SPE 90975

Multistage Oil-Base Frac-Packing in the Thick Inglewood Field Vickers/Rindge Formation Lends New Life to an Old Producing Field

W.H. Moodie, SPE, Plains Exploration & Production, W.A. Minner, SPE, Pinnacle Technologies, Inc, M. Fernandez, D. Lockman, Plains Exploration & Production, W. Burgett, Jr., Weatherford Completion Systems

This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Houston, Texas, U.S.A., 26–29 September 2004.

Abstract

The Inglewood Field, located along the Newport-Inglewood fault trend in the Los Angeles Basin, was discovered in 1924 and has an estimated ultimate recovery of 400 million barrels of oil. The traditional shallow reservoir production target zones are the Vickers and Rindge formations, which have been waterflooded since 1954. These intervals consist of a 1200’-1800’+ thick sequence of friable turbidite sands in the depth range of 1000’-3000’. Contemporary reservoir development in the complex, faulted reservoir rock has been connected with improved reservoir characterization, leading to infill drilling and waterflood pattern realignment. However, infill well success using conventional water-base cased-hole and openhole gravel packing has been marginal and inconsistent, because the long intervals and large reservoir pressure variations across the completion column make it difficult to complete the wells with an effective gravel pack and without formation damage.

In 2003, a radically different frac pack completion strategy was developed and evaluated. This low-cost frac-packing strategy has the advantages of true wellbore stimulation (or at least skin minimization) and ability to effectively connect across the highly laminated formation layers. Eleven wells were completed with as many as 8 stacked frac pack stages per well, with each stage pumped over a wire-wrapped screen to enable fracturing and gravel packing in one step. In the new wells, a limited entry perforation strategy was used to effectively distribute the fracture treatments across each stage interval. 20° API Inglewood crude was used as both the frac fluid and completion fluid to virtually eliminate formation damage, reduce costs, and simplify completion procedures. Several innovative new downhole tools (based on cementing tool technology) and procedures were developed to enable multiple stages to be performed in a simple yet effective manner, and allow the technique to be applied in both new wells and to remediate existing cased-hole completions.

Average initial production rate from the frac pack wells was 110 BOPD and 1250 BWPD. This response is much better than the rates from cased-hole gravel packs, and on par with open-hole gravel pack wells, but without the risk associated with gravel packing a thick openhole interval in a single step. Stabilized oil cuts have settled in at >5%, which compares favorably to the field average of 3% due to more effective completion of the deeper, lower permeability intervals that have been less swept by the waterflood. In response, additional wells will be completed at Inglewood and several other Los Angeles Basin fields in 2004.

Introduction

In 2002, 10 new Vickers/Rindge formation producing wells were drilled in the Inglewood field. These wells were cased hole completions with very long (1200’-1800’) perforated intervals and gravel packed inner liners. The wells were less productive than expected, and the difficulty of gravel packing the long completion intervals led to sand control failures. In 2003 another 10 new producing wells were planned and the decision was made to complete these wells using conventional open hole gravel packs to improve well productivity. However, due to outright failure of one well immediately and difficulty in completing the next two, the decision was made to try another completion technique for the remaining seven wells.

The completion technique chosen featured oil-base frac packing using inner liners and limited entry perforating. This technique was pioneered during 300+ *single*-stage fracture treatments pumped in the Pyramid Hills formation at the Mt Poso field in Kern County from 1999 until 2003. These treatments were pumped down the casing/liner annulus using crude oil as the fracturing fluid. High sand concentrations were successfully placed with very few problems. Very effective completions were achieved and the severe proppant flowback problems experienced at Mt Poso were solved.

In the Inglewood field, the Mt Poso fracturing technique was modified and extended using common, low cost completion tools to enable economic *multiple*-stage frac packing of the long productive intervals. By using native crude oil as the fracturing fluid, treatment costs were significantly reduced, and formation damage was minimized, if not eliminated. Fracture treatment data has also provided qualitative reservoir information across the completion column, assisting with understanding adjoining waterflood injector conformance and performance.

The production performance of the cased hole frac pack wells has been equal to or better than the open hole wells. Effective and durable sand control has been achieved – the risk of sand control failure has been significantly reduced, compared to both cased hole and open hole conventional gravel packs. Further, completion costs are no greater than for both conventional cased hole and open hole gravel packing.

The application of cased hole frac packs has also been extended to recompletions of existing cased hole gravel packs, to address poor productivity or sand control failure.

Field Setting

As shown in Figure 1, The Inglewood field is located in the northwestern portion of the Los Angeles Basin, ten miles southwest of downtown Los Angeles. The field is at the northern end of the Newport-Inglewood trend. As of January 2004, 1386 wells have been completed, and there are 341 active producers and 155 active injectors. Current field productive area is 1215 acres.

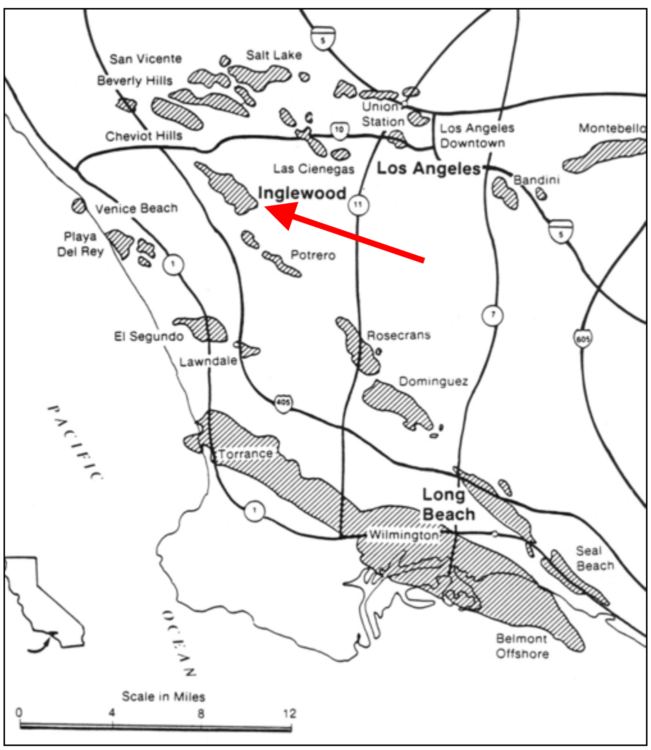

Figure 1. Location of the Inglewood field, Los Angeles, CA.

