

Hydraulically Isolated Multilaterals Optimizing the Subsea Well Installation A Case Study

Cliff Hogg, Baker Oil Tools

This paper was prepared for presentation at the AADE 2005 National Technical Conference and Exhibition, held at the Wyndam Greenspoint in Houston, Texas, April 5-7, 2005. This conference was sponsored by the Houston Chapter of the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individuals listed as author/s of this work.

Abstract

This paper describes the recent installation of the world's first sub-sea, level 6, hydraulically isolated multilateral system, offshore Ukraine. The drivers leading to the selected system are covered along with a discussion of the installation itself. Finally, lessons learned and plans going forward are discussed.

Among the primary challenges and drivers of this project was the need to increase gas production by intersecting separate sections of a carbonate reservoir while at the same time, reducing the capital cost and maintenance expenses associated with the installation of a satellite platform. Also required was a multilateral system capable of providing hydraulic integrity at the junction in order to eliminate gas migration concerns. Additionally, problematic shales necessitated the use of a mechanically sound junction system with high collapse ratings. The winter freezing risk common to the Sea of Azov and the impact of this on the sub sea wellhead and multilateral selection were also a factor in the final multilateral selection.

Introduction

A multilateral well solution must offer benefits and advantages over conventional well systems in order to play a role in the Petroleum industry.

Typically, when considering the installation of a multilateral system, the operator begins with the reservoir analysis. The focus is on either increasing production or improving the ultimate reservoir recovery. Both of these

goals can often be achieved as a result of the increased reservoir exposure possible or the increased number of reservoir targets that can be accessed with a multilateral.

Economic benefits can also be realized from a decrease in tangible and intangible installation costs of the multilateral as compared to two separate single wells. Drilling costs, casing requirements, and downhole completion equipment can all be cost optimized when creating multiple wellbores in a single well. Often times, the perception is that these cost savings will only be seen in deep wells or wells with significant drilling difficulties. Certainly these types of wells can offer significant savings but even shallow wells can realize reduced costs when utilizing a multilateral approach. Wellhead costs, rig mobilization expenses, pipeline and surface production gathering systems all can be reduced in the typical multilateral installation.

Along with the potential production increases and the cost savings achieved during installation, the incremental risk of installation and production must be included as part of the initial analysis. Fortunately, today's generation of multilateral systems have evolved into low risk, well-proven systems requiring minimal trips and few moving parts downhole. As a result, the reliability and confidence in the multilateral industry has continued to grow and expand into new markets with new opportunities. One such opportunity was the recent multilateral installation in the Ukrainian portion of the Sea of Azov. Providing both increased production and installation cost savings, the multilateral installation provided a technically advantageous solution to the operator requirements.

Sea of Azov, Ukraine

The Sea of Azov is an inland sea of approximately 14,000 square miles in size located between Ukraine and Russia (Figure 1). Extremely shallow in depth with depths no greater than 20 meters, up to 80% of the offshore area is considered to be hydrocarbon rich with initial hydrocarbon resources assessed at 2.3 billion barrels oil equivalent. Ukraine, at one time the largest natural gas importer in the world, has within the past few years worked aggressively to develop these oil and gas reserves and lessen their dependence on imports.

In order to expedite the offshore exploration, the Ukrainian government in late 2002 provided a substantial monetary investment with the Ukrainian state oil & gas company. This investment was specifically earmarked for existing, new technologies that could enhance production and was intended for near term field development. A consulting firm was hired by the operator to help identify potential projects along with the complementary technologies that could be utilized. As a result of this search, candidate wells utilizing sub sea wellheads in conjunction with multilateral systems were selected as the technology of choice.

Logistical, Environmental and Reservoir Challenges of the Candidate Well

Water depth at the well location was only 11 meters. The operator had previously utilized production platforms with six to eight slots in other offshore fields. However, the reservoir target in this particular location was of limited size, requiring fewer wellbores and therefore making it impossible to justify economically a surface platform. Additionally, the frozen surface conditions of the Sea of Azov can create potential risks for any surface structures exposed to these crushing forces. Also, ships

and fishing trawlers travel this area in abundance and are a continuous threat of collision with any surface facility.

