PRODUCTION AND RESERVOIR ASPECTS OF TWO HORIZONTAL WELLS IN THE MCKEE FIELD

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Abstract

During 1990, Petrocorp Exploration Limited drilled and completed two horizontal wells in the McKee Sandstone reservoir. The horizontal wells were drilled in the northern part of the reservoir to improve the oil recovery by repressing the coning problem experienced in conventional wells. Steps were taken to facilitate an optimum completion in the geologically complex reservoir; petrophysical logging to identify fractured zones, cementing the liner to provide isolation and selective perforating. Production data compares the horizontal wells performance against offset vertical wells.

Introduction

Today the application and drilling of horizontal wells is commonplace. Reduced costs and risks associated with the drilling of horizontal wells has seen many hundreds of these wells drilled successfully all over the world. The main benefits of horizontal wells (increased productivity and improved sweep efficiency) have been realised in many oilfields.

Petrocorp Exploration Ltd investigated the possibility of drilling horizontal wells in the northern area of the McKee field which is characterised by a large gas cap overlying a thin oil column. Production from conventional wells in this area of the field are plagued by high GOR production and low oil recovery.

This paper discusses the reservoir engineering aspects of the two horizontal wells drilled in the McKee field, including:

- Justification and expectation.
- Drilling and completion method.
- Performance and production results.

Field History

The McKee field is located in onshore Taranaki in New Zealand, about 30 km east of New Plymouth. The field is 100% owned and operated by Petrocorp Exploration Ltd, a subsidiary of the Fletcher Challenge Group of Companies. The field was discovered in September 1979 by the exploration well McKee-1 and commercial production began in October 1981.

Between 1980 and 1989 the McKee field was developed with 21 conventional wells from 11 surface locations producing to a central production station.

Before production started on the first horizontal well (Jan. 1990), McKee field produced 10,600 BOPD (1685 m^3/d), 9.0 mmscf/d gas (256,000 m^3/d gas), with a water cut of 5%. Individual wells produced at rates from 200 BOPD (32 m^3/d oil) up to 1450 BOPD (230 m^3/d oil).

Wells are all completed on a single zone with sets of perforations spaced with blank sections to allow for possible selective plugging of zones at later dates.

Two and seven-eighth inch tubing has been used in all the wells with sidepocket mandrels installed in case of future requirement to run gaslift valves for artificial lifting. All wells are still producing under natural flow.

McKee Field Description

The field has two separate gas caps and a common oil-water contact. The gas-oil contact in the northern part of the field is lower than in the south. This results in an oil column in the north which is only 58 m thick, whereas in the south and central the oil column is 232 m thick. The different gas-oil contacts arise from a saddle. The oil water contact was established at 2165 m TVSS.

The oil initially in place (STOIIP) is estimated to have been some 106 MMstb and the gas initially in place (GIIP) is estimated at 183 Bscf.

The accumulation occurs in the sandstone McKee Formation about 2000 m (6562 ft) below sea level (TVSS) in one of several overthrust structures found in the Upper Eocene/Oligocene marginal marine sediments of eastern onshore Taranaki. It belongs to the Kapuni Group and represents the last of a series of coastal transgressions.

The reservoir is sealed by the overlying marine claystone of the Turi Formation, and by the overthrust fault which juxtaposes the reservoir with the Miocene marine claystones of the Mohakatino and Mahoenui Formations.

The McKee sand is on average, about 70 m thick, and although superficially it has a homogeneous appearance, it is heterogeneous on a metre scale. This is due to the presence of subtle variations in grain size, thin calcareous cemented beds, small scale healed faults and fractures, and indistinct sedimentary structures. Reservoir quality suffers from significant degradation of primary reservoir properties due to diagenetic processes.

In the northern half of the field the sand is interbedded with a band of shales and thin coal beds which gradually thicken towards the north. This feature is known as the Intra McKee Shale and divides the McKee Formation into the 'A' and 'B' sands. The 'B' sand averages 12 m thick and is generally of poorer quality than the 'A' sand.

Effective permeabilities to oil measured from well tests are mainly in the 5-20 millidarcy range.

Oil and Gas Properties

The McKee field oil is a waxy crude with an API gravity of about 39°. The pour point is about 32°C and sulphur content is negligible. The reservoir temperature averages 80°C and the initial pressure was 3415 psia at a datum level of 2100 m TVSS. The oil accumulation was initially saturated but with some variation of bubble point within the oil column. Under initial reservoir conditions the solution gas-oil ratio (GOR) averaged some 680 scf/stb and oil viscosity was 0.4 centipoise. This is approximately the same viscosity as the formation water at reservoir temperature and pressure.

Geological Uncertainties

The structure was recognised and mapped from seismic reflections off the overlying limestone Tikorangi Formation, about 500-600 m above the reservoir (Figure 1). In the overthrust, the McKee Formation itself is not resolvable from seismic data on account of steep dips and complex faulting. Early seismic mapping recognised that the structure rolled over from the overthrust fault to form a very steeply southeasterly dipping flank which could not be accurately located as it was beyond the capabilities of the seismic resolution.