The field was discovered in 1924 by the Standard oil Company of California. The initial well was completed in the Vickers reservoir and had an initial production of 145 bpd of 19 degree gravity oil. Peak production was reached in 1925 at 18,300 bopd. Six deeper zones were discovered later and also developed. The shallow Vickers and Rindge reservoir zones have been undergoing waterflooding since 1954.

Geologic Description. The producing zones in the Inglewood field are confined from Middle Miocene to Upper Pliocene, approximately 15 million to 2 million years in age (Figure 2). The Vickers and Rindge Zones account for more than 60% of the total cumulative production to date. The Vickers and Rindge reservoir zones are contained within the Pico and Repetto Formations and were deposited during the Middle and Upper Pliocene. The Vickers and Rindge zones were deposited in the middle to outer portion of deep water turbidite fans. These fans spread across the basin floor from a northeast sand source. By the end of Vickers time, the basin had begun to shallow and the basin center shifted to the southwest.

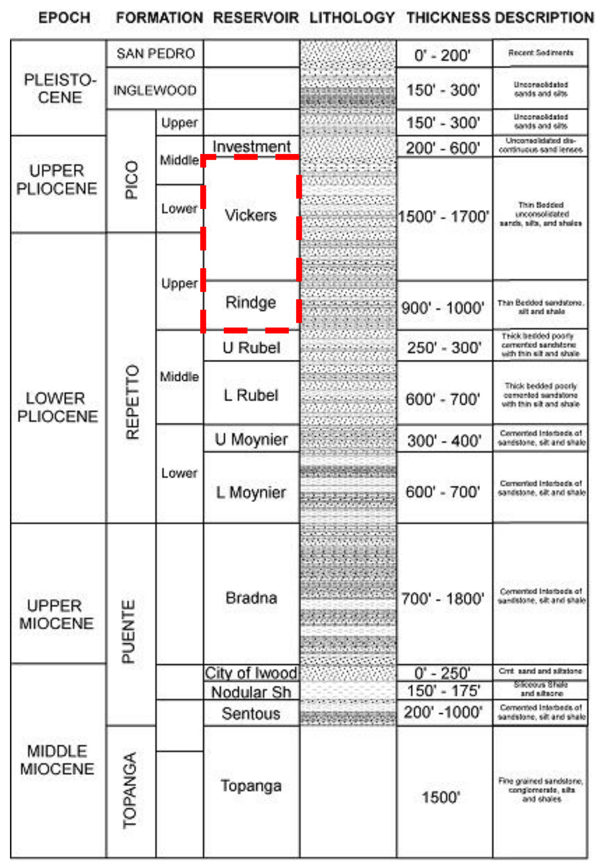

Figure 2. Stratigraphic Section at the Inglewood field.

The Figure 3 type log shows that the sands in the Vickers and Rindge zones are numerous but not individually thick. Lateral continuity of sand packages is good but vertical communication across the laminated intervals is very poor. Permeability is highest at the top of the Vickers at 100+ mD, decreasing with depth to less than 50 mD. Porosities range from 33% in the shallowest sands to 27% in the deeper sands.

The major folding of the Inglewood anticline began during the deposition of the Vickers Zone and peaked towards the end of Pliocene, when the Inglewood formation was being deposited on top of the Vickers zones. The field occupies the crest of an elongated anticline with abundant and complicated normal faulting through the Vickers and Rindge zones. Most of these normal faults act as barriers to fluid flow due to juxtaposition of the sands. Structural dips in these zones are generally less than 20 degrees.

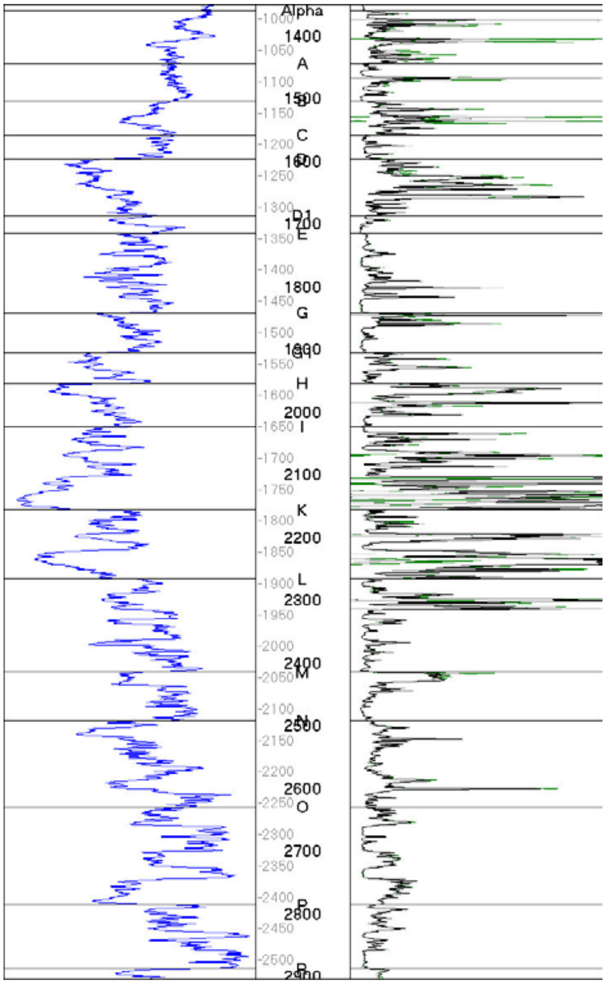

Figure 3. Inglewood Field type log - SP/ induction resistivity, Vickers Zone.

