MAJOR PROJECT

ON

MULTILATERAL WELL COMPLETION AND ITS APPLICATIONS

SUBMITTED BY

PARREKH YASH CHIRAG (R010206037)

&

SHAH PINKESH VIJAY (R010206053)

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MULTILATERAL WELL COMPLETION AND ITS APPLICATIONS

A thesis submitted in partial fulfillment of the requirements for the Degree of

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(Applied Petroleum Engineering)

Submitted By

PAREKH YASH CHIRAG

R010206037

B.Tech APE Upstream

SHAH PINKESH VIJAY

R010206053

B.Tech APE Upstream

Under the guidance of

Dr. Pradeep Joshi

HOD

Geology & Earth science

Approved

....

15/5/10

DEAN

College of Engineering

University of Petroleum & Energy Studies

Dehradun

May, 2010

CERTIFICATE

This is to certify that the work contained in this thesis titled "MULTILATERAL WELL COMPLETION & IT'S APPLICATIONS" has been carried out by PAREKH YASH CHIRAG and SHAH PINKESH VIJAY under my supervision in partial fulfillment of the requirements for degree of Bachelor of Technology and has not been submitted elsewhere for a degree.

Dr. PRADEEP JOSHI

HOD

GEOLOGY & EARTH SCIENCE

15 May 2010

Date

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List of Figures

Table of Contents

Abstract

An abstract of the thesis of Parekh Yash Chirag & Shah Pinkesh Vijay for the Bachelor of Technology Degree in Applied Petroleum Engineering presented May 2010.

Title: Multilateral Well Completion and its Applications

A multilateral well is a single well with one or more wellbore branches radiating from the main borehole. It may be an exploration well, an infill development well or a reentry into an existing well. It may be as simple as a vertical wellbore with one sidetrack or as complex as a horizontal, extended-reach well with multiple lateral and sublateral branches.

A horizontal well has a better chance of intersecting more fractures than a vertical well, but there is a limit to how far horizontal wells can be drilled. By drilling other laterals from the same wellbore, twice the number of fractures can often be exposed at a much lower cost than drilling long horizontal sections or another well. Horizontal fan wells and their related branches usually target the same reservoir interval. The goal of this type of well is to increase production rates, improve hydrocarbon recovery and maximize production from that zone. Multilateral wells allow costs to be amortized over several reservoir penetrations and in some cases have eliminated the need for infill drilling. In heterogeneous reservoirs with layers, compartments or randomly oriented natural fractures, more pockets of oil and gas can be exploited and an increased number of fractures can be intersected by drilling multilateral wells.

In anisotropic formations with unknown directions of preferred permeability, drilling multibranched wells can reduce economic risk. Lateral branches can balance the nonuniform productivity or injectivity of different layers.

Multilateral wells provide extensive information about the reservoir and can be useful for exploration and formation evaluation in addition to their capability to efficiently and economically drain reservoirs.

The classification of multilateral completion is done on the basis of level of complexity. On comparing all the multilateral technologies Level 6 was the most advance and had the highest level of complexity. As the functionality of the multilateral improves, the risk and complexity of the system increase as well. The increased amount of equipment and procedures involved along

with the cumulative risk can make it difficult to economically justify many of the wells for which multilaterals have been considered. On this basis Level 1 to 5 were designed.

In order to improve the economical viability of these high-end systems, a new type of multilateral was required that not only advanced the functionality of the system to a new level, but also did so with an overall decrease in risk as compared to current complex multilateral completions.

As defined by the industry's multilateral focus group, TAML, a Level 6 multilateral provides hydraulic integrity at the junction area and does so not through the use of completion "straddle" equipment, but instead creates the hydraulic integrity at the casing point itself. By not depending upon this additional completion equipment for the seal, the potential inner diameter of the junction is increased, leading to a wider variety of equipment that can be run during the completion phase and later during re-entry applications. In addition, the larger ID of a Level 6 system allows for maximum production flow from each leg without creating a choke situation.

Chapter 1

History of Multilateral Technology

As with many advances in petroleum technology, the first multilateral well was accomplished by a Soviet drilling engineer. Alexander Mikhailovich Grigoryan (Father of Multilateral Technology) was born during 1914 in Baku, the capital of today's Republic of Azerbaijan, then a principal center of oil production. After graduation from high school, he worked as a driller's assistant, became an apprentice and ultimately graduated as a petroleum engineer in 1939 from Azerbaijan Industrial Institute.

Alexander Mikhailovich

During most of the Soviet era, the official policy was to produce as much oil as possible, since it was a strategic commodity and one of the few exports that could be exchanged for grain and other consumer goods. High quotas were imposed on drillers to bore as many holes as they could. The prevailing attitude was that the more holes drilled, the greater the likelihood of successfully tapping a reservoir and thereby achieving greater production.

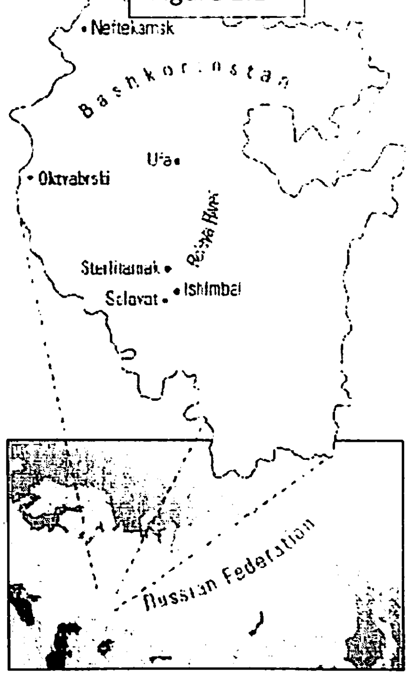
Grigoryan was an innovator and inventor. Upon graduation, he began working as an oilfield driller and soon was attached to the Ministry of Oil. Believing that "he could produce more oil by following a known oil sand than by merely penetrating it with a number of boreholes", he drilled one of the world's first directional wells—Baku 1385—in 1941, nearly 20 years before anyone else attempted such a feat. Without a whipstock or a rotating drill-string, he used a down-hole hydraulic motor to penetrate oil-bearing rock and significantly expand reservoir exposure and production. It was the first time that a turbodrill was used for both vertical and horizontal sections of a borehole.

Grigoryan's pioneering work in horizontal drilling technology led to scores of other successful horizontal wells across the USSR and his elevation to department head at the All-Union Scientific-Research Institute for Drilling Technology (VNIIBT). He was not, however, satisfied with these accomplishments. He developed a new borehole sidetrack kickoff technique and a device for stabilizing and controlling curvature without deflectors. But all of these innovations were in preparation for his major contribution to drilling technology.

Inspired by the theoretical work of American scientist L. Yuren, who maintained that increased production could be achieved by increasing borehole diameter in the productive zone, Grigoryan took the theory a step further and proposed branching the borehole in the productive zone to increase surface exposure, "just as a tree's roots extend its exposure to the soil." In 1949, he took his ideas to noted Russian scientist K. Tsarevich, who confirmed that branching a well in a productive zone with uniform rock permeability should yield an increase in oil production in proportion to the number of branches.

Grigoryan put this new theory into practice in the Bashkiria field complex in what is today Bashkortostan, Russia. There, in 1953, he used down-hole turbodrill without rotating drillstrings to drill Well 66/45, the first multilateral well. Bashkiria field complex lies in southern Bashkortostan Late Carboniferous carbonate reefs built by rugose corals trap vast oil reserves. The fields had been in production since before 1930, and most wells produced low volumes at the time Grigoryan first attempted a multilateral well.

Figure 1.1



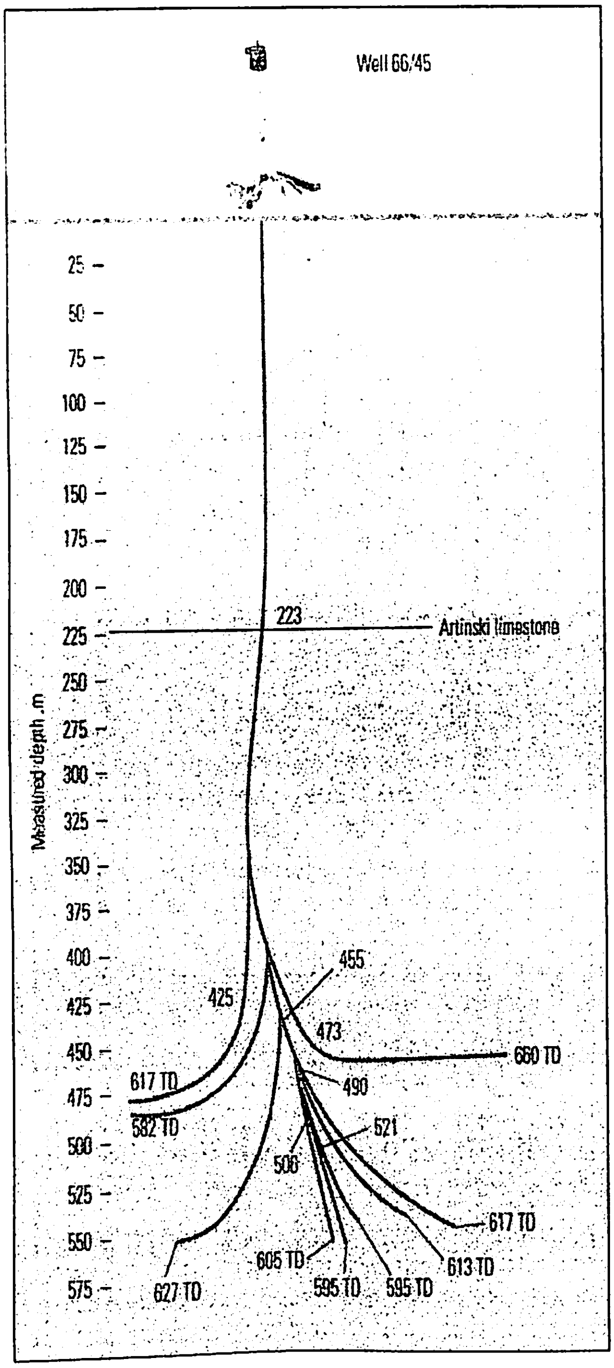
^ Map of Bashkortostan inset in a map of the Russian Federation. The first multilateral wells were drilled in the Ishimbai region in the south-central region of the republic.

Grigoryan chose to drill Well 66/45 in Bashkiria's Ishimbai nefti field, which evidenced an interval of Artinskian carbonate rocks with good reservoir properties and wide area distribution. His target was the Akavassky horizon, an interval that ranged from 10 to 60 m [33 to 197 ft] thick. Grigoryan drilled the main bore to a total depth of 575 meters [1886 ft], just above the pay zone. From that point, he drilled nine branches from the open borehole without cement bridges or whipstocks; the window configuration enabled insertion of tools on drillpipe into the sidetracks without instrumentation. He drilled by touch alone, "slanting away from the vertical bore like roots of a tree, each branch extending for 80 to 300 meters [262 to 984 ft] in different directions into the producing horizon."

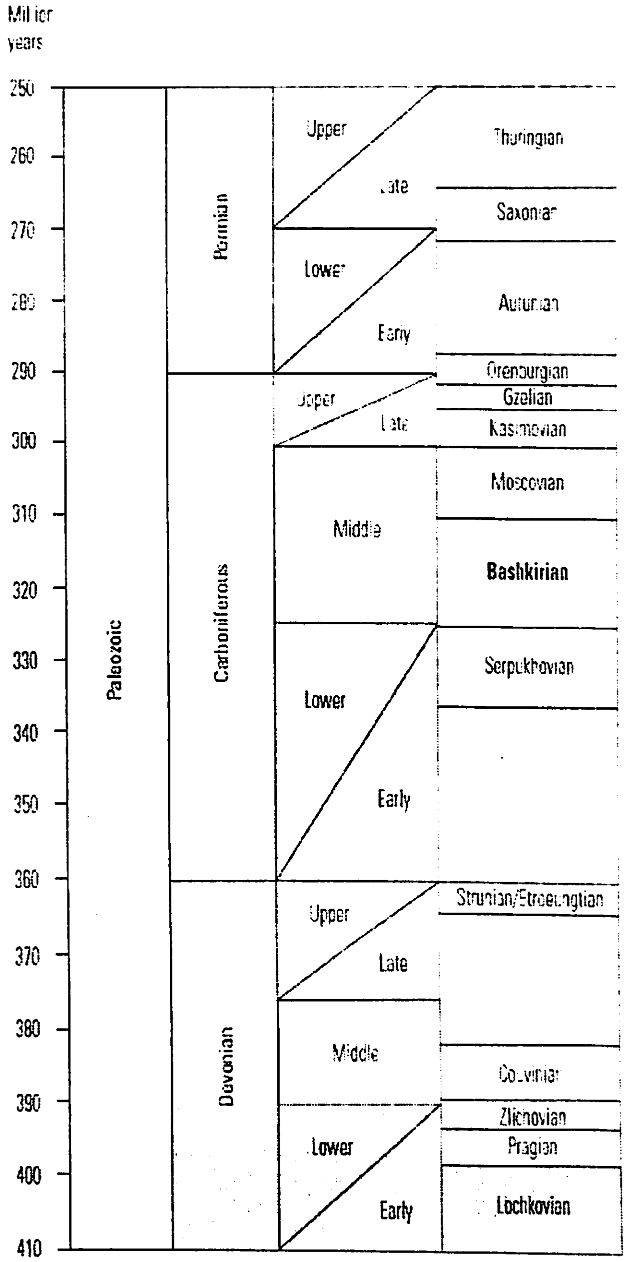
Grigoryan allowed the drill bit to follow the pay zone into the most productive zones, the branches curving automatically to the planned trajectory. Drilling speed and penetration rate depended entirely on the hardness of the rock and downhole motor capabilities. When completed, Well 66/45 had nine producing laterals with a maximum horizontal reach from kickoff point of 136 meters [447 ft] and a total drainage of 322 meters [1056 ft].

Compared with other wells in the same field, 66/45 penetrated 5.5 times the pay thickness. Its drilling cost was 1.5 times more expensive, but it produced 17 times more oil at 755 B/D [120 m^3/d] versus the typical 44 B/D [7 m^3/d].

Under the auspices of the Soviet Oil Industry Ministry, another 110 multilateral wells were drilled in Russian oil fields over the next 27 years, with Grigoryan drilling 30 of them himself. About 50 of these first multilaterals were exploratory; the remainder was for delineation of reefs and channel structures.



^ An early multilateral well. Drilled in Bashkiria, now Bashkortostan, one of Russia's most prolific regions, the first multilateral well had nine lateral branches that tapped the Ishimbainefti field reservoir.



^ Bashkiria stratigraphic column. The first multilateral well target was within the Akavassky horizon, in the center of the lower Bashkirian sequence, middle Carboniferous era. [Adapted from Haq BU and Van Eysinga FWB: Geological Time Table, 4th ed. Amsterdam, The Netherlands: Elsevier Science BV, 1994.]

Figure 1.2

Chapter 2

Introduction

In 1953, a unique oil well called simply 66/45 was drilled with turbodrills in the Bashkiria field near Bashkortostan, Russia. This well ultimately had nine lateral branches from a main borehole that increased exposure to the pay zone by 5.5 times and production by 17-fold, yet the cost was only 1.5 times that of a conventional well.

It was the world's first truly multilateral well, although rudimentary attempts at multilaterals had been made since the 1930s. Under the auspices of the Soviet Oil Industry Ministry, another 110 such wells were drilled in Russian oil fields over the next 27 years. Not until ARCO drilled the K-142 dual-lateral well in New Mexico's Empire field in 1980, did another operator attempt such a feat, for multilaterals were simply too difficult and too risky, requiring substantial investment of both time and technology.

A multilateral well is a single well with one or more wellbore branches radiating from the main borehole. It may be an exploration well, an infill development well or a reentry into an existing well. It may be as simple as a vertical wellbore with one sidetrack or as complex as a horizontal, extended-reach well with multiple lateral and sublateral branches. General multilateral configurations include multibranched wells, forked wells, wells with several laterals branching from one horizontal main wellbore well with several laterals branching from one vertical main wellbore, wells with stacked laterals, and wells with dual-opposing laterals. These wells generally represent two basic types: vertically staggered laterals and horizontally spread laterals in fan, spine-and-rib or dual-opposing T shapes.

Vertically staggered wells usually target several different producing horizons to increase production rates and improve recovery from multiple zones by commingling production. Wells in the Austin Chalk play in Texas (USA) are typically of this type. Their production is a function of the number of natural fractures that the wellbore encounters. A horizontal well has a better chance of intersecting more fractures than a vertical well, but there is a limit to how far horizontal wells can be drilled. By drilling other laterals from the same wellbore, twice the number of fractures can often be exposed at a much lower cost than drilling long horizontal sections or another well. Horizontal fan wells and their related branches usually target the same reservoir interval. The goal of this type of well is to increase production rates, improve hydrocarbon recovery and maximize production from that zone.

Multiple thin formation layers can be drained by varying the inclination and vertical depth of each drain hole. In a naturally fractured rock with an unknown or variable fracture orientation, a fan configuration can improve the odds of encountering fractures and completing an economic well. If the fracture orientation is known, however, a dual-opposing T wells can double the length of lateral wellbore exposure within the zone. In non-fractured, matrix-permeability reservoirs, the spine-and-rib design reduces the tendency to cone water. Lateral branches are sometimes curved around existing wells to keep horizontal wellbores from interfering with a vertical well's production.

Multilateral Well Configurations

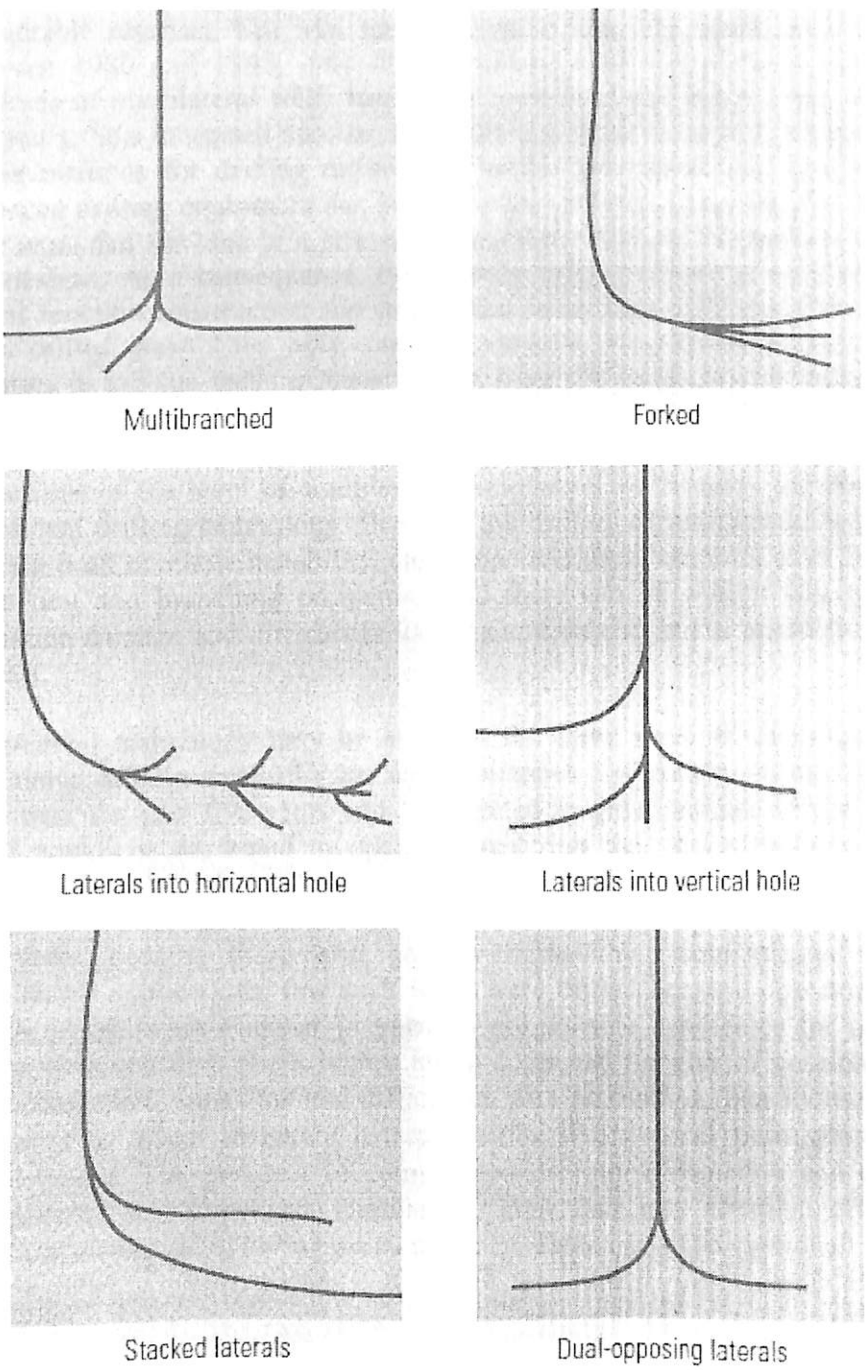


Figure 2.1

^ Common forms of multilateral wells in use today. Wellbore design and configuration are dictated by specific formation and reservoir drainage requirements.

A successful multilateral well that replaces several vertical wellbores can reduce overall drilling and completion costs, increase production and provide more efficient drainage of a reservoir. Furthermore, multilaterals can make reservoir management more efficient and help increase recoverable reserves. But why has it taken so long for multilateral technology to catch on? Between 1980 and 1995, only 45 multilateral well completions were reported; since 1995, hundreds of multilateral wells have been completed and many more are planned over the next few years. This increased number of multilateral wells is related to a rapid sequence of advances in the methods for drilling multilateral wells—directional and horizontal drilling techniques advanced drilling equipment and coiled tubing drilling. However, the levels of well complexity have remained low due to a lack of comparable advances in multilateral completion equipment and designs. As a consequence, the primary risks involved in multilateral wells have been in lateral Junction construction and completion rather than drilling. Of the hundreds of multilateral wells drilled, most have been simple open-hole completions in hard rock; many have been reentries to salvage wells or boost output from old fields, but an increasing number represents new, development wells seeking to maximize drainage of known reservoirs.

Regardless of the level of complexity, multilateral wells today are drilled with state-of-the art directional drilling technology. Even so, the drilling of multilateral wells involves certain risks ranging from borehole instability, stuck pipe and problems with over-pressured zones to casing, cementing and branching problems. And there can be a high risk of drilling or completion formation damage and difficulties locating and staying in the productive zone while drilling the laterals.

Multilateral technology may be at about the same level of development that horizontal and directional drilling were 10 years ago. Horizontal and reentry multilateral drilling has increased 50% over the past five years and is expected to grow another 15% a year through 2000. This rapid growth is attributed to operators realizing that the advantages of multilateral systems increasingly outweigh the disadvantages.

For years, because there were so few reliable and sophisticated examples of successful multilateral applications, few such wells were drilled because operators lacked benchmarks by which to determine whether prospects were suitable candidates for multilateral development. There were concerns about higher initial costs and the risk of possible interference of laterals with each other, crossflow and difficulties with production allocations. An increased sensitivity and concern about reservoir heterogeneities like vertical permeability deterred multilateral development. The prospect of complicated drilling, completion and production technologies, complicated and expensive stimulation, slow and less effective cleanup, and cumbersome wellbore management during production also made operators cautious.

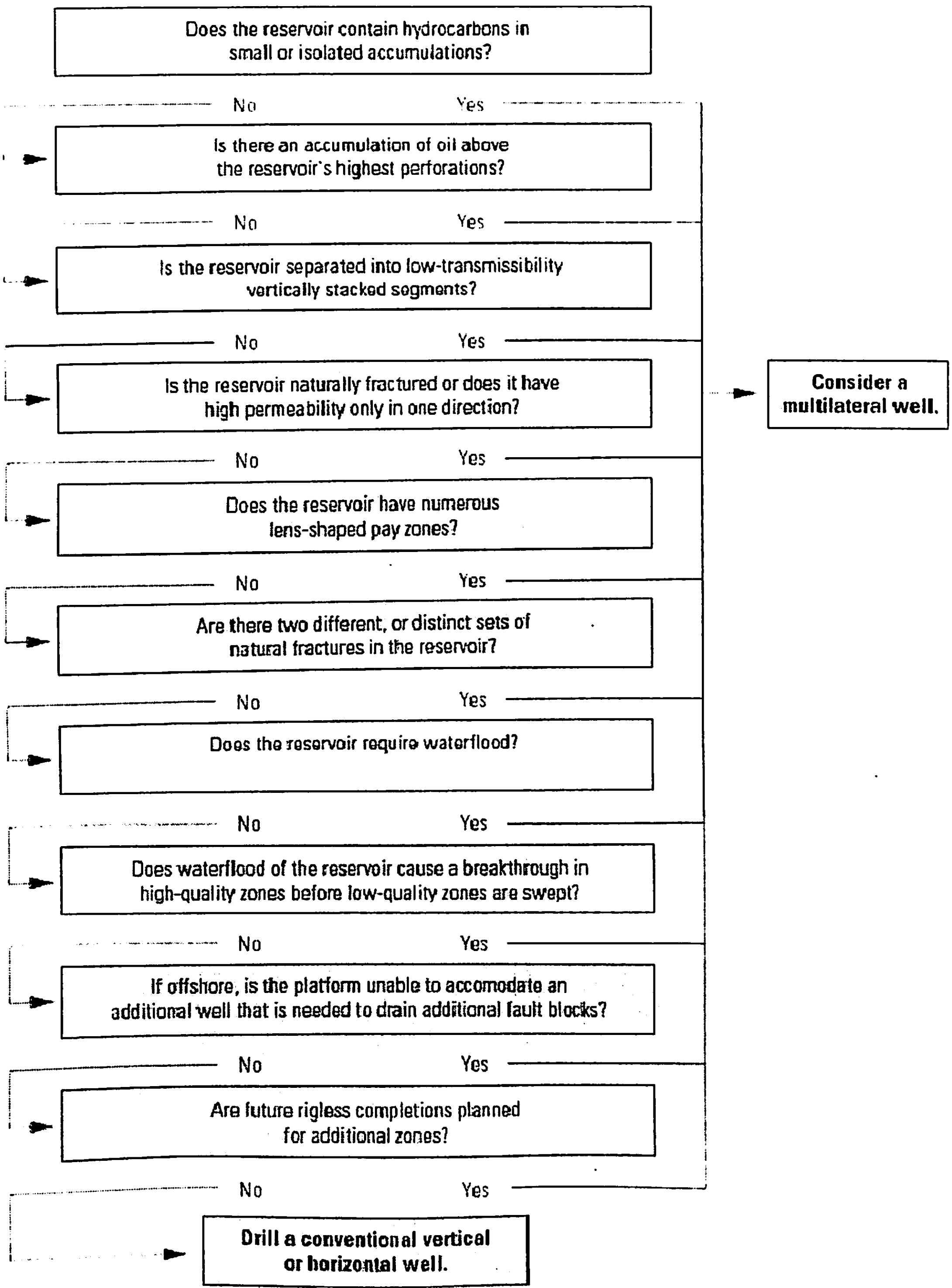


Figure 2.2

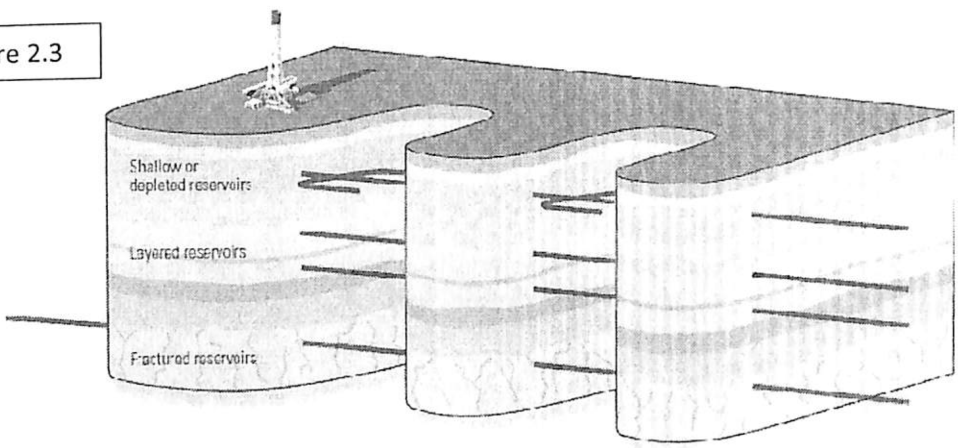
Determining if multilateral technology is applicable.

