RECOVERY TECHNOLOGY

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Chapter 11

INTRODUCTION

The technology of recovering hydrocarbons in the Cooper region has become more sophisticated in the last decade. Drilling, fracture stimulation, acidisation and pumping techniques have been applied to optimise recovery in challenging and variable subsurface conditions and some of the more important techniques are reviewed below.

HORIZONTAL DRILLING

The first horizontal drilling in the Cooper region was Meranji 14H (horizontal) development well in 1993 which had a horizontal section of 400 m in a total drilled depth of 2310 m. Located ~30 km northwest of Moomba, the well had the relatively thin Eromanga Basin Namur Sandstone oil reservoir as its target. The vertical wells in the field were all producing oil with a large water content and it was anticipated that a horizontal well would reduce the percentage of water and in doing so allow an increased oil recovery by reducing water handling costs and increasing the volume of oil accessed by a single well. The best flow rate achieved from Meranji 14H was 254 kL/day (1600 bopd). The total recovery flow rate and producing water cut are approximately the same as the adjacent vertical wells; this initial attempt at improving recovery using horizontal drilling was unsuccessful.

In 1996 the Big Lake 56H gas development well was drilled to target Tirrawarra Sandstone as an experiment to improve deliverability and recovery in a thick reservoir unit. The Tirrawarra Sandstone has a zone of good to moderate permeability in the centre of the field surrounded by an area of low permeability; Big Lake 56H was designed to increase drainage from the large lower permeability area of the reservoir. The well had a near horizontal section of 646 m in a total drilled length of 3709 m (Fig. 11.1). High temperatures were expected and precautions were taken to cool the mud and to use a minimum of temperature sensitive equipment while drilling. The highly abrasive nature of the sandstone reservoir caused delays with frequent removal of worn drilling bits. On initial clean-up Big Lake 56H flowed at 198 000 m^3/day (7.0 mmcfd) then reduced to 99 000 m^3/day (3.5 mmcfd) over a period of extended production against line pressure from an uncased open hole section of the well. A portion of the Tirrawarra that was cased was perforated and the flow rate increased to 127 000 m^3/day (4.5 mmcfd). The well continues to flow steadily at this rate into the gathering system. In comparison, drillstem tests of vertical wells which penetrate the Tirrawarra Sandstone in Big Lake Field have flow rates which range from a rate too small to measure (RTSTM) to 127 000 m^3/day (4.5 mmcfd).

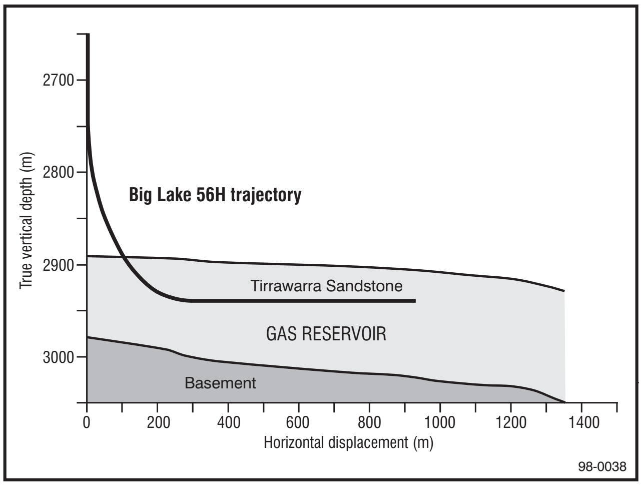


Fig. 11.1 *Horizontal well trajectory, Big Lake 56H.*

Big Lake 56H penetrated a thicker than expected Eromanga Basin Namur oil section. In 1997 two near-horizontal oil development wells were drilled to the Namur reservoir from close-spaced surface locations (58 m apart). Big Lake 58 was drilled to the southwest and penetrated the oil reservoir at a maximum angle of 76° from the vertical. Big Lake 59 was drilled in a north–northeast direction and had a maximum angle of 84° from the vertical in the oil reservoir (Fig. 11.2). Production rates have been 239 kL/day (1500 bopd) each compared to 80 kL/day (500 bopd) from adjacent vertical wells.

The Daralingie Formation in the Moomba Field was first used for sales gas storage in 1981 and for ethane storage in 1984 (Keleman, 1986). The Moomba 18H gas storage–

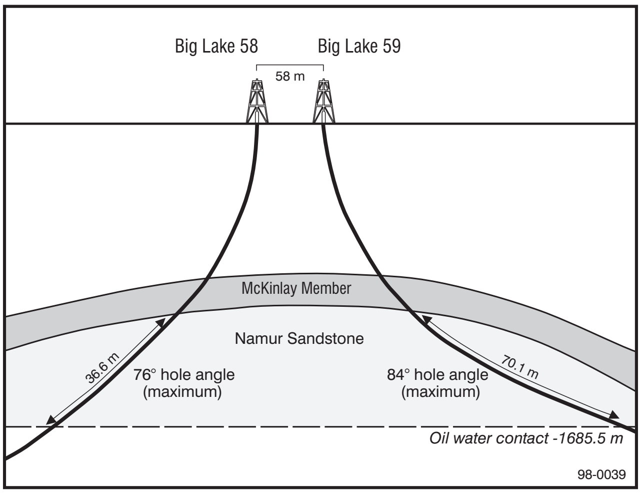


Fig. 11.2 *Schematic section of high angle-wells, Big Lake 58 and 59 (data courtesy of Santos).*

development well was drilled in 1996 when the abandoned Moomba 18 gas well was re-entered and a lateral section was drilled out through the casing into the Daralingie Formation; a near horizontal section of 142 m was drilled in the 2 m thick reservoir (Fig. 11.3). The well was designed to increase gas withdrawal rates from the storage reservoir. A flow rate of 850 000 m^3/day (30 mmcfd) was achieved compared to 283 000 – 425 000 m^3/day (10–15 mmcfd) from nearby vertical wells.