The location of the well presented additional environmental difficulties from a scheduling standpoint. During the winter months, the surface water freezes solid and can potentially crush and sink drilling rigs. It became imperative therefore that any work performed would have to be reliable enough to ensure that the drilling rig would be ready to move off the well by the winter freeze. Therefore risk and contingency plans became an even more vital part of the multilateral planning process.

Targeted production for this project was a well fractured, carbonate gas zone located at an approximate depth of 1,000 meters. Typical production from similar gas reservoirs in the Azov Sea produce 150-200,000 m³/day. No condensate production was anticipated for the wellbore. Reservoir and geologic analysis indicated that two horizontal wells could provide the necessary reservoir exposure and drainage to effectively produce the majority of the reservoir.

Designing the Well

With the ability to deplete this field from only two wellbores, the need for an expensive satellite production platform was eliminated and instead, a shallow water, sub sea wellhead and tree was selected for the project. In addition to the economic savings, this selection also minimized the potential hazards resulting from the frozen surface in the winters and the fishing and trawling activities in the summer months.

In order to further optimize the economics of the project and gain access to the new technology funds being offered, several multilateral systems were investigated with the intention of combining the two individual wellbores into a single parent wellbore to surface. With both wellbores producing from the same reservoir, differential pressure and cross flow concerns between the two wells were not

an issue and there was no need to produce the two laterals independently from one another. It was imperative however that the junction point of the multilateral provide hydraulic isolation from the formation in order to eliminate potential water infiltration or gas channeling from the fractured carbonates. Also, the lateral wellbores themselves needed the ability to utilize External Casing Packers as part of the liner configuration to address these water and gas influx and channeling issues. Finally, in order to avoid the extreme winter months and frozen surfaces, the multilateral system needed to be available immediately and also needed to be simplistic and low risk enough to avoid any possible installation delays that could jeopardize the drilling rig.

Selecting the Optimum Multilateral System

With multilateral technology continuing to grow and evolve, there are now a large number of multilateral systems being provided by a handful of service companies. With the gas channeling and water influx concerns at the junction however, many of these existing ML systems that provide little or no support or isolation at the junction point were immediately eliminated from consideration. Eventually, the focus began to center on splitter-type ML systems that offered hydraulically isolated junctions and low risk installations.

A splitter type multilateral system is a manufactured junction with two or more legs extending below and is typically, although not always, utilized in new well systems. The junction is carried downhole as part of the intermediate liner string and hung off in the open hole. After cementing the splitter junction in place, the legs can then be independently drilled and completed. The resulting junction assembly provides hydraulic isolation and mechanical support without the need for straddle tubing assemblies to provide this isolation feature.

This feature was considered advantageous in this project since both zones were to produce from the same reservoir and flow was to be commingled. By not requiring a straddled completion across the junction, the overall equipment cost and number of trips required for installation could be minimized. Additionally, by not having to run straddle tubular completions to provide isolation, choke points for the gas production could be eliminated.

There are several types of multilateral splitter systems currently available to the oil industry, designed to fit a variety of challenges. Some are most suitable for high-pressure requirements. Others utilize reformable technology and attempt to minimize hole size requirements while providing maximum casing sizes downhole.

In this Ukrainian installation, target depth for the junction installation was only 615 meters. With this shallow depth, minimizing the open hole size at the junction point was not a primary consideration. Of more concern was the potential hazards created with the surface ice if the drilling rig was forced to stay on location longer than expected as a result of installation difficulties. The primary driver therefore in choosing a specific splitter technology was selecting a system with minimal installation risks and complexities.

The splitter system chosen utilized two 5-1/2" casing legs hung below a common 5-1/2" casing string. Requiring no downhole milling, washovers or reformations, the system is run and landed in a 13-3/8" open hole section. After cementing the junction in place, each leg can then be drilled out to 4-3/4" open hole, liner run, and the casing perforated, stimulated, and completed as desired.

