Department Petroleum Engineering

Chair of Drilling Engineering and Well Completion

Master Thesis:

"Application of Dual Lateral Technology on an Existing Well in Sawan Gas Field of Pakistan"

In collaboration with

OMV (Pakistan) Exploration Gesellschaft m.b.H.

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AFFIDAVIT

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

22nd September, 2016

Date

Signature

Acknowledgment

All the praises are of Almighty Allah who bestowed me with the ability and potential to complete this project within due course of time.

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Dedication

Dedicated to those personalities who took me by finger, to teach me how to walk and also those who rewarded me with pen and taught me how to write

Executive Summary

Through multilateral technology, E & P companies now are able to overcome production decline from mature fields and to maximize recoverable reserves from already capitalized assets. Multilateral technology is not yet applied on any of the fields in Pakistan. However, as of today, multi-lateral technology is used significantly all over the world.

Junction construction and completion strategies are the basic differentiators between multilaterals and conventional wells. For this project, Well Sawan 12 was chosen as the case study from OMV Pakistan, to apply multilateral technology with desired well configuration as dual opposed lateral. Lot of research and enough background knowledge is required for a successful multilateral project, involving all the technical disciplines from the operator as well as from service providers. This project is mainly focusing on the drilling prospective of dual opposed lateral well while considering hydraulic fracturing for the proposed wellbores. On the basis of considerations like hydraulic fracturing and completion strategy, bundle of assumptions were required while designing the dual opposed lateral well. The conceptual design includes trajectory planning, junction construction method, drilling of lateral wellbore and selection of multilateral system which is fit for purpose for the said case well.

Landmark Software package has been used for engineering design, where input data is gathered from parent wellbore and offset horizontal well. Trajectory, Casing Design, Hydraulics, torque and Drag is first evaluated for each of the laterals, then project includes overview of lateral borehole drilling along with junction construction while using preferred multilateral junction system. A cost estimate for the Sawan 12 dual lateral well has been done along with its comparison to two of separate drilling projects for exploiting subsurface tight gas sands of the Sawan field. Based on conceptual assumptions the total time for drilling, stimulation and completion is estimated to be 93 days. Cost for mother borehole and lateral borehole are calculated to be 11.59 MM$ and 10.04 MM$ respectively in comparison to two new single horizontal wells that would cost 29.6 MM$ in total. Therefore, around 7.97 MM$ savings can be realized by utilizing dual lateral junction technology. The cost of the junction equipment is only 250K$ to 350K$ in total (including diverters) and also depends where the equipment is shipped around the world.

As the complexity and risks involved in execution of multilateral project is very high, it demands significant amount of input and cooperation from all the technical disciplines during planning and all the project phases, to make it successful. An effort is made to provide a generalized study and concept of multilaterals along with the conceptual design of dual lateral well for Sawan field of Pakistan. From technical standpoint, the proposed design can be considered as feasible. However in case of realization, strong focus needs to be given in the reservoir engineering work in order to ensure proper placement of the horizontal well-paths within the pay zone with realistic production performance forecasts.

Abstract:

Over the last few years, the continuous decline in Oil price has compelled Exploration and Production Companies to review their investment strategies once again. This decline has lead them to invest in existing fields rather than stepping into exploration of new areas, which require a large amount of investment. Deeper and more extreme environments are being produced to increase production capacities, and new technologies are being encouraged in the attempt to generate as much value from a well as possible. The use of developed technologies such as multilateral drilling over conventional drilling is one way to push the performance of existing wells.

The concept of multilateral wells is not new. During early 1990's, the conceptual techniques have progressed sufficiently for the technology to be considered fully developed. Completion techniques for multilateral wells including remedial work have been slow regarding implementation. However, all of these technical limitations have been overcome through innovative technology available in the market. Through multilateral technology, Exploration and Production (E&P) companies now can avert the production decline from mature fields, and to maximize recoverable reserves from depreciated assets. Multilateral technology has never been applied on any of the fields in Pakistan. OMV Pakistan has now decided to implement multilateral drilling specifically for tight gas reservoirs, to meet its commitments.

This project delivered a comprehensive insight of multilateral technology along with a conceptual design of a dual opposed lateral well while using preferred multilateral junction system, on Sawan-12 in OMV Sawan Gas Field of Pakistan. Starting from the motivations and advantages of multilateral technology for an E&P Company, this project explains briefly about the technical criteria and limitations for a multilateral project using a dual lateral approach.

A Dual opposed lateral well is a type of multilateral well with both the laterals opposing each other. This project is focusing on the technical evaluation of an existing well on the OMV operated Sawan Gas Field in Pakistan. The case study demonstrates the basis of design for implementation of the dual lateral technology in order to complete the wells with ten stage propped fracture completions. Concerning the financial limitations for the Dual lateral well, the non-productive or vertical part of the well is considered to be cost-driven; whereas the productive part of the well, consisting of the horizontal sections, is considered to be value driven. Hence, the application of dual lateral technology on the existing wells of Sawan field of Pakistan will be a positive addition towards OMVs production gain in near future with reduced CAPEX.