AIR DRILLING TIGHT GAS RESERVOIRS

Swan Lake 1 was drilled with mud in 1986. In 1996 it was re-entered, a hole drilled through the casing above the Permian gas target reservoirs and Swan Lake 1 DW1 (deviated well) drilled with air roughly parallel to the original well-bore. The top Toolachee Formation intersections were within 0.3 m of each other in the two wells. In Swan Lake 1, the top 7.3 m of the Toolachee was tested and flowed at RTSTM; in comparison Swan Lake 1 DW1 recorded a flow of 5097 m^3/day (0.18 mmcfd) over the top 13.7 m of the formation (Table 11.1). Log pay in the original well is below the tested intervals. Flow test 2 in the deviated well tested the Toolachee to a depth which included all of the log pay in the original well and flowed at 133 088 m^3/day (4.7 mmcfd). Flow test 3 included all of the Toolachee section which flowed at 232 196 m^3/day (8.2 mmcfd); lower Toolachee Formation sands previously interpreted as wet on logs contained gas pay.

In summary, the non pay zone at the top of the Toolachee Formation flowed at uneconomic rates in both wells with the air drilled well giving the best flow rate; air drilling did not enable the top tight reservoirs to flow at economic rates. The pay zone untested in the original well flowed at economic rates in the air drilled well.

In Swan Lake 1, the lower targets, the basal Patchawarra Formation and the Tirrawarra Sandstone were drillstem tested and flowed at 10 900 m^3/day (0.39 mmcfd). The adjacent air drilled Swan Lake 2, tested the same interval on a flow test with a resulting flow rate of 10 477 m^3/ day (0.37 mmcfd). Air drilling in this example gave essentially the same result as mud drilling in a tight gas sand.

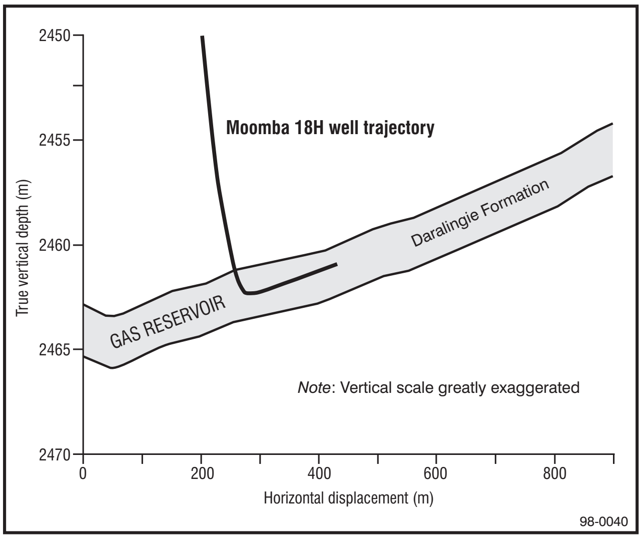


Fig. 11.3 *Horizontal well trajectory, Moomba 18H.*

Air drilling was then tested in the Tindilpie Field. The main target was the Patchawarra Formation. In Tindilpie 1, drilled with mud in 1970, the best test from a number of intervals in the Patchawarra Formation above the Patchawarra coal (Vc) was 58 900 m^3/day (2.08 mmcfd). Tindilpie 2 appraisal well was also drilled with mud and flowed at RTSTM above Vc and at 14 158 m^3/day (0.5 mmcfd; best test) below Vc. Tindilpie 2 DW1 was drilled out from Tindilpie 2 through the casing above the target and used air as the drilling fluid. The best flow test result in the deviated well was 39 600 m^3/day (1.4 mmcfd) with approximately 183 m of the Patchawarra Formation (above Vc) open. In this case the air drilled test result was better than in the adjacent well but not as good as the original Tindilpie 1 result.

Air drilling was also tested in the deep tight gas reservoirs of the Nappamerri Trough. Burley 1, drilled with mud in 1971, tested a thick Permian section; most tests flowed at RTSTM. However, the lower Epsilon Formation flowed gas at 25 202 m^3/day (0.89 mmcfd). Burley 3 was drilled 150 m from Burley 1 and the Permian section from the top Toolachee Formation was drilled with air. In Burley 1, two individual Toolachee intervals flowed gas on test at 5097 and 4531 m^3/day (0.18 and 0.16 mmcfd). In Burley 3 with all of the formation open a flow test recorded 425 m^3/day (0.015 mmcfd). The air drilled well had a ten times poorer result than the mud-drilled well. Burley 3 never reached the basal Epsilon target as down-hole fires on two occasions damaged the drill collars and the well was abandoned.

Air drilling was tried in the Moomba North Field where a large number of tight Permian gas reservoirs exist. Moomba 86, the northeasternmost well on the field, was drilled conventionally with mud through the Toolachee and Epsilon reservoirs, but was converted to air to drill the Patchawarra Formation above Vc. The Patchawarra Formation was flow tested and produced gas at RTSTM. The two nearest wells to Moomba 86, previously drilled with mud, Moomba 73 and Moomba 26 had Patchawarra tests of 22 653 and 14 158 m^3/day (0.8 and 0.5 mmcfd) respectively. Although not immediately adjacent to a mud-drilled well, air drilling in Moomba 86 failed to improve gas deliverability in the Patchawarra Formation.

