SPE 64400

New Workover and Completion Technology Utilised in Bass Strait

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This paper was prepared for presentation at the SPE Asia Pacific Oil and Gas Conference and Exhibition held in Brisbane, Australia, 16-18 October 2000.

Abstract

As production from the Gippsland Basin in Bass Strait Australia passes the 30 year mark, the need to find innovative techniques to maximize production from this world class maturing basin is a principle priority for the operator. To address this issue, Esso Australia, on behalf of the 50:50 joint venture with BHP, recently embarked on a concentrated program to trial and evaluates several new technologies being developed by industry.

This paper discussed several technologies that were employed to increase production, enhance reservoir recovery and improve well integrity. Varying degrees of success were achieved during these trials and the successes, failures and lessons learned will be outlined.

The technologies discussed include:

- Scab liners with inflatable packers set through tubing in horizontal wells to isolate water/gas production;
- Gas and water shut off techniques utilizing polymer technology;
- Wellhead leak sealing technology using differential pressure-set coagulating Coagulating polymers;
- Wire lineless completions using expendable plugs and perforating gun hanger systems on space limited platforms (during infill drilling operations);
- Through-tubing deep penetration perforating charges used to stimulate production from well with extensive near wellbore damage; and
- Mini-fracturing gas stimulation technology used on poor performing reservoirs.

The high level of mechanical success combined with encouraging reservoir success in some instances is promoting a continued search for further production enhancing techniques.

Introduction

Esso/BHPP's operations in Bass Strait, South Eastern Australia, include 16 production platforms, five sub-sea completions and two single mono-towers (**Fig. 1**).
From these facilities there are 364 wells, the majority being oil and/or gas producers with the remainder injecting for reservoir management.

Since production commenced from the Gippsland Basin in 1969 with the installation of the Barracouta platform, significant ongoing drilling and workover activities have enhanced and maintained production levels Until the mid to late 1990s, traditional tubing pull, mechanical isolation and cement squeeze techniques have yielded high levels of mechanical and reservoir success with stronger workover economics. An ever declining list of high quality opportunities, as evaluated using traditional techniques, made it necessary to embark on a search for technologies that world continue to achieve mechanical and reservoir objectives while at the same time reducing workover costs.

After implementation of each new technology, an evaluation based on both mechanical and reservoir factors were performed. Mechanical success was defined as the completion of the required scope of work with appropriate testing successfully completed. Reservoir success was defined by long and short term reservoir performance compared against pre-job expectations. This paper concentrates on the mechanical aspects of each technology, however reservoir performance has also been discussed where appropriate.

Each of the new technologies trailed are discussed in the following sections;

Scab Liners with Inflatable Packers

A number of horizontal wells in Bass Strait were identified as potentially producing either gas or water preferentially from the heel of the horizontal section. The cost of traditionally used methods for water or gas shut-off such as tubing pull re-completions for installation of mechanical isolation equipment or cement squeezes made them uneconomic.

Recent industry developments have allowed the use of through-tubing technology to isolate these sections at a fraction of the cost of conventional workovers. Research indicated that less than 12 jobs had been performed worldwide using this type of technology in the small diameters required for Bass Strait applications.

For the purposes of this discussion a scab liner is defined as an assembly consisting of two inflatable packers separated by enough small diameter tubing to place the packers at the upper and lower ends of the zone to be isolated (**Fig. 2**).

The interval tubing is required for two reasons. Firstly acting with the packers as the mechanical barrier that isolates the undesirable water or gas zone and secondly as the conduit through which the reservoir fluid from any zones below the scab liner will be produced.

The maximum Outside Diameter (OD) of the scab liner assembly has to be small enough to run through the smallest Inside Diameter (ID) of the existing completion string and then set in the production casing or liner below the end of tubing. The ration of casing or liner below the end of tubing. The ration of casing ID to uninflated packer OD, called the "expansion factor", is a critical design parameter that governs the maximum differential pressure allowable across the scab liner assembly.