Kurzfassung:

Im Laufe der letzten Jahre hat der stetige Rückgang des Ölpreises E & P Unternehmen gezwungen ihre Investment Strategien zu überprüfen und neu zu evaluieren. Diese Situation hat dazu geführt dass vermehrt in vorhandenen Feldern investiert wurde als dass neue Gebiete erschlossen wurden. Es wird aus immer tieferen und schwierigeren Umgebungen produziert um die Produktionskapazität zu erhöhen. Dabei werden immer mehr neue Technologien verwendet um die Wertschöpfung einer Bohrung zu steigern. Der Einsatz der entwickelten Technologien wie multilaterales Richtbohren im Vergleich zum konventionellen Richtbohren ist ein Weg, die Kapazität vorhandener Bohrungen zu erhöhen.

Das Konzept der multilateralen Bohrtechnik ist nicht neu. Während der frühen 1990er Jahre wurde diese Art von Bohrtechnik ausreichend entwickelt, sodass man diese Technik heute als voll ausgereift ansehen kann. Komplettierungs Techniken für multilaterale Bohrung einschließlich der Instandsetzung haben aber vergleichsweise lang gebraucht um vollständig implementiert werden zu können. Durch die multilaterale Bohrtechnologie koennen Exploration und Produktion (E&P) Unternehmen nun dem Produktionsabfall ausgebeuteter Felder frühzeitig entgegenwirken und so positiv zur Maximierung der förderbaren Reserven beitragen. Diese spezielle Bohrtechnologie wurde bis heute noch auf keinen Feldern der OMV Pakistan angewendet. Daher hat sich OMV Pakistan entschieden die multilaterale Bohrtechnologie speziell für dichte Gas Lagerstätten zu implementieren um ihre Verbindlichkeiten zu erfüllen.

Dieses Projekt liefert einen umfassenden Ueberblick von multilateralen Bohrtechnologien zusammen mit einem Konzept fuer eine duale Komplettierung. Dabei wurde bevorzugt ein multilaterales Kreuzungssystem, auf Sawan-12 in OMV Sawan Gasfeld in Pakistan angewandt. Ausgehend von der Motivation und den Vorteilen der multilateralen Technologie für ein E & P-Unternehmen erläutert dieses Projekt den Ansatz sowie die technischen Kriterien und Einschränkungen. Dieses Projekt konzentriert sich auf die technische Bewertung einer bestehenden Bohrung auf dem von der OMV betriebenen Gasfeld Sawan in Pakistan. Die Fallstudie zeigt die Grundlage der Konzeption für die Umsetzung einer Komplettierung mit einem “10 Stage Hydraulic Fracturing”. Über die Kosten koennen folgende Aussagen getroffen werden. Der vertikale Bereich der Bohrung der als nicht produktiv angesehen wird, wurde als reiner Kostenfaktor angesehen. Wobei die lateralen, produktiven Teile der Bohrung als Wertsteigerung des Assets angesehen werden können. Daher wird die Anwendung von zwei seitlichen multilateralen Bohrlöchern in der vorhandenen Bohrung im Sawan Feld von Pakistan bei gleichzeitig reduziertem Investmentaufwand eine positive Ergänzung zur zukünftigen Produktionsstrategie sein.

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1 INTRODUCTION

1.1 Multilateral Well

According to TAML (2004), Multilateral well is defined as “One in which more than one horizontal or near horizontal lateral well is drilled from a single side (mother-bore) and connected back to single main bore. The branch may be vertical, horizontal, inclined or the combination of the three”.

Like a horizontal well, maximum reservoir exposure (increase in production) and economics (decreased cost) justify the design and implementation of a multi-lateral in a given field. Multiple lateral sections drilled from single main borehole drains their respective reservoirs and produce through that single main borehole. The multilateral well can be either a development well, an exploration well or a re-entry well.

Advantages of multilateral wells are:

- Reduced development cost for a field.
- Accessing multiple targets using single parent wellbore, to reduce platform size, weight, cost and surface footprints.
- Increased productivity per well slot.
- Reservoir exposure per total footage drilled is increased.
- Reduced cuttings and mud disposal helps reduction in environmental impact.
- Maximized acreage.

1.2 Technological progression of Multilaterals

Drilling the multilateral is a proven concept. However successful applications of multilaterals occurred in early 1990s. Technical limitations that had been lagged for completion of these wells have now been overcome through innovative techniques and tools, available in market.

Drilling of multilaterals had been attempted since the 1930’s, but in 1949 a Russian engineer, Alexander Grigoryan Known as father of multilateral technology started work and came up with design of very first truly multilateral well. Hence, in 1953, the well 66/45 was drilled in the former U.S.S.R’s Bashkiria field having 1886 ft. of main borehole with nine lateral branches with lateral length ranged from 262 to 984 ft. (from kick-off point). The cost of well 66/45 cost was 1.5 times of other conventional wells of the area, but its production was 17 times more as compared to adjacent wells in that field.

Therefore over 100 multi-lateral wells followed this successful application in that area (TAML 2004). Since then, evolution of multilateral drilling started from the open-hole sidetracks techniques to a wide range of geometrical settings and complexities. As of today, multi-lateral drilling is used significantly all over the world.

During mid 1990’s multilateral wells were completed using flow through guidestock in the main bore and a slotted or screen pack placed across the junction for mechanical support. For commingled production flow was allowed through the guidestock from the main bore completion and up through the perforations or slots in the lateral liner overlapping in the main bore.