Traditional Completion Techniques

The completion method in the Inglewood field has been driven by the need to produce from the long productive intervals found in these interbedded turbidite sand shale sequences. Early on, wells were produced using slotted liners set in long open hole intervals. Later completions progressed to open hole gravel packing, and then cased hole perforated gravel packs. Each of these methods offered some positive aspects as well as some drawbacks.

The early slotted liners landed in open hole provided some measure of wellbore access to the entire productive interval. This was important considering the highly laminated nature of the sediments and the overall length of the completion interval. It was a simple completion method and generally offered a high rate of success in mechanical deployment. The drawbacks included a total lack of hydraulic isolation, a good chance of formation damage and liner plugging, and a lack of robust formation sand control. Future stimulation and remediation options were also compromised by the lack of hydraulic isolation.

Open hole gravel packing was an advancement on the earlier landed liners in providing for better sand control as the water cut in the field increased. It also provided access to all available reserves from the laminated reservoir. Drawbacks of this completion method were much the same as an open hole completion. Hydraulic isolation and formation damage were still problems. Obtaining an effective gravel pack was problematic due to the long completion interval covering sections with varying permeability, reservoir pressure and borehole diameter. With waterflood maturity and variable injector performance, large differences in pore pressure gradient across the completion column (varying from 0.2 to 0.5 psi/ft) made the gravel packing problems especially acute.

Cased hole gravel packing offered solutions to some to the problems encountered with both open hole methods but also had several significant new drawbacks. Hydraulic isolation to some extent was achieved, depending upon the placement of perforations. Some of the permeability and pressure affects were ameliorated and the problem of varying borehole geometry was completely solved. Due to the laminated formation character and poor perforation effectiveness, wellbore access to the completion column was significantly poorer than from open hole completions – despite huge perforating jobs, with the number of perforations exceeding 6400 in some wells. Obtaining an effective gravel pack was easier but was still a problem due to formation damage, which inhibits packing of the perforation voids. The most serious problems occurred when only one or two perforations connected into an interval overpressured by waterflood injection. The resulting high rate of production through only one or two perforations and gravel pack voids led to high rates of liner failure and loss of sand control. Overall this was the most expensive of all the options, with very long sections of wire wrapped screen required as well as massive perforating jobs. Technically this was also a difficult completion method to deploy.

Given the nature of the production interval and problems associated with the traditional completion methods, a new method of completion was needed that included the advantages of the traditional methods, but solved the problems inherent with each of them. The objectives were to effectively control formation sand, contact all available reserves, mitigate formation damage problems, have a high chance of successful mechanical deployment, offer some hydraulic isolation and be cost effective. After some deliberation a method using frac packing and unconventional tools was devised which would satisfy these requirements.

Key Frac Pack Advantages

Frac packing has solved many of the problems associated with the past methods of completion. Advantages include:

- Selective cased hole completion method – intervals swept by the waterflood may be bypassed if desired.
- Hydraulic isolation – achieved through perforation interval selection and by limiting the number of perforations. The combination of downhole tools used and the pressure drop associated with vertical flow in a sand-packed annulus provides isolation between stages, and even between perforation intervals in the same stage.
- Effective connection of the laminated sand intervals to the wellbore – fracture height growth provides a more effective wellbore connection than is possible using

conventional cased hole perforating, helping to assure that all targeted zones have the ability to produce.

- Good vertical treatment distribution – use of a multiple-cluster limited entry perforation strategy helps assure that the entire treatment stage interval is stimulated.
- True stimulation, or at least skin minimization – near-wellbore damage from drilling and completion operations is bypassed.
- Non-damaging fracture fluid – use of straight crude oil with no polymer minimizes frac face permeability damage and proppant pack damage.
- Completion durability – the limited number of perforations and the 'reservoir' of frac sand outside of each perforation effectively control formation sand production and prevents liner erosion.
- The cluster perforation strategy reduces flow velocity from high pressure overpressured intervals (caused by adjoining waterflood injectors) by spreading the production over multiple perforations, reducing tendency for "blast hole" mechanical liner failure.
- Chances for crossflow problems during completion operations, associated with flow from overpressured to underpressured intervals, are lessened by completing the thick formation interval with multiple stages.

Novel Completion Tools Enable Economical Multi-Stage Strategy

To implement the multiple stage completion technique, downhole tools had to be developed that were cost effective, readily available, simple to use, and needed little or no testing. By using several off the shelf items in new ways the desired objectives were achieved.

Figure 4 presents a schematic of the gravel pack liner and downhole equipment.

With the exception of the first stage in a given well (although it could be used there also) the first item is the drive over adapter, followed by two casing cup sealing elements that look up. These cups seal the outside of the liner section from the previously treated zone below. They also provide some measure of hydraulic isolation between stages after the well is placed on production.

On top of the cups is an upside down cementing float collar. The float collar prevents downward fluid flow during fracturing but allows upward flow while running the liner in the hole. The float collar effectively seals the inside of the liner of the current stage from the previous stage below. Float collars are rated for high differential pressure and are designed to be easily drilled out during final well completion.

The liners used were a combination string consisting of 10'-20' wire wrapped screen sections covering only the perforated intervals, with blank sections in between. In addition, the top of each liner was perforated with 20' of semi perf slots. The specification for the slots was generally 0.020" width, 2" length, and 24 rows on 6" centers. If smaller frac sand was used, slots were cut to 0.012" in width. Size of the liner was an important consideration since fracturing was done down the liner casing annulus. A normal combination for the Inglewood field was 7" base pipe with 9 5/8" 36# casing. Consideration was given to limiting the annular velocity of the fracturing fluid to no more than 40 ft/sec to limit erosion tendency. A lower velocity also lessens chances for annular bridging, which can occur when the carrier fluid takes a shortcut to deeper perfs through the inside of the liner. All liner sections also included centralizing lugs placed above and below the perforated and wire wrapped screen sections to ensure that the liners were properly centralized in the casing.