As more multilaterals were drilled successfully, however, even the simplest wells demonstrated the potential of this emerging technology. The main benefits of these successful wells have been increased production, increased reserves and an overall reduction in reservoir development costs.

Production from known reserves has traditionally been expanded by drilling additional wells to increase drainage and sweep efficiency. As a consequence, both capital expenditures and operating costs have also increased with every new well. To counteract these cost increases, multilateral technology is now being employed to increase borehole contact with the reservoir, improve operating efficiency and reduce well costs. These goals are achieved primarily by drilling the main trunk and overburden from surface to the reservoir only once and by reducing surface equipment to a single installation at a significant cost-savings. Furthermore, this can be achieved in both offshore platform and subsea situations where a limited number of slots is available and in onshore locations where surface installations are expensive or where the lease has an irregular configuration.

Multiple lateral penetrations in the same reservoir or in independent reservoirs not only produce significant cost-savings, but increase production rates appreciably. Such penetrations are commonly used to increase the effective drainage and depletion of a reservoir, particularly when reservoirs have restricted hydrocarbon mobility due to low permeability, low porosity or other characteristics that limit production flow. When independent reservoirs are targeted, production can either be commingled into a single production tubing string or produced separately in multiple production tubing strings.

Figure 2.3



Enhancing productivity with multilateral well configurations. In shallow or depleted reservoirs, branched horizontal wellbores are often most efficient, whereas in layered reservoirs, vertically stacked drainholes are usually best. In fractured reservoirs, dual-opposing laterals may provide maximum reservoir exposure, particularly when fracture orientation is known.

Multilateral wells are also an economical way of rapidly depleting a reservoir, effectively accelerating production, shortening the field life cycle and reducing operating costs. Multilateral wells are often able to overcome the shortcomings of both horizontal and conventional wells, particularly if there are geological factors like thinly layered formations or a significantly fractured system, and in specific enhanced oil recovery scenarios such as steam-assisted gravity drainage. In addition, the application of multilateral technology can result in decreased water and gas coning.

Because of the capability to more thoroughly drain reservoirs vertically and horizontally, recoverable reserves per well and per field are increased considerably while both capital and operating costs per well and per field are minimized. In fact, the cost of achieving the same degree of drainage with conventional wells would be prohibitive in most cases, especially situations like deepwater subsea developments.

Multilateral wells allow costs to be amortized over several reservoir penetrations and in some cases have eliminated the need for infill drilling. In heterogeneous reservoirs with layers, compartments or randomly oriented natural fractures, more pockets of oil and gas can be exploited and an increased number of fractures can be intersected by drilling multilateral wells.

In anisotropic formations with unknown directions of preferred permeability, drilling multibranched wells can reduce economic risk. Lateral branches can balance the nonuniform productivity or injectivity of different layers.

Multilateral wells provide extensive information about the reservoir and can be useful for exploration and formation evaluation in addition to their capability to efficiently and economically drain reservoirs.

Classification of Multilateral Wells

TAML Classification

Until 1997, there was considerable confusion regarding multilateral technology. Few terms that described the technology were universally agreed upon, and a classification of multilateral wells by difficulty and risk was lacking. As a consequence, under the leadership of Eric Diggins of Shell UK Exploration and Production, a forum called "Technology Advancement—Multi Laterals (TAML)" was held in Aberdeen, Scotland, in the spring of 1997. Its goal was to provide a more unified direction for multilateral technology development. Experts in multilateral technology from leading oil companies shared experiences and agreed to a classification system that ranks multilateral wells by complexity and functionality.

Today, multilateral wells are referred to by level of complexity from Level 1 through 6S, and described with a code to represent type and functionality (see. "Classifying Multilateral Wells," page 20).

The three characteristics used to evaluate multilateral technology are connectivity, isolation and accessibility. Of these, the form of connectivity or junction between the main trunk and lateral wellbore branches is not only the most distinguishing feature, but also the riskiest and most difficult to achieve. For this reason, about 95% of multilateral wells drilled worldwide have been Level 1 or 2. Some 85% of 1998 multilaterals have been Levels 1 to 4, with 50% of those Levels 1 and 2. But the race is on; virtually all major operators and drilling service companies are developing multilateral connectivity, isolation and accessibility capabilities. In addition, new junction systems are emerging to facilitate increasingly higher levels of difficulty.

Level 1 is essentially a simple open-hole sidetracking technique, much like the first multilaterals drilled in Russia. The main trunk and lateral branches are always open-hole with unsupported junctions. Lateral access and production control are limited.
In Level 2 wells, the main bore is cased, but the lateral junction remains open-hole, or possibly with a "drop-off" liner—casing placed in lateral sections without mechanical connection or cementing—to provide full-opening main wellbore access and improve the potential for reentry into the lateral.

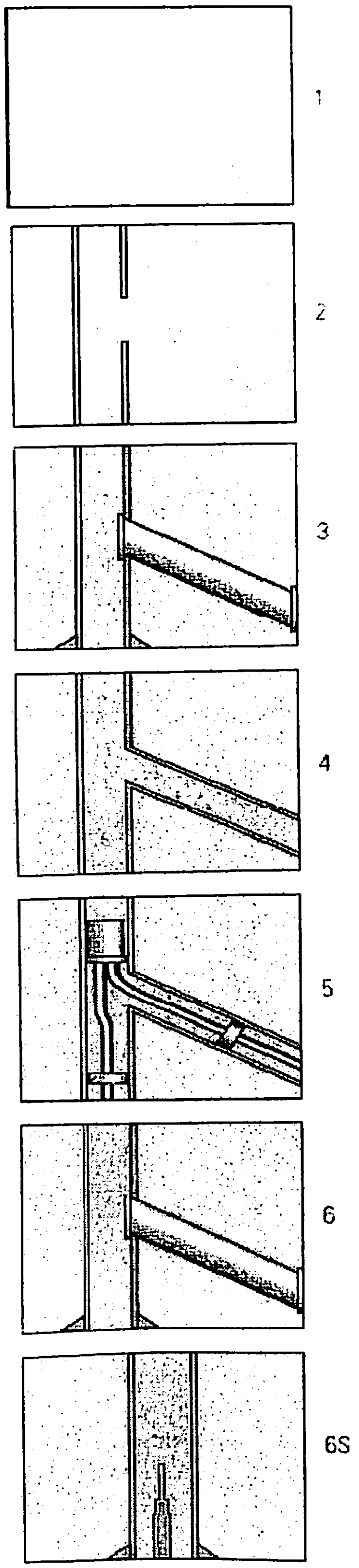


Figure 2.4

Multilateral well complexity ranking (Level 1 to 6S)

This general classification is based on junction complexity.

- Level 1 is an open-hole sidetrack or unsupported junction.

- Level 2 has a cased and cemented main bore, or trunk, with open-hole lateral.

- Level 3 is a cased and cemented main bore with lateral cased, but not cemented.

- Level 4 has both main bore and lateral cased and cemented at the junction.

- Level 5 pressure integrity is achieved at the junction with completion equipment.

- For Level 6, junction pressure integrity is achieved with casing and without the assistance of or dependence on completion equipment.

- In the subcategory Level 6S, a downhole splitter, basically a subsurface dual-casing wellhead, divides a large main bore into two equal-size laterals.

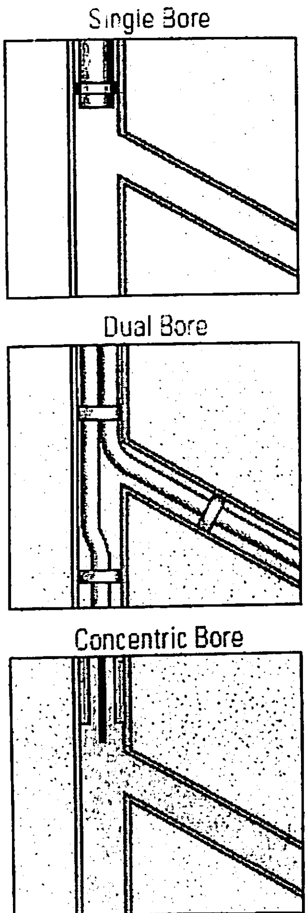


Figure 2.5

Multilateral well descriptions

In addition to criteria such as the number of junctions and well type—producer with or without artificial lift, injector or multipurpose—the completion type, whether single, dual or concentric, has a major impact on the type of equipment that is needed at the junction.

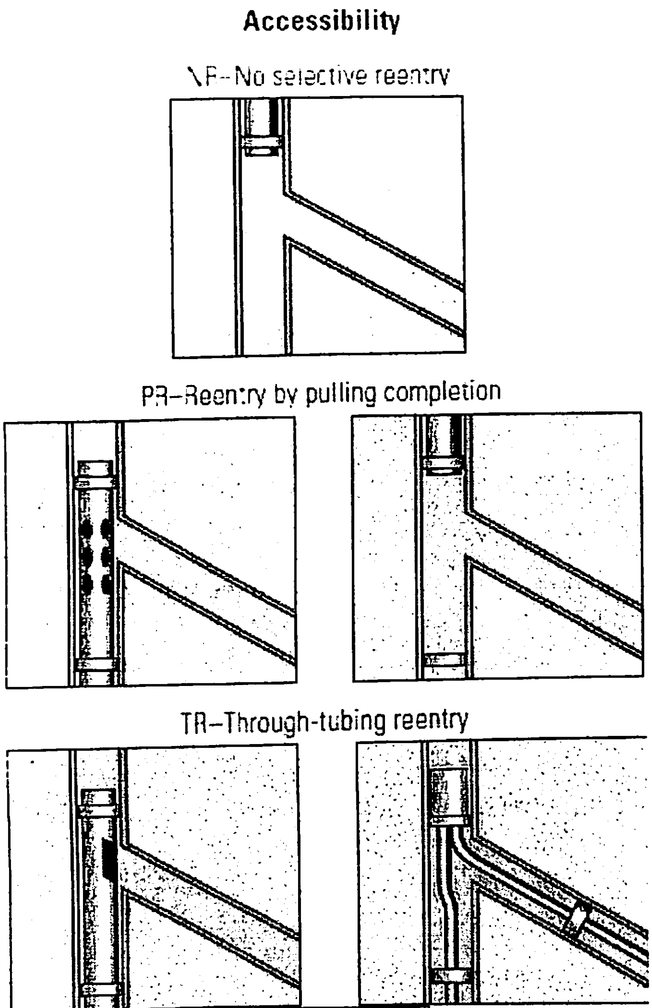


Figure 2.6

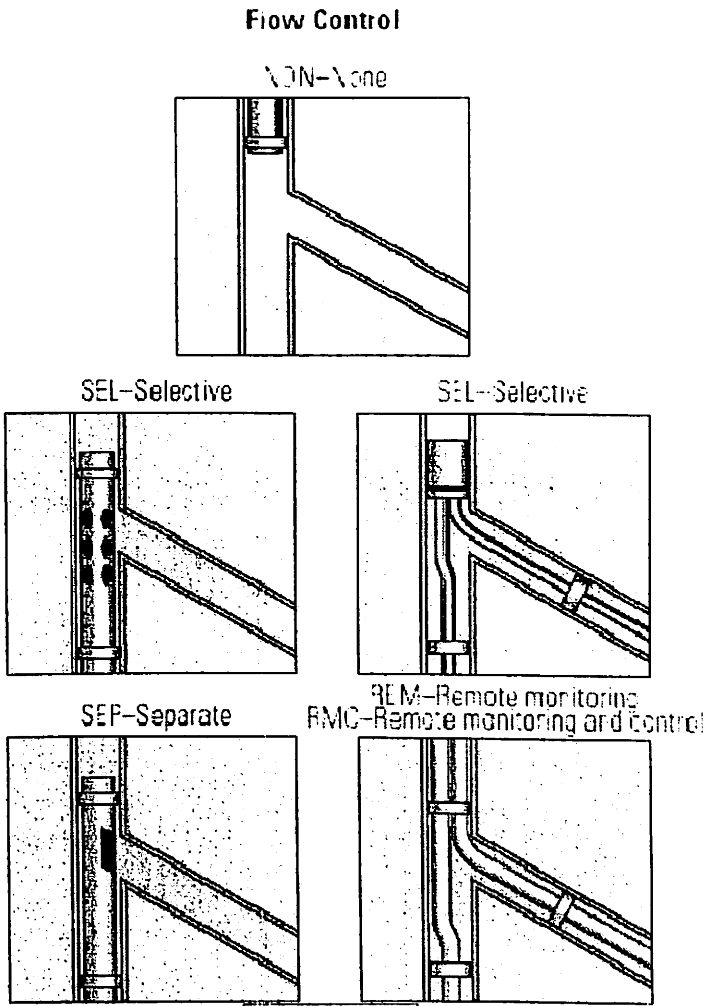


Figure 2.7

Junction Types

The categories of accessibility are no selective reentry, reentry by pulling completion and through-tubing reentry (right). Flow control (left) is the degree to which fluid flow across a junction can be adjusted—no control, selective or separate control, and remote monitoring or remote monitoring and control.

Chapter 3

Casing Exit Systems

Why Make a Casing Exit?

- When there is a 'Fish' stuck in the well which is unable to be removed, or uneconomical to be removed.
- To access different locations in the reservoir.
- Allow Multi-Lateral well completions which produce oil & gas from several zones through one well bore.
- Allow offshore platforms to fully develop the field with a limited number of Slots.

Exit Orientation

While making a casing exit we have two options. We can exit at the high side or the low side. High side exits are always preferred because

- Lower risk of milling and drilling problems
- Exiting low side risks short windows (access problems)
- Whipstock top may 'sag' into wellbore (access problems)
- Drill string may 'key seat' when POOH

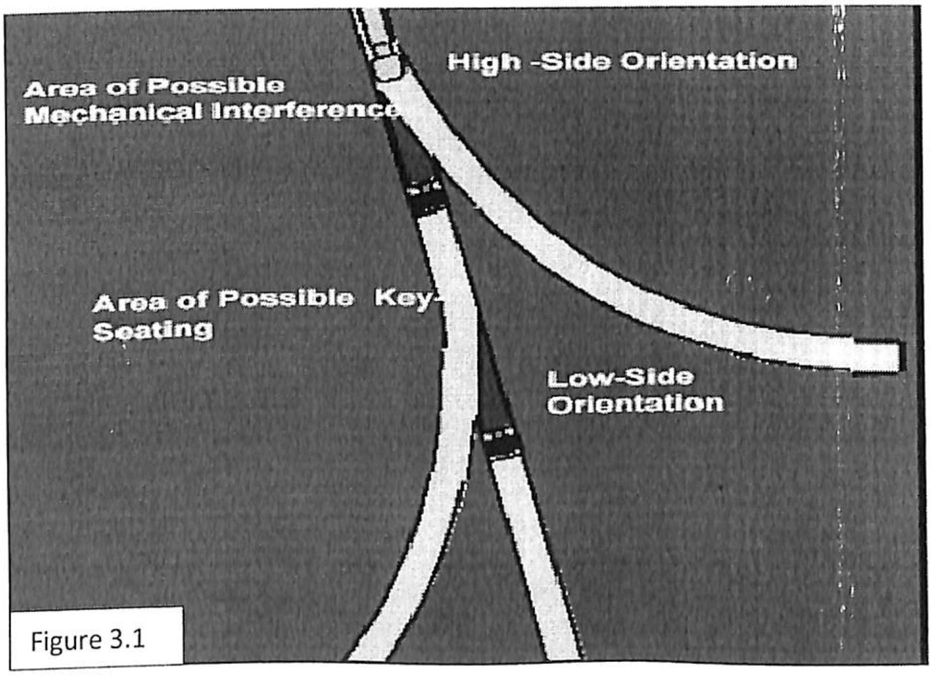
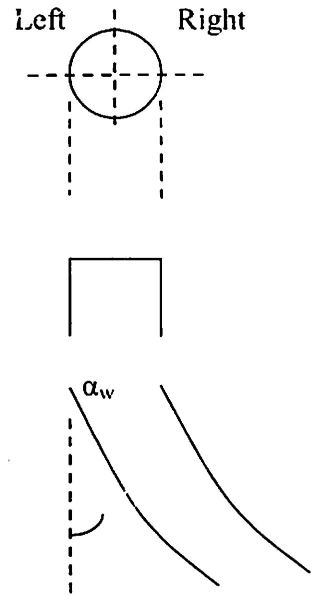


Figure 3.1

The following table gives the exit orientation for different borehole angle i.e. angle made by borehole with the vertical.



Hole Angle (α_w)	Exit Orientation	
	Left	Right
0° -5°	Any Direction	
15° - 30°	0° - 60°	0° - 60°
30° - 60°	15° - 60°	14° - 45°
60° - 90°	30° - 45°	15° - 45°

Caution: Always avoid direct high side orientation with any Casing Exit in holes of 5° Deviation and more.

Tools used for Casing Exit operation

- Bridge Plug
- Bottom Trip Anchor
- Whipstock
- Window Mill
- Flex Joint
- Watermelon Mill

Casing Exit Process

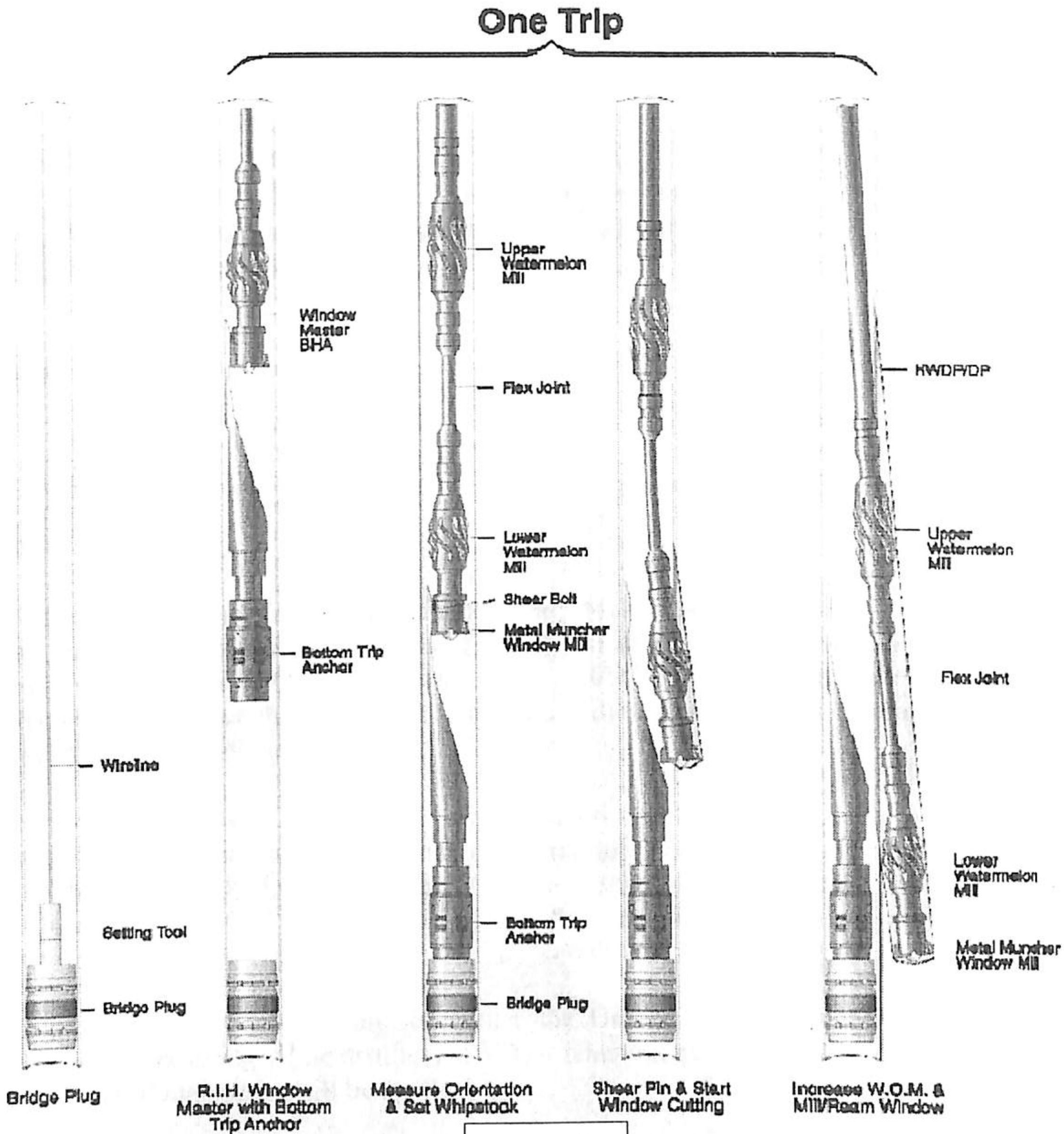


Figure 3.2

Whipstock

Why Whipstocks are Oriented

- For Directional Drilling
- To hit the geological target
- To aid reservoir engineering
- To avoid other wells
- To allow intersection by a relief well in the event of a blowout
- To reduce doglegs and allow greater TD to be reached
- For equity determination
- Government regulations

Whipstock Anchoring Methods

- Bottom Trip Anchor
- Bridge Plug

Bottom Trip Anchor

The Bottom Trip Anchor is used to anchor Whipstock in place in wellbore. It is attached to the lower end of the Whipstock by means of a drill-pipe connection. The Anchor is retrievable with straight over-pull on the whipstock. For retrievable applications, an applicable Debris Management System consisting of Excluder, Unloader and Emergency disconnect, should be run between the whipstock and anchor.

The debris management system will keep the debris of the drilling of the milling and drilling operations from falling around the anchor and fouling the slips during retrieval. To activate the setting sequence, only a bottom or restriction in the wellbore is required. The bottom can be in the form of a Permanent or retrievable Bridge Plug, top of cement, liner top, Production Packer, etc.

When using the bottom trip anchor, either the Universal Bottom Hole Orientation method (UBHO), or measuring while drilling (MWD) orientation method when a hole of 5° or greater at the Kick Off Point exists, will be applicable.

Operation

- Apply a thread lock to the threads and makeup the anchor to the whipstock using 140% of A.P.I recommended torque for particular tool joint thread.
- Determine the shear values needed to set Anchor. A minimum of three screws must be used at 120° apart for even shear.
- Approximately 15 ft from the false bottom (i.e. Bridge Plug, Cement Retainer, etc.), orient the Whipstock face to its desired direction.
- Set down 5000 lb over the predetermined shear value.
- There should be approximately one foot of travel after the shear.
- Pickup approximately 5,000 lbs over-pull to check the set condition of the Anchor.
- If the anchor does not move up hole, it is set and the whipstock shear bolt can be sheared and window milling can begin.

Bridge Plugs

There are many types of Bridge plugs dependent on the application, for tubing less completion, for completion with tubing (thru-tubing) and broadly there are two types of bridge plugs Retrievable and Drillable.

Drillable Bridge Plugs are classified on the basis of size of the borehole; they are used for tubing less completion. In a conventional Bridge Plug we have solid ring slips and a swab poof packing element system with positive anti-extrusion back-up rings.

Operation

- The bridge plug is made-up to appropriate size and model wire-line pressure setting assembly and wireline adapter kit and run to setting depth.
- When the pressure setting assembly is actuated the tension mandrel in the adapter kit moves upwards, pulling the body of the bridge plug up with respect to the setting sleeve, thereby setting and packing-of the bride plug up with respect to the setting sleeve, there by setting and packing-off the bridge plug.
- Continued upward movement then shears the shear pin or shear screws, leaving the wireline pressure setting assembly and adapter kit free to be retrieved from the well.

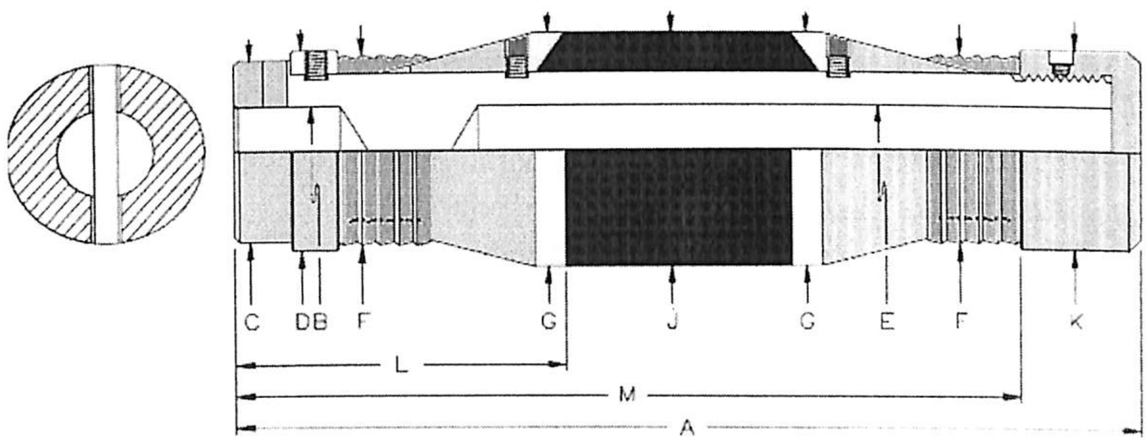


Figure 3.3

Whipstock Retrievable Tools

1. Solid Lug Tool

Features & Benefits

- Solid body construction for strength and durability
- Can be easily disengaged and reengaged multiple times
- Will take weight for cocking fishing jars, should this become necessary
- Jets at top of tool to clean retrieving slot
- Dovetail slot prevents dropping whipstock while pulling out of hole

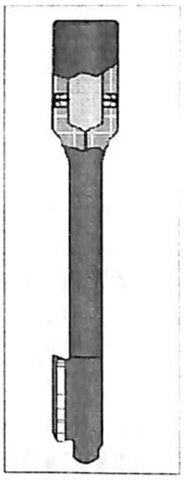


Figure 3.4

2. Special Box Tap

Features & Benefits:

- Manufactured from high quality ANSI 8620 material
- Carburized wickers for high surface hardness and proper carrying strength
- Available with right-handed or left-handed wickers or connections
- Various sizes, length, and connections are available on request to handle specific types of profiles

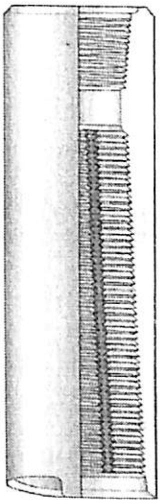


Figure 3.5

Variables for Selecting the Correct Whipstock

Type of Rig (check pick up, pump and rotary capacities)

- Rotary drilling/Rotary work over/Hydraulic Work over/Coiled Tubing
- Does it have sufficient rotary torque capacity? (see chart)
- Does it have sufficient pump capacity to operate motor and/or clean cutting from wellbore?
- Does it have sufficient pick up or slack off capacity to reliably set anchor and mill window?

Depth

- Pick up and/or slack off weight may be limited in extremely deep or extended reach wells
- Slack off weight for setting the anchor and milling may be limited at extremely shallow depths

Casing Size

- Most common sizes are covered
- Check for extremely heavy weight / thick wall
- High grades, grades higher than Q-125 casing can be problematic
- ID, Drift?
- CRA material with more than 13% Chromium can be problematic

Work String

- Is work string capable of handling milling stresses?

Weight Joints

- Are enough weight joints available for adequate setting and milling weight?

Restrictions in the Well

- Completion equipment or heavier case weight up borehole Retrievable or Permanent
- Will the whipstock need to be retrieved?

1. Permanent Packer
2. Retrievable Bottom Trip Anchor

Cement at KOP

- Is the casing cemented at the chosen KOP?

Dual String

- Annulus size (if it is equal to or more than ½ the mill diameter for the inner string it may not be possible
- Is the annulus cemented (very important)?

