

EXPLORATION and PRODUCTION ECONOMICS

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Chapter 12

INTRODUCTION

MESA has developed an economic model for oil exploration and development in the Marla region as a guide to potential explorers in the Officer Basin region. Although the Officer Basin has gas potential, gas discovery economics have not yet been modelled as development is dependent on future links between gas reserves in the northwest of Australia and markets on the eastern seaboard (Fig. 4.1). If sufficient reserves are discovered, a pipeline to either the Adelaide or eastern Australian markets (via Moomba) may be economic.

Development of oil reserves is generally less capital intensive than gas. Two scenarios were examined:

- The ≤ 30 mmbbl OOIP (original oil in place) case, in which oil is trucked from Marla and the infrastructure required is a trunkline from the field to the Stuart Highway, storage tank, yard, office and workshop at Marla, basic surface facilities and truck loading facilities.
- The 100–200 mmbbl OOIP case, in which oil is piped to Port Bonython and the infrastructure required is the same apart from a larger storage tank and trunkline.

In both cases, a single oil pool in a single field has been modelled on a stand-alone basis — it is likely that more than one oil pool and field would be discovered.

Marla has diesel generated power, water and communication infrastructure available, and the fully sealed Stuart Highway runs through the area. It is currently uneconomic for oil from a new discovery in Central Australia to be transported via rail to Adelaide even though the railway runs through the region. Trucking oil to the Port Stanvac refinery near Adelaide using two or three tank road trains is the alternative. Privatisation of the rail freight network may improve rail transport economics in the future.

METHODOLOGY

Two Microsoft Excel spreadsheets were used to develop the economic model. The first spreadsheet modelled oil production for a range of field sizes and permeability thickness kh (which determines the flow capacity of a well; in millidarcy feet (md.ft)), and results were placed into the economic model adapted from the Cooper Basin gas model (McDonough, 1996, in press). Reservoir properties were based on the early Palaeozoic P3 Pacoota Sandstone reservoir in the Mereenie Oilfield as this information is very limited in the Officer Basin. It is likely that the Mereenie case is more

conservative and that Officer Basin reservoirs may have better reservoir characteristics.

The second spreadsheet determines the net present value of the project by calculating exploration, capital and operational costs, royalty and revenue for a range of field sizes, enabling minimum economic field size in the region to be determined. A high oil price of US\$25/bbl and a low oil price of US\$18/bbl were used. This covers variations in oil price forecasts for 1997, which range from US\$19 to US\$25/bbl (Bell, 1997). Appendix 12.1 is a summary of information used in the model. Other sources of information used were GPA Engineering Pty Ltd (GPA, 1996) and Bureau of Resource Sciences (BRS, 1996).

EXPLORATION SUCCESS RATIOS

The Australian historical base case success ratio for a wildcat well to discover an economic field is $\sim 1:12.5$; the success ratio over the period 1978–87 was 1:8.3, reflecting modern techniques and knowledge (MacKenzie and Cai, 1993). A total of eight petroleum exploration wells have been drilled in the entire Officer Basin, but none of these are in the Marla area.

In the economic model, oil is discovered by the fifth exploration well of the hypothetical drilling program, or the thirteenth petroleum exploration well in the Officer Basin, a 1:13 success ratio — comparable to the historical Australian case and more conservative than the modern Australian case. A pessimistic case where oil is discovered in the eighth exploration well was examined as part of the case study below.

EXPLORATION AND DEVELOPMENT SCENARIOS

An exploration program, based on the combined program for PEL 61 and 63, was used up to the discovery of a single oil field in Year 3. The development program was then applied and run until either production ceased due to depletion or until one PPL term (21 years) had elapsed. A single Murnaroo Formation oil pool was modelled but there is a good possibility of multiple stacked hydrocarbon pools in the Officer Basin. In the Marla area, stacked pools in the Arcoellinna, intra-Ouldburra, Relief and Murnaroo are possible. In the Munta area, stacked pools in the Arcoellinna, Relief, Murnaroo, Tarlina and Pindyin are possible. It is also likely that more than one field would be discovered in a particular area (Mackie, 1994). Table 12.1 shows the field sizes that were modelled using US\$18/bbl

Table 12.1 Field sizes used for the economic model, in imperial and metric units.