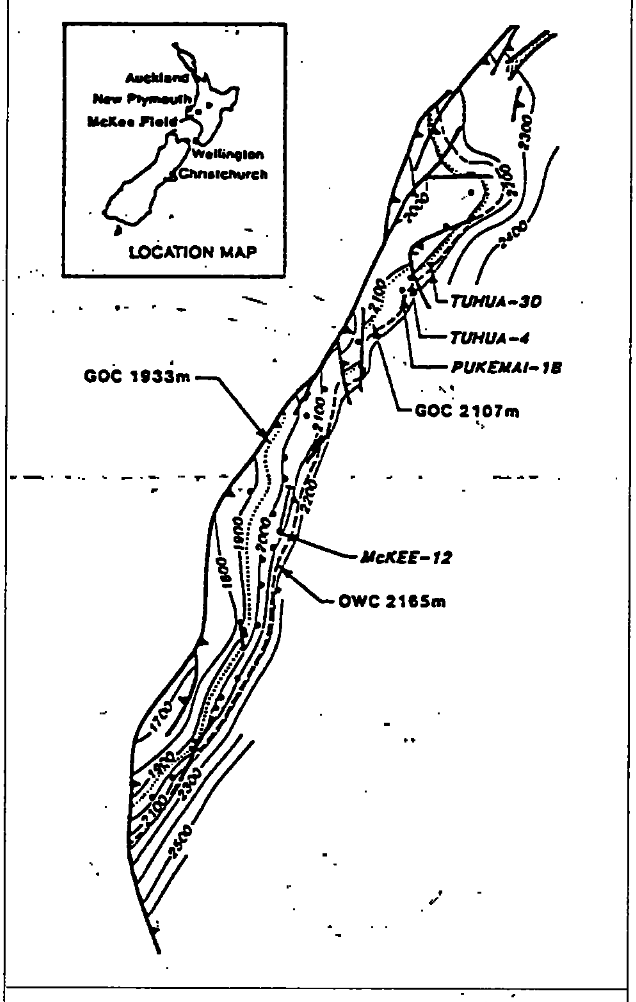

Figure 1: McKee field location and map.

Appraisal of the structure was therefore conducted with very poor structural control, especially in the dip direction. Location of wells in positions suitable for completion frequently required that they be sidetracked. Each well in the field required, on average, one sidetrack. The precision required for well targeting is well beyond that of the seismically controlled map, and so this task is primarily based on well data.

The steep formation dips, typically ranging from 30 to 50° and in some areas in excess of 70°, demand a high degree of deviation precision. Well target tolerances are typically plus or minus 15 m in dip direction.

To date there have been 41 well tracks, including sidetracks, drilled into the McKee reservoir. Data from these well tracks have provided most of the information which makes up the current map of the field. Twenty-four wells have been completed, and all but three are connected to flowlines for production.

Reservoir Behaviour

The main feature of production character is the tendency of well drawdowns to create cusps of gas from the gas cap to the wellbores. These may take several years or only a few months to develop, depending on how far the well completions are from the gas cap. If unchecked, this cusping results in very rapidly rising GOR's and a consequent deterioration in oil rates, severely limiting the useful life of wells (as oil producers). It was found that GOR's were controllable provided that well perforation intervals were sufficiently far from the gas cap.

In the central and southern parts of the field initial well rates were typically in the 1000 to 1500 stb/d range, but with the need to control rising GOR's most wells have been choked back to lower rates.

In the north, where the oil column is 58 m thick and where reservoir quality is not as good as in the central and southern parts of the field, sustained production has only been achieved at low rates typically below 100 stb/d.

Performance Modelling

The key to maximising oil recovery is to promote as uniform as possible expansion of gas towards the wellbores, thereby displacing the maximum amount of oil before the wells become gassed out.

Successful prediction of future performance is dependent upon the prediction of gas breakthrough times (Joshi, 1986; Chaperon, 1986; Giger, 1986; and Papatzacos *et al*, 1989) and subsequent well performance. This is one of the most difficult reservoir predictions to make, as actual performance is highly dependent upon reservoir heterogeneities. Once gas breakthrough at wells has occurred there remains in most cases a considerable potential for further oil production, albeit at greatly diminished rates.

The most important consideration at this stage becomes to limit the production of free gas sufficiently to prevent major pressure depletion in the reservoir.

Computer simulation studies of the field have been ongoing since 1983 and these have played a central role in formulating the optimum development of reservoir drainage and offtake management. Matches of the performance of the simulation models with actual reservoir performance to date indicate that depletion of the central and southern parts of the field is being dominated by gas cap expansion and gravity drainage. This latter depletion mechanism is significant because of the high formation dips and relatively large oil column of the reservoir. It is believed that these natural drainage mechanisms will lead to a relatively good recovery from that part of the field.