The basal Patchawarra Formation and the Tirrawarra Sandstone were drilled with air in Coonatie 4 appraisal well during 1997. An open hole flow test of the basal Patchawarra flowed at 8495 m^3/day (0.3 mmcfd) in Coonatie 4 compared to a drillstem test of the same interval in Coonatie 2 that flowed at 14 158 m^3/day (0.5 mmcfd). When Coonatie 4 was deepened into the upper Tirrawarra Sandstone, the open hole flow rate increased to 14 158 m^3/day (0.5 mmcfd). It is hard to determine the contribution of the Tirrawarra Sandstone to the flow rate, but if the extra 5663 m^3/day (0.2 mmcfd) is taken as an approximate addition, then it is the same as the Tirrawarra test in Coonatie 2.

Air drilling in tight gas reservoirs in the South Australian Cooper Basin area has had limited success as shown in Table 11.1. The Tindilpie 2 DW1 probably represents the best increase in flow rate. The remainder of the accurate comparisons between air and mud drilling resulted in the air drilling result being the same or worse. In addition a number

Table 11.1 *A comparison of gas flow rates between wells drilled with air versus mud.*

Well	Formation	Drilling type M (mud) A (air)	Flow rate m³/day	mmcfd	Comments
Swan Lake 1	Toolachee Formation	M	RTSTM	RTSTM	Tested top 7.3 m of formation above log pay (13.1 m pay untested).
Swan Lake 1 DW1	Toolachee Formation	A	5 097 232 200	0.18 8.2	Tested above log pay. All formation opened; major increase.
Swan Lake 1	basal Patchawarra Formation – Tirrawarra Sandstone	M	10 900	0.39	Flow rates comparable for both drilling types.
Swan Lake 2	basal Patchawarra Formation – Tirrawarra Sandstone	A	10 477	0.37	
Tindilpie 1	Patchawarra Formation above Vc	M	58 900	2.08	Flow rates were better above Vc with air drilling.
Tindilpie 2	Patchawarra Formation above Vc Patchawarra Formation below Vc	M M	RTSTM 14 158	RTSTM 0.5	
Tindilpie 2 DW1	Patchawarra Formation above Vc	A	39 600	1.4	
Burley 1	Toolachee Formation	M	5 100 4 531	0.18 0.16	Both drilling types gave low flow rates; mud drilling produced a better result.
Burley 3	Toolachee Formation	A	425	0.015	
Moomba 86	Patchawarra Formation above Vc	A	RTSTM	RTSTM	
Moomba 73	Patchawarra Formation	M	22 653	0.8	Nearest well to Moomba 86.
Moomba 26	Patchawarra Formation	M	14 158	0.5	Next nearest well to Moomba 86.
Coonatie 2	basal Patchawarra Formation Tirrawarra Sandstone	M M	14 158 5 663	0.5 0.2	Nearest well to Coonatie 4.
Coonatie 4	basal Patchawarra Formation basal Patchawarra Formation – Tirrawarra Sandstone	A A	8 495 14 158	0.3 0.5	

RTSTM rate too small to measure
Vc Patchawarra coal

of mechanical problems were identified while air drilling. When penetrating coal seams, the holes caved badly and the coal fragments settled around and jammed the drill pipe; several bottom-hole assemblies were lost. In Burley 3 the combination of high temperature, high air pressure, gas and possibly coal dust caused down-hole fires which partially melted the drill collars causing a break in the drill string on two occasions and led to the abandonment of the well.

NITRIFIED ACIDISATION

Acid has traditionally been used to reduce formation damage in relatively tight sandstone reservoirs and improve deliverability and increase recoverable reserves. The wells are 'killed' by a heavy weight fluid then injected with acid using a completion fluid. The reservoir is then allowed to soak in the acid before back-flowing the well to remove the acid and completion fluid and to measure the post acidising flow rate.

Nitrified acidisation was introduced to the Cooper Basin in 1996. This method uses a coiled tubing unit and is applied to highly depleted gas reservoirs which could be susceptible to formation damage if killed with overbalanced completion fluid. Nitrogen is initially pumped into the formation as an injectivity test. Acid is then squeezed with nitrogen into the formation and is finally displaced out of the well with nitrogen. The technique is designed to remove well-bore formation damage which has occurred during the productive life of the well without causing additional damage with kill fluids.

To July 1996 three wells in the Della and Moomba Fields were subjected to nitrified acidisation treatments and each had a post acid wash gas flow increase. During 1997 a further seven gas wells in the Big Lake, Moomba, Daralingie and Tirrawarra Fields had nitrified acidisation programs. Most of the initial ten wells showed flow rate increases. The overall deliverability increase achieved with the first ten wells was 362 452 m^3/day (12.8 mmcfd). The encouraging results will lead to further gas wells receiving nitrified acid treatments during 1998.