	Field size (million barrels)	Field size (kilolitres)
CASE 1 (<30 million barrels)		
	5	794 940
	10	1 589 875
	15	2 384 810
	20	3 179 750
	30	4 769 630
CASE 2 (>30 million barrels)		
	50	7 949 380
	100	15 898 760
	200	31 797 510

and US\$25/bbl for the oil price and for a range of reservoir properties.

Case 1 was used to determine the minimum economic field size; Case 2 was used to determine a conservative upside potential. Much larger field sizes are possible in the Officer Basin (see Ch. 11). Facilities required for Case 1 and 2 are shown on Figure 12.1.

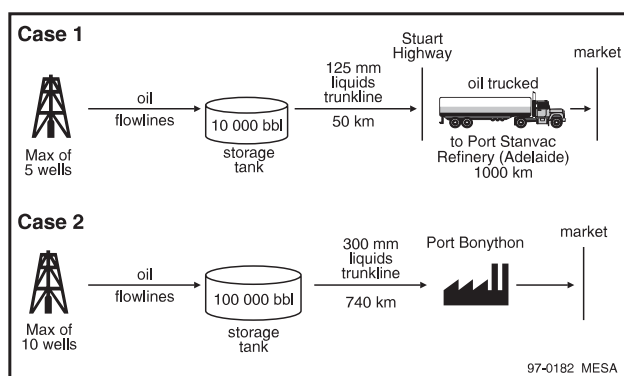


Fig. 12.1 Case 1 and 2 schematic of facilities.

Case 1

The first exploration and development scenario, for fields ≤30 mmbbl OOIP, was as follows:

Year 0

Apply for PEL, negotiate access agreement with Anangu Pitjantjatjara.

Year 1 — exploration

Construct access roads and, using existing seismic grid, drill two exploration wells.

Year 2 — exploration

Construct access road and drill one exploration well; acquire and interpret 320 km of seismic.

Year 3 — exploration and discovery of oil

Construct access road and drill two exploration wells; acquire and interpret 250 km of seismic. The second exploration well discovers oil and is completed. Apply for a PPL, and initially limit oil production to 330 bopd

(52 m³/day); commence trucking oil to Port Stanvac near Adelaide. Pay petroleum royalty.

Year 4 — development

Conduct geological and geophysical data review, estimate oil reserves, and plan development drilling. A total of five wells will be used to produce from the field. The development drilling program is determined from the production profiles. The maximum field production rate is set at 1000 bopd (158.9 m³/day), with a limit of five wells; higher volumes of oil could not be handled by trucking to Adelaide (Appendix 12.1).

For the purpose of modelling flowlines, the field is assumed to be circular (radius = 5 km; area = 75 km²); the discovery well is assumed to be near the field centre and development wells are sited halfway between the edge and centre of the field. As the reservoir is assumed to be a solution gas drive, it is assumed that there will be no water production and therefore no associated disposal requirements. Site a 10 000 bbl (1589 m³) storage tank at the field.

Year 5 onwards — development

Construct a 50 km pipeline to the Stuart Highway, establish a truck loading facility on the highway and truck oil to Adelaide. Acquire and interpret 100 km of development seismic. Drill development wells as required by the production model.

Case 2

The second exploration and development scenario, for fields in the 50–200 mmbbl OOIP range, was as follows:

Year 0

Apply for PEL, and negotiate access agreement with Anangu Pitjantjatjara.

Year 1 — exploration

Construct access roads and, using the existing seismic grid, drill two exploration wells.