The well's tendency to cusp gas is much greater in the northern part of the field where the oil column is 58 m thick as compared to the main part of the field (234 m).

Reservoir modelling studies have shown that gas cap expansion will be the primary mechanism for recovery of oil from the northern area. The ultimate recovery will depend upon how efficiently gas sweeps the oil column.

Ideally of course, the gas cap would expand uniformly as oil is withdrawn from the reservoir, but the high relative mobility of gas compared to oil acts to draw gas cap gas into the producing wells, thereby bypassing much of the oil.

In order to determine the variation of sweep efficiency with location and number of drainage points, a single well computer simulation model was created to represent typical reservoir conditions in the northern area. It was concluded that the optimum depth for well completions was in the range 2140 to 2155 m TVSS which is as far from the gas cap as practicable without incurring water production problems. Despite this, wells can be expected to begin to produce gas cap gas within a few months unless very low oil production rates are imposed. Even for initial rates as low as 100 stb/d, gas production cannot be expected to be postponed for more than 18 months. The oil production rates required to prevent gas from cusping as far as the wells, for an indefinite period, were calculated to be far too low for practical and economic production. Thus in practice high GOR's can be expected to be a normal feature of production from the northern area.

The depositional structure of the McKee reservoir sand also plays an important part in the way in which wells drain the reservoir.

The main feature of deposition is that of subtle laminations of varying permeability which are largely parallel to the bedding planes, and thus follow the dip direction. This means that the average permeability across the sand bed is significantly less than the permeability parallel to the bedding.

Discussion on Horizontal Wells

In order to promote the most uniform gas cap expansion possible, the application of horizontal wells was considered. The wells would then be drilled horizontally through the formation, parallel to the oil-water contact.

In principle such wells would provide the most efficient practicable drainage of the area. A 300-400 m length of productive interval should be achievable. This would yield high flow rates for a very low drawdown.

A sustainable production life from a horizontal well should be attainable by producing at lower drawdowns than are feasible in the existing conventional wells. Oil recovery will then increase because of improved volumetric sweep efficiency.

The results of the computer simulations were used to derive estimates of the variation in oil and gas recovery over a range of well spacings for both a conventional development and the horizontal well development. Oil recovery varies as the number of wells is increased (Figure 2).

Both high and low recovery estimates have been made to cover the uncertainties in sweep efficiency which are largely a result of inaccuracies in forecasting the amount of gas produced after breakthrough, but before oil production effectively ceases.

Increased oil recovery will be possible by optimum location of horizontal wells; that is, by identifying those regions which do not possess effective offtake points for oil draining from updip locations. It is unlikely that there will be significant lateral movement of oil at low reservoir pressures or low well drawdowns.

Economic Justification and Costs

The justification for the decision to drill two horizontal wells was based on incremental economics of horizontal completions versus conventional infill wells. The estimated costs of the horizontal wells were about 60-70% higher than that of conventional wells. Figure 3 shows the relative cost elements of the two types of wells. Note the high evaluation and completion cost.

This cost was considered necessary for the first two wells. Production profiles for all of the cases were based on field simulation work mentioned earlier in the text. On the basis of these production profiles, drilling the wells horizontal would provide sufficient incremental to justify the additional expense.

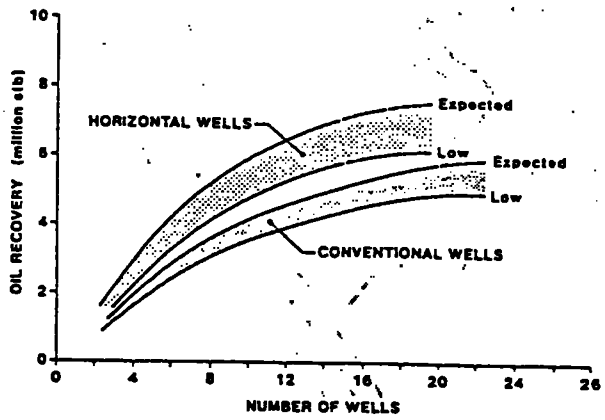

Figure 2: Oil recovery efficiency.

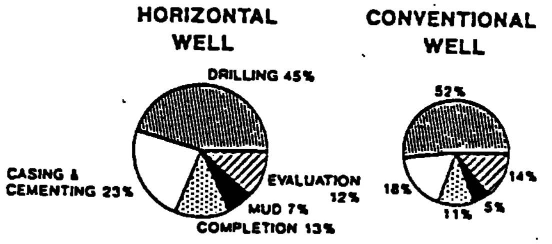

Figure 3: Relative well costs.

Completion Philosophy

For our application of horizontal drilling the following features and aspects were considered important:

(i) Medium radius drilling (radius of approximately 300 m), was selected due to the ability to drill a horizontal section of between 300 and 600 m at a lower cost than long radius drilling. Also it would be possible to run a standard production string to enable normal wireline operations.