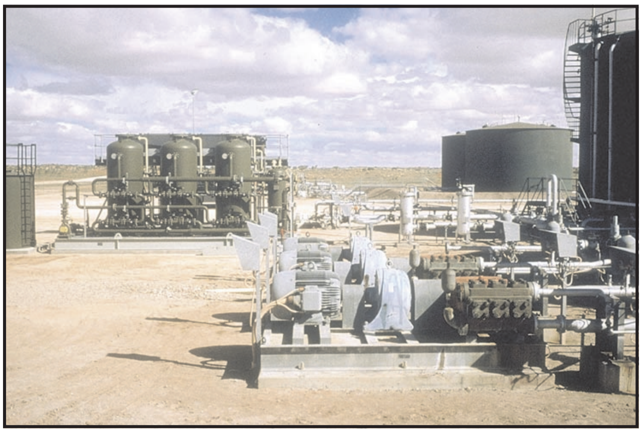
WATER-FLOOD SECONDARY OIL RECOVERY

In 1979 oil reservoirs were discovered in the Murta Formation (Eromanga Basin) of the Dullingari Field, located ~60 km east of Moomba; production commenced in 1982. The reservoirs of Cretaceous age were deposited in a lacustrine environment and consist of three sandstone units. The oldest, the 49-0 sand, was deposited on a proximal delta slope. It is 1.5–3 m thick but has low permeability and its contribution to the oil production is limited as it is only completed in one well. The 48-6 sand is approximately 0.3 m thick and is interpreted as a lacustrine fan. This reservoir is separated by 1.2 m of siltstone from the 48-5 reservoir, a 0.3 m thick shoreline-bar sandstone with good porosity and permeability. The 48-5 and 48-6 reservoirs have a volumetrically calculated original oil-in-place of 1.44 x 10^6 kL (9.1 mmstb; Robinson and Butler, 1989). However, material balance calculations assuming no water-drive give an estimate in the range of 2.2–7.5 x 10^6 kL (14–47 mmstb). This includes a large volume of oil in low permeability reservoirs in contact with the 48-5 and 48-6 sands. The edge of the Murta reservoir is defined by a zero pay contour as the reservoirs are present but tight down flank. Eight appraisal wells were drilled seeking down-dip reservoir extensions because the production decline indicated a large original oil-in-place as no water was produced with the oil. It was then realised that low permeability sands in contact with the 48-5 and 48-6 reservoirs were contributing to the oil production and the reservoir had a depletion drive.

An enhanced oil recovery (EOR) scheme using a low pressure water flood of the 48-5 and 48-6 sands was implemented in 1984 after 240 000 kL (1.5 mmstb) of primary production had been achieved. It aimed to improve the recovery in the good quality thin reservoirs and at the same time allowing cross flow from the adjacent tighter oil sands. The injection project started with two injectors and was later expanded to four, all relatively low on the structure, with eleven producing oil wells on pump while an average reservoir pressure was maintained at ~8621 kPa. A fifth injector was added in 1990. The ultimate recoverable reserves are 920 000 kL (6.4 mmstb) of which 460 000 kL (3.5 mmstb) are attributable to the water-flood project.

Another water-flood EOR scheme was implemented in the Murta reservoir of the Limestone Creek–Biala oil field in 1993. The underlying Namur Sandstone was perforated to allow the Great Artesian Basin aquifer to dump into the Murta forcing oil from the dump flood well towards surrounding producers. There has been a measured increase in the Murta reservoir pressure, but no change in the oil production declining trend.

The Gidgealpa Field, Birkhead Formation (Eromanga Basin) oil reservoir was subjected to a water dump flood trial in October 1995. The Birkhead is a partial depletion drive reservoir. The underlying Hutton Sandstone was perforated in Gidgealpa 22 and allowed to flood into the oil reservoir. A minor increase in reservoir pressure has been recorded since the flood commenced. The Birkhead reservoir in Gidgealpa 22 was fracture stimulated to allow increased access of the Hutton water to the depleted reservoir. No significant change in oil production has been recorded to date.



Filters, injection pumps and tanks used during water-flood secondary oil recovery, Dullingari Field. *(Photo 45947)*

GAS-FLOOD SECONDARY OIL RECOVERY

The Tirrawarra Field discovered in 1970 was the first Permian oil field found in the Cooper Basin. The field also has the largest in-place oil accumulation in the basin with estimates ranging from 19.56 x 10^6 kL (123 mmbbl; Pecanek and Paton, 1984) to 25.9 x 10^6 kL (163 mmbbl; Seggie *et al.*, 1994). The reservoir is the Tirrawarra Sandstone with minor volumes in the younger basal Patchawarra Formation and the older Merrimelia Formation. The nearby Moorari Field was discovered soon after Tirrawarra in 1971 and like Tirrawarra has oil in the Tirrawarra Sandstone. Moorari contains approximately 2.07 x 10^6 kL (13 mmbbl) oil-in-place (Brown and Barley, 1986).

Production commenced in 1983 from the Tirrawarra and Moorari Fields. Individual wells showed substantial declines in productivity as the Tirrawarra oil is under-saturated at initial reservoir conditions. As reservoir pressures fall below the bubble-point the oil phase shrinks rapidly with a major loss of liquids production. To minimise this affect bottom-hole flowing pressures were maintained where possible above the bubble-point. The Tirrawarra reservoir has low permeability and no active aquifer. The maintenance of pressure support was thought necessary to slow the deliverability decline and increase oil recovery. Studies of the oil characteristics indicated that the oil was amenable to miscible gas flooding.