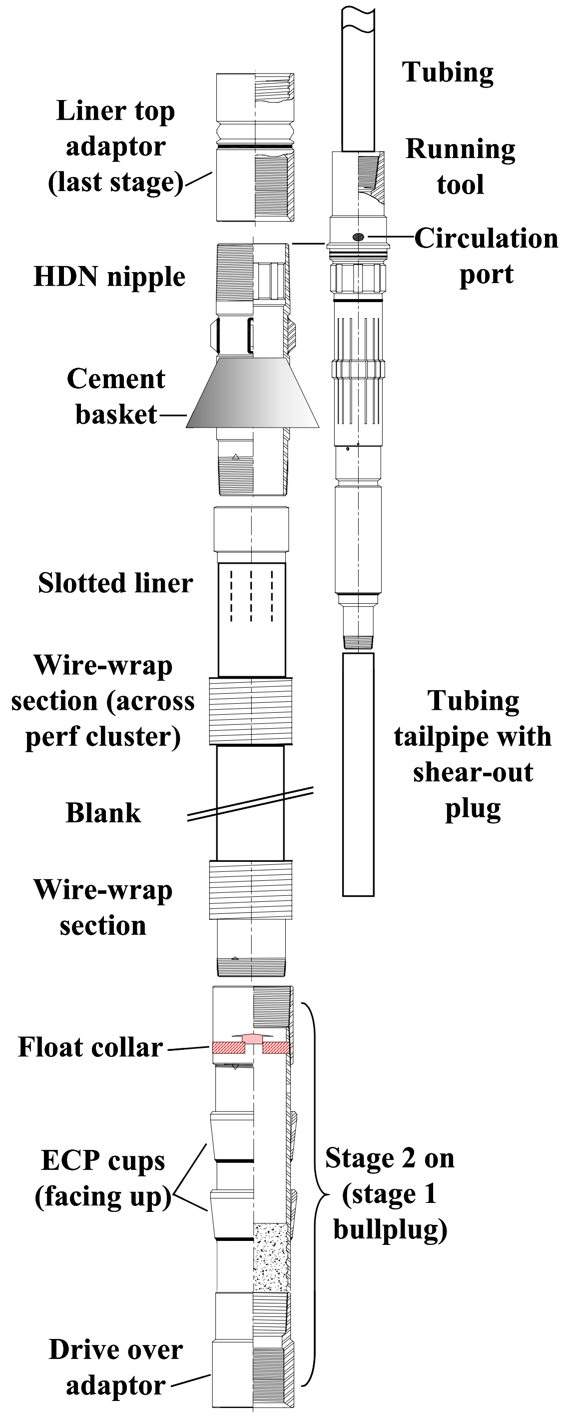

Figure 4. Schematic of gravel pack liner and downhole equipment.

On top of the upper semi-perforated section is another common piece of equipment used in a unique way. A common metal-petal cementing basket was placed upside down to act as a “proppant check valve”. During the prop frac injection down the annulus, the cement basket petals collapse and do not hinder flow. However, with flow back up the annulus (e.g. during annulus pressure bleedoff, or due to an overpressured interval feeding in while preparing for the next stage), the basket expands and bridges off the proppant backflow. Differential pressure is spread across the resulting annular proppant pack rather than just across the cement basket itself. This tool has proven to be very effective in keeping proppant in place after treatment shutdown.

The running tool is the last piece of equipment on the liner. These adapters are referred to as “one step tools”, and were developed in the early 90’s to drill in liners with welded on underreamers using foam fluids in shallow heavy oil reservoirs. When a liner was drilled in, it was immediately gravel packed in place and then the running tools were released off of the top of the liner using a straight pull release. The liner was circulated clean leaving a well which had been underreamed, gravel packed and prepared for production in one step.

The top of the “one step tool” is simply an adapter with wicker threads on top and splines in the middle. The tool is made up on the adapter, and tubing is run below to act as gravel packing washpipe. The washpipe contains a pump-out plug to prevent oil flow up the tubing while running the liner in the hole. The adapter is either screwed into a collar or welded on to the top of the liner prior to running the liner in the hole. The tool’s straight pull release and circulating ports have proven to be extremely useful in deviated holes and for cleaning out the casing in the event that a premature screenout should occur.

Frac Pack Completion Procedure

New Wells. The completion procedure for a typical well starts with selection of the target zones to be stimulated. In a typical Inglewood well the total gross completion interval will range from 1200’ to 1800’ from top to bottom. In this large interval many sands of varying pressure, permeability, porosity and grain sizing will be distributed in packages ranging from several 10’s of feet to 100’ or more. Typically these sands will be finely to coarsely laminated. These sands are separated from each other by interbedded shales, silts and claystones, which may or may not be laterally continuous in nature.

The normal practice is to subdivide the total gross interval into subintervals of roughly 200 feet. In this subinterval, normally the 4 points opposite the best looking sand packages in the interval are chosen for perforating. Perforating is done using 4 jspf in a 1 to 2 ft interval. Perforations are at zero degree phasing at each setting. Typical practice in Inglewood is to use select fire guns to accomplish perforating a stage with a single run.

The perforations are chosen and a workover rig is moved on to the well and tubing is run to TD. The well is cleaned out if necessary and the wellbore is completely displaced with oil. The tubing is pulled from the well and bond logs are run to correlate with. After running the logs, the first stage is perforated. The liner is measured and adjusted to center up the 10’-20’ screen sections on the perforated intervals. The typical screen in Inglewood is 0.012” wire wrapped screen on a base pipe that is slotted with 0.100” slots. These slots in the base pipe are typically 24 rows, 2” in length and 6” on center. The liner is made up and hung in the slips and then a tubing tail washpipe is made up and run inside the liner. This tubing tail has a sliding sleeve and plug in the bottom of the tubing. The tubing is plugged to prevent oil from flowing up the tubing while the liner assembly is run in the hole. The tubing tail is made up onto the liner running tool, which is in turn made up onto the liner. The entire assembly is then run into the well on tubing.

