

Monobore design can benefit high-rate gas wells

MONOBORE COMPLETION techniques are becoming more standard in the industry today.

“Monobore” describes a completion in which the ID of the completion string is the same size from top to bottom.

As the industry moves toward high rate gas completions, many of which will rely on 9 $\frac{1}{2}$ -in. tubing, the benefits of running monobore completions are more readily attained.

These benefits fall into two main categories: well production and remedial operations.

PRODUCTION BENEFITS

The most obvious benefit associated with increased tubing size is greater per well deliverability.

This reduces the number of wellbores required to drain a reservoir efficiently.

For offshore projects in particular, this can mean a reduction in the number of platforms required.

Reducing the number of wellbores decreases both operational and maintenance expenses for the field. Long-term reliability is increased as monobore completions tend to be less complex than standard completions and the elimination of internal restrictions reduces areas of gas turbulence.

To demonstrate the well production benefits, a hypothetical high-rate gas reservoir was constructed from which inflow performance models were run to determine the number of wellbores needed at project's beginning and end to meet field deliverability requirements of 1.6 bcf/d.

Simulations were run for 5 $\frac{1}{2}$ -in., 7-in., and 9 $\frac{1}{2}$ -in. completions. In addition, drilling and completion costs were estimated and accounted for increased rig capacity needed for running a 9 $\frac{1}{2}$ -in. completion string. The estimate accounted for no topside structures or equipment other than wellheads and Christmas trees.

The results of combining these two estimates are shown in Figure 1.

REMEDIAL ADVANTAGES

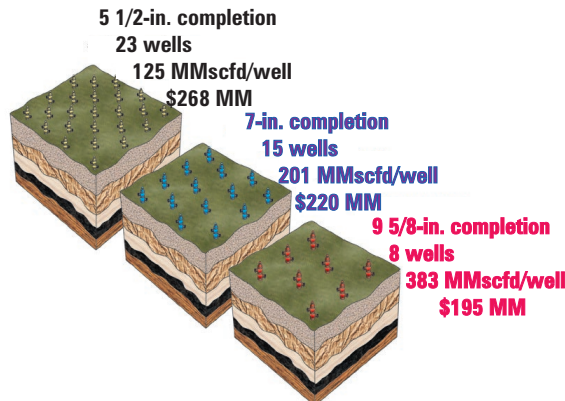
The remedial advantages of monobores may not be realized until later in the field's life.

Running service and intervention equipment is made easier by the elimination of restrictions. In addition, one has full access to the liner top to allow easier squeeze or mechanical isolation. By increasing tubing size—thus reducing the frictional pressure drop during production—it is possible to delay the need to bring compression on line as well.

Thus, the value of increasing tubing size can reach into the millions of dollars for infrastructure, wellbore construction, and maintenance alone.

However, the dramatically decreased field development time that running 9 $\frac{1}{2}$ -in. monobores provides cannot be ignored. This shortened time to first production will allow operators to either

Figure 1: Cost simulations



produce first gas much quicker or delay starting the project by that same amount of time.

This factor can be the most significant impact on the net present value of a large project. For many projects, this increase in value more than pays for the increase in cost associated with using larger tubing.

The original high-rate gas completions were run by Mobil Oil Indonesia in their Arun field in 1991 and 1992 and are shown in Figure 2 as the “Original Completion Concept.”

This project called for a 3-trip comple-

tion system where a 10-in. liner was set and an intermediate tubing string was landed in the tieback receptacle (TBR) below the liner hanger. This portion landed static seals into the TBR with an upper polished bore receptacle (PBR) above a compression-set packer.

The third trip landed a set of dynamic production seals into the PBR and was tied back to surface.

Eleven completions of this type were put into service with no equipment failures since that time while delivering higher than predicted production.

DESIGN IMPROVEMENTS

Responding to a growing industry demand for an improved 9 $\frac{1}{2}$ -in. completion design, one service company undertook a design program to develop an integrated large monobore completion system. Considering the success of the Arun field development, this concept was used as a starting point.

At the time of the Arun project there was no 9 $\frac{1}{2}$ -in. tubing retrievable safety valve (TRSV) available. With production rates in excess of 200 MMscfd anticipated, the potential impact any loss of well control will have is magnified.

Environmental, health, and economic consequences of such an event made the development and installation of a reliable 9 $\frac{1}{2}$ -in. TRSV critical.

The second area identified for improvement was the elimination of the upper dynamic seal stack and the associated PBR.

Doing so has several advantages. First, the completion will be less complicated and a potential leak path is eliminated.

In addition, the third trip required to land the upper completion is no longer necessary. Completion cost will be lower as well as both pieces of equipment will be unnecessary.

To realize these benefits, a packer capable of withstanding all compressive and tensile loads on the tubing string during production, stimulation, or well kill operations is needed.

Referring to Figure 3, the latest evolution of the 9⁵/₈-in. monobore completion system is shown as the "Improved Completion Concept." After setting the 9⁵/₈-in. liner, the rest of the completion can be run on the second trip. After clean up, the well can be produced.