This type of well completions were lacking junction stability and ability for reentry into the main boreholes, leading to the innovations for higher level of multilaterals of level 4 and onwards (level 5 and level 6). Hence, the improvement of drilling tools, well construction methods and advancement in completion techniques made it much easier for E&P companies to implement multilateral technology. These days multilateral technology has emerged as a mature and a reliable well construction method.

1.3 Multilateral Well Configurations

There are different multilateral well configurations depending upon the type of reservoir. Multilateral well applications are in particular used for the production from depleted reservoirs, heavy oil reservoirs, fractured reservoirs, compartmentalized reservoirs, thin layered reservoirs and tight reservoirs. A multi-lateral well geometry is usually described by its configuration (stacked, planar, radial, and opposed) and by the number of laterals (dual-lateral, trilateral, etc.as shown in figures below).

Hence multilateral well configuration can be:

- Multi-branched
- Laterals in to horizontal hole
- Laterals in to vertical hole
- Stacked lateral
- Dual opposing lateral
- Forked

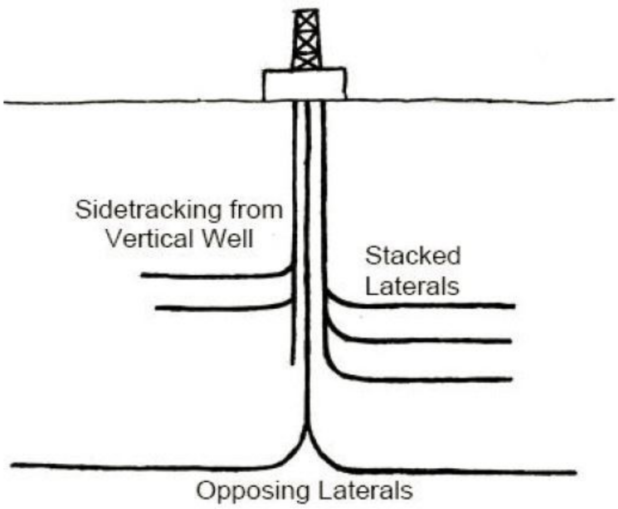

Figure 1: Multilateral well configurations (Biodiversity Conservation Alliance 2003).

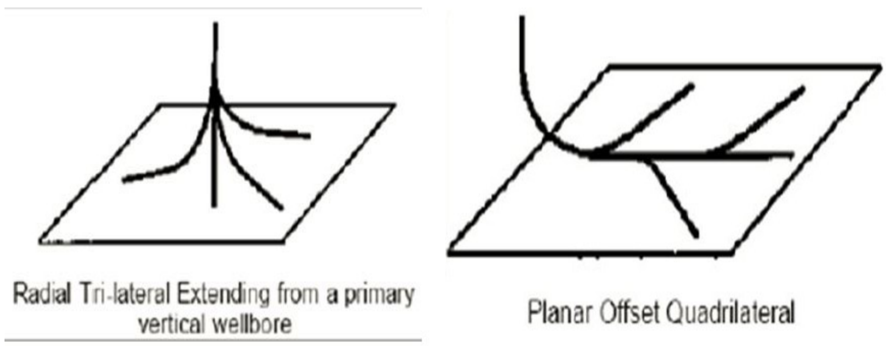

Figure 2: Radial Tri-Lateral configuration and Planar Offset, multilateral well configurations

To get more drainage area and for improved flood pattern, horizontal fanned laterals are suitable in shallow and heavy oil reservoir. To produce from layered reservoir, vertically stacked lateral drilling is used to produce different layers with single wellhead.

Dual opposing laterals are suitable for naturally fractured reservoir or reservoir with low permeability. Increase in cumulative production is assured with Hydraulic fracturing technique for horizontal section of dual laterals for tight reservoirs. As compared to single Horizontal well, dual opposed lateral will intersect more fractures, especially if the stress orientation is known. The cumulative production of dual lateral well greatly exceeds the horizontal well when horizontal permeability varies (Fraija et al., 2002).

Production performance comparison of dual opposed lateral and horizontal wells, done by the Amro,M.M, has shown that the dual opposed lateral configuration accelerates the recovery by 90% at the early stage of production (without presence of water) as compared to horizontal wells[1].

The given task for this thesis project is to give a conceptual design of a dual opposed lateral for well Sawan-12 of Pakistan. The details of motivation and reservoir strategies for choosing this only configuration is beyond the project scope, however the dual opposed lateral is considered for the same subsurface sand layer (D-Interval).

1.4 TAML (Technical Advancement for Multilaterals)

In an effort to distinguish multilateral systems within the oil and gas industry, a classification system was developed by a consortium group named as TAML (Technical Advancement for Multilaterals), comprised of operators and services companies. The group collaborated with a common goal for a worldwide transfer of multilateral experience.

Depending upon the junction complexity and functionality TAML classified multilaterals into six levels. The multilateral classification and ranking system defined by TAML serves as the industry standard for describing multilateral wells.

1.4.1 TAML Levels

TAML Level 1

According to TAML, Level 1 junction is referred to an open hole junction without any tubular support at the junction. It may have completion in either wellbores. It is the simplest level of multilateral completions which depends entirely on the natural stability of the wellbore.

TAML Level 2

In Level 2, main bore hole is cased and cemented while lateral is open hole.

TAML Level 3

Level 3 refers to type of junction where main bore hole is cased and cemented while lateral liner is anchored to main bore but not cemented at the junction. The junction type selected for the Sawan 12-DL (dual lateral) is Level 3, but for fracturing operation, a temporary level 5 junction is achieved by using Frac-diverters offered by Baker Hughes.

