot design. It will be connected to Compressor Platform with a permanent bridge. It will support one drilling rig, living quarters and utilities facility. It will be to drill 15 wells for crude oil and 2 wells for free gas production. Two slots could be used for gas injection wells which might be required in future. The wells for free gas production is explained in the subsequent article of this report. Typical plan and elevation is shown in Fig. 30-5-17.

(c) 8-leg Production Platform

The Production Platform (BEP-A) will be an 8-leg structure. It will accommodate the crude oil production facilities for 30,000 BPD capacity. The space for compressors for possible gas injection scheme is prepared on its deck. The well stream from the Well Platform will be piped to this platform for gas separation and pumped to an Offshore Storage Barge by way of the Riser Platform where all crudes from other fields will be gathered and mixed. 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. 30-5-14 respectively.

(d) 8-leg Well and Production Platform

The Well and Production Platform (BEWP-A) will be installed to drill wells and to produce crude oil. It will be an 8-leg, self-contained structure with a removable drilling rig and its related facilities. It will also accommodate the crude oil production facilities for 30,000 BPD handling capacity. The crude oil after gas separation will be pumped and transported through a submarine pipeline to the Riser Platform. The 6" submarine pipeline will be installed between this platform and the Riser Platform. 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. 30-5-18 respectively.

(e) 3-leg Flare Jacket

Two 3-leg Flare Jackets (BEV-A and BEV-B) will be installed for flaring out the associated gas, and free gas in case of emergency. One jacket will be installed for BEP-A, and the other for BEWP-A.

(f) Offshore Storage and Loading Facilities

Offshore storage and loading facilities will consist of two SALMs and an Offshore Storage Barge. One SALM will serve for the floating storage vessel and the other for a visiting tanker. The Offshore Storage Barge with 1,400,000 bbls storage capacity will be moored to SALM at the water depth of 234'.

(ii) Seligi Field

(a) 8-leg Well and Production Platform

The Well and Production Platform (SEWP-A) will be installed at 'A' block area to drill wells and to produce crude oil. It will be an 8-leg, self-contained type structure with a removable rig and its related facilities. It has been designed to drill 8 wells. It will also accommodate the crude oil production facilities for 15,000 BPD handling capacity. The crude oil after gas separation will join with the crude from Pulai field on this structure. The oil, then, will be pumped and transported by the submarine pipeline to the Riser Platform in Bekok field. The 10" submarine pipeline will be installed from here to the Riser Platform. 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. 30-5-18 respectively.

(b) 8-leg Well and Production Platform

The Well and Production Platform (SEWP-B) will be installed at 'B' block area. It has been designed to drill 11 wells and to handle 21,000 BPD crude oil. The crude will be pumped and transported by 6" submarine pipeline to SEWP-A. 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. 30-5-18 respectively.

(c) 3-leg Flare Jacket

Two 3-leg Flare Jackets (SEV-A and SEV-B) will be installed in Seligi field to flare the associated gas. One jacket will be installed for SEWP-A, and the other for SEWP-B.

(iii) Pulai Field

(a) 8-leg Well and Production Platform

The Well and Production Platform (PUWP-A) will be installed to drill and to produce oil and gas.

It will be an 8-leg, self-contained type structure with a removable rig and its related facilities. It has been designed to drill 8 wells for crude oil and 2 wells for free gas production. It will also accommodate the crude oil production facilities for 15,000 BPD handling capacity, living quarters and utilities facility. After gas separation the oil will be pumped and transported to SEWP-A through 6" submarine pipeline. 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. 30-5-18 respectively.

(b) 3-leg Flare Jacket

A 3-leg Flare Jacket (PUV-A) will be installed adjacent to PUWP-A for flaring the associated gas, and free gas in case of emergency.

1.2.2 Tapis Oil Field

(1) Design Bases

1) Oil Production Rate and Number of Wells

Production Rate	:	55,000 BPD
Number of Wells	:	28 Wells

2) Assumed Oil Properties

Specific gravity of oil	:	40° API
Viscosity of oil	:	6 cp at 60°F
GOR	:	3,000 SCF/STB

3) Assumed Gas Properties

Specific gravity of gas	:	0.85 (Air = 1)
Viscosity of gas	:	0.009 cp at 60°F

(2) Conceptual Design

Location of Tapis oil field is shown in Fig. 30-9-1. The alternatives for the conceptual design for the development of Tapis oil field have been set up as described below.

1) Case Setting

a. Case IA - Offshore Storage Case

The crude oil will be stored in Offshore Storage Barge connected with one of Well and Production Platforms by a submarine pipeline. Facilities arrangement and block flow diagram are shown in Fig. 18-5-1 and Fig. 18-5-2 respectively.

b. Case IB - Onshore Terminal Case

The crude oil will be pumped to an onshore terminal in Dungun area, and will be loaded to a visiting tanker by means of SBM. Facilities arrangement and block flow diagram are shown in Fig. 18-5-3 and Fig. 18-5-4 respectively.

2) Facilities Description

The selection of the optimum case between two alternatives had to be made after obtaining the results of economic evaluation, as the capital investment costs and operating costs are different for each case and so the simple comparison of capital investment is not suitable for the selection of an optimum case. Therefore, estimates of capital investment and operating costs were carried out for two alternative cases and the economic evaluation was performed based on them as described in Part C.

As the result of the economic evaluation, Case IA is more profitable. Therefore, the facilities description will be made for this case and this will also cover the production facilities for both cases.

Crude oil production system in Case IA for Tapis field consists of the following facilities.

1 ...	8-leg Well and Production Platform	TAWP-A
2 ...	6-leg Well and Production Platform	TAWP-B & C
3 ...	3-leg Flare Jacket	TAV-A, B & C
1 ...	Offshore Storage and Loading Facilities	

Submarine Pipelines

Major equipment to be installed are tabulated with simple specification in Table 18-5-1.

a. 8-leg Well and Production Platform

The Well and Production Platform (TAWP-A) will be installed to drill wells and to produce crude oil. It will be an 8-leg, self-contained type structure with a removable drilling rig and its related facilities. It will also accommodate the crude oil production facilities with 25,000 BPD handling capacity, living quarters and utility facilities. 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. 30-5-18 respectively.

b. 6-leg Well and Production Platform

The Well and Production Platforms (TAWP-B and TAWP-C) will be installed to drill wells and to produce crude oil. It will be a 6-leg, tender type structure. It will support the crude oil production facilities with 15,000 BPD handling capacity. Both of these platforms are quite similar and are designed to drill 8 wells. 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.

The well fluids produced from TAWP-B and TAWP-C are treated to separate gas, and transported by an inter-platform submarine pipeline to TAWP-A. Two 6" submarine pipelines will be installed between TAWP-A and TAWP-B and between TAWP-A and TAWP-C respectively.

c. 3-leg Flare Jacket

Three 3-leg Flare Jackets (TAV-A, TAV-B and TAV-C) will be installed in Tapis field to flare the associated gas. These structures are for TAWP-A, TAWP-B, and TAWP-C respectively installed adjacent to them.

d. Offshore Storage and Loading Facilities

Offshore storage and loading facilities consist of two SALMs and an Offshore Storage Barge. One SALM will serve for the Offshore Storage Barge and the other will serve for a visiting tanker. The Offshore Storage Barge with 1,200,000 bbls storage capacity will be moored to one of SALMs at the water depth of 225'.

1.2.3 Bekok and Pulai Fields Gas Utilization

(1) Design Bases

1) Production Rate

Field	Design Production Rate
Bekok	130 MMSCFD
Pulai	60 MMSCFD

2) Gas Properties

Data on gas properties were not available at this time, so the following properties are assumed and commonly used for both fields.

Specific gravity: 0.85 (Air = 1)
Viscosity : 0.015 cp at 100°F

3) Number of Wells

With regard to the free gas production, the number of producing wells is shown below based on the condition that each well can produce 30 MMSCFD.

Bekok field ...... 2 wells
Pulai field ...... 2 wells

(2) Conceptual Design

Conceptual design for gas utilization in Peninsular area is for gathering, treating and transporting the associated gas and free gas produced at offshore platforms to supply to a shore-based fertilizer and power plant(s) at Dungun area.

Associated gas from Seligi field has not been taken into consideration for gas utilization. Because estimated gas cost seems to become obviously high due to short oil production life of this field, if Seligi field is added to gas utilization scheme for Bekok and Pulai fields.

1) Combined Development of Bekok and Pulai Fields

Associated gas produced from Bekok and Pulai fields will be supplied to the onshore plants as the first priority by adjusting free gas production from each field. Total gas deliverability from both fields is 150 MMSCFD and the gas at the tentative arrival pressure of 200 psig will be transported to the onshore plants at Dungun area and be kept constant rate throughout 20 years. Facilities arrangement and block flow diagram are shown in Fig. 19-5-1 and Fig. 19-5-2 respectively.

2) Facilities Description

Gas production system in two fields consists of the following facilities:

Bekok Field

1 ... 8-leg Production and Compressor Platform BEPC-A
Submarine Pipelines

Pulai Field

1 ... 8-leg Production and Compressor Platform PUPC-A
Submarine Pipeline

Major equipment to be installed are tabulated with simple specifications in Table 19-5-1.

a. Bekok Field

(i) 8-leg Production and Compressor Platform

The Production and Compressor Platform (BEPC-A) will be an 8-leg structure. Gas turbine driven compressors will be located on the upper deck of this platform. A lower deck will contain inter-coolers and lube and seal oil systems for the compressors. The processing facilities to handle 130 MMSCFD gas will be also equipped on the platform. A 24" gas Transmission Line will be installed between Riser Platform (BER-A) which is described in the section of oil production facilities and the shore of Dungun area, totalling about 144 miles. A 16" gas flow line will be also installed in Bekok field between BEWP-A and BER-A, totalling about 3 miles. Typical mechanical flow diagram and typical plan and elevation are shown in Fig. 30-5-6 and Fig. 30-5-25 respectively. Typical utility flow diagrams for this structure are presented in two sheets, Fig. 30-5-10 and Fig. 30-5-12 respectively.

b. Pulai Field

(i) 8-leg Production and Compressor Platform

The Production and Compressor Platform (PUPC-A) will be an 8-leg structure. The compressors will be equipped on the upper deck and driven by gas turbines. A lower deck will contain inter-coolers and lube and seal oil systems for the compressors. The processing facilities to handle 60 MMSCFD gas will be also equipped on this platform. A 12" gas gathering line will be installed between PUPC-A and BER-A. Typical mechanical flow diagram and typical plan and elevation are shown in Fig. 30-5-6 and Fig. 30-5-25 respectively. Typical utility flow diagrams for this structure are also presented in two sheets, Fig. 30-5-10 and Fig. 30-5-12.

1.2.4 Tapis Oil Field Gas Utilization

The most proper scheme to utilize the associated gas produced from Tapis field is considered to be the tie-in of a gas line to Bekok field. However, as more delineation wells will be required to confirm the gas availability, Tapis field has been excluded from the combined production scheme with the other fields at this time. Therefore, as for the gas utilization of Tapis field, only the most probable case of tie-in to Bekok field has been studied and capital investment has been estimated for reference. The facilities capacity for gas utilization is assumed to be 50 MMSCFD.

This gas production system consists of the following facilities:

1 ... 6-leg Compressor Platform TAC-A
2 ... 8" Submarine Gas Gatherring Line
1 ... 10" Submarine Gas Transmission Line

Facilities arrangement and block flow diagram are shown in Fig. 20-5-1 and Fig. 20-5-2 respectively.

Capital investment for the facilities has been estimated and is summarized in the following:

Offshore platforms	M$13,360,000
Offshore production equipment	6,177,000
Submarine pipelines	12,654,000
Others	7,115,000
Total	M$39,306,000

Note: Others include the costs such as engineering, pre-start-up expense and contingency.

1.2.5 Jerneh Gas Field

Jerneh gas field is located about 82 miles from the east coast of Peninsular Malaysia as shown in Fig. 30-9-1. Before the decision to develop Jerneh gas field as an individual field it will be better to confirm the gas availability from other fields adjacent to Jerneh gas field and to confirm the possibility of combined development with them by further exploratory work. However, the capital investment for Jerneh gas field has been tentatively estimated below for reference as an individual field. Free gas production from this field is assumed 240 MMSCFD.

Gas produced from the field is assumed to be transmitted to Tg. Merang which is the nearest shore point from the field.

Gas production system of Jerneh field consists of the following facilities:

1 ...	8-leg Well and Production Platform	JEWP-A
1 ...	6-leg Well and Production Platform	JEWP-B
1 ...	4-leg Compressor Platform	JEC-A
1 ...	22" Submarine Gas Gathering Line	
1 ...	26" Submarine Gas Transmission Line	

Facilities arrangement and block flow diagram are shown in Fig. 21-5-1 and Fig. 21-5-2 respectively.

Capital investment of these facilities has been estimated and is summarized in the following:

Development wells	M$32,512,000
Offshore platforms	44,544,000
Offshore production equipment	51,275,000
Submarine pipelines	103,208,000
Others	51,171,000
Total	M$282,710,000

Note: Others include the costs such as engineering, pre-start-up expense and contingency.

2. CONCLUSIONS AND RECOMMENDATIONS

Several alternative cases for the development of oil and gas fields in Peninsular 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.

Bekok, Pulai and Seligi group (crude oil)
Tapis (crude oil)
Bekok and Pulai group (gas)
Tapis (gas)
Jerneh (gas)

(1) Field Development Schemes

1) Bekok, Pulai and Seligi Fields (crude oil)

The scheme for combined development of these fields has been selected. The maximum production rate is predicted as 109,200 BPD.

The facilities mainly consist of well and production platforms, offshore storage and loading facilities and submarine pipelines.

2) Tapis Field (crude oil)

Tapis field is different from the fields described above in the stage of exploration and so this field was not considered to be combined with those fields. Therefore, the possibility of combined development is to be studied when the exploration stage for this field advances in future.

The maximum production rate is predicted as 53,850 BPD.

The facilities mainly consist of well and production platforms, offshore storage and loading facilities and submarine pipelines.

3) Bekok and Pulai Fields (gas)

In the above-mentioned development scheme of oil fields in this area, associated gas produced from Bekok and Pulai fields will be supplied to onshore plants as the first priority by adjusting free gas production from each field. Total gas deliverability from both fields is predicted as 150 MMSCFD and the rate is kept constant throughout 20 years. The facilities mainly consist of production and compressor platforms and submarine pipelines.

4) Tapis Field (gas)

Tapis field, though having some uncertain factors at present, has a possibility of being an associated gas source of large scale and of being tied in to Bekok field. The facilities mainly consist of compressor platform and submarine pipelines.

(2) Exploratory Works for Potential Fields

1) Jerneh Field (gas)

Although there is little uncertainty as to the reserves and gas deliverability of Jerneh field, the field development schedule is recommended to be postponed. Strongly recommended are exploratory works for Bintang and other prospects adjacent to Jerneh field for combined fields development, taking into consideration the cost of transmission line more than 100 miles in length.

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:

<u>Capital Investment Cost</u>

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 ($C_1 + C_2 + C_3$)

<u>Annual Operating Cost</u>

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 Bekok, Pulai and Seligi Fields

(1) Bases of Cost Estimate

Capital investment and operating cost for these fields have been estimated based on the basic cost data and computation method described in 1.1. Operation organizations for these combined fields are tentatively assumed as shown in Fig. 31-6-4 for Cases IA, IB and II and Fig. 31-6-3 for Case III.

(2) Capital Investment Cost Estimate

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

Case IA	M$735,436,000
Case IB	M$788,085,000
Case II	M$635,804,000
Case III	M$509,321,000

(3) Annual Operating Cost Estimate

Estimated annual operating costs for each case are different year by year. The reasons of the difference are as follows:

- Change of chemical cost in proportion to the change of oil production rate.

- Change of operating supplies cost, repairs and maintenance cost and insurance cost which will not be required for a field after the stop of oil production from the field.

- Change of operating personnel cost and service contractors' fee except tug boat service. These costs are divided between oil operation and gas in proportion to each production rate in terms of calorific value, as the operation for free gas production is required in this case.

Estimated operating costs for each case are shown in Table 17-6-2 to Table 17-6-5.

(4) Project and Investment Schedules

The project schedule for Case IA selected as an optimum case is shown in Fig. 17-6-1. The investment schedule for each case is shown in Table 17-6-6 thru Table 17-6-9.

The following construction equipment are assumed to be available:

Self-contained Drilling Rig 4

Derrick Barge (500 ton) 2

Lay Barge 2

1.2.2 Tapis Oil Field

(1) Bases of Cost Estimate

Capital investment and operating costs for this field have been estimated based on the basic cost data and computation method described in 1.1. An operation organization for this field is tentatively assumed as shown in Fig. 31-6-2.

(2) Capital Cost Estimate

As for this field, there are two cases and the estimated capital investments are summarized below. The breakdowns are shown in Table 18-6-1.

Case IA	M$407,736,000
Case IB	M$453,705,000

(3) Annual Operating Cost Estimate

Estimated annual operating costs for each case are different year by year, because of the change of chemical cost in proportion to the change of oil production rate.

Estimated operating costs for each case are shown in Table 18-6-2 and Table 18-6-3.

(4) Project and Investment Schedules

The project and investment schedules for Case IA (optimum case) have been prepared and are shown in Fig. 18-6-1 and Table 18-6-4.

The following construction equipment are assumed to be available:

Tender Assisted Drilling Rig 1
Self-contained Drilling Rig 1
Derrick Barge (500 ton) 1
Lay Barge 1

The investment schedule for Case IB is shown in Table 18-6-5.

1.2.3 Bekok and Pulai Fields Gas Utilization

(1) Bases of Cost Estimate

Capital investment and operating costs for these fields have been estimated based on the basic cost data and computation method described in 1.1. An operation organization for these fields is tentatively assumed as shown in Fig. 31-6-4.

(2) Capital Investment Cost Estimate

As for these fields, estimated capital investment is M$291,728,000. The breakdown is shown in Table 19-6-1.

(3) Annual Operating Cost Estimate

Estimated annual operating costs are different year by year and shown in Table 19-6-2. The reasons of the difference are as follows:

- Change of chemical cost in proportion to the change of oil production rate.
- Change of operating supplies cost, repairs and maintenance cost and insurance cost which will not be required for a field after the stop of oil production from the field.

- Change of operating personnel cost and service contractors' fee except tug boat service. These costs are divided between oil operation and gas operation in proportion to each production rate in terms of calorific value, as the operation for free gas production is required in this case.

(4) Project and Investment Schedule

The project and investment schedules have been prepared and are shown in Fig. 19-6-1 and Table 19-6-3.

The following construction equipment are assumed to be available:

Self-contained Drilling Rig 1
Derrick Barge (500 ton) 1
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 cannot 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 Peninsular Area the following four cases for the development of Bekok, Pulai and Seligi fields and two cases for the development of Tapis oil field have been selected as alternative schemes. The profitability analysis for each case has been carried out.

2.2.1 Bekok, Pulai and Seligi Fields

Case IA : Bekok, Pulai and Seligi (A, B), Offshore Storage Case

Case IB : Bekok, Pulai and Seligi (A, B), Onshore Terminal Case

Case II : Bekok, Pulai and Seligi (A), Offshore Storage Case

Case III: Bekok and Pulai, Offshore Storage 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 17-6-10, 11, 12 and 13. Descriptions of each case are as follows;

Case IA: For the reason of operation at offshore, operating cost is higher but capital investment cost is lower than the case of laying a pipeline to shore. 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. Maximum DCF ROR is 21.04% in this year. Profitability after this year will become worse due to declining oil production rate.

Case IB: Capital investment becomes higher because the cost for laying of a pipeline to shore is high, but operating cost is lower for the operation and maintenance at onshore facilities. The profit will become a peak in the seventeenth year after the project start (in the fourteenth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR is 19.42% in this year. Profitability after this year will become worse due to declining oil production rate.

Case II: As this case excludes the Seligi B Block, oil production rate is low and capital investment cost is low in comparison with above Case IA and Case IB. The profit will become a peak in the fifteenth year after the project start (in the twelfth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR is 19.78% in this year. Profitability after this year will become worse due to declining oil production rate.

Case III: As this case excludes the Seligi A and B Blocks, oil production rate is low and capital investment cost is low in comparison with above Cases IA, Case IB and Case II. The profit will become a peak in the fifteenth year after the project start (in the twelfth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR is 20.77% in this year. Profitability after this year will become worse due to declining oil production rate.

In comparison of above four cases, maximum DCF ROR is 21.04% for Case IA as shown in Cash Flow Table for Operating Company. Therefore, Case IA can be said to be more advantageous. However, even if Case IA is adopted, the profitability of Operating Company after fourteenth year will become worse.

2.2.2 Tapis Oil Field

Case IA: Offshore Storage Case

Case IB: Onshore Terminal Case

Each of the profitability yardsticks obtained for each case is shown in Table 31-6-6 and Cash Flow Tables for Petronas and Operating Company are shown in Tables 18-6-6 and 7. The profitability study for both offshore storage case and onshore terminal case for the development of Tapis field was carried out. Descriptions of each case are as follows;

Case IA: The profit will become a peak in the ninth year after the project start (in the sixth year after the production start) as shown in Cash Flow Table for Operating Company. Maximum DCF ROR is 15.05% in this year.

Case IB: The profit will become a peak in the ninth year after the project start (in the sixth year after the production start) as shown in Cash Flow Table for Operating Company and maximum DCF ROR is 12.51%.

In comparison of above two cases, as Case IA will maintain high values of DCF ROR throughout the project life, Case IA will be more profitable than the other.

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 19-6-4 shows the analyzed results based on the PS Agreements under the condition to obtain 10% DCF ROR.

2.3.1 Bekok and Pulai Fields Gas Utilization

For these fields, gas cost has been calculated for the following one case.

Offshore Compression Case

Unit: M¢/1,000 SCF

	Discount Rate				
	0%	5%	10%	15%	20%
Gas Cost	45.7	62.2	83.8	109.7	139.1

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 curves are shown in Fig. 31-6-6. The results of sensitivity analysis for each case are as follows;

2.4.1 Bekok, Pulai and Seligi Fields (Case IA)

Production Rate Change	-20%	-10%	0%		
DCF ROR (%)	14.76	18.62	21.04		

Sales Prices Change	-20%	-10%	0%	10%	20%
DCF ROR (%)	14.67	18.53	21.04	23.40	25.60

Investment Change	-20%	-10%	0%	10%	20%
DCF ROR (%)	26.29	23.46	21.04	18.98	17.09

2.4.2 Tapis Oil Field (Case IA)

Production Rate Change	-20%	-10%	0%
DCF ROR (%)	5.56	10.63	15.05

Sales Prices Change	-20%	-10%	0%	10%	20%
DCF ROR (%)	5.56	10.63	15.05	19.30	21.76

Investment Change	-20%	-10%	0%	10%	20%
DCF ROR (%)	22.30	18.91	15.05	11.69	8.75

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.

Bekok, Pulai and Seligi group (crude oil)

Case IA	110,000 BPD	M$ 735,436,000
Case IB	110,000 BPD	M$ 788,085,000
Case II	90,000 BPD	M$ 635,804,000
Case III	75,000 BPD	M$ 509,321,000

Tapis (crude oil)

Case IA	55,000 BPD	M$ 407,736,000
Case IB	55,000 BPD	M$ 453,705,000

Bekok and Pulai group (gas)

	190 MMSCFD	M$ 291,728,000

Tapis (gas)

	50 MMSCFD	M$ 39,306,000

Jerneh (gas)

	240 MMSCFD	M$ 282,710,000

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:

- Bekok, Pulai and Seligi combined fields development case with offshore storage and loading facilities.

- Tapis field development case with offshore storage and loading facilities

The cost of net gas delivered to a shore point has been estimated for Bekok and Pulai 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(s)	Cumulative Net Cash Flow (M$ 1,000)	DCF ROR (%)	Cumulative Net Cash Flow (M$ 1,000)	Payout Time (year)
Bekok, Pulai and Seligi	1,770,974	21.0	727,775	5.1
Tapis	702,728	15.1	239,153	5.6

- Gas -

Gas Cost by Discount Factors (M¢/1,000 CF)

Name of Field	Discount Factor (%) 0	5	10	15	20
Bekok and Pulai	45.7	62.2	83.8	109.7	139.1

TABLE

TABLE

TABLE LIST VOL. II (PENINSULAR AREA)

Vol. II

TITLE

Vol. II

TITLE

Vol. II

TITLE

Vol. II Table A-1

ORIGINAL HYDROCARBONS IN PLACE - DEVELOPMENT FIELDS OF PENINSULAR MALAYSIA

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)
BEKOK	a2	111.40	465.80	133.68	0.0	N.D 57.20	486.22
						R.G 57.55	513.60
	a4	5.53	0.0	6.64	0.0		
	a5	29.08	0.0	34.90	0.0		
	b1	0.0	137.91	0.0	0.0		
	b2	0.0	47.85	0.0	0.0		
	b3	179.75	429.09	188.73	0.0	N.D 56.20	520.91
						R.G 55.89	506.04
	b4	150.48	38.19	127.91	0.0	N.D 33.61	131.64
						R.G 33.42	129.74
	TOTAL	476.25	1118.84	491.86	0.0	N.D 147.01	1138.77
	PROVED RESVS.	27.87	276.04	28.78		R.G 146.86	1149.38
	PROBABLE RESVS.	407.38	731.53	420.74			
	POSSIBLE RESVS.	41.00	111.26	42.34			
PULAI	a	0.0	209.39	0.0	0.0		
	b1	4.32	58.38	1.51	0.0		
	b2	59.47	43.15	20.82	0.0	*(1)21.30	48.36
						*(2)25.32	46.18
	b3	65.50	6.35	22.93	0.0	*(1)13.95	18.55
						*(2)16.49	18.34
	c2	0.0	2.54	0.0	0.0		
	e	0.0	33.00	0.0	0.0		
	TOTAL	129.30	352.79	45.25	0.0	*(1)35.25	66.91
						*(2)41.81	64.52
	PROVED RESVS.	24.69	343.08	8.64			
	PROBABLE RESVS.	98.15	9.62	34.35			
	POSSIBLE RESVS.	6.46	0.09	2.26			

Note, N.D: Natural Depletion Case R.G: Restricted Gas Production Case *(1):Water/Oil=0.2Case *(2):Water/Oil=0.4Case

Vol. II Table A-1 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - DEVELOPMENT FIELDS OF PENINSULAR MALAYSIA

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)
SELIGI	A	a1	0.0	11.27	0.0	0.0		
	A	a2	48.5	15.03	19.40	0.0	9.11	20.52
	A	b1	0.0	66.00	0.0	0.0		
	A	b2	61.64	3.00	30.82	0.0	9.61	25.24
	A	c	21.39	0.0	17.11	0.0	2.66	11.84
	B	a2	0.0	542.30	15.29	0.0		
	B	b1	0.0	61.50	127.24	0.0		
	B	b2	30.57	160.49	15.29	0.0	9.73	126.13
	B	c	159.05	25.65	127.24	0.0	20.00	96.30
	TOTAL		321.15	885.35	209.86	0.0	51.11	280.03
	PROVED RESVS.		61.89	282.74	40.44			
	PROBABLE RESVS.		259.26	602.61	169.42			
	POSSIBLE RESVS.							
TAPIS	A	a3	111.54	388.83	66.93	0.0	30.13	260.42
	A	a4	0.0	215.65	0.0	0.0		
	A	a5	58.61	127.43	30.36	0.0	12.01	110.06
	B	a3	44.90	10.46	26.94	0.0	8.28	27.23
	B	a4	116.35	0.0	69.81	0.0	19.12	52.63
	B	a5	62.04	3.20	37.23	0.0	8.76	24.34
	TOTAL		393.43	745.57	231.26	0.0	78.30	474.68
	PROVED RESVS.		16.42	58.13	9.65			
	PROBABLE RESVS.		377.01	687.44	221.61			
	POSSIBLE RESVS.							

Vol. II Table A-2

ORIGINAL HYDROCARBONS IN PLACE - POTENTIAL FIELDS OF PENINSULAR

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)
PETA	b	0.0	2.68	0.0	0.0		
	TOTAL	0.0	2.68	0.0	0.0		
	PROVED RESVS.		2.68				
	PROBABLE RESVS.						
	POSSIBLE RESVS.						
BELUMUT	a1	0.0	81.93	0.0	0.0		
	b1	0.0	281.94	0.0	0.0		
	TOTAL	0.0	363.88	0.0	0.0		
	PROVED RESVS.		35.98				
	PROBABLE RESVS.		327.90				
	POSSIBLE RESVS.						
ANGSI	b1	4.18	0.0	4.42	0.0		
	b2	0.84	0.0	0.88	0.0		
	b3	0.22	0.0	0.24	0.0		
	c	0.0	0.35	0.0	0.0		
	TOTAL	5.24	0.35	5.54	0.0		
	PROVED RESVS.	0.87	0.35	0.92			
	PROBABLE RESVS.	4.37		4.62			
	POSSIBLE RESVS.						

Vol. II Table A-2 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - POTENTIAL FIELDS OF PENINSULAR

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)
BESAR	a	0.0	5.35	0.0	0.0		
	b1	0.0	150.99	0.0	0.0		
	b2	0.0	14.44	0.0	0.0		
	TOTAL	0.0	170.78	0.0	0.0		
	PROVED RESVS.		41.69				
	PROBABLE RESVS.		129.09				
	POSSIBLE RESVS.						
JERNEH	a1	0.0	360.00	0.0	0.0		
	a2	0.0	98.05	0.0	0.0		
	a3	0.0	1009.96	0.0	0.0		
	c1	0.0	2370.50	0.0	0.0		
	c2	0.0	540.97	0.0	0.0		
	c4	0.0	831.72	0.0	0.0		
	c5	0.0	422.40	0.0	0.0		
	TOTAL	0.0	5639.60	0.0	0.0		
	PROVED RESVS.		3360.00				
	PROBABLE RESVS.		2279.60				
	POSSIBLE RESVS.						