Wellbore inclination

- Vertical
  It can be hard to hold angle outside the casing when milling a window in a vertical wellbore
  Vibration will also be worse in a vertical well (<10 deg)

- Deviated
- Horizontal
  Set down weight/WOB can be severely limited in extended reach wells
  Borehole cleaning is problematic

Formation Type
- Hard (>25 ksi compressive strength)
  Can cause problem finishing window and rat hole
- Medium (15-25 ksi compressive strength)
  Stable milling but some formation may slow ROP
- Soft (<15 ksi compressive strength)
  Fast milling/drilling but no support for mills/window

Target Zone
- Long Radius or Short Radius

Whipstock Accessory Equipment

Debris Management for Retrievable Applications

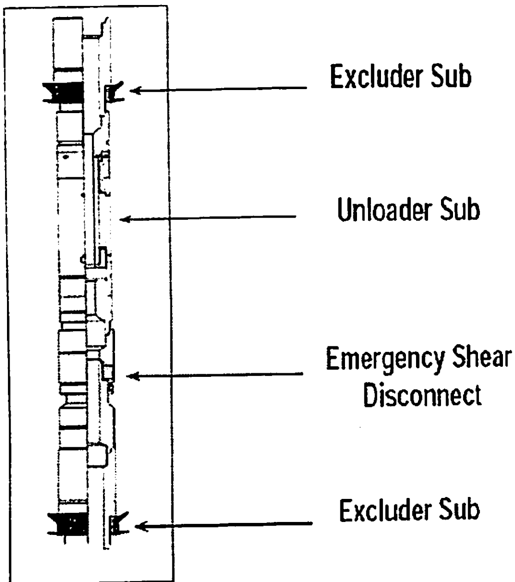


Figure 3.6

1. Emergency Shear Disconnect

FEATURES/BENEFITS:

- Allows recovery of whipstock should packer or anchor fail to release, ensuring whipstock recovery even in “worst case scenario”
- The joint is rotationally locked
- Adjustable shear ring values allows same tool to be dressed for different release load
- Internally sealed to allow setting of hydraulic packer / anchor with drillpipe pressure

2. Unloader Valve

FEATURES/BENEFITS:

- Prevents well swabbing during whipstock retrieval
- It is rotationally locked to withstand high torsion loads
- Acts as an indicator that the whipstock is free

3. Debris Excluder Sub

FEATURES/BENEFITS:

- Debris barrier prevents debris from accumulating around the anchor or packer
- Can be run as a debris barrier on all whipstock systems
- Port above cup to prevent swabbing during retrieval

a) Top view of window with whipstock removed

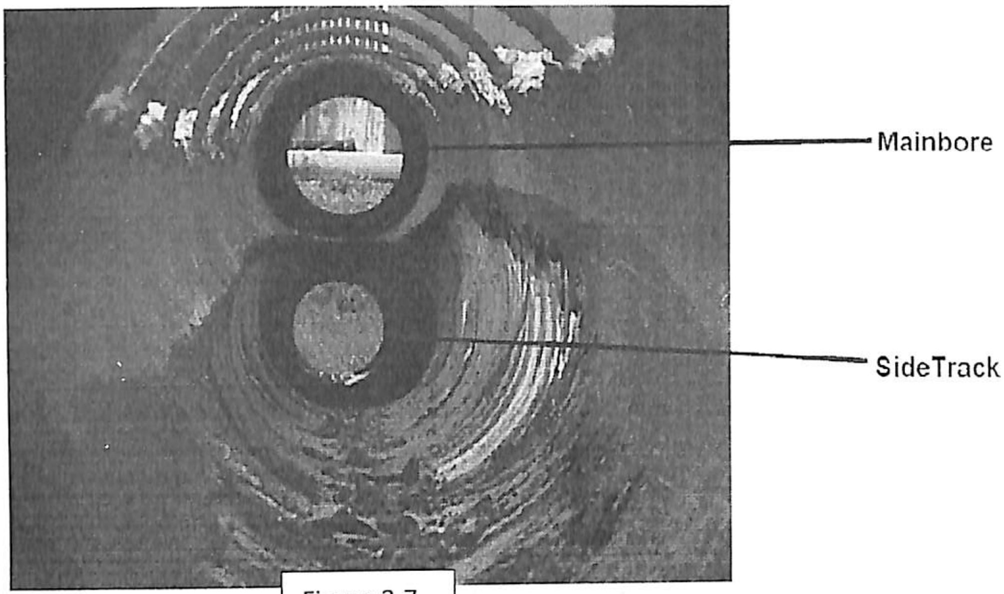


Figure 3.7

b) Bottom of Window

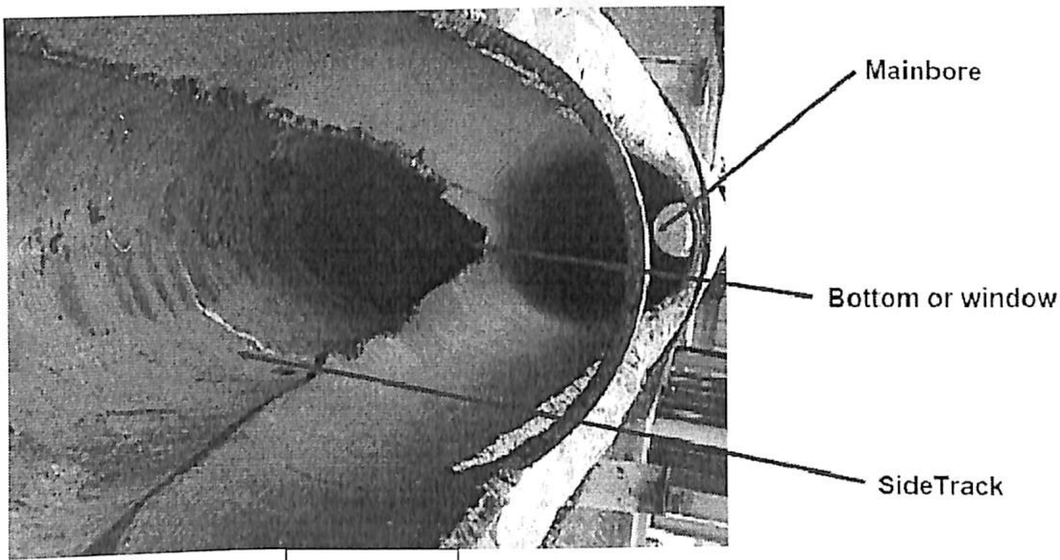


Figure 3.8

Chapter 4

Directional Drilling

Definition:

The science of directing a well bore along a predetermined trajectory to intersect a designated subsurface target.

Kick off point (KOP):

The kick off point is defined as the point below surface location where the well is deflected from the vertical.

Target:

A predetermined point in the reservoir that D.D should reaches to it.

Well classification

1. Vertical Well
   Wells with less than 10° deviation

2. High Inclination Well
   Wells between 60 and 85° deviation

3. Horizontal Well
   Wells with more than 85° deviation

4. Extended Reach Well
   Horizontal/TVD displacement greater than 2.5

5. Designer Well
   Wells with significant turn in the horizontal plane of 30 to 180 degrees, and turn not restricted by inclination

Reasons for Directional Drilling

1. Side-tracking existing well (because of hole problems or fish or reaching new targets)
2. Restricted surface locations (inaccessible locations)
3. To reach multiple targets
4. To reduce number of offshore platforms
5. Horizontal Drilling
6. To reach thin reservoirs (using horizontal wells)
7. Salt dome drilling (directing the well from the salt dome to avoid casing collapse problems)
8. To avoid gas or water coning
9. For intersecting fractures
10. Relief wells
11. For controlling vertical wells
12. Shoreline drilling

Directional Drilling applications

1. Multiple Targets

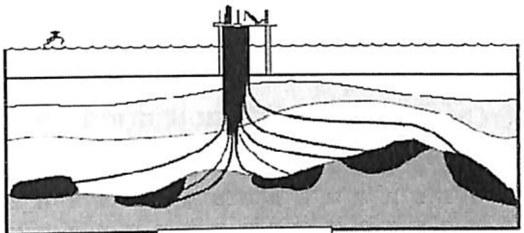


Figure 4.1

2. Relief Well

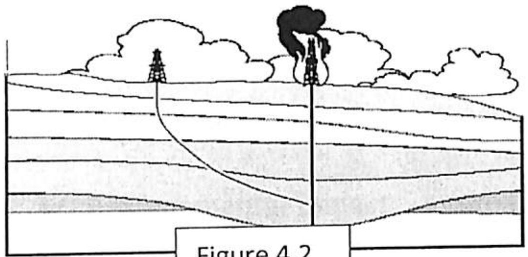


Figure 4.2

3. Side-tracking
4. Inaccessible locations
5. shoreline drilling
6. salt dome drilling
7. horizontal well
8. fault drilling

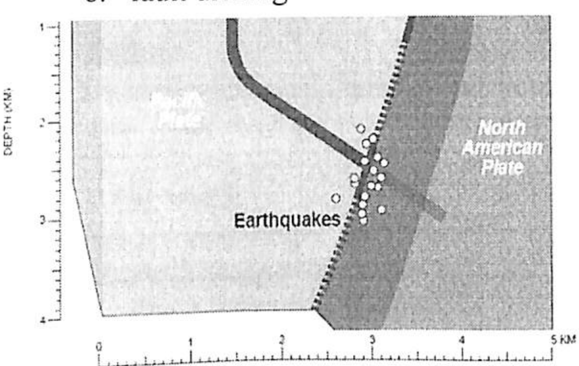


Figure 4.3

Drilling Fluid Selection

Virtually all of the considerations for choosing a fluid for drilling a vertical hole apply to choosing a fluid for a directional hole:

- Formation protection
- Hole cleaning
- Lubricity
- Inhibition
- Fluid weight required
- Economics
- Environmental impact

Deflection Tools

Borehole angles are usually kicked off by jetting, whip stocks or some type of bent sub, downhole motor tools.
Geology affects the decision as well as the desire to use a steering tool.

1. Jetting:

It was a widely used technique several years ago. It involved the use of a large bit jet and two smaller jets. After washing 6-8 ft rotary was used to drill the rest of the joint

2. Whip stock

Whipstock is a very simple device used to kick off the well.
Separated into 2 categories:

i. Open hole whip stocks
ii. Casing whip stocks

3. Bent subs:

Bent subs are used with downhole motors. The sub has 1/2 -5/2 degree of bend in it that will deflect the motor in the desired direction.

Jetting

A standard soft formation tri-cone bit, with one very large nozzle and two smaller ones.

Important parameter:

1. Geology:

S.S & oolitic limestone (best)

Unconsolidated S.S & very soft rock (good)

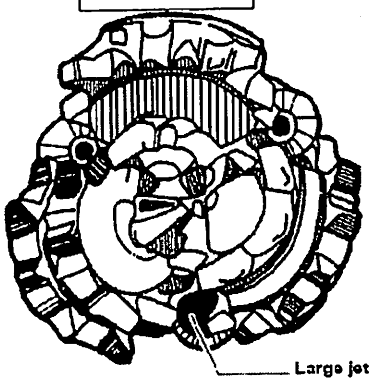
Very soft rocks erode too much (bad)

As a rough rule of thumb, ROP>24m/hr using normal drilling parameters

2. Hydraulic energy

A rule of thumb: mud velocity through the large jet should be at least 500 ft/sec.

Figure 4.4



Advantages

1. Same BHA to change trajectory & drilling ahead
2. Simple and cheap method in soft formations.
3. Dogleg severity can be partly controlled from surface by varying the number of feet "jetted" each time.
4. The survey tool is not far behind the bit.
5. Orientation of tool face is fairly easy

Disadvantages

1. Only works in soft formation and therefore at shallow depths

2. High dogleg severities are often produced. Deviation is produced in a series of sudden changes, rather than a smooth continuous change. For this reason, it is normal practice to jet an under gauge hole and then open it out to full gauge, which smoothes off the worst of the doglegs

Whip stocks

1. Standard removable Whip stock
2. used to kick off wells
3. Sidetracking

Advantages

It is a fairly simple piece of equipment which requires relatively little maintenance and has no temperature limitations.

Disadvantage

1. If the whip stock is set on the fill, then whip stock rotate when drilling starts
2. Fill tend to wash away, causing the bit to slide down the side of the well bore and entire whip stock assembly to rotate
3. Critical: when bit leaves the end of wedge, if the rock too soft & circulation too high, bit can lose curvature and continue straight
4. Number of "trips" involved
5. Whip stock produced a sudden, sharp deflection

Circulating Whip stock

The drilling mud initially flows through a passage to the bottom of the whip stock which permits more efficient cleaning of the bottom of the hole and ensures a clean seat for the tool.

It is most efficient for washing out bottom hole fills.

Permanent Casing Whip stock is used where a "window" is to be cut in casing for a sidetrack

Advantage

- operation usually takes less time

Disadvantage

- Gives a sharp dogleg
- Casing window is too short.
- Numerous trips & long hours of rotation can wear or damage the casing, difficult to trip out the BHA through the casing window

Schematic Diagram of Whipstock Assembly

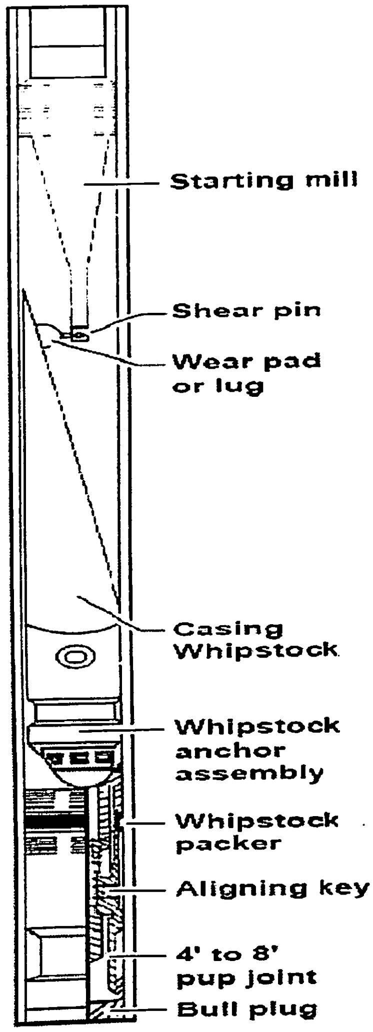


Figure 4.5

Downhole motors

Was developed in 1966, and 2 years later the Positive Displacement Motors (PDM) began to be used in the US

PDM & turbine + Bent Sub + Bent Housing or eccentric stabilizers

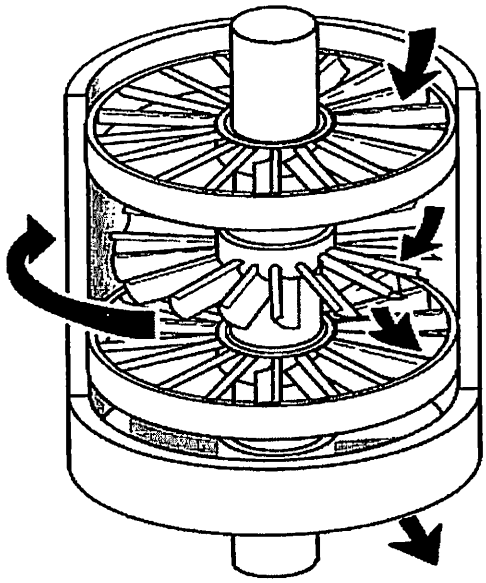


Figure 4.6

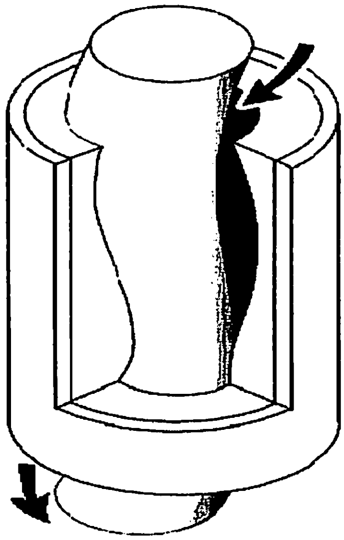


Figure 4.7

Factors Affecting directional behavior of rotary assemblies

1. Gauge and placement of stabilizers
2. Diameter and length of drill collars
3. Weight -on-bit
4. Rotary speed

Bit type

- Formation anisotropy and dip angle of the bedding planes
- Formation hardness
- Flow rate
- Rate of penetration

Bent Sub

The bent sub is an important tool connected with downhole motors. For lateral drilling, the bent sub maintains a lateral force on the bits to produce the required deflection. The bent sub is made by high tensile alloy steel and special heat treatment, with high strength, good toughness and long service life.

Two types of bent subs:

1. constant angle bent subs and
2. adjustable angle bent subs are available

The constant angle bent subs are more common to use. It has the advantages of simple structure, convenient use and low cost.

Types of Directional well trajectories

1. Build and hold
2. Build-hold-drop (S type)
3. Build-hold-drop-hold (modified S type)
4. Continuous build
5. Deep Kickoff and Build

Principles of BHA (Fulcrum)

- The Fulcrum principle is used to build angle (increase borehole inclination)
- Full gauge near bit stabilizer, followed by 40 to 120ft DC, before the first string stabilizer, or no string stabilizer

The rate of build will be INCREASED by the following:

1. Increasing the distance from the near-bit stabilizer to the first string stabilizer
2. Increase in hole inclination
3. Reduction of drill collar diameter
4. Increase in weight on bit
5. Reduction in rotary speed
6. Reduction in flow rate

Principles of BHA (Stabilization)

The Stabilization (Packed Hole) Principle: hold angle and direction

Three stabilizers in quick succession behind the bit separated by short, stiff drill collar sections, then the three stabilizers will resist going around a curve and force the bit to drill a reasonably straight path

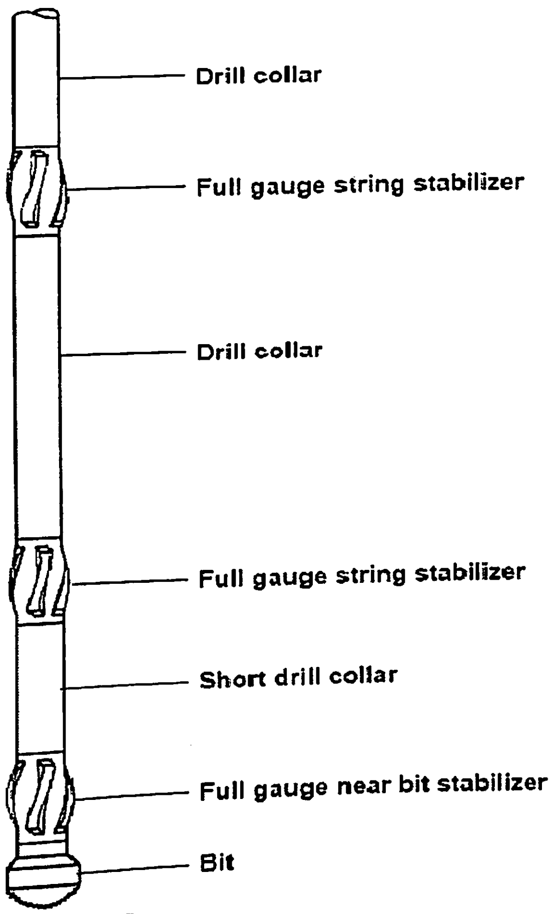


Figure 4.8

Chapter 5

Level 2 Multilateral System

LEVEL 2 MULTILATERAL SYSTEMS

A Level 2 Multilateral is constructed using the Window-Master™ Whipstock System to create the casing exit window. This system can be deployed in one-trip with the use of a collet and casing profile for depth control and MWD/Gyro for orientation of the whipstock face. A Retrievable TorqueMaster™

Packer is incorporated to anchor the system during milling and lateral drilling operations. Once the lateral is completed, the entire Window-Master and Retrievable TorqueMaster Packer can be retrieved from the well to retain full mainbore ID below the junction window. For permanent thru-tubing access into the lateral, a Lateral Entry Nipple (LEN) can be run in the final completion when a permanent ML™ TorqueMaster Packer is installed.

The ML TorqueMaster Packer offers a profile that aligns to both the milling anchor and the production anchor for exact orientation of the whipstock face and LEN to the casing exit window.

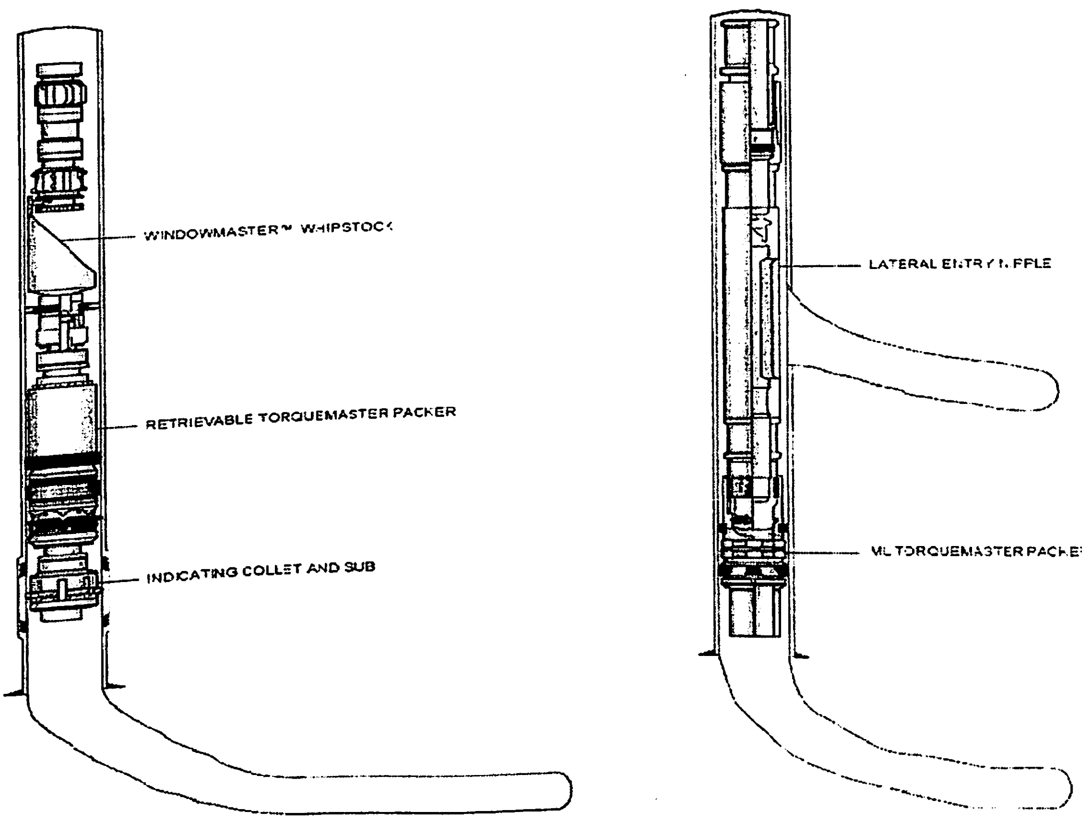


Figure 5.1

Chapter 6

Level 3 Completion System

The cornerstone of the Level 3 Multilateral System is the HOOK Hanger. It is used to create a junction providing a supported lateral and selective access into both wellbores. A HOOK Hanger Level 3 Multilateral begins with the WindowMaster™ Whipstock System to create the casing exit window. This system is easily deployed in one-trip to the desired depth with MWD/ Gyro for orientation of the whipstock face.

A Retrievable TorqueMaster™ Packer can be incorporated to anchor the system during milling and lateral drilling operations, or alternatively, a Bottom Trip Anchor can be utilized. Once the lateral is completed, the entire WindowMaster and Retrievable TorqueMaster, or Bottom Trip Anchor System, can be pulled from the well to maintain maximum mainbore ID below the junction window. The screen or liner along with the HOOK Hanger assembly is run into the well on the same trip. A bent joint guides the screen or liner into the lateral.

As the HOOK Hanger enters the casing exit, the hook extension automatically orients and engages at the bottom of the casing exit window. This self-orienting feature ensures that once landed the HOOK Hanger window is properly aligned and therefore providing continued mainbore access without any additional milling or wash over operations. A hold-down assembly can then be activated to anchor the HOOK Hanger in place.

Advantages of the Level 3 HOOK Hanger over other multilateral systems include:

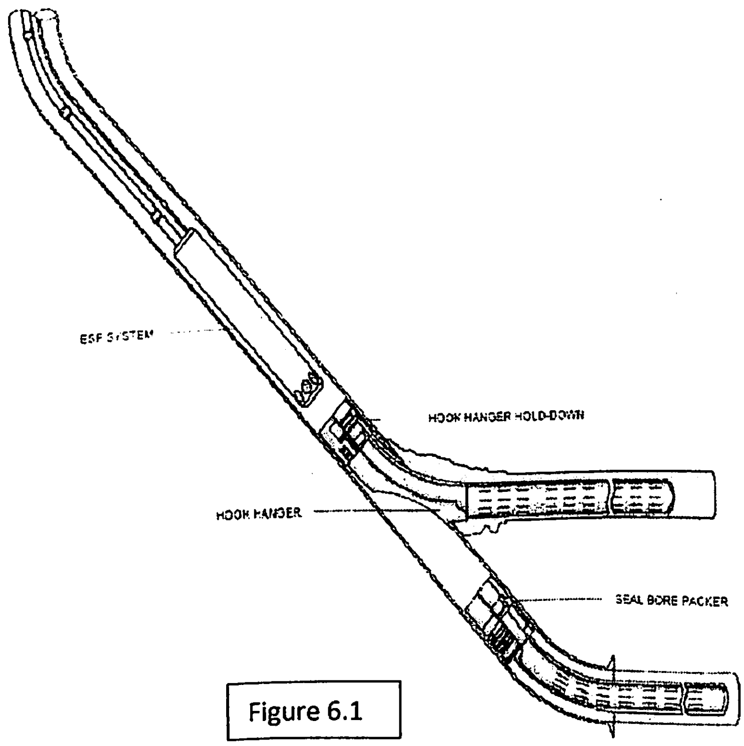


Figure 6.1

Simple, low risk deployment of the Hook Hanger assembly
Affordable supported junction option for a variety of environments
Available in stackable models and with sand exclusion options
Simple diverter installation for re-entry into the lateral or mainbore

The HOOK Hanger diverters are deployed on coiled tubing or coupled pipe. The lateral diverter is an inner sleeve that straddles the mainbore window to direct all re-entry into the lateral. The mainbore diverter is run inside the HOOK Hanger where the helical profile orients a scoop face to deflect all re-entry into the mainbore.

Introduction

With the continuing advancement of multilateral technology, operators are beginning to demand more specialized multilateral systems to suit particular reservoir development applications. Multilateral wells are now being used to recover hydrocarbons in a wide variety of different reservoirs and geographic locations. Heavy oil producers, require multilateral technology to maximize their reservoir exposure on a per well basis. However, the system design must be operationally simple in order to be economic in many of these shallow, low pressured, heavy oil developments.

In an effort to lower risk and maximize returns in heavy oil applications, Halliburton's Sperry-Sun Multilateral Technology group has developed a TAML Level 3 system that is a simplified, yet improved version of the traditional TAML Level 4 RMLSTM (Retrievable Multi-Lateral System) junction. It is simpler than a Level 4 to install, and it has increased strength over a Level 2 junction providing to the longevity of the lateral well bore.

The MACH-3TM (Mechanically Attached Casing Hang off) system constructs a Level 3 junction that physically "locks" the lateral liner into the main bore casing to provide junction strength with a minimal restriction of access to the lower main bore. The system has potential applications in the recovery of medium and light oil, as well as in low pressured gas reservoirs. The reduced installation time also makes the system practical for offshore multilateral wells, where the expensive rig costs of performing multilateral operations can be significantly reduced. While being specially suited for heavy oil developments, the MACH-3TM system can be applied to a variety of different reservoirs requiring a TAML Level 3 solution.

Concept and Design

The utilization of a TAML Level 3 junction to construct a multilateral well is not a new idea. The first Level 3 multilateral well in the world was constructed in 1993 using Halliburton's Sperry-sun LTBS™ (Lateral Tie Back System) in Northern Alberta, Canada, The system has gone on to build 105 Level 3 junctions globally, and it is still being used today. Many multilateral projects are now being constructed with the Level 4 RMLS™ system, which has been used to build over 200 junctions to date. This system provides mechanical and hydraulic isolation at the junction, which is often a requirement, particularly in unconsolidated formations.

