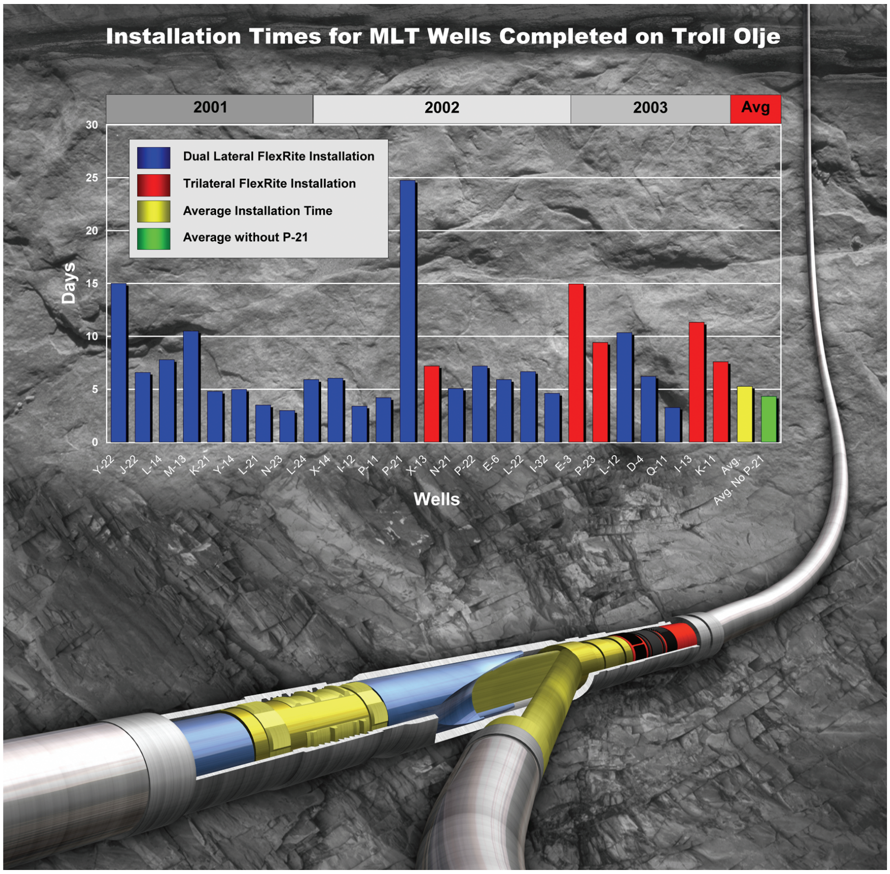
Boon or bane: 10 years of multilateral completions

Jim Oberkircher, Ray Smith, Halliburton Energy Services
Ian Thackwray, Woodside Energy Ltd

THE OIL INDUSTRY has successfully drilled and completed hundreds of complex multilateral fields and has developed whole fields with the technology. Yet the industry's perception of multilateral is that the technology is risky.



The average installation time for multilateral wells in the Troll field is approximately five days, with several multilateral wells completed in 3-4 days.

RISK AND VALUE

From a reliability perspective, multilateral can be subdivided into three evolutionary eras. The early days, from 1993 to 1997, offered the first-generation systems of considerable complexity and inherent mechanical risk. The second-generation systems evolved from 1997 to 2000 and the established Level 3 and Level 4 super-systems became dominant. Large-scale implementation of the super-systems occurred in 2000-2003.

An attempt was made in mid 2002 to assess the reliability of multilateral installations from a global perspective for multilateral systems, since 1993, of Level 3 and above complexity to estimate the risk of failure for permutations of multiple laterals per well or successive multilateral wells and derive a total risked cost for construction of the options under consideration.

Statistics for 2001 and 2002 show only four wells experienced any failure of the 208 wells installed in all areas, giving a 1.9% failure rate, well down from the 4.9% failure rate of 1993-2002. From 2001 through mid 2003, 27 multilateral wells were installed in floater applications with only one failure, resulting in a 3.7% failure rate. Continued success in this arena has led to the installation of subsea tri-lateral wells.

Publicly published case studies for complete multilateral well failures during production are rare. There may well also be failed junctions downhole of which operators are unaware. Principal multilateral production risks leading to failure include collapse of junction liner, massive sand influx at junction, and continuous sand influx at the junction.

BOON: TROLL OLJE FIELD

Troll Olje is part of the Troll gas field, located in the Norwegian sector of the North Sea in 315-340 m of water. Norsk Hydro is developing a 22- 26-m oil zone of the Troll Olje oil province and a 13-m oil zone of the Troll Olje gas province to recover 1.33 billion barrels of oil.

As of May 2003, 89 wells had been drilled and completed, of which 23 were multilateral wells, including two tri-laterals. The wells are tied-in to two Troll floating production platforms.

The multilateral well concept was introduced on Troll Olje to increase the total drainage area from the existing sub-sea template structures. Further development of Troll Olje includes another 10-15 multilateral wells. These multilateral wells contribute another estimated 90 MMbbl of reserves. Drilling these targets with conventional wells instead would require another six wellhead templates.

The tri-lateral X-13 well produces 22,000 b/d from the longest total production screen section in the Troll field, 6,580 m. The draw-down of 0.5 bars is lower than that in traditional horizontal wells, delaying gas break through. This well alone will add 1.5 MMbbl of oil to Troll Olje's total output.