(ii) The ability to relate petrophysical parameters to production characteristics was considered essential. Therefore a logging programme consisting of a combination porosity/resistivity tool and a formation micro scanner electrical image tool was planned to be run.

(iii) Cemented Liner. The advantages of cementing the production liner were it would: (a) provide means to control unwanted water or gas production and allow methods for effective stimulations and other treatments; (b) perforate selectively, thus avoiding possible minor faults or fractured intervals; (c) ensure effective separation of higher (possibly gas bearing) intervals; (d) be operationally simple, as only minor modifications to a conventional liner cementing job were required.

These advantages were considered to out-weigh the cost advantage of a slotted liner.

Choice of Locations

Due to the uncertain geology in the northern area an alternative location was sought for the first horizontal well in the central area of the field (McKee-12). This would allow the new drilling technology to be applied in a geologically, relatively low risk area, thereby lowering the risk of an unsuccessful well. The relative rewards (as compared to a conventional well) were thought to be less than in the north, but sufficient to be justified in terms of additional production and recovery.

The second horizontal well (Tuhua-4) would then be placed in the northern area. It was decided to place the well in an area situated between the conventional wells Pukemai-1B and Tuhua-3D for the following reasons:

(i) It is in a part of the reservoir with relatively low well density.

(ii) It should be possible to reach up to 300 m horizontal section before drilling out of the structure.

(iii) Good structural control due to the proximity and the good correlation between Pukemai-1B and Tuhua-3D.

(iv) Good production behaviour of, initially, Pukemai-1B and particularly Tuhua-3D. The remaining two wells drilled to date in the northern area, Tuhua-1 and Tuhua 2B, developed an uncontrollably high GOR and were eventually closed in. Pukemai-1B recently developed a water production problem and is closed in at the time of writing.

The planned wellpaths and geological cross-sections of McKee-12 and Tuhua-4 respectively are shown in Figures 4 and 5.

Horizontal Wells

Drilling

Casing schemes used for these wells can be seen in Table 1.

A Freshwater/Gel mud, 8.7-9.0 ppg was used to drill 17-1/2" hole to the 13-3/8" casing setting point (600 m in McKee-12, 407 m in Tuhua-4). The 12-1/4" hole to the 9-5/8" casing point was drilled with a KCL/Gel/PHPA, 8.8-8.9 ppg mud. Rheological properties were designed to maintain laminar flow.

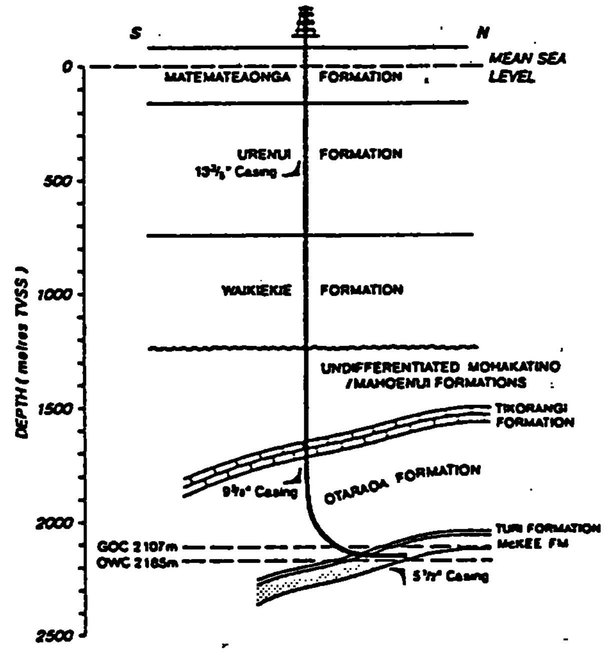

Figure 4: Tuhua planned well path and cross-section.

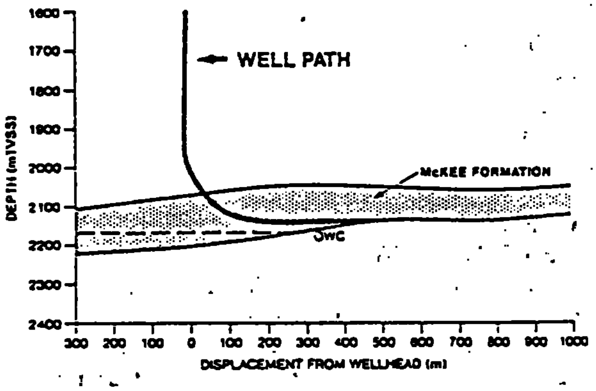

Figure 5: McKee-12 well path and cross-section.

	Depth Set		Size (inches)	
McKee-12	38		20	
	598		13-3/8	
	2065		9-5/8	
	2728	(TD)	5-1/2	(liner)
Tuhua-4	57		20	
	405		13-3/8	
	2190		9-5/8	
	2710	(TD)	5-1/2	(liner)

Table 1: Casing schemes for the horizontal wells.

The 9-5/8" was set 30 m (98 ft) above the kick off point for the horizontal build sections.

