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Drilling and Completion Technologies to meet Challenges of Waxy, High Pour-Point Oil Production

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Summary

The Mangala field located in the sparsely populated, remote, undeveloped Thar Desert of NW India is the country's largest onshore producing oilfield. The field development includes 100 production (11 horizontal) and 50 plus water-injection wells, all directionally drilled from wellpads. The oil is waxy, low GOR crude, with a pour point above 40 Deg C. Wells are producing up to 12,000 bopd.

Drilling efforts were geared towards ways to develop the field with significant savings in both land and infrastructure costs while minimizing environmental impacts. A compact rig design coupled with a multi-well pad concept was the chosen solution. An innovative onshore pad drilling system which was implemented via a custom built Rapid Rig technology that allows fast, efficient drilling operations on multi-slot pads to enhance the success of the extensive drilling campaign.

Completion design challenges included; high CO_2 content, high wax appearance temperature, high pour point, high viscosities, possible emulsions, sand production and the need for artificial lift. Hot water was selected as the field wide medium for maintaining flow assurance. A completion design was developed, which allows hot water circulation inside the production annulus with a coiled tubing string run with the production tubing to maintain temperatures above pour point. The hot water supply is also used to provide power fluid to the annulus for jet pumping. Some wells have ESPs installed.

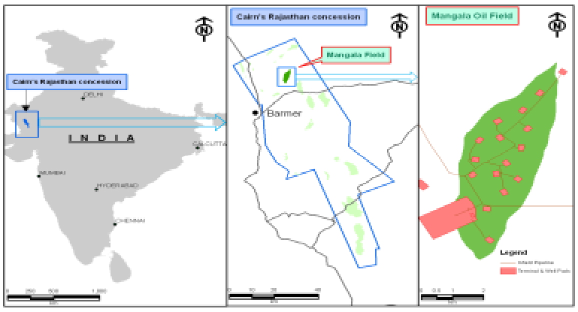
Specialized rig setup and well head systems were designed to allow simultaneous deployment of production tubing, heater string, chemical and instrument lines, and ESP cables. The wellhead design ensures that barrier policies are maintained throughout the well construction. Simultaneous running of all completion components warranted specially designed tubing running system and CT deployment system built into the completion rig. Jet pump power fluid exposes the completion to high loads which also made the completion design quite challenging.

This presentation describes the successful design and deployment of these innovative drilling and completions technologies. To date148 wells have been drilled and more than 100 completions have been deployed successfully and are delivering ~125,000 bopd from the field.

Keywords*: Innovative drilling and completion technology and practices, waxy, high pour point oil, heater strings*

Introduction

The Mangala Field is located in the Barmer Basin of northern state of Rajasthan, India – see Figure 1.



The basin is a Tertiary rift, predominantly consisting of Palaeocene-Eocene sediments. The Mangala Field was discovered in January 2004. Mangala was appraised in 2004 with the drilling of 6 wells, the acquisition of a 3D seismic survey, and major data gathering efforts involving core analysis, fluids, and well testing.

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The main reservoir unit in the Mangala Field is the Fatehgarh Group, consisting of interbedded sands and shales. The depth of the Mangala structural crest at the Fatehgarh level is ~600mSS and the oil-water contact (OWC) is at ~960mSS. Five reservoir units are recognized in the Fatehgarh Formation, named FM1 through to FM5 from the top downwards. FM1 and FM2 comprise the Upper Fatehgarh Formation and FM3, FM4 and FM5 form the Lower Fatehgarh Formation. Fatehgarh sand properties are excellent, with porosities of 21to 28% and an overall average permeability of ~5 Darcies.

Mangala reservoir contains waxy sweet crude oil with API gravity ranging from 20ºAPI near the OWC to 28ºAPI or higher in the oil column (average ~27ºAPI). The crude has an in-situ oil viscosity of between 9 and 22 centipoise (cP), with live oil wax appearance temperature (WAT) very close to reservoir temperature, which is 65°C at the OWC. The pour point is 40 to 45 degC. The field is being developed with a hot water (70 to 85 degC) flood. These attributes have a great influence on well completion design.

The Mangala Field development comprises a central process facility, 18 well pads and interconnecting production and water piping and utilities. Electric power and heated water are distributed to the wellpads from the central facility. Processed crude is exported 600 km via one of the longest heated pipelines in the world to refineries and export facilities on the coast. The field is producing 125,000 bbls of oil per day. Two adjacent fields were also developed to support the project; the Raageshwari gas field for plant process fuel, which required an extensive fracture stimulation program and the Thumbli acquifer to provide water for flow assurance and water flooding via 5 large capacity (50,000 bbls per day) ESP water wells.