While satisfied with the features of the system, the operator did have concerns with the required 4-3/4" hole size into the reservoir. Modern drilling technology is still lagging somewhat in this region and drilling 4-3/4" holes in past wells had resulted in low rates of penetration. An

inquiry was made therefore about using the same type system but in a larger size utilizing two 7" casing legs that could be run in a 16" or 17-1/2" open hole section. As previously mentioned, junction depth was shallow and large hole size was not a primary concern. With winter less than seven months out at this point however, the operator did not have the time to wait for the manufacturing of the larger size system and eventually chose to utilize the existing 5-1/2" sized splitter which was available for immediate usage. In order to minimize the amount of time spent drilling with a 4-3/4" assembly however, the well was designed such that the casing shoe on only one of the 5-1/2" legs would need to be drilled out and additional hole drilled. The other 5-1/2" leg would be run as part of the splitter junction with enough length to extend directly into the previously drilled 8-1/2" hole to the target reservoir.

Installing the Multilateral Well

In late October of 2003, the operator began drilling the multilateral candidate well in the Sea of Azov. Due to this late spud date, the 13-3/8" casing was not set to depth until late November as the temperatures began dropping and the sea began freezing. Rather than jeopardize the operation, a decision was made to temporarily abandon the project until the following Spring.

As spring arrived, the rig was moved back on location and drilling recommenced. With the 13-3/8" casing shoe at 450 meters, an 8-1/2" hole was drilled from the casing shoe to a depth of 1,222 meters into the target formation. Inclination at the shoe was vertical but the hole inclination reached 57 degrees at TD. Drilling was difficult due to the presence of virgin, gumbo like shales in this interval that resulted in the loss of one BHA assembly and sidetracks on four separate occasions. With the 8-1/2" hole drilled to target, a hole opener was then run in order to increase the hole size immediately below the 13-3/8"

casing shoe to a 12-1/4" diameter for a depth of 200 meters. This increased hole size was necessary in order to accommodate the running and cementing of the 11-3/4" OD splitter assembly.

With the mainbore hole drilled, the splitter junction was prepared for installation downhole. Below the mainbore leg of the junction approximately 580 meters of additional 5-1/2" casing along with a conventional float valve/landing collar/Pack off bushing cementing assembly were run. The other leg of the junction, also 5-1/2" diameter, was run with a cement bull nose shoe resulting in complete and conventional well control capabilities for the junction system during run in and installation. Finally, run above the splitter junction was an external casing packer and a mud line hanger assembly.

The splitter junction does not require a specific downhole orientation in order to function but may require a specific orientation to best optimize the intended drilling program. The splitter assembly contains a vertical orientation profile that can be utilized to determine orientation of the two casing legs through the utilization of MWD or a gyro survey. In this particular shallow application however, the orientation at surface was noted and the casing scribed as it was run to ensure that the correct orientation was maintained.

With the splitter junction in position, and the assembly hung off in the wellhead, the junction along with the 5-1/2" casing was cemented in place. The splitter can be cemented down casing with a conventional liner wiper plug/cementing assembly if desired. For this particular application however with the external casing packer below the mud line hanger, a decision was made to cement the assembly utilizing an inner cement string stabbed into a drillable pack off bushing in the 5-1/2" mainbore production casing. A faulty meter led to less displacement than was required to bump the plug and continued pressure was therefore required to prevent u-tubing of the cement. After

the cement had set, the tubing was pulled back into the polished bore receptacle above the splitter. With pressure applied down the cement string, the external casing packer was successfully inflated and the cementing string pulled from the well.

Once cemented in place, the 5-1/2" mainbore production casing was tubing conveyed perforated and the well was drawn down for a variety of drawdown and shut in tests. With the well flowing well enough to eliminate an acid stimulation, plans were made to begin drilling and completion operations for the lateral 5-1/2" leg of the multilateral. A bridge plug was run and installed in the 5-1/2" mainbore just above the perforations to isolate production during drilling and completion operations in the upper lateral.