[1] Oil Gas European Magazine, 36 (6), Article by Amro. M.M.

TAML Level 4

Level 4 has both the main bore and lateral bore cased and cemented but the pressure integrity at junction is not provided by the cement at this point. Hence Level 3 and Level 4 provide mechanical support at the junction, not the pressure isolation. In higher levels of multilateral junction, pressure integrity is achieved either by using completion equipment or casing.

TAML Level 5

In Level 5 junction, pressure integrity is achieved by isolation packers and mechanical seats which may or may not be cemented. Most of the times, for unconventional well applications or where hydraulic fracturing is required, a temporary level 5 junction is created to support stimulation job as considered here for Sawan 12 Dual lateral well.

TAML Level 6

The Level 6 junction refers to junction where pressure integrity is achieved by casing string at the junction. Casing may or may not be cemented. This eliminates the need of extensive completion equipment for pressure integrity.

Another TAML level is being named as TAML Level 6S, where a downhole splitter is used. Here in TAML Level 6S, a large main borehole is separated into two small lateral boreholes, which is equivalent to the downhole double-casing wellhead. A clear view of TAML levels is shown below in figures.

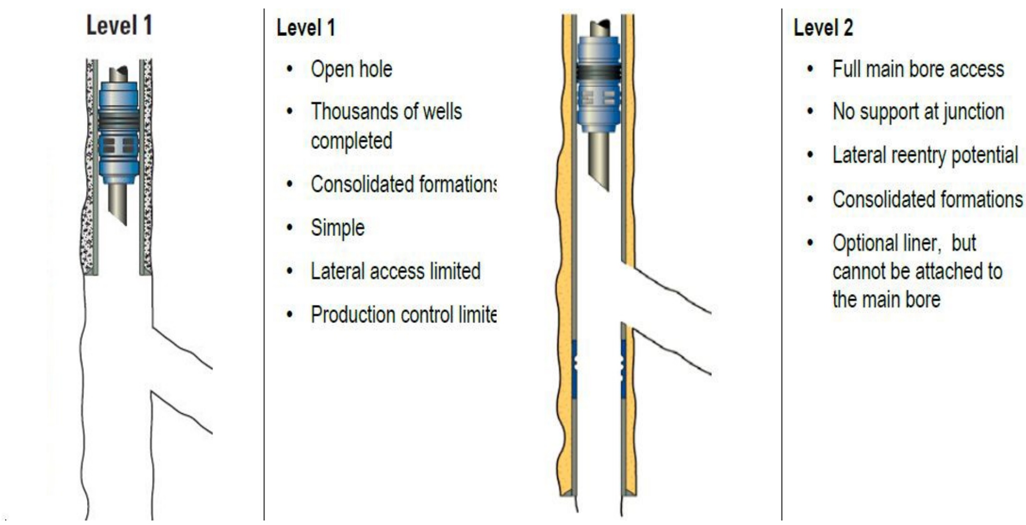

Figure 3: Illustration of TAML level 1 and Level 2

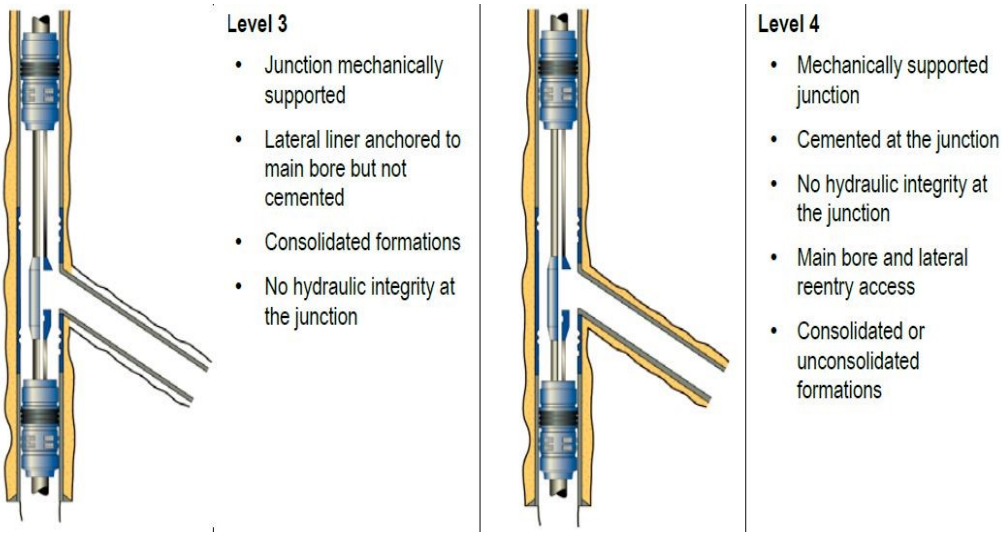

Figure 4: Illustration of TAML level 3 and Level 4

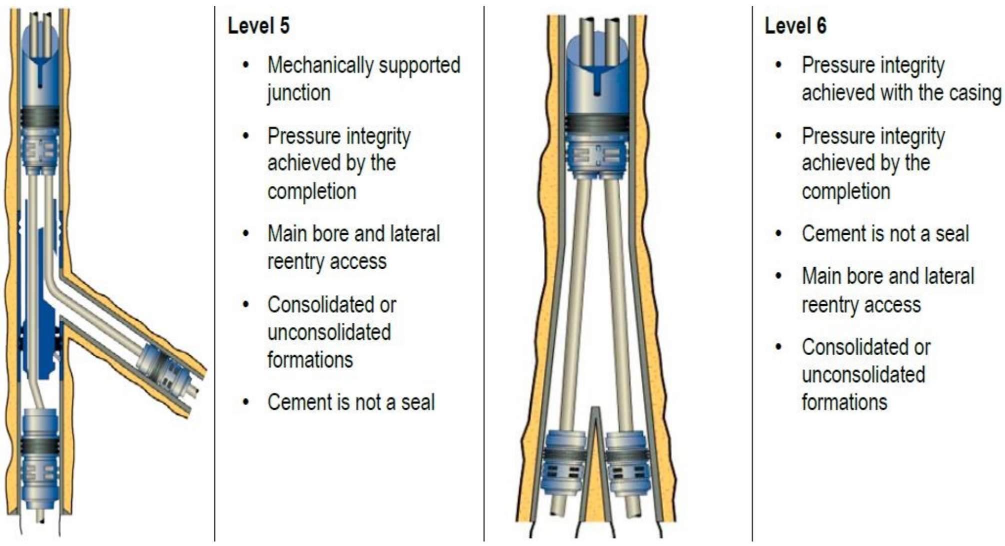

Figure 5: Illustration of TAML level 5 and Level 6

1.5 Project Objectives

In Pakistan, multilateral technology has not been implemented till date. OMV Pakistan is now looking forward to implement multilateral technology on its mature fields to increase production rate with reduced CAPEX. Therefore, a well of Sawan Gas field was chosen as a case study to implement dual opposed lateral technology along with hydraulic fracturing of tight sands of subsurface D-interval. The basic objective is to gather generalized technical knowledge of multilateral technology along with a conceptual design of Sawan 12 dual opposed lateral well, with the given considerations. While considering this proposed design and multilateral system, other fields can also be developed in near future, with modified or different multilateral well construction methods and completion systems available in market.

2 LITERATURE REVIEW