A total of 148 wells were drilled from January 2009 to June 2011 with two drilling rigs, of which 100 are production wells and 48 injector wells. The 100 production wells were completed between March 2009 and August 2011 utilizing a dedicated completion rig.

Well Completion Design Issues

The primary well completion and flow assurance challenges for the Mangala wells are described below.

Oil viscosity

The crude oil viscosity ranges from 9 to 22 cP and this impacts the well productivity and results in an unfavorable oil/water mobility ratio. The reservoir simulations forecast early water cuts and the requirement of wells to be operated at high water cut for the majority of well life.

Wax content

The crude has a live oil wax appearance temperature at 65degC just below the reservoir temperature, and has significant wax content with up to 26wt%. Along with the high pour point, this property required the use of heated fluids during drilling and completion, the use of hot water in the water flood and the need for both hot water and/or electric heat tracing for flow assurance.

Pour point

The crude has a pour point of 40 to 45 degC. To keep the tubing contents at or above this temperature hot water is able to be circulated into the production annulus using a coiled tubing heater string run parallel with the production tubing. The returns are taken on an annulus outlet valve and connected back to the production system. A lot of simulation work was conducted using an industry standard stress analysis program that has thermal prediction capability to determine the optimum coil size, depth and circulation rates and temperatures. The simulations showed that an 1-1/2" coiled tubing string was required for the large size producer and a 1" coil string for the smaller producer run to a depth of 700 to 800m TVD. Field measurements once on production confirmed the initial simulations and designs were quite accurate.

The initial cost of providing this form of heating to the wellbore were small compared to other methods such as heater cables, due to the fact that the hot water was designed into the system for water flooding, flow assurance and jet pumping. The hot water power fluid is manifolded at the wellhead for this heater string or for jet pumping. Methods for running and installing this heater string were developed and the coil string is run in parallel with the tubing and chemical injection lines and ESP cable where required. The heater string is guided and protected using cross coupling clamps that also accommodate the other lines. The wellhead termination design is discussed further below.

Sand Potential

There is potential for sand production in the Fategarh sands as the unconfined compressive strengths within the sands were generally less than 1000psi and there is a low amount of cementing material in the sands. Extensive studies were conducted to evaluate the sand production potential for these wells. Data was available from 6 appraisal well tests which did not produce sand of any significance, albeit with clean oil and no water. Studies performed included; log derived and core strength based sanding prediction methods and models, field analog reviews and core perforating tests with water and oil. The result was that it was decided to initially complete and produce the deviated wells with a sand management strategy without installing sand face sand control. These wells are cased and perforated with 5 spf TCP guns. Drawdown was initially limited to 200 psi (based on the studies) and was increased in wells where sand was not observed.

The horizontal wells were completed with wire wrapped sand screens as these higher rate producers would be difficult to retrofit sand control in, ESPs were planned and there was a desire to have low exposure to sand production on these wells. Two horizontal wells have wire wrapped screens and swell packers and nine wells are completed with ICD screen systems with swell packers. Reference 1 provides further detail on the completions in these wells.

The field production system is designed to handle sand loadings up to 200 lbs per 1000bbls to enable the sand management production strategy.

To further reduce the risk of future sand production the wells drilled in the latter half of the development were completed with sand screens run in open hole across the reservoir. The production casing is set above the reservoir, the reservoir drilled with a synthetic drill in fluid and sand screens are installed, all with the drilling rig. The completion rig then installs the upper or cased part of the completion. Two different screens systems are used; either conventional wire wrapped screens or wire wrapped screens incorporating a sliding sleeve and swell packers. Reference 4 provides further information on this completion type.

Stand alone wire wrapped sand screens with a 300 micron aperture were selected as the sand screen to be used in these completions. The sands are very uniform, (uniformity coefficient less than 4) and contain very low amounts of fines. A number of methods were used to determine the screen type and aperture size including fractal particle size distribution analysis. (Reference 3)

Corrosion

The CO_2 content of the associated gas is between 15 to 25 mol %. There is no measured H2S. The base metallurgy for the completion material is 13Cr or equivalent materials. Production tubing is 13Cr 80ksi material. Casing material from production packer depth to and across the reservoir is 13Cr 80 ksi. The production casing above the packer is 1Cr 80 ksi material. This material was selected to provide a level of corrosion resistance above that of carbon steel as the production annulus is exposed to jet pump power fluid. To mitigate the power fluid water corrosivity, there is a tight specification on oxygen levels in the water and a corrosion inhibitor is also used in the water. Production Xmas trees are API6A FF class and wellheads API6A DD.