Three workovers have been performed using this technology, with two attempting to shut off water and one isolating a gas zone. Two operations had a minimum ID in the tubing of 3.456" inflating into a production liner with ID 4.892". The other operation has a minimum ID of 2.992" in the tubing inflating into a production liner with the ID of 3.937".

Technique

The scab liner assembly consisted of two inflatable packers, interval tubing, choke coupling, circulating tool and a hydraulic release tool which wax run to isolation depth via a 1.66" OD jointed workstring. This operation used a concentric workover unit, with the subject wells killed prior to rigging up. Coiled tubing (CT) was not used due to the relatively high cost based on 1) limited CT unit availability and 2) the requirement for specialized jacking equipment to run jointed tubing between the packers.

While minor differences in operational techniques exist a typical scab liner setting operation involves pumping a phenolic ball to a choke coupling located at the end of the scab liner assembly. The circulating tool, which is located above the running tool, assists the ball pumping operation by allowing fluid that has been pumped down the work string to be circulated back through the workstring by tubing annulus. This took is useful in the event that the reservoir locks up, increasing pumping resistance at surface.

Once the phenolic ball is seated, the setting operation is suspended for approximately 12 hours to allow the Bottom Hole Temperature (BHT) to stabilize. It is important to ensure that the packers are set as close as possible to the original BHT as every 1ºF rise in temperature increases the pressure inside the packer elements by 35 psi. After temperature stabilization, the workstring is pressured up against the ball in the choke coupling and the lower packer is inflated via an injection port until the shear setting pressure has been obtained.

Workstring pressure is increased further until the shear set pressure of the upper packer is reached. A further increase in pressure shears the choke coupling, releasing the ball into the wellbore. Another ball is pumped to release the workstring from the scab liner assembly via the hydraulic release tool.

All packers with the exception of one were inflated without incident. The operational difficulties experienced on the one well resulted from an inability to maintain pressure in workstring whilst attempting to set the upper packer. The phenolic ball that was pumped to set the packers did not seal in the choke coupling. A subsequent ball was released and the lower packer set. Increasing pressure to attempt to set the upper packer caused the choke coupling to shear prematurely, leaving the upper packer unset. It is believed that continual cycling of the pressure during diagnostic activities when the original ball did not seat resulted in a weakening of the choke coupling pins, causing them to shear prematurely.

Due to the inability to set the upper packer during the workover, another inflatable packer was run and latched into the release sub of the un-set upper packer. This operation proceeded without incident.

Test on the lower packer are performed by slacking off or picking up weight on the workstring to ensure mechanical integrity. Pressure integrity cannot be confirmed as there are open perforations both above and below the packer. Both mechanical and pressure integrity of the upper packer are tested.

Results

All jobs were classified as mechanical successes, while the reservoir results varied. The reservoir performance of the three workovers is summarized below:

- Workover 1- Gas production was reduced by more than 50% with a corresponding 250% increase in oil production.
- Workover 2- Water production reduced by approximately 50% in the short term but returned to original rates within one month of production. It is believed that local stratigraphy or a behind-pipe cement channel caused this premature water production from the middle of the horizontal section.
- Workover 3- No evidence of reduced water production was reported. The results of this workover supported the theory of field wide tilting contacts resulting in the toe of the well being watered out.

Gas and Water Shutoff Techniques Utilizing Polymer Technology

A gas and water shut-off, otherwise known as a conformance squeeze, was performed using a cross-linking polymer gel to allow for production from a deeper reservoir zone. This technology offers an alternative to zonal isolation with scab liner assemblies. The success of the conformance squeeze is dependant upon the ability of the polymer gel to propagate beyond the wellbore and through the rock matrix at the proposed isolation depth.

There are a number of factors, which need to be considered when implementing this type of technology. These include the temperature of the zone being isolated, the concentration of the fluid providing the isolation, pH and most importantly reservoir characteristics such as porosity, permeability and clay content.