The 8-1/2" hole to TD was drilled with a KCL/PHPA mud system, 9.0 ppg mud weight with total solids maintained at less than 2%. The rheological properties were designed to give laminar flow in the build sections and turbulent flow in the horizontal section.

Due to the dip angles in the McKee formation, both horizontal wells drilled out of the base of the McKee formation. McKee-12 drilled 364 m of horizontal section, while Tuhua-4 drilled 327 metres of horizontal section. McKee-12 exposed 514 m along hole of reservoir sand. Tuhua-4 was horizontal before entering the reservoir and exposed 194 m of reservoir sand.

Evaluation

Both wells were evaluated with electric logs. The logs were run by Schlumberger using their Tough Logging Conditions (TLC) drillpipe conveyed system. Logs run in McKee-12 were MSFL/DLL/GR. Evaluation of the log showed a higher than expected water saturation. Water saturation ranges from 30-35% which is some 10% higher than seen on conventional wells at this depth.

In Tuhua - 4 two logging runs were made. The first was MSFL/DLL/CNL/LDL/GR, the second run was FMS/GR. The resistivity and porosity logs showed results similar to the other wells in this area. The FMS/GR, however, indicated a high incidence of fractures or minor faults. A total of 58 fractures or minor faults were interpreted along the horizontal well bore, most of which were interpreted as being conductive.

The results caused concern as to the extent the faults/ fractures would affect production behaviour.

The actual well path and the modified geological cross-sections of McKee-12 and Tuhua-4 are shown in Figures 5 and 6.

Completion

A 5-1/2" 17 lb/ft VAM production liner was run and cemented over the entire length in both McKee-12 and Tuhua-4. To ensure a good cement bond in the horizontal section of the hole, the liner was rotated during the hole cleaning and cementing stages. The liner hanger was fitted with a bearing assembly to allow the rotation. Solid centralisers were run one per joint on the liner. They were not secured to the casing allowing the casing to rotate within the centralisers. During the cementing of McKee-12 the liner was rotated with an average torque of 1000 ft/lb.

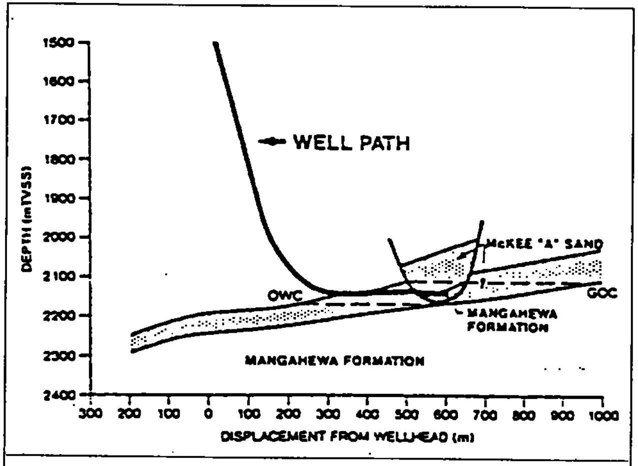

Figure 6: Tuhua-4 well path and cross-section.

The rotation was stopped just prior to the bumping of the wiper plug. In Tuhua-4 the torque was 6200 lbs.

The quality of the cement bond throughout the build sections was checked with a CBL/VDL logging run. A conventional CBL tool fitted with wheels for centralisation was used. The tool was used to evaluate the liner lap and cement bond to a depth equivalent to a deviation angle of 75°. The cement bond was found to be excellent.

The completion fluid used was a 8.5 ppg KCL brine filtered to a 2 micron (nominal) particle size.

Both wells were perforated with tubing conveyed 3-3/8" 4 spf 60° phasing HSD casing guns. In McKee-12 the guns were loaded in 58 m of shots with 6.5 m of spacers giving a total of 335 m of perforations.

In Tuhua-4 the guns were loaded with 116 m of perforations and 45 m of blank sections, leaving fractured intervals un-perforated.

The TCP guns were fired by an annular pressured firing system after a RTTS packer had been set to isolate the annulus.

McKee-12 also had a zone in the build section (42°-45° inclination) of 27.5 m perforated with wireline conveyed 3-3/8" 4 spf 60° phasing HSD guns. The well was then completed with 2-7/8" EUE tubing with a straddle (twin) packer assembly. The purpose of this was to allow the top perforated section to be isolated from the horizontal section. A wireline operated sliding side door was included to control the production from this zone. The McKee-12 completion is depicted in Figure 7.

Tuhua-4 was completed with a single packer (set at 32° inclination) and a conventional tail pipe assembly.