Emulsions

Laboratory studies indicated a high possibility of emulsions forming with viscosities up to 250 cP if the produced fluids were sheared. There was therefore concern that emulsions would form either in the jet pumps or ESPs. Initial designs for the ESPs and jetpumps incorporated the possibility of having to pump the high viscosity emulsions. To date emulsions have not been observed to form in the jet pumps or the ESPs.

Artificial lift

Artificial lift is a primary requirement of the well completions due to the viscous crude, early water cut arrival and a long predicted well life at high water cut. The main artificial lift mechanism selected for the deviated production wells was jet pumps. ESPs were selected for the higher rate horizontal wells.

Jet pumps

Jet pumps were selected because of the availability of high pressure hot water, as surface flow assurance plans were to flood the pipework with hot water (85degC) and the flow assurance benefit of jet pumping with hot water. Jet pumps are also sand tolerant and this fits with the sand management strategy. The jet pump scheme is to pump the power fluid down the production annulus and take the combined fluid returns up the tubing. This scheme was selected so that no well fluid was able to contact the casing (corrosion concerns) and there was no risk of crude gelling or waxing up the production annulus. The power fluid is available to the wellhead at 2500 psi and 70 to 80 degC. Each wellhead has a flow controller to control the power fluid rate. The power fluid water can either be directed down the annulus for jet pumping or to the heater string for hot water circulation when the well is on natural flow or is shut in, via a manifold at the wellhead. The central plant has 5 of 4 megawatt power fluid pumps each able to deliver 90,000 bbl per day of water. Jet pump power fluid ratios are between 0.5 and 1 bbl per reservoir bbl.

Two sizes of jet pumps are used (4-1/2” and 3-1/2”) and they are positioned in a sliding sleeve with a lock mandrel, above the production packer, and are readily installed and retrieved with slickline. Material is 17-4PH with tungsten carbide nozzles and throats.

ESPs

ESPs were selected for the horizontal wells as the jet pump was not capable of delivering the 10,000 plus bbl per day design rate for these wells. The ESPs for the horizontal wells are configured as follows;

- Downhole sensor package with intake and discharge pressure measurement
- Pump - 22 stage 675 OD 13Cr housing with high abrasion resistance design
- Seal – 513 OD 13Cr housing, tandem seal; double bag plus labyrinth
- Motor – 460 HP 13Cr housing
- Round No2 cable is used to the packer, the MLE comes with a factory molded packer penetrator
- Surface equipment is a 624 KVA variable speed drive with filtered pulse width modulation output
- Transformers – 700 KVA Phase shift stepdown transformer and step up transformer
- Specific cable clamps are used to accommodate the ESP cable, coiled tubing heater string and the chemical injection system

The ESP systems are run beneath an ESP packer.

Below the ESP system are a perforated joint, dual chemical injection mandrels, a tubing space out joint, and a stinger for a reservoir control valve. The reservoir control valve is mounted on a packer set below the ESP system and provides fluid loss control during well workovers. A sliding sleeve and nipple profile are run between the ESP and ESP packer to allow self flow or injection around the ESP.

Chemical Injection

With the potential for wax deposition, pour point concerns, potential for scale and corrosion concerns there was a requirement to provide downhole chemical injection. To provide surety of injection performance and alleviate possible chemical combination issues, two chemical injection mandrels are run in each well and are located below the sliding sleeve and above the production packer.

In ESP wells the mandrels are run below the ESP intake. 3/8” OD Alloy 825 was selected as the chemical injection line as the annulus is operated above 70 degC. Dual encapsulated lines are used. The chemical injection lines are able to be run continuous through the tubing hanger and terminate on the wellhead outlet.

Reservoir Performance

Reservoir performance characteristics used in the well design are; average GOR of 180scf/stb, bubble point pressure is very close to the reservoir pressure, the Fatehgarh formation has high porosity, high permeability oil wet sands, with forecasted productivity index (PI) of 100 bpd/psi for the FM3 sand and 70 bpd/psi for the FM4 sand. FM1, FM2 and FM5 sand productivities range from 1 to 30 bpd/psi.

Well types

The field has been developed with a combination of well types. Each individual well is completed in only one of the 5 sand units i.e. each sand unit has a specific set of well completions for both production and injection. The FM1, FM2 and FM5 sands are completed with both cased and perforated and open hole screen deviated wells. The FM3 and FM4 sands are more continuous and are completed with horizontal wells. Details of the horizontal well completions are provided further in the paper.