Drilling and Completing the Lateral Wellbore

In order to guide the drilling assemblies into the lateral leg of the splitter, a diverter assembly was run on pipe and landed in the junction. This diverter tool contained a collet assembly designed to land in a corresponding collet profile of the splitter and provides depth verification for the assembly when landing. Furthermore, when running multiple splitters in a single well, these collet profiles can be sized differently in each junction allowing diverters to only land in the intended junction and therefore providing continued re-entry access into all wellbore legs. Once landed on depth, the diverter assembly was rotated from surface until a dog sub on the diverter assembly engaged in the vertical profile of the splitter thereby ensuring that the diverter face was correctly oriented into the lateral leg. This orientation profile in the splitter is the same profile that can be utilized to determine the orientation of the splitter junction itself.

As a final step in setting the diverter, set down weight was applied shearing the diverter from the running assembly. Additionally, the diverter has a packing element

that is energized with the set down weight and is rated for 7,500 psi from above. This allows for later fracturing or acidizing of the lateral zone in situations where a bridge plug has not been run in the mainbore. With the diverter landed and verified, and the packing element energized, the running tool was retrieved from the well and the drilling BHA rigged up.

The lateral drilling assembly consisted of a 4-3/4" bit, stabilizer, 3.74" mud motor, and 2-7/8" heavy weight drill pipe crossing over to 5" drill pipe to surface. Upon reaching the junction, the drilling bottom hole assembly engaged against the diverter and initially appeared unable to drift into the lateral leg of the splitter. After working rotation of the drill pipe down to the bottom hole assembly however, the bit and drilling assembly successfully slid into the lateral shoe and tagged against the cement shoe.

On this initial drilling trip, the operator wanted to drill at least 40 meters of formation before retrieving the assembly. The MWD Survey tool planned for utilization in the second bottom hole drilling assembly will not work properly within 3 meters of adjoining metals such as the mainbore leg of the multilateral well. It was felt that 40 meters distance was enough to ensure that this 3-meter standoff was achieved. The shoe was milled out and 40 meters of formation were drilled over the next 3-1/2 hours.

During a subsequent bit change out trip, difficulties were encountered passing the drilling assembly back through the splitter assembly. After numerous attempts at entry, the drilling assembly was pulled and an impression block was run. Indications were that the diverter was correctly positioned but a decision was made to retrieve and inspect the diverter nevertheless. After retrieving on drill pipe, the diverter showed no signs of failure, incorrect positioning or damage to the diverter face. A backup diverter was run and the 4-3/4" hole cleaned down to the current 900 meter TD.

With the second diverter in place, the drilling assembly was still unable to pass through the junction area. Eventually, two of the 10 foot drilling collars were removed from the bottom hole assembly. Additionally, the drill pipe was lowered and then stopped rapidly in order to create harmonics downhole and help ease the bit past the diverter assembly. These operations were successful as the bit slid into the lateral leg on the second attempt. It now appears that the rigidity of the assembly in combination with the large OD of the collars was the primary reason for the difficulties. Standoff between the diverter and the splitter ID may have played a role as well in the drift difficulties.

With the drilling assembly now back on bottom, additional hole was drilled until the final 1,075 meter desired depth was achieved. During this additional drilling, several additional bit trips were made and the assemblies were able to drift through the junction without difficulty. Drilling penetration rates were extremely slow with average rates of only 1 meter per hour as the lateral bore reached a 42-degree inclination.

With the lateral leg now drilled to target depth, an attempt was made to log the 4-3/4" open hole portion of the wellbore. Unfortunately, the logging tools were unable to reach this depth as a result of tight spots in the 2-7/8" drill pipe. The drill pipe was therefore pulled and replaced with the 3-1/2" production casing string crossing over to 5-1/2" drill pipe to surface. With this tubing string in place, the lateral hole was successfully logged.