The project is regarded as such a success that at least two more tri-lateral wells are planned, and a suitable candidate area to install a quad-lateral has been identified.

Development of Troll Olje will involve drilling at least 32 multilateral wells. The multilateral solution will recover more oil from the four-well template than conventional monobores due to the greater density of wells that can be placed in the low permeability sands. Greater well density creates better drainage and makes it economic to drain sands that have a permeability as low as 100 millidarcy.

BOON: ORINOCO FIELD

Petrozuata, CA, a joint venture company of **Conoco Orinoco Inc** and **Petroleos de Venezuela SA (PDVSA)**, is developing extra heavy crude in a 74,000-acre block in the Zuata field in the western portion of the Faja del Orinoco in Venezuela.

It is one of the world's largest multilateral developments. Each well is designed and geosteered to assure efficient reservoir access based on 3D seismic, vertical stratigraphic well control and detailed geologic facies maps.

Petrozuata drilled multilateral wells to develop portions of the reservoir that could be reached from a single surface location to increase well rates while maintaining manageable lateral length.

Using a combination of well types, designs can be tailored to access the oil in several adjacent areas with fewer pads and wells than the original design would have required.

The relative cost of drilling and completing a nine-rib fishbone well was 1.18 times the cost of a single lateral well. The relative costs for other wells were 1.58 times for stacked dual lateral, 1.67 times for gullwing dual lateral, and 2.54 times for the more complex crow's foot triple lateral. Petrozuata has found that the increased production rates justify the investment.

Multilateral well designs have increased well productivity and estimated ultimate recovery per well, while decreasing cost per barrel of oil developed in the Petrozuata operation.

BANE: EAST WILMINGTON FIELD

The Long Beach Unit of the East Wilmington Oil Field is just offshore at the Southwestern Extension of the Los Angeles Basin of California. The B743A well, designed to tap reserves with two horizontal laterals in the F and X sands of this field, was to serve as a replacement for two damaged wells that had been abandoned.

As this well utilized an existing, abandoned wellbore, the original well was plugged back with cement and the lower lateral initiated with sidetrack from a section-milled portion of the casing. After a sidetrack due to geologic reasons, the well was successfully landed and completed. Operations then began on the second, upper lateral.

A packer was set across the desired kick-off point. The first attempt to set the packer was unsuccessful, and, after several attempts to retrieve it, the packer was pushed to the top of the 4 1/2-in. liner top of the first lateral.

A new packer was set, and a portion of the casing milled out. A 6 1/8-in.. hole was drilled to total depth. The well was changed out to a sized salt fluid, and the whipstock was pulled.

A 6 ⅛-in. clean-out and reaming assembly was run and eventually parted, leaving a fish in the hole. After cleaning out to the top of the fish, the completion was run in the hole. The lateral was cemented and the liner top was washed over with some difficulty.

After several unsuccessful fishing trips to clean out debris, it was decided to rig-down the more expensive drilling rig and use a completions rig to finish operations. The sized salt mud was swapped over for fresh water and a downhole video camera run. Cement returns were visible but neither the 4 ½-in. liner top nor the window was visible.

Several attempts to re-enter the lateral were unsuccessful. It was decided to run the production equipment to ascertain if the check valve on the injection packer was functioning properly.

The check valve prevented cement from entering the complete interval but would allow some production without retrieval. The electronic submersible pump failed after only two days due to sand content with only marginal oil being produced.

After the pump was pulled, part of the junction collapsed and the upper lateral could not be re-entered. Fishing operations began, but these caused the junction to lose integrity and cement and shale started to slough into the well.

A suspected split in the casing exacerbated problems, and a decision was made to abandon both laterals. Debris management was a major factor in the untimely demise of this project.

Once trouble began, it continued to escalate until the project was abandoned. Improvements in the procedures and methodology have to be implemented to improve this system for this application.

The average cost of two conventional wells in this area is roughly $700,000 each for a total cost of $1.4 million.

The multilateral well was expected to come in around $1 million for a potential savings of $400,000. The final cost of the failed multilateral was $2 million.

THE FUTURE

The industry has yet to vigorously pursue many applications for multilaterals, such as in exploration wells, mitigating geologic risks, and navigating non-heterogeneous reservoirs. Exploration targets could be easily delineated with laterals, while maintaining access to the mainbore.

The ability to re-drill to other positions if the original target is not as anticipated can minimize the impact of geologic uncertainty.

Putting in more "straws," effectively draining otherwise bypassed reserves, can reduce the effects of smaller-than-expected reservoir drainage patterns.

Niche markets, such as coal bed methane fields, will require dewatering and gas production from increased access through the coal seams.

Cost-effectively multiplying the potential reservoir penetrations, i.e., taking a "shotgun" approach to reservoir development, can reduce geologic and reservoir risk in some cases.

The amalgamation of emerging technologies, including intelligent completions, expandable tubulars, advanced drilling and production systems, real-time information flow, and downhole factories, through MLT demonstrates the quantum leap of this technology.

Boon or bane? As with any technology the answer can be both, and history has proved this out. The question is whether the industry can learn the lessons from both the successes and the failures. Perceived risks may by high, but the pay-off is much greater.

REFERENCE

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