Approximately half of the production wells have 4-1/2" tubing and half 3-1/2" tubing to allow for varying well productivity. Of the production wells approximately half were completed as cased and perforated wells and as the field was developed the wells were completed with sand screens run in open hole across the reservoir as opposed to cased and perforate. A typical well schematic is shown in Figure attached.

All water injection wells are 4-1/2" tubingless completions, with an individual well perforated in only one of the five sand units.

Completion Operations

The wells were left suspended after drilling with brine in the casing. A wellbore cleanout operation is conducted prior to running the completion, where the well is cleaned and displaced to clean brine, either potassium carbonate or sodium formate. Cement evaluation logs are run either off line prior to the completion or during the completion.

For the cased and perforated wells, 4-1/2" 5 spf deep penetrating TCP guns with bottom mounted hydraulic release gun anchors are deployed with drill pipe or wireline prior to running the completion. The upper completion is installed above the TCP guns.

The main upper completion consists of:

- A flow control nipple
- A hydraulic set production packer (7" or 9-5/8")
- Two chemical injection subs with 3/8" Alloy 825 injection lines to surface
- Permanent gauge (some wells)
- A sliding sleeve
- 4-1/2" or 3-1/2" 13Cr80ksi tubing to surface
- A coiled tubing string is run parallel to the tubing string to at least 700 m to allow hot water circulation in the annulus for flow assurance.
- Tubing hanger provides termination for production tubing, heater string, chemical injection and instrument lines (and ESP cables on some wells)

For the ESP horizontal wells additional completion components are included as mentioned in the ESP section above.

In the case of the open hole screen wells, no TCP guns are run and the upper completion is as described above. These wells were suspended with bridge plugs set in the casing by the drilling rig.

The Xmas tree is installed after the rig skids to the next well. Perforating is conducted after the well is tied into the production system.

Completion Equipment

Two types of production packers are used, retrievable straight pull to release and cut mandrel to release, both are hydraulic set. Sliding sleeves have a guide channel incorporated to allow chemical injection and permanent gauge lines to transit the sleeve without exposure to the flow ports, this feature was necessary as jet pump power fluid is pumped into the tubing via this sleeve.

Permanent gauges are electric resonating diaphragm type. These systems have very high reliability, excellent stability and are robust; features desired in these jet pumped completions.

Chemical injection mandrels are a dual injection valve design.

Flow control profiles are non selective type. Profiles are located in the tubing hanger, sliding sleeve and nipple below the packer. For ESP wells additional profiles are in a sliding sleeve and nipple profile below the ESP packer.

Horizontal Well Description

There are 11 horizontal wells in the development. The horizontal reservoir sections range from 300 m to 800 m in length. The lower completion design for these horizontal wells uses a 300 micron stand-alone sand screen completion, with swell packers, in an 8½" hole. Inflow control devices are installed with the sand screens in 9 of the 11 horizontal wells. The screen completion is hung off in the production casing with a liner hanger and packer system. The 9-⅝" production casing was landed in the top of the reservoir and the 8-½" hole section drilled entirely in the reservoir with a synthetic based reservoir drill in fluid. A tangent section is provided in the 9-5/8" casing for the ESP. A robust design for the screen systems and liner hanger was used to mitigate any potential hole condition issues.

The sandface completion was installed immediately after drilling to TD by the drilling rig and comprises a reamer shoe, seal sub, 5-1/2" hybrid ICD screens with reactive oil swell open hole packers and low friction centralizers, a flapper valve for fluid loss control and a 9-5/8" x 7" liner hanger set in the production casing. An inner 2-7/8" washpipe was run with the screens. The open hole and screens were displaced to a low solids synthetic base fluid and the installation tool string retrieved. The fluid loss flapper was closed by a shifting tool on the wash pipe as the string was retrieved. The drill-in fluid was displaced from the casing with brine after confirming the flapper valve was closed.

The wells were suspended after installing the screen systems and the drilling rig moved off the well. The completion rig was then used to install the upper completion including an ESP. This completion has a reservoir control valve installed on a wireline set packer below the same type of upper completion as for the deviated production well.

ESPs were not initially installed in the first horizontal wells. Refer to attached figure for a schematic of the horizontal well completion prior to installation of the ESP.

Wellhead Systems

The wellhead systems used are multi-bowl compact type systems with proprietary connections. These systems are used because of the time and cost savings available with riser, BOP and Xmas tree installation and no waiting on cement time. The systems are particularly beneficial on pad drilling where multiple wells are drilled and completed in sequence. Three wellhead types are used in the Mangala field; water injector, light producer (3-1/2" tubing x 7" casing) and the heavy producer (4-1/2" tubing x 9-5/8" casing).