Difficulties were encountered when attempting to pull this 3-1/2" string back to surface after the logging operations. The tubing became stuck a meter and a half off bottom and free point testing indicated that the sticking point was in the beginning of the build section.

A decision was made to pump cement down the existing, stuck in hole, 3-1/2" casing string. Once cemented, the 3-1/2" shoe was found to leak at a pressure

of 110 Bars. A solid steel plug was therefore pumped to the existing shoe and 6 meters of additional cement spotted above this plug. With the liner now cemented in place, a string shot was run on wire line and the tubing backed off at a depth of 632 meters. This placed the top of the 3-1/2" liner in the lateral leg portion of the splitter assembly, therefore not impeding flow or re-entry capabilities in the mainbore side of the multilateral. A Liner Hanger/Packer assembly was then run on tubing, and set in the lateral leg with the new assembly tying back into the existing 3-1/2" casing stub.

Once the Liner Hanger/Packer had been successfully set, the lateral zone was usefully perforated with wire line conveyed 54mm TCP guns. At this point, multilateral operations were suspended while the lateral reservoir was subjected to shut-in and drawdown tests.

With the lateral installed and completed, the lateral bore diverter installed in the splitter junction was ready to be retrieved. This was accomplished with a retrieving tool run in on tubing and designed to wash over or envelope the diverter face. Once engaged, the diverter snapped into an inner profile of the retrieving tool and the entire assembly was recovered with a straight pull release. An additional trip was then required in order to retrieve the previously installed mainbore bridge plug.

Final Completion

With both legs of the multilateral completed, preparations for the final completion began. The 13-3/8" tieback was run, landed and tested followed by the 9-5/8" tieback. After nipping up the BOP, a scraper run was made in the 9-5/8" casing to a depth of 580 meters in preparation for the final completion installation. The final completion consisted of a hydraulic packer set at a depth of 578 meters in the 9-5/8" casing along with a surface controlled subsurface safety valve and 3-1/2" production tubing hung back to the tubing hanger (Figure 2).

Once the downhole completion was installed, the final stage of the multilateral installation involved removing the BOPs, installing and testing the Sub Sea Tree, and connection of the production umbilical.

Final Results

The multilateral well was spudded in late 2003 and finally completed in July of 2004 with a suspension of operations during the winter of 2003/2004. Target zones in the reservoir were successfully drilled and completed as designed. Some delays were encountered as a result of drilling issues, tight holes, and drift difficulties but all challenges were successfully overcome. Constant cooperation and communication between the operator and the service companies were key in the development and implementation of these contingency plans that allowed for a successful installation.

The well continues to produce commingled gas from both legs of the multilateral well. Production from this multilateral was last reported at approximately 600,000 m³/day. Typical production from conventional wells in this area average around 150,000 m³/day.

Conclusions and Lessons Learned

Overall, the multilateral project was a success. Not every aspect of the well installation went off perfectly but personnel, plans and equipment were available to ensure that the difficulties did not become insurmountable. Lessons learned from this first installation in the region will be utilized to further optimized the multilateral planning and installation for future applications.

Although not unexpected based on past experiences, the slow penetration rate when drilling with a 4-3/4" bit is still a cause for concern. In considering future multilateral installations, the operator will most likely consider one of two options. Firstly, utilize the same splitter system type but in a 7" x 7" size that was

unavailable for this project due to timing issues.

Alternately, the operator is also considering other types of multilaterals such as a mechanically supported junction utilizing a straddle assembly to provide hydraulic isolation of the junction. This option would also allow for 7" production casing and eliminate the need for 4-3/4" drilling activities.

Difficulties in passing the bit assembly into the lateral bore also merit further discussion. In review, it appears the combination of a rigid drilling BHA with some standoff between the diverter and splitter ID led to difficulties passing the drill bit into the lateral leg. The interaction between these components will be more closely monitored in the future and existing tools potentially modified.