Multilateral projects need comprehensive planning, involving all the technical disciplines and continuous coordination with vendors who provide well construction and completion systems, meeting operator's requirements. Operators now are able to choose the multilateral completion system which is fit for purpose. Depending upon the multilateral junction functionality and considering associated risks, TAML levels can be selected accordingly. Here below are mentioned case histories of few multilaterals. These case histories only focus on dual laterals and TAML level 3 or level 4 junction system, as for this project the conceptual design of Sawan-12 Dual opposed Lateral is of TAML level 3.

According to TAML (Technical Advancement of Multi Laterals) junction classification system, both level 3 and level 4 junctions are defined as having a cased and cemented main bore but the difference between the two lies in the construction of the lateral. In level 3 construction, the lateral is cased but not cemented while in level 4, the lateral bore is cased and cemented at the junction for mechanical support.

Offshore application of dual lateral with level 4, to develop marginal fields, has also been proven. Rita Well 44/22c-12 and 12z, is the first level 4 dual lateral well in the challenging carboniferous area of the southern North Sea. Two main fault blocks of Rita was accessed from a single subsea wellhead. Despite of attractive economic development scenario, it set project team from all technical disciplines, with many well design challenges. Few of them were:

- Directional planning according to reservoir strict targets for each leg.
- The use of five different liner hanger systems for that single dual lateral well.
- Horizontal drilling up to 3000 ft. while managing trajectory, hole stability and formation damage objective.
- They placement of junction in very confined area and getting cement isolation around the junction was also challenging.
- Deployment of long 4 in. lower completion with sand screens.

After extensive planning and selection process, a level 4 junction was chosen to meet the well objectives. For completion, perforated whipstock technology was adopted.

The disadvantage of the chosen perforated whipstock option is that the re-entry is only possible to upper lateral.

The success of the well from drilling and production prospective has demonstrated the effectiveness of this technology for the development of mature and marginal fields, with high drilling risks. [1]

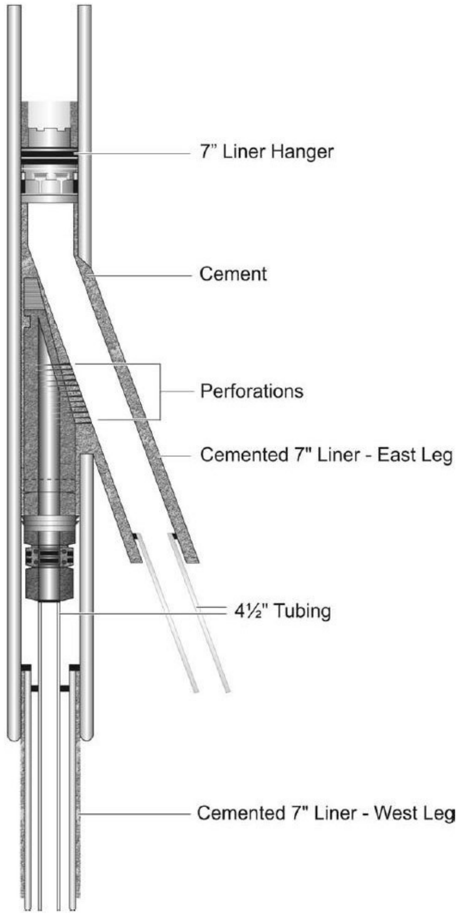

Figure 6: Multilateral junction-Perforated whipstock for Rita well [2]

Another success story of modified design of level 4 junction with intelligent completion for downhole flow control from each leg is completion of BP Deepwater subsea well FP-02. Hollow Whipstock strategy with perforations through tubing, lateral liner and whipstock was chosen. Then a straddle pack off was run to isolate the tubing perforations at the junction area and flow control from lateral was then achieved through installation of downhole ball valves.