Well Pads

The wells are drilled from 18 well pads located across the field. Each well pad can accommodate 24 wells configured in two rows of 12. There are 6 cellars in a row with 2 wells in each cellar and the cellar dimensions are 14 m x 3 m x 5 m deep. The wellheads and Xmas trees are all below ground level with production and injection pipework to and from the wellhead also below ground for 22 m from the well cellars. Production and injection manifolds run above ground along the centre of the well pad and the two lines of well slots feed to the central manifold. Keeping the wellheads, Xmas trees and piping below ground level was a key design feature that allowed skiddable drilling and completion operations to be conducted with the Xmas trees and flowlines in place. This feature contributed significantly to reduced well construction times.

Rapid Drilling Rig

To execute the multi-pad drilling as way forward and after zeroing in and freezing the well designs for the development campaign, now it was necessary to contract the suitable rigs for execution. The tender was floated for 1000 – 1500 HP , new build, highly mobile, automated , fast moving rigs with allowable hours for rig moves between the wells specified clearly (before the pads got built) to major rig operators in the world. Also a set of key drivers were charted out for short listing the best suited rigs for the proposed development campaign.

The key drivers for the selection of the rigs for the development campaign were as follows:

- Rig should be designed to suit multi-well pad drilling
- Self deploying rigs with smaller footprint leading to ease of transport and faster on site rig up
- Rig designed to function with minimum crew

- Hazardous operations like pick up / lay down of tubular, making up connections etc. have been mechanized
- Rig designed as a cyber rig – mechanized controls

Figure: Rapid Rig deployed on Mangala Pads

Based on the above key drivers and after detailed techno-commercial evaluation of the offers, the Cairn drilling team settled for the NOV custom built highly mobile skid mounted "Super singles" of 1000HP and AC driven Rapid rigs offered by Weatherford. This rig has drilled to the limit and delivered best drilling performance benchmarked to similar well types in the world in the Rushmore database. The requirement for rig selection was to have unique rigs compatible with the multi-pad concept which are able to drill all development wells with utmost cost saving. Slot to slot rig move and spud was achieved in 4-6 hours and interpad rig moves in 60 hours

Completion Rig

The rig used for completion operations was a newly built self propelled LCI-550 with a specially designed substructure and skidding system for these well pads. The rig sits on the skidding system which allows the rig to be moved along the line of well cellars and the rig is able to move with pipe in the derrick. The rig substructure enables BOP tree installation via integrally mounted rails under the rig floor. This was not without a design challenge as a 13-5/8" BOP is required due to the size of the tubing hanger in the production wells. Tanks and pumps remain in a fixed position on a pad and flexible lines are used to connect to the rig and well. These features made rig move times between wells very efficient and well to well move times are 2 hours or less. A shear test for the BOP shear ram was conducted at the BOP manufacturing facility to prove the shear of the full completion string including 4-1/2 tubing, chemical injection lines, ESP cable and coiled tubing.

A specially designed tubing handling and guide system for the coiled tubing and control lines was developed for the rig. An offshore style system was the platform used which incorporates; Flush mounted bowl, air operated slips and air operated guide/pusher arms for the coiled tubing heater string and chemical injection lines and ESP cable. Modifications to the slips were required to enlarge the opened running diameter to allow the made up completion clamps to drift the slips. All modifications were trialed in the workshop prior to the first completion being run. All production tubing is 13Cr 80ksi material and non-marking slips and tongs and JAM system is used for tubular make up.

The coiled tubing heater string is run from a trailer mounted spooler located near the rig. A specific goose neck to support the coiled tubing was manufactured and fitted to the rig mast for the project. Completion times range between 3 and 5.5 days and have shown consistent improvement.

Most pleasing of all aspects of the completion campaign was the safety performance, with no LTIs during the campaign. NPT for the 100 completions was less than 1%. Contributing to this performance was; a strong safety culture, an active STOP program run with full support of the crews, internal and external safety audits and adherence to pre-job safety talks and JSA usage.

Conclusions

The challenge of developing and producing waxy, high pour point oil was successfully overcome by the use of innovative drilling and completion technologies. Mangala field production wells were successfully drilled and completed as per design and produce at design rates.

Proving and testing the completion components and service equipment prior to the first well contributed to the success especially given the unusual combination of running coiled tubing with the production tubing and ancillary lines.

Implementing such a campaign in a remote environment with no oilfield infrastructure is feasible with good planning and commitment from all parties involved.

The success was due to a strong combined team comprising multidisciplinary team and service company personnel.

Figure: Completed Mangala Wellpad with Wells in Cellar

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Figures: Deviated and Horizontal Well Completion