A pilot gas injection EOR scheme commenced in the Tirrawarra Field in 1984 when Tirrawarra 15 producing well was converted to an injector to supply energy to the surrounding six producing wells (Figs 11.4, 11.5). An observation well, Tirrawarra 35, was added to the pilot injection program to provide data for a study of the effectiveness of the pilot injector. Tirrawarra Field, Patchawarra Formation separator gas was used as the injector fluid. Prior to long-term injection commencing in Tirrawarra 15, a ‘huff and puff’ experiment was carried out on the well in early 1984, using Patchawarra gas. Injection rates varied from 99 000 to 170 000 m^3/day (3.5–6.0 mmcfd) over several months and the total volume injected was 7.0 x 10^6 m^3 (247 mmcf). The well was shut in for approximately one week for a ‘soak’ period; well head pressures were measured and a production logging tool was used to monitor any cross flow between perforations. The puff section of the experiment involved back-flowing the well for approximately one week. About 660 000 m^3 (23.3 mmcf) of gas was produced with no significant quantities of oil recovered. Later in 1984 the Moorari Field pilot injector project commenced using Moorari 3 as the injector well with four adjacent producers (Figs 11.5, 11.6).

In 1985 radioactive tracer was added to the Tirrawarra Field injection gas to track the injector gas fronts. Production decline of the pilot producers was arrested by the gas injection. In Tirrawarra 15 pattern, response times seen in the production rate declines of the surrounding producers to the effects of gas injection varied from 5 to 13 months.

From 1984 to 1995 an additional eleven injector wells were added to the Tirrawarra EOR scheme. In 1986 a below bubble-point production trial commenced and in 1987 ethane from the Moomba plant became the secondary recovery injection fluid. Ethane injection into the Moorari

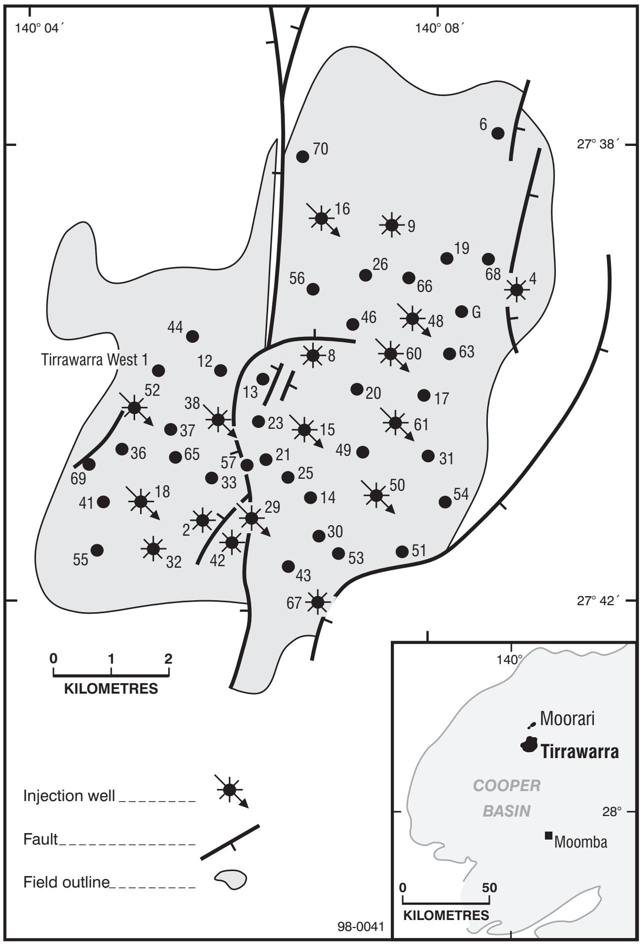


Fig. 11.4 Tirrawarra Field EOR scheme 1.1.95 (data courtesy of Santos).

Field also commenced in 1987. The later EOR patterns that were established in the Tirrawarra main field area were designed to include more of the northern area of the field in the EOR pattern.

With full EOR development and ethane injection until breakthrough volumes of ethane make oil production uneconomic, it is expected that total oil recovery from Tirrawarra will be 5.5 x 10^6 kL (37.7 mmbbl) of which 3.04 x 10^6 kL (19.1 mmbbl) would be primary and the remainder secondary oil. In Moorari, using the single injector, it is expected that 0.67 x 10^6 kL (4.2 mmbbl) of oil will be recovered of which 0.4 x 10^6 kL (2.5 mmbbl) would be through primary recovery (Rodda and Paspaliaris, 1989). At January 1998 the Tirrawarra Field had produced 3.8 x 10^6 kL (20.6 mmbbl) of oil and Moorari 0.5 x 10^6 kL (2.7 mmbbl). Both fields are expected to produce until 2012.

Well head of a Tirrawarra Field gas injector. (Photo 35486)

In December 1996 ethane injection into Tirrawarra and Moorari Fields ceased as the operator required the ethane as a substitute for sales gas and pure ethane was required to supply ICI in Sydney as a petrochemical feedstock. It is expected that ethane injection will not occur for all of 1997 and 1998 as extra gas deliverability is required to meet South Australian and interstate markets. The effect on oil production rates and recovery has not yet been quantified.

PLUNGER LIFT SYSTEMS

Gas wells

In the period 1986 to 1996, 18 gas wells in the Cooper Basin had plunger lift systems installed (Toolachee, Tirrawarra, Daralingie, Deina, Bimbaya, Marana, Thurakinna, Cooba and Cooper's Creek Fields). The wells had experienced production difficulties because of reduced formation pressure, increasing liquids (condensate and water) and reduced gas flow rates. Liquid build-up in the production tubing had been gradually killing these wells and allowing only intermittent production after frequently being blown down to atmosphere to unload accumulated liquids.

Plunger lift uses a piston in the production tubing to lift liquids to the surface. The annulus has a connection to the tubing through perforations and a build-up of pressure in the annulus by the gas is required to lift the liquid load. The piston periodically clears the tubing of liquids which allows an intermittent flow of gas from the well. Having unloaded the fluid in the tubing, the piston falls back to the bottom of the well through accumulated fluids until sufficient gas pressure builds up to repeat the lifting cycle (Fig. 11.7).