After setting the liner on bottom a swedge is screwed into the tubing, which is then connected to the rig pump system via a choke manifold. The tubing is pressured up and the sliding sleeve shears open; the tubing is now open into the liner and is used as a dead string during the fracturing treatment. The choke manifold is closed and the well is ready to fracture.

To fracture the well the high pressure pumping equipment is connected to the well through a frac spool underneath the blowout prevention equipment. These connections can be flanged or screwed into collars welded to the spool. Typically at Inglewood the frac spool has collars welded to the spool and two high pressure treating lines are connected using screwed swedges.

The frac lines are pressure tested and the lines are displaced with oil after pressure testing. The wellhead valves are opened and normally one breakdown injection is pumped down the tubing casing annulus consisting of about 125 bbl pumped at 30 bpm. Pressure is monitored on both the high pressure side and on the tubing side during this breakdown. The breakdown injection ends with a rate stepdown, and the pressure decline is monitored until fracture closure has been observed. Fracture entry friction, number of holes open, frac gradient, closure pressure and fluid efficiency are evaluated. A frac model simulation is performed for final pad sizing. The pumping schedule is adjusted if necessary, and then the main treatment is pumped. The tubing string is used throughout the treatment to continuously monitor the bottom hole pressure.

At the end of a typical propped frac treatment, the rate is stepped down with 30 bbls left to displace. The normal procedure is to step down from 30 bpm to 20 bpm at 30 bbls and then to 15 bpm with 20 bbls left and then to 5 bpm with 15 bbls left. At this point valves on the tubing manifold are opened into the tank and pressure on the deadstring is noted. With about 10 bbls left and 14 ppg sand in the annulus, the choke is slowly opened to drop the tubing pressure by 150 to 200 psi. A portion of the injected fluid now is directed away from the perforations and the sand slurry attempts to flow through the screen and up the tubing, resulting in the screen packing off. As the packoff occurs the pressure in the tubing will continue to drop as more screen area is packed off and pressure differential builds across the remaining screen interval. When the entire screen is packed off the injection pressure spikes in the annulus. When injection pressure increases by 500 psi, the displacement of the frac is shut down. Normally 2 to 5 bbls of sand slurry is left above the liner top. After shutdown of the treatment, the sandpack surrounding the screens is allowed to dehydrate further for a few minutes and then the tubing is shut in. At this point, normal post-frac leakoff takes over. The pressure is then monitored for post-frac leakoff calibration.

After fracture closure has occurred, the tubing is again opened to the tank and the well is allowed to bleed down as quickly as possible. After the tubing TIW valve is closed, a liner release 'dart' is placed on top of the TIW valve and the hose to the manifold is reconnected. The TIW is opened to allow the dart to fall. The normal fall rate for the dart is about 200 to 300 ft/min in the 20° API crude. After waiting for the dart to fall to the liner top, the rig pump is used to pressure up the dart in the liner setting tool, releasing the tool and tubing string from the top of the liner. A valve at the liner top is also opened. At this point the frac pumps are used to reverse circulate the sand left in the annulus (above the liner top) to the surface where shakers separate the sand from the oil. The sand is dumped into a steel pit that is cleaned out later. Circulation with the frac pumps is continued until the returns are clear of sand. The pumps are shut down and the tubing is allowed to bleed off if there is any pressure. The blowout preventer is then opened and the tubing is pulled from the well, leaving the well ready to be perforated for the next stage.

For the next stage the steps are the same. The well is perforated, the liner is made up and the tools are made up to the liner. The liner is then run into the well. The difference between the first stage and subsequent stages occurs when the liner reaches bottom. For subsequent stages the liner is not merely rested on bottom (bottom now being the top of the liner from the previous stage) but is driven on to the top of the previous stage's liner using a drive over adapter on the bottom of the subsequent stage's liner. If it is the last stage to be pumped into the well, a liner top adapter is run into the well and driven over the top of the liner stub. This adapter is typically a steel seal adapter, which does not form a hydraulic seal, but holds the liner top in place and prevents the gravel pack from being produced up the annulus.

With an early morning start, two stages can generally be performed on the first day, then one on day 2, two on day 3, one on day 4, etc.

Frac Pack Treatment Design

Staging Strategy. Stage and perforation strategy are key to successful stimulation of the thick Vickers/Rindge target formation intervals. The average total completion interval length for the 11 wells completed to date has been very large at 1460 feet. These completion intervals were each divided into 5 to 8 stage intervals with an average gross thickness of 225 feet.

A multiple-cluster limited entry perforation strategy was used to vertically distribute the fracture treatments across each stage interval. In most cases, each stage interval was perforated with 4 clusters of 4 holes, for a total of 16 holes. The number of perf clusters was occasionally varied from 3 to 5, depending upon the target sand layout and stage thickness, while keeping the total number of holes at about 16. Average total perf interval per stage has been 155 feet, resulting in an average perf cluster spacing of about 50 feet. Note that the goal is to create an independent fracture from each perf cluster setting, to avoid the fracture coalescence that can occur with hydraulic perf cluster linkup outside of the casing.

Each 4-hole perforation cluster was shot at 0° phasing over a 1 to 2 ft interval. A phasing of 0° is believed to be advantageous because it encourages all holes to break down once one hole breaks down. The fracture also tends to initiate as a single plane, improving the wellbore-to-fracture connection. Although it is unlikely that the fracture initiation direction is aligned with preferred fracture orientation, the rock is soft enough that erosion smoothes the transition into preferred fracture orientation.

With a perforation diameter of 0.42" and 16 holes, the theoretical perforation pressure drop was 430 psi at 30 bpm.

Frac Fluid. The frac fluid used was 20° API Inglewood crude oil. This oil has a viscosity of about 80 cp at surface conditions and 20-30 cp at the average reservoir temperature of 120° F.

Advantages of using Inglewood crude oil include a) low cost – the oil is simply 'borrowed' for fracturing use, b) non-reactive character with formation clays, c) no polymer residue to damage the fracture face or proppant pack, and d) operational ease of use, with no quality control (base gel viscosity, crosslinking or breaking) concerns.