Vol. II Table A-2 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - POTENTIAL FIELDS OF PENINSULAR

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)
PILONG	a1	0.0	43.79	0.0	0.0		
	a2	0.0	185.81	0.0	0.0		
	a3	0.0	74.56	0.0	0.0		
	b1	0.0	130.96	0.0	0.0		
	b3	0.0	20.12	0.0	0.0		
	b5	0.0	26.04	0.0	0.0		
	b6	0.0	4.73	0.0	0.0		
	b7	0.0	3.55	0.0	0.0		
	TOTAL	0.0	489.66	0.0	0.0		
	PROVED RESVS.		59.37				
	PROBABLE RESVS.		430.17				
	POSSIBLE RESVS.						
BINTANG	a	0.0	122.30	0.0	0.0		
	b1	0.0	541.70	0.0	0.0		
	b2	0.0	1156.30	0.0	0.0		
	c	0.0	205.20	0.0	0.0		
	TOTAL	0.0	2025.20	0.0	0.0		
	PROVED RESVS.		67.09				
	PROBABLE RESVS.		1958.11				
	POSSIBLE RESVS.						

Vol. II Table A-2 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - POTENTIAL FIELDS OF PENINSULAR

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)
SEPAT	a4	0.0	13.87	0.0	0.0		
	a5	0.0	27.96	0.0	0.0		
	TOTAL	0.0	41.83	0.0	0.0		
	PROVED RESVS.		8.25				
	PROBABLE RESVS.		33.58				
	POSSIBLE RESVS.						
BUJANG	a2	0.0	10.22	0.0	0.0		
	a3	0.0	8.70	0.0	0.0		
	a4	0.0	4.05	0.0	0.0		
	b2	0.0	31.44	0.0	0.0		
	b3	0.0	0.18	0.0	0.0		
	b4	0.0	12.89	0.0	0.0		
	TOTAL	0.0	67.48	0.0	0.0		
	PROVED RESVS.		55.69				
	PROBABLE RESVS.		11.79				
	POSSIBLE RESVS.						
SOTONG	A a1	0.0	0.0	0.0	179.		
	A a2	51.99	106.30	49.39	0.	11.97	127.85
	A a3	25.49	0.0	20.65	389.		
	A a5	8.62	29.04	6.98	0.		
	A a6	4.89	10.78	3.96	0.		
	B a1	7.31	0.0	8.10	78.		
	B a2	0.73	0.0	0.08	18.		
	B a3	2.86	0.0	3.16	58.		
	B a4	0.95	0.0	1.05	66.		
	B a8	1.24	0.0	1.38	19.		

Vol. II Table A-2 (Continued)

ORIGINAL HYDROCARBONS IN PLACE - POTENTIAL FIELDS OF PENINSULAR

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)
	C a2	2.05	0.0	2.27	74.		
	C a4	1.97	0.0	2.19	51.		
	C a7	1.97	0.0	2.19	50.		
	C a8	3.21	0.0	3.56	162.		
	C a10	0.0	10.78	0.0	0.0		
	TOTAL	113.29	156.90	104.96	1244.	*(1)29.65	382.54
	PROVED RESVS.	88.08	156.90	72.26		*(2)33.00	280.76
	PROBABLE RESVS.	25.21		32.70			
	POSSIBLE RESVS.						
DUYONG	a1	0.0	37.88	0.0	0.0		
	a2	0.0	111.85	0.0	0.0		
	b2 - b4	0.0	3804.40	0.0	0.0		
	b5	0.0	1623.04	0.0	0.0		
	TOTAL	0.0	5577.17	0.0	0.0		
	PROVED RESVS.		79.07				
	PROBABLE RESVS.		5498.10				
	POSSIBLE RESVS.						
ANDING	a1	0.39	0.0	0.48	0.0		
	a2	0.0	0.63	0.0	0.0		
	a4	0.0	0.46	0.0	0.0		
	a5	0.0	0.92	0.0	0.0		
	b	0.0	2.34	0.0	0.0		
	TOTAL	0.39	4.35	0.48	0.0		
	PREVED RESVS.	0.39	4.35	0.48			
	PROBABLE RESVS.						
	POSSIBLE RESVS.						

Note: *(1) CASE 1 *(2) CASE 2

Table 1-2-1 CORRELATION TABLE
Vol. II , BEKOK FIELD

Well No.	1				2				3			
D.F.E.	75				72				32			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top J	4218	4143			4454	4382			5035	4997		
Top a_1	4540	4465	4633	4558	4762	4690	4865	4793	5355	5317	5510	5472
a_2	4693	4618	4820	4745	4915	4843	5046	4974	5508	5470	5670	5632
a_3	4875	4800	4887	4812	5092	5020	5162	5090	5735	5697	5767	5729
a_4	4952	4877	4980	4905	5174	5102	5215	5143	5794	5756	5870	5832
a_5	5054	4979	5182	5107	5266	5194	5410	5338	5940	5902	6180	6142
Top b_1	6200	6125	6235	6160	6394	6322	6445	6373	7000	6962	7050	7012
b_2	6290	6215	6340	6265	6480	6408	6504	6432	7100	7062	7165	7127
b_3	6585	6510	6786	6711	6728	6656	6998	6926	7360	7322	7575	7537
b_4	6858	6783	7078	7003	7062	6990	7247	7175	-	-	-	-
b_5	7108	7033	7188	7113	7253	7181	7360	7288				
b_6	7222	7147	7303	7228	7378	7306	7470	7398				
T.D.	8296	8221			8244	8172			7630	7592		

Table 1-2-1 (Continued)
Vol. II

CORRELATION TABLE
BEKOK FIELD

Well No.	4				5				6			
D.F.E.	68				32				32			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top J	4918	4850			4720	4688			4593	4561		
Top a_1	5235	5167	5330	5262	5038	5006	5141	5109	4892	4860	5018	4986
a_2	5380	5312	5500	5432	5200	5168	5312	5280	5052	5020	5144	5112
a_3	5535	5467	5630	5562	5351	5319	5430	5398	5176	5144	5246	5214
a_4	5648	5580	5677	5609	5463	5431	5488	5456	5305	5273	5346	5314
a_5	5726	5658	5880	5812	5553	5521	5742	5710	5400	5368	5525	5493
Top b_1	6730	6662	6789	6721	6612	6580	6682	6650	-	-	-	-
b_2	6880	6812	6910	6842	6748	6716	6790	6758				
b_3	7108	7040	7284	7216	6995	6963	7202	7170				
b_4	-	-	-	-	7295	7263	7486	7454				
b_5					7511	7479	7622	7590				
b_6					7668	7636	7781	7749				
T.D.	7332	7264			7763	7731			5680	5648		

RESERVOIR DATA

FIELD NAME; BEKOK RESERVOIR NAME; A2

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.082	0.	1.308653	0.5950	0.01284
200.	1.154	103.	0.088323	0.5070	0.01306
400.	1.194	207.	0.045066	0.4450	0.01328
600.	1.220	310.	0.029957	0.4000	0.01350
1000.	1.275	517.	0.017674	0.3340	0.01419
1400.	1.332	724.	0.012406	0.2820	0.01496
1600.	1.360	828.	0.010780	0.2630	0.01543
2000.	1.429	1035.	0.008532	0.2260	0.01638
2320.	1.484	1200.	0.007321	0.1900	0.01725
2390.	1.482	1200.	0.007106	0.1900	0.01743

SL	KG/KO	KRO
0.60	250.0000	0.0569
0.65	80.0000	0.0983
0.70	28.0000	0.1561
0.75	9.5000	0.2330
0.80	2.8500	0.3318
0.85	0.8500	0.4552
0.90	0.2000	0.6058
0.95	0.0380	0.7865
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2320.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 2390.0000
EFFECTIVE COMPRESSIBILITY = 0.0000323
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3700
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 136.0750
OIL PRODUCTION RATE (MSTB/D) = 5.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 3.5842

Vol. II Table 1-3-1
RESERVOIR PARAMETERS

RESERVOIR DATA

FIELD NAME; BEKOK RESERVOIR NAME; B3

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.036	0.	1.404877	0.6400	0.01362
200.	1.110	70.	0.095094	0.5500	0.01384
400.	1.150	141.	0.048666	0.4830	0.01405
600.	1.169	211.	0.032449	0.4380	0.01427
1000.	1.208	352.	0.019308	0.3750	0.01487
1400.	1.248	493.	0.013631	0.3250	0.01553
1600.	1.267	563.	0.011889	0.3050	0.01594
1800.	1.287	633.	0.010531	0.2850	0.01635
2400.	1.347	844.	0.007876	0.2370	0.01765
2600.	1.368	915.	0.007285	0.2240	0.01810
2985.	1.414	1050.	0.006407	0.2000	0.01900
3020.	1.412	1050.	0.006339	0.2001	0.01908

SL	KG/KO	KRO
0.60	250.0000	0.0569
0.65	80.0000	0.0983
0.70	28.0000	0.1561
0.75	9.5000	0.2330
0.80	2.8500	0.3318
0.85	0.8500	0.4552
0.90	0.2000	0.6058
0.95	0.0380	0.7865
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2985.0000
INITIAL RESERVOIR PRESSURE (PSIG) = 3031.0000
EFFECTIVE COMPRESSIBILITY = 0.0000515
WATER FORMATION VOLUME FACTOR = 1.2500
IREDUCIBLE WATER SATURATION = 0.2930
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 191.1196
OIL PRODUCTION RATE (MSTB/D) = 5.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 1.9088

Vol. II Table 1-3-2
RESERVOIR PARAMETERS

RESERVOIR DATA

FIELD NAME; REKOK RESERVOIR NAME; B4

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.037	0.	1.414498	0.6600	0.01369
200.	1.100	56.	0.095784	0.5700	0.01390
400.	1.143	113.	0.049039	0.5020	0.01411
600.	1.146	169.	0.032712	0.4580	0.01433
1000.	1.187	282.	0.019468	0.4000	0.01491
1400.	1.216	394.	0.013753	0.3400	0.01556
1800.	1.246	507.	0.010631	0.3100	0.01639
2400.	1.294	676.	0.007954	0.2630	0.01764
3018.	1.352	850.	0.006403	0.2200	0.01903
3080.	1.349	850.	0.006285	0.2203	0.01917

SL	KG/KO	KRO
0.60	250.0000	0.0569
0.65	80.0000	0.0983
0.70	28.0000	0.1561
0.75	9.5000	0.2330
0.80	2.8500	0.3318
0.85	0.8500	0.4552
0.90	0.2000	0.6058
0.95	0.0380	0.7865
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 3018.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 3081.0000
EFFECTIVE COMPRESSIBILITY = 0.0000409
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3710
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 150.6270
OIL PRODUCTION RATE (MSTB/D) = 5.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.2105

Vol. II Table 1-3-3
RESERVOIR PARAMETERS

Vol. II Table 1-3-4
PREDICTED PERFORMANCE
(NATURAL)

FIELD NAME; BEKOK RESERVOIR NAME; A2

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	2368.	3.35	25.00	30.00	1200.	4.563	5.476	0.04
1.00	2349.	6.71	25.00	30.00	1200.	9.126	10.951	0.59
1.50	2331.	10.06	25.00	30.00	1200.	13.689	16.427	1.49
2.00	2312.	13.41	25.00	31.32	1256.	18.252	22.144	2.45
2.50	2291.	16.77	25.00	33.55	1406.	22.815	28.267	3.02
3.00	2268.	20.10	24.82	38.18	1702.	27.346	35.236	4.03
3.50	2240.	23.23	23.38	44.68	2218.	31.613	43.391	5.37
4.00	2206.	26.04	20.94	54.16	3053.	35.434	53.276	6.43
4.50	2163.	28.55	18.72	67.01	4319.	38.851	65.506	7.32
5.00	2107.	30.80	16.75	87.16	6225.	41.909	81.414	8.08
5.50	2033.	32.80	14.92	112.48	9136.	44.633	101.943	8.73
6.00	1936.	34.57	13.20	146.41	13276.	47.041	128.666	9.28
6.50	1815.	36.13	11.66	182.46	18412.	49.170	161.969	9.74
7.00	1667.	37.51	10.27	222.41	25433.	51.044	202.562	10.14
7.50	1492.	38.71	8.94	264.23	34035.	52.676	250.789	10.48
8.00	1294.	39.75	7.74	299.72	44142.	54.088	305.494	10.78
8.50	1075.	40.64	6.65	329.39	55116.	55.303	365.614	11.03
9.00	847.	41.40	5.64	338.35	64813.	56.332	427.369	11.24

Vol. II Table 1-3-4 (CONTINUED)

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)
9.50	628.	42.04	4.77	322.43	69053.	57.202	486.219	11.42

PREDICTED PERFORMANCE (NATURAL)

FIELD NAME; BEKOK RESERVOIR NAME; B3

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	2994.	2.39	25.00	26.25	854.	4.563	4.791	0.0
1.00	2965.	4.78	25.00	26.53	1074.	9.126	9.634	0.90
1.50	2935.	7.16	25.00	28.48	1174.	13.689	14.832	1.66
2.00	2902.	9.55	25.00	32.32	1406.	18.252	20.732	2.52
2.50	2865.	11.87	24.27	37.96	1769.	22.681	27.660	3.58
3.00	2822.	14.02	22.57	44.74	2238.	26.802	35.825	4.61
3.50	2771.	16.00	20.70	52.76	2959.	30.579	45.454	5.55
4.00	2708.	17.81	18.93	65.03	4007.	34.035	57.324	6.39
4.50	2631.	19.46	17.34	80.65	5428.	37.199	72.044	7.13
5.00	2539.	20.98	15.85	100.95	7431.	40.091	90.470	7.79
5.50	2426.	22.35	14.38	125.29	10246.	42.716	113.337	8.38
6.00	2287.	23.59	12.94	154.75	13829.	45.078	141.582	8.89
6.50	2126.	24.69	11.58	183.93	18202.	47.191	175.153	9.34
7.00	1944.	25.68	10.31	214.46	23722.	49.072	214.296	9.74
7.50	1737.	26.54	9.08	244.67	30612.	50.730	258.953	10.09
8.00	1508.	27.30	7.92	273.77	38892.	52.175	308.921	10.39
8.50	1260.	27.95	6.85	296.20	47995.	53.426	362.983	10.65
9.00	1007.	28.52	5.89	307.19	56027.	54.502	419.051	10.87

Vol. II Table 1-3-5 (CONTINUED)

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)
9.50	761.	29.00	5.03	296.01	61142.	55.419	473.080	11.06
10.00	541.	29.41	4.30	262.08	59488.	56.203	520.914	11.21

PREDICTED PERFORMANCE (NATURAL)

FIELD NAME; BEKOK RESERVOIR NAME; B4

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	2998.	1.21	10.00	8.53	855.	1.825	1.556	0.16
1.00	2949.	2.42	10.00	8.60	867.	3.650	3.126	0.33
1.50	2906.	3.64	10.00	8.77	885.	5.476	4.726	0.76
2.00	2862.	4.85	10.00	9.06	929.	7.301	6.380	1.13
2.50	2815.	6.06	10.00	9.70	1016.	9.126	8.150	1.51
3.00	2765.	7.26	9.92	10.78	1182.	10.936	10.118	1.90
3.50	2711.	8.42	9.58	12.27	1375.	12.685	12.357	2.29
4.00	2653.	9.52	9.10	13.26	1545.	14.346	14.776	2.64
4.50	2593.	10.57	8.65	14.21	1758.	15.924	17.369	2.98
5.00	2530.	11.57	8.21	15.52	2030.	17.423	20.202	3.30
5.50	2462.	12.51	7.79	17.10	2372.	18.845	23.323	3.61
6.00	2389.	13.41	7.38	18.95	2795.	20.192	26.782	3.90
6.50	2310.	14.25	6.97	21.14	3292.	21.465	30.640	4.17
7.00	2224.	15.05	6.59	23.45	3829.	22.668	34.920	4.43
7.50	2133.	15.81	6.24	25.74	4441.	23.808	39.619	4.66
8.00	2035.	16.52	5.91	28.22	5150.	24.887	44.770	4.89
8.50	1930.	17.20	5.58	31.00	5977.	25.905	50.429	5.11
9.00	1816.	17.84	5.26	33.83	6923.	26.865	56.603	5.31

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)
9.50	1696.	18.44	4.95	36.70	7938.	27.768	63.301	5.50
10.00	1568.	19.00	4.66	39.42	9040.	28.618	70.495	5.67
10.50	1434.	19.53	4.38	41.98	10132.	29.417	78.158	5.84
11.00	1298.	20.02	4.09	43.45	11175.	30.163	86.087	5.99
11.50	1161.	20.48	3.77	43.95	12135.	30.852	94.109	6.13
12.00	1028.	20.90	3.49	43.68	12887.	31.488	102.083	6.26
12.50	896.	21.30	3.23	42.87	13700.	32.078	109.907	6.38
13.00	768.	21.66	2.99	41.97	14296.	32.624	117.568	6.49
13.50	646.	22.00	2.79	40.16	14464.	33.133	124.898	6.59
14.00	537.	22.31	2.61	36.95	13672.	33.608	131.643	6.69

PREDICTED PERFORMANCE
(RESTRICTED GAS PRODUCTION CASE)

FIELD NAME; BEKOK RESERVOIR NAME; A2

RESTRICTED GAS PRODUCTION 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	2368.	3.35	25.00	30.00	864.	4.563	5.476	0.0
1.00	2348.	6.71	25.00	30.00	1200.	9.126	10.951	0.37
1.50	2329.	10.06	25.00	30.00	1200.	13.689	16.427	0.98
2.00	2310.	13.41	25.00	31.78	1272.	18.252	22.227	1.76
2.50	2290.	16.77	25.00	33.44	1410.	22.815	28.330	2.72
3.00	2266.	20.09	24.78	39.57	1738.	27.338	35.552	3.83
3.50	2240.	23.21	23.26	43.08	2220.	31.583	43.414	5.02
4.00	2204.	26.00	20.81	56.09	3086.	35.381	53.651	6.18
4.50	2166.	28.22	16.54	60.00	4201.	38.400	64.602	7.03
5.00	2128.	29.90	12.54	60.00	5442.	40.689	75.554	7.65
5.50	2089.	31.22	9.85	60.00	6830.	42.487	86.505	8.12
6.00	2050.	32.29	7.95	60.00	8363.	43.938	97.456	8.49
6.50	2011.	33.17	6.56	60.00	10028.	45.136	108.407	8.78
7.00	1971.	33.91	5.54	60.00	11758.	46.147	119.358	9.02
7.50	1931.	34.56	4.80	60.00	13373.	47.023	130.310	9.23
8.00	1892.	35.13	4.24	60.00	14990.	47.797	141.261	9.40
8.50	1852.	35.64	3.80	60.00	16673.	48.491	152.212	9.56

 Table 1-3-7 CONTINUED

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)
9.00	1813.	36.10	3.43	60.00	18417.	49.116	163.163	9.70
9.50	1773.	36.51	3.11	60.00	20221.	49.684	174.114	9.82
10.00	1733.	36.89	2.84	60.00	22086.	50.203	185.065	9.94
10.50	1694.	37.24	2.61	60.00	24011.	50.679	196.017	10.04
11.00	1654.	37.57	2.40	60.00	25992.	51.118	206.968	10.14
11.50	1614.	37.86	2.22	60.00	28029.	51.524	217.919	10.22
12.00	1574.	38.14	2.07	60.00	29966.	51.902	228.870	10.30
12.50	1535.	38.40	1.94	60.00	31851.	52.257	239.821	10.38
13.00	1495.	38.65	1.83	60.00	33744.	52.591	250.773	10.45
13.50	1456.	38.88	1.73	60.00	35640.	52.907	261.724	10.52
14.00	1416.	39.10	1.64	60.00	37543.	53.207	272.675	10.58
14.50	1377.	39.31	1.56	60.00	39581.	53.491	283.626	10.64
15.00	1337.	39.51	1.48	60.00	41706.	53.761	294.577	10.70
15.50	1298.	39.70	1.40	60.00	43794.	54.017	305.528	10.75
16.00	1258.	39.88	1.34	60.00	45850.	54.262	316.479	10.80
16.50	1218.	40.05	1.28	60.00	47892.	54.495	327.431	10.85
17.00	1179.	40.21	1.23	60.00	49911.	54.719	338.382	10.90

Vol. II Table 1-3-7 (CONTINUED)

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)
17.50	1139.	40.37	1.18	60.00	51894.	54.935	349.333	10.94
18.00	1099.	40.52	1.14	60.00	53822.	55.142	360.284	10.99
18.50	1059.	40.67	1.10	60.00	55685.	55.342	371.235	11.03
19.00	1020.	40.81	1.06	60.00	57480.	55.536	382.187	11.07
19.50	979.	40.95	1.03	60.00	59284.	55.724	393.138	11.11
20.00	939.	41.08	1.00	60.00	61075.	55.906	404.089	11.14
20.50	899.	41.21	0.97	60.00	62745.	56.083	415.040	11.18
21.00	859.	41.34	0.95	60.00	64278.	56.255	425.991	11.22
21.50	818.	41.47	0.92	60.00	65658.	56.424	436.942	11.25
22.00	778.	41.59	0.91	60.00	66861.	56.589	447.894	11.28
22.50	737.	41.71	0.89	60.00	67863.	56.752	458.845	11.32
23.00	696.	41.82	0.88	60.00	68636.	56.913	469.796	11.35
23.50	655.	41.94	0.87	60.00	69010.	57.072	480.747	11.38
24.00	614.	42.06	0.87	60.00	68814.	57.231	491.698	11.41
24.50	573.	42.18	0.87	60.00	68379.	57.390	502.649	11.45
25.00	532.	42.29	0.88	60.00	67683.	57.551	513.601	11.48

PREDICTED PERFORMANCE
(RESTRICTED GAS PRODUCTION CASE)

FIELD NAME; BEKOK RESERVOIR NAME; B3

RESTRICTED GAS PRODUCTION 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	2994.	2.39	25.00	26.25	854.	4.563	4.791	0.0
1.00	2964.	4.78	25.00	26.70	1079.	9.126	9.665	0.68
1.50	2934.	7.16	25.00	29.22	1206.	13.689	14.998	1.50
2.00	2901.	9.55	25.00	31.58	1422.	18.252	20.762	2.26
2.50	2862.	11.86	24.22	39.92	1782.	22.673	28.048	3.34
3.00	2818.	14.01	22.49	45.37	2276.	26.777	36.329	4.40
3.50	2767.	15.98	20.62	53.46	3006.	30.541	46.086	5.38
4.00	2709.	17.66	17.62	60.00	3951.	33.758	57.038	6.21
4.50	2652.	18.97	13.67	60.00	4977.	36.253	67.989	6.83
5.00	2596.	20.00	10.83	60.00	6112.	38.229	78.940	7.29
5.50	2542.	20.86	8.93	60.00	7307.	39.859	89.891	7.67
6.00	2487.	21.58	7.55	60.00	8592.	41.237	100.842	7.99
6.50	2433.	22.19	6.48	60.00	9968.	42.419	111.794	8.27
7.00	2379.	22.73	5.63	60.00	11400.	43.447	122.745	8.50
7.50	2325.	23.21	4.98	60.00	12781.	44.355	133.696	8.70
8.00	2272.	23.64	4.47	60.00	14128.	45.172	144.647	8.88
8.50	2218.	24.02	4.06	60.00	15529.	45.913	155.598	9.04

Vol. II Table 1-3-8 (CONTINUED)

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
9.00	2166.	24.38	3.70	60.00	16957.	46.588	166.549	9.19
9.50	2115.	24.70	3.40	60.00	18412.	47.208	177.501	9.32
10.00	2064.	25.00	3.14	60.00	19908.	47.781	188.452	9.44
10.50	2013.	25.28	2.91	60.00	21446.	48.311	199.403	9.56
11.00	1962.	25.54	2.70	60.00	23017.	48.804	210.354	9.66
11.50	1911.	25.78	2.52	60.00	24622.	49.265	221.305	9.76
12.00	1860.	26.00	2.36	60.00	26257.	49.696	232.257	9.85
12.50	1810.	26.21	2.22	60.00	27911.	50.101	243.208	9.94
13.00	1759.	26.41	2.09	60.00	29669.	50.481	254.159	10.02
13.50	1709.	26.60	1.96	60.00	31474.	50.840	265.110	10.10
14.00	1658.	26.78	1.85	60.00	33303.	51.178	276.061	10.17
14.50	1608.	26.95	1.76	60.00	35143.	51.499	287.012	10.24
15.00	1558.	27.11	1.67	60.00	36931.	51.803	297.964	10.30
15.50	1508.	27.26	1.59	60.00	38706.	52.093	308.915	10.36
16.00	1457.	27.40	1.52	60.00	40475.	52.369	319.866	10.42
16.50	1407.	27.54	1.45	60.00	42230.	52.635	330.817	10.47
17.00	1357.	27.67	1.39	60.00	44181.	52.888	341.768	10.53

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)
17.50	1307.	27.80	1.33	60.00	46084.	53.131	352.719	10.58
18.00	1257.	27.92	1.28	60.00	47896.	53.364	363.671	10.63
18.50	1207.	28.04	1.23	60.00	49650.	53.589	374.622	10.67
19.00	1158.	28.15	1.19	60.00	51338.	53.806	385.573	10.72
19.50	1108.	28.26	1.15	60.00	52919.	54.016	396.524	10.76
20.00	1059.	28.37	1.12	60.00	54379.	54.220	407.475	10.80
20.50	1010.	28.47	1.09	60.00	55721.	54.419	418.427	10.84
21.00	960.	28.58	1.06	60.00	57075.	54.613	429.378	10.88
21.50	910.	28.67	1.04	60.00	58324.	54.803	440.329	10.92
22.00	860.	28.77	1.02	60.00	59406.	54.989	451.280	10.96
22.50	810.	28.87	1.00	60.00	60274.	55.172	462.231	11.00
23.00	760.	28.96	0.99	60.00	60893.	55.353	473.182	11.03
23.50	710.	29.06	0.98	60.00	61228.	55.533	484.134	11.07
24.00	659.	29.15	0.98	60.00	61201.	55.712	495.085	11.11
24.50	609.	29.24	0.99	60.00	60597.	55.891	506.036	11.14

Vol. II Table 1-3-9

PREDICTION PERFORMANCE
(RESTRICTED GAS PRODUCTION CASE)

FIELD NAME; BEKOK RESERVOIR NAME; B4

RESTRICTED GAS PRODUCTION 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	2997.	1.21	10.00	8.54	855.	1.825	1.559	0.13
1.00	2947.	2.42	10.00	8.60	867.	3.650	3.128	0.20
1.50	2902.	3.64	10.00	8.82	891.	5.476	4.738	0.57
2.00	2858.	4.85	10.00	9.18	939.	7.301	6.413	0.97
2.50	2811.	6.06	10.00	9.78	1029.	9.126	8.197	1.35
3.00	2761.	7.26	9.90	10.88	1196.	10.933	10.183	1.75
3.50	2706.	8.42	9.55	12.36	1379.	12.676	12.439	2.15
4.00	2649.	9.51	9.07	13.32	1557.	14.331	14.871	2.52
4.50	2589.	10.56	8.62	14.33	1774.	15.905	17.486	2.86
5.00	2528.	11.52	7.90	15.00	2035.	17.347	20.224	3.19
5.50	2469.	12.35	6.88	15.00	2331.	18.602	22.962	3.47
6.00	2410.	13.08	6.02	15.00	2659.	19.702	25.699	3.71
6.50	2354.	13.72	5.30	15.00	3001.	20.668	28.437	3.93
7.00	2299.	14.29	4.72	15.00	3352.	21.531	31.175	4.12
7.50	2244.	14.81	4.26	15.00	3695.	22.308	33.913	4.29
8.00	2190.	15.28	3.88	15.00	4041.	23.017	36.650	4.44
8.50	2137.	15.71	3.56	15.00	4399.	23.667	39.388	4.59

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)
9.00	2085.	16.11	3.29	15.00	4767.	24.267	42.126	4.71
9.50	2033.	16.48	3.04	15.00	5148.	24.822	44.864	4.84
10.00	1982.	16.82	2.82	15.00	5540.	25.336	47.602	4.95
10.50	1931.	17.14	2.60	15.00	5944.	25.811	50.339	5.05
11.00	1881.	17.43	2.43	15.00	6357.	26.255	53.077	5.14
11.50	1831.	17.71	2.28	15.00	6777.	26.672	55.815	5.23
12.00	1781.	17.97	2.15	15.00	7194.	27.065	58.553	5.32
12.50	1732.	18.22	2.04	15.00	7604.	27.437	61.291	5.40
13.00	1683.	18.45	1.93	15.00	8019.	27.788	64.028	5.47
13.50	1634.	18.67	1.82	15.00	8436.	28.120	66.766	5.54
14.00	1586.	18.88	1.73	15.00	8854.	28.436	69.504	5.61
14.50	1538.	19.08	1.66	15.00	9272.	28.738	72.242	5.67
15.00	1490.	19.27	1.59	15.00	9679.	29.029	74.980	5.73
15.50	1442.	19.46	1.53	15.00	10048.	29.307	77.717	5.79
16.00	1394.	19.63	1.46	15.00	10384.	29.574	80.455	5.85
16.50	1347.	19.81	1.42	15.00	10752.	29.833	83.193	5.90
17.00	1300.	19.97	1.37	15.00	11119.	30.084	85.931	5.95

 Table 1-3-9 (CONTINUED)