[1,2] “Successful Application of Dual Lateral Junction Technology to Develop a Marginal Gas Field in the Carboniferous Area of the UKCS Southern North Sea, IADC/SPE 128461.

Motherbore flowed up through perforated hollow whipstock, 7-5/8” liner and in between OD of 4-1/2” tubing and ID of 7-5/8” liner. Flow was connected to upper completion with variable DHFC valves. The schematics below illustrates the modified design of level 4 junction.

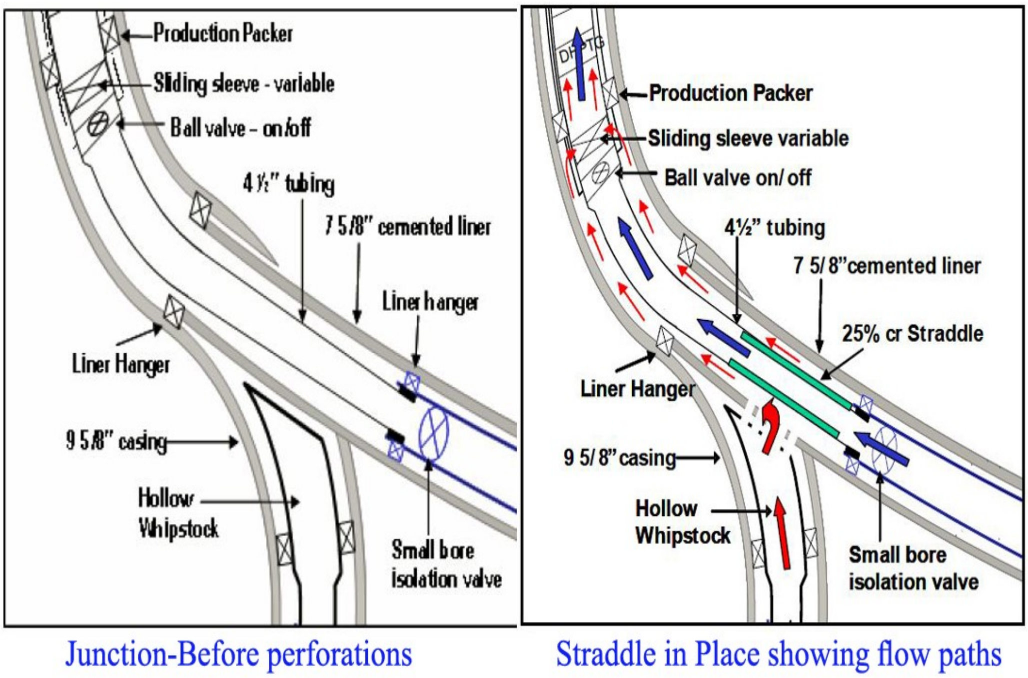

Figure 7: Modified design of TAML level 4 with intelligent completion[1]

Baker Hughes Level 3 FracHOOK hanger system has already been used to develop unconventional reservoirs, like in development of Bakken Shale located in North Dakota. This multilateral system along with open hole completion, can now be used to develop unconventional reservoirs around the globe.

The completion method used for Bakken wells included open hole packer and sleeve one trip system. The same system is chosen for the said well (Sawan 12-DL) as fit for purpose in this case for meeting the OMV requirements.

[1]The evolution of TAML L-4 to meet the challenges of a BP Deepwater subsea well. SPE/IADC 105524.

Level 4 junction with this system can be achieved by cementing the lateral liner up to junction area. It provides a temporary level 5 junction for stimulation job and desired pressure integrity of 10K psi. To avoid the risk associated with debris management, Lateral liner is not cemented up to the junction area, hence lead us to have a level 3 type junction for Sawan 12 dual lateral.

The application of the Baker Hughes FracHOOK multilateral system in Mississippi Lime Basin of Oklahoma has proven the improved economics of the similar project, by reducing 25% of cost compared to two single well multistage frac-completions. As Mississipi Basin is relatively shallower, tight oil formation, which required horizontal drilling and hydraulic fracturing to gain full production potential, the system was chosen to deliver a mechanically-supported multilateral junction with selective high-pressure fracturing capabilities for both laterals.

A modified design and well construction sequence is proposed for the Sawan 12-DL as it differs in terms of geological, reservoir conditions, and existing well profile of Sawan 12. The figure bellows illustrates the installed FracHOOK hanger system for completing the wells Mississippi Lime Basin of Oklahoma.