Although the Level 4 creates a hydraulically isolated junction, there remain many applications where a Level 3 junction is faster and more economical to construct. The LTBS™ was the frontrunner in the global multilateral market and was the starting point from which many of the new systems have evolved. Many of its features, as well as the features of ITBS™ (Isolated Tie Back System) Level 5 system[2] and the RMLS™ have been incorporated into the design of the newer, more functional MACH-3™ Level 3 system. The system offers faster installation and improved functionality over its LTBS™ ancestor. It was developed in response to a need for:

A junction that does not require cementing of the lateral liner
A mechanically tied-back lateral liner to the main casing string
Minimal restriction for re-entry access of the lateral and main bore
A reduced number of operational steps to complete the junction

Reliable, simple deflection of the lateral liner

After drilling and completing the lower lateral, the system was designed to use a pre-milled window joint₁ and drilling whipstock to facilitate casing exit. After the lateral well bore has been drilled to total depth, the liner is installed and completed with a swivel and a Transition Joint assembly that locks into a specific profile of the main casing string above the window. The liner is diverted into the lateral well bore by a retrievable deflection device that is anchored in place by an adaptation of the Sperry-sun latch system₁. The Transition Joint is critical in protecting the structural integrity of the junction while providing access to the main casing below the junction. It is rotated into alignment by engaging an orienting tool several casing joints above the junction. The orienting tool turns the swivel and Transition

Joint into alignment and then pushes it down into locking profile to complete the junction. With the Transition Joint in place and permanently installed on the liner, the liner deflector can then be retrieved to restore nearly full-bore access to the main casing below the junction. The result is a mechanically attached, unsealed Level 3 junction with a slightly reduced drift ID.

The system specifications are:

9-5/8 inch, 47 lb./ft casing
8-1/2 inch lateral wellbore drill-out
7 inch lateral liner
7-1/2 inch drift access below junction
6 inch drifts access to lateral liner

There are plans to develop the system for 7" main casing and 4-1/2" lateral liner.

Operational Sequences

Step One: Drilling the Lateral. The operational sequence begins with drilling out of a lateral pre-milled window to create the lateral well bore. This is done with a traditional multilateral system and whipstock. Once the lateral has been drilled and the well bore is stable, the drilling whipstock is removed in preparation of running the lateral liner. Figure 6.2

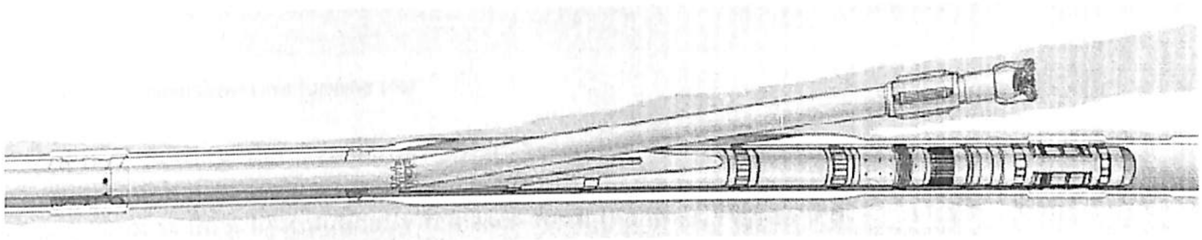


Figure 6.2 Drilling the lateral

Step Two: Installing the Deflector. The system deflector is then run into the lower latch assembly (landing profile). This automatically orients the deflector towards the lateral window. Figure 6.3

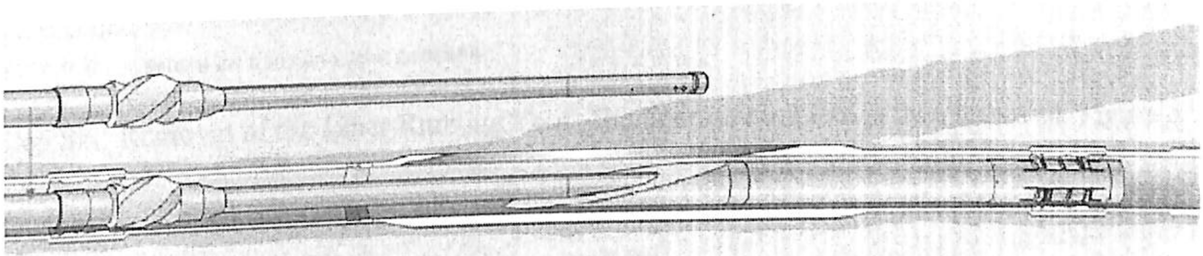


Figure 6.3 Installing the Deflector

Step Three: Running the Lateral Liner. The lateral liner and transition joint assemblies are then run into the hole. A bullnose on the lateral liner deflects off of the deflector assembly and into the lateral well bore. The complete length of the liner is continued into the well, followed by a casing swivel and the Transition Joint assembly. The liner can be comprised of slotted pipe, casing or screens. Figure 6.4

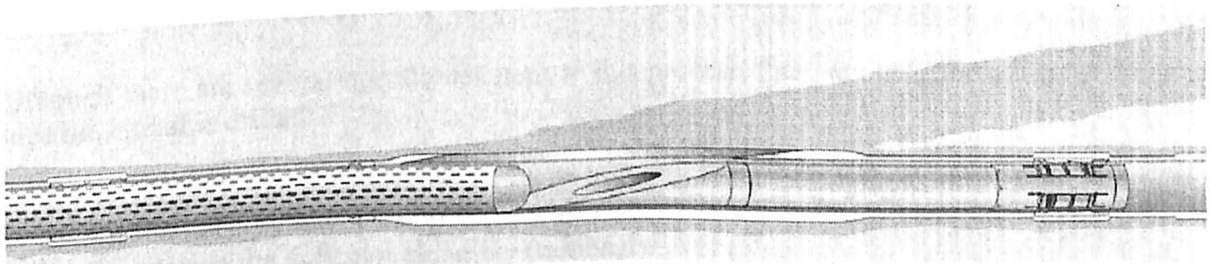


Figure 6.4 Running the lateral Liner

Step Four: Orienting the Liner Running Tool. The liner running tool engages the upper orienting latch coupling. The drill pipe is then rotated to engage the orienting latch assembly. When located, the Kelly mandrel is released from the latch assembly and the running tool stroke is initiated. Figure 6.5

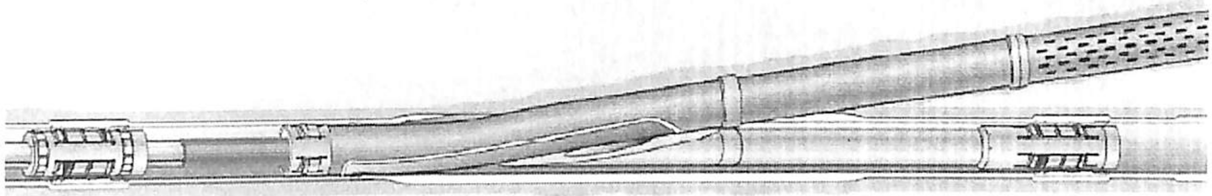


Figure 6.5 Orienting the Liner Running Tool

Step Five: Setting the Transition Joint Assembly. The liner running tool strokes through the orienting latch assembly as the Transition Joint locks into a profile in the main casing. The liner running tool is then hydraulically released from the liner. Figure 6.6

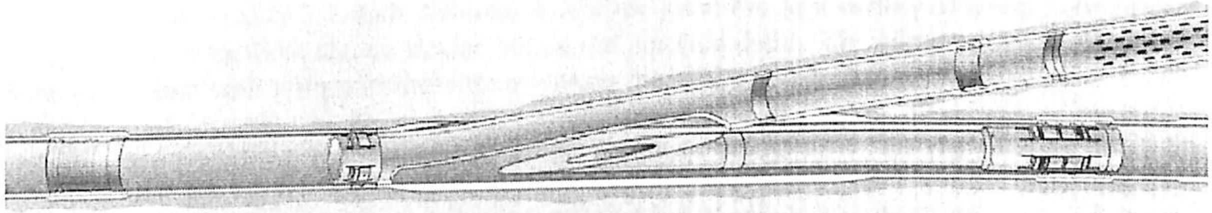


Figure 6.6 Setting the transition Joint Assembly

Step Six: Removal of the Liner Running Tool. The liner running tool is then removed. Figure 6.7

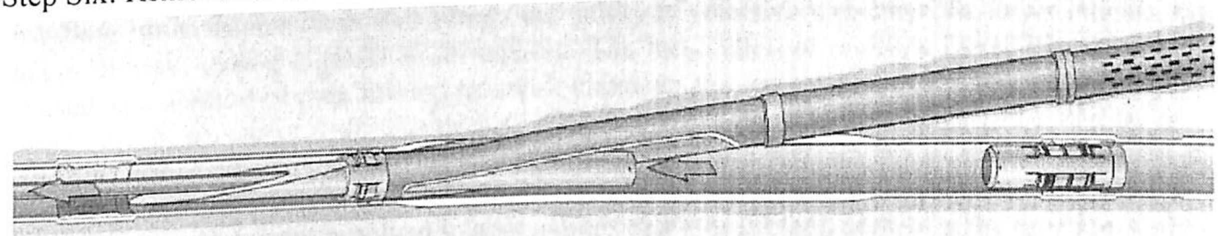


Figure 6.7 Removal of the Liner Running Tool

Step Seven: Retrieval of the Deflection Tool. The liner deflector can be retrieved, or it can be left in the hole. If it is important to restore near full-bore access to the main casing below the junction, the deflector can be retrieved with an extra trip in the hole. Figure 6.8

Although there are several operational steps to this process, there are only three trips in the hole once the lateral is drilled:

1. To set the deflector assembly.
2. To run the liner and Transition Joint assembly.
3. To retrieve the deflector assembly (optional).

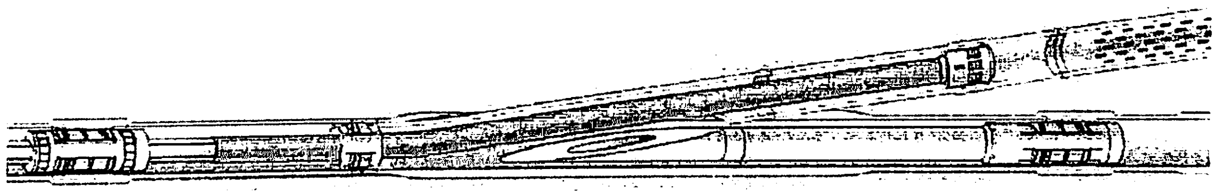


Figure 6.8 Retrieval of the Deflection Tool

Completion Options

There are many completion options for this Level 3multilateral junction system. An artificial lift pump (conventional reciprocating rod pump or progressive cavity pump) can be installed above or below the junction to optimize the drawdown of the specific laterals. Access to the main casing is possible up to 7.5-inch diameter below the junction, so a variety of completion packers and tubing anchors tools can be landed below the junction depth. The completion can be tailored to the individual well with minimal limitations on the actual equipment used.
A re-entry whipstock can be provided to facilitate the workover or clean out of the lateral wellbore. By installing the whipstock in the junction temporarily, all the re-entry tools are deflected into the lateral wellbore. After the work on the lateral well bore is completed, the whipstock can be retrieved to restore access to the main casing below the junction. No deflection device is required for main bore re-entry. Additionally, it will be possible to stack the junctions and provide more than one lateral capability from a single parent well bore. This requires that the lateral well bores be completed in sequence from the bottom of the well to the top.
Installing multiple junctions will forego the ability to selectively re-enter the lower laterals, but access to main casing is possible throughout. The installation of multiple Level 3 junctions can be used as a method of maximizing reservoir exposure and saving cost in a single well project.

Sand Control

A Level 3 junction is not practical in applications that require sand control at the junction. Only a Level 4 junction or higher is acceptable in these situations because the junction must be completely sealed in order to guarantee sand exclusion.

Although the cemented sheath created during the construction of a Level 4 does not qualify as a high-pressure seal, it does provide a complete non-permeable barrier to the migration of formation sand through the junction. By the nature of a Level 3 multilateral junction it is not hydraulically sealed. This makes the selection of the junction depth a very important consideration.

Typically a Level 3 junction is installed within, or just above the reservoir formation where the pressure differentials across the junction can be minimized. The result is that the junction is often positioned at a high inclination, anywhere between 60 degrees and horizontal. The reservoir rock formation at the junction depth must be considered relatively consolidated. Otherwise formation sand and fine-grained materials can contaminate the producing fluid stream by flowing into the casing around the junction. The consequences of producing sand from the reservoir may vary; often-serious erosion problems can occur.

Certain heavy oil applications, however, do not consider sand production to be detrimental to their operations. In such circumstances the Level 3 technology can still be utilized because the production of these unconsolidated reservoirs depends on pumping the sand and oil to surface as slurry to best maintain oil production. The lateral liner then maintains the structure of the wellbore under stressed conditions and provides an open conduit for the reservoir fluids to flow. If a sand accumulation forms and threatens the well's production rates, a specialized re-entry whipstock can be installed to reenter the lateral and circulate/wash away the blockage. Level 3 junctions are functional in unconsolidated reservoirs, but they do not prevent sand from flowing in around the junction of the main casing.

Some thought was given to including a sand control feature in the MACH-3™ system design in the form of a low pressured seal or "sand-barrier". This idea was dismissed under the premise that, in the majority of multilateral applications, the most reliable and the safest method of sand control is always the installation of a cemented Level 4, or a hydraulically sealed Level 5, multilateral junction. This is because a single barrier cannot eliminate borehole erosion, while cement prevents a micro-annulus from forming around the junction and allowing formation material to migrate into the junction. For these reasons a Level 3 system should only be considered in situations where sand control does not present a problem for the production of the well.

Application of Level 3 Technology

The MACH-3™ system was originally developed for the Orinoco Heavy Oil Belt of Venezuela where operators required a system that was fast, simple to install and allowed a progressive cavity pump to be installed below the junction depth. It was also important that the lateral liner be quickly and reliably deflected into the lateral wellbore without a complicated orientation procedure. Unfortunately, before the MACH-3™ system could be launched in this market, the Venezuelan oil producers experienced serious production problems with their previously installed Level 3 systems due to uncontrollable sand inflow around the junction. The conclusion of their experiment with Level 3 systems was to discontinue their use in favor of the Level 4 systems that sealed the junction with cement and prevented sand production from the reservoir.

Conclusions

As multilateral technology advances, operators will continue to benefit from improved functionality, easier installation, and a wider selection of multilateral solutions. The latest available multilateral system is Halliburton's MACH-3™, which provides a practical Level 3 junction for a variety of applications. This system can be installed faster and more economically than a Level 4 system, while lending more structural strength to the junction than a Level 2. The improved features of this system will allow for easy selective

Chapter 7

Level 4 Completion System

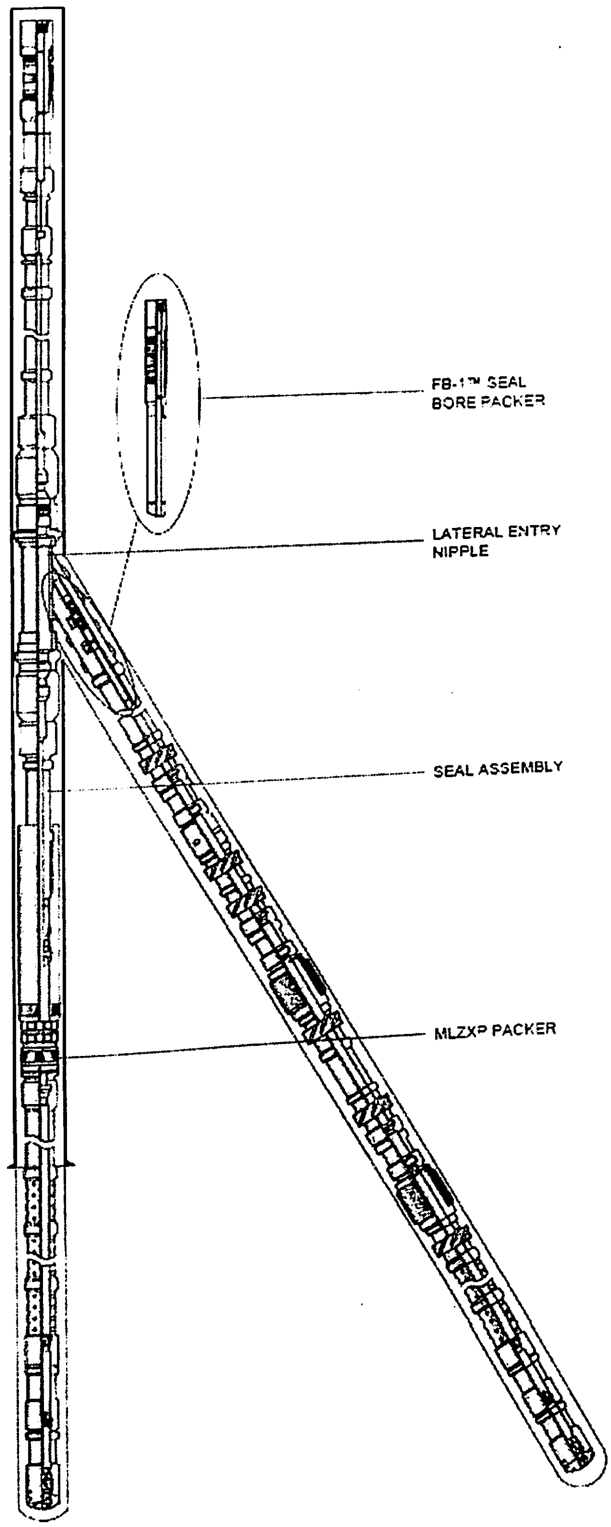


Figure 7.1

The Level 4 Multilateral System provides a lateral liner that has been cemented back to the junction area utilizing Baker Oil Tools' ROOT System℠ Process. This technique offers mechanical integrity at the junction, but it does not provide pressure integrity. In order to create a Level 4 junction, the mainbore is first drilled and completed using conventional procedures.

Either an MLZXP™ Liner Hanger Packer or ML Torquemaster™ Packer is then run and set below the intended junction depth. These two tools both contain an integral orientation profile used to orient the ML Whipstock Assembly in the desired direction for kickoff. An orientation run is made to determine this profile orientation, and the ML Whipstock Assembly is adjusted at the surface to the desired window azimuth.

The ML Whipstock is next run and stung into the MLZXP or ML Torquemaster Packer where it self-orients on the profile. The window is milled and the lateral is drilled to the desired depth. Conventional liner or screen assemblies are then run in the lateral bore. The liner portion is cemented in place and sufficient cement is pumped to allow for displacement into the junction area.

With the lateral liner cemented in place, access into the lower bore is then regained with the use of a washover operation. This procedure utilizes a washover assembly designed to retrieve both the lateral liner extending into the mainbore and the ML Whipstock itself. Once this occurs, the lower bore is again accessible.
Several completion options are available with a Level 4 Multilateral System. A standard sliding sleeve can be installed for flow control and isolation capabilities. If selective access into either lateral is also desired, a Baker Oil Tools Lateral Entry Nipple (LEN) can be utilized. This LEN contains a pre-milled window that matches up to the existing casing exit when the LEN is installed and automatically oriented into the MLZXP or ML Torquemaster Packer. Once the LEN is in place, production isolation or thru-tubing selective access into either bore is possible by first running specifically designed diverters or blanking sleeves into the LEN system.

Key features of the Level 4 Multilateral System include:

- Mechanical support achieved at the junction by cementing the lateral
- Production isolation and control is possible using standard Baker Oil Tools flow control devices
- Selective re-entry access in addition to production isolation and flow control is possible with the utilization of Baker Oil Tools' Lateral Entry Nipple system

Case History Norway's Åsgard Smørbukk Sør Field

(LEVEL 4 COMPLETION)

The Åsgard subsea development incorporates three separate fields 120 miles offshore at 984-ft water depth in the Norwegian Sea: Smørbukk, Smørbukk Sør and Midgard, Fig. 7.2 the prospect development is at an advanced stage with limited availability of subsea template slots for new well development. On Smørbukk Sør Field, there are four templates: three for production and one for injection. The injection template had only one available slot. Since Statoil planned to inject gas into two formations, it was necessary to drill a multilateral well using the single slot.

This well would require a Technology Advancement for Multilaterals (TAML) Level 4 multilateral (ML) junction system to prevent sand incursion, which was a problem with both formations, and it would also have to be capable of being switched to production after 10 years of gas injection.

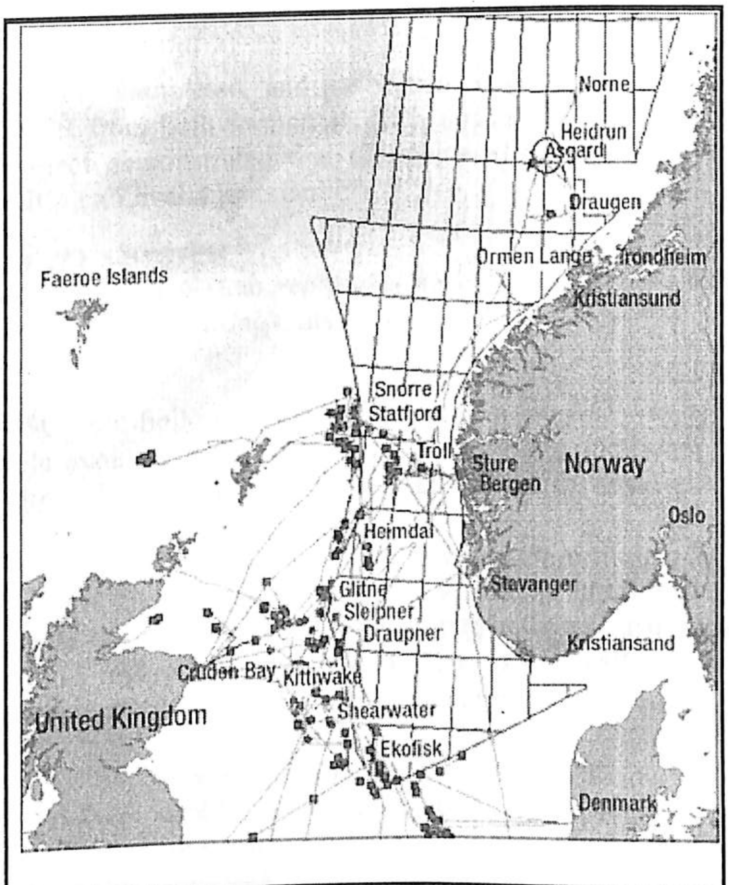


Fig. 7.2. The Åsgard development is located in the extremely harsh region of the Norwegian Sea.

The project presented complex challenges in a daunting environment. The weather can switch from benign calm to full gale within an hour, and sea conditions can be harsh. The well would be drilled from a semisubmersible rig, and the multilateral system would have to minimize risk in heaving seas, be simple to install, and require as few pipe trips as possible.

There were additional complications: 13% Cr-S-110 casing used for the well would be difficult to mill and the rock at the casing exit would be hard, impermeable sandstone with possible quartz stringers. The casing exit itself had to be long enough so that a rotary steerable drilling system could navigate through the window to drill the lateral. Finally, the static downhole temperature could reach 284°F.

On the positive side, since injection was to be controlled by a new downhole instrumentation and control system that was undergoing qualification testing, it would not be necessary to maintain full workover access to the main bore after completion of the multilateral. Instead, a hollow whipstock could be left in place and perforated.

The Weatherford/Statoil team decided to take a new approach based on the hollow-whipstock technology used for more than 10 years in the North Sea. The new approach would combine the setting of the whipstock and all milling and rat hole operations into a single run, saving two pipe trips and about $2 million in rig costs. Perforating the hollow whipstock through the liner using wireline would save an additional trip, and the resulting perforations would allow fluid access to and from both the main bore and the new lateral. Stage cementing would isolate permeable formations and create a TAML Level 4 junction; liners would include sand screens and swell packers.

The well was successfully completed, and gas injection had an immediate positive effect on adjacent producing wells from both formations. It is unusual to use a multilateral well for gas injection, but this project demonstrated that the single-trip method could be applied to any multilateral well requiring a Level 4 junction.

SINGLE-TRIP TAML LEVEL 4 SYSTEM

The single-trip TAML Level 4 system represents an extension of two existing technologies: hollow whipstocks and single-trip casing exits.

Hollow whipstock

Developed in the 1990s, the hollow whipstock provides a simpler way to construct a TAML Level 4 junction while avoiding the time and risk of installing additional junction equipment. The technology used overlapping casing strings plus cement for maximum strength, stability, and to prevent sand intrusion.[1]
Hollow whipstocks do not require any special liner or completion equipment and are compatible with reservoir sand control and completion systems, including intelligent well control devices. The disadvantage is that the technology prohibits future re-entry to the main bore below the junction; however, a 2003 review of existing multilateral subsea wells reveals that such re-entry is normally very expensive and often unsatisfactory, making it a low priority.

The useful feature of the hollow whipstock is that it contains pressure during the milling and lateral drilling stages, and then enables perforating with a zero-phase gun. It is possible to shoot low-debris charges in a single line through the liner and faceplate of the hollow concave without penetrating the backside of the whipstock.

Using the hollow whipstock for both milling and production phases reduces overall risk by eliminating difficult whipstock fishing operations, but mills must be able to pass over the hollow face of the whipstock without damaging or compromising the integrity of the perforation zone. Special whipstock features were developed to achieve this, including a bronze lug at the nose of the whipstock and rails alongside the concave portion. In addition, retrieval features were added in case orientation failed and the tool had to be retrieved before milling began, Fig.7.3. The original hollow whipstock required three runs for the running tool, the starter mill and the multilateral window mill.

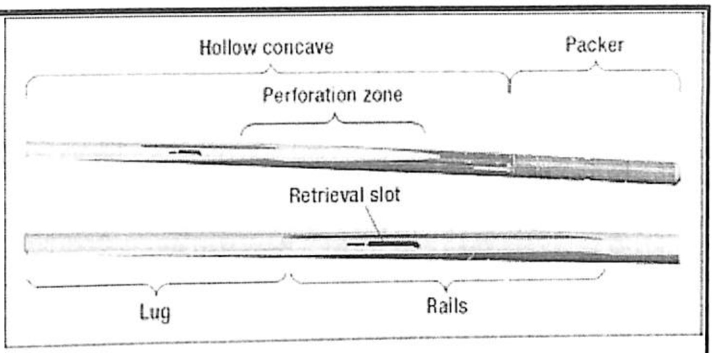


Fig. 7.3. Hollow whipstock with a 9-ft-long perforation zone.

Single-trip casing exit system. The first single-trip casing exit systems were introduced in the early to mid-1990s; it took years of effort to develop a reliable, single-trip casing exit system that incorporated more than one mill. Much of that work went into designing a lead mill with a smooth, smaller-diameter pilot nose with full-gage aggressive cutting blades behind it. The pilot rode on the whipstock's sacrificial lug and directed the starter mill into the casing wall. New designs for the bottom hole assembly (BHA) included one or two additional mills, depending on the concave angle. These mills helped steer the lead mill to ensure that the exit was milled to gage, Fig. 7.4.

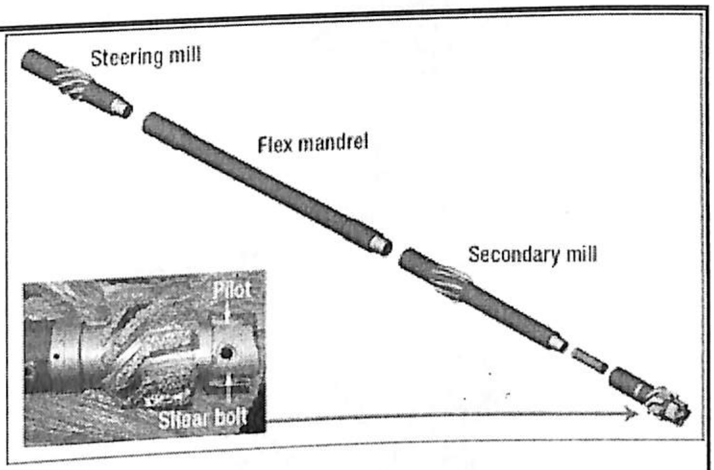


Fig. 7.4 Milling portion of the single-trip system combines three mills with a shear-bolt mechanism that attaches it to the whipstock.