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)
17.50	1253.	20.13	1.33	15.00	11464.	30.327	88.669	6.00
18.00	1207.	20.29	1.29	15.00	11791.	30.563	91.406	6.05
18.50	1161.	20.44	1.25	15.00	12098.	30.791	94.144	6.10
19.00	1115.	20.59	1.23	15.00	12381.	31.015	96.882	6.14
19.50	1069.	20.74	1.20	15.00	12640.	31.234	99.620	6.19
20.00	1023.	20.88	1.18	15.00	12872.	31.449	102.358	6.23
20.50	977.	21.02	1.15	15.00	13152.	31.659	105.095	6.28
21.00	931.	21.15	1.13	15.00	13442.	31.865	107.833	6.32
21.50	885.	21.29	1.11	15.00	13722.	32.067	110.571	6.36
22.00	839.	21.42	1.09	15.00	13971.	32.265	113.309	6.40
22.50	793.	21.55	1.06	15.00	14163.	32.460	116.046	6.44
23.00	747.	21.68	1.05	15.00	14308.	32.652	118.784	6.48
23.50	702.	21.80	1.05	15.00	14401.	32.843	121.522	6.52
24.00	657.	21.93	1.04	15.00	14437.	33.033	124.260	6.56
24.50	612.	22.06	1.04	15.00	14363.	33.223	126.998	6.59
25.00	568.	22.19	1.06	15.00	13985.	33.417	129.735	6.63

Table 2-2-1 CORRELATION TABLE
Vol. II PULAI FIELD

Well No.	1				2				3			
D.F.E.	31				31				31			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top J	2430	2399			2716	2685			2710	2679		
Top a	2620	2589	3068	3037	2910	2879	3355	3324	2859	2828	3290	3259
Top b_1	3593	3562	3670	3639	3874	3843	3923	3892	3794	3763	3884	3853
b_2	3734	3703	3825	3794	4026	3995	4156	4125	3936	3905	4040	4009
b_3	3867	3836	4023	3992	4182	4151	4340	4309	4070	4039	4217	4186
Top c_1	4124	4093	4320	4289	4468	4437	4638	4607	4295	4264	4483	4452
c_2	4569	4538	4591	4560	4851	4820	4880	4849	4725	4694	4745	4714
c_3	4625	4594	4777	4746	4900	4869	5084	5053	4790	4759	4960	4929
Top d	5192	5161	5305	5274	5470	5439	5567	5536	5360	5329	5450	5419
Top e	6095	6064	6181	6150	6387	6356	6451	6420	6262	6231	6417	6386
T.D.	7063	7032			6583	6552			7268	7237		

Table 2-2-1 (Continued)　　CORRELATION TABLE
Vol. II　　PULAI FIELD

Well No.	4			
D.F.E.	31			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top J	2581	2550		
Top a	2770	2739	3256	3225
Top b_1	3825	3794	3902	3871
b_2	3986	3955	4082	4051
b_3	4140	4109	4394	4363
Top c_1	4528	4497	4656	4625
c_2	4908	4877	4938	4907
c_3	4984	4953	5160	5129
Top d	-	-	-	-
Top e				
T.D.	5333	5302		

RESERVOIR DATA

FIELD NAME; PULAI RESERVOIR NAME; B2

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.042	0.	1.181636	0.9200	0.01166
100.	1.053	20.	0.149525	0.8500	0.01179
200.	1.061	40.	0.078859	0.8050	0.01192
400.	1.073	80.	0.039769	0.7250	0.01218
600.	1.085	121.	0.026115	0.6600	0.01244
1000.	1.107	201.	0.015072	0.5820	0.01340
1400.	1.132	282.	0.010354	0.5200	0.01450
1740.	1.155	350.	0.008134	0.4800	0.01566
1790.	1.154	350.	0.007880	0.4804	0.01583

SL	KG/KO	KRO
0.55	260.0000	0.0455
0.60	58.0000	0.0787
0.65	24.0000	0.1250
0.70	8.6000	0.1866
0.75	2.0000	0.2657
0.80	1.0000	0.3644
0.85	0.3300	0.4851
0.90	0.0650	0.6297
0.95	0.0100	0.8006
1.00	0.0001	1.0000

BUBLE POINT PRESSURE (PSIG) = 1740.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 1790.0000
EFFECTIVE COMPRESSIBILITY = 0.0000264
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3040
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 72.2180
OIL PRODUCTION RATE (MSTB/D) = 1.4000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.8728

RESERVOIR PARAMETERS

RESERVOIR DATA

FIELD NAME; PULAI RESERVOIR NAME; B3

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.042	0.	1.181636	0.9200	0.01166
100.	1.053	20.	0.149525	0.8500	0.01179
200.	1.061	40.	0.078859	0.8050	0.01192
400.	1.073	80.	0.039769	0.7250	0.01218
600.	1.085	121.	0.026115	0.6600	0.01244
1000.	1.107	201.	0.015072	0.5820	0.01340
1400.	1.132	282.	0.010354	0.5200	0.01450
1740.	1.155	350.	0.008134	0.4800	0.01566
1790.	1.154	350.	0.007880	0.4804	0.01583

SL	KG/KO	KRO
0.55	260.0000	0.0455
0.60	68.0000	0.0787
0.65	24.0000	0.1250
0.70	7.6000	0.1866
0.75	3.0000	0.2657
0.80	1.0000	0.3644
0.85	0.3300	0.4851
0.90	0.0640	0.6297
0.95	0.0100	0.8006
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 1740.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 1790.0000
EFFECTIVE COMPRESSIBILITY = 0.0000264
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3040
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 65.5026
OIL PRODUCTION RATE (MSTB/D) = 3.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.1190

FIELD NAME; PULAI RESERVOIR NAME; B2

PREDICTED PERFORMANCE

NATURAL DEPLETION CASE

WATER ENC. / OIL PROD. = 0.2

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	1762.	1.77	7.00	2.45	350.	1.278	0.447	0.11
1.00	1738.	3.54	7.00	2.45	350.	2.555	0.895	0.35
1.50	1717.	5.31	7.00	2.47	354.	3.833	1.345	0.58
2.00	1697.	7.08	7.00	2.51	364.	5.111	1.802	0.83
2.50	1677.	8.85	7.00	2.67	403.	6.388	2.290	1.09
3.00	1655.	10.61	7.00	3.17	513.	7.666	2.869	1.36
3.50	1630.	12.38	7.00	4.05	645.	8.943	3.608	1.64
4.00	1601.	14.15	7.00	5.02	801.	10.221	4.523	1.92
4.50	1567.	15.92	7.00	6.40	1042.	11.499	5.691	2.19
5.00	1525.	17.69	7.00	8.48	1413.	12.776	7.239	2.47
5.50	1471.	19.46	7.00	11.70	1962.	14.054	9.374	2.75
6.00	1399.	21.23	7.00	16.22	2720.	15.332	12.336	3.02
6.50	1303.	23.00	7.00	22.73	3850.	16.609	16.485	3.29
7.00	1170.	24.77	7.00	32.40	5524.	17.887	22.399	3.55
7.50	991.	26.50	6.85	44.41	7260.	19.138	30.504	3.81
8.00	789.	28.09	6.30	49.53	8416.	20.288	39.544	4.04
8.50	590.	29.49	5.55	48.31	8842.	21.300	48.361	4.24

PREDICTED PERFORMANCE

FIELD NAME; PULAI   RESERVOIR NAME; B3

NATURAL DEPLETION CASE   WATER ENC. / OIL PROD. = 0.2

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	1705.	1.64	5.89	2.14	378.	1.075	0.391	0.15
1.00	1657.	3.21	5.62	2.16	390.	2.101	0.784	0.36
1.50	1613.	4.69	5.32	2.14	415.	3.072	1.175	0.55
2.00	1571.	6.10	5.05	2.19	456.	3.994	1.574	0.73
2.50	1529.	7.43	4.80	2.32	517.	4.870	1.998	0.91
3.00	1488.	8.71	4.57	2.53	591.	5.703	2.459	1.08
3.50	1445.	9.92	4.36	2.77	684.	6.499	2.965	1.25
4.00	1401.	11.08	4.17	3.09	806.	7.260	3.530	1.40
4.50	1354.	12.19	3.98	3.50	961.	7.986	4.168	1.55
5.00	1305.	13.25	3.79	3.98	1153.	8.677	4.895	1.70
5.50	1251.	14.25	3.60	4.57	1392.	9.335	5.729	1.83
6.00	1192.	15.21	3.43	5.24	1666.	9.960	6.685	1.96
6.50	1127.	16.12	3.26	5.90	1963.	10.556	7.762	2.08
7.00	1057.	16.98	3.11	6.62	2304.	11.123	8.969	2.20
7.50	982.	17.80	2.96	7.36	2686.	11.663	10.312	2.31
8.00	900.	18.58	2.80	8.07	3091.	12.174	11.785	2.42
8.50	814.	19.32	2.64	8.72	3508.	12.656	13.376	2.52

Vol. II Table 2-3-4 (CONTINUED)

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)
9.00	724.	20.02	2.50	9.25	3912.	13.112	15.065	2.61
9.50	631.	20.67	2.35	9.62	4242.	13.541	16.820	2.69
10.00	540.	21.29	2.21	9.50	4305.	13.946	18.554	2.78

FIELD NAME; PULAI RESERVOIR NAME; B2

NATURAL DEPLETION CASE WATER ENC. / OIL PROD. = 0.4

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	1764.	1.77	7.00	2.45	350.	1.278	0.447	0.20
1.00	1743.	3.54	7.00	2.45	350.	2.555	0.894	0.64
1.50	1725.	5.31	7.00	2.46	352.	3.833	1.342	1.09
2.00	1709.	7.08	7.00	2.48	356.	5.111	1.795	1.58
2.50	1693.	8.85	7.00	2.54	369.	6.388	2.258	2.08
3.00	1676.	10.61	7.00	2.69	401.	7.666	2.749	2.60
3.50	1659.	12.38	7.00	3.05	473.	8.943	3.306	3.14
4.00	1639.	14.15	7.00	3.67	581.	10.221	3.975	3.71
4.50	1616.	15.92	7.00	4.40	679.	11.499	4.778	4.27
5.00	1591.	17.69	7.00	5.15	806.	12.776	5.719	4.82
5.50	1561.	19.46	7.00	6.23	984.	14.054	6.857	5.38
6.00	1525.	21.23	7.00	7.75	1235.	15.332	8.271	5.93
6.50	1481.	23.00	7.00	9.80	1588.	16.609	10.060	6.48
7.00	1425.	24.77	7.00	12.64	2041.	17.887	12.367	7.03
7.50	1355.	26.54	7.00	16.27	2635.	19.165	15.337	7.57
8.00	1268.	28.31	7.00	21.08	3428.	20.442	19.184	8.10
8.50	1154.	30.08	7.00	27.52	4495.	21.720	24.207	8.63

Vol. II Table 2-3-5 (CONTINUED)

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)
9.00	1006.	31.84	7.00	36.13	5886.	22.997	30.801	9.15
9.50	830.	33.53	6.68	42.37	6705.	24.217	38.535	9.65
10.00	654.	35.06	6.05	41.89	7060.	25.321	46.181	10.09

PREDICTED PERFORMANCE

FIELD NAME; PULAI

RESERVOIR NAME; B3

WATER ENC. / OIL PROD. =0.4

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	1712.	1.65	5.91	2.14	377.	1.078	0.390	0.29
1.00	1672.	3.23	5.69	2.17	385.	2.117	0.785	0.69
1.50	1635.	4.75	5.45	2.13	400.	3.111	1.174	1.08
2.00	1599.	6.20	5.22	2.15	423.	4.063	1.566	1.47
2.50	1564.	7.60	5.01	2.20	457.	4.977	1.967	1.83
3.00	1529.	8.94	4.80	2.30	504.	5.854	2.386	2.19
3.50	1494.	10.22	4.62	2.46	560.	6.697	2.835	2.54
4.00	1458.	11.46	4.45	2.62	623.	7.509	3.314	2.87
4.50	1420.	12.66	4.29	2.83	701.	8.292	3.831	3.19
5.00	1381.	13.81	4.14	3.08	796.	9.047	4.394	3.51
5.50	1340.	14.92	3.98	3.39	911.	9.773	5.013	3.81
6.00	1296.	15.99	3.82	3.73	1047.	10.471	5.695	4.10
6.50	1249.	17.01	3.67	4.13	1208.	11.141	6.448	4.37
7.00	1199.	17.99	3.52	4.57	1397.	11.785	7.283	4.64
7.50	1143.	18.93	3.38	5.07	1602.	12.402	8.209	4.90
8.00	1084.	19.84	3.25	5.53	1813.	12.994	9.219	5.14
8.50	1021.	20.71	3.12	6.01	2046.	13.564	10.316	5.37

Vol. II Table 2-3-6 (CONTINUED)

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)
9.00	954.	21.54	2.99	6.48	2292.	14.109	11.498	5.60
9.50	883.	22.34	2.86	6.90	2545.	14.631	12.759	5.81
10.00	810.	23.10	2.73	7.29	2798.	15.129	14.089	6.01
10.50	733.	23.82	2.61	7.61	3039.	15.605	15.477	6.21
11.00	655.	24.52	2.49	7.82	3243.	16.058	16.904	6.39
11.50	577.	25.18	2.37	7.85	3395.	16.491	18.337	6.56

Table 3-2-1 CORRELATION TABLE
Vol. II SELIGI FIELD

Well No.	1				2				3			
D.F.E.	31				31				31			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top J	3794	3763			3696	3665			3531	3500		
Top a_1	4045	4014	4060	4029	3936	3905	3967	3936	3770	3739	3804	3773
a_2	4176	4145	4535	4504	4051	4020	4395	4364	3870	3839	4260	4229
Top b_1	5137	5106	5153	5122	4962	4931	5060	5029	4870	4839	4932	4901
b_2	5270	5239	5560	5529	5123	5092	5404	5373	5064	5033	5315	5284
b_3	5664	5633	5815	5784	5508	5477	5645	5614	5435	5404	5667	5636
Top c	6190	6159	6425	6394	6020	5989	6205	6174	5961	5930	6143	6112
T.D.	9012	8981			7050	7019			7030	6999		

Table 3-2-1 (Continued) CORRELATION TABLE
Vol. II SELIGI FIELD

Well No.	4			
D.F.E.	31			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top J	3684	3653		
Top a_1	3919	3888	3955	3924
a_2	4050	4019	4455	4424
Top b_1	5065	5034	5134	5103
b_2	5224	5193	5556	5525
b_3	5598	5567	5773	5742
Top c	6170	6139	6400	6369
T.D.	6650	6619		

Vol. II Table 3-3-1
RESERVOIR PARAMETER

RESERVOIR DATA

FIELD NAME; SELIGI RESERVOIR NAME; A2 (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.050	0.	1.179711	0.5580	0.01182
200.	1.079	44.	0.079072	0.4750	0.01206
400.	1.100	88.	0.040058	0.4350	0.01229
600.	1.112	132.	0.026431	0.4030	0.01252
1000.	1.131	220.	0.015373	0.3580	0.01339
1815.	1.165	400.	0.008031	0.3000	0.01554
1825.	1.165	400.	0.007983	0.3000	0.01557

SL	KG/KO	KRO
0.65	87.0000	0.0602
0.70	44.5000	0.1095
0.75	16.7000	0.1804
0.80	5.3500	0.2770
0.85	1.9700	0.4033
0.90	0.5000	0.5632
0.95	0.1000	0.7608
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 1815.0000
INITIAL RESERVOIR PRESSURE (PSIG) = 1820.0000
EFFECTIVE COMPRESSIBILITY = 0.0000276
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.4060
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 48.4676
OIL PRODUCTION RATE (MSTB/D) = 1.7500
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.3785

RESERVOIR PARAMETER

RESERVOIR DATA

FIELD NAME; SELIGI RESERVOIR NAME; B2 (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.045	0.	1.225899	0.8000	0.01204
200.	1.080	45.	0.082236	0.6800	0.01228
400.	1.102	89.	0.041696	0.6150	0.01251
600.	1.114	134.	0.027537	0.5750	0.01274
800.	1.127	179.	0.020367	0.5450	0.01314
1000.	1.138	223.	0.016049	0.5140	0.01361
2000.	1.194	446.	0.007581	0.3950	0.01627
2240.	1.208	500.	0.006727	0.4500	0.01704
2260.	1.207	500.	0.006667	0.4501	0.01711

SL	KG/KO	KRO
0.65	87.0000	0.0602
0.70	44.5000	0.1095
0.75	16.7000	0.1804
0.80	5.3500	0.2770
0.85	1.9700	0.4033
0.90	0.5000	0.5632
0.95	0.1000	0.7608
1.00	0.0000	1.0000

BUBLE POINT PRESSURE (PSIG)	= 2240.0000
INITIAL RESERVOIR PRESSURE (PSIG)	= 2260.0000
EFFECTIVE COMPRESSIBILITY	= 0.0000330
WATER FORMATION VOLUME FACTOR	= 1.0250
IREDUCIBLE WATER SATURATION	= 0.4260
FINAL PRESSURE (PSIG)	= 500.0000
ORIGINAL OIL IN PLACE (MMSTB)	= 61.6553
OIL PRODUCTION RATE (MSTB/D)	= 2.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.	= 0.0574

RESERVOIR DATA

FIELD NAME; SELIGI RESERVOIR NAME; C (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.071	0.	1.260539	0.9600	0.01218
200.	1.103	62.	0.084529	0.8260	0.01242
400.	1.124	124.	0.042842	0.7670	0.01265
600.	1.141	185.	0.028282	0.7300	0.01289
1000.	1.176	309.	0.016468	0.6650	0.01377
2000.	1.256	618.	0.007766	0.5500	0.01648
2590.	1.310	800.	0.005939	0.5000	0.01846
2630.	1.309	800.	0.005847	0.5003	0.01859

SL	KG/KO	KRO
0.65	87.0000	0.0602
0.70	44.5000	0.1095
0.75	16.7000	0.1804
0.80	5.3500	0.2770
0.85	1.9700	0.4033
0.90	0.5000	0.5632
0.95	0.1000	0.7608
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2590.0000
INITIAL RESERVOIR PRESSURE (PSIG) = 2630.0000
EFFECTIVE COMPRESSIBILITY = 0.0000340
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.4240
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 21.3620
OIL PRODUCTION RATE (MSTB/D) = 2.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0000

RESERVOIR PARAMETER

RESERVOIR DATA

FIELD NAME; SELIGI RESERVOIR NAME; B2 (B-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.045	0.	1.225899	0.8000	0.01204
200.	1.080	45.	0.082236	0.6800	0.01228
400.	1.102	89.	0.041696	0.6150	0.01251
600.	1.114	134.	0.027537	0.5750	0.01274
800.	1.127	179.	0.020367	0.5450	0.01314
1000.	1.138	223.	0.016049	0.5140	0.01361
2000.	1.194	446.	0.007581	0.3950	0.01627
2240.	1.208	500.	0.006727	0.4500	0.01704
2260.	1.207	500.	0.006667	0.4501	0.01711

SL	KG/KO	KRO
0.65	87.0000	0.0602
0.70	44.5000	0.1095
0.75	16.7000	0.1804
0.80	5.3500	0.2770
0.85	1.9700	0.4033
0.90	0.5000	0.5632
0.95	0.1000	0.7608
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2240.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 2260.0000
EFFECTIVE COMPRESSIBILITY = 0.0000312
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3136
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 30.5326
OIL PRODUCTION RATE (MSTB/D) = 2.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 5.1691

Vol. II Table 3-3-5

RESERVOIR PARAMETER

RESERVOIR DATA

FIELD NAME; SELIGI RESERVOIR NAME; C (B-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.071	0.	1.260539	0.9600	0.01218
200.	1.103	62.	0.084529	0.8260	0.01242
400.	1.124	124.	0.042842	0.7670	0.01265
600.	1.141	185.	0.028282	0.7300	0.01289
1000.	1.176	309.	0.016468	0.6650	0.01377
2000.	1.256	618.	0.007766	0.5500	0.01648
2590.	1.310	800.	0.005939	0.5000	0.01846
2630.	1.309	800.	0.005847	0.5003	0.01859

SL	KG/KO	KRO
0.65	87.0000	0.0723
0.70	44.5000	0.1250
0.75	16.7000	0.1985
0.80	5.3500	0.2963
0.85	1.9700	0.4219
0.90	0.5000	0.5787
0.95	0.1000	0.7702
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2590.0000
INITIAL RESERVOIR PRESSURE (PSIG) = 2630.0000
EFFECTIVE COMPRESSIBILITY = 0.0000331
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3810
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 159.0580
OIL PRODUCTION RATE (MSTB/D) = 3.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.1283

Vol. II Table 3-3-6

PREDICTED PERFORMANCE

FIELD NAME; SELIGI RESERVOIR NAME; A2 (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	1762.	2.64	7.00	3.00	456.	1.278	0.547	0.06
1.00	1712.	5.27	7.00	3.58	597.	2.555	1.201	0.37
1.50	1641.	7.91	7.00	5.76	1138.	3.833	2.253	0.67
2.00	1516.	10.53	6.95	11.82	2171.	5.102	4.409	0.97
2.50	1348.	12.99	6.54	16.94	3082.	6.295	7.501	1.22
3.00	1151.	15.18	5.81	20.99	4186.	7.356	11.333	1.44
3.50	925.	17.11	5.12	24.39	5392.	8.291	15.785	1.64
4.00	687.	18.79	4.48	25.92	6102.	9.109	20.516	1.80

REDICTED PERFORMANCE

FIELD NAME; SELIGI 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 PRODUCTION OIL (MMSTB)	CUMULATIVE PRODUCTION GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.50	2166.	1.78	6.00	2.95	486.	1.095	0.539	0.08
1.00	2097.	3.55	6.00	2.90	481.	2.190	1.068	0.28
1.50	2031.	5.33	6.00	3.06	547.	3.285	1.627	0.49
2.00	1956.	7.10	6.00	4.12	928.	4.380	2.379	0.74
2.50	1807.	8.88	6.00	10.61	2711.	5.476	4.315	1.04
3.00	1574.	10.57	5.72	18.21	3718.	6.520	7.638	1.26
3.50	1312.	12.09	5.11	22.02	4962.	7.452	11.656	1.46
4.00	1034.	13.41	4.47	24.88	6161.	8.269	16.197	1.63
4.50	756.	14.57	3.91	25.87	6958.	8.981	20.918	1.77
5.00	507.	15.58	3.42	23.67	6697.	9.606	25.238	1.90

Vol. II Table 3-3-8
PREDICTED PERFORMANCE

FIELD NAME: SELIGI   RESERVOIR NAME; C (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	2508.	1.71	2.00	1.68	874.	0.365	0.307	0.03
1.00	2423.	3.42	2.00	1.90	1041.	0.730	0.653	0.10
1.50	2321.	5.13	2.00	2.52	1569.	1.095	1.112	0.19
2.00	2157.	6.84	2.00	4.64	3609.	1.460	1.960	0.28
2.50	1870.	8.52	1.97	9.06	5666.	1.819	3.613	0.35
3.00	1510.	10.05	1.80	12.61	8645.	2.147	5.914	0.42
3.50	1092.	11.36	1.53	15.85	12001.	2.426	8.806	0.48
4.00	677.	12.45	1.28	16.60	13510.	2.660	11.835	0.53

Vol. II Table 3-3-9
PREDICTED PERFORMANCE

FIELD NAME; SELIGI   RESERVOIR NAME; B2 (B-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	2245.	3.59	6.00	3.00	376.	1.095	0.548	0.0
1.00	2225.	7.17	6.00	5.51	965.	2.190	1.554	0.11
1.50	2203.	10.76	6.00	6.74	1657.	3.285	2.785	0.27
2.00	2161.	14.26	5.85	16.24	3757.	4.353	5.750	0.60
2.50	2097.	17.54	5.50	25.97	6269.	5.356	10.490	0.93
3.00	1995.	20.60	5.12	41.94	10467.	6.290	18.145	1.18
3.50	1845.	23.34	4.59	62.44	17350.	7.127	29.542	1.38
4.00	1646.	25.67	3.90	85.30	27216.	7.839	45.112	1.54
4.50	1390.	27.63	3.28	108.91	39378.	8.437	64.991	1.67
5.00	1113.	29.28	2.76	119.17	46867.	8.940	86.741	1.77
5.50	835.	30.68	2.34	114.90	50969.	9.367	107.713	1.86
6.00	583.	31.86	1.98	100.92	49740.	9.728	126.132	1.93

Vol. II Table 3-3-10

FIELD NAME; SELIGI RESERVOIR NAME; C (B-BLOCK) PREDICTED PERFORMANCE

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	2534.	1.72	15.00	12.50	871.	2.738	2.282	0.27
1.00	2466.	3.44	15.00	14.03	1022.	5.476	4.843	0.82
1.50	2387.	5.13	14.74	17.88	1493.	8.166	8.106	1.41
2.00	2270.	6.73	13.91	29.26	3065.	10.706	13.448	2.02
2.50	2075.	8.19	12.73	53.50	5147.	13.029	23.213	2.53
3.00	1834.	9.51	11.46	71.55	7508.	15.122	36.271	2.97
3.50	1545.	10.67	10.15	91.87	10887.	16.974	53.040	3.36
4.00	1205.	11.69	8.88	113.82	14610.	18.594	73.814	3.69
4.50	849.	12.58	7.71	123.20	17332.	20.002	96.300	3.97

Table 4-2-1 CORRELATION TABLE
Vol. II TAPIS FIELD

Well No.	1				2				3			
D.F.E.	30				32				32			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top J	4040	4010			4535	4503			5038	5006		
Top a_1	4295	4265	4307	4277	4780	4748	4790	4758	5304	5272	5316	5284
a_2	4416	4386	4445	4415	4886	4854	4915	4883	5406	5374	5430	5398
a_3	4607	4577	4718	4688	5065	5033	5134	5102	5572	5540	5656	5624
a_4	4735	4705	4795	4765	5146	5114	5185	5153	5690	5658	5732	5700
a_5	4845	4815	4895	4865	5248	5216	5292	5260	5780	5748	5842	5810
T.D.	8182	8152			7396	7364			6100	6068		

Table 4-2-1 (Continued) CORRELATION TABLE
Vol. II TAPIS FIELD

Well No.	4			
D.F.E.	32			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top J	5856	5824		
Top a_1	6086	6054	6100	6068
a_2	6173	6141	6210	6178
a_3	6302	6270	6395	6363
a_4	6432	6400	6480	6448
a_5	6536	6504	6604	6572
T.D.	7100	7068		

Vol. II Table 4-3-1

RESERVOIR PARAMETER

RESERVOIR DATA

FIELD NAME; TAPIS RESERVOIR NAME; A3 (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.067	0.	1.266313	0.9950	0.01219
200.	1.100	48.	0.084925	0.8850	0.01243
400.	1.129	96.	0.043048	0.8030	0.01267
600.	1.132	145.	0.028421	0.7450	0.01291
1000.	1.159	241.	0.016554	0.6600	0.01379
1600.	1.192	386.	0.009928	0.5800	0.01536
2000.	1.214	482.	0.007812	0.5400	0.01651
2490.	1.240	600.	0.006222	0.5000	0.01813
2530.	1.239	600.	0.006121	0.5001	0.01827

SL	KG/KO	KRO
0.65	93.0000	0.1250
0.70	50.0000	0.1866
0.75	18.5000	0.2657
0.80	5.3500	0.3644
0.85	1.9000	0.4851
0.90	0.4200	0.6297
0.95	0.0600	0.8006
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2490.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 2530.0000
EFFECTIVE COMPRESSIBILITY = 0.0000182
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3030
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 111.5000
OIL PRODUCTION RATE (MSTB/D) = 2.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 3.0673

Vol. II Table 4-3-2
RESERVOIR PARAMETER

RESERVOIR DATA

FIELD NAME; TAPIS RESERVOIR NAME; A5 (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.067	0.	1.266313	0.9950	0.01219
200.	1.100	48.	0.084925	0.8850	0.01243
400.	1.129	96.	0.043048	0.8030	0.01267
600.	1.132	145.	0.028421	0.7450	0.01291
1000.	1.159	241.	0.016554	0.6600	0.01379
1600.	1.192	386.	0.009928	0.5800	0.01536
2000.	1.214	482.	0.007812	0.5400	0.01651
2490.	1.240	600.	0.006222	0.5000	0.01813
2530.	1.239	600.	0.006121	0.5001	0.01827

SL	KG/KO	KRO
0.65	93.0000	0.1517
0.70	50.0000	0.2160
0.75	18.5000	0.2963
0.80	5.3500	0.3944
0.85	1.9000	0.5120
0.90	0.4200	0.6510
0.95	0.0600	0.8130
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2490.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 2530.0000
EFFECTIVE COMPRESSIBILITY = 0.0000184
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.2510
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 50.5850
OIL PRODUCTION RATE (MSTB/D) = 2.0000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 2.2157

RESERVOIR DATA

FIELD NAME; TAPIS RESERVOIR NAME; A3 (B-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.074	0.	1.287482	0.9650	0.01239
200.	1.106	48.	0.086468	0.8450	0.01262
400.	1.129	96.	0.043895	0.7550	0.01285
600.	1.142	145.	0.029026	0.6900	0.01309
1000.	1.169	241.	0.016963	0.6100	0.01395
1600.	1.202	386.	0.010201	0.5290	0.01548
2000.	1.227	482.	0.008043	0.4880	0.01660
2490.	1.256	600.	0.006411	0.4420	0.01806
2690.	1.254	600.	0.005929	0.4425	0.01867