While it is possible that the oil may be slightly damaging to formation permeability due to precipitated asphaltene and wax particulates, no evidence for this has been observed.

Disadvantages of using the oil include safety and on-site housekeeping. Reid vapor pressure is low enough to not be a concern. The moderately low flashpoint is addressed by several standard precautions, and procedures were developed to minimize on-site leakage and spills.

Initial concerns regarding excessive leakoff in the 100 mD rock and possible proppant transport deficiencies proved to be unfounded. Based on observed leakoff behavior, prop frac slurry efficiencies were estimated to be on the order of 35%, allowing for reasonable pad fractions. Proppant transport appears to be excellent, based on the general lack of downhole reactions to prop loadings as high as 14 ppg, and experience with restarting injection after unexpected treatment shutdowns and with reversing the wellbore clean after monitoring the prop frac pressure decline.

Proppant. Both 20/40 mesh and 16/30 mesh sand have been used for conventional gravel packing of the Inglewood Vickers/Rindge formation.

The initial frac pack treatments used 20/40 mesh Ottawa sand to be conservative from a proppant transport and bridging standpoint.

Proppant size was increased to 16/30 mesh and then 12/20 mesh Brady sand during later treatments to increase fracture conductivity. After some bridging sensitivity was experienced with 12/20 mesh sand, proppant size was standardized at 16/30 mesh.

In the wells completed to date, there does not appear to be any correlation between well productivity and proppant size. Thus, there is no evidence for conductivity restriction from the smaller sand sizes. For example, there are several wells treated with 20/40 mesh sand that gross more than 2000 bpd with a significant fluid level over the pump. Productivity is likely a stronger function of local formation properties and reservoir pressure (waterflood impact).

Tip Screenout Design. Tip screenout (TSO) initiation occurs when the initial clean pad volume is depleted and proppant reaches the fracture tip. Further pumping then serves to 'inflate' fracture width and pack the fracture with proppant. The larger fracture width increases fracture conductivity, increasing flow capacity and lessening non-darcy and multiphase flow pressure drop. Many frac pack treatments are designed to *maximize* TSO pressure rise. However, in the Inglewood Vickers/Rindge formation, the goal was to achieve a *moderate* TSO pressure rise, on the order of several hundred psi or less. An *aggressive* TSO limits fracture dimensions, including both half-length and height. A *limited* TSO pressure rise thus enables greater fracture height growth, which is key for creating an effective connection across the laminated formation layers with the multiple-cluster limited entry perforation strategy employed.

A typical treatment pumping schedule is shown in Table 1, consisting of 100,000 lbs 16/30 Brady sand proppant pumped in 715 bbl slurry at 30 bpm. Maximum proppant loading is relatively high at 14 ppg to assist with creating effective fracture conductivity.

Table 1. General Inglewood Vickers/Rindge hydraulic fracture treatment design

Fracture Fluid	20° API Inglewood Crude
Injection Rate, bpm	30
Breakdown Injection, Bbl	125
Pad volume, mgal	10.5
1 ppg, clean mgal	2
2 ppg, clean mgal	2
4 ppg, clean mgal	2
6 ppg, clean mgal	2
8 ppg, clean mgal	2
10 ppg, clean mgal	2
12 ppg, clean mgal	2
14 ppg, clean mgal	1
Proppant Type	16/30 Brady
Total Proppant, Mlbs	100
Pad Fraction, %	35%
Total Clean Volume, bbl	610
Total Dirty Volume, bbl	715

TSO pressure rise is controlled by pad fraction. With relatively high oil leakoff and the desire to limit TSO pressure rise, the base case pad fraction is relatively large at 35% of total dirty volume. Note that because the wellbore is initially full of frac fluid (Inglewood oil), the pipe displacement volume of 100-200 bbl counts as pad, and thus the actual surface pad volume pumped is reduced by wellbore volume.

Rigorous fracture modeling is not feasible due to the complexities associated with the highly layered formation, an unknown pore pressure distribution, and the multiple cluster limited entry perforation strategy. Simplified modeling suggests that created propped half-lengths are on the order of 50 feet, with 3 psf prop concentration. General prop frac shutdown fluid efficiency is estimated to be in the range of 30% to 35%.

Frac Pack Treatment Behavior

Frac Pack Example. Stage 4 of well LAI1-412 (Vickers D-E interval) is used to illustrate typical frac pack behavior.

The perforations, consisting of 4 perf clusters of 4 holes each, were broken down with 125 bbl crude oil. Figure 5 shows an easy breakdown with little character. The rate stepdown at the end of the injection showed unexpectedly low perforation friction of 170 psi. Near-wellbore friction, a measure of fracture initiation complexity, was very low at 55 psi.

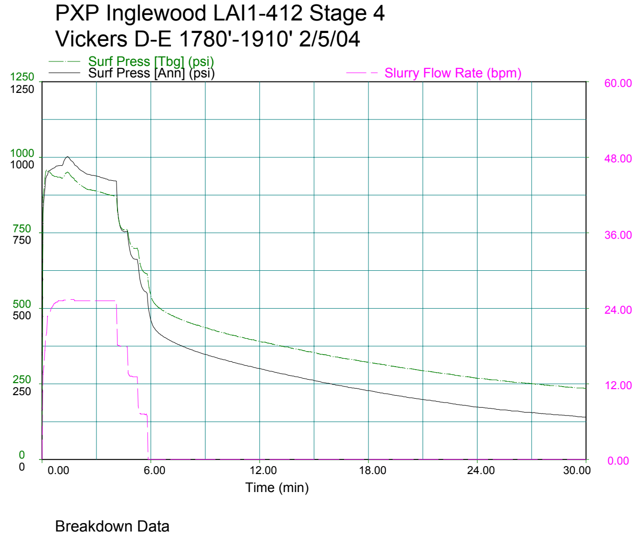

Figure 5. Breakdown injection data from LAI1-412 stage 4.