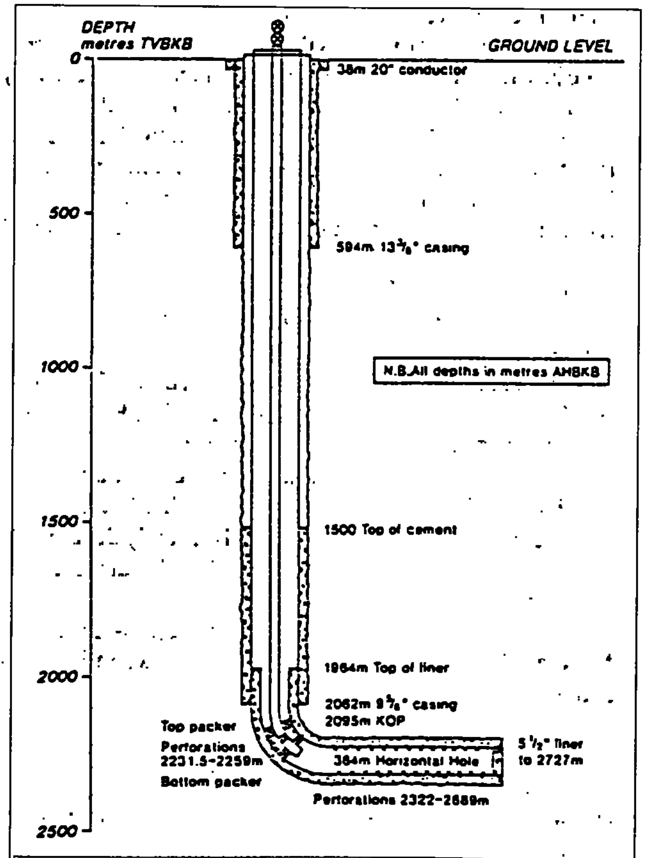

Figure 7: McKee-12 completion.

Performance Predictions

The following factors affected the performance estimates:

(i) Length of the horizontal section.
(ii) Critical coning rate and performance during GOR control.
(iii) Thickness of pay.

The initial estimates and the actual results are described below.

Horizontal Length

With careful positioning of the well in this complex geology reservoir, it was estimated that around 300 m section would be possible to obtain. McKee-12 achieved a 364 m section before drilling out of the sand, while Tuhua-4, the northern area well, drilled out after 194 m (161 m was perforated) of horizontal section.

Critical Coning Rate

As discussed before, commercial production below the critical coning rate was not possible. However, the time to gas breakthrough was believed to be longer (although difficult to quantify) and once occurred should be easier to control. Optimum completion interval for McKee-12 was calculated at 2130 m TVSS (OGOC 1933 m TVSS, OOWC 2167 m TVSS), and for Tuhua-4 at 2142 m (OGOC at 2107 m TVSS, OOWC 2167 m TVSS). Table 2 lists the time to gas breakthrough for the horizontal wells and for the conventional wells. Note that the time to gas breakthrough occurred much quicker than expected.

Also, the controlling of the GOR has proven more difficult than expected. In addition, unexpected high water cuts developed in a short time in McKee-12.

Thickness of Pay

In the central area the oil bearing interval is 234 m with an isohcore sand thickness of about 100 m while in the northern area the oil section is 58 m with a sand thickness of 50 m.

The PI multiplication factors were calculated for the above variables. Appendix A presents the equations (Joshi, 1986; Giger, 1984) and assumptions used. Subsequently the PI factors were compared with measured PI. The results are presented in Table 3. Note that for Tuhua-4 the actual measured PI was close to predicted, while for McKee-12 it was lower (3.3 vs 5.1 bbl/psi·D). Coreplug relative permeability tests suggest that the higher average water saturation in McKee-12 is the cause of a lower absolute permeability to both fluids, and therefore the lower than expected PI.

Production Results

Table 2 shows the horizontal wells' performance, relative to the conventional wells in the central and the northern area. Although the initial rates were the highest achieved in the respective parts of the field, they were lower than expected. Also, gas breakthrough occurred much sooner than in the conventional wells. In addition, an immediate high water cut occurred on McKee-12. This also contributed to the well's lower than expected performance.

The cumulative oil production vs cumulative gross fluid production for Tuhua-4 is plotted in Figure 8, and for comparison, the four other northern area producers. The plot illustrates the high gas production associated with the oil, and indeed, three of four conventional wells out-performed the horizontal wells in this respect.

Well ref	Production start	Initial[1] rate bopd	Months[2] to gas	Oil rate bopd	GOR scf/bbl	WC (%)
Central						
MK-2	May-84	1107	66	714	1357	13.5
MK-4	Apr-84	947	44	331	2450	3.8
MK-5	Nov-84	1410	20	575	1150	4.9
MK-6	Jun-87	1024	17	463	1448	0
MK-7	Jul-87	1310	20	583	1345	0
MK-8	Aug-87	1007	35	1026	965	0
MK-9	Sep-87	998	12	330	1448	0
MK-10	Sep-87	776	15	330	1459	0
MK-11	Jan-89	961	-	973	791	0
MK-12[3]	Jan-90	1562	1.2	648	2670	26
North						
PK-1B	Mar-84	371	-	Suspended Nov 88 due to water		
TU-1	Jul-84	143	1.0	Suspended Nov 88 due to GOR		
TU-2	Dec-84	241	4	Suspended Mar-88 due to GOR		
TU-3	Oct-88	390	6	163	2570	0
TU-4[3]	Mar-90	492	0.7	320	2580	0

[1] First month of continuous production averaged.
[2] The time to gas production above that of solution gas despite choke control.
[3] Horizontal well.