SL	KG/KO	KRO
0.65	93.0000	0.0723
0.70	50.0000	0.1250
0.75	18.5000	0.1985
0.80	5.3500	0.2963
0.85	1.9000	0.4219
0.90	0.4200	0.5787
0.95	0.0600	0.7702
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG)	= 2490.0000
INITIAL RESERVOIR PRESSURE (PSIG)	= 2690.0000
EFFECTIVE COMPRESSIBILITY	= 0.0000207
WATER FORMATION VOLUME FACTOR	= 1.0250
IREDUCIBLE WATER SATURATION	= 0.3970
FINAL PRESSURE (PSIG)	= 500.0000
ORIGINAL OIL IN PLACE (MMSTB)	= 44.9000
OIL PRODUCTION RATE (MSTB/D)	= 3.2500
FRACTION OF RESERVOIR GAS AND OIL VOL.	= 0.1898

RESERVOIR DATA

FIELD NAME; TAPIS RESERVOIR NAME; A4 (B-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.074	0.	1.287482	0.9650	0.01239
200.	1.106	48.	0.086468	0.8450	0.01262
400.	1.129	96.	0.043895	0.7550	0.01285
600.	1.142	145.	0.029026	0.6900	0.01309
1000.	1.169	241.	0.016963	0.6100	0.01395
1600.	1.202	386.	0.010201	0.5290	0.01548
2000.	1.227	482.	0.008043	0.4880	0.01660
2490.	1.256	600.	0.006411	0.4420	0.01806
2690.	1.254	600.	0.005929	0.4425	0.01867

SL	KG/KO	KRO
0.65	93.0000	0.0481
0.70	50.0000	0.0939
0.75	18.5000	0.1623
0.80	5.3500	0.2577
0.85	1.9000	0.3847
0.90	0.4200	0.5477
0.95	0.0600	0.7513
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG)	= 2490.0000
INITIAL RESERVOIR PRESSURE (PSIG)	= 2690.0000
EFFECTIVE COMPRESSIBILITY	= 0.0000217
WATER FORMATION VOLUME FACTOR	= 1.0250
IREDUCIBLE WATER SATURATION	= 0.4480
FINAL PRESSURE (PSIG)	= 500.0000
ORIGINAL OIL IN PLACE (MMSTB)	= 116.3500
OIL PRODUCTION RATE (MSTB/D)	= 2.6000
FRACTION OF RESERVOIR GAS AND OIL VOL.	= 0.0000

Vol. II Table 4-3-5

RESERVOIR PARAMETER

RESERVOIR DATA

FIELD NAME; TAPIS RESERVOIR NAME; A5 (B BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.074	0.	1.287482	0.9650	0.01239
200.	1.106	48.	0.086468	0.8450	0.01262
400.	1.129	96.	0.043895	0.7550	0.01285
600.	1.142	145.	0.029026	0.6900	0.01309
1000.	1.169	241.	0.016963	0.6100	0.01395
1600.	1.202	386.	0.010201	0.5290	0.01548
2000.	1.227	482.	0.008043	0.4880	0.01660
2490.	1.256	600.	0.006411	0.4420	0.01806
2690.	1.254	600.	0.005929	0.4425	0.01867

SL	KG/KO	KRO
0.65	93.0000	0.0983
0.70	50.0000	0.1561
0.75	18.5000	0.2330
0.80	5.3500	0.3318
0.85	1.9000	0.4552
0.90	0.4200	0.6058
0.95	0.0600	0.7865
1.00	0.0010	1.0000

BUBLE POINT PRESSURE (PSIG) = 2490.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 2690.0000
EFFECTIVE COMPRESSIBILITY = 0.0000198
WATER FORMATION VOLUME FACTOR = 1.0250
IREDUCIBLE WATER SATURATION = 0.3540
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 62.2000
OIL PRODUCTION RATE (MSTB/D) = 2.2500
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0457

PREDICTED PERFORMANCE

FIELD NAME; TAPIS

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	2505.	3.27	20.00	12.00	600.	3.650	2.190	0.14
1.00	2481.	6.55	20.00	13.02	679.	7.301	4.566	0.55
1.50	2457.	9.82	20.00	15.75	960.	10.951	7.442	1.28
2.00	2419.	13.10	20.00	29.87	2112.	14.602	12.893	2.35
2.50	2348.	16.37	20.00	61.58	4308.	18.252	24.133	3.40
3.00	2210.	19.58	19.60	125.12	9269.	21.830	46.970	4.25
3.50	1955.	22.51	17.89	244.38	18853.	25.095	91.574	4.96
4.00	1555.	24.99	15.18	391.92	34599.	27.866	163.107	5.54
4.50	1014.	27.02	12.40	533.14	48234.	30.128	260.416	6.00

Vol. II Table 4-3-7

PREDICTED PERFORMANCE

FIELD NAME; TAPIS RESERVOIR NAME; A5 (A-BLOCK)

NATURAL DEPLETION CASE

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
0.50	2500.	2.89	8.00	4.80	600.	1.460	0.876	0.06
1.00	2473.	5.77	8.00	5.32	712.	2.920	1.847	0.26
1.50	2443.	8.66	8.00	7.17	1131.	4.380	3.156	0.58
2.00	2396.	11.55	8.00	13.11	2506.	5.841	5.550	1.01
2.50	2305.	14.43	8.00	27.72	4746.	7.301	10.609	1.38
3.00	2132.	17.27	7.86	55.59	10301.	8.735	20.756	1.71
3.50	1812.	19.86	7.17	108.06	20839.	10.044	40.479	1.99
4.00	1313.	22.02	6.00	172.56	38861.	11.138	71.974	2.22
4.50	701.	23.73	4.75	208.65	46362.	12.006	110.058	2.39

PREDICTED PERFORMANCE

FIELD NAME; TAPIS RESERVOIR NAME; A3 (B-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	2473.	2.64	6.50	3.92	616.	1.186	0.716	0.16
1.00	2385.	5.06	5.95	3.91	701.	2.273	1.430	0.33
1.50	2304.	7.17	5.19	4.07	902.	3.221	2.172	0.53
2.00	2209.	9.12	4.79	5.50	1463.	4.095	3.176	0.73
2.50	2079.	10.91	4.40	8.60	2413.	4.899	4.746	0.93
3.00	1913.	12.55	4.03	11.62	3458.	5.635	6.867	1.09
3.50	1708.	14.04	3.66	15.33	5063.	6.303	9.666	1.23
4.00	1454.	15.37	3.27	20.06	7354.	6.900	13.327	1.36
4.50	1157.	16.54	2.88	24.77	9633.	7.427	17.849	1.47
5.00	847.	17.56	2.52	26.19	11234.	7.886	22.630	1.56
5.50	553.	18.45	2.18	25.23	11603.	8.284	27.234	1.64

PREDICTED PERFORMANCE

FIELD NAME; TAPIS RESERVOIR NAME; A4 (B-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	2407.	2.04	13.00	8.07	642.	2.373	1.473	0.26
1.00	2306.	4.08	12.98	8.76	719.	4.742	3.072	0.71
1.50	2203.	6.03	12.45	10.14	940.	7.015	4.922	1.19
2.00	2085.	7.83	11.46	13.53	1488.	9.106	7.392	1.66
2.50	1927.	9.47	10.50	20.13	2316.	11.022	11.065	2.10
3.00	1739.	10.97	9.57	25.87	3155.	12.769	15.786	2.47
3.50	1524.	12.34	8.68	32.03	4293.	14.352	21.632	2.80
4.00	1282.	13.55	7.78	38.43	5653.	15.771	28.646	3.10
4.50	1020.	14.64	6.91	43.72	7010.	17.033	36.627	3.36
5.00	752.	15.59	6.09	45.72	7871.	18.144	44.971	3.59
5.50	514.	16.43	5.33	41.94	7711.	19.117	52.626	3.78

Vol. III Table 4-3-10

PREDICTED PERFORMANCE

FIELD NAME; TAPIS RESERVOIR NAME; A5 (B 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	2435.	1.98	6.75	4.15	642.	1.232	0.757	0.14
1.00	2343.	3.96	6.75	4.58	731.	2.464	1.594	0.36
1.50	2242.	5.94	6.75	5.80	1034.	3.696	2.652	0.62
2.00	2101.	7.91	6.71	9.61	2034.	4.920	4.405	0.91
2.50	1890.	9.77	6.33	16.08	3170.	6.075	7.340	1.17
3.00	1616.	11.42	5.64	22.84	5153.	7.104	11.509	1.39
3.50	1265.	12.86	4.90	31.92	8125.	7.998	17.336	1.58
4.00	866.	14.08	4.15	38.40	10358.	8.756	24.344	1.73

Table 5-2-1 CORRELATION TABLE
Vol. II PETA FIELD

Well No.	1			
D.F.E.	31			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top J	3490	3459		
Top a_1	3853	3822	4037	4006
a_2	4122	4091	4132	4101
a_3	4330	4299	4430	4299
a_4	4745	4714	4807	4776
a_5	4855	4824	5000	4969
Top b	6084	6053	6120	6089
T.D.	7333	7302		

Table 6-2-1 CORRELATION TABLE
Vol. II BELUMUT FIELD

Well No.	1				2			
D.F.E.	31				31			
Zone	Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top "J"	3345	3314			2725	2694		
Top a_1	3558	3527	3628	3597	2923	2892	2995	2964
a_2	3660	3629	3750	3719	3060	3029	3180	3149
a_3	3875	3844	3985	3956	3220	3189	3330	3299
a_4	4075	4044	4160	4129	3428	3397	3503	3472
Top b_1	4220	4189	4243	4212	3543	3512	3560	3529
b_2	4343	4312	4646	4615	3655	3624	3990	3959
Top c	4790	4759	4855	4824	4095	4064	4158	4127
T.D.	4975	4944			5038	5007		

Table 7-2-1 CORRELATION TABLE
Vol. II ANGSI FIELD

Well No.	1			
D.F.E.	31			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top J	6450	6419		
Top a	6922	6891	6945	6914
Top b_1	7935	7904	8098	8067
b_2	8200	8169	8310	8279
b_3	8405	8374	8530	8499
Top c	8960	8929	8980	8949
T.D.	10132	10101		

Table 8-2-1 CORRELATION TABLE
Vol. II BESAR FIELD

Well No.	1			
D.F.E.	32			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top J	4740	4708		
Top a	5246	5214	5265	5233
Top b_1	6644	6612	6845	6813
b_2	6880	6848	6995	6963
b_3	7040	7008	7282	7250
Top c_1	7387	7355	7436	7404
c_2	8035	8003	8075	8043
c_3	8237	8205	8303	8271
T.D.	8617	8585		

Table 9-2-1 CORRELATION Table
Vol. II JERNEH FIELD

Well No.	1A				2				3			
K.B.E.	31				31				32			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top a_1	4000	3969	4044	4013	4240	4209	4282	4251	4116	4084	4170	4138
a_2	4242	4211	4312	4281	4510	4479	4538	4507	4373	4341	4435	4403
a_3	4346	4315	4482	4451	4592	4561	4750	4719	4504	4472	4644	4612
Top b	4900	4869	5055	4024	5329	5298	5400	5369	5004	4972	5148	5116
Top c_1	5515	5484	5654	5623	5829	5798	5972	5941	5614	5582	5747	5715
c_2	5734	5703	5852	5821	6008	5977	6090	6059	5826	5794	5970	5938
c_3	5999	5968	6124	6093	6318	6287	6432	6401	6112	6080	6170	6138
c_4	6226	6195	6320	6289	6567	6536	6627	6596	6275	6243	6370	6338
c_5	6373	6342	6580	6549	6720	6689	6900	6869	6432	6400	6620	6588
T.D.	6916	6885			7156	7125			6738	6706		

Table 10-2-1 CORRELATION TABLE
Vol. II PILONG FIELD

Well No.	1			
K.B.E.	73			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top a_1	3766	3693	3842	3769
a_2	3920	3847	4032	3959
a_3	4180	4107	4385	4312
Top b_1	5763	5690	5790	5717
b_2	6155	6082	6434	6361
b_3	6570	6497	6635	6562
b_4	6724	6651	6820	6747
b_5	7785	7712	7817	7744
b_6	8356	8283	8390	8317
b_7	8677	8604	8687	8614
T.D.	9200	9127		

Table 11-2-1 CORRELATION TABLE
Vol. II BINTANG FIELD

Well No.	2				3			
K.B.E.	31				31			
Zone	Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top a	4120	4089	4192	4161	4305	4274	4350	4319
Top b_1	4626	4595	4688	4657	4830	4799	4837	4806
b_2	4721	4690	4782	4751	4921	4890	4935	4904
b_3	4964	4933	5010	4979	5160	5129	5192	5161
b_4	5103	5072	5162	5131	5317?	5286?	-	-
Top c	5790	5759	5875	5844	5918	5887	5960	5929
T.D.	6610	6579			6224	6193		

Table 12-2-1 CORRELATION TABLE
Vol. II SEPAT FIELD

Well No.	1			
K.B.E.	31			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top a_1	3012	2981	3084	3053
a_2	3326	3295	3455	3424
a_3	3968	3937	4095	4064
a_4	4176	4145	4202	4171
a_5	4530	4499	4555	4524
a_6	4776	4745	4840	4809
T.D.	5955	5924		

Table 13-2-1 CORRELATION TABLE
Vol. II BUJANG FIELD

Well No.	1			
K.B.E.	31			
Zone	Top		Base	
	Log	Subsea	Log	Subsea
Top a_1	3368	3337	3390	3359
a_2	3753	3722	3885	3854
a_3	4132	4101	4178	4147
a_4	4350	4319	4388	4357
Top b_1	4510	4479	4575	4544
b_2	4645	4614	4753	4722
b_3	4855	4824	4865	4834
b_4	5112	5081	5266	5235
b_5	5370	5339	5400	5369
T.D.	5675	5644		

Table 14-2-1 CORRELATION TABLE
Vol. II SOTONG FIELD

Well No.	1				2				3			
K.B.E.	36				35				36			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top TRENGGANU SH.	6747	6711			6762	6727			6755	6719		
Top a_1	6962	6926			6982	6947			6959	6923		
a_2	7096	7060	7300	7264	7117	7082	7333	7298	7104	7068	7312	7276
a_3	7318	7282	7386	7350	7353	7318	7426	7391	7323	7287	7395	7359
a_4	7417	7381	7446	7410	7460	7425	7504	7469	7437	7401	7472	7436
a_5	7477	7441	7510	7474	7533	7498	7610	7575	7497	7461	7592	7556
a_6	7585	7549	7610	7574	7670	7635	7690	7655	7617	7581	7640	7604
a_7	7638	7602	7668	7632	7720	7685			7667	7631	7690	7654
a_8	7692	7656	7766	7730	7810	7775	7848	7813	7737	7701	7780	7744
a_9	7782	7746			7866	7831			7797	7761		
a_{10}	8160	8124			8287	8252			8227	8191		
T.D.	10018	9982			9613	9578			10056	10020		

Table 14-2-1 (Continued) Vol. II

CORRELATION TABLE
SOTONG FIELD

Well No.	4				5				6			
K.B.E.	36				36				36			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top TRENGGANU SH.	6317	6281			7166	7130			7247	7211		
Top a_1	6533	6497			7455	7419			7530	7494		
a_2	6667	6631	6877	6841	7597	7561	7777	7741	7698	7662	7929	7893
a_3	6900	6864	6940	6904	7808	7772	7847	7811	7954	7918	7990	7954
a_4	7000	6964	7057	7021	7879	7843	7917	7881	8086	8050	8120	8084
a_5					7934	7898	7954	7918	8176	8140	8270	8244
a_6					8043	8007	8066	8030	8308	8272	8328	8292
a_7					8111	8075	8133	8097	8373	8337	8458	8422
a_8					8168	8132	8240	8204	8458	8422	8495	8459
a_9					8286	8250			8500	8464		
a_{10}					8712	8676			8878	8842		
T.D.	8919	8883			9931	9895			10487	10451		

RESERVOIR DATA

FIELD NAME; SOTONG RESERVOIR NAME; A2 (A-BLOCK)

NATURAL DEPLETION CASE

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.102	0.	1.404880	0.7000	0.01344
100.	1.140	31.	0.178700	0.6110	0.01355
200.	1.170	62.	0.094750	0.5500	0.01366
400.	1.196	123.	0.048310	0.5060	0.01389
600.	1.217	185.	0.032090	0.4800	0.01411
1000.	1.246	308.	0.018900	0.4270	0.01482
1200.	1.260	369.	0.015580	0.4050	0.01522
1600.	1.291	492.	0.011470	0.3620	0.01613
2000.	1.325	615.	0.009070	0.3280	0.01714
2500.	1.371	769.	0.007200	0.2830	0.01849
3088.	1.431	950.	0.005890	0.2450	0.02023
3102.	1.431	950.	0.005870	0.2450	0.02028

SL	KG/KO	KRO
0.55	35000.0000	0.0010
0.60	3000.0000	0.0080
0.65	380.0000	0.0270
0.70	80.0000	0.0640
0.75	25.0000	0.1250
0.80	11.0000	0.2160
0.85	5.0000	0.3430
0.90	1.8700	0.5120
0.95	0.5200	0.7290
1.00	0.1000	1.0000

BUBLE POINT PRESSURE (PSIG) = 3088.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 3102.0000
EFFECTIVE COMPRESSIBILITY = 0.0000194
WATER FORMATION VOLUME FACTOR = 1.0696
IREDUCIBLE WATER SATURATION = 0.5130
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 51.9960
OIL PRODUCTION RATE (MSTB/D) = 1.5000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 1.4938

RESERVOIR DATA

FIELD NAME; SOTONG RESERVOIR NAME; A,B,C-BLOCK

NATURAL DEPLETION CASE (CASE-1)

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.060	0.	1.424120	0.8250	0.01332
100.	1.086	26.	0.181030	0.7350	0.01344
200.	1.100	52.	0.095920	0.6650	0.01355
400.	1.123	103.	0.048040	0.5920	0.01379
600.	1.143	155.	0.032390	0.5400	0.01402
1000.	1.182	258.	0.019040	0.4650	0.01478
1200.	1.198	310.	0.015670	0.4430	0.01519
1600.	1.231	413.	0.011510	0.4000	0.01620
2000.	1.266	516.	0.009100	0.3600	0.01733
2500.	1.311	645.	0.007220	0.3200	0.01876
3140.	1.370	810.	0.005830	0.2800	0.02078
3190.	1.369	810.	0.005750	0.2801	0.02095

SL	KG/KO	KRO
0.55	20000.0000	0.0010
0.60	1350.0000	0.0080
0.65	105.0000	0.0270
0.70	20.0000	0.0640
0.75	10.0000	0.1250
0.80	5.7000	0.2160
0.85	2.8000	0.3430
0.90	1.2400	0.5120
0.95	0.4000	0.7290
1.00	0.1000	1.0000

BUBLE POINT PRESSURE (PSIG) = 3140.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 3190.0000
EFFECTIVE COMPRESSIBILITY = 0.0000269
WATER FORMATION VOLUME FACTOR = 1.0697
IREDUCIBLE WATER SATURATION = 0.5003
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 59.8890
OIL PRODUCTION RATE (MSTB/D) = 2.5000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 2.8686

Vol. II Table 14-3-3

RESERVOIR PARAMETERS

RESERVOIR DATA

FIELD NAME; SOTONG RESERVOIR NAME; A,B,C-BLOCK

NATURAL DEPLETION CASE (CASE-2)

PRESSURE (PSIG)	FVFO	RS (SCF/STB)	FVFG	VISO (C.P.)	VISG (C.P.)
0.	1.060	0.	1.424120	0.8250	0.01332
100.	1.086	26.	0.181030	0.7350	0.01344
200.	1.100	52.	0.095920	0.6650	0.01355
400.	1.123	103.	0.048040	0.5920	0.01379
600.	1.143	155.	0.032390	0.5400	0.01402
1000.	1.182	258.	0.019040	0.4650	0.01478
1200.	1.198	310.	0.015670	0.4430	0.01519
1600.	1.231	413.	0.011510	0.4000	0.01620
2000.	1.266	516.	0.009100	0.3600	0.01733
2500.	1.311	645.	0.007220	0.3200	0.01876
3140.	1.370	810.	0.005830	0.2800	0.02078
3190.	1.369	810.	0.005750	0.2801	0.02095

SL	KG/KO	KRO
0.55	20000.0000	0.0010
0.60	1350.0000	0.0080
0.65	105.0000	0.0270
0.70	20.0000	0.0640
0.75	10.0000	0.1250
0.80	5.7000	0.2160
0.85	2.8000	0.3430
0.90	1.2400	0.5120
0.95	0.4000	0.7290
1.00	0.1000	1.0000

BUBLE POINT PRESSURE (PSIG) = 3140.0000
INITIAL RESERVOIR PRESSURE (PSIG)= 3190.0000
EFFECTIVE COMPRESSIBILITY = 0.0000266
WATER FORMATION VOLUME FACTOR = 1.0697
IREDUCIBLE WATER SATURATION = 0.5057
FINAL PRESSURE (PSIG) = 500.0000
ORIGINAL OIL IN PLACE (MMSTB) = 223.6200
OIL PRODUCTION RATE (MSTB/D) = 2.5000
FRACTION OF RESERVOIR GAS AND OIL VOL.= 0.0361

Vol. II Table 14-3-4
RESERVOIR PARAMETERS

FIELD NAME; SOTONG RESERVOIR NAME; A2 (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	2947.	5.27	15.00	41.41	3889.	2.738	7.559	1.48
1.00	2699.	9.72	12.69	63.57	6528.	5.053	19.161	2.95
1.50	2386.	13.06	9.52	80.83	10503.	6.790	33.914	4.01
2.00	2011.	15.83	7.90	99.41	15282.	8.233	52.059	4.91
2.50	1605.	18.13	6.54	114.08	20115.	9.426	72.880	5.63
3.00	1195.	20.03	5.41	117.27	23495.	10.412	94.284	6.22
3.50	865.	21.62	4.55	103.98	21459.	11.243	113.262	6.71
4.00	552.	23.01	3.95	79.90	18564.	11.965	127.845	7.14

RESERVOIR PARAMETERS

FIELD NAME; SOTONG RESERVOIR NAME; A,B,C-BLOCK

NATURAL DEPLETION CASE (CASE-1)

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	3153.	3.05	10.00	8.10	810.	1.825	1.478	0.0
1.00	3111.	6.06	9.87	15.80	2602.	3.627	4.362	0.36
1.50	3043.	8.89	9.31	30.59	4102.	5.326	9.945	0.85
2.00	2950.	11.47	8.45	40.30	5588.	6.867	17.301	1.22
2.50	2830.	13.78	7.59	50.15	7680.	8.253	26.456	1.55
3.00	2677.	15.86	6.81	60.03	10099.	9.497	37.412	1.83
3.50	2489.	17.72	6.11	70.82	13296.	10.611	50.339	2.07
4.00	2336.	19.38	5.46	80.85	16509.	11.607	65.096	2.26
4.50	2143.	20.86	4.86	89.29	20533.	12.494	81.392	2.46
5.00	1933.	22.18	4.32	96.28	23748.	13.283	98.965	2.61
5.50	1738.	23.36	3.87	96.71	26414.	13.989	116.616	2.77
6.00	1538.	24.41	3.47	96.40	28826.	14.622	134.211	2.89
6.50	1360.	25.37	3.12	92.01	30177.	15.192	151.005	3.01
7.00	1163.	26.22	2.82	87.16	31452.	15.706	166.914	3.11
7.50	996.	27.00	2.55	80.07	31313.	16.171	181.527	3.21
8.00	883.	27.72	2.34	71.58	29849.	16.599	194.592	3.28
8.50	748.	28.37	2.16	63.08	28711.	16.992	206.105	3.37

Vol. II Table 14-3-5 (CONTINUED)

TIME (YEAR)	RESERVOIR PRESSURE (PSIG)	RECOVERY (%)	PRODUCTION RATE OIL (MSTB/D)	GAS (MMSCF/D)	GAS OIL RATIO (SCF/STB)	CUMULATIVE PRODUCTION OIL (MMSTB)	GAS (MMMSCF)	WATER ENCROACH. (MMBBL)
9.00	593.	28.97	1.97	55.61	27838.	17.351	216.255	3.45
9.50	500.	29.52	1.81	48.12	25351.	17.681	225.037	3.50

RESERVOIR PARAMETERS

FIELD NAME; SOTONG RESERVOIR NAME; A,B,C-BLOCK

NATURAL DEPLETION CASE (CASE-2)

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	3055.	0.81	9.92	18.87	2852.	1.810	3.445	0.22
1.00	2923.	1.59	9.53	29.19	3285.	3.549	8.773	0.58
1.50	2786.	2.32	8.95	31.64	3816.	5.182	14.548	0.92
2.00	2642.	3.00	8.38	34.61	4475.	6.712	20.865	1.24
2.50	2490.	3.64	7.84	38.16	5290.	8.143	27.830	1.54
3.00	2345.	4.24	7.30	41.43	6094.	9.476	35.392	1.81
3.50	2192.	4.79	6.78	44.51	7068.	10.714	43.516	2.07
4.00	2030.	5.31	6.31	47.62	8036.	11.866	52.208	2.30
4.50	1878.	5.79	5.89	49.73	8858.	12.940	61.285	2.52
5.00	1723.	6.23	5.49	50.94	9756.	13.942	70.582	2.73
5.50	1568.	6.65	5.11	52.35	10665.	14.875	80.136	2.91
6.00	1426.	7.04	4.77	52.14	11200.	15.746	89.652	3.09
6.50	1281.	7.41	4.47	51.47	11874.	16.562	99.047	3.26
7.00	1141.	7.75	4.19	51.04	12367.	17.326	108.362	3.41
7.50	1010.	8.07	3.93	49.10	12617.	18.045	117.323	3.56
8.00	902.	8.37	3.69	46.06	12350.	18.717	125.731	3.68
8.50	796.	8.65	3.45	41.93	11969.	19.348	133.384	3.81

Vol. II Table 14-3-6 (CONTINUED)

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)
9.00	692.	8.92	3.25	38.58	11784.	19.941	140.426	3.93
9.50	592.	9.17	3.07	35.99	11630.	20.502	146.994	4.04
10.00	515.	9.41	2.91	32.43	10752.	21.032	152.913	4.14

Table 15-2-1 CORRELATION TABLE
Vol. II DUYONG FIELD

Well No.	1				2				3			
K.B.E.	31				37				36			
Zone	Top		Base		Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top TRENGGANU SH.	5786	5755	-	-	6484	6447	-	-	7410	7374	-	-
Top a_1	5309	5278	5339	5308	6013	5976	6040	6003	6951	6915	6977	6941
a_2	5545	5514	5596	5565	6230	6193	6260	6223	7171	7135	7200	7164
Top b_1	6735	6704	6808	6777	7263	7226	7371	7334	-	-	-	-
b_2	6901	6870	7027	6996	7439	7402	7539	7502	8222	8186	8365	8329
b_3	7060	7029	7118	7087	7574	7537	7630	7593	8435	8399	8475	8439
b_4	7182	7151	7198	7167	7689	7652	7706	7769	8559	8523	8593	8557
b_5	7374	7343	7482	7451	7867	7830	7958	7921	8745	8709	8808	8772
T.D.	9942	9911			8294	8257			10365	10329		

	Well No.1	Well No.2	Well No.3
zone b5	7374' - 7389' 5488 psig 288°F oil 48.5° gas 0.719	7858' - 7888' 5697 psig 274°F oil 48.1° gas 0.7	8744' - 8764' 5640 psig 296°F * Tight
zone b4		7690' - 7704' 5543 psig at 7656' 5678 psig at 7663' 283°F gas 0.7	8560' - 8590' 5585 psig at 8514' 288°F * Tight & Water
zone b1	FIT at 6794' 4643 psig	7302'-7312' 4930 psig at 7307' 278°F 44.5° 7270'-7278' 4915 psig at 7274' 44.7°	8222'-8254' 5275 psig 298°F 47.1°
zone a2	5570' - 5590' 3100 psig 54.7°	6240' - 6256' 3122 psig at 6248' 52° 0.68	
zone a1		6020' - 6038' 2797 psig at 6029'	6952' - 6976' 3040 psig

Table 15-3-1 PRESSURE AND FLUID DATA
Vol. II DUYONG FIELD

Table 16-2-1 CORRELATION TABLE
Vol. II ANDING FIELD

Well No.	1				2			
K.B.E.	33				36			
Zone	Top		Base		Top		Base	
	Log	Subsea	Log	Subsea	Log	Subsea	Log	Subsea
Top TRENGGANU SH.	6675	6642	6931	6898	6610	6574	6862	6826
Top a_1	6931	6898	6956	6923	6862	6826	6877	6841
a_2	7324	7291	7393	7350	7237	7201	7300	7264
a_3	7460	7427	7483	7450	7361	7325	7390	7354
a_4	7497	7464	7628	7595	7418	7382	7495	7459
a_5	7674	7641	7820	7787	7550	7514	7717	7681
a_6	7867	7834	7940	7909	7766	7730	7937	7901
Top b	8324	8291			8380	8344		
T.D.	8625	8592			9017	8981		

Table 17-5-1 (Vol. II)

MAJOR EQUIPMENT LIST

FOR BEKOK, PULAI AND SELIGI FIELDS - CASE IA

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V-1 1ST STAGE PRODUCTION SEPARATOR	PUWP-A SEWP-A	1 1	SIZE: 5'-6" I.D. x 16'-6" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
	SEWP-B	1	SIZE: 7'-0" I.D. x 14'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
	BEWP-A BEP-A	1 1	SIZE: 7'-6" I.D. x 15'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
V-2 2ND STAGE PRODUCTION SEPARATOR	PUWP-A SEWP-A	1 1	SIZE: 5'-6" I.D. x 16'-6" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
	SEWP-B	1	SIZE: 7'-0" I.D. x 14'-0" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
	BEWP-A BEP-A	1 1	SIZE: 7'-6" I.D. x 15'-0" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
V-3 3RD STAGE PRODUCTION SEPARATOR	PUWP-A SEWP-A	1 1	SIZE: 12'-0" I.D. x 24'-0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
	SEWP-B	1	SIZE: 14'-0" I.D. x 28'-0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
	BEWP-A BEP-A	1 1	SIZE: 15'-0" I.D. x 30'-0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
V-4 TEST SEPARATOR	BEWP-A BEP-A PUWP-A SEWP-A SEWP-B	1 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	BEWP-A BEP-A PUWP-A SEWP-A SEWP-B	2 2 2 2 2	CAPACITY: 35 SCFM
P-2 CRUDE TRANSFER PUMP	PUWP-A SEWP-A	2 2	CAPACITY: 440 GPM TYPE: HORIZONTAL
	SEWP-B	2	CAPACITY: 620 GPM TYPE: HORIZONTAL
	BEWP-A BEP-A	2 2	CAPACITY: 880 GPM TYPE: HORIZONTAL

Table 17-5-1 (Vol. II)

MAJOR EQUIPMENT LIST

FOR BEKOK, PULAI AND SELIGI FIELDS - CASE IA (Cont'd)

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
P-152 FIRE WATER PUMP	BEWP-A BEP-A PUWP-A SEWP-A SEWP-B	1 1 1 1 1	CAPACITY: 1,500 GPM TYPE: VERTICAL
TK-1 DEEMULSIFIER TANK	BEWP-A BEP-A PUWP-A SEWP-A SEWP-B	1 1 1 1 1	SIZE: 6'-0" I.D. x 15'-6" H
TK-2 DEFOAMANT TANK	BEWP-A BEP-A PUWP-A SEWP-A SEWP-B	1 1 1 1 1	SIZE: 6'-0" I.D. x 15'-6" H
M-1 INLET MANIFOLD	BEWP-A BEP-A PUWP-A SEWP-A SEWP-B	1 1 1 1 1	HIGH PRESSURE HEADER LOW PRESSURE HEADER TEST HEADER
FM-1 FLOW METER	PUWP-A SEWP-A	1 1	DESIGN RATE: 480 GPM (MAX.)
	SEWP-B	1	DESIGN RATE: 660 GPM (MAX.)
	BEWP-A BEP-A	1 1	DESIGN RATE: 950 GPM (MAX.)