Fracture closure pressure was identified from the G-function plot shown in Figure 6. The fracture closure gradient of 0.59 psi/ft is about average for the Vickers, indicating neither significant pore pressure depletion or charging in this stage. Breakdown efficiency of 50% was somewhat greater than average. A pad fraction of 35% was planned.

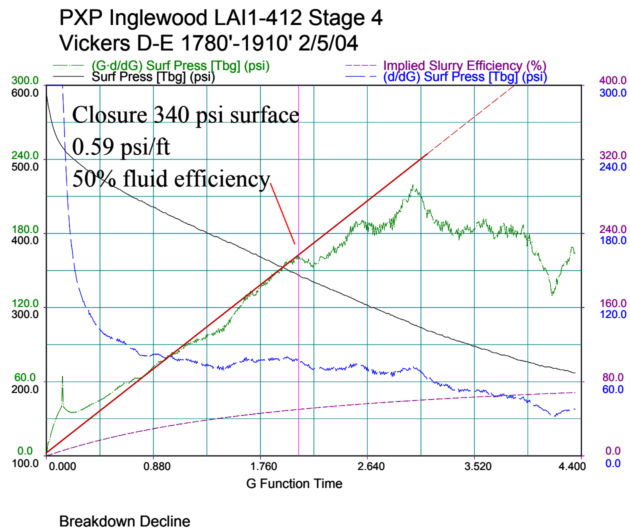

Figure 6. Pressure decline following the breakdown injection plotted against the dimensionless fluid loss function G to identify fracture closure.

The propped fracture treatment is shown in Figure 7. With injection down the 9-5/8" x 3-1/2" annulus, the static tubing pressure shows bottom hole pressure behavior. An inverted hydrostatic curve shows how annulus injection pressure changes relative to changes in hydrostatic. Injection rate is reduced to 5 bpm at 10 bbl before the end of the flush, and the tubing is opened to gravel pack the liner. The resulting sharp injection pressure increase at shutdown shows that a good liner pack-off was achieved. The planned treatment of 100,000 lbs 12/20 Brady sand at a maximum loading of 14 ppg was successfully placed.

The static string tubing pressure shows the impact of tip screenout. Net pressure increased from 200 psi after the breakdown to 385 psi at propped frac shutdown.

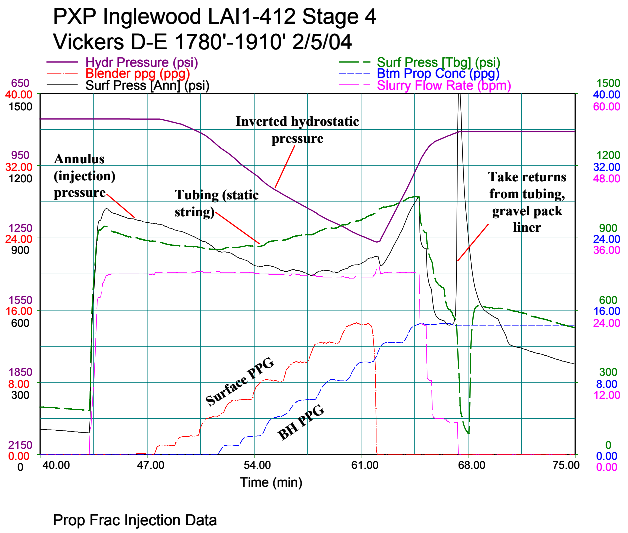

Figure 7. Basic prop frac injection data for LAI1-412 stage 4.

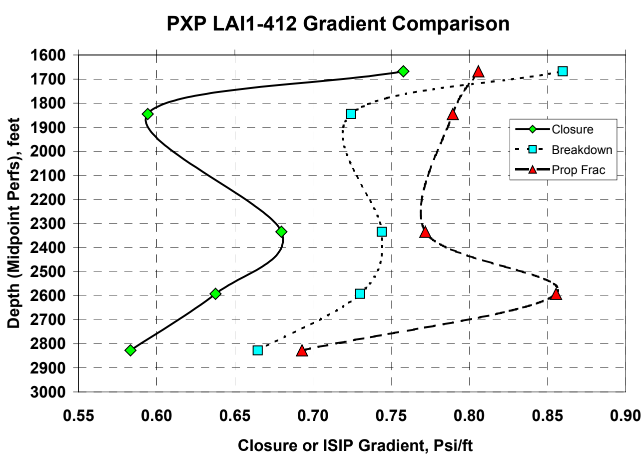

Figure 8. LAI1-412 fracture closure and ISIP gradient comparison.

Figure 8 compares fracture closure and ISIP gradients across the completion interval in well LAI1-412. This type of comparison plot provides from useful qualitative comparisons across the completion column and from well to well.

Fracture closure gradient provides an indirect indication of pore pressure gradient and thus waterflood support effectiveness. From simple plain strain analysis, fracture closure gradient changes by about two-thirds of the change in pore pressure gradient. Overall, fracture closure gradient was elevated in this well, indicating significant waterflood support (or overpressure) from adjoining injectors. Pore pressure appears to be especially charged in the top stage 5 (Vickers Alpha-C), which has the highest permeability and is the shallowest interval waterflooded. Note that the prop frac ISIP was lower than the breakdown ISIP for the top stage – indicating that net pressure dropped over the course of this treatment. Thus, it appears that the stage 5 fracture grew vertically or laterally into lower stress during the treatment.

Treatment Behavior Summary. Table 2 summarizes the fracture pressure analysis results from 53 fracture stages in 11 wells. Several observations can be made:

- The average fracture closure gradient is 0.58 psi/ft, with quite a large range from 0.46-0.76 psi/ft. Assuming that the initial undisturbed fracture closure gradient was uniform, this range implies a variation in pore pressure gradient of 0.45 psi/ft.
- The average observed perforation friction of 500 psi is close to the design value of 430 psi, suggesting that perforation effectiveness and vertical treatment distribution has been good.
- Average near-wellbore friction, a measure of fracture initiation complexity, is low at 105 psi. Consistent with this finding, significant bridging sensitivity was encountered only during several stages. Only one screenout attributable to formation bridging has occurred during about 60 stages, during a treatment with the coarser 12/20 proppant. The relatively viscous crude oil frac fluid has likely played a role in the apparent forgiving fracturing behavior.
- The average breakdown fluid efficiency of 40% is relatively high, likely due to the viscosity of the oil and relatively high reservoir pressure.
- The average net pressure rise from the breakdown to the prop frac is relatively modest at 120 psi. Thus, the pad fraction could likely be reduced from the average of 35%. However, the pad sizing strategy appears to be appropriate considering the goal of creating fracture height growth across the highly laminated formation, and the observed high productivity of the frac pack wells.