To simplify running single-trip whipstocks, a new setting mechanism for hydraulic anchors was designed. The new design generates hydraulic pressure by flowing drilling fluid through a changeable nozzle restriction inside the lead mill. As a result, increasing the flow creates a greater pressure drop. The high pressure from the upstream side of the restriction flows through a copper line outside the mill to the packer-setting valve below, Figs. 7.5 and 7.6.

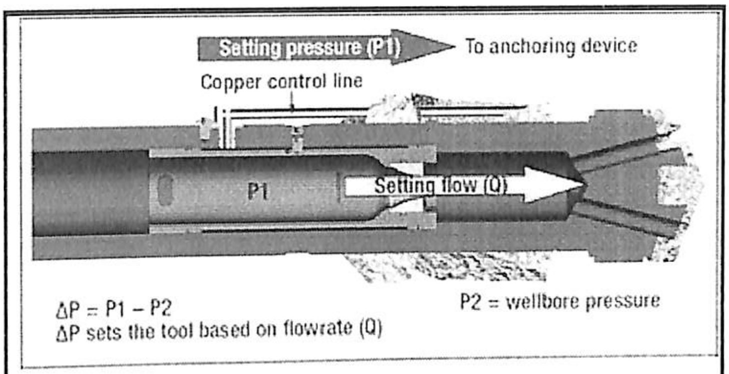


Fig. 7.5. The whipstock packer is set using the pressure differential created by a restrictive nozzle within the nose of the milling assembly.

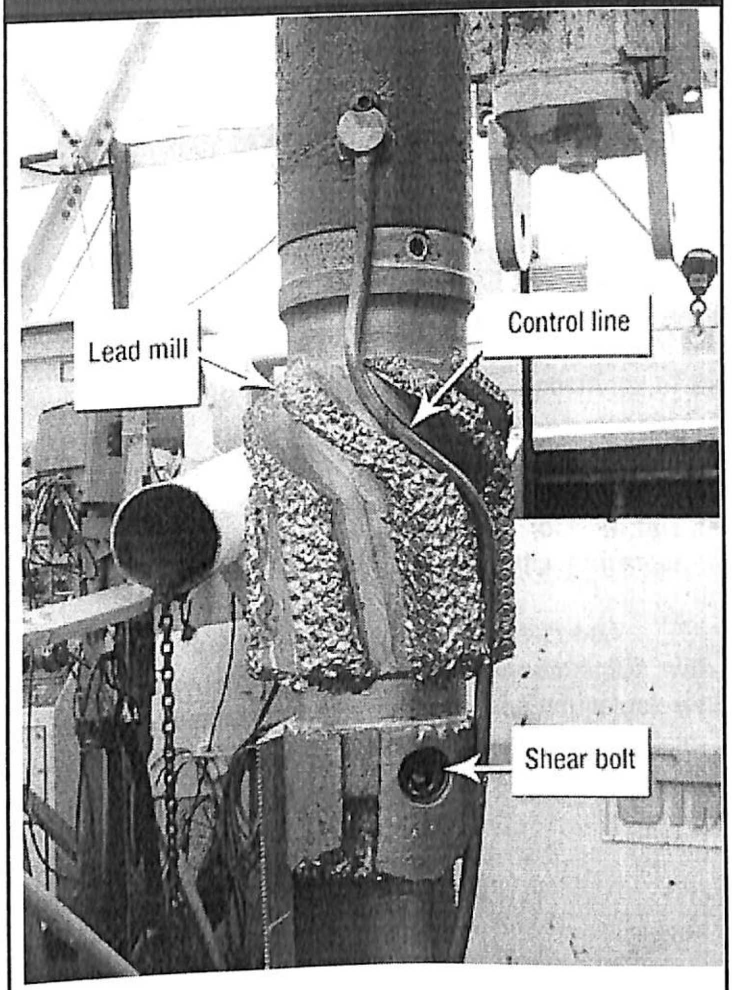


Fig. 7.6. The control line and shear bolt are used to separate the whipstock from the lead mill after the packer is set.

The system design allowed sufficient drilling fluid flow to operate the MWD without setting the packer. A computer program was used to determine the optimum flow rates. After orientation was set, the flow rate was increased to set the packer and anchor. This system became an industry standard for making casing exits that allowed stiff rotary-steerable systems (RSS) to be run through the window. The only difficulty was that this system was designed for situations where the main bore of the well would be abandoned. For Statoil in the Norwegian Sea, the technology would have to be modified to provide fluid access to both the lateral and the main bore.

Merging technologies

This project provided the opportunity to merge single-trip casing exits and hollow whipstock technology into a single process that would incorporate the best features of both and save substantial rig time. Several enhancements were incorporated into the system design. First, the rails of the whipstock (the projecting portions on each side of the concave) were extended and strengthened to provide additional support for the pilot nose of the lead mill to protect the integrity of the hollow portion of the concave. Second, the 9⅝-in. packer was redesigned to allow hydraulic setting as described above and was further refined to allow the set packer to withstand 5,000 psi from above and below the packer at 302° F. Third, the two retrieval features of the single-trip system were left in place—a retrieving slot in the side, and a die collar on top—in case the tool had to be retrieved before milling.

RUNNING PROCEDURE

The Weatherford-Statoil team ran the new system using the following basic procedure, Fig. 7.7:

1. Run the whipstock/packer assembly, orient, set at the required depth, and shear the milling assembly free.
2. Mill the casing exit and rat hole, reaming and cleaning it to ensure trouble-free entry of the subsequent drilling assembly.
3. Run the drilling assembly and drill the lateral, logging the positions of the radioactive tags in the whipstock for future reference.
4. Run, set and cement the liner (liner hanger shown at top), perforate the liner and/or perform sand control operations.
5. Run in zero-phase perforating guns to perforate the whipstock. In this case, the team ran the gun on wireline to save time, using the radioactive tags on the whipstock to position and orient the gun.
6. Complete the lateral and start commingled or separate production.

Before start of the running procedure, a gauge run is recommended with a stiff assembly to thoroughly scrape and clean the casing at the point where the whipstock will be set. While some operators may wish to omit this step, it prevents a host of potential problems.

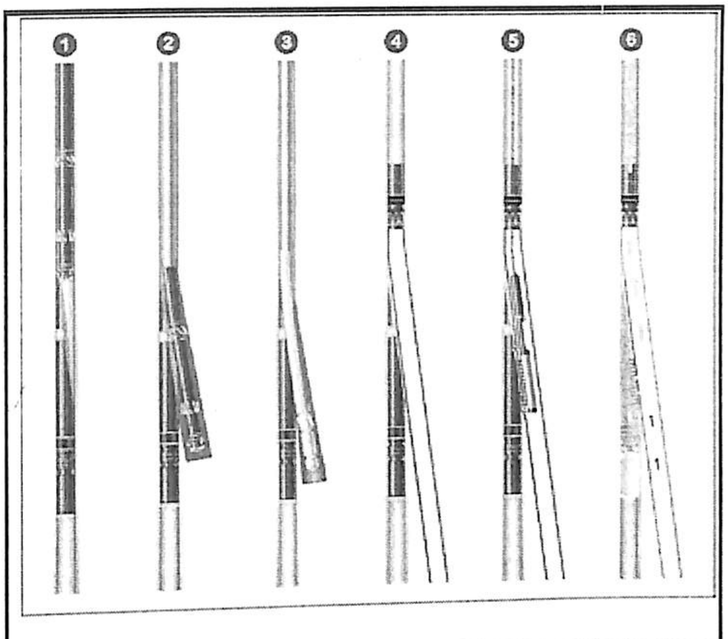


Fig. 7.7. Main steps in creating the TAML Level 4 connection.

PRE-JOB CONCERNS

While the approach used was straightforward, there were a number of pre-job concerns. First was the issue of milling the super 13%-Cr, 110-ksi) casing. The team reviewed previous milling reports of jobs that had used the same mills for super duplex P-110 with 25% chrome in heavy-wall Q-125 casing to determine the optimum milling parameters for this job. The second concern was that the exit would be in a very competent, dirty and hard sandstone formation. Following a discussion with product line management and R&D engineers, the team decided to have available a diamond mill that had previously achieved very good results as a backup mill in a hard sandstone formation.

Perforating the super 13 Cr casing presented another potential for trouble. Nominal perforation hole size in an 80-kip yield material is 0.33 in. Given the 125-kip yield material, the team anticipated a reduced hole size of 0.32 in. and a corresponding flow area reduction from 2.8 sq in. to 2.7 sq. in. Because of reduced hole size, the team decided to make two perforation runs to ensure sufficient total flow area (TFA) through the hollow concave of the whipstock even if some of the shots missed the perforation area. To deal with high temperature in the well, the team decided to use a high-temperature HMX charge in the perforation guns. This charge can perform after 200 hr at 295°F. Accommodating the substantial heave of the rig required a higher value shear attachment that could withstand the stress and still shear when expected. Finally, the team prepared a detailed procedure to communicate all stages of the completion process, including risk analysis, contingencies, comprehensive pre-testing of assemblies, and every step of the job to provide clear QHSE guidelines and achieve a seamless operation.

MAIN BORE DRILLING AND COMPLETION

Drilling and completion of the main bore proceeded without incident as follows:

1. The 20-in. casing was set at 2,608 ft and cemented to surface.

2. The 13⅜-in. casing was set at 6,936-ft MD and partially cemented with the top of the cement at 5,623 ft.

3. 10¾-in. x 9⅝-in. tapered casing string was set at 13,454-ft MD with a total vertical depth (TVD) of 12,648 ft, and cemented in place with the top of the cement being logged at 7,523-ft MD.

4. The 8½-in. diameter main bore was then drilled horizontally into the lower formation to a TD of 20,538 ft.

After cleaning the main bore thoroughly to TD and running the requisite logs, the team completed it using a 5½-in. sand screen. Because the screen was so long, and because of the critical need to place the top liner hanger at the correct depth, the sand screen was run in two sections.

Run 1: Setting the sand screen lower section. The lower screen section was run to TD. It consisted of a 2,418-ft assembly that incorporated a bullnose assembly; 5½-in.-OD sand-screen sections; 7.9-in.-OD, 5½-in.-ID, 20-lb/ft swell packers at suitable intervals; an upper polished bore receptacle (PBR) for the second section; and a hydraulic release running tool. The assembly was run on 5½-in. drill pipe. Once this assembly reached TD, it was released by circulating a 1½-in. ball to bottom and pressuring up to shear-release the running tool.

Run 2: Setting the sand screen second section. The balance of the main bore screen liner, which was run in next, consisted of a 6.1-in.-OD bullnose with a 2-in. hole; 5½-in.-OD sand-screen sections; the same type of swell packers at suitable intervals; an open hole packer; a hydraulic cementing sliding sleeve (HCSS); a crossover to 7-in., 29-lb/ft tubing; 7-in. tubing; 7-in. liner hanger and packer; and a liner running tool. This assembly was also run on 5½-in. drill pipe. Once this second string tagged the PBR of the lower sand-screen section, the liner hanger was set using the same type of ball-dropping mechanism.

Run 3. Setting the open hole packer and cementing The new work string consisted of a shifting tool assembly for setting the open hole packer; a washing tool with HCSS shifting tool; a no-go assembly; 3½-in. wash pipe; 3½-in. drill pipe; and packer-setting assembly, all run on 5½-in. drill pipe. The work string was run in, landed on the no-go, and then pulled up slowly to snap through the HCSS and open hole packer profiles. A 4-ton overpull indicated that the packer had been set and the HCSS closed. The string was then run back to open the HCSS and position the wash tool for the stage cement.

The stage cement job isolated the permeable formations between the reservoir and the 9⅝-in. casing shoe. Then the team released the drill pipe dart, circulated it to bottom, and landed it with good surface indication. The string was picked up slowly to close the HCSS, and pressure was applied to verify that the HCSS was closed. Then the string was pulled up to clear the packer setting assembly above the PBR to facilitate circulating out the excess cement. After cleanout, the work string was lowered again to locate the packer-setting dog sub on the top of the liner PBR. A set-down weight of 30 t set the packer, and good surface shear was observed.

Run 4. Cleaning and logging the hole The 7-in. and 5½-in. liners and screens, just set all the way to bottom, were cleaned out. The 9⅝-in. casing was then scraped, particularly in the area where the single-trip hollow whipstock would be set. These operations were absolutely essential because there would be no future access to the main bore after the lateral was completed, and any debris in the main bore could affect the setting of the whipstock packer. The team also ran an ultrasonic imager-tool log to assess any wear in the 9⅝-in. casing where the single-trip hollow whipstock would be set. This completed work on the main bore, Fig. 7.8.

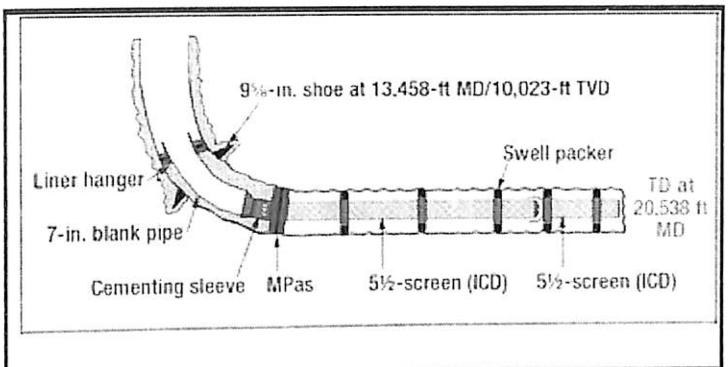


Fig. 7.8. Main bore completion.

DRILLING THE UPPER LATERAL

Even though the new approach to a TAML Level 4 junction eliminated two runs, it still required several runs to complete the job.

Run 5. Milling the casing exit The mill assembly was attached to the hollow whipstock using a shear bolt of greater than normal strength to compensate for the rig heaving. The whipstock assembly was then run in the well on 5½-in. drill pipe at a controlled rate to minimize stress on the bolt. The whipstock was oriented and the flow rate increased to set the whipstock packer/anchor so that the top of the whipstock would be at 13,607-ft MD and 64° inclination. The whipstock was positioned adjacent to the formation, which was hard, impermeable sandstone with quartz stringers. The team had selected this formation to provide a consolidated formation for milling the window and rat hole.

The work string was slacked off to confirm the setting of the packer/anchor, and then picked up to shear the attachment bolt. The casing pressure was tested to 1,500 psi to verify the integrity of the packer. After completing this successful test, milling of the window was started using minimal weight to avoid digging into the hollow whipstock. Milling of the 9⅝-in. casing-exit window and rat hole, each 6 m in length, through the 53.5-lb/ft super 13% Cr casing was completed in a total of 5½ hr. This step was completed by sliding and pulling the mill assembly through the window to ream and polish it. The lack of drag indicated that the window was clean and would provide access for the stiff RSS assembly.

Run 6. Drilling the lateral In this run, an RSS, consisting of a drilling motor, bent housing, and PDC bit was lowered into the hole and through the window to drill the lateral to 13,586 ft. It took several runs using PDC bits to reach the TD goal of 15,889 ft in the upper formation. Upon reaching TD, pressure points and hole conditions were checked in the sliding mode to ensure that the lateral was clean and up to gage.

Run 7. Running liner and sand screen, and setting packers The team made up the liner assembly for the lateral and ran it to setting depth at a slow rate (1.5 min. per stand), taking weights up and down, and breaking circulation every 3,219 ft. The string was made up of a bull nose assembly; open-hole packer; 5½-in. sand screen; 7.9-in. OD swell packers at intervals; another open hole packer; an HCSS cementing sleeve; 7-in. tubing for the upper liner; liner hanger and packer with PBR; and a liner hanger setting tool, all run on 5½-in. drill pipe.

The liner assembly was run to planned depth, placing the liner hanger and PBR inside the 9⅝-in. casing at 13,179 ft. Then circulation was re-established and the liner hanger was set by dropping a 1½-in. ball, circulating to bottom and pressuring up. After pressure was bled off, weight of 30 t was set down to verify that the hanger was set, and pressure was re-applied to shear out the ball seat and enable the setting tool to be released. A separate run was made to set both open hole packers prior to cementing.

Run 8. Stage cementing A work-string was made up to open the HCSS, stage-cement the upper liner to isolate the permeable formations above the formation, close the HCSS, clean out excess cement from the 7-in. liner and 9⅝-in. casing, and set the liner-hanger packer. The work-string consisted of a shifting tool for the open-hole packer; a wash tool with shifting tool for the HCSS; no-go assembly; 3½-in. wash pipe and drill pipe; and liner-hanger packer-setting assembly. The work-string was run on 5½-in. drill pipe until the packer setting assembly settled in the PBR and landed on the no-go. The work-string was then pulled up slowly to snap the shifting tool through the HCSS and open-hole packer profiles and to ensure that the upper open-hole packer was set. The cement stand was installed at surface.
After slacking off to the no-go, a stage cement job was performed using the wash tool through the HCSS, thereby isolating permeable formations and the whipstock. A dart was then pumped down to its seat, and additional pressure applied to shear it out to re-establish circulation. Then the string was picked up to close the HCSS, and re-establish circulation to clean out the excess cement in the liner and 9⅝-in. casing. Finally, the liner-hanger packer was set by applying set-down weight on the liner top PBR. To isolate the lateral during perforation and also to facilitate flow through the main bore after perforation was complete; a short 5-in. liner was landed and set inside the lateral's 7-in. liner.

Perforating the hollow whipstock After the upper lateral was completed, the team flowed the lateral to clean up the lower formation. Then a plug was set in the 5-in. inner liner to isolate the lower portion of the lateral during perforation operations. The hollow whipstock was perforated in two separate runs, one to 13,125-ft MD and the other to 13,333-ft MD. The 3⅜-in. orienting guns were used at two shots per foot with 0° phasing located at 157° and 164° from the high side, Fig. 7.9. Radioactive tags in the hollow whipstock were used for depth control and orientation.

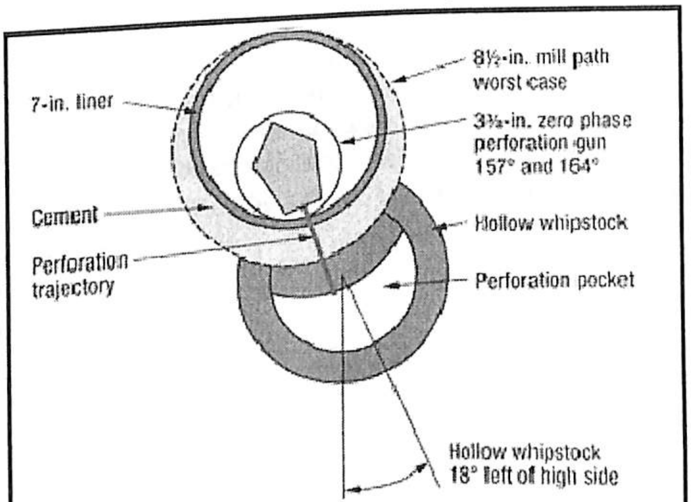


Fig. 7.9. The hollow whipstock was perforated in two passes.

After perforation, the main bore was successfully unloaded and cleaned; however, attempts to retrieve the plug from the 5-in. liner in the lateral were unsuccessful. The only way to gain access to the upper formation was to perforate the 5-in. liner above the plug using limited-entry shots. This operation was successful, and the well was handed over to operations. Figure 7.10 shows the schematic for the completed junction.

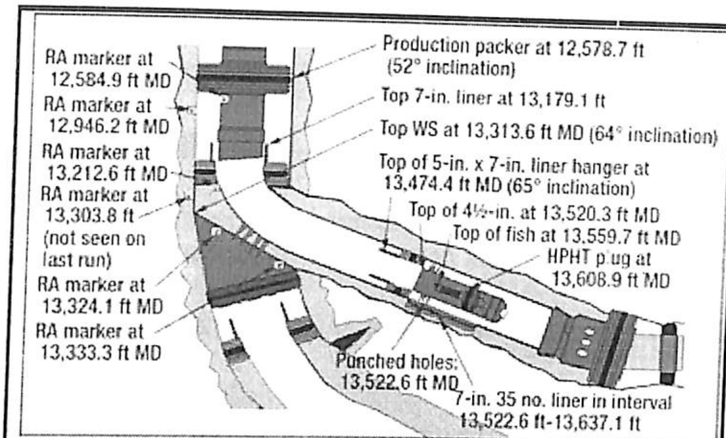


Fig. 7.10. Completed TAML Level 4 junction.

CONCLUSIONS

The first run of this single-trip hollow whipstock system proceeded without incident. The simplicity of the approach reduced risk for Statoil, and the elimination of two runs saved about \$2 million in rig time. The ability to create a TAML Level 4 junction so easily was a major advantage in addition to increasing the stability of the junction and preventing future sand damage.

The well was placed on gas injection at a combined rate of 190 MMcfd with positive response from the producing wells in the same formations. An estimated 30% of the injected gas is going through the perforated hollow whipstock into the lower formation with the remainder flowing to the upper formation. Because this project proceeded so quickly, the downhole control system was not qualified in time to be installed, and the well was completed without it. Because the well was an injection well, it had to be cleaned up using the rig facilities, and platform production facilities could not be used. The ability of the hollow-whipstock approach to isolate the two zones for separate unloading and cleanup was an important advantage. The successful installation of this system in a subsea injection well demonstrates that this technology can be used for many different applications. The caveat is that it requires precise and highly detailed planning of all downhole operations.

Chapter – 8

Level 5 Multilateral Completion

The Level 5 Multilateral System offers pressure integrity at the junction through the use of completion equipment designed to straddle the junction area.

Typically, a Level 5 Multilateral System builds from the basic Level 4 ROOT System in terms of cementing the lateral in place.

The hydraulic isolation of the junction is then achieved by isolating the junction using three conventional isolation packers: in the lateral, in the mainbore below the window, and in the mainbore above the packer. Along with these packers, a Scoophead Diverter Tool is utilized down hole to place and tie back the production tubing between each packer. Commingled production, isolated dual production, and selective access into each bore are all possible completion options.

Illustrated below is a Level 5 Multilateral system utilizing a Selective Re-entry Tool (SRT™) above the junction to provide commingled production of both zones. Selective thru-tubing access into either bore is possible through the use of a diverting tool that can be run in the SRT on either coiled tubing or wireline.

Not pictured but also possible is the utilization of a dual packer above the junction providing isolated production from each zone and continued thru-tubing access into either wellbore.

Key features of the Level 5 Multilateral System include:

- Pressure integrity at the junction achieved with completion packers and straddle tubing
- Commingled or isolated dual production completion options
- Selective access into either bore is possible in both commingled and dual production completion options

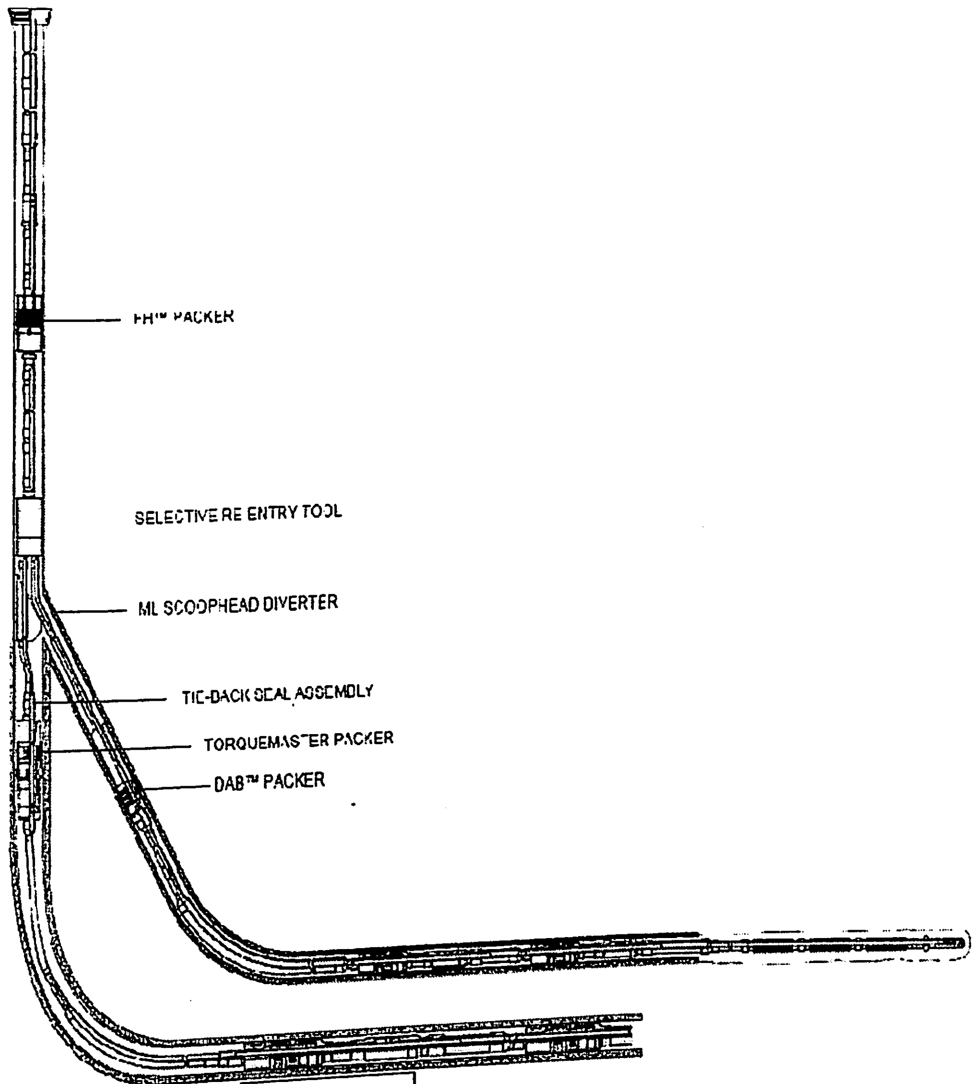


Figure 8.1

A Typical Level 5 completion System by Baker Hughes Inclusive

1. FH™ and FHL™ packer:

Single String Hydraulic/Hydrostatic Set Packers

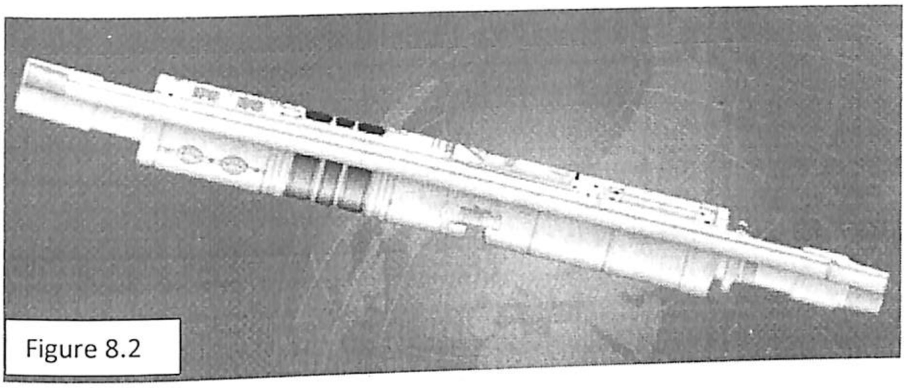


Figure 8.2

This packer can be run as a single packer or as a lower packer in multiple packer hookups using dual- or triple-string packers; use where well conditions prohibit mechanically set packers.

1. Selective Re-entry Tool

A method for completing multi-lateral wells and maintaining selective re-entry into laterals is presented. In accordance with the present invention, a first lateral well is drilled from a primary well bore and a string of external casing packers and a packer bore receptacle are run therein.

Once the orientation of the packer bore receptacle is determined, an orientation anchor of a retrievable whipstock assembly is mounted there to. Thereafter, a second lateral well may be drilled. Once the second lateral well is drilled, the whipstock assembly may be retrieved and replaced with a Scoophead diverter assembly which also includes an orientation anchor for mating with the packer bore receptacle. At this time, a string of external casing packers may be run into the second lateral well through the Scoophead diverter assembly.

Finally, a selective reentry tool is run into the Scoophead assembly. The selective re-entry tool includes a diversion flapper for selecting either the first or second lateral well bore. Selective re-entry is desirable for the purpose of performing well intervention techniques. The re-entry tool may be actuated by a device located on a coil tubing work string which may be operated from the surface.