Table 17-6-1 (Vol. II) **CAPITAL INVESTMENT COST ESTIMATION**

(M$ 1,000)

BEKOK, PULAI AND SELIGI FIELDS	CASE I A	CASE I B	CASE II	CASE III
1. Exploration & Appraisal Wells	56,586	56,586	56,586	35,067
2. Engineering	55,598	59,911	47,438	38,841
3. Development Wells	182,156	182,156	147,821	122,845
4. Facilities				
a. Offshore Platforms	182,792	171,681	141,363	105,158
b. Offshore Production Equipment	27,455	49,373	36,843	25,921
c. Submarine Pipelines	18,446	121,829	14,450	14,429
d. Offshore Storage & Loading Facilities .	131,950	-	120,726	106,883
e. Onshore Terminal & Loading Facilities .	-	43,643	-	-
f. Support Facilities	13,178	30,417	13,177	13,178
Sub Total	373,821	416,943	326,559	265,569
5. Pre-start up Expense	6,117	6,588	5,218	4,273
6. Contingencies	61,158	65,901	52,182	42,726
TOTAL	735,436	788,085	635,804	509,321

ANNUAL OPERATION COST ESTIMATION

Table 17-6-2 (Vol.II)

BEKOK, PULAI AND SELIGI FIELDS CASE IA

(M$ 1,000)

	1	2	3	4	5	6	7	8	9	10
1. Direct Cost										
a. Operating Personnel				1,900	1,895	1,869	1,801	1,501	1,288	1,1
b. Operating Management				190	190	187	180	150	129	1
c. Repair & Maintenance				19,713	19,713	19,713	19,713	19,713	19,713	14,8
d. Operating Supplies				2,037	2,037	2,037	2,037	2,037	2,037	1,5
e. Chemical				4,592	4,531	4,252	3,576	1,928	1,316	9
f. Service Contract				4,884	4,874	4,841	4,745	4,318	4,016	3,7
Sub Total				33,316	33,240	32,899	32,052	29,647	28,499	22,3
2. Indirect Cost										
a. Indirect Personnel				1,046	1,044	1,029	991	826	709	6
b. Insurance				9,957	9,957	9,957	9,957	9,957	9,957	7,4
Sub Total				11,003	11,001	10,986	10,948	10,783	10,666	8,0
TOTAL				44,319	44,241	43,885	43,000	40,430	39,165	30,4

TION

(M$ 1,000)

	5	6	7	8	9	10	11	12	13	14	15	16	17	18
0	1,895	1,869	1,801	1,501	1,288	1,110	998	767	587	523	465	424	391	361
0	190	187	180	150	129	111	100	77	59	52	47	42	39	36
3	19,713	19,713	19,713	19,713	19,713	14,851	14,851	14,851	12,794	12,794	12,794	12,794	12,794	12,794
7	2,037	2,037	2,037	2,037	2,037	1,514	1,514	1,514	1,293	1,293	1,293	1,293	1,293	1,293
2	4,531	4,252	3,576	1,928	1,316	973	805	531	361	310	272	241	216	195
4	4,874	4,841	4,745	4,318	4,016	3,764	3,607	3,282	3,025	2,936	2,852	2,794	2,751	2,703
6	33,240	32,899	32,052	29,647	28,499	22,323	21,875	21,022	18,119	17,908	17,723	17,588	17,484	17,383
6	1,044	1,029	991	826	709	612	549	422	323	290	257	234	216	198
7	9,957	9,957	9,957	9,957	9,957	7,473	7,473	7,473	6,419	6,419	6,419	6,419	6,419	6,419
3	11,001	10,986	10,948	10,783	10,666	8,085	8,022	7,895	6,742	6,709	6,676	6,653	6,635	6,617
9	44,241	43,885	43,000	40,430	39,165	30,408	29,897	28,917	24,861	24,617	24,399	24,241	24,119	24,000

	11	12	13	14	15	16	17	18	19	20	21	22	23
10	998	767	587	523	465	424	391	361	338	312	287	277	188
11	100	77	59	52	47	42	39	36	34	31	29	28	19
51	14,851	14,851	12,794	12,794	12,794	12,794	12,794	12,794	12,794	12,794	12,794	12,794	12,794
14	1,514	1,514	1,293	1,293	1,293	1,293	1,293	1,293	1,293	1,293	1,293	1,293	1,293
73	805	531	361	310	272	241	216	196	178	165	155	145	94
64	3,607	3,282	3,025	2,936	2,852	2,794	2,751	2,703	2,672	2,637	2,604	2,586	2,461
23	21,875	21,022	18,119	17,908	17,723	17,588	17,484	17,383	17,309	17,232	17,162	17,123	16,849
512	549	422	323	290	257	234	216	198	185	173	157	152	104
473	7,473	7,473	6,419	6,419	6,419	6,419	6,419	6,419	6,419	6,419	6,419	6,419	6,419
085	8,022	7,895	6,742	6,709	6,676	6,653	6,635	6,617	6,604	6,592	6,576	6,571	6,523
408	29,897	28,917	24,861	24,617	24,399	24,241	24,119	24,000	23,913	23,824	23,738	23,694	23,372

ANNUAL OPERATION COST ESTIMATION

Table 17-6-3 (Vol.II) BEKOK, PULAI AND SELIGI FIELDS CASE IB (M$ 1,000)

	1	2	3	4	5	6	7	8	9	10
1. Direct Cost										
a. Operating Personnel				1,900	1,895	1,869	1,801	1,501	1,288	1,110
b. Operating Management				190	190	187	180	150	129	111
c. Repair & Maintenance				11,806	11,806	11,806	11,806	11,806	11,806	8,560
d. Operating Supplies				2,195	2,195	2,195	2,195	2,195	2,195	1,671
e. Chemical				4,592	4,531	4,252	3,576	1,928	1,316	973
f. Service Contract				4,884	4,874	4,841	4,745	4,318	4,016	3,764
Sub Total				25,567	25,491	25,150	24,303	21,898	20,750	16,189
2. Indirect Cost										
a. Indirect Personnel				1,046	1,044	1,029	991	826	709	612
b. Insurance				9,484	9,484	9,484	9,484	9,484	9,484	6,998
Sub Total				10,530	10,528	10,513	10,475	10,310	10,193	7,610
TOTAL				36,097	36,019	35,663	34,778	32,208	30,943	23,799

(M$ 1,000)

5	6	7	8	9	10	11	12	13	14	15	16	17	18
1,895	1,869	1,801	1,501	1,288	1,110	998	767	587	523	465	424	391	361
190	187	180	150	129	111	100	77	59	52	47	42	39	36
11,806	11,806	11,806	11,806	11,806	8,560	8,560	8,560	7,184	7,184	7,184	7,184	7,184	7,184
2,195	2,195	2,195	2,195	2,195	1,671	1,671	1,671	1,179	1,179	1,179	1,179	1,179	1,179
4,531	4,252	3,576	1,928	1,316	973	805	531	361	310	272	241	216	196
4,874	4,841	4,745	4,318	4,016	3,764	3,607	3,282	3,025	2,936	2,852	2,794	2,751	2,703
25,491	25,150	24,303	21,898	20,750	16,189	15,741	14,888	12,395	12,184	11,999	11,864	11,760	11,659
1,044	1,029	991	826	709	612	549	422	323	290	257	234	216	198
9,484	9,484	9,484	9,484	9,484	6,998	6,998	6,998	5,944	5,944	5,944	5,944	5,944	5,944
10,528	10,513	10,475	10,310	10,193	7,610	7,547	7,420	6,267	6,234	6,201	6,178	6,160	6,142
36,019	35,663	34,778	32,208	30,943	23,799	23,288	22,308	18,662	18,418	18,200	18,042	17,920	17,801

	11	12	13	14	15	16	17	18	19	20	21	22	23
0	998	767	587	523	465	424	391	361	338	312	287	277	188
1	100	77	59	52	47	42	39	36	34	31	29	28	19
0	8,560	8,560	7,184	7,184	7,184	7,184	7,184	7,184	7,184	7,184	7,184	7,184	7,184
1	1,671	1,671	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179
3	805	531	361	310	272	241	216	196	178	165	155	145	94
4	3,607	3,282	3,025	2,936	2,852	2,794	2,751	2,703	2,672	2,637	2,604	2,586	2,461
9	15,741	14,888	12,395	12,184	11,999	11,864	11,760	11,659	11,585	11,508	11,438	11,399	11,125
2	549	422	323	290	257	234	216	198	185	173	157	152	104
8	6,998	6,998	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944
0	7,547	7,420	6,267	6,234	6,201	6,178	6,160	6,142	6,129	6,117	6,101	6,096	6,048
9	23,288	22,308	18,662	18,418	18,200	18,042	17,920	17,801	17,714	17,625	17,539	17,495	17,173

ANNUAL OPERATION COST ESTIMATION

Table 17-6-4 (Vol.II) BEKOK, PULAI AND SELIGI FIELDS CASE II (M$ 1,000)

	1	2	3	4	5	6	7	8	9	10
1. Direct Cost										
a. Operating Personnel				1,816	1,814	1,796	1,725	1,412	1,245	1,11[illegible]
b. Operating Management				183	180	180	173	142	124	11[illegible]
c. Repair & Maintenance				16,713	16,713	16,713	16,713	14,480	14,480	14,48[illegible]
d. Operating Supplies				1,722	1,722	1,722	1,722	1,499	1,499	1,49[illegible]
e. Chemical				3,708	3,680	3,520	2,997	1,641	1,224	97[illegible]
f. Service Contract				4,582	4,580	4,552	4,453	4,011	3,774	3,58[illegible]
Sub Total				28,724	28,689	28,483	27,783	23,185	22,346	21.76[illegible]
2. Indirect Cost										
a. Indirect Personnel				1,001	998	988	950	777	686	612
b. Insurance				8,433	8,433	8,433	8,433	7,315	7,315	7,315
Sub Total				9,434	9,431	9,421	9,383	8,092	8,001	7,927
TOTAL				38,158	38,120	37,904	37,166	31,277	30,347	29,688

(M$ 1,000)

	6	7	8	9	10	11	12	13	14	15	16	17	18	19
	1,796	1,725	1,412	1,245	1,113	1,001	772	584	521	470	424	391	361	330
	180	173	142	124	112	99	76	58	53	48	43	38	36	33
	16,713	16,713	14,480	14,480	14,480	14,480	14,480	12,430	12,430	12,430	12,430	12,430	12,430	12,430
	1,722	1,722	1,499	1,499	1,499	1,499	1,499	1,250	1,250	1,250	1,250	1,250	1,250	1,250
	3,520	2,997	1,641	1,224	973	808	531	361	310	272	241	216	196	180
	4,552	4,453	4,011	3,774	3,584	3,429	3,106	2,840	2,751	2,677	2,614	2,563	2,520	2,482
	28,483	27,783	23,185	22,346	21.761	21,316	20,464	17,523	17,315	17,147	17,002	16,888	16,793	16,705
	988	950	777	686	612	551	424	323	287	259	234	216	198	183
	8,433	8,433	7,315	7,315	7,315	7,315	7,315	6,220	6,220	6,220	6,220	6,220	6,220	6,220
	9,421	9,383	8,092	8,001	7,927	7,866	7,739	6,543	6,507	6,479	6,454	6,436	6,418	6,403
	37,904	37,166	31,277	30,347	29,688	29,182	28,203	24,066	23,822	23,626	23,456	23,324	23,211	23,108

	11	12	13	14	15	16	17	18	19	20	21	22	23
3	1,001	772	584	521	470	424	391	361	330	307	292	274	188
2	99	76	58	53	48	43	38	36	33	30	30	28	18
0	14,480	14,480	12,430	12,430	12,430	12,430	12,430	12,430	12,430	12,430	12,430	12,430	12,430
9	1,499	1,499	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
8	808	531	361	310	272	241	216	196	180	165	155	145	94
1	3,429	3,106	2,840	2,751	2,677	2,614	2,563	2,520	2,482	2,446	2,423	2,400	2,278
1	21,316	20,464	17,523	17,315	17,147	17,002	16,888	16,793	16,705	16,628	16,580	16,527	16,258
2	551	424	323	287	259	234	216	198	183	170	163	152	104
5	7,315	7,315	6,220	6,220	6,220	6,220	6,220	6,220	6,220	6,220	6,220	6,220	6,220
7	7,866	7,739	6,543	6,507	6,479	6,454	6,436	6,418	6,403	6,390	6,383	6,372	6,324
3	29,182	28,203	24,066	23,822	23,626	23,456	23,324	23,211	23,108	23,018	22,963	22,899	22,582

ANNUAL OPERATION COST ESTIMATION

Table 17-6-5 (Vol.II) BEKOK, PULAI AND SELIGI FIELDS CASE III (M$ 1,000)

	1	2	3	4	5	6	7	8	9	10
1. Direct Cost										
a. Operating Personnel				1,681	1,676	1,651	1,560	1,367	1,207	1,07
b. Operating Management				168	168	165	155	137	122	10
c. Repair & Maintenance				13,528	13,528	13,528	13,528	13,528	13,528	13,52
d. Operating Supplies				1,410	1,410	1,410	1,410	1,410	1,410	1,41
e. Chemical				3,076	3,051	2,891	2,367	1,641	1,224	9
f. Service Contract				3,917	3,912	3,876	3,752	3,493	3,274	3,0
Sub Total				23,780	23,745	23,521	22,772	21,576	20,765	20,1
2. Indirect Cost										
a. Indirect Personnel				925	923	910	860	753	666	59
b. Insurance				6,855	6,855	6,855	6,855	6,855	6,855	6,85
Sub Total				7,780	7,778	7,765	7,715	7,608	7,521	7,44
TOTAL				31,560	31,523	31,286	30,487	29,184	28,286	27,63

(M$ 1,000)

5	6	7	8	9	10	11	12	13	14	15	16	17	18	1
676	1,651	1,560	1,367	1,207	1,074	968	744	569	508	450	409	381	348	3
168	165	155	137	122	107	97	74	56	51	46	41	38	36	
528	13,528	13,528	13,528	13,528	13,528	13,528	11,547	11,547	11,547	11,547	11,547	11,547	11,547	11,5
410	1,410	1,410	1,410	1,410	1,410	1,410	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,1
051	2,891	2,367	1,641	1,224	973	808	531	361	310	272	241	216	196	1
912	3,876	3,752	3,493	3,274	3,096	2,951	2,652	2,416	2,332	2,256	2,184	2,159	2,116	2,0
745	23,521	22,772	21,576	20,765	20,188	19,762	16,714	16,115	15,914	15,737	15,588	15,507	15,409	15,3
923	910	860	753	666	593	534	409	312	279	249	221	211	193	1
855	6,855	6,855	6,855	6,855	6,855	6,855	5,794	5,794	5,794	5,794	5,794	5,794	5,794	5,7
778	7,765	7,715	7,608	7,521	7,448	7,389	6,203	6,106	6,073	6,043	6,015	6,005	5,987	5,9
523	31,286	30,487	29,184	28,286	27,636	27,151	22,917	22,221	21,987	21,780	21,603	21,512	21,396	21,3

11	12	13	14	15	16	17	18	19	20	21	22	23
968	744	569	508	450	409	381	348	328	302	279	269	183
97	74	56	51	46	41	38	36	33	30	28	28	18
13,528	11,547	11,547	11,547	11,547	11,547	11,547	11,547	11,547	11,547	11,547	11,547	11,547
1,410	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166	1,166
808	531	361	310	272	241	216	196	180	165	155	145	94
2,951	2,652	2,416	2,332	2,256	2,184	2,159	2,116	2,088	2,055	2,024	2,009	1,892
19,762	16,714	16,115	15,914	15,737	15,588	15,507	15,409	15,342	15,265	15,199	15,164	14,900
534	409	312	279	249	221	211	193	180	168	155	150	102
6,855	5,794	5,794	5,794	5,794	5,794	5,794	5,794	5,794	5,794	5,794	5,794	5,794
7,389	6,203	6,106	6,073	6,043	6,015	6,005	5,987	5,974	5,962	5,949	5,944	5,896
27,151	22,917	22,221	21,987	21,780	21,603	21,512	21,396	21,316	21,227	21,148	21,108	20,796

Table 17-6-6 (Vol II) **INVESTMENT SCHEDULE**

(M$ 1,000)

BEKOK, PULAI AND SELIGI FIELDS CASE IA

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	56,586	-	-	
2. Engineering	55,598	-	-	
3. Development Wells	-	28,971	153,185	
4. Offshore Platforms	42,134	111,542	29,116	
5. Offshore Production Equipment	7,661	18,123	1,671	
6. Submarine Pipelines	-	6,279	12,167	
7. Offshore Storage & Loading Facilities	20,320	74,419	37,211	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	4,392	8,786	-	
10. Pre-start up Expense	1,301	2,482	2,334	
11. Contingencies	13,010	24,813	23,335	
Total	201,002	275,415	259,019	

Table 17-6-7 (Vol. II) INVESTMENT SCHEDULE

BEKOK, PULAI AND SELIGI FIELDS CASE IB

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	56,586	-	-	
2. Engineering	59,911	-	-	
3. Development Wells	-	43,406	138,750	
4. Offshore Platforms	42,136	110,800	18,745	
5. Offshore Production Equipment	10,432	26,899	12,042	
6. Submarine Pipelines	46,556	64,473	10,800	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	1,651	16,716	25,276	
9. Support Facilities	5,431	13,038	11,948	
10. Pre-start up Expense	1,661	2,753	2,174	
11. Contingencies	16,612	27,534	21,755	
Total	240,976	305,619	241,490	

Table 17-6-8 (Vol. II) INVESTMENT SCHEDULE

BEKOK, PULAI AND SELIGI FIELDS CASE II

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	56,586	-	-	
2. Engineering	47,438	-	-	
3. Development Wells	-	41,784	106,037	
4. Offshore Platforms	38,435	88,186	14,742	
5. Offshore Production Equipment	5,972	21,643	9,228	
6. Submarine Pipelines	-	6,279	8,171	
7. Offshore Storage & Loading Facilities	19,202	69,728	31,796	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	-	8,783	4,394	
10. Pre-start up Expense	1,110	2,364	1,744	
11. Contingencies	11,105	23,640	17,437	
Total	179,848	262,407	193,549	

Table 17-6-9 (Vol. II) INVESTMENT SCHEDULE

BEKOK, PULAI AND SELIGI FIELDS CASE III

(M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	35,067	-	-	
2. Engineering	38,841	-	-	
3. Development Wells	-	43,406	79,439	
4. Offshore Platforms	38,862	61,681	4,615	
5. Offshore Production Equipment	5,591	14,440	5,890	
6. Submarine Pipelines		12,819	1,610	
7. Offshore Storage & Loading Facilities	15,875	44,145	46,863	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	4,392	8,786	-	
10. Pre-start up Expense	1,036	1,853	1,384	
11. Contingencies	10,356	18,528	13,842	
Total	150,020	205,658	153,643	

*** 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 OIL BEKOK, PULAI AND SELIGI FIELDS

 CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE CASE

*** 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	: 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)	201002.	275415.	259019.	0.	0.	0.	0.	0.	0.	0.	735436.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	39859.	39331.	36904.	31038.	16733.	11424.	8453.	183742.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	32.41	32.41	32.41	32.41	32.41	32.41	32.39	
BASIC PRICE OF OIL (M$/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	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	735436.
OIL PRODUCTION (M BBL/YEAR)	6993.	4617.	3128.	2694.	2351.	2084.	1872.	1697.	1551.	1431.	212160.
SALES PRICE OF OIL (M$/BBL)	32.39	32.44	32.51	32.51	32.51	32.51	32.51	32.51	32.51	32.51	
BASIC PRICE OF OIL (M$/BBL)	58.02	60.92	63.97	67.17	70.53	74.05	77.76	81.64	85.73	90.01	

*** 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 OIL BEKOK, PULAI AND SELIGI FIELDS

(CONT'D)

VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE CASE

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR. TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	735436.
OIL PRODUCTION (M BBL/YEAR)	1336.	1252.	825.	215573.
SALES PRICE OF OIL (M$/BBL)	32.51	32.51	32.51	
BASIC PRICE OF OIL (M$/BBL)	94.51	99.24	104.20	

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE 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 OIL	0.	0.	0.	632996.	624611.	586068.	492911.	265735.	181423.	134158.	2917901.
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.	12500.	0.	0.	0.	0.	0.	0.	12500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	10000.	0.	0.	0.	0.	0.	0.	10000.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	2648.	2613.	2452.	1848.	772.	585.	440.	11357.
5 TOTAL CASH INFLOW	0.	0.	0.	648145.	627224.	588520.	494759.	266507.	182008.	134598.	2941758.
6 INCOME TAX	0.	0.	0.	291665.	282251.	264834.	222641.	119928.	81904.	60569.	1323790.
7 NET CASH FLOW	0.	0.	0.	356480.	344974.	323686.	272118.	146579.	100104.	74029.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	356480.	701453.	1025139.	1297257.	1443835.	1543939.	1617967.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	110987.	73390.	49829.	42915.	37451.	33198.	29821.	27033.	24707.	22796.	3370022.
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.	0.	0.	0.	0.	0.	0.	0.	12500.
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.	10000.
4 RESEARCH FUND FROM OIL CO.	387.	302.	208.	180.	157.	139.	125.	113.	103.	95.	13166.
5 TOTAL CASH INFLOW	111374.	73692.	50037.	43095.	37608.	33337.	29946.	27146.	24811.	22891.	3395688.
6 INCOME TAX	50118.	33161.	22517.	19393.	16924.	15002.	13475.	12216.	11165.	10301.	1528055.
7 NET CASH FLOW	61256.	40530.	27520.	23702.	20684.	18335.	16470.	14930.	13646.	12590.	
8 CUMULATIVE NET CASH FLOW	1679222.	1719752.	1747272.	1770974.	1791658.	1809993.	1826463.	1841393.	1855038.	1867628.	

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE CASE

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	21282.	19944.	13142.	3424390.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	12500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	10000.
4 RESEARCH FUND FROM OIL CO.	89.	83.	55.	13394.
5 TOTAL CASH INFLOW	21371.	20028.	13197.	3450283.
6 INCOME TAX	9617.	9012.	5939.	1552622.
7 NET CASH FLOW	11754.	11015.	7258.	
8 CUMULATIVE NET CASH FLOW	1879382.	1890397.	1897655.	

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

 CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE 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.	300520.	276972.	247505.	198166.	101661.	66122.	46570.
CUMULATIVE PRESENT WORTH	0.	0.	0.	300520.	577492.	824997.	1023162.	1124823.	1190945.	1237514.
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.	255365.	224657.	191631.	146455.	71718.	44526.	29934.
CUMULATIVE PRESENT WORTH	0.	0.	0.	255365.	480022.	671653.	818108.	889826.	934352.	964287.
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.	218571.	183927.	150068.	109704.	51385.	30516.	19623.
CUMULATIVE PRESENT WORTH	0.	0.	0.	218571.	402498.	552566.	662270.	713655.	744170.	763794.

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	36700.	23126.	14955.	12267.	10195.	8607.	7363.	6357.	5534.	4862.
CUMULATIVE PRESENT WORTH	1274213.	1297339.	1312294.	1324560.	1334755.	1343362.	1350725.	1357082.	1362615.	1367477.
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	22518.	13545.	8361.	6546.	5193.	4185.	3418.	2816.	2340.	1963.
CUMULATIVE PRESENT WORTH	986804.	1000349.	1008710.	1015256.	1020449.	1024634.	1028052.	1030868.	1033208.	1035171.
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	14120.	8124.	4797.	3592.	2726.	2101.	1641.	1294.	1028.	825.
CUMULATIVE PRESENT WORTH	777913.	786037.	790833.	794426.	797152.	799253.	800894.	802188.	803216.	804041.

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE CASE

* * 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	4323.	3859.	2422.
CUMULATIVE PRESENT WORTH	1371800.	1375658.	1378079.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	1666.	1419.	850.
CUMULATIVE PRESENT WORTH	1036837.	1038256.	1039106.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	670.	546.	313.
CUMULATIVE PRESENT WORTH	804711.	805256.	805569.

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE CASE

* * 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 OIL	0.	0.	0.	271284.	267691.	251172.	211248.	113886.	77753.	57496.	1250528.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	258366.	254943.	239212.	158360.	40430.	39165.	30408.	1020884.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	129183.	127472.	119606.	100594.	54232.	37025.	27379.	595491.
4 TOTAL CASH INFLOW	0.	0.	0.	658833.	650106.	609990.	470202.	208548.	153943.	115284.	2866900.
5 ROYALTY	0.	0.	0.	129183.	127472.	119606.	100594.	54232.	37025.	27379.	595491.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	12500.	0.	0.	0.	0.	0.	0.	12500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	10000.	0.	0.	0.	0.	0.	0.	10000.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	2648.	2613.	2452.	1848.	772.	585.	440.	11357.
OPERATING EXPENSES	0.	0.	0.	258366.	254943.	239212.	158360.	40430.	39165.	30408.	1020884.
(M$/BBL)	0.0	0.0	0.0	6.48	6.48	6.48	5.10	2.42	3.43	3.60	5.56
9 OPERATING COST	0.	0.	0.	44319.	44241.	43885.	43000.	40430.	39165.	30408.	285448.
CAPITAL COST RECOVERY	0.	0.	0.	214047.	210702.	195327.	115360.	0.	0.	0.	735436.
INCOME BEFORE TAX	0.	0.	0.	256136.	265077.	248720.	209399.	113115.	77168.	57057.	1226671.
10 INCOME TAX	0.	0.	0.	115261.	119285.	111924.	94230.	50902.	34726.	25676.	552002.
11 CAPITAL INVESTMENT	201002.	275415.	259019.	0.	0.	0.	0.	0.	0.	0.	735436.
12 TOTAL CASH OUTFLOW	201002.	275415.	259019.	303911.	293611.	277867.	239672.	146335.	111500.	83902.	2192230.
13 NET CASH FLOW	-201002.	-275415.	-259019.	354922.	356495.	332123.	230530.	62213.	42442.	31381.	
14 CUMULATIVE NET CASH FLOW	-201002.	-476417.	-735436.	-380514.	-24020.	308103.	538633.	600846.	643289.	674670.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	12.83	18.59	19.69	20.28	20.63	
16 CORPORATE CAPITAL	201002.	275415.	259019.	0.	0.	0.	0.	0.	0.	0.	735436.
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 5.1 YEARS

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	47566.	31453.	21355.	18392.	16051.	14228.	12780.	11586.	10589.	9770.	1444291.
2 SALES REVENUE FROM COST OIL	29897.	28917.	20338.	17516.	15286.	13550.	12172.	11034.	10085.	9304.	1188978.
3 SALES REVENUE FROM ROYALTY OIL	22650.	14978.	10169.	8758.	7643.	6775.	6086.	5517.	5042.	4652.	687761.
4 TOTAL CASH INFLOW	100113.	75347.	51863.	44667.	38980.	34553.	31038.	28136.	25716.	23726.	3321032.
5 ROYALTY	22650.	14978.	10169.	8758.	7643.	6775.	6086.	5517.	5042.	4652.	687761.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	12500.
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.	10000.
8 RESEARCH FUND TO PETRONAS	387.	302.	208.	180.	157.	139.	125.	113.	103.	95.	13166.
OPERATING EXPENSES	29897.	28917.	24861.	24617.	24399.	24241.	24119.	24000.	23913.	23824.	1273672.
(M$/BBL)	4.28	6.26	7.95	9.14	10.38	11.63	12.88	14.14	15.42	16.65	6.00
9 OPERATING COST	29897.	28917.	24861.	24617.	24399.	24241.	24119.	24000.	23913.	23824.	538236.
CAPITAL COST RECOVERY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	735436.
INCOME BEFORE TAX	47178.	31151.	21147.	18213.	15894.	14089.	12656.	11472.	10485.	9674.	1418624.
10 INCOME TAX	21230.	14018.	9516.	8196.	7152.	6340.	5695.	5163.	4718.	4353.	638384.
11 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	735436.
12 TOTAL CASH OUTFLOW	74165.	58214.	44755.	41750.	39351.	37495.	36025.	34793.	33777.	32925.	2625473.
13 NET CASH FLOW	25948.	17133.	7108.	2916.	-371.	-2942.	-4987.	-6656.	-8061.	-9199.	
14 CUMULATIVE NET CASH FLOW	700618.	717751.	724859.	727775.	727404.	724462.	719475.	712819.	704757.	695559.	
15 DCF ROR OF NET CASH FLOW (%)	20.86	20.99	21.03	21.04	21.04	21.03	21.02	21.00	20.99	20.97	
16 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	735436.
17 INTEREST	0.	0.	0.	0.	15.	149.	478.	982.	1649.	2471.	5742.
18 BANK BORROWING	0.	0.	0.	0.	386.	3091.	5464.	7638.	9710.	11670.	37959.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	386.	3477.	8941.	16579.	26289.	37959.	