Polymer isolation of a two meter perforation interval was performed on one well, which was preferentially producing gas. Electric logs performed before the isolation of this sand indicated a temperature of 183ºF at isolation depth. The horizontal permeability was 1-3 darcy and vertical permeability was between 40-80% of the horizontal permeability. The porosity was approximately 22% over the entire sand interval. The clay content of the sandstone was reported between 10-15% with the clay containing 80% Illite/Smectite and 20% Kaolinite.

Technique

The conformance squeeze involves pumping a number of fluid stages through the production tubing and into the perforation interval to be isolated, whilst continually observing the surface pressure for indications that isolation is progressing.

Based on laboratory testing and wellbore temperature model ling,, the polymer gel is designed to start setting only once it has reached the outer edge of the "theoretical placement volume" the perforated one. It is important to have accurate BHT data as the fluid program, in particular the gelatin response of the polymer stages, is highly dependent upon accurate wellbore temperature modeling. The design and testing process must take into account the cooling effect of any fluids pumped into the formation including kill fluids and preflush stages.
The first stage is a buffered preflush, which is pumped to provide a compatible fluid before the polymer gels re pumped. Fluid compatibility is important to ensure that the polymer gel sets within the design time limits.

Following the preflight, a series of polymer stages are pumped into the formation. The objective of the operation is to have all polymer stages set up and achieve squeeze pressure during the final stages of the displacement. Regardless of stage and as the polymer begins to set, flow will be diverted from higher to lower permeability regions of the reservoir. Due to cooling of the formation as polymer gel is pumped, subsequent polymer stages will contain more cross-linking additive to ensure setup at lower temperatures. The reduction in the overall permeability of the formation should be evidenced at surface by an increase in the Tubing Head Pressure (THP) as the job progresses.

If is important that the surface pressure is closely monitored throughout the pumping programs as not to exceed the formation fracture gradient. This is to keep the polymer fluids from being pumped away in a fracture, maintaining the integrity of the conformance squeeze. This is of particular importance as the final stage is being pumped when it is expected that permeability has been significantly reduced by the previous gel stages. Once all stages are pumped, the gel is left for approximately 30 hours to continue cross-linking. The remaining polymer gel in the wellbore is circulated out. The polymer squeeze is then subjected to a draw down or negative pressure test to ensure integrity. A deeper zone can then be perforated upon completion of the shut-off operation.

Results

A 100 bbl preflush, two stages of polymer gel, and a displacement were pumped into the formation over 7 hours. The first gel stage consisted of 250 bbls, the second 40 bbls. A 6bbl cross-linked polymer post flush was pumped as part of the displacement stage to prevent non-setting fluids reaching the formation in the event that squeeze pressure was not attained.

During the pumping operation there was no significant increase in THP observed. This indicated that the gel was not setting up at the tip of the treatment zone and creating diversion. This was not entirely unexpected as the initial formation temperature was at the lower end of the ideal design temperature for the polymer being utilized. Temperature conditions were known prior to commencement of operations, but it was considered that mechanical success was still possible if adequate setup time was allowed even in the absence of observed diversion.

At the completion of the operation the gel was allowed to cure for 30 hours before perforating the deeper zone.

The squeezed zone was subjected to a drawn down pressure 300 psi below pre-job reservoir pressure. THP increased by 50 psi over a 60 minute interval, meeting the acceptable leak rate criteria, indicating mechanical success.

After the completion of the shut-off a new zone was perforated and flowed to determine the composition of the new reservoir fluid. The well came on line with 83 kl/d of oil at 55% water cut and a Flowing Gas Oil Ration (FGOR) of 1383 m^3/kl. Although the FGOR was reduced by a factor of four this reduction was only short term. The well shortly returned to gas rates which were outside platform constraints and this workover was classified as unsuccessful from a reservoir perspective. The post isolation production response is inconclusive with the respect to the possible source of increased gas production. Insufficient polymer penetration may result in a contribution from the polymer isolated zone, or the newly perforated zone could be producing more gas than anticipated. A logging program is proposed to determine the relative gas contributions of each zone and hence confirmation of isolation performance.