Representing the first multilateral in the region for an operator with minimal multilateral experience, this project demonstrated that it is feasible and economically advantageous to consider today's generation of multilateral systems for a wide variety of wellbore environments. Certainly not the deepest installation or most complex from a completion standpoint, this project nevertheless provided economic benefits to the operator in terms of both production increases and initial cost savings. Cooperation and communication between the operator and service company again proved to be a key component in the eventual success of this project.

Nomenclature

BHA = *bottom hole assembly*
BOP = *blowout preventer*
ML = *Multilateral*
MWD = *Measurement while drilling*
ROP = *drilling rate of penetration*
TD = *total depth*



Fig. 1- The Sea of Azov is bordered by Ukraine and Russia and just north of the Black Sea

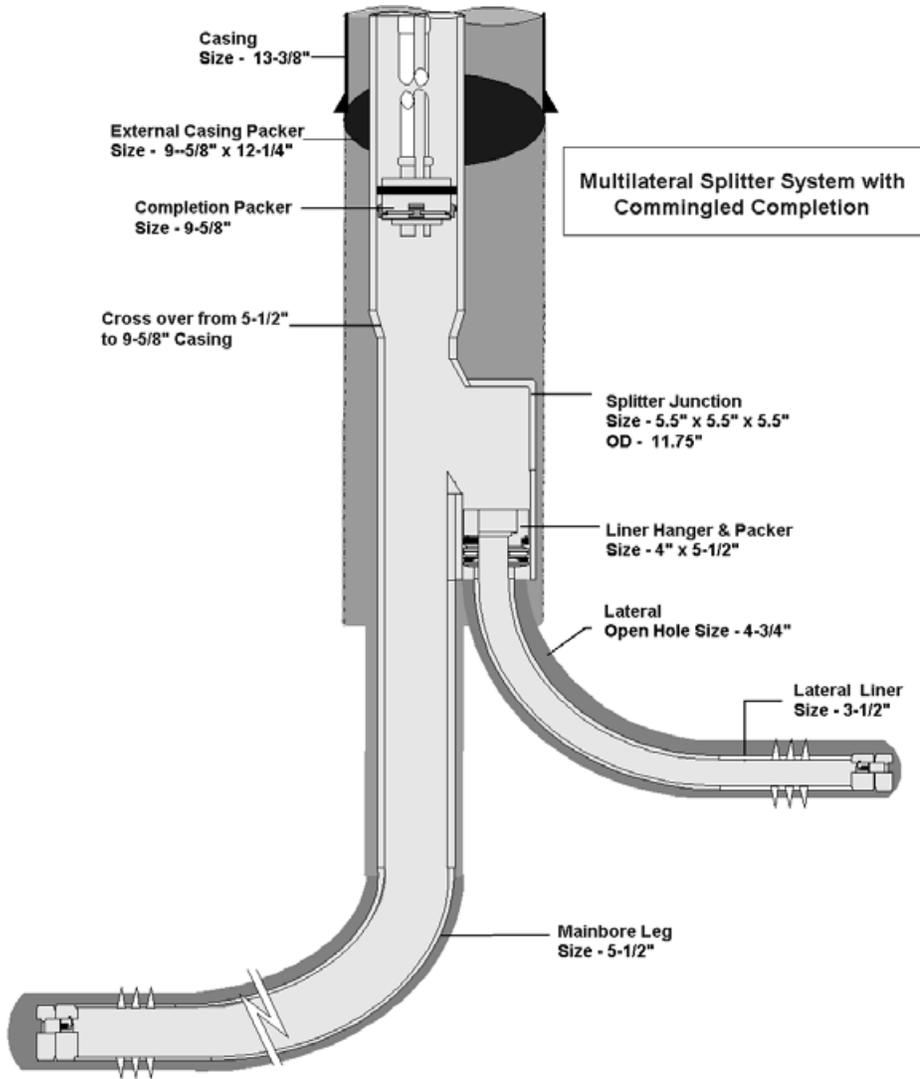


Fig. 2- Splitter final completion providing hydraulic isolation at the junction and commingled production