21 PAYOUT TIME 5.1 YEARS

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	9121.	8548.	5632.	1467590.
2 SALES REVENUE FROM COST OIL	8687.	8141.	5364.	1211168.
3 SALES REVENUE FROM ROYALTY OIL	4343.	4070.	2682.	698856.
4 TOTAL CASH INFLOW	22151.	20758.	13679.	3377618.
5 ROYALTY	4343.	4070.	2682.	698856.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.
7 BONUS	0.	0.	0.	12500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	10000.
8 RESEARCH FUND TO PETRONAS	89.	83.	55.	13394.
OPERATING EXPENSES	23738.	23694.	23372.	1344476.
(M$/BBL)	17.77	18.92	28.33	6.24
9 OPERATING COST	23738.	23694.	23372.	609040.
CAPITAL COST RECOVERY	0.	0.	0.	735436.
INCOME BEFORE TAX	9032.	8464.	5577.	1441696.
10 INCOME TAX	4064.	3809.	2510.	648767.
11 CAPITAL INVESTMENT	0.	0.	0.	735436.
12 TOTAL CASH OUTFLOW	32235.	31657.	28619.	2717981.
13 NET CASH FLOW	-10084.	-10898.	-14940.	
14 CUMULATIVE NET CASH FLOW	685475.	674576.	659636.	
15 DCF ROR OF NET CASH FLOW (%)	20.96	20.95	20.93	
16 CORPORATE CAPITAL	0.	0.	0.	735436.
17 INTEREST	3440.	4555.	5952.	19689.
18 BANK BORROWING	13524.	15453.	20893.	87828.
19 REPAYMENT	0.	0.	0.	0.
20 BORROWING BALANCE	51483.	66935.	87828.	

21 PAYOUT TIME 5.1 YEARS

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE 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	-196158.	-255979.	-229276.	299206.	286222.	253956.	167880.	43148.	28035.	19741.
CUMULATIVE PRESENT WORTH	-196158.	-452137.	-681413.	-382207.	-95985.	157972.	325851.	369000.	397034.	416776.
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	-191648.	-238726.	-204103.	254249.	232160.	196626.	124073.	30440.	18878.	12689.
CUMULATIVE PRESENT WORTH	-191648.	-430373.	-634477.	-380228.	-148068.	48557.	172630.	203070.	221948.	234637.
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	-187435.	-223327.	-182636.	217616.	190070.	153979.	92938.	21810.	12938.	8318.
CUMULATIVE PRESENT WORTH	-187435.	-410762.	-593399.	-375783.	-185713.	-31734.	61204.	83013.	95952.	104270.

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	15546.	9776.	3863.	1509.	-183.	-1381.	-2229.	-2834.	-3269.	-3553.
CUMULATIVE PRESENT WORTH	432322.	442098.	445960.	447469.	447286.	445905.	443676.	440842.	437573.	434020.
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	9539.	5726.	2159.	805.	-93.	-672.	-1035.	-1256.	-1382.	-1434.
CUMULATIVE PRESENT WORTH	244176.	249901.	252061.	252866.	252773.	252101.	251067.	249811.	248428.	246994.
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	5981.	3434.	1239.	442.	-49.	-337.	-497.	-577.	-607.	-603.
CUMULATIVE PRESENT WORTH	110251.	113685.	114924.	115366.	115317.	114980.	114483.	113906.	113299.	112696.

TABLE 17-6-10 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I A : BEKOK, PULAI & SELIGI (A, B), OFFSHORE STORAGE CASE

* * 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	-3709.	-3818.	-4984.
CUMULATIVE PRESENT WORTH	430311.	426493.	421509.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	-1429.	-1404.	-1750.
CUMULATIVE PRESENT WORTH	245565.	244161.	242411.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	-575.	-540.	-644.
CUMULATIVE PRESENT WORTH	112121.	111581.	110938.

* 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 OIL BEKOK, PULAI AND SELIGI FIELDS

 CASE I B : BEKOK, PULAI & SELIGI (A, B), ONSHORE TERMINAL CASE

* 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	: 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)	240976.	305619.	241490.	0.	0.	0.	0.	0.	0.	0.	788085.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	39859.	39331.	36904.	31038.	16733.	11424.	8453.	183742.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	32.41	32.41	32.41	32.41	32.41	32.41	32.39	
BASIC PRICE OF OIL (M$/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	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	788085.
OIL PRODUCTION (M BBL/YEAR)	6993.	4617.	3128.	2694.	2351.	2084.	1872.	1697.	1551.	1431.	212160.
SALES PRICE OF OIL (M$/BBL)	32.39	32.44	32.51	32.51	32.51	32.51	32.51	32.51	32.51	32.51	
BASIC PRICE OF OIL (M$/BBL)	58.02	60.92	63.97	67.17	70.53	74.05	77.76	81.64	85.73	90.01	

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II   CASE I B : BEKOK, PULAI & SELIGI (A, B), ONSHORE TERMINAL CASE

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	788085.
OIL PRODUCTION (M BBL/YEAR)	1336.	1252.	825.	215573.
SALES PRICE OF OIL (M$/BBL)	32.51	32.51	32.51	
BASIC PRICE OF OIL (M$/BBL)	94.51	99.24	104.20	

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I B : BEKOK, PULAI & SELIGI (A, B), ONSHORE TERMINAL 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 OIL	0.	0.	0.	632996.	624611.	586068.	492911.	265735.	181423.	134158.	2917901.
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.	12500.	0.	0.	0.	0.	0.	0.	12500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	10000.	0.	0.	0.	0.	0.	0.	10000.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	2648.	2613.	2452.	1947.	730.	543.	406.	11341.
5 TOTAL CASH INFLOW	0.	0.	0.	648145.	627224.	588520.	494858.	266465.	181967.	134565.	2941741.
6 INCOME TAX	0.	0.	0.	291665.	282251.	264834.	222686.	119909.	81885.	60554.	1323783.
7 NET CASH FLOW	0.	0.	0.	356480.	344974.	323686.	272172.	146556.	100082.	74011.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	356480.	701453.	1025139.	1297311.	1443867.	1543948.	1617958.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	110987.	73390.	49829.	42915.	37451.	33198.	29821.	27033.	24707.	22796.	3370022.
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.	0.	0.	0.	0.	0.	0.	0.	12500.
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.	10000.
4 RESEARCH FUND FROM OIL CO.	354.	269.	200.	180.	157.	139.	125.	113.	103.	95.	13075.
5 TOTAL CASH INFLOW	111341.	73659.	50029.	43095.	37608.	33337.	29946.	27146.	24811.	22891.	3395596.
6 INCOME TAX	50103.	33146.	22513.	19393.	16924.	15002.	13475.	12216.	11165.	10301.	1528014.
7 NET CASH FLOW	61237.	40512.	27516.	23702.	20684.	18335.	16470.	14930.	13646.	12590.	
8 CUMULATIVE NET CASH FLOW	1679195.	1719707.	1747222.	1770924.	1791608.	1809943.	1826413.	1841343.	1854988.	1867578.	

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I B : BEKOK, PULAI & SELIGI (A, B), ONSHORE TERMINAL CASE

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	21282.	19944.	13142.	3424390.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	12500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	10000.
4 RESEARCH FUND FROM OIL CO.	89.	83.	55.	13303.
5 TOTAL CASH INFLOW	21371.	20028.	13197.	3450191.
6 INCOME TAX	9617.	9012.	5939.	1552581.
7 NET CASH FLOW	11754.	11015.	7258.	
8 CUMULATIVE NET CASH FLOW	1879332.	1890347.	1897605.	

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I B : BEKOK, PULAI & SELIGI (A, B), 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.	300520.	276972.	247505.	198205.	101645.	66107.	46558.
CUMULATIVE PRESENT WORTH	0.	0.	0.	300520.	577492.	824997.	1023202.	1124846.	1190953.	1237511.
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.	255365.	224657.	191631.	146485.	71707.	44516.	29927.
CUMULATIVE PRESENT WORTH	0.	0.	0.	255365.	480022.	671653.	818137.	889844.	934360.	964287.
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.	218571.	183927.	150068.	109726.	51377.	30509.	19618.
CUMULATIVE PRESENT WORTH	0.	0.	0.	218571.	402498.	552566.	662292.	713669.	744177.	763796.

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	36689.	23116.	14953.	12267.	10195.	8607.	7363.	6357.	5534.	4862.
CUMULATIVE PRESENT WORTH	1274199.	1297315.	1312267.	1324533.	1334728.	1343335.	1350698.	1357055.	1362588.	1367450.
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	22511.	13539.	8359.	6546.	5193.	4185.	3418.	2816.	2340.	1963.
CUMULATIVE PRESENT WORTH	986798.	1000337.	1008696.	1015243.	1020436.	1024621.	1028039.	1030855.	1033195.	1035158.
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	14115.	8120.	4796.	3592.	2726.	2101.	1641.	1294.	1028.	825.
CUMULATIVE PRESENT WORTH	777911.	786031.	790827.	794419.	797145.	799246.	800888.	802181.	803210.	804035.

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

 CASE I B : BEKOK, PULAI & SELIGI (A, B), ONSHORE TERMINAL CASE

* * 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	4323.	3859.	2422.
CUMULATIVE PRESENT WORTH	1371773.	1375631.	1378052.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	1666.	1419.	850.
CUMULATIVE PRESENT WORTH	1036824.	1038243.	1039093.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	670.	546.	313.
CUMULATIVE PRESENT WORTH	804704.	805250.	805563.

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE I B : BEKOK, PULAI & SELIGI (A, B), 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.	271284.	267691.	251172.	211248.	113886.	77753.	57496.	1250528.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	258366.	254943.	239212.	178121.	32208.	30943.	23799.	1017592.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	129183.	127472.	119606.	100594.	54232.	37025.	27379.	595491.
4 TOTAL CASH INFLOW	0.	0.	0.	658833.	650106.	609990.	489963.	200326.	145721.	108675.	2863608.
5 ROYALTY	0.	0.	0.	129183.	127472.	119606.	100594.	54232.	37025.	27379.	595491.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	12500.	0.	0.	0.	0.	0.	0.	12500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	10000.	0.	0.	0.	0.	0.	0.	10000.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	2648.	2613.	2452.	1947.	730.	543.	406.	11341.
OPERATING EXPENSES	0.	0.	0.	258366.	254943.	239212.	178121.	32208.	30943.	23799.	1017592.
(M$/BBL)	0.0	0.0	0.0	6.48	6.48	6.48	5.74	1.92	2.71	2.82	5.54
9 OPERATING COST	0.	0.	0.	36097.	36019.	35663.	34778.	32208.	30943.	23799.	229507.
CAPITAL COST RECOVERY	0.	0.	0.	222269.	218924.	203549.	143343.	0.	0.	0.	788085.
INCOME BEFORE TAX	0.	0.	0.	256136.	265077.	248720.	209301.	113156.	77209.	57090.	1226687.
10 INCOME TAX	0.	0.	0.	115261.	119285.	111924.	94185.	50920.	34744.	25690.	552010.
11 CAPITAL INVESTMENT	240976.	305619.	241490.	0.	0.	0.	0.	0.	0.	0.	788085.
12 TOTAL CASH OUTFLOW	240976.	305619.	241490.	295689.	285389.	269645.	231504.	138090.	103256.	77275.	2188930.
13 NET CASH FLOW	-240976.	-305619.	-241490.	363144.	364717.	340345.	258459.	62236.	42465.	31399.	
14 CUMULATIVE NET CASH FLOW	-240976.	-546595.	-788085.	-424941.	-60225.	280120.	538579.	600814.	643280.	674679.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	10.76	16.93	17.98	18.56	18.90	
16 CORPORATE CAPITAL	240976.	305619.	241490.	0.	0.	0.	0.	0.	0.	0.	788085.
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 5.2 YEARS

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE I B : BEKOK, PULAI & SELIGI (A, B), ONSHORE TERMINAL 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 OIL	47566.	31453.	21355.	18392.	16051.	14228.	12780.	11586.	10589.	9770.	1444291.
2 SALES REVENUE FROM COST OIL	23288.	22308.	18662.	17516.	15286.	13550.	12172.	11034.	10085.	9304.	1170792.
3 SALES REVENUE FROM ROYALTY OIL	22650.	14978.	10169.	8758.	7643.	6775.	6086.	5517.	5042.	4652.	687761.
4 TOTAL CASH INFLOW	93504.	68738.	50186.	44667.	38980.	34553.	31038.	28136.	25716.	23726.	3302846.
5 ROYALTY	22650.	14978.	10169.	8758.	7643.	6775.	6086.	5517.	5042.	4652.	687761.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	12500.
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.	10000.
8 RESEARCH FUND TO PETRONAS	354.	269.	200.	180.	157.	139.	125.	113.	103.	95.	13075.
OPERATING EXPENSES	23288.	22308.	18662.	18418.	18200.	18042.	17920.	17801.	17714.	17625.	1207570.
(M$/BBL)	3.33	4.83	5.97	6.84	7.74	8.66	9.57	10.49	11.42	12.32	5.69
9 OPERATING COST	23288.	22308.	18662.	18418.	18200.	18042.	17920.	17801.	17714.	17625.	419485.
CAPITAL COST RECOVERY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	788085.
INCOME BEFORE TAX	47211.	31184.	21155.	18213.	15894.	14089.	12656.	11472.	10485.	9674.	1418716.
10 INCOME TAX	21245.	14033.	9520.	8196.	7152.	6340.	5695.	5163.	4718.	4353.	638425.
11 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	788085.
12 TOTAL CASH OUTFLOW	67538.	51587.	38551.	35551.	33152.	31296.	29826.	28594.	27578.	26726.	2559322.
13 NET CASH FLOW	25966.	17151.	11635.	9115.	5828.	3257.	1212.	-457.	-1862.	-3000.	
14 CUMULATIVE NET CASH FLOW	700645.	717796.	729432.	738547.	744375.	747632.	748844.	748387.	746524.	743524.	
15 DCF ROR OF NET CASH FLOW (%)	19.14	19.26	19.33	19.38	19.40	19.42	19.42	19.42	19.41	19.41	
16 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	788085.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	18.	113.	316.	447.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	476.	1975.	3316.	5767.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	476.	2450.	5766.	

21 PAYOUT TIME 5.2 YEARS

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE I B : BEKOK, PULAI & SELIGI (A, B), ONSHORE TERMINAL CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	9121.	8548.	5632.	1467590.
2 SALES REVENUE FROM COST OIL	8687.	8141.	5364.	1192982.
3 SALES REVENUE FROM ROYALTY OIL	4343.	4070.	2682.	698856.
4 TOTAL CASH INFLOW	22151.	20758.	13679.	3359432.
5 ROYALTY	4343.	4070.	2682.	698856.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.
7 BONUS	0.	0.	0.	12500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	10000.
8 RESEARCH FUND TO PETRONAS	89.	83.	55.	13303.
OPERATING EXPENSES	17539.	17495.	17173.	1259777.
(M$/BBL)	13.13	13.97	20.82	5.84
9 OPERATING COST	17539.	17495.	17173.	471692.
CAPITAL COST RECOVERY	0.	0.	0.	788085.
INCOME BEFORE TAX	9032.	8464.	5577.	1441788.
10 INCOME TAX	4064.	3809.	2510.	648808.
11 CAPITAL INVESTMENT	0.	0.	0.	788085.
12 TOTAL CASH OUTFLOW	26036.	25458.	22420.	2633233.
13 NET CASH FLOW	-3885.	-4699.	-8741.	
14 CUMULATIVE NET CASH FLOW	739640.	734940.	726199.	
15 DCF ROR OF NET CASH FLOW (%)	19.40	19.40	19.39	
16 CORPORATE CAPITAL	0.	0.	0.	788085.
17 INTEREST	617.	1009.	1628.	3701.
18 BANK BORROWING	4501.	5709.	10369.	26346.
19 REPAYMENT	0.	0.	0.	0.
20 BORROWING BALANCE	10268.	15976.	26346.	

21 PAYOUT TIME 5.2 YEARS

TABLE 17-6-11 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE I B : BEKOK, PULAI & SELIGI (A, B), 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	-235169.	-284051.	-213760.	306138.	292823.	260243.	188219.	43164.	28050.	19753.
CUMULATIVE PRESENT WORTH	-235169.	-519220.	-732980.	-426842.	-134019.	126224.	314442.	357606.	385656.	405409.
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	-229762.	-264906.	-190291.	260139.	237514.	201493.	139104.	30451.	18888.	12697.
CUMULATIVE PRESENT WORTH	-229762.	-494667.	-684958.	-424820.	-187305.	14188.	153292.	183742.	202631.	215327.
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	-224711.	-247818.	-170277.	222657.	194454.	157791.	104197.	21818.	12945.	8323.
CUMULATIVE PRESENT WORTH	-224711.	-472530.	-642806.	-420149.	-225696.	-67905.	36292.	58110.	71055.	79378.

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	15557.	9786.	6323.	4718.	2873.	1529.	542.	-195.	-755.	-1159.
CUMULATIVE PRESENT WORTH	420966.	430752.	437075.	441792.	444665.	446194.	446736.	446541.	445786.	444627.
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	9545.	5732.	3535.	2518.	1463.	743.	252.	-86.	-319.	-468.
CUMULATIVE PRESENT WORTH	224873.	230604.	234139.	236657.	238120.	238863.	239115.	239028.	238709.	238241.
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	5985.	3438.	2028.	1382.	768.	373.	121.	-40.	-140.	-197.
CUMULATIVE PRESENT WORTH	85363.	88801.	90829.	92210.	92978.	93352.	93472.	93433.	93292.	93096.

* * 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	-1429.	-1646.	-2916.
CUMULATIVE PRESENT WORTH	443198.	441552.	438636.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	-551.	-605.	-1024.
CUMULATIVE PRESENT WORTH	237691.	237085.	236061.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	-221.	-233.	-377.
CUMULATIVE PRESENT WORTH	92874.	92642.	92265.

ECONOMIC ANALYSIS FOR MALAYSIA PROJECT

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE CASE

* PREMISES *

PRODUCTION LIFE	: 20 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)	179848.	262407.	193549.	0.	0.	0.	0.	0.	0.	0.	635804.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	32193.	31938.	30551.	26017.	14224.	10636.	8453.	154012.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	32.44	32.44	32.44	32.44	32.41	32.41	32.39	
BASIC PRICE OF OIL (M$/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	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	635804.
OIL PRODUCTION (M BBL/YEAR)	6993.	4617.	3128.	2694.	2351.	2084.	1872.	1697.	1551.	1431.	182430.
SALES PRICE OF OIL (M$/BBL)	32.39	32.46	32.51	32.51	32.51	32.51	32.51	32.51	32.51	32.51	
BASIC PRICE OF OIL (M$/BBL)	58.02	60.92	63.97	67.17	70.53	74.05	77.76	81.64	85.73	90.01	

* 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 OIL BEKOK, PULAI AND SELIGI FIELDS

(CONT'D)
PAGE 2

VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE CASE

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR. TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	635804.
OIL PRODUCTION (M BBL/YEAR)	1336.	1252.	825.	185843.
SALES PRICE OF OIL (M$/BBL)	32.51	32.51	32.51	
BASIC PRICE OF OIL (M$/BBL)	94.51	99.24	104.20	

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE 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 OIL	0.	0.	0.	511727.	507673.	485626.	413556.	225890.	168909.	134158.	2447537.
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.	7500.	0.	0.	0.	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.	0.	0.	0.	0.	0.	0.	5000.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	2141.	2124.	2032.	1730.	661.	514.	436.	9637.
5 TOTAL CASH INFLOW	0.	0.	0.	521368.	509797.	487658.	415286.	226550.	169423.	134594.	2464673.
6 INCOME TAX	0.	0.	0.	234615.	229409.	219446.	186878.	101948.	76240.	60567.	1109103.
7 NET CASH FLOW	0.	0.	0.	286752.	280389.	268212.	228407.	124603.	93183.	74027.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	286752.	567141.	835353.	1063760.	1188362.	1281544.	1355570.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	110987.	73435.	49829.	42915.	37451.	33198.	29821.	27033.	24707.	22796.	2899704.
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.	0.	0.	0.	0.	0.	0.	0.	7500.
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.	5000.
4 RESEARCH FUND FROM OIL CO.	384.	298.	208.	180.	157.	139.	125.	113.	103.	95.	11439.
5 TOTAL CASH INFLOW	111370.	73734.	50037.	43095.	37608.	33337.	29946.	27146.	24811.	22891.	2918642.
6 INCOME TAX	50117.	33180.	22517.	19393.	16924.	15002.	13475.	12216.	11165.	10301.	1313385.
7 NET CASH FLOW	61254.	40553.	27520.	23702.	20684.	18335.	16470.	14930.	13646.	12590.	
8 CUMULATIVE NET CASH FLOW	1416823.	1457376.	1484896.	1508598.	1529282.	1547617.	1564087.	1579017.	1592662.	1605252.	

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	21282.	19944.	13142.	2954072.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.
4 RESEARCH FUND FROM OIL CO.	89.	83.	55.	11667.
5 TOTAL CASH INFLOW	21371.	20028.	13197.	2973237.
6 INCOME TAX	9617.	9012.	5939.	1337952.
7 NET CASH FLOW	11754.	11015.	7258.	
8 CUMULATIVE NET CASH FLOW	1617006.	1628021.	1635279.	

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE 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.	241738.	225118.	205087.	166334.	86419.	61550.	46569.
CUMULATIVE PRESENT WORTH	0.	0.	0.	241738.	466856.	671943.	838277.	924697.	986246.	1032815.
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.	205416.	182597.	158789.	122930.	60965.	41448.	29934.
CUMULATIVE PRESENT WORTH	0.	0.	0.	205416.	388013.	546801.	669732.	730697.	772145.	802078.
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.	175819.	149493.	124349.	92082.	43681.	28406.	19623.
CUMULATIVE PRESENT WORTH	0.	0.	0.	175819.	325312.	449660.	541742.	585423.	613829.	633452.

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	36698.	23140.	14955.	12267.	10195.	8607.	7363.	6357.	5534.	4862.
CUMULATIVE PRESENT WORTH	1069513.	1092652.	1107607.	1119873.	1130068.	1138675.	1146038.	1152395.	1157928.	1162790.
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	22517.	13552.	8361.	6546.	5193.	4185.	3418.	2816.	2340.	1963.
CUMULATIVE PRESENT WORTH	824595.	838148.	846508.	853055.	858248.	862433.	865851.	868667.	871007.	872970.
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	14119.	8128.	4797.	3592.	2726.	2101.	1641.	1294.	1028.	825.
CUMULATIVE PRESENT WORTH	647571.	655699.	660496.	664088.	666814.	668915.	670556.	671850.	672878.	673703.

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(X M$ 1000)

(CONT'D)
PAGE 6

TERM	21	22	23
PRESENT WORTH			
5.00% DISCOUNT RATE	0.37	0.35	0.33
PRESENT WORTH	4323.	3859.	2422.
CUMULATIVE PRESENT WORTH	1167113.	1170971.	1173392.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	1666.	1419.	850.
CUMULATIVE PRESENT WORTH	874636.	876055.	876905.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	670.	546.	313.
CUMULATIVE PRESENT WORTH	674373.	674918.	675231.

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE CASE

** 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 OIL	0.	0.	0.	219311.	217574.	208125.	177238.	96810.	72390.	57496.	1048944.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	208868.	207214.	198215.	168798.	35335.	30347.	29688.	878464.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	104434.	103607.	99107.	84399.	46100.	34471.	27379.	499498.
4 TOTAL CASH INFLOW	0.	0.	0.	532613.	528395.	505448.	430435.	178244.	137208.	114564.	2426903.
5 ROYALTY	0.	0.	0.	104434.	103607.	99107.	84399.	46100.	34471.	27379.	499498.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	7500.	0.	0.	0.	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.	0.	0.	0.	0.	0.	0.	5000.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	2141.	2124.	2032.	1730.	661.	514.	436.	9637.
OPERATING EXPENSES	0.	0.	0.	208868.	207214.	198215.	168798.	35335.	30347.	29688.	878464.
(M$/BBL)	0.0	0.0	0.0	6.49	6.49	6.49	6.49	2.48	2.85	3.51	5.70
9 OPERATING COST	0.	0.	0.	38158.	38120.	37904.	37166.	31277.	30347.	29688.	242660.
CAPITAL COST RECOVERY	0.	0.	0.	170710.	169094.	160311.	131632.	4058.	0.	0.	635804.
INCOME BEFORE TAX	0.	0.	0.	209670.	215450.	206094.	175508.	96149.	71876.	57061.	1031808.
10 INCOME TAX	0.	0.	0.	94352.	96953.	92742.	78979.	43267.	32344.	25677.	464313.
11 CAPITAL INVESTMENT	179848.	262407.	193549.	0.	0.	0.	0.	0.	0.	0.	635804.
12 TOTAL CASH OUTFLOW	179848.	262407.	193549.	246585.	240803.	231785.	202274.	121305.	97676.	83180.	1859409.
13 NET CASH FLOW	-179848.	-262407.	-193549.	286029.	287591.	273662.	228161.	56940.	39532.	31383.	
14 CUMULATIVE NET CASH FLOW	-179848.	-442255.	-635804.	-349775.	-62184.	211478.	439640.	496579.	536111.	567494.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	10.18	17.02	18.20	18.85	19.27	
16 CORPORATE CAPITAL	179848.	262407.	193549.	0.	0.	0.	0.	0.	0.	0.	635804.
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 5.2 YEARS

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	47566.	31472.	21355.	18392.	16051.	14228.	12780.	11586.	10589.	9770.	1242727.
2 SALES REVENUE FROM COST OIL	29182.	28203.	20338.	17516.	15286.	13550.	12172.	11034.	10085.	9304.	1045134.
3 SALES REVENUE FROM ROYALTY OIL	22650.	14987.	10169.	8758.	7643.	6775.	6086.	5517.	5042.	4652.	591777.
4 TOTAL CASH INFLOW	99398.	74662.	51863.	44667.	38980.	34553.	31038.	28136.	25716.	23726.	2879634.
5 ROYALTY	22650.	14987.	10169.	8758.	7643.	6775.	6086.	5517.	5042.	4652.	591777.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	7500.
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.	5000.
8 RESEARCH FUND TO PETRONAS	384.	298.	208.	180.	157.	139.	125.	113.	103.	95.	11439.
OPERATING EXPENSES	29182.	28203.	24066.	23822.	23626.	23456.	23324.	23211.	23108.	23018.	1123480.
(M$/BBL)	4.17	6.11	7.69	8.84	10.05	11.26	12.46	13.68	14.90	16.09	6.16
9 OPERATING COST	29182.	28203.	24066.	23822.	23626.	23456.	23324.	23211.	23108.	23018.	487676.
CAPITAL COST RECOVERY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	635804.
INCOME BEFORE TAX	47182.	31174.	21147.	18213.	15894.	14089.	12656.	11472.	10485.	9674.	1223787.
10 INCOME TAX	21232.	14028.	9516.	8196.	7152.	6340.	5695.	5163.	4718.	4353.	550706.
11 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	635804.
12 TOTAL CASH OUTFLOW	73448.	57516.	43960.	40955.	38578.	36710.	35230.	34004.	32972.	32119.	2284894.
13 NET CASH FLOW	25950.	17146.	7903.	3711.	402.	-2157.	-4192.	-5867.	-7256.	-8393.	
14 CUMULATIVE NET CASH FLOW	593444.	610590.	618493.	622204.	622606.	620449.	616257.	610390.	603133.	594740.	
15 DCF ROR OF NET CASH FLOW (%)	19.55	19.70	19.76	19.78	19.78	19.77	19.76	19.74	19.72	19.71	
16 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	635804.
17 INTEREST	0.	0.	0.	0.	0.	86.	347.	777.	1364.	2100.	4675.
18 BANK BORROWING	0.	0.	0.	0.	0.	2243.	4539.	6645.	8621.	10492.	32540.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	2243.	6782.	13427.	22047.	32540.	