Wellhead Seal Technology

A significant percentage of Bass Strait wells contain original equipment, which can be in excess of 30 years old. The wellhead seals and Surface Controlled Subsurface Safety Valve (SC-SSSV) control lines have deteriorated over time in some wells. The cost of re-installing wellhead equipment to integrity was substantially reduced due to the introduction of sealant technology. Replacing failed casing hanger seals or repairing SC-SSSV control lines has typically required an expensive tubing pull re-completion to gain access to the failed components.

Advances in sealant technology have resulted in the introduction of differential pressure activated coagulating sealants which remain fluid in any hydraulic system until the sealant passes through a leak site and experiences a pressure drop. The driver for utilizing this technology was the significant cost savings compared to a traditional tubing pull workover, as only minimal personnel and pumping equipment are required to carry out repairs.

The technology was utilized in a number of different failure scenarios including casing hanger, tubing hanger and control line seal failures.

For each job, leak-specific information was required before a special sealant formula was mixed. Information required included the leak rate, travel time for the sealant to reach leak site, differential pressure across the leak, and the flowing and shut in temperature conditions.

The potential leak sites for control lines include; seals associated with passage through the wellhead or connection to SC-SSSV or holes within the control line itself.

Results

To date eight repairs have been attempted using this technology. The results are outlined below:

- Control line failures- three of four were successful (75%)
- Casing hanger or tubing hanger seal failures- three of four was successful (75%).

When assessing the remedial work for the one unsuccessful control line repair, diagnostic testing indicated an increase in the control line pressure when pressuring up the tubing by production casing annulus. The tubing pack-off and the control line seals were tested positive indicating that the leak was in the control line. The sealant was pumped down the control line and allowed to set until enough pressure could be maintained to open the SC-SSSV. Within one week it was reported that the control line could not maintain pressure. Another attempt was made to seal the leak with the coagulating polymer and control line pressure was maintained above the SC-SSSV opening pressure. When lift gas was injected into the tubing by production casing annulus, the control line pressure increased. A final attempt was made to pump sealant down the control line to seal the leak. With pressure on the control line, an attempt was made to flow the well however all indications were the SC-SSSV was not opened. The ability to maintain pressure on the control line suggested that the leak was sealed, however the inability to open the SC-SSSV would indicate that there might have been a blockage in the control line.

Difficultly was experienced on the single unsuccessful casing hanger repair due to a substantial leak rate. A large enough differential pressure could not be obtained, preventing the polymer coagulating at the leak site.

The most significant measure of success for this technology has been the cost savings associated with not having to pull tubing, as well as the production it has brought back on stream for the cheap price. In total more than $10M worth of savings have been realized with more than 5kbd of production reinstated.

Wire lineless Completions Utilizing Expendable Plugs and Perforating Gun Hanger Systems

Traditionally, Bass Strait completion operations have used slickline to run and retrieve wireline-set plugs for the packer setting and pressure testing operations. In addition, typically conductor line is utilized to perforate wells after the completion has been run.

Expendable plugs and perforating gun hanger systems offered the advantage of completing wells on space limited platforms without the need to mobilize slickline or skid the drilling rig back to a well to rig up conductor line for perforating. While the primary application for these technologies is in high angle wells where wireline intervention is difficult or impossible, in this application it afforded significant rig time/ cost savings in a space-limited environment.

Technique- Expendable plugs

Expendable plug assemblies are installed below the production packer as an integral part of the tubing string, allowing hydraulic packer setting and pressure testing of the completion string.

A typical expendable plug assembly (**Fig. 3**) consists of a debris barrier to prevent debris build-up, an auto-fill device to allow tubing to fill when running the completion into the hole, and the plug itself. The plug consists of a fresh water reservoir kept separate from a salt plug until a pre-determined number of pressure cycles are completed. The pressure cycles progressively move an inner mandrel, eventually opening up a conduit for the fresh water to contact the salt plug and expend it. During pressure cycling, pressure and volume is monitored to determine when the plug has expended.

After running the completion, pressure is applied to the tubing to set the packer and test the tubing. Once the production packer has been set at the appropriate depth, the tubing hanger is landed in the tubing head and the production annulus is pressure tested. The drilling rig could then move on to the next well slot as a pump could now be used to expend the plug by pressure cycling once the surface facilities had been installed to prepare the well for production.