Plunger lift is not successful in all gas wells as the gas–liquid ratio has to be great enough to provide the lifting energy and the lower the gathering system line pressure, the more effective the plunger lift operation. Total gas deliverability from the 18 wells with plunger lift installed has been increased by 198 000 – 227 000 m^3/day (7–8.0 mmcfd).

Oil wells

The Moorari, Tirrawarra, Woolkina and Fly Lake–Brolga oil fields have relatively high gas–oil ratios in the Tirrawarra oil reservoir. This property makes the Tirrawarra Formation unsuitable for mechanical pumping operations as gas bubbling out of the oil in the well would severely reduce the efficiency of the pump. Moorari and the adjacent Tirrawarra Field have been subjected to EOR methods. Moorari 6 is separated from the remainder of the field by a series of faults and does not receive pressure support from the EOR project (Fig. 11.6). In 1987 a plunger lift was installed on the Moorari 6 oil well (Barry, 1988). Moorari 6 has a high gas–liquid ratio and the well had to be frequently blown down to atmosphere to prevent water loading in the production tubing, which stopped production. As the reservoir pressure in the oil reservoir drops below the bubble-point the gas–oil ratio of 362–711 m^3/kL (2000–4000 scf/bbl) was forecast to increase to 1781 m^3/kL (10 000

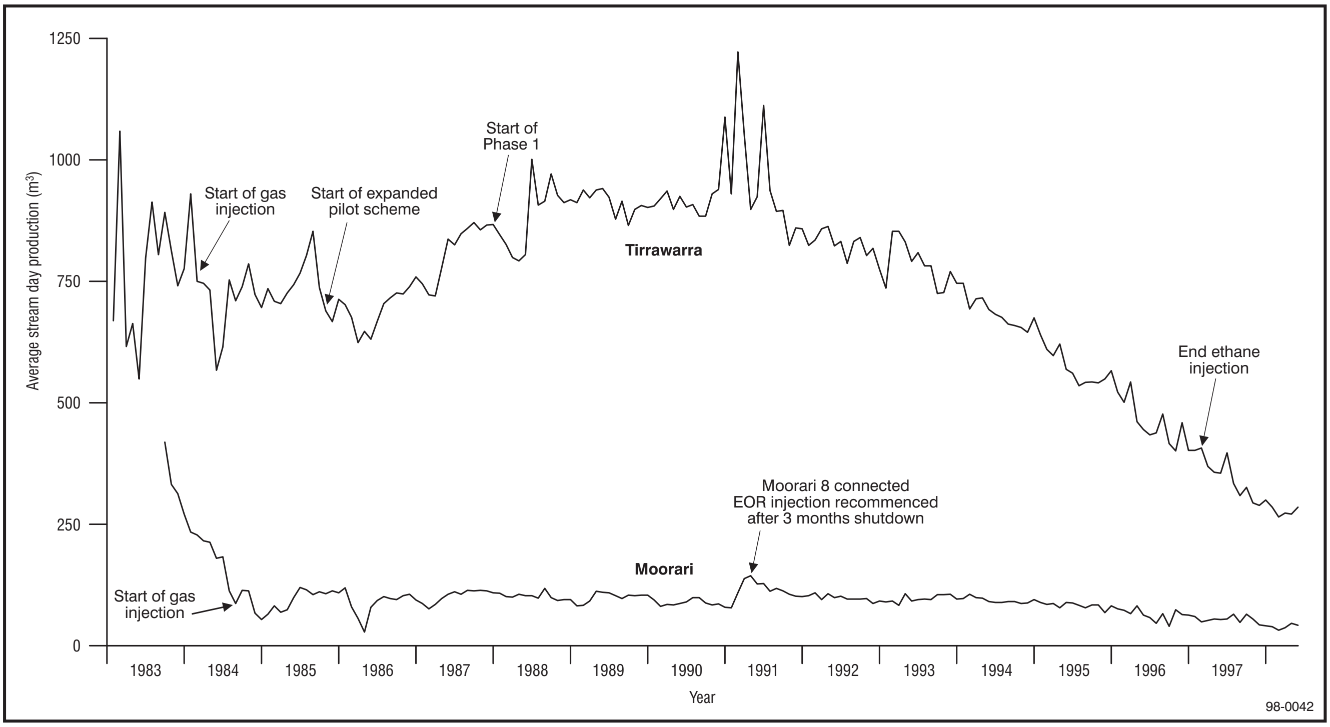


Fig. 11.5 *Tirrawarra and Moorari Fields' production history (after Rodda and Paspaliaris, 1989).*

scf/bbl). The installation of plunger lift in Moorari 6 produced an increase of 5.9 kL (37 bbl) of oil per day. To the end of 1997 Moorari 6 had produced 46 000 kL (0.289 mmbbl) of oil.