21 PAYOUT TIME 5.2 YEARS

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE CASE

** CASH FLOW TABLE FOR OPERATING COMPANY **
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	9121.	8548.	5632.	1266026.
2 SALES REVENUE FROM COST OIL	8687.	8141.	5364.	1067324.
3 SALES REVENUE FROM ROYALTY OIL	4343.	4070.	2682.	602873.
4 TOTAL CASH INFLOW	22151.	20758.	13679.	2936220.
5 ROYALTY	4343.	4070.	2682.	602873.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.
7 BONUS	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.
8 RESEARCH FUND TO PETRONAS	89.	83.	55.	11667.
OPERATING EXPENSES	22963.	22899.	22582.	1191924.
(M$/BBL)	17.19	18.29	27.37	6.41
9 OPERATING COST	22963.	22899.	22582.	556120.
CAPITAL COST RECOVERY	0.	0.	0.	635804.
INCOME BEFORE TAX	9032.	8464.	5577.	1246859.
10 INCOME TAX	4064.	3809.	2510.	561089.
11 CAPITAL INVESTMENT	0.	0.	0.	635804.
12 TOTAL CASH OUTFLOW	31460.	30862.	27829.	2375042.
13 NET CASH FLOW	-9309.	-10103.	-14150.	
14 CUMULATIVE NET CASH FLOW	585432.	575328.	561178.	
15 DCF ROR OF NET CASH FLOW (%)	19.69	19.67	19.66	
16 CORPORATE CAPITAL	0.	0.	0.	635804.
17 INTEREST	2976.	3990.	5279.	16920.
18 BANK BORROWING	12284.	14093.	19430.	78347.
19 REPAYMENT	0.	0.	0.	0.
20 BORROWING BALANCE	44824.	58917.	78347.	

21 PAYOUT TIME 5.2 YEARS

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE 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	-175514.	-243889.	-171324.	241128.	230901.	209255.	166155.	39491.	26112.	19743.
CUMULATIVE PRESENT WORTH	-175514.	-419403.	-590727.	-349598.	-118698.	90557.	256712.	296203.	322315.	342057.
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	-171478.	-227450.	-152514.	204897.	187288.	162015.	122798.	27859.	17584.	12690.
CUMULATIVE PRESENT WORTH	-171478.	-398929.	-551443.	-346545.	-159258.	2758.	125556.	153415.	170999.	183689.
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	-167709.	-212779.	-136473.	175375.	153333.	126875.	91983.	19961.	12051.	8319.
CUMULATIVE PRESENT WORTH	-167709.	-380488.	-516961.	-341586.	-188253.	-61378.	30605.	50566.	62617.	70936.

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	15547.	9783.	4295.	1921.	198.	-1013.	-1874.	-2498.	-2943.	-3241.
CUMULATIVE PRESENT WORTH	357605.	367388.	371682.	373603.	373801.	372788.	370914.	368416.	365474.	362232.
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	9539.	5730.	2401.	1025.	101.	-492.	-870.	-1107.	-1244.	-1308.
CUMULATIVE PRESENT WORTH	193228.	198958.	201359.	202384.	202485.	201992.	201122.	200016.	198771.	197463.
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	5982.	3437.	1377.	562.	53.	-247.	-418.	-508.	-547.	-550.
CUMULATIVE PRESENT WORTH	76917.	80354.	81731.	82294.	82347.	82100.	81682.	81173.	80627.	80077.

TABLE 17-6-12 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE II : BEKOK, PULAI & SELIGI (A), OFFSHORE STORAGE CASE

* * 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	-3424.	-3539.	-4721.
CUMULATIVE PRESENT WORTH	358808.	355269.	350548.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	-1319.	-1302.	-1657.
CUMULATIVE PRESENT WORTH	196143.	194842.	193184.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	-530.	-501.	-610.
CUMULATIVE PRESENT WORTH	79546.	79046.	78436.

ECONOMIC ANALYSIS FOR MALAYSIA PROJECT

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE CASE

PREMISES

PRODUCTION LIFE	: 20 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)	150020.	205658.	153643.	0.	0.	0.	0.	0.	0.	0.	509321.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	26718.	26463.	25076.	20542.	14224.	10636.	8453.	132112.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	32.44	32.46	32.46	32.44	32.41	32.41	32.39	
BASIC PRICE OF OIL (M$/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	19	20	20YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	509321.
OIL PRODUCTION (M BBL/YEAR)	6993.	4617.	3128.	2694.	2351.	2084.	1872.	1697.	1551.	1431.	160530.
SALES PRICE OF OIL (M$/BBL)	32.39	32.46	32.51	32.51	32.51	32.51	32.51	32.51	32.51	32.51	
BASIC PRICE OF OIL (M$/BBL)	58.02	60.92	63.97	67.17	70.53	74.05	77.76	81.64	85.73	90.01	

****
* 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 OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE CASE

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	509321.
OIL PRODUCTION (M BBL/YEAR)	1336.	1252.	825.	163943.
SALES PRICE OF OIL (M$/BBL)	32.51	32.51	32.51	
BASIC PRICE OF OIL (M$/BBL)	94.51	99.24	104.20	

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE CASE

* * 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 OIL	0.	0.	0.	424698.	420904.	398844.	326527.	225890.	168909.	134158.	2099929.
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.	7500.	0.	0.	0.	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.	0.	0.	0.	0.	0.	0.	5000.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1777.	1761.	1669.	1331.	630.	503.	426.	8096.
5 TOTAL CASH INFLOW	0.	0.	0.	433975.	422665.	400512.	327858.	226520.	169412.	134584.	2115524.
6 INCOME TAX	0.	0.	0.	195289.	190199.	180230.	147536.	101934.	76236.	60563.	951986.
7 NET CASH FLOW	0.	0.	0.	238686.	232466.	220282.	180322.	124586.	93177.	74021.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	238686.	471152.	691434.	871756.	996342.	1089519.	1163540.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	110987.	73435.	49829.	42915.	37451.	33198.	29821.	27033.	24707.	22796.	2552096.
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.	0.	0.	0.	0.	0.	0.	0.	7500.
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.	5000.
4 RESEARCH FUND FROM OIL CO.	374.	272.	208.	180.	157.	139.	125.	113.	103.	95.	9862.
5 TOTAL CASH INFLOW	111360.	73707.	50037.	43095.	37608.	33337.	29946.	27146.	24811.	22891.	2569457.
6 INCOME TAX	50112.	33168.	22517.	19393.	16924.	15002.	13475.	12216.	11165.	10301.	1156253.
7 NET CASH FLOW	61248.	40539.	27520.	23702.	20684.	18335.	16470.	14930.	13646.	12590.	
8 CUMULATIVE NET CASH FLOW	1224788.	1265326.	1292846.	1316548.	1337232.	1355567.	1372037.	1386967.	1400612.	1413202.	

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE CASE

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	21282.	19944.	13142.	2606464.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.
4 RESEARCH FUND FROM OIL CO.	89.	83.	55.	10089.
5 TOTAL CASH INFLOW	21371.	20028.	13197.	2624052.
6 INCOME TAX	9617.	9012.	5939.	1180820.
7 NET CASH FLOW	11754.	11015.	7258.	
8 CUMULATIVE NET CASH FLOW	1424956.	1435971.	1443229.	

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE 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.	201218.	186642.	168438.	131317.	86407.	61546.	46565.
CUMULATIVE PRESENT WORTH	0.	0.	0.	201218.	387859.	556297.	687614.	774021.	835567.	882133.
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.	170984.	151389.	130413.	97050.	60957.	41445.	29931.
CUMULATIVE PRESENT WORTH	0.	0.	0.	170984.	322372.	452785.	549835.	610792.	652237.	682169.
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.	146348.	123942.	102127.	72697.	43675.	28404.	19621.
CUMULATIVE PRESENT WORTH	0.	0.	0.	146348.	270290.	372417.	445114.	488789.	517193.	536814.

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	36695.	23131.	14955.	12267.	10195.	8607.	7363.	6357.	5534.	4862.
CUMULATIVE PRESENT WORTH	918828.	941959.	956914.	969181.	979376.	987983.	995347.	1001704.	1007237.	1012099.
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	22515.	13547.	8361.	6546.	5193.	4185.	3418.	2816.	2340.	1963.
CUMULATIVE PRESENT WORTH	704684.	718231.	726592.	733138.	738332.	742517.	745934.	748751.	751091.	753053.
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	14118.	8125.	4797.	3592.	2726.	2101.	1641.	1294.	1028.	825.
CUMULATIVE PRESENT WORTH	550932.	559057.	563854.	567446.	570172.	572273.	573914.	575208.	576236.	577061.

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE CASE

** 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	4323.	3859.	2422.
CUMULATIVE PRESENT WORTH	1016423.	1020281.	1022703.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	1666.	1419.	850.
CUMULATIVE PRESENT WORTH	754719.	756139.	756989.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	670.	546.	313.
CUMULATIVE PRESENT WORTH	577731.	578277.	578589.

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

(CONT'D)

TERM	1	2	3	4	5	6	7	8	9	10	10YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	182014.	180388.	170933.	139940.	96810.	72390.	57496.	899970.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	173346.	171798.	162793.	126240.	29184.	28286.	27636.	719283.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	86673.	85899.	81397.	66638.	46100.	34471.	27379.	428557.
4 TOTAL CASH INFLOW	0.	0.	0.	442033.	438084.	415123.	332818.	172094.	135147.	112512.	2047807.
5 ROYALTY	0.	0.	0.	86673.	85899.	81397.	66638.	46100.	34471.	27379.	428557.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	7500.	0.	0.	0.	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.	0.	0.	0.	0.	0.	0.	5000.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	1777.	1761.	1669.	1331.	630.	503.	426.	8096.
OPERATING EXPENSES	0.	0.	0.	173346.	171798.	162793.	126240.	29184.	28286.	27636.	719283.
(M$/BBL)	0.0	0.0	0.0	6.49	6.49	6.49	6.15	2.05	2.66	3.27	5.44
9 OPERATING COST	0.	0.	0.	31560.	31523.	31286.	30487.	29184.	28286.	27636.	209962.
CAPITAL COST RECOVERY	0.	0.	0.	141786.	140275.	131507.	95753.	0.	0.	0.	509321.
INCOME BEFORE TAX	0.	0.	0.	172737.	178627.	169264.	138609.	96180.	71886.	57071.	884374.
10 INCOME TAX	0.	0.	0.	77732.	80382.	76169.	62374.	43281.	32349.	25682.	397968.
11 CAPITAL INVESTMENT	150020.	205658.	153643.	0.	0.	0.	0.	0.	0.	0.	509321.
12 TOTAL CASH OUTFLOW	150020.	205658.	153643.	205241.	199565.	190520.	160830.	119195.	95609.	81123.	1561402.
13 NET CASH FLOW	-150020.	-205658.	-153643.	236791.	238519.	224603.	171988.	52899.	39537.	31389.	
14 CUMULATIVE NET CASH FLOW	-150020.	-355678.	-509321.	-272530.	-34010.	190592.	362580.	415479.	455016.	486405.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	11.28	17.53	18.87	19.65	20.14	
16 CORPORATE CAPITAL	150020.	205658.	153643.	0.	0.	0.	0.	0.	0.	0.	509321.
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 5.2 YEARS

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE 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 OIL	47566.	31472.	21355.	18392.	16051.	14228.	12780.	11586.	10589.	9770.	1093755.
2 SALES REVENUE FROM COST OIL	27151.	22917.	20338.	17516.	15286.	13550.	12172.	11034.	10085.	9304.	878636.
3 SALES REVENUE FROM ROYALTY OIL	22650.	14987.	10169.	8758.	7643.	6775.	6086.	5517.	5042.	4652.	520837.
4 TOTAL CASH INFLOW	97367.	69376.	51863.	44667.	38980.	34553.	31038.	28136.	25716.	23726.	2493221.
5 ROYALTY	22650.	14987.	10169.	8758.	7643.	6775.	6086.	5517.	5042.	4652.	520837.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	7500.
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.	5000.
8 RESEARCH FUND TO PETRONAS	374.	272.	208.	180.	157.	139.	125.	113.	103.	95.	9862.
OPERATING EXPENSES	27151.	22917.	22221.	21987.	21780.	21603.	21512.	21396.	21316.	21227.	942393.
(M$/BBL)	3.88	4.96	7.10	8.16	9.26	10.37	11.49	12.61	13.74	14.83	5.87
9 OPERATING COST	27151.	22917.	22221.	21987.	21780.	21603.	21512.	21396.	21316.	21227.	433072.
CAPITAL COST RECOVERY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	509321.
INCOME BEFORE TAX	47192.	31200.	21147.	18213.	15894.	14089.	12656.	11472.	10485.	9674.	1076394.
10 INCOME TAX	21236.	14040.	9516.	8196.	7152.	6340.	5695.	5163.	4718.	4353.	484378.
11 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	509321.
12 TOTAL CASH OUTFLOW	71411.	52216.	42115.	39120.	36732.	34857.	33418.	32189.	31180.	30328.	1964961.
13 NET CASH FLOW	25956.	17160.	9748.	5546.	2248.	-304.	-2380.	-4052.	-5464.	-6602.	
14 CUMULATIVE NET CASH FLOW	512361.	529521.	539269.	544815.	547063.	546759.	544379.	540327.	534862.	528260.	
15 DCF ROR OF NET CASH FLOW (%)	20.47	20.64	20.72	20.76	20.77	20.77	20.76	20.75	20.73	20.72	
16 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	509321.
17 INTEREST	0.	0.	0.	0.	0.	12.	120.	387.	799.	1346.	2665.
18 BANK BORROWING	0.	0.	0.	0.	0.	316.	2500.	4440.	6263.	7947.	21467.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	316.	2816.	7256.	13519.	21467.	

21 PAYOUT TIME 5.2 YEARS

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS
VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE CASE

* * CASH FLOW TABLE FOR OPERATING COMPANY * *
(X M$ 1000)

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	9121.	8548.	5632.	1117054.
2 SALES REVENUE FROM COST OIL	8687.	8141.	5364.	900827.
3 SALES REVENUE FROM ROYALTY OIL	4343.	4070.	2682.	531932.
4 TOTAL CASH INFLOW	22151.	20758.	13679.	2549807.
5 ROYALTY	4343.	4070.	2682.	531932.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.
7 BONUS	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.
8 RESEARCH FUND TO PETRONAS	89.	83.	55.	10089.
OPERATING EXPENSES	21148.	21108.	20796.	1005445.
(M$/BBL)	15.83	16.86	25.21	6.13
9 OPERATING COST	21148.	21108.	20796.	496124.
CAPITAL COST RECOVERY	0.	0.	0.	509321.
INCOME BEFORE TAX	9032.	8464.	5577.	1099466.
10 INCOME TAX	4064.	3809.	2510.	494761.
11 CAPITAL INVESTMENT	0.	0.	0.	509321.
12 TOTAL CASH OUTFLOW	29645.	29071.	26043.	2049717.
13 NET CASH FLOW	-7494.	-8312.	-12364.	
14 CUMULATIVE NET CASH FLOW	520767.	512454.	500090.	
15 DCF ROR OF NET CASH FLOW (%)	20.71	20.69	20.68	
16 CORPORATE CAPITAL	0.	0.	0.	509321.
17 INTEREST	2017.	2811.	3863.	11355.
18 BANK BORROWING	9511.	11123.	16227.	58328.
19 REPAYMENT	0.	0.	0.	0.
20 BORROWING BALANCE	30978.	42101.	58328.	

21 PAYOUT TIME 5.2 YEARS

* * 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	-146405.	-191145.	-136000.	199620.	191502.	171742.	125247.	36688.	26116.	19746.
CUMULATIVE PRESENT WORTH	-146405.	-337549.	-473550.	-273929.	-82428.	89314.	214561.	251250.	277365.	297111.
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	-143038.	-178261.	-121069.	169626.	155331.	132971.	92565.	25882.	17586.	12693.
CUMULATIVE PRESENT WORTH	-143038.	-321300.	-442368.	-272742.	-117412.	15559.	108124.	134006.	151592.	164285.
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	-139894.	-166763.	-108335.	145186.	127170.	104130.	69337.	18544.	12053.	8320.
CUMULATIVE PRESENT WORTH	-139894.	-306657.	-414992.	-269806.	-142637.	-38506.	30830.	49375.	61427.	69748.

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	15551.	9791.	5297.	2870.	1108.	-143.	-1064.	-1725.	-2216.	-2550.
CUMULATIVE PRESENT WORTH	312662.	322453.	327750.	330621.	331729.	331586.	330522.	328797.	326581.	324031.
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	9541.	5735.	2961.	1532.	564.	-69.	-494.	-764.	-937.	-1029.
CUMULATIVE PRESENT WORTH	173826.	179561.	182522.	184054.	184618.	184549.	184055.	183291.	182354.	181324.
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	5983.	3440.	1699.	841.	296.	-35.	-237.	-351.	-412.	-433.
CUMULATIVE PRESENT WORTH	75730.	79170.	80869.	81709.	82006.	81971.	81734.	81382.	80971.	80538.

TABLE 17-6-13 CASH FLOW TABLE FOR OIL BEKOK, PULAI AND SELIGI FIELDS

VOL.II CASE III : BEKOK & PULAI, OFFSHORE STORAGE CASE

* * 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	-2756.	-2912.	-4125.
CUMULATIVE PRESENT WORTH	321275.	318363.	314238.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	-1062.	-1071.	-1448.
CUMULATIVE PRESENT WORTH	180262.	179191.	177743.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	-427.	-412.	-533.
CUMULATIVE PRESENT WORTH	80111.	79699.	79166.

Table 18-5-1 (Vol. II)

MAJOR EQUIPMENT LIST

FOR TAPIS OIL FIELD - CASE IA

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V-1 1ST STAGE PRODUCTION SEPARATOR	TAWP-B TAWP-C	1 1	SIZE: 5'-6" I.D. x 16'-6" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
	TAWP-A	1	SIZE: 7'-0" I.D. x 14'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: HORIZONTAL
V-2 2ND STAGE PRODUCTION SEPARATOR	TAWP-B TAWP-C	1 1	SIZE: 5'-6" I.D. x 16'-6" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
	TAWP-A	1	SIZE: 7'-0" I.D. x 14'-0" S-S DESIGN PRESS.: 100 PSIG @ 150°F TYPE: HORIZONTAL
V-3 3RD STAGE PRODUCTION SEPARATOR	TAWP-B TAWP-C	1 1	SIZE: 12'-0" x 24'-0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
	TAWP-A	1	SIZE: 14'-0" I.D. x 28'-0" S-S DESIGN PRESS.: 50 PSIG @ 150°F TYPE: HORIZONTAL
V-4 TEST SEPARATOR	TAWP-A TAWP-B TAWP-C	1 1 1	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 300 PSIG @ 150 PF TYPE: HORIZONTAL
C-151 INSTRUMENT AIR COMPRESSOR	TAWP-A TAWP-B TAWP-C	2 2 2	CAPACITY: 35 SCFM
P-2 CRUDE TRANSFER PUMP	TAWP-B TAWP-C	2 2	CAPACITY: 440 GPM TYPE: HORIZONTAL
	TAWP-A	2 2	CAPACITY: 730 GPM TYPE: HORIZONTAL
P-152 FIRE WATER PUMP	TAWP-A TAWP-B TAWP-C	1 1 1	CAPACITY: 1,500 GPM TYPE: VERTICAL
TK-1 DEEMULSIFIER TANK	TAWP-A TAWP-B TAWP-C	1 1 1	SIZE: 6'-0" I.D. x 15'-6" H
TK-2 DEFOAMANT TANK	TAWP-A TAWP-B TAWP-C	1 1 1	SIZE: 6'-0" I.D. x 15'-6" H
M-1 INLET MANIFOLD	TAWP-A TAWP-B TAWP-C	1 1 1	HIGH PRESSURE HEADER LOW PRESSURE HEADER TEST HEADER
FM-1 FLOW METER	TAWP-B TAWP-C	1 1	DESIGN RATE: 480 GPM (MAX.)
	TAWP-A	1	DESIGN RATE: 780 GPM (MAX.)

Table 18-6-1 (Vol. II)

CAPITAL INVESTMENT COST ESTIMATION

(M$ 1,000)

TAPIS OIL FIELD	CASE I A	CASE I B
1. Exploration & Appraisal Wells	16,137	16,137
2. Engineering	32,073	35,837
3. Development Wells	109,476	109,476
4. Facilities		
a. Offshore Platforms	67,173	67,173
b. Offshore Production Equipment	24,394	26,325
c. Submarine Pipelines	5,019	94,864
d. Offshore Storage & Loading Facilities	101,493	—
e. Onshore Terminal & Loading Facilities	—	38,430
f. Support Facilities	13,178	22,099
Sub Total	211,257	248,891
5. Pre-start up Expense	3,525	3,943
6. Contingencies	35,268	39,421
TOTAL	407,736	453,705

ANNUAL OPERATION COST ESTIMATION

Table 18-6-2 (Vol.II) TAPIS OIL FIELD CASE IA (M$ 1,000)

	1	2	3	4	5	6	7	8	9
1. Direct Cost									
a. Operating Personnel				1,801	1,801	1,801	1,801	1,801	1,801
b. Operating Management				180	180	180	180	180	180
c. Repair & Maintenance				11,570	11,570	11,570	11,570	11,570	11,570
d. Operating Supplies				1,176	1,176	1,176	1,176	1,176	1,176
e. Chemical				2,266	2,098	1,875	1,435	1,085	434
f. Service Contract				3,688	3,688	3,688	3,688	3,688	3,688
Sub Total				20,681	20,513	20,290	19,850	19,500	18,849
2. Indirect Cost									
a. Indirect Personnel				991	991	991	991	991	991
b. Insurance				5,814	5,814	5,814	5,814	5,814	5,814
Sub Total				6,805	6,805	6,805	6,805	6,805	6,805
TOTAL				27,486	27,318	27,095	26,655	26,305	25,654

ANNUAL OPERATION COST ESTIMATION

Table 18-6-3 (Vol.II) TAPIS OIL FIELD CASE IB (M$ 1,000)

	1	2	3	4	5	6	7	8	9
1. Direct Cost									
a. Operating Personnel				1,801	1,801	1,801	1,801	1,801	1,801
b. Operating Management				180	180	180	180	180	180
c. Repair & Maintenance				6,571	6,571	6,571	6,571	6,571	6,571
d. Operating Supplies				1,313	1,313	1,313	1,313	1,313	1,313
e. Chemical				2,266	2,098	1,875	1,435	1,085	434
f. Service Contract				3,739	3,739	3,739	3,739	3,739	3,739
Sub Total				15,870	15,702	15,479	15,039	14,689	14,038
2. Indirect Cost									
a. Indirect Personnel				991	991	991	991	991	991
b. Insurance				5,415	5,415	5,415	5,415	5,415	5,415
Sub Total				6,406	6,406	6,406	6,406	6,406	6,406
TOTAL				22,276	22,108	21,885	21,445	21,095	20,444

Table 18-6-4 (Vol. II) **INVESTMENT SCHEDULE**

TAPIS OIL FIELD CASE I A (M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	16,137	-	-	
2. Engineering	32,073	-	-	
3. Development Wells	-	23,459	86,017	
4. Offshore Platforms	14,412	50,655	2,106	
5. Offshore Production Equipment	4,478	12,997	6,919	
6. Submarine Pipelines	-	2,982	2,037	
7. Offshore Storage & Loading Facilities	-	34,775	66,718	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	-	8,786	4,392	
10. Pre-start up Expense	508	1,336	1,681	
11. Contingencies	5,083	13,365	16,820	
Total	72,691	148,355	186,690	

Table 18-6-5 (Vol. II) INVESTMENT SCHEDULE

(M$ 1,000)

TAPIS OIL FIELD CASE I B

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	16,137	-	-	
2. Engineering	35,837	-	-	
3. Development Wells	-	23,459	86,017	
4. Offshore Platforms	14,412	50,655	2,106	
5. Offshore Production Equipment	5,169	14,237	6,919	
6. Submarine Pipelines	-	55,931	38,933	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	899	22,545	14,986	
9. Support Facilities	1,842	11,049	9,208	
10. Pre-start up Expense	582	1,779	1,582	
11. Contingencies	5,816	17,788	15,817	
Total	80,694	197,443	175,568	

* 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 18-6-6 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD

VOL.II CASE I A : OFFSHORE STORAGE 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)	72691.	148355.	186690.	0.	0.	0.	0.	0.	0.	407736.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	19655.	18214.	16279.	12447.	9417.	3760.	79772.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	32.36	32.36	32.36	32.36	32.36	32.36	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	52.63	

TABLE 18-6-6 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD

VOL.II CASE I A : 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	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	311657.	288808.	258126.	197364.	149320.	59620.	1264895.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	7500.	0.	0.	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.	0.	0.	0.	0.	0.	5000.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1304.	1208.	1080.	826.	625.	249.	5292.
5 TOTAL CASH INFLOW	0.	0.	0.	320461.	290017.	259206.	198190.	149944.	59869.	1277686.
6 INCOME TAX	0.	0.	0.	144208.	130507.	116643.	89186.	67475.	26941.	574959.
7 NET CASH FLOW	0.	0.	0.	176254.	159509.	142563.	109005.	82469.	32928.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	176254.	335763.	478326.	587331.	669800.	702728.	

TABLE 18-6-6 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD

VOL.II CASE I A : OFFSHORE STORAGE 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.	148586.	128066.	109010.	79381.	57197.	21750.
CUMULATIVE PRESENT WORTH	0.	0.	0.	148586.	276652.	385662.	465043.	522240.	543991.
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.	126260.	103877.	84401.	58667.	40351.	14646.
CUMULATIVE PRESENT WORTH	0.	0.	0.	126260.	230137.	314538.	373205.	413555.	428202.
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.	108068.	85044.	66095.	43945.	28911.	10038.
CUMULATIVE PRESENT WORTH	0.	0.	0.	108068.	193112.	259207.	303152.	332063.	342101.

TABLE 18-6-6 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD
VOL.II CASE I A : OFFSHORE STORAGE 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.	133567.	123775.	110626.	84585.	63994.	25551.	542098.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	127207.	117881.	105358.	80557.	60947.	24335.	516284.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	63604.	58940.	52679.	40278.	30473.	12167.	258142.
4 TOTAL CASH INFLOW	0.	0.	0.	324378.	300596.	268662.	205420.	155414.	62053.	1316523.
5 ROYALTY	0.	0.	0.	63604.	58940.	52679.	40278.	30473.	12167.	258142.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	7500.	0.	0.	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.	0.	0.	0.	0.	0.	5000.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	1304.	1208.	1080.	826.	625.	249.	5292.
OPERATING EXPENSES	0.	0.	0.	127207.	117881.	105358.	80557.	60947.	25654.	517603.
(M$/BBL)	0.0	0.0	0.0	6.47	6.47	6.47	6.47	6.47	6.82	6.49
9 OPERATING COST	0.	0.	0.	27486.	27318.	27095.	26655.	26305.	25654.	160513.
CAPITAL COST RECOVERY	0.	0.	0.	99721.	90563.	78263.	53902.	34642.	0.	357090.
INCOME BEFORE TAX	0.	0.	0.	124763.	122567.	109546.	83759.	63369.	25302.	529306.
10 INCOME TAX	0.	0.	0.	56144.	55155.	49296.	37692.	28516.	11386.	238188.
11 CAPITAL INVESTMENT	72691.	148355.	186690.	0.	0.	0.	0.	0.	0.	407736.
12 TOTAL CASH OUTFLOW	72691.	148355.	186690.	156037.	142622.	130149.	105451.	85919.	49457.	1077370.
13 NET CASH FLOW	-72691.	-148355.	-186690.	168341.	157975.	138513.	99969.	69495.	12597.	
14 CUMULATIVE NET CASH FLOW	-72691.	-221046.	-407736.	-239395.	-81420.	57092.	157062.	226557.	239153.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	5.06	11.51	14.61	15.05	
16 CORPORATE CAPITAL	72691.	148355.	186690.	0.	0.	0.	0.	0.	0.	407736.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	

21 PAYOUT TIME 5.6 YEARS

TABLE 18-6-6 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD

VOL.II CASE I A : OFFSHORE STORAGE 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	-70939.	-137886.	-165253.	141915.	126834.	105913.	72801.	48199.	8321.
CUMULATIVE PRESENT WORTH	-70939.	-208825.	-374077.	-232162.	-105328.	585.	73386.	121585.	129905.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44
PRESENT WORTH	-69308.	-128592.	-147109.	120591.	102878.	82003.	53804.	34002.	5603.
CUMULATIVE PRESENT WORTH	-69308.	-197900.	-345009.	-224418.	-121540.	-39537.	14267.	48270.	53873.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30
PRESENT WORTH	-67785.	-120297.	-131637.	103216.	84226.	64217.	40302.	24362.	3840.
CUMULATIVE PRESENT WORTH	-67785.	-188082.	-319718.	-216502.	-132276.	-68059.	-27756.	-3394.	446.

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* 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 *

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TABLE 18-6-7 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD

VOL.II CASE I B : ONSHORE TERMINAL 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)	80694.	197443.	175568.	0.	0.	0.	0.	0.	0.	453705.
OIL PRODUCTION (M BBL/YEAR)	0.	0.	0.	19655.	18214.	16279.	12447.	9417.	3760.	79772.
SALES PRICE OF OIL (M$/BBL)	0.0	0.0	0.0	32.36	32.36	32.36	32.36	32.36	32.36	
BASIC PRICE OF OIL (M$/BBL)	35.62	37.40	39.27	41.24	43.30	45.46	47.74	50.12	52.63	

TABLE 18-6-7 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD

VOL.II CASE I B : 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	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	311657.	288808.	258126.	197364.	149320.	59620.	1264895.
2 REVENUE FROM OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 BONUS FROM OIL COMPANY	0.	0.	0.	7500.	0.	0.	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.	0.	0.	0.	0.	0.	5000.
4 RESEARCH FUND FROM OIL CO.	0.	0.	0.	1304.	1208.	1080.	826.	625.	249.	5292.
5 TOTAL CASH INFLOW	0.	0.	0.	320461.	290017.	259206.	198190.	149944.	59869.	1277686.
6 INCOME TAX	0.	0.	0.	144208.	130507.	116643.	89186.	67475.	26941.	574959.
7 NET CASH FLOW	0.	0.	0.	176254.	159509.	142563.	109005.	82469.	32928.	
8 CUMULATIVE NET CASH FLOW	0.	0.	0.	176254.	335763.	478326.	587331.	669800.	702728.	