Technique- Perforating gun hanger systems

Permanent production and gas lift flow lines are installed prior to perforating so that an under balanced condition at the producing interval can be developed. This underbalance is achieved by unloading fluid from the tubing using lift gas. There is a delay of the order of 2-3 days required for flowline installation during which the rig is skidded to the subsequent operation in the interest of maximizing productive rig time.

Given space constraints while drilling on the smaller first generation Bass Strait platforms, traditionally through-tubing conductor line perforating techniques required the rig to be skidded back to the well in question to allow access for conductor line rig-up, significantly increasing perforating cost. Rig time savings were realized under conductorline conveyed gun hanger systems installed inside the production casing prior to running the completion. This system uses a time-delayed, hydraulically activated firing sequence that could be initiated after flowlines had been installed. This kept perforating operations off the rig critical path so that subsequent operations did not have to be interrupted.

The expendable plug isolates the hydraulic firing head from packer set and tubing test pressures. When the plug is expended, pressure can then be applied to the gun system to initiate the firing sequence.

Results

To date eight jobs have been completed using expendable plug and perforating gun hanger technology. In all cases the perforating gun hanger system worked without incident while the expendable plug technology had mixed results as outlined below:

- Ability to set the packer and test the tubing with the expendable plug- seven of eight was successful (87.5%).
- Expelling the expendable plug- five of eight were successful (62.5%).

On three wells, difficulty was experienced expending the plug after the packer had been set. The operational difficulties were a result of surface pressure limitations where the tubing could not be pressured to the required cycle pressure limit. Pressure was cycled a minimum of 20 times with no indication of the plug expending. To expel the plug, a slickline unit was mobilized so that a spear could be run to puncture the debris barrier and the protective membrane, dissolving the plug. In these instances no cost savings were realized, as slickline was required for well intervention.

Another operational difficulty experienced included the inability to maintain pressure on the tubing after the expendable plug had been run in the completion. A slickline plug had to be run to set the packer. It is believed that debris became lodged in the auto-fill device causing it not to affect a seal during the closing operation.

While some difficulties were experienced with the expendable plug, the five successful operations saved more than $1M in rig time.

Perforating with Deep Penetrating Charges

Perforating is a critical component of the well completion process and continuous effort is focused on increasing well productivity through this technology. Perforating with deep penetration charges has been performed on a number of wells in Bass Strait providing increased productivity from reservoirs containing lower quality sands.

The deep penetrating perforating charges offer increased penetration depth and a larger whole size for improved reservoir connectivity when compared to conventional perforating charges.

Technique

The main differences between conventional perforating charges and the deep penetrating charges are in the proprietary design of the charge itself. Material selection, improved manufacturing tolerances, quality control, and charge geometry optimization have all contributed to improved penetration performance.

Regardless of charge, perforating operations are carried out to maximize depth control and reservoir productivity. Gamma Ray/Casing Collar Locator (GR/CCL) tools are run on all perforating toolstrings for correlation and depth control. Measurement While Perforating Tools (MWPT) is utilized for precise control of under balance pressure plus short-term reservoir response immediately prior to and following perforation.

To evaluate the effectiveness of the deep penetrating charges, one well, which had previously been perforated with conventional charges, was perforated over a similar interval using the deep penetrating charges.

Results

The well test results using conventional charges and deep penetrating charges are outlined in Table 1.1.

Table 1.1: Well Test Data.

	Conventional Charges	Deep Penetrating Charges
Interval	3517-3519m	3517-3519m
Oil Rate (kl/d)	78	259
Water Rate (kl/d)	522	388
Water Cut	87	60
Choke (%)	100	100

The well was perforated with conventional charges in 1992. This well exhibited flow stability problems despite a downgrade in the tubing size from 4-1/2” to 3-1/2” in 1996 and several gas lift valve change-outs. Studies indicated that the most likely reason for the slugging was excessive near wellbore damage.