Year 2 — exploration

Construct an access road and drill one exploration well; acquire and interpret 320 km of seismic.

Year 3 — exploration and discovery of oil

Construct an access road and drill two exploration wells; acquire and interpret 250 km of seismic. The second exploration well discovers a large oil field and is completed. Apply for a PPL; initially limit oil production to 3300 bopd (520 m³/day), and commence trucking to Port Stanvac. Site a 100 000 bbl (15 898 m³) storage tank at the field. Commence a feasibility study and construction of a 740 km trunkline to Port Bonython (the Moomba–Port Bonython trunkline was used as model; McDonough, 1996).

Year 4 — development

Conduct geological and geophysical data review, estimate oil reserves, plan development drilling with a

maximum of 10 wells and limit field production to 10 000 bbl/day (1589 m³/day). Complete the construction of a trunkline to Port Bonython. The development model is not entirely realistic as the amount of oil produced daily during Years 3 and 4 while the trunkline is being constructed could not be handled by trucking alone. However, this is somewhat offset by the capacity of the trunkline (33 000 bbl/day or 5250 m³/day).

Year 5 onwards — development

Acquire, process and interpret 200 km of development seismic. Drill development wells as required by the production model.

Royalty and licence fees

Guidelines for the payment of petroleum royalty were applied to these scenarios. Licensees pay royalty at a rate of 10% of the value of the petroleum at the wellhead minus all expenses (capital and operating costs) actually incurred in treating, processing or refining the petroleum downstream of the wellhead. PEL application fees were included for the first five years of the model (one PEL term). PPL application, rental and renewal fees were applied from the year that production commenced and continued for 21 years (one PPL term) or until the field ceased production.

RESULTS

For each field size, the following kh values were used for a 60 m thick pay zone within the Murnaroo Formation:

- 250 md.ft — the most pessimistic case where permeability = 0.787 md (based on average permeability data for the early Palaeozoic Pacoota Sandstone P3 reservoir, Mereenie oil field, Northern Territory).
- 1000 md.ft — calculated using arithmetic average permeability (5.371 md) from the Murnaroo Formation, Marla region (Ch. 10).
- 9200 md.ft — geometric average permeability from the Murnaroo Formation (46 md), Marla region (Ch. 10).
- 17 700 md.ft — geometric average permeability from the Murnaroo Formation (86 md), Munta region (Ch. 10).

20 mmbbl OOIP case study

Results for a 20 mmbbl OOIP field (kh = 9200 md.ft) are summarised on Figure 12.2 as an example of how each OOIP and kh scenario was modelled. Oil production and the timing of development drilling was calculated for this field size and kh, and input into the economic model. Exploration expenditure, capital expenditure (CAPEX), operating expenditure (OPEX), revenue and petroleum royalty were modelled over a 20-year period and the net present value (NPV) of the project calculated at a discount rate of 12.5%. All calculations are before tax.

A breakdown of the net present value (Fig. 12.2) reveals that OPEX is the most significant component of the NPV, profit is next, while royalty, CAPEX and exploration

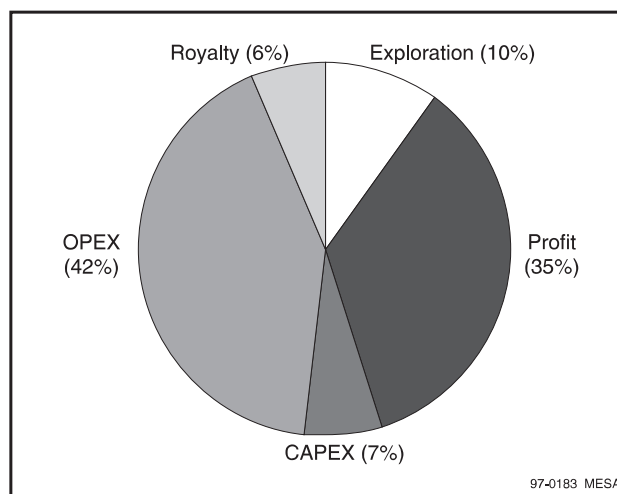


Fig. 12.2 Net present value analysis over the life of the project; revenue versus costs (20 mmbbl OOIP field, kh = 9200 md.ft).

expenditure are relatively minor components. A reduction in the price of oil from US\$25 to US\$18/bbl results in a major reduction of profit and hence royalty (Table 12.2).