2. ML Scoophead Diverter

A Scoophead/diverter system is run into a wellbore using a novel Scoophead running tool. The running tool allows circulation through its inside diameter, and has internal pressure integrity to test any seals below the running tool prior to releasing the Scoophead. This also allows circulation while running in order to apply MWD techniques. This run-in tool includes a mounting head from which extends a running stump and a housing (or connecting mandrel) parallel to the running stump. The running stump and housing are sized and configured to be respectively received in large and small diameter bores in the Scoophead. The Scoophead running tool thus allows torque to be transmitted about the centerline of the Scoophead assembly in spite of being attached into one of the offset bore. This torque transmission is accomplished by connecting the connecting mandrel between the running tool and Scoophead at the same offset as the large bore of the Scoophead.

This transfer of torque is important in order to reliably manipulate the Scoophead assembly with the running string. The connecting mandrel of the running tool has an internal bypass sleeve that opens at a predetermined pressure that allows a tripping ball to be circulated down to its seat if the Scoophead is to run and be anchored into a closed system.

A novel scoophead/diverter assembly is presented which is installed at the juncture between a primary wellbore and a lateral branch and which allows the production tubing of each to be oriented and anchored. This scoophead/diverter assembly further provides dual seal bores for tying back to the surface with either a dual packer completion or a single tubing string completion utilizing a selective re-entry tool. The scoophead/diverter assembly comprises a scoophead, a diverter sub, two struts as connecting members between the scoophead and diverter sub and a joint of tubing communicating from the scoophead, thru the diverter sub, and to the primary wellbore. The scoophead has a large and small bore. The large bore is a receptacle for a tie back sleeve run on top of the lateral wellbore string, and the small bore is a seal bore to tie the primary wellbore back to surface.

Below the scoophead, a joint of tubing is threaded to the small bore. The tubing passes through an angled smooth bore in the diverter sub which causes the tubing joint to deflect from the offset of the small bore of the scoophead back to the centerline of the scoophead, and thus the centerline of the borehole with which it is concentric. In accordance with an important feature of the scoophead, the profile in the top of the scoophead is configured so that it directs the production tubing for the lateral wellbore into the large bore of the scoophead and also orients a parallel seal assembly when tying back to the surface with a dual packer completion or a single tubing completion. The orientation is accomplished by combining a sloped profile with a slotted inclined surface around the small bore and a compound angled surface above the slot.

Tie Back Seal Assembly

Two standard seal assembly variations are available.

- PBR Style
- Tieback Style

The PBR style is used for high pressure situations in tieback or completion applications. The tie-back style is used for low pressure tieback applications.
The only difference between the two styles is the metal space ring that backs up the packing. For PBR style, the space ring has an upset that is .010 inch on diameter smaller than the sealing surface ID. For tieback style, the space ring is .032 inch on diameter smaller than the sealing surface ID.

The increased clearance on the tieback seal assembly allows easier installation into the seal bore and reduces pressure rating of the seals to 5,000 psi at 250° F. For a liner setting sleeve with an extension, the seal assembly is designed to locate on top of the extension so the guide nose does not contact the liner setting sleeve body.

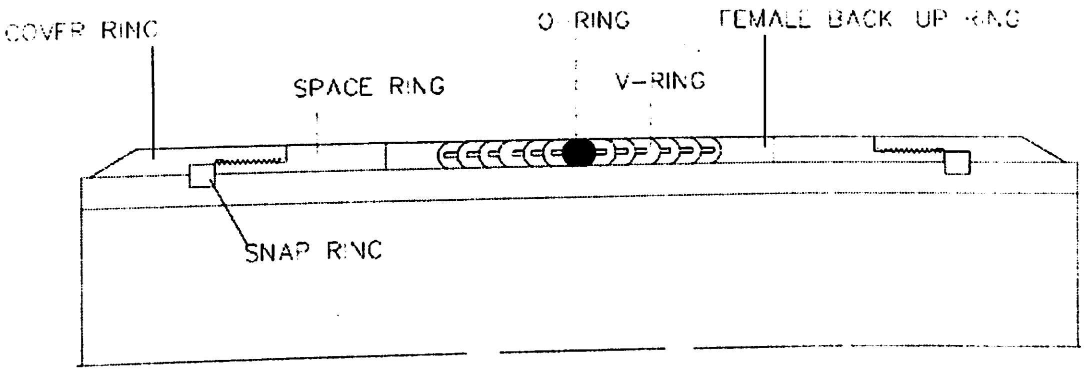
A locating shoulder is provided on the seal assembly below the top connection for this purpose. The locating shoulder may be a metal ring installed below the top connection or integral with the seal assembly mandrel depending on seal OD or top connection thread requirements. For a PBR completion, the PBR hook-up will determine where or how the seal assembly locates.

The seal assembly mandrel is one piece construction with a collared or integral top connection. The standard material used is AISI 4140 alloy steel for high strength. The mandrel ID is full opening to the thread size and weight ordered unless specified. The OD of the mandrel is determined by the seal size requested. Therefore the mandrel may not match the burst and collapse ratings of the casing. The mandrel length is determined by the liner setting sleeve extension length or cementing PBR length.

Seal assemblies are currently available with chevron type Molyglass or V-Ryte® packing. Three sets of seals spaced one foot apart (on center) located directly above the guide nose are standard for seal assemblies. Additional sets can be added if mandrel length permits.

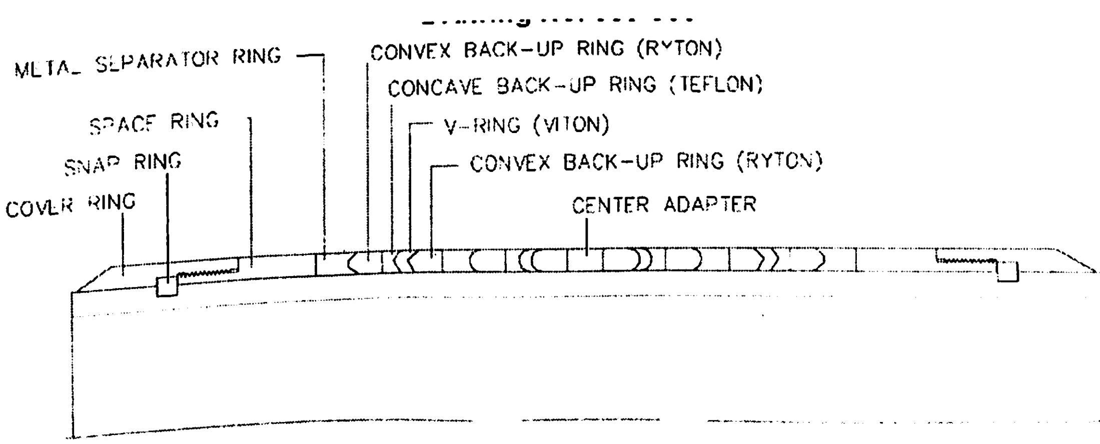
Molyglass seals are used for standard high pressure (10,000 psi @ 300° F) applications. V-Ryte® packing is for high performance (15,000 psi @ 450° F) applications. Neither packing type should be allowed to leave the seal bore while under pressure.

- Half mule shoe.
- Round nose.
- Round nose w/aluminum bull nose.



MOLYGLASS SEAL SET

Figure 8.3



V-RYTE SEAL SET

Figure 8.4

CASE STUDY of Troll West Field

Introduction to the Troll West field

The Troll Field is located approximately 80 km north west of Bergen, in the Norwegian Sector of the North Sea. The water depth is 315 — 340m. The field is divided by two major, curved, north-south trending faults which separate the field into three provinces. Troll West Oil Province (TWOP) and Troll West Gas Province (TWGP), both producing from a sandstone reservoir and operated by Norsk Hydro. The third province is Troll East with gas production, operated by Statoil.

Figure 8.5

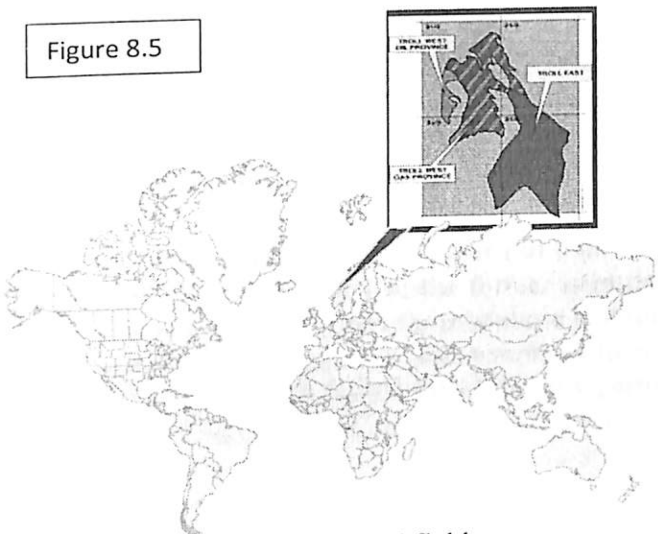


Figure: The location of the Troll field.

The Troll West oil column is approximately 22-26m thick in TWOP and 11-13m thick in TWGP. The overall area of the field is 200 sq km. The combined development is estimated to recover a total of 1.45 billion barrels of oil. Norsk Hydro started production from the Troll B platform in 1995 and from the Troll C platform in 1999. Statoil started gas production from the Troll A platform at Troll East in 1996. There is communication between the three areas that affect the fluid flow and have impact on production strategy of the field. When the field was discovered back in 1979, and for many years to follow, it was considered a gas field with no commercial oil available. Today the Hydro operated part of the field is producing approximately 200 000 bbls/day of oil, making it the second largest producing oil field in the North Sea. The field currently accounts for more than 11% of Norway's oil production.

The multilateral well concept was introduced on Troll West primarily to increase the total drainage area from the existing sub-sea template structures. New horizontal producers are continuously being drilled to recover reserves from the relatively thin oil layers before gas production induces oil column movements that are too large. By March 2006, a total of 109 wells had been drilled and completed on the Troll West Field, including 41 multilateral wells with a total of 54 multilateral junctions.

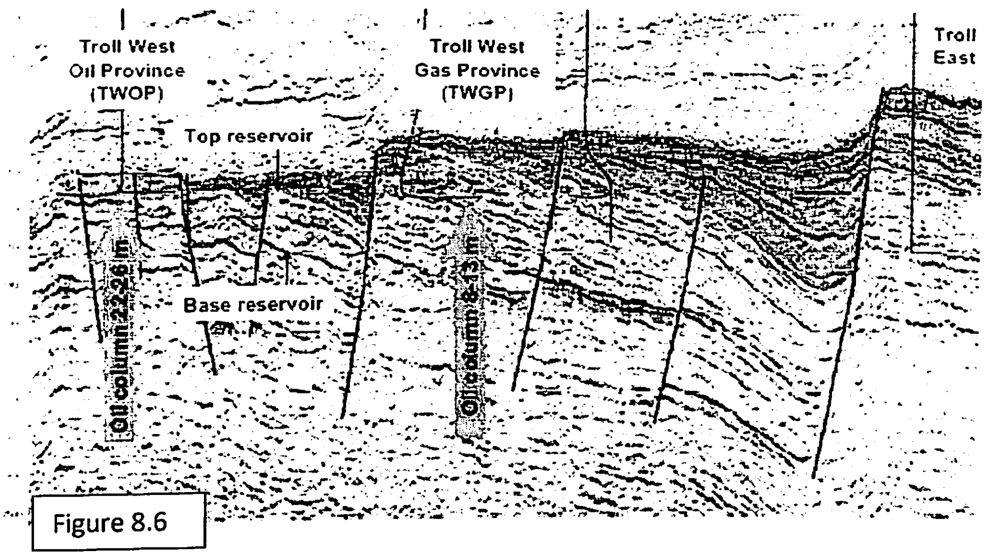


Figure 8.6

Figure: The Troll reservoir section.

The reservoir sands on Troll Olje consist of both clean sands (C-Sand) and micaseous sands (M-Sand) where the permeability of the former is in the 1 — 10 Darcy range. It is the clean sands that have been the main targets for monobore horizontal producers. The multilateral solution will recover more oil from the four-well templates 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 of as low as 100 millidarcy.

The Troll West Oil Province and Troll West Gas Province are commonly referred to as Troll Olje (oil); this is the term that will be used in the remainder of this study.

Development of the FlexRite® System and Variants

FlexRite System Development

Prior to the development of the FlexRite system in 2000 (the system was originally referred to as ITBS, i.e. Isolated Tie- Back System) three TAML Level 4 multilateral wells had been installed on Troll Olje. In these wells, junction isolation was achieved with a formation resin squeeze and special cement around the lateral milled through liner. Junction related production problems were initially experienced in two of the wells with lumps of resin flowing back and plugging surface equipment. The MLT operations on these wells had been completed in 22 days, 17.9 days and 14.6 days, respectively. In order to further improve the reliability of the junction and the installation time, a new system would be required.

The operator Norsk Hydro accepted a proposal to develop an existing prototype system into a TAML level 5 multilateral system, initially tailor made for the Troll Olje field, where the following objectives were defined for the project development;

- Employ mechanical seal to isolate the junction (TAML Level 5)
- Installation time potential of less than 6 days
- Robust and simple installation process from floating rigs with no milling of steel
- Optimize flow area,
- Ensure access to main bore, and preferably access to laterals.
- Demonstrate ability to plug both main bore and lateral above junction

The project was taken through the normal stages of concept evaluation and initial risk/feasibility review, detailed design, prototype equipment manufacturing and testing, implementation of changes based on testing, re-testing of implemented changes and manufacturing of field equipment in 13Cr material. The first field installation commenced in November 2000 and was completed in January 2001, this was well Y-22 on Troll Olje.

The main component in the FlexRite system is the Flexible Junction, it is the junction that provides connectivity to the main bore and lateral branch provides hydraulically and mechanically isolation and allows access to the branches. The junction has a D-shaped lateral leg with a D-to-round coupler in the bottom end with a 6 5/8-in. pin thread down. It has a mainbore leg consisting of a D-shaped upper half with a 4" OD round seal stinger below. Compared to an alternative design with two 4-in. tubing joints side by side the D-shapes offers a larger flow area (17.7 in2 vs. 9.08 in2) in addition to mechanical stability and increased tensile and compressive strength. The two D-shaped legs are welded to a Y-block connecting the two round bores of the Y-block to the two D- sections. The round bores in the Y-block are hone bores with 3.437" ID, these bores can be used for setting a bridge plug or for landing of a junction straddle seal sub.

Figure: The FlexRite junction.

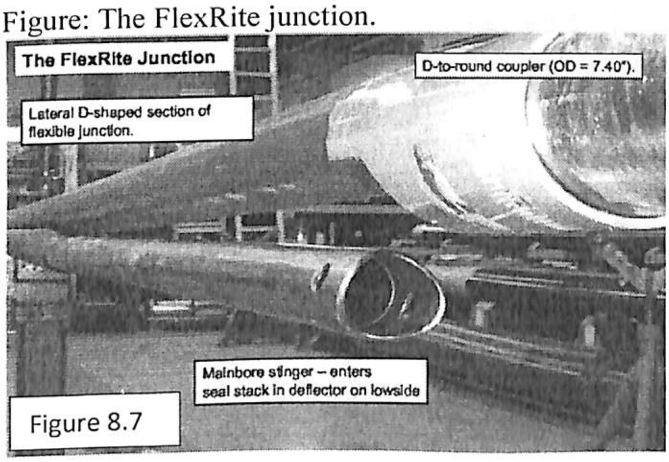


Figure 8.7

FlexRite-Intelligent Completion Interface (ICI) System:

In 2003 Norsk Hydro concluded that some of the future multilateral wells on Troll Olje would require individual downhole branch control. To achieve this new variant of Flexible Junction and some additional tooling was developed. In the flexible junction the existing Y-block, allowing flow co- mingling from the two legs in the junction, was replaced. In the new Y-block the bore connecting to the mainbore leg was expanded and threaded, whereas the lateral leg was connected through a banana shaped flow area utilizing the available area of the Y-block. A 6m 5 1/2-in. polished bore receptacle (PBR) was made up to the Y-block mainbore, and a 7 5/8-in. joint was made up to the Y-block on the outside to create a 7 5/8 x 5 1/2-in. annulus for the lateral branch fluid flow.

A seal stinger run on the bottom of the intelligent completion is installed in the junction PBR to form a pressure tight seal preventing crossflow between the lateral and mainbore. This arrangement allows flow from the lateral to follow an annular path up to the Inflow Control

Device regulating the annulus to tubing flow, and flow from the mainbore to follow the internal tubing path to a Shrouded Inflow Control Device regulating the through tubing flow
The FlexRite-ICI system components were design and tested in 2003, the first field installation was completed in July 2005, this was well P-24 on Troll Olje.

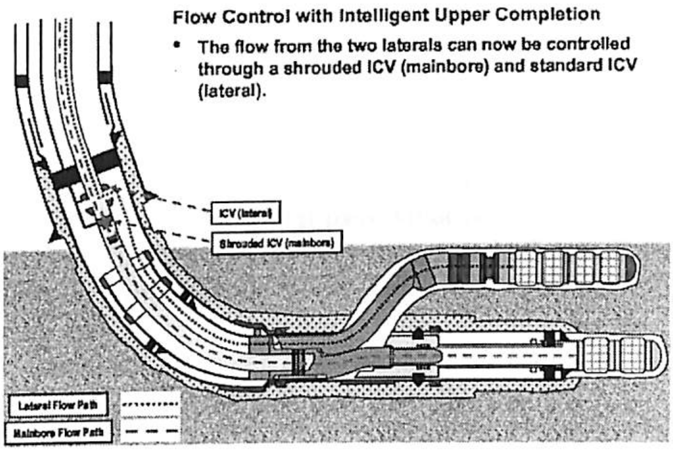


Figure: FlexRite ICI completion sketch

Figure 8.8

ReFlexRite® System Development

The project objective was to develop a re-entry multilateral solution that would enable additional lateral branches to be added to existing Troll Olje single horizontal wells. The new lateral branches are completed with the FlexRite® junction system, while maintaining the production from the original well.

The main features of the ReFlexRite® solution from 10 %-in. casing in existing Troll Olje wells were:

- A 10 3/4-in. ML packer that will be installed in the existing 10 %-in. liner to provide the permanent depth and orientation reference for all multilateral junction related operations carried out in the well.
- A sealing arrangement to be run below the ML packer.
- A 10 3/4-in. window bushing that will lock into the top of the 10 3/4-in. ML packer. The purpose of the window bushing is to reduce the casing size to an equivalent 9 5/8- in. 53.5# ID in order to use existing equipment for milling and subsequent operations.
- A latch system for equipment to be set in the window bushing, combining the standard latch system (lock and depth reference) and an orienting Muleshoe arrangement (alignment).
- A 9 5/8-in. MillRite milling system, installed in the 10 %- in. window bushing, to create an initial controlled geometry 1st pass window.
- A 9 5/8-in. Drilling Whipstock for opening up the 1st pass window to 8 1/2-in. full gage.
- The system was successfully developed, tested and installed in Troll Olje well H-2, see case history to follow. The system has since been upgraded in that the Window Bushing has been converted to a Latch Interface Assembly and 10 3/4-in. MillRite, Whipstock and Deflector has been developed and tested.

FlexRite Installation Operational Sequence

1. Main Bore Above Reservoir Section.

The FlexRite multilateral wells are drilled as per normal until the 13-3/8-in. casing is set about 120mTVD above the reservoir. A 12 1/4 x 13 1/2-in. holes is then drilled and under- reamed, typically in one operation while building inclination from 45 — 60 degrees at the 13-3/8-in. shoe to horizontal in the reservoir. The bottom 100m or more of the section is drilled horizontally in the reservoir in order to place the FlexRite junctions in this area. The actual length depends on number of junctions planned for the well. To date a maximum of three junctions have been installed in one well.

On Troll Olje there are reservoir sands with permeability in excess of 10 Darcy, and draw down is only 1 - 2 bars even for liquid production rates at 19,000 — 25,000 barrels/day. Hence, the multilateral junction should preferably be placed horizontally in the reservoir to limit the hydrostatic pressure effects from gas or water ingress in one lateral, on the other lateral.

2. Liner with Pre-milled FlexRite Window

The 12-1/4-in. hole section is under-reamed to 13 1/2-in. in order to enable easy orientation of the subsequent 10-3/4 x 95/8-in. liner with the pre-milled FlexRite windows, one window is installed for each additional lateral branch planned. The 9-5/8-in. liner section consists of a shoe track with three joints of casing above, followed by the lower window assembly with a drillable alignment bushing, a latch coupling and a pre-milled window section for drilling the lateral branch. The drillable alignment bushing is aligned to the lower window, and the lower window is aligned to any window above by use of casing alignment subs. Above the uppermost window there is a 9 5/8 x 10 ¾-in. alignment crossover, for use during junction lading, then 10-¾-in. casing joints above.

The liner is run with an inner string that contains an MWD and an orienting key sub that is stung into the drillable alignment bushing to enable window orientation. At section TD, the window is oriented to high side, and the liner hanger is set. A lower dart plug is pumped down and lands above the inner string MWD; a rupture disk sub is then sheared to establish communication past the MWD. The cement is mixed, pumped and displaced with a top dart plug landing and isolating the open port, application of a higher pressure shears another rupture disk to re-establish communication. A 10 ¾- in. tie-back string in then installed back to the sub-sea wellhead.

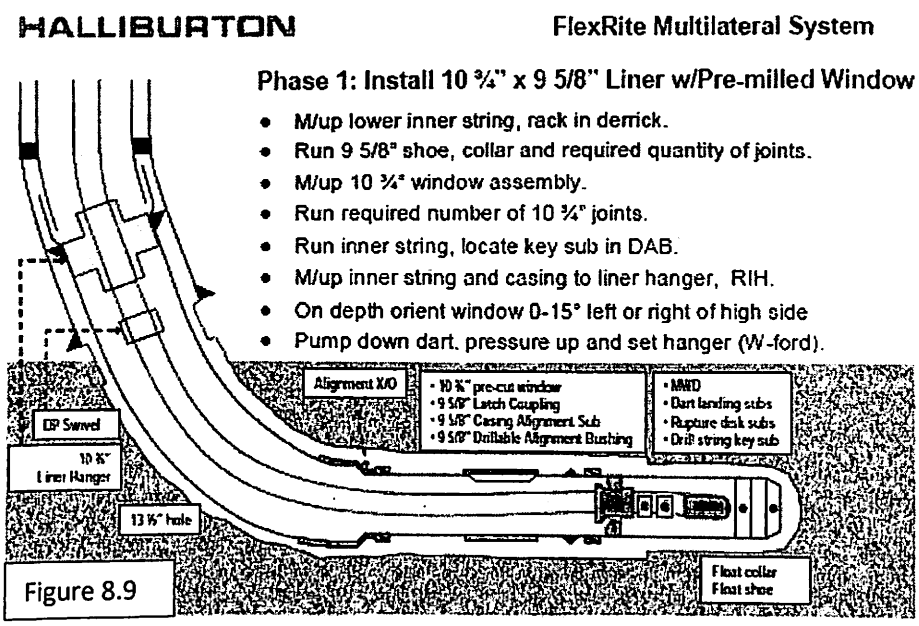


Figure 8.9

Figure: Installation of liner with pre-milled window.

3. Drilling and Completing the Main Bore Reservoir Section

The 8 1/2-in. main bore section is drilled horizontally using a rotary steerable system. The length of the mainbore section varies from 3000 to 5500m. In some wells open hole sidetracks of 1000 to 1500m are performed to further increase the reservoir exposure (acting as a "twig on the branch"). The main bore is then completed with a combination of 5 1/2-in. and 6 5/8-in. screens, hung off with a screen liner hanger packer below the latch and pre-milled window. Basically, the main bore is drilled and completed independently of the MLT feature of the well as such.

4. Casing Exit to Drill Lateral

A drilling whipstock is installed in the latch coupling below the pre-milled window. Normally the whipstock is run bolted to the milling assembly and the running bolt sheared off with a combination of torque and weight down. The window milling is then performed, milling through the aluminum sleeve on the outside of the pre-milled window joint plus 1.5 — 2m of formation. The entire milling process takes typically 5 hrs with good recovery of aluminum. The whipstock is either run open with hydrostatic communication to the main bore, or with a fluid loss seal stinger below stinging into the mainbore PBR.

5. Drill Lateral Branch Reservoir Section.

The 8 1/2-in. lateral branch section is drilled horizontally using a rotary steerable system. The horizontal length of the lateral branch varies from 3000 to 5500m. Again, in some wells open hole sidetracks are performed to further increase the reservoir exposure.

6. Completion of Lateral Branch and Landing of Junction

The drilling whipstock is retrieved with straight over pull using a hydraulic retrieval tool engaging the open throat of the whipstock.

After whipstock retrieval a clean-out run may be performed prior to installation of the FlexRite deflector that is run and set in the latch coupling. A tail pipe below the deflector includes a seal stinger that lands in the screen hanger PBR below to isolate between main bore and lateral.

The lateral screens are run with a bullnose designed to deflects off of the deflector assembly and enter into the lateral well bore. Above the 5 1/2 x 6 5/8-in. screens there is a swivel sub, to enable orientation of junction without turning the screens, followed by the Flexible junction and a screen hanger/packer. An MWD is made up to an extension under the screen hanger/packer. The lateral screen liner is RIH on a landing string, prior to landing the Flexible Junction in the deflector the lateral leg is oriented high side, and the mainbore leg is landed in the deflector seal receptacle. The screen hanger/packer will then be set and the landing string with MWD retrieved.

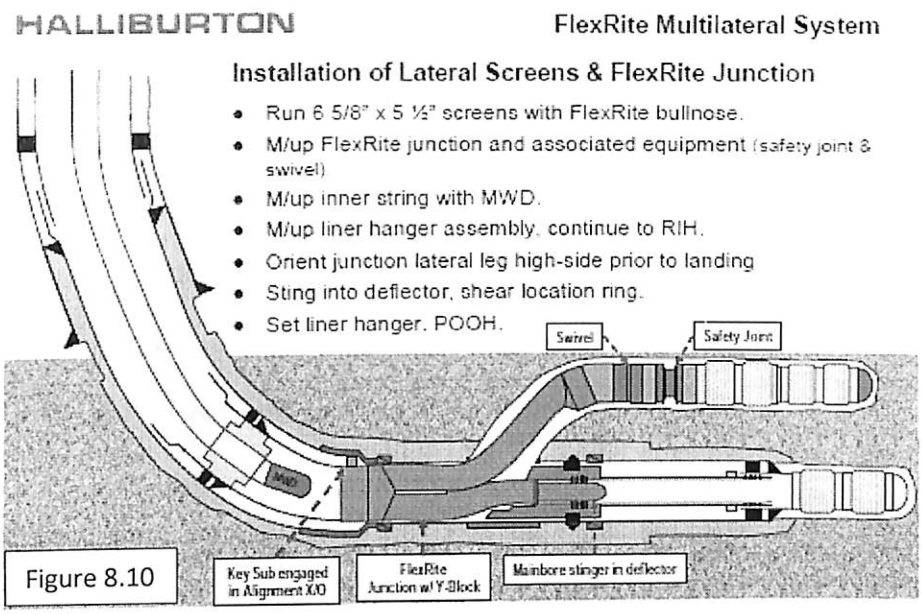


Figure 8.10

Figure: Installation of lateral screens and FlexRite junction.

7. Additional Junctions

If additional junctions are to be installed the process is repeated from casing exit to completion of lateral branch for each of the pre-cut windows installed.

8. Well Completion

A middle completion with a pressure operated isolation valve is installed to secure the well and allow for pulling the BOP.
The horizontal X-mas tree is then installed and the BOP re-run prior to installation of the upper completion.

Statistics for 50 FlexRite junctions installed by March 2006

By March 2006 a total of 54 multilateral junctions had been installed on Troll Olje using the following systems and system variants:

- 3 x System 4503 (system now obsolete)
- 48 x FlexRite
- 2 x FlexRite Intelligent Completion Interface (ICI)
- 1 x ReFlexRite

These junctions were installed in the following well configurations:

- 30 dual-laterals (one junction in the well)
- 9 tri-laterals (two junctions in the well)
- 2 quad-laterals (three junctions in the well)

Below are a summary of installation time and a brief description of major events causing non productive time on the 50 FlexRite and FlexRite ICI junctions installed by March 2006.