TABLE 18-6-7 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD

VOL.II CASE I B : ONSHORE TERMINAL 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.	148586.	128066.	109010.	79381.	57197.	21750.
CUMULATIVE PRESENT WORTH	0.	0.	0.	148586.	276652.	385662.	465043.	522240.	543991.
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.	126260.	103877.	84401.	58667.	40351.	14646.
CUMULATIVE PRESENT WORTH	0.	0.	0.	126260.	230137.	314538.	373205.	413555.	428202.
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.	108068.	85044.	66095.	43945.	28911.	10038.
CUMULATIVE PRESENT WORTH	0.	0.	0.	108068.	193112.	259207.	303152.	332063.	342101.

TABLE 18-6-7 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD
VOL.II CASE I B : ONSHORE 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	9YR. TOTAL
1 SALES REVENUE FROM PROFIT OIL	0.	0.	0.	133567.	123775.	110626.	84585.	63994.	25551.	542098.
2 SALES REVENUE FROM COST OIL	0.	0.	0.	127207.	117881.	105358.	80557.	60947.	24335.	516284.
3 SALES REVENUE FROM ROYALTY OIL	0.	0.	0.	63604.	58940.	52679.	40278.	30473.	12167.	258142.
4 TOTAL CASH INFLOW	0.	0.	0.	324378.	300596.	268662.	205420.	155414.	62053.	1316523.
5 ROYALTY	0.	0.	0.	63604.	58940.	52679.	40278.	30473.	12167.	258142.
6 PAYMENT FOR OIL BASIC PRICE	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 BONUS	0.	0.	0.	7500.	0.	0.	0.	0.	0.	7500.
DISCOVERY BONUS	0.	0.	0.	2500.	0.	0.	0.	0.	0.	2500.
PRODUCTION BONUS	0.	0.	0.	5000.	0.	0.	0.	0.	0.	5000.
8 RESEARCH FUND TO PETRONAS	0.	0.	0.	1304.	1208.	1080.	826.	625.	249.	5292.
OPERATING EXPENSES	0.	0.	0.	127207.	117881.	105358.	80557.	60947.	24335.	516284.
(M$/BBL)	0.0	0.0	0.0	6.47	6.47	6.47	6.47	6.47	6.47	6.47
9 OPERATING COST	0.	0.	0.	22276.	22108.	21885.	21445.	21095.	20444.	129253.
CAPITAL COST RECOVERY	0.	0.	0.	104931.	95773.	83473.	59112.	39852.	3891.	387031.
INCOME BEFORE TAX	0.	0.	0.	124763.	122567.	109546.	83759.	63369.	25302.	529306.
10 INCOME TAX	0.	0.	0.	56144.	55155.	49296.	37692.	28516.	11386.	238188.
11 CAPITAL INVESTMENT	80694.	197443.	175568.	0.	0.	0.	0.	0.	0.	453705.
12 TOTAL CASH OUTFLOW	80694.	197443.	175568.	150827.	137412.	124939.	100241.	80709.	44247.	1092079.
13 NET CASH FLOW	-80694.	-197443.	-175568.	173551.	163185.	143723.	105179.	74705.	17807.	
14 CUMULATIVE NET CASH FLOW	-80694.	-278137.	-453705.	-280154.	-116969.	26753.	131933.	206638.	224444.	
15 DCF ROR OF NET CASH FLOW (%)	0.0	0.0	0.0	0.0	0.0	2.12	8.66	11.90	12.51	
16 CORPORATE CAPITAL	80694.	197443.	175568.	0.	0.	0.	0.	0.	0.	453705.
17 INTEREST	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
18 BANK BORROWING	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
19 REPAYMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
20 BORROWING BALANCE	0.	0.	0.	0.	0.	0.	0.	0.	0.	

21 PAYOUT TIME 5.8 YEARS

TABLE 18-6-7 CASH FLOW TABLE FOR OIL TAPIS OIL FIELD

VOL.II CASE I B : 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
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	-78749.	-183509.	-155408.	146307.	131017.	109897.	76595.	51812.	11762.
CUMULATIVE PRESENT WORTH	-78749.	-262259.	-417666.	-271359.	-140342.	-30445.	46150.	97962.	109724.
10.00% DISCOUNT RATE	0.95	0.87	0.79	0.72	0.65	0.59	0.54	0.49	0.44
PRESENT WORTH	-76939.	-171141.	-138345.	124324.	106271.	85088.	56608.	36552.	7920.
CUMULATIVE PRESENT WORTH	-76939.	-248079.	-386425.	-262101.	-155830.	-70743.	-14135.	22417.	30337.
15.00% DISCOUNT RATE	0.93	0.81	0.71	0.61	0.53	0.46	0.40	0.35	0.30
PRESENT WORTH	-75248.	-160101.	-123794.	106411.	87004.	66633.	42403.	26189.	5428.
CUMULATIVE PRESENT WORTH	-75248.	-235349.	-359143.	-252733.	-165729.	-99096.	-56693.	-30504.	-25076.

Table 19-5-1 (Vol. II)

MAJOR EQUIPMENT LIST

FOR BEKOK AND PULAI FIELDS GAS UTILIZATION

ITEM NO. & NAME	LOCATION	QUANTITY	DESCRIPTION
V-101 PRODUCTION SEPARATOR	BEPC-A PUPC-A	1 1	SIZE: 5'-0" I.D. x 15'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
V-102 TEST SEPARATOR	BEPC-A PUPC-A	1 1	SIZE: 5'-0" I.D. x 15'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
V-103 LIQUID KNOCKOUT DRUM	BEW-A PUWP-A	2 2	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
V-104 GLYCOL CONTACTOR	BEPC-A PUPC-A	1 1	SIZE: 7'-6" I.D. x 28'-6" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: VERTICAL
V-105 CONDENSATE SURGE VESSEL	BEPC-A PUPC-A	1 1	SIZE: 4'-6" I.D. x 15'-0" S-S DESIGN PRESS.: 1,200 PSIG @ 150°F TYPE: HORIZONTAL
V-111 KNOCKOUT DRUM	BEPC-A PUPC-A	1 1	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: VERTICAL
V-112 UNIT SUCTION SCRUBBER	BEPC-A PUPC-A	2 2	SIZE: 3'-6" I.D. x 10'-0" S-S DESIGN PRESS.: 300 PSIG @ 150°F TYPE: VERTICAL
GR-101 GLYCOL REGENERATOR	BEPC-A PUPC-A	1 1	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	BEW-A PUWP-A	1 1	SIZE: 24" DIA. x 7'-6" L
C-111 GAS TURBINE COMPRESSOR	BEPC-A	2	CAPACITY: 150 MMSCFD
	PUPC-A	2	CAPACITY: 45 MMSCFD
C-151 INSTRUMENT AIR COMPRESSOR	BEPC-A PUPC-A	2 2	CAPACITY: 35 SCFM
P-152 FIRE WATER PUMP	BEPC-A PUPC-A	1 1	CAPACITY: 1,500 GPM TYPE: VERTICAL
P-153 SEA WATER PUMP	BEPC-A	2	CAPACITY: 1,000 GPM TYPE: VERTICAL
	PUPC-A	2	CAPACITY: 300 GPM TYPE: VERTICAL
TK-101 CORROSION INHIBITOR TANK	BEPC-A PUPC-A	1 1	CAPACITY: 20 BBL SIZE: 5'-0" I.D. x 8'-0" H
TK-102 GLYCOL STORAGE TANK	BEPC-A PUPC-A	1 1	CAPACITY: 20 BBL SIZE: 5'-0" I.D. x 8'-0" H
E-111 AFTERCOOLER	BEPC-A PUPC-A	4 2	SHELL AND TUBE
M-101 INLET MANIFOLD	BEPC-A PUPC-A	1 1	PRODUCTION HEADER TEST HEADER

Table 19-6-1 (Vol. II) **CAPITAL INVESTMENT COST ESTIMATION**

(M$ 1,000)

	BEKOK AND PULAI FIELDS GAS UTILIZATION	
1.	Exploration & Appraisal Wells	
2.	Engineering	23,894
3.	Development Wells	12,187
4.	Facilities	
	a. Offshore Platforms	54,566
	b. Offshore Production Equipment	22,723
	c. Submarine Pipelines	149,375
	d. Offshore Storage & Loading Facilities .	-
	e. Onshore Terminal & Loading Facilities .	-
	f. Support Facilities	-
	Sub Total	226,664
5.	Pre-start up Expense	2,636
6.	Contingencies	26,347
	TOTAL	291,728

ANNUAL OPERATION COST ESTIMATION

Table 19-6-2 (Vol.II) BEKOK AND PULAI FIELDS GAS UTILIZATION (M$ 1,000)

	1	2	3	4	5	6	7	8	9	10
1. Direct Cost										
a. Operating Personnel				450	455	480	549	848	1,062	1,240
b. Operating Management				45	46	48	55	85	106	124
c. Repair & Maintenance				2,370	2,370	2,370	2,370	2,370	2,370	2,370
d. Operating Supplies				876	876	876	876	876	876	876
e. Chemical				107	107	107	107	107	107	107
f. Service Contract				635	645	678	775	1,201	1,504	1,75
Sub Total				4,483	4,499	4,559	4,732	5,487	6,025	6,47
2. Indirect Cost										
a. Indirect Personnel				249	251	264	302	467	584	68
b. Insurance				2,553	2,553	2,553	2,553	2,553	2,553	2,55
Sub Total				2,802	2,804	2,817	2,855	3,020	3,137	3,23
TOTAL				7,285	7,303	7,376	7,587	8,507	9,162	9,70

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(M$ 1,000)

5	6	7	8	9	10	11	12	13	14	15	16	17	18
455	480	549	848	1,062	1,240	1,351	1,582	1,763	1,826	1,885	1,925	1,958	1,989
46	48	55	85	106	124	135	158	176	183	189	193	196	199
2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370
876	876	876	876	876	876	876	876	876	876	876	876	876	876
107	107	107	107	107	107	107	107	107	107	107	107	107	107
645	678	775	1,201	1,504	1,755	1,912	2,238	2,494	2,583	2,667	2,725	2,769	2,817
4,499	4,559	4,732	5,487	6,025	6,472	6,751	7,331	7,786	7,945	8,094	8,196	8,276	8,358
251	264	302	467	584	683	744	871	970	1,006	1,036	1,059	1,077	1,095
2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553
2,804	2,817	2,855	3,020	3,137	3,236	3,297	3,424	3,523	3,559	3,589	3,612	3,630	3,648
7,303	7,376	7,587	8,507	9,162	9,708	10,048	10,755	11,309	11,504	11,683	11,808	11,906	12,006

	11	12	13	14	15	16	17	18	19	20	21	22	23
0	1,351	1,582	1,763	1,826	1,885	1,925	1,958	1,989	2,012	2,037	2,062	2,073	2,162
4	135	158	176	183	189	193	196	199	201	204	206	207	216
0	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370	2,370
6	876	876	876	876	876	876	876	876	876	876	876	876	876
7	107	107	107	107	107	107	107	107	107	107	107	107	107
5	1,912	2,238	2,494	2,583	2,667	2,725	2,769	2,817	2,847	2,883	2,916	2,934	3,058
2	6,751	7,331	7,786	7,945	8,094	8,196	8,276	8,358	8,413	8,477	8,537	8,567	8,789
3	744	871	970	1,006	1,036	1,059	1,077	1,095	1,102	1;120	1,135	1,140	1,189
3	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553	2,553
6	3,297	3,424	3,523	3,559	3,589	3,612	3,630	3,648	3,655	3,673	3,688	3,693	3,742
8	10,048	10,755	11,309	11,504	11,683	11,808	11,906	12,006	12,068	12,150	12,225	12,260	12,531

Table 19-6-3 (Vol. II) INVESTMENT SCHEDULE

BEKOK AND PULAI FIELDS GAS UTILIZATION (M$ 1,000)

Item \ Year	1ST	2ND	3RD	
1. Exploration & Appraisal Wells	-	-	-	
2. Engineering	23,894	-	-	
3. Development Wells	-	-	12,187	
4. Offshore Platforms	5,725	29,550	19,291	
5. Offshore Production Equipment	-	9,977	12,746	
6. Submarine Pipelines	-	58,994	90,381	
7. Offshore Storage & Loading Facilities	-	-	-	
8. Onshore Terminal & Loading Facilities	-	-	-	
9. Support Facilities	-	-	-	
10. Pre-start up Expense	297	993	1,346	
11. Contingencies	2,962	9,926	13,459	
Total	32,878	109,440	149,410	

* 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 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION

VOL.II CASE I A : OFFSHORE COMPRESSION CASE

* 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)	32878.	109440.	149410.	0.	0.	0.	0.	0.	0.	0.	291728.
GAS PRODUCTION (MMSCF/DAY)	0.	0.	0.	150.	150.	150.	150.	150.	150.	150.	1050.
SALES PRICE OF GAS (M¢/MSCF)	0.0	0.0	0.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	

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.	291728.
GAS PRODUCTION (MMSCF/DAY)	150.	150.	150.	150.	150.	150.	150.	150.	150.	150.	2550.
SALES PRICE OF GAS (M¢/MSCF)	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	267.0	

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION

VOL.II CASE I A : OFFSHORE COMPRESSION CASE

* INPUT DATA BY YEAR *

TERM	21	22	23	23YR TOTAL
CAPITAL INVESTMENT (M$ 1000)	0.	0.	0.	291728.
GAS PRODUCTION (MMSCF/DAY)	150.	150.	150.	3000.
SALES PRICE OF GAS (M¢/MSCF)	267.0	267.0	267.0	

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION

VOL.II CASE I A : OFFSHORE COMPRESSION 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.	0.	66513.	66513.	66513.	66513.	66513.	66513.	66513.	465591.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	0.	0.	0.	325.	325.	325.	325.	325.	325.	325.	2277.
4 TOTAL CASH INFLOW	0.	0.	0.	66838.	66838.	66838.	66838.	66838.	66838.	66838.	467868.
5 INCOME TAX	0.	0.	0.	30077.	30077.	30077.	30077.	30077.	30077.	30077.	210540.
6 NET CASH FLOW	0.	0.	0.	36761.	36761.	36761.	36761.	36761.	36761.	36761.	
7 CUMULATIVE NET CASH FLOW	0.	0.	0.	36761.	73522.	110283.	147044.	183805.	220566.	257327.	

TERM	11	12	13	14	15	16	17	18	19	20	20YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	66513.	66513.	66513.	66513.	66513.	66513.	66513.	66513.	66513.	66513.	1130721.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
PRODUCTION BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	325.	325.	325.	277.	201.	202.	202.	203.	203.	203.	4742.
4 TOTAL CASH INFLOW	66838.	66838.	66838.	66790.	66714.	66715.	66715.	66716.	66716.	66716.	1135462.
5 INCOME TAX	30077.	30077.	30077.	30055.	30021.	30022.	30022.	30022.	30022.	30022.	510958.
6 NET CASH FLOW	36761.	36761.	36761.	36734.	36693.	36693.	36693.	36694.	36694.	36694.	
7 CUMULATIVE NET CASH FLOW	294088.	330849.	367610.	404344.	441037.	477730.	514423.	551117.	587810.	624504.	

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION

VOL.II CASE I A : OFFSHORE COMPRESSION CASE

** CASH FLOW TABLE FOR PETRONAS **
(X M$ 1000)

(CONT'D)
PAGE 4

TERM	21	22	23	23YR. TOTAL
1 SALES REVENUE FROM PROFIT GAS	66513.	66513.	66513.	1330260.
2 BONUS FROM OIL COMPANY	0.	0.	0.	0.
DISCOVERY BONUS	0.	0.	0.	0.
PRODUCTION BONUS	0.	0.	0.	0.
3 RESEARCH FUND FROM OIL CO.	204.	204.	205.	5355.
4 TOTAL CASH INFLOW	66717.	66717.	66718.	1335612.
5 INCOME TAX	30022.	30023.	30023.	601026.
6 NET CASH FLOW	36694.	36694.	36695.	
7 CUMULATIVE NET CASH FLOW	661198.	697893.	734588.	

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION

VOL.II CASE I A : OFFSHORE COMPRESSION CASE

* * PRESENT WORTH OF NET CASH FLOW FOR PETRONAS * *
(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	0.	0.	0.	30990.	29515.	28109.	26771.	25496.	24282.	23126.
CUMULATIVE PRESENT WORTH	0.	0.	0.	30990.	60505.	88614.	115385.	140881.	165162.	188288.
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.	26334.	23940.	21764.	19785.	17986.	16351.	14865.
CUMULATIVE PRESENT WORTH	0.	0.	0.	26334.	50274.	72037.	91822.	109809.	126160.	141025.
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.	22540.	19600.	17043.	14820.	12887.	11206.	9745.
CUMULATIVE PRESENT WORTH	0.	0.	0.	22540.	42139.	59182.	74003.	86890.	98096.	107840.

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	22024.	20976.	19977.	19012.	18086.	17225.	16405.	15624.	14880.	14171.
CUMULATIVE PRESENT WORTH	210312.	231288.	251265.	270276.	288362.	305587.	321991.	337615.	352495.	366666.
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	13513.	12285.	11168.	10145.	9213.	8375.	7614.	6922.	6293.	5721.
CUMULATIVE PRESENT WORTH	154538.	166823.	177991.	188137.	197349.	205724.	213338.	220260.	226553.	232273.
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	8473.	7368.	6407.	5567.	4836.	4205.	3657.	3180.	2765.	2404.
CUMULATIVE PRESENT WORTH	116314.	123682.	130089.	135656.	140492.	144697.	148354.	151533.	154298.	156702.

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION

VOL.II CASE I A : OFFSHORE COMPRESSION CASE

* * 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	13497.	12854.	12242.
CUMULATIVE PRESENT WORTH	380163.	393016.	405258.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	5201.	4728.	4298.
CUMULATIVE PRESENT WORTH	237474.	242202.	246500.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	2091.	1818.	1581.
CUMULATIVE PRESENT WORTH	158793.	160611.	162192.

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION
VOL.II CASE I A : OFFSHORE COMPRESSION 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.	0.	28506.	28506.	28506.	28506.	28506.	28506.	28506.	199539.
2 SALES REVENUE FROM COST GAS	0.	0.	0.	36546.	36546.	36546.	36546.	36546.	36546.	36546.	255819.
3 SALES REVENUE FROM ROYALTY GAS	0.	0.	0.	14618.	14618.	14618.	14618.	14618.	14618.	14618.	102328.
4 TOTAL CASH INFLOW	0.	0.	0.	79669.	79669.	79669.	79669.	79669.	79669.	79669.	557686.
5 ROYALTY	0.	0.	0.	14618.	14618.	14618.	14618.	14618.	14618.	14618.	102328.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 RESEARCH FUND TO PETRONAS	0.	0.	0.	325.	325.	325.	325.	325.	325.	325.	2277.
OPERATING EXPENSES	0.	0.	0.	36546.	36546.	36546.	36546.	36546.	36546.	36546.	255819.
8 OPERATING COST	0.	0.	0.	7285.	7303.	7376.	7587.	8507.	9162.	9708.	56928.
CAPITAL COST RECOVERY	0.	0.	0.	29261.	29243.	29170.	28959.	28039.	27384.	26838.	198891.
INCOME BEFORE TAX	0.	0.	0.	28180.	28180.	28180.	28180.	28180.	28180.	28180.	197262.
9 INCOME TAX	0.	0.	0.	12681.	12681.	12681.	12681.	12681.	12681.	12681.	88768.
10 CAPITAL INVESTMENT	32878.	109440.	149410.	0.	0.	0.	0.	0.	0.	0.	291728.
11 TOTAL CASH OUTFLOW	32878.	109440.	149410.	34910.	34928.	35001.	35212.	36132.	36787.	37333.	542028.
12 NET CASH FLOW	-32878.	-109440.	-149410.	44760.	44742.	44669.	44458.	43538.	42883.	42337.	
13 CUMULATIVE NET CASH FLOW	-32878.	-142318.	-291728.	-246968.	-202226.	-157558.	-113100.	-69562.	-26679.	15658.	
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	1.15	
15 CORPORATE CAPITAL	32878.	109440.	149410.	0.	0.	0.	0.	0.	0.	0.	291728.
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 9.6 YEARS

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION
VOL.II CASE I A : OFFSHORE COMPRESSION 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	28506.	28506.	28506.	28506.	28506.	28506.	28506.	28506.	28506.	28506.	484595.
2 SALES REVENUE FROM COST GAS	36546.	36546.	36546.	26816.	11683.	11808.	11906.	12006.	12068.	12150.	463893.
3 SALES REVENUE FROM ROYALTY GAS	14618.	14618.	14618.	14618.	14618.	14618.	14618.	14618.	14618.	14618.	248509.
4 TOTAL CASH INFLOW	79669.	79669.	79669.	69940.	54807.	54932.	55030.	55130.	55192.	55274.	1196995.
5 ROYALTY	14618.	14618.	14618.	14618.	14618.	14618.	14618.	14618.	14618.	14618.	248509.
6 BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
DISCOVERY BONUS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 RESEARCH FUND TO PETRONAS	325.	325.	325.	277.	201.	202.	202.	203.	203.	203.	4742.
OPERATING EXPENSES	36546.	36546.	36546.	26816.	11683.	11808.	11906.	12006.	12068.	12150.	463893.
8 OPERATING COST	10048.	10755.	11309.	11504.	11683.	11808.	11906.	12006.	12068.	12150.	172165.
CAPITAL COST RECOVERY	26498.	25791.	25237.	15312.	0.	0.	0.	0.	0.	0.	291728.
INCOME BEFORE TAX	28180.	28180.	28180.	28229.	28305.	28304.	28304.	28303.	28303.	28302.	479852.
9 INCOME TAX	12681.	12681.	12681.	12703.	12737.	12737.	12737.	12736.	12736.	12736.	215933.
10 CAPITAL INVESTMENT	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	291728.
11 TOTAL CASH OUTFLOW	37673.	38380.	38934.	39102.	39239.	39365.	39463.	39563.	39625.	39708.	933079.
12 NET CASH FLOW	41997.	41290.	40736.	30838.	15568.	15567.	15567.	15567.	15566.	15566.	
13 CUMULATIVE NET CASH FLOW	57654.	98944.	139680.	170518.	186086.	201653.	217220.	232786.	248353.	263919.	
14 DCF ROR OF NET CASH FLOW (%)	3.70	5.59	7.04	7.92	8.29	8.62	8.91	9.15	9.37	9.56	
15 CORPORATE CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	291728.
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 9.6 YEARS

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION
VOL.II CASE I A : OFFSHORE COMPRESSION CASE

** 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	28506.	28506.	28506.	570111.
2 SALES REVENUE FROM COST GAS	12225.	12260.	12531.	500908.
3 SALES REVENUE FROM ROYALTY GAS	14618.	14618.	14618.	292364.
4 TOTAL CASH INFLOW	55349.	55384.	55655.	1363380.
5 ROYALTY	14618.	14618.	14618.	292364.
6 BONUS	0.	0.	0.	0.
DISCOVERY BONUS	0.	0.	0.	0.
7 RESEARCH FUND TO PETRONAS	204.	204.	205.	5355.
OPERATING EXPENSES	12225.	12260.	12531.	500909.
8 OPERATING COST	12225.	12260.	12531.	209181.
CAPITAL COST RECOVERY	0.	0.	0.	291728.
INCOME BEFORE TAX	28302.	28302.	28300.	564756.
9 INCOME TAX	12736.	12736.	12735.	254140.
10 CAPITAL INVESTMENT	0.	0.	0.	291728.
11 TOTAL CASH OUTFLOW	39783.	39818.	40090.	1052768.
12 NET CASH FLOW	15566.	15566.	15565.	
13 CUMULATIVE NET CASH FLOW	279485.	295051.	310616.	
14 DCF ROR OF NET CASH FLOW (%)	9.72	9.87	10.00	
15 CORPORATE CAPITAL	0.	0.	0.	291728.
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 9.6 YEARS

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION

VOL.II CASE I A : OFFSHORE COMPRESSION 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	-32086.	-101717.	-132253.	37733.	35922.	34156.	32376.	30196.	28325.	26633.
CUMULATIVE PRESENT WORTH	-32086.	-133802.	-266056.	-228322.	-192400.	-158244.	-125869.	-95673.	-67347.	-40714.
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	-31348.	-94861.	-117733.	32064.	29137.	26445.	23927.	21302.	19074.	17119.
CUMULATIVE PRESENT WORTH	-31348.	-126209.	-243942.	-211878.	-182741.	-156296.	-132368.	-111066.	-91992.	-74872.
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	-30659.	-88742.	-105350.	27444.	23855.	20709.	17923.	15263.	13072.	11223.
CUMULATIVE PRESENT WORTH	-30659.	-119401.	-224751.	-197307.	-173452.	-152743.	-134820.	-119557.	-106485.	-95262.

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	25161.	23560.	22137.	15960.	7673.	7308.	6960.	6628.	6312.	6012.
CUMULATIVE PRESENT WORTH	-15553.	8007.	30144.	46104.	53777.	61085.	68044.	74672.	80985.	86997.
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	15438.	13798.	12376.	8517.	3909.	3553.	3230.	2936.	2670.	2427.
CUMULATIVE PRESENT WORTH	-59434.	-45636.	-33260.	-24743.	-20834.	-17281.	-14051.	-11114.	-8445.	-6018.
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	9680.	8276.	7100.	4674.	2052.	1784.	1551.	1349.	1173.	1020.
CUMULATIVE PRESENT WORTH	-85582.	-77306.	-70206.	-65532.	-63480.	-61696.	-60145.	-58796.	-57623.	-56603.

TABLE 19-6-4 CASH FLOW TABLE FOR GAS BEKOK AND PULAI FIELDS GAS UTILIZATION

VOL.II CASE I A : OFFSHORE COMPRESSION CASE

* * 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	5725.	5453.	5193.
CUMULATIVE PRESENT WORTH	92722.	98175.	103367.
10.00% DISCOUNT RATE	0.14	0.13	0.12
PRESENT WORTH	2206.	2006.	1823.
CUMULATIVE PRESENT WORTH	-3812.	-1806.	17.
15.00% DISCOUNT RATE	0.06	0.05	0.04
PRESENT WORTH	887.	771.	671.
CUMULATIVE PRESENT WORTH	-55716.	-54945.	-54274.

Table 29-6-1 (Vol. II) **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. II) 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. II)

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. II) **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. II) 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. II)

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. II) 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. II)

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. II)

COST OF 12 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'	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 (Vol. II)

COST OF 18 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'	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. II)

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. II)

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. II)

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. II) **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. II)

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. II) 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. II)

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. II)

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. II)

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. II)

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. II)

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. II)

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. II) ANNUAL OIL PRODUCTION AND FOB PRICE PER BARREL

PENINSULAR AREA

FIELD	Bekok, Pulai & Seligi Fields									Tapis Field		
CASE	Case IA, IB (Bekok, Pulai & Seligi A,B)			Case II (Bekok, Pulai & Seligi A)			Case III (Bekok & Pulai)			Case IA, IB (Tapis)		
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	39,859	32.41	12.76	32,193	32.44	12.77	26,718	32.44	12.77	19,655	32.36	12.74
5	39,331	32.41	12.76	31,938	32.44	12.77	26,463	32.46	12.78	18,214	32.36	12.74
6	36,904	32.41	12.76	30,551	32.44	12.77	25,076	32.46	12.78	16,279	32.36	12.74
7	31,038	32.41	12.76	26,017	32.44	12.77	20,542	32.44	12.77	12,447	32.36	12.74
8	16,733	32.41	12.76	14,224	32.41	12.76	14,224	32.41	12.76	9,417	32.36	12.74
9	11,424	32.41	12.76	10,636	32.41	12.76	10,636	32.41	12.76	3,760	32.36	12.74
10	8,453	32.39	12.75	8,453	32.39	12.75	8,453	32.39	12.75			
11	6,993	32.39	12.75	6,993	32.39	12.75	6,993	32.39	12.75			
12	4,617	32.44	12.77	4,617	32.46	12.78	4,617	32.46	12.78			
13	3,128	32.51	12.80	3,128	32.51	12.80	3,128	32.51	12.80			
14	2,694	32.51	12.80	2,694	32.51	12.80	2,694	32.51	12.80			
15	2,351	32.51	12.80	2,351	32.51	12.80	2,351	32.51	12.80			
16	2,084	32.51	12.80	2,084	32.51	12.80	2,084	32.51	12.80			
17	1,872	32.51	12.80	1,872	32.51	12.80	1,872	32.51	12.80			
18	1,697	32.51	12.80	1,697	32.51	12.80	1,697	32.51	12.80			
19	1,551	32.51	12.80	1,551	32.51	12.80	1,551	32.51	12.80			
20	1,431	32.51	12.80	1,431	32.51	12.80	1,431	32.51	12.80			
21	1,336	32.51	12.80	1,336	32.51	12.80	1,336	32.51	12.80			
22	1,252	32.51	12.80	1,252	32.51	12.80	1,252	32.51	12.80			
23	825	32.51	12.80	825	32.51	12.80	825	32.51	12.80			

Note: Crude price is as of middle of 1976

Table 31-6-1 (Vol. II) 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. II)

ANNUAL OPERATING COST FOR OIL

UNIT: M$1,000

AREA / FIELD / YEAR	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. II)

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. II)

INVESTMENT SCHEDULE 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	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. II)

ANNUAL OPERATING COST 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								
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. II)

PROFITABILITY YARDSTICKS OF OIL

AT THE YEAR OF MAX. R.O.R. FOR OPERATING COMPANY

UNIT : M$1,000

AREA	FIELD	CASE	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.

FIGURE

FIGURE