Table 2: McKee wells, performance indicators (August 1990).

Well	Comments	PIF	PI bbl/(psi·D)
McKee-12	Planned, L=300 M	2.0	4.3
	Adjusted to L =364 m	2.4	5.1
	Actual well-test	1.6	3.3
McKee-9	Comparison well	1.0	2.1
Tuhua-4	Planned; L=300 m	4.4	3.5
	Adjusted to L=161 m	2.9	2.3
	Actual well-test	3.3	2.6
Tuhua-3	Comparison well	1.0	0.8

Table 3: PI multiplication factors and actual PI for horizontal and typical conventional wells, McKee field.

Figure 9 plots well-test data for the remaining producing conventional northern well, Tuhua-3, and for Tuhua-4 from start-up through to August 1990. The plot shows that the current actual oil production rate of Tuhua-4 is twice that of Tuhua-3 (320 bbl/day versus 163 bbl/day) and that the GOR is now comparable.

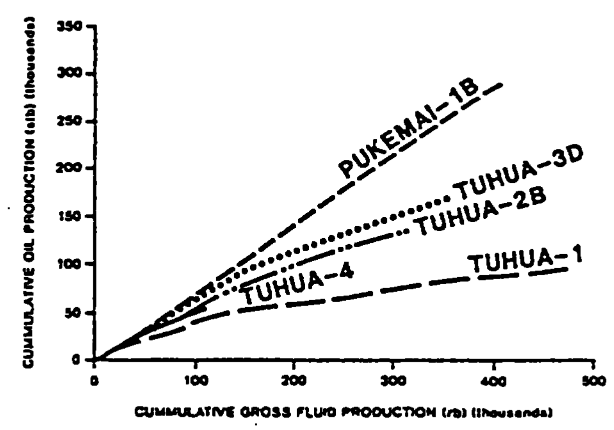

Figure 8: Cumulative oil vs cumulative gross fluid production.

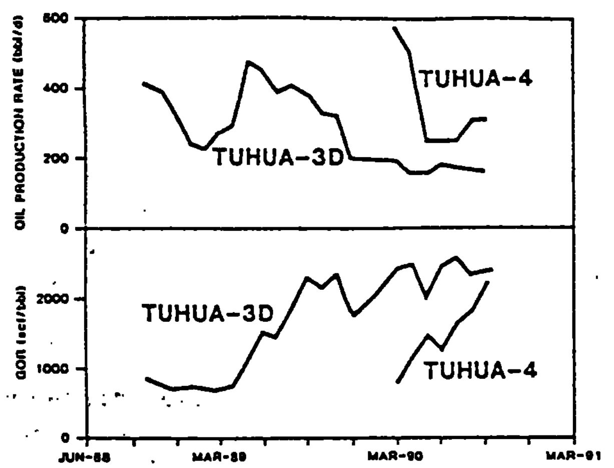

Figure 9: Tuhua-4 and Tuhua-3 well test data.

The oil production rates for all the northern wells are shown in Figure 10. The plot shows that Tuhua-4 is a good, although not superior, oil producer.

Well -test data for McKee-12 and for a typical central area well, McKee-10, is plotted in Figure 11. This shows the much faster build up of GOR and the higher water production. The present oil production rate of 648 bbl/day is some 10% above the average production (590 bbl/day) of the conventional wells in the central area, but is still outperformed by three of the conventional wells.

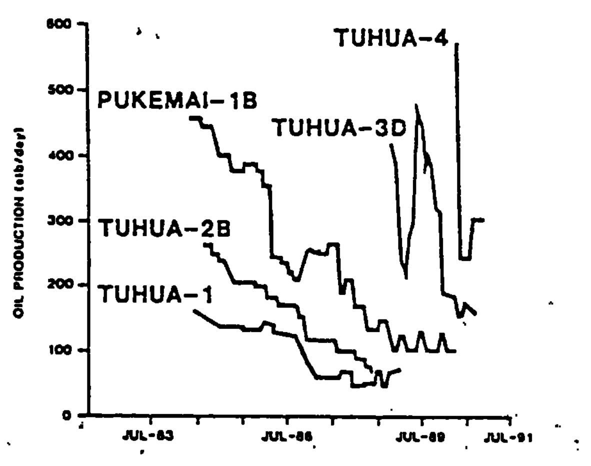

Figure 10: Oil production rates from the northern wells.