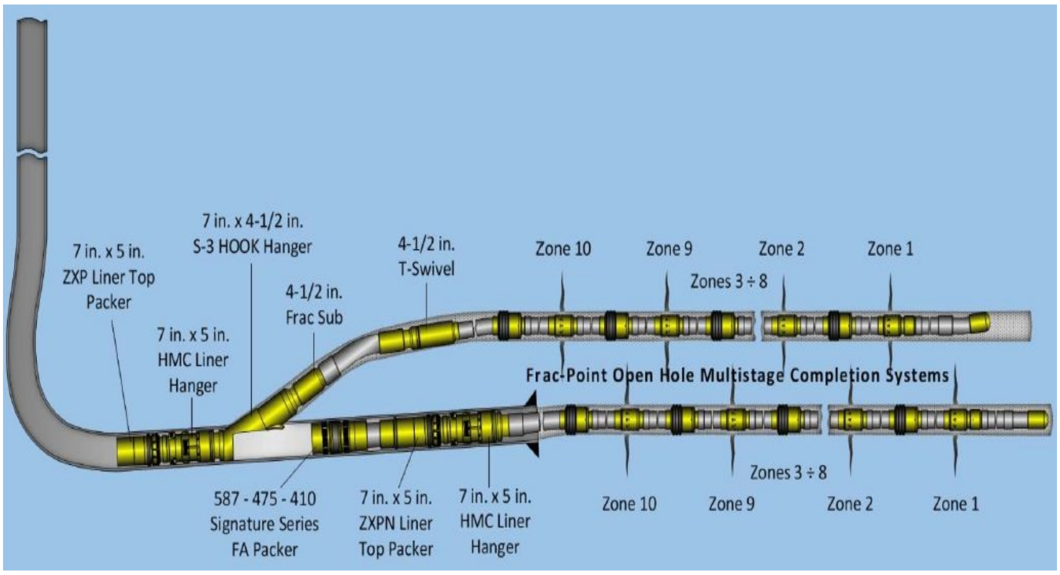

Figure 8: FracHOOK multilateral fracturing system in Mississippi Lime Basin of Oklahoma[1]

Few of the cases exists which reveal that operator has decided to construct higher level junctions to meet the well objectives, but they failed to obtain the desire results due to failure in junction installations and completing the well. This in return made those well of lower TAML level.

[1] Case History: “FracHOOK Multilateral Casing Fracturing System Saved Operator 25% in Project Cost” by Baker Hughes. Location: Mississippi Lime, Oklahoma.

3 PLANNING FOR MULTILATERALS

3.1 Motivation

Those companies who are not yet considering the implementation of multilateral technology have the reasons that: it is way too complex, high technical risks are involved, it's costly and they have never tried it before. Through field proven techniques and tools for multilateral technology provided by the services companies, E&P are nowadays able to make their reservoir development much easier for generating revenues. The risk associated and multilateral's reliability is also described later, which gives an idea that, is it still risky to apply multilateral in this era of innovative technologies and tools? A brief overview of reliability of multilaterals in comparison to other now existing technologies is also given to encourage the operators to practice this technology, especially in Pakistan.

Depending on specific filed applications, justification for considering multilateral project should be given in brief. Drivers for implementing multilateral technology can be cost reduction during field development, increased reserves, slot conservation for offshore application, heavy oil production and accelerated reserves.

3.1.1 Cost Reduction

During the mature field development, percent of drilling costs is borne by the already drilled borehole. Drilling Cost depends on the number of laterals and different TAML levels considered for junction construction. Additional cost for rig mobilization, drilling laterals and completion tools may cost 1.5 to 2 times more than the cost of the parent well. The ratio of expected increase in production and drilling cost needed to be analyzed to see if the project is economically feasible or not.

3.1.2 Increased Reserves

To exploit the isolated pay zones or compartmentalized reservoirs, separate drilling projects will be uneconomic. So to get access to smaller or marginal reservoirs, multilaterals can be drilled. Thus the number of laterals and wellbore geometry is defined to optimally exploit these reservoirs.

3.1.3 Drainage Optimization

For higher production through increased reservoir exposure, multilaterals are implemented. Multilaterals proposed under this driver are drilled in same horizontal plane. Generally laterals are radially opposed or in any planar configuration which contribute for obtaining higher aerial drainage. This driver is more important when the price per barrel and OPEX is high.

In remote locations where number of pads and size is limited, multilaterals is implemented for maximum penetrations in the reservoir from existing well heads. Likewise in offshore applications, slot conservation is achieved with increase in aggregate production per slot.

When all above mentioned drivers meet the business environment, these drivers become motivation for an E&P company to step forward for implementation of multilaterals. Business environment for an Exploration and Production company means economic conditions, risk tolerance and time allotted for development of a specific field.

3.2 Project Planning

Once reservoir development economics directs the decision makers to go for drilling the multilaterals, planning process is then started. The only functionality needed to meet well objectives, is the outcome of planning process. Planning process for well design is initiated with the input of operating conditions or physical environment of the well, data acquisition for the chosen well and services that may be needed over the well life cycle. These are referred as planning categories as given in the table below.

Table 1: Planning categories for multilaterals.

1) Operating Conditions	**2) Data Acquisition**	**3) Functionality**
Geology	Geology	Control of flow from both laterals
Reservoir	Reservoir	Access to laterals
Drilling/Workover	Production	Junction integrity (TAML Level)
Completion	Geophysical	Ability to Construct
Production	Petrophysical	Liner
Business		Ability to Repair

After analysis of planning categories, the type of well configuration and multilateral level needed, can be decided. Through variety of available completion and well construction techniques, now available in market, operator then can asks vendors to make proposals of their junction system to be considered for application on that specific well, which should be fit for purpose to meet their well objectives. The complete planning process for a multilateral is shown in figure below.