Table 2. Fracture pressure analysis results summary, based on data from 53 stages in 11 wells.

Parameter	Average	Range
Fracture Closure Gradient, psi/ft	0.58	0.46 – 0.76
Breakdown ISIP Gradient, psi/ft	0.70	0.57 – 0.86
Prop frac ISIP Gradient, psi/ft	0.75	0.54 – 0.87
Perforation Friction (30 bpm), psi	500	90 – 2300
Near-Wellbore Friction (30 bpm), psi	105	0 – 520
Breakdown Efficiency, %	40%	20% - 60%
Pad Fraction, %	35%	25% - 50%
Breakdown Net Pressure, psi	220	70 – 400
Prop Frac Net Pressure, psi	340	20 – 770

Frac Pack Well Production Performance

Compared with conventional cased hole gravel pack wells, the nine new frac pack wells have had greater well productivity, lower production decline rate, and larger reserves. Two remedial frac pack recompletions have more than doubled previous cased hole gravel pack well productivity.

After frac fluid (crude oil) load recovery, the average first month production from the nine new frac pack wells was 92 bopd + 1001 bwpd. For 2002 conventional cased hole gravel pack wells with similar geology and properties, the average was 45 bpod + 499 bwpd. Thus, the frac pack wells have been approximately twice as productive as the cased hole gravel pack wells. This productivity improvement was achieved despite limiting the frac pack completion intervals to about two-thirds of the cased hole gravel pack intervals, leaving the remaining interval for future addpay completions.

The production decline rates from the new frac pack wells have been significantly lower than observed from cased hole gravel pack completions. Cased hole gravel pack wells typically experience significant production decline and require HF acidizing stimulation as often as once a year, due to fines invasion into inefficiently packed perforation tunnels. The frac pack wells have proven to be resistant to this type of damage due to the much larger contact area between the formation sand and proppant.

The frac pack wells access greater oil reserves due to a more effective connection across the full completion column. In a cased hole gravel pack, access to the full pay column is limited by perforation economics and by limited perforation effectiveness. It is not economically or technically feasible to perforate many of the smaller sand laminations across the pay column. However, fracture height growth can effectively connect the fine laminations to the wellbore. Booked reserves have averaged 170,000 Bbl oil for the frac pack completions, compared with 95,000 Bbl oil for the cased hole gravel packs.

Two frac pack recompletions have been performed to date. One cased hole gravel pack had severe production decline to 25 bopd + 285 bwpd in two months, followed by liner failure and no production. After a remedial frac pack recompletion, stabilized production increased to 66 bopd + 550 bwpd. A second recompletion of a poorly performing cased hole gravel pack increased production rate from 18 bopd + 45 bwpd to 40 bopd + 167 bwpd.

To put these production rates in perspective, the current average production rate per well in the Inglewood field is 22 bopd + 692 bwpd.

Future Plans

Several new Vickers/Rindge wells have already been completed in 2004, and there are a number of addpay intervals in the 2003 wells that will also be completed. Adding fracture stages to an existing well is easily performed by simply latching a new completion stage liner on top of the existing liner.

Two recompletions have been successfully performed in cased hole gravel pack wells that had failed liners and/or poor productivity. With the current development strategy, the number of new infill well locations left at Inglewood is limited. Thus, if the current spacing strategy is not changed, the frac pack focus will likely shift from new wells to recompletions. There will also be a limited number of new wells drilled to replace wells that are too damaged to recomplete.

The frac pack recompletions of two wells in the Montebello field are currently in the planning stages. The zones targeted are at a similar depth to the Vickers/Rindge, and suffer from the same formation damage restrictions, and thus the technique has good potential at Montebello.

Finally, the frac pack completion of deeper formation intervals at Inglewood and at several urban drillsites is being evaluated.

Conclusions

- Frac packing in the Inglewood field provides the productivity of an open-hole completion without the high risk of gravel pack failure and loss of completion selectivity associated with conventional open hole gravel packing.
- Frac packing takes advantage of the wellbore stability and completion selectivity benefits of a cased hole completion, while avoiding the drawbacks of poor productivity, gravel pack failure risk, and high cost associated with conventional cased hole gravel packing.
- Compared with conventional cased hole gravel pack completions, the frac pack completions have twice the productivity, greater reserves, and significantly lower production decline rates.
- The novel use of simple downhole tools and straight crude oil fracture fluid allows multiple fracture stages to be performed economically, a key requirement for completing the thick Vickers/Rindge completion column.
- Completion costs using the multi-stage frac packing technique are on par with conventional open hole gravel packing and less than conventional cased hole gravel packing.
- Using crude oil as the fracture fluid minimizes or eliminates formation and proppant pack damage, makes fluid quality control simple, and has significant cost advantages over water-based crosslinked fluids.
- The multiple-cluster limited entry perforation strategy in combination with fracture height growth appears to effectively connect the highly laminated Vickers/Rindge formation to the wellbore.
- With several modifications to tools and procedures, the frac packing technique can be successfully used to recomplete conventional cased hole gravel pack completions with poor productivity or failed liners.

Acknowledgements

The authors would like to thank Plains Exploration and Production for permission to publish the presented data.

SI Metric Conversion Factors

in × 2.54*	E-03 = m
ft × 3.048*	E-01 = m
bbl × 1.589 872	E-01 = m^3
psi × 6.894 759	E-02 = bar

*Conversion factor is exact.