Installation Time

The installation time related to multilateral operations is monitored and agreed on between the supplier and operator for each well. The installation time is split into three categories:

- Direct productive MLT time (the time for the MLT related operations)
- Direct non productive MLT time (non productive time related to MLT operations)
- Associated time, i.e. both productive and non productive time to perform operations that would normally not have been performed if the well was a regular well.

The operator defines what the associated time is, but examples are; precautionary clean-up runs and installation of middle completion. The fact that the wells are both dual, tri and quad laterals affects the installation time per junction somewhat, mainly because the operation to install the 9 5/8-in. x 10 %-in. liner with pre-milled windows is performed once in each well. It should be noted that the average non productive time for dual laterals are considerably higher than for tri- and quad-lateral wells. The main reason for this is that only dual lateral wells were installed the first couple of years, and there were both a learning curve and especially one well with major non productive time (20 days). Excluding this one well from the statistics would reduce the average NP time and total time with about 1 day.

It should also be noted that on the two quad-lateral wells there is only 1 hour non productive MLT time for a total time of more than 18 days. Both quad-laterals were installed after more than 3 years of FlexRite operations, and possibly the attention level have been higher than normal with more time spent on precautionary associated operations like clean-out runs.

Major events causing non productive time

1. Casing Exit to drill lateral

Of the first 50 casing exits made through pre-milled windows on Troll Olje only one particularly problematic job has been experienced. On this well the milling assembly got stuck early in the milling operation, when free the milling continued but steel cutting were observed in return flow, not aluminum. The whipstock was changed out, and a window was then milled with aluminum cuttings in the returns indicating a correctly milled window. However, when completing the well the bullnose on the lateral screen liner would not exit over the deflector due to the window geometry, a total of 18 days were subsequently spent to correct the window geometry in order to successfully land the junction.

There were some initial problems with pre-mature bolt shear resulting in two lost whipstocks, both were recovered on first attempt.

2. Open Hole Drilling Problems

There have not been any lateral drilling problems, however, there have been a discussion regarding the bending moment that the BHA and drill string is exposed to when rotated through the window. Only once has a drill string parted when drilling the lateral. In an attempt to run an overshot past the whipstock to catch the parted drill string the whistock tip got damaged. The whipstock was changed-out and a modified overshot used to for fishing in the lateral. Tripping past whipstock and through the window has not presented any problems.

3. Whipstock Retrieval

The whipstock is retrieved by engaging in the internal bore, either by a spear or by a hydraulic retrieval tool. On two occasions the engagement in the internal bore has failed. First when a spear grapple broke and prevented engagement, and secondly when a cone lost from a tri-cone bit was stuck in the internal bore. On both occasions the whipstock was washed over and retrieved on the following run.

4. Deflector Installation

The first two of three failures to set the deflector correctly was created by metal junk pieces in the latch coupling area. The junk was later recovered, and the deflector correctly installed so that the lateral screens would enter the lateral. On the third failure it was not noticed that the deflector slipped out of the latch with set down weight and landed on a no-go a meter further down. Again, the deflector was correctly installed on the second attempt.

5. Junction Installation

On the first four of six installations the junction did not land in the deflector on the first attempt. Twice the lateral swivel, and twice the lower connection on the FlexRite junction, would not enter that lateral due to an excessive OD of 8.45-in. run into an 8 1/2-in. hole. When the OD was reduced to approximately 7 1/2-in. this was no longer an issue. On three of the four wells the situation was corrected, either by setting a straddle, reducing the OD on the junction or removing the swivel. On one well the junction was stuck un-landed. Since the junction was open a secondary screen section was installed as a lower completion. This did not prove very successful from a production point of view, and indications are that the screens plugged.

On one well the lateral bullnose would not pass the deflector and enter into the lateral despite the deflector being correctly set, most likely there was a window geometry issue. After two drift / dummy runs the screen bullnose did enter the lateral.

On one well a large amount of 5 1/2-in. x 8 1/4-in. centralizers fins were sheared off when pushing the screens past the deflector and into the lateral. The reason behind this single occasion incident was never fully established, but indications are that there was a severe dog leg caused by a hard stringer just outside the window. Many of these fms ended up in the throat of the deflector prevented landing of the junction. Screens and deflector were retrieved, a new deflector installed after clean-up and screens re-run and FlexRite junction landed.

Finally, on one well the junction was set high and in an un-landed position due to a tally error. In this well the gap between the junction mainbore stinger and the deflector was closed by a straddle.

Economic effects from the use of multilateral branched wells

Several studies have been performed recently in order to evaluate the benefits of utilizing multilaterals on Troll without being able to do justice to all the benefits.

First of all, with an initial target number of 170 reservoir locations and a fully exploited infrastructural slot number of 110, there are few other options. If space would permit, and if possible from an infrastructural point, the cost for subsea template installations including flow lines and risers would put the economics out of the context. Furthermore, the application of multilateral drilling gives the opportunity to pursue "less" promising targets, hence, comparing a multilateral well with the earlier drilled monobore wells would be a dissimilar comparison.

Basically, an extra branch on a well will add to the overall well cost by approximately 30%, or, result in a cost reduction of +12 MUSD compared to drilling two single laterals well.

Review of wells on production so far indicates that the daily production rate from a dual lateral is approximately 50 % higher than for a single bore well. However, the cumulative production over the lifetime of the well is 100% higher, i.e. a dual lateral will produce twice as much as a single bore well. This is presumed to be due to a more uniform inflow over a greater area of the reservoir and a thus, a limitation of the gas coning effect which again will prolong the lifetime of the well.

Conclusions

The multilateral wells installed on Troll Olje have been both a necessity and a great success. All wells drilled the last couple of years have been multilateral wells, and is now established as the norm for drilling on this field. The installation of multilateral wells will continue with two to three drilling rigs for several years.

Chapter 9

LEVEL 6 MULTILATERAL SYSTEMS

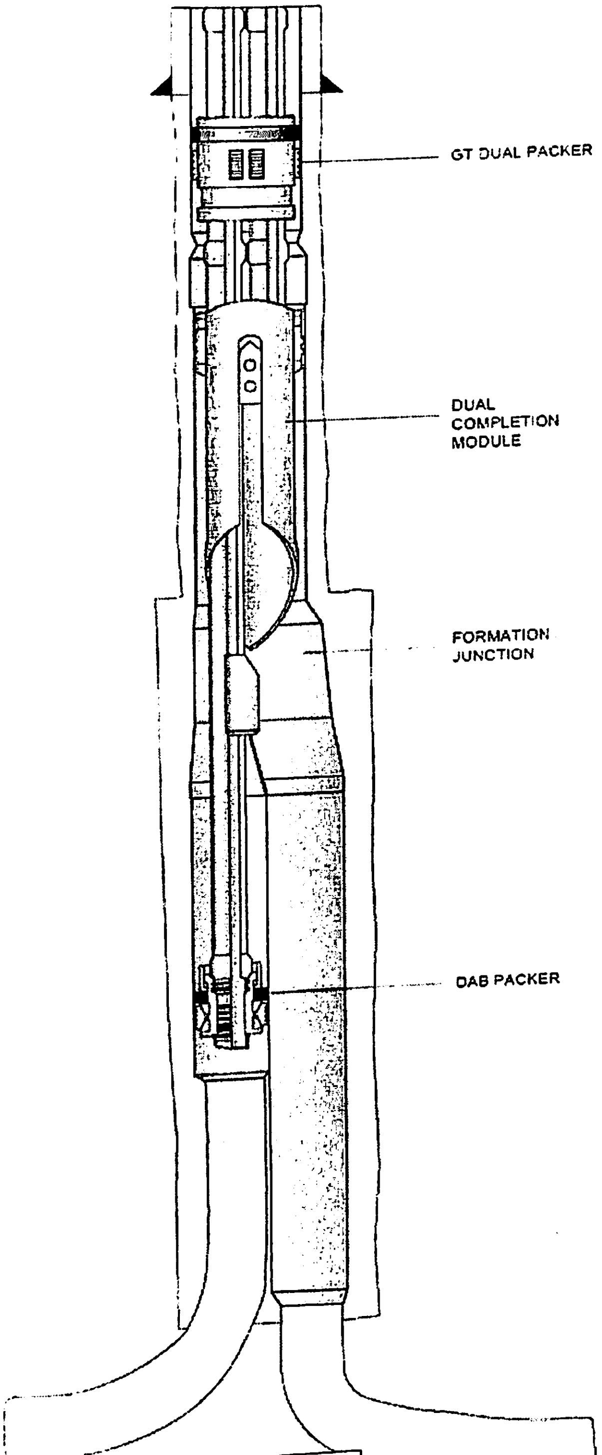


Figure 9.1

Level 6 Multilateral Technology by Baker Hughes Inclusive

Baker Oil Tools completed the world's first Level 6 Multilateral with the FORMation Junction™ Multilateral Junction System. The FORMation Junction is an inverted Y-Block™ junction that is installed with one leg in a pre-formed, non-circular shape to allow two 7" (177 mm) legs to drift inside 13-3/8" (339 mm) casing or a 12-1/4" (311 mm) open hole while being run in on a 9-5/8" casing string. The 9-5/8" (244 mm) casing is landed such that the FORMation Junction rests in a 17" (431 mm) under reamed section. The pre-formed 7" (177 mm) leg is then re-formed with a swaging assembly back to drift ID dimensions for 7" (177 mm) casing. The FORMation Junction is pressure tested and cemented in place using an inner cementing string. The legs can then be selectively drilled out with the simple installation of the desired diverter.

Advantages of the FORMation Junction Level 6 System over other multilateral systems include:

- Elimination of window exit creation
- Pressure integrity at the junction using the casing
- Low risk, simple installation procedures
- Utilizes standard casing and cementing equipment and procedures

The illustrated installation shows one of the optional final completion options - the Dual Completion Module (DCM). This module allows for separate production of each leg to surface. The DCM self-orients on a key, which directs one tubing string to sting into a seal bore packer. The annulus is then isolated by a GT™ Dual Production Packer. The DCM also provides permanent, thru-tubing re-entry access into each lateral

LEVEL 6 MULTILATERAL SYSTEMS

The DeepSet™ Splitter (DSS) is based on conventional splitter design with an inverted "Y" Block junction. The 13-3/8" x 7-5/8" x 7-5/8" DeepSet Splitter is conveyed on 13-3/8" casing into a drilled/underreamed hole of 17-1/2". A riser system is then installed inside the DeepSet Splitter to provide a separate conduit for cementing operations and to ensure velocities are sufficient to clean the hole during drilling.

Advantages of the DeepSet Splitter Level 6 System over other multilateral systems include:

- Elimination of casing exit and the resulting debris
- Provides highest-pressure integrity at the junction using the casing
- Low risk, simple installation procedures
- Optional riser systems as required isolates the junction from drilling and cementing operations

The illustrated installation shows one of the final completion options - the DSS™ Scoophead Diverter. This module allows for separate production of each leg to surface. The DSS Scoophead Diverter self-orients on a key that directs one tubing string to sting into a 7-5/8" (193 mm) seal bore packer. The second tubing string telescopes through the DSS Scoophead Diverter and stings into the second 7-5/8" (193 mm) seal bore packer. The well produces and is re-entered as if the laterals were two independent wells.

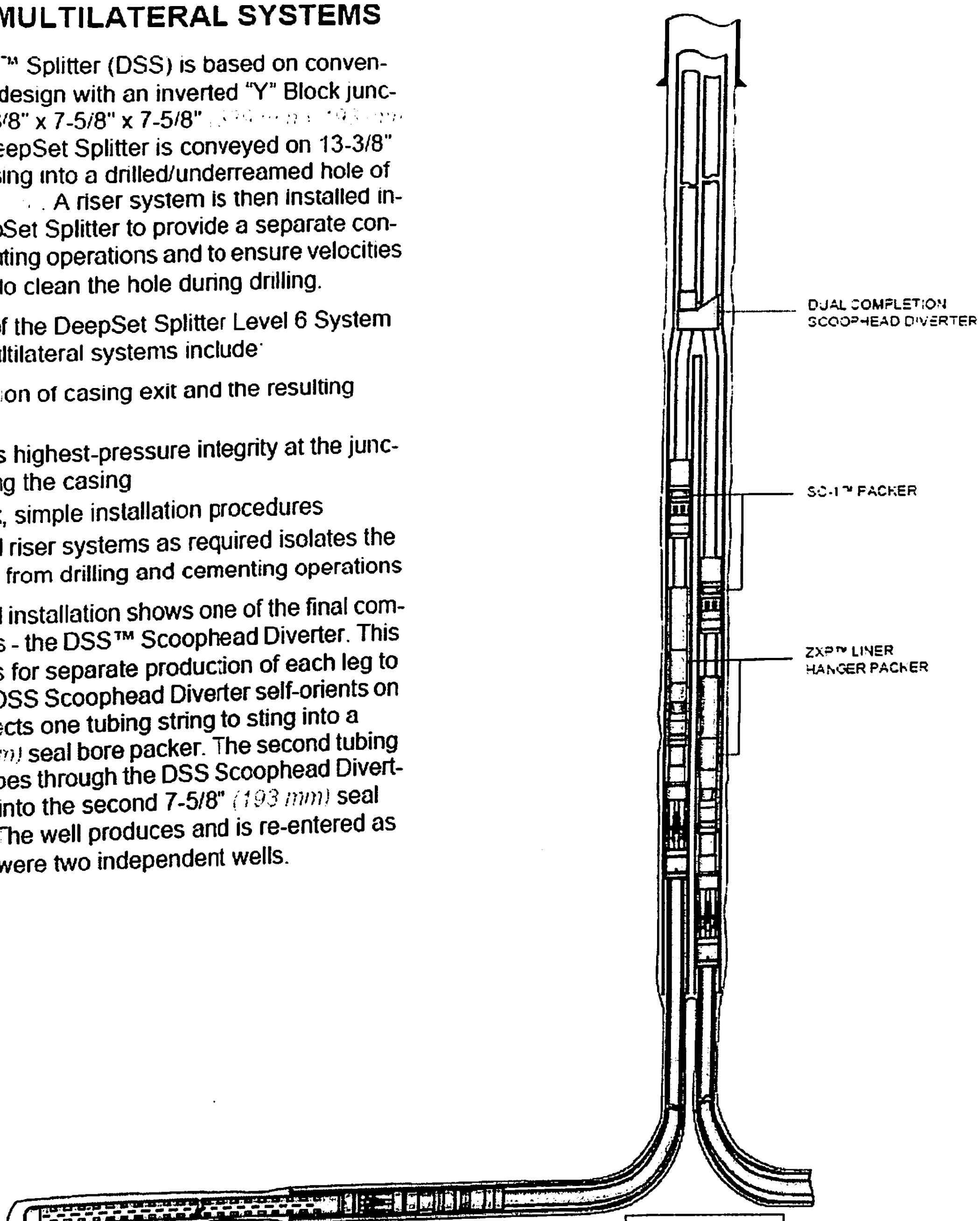


Figure 9.2

Case History of South Belridge Field near Bakersfield, California

Introduction

Multilateral systems offer potential reservoir benefits of increased production and greater reservoir recovery efficiency. It is only within the last few years, however, that drilling and completion technologies have advanced to the point that these reservoir benefits can be realized in a wide variety of field and well environments. Multilaterals offering junction support, production isolation, selective re-entry, and even hydraulic isolation of the junction have been developed and commercially proven around the world. Unfortunately, a disturbing trend has become apparent with these high-end multilateral installations. As the functionality of the multilateral improves, the risk and complexity of the system increase as well (Fig. 9.3). The increased amount of equipment and procedures involved along with the cumulative risk can make it difficult to economically justify many of the wells for which multilaterals have been considered.

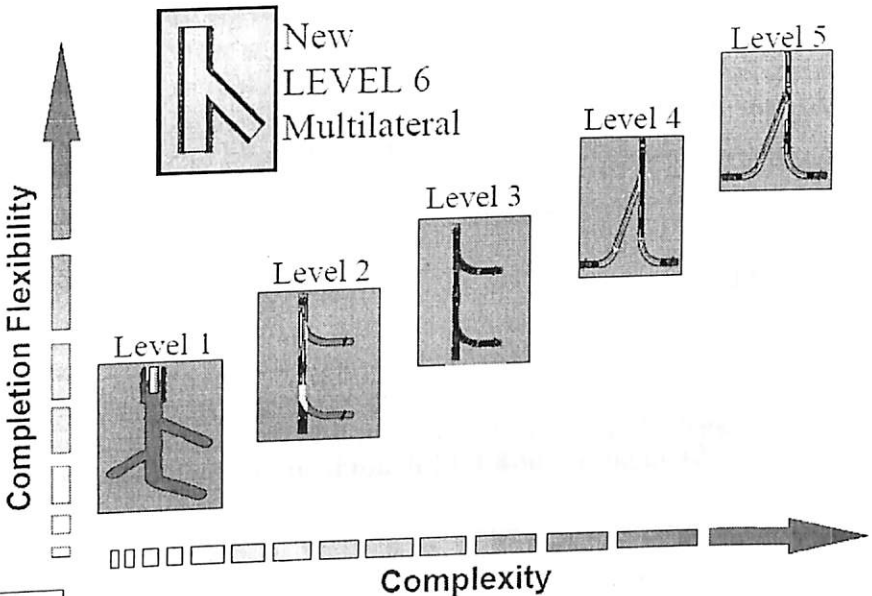


Figure 9.3 Increases in multilateral flexibility have in the past resulted in corresponding increases in the complexity of the system. The new Level 6 multilateral system; however, increases flexibility while minimizing risk.

In order to improve the economical viability of these high-end systems, a new type of multilateral was required that not only advanced the functionality of the system to a new level, but also did so with an overall decrease in risk as compared to current complex multilateral completions.

Designing a Low-Risk Level 6 Multilateral Solution

As defined by the industry's multilateral focus group, TAML, a Level 6 multilateral provides hydraulic integrity at the junction area and does so not through the use of completion "straddle" equipment, but instead creates the hydraulic integrity at the casing point itself. By not depending upon this additional completion equipment for the seal, the potential inner diameter of the junction is increased, leading to a wider variety of equipment that can be run during the completion phase and later during re-entry applications. In addition, the larger ID of a Level 6 system allows for maximum production flow from each leg without creating a choke situation.

Several techniques for creating the downhole junction casing seal have been advocated. One idea has been to carry the lateral casing into the well and somehow seal against the mainbore casing already in place. Trying to create a high pressure seal downhole has proven to be extremely difficult, however, due to uncertainties regarding casing exit geometry and quality, the unique shape required of the seals themselves, and the difficulties in maintaining the seal as the pressure differentials fluctuate.

Another technique to create the downhole junction casing seal has been to carry the entire junction area component downhole in a single piece so as to eliminate the need for downhole sealing of separate components. This concept has been used commercially in the past with encouraging results and is referred to in the industry as multilateral downhole splitter technology. The drawback to this system, however, has been the larger size casing required from surface to the junction setting depth. As an example, in order to carry a junction downhole with two 7-in. legs, a minimum of 16-in. casing will be required down to the junction depth. This can result in increased drilling and casing costs that will negatively affect project economics.

A final solution to creating the downhole casing seal is to carry the junction downhole as a single component but somehow reduce the system's outer diameter during run-in. By reducing the effective OD of the component, it can be run through standard casing sizes, minimizing drilling and casing costs. It is this type of Level 6 multilateral system that has been developed and recently run in the South Belridge field.

Level 6 "Formed Metal" Multilateral Description

The new Level 6 multilateral system consists of a joint of standard 9-5/8-in. casing and a 9-5/8" x 7" x7" inverted "Y" crossover, below which are attached two 7-in. casing strings. The longer of the two 7-in. legs is made of conventional casing but is formed around the second, shorter 7-in. leg. Due to the noncircular shape of the first leg around the second, the overall OD of the two casing strings is no more than 12.0 in. at any point along the length of the junction. As a result, the junction is capable of passing through 13-3/8-in. casing or 12-1/4-in. open hole (Fig. 9.4).

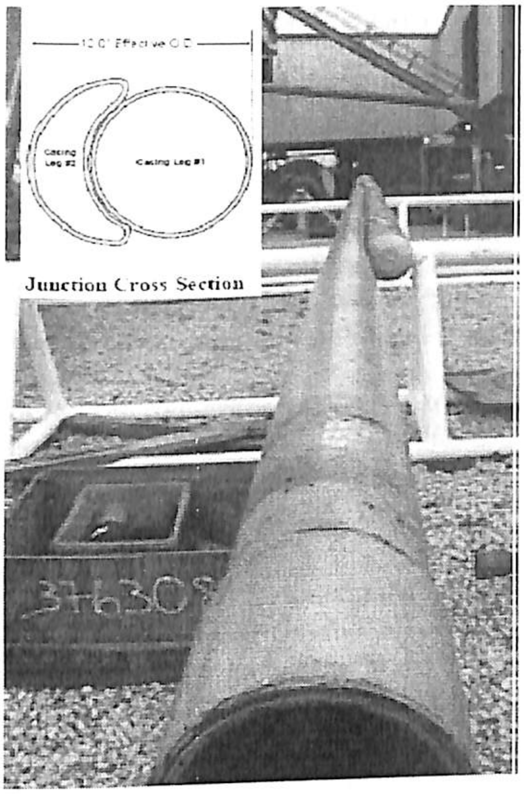


Fig. 9.4 - Formed metal, Level 6 multilateral As seen from the bottom looking up. The Longer, pre-formed, leg #1 is located on the left. The fully circular, leg #2 is to the right.

Standard cementing float equipment is located below the deformed portion of the first 7-in. casing leg while the second leg is blanked off with a drillable bull plug. The float equipment allows the junction to be cemented in place once landed to depth. Accessory equipment used with the Level 6 system includes a swaging string to reform the non-circular junction leg, and diverters designed to allow selective re-entry access into either leg of the multilateral. These accessories and their operation are covered in more detail during the job run description later in this report.

Selecting the First Field Run

With the formed metal multilateral system thoroughly tested in the lab and in the service company's test well, it was now time to run the system in an actual operator-owned well. Multilateral systems typically provide the greatest cost-saving benefits in wells that are difficult or expensive to drill, as is often typical in offshore or deep well environments. The intent of this test, however, was not to prove the economics of the system but rather the mechanical abilities of the system itself. Therefore, the desired well needed to be in a less costly, more quickly and easily drilled well in which tubing trips, contingency runs, equipment and personnel transportation were all minimized from both cost and time standpoints.

Thus, preferred criteria for this test were defined as:

- Onshore, domestic United States
- Shallow well depth
- Vertical well
- Open-hole or slotted liner completions of the two junction legs
- Commingled production of the two casing legs (From a completion basis, there are options available for completing Level 6 ML systems with dual production to surface or with more complex casing designs below the junction. For this first test, however, the main emphasis was on the junction construction process itself.
- Involvement of operators and contractors with previous worldwide multilateral experience.

Vital to the selection and implementation process was the desire of the service company to involve an operator with previous multilateral experience and an ongoing commitment to the multilateral process. The operator in turn was intent on working with a service company offering the highest level of multilateral experience and commitment.

The test system was designed around these specific and standard well size parameters.

- 13-3/8-in. surface casing
- 9-5/8-in. intermediate casing with two 7-in. casing legs
- 6-1/4-in. open holes drilled from each leg.

The Candidate Well Is Found

A suitable candidate field was eventually found in the South Belridge Field outside Bakersfield, California. The field is operated by Aera Energy LLC, one of the dominant onshore operators in California. Aera Energy LLC in turn partially owned by Shell Oil Co., a worldwide operator with extensive multilateral experience. Primary production from the field is heavy oil from a series of seven separate, stacked sands. Typically a horizontal well has been drilled in each sand zone and produced with rod pumps.

Vertical steam injection wells are used in the field as well in order to improve the heavy oil flow. In addition, the horizontal producing wells themselves are periodically steamed and also are occasionally re-entered in order to clean out accumulated formation sand. In the past, multilateral wells have been completed in the field but with less than successful results due to excessive sand influx in the junction area. The sealed junction capability of the Level 6 system offered relief from this particular problem.

Meeting the Required Candidate Well Criteria

South Belridge candidate well met most but not all of the criteria that had been previously determined. Sizing specifications of the system were suitable and standard for the field. The onshore location and close proximity to Bakersfield made equipment and personnel transportation and availability much more efficient. The shallow environment of the field ensured that the well could be quickly drilled and completed with minimal time required for tubing trips or contingency runs.

Slotted liner was to be landed in each leg of the junction with no gravel packing or further cementing operations required. The prior multilateral experience of both Aera and Shell insured full support from all involved parties.

The one criterion that was not met by this candidate was the request for a vertical wellbore. The intended well would require that the junction be placed in a horizontal environment so as to maximize the drainage potential of the two sand zones. While the horizontal nature of the junction placement made the project more complex, it was not enough of an increase in risk and complexity to negate all of the other favorable criteria, and the decision was made to proceed with the project.

Funding the Level 6 Multilateral Field Test

With the candidate well selected, the next step was to determine how the multilateral construction and completion would be supported and funded. As stated previously, the shallow, simple, inexpensive drilling nature of this particular field is not normally conducive to this type of multilateral system. The Level 6 system will cost several time more than the typical cost of drilling and completing a standard horizontal producing well in this field. As a result, the project could not be justified strictly on favorable economics. Therefore, it became essential that the project be subsidized in some manner in order for the local operator to go forward with it.

Keeping in mind that the final completion would provide the equivalent of two horizontal wellbores, the operator was willing to proceed with the project as long as final costs did not exceed 1.75 those of a standard horizontal system. In order to achieve this goal, Baker Oil Tools was willing to provide the multilateral system for free, charging only for local non-multilateral specific operations. This resulted in an anticipated project cost acceptable to Aera.

One final hurdle remained, however, and that was the issue of project risk and the possibility that a problem job might result in unanticipated expenses, or only one bore, or even no wellbores available to the local operator. Baker was not in a position to compensate Aera Energy if this event occurred and Aera was concerned about taking on this additional risk. The problem was solved when Shell Oil stepped in and offered to indemnify Aera against 1) costs above 1.75 times a conventional well for delivery of a ML, 2) costs above a conventional well for delivery of a single horizontal or, 3) total well cost if no producing wellbore was delivered.

In the end, all three involved parties made some financial sacrifices in order to push the project ahead. In all likelihood, failure to make these compromises by any one of the parties would have resulted in cancellation of the project.

Installing the Formed Metal Level 6 Multilateral

Preparing the Well and Junction Area

The well was spudded on September 13, 1998, and 14-in. casing installed to a depth of 90 ft. A 9-7/8-in. hole was then drilled to 1,856 ft MD / 1,109 ft TVD at 96.6^{0} hole inclination. The curve section sustained an average dog-leg severity of $9.2^{0}/100$ ft and a maximum dog-leg severity of $13.5^{0}/100$ ft. A hole opener was then used to enlarge the entire curve and lateral to 13 in. hole diameter.

In order to accommodate the re-formed junction a diameter, a 100-ft tangent section from 1,562 ft to 1,662 ft was under- reamed to a diameter of 17 in. This particular section had a 92.6_{o} hole inclination, and there was concern that a standard under- reaming tool would tend to fall towards the low side of the hole. To combat this concern, a two-foot-long cylinder with 12-1/2-in. stabilizer pads was added to the under-reamer's nose in order to keep the under-reamer centralized within the original 13-in. hole. The under-reaming went smoothly.

Running the Formed Metal Junction

With the under-reaming complete, the formed metal junction was prepared for running. As described earlier, the formed metal junction consists of two 7-in. legs that are merged together into a common 9-5/8-in. casing string. Furthermore, the longer of the two legs is formed around the second so as to reduce the effective OD to 12.0 in. Standard float equipment and landing collars are installed at the bottom of this preformed leg in the section that remains circular.

For this particular field application, 250 ft of 7-in. casing were run below the preformed portion of leg #1. This was done to place the 7-in. casing into the first reservoir target. The Level 6 system can be run with any extra length in the first leg, and the float and landing collars were simply placed at the bottom of this 250-ft casing length rather than immediately below the junction.