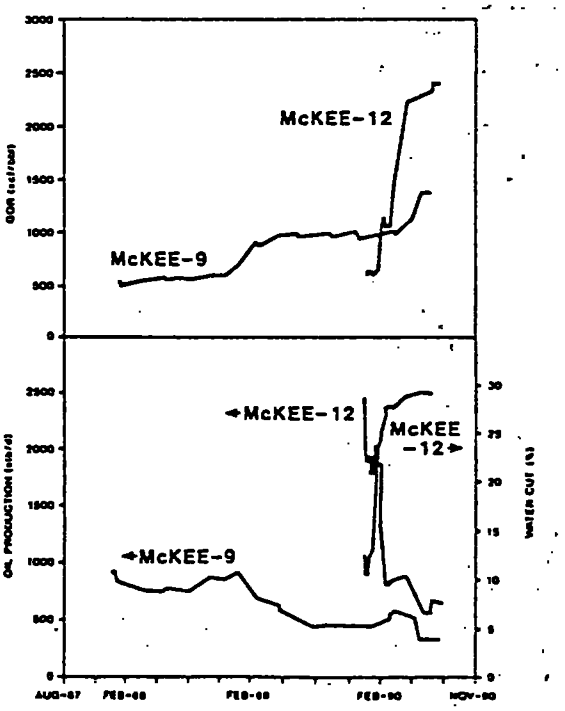

Figure 11: McKee-12 and McKee-9 well test data.

Despite the precautions to identify fractures and conductive minor faults, and not perforating those intervals, it is suspected that due to the high incidence of open fractures, these have adversely affected production on both wells. The rapidly rising GOR is a disappointment and will ultimately affect the oil recovery of Tuhua-4 and also McKee-12.

Their longer term production performance is still uncertain but the higher oil production rate is still encouraging.

At this stage it is felt that more production history is needed from both wells to fully evaluate the future potential of horizontal wells in the McKee field. Two wells, one appraisal and one development well, are proposed to be drilled in the northern area early next year.

Conclusions

Two horizontal wells were successfully drilled in the geologically complex McKee reservoir. Initial PI's were close to the those predicted for horizontal wells.

Steps were taken to facilitate an optimum completion; petrophysical logging to identify fractured/faulted zones, cementing the liner to provide isolation and selective perforating.

Despite these precautions, early gas breakthrough and subsequent gas production problems have resulted in oil production rates and ultimate recovery that are lower than expected. In addition, water production in McKee-12, is higher than in any other well.

However, current oil production rates are not discouraging; they are higher than the average conventional well. Tuhua-4, the horizontal well drilled in the northern part of the field, produces at a rate twice that of the remaining oil producer in this area.

Appendix

The PI (Productivity Index) for a vertical well can be expressed as (steady state) :

$$PI_V = \frac{C_1 k_0 h}{\%_0 B_0} \cdot \frac{1}{(\ln (r_e/r_w) - 1/2 + S)} \quad \text{------(A1)}$$

For a horizontal well (steady state) :

$$PI_H = \frac{C_1 k_H h}{\%_0 B_0} \cdot \frac{1}{[\ln(4r_e/L)+hk_H/k_V(\ln((k_H/k_V)h/2!r_w h)+S)]} \quad \text{------(A2)}$$

The PIF (Productivity Improvement Factor) is :

$$PIF = \frac{PI_H}{PI_V} \quad \text{......(A3)}$$

The following data were used to calculate the PI factors listed in Table 3:

Tuhua - 4 $r_e = 500$ m;
$r_{wh} = 0.1$ m ;
$B_0 = 1.33$;
$\mu_0 = 0.4$ cp ;
$h = 27$ m ;
$K_0 = 9.6$ mD ;
$K_H = 9.6$ mD ;
$K_H/K_V = 10$;
$S = 6.2$ (conventional, based on well test analysis) ;
$S = 0$ (horizontal)

Nomenclature

h	Reservoir thickness
k	Permeability
L	Horizontal well length (completion interval)
PI	Productivity index
PIF	Productivity Improvement Factor
r	radius
S	Mechanical skin factor
μ	Viscosity

Subscripts

e	Drainage boundary
H	Horizontal
o	Oil
V	Vertical
w	Well

Constants

	Si Units	Field Units
C_1	2π	7.08×10^{-3}

Aquifer

Establishment of an oil water contact was not straightforward in the early stages of the field evaluation because there is a large capillary transition zone. An average capillary curve derived from normalised permeability data is shown in Figure 6. Water saturations evaluated from logs exhibited a gradual increase with depth with no obvious water contact. A practical working contact level was established from the RFT pressure data which yielded an average depth of 2165 metres TVSS at which the continuous oil phase intersects the continuous water phase.

There is therefore oil found below this oil-water contact (see Figure 6) but, except for occasional isolated pockets (where presumably the reservoir quality is exceptionally good) this is immobile residual oil. McKee-1, the discovery well, was drilled through the residual oil zone and a short well test produced mainly water but with no more than 5% oil. The permeability seen from this test was only 0.5 millidarcies. This is one of several indications that there is considerable deterioration of reservoir quality in the aquifer.

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