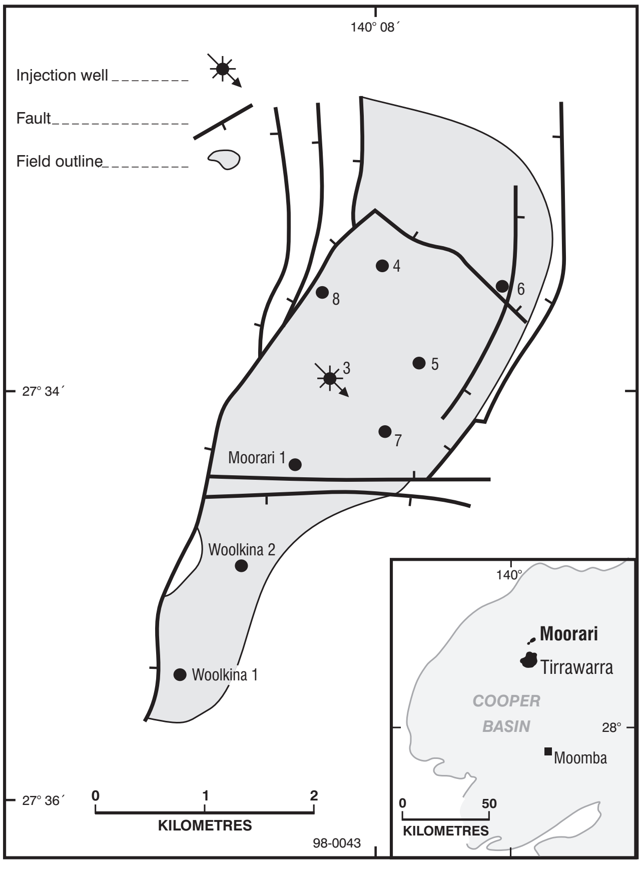


Fig. 11.6 *Moorari–Woolkina Field EOR scheme 1.1.95 (data courtesy of Santos).*

Tirrawarra 42, located at the southern edge of the Tirrawarra West Field, is a Tirrawarra oil producer which had production problems with fluid loading in the production string. A plunger lift was installed in 1987; production increased, but the rate was erratic. In 1990 a gas lift valve was added to the plunger lift to allow ethane to be injected into the annulus to add lifting energy for the plunger operation (artificially increasing the gas–oil ratio). At the end of 1997 the well had ceased production, having produced 20 000 kL (0.126 mmbbl) of oil to date. Tirrawarra 44 oil well, located on the northern margin of the field, had a gas-assisted plunger lift system installed in 1992. Production has been poor since the installation with the well unable to produce for the majority of the time; production from the well is 1000 kL (0.006 mmbbl) of oil.

HYDRAULIC FRACTURING

Gas reservoirs

The Cooper Basin sandstone reservoirs are generally poor to medium quality in terms of porosity and permeability. A large volume of gas is contained in low permeability reservoirs which require stimulation to increase effective permeability to allow the well to flow at an economic rate and improve the gas recovery. The Moomba Field, discovered in 1966, is a good example of a large volume low permeability reservoir. Hydraulic fracturing of the tight reservoirs involves pumping a fluid containing hard spherical proppant material (sand, glass, sintered bauxite etc.) under high pressures into a cased and perforated well. The high pressure fluid induces fractures in the sandstone reservoir which propagate away from the well as vertical wings. The proppant keeps the fractures open after the pressure is released and the fracture fluid is produced out of the well in post-fracture clean-up. The fractures increase the surface area of the well allowing an increased flow of gas to