To trial the deep penetrating technology the well was first perforated with conventional charges. No improvement in production was seen and approximately two months later the well was perforated using deep penetrating charges. A significant increase in oil rate and a reduction in water rate were experienced.

The result proved that these charges were able to penetrate past the near wellbore damage where conventional charges could not.

Mini-fracturing Gas Stimulation Technology

Wellbore damage can be experienced during perforating as the crushed rock particles bridge across the pore throats increasing flow resistance and reducing productivity. In some cases the damage can be so severe that only a portion of the perforations will produce.

To reduce the risk of damaging the formation, it is common practice in Bass Strait to perforate in an underbalanced state to encourage rock particles to flow out of the tunnels immediately after perforating. Stimulation technology is also available to remove near wellbore damage using extreme overbalance as an alternative.

Gas stimulation involves perforating the damaged zone in an extreme overbalanced state. The pressure exerted on the formation during stimulation exceeds the fracture gradient of the formation; creating short fractures and forcing crushed rock particles into the formation (**Fig. 4**). The fractures improve reservoir to wellbore connectivity, bypassing the near wellbore damage.

To date there has been one gas stimulation attempted in the Bass Strait.

Technique

In general the operation is very similar to conventional perforating with the main difference being the requirement of a 100+m gas cushion below the surface wellhead. This cushion eliminates the chance of fluid surging to the surface under the shock of firing the stimulation tool. There is a risk of damaging the surface and downhole equipment during a stimulation operation if this gas cushion is not present.

The stimulation tool consists of three major components- the explosive igniter, the stimulation material and the hardware. The explosive igniter consists of a detonator and a primer cord. The simulation material is a solid which when ignited, becomes a high-pressure gas (15,000 psi). The hardware consists of a top firing head, the individual connectors and a bottom bull-nose. The bull nose is used for centralization and has a larger OD than the stimulation material to ensure that the material is conveyed downhole with the minimal amount of damage. The connectors also have a larger OD than the stimulation material and are used to connect the tool components.

The stimulation tool with GR/CCL tools and adequate weight bars is conveyed to stimulation depth via conductor line. Once the stimulation tool has been correlated on depth with the gamma ray tool, the detonator is fired and the solid material oxidizes within milliseconds, producing a burst of high-pressure gas. This high velocity gas enters the perforations cleaning out the tunnels by initiating short fractures in the formation (approximately 1-6 feet long). As the stimulation material continues to burn, fractures are propagated through the damaged zone, resulting in an improved flow path from the formation to the wellbore.

Results

Unfortunately sand and accumulation in the well prevented the stimulation tool from reaching depth on the first attempt. The well was subsequently cleaned out and the stimulation operation continued.

It is believed that the well killing operation during the sand wash either damaged the formation beyond what the gas stimulation could repair or assisted in the development of a void behind casing which dissipated the pressure wave reducing stimulation effectiveness. No increase in production was seen after the stimulation and the job was classified as unsuccessful.

Conclusions

As operations in Bass Strait continue to mature Esso will continue to use cost effective measures to maintain and enhance production. The recent trials of new technologies have proven that, when evaluated and implemented in appropriated situations, the reward out weighs the risk.

Esso will continue to take on the challenge of new technologies trailing, evaluating and learning from their implementation.

Acknowledgements

The authors would like to thank Esso Australia Pty Ltd and BHP Petroleum for permission to publish this paper. They would also like to thank the many members of the Esso Production Department and Service Company representatives for their assistance in its preparation.

NOMENCLATURE

OD – Outside Diameter
ID – Inside Diameter
CT – Coiled Tubing
BHT – Bottom Hole Temperature
THP – Ltubing Head Pressure
FGOR – Flowing Gas Oil Ratio
SC-SSSV – Surface Controlled Subsurface Safety Valve
Kbd – 1000 barrels per day
Bbl – 1 barrel (159 litres)
GR/CCL – Gamma Ray/Casing Collar Locator
NWPT – Measurement While Perforating Tool
Kl/d – 1000 litres per day
% - Percentage