Table 12.2 Net present value of profit and expenses for a 20 mmbbl OOIP field (kh = 9200 md.ft).

Cash flow	NPV (\$ million)	
	US\$18/bbl	US\$25/bbl
Exploration	5.3	5.3
CAPEX	3.5	3.5
OPEX	22.2	22.2
Profit before tax and royalty	5.8	18.5
Royalty	1.9	3.4
Revenue	21.9	7.27

A breakdown of OPEX (Fig. 12.3) indicates that transport costs (i.e. trucking oil from Marla to Port Stanvac) are the most significant operating expense. PEL application fees and rent averaged under \$5000/year and were applied over the first five years of the model (one PEL term). PPL application, rental and renewal fees were ~\$20 000/year for case 1 and \$94 000/year for case 2. Other land access costs are:

- payment of compensation of a minimum of \$20 000 per annum to AP when exploration is carried out and,

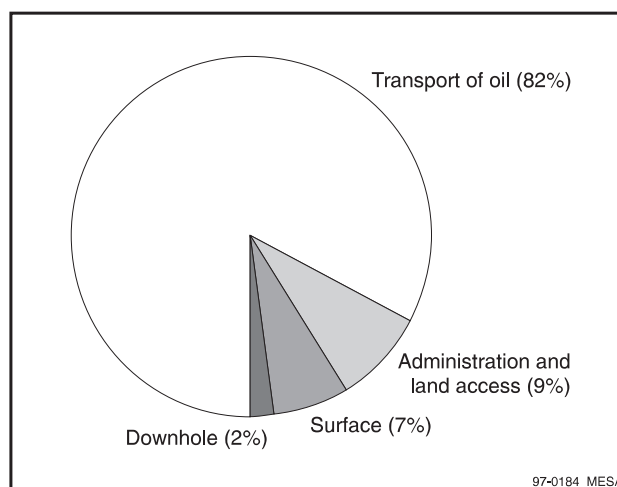


Fig. 12.3 Net present value analysis of operating expenditure (20 mmbbl OOIP field, kh = 9200 md.ft).

- payment of production royalties to AP of 1–3% on a sliding scale based on the quantity of oil and gas produced, following an economic discovery.

CAPEX has been divided into road construction and vehicles, development drilling and seismic, and surface equipment (trunkline, flowlines, pumps) on Figure 12.4. Surface equipment makes up nearly half of the CAPEX due to construction costs of a trunkline from the field to the Stuart Highway. Seismic and drilling costs are the other significant component of CAPEX.

The net present value of the before tax cash flows for the project is \$21.9 million for an oil price of US\$25/bbl, representing an internal rate of return of 44.5% (a real discount rate of 12.5% was used in all cases). The cashflows over the life of the project are shown on Figure 12.5. The impact of exploration and capital expenditure during the first three years of the project are obvious. Once the pipeline is commissioned, production generates revenue and positive cashflows commence. Operating costs total ~\$4.9 million/year. Wells were drilled in Years 1 (discovery well), 2, 14 and 15 (two wells).