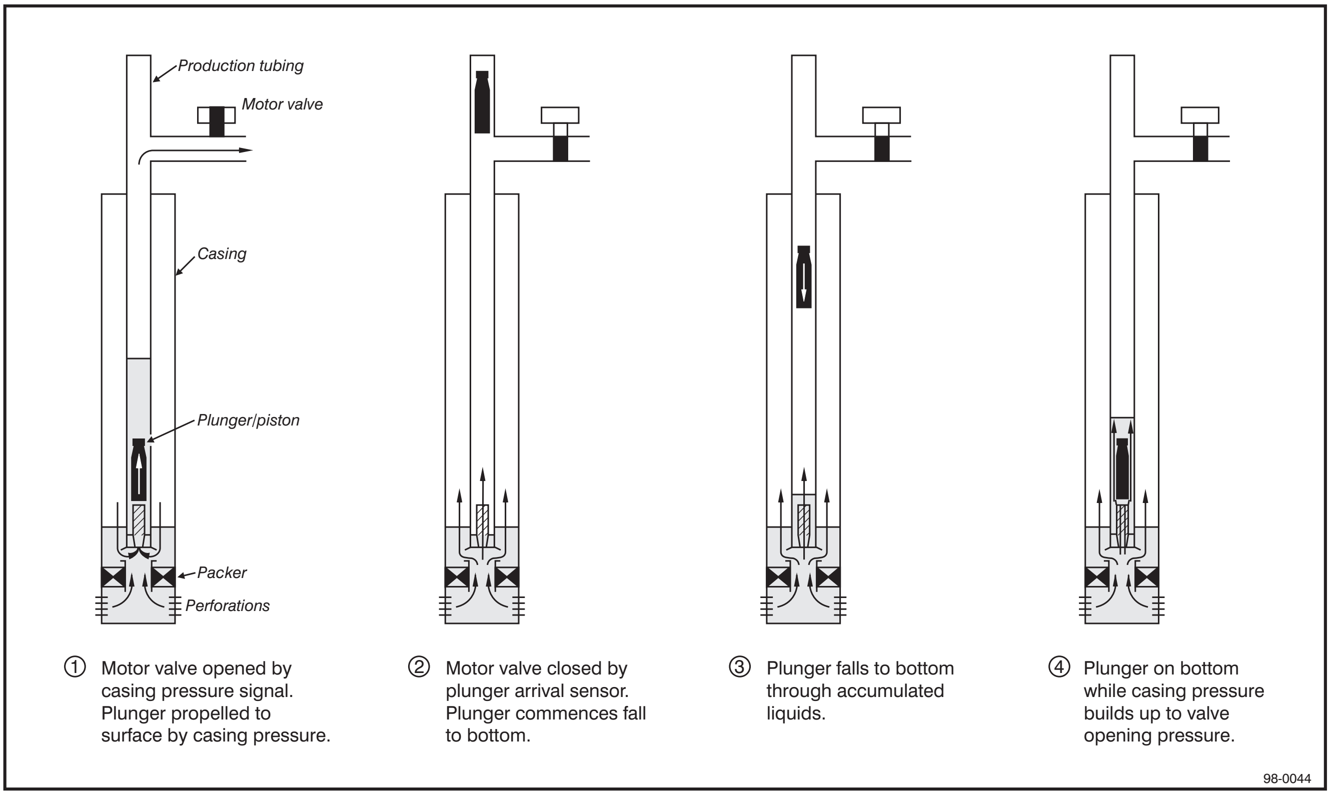


Fig. 11.7 *A typical plunger lift cycle (after Barry, 1988).*

occur and also drain a larger volume of reservoir than a standard well.

One of the earliest fracture operations in the Cooper Basin was on Moomba 6 in 1968. Fracture stimulation of Moomba wells has been successfully carried out on an irregular basis up to and including 1997. The Moomba North area has the highest number of fractured gas wells in the field as the Toolachee and Daralingie reservoirs are generally of a lower permeability than the southern remainder of the field. The materials used, the design and size of hydraulic fractures have changed with time. Many of the modern fracture treatments in the Cooper Basin are carried out on better quality reservoirs prior to production to increase permeability and to penetrate well-bore zones which may have been damaged by drilling fluids. The fracture increases the well's initial production rate and avoids a long flow period while the well 'cleans up'.

Hydraulic fracturing of gas reservoirs in 1997 resulted in five successful programs averaging 65 000 m^3/day (2.3 mmcfd) pre-fracture increasing to 139 000 m^3/day (4.9 mmcfd) post-fracture.

Fracture stimulation of gas wells has been an integral part of a number of tight gas evaluation programs. In 1982 the South Australian Oil and Gas Corporation Sole Risk Gas Program included the drilling and fracturing of Early Permian reservoirs in Big Lake 26 and 27 (Stanley and Halliday, 1984). This was followed in 1983–85 by the Accelerated Gas Program in which Big Lake 29, 30 and 31 were drilled and fractured (Crosby *et al.*, 1995).

In 1994 the Bulyeroo 1 well was drilled in the Nappamerri Trough, the deepest area of the Cooper Basin, in which tight reservoirs and a large tight gas resource had been identified by earlier drilling. The aim was to fracture stimulate the best of the Permian reservoirs. The Early Permian reservoirs proved to be too tight to fracture stimulate and a fracture program was carried out on the Late Permian Toolachee Formation instead. Although mechanically successful, the fracture program did not provide an economic gas rate from the well.

Zones which flow at measurable but uneconomic gas rates (e.g. 14 100 m^3/day (0.5 mmcfd)) can often be successfully stimulated by hydraulic fracturing, but tight reservoirs have not generally produced economic flow rates after fracturing.

Positive results from 1996 where fracture projects on seven wells added 617 300 m^3/day (21.8 mmcfd) and from 1997 where fracturing six wells added 356 800 m^3/day (12.6 mmcfd) deliverability means that fracturing of gas reservoirs will continue in the Cooper Basin as a method of

Surface equipment used during hydraulic fracturing, Tirrawarra 48. (Photo 45948) adding deliverability and increasing the recovery of gas reserves.

Oil reservoirs

Fracture stimulation of oil wells commenced in the Tirrawarra Field in 1971 (Rodda and Paspaliaris, 1989). The first fracture program of the Tirrawarra Sandstone in Tirrawarra 2 was unsuccessful. Tirrawarra 9, fractured in 1972, was moderately successful and by the time Tirrawarra 12 and 14 were fractured in 1981 the technique was proven. A typical Tirrawarra fracture program consists of 45 000–82 000 kg of proppant with 190–300 m^3 of water based gel. The Tirrawarra Sandstone contains a high gas–oil ratio oil and it was found that by fracturing the reservoir the oil production rate increased in most wells as did the productivity index which measures the amount of oil produced per day for each unit drop in the oil reservoir pressure. Fracturing has increased the average well productivity and injectivity by two to three times enabling economic development of low permeability reservoir areas. Analysis of the oil reservoir tests indicated that the wells were generally not damaged by drilling fluids and the effect of the fractures was to connect the well to higher permeability reservoir zones from which the higher flow rates resulted. All oil wells in the Tirrawarra Field were fractured early in their production history. Refracturing was also carried out after a number of years of production where it was felt that the original fractures had closed-up.

Oil well fracturing was previously concerned with Cooper Basin Patchawarra Central fields near Tirrawarra where the thick Tirrawarra Sandstone was the major target (Woolkina, Moorari, Fly Lake and Brolga Fields). As the Cooper Basin oil fields have been fully developed the number of fracture projects has declined in recent years.

More recent oil field fracture operations have involved the relatively shallow and very thin reservoirs of the Eromanga Basin Murta Formation. Production from the Murta relies on the presence of thin high permeability streaks in a much larger volume of oil saturated low permeability reservoir. Fracturing of the Murta allows a much larger area of low permeability reservoir to be in contact with high permeability streaks than in unfractured wells. This allows access to larger volumes of oil-in-place and increases oil recovery per well. Murta fracture projects have taken place in the Jena, Merrimelia and Wancoocha Fields with encouraging results.