In order to develop equipment with sufficient reliability, it is critical that a thorough design verification test program be conducted. This ensures the reliability of newly developed equipment and provides an industry appropriate (rather than operator or project specific) solution.

EQUIPMENT DETAILS

A 9⁵/₈-in. wellhead plug incorporating a non-bearing no-go has been developed. The no-go feature allows a significantly larger bore while decreasing its OD. This feature, along with its short length, can potentially reduce the size and therefore cost of the riser, tree, associated valves and the BOP stack.

A back pressure valve has also been developed that uses the same service equipment as the wellhead plug. A larger flow area through this valve is available due to the wellhead plug's increased ID. Both the wellhead plug and back pressure valve have been successfully run downhole.

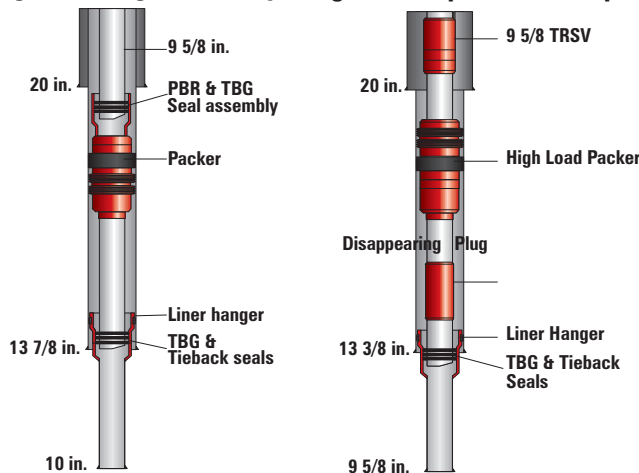
The liner hanger selected for the 9⁵/₈-in. completion system uses unique slip geometry that greatly reduces the stress imparted to the production casing.

Unlike standard cone and wedge type systems, increasing the load capacity of this hanger does not alter the OD/ID ratio of the tool. Thus, the tool can be modified to accept a variety of load conditions.

Depending on whether liner rotation is required, this liner hanger can be set either mechanically or hydraulically. The design was used successfully in Arun, has a considerable field history and a battery of successful design verification tests for the hanger, liner wiper plugs, drill pipe darts and landing collars.

Perhaps the most significant feature of the slim 9⁵/₈-in. TRSV developed for the system is its capability to be run inside

Figure 2: Original concept **Figure 3: Improved concept**



13³/₈-in. production casing. This geometry is a direct result of cooperative design efforts between the service company and major operators.

The original design called for a 14¹/₂-in. OD for a 9⁵/₈-in. valve, which is unacceptable to the operator community.

To get the reduced OD/ID ratio, the use of contoured flapper technology is needed. While a standard, proven platform was chosen to base the design upon, three new features have been developed to provide reliability and performance.

First, dual rod piston actuation with independent metal-to-metal sealing was selected to improve the performance of the valve.

Second, a mechanism combining a compression spring and beam spring has been used to close the flapper. Due to its weight, the use of a standard torsion spring closure mechanism is not desirable. This modification allowed the design team to produce a more robust hinge configuration for the flapper/seat.

Lastly, flapper supports have been placed in pockets machined into the seat that provide a greater bearing area. These supports prevent flapper deflection under load. This valve design has been successfully high-rate gas slam tested at rates in excess of 400 MMscfd and endurance tested to simulate a 20-year life cycle. Seven of these valves have been run to date in the Gulf of Mexico.

The hydraulic-set packer developed to eliminate the upper PBR and seal assembly incorporates 360° bi-directional slips. This minimizes both the stress

imparted and any slip invasion in the production casing.

The slip is located above the multi-durometer element package, which prevents compressive loads from being transmitted through the elements as a burst load into the production casing. Since there is no slip below the element, ramped element technology is used to set the element package.

Instead of using compressive force to seal the element to the production casing the element is forced up onto a portion of the mandrel with an increased OD. This axial force seals the annulus and prevents element relaxation over time. The packer design also allows for retrieval in the event of an emergency while providing permanent packer performance and reliability.

Testing to ISO V0 requirements were scheduled to be completed in late March. Three methods are available to set the high load packer, two of which require no intervention.

The first of these (and easiest) is to apply pressure against the liner or formation to set the packer. If that is not possible, a disappearing plug has been developed. The barrier is comprised of a salt/sand matrix.

By running a fill device above the matrix one can run in with the tubing closed. When infused with water or some completion fluids the matrix dissolves and can be expended by applied pressure from the surface, allowing full access to the liner.

The third option is a retrievable bridge plug. The design selected is currently available and has an extensive field history.

FOCUS ON COSTS

Natural gas is becoming a larger portion of many nations' energy strategy. Thus, the pressure to deliver gas supplies safely, reliably, and more economically is growing.

The benefits associated with monobore completions in general, and large monobore completions in particular, will help realize this goal. ■