The discovery of oil was delayed until Year 10 for this case study to see what effect lack of initial exploration success would have on overall project economics. A delay means that a more expensive exploration program is required and that generation of revenue from production occurs later. If the discovery of oil is delayed until Year 10 of the exploration licence after the drilling of eight exploration wells, a 20 mmbbl OOIP sized field is not economic. This

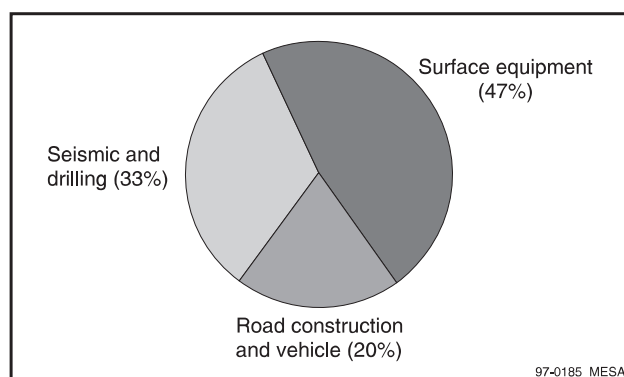


Fig. 12.4 Net present value analysis of capital expenditure (20 mmbbl OOIP field, kh = 9200 md.ft).

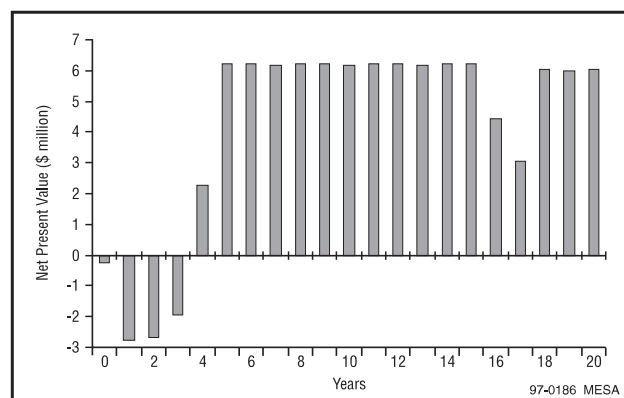


Fig. 12.5 Net present values (before tax cash flow) for 20 mmbbl OOIP field over the life of the project (kh = 9200 md.ft, US\$25/bbl oil price, discount rate = 12.5%).

implies that a successful exploration strategy is to drill wells within the first five years to bring forward possible discoveries.

Discussion

Tables 12.3–12.6 summarise the NPVs and IRR (internal rate of return) of all scenarios modelled with a real discount rate of 12.5 %.

Table 12.3 NPV for all field sizes and kh; oil price = US\$25/bbl.

Field size (million barrels)	kh (md.ft)			
	250	1000	9200	17 700
Case 1				
5	-2.1	-1.9	6.5	6.5
10	5.5	6.7	12.5	13.4
15	11.0	12.2	18.1	17.6
20	14.9	16.8	21.9	22.1
30	19.7	22.1	23.2	23.2
Case 2				
50	-14.9	35.6	80.2	—
100	28.3	110.4	129.2	135.4
200	120	199.4	219.6	223.4

Table 12.4 NPV for all field sizes and kh (oil price = US\$18/bbl).

Field size (million barrels)	kh (md.ft)			
	250	1000	9200	17 700
Case 1				
5	-7.2	-6.9	-1.6	-1.6
10	-3.1	-2.3	1.9	2.8
15	-0.2	0.6	5.1	5.2
20	2.2	3.4	7.3	7.6
30	5.1	6.9	7.6	7.6
Case 2				
50	-57.5	-29.6	80.2	—
100	-33.1	11.5	25.68	29.43
200	14.8	60.2	74.63	76.30

Table 12.5 IRR as a percentage, for all field sizes and kh (oil price = US\$25/bbl).

Field size (million barrels)	kh (md.ft)			
	250	1000	9200	17 700
Case 1 IRR (%)				
5	-1.5	-4.7	43.9	43.9
10	29.8	32.2	42.1	42.8
15	35.9	37.0	44.4	44.4
20	39.0	41.1	44.4	45.0
30	41.0	42.0	42.1	42.1
Case 2 IRR (%)				
50	5.7	66.1	118.9	—
100	21.91	93.67	100.46	101.42
200	70.50	99.93	101.76	101.76

Table 12.6 IRR as a percentage, for all field sizes and kh (oil price = US\$18/bbl).