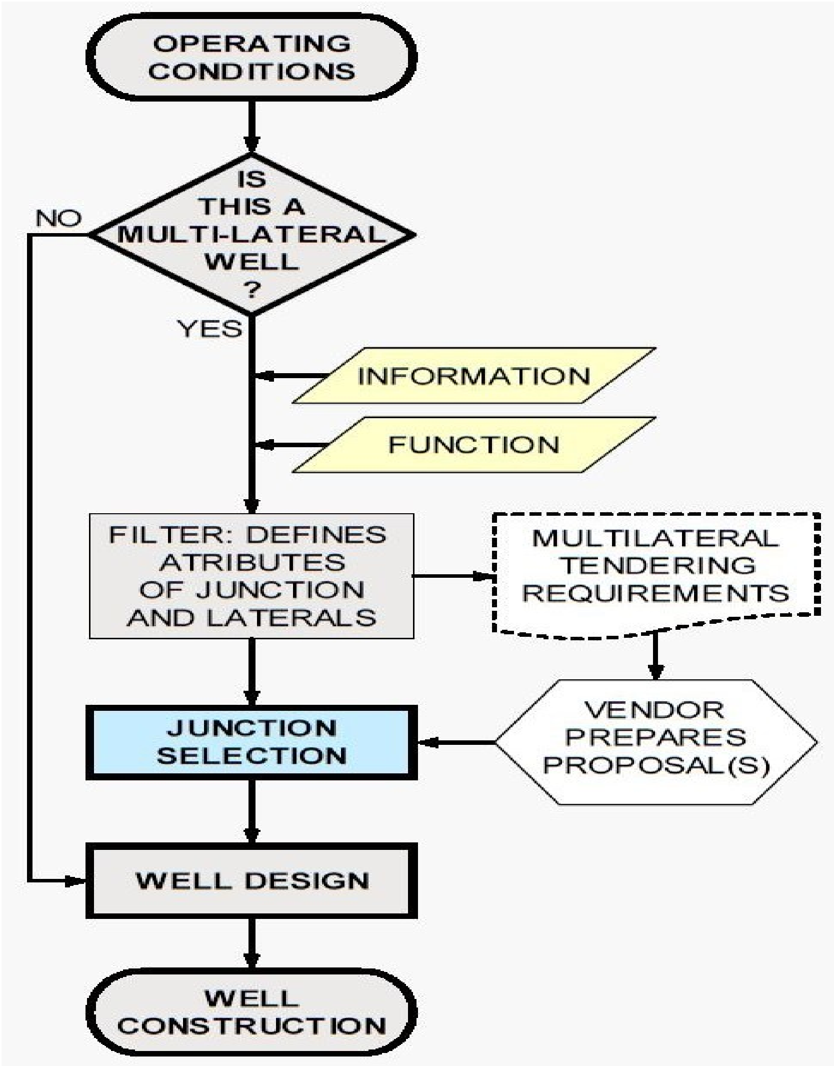

Figure 9: Multilateral well planning flow chart[1]

As planning for multilateral is one of the critical phase for the success of drilling and completion installation of a well. All the teams from each department involved, have to be on the same page for extensive discussions and cooperation with each other during planning and execution phase.

As Lot of services are needed to execute the multilateral project, lack of required level of cooperation from a single technical discipline or department may can jeopardize the whole project.

[1] A rational Approach to multilateral project planning, SPE 77528, 2002.

It is better to report a single point of contact (project manager-Operator) to avoid any discrepancies during project planning and execution. The organizational setup for coordination may look like as below.

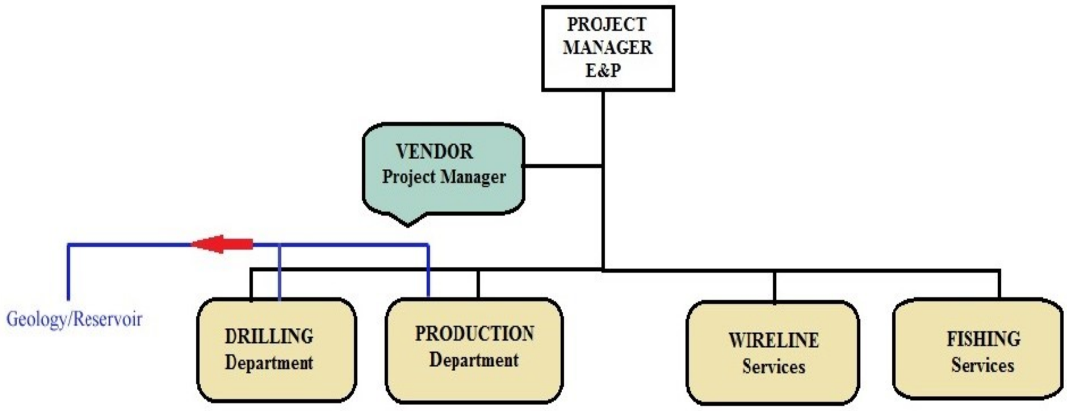

Figure 10: Way of Coordinating and reporting during planning and execution of a multilateral project

3.3 Selection criteria of Multilaterals

Because of high economics and technical complexities involved, strong justification is needed for implementing multilateral technology on a specific field. Basic drivers or motivation for this technology is