The Level 6 junction along with the 7-in. casing and upper 9-5/8in. casing were run to depth without major problems. Once the build sections were reached, the casing did have to be spudded into the well, and the casing fluid level had to be topped off after every 4 to 6 joints. Centralizers were used on both the 7-in. and 9-5/8-in. casing in order to maintain standoff for later cementing operations. After 5-1/2 hours, the formed metal junction was on depth in the under-reamed section, and the 9-5/8-in. casing was hung off at the rotary table.

Determining Orientation of the Formed Metal Junction

The formed metal junction does not require a specific orientation downhole. The legs can be located side by side or one on top of the other as desired and required by the drilling program. In this particular application, it was desired to have the two legs side by side.

With the junction run to depth, an orientation run was made. This run consisted of an orientation anchor run below an MWD system. The orientation anchor is designed to land in a swage diverter that is pre-installed in the junction prior to running (Fig. 9.5).

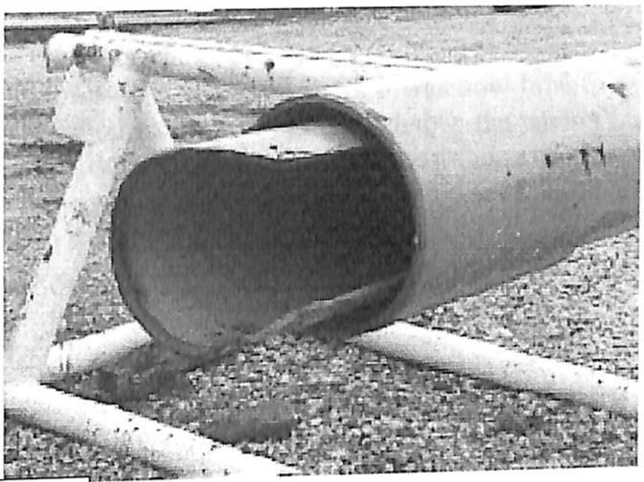


Figure 9.5 The swage diverter pre-installed in the top of the formed metal junction.

The swage diverter is designed to guide the swaging string into leg #1 during the reforming process. This diverter in turn lands in the orientation key that is installed in the formed metal junction itself (Fig 9.6). As a result, determining the orientation of the anchor once landed will in turn allow us to determine orientation of the two junction legs.

Figure 9.6 The swage diverter after removal from the well. Note the slot on the left that orients against the formed metal junction profile and ensures proper alignment of the diverter in order to provide entry into leg #1.

Once the orientation anchor was landed, multiple readings were taken, and it was determined that the two legs were within 18 degrees of horizontal orientation this orientation was within requirements for the drilling operations. If orientation had proven not to be satisfactory; however, the junction could have been re-aligned by turning the 9-5/8-in. casing at surface. In the event that this Level 6 junction were run as a liner, the junction could have been turned by rotating the MWD tubing string which would transmit torque to the junction itself. There is some question, however, as to whether, in a horizontal environment such as this, the junction could have been successfully rotated through the build section.

Re-forming the Non-Circular Casing Leg

With the junction landed and properly oriented, it was now time to reform the pre-formed casing leg. This was accomplished using a swage that shapes the casing back into its original circular configuration. The swaging string consisted of a swage, a pump-out ball seat sub, two 20-ft expansion joints, a casing spear, jars and accelerators, and 3-1/2-in. drill pipe to surface with inverted packer cups in the upper joint of drill pipe (Fig. 9.7).

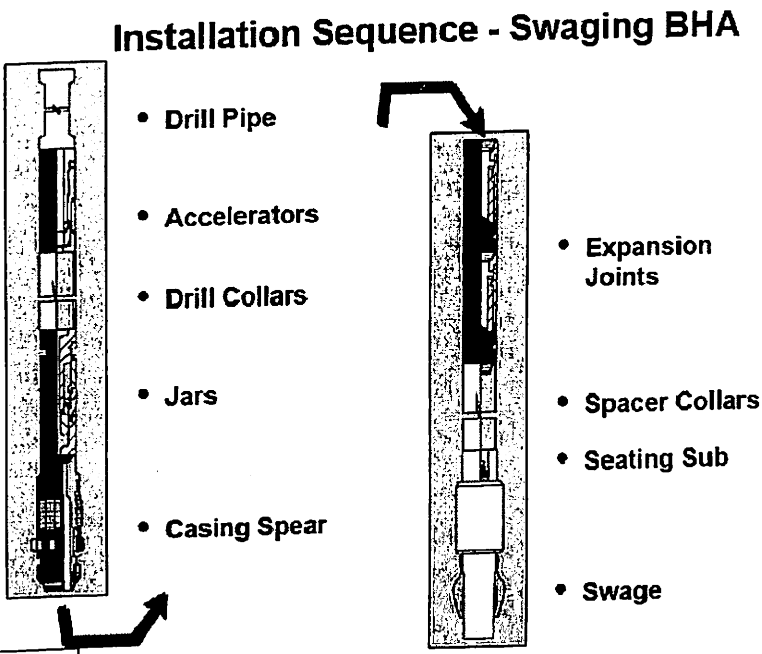


Figure 9.7 After tagging the pre-formed casing with the swage, continued weight will stroke close the expansion joints. The casing spear is then set and a ball is dropped and landed in the seating sub. Pressuring up the swaging string will then drive the swage through the pre-formed casing leg.

The swaging string was run downhole and the swage allowed bottoming out against the pre-installed swage diverter. With the swage bottomed out, additional weight was set down, and the expansion joints were allowed to stroke closed. The casing spear was then set and a 1-1/2-in. ball was dropped through the drill pipe and circulated into the landing collar at the bottom of the 7-in. casing string. With the ball seated at the bottom of the casing and the inverted cups sealing off at the top of the 9-5/8-in. casing, the entire casing and junction configuration was hydraulically isolated. As a result, pressure could be applied to the re-formed casing leg in order to begin the reformation process.

With the ball on seat, 300 psi of pressure was applied to the junction and the preformed leg. At this point, problems with the swage pump occurred when the pump was unable to supply the volume of air required to maintain adequate pressure. The ball had not sealed perfectly, and consequently the pump could not keep up. Eventually a second, larger pump was called out to create the pressure required to blow out the ball in the landing collar. With this new pump, pressure was momentarily increased before dropping back off. It was not known for sure whether the ball had indeed blown as intended, but a decision was made to proceed with the swaging process.

In order to begin the swaging process, a second, larger ball was dropped through the drill string and landed in the ball seat sub located directly above the swage itself. Pressure was then applied to the drill string, creating a piston effect on the swage. With the casing spear set above the swage and expansion joints, the swage had nowhere to go but down and through the pre-formed leg. During the swaging process, the pressure continually varied from between 1,700 to 2,500 psi as the swage pushed its way through the pre-formed leg. Although it appeared that the swage was working its way through the junction, it was difficult to determine the exact position of the swage due to several factors. First, the procedure called for stroking the expansion joints closed prior to setting the casing spear. The horizontal environment of the well, however, made it difficult to determine if this had occurred because of the horizontal drag. In addition, the swage location is supposed to be determined through monitoring pumped fluid volume. A leak in the second ball seat made this calculation difficult.

Because of the uncertainty of the swage location, the casing spear was released, a 15-ft pup joint added, and the casing spear was reset 15 ft farther down. This action in turn allowed for 15 ft more of stroke and would guarantee that the swage had successfully reformed the entire non-circular portion of the casing. After a few more feet of swaging movement, the pressure was increased to 6,000 psi, and the ball seat was blown. The swaging string was now ready to retrieve from the well.

Retrieving the Swage String

Difficulty was encountered in pulling the swage back through the junction for several reasons. First, though mechanical jars and accelerators had been placed in the swaging string, the tools were placed too far below the curve. Horizontal drag kept the required amount of tension from reaching these tools, and as a result, they could not be successfully activated downhole to assist with the retrieval process. Another reason for swage retrieval difficulty was the minimal amount of casing weight available. With the casing not yet cemented in place, the casing weight was only about 50,000 lb over the work string weight and as a result, attempts to pull the swage resulted in a lifting of the casing. Eventually, hydraulic casing jacks had to be ordered to secure the casing and allow enough weight to be pulled on the swage. With the jacks in place, approximately 150,000 lb of force was required to pull the swage back through the junction, after which the swaging string was tripped out of the hole.

Verifying Junction Integrity

With the casing leg reformed and the swage retrieved, it was time to cement the system in place. Before doing so, however, a decision was made to verify the junction integrity and insure that the swaging action and pressures had not damaged the system. A cementing slick stinger was made up on drill pipe and run in the hole to test the junction. The slick stinger was stabbed into the pack-off bushing located at the bottom of the pre-formed 7-in. casing leg, and the well was circulated at approximately 7 bbls/min and 500 psi. The lack of return fluid between the 9-5/8-in. casing and 3-1/2in. drill pipe was a good indicator that the junction still had integrity.

As a further test to verify junction integrity, the stinger was re-stabbed into the pack-off bushing after adding a ported sub and a swab cup assembly to the stinger string directly below the uppermost joint of drill pipe. A ball was dropped and landed in the pre-installed ball seat located directly above the slick stinger. This action isolated the lower end of the drill string and junction while the swab cup assembly isolated the 9-5/8-in. x 3-1/2-in. annulus. As a result, pressure applied in the drill string and through the ported sub could be conveyed to the entire junction and casing strings to verify junction integrity (Fig. 9.8).

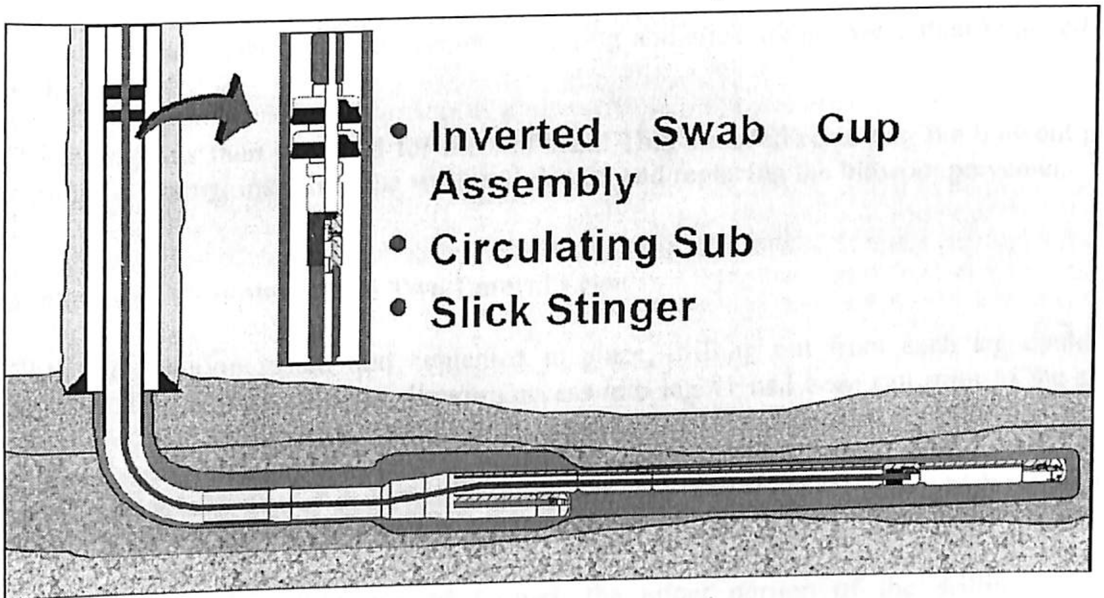


Figure 9.8 After reforming the pre-formed casing leg, the entire junction and casing string can be pressure tested. A slick stinger with a ball seat directly above stings into the pack-off bushing and pressure isolates the bottom of the casing string. An inverted swab cup assembly run below the uppermost joint of drill pipe provides pressure isolation between the drill pipe and 9-5/8" casing string. Pressure is then applied in the drill string, through the circulating sub, and the entire system can be pressured up.

Pressure was applied up to 600 psi and held for 30 minutes. With junction integrity again verified, the stinger string assembly was retrieved from the well.

Cementing the Junction in Place

The next step in the junction construction process was to cement the junction in place. With landing collars and pack-off bushings in place in the 7-in. casing leg, a cement stinger and string could have been immediately run into the hole and cementing operations begun. However, there was concern about leaving the preinstalled swaging diverter in place downhole. This diverter has a tight fit with the second casing leg, and there was concern that any cement stringers in the well would make later retrieval of this tool more difficult. Therefore, the decision was made to

replace the swaging diverter with a drilling diverter that would also direct the cement stringer into the long casing leg containing the float equipment. The drilling diverter; however, has much less metal-to-metal contact with the second casing leg and is, therefore, less vulnerable to cement stringer interference.
The pulling tool for the swage diverter was made up and run in the hole along with mechanical jars and accelerators. The pulling tool was stabbed and latched into the swaging diverter, and with 43,000 lb of tension, the diverter was released from the junction and retrieved from the well without difficulty. The drilling diverter was then picked up and run in the hole with the same work string and running tool. While stabbing into the junction, the work string was seen to rotate slightly as the drilling diverter oriented itself onto the orientation key of the junction. A ball was circulated down the drill pipe and landed in the running tool. Pressure of 2,000 psi was then applied, releasing the diverter, and the running tool was retrieved.

The cementing work string was run and the slick stinger stabbed into the pack-off bushing. The cementing program consisted of 64 bbl of pre-flush, 98 bbl of lead cement, and 64 bbl of tail cement. The drill pipe wiper plug was released and pumped down until it landed and sealed in the landing collar. The slick stinger was then pulled out of the drillable pack-off bushing and circulation begun in order to ensure that any excess cement would not migrate back to the junction and diverter area. The cementing string and slick stinger were then removed from the well.

The casing was then prepared for the wellhead. This included removing the blowout preventer, cutting the casing, installing the wellhead flange, and replacing the blowout preventer.

Drilling and Completing the Two Lateral Legs.

With the junction tested and cemented in place, drilling out from each leg could now be initiated. The drilling diverter allowing access into leg #1 had been run prior to the cementing operations, and as a result, the drilling assembly was run immediately after cementing. The drilling assembly string consisted of a 6-1/8-in. tri-cone roller bit attached to an MWD and mud motor with a 1.83-degree bend (the local operator's conventional BHA), which was run with 3-1/2-in. drill pipe from surface.

The drill bit successfully passed through the upper portion of the drilling diverter, but unfortunately, the bit appeared to stack out on the lower portion of the diverter rather than kicking on off into leg #1. MWD measurements confirmed that the bit was properly aligned with the first lateral. After working the string up and down several times, the bit still would not pass into the lateral leg, and it was also hanging up when trying to pull back through the diverter. Eventually, the decision was made to retrieve the drilling assembly for inspection. During this recovery, excessive drag was noted for the first ten feet above the diverter itself.

Inspection of the drilling assembly revealed broken teeth on two of the three cones, and a decision was made to change the configuration of the drilling assembly to ensure passage into the lateral leg. The bit was changed from 6-1/8 in. to 6 in., and the motor bend was reduced from 1.83 degrees to 1.5 degrees. The drill string was tripped back in and was hanging up 10-15 ft above the diverter. This combined with the excessive drag of the previous trip led to the belief that the drilling diverter may have prematurely released on the previous trip and had worked its way up the casing. Therefore, the drill string was tripped out and preparations made to recover the drill string diverter.

The drilling diverter pulling tool was made up and tripped in along with jars and accelerators. Once the pulling tool was stabbed into the diverter, 10,000 lb of over-pull was applied and rotation of the drill pipe was unsuccessfully attempted. The combination of over-pull and inability to rotate indicated that the pulling tool was latched into the diverter and that the diverter was actually still in the junction and had not released as had been suspected. The pulling tool was already latched into the diverter; however, and with 48,000 lb of over-pull, the jars fired, and the diverter was released and recovered from the well. Upon recovery, the pulling tool was found to be stuck in the diverter, and the entire assembly was sent back to the service company's district warehouse for further investigation.

Rather than running back in the hole with the backup diverter, a decision was made to re-run the original swage diverter that had been pre-installed in the junction. This swage diverter offers more ID clearance, and it was felt that the drilling assembly stood a better chance of passing into the lateral leg. The swage diverter and running tool were tripped in and successfully latched into the junction. Left-hand torque was applied to the running tool and successfully released from the diverter, and the running tool was retrieved from the well. The same drilling assembly as before, with the 6-in. bit and 1.5-degree, motor bend, was run back into the wellbore and successfully kicked off into lateral leg #1. The cement joint was drilled through and drilling continued into the formation. After drilling ahead for 135 ft, it was concluded that the motor was not building angle fast enough. Therefore, the assembly was pulled from the well and replaced with a 1.83-degree motor bend. This assembly successfully passed into leg #1, and drilling of the first lateral leg was completed. Final length of this lateral was 1,700 ft.

With lateral leg #1 drilled, the drilling mud was displaced with 5% KCl and water as the completion fluid prior to running 4-1/2-in. slotted liner. The liner was run in with centralizers at every joint. Once in the open hole, considerable working of the pipe was required, but the liner was eventually run to depth.

The liner was tagged on bottom and the liner seal assembly set. This was done mechanically, by first rotating to activate the setting tool and then spudding down to set the lead seal. Rotation released the running tool that was then successfully retrieved.

With leg #1 drilled and completed, access into leg #2 was required. The pulling tool for the swage diverter was made up and run in along with the jars and accelerator. The drilling diverter was successfully released and retrieved with 45,000 lb of over-pull.

The drilling diverter for the second lateral was run in using the same tools and techniques as had been used for the previous drilling diverter runs. The drilling diverter was successfully latched into the junction and released using left-hand torque. With the second leg drilling diverter properly landed, access into the second leg by the drilling assembly was now possible.

The same drilling assembly, with 6-in. bit and 1.83-degree mud motor, was run into the second lateral and had no difficulty passing through the diverter and into the second leg. After drilling out the cement shoe at the bottom of the leg, 2,016 ft of open hole was drilled. During this process, one bit change was required after the bit was found to be pinched in.

After removing the drilling assembly, the drilling mud was displaced with 5% KCl and water as the completion fluid. The second 4-1/2-in. slotted liner was run, similar to the first. A sand barrier interference seal assembly was run on top of this liner along with a no-go sub designed to land in the second leg of the junction.

The liner had to be driven all the way in and eventually stacked out on top of the drilling diverter. After further analysis, it was realized that an error had been made and that the no-go of the liner was 6.300 in. and unfortunately, the ID of the drilling diverter's latch mechanism was only 6.250 in.

With this critical error, the only action to be taken was to pull the entire liner from the well. After retrieval, several centralizers were replaced and the open hole section reamed prior to replacing the liner in the well.

The 4 1/2-in. slotted liner was re-run although the no-go sub was removed. Rather than rely on the no-go sub, the length of the liner was increased so that it would bottom out at the end of the open hole and leave the liner packer in the lateral leg of the junction. With this trip, the liner went in the open hole much smoother, with spudding required only for the last 600 ft. The liner packer was set with pressure, and the running tool was retrieved. The second leg drilling diverter was then retrieved without difficulty using the same tools and techniques as in previous trips.
As the final step in the completion process, the wellhead, pump, and completion string were installed (Fig. 9.9).

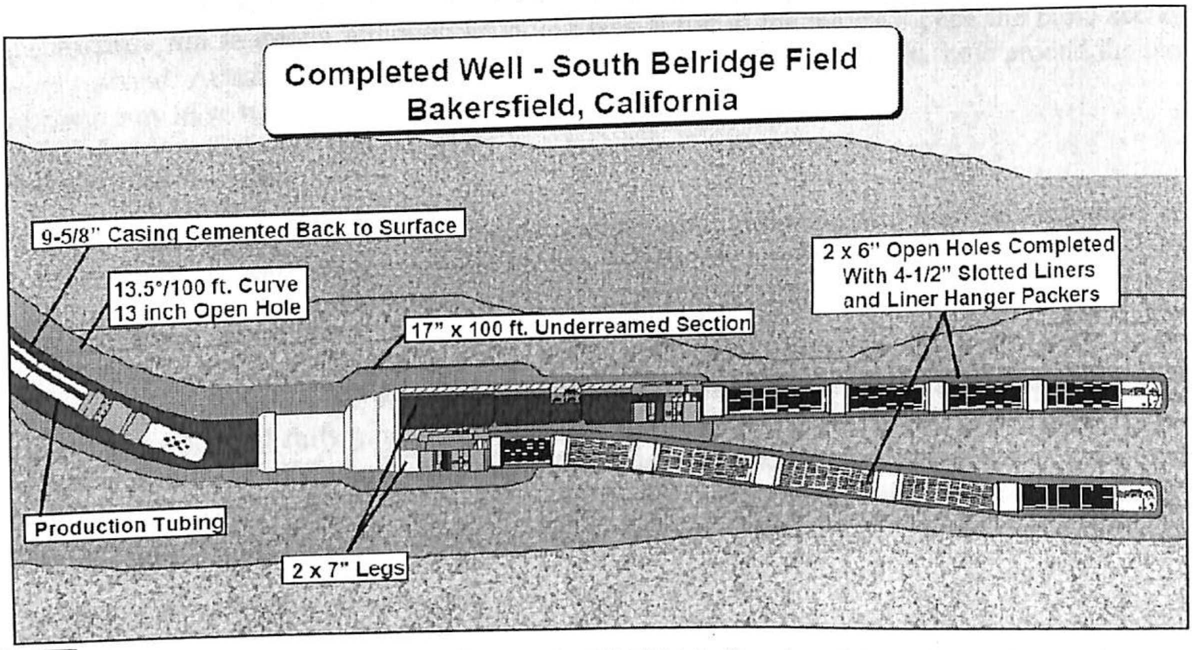


Figure 9.9 The completed Level 6 multilateral system offers two horizontal 4-1/2" slotted liners hung off the two 7" casing legs of the junction. The junction in turns ties into 9-5/8" casing that is run to surface. Production tubing was landed in the lowest portion of the well in order to maximize pump efficiency. Both zones are produced commingled to surface.

Current Well Status

Nine months after completion, the Level 6 multilateral well continues to produce satisfactorily in quantities significantly higher than would have been achieved with a conventional single-sand, horizontal completion. The well has been steam stimulated on several occasions without complication, and the junction has accomplished its goal of eliminating sand influx. To date, no tubing re-entry into both wellbore has been required and therefore, the diverter systems have not yet been re-run since the initial well completion.

The Continuing Improvement Process

While the field run was a success for all parties involved, there were still several opportunities for improvement. Most of these issues have been addressed and changes in both system design and procedures have already been completed.

Running the Junction to Depth

As stated in the Level 6 system description, the junction is capable of being run through 13-3/8-in. casing or 12-1/4-in. open hole. During discussions with the operator, concern was expressed about running the junction system through these hole sizes, considering the horizontal nature of the wellbore. A decision was made to increase the casing size to 14 in., allowing for a hole size of 13 in. to be drilled through the intended junction setting depth. The junction and casing were successfully run to depth, although spudding was required for the case once the build sections were reached. Attempting to run the casing through the smaller 12-1/4-in. hole around the build sections may have been more problematic.

Swaging the Junction

The pre-formed junction leg was swaged successfully, although with less certainty than was anticipated. There were several reasons for this uncertainty that merit discussion.

Expansion Joint Closure

In order to fully stroke the swage through the pre-formed leg, the two 20-ft expansion joints needed to be stroked fully closed downhole. Unfortunately, the position of the expansion joints in the well made it difficult to determine if this had been accomplished. On future runs of the system, the expansion joints will be placed in the vertical portion of the wellbore if possible in order to eliminate the drag and ensure that the expansion joints have fully closed.

Ball Seat Leakage While Pressuring Up

Two ball seats were used on this field test. The first was located below the pre-formed casing leg and was designed to allow the junction area to be pressured up in order to begin the reforming process. Unfortunately, this ball seat was located horizontally in this particular application and the ball failed to maintain a proper seal. This led to leakage around the seat and difficulty in blowing out the ball once pressuring up was concluded. For future applications, this step has been eliminated. Further testing of the Level 6 system confirms that this initial pressuring up stage is unnecessary and that the pre-formed leg does not need to be pre-pressured prior to driving the swage through the leg. Eliminating this step will reduce both risk and time involved in re-forming the junction.

The second ball seat is located above the swage and provides the plugging action that allows the pressure to drive the swage through the pre-formed leg. This ball seat also was located horizontally on this project and did not maintain a proper seal. In future horizontal applications, a more suitable ball will be used along with a ball seat offering an O-ring seal to help maintain the seal. Finally, a more robust pump will be provided when required if the rig pump cannot keep up with the required air volumes.

Retrieving the Swage

The swage required 150,000 lb of upward pull to pull the swage back through the pre-formed leg. On a shallow-environment well such as this, this amount of pull was difficult to achieve and casing jacks were required to keep the casing in the hole. Two changes will improve the recovery process and reduce the amount of upward force required.

Jar and Accelerator Position

The jars and accelerator on the swaging string were placed too far around the curve, and as a result, they could not aid in recovery of the swage. On future applications, the jars and accelerator will be placed higher up in the well where they will be able to fire off and assist in recovery.

Swage Design.

The swage used on this particular field test is an off-the-shelf swage provided by the service company. In order to reduce the upward force required for recovery, a new swage has been developed and tested. This two-piece swage is designed such that during the recovery process, the OD of the swage is very slightly reduced, leading to smaller forces required to pull the swage through the junction. The resulting pre-formed leg still maintains the desired 7-in. drift ID, however, and the required tensile forces have been shown to be less than half of those required for this first field run.

Cementing the Junction in Place

Prior to beginning the job, a cementing company was consulted to determine the optimum cement design for the system. The cementing company was concerned that mud displacement in the large- ID under-reamed section would be extremely difficult without high cement pump rates that would be difficult to achieve. In order to obtain the best possible cement coverage, centralizers were used on both the 7-in. and 9-5/8-in. casing to achieve optimum standoff. The cement job was successful, although no attempt was made to determine the efficiency of mud displacement that was achieved.

Drilling Diverters and Running Tools

Problems were encountered trying to run the drill string assembly into the first leg and in trying to run the slotted liner into the second leg. Furthermore, the drilling diverter at one point was thought to have been accidentally released and could not be re-latched into the junction without first retrieving the diverter from the well and redressing the tool. These difficulties led to a redesign of both the diverters and the associated running tools.

Drilling Diverter Design

Since the completion of this first field run, the drilling diverters have been modified with a resulting larger tool ID. 6-1/8-in. bits with motor kick-offs of up to 2.5 degrees are now possible as was originally intended. A variety of motor and bit configurations, liner hangers, and sand screen assemblies have been drifted through these newly designed diverters at the service company's test well facility.

Running tool design

The running tools used with the drilling and swage diverters relied on rotational and ball seat pressures to release the diverters. As a result, the running tools required redressing between each latch and release effort. More flexible running tools have been developed since this field run that are capable of repeatedly latching and releasing the diverters without the need for redressing between each action. The primary release mechanism with the new tools is hydraulic differential pressures created with an internal orifice.

During this field run, the drilling diverter was thought to have prematurely released and the pulling tool was used to retrieve the diverter to surface. With the new hydraulic running tool, however, the diverter could have been latched with the running tool and immediately run back downhole and landed in the junction. There would have been no need to first retrieve the tool to the surface.

Conclusions

Overall, the Level 6 formed metal junction and its accessories worked as intended, and the world's first Level 6 multilateral system was successfully installed. The main success points of the job were:

- Under-reamed to a 17-in. diameter for 100 ft at 92 degrees deviation
- The junction was installed at 92 degrees through dog legs of up to 13.47°/100 ft.
- The first leg of the junction extending 250 ft below the junction was successfully positioned at 97 degrees deviation.
- The junction was pressure tested after the installation.
- The junction and casing were cemented in place.
- 6-in. lateral hole was drilled for 1,700 ft from the first leg and 4-1/2-in. slotted liner was installed.
- 6-in. lateral hole was drilled for 2,016 ft from the second leg and 4-1/2-in. slotted liner was installed.

Areas that were targeted for improvement were:

- Improving the cement process in the large annular flow areas
- Increasing the ID through the drilling diverters, improving the swaging process, including the ball sealing, pumping, and monitoring aspects
- Improving the design and functionality of the diverter running tool

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