Field size (million barrels)	kh (md.ft)			
	250	1000	9200	17 700
Case 1 IRR (%)				
5	—	—	2.0	2.0
10	-1.6	3.5	18.4	20.3
15	11.9	13.9	23.5	23.7
20	17.0	19.8	24.9	25.5
30	21.0	23.1	23.4	23.4
Case 2 IRR (%)				
50	—	—	10.9	—
100	-0.6	18.4	25.8	27.3
200	16.2	31.0	33.7	33.7

Minimum economic field size

NPV results for high (US\$25/bbl) and low (US\$18/bbl) oil prices at a real discount rate of 12.5% have been plotted for Case 1 field sizes versus NPV for each individual kh (Figs 12.6–9).

The 250 md.ft case (Fig. 12.6) represents the most conservative scenario with the poorest reservoir quality. The worst case minimum economic field size (note: original oil in place, not recoverable oil) ranges from 15 mmbbl for US\$18/bbl oil down to 6 mmbbl for US\$25/bbl oil. Better reservoir quality in the 1000 md.ft case means that the minimum economic field size drops slightly to 14 mmbbl for US\$18/bbl oil; there is little change in the US\$25/bbl case (Fig. 12.7). The profitability increases with the improvement in reservoir quality. Increases in kh extend the number of

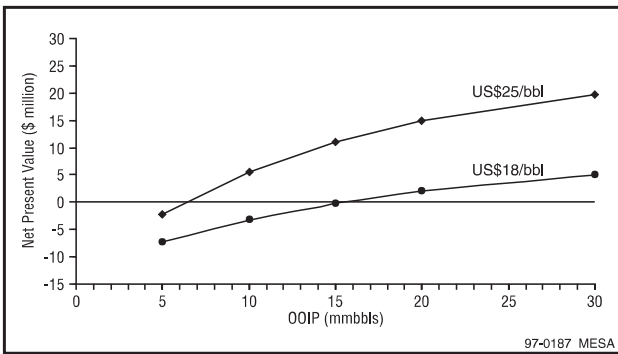


Fig. 12.6 Net present value of before tax cash flows (discount rate = 12.5%) versus Case 1 field sizes for kh = 250 md.ft.

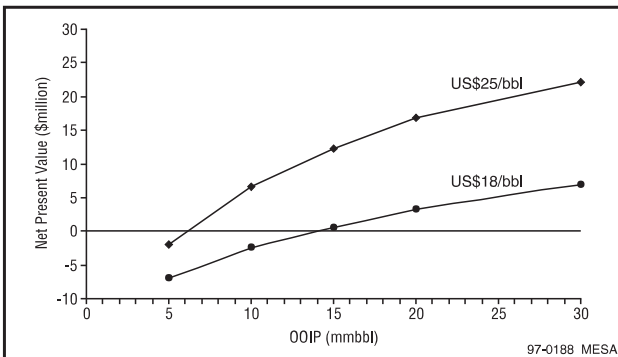


Fig. 12.7 Net present value of before tax cash flows (discount rate = 12.5%) versus Case 1 field sizes for kh = 1000 md.ft.

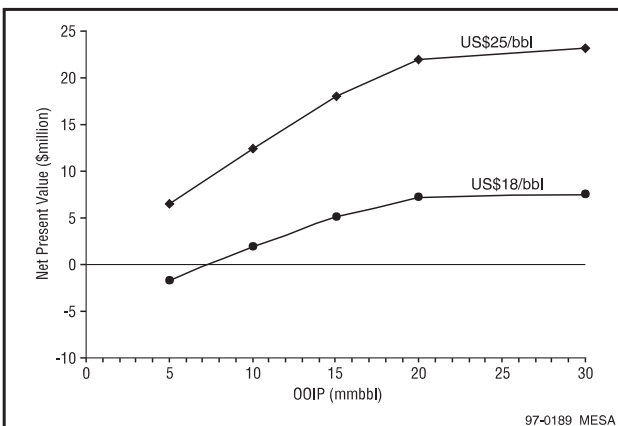


Fig. 12.8 Net present value of before tax cash flows (discount rate = 12.5%) versus Case 1 field sizes for kh = 9200 md.ft.

years that maximum production is achieved and influences the timing of development wells.

The 9200 and 17 700 md.ft cases show a dramatic increase in profitability from the low end cases, and the minimum economic field size drops to 7 mmbbl for US\$18/bbl and <5 mmbbl OOIP for US\$25/bbl (Figs 12.8, 12.9). There is little difference between the two, as field production is limited to 1000 bbl/day (158.9 m³/day) by oil transport constraints, and both models achieve the production limit for a similar period of time. The only variation between the two is in the timing and number of development wells, which produces minor variations in NPV.

Further increases in kh or field size above 30 mmbbl OOIP would necessitate modification of the development scenario as alternative oil transport scenarios would become economic and the production limit could be removed or increased.

Upside potential

Three large field sizes (50, 100 and 200 mmbbl OOIP) were modelled as Case 2 to explore the upside economic potential of Officer Basin oil and the feasibility of a trunkline to Port Bonython. The production limit was increased to 10 000 bbl/day (15 898 m³/day) and NPV calculated for the standard kh values used in Case 1. Figure 12.10 shows NPVs for all scenarios modelled at an oil price of US\$25/bbl. The minimum economic field size for Case 2 (kh = 250 md.ft) is ~70 mmbbl OOIP for an oil price of US\$25/bbl.

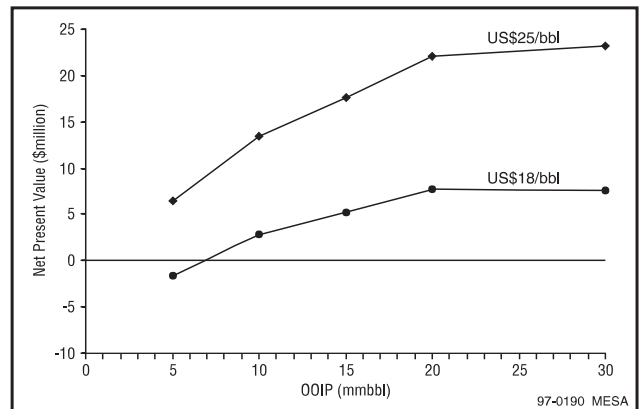


Fig. 12.9 Net present value of before tax cash flows (discount rate = 12.5%) versus Case 1 field sizes for kh = 17 700 md.ft.

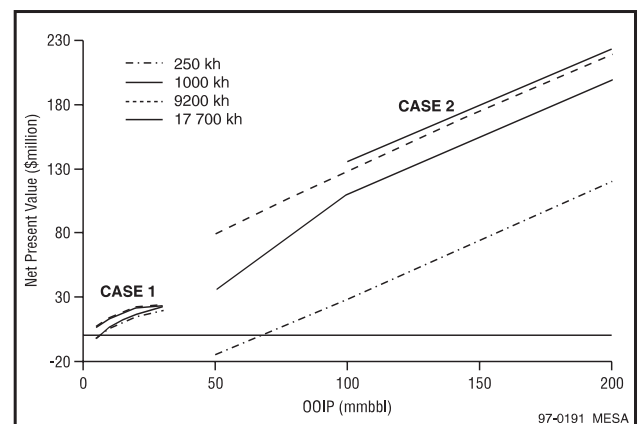


Fig. 12.10 Net present value of before tax cash flows (discount rate = 12.5%) for each kh versus Case 1 and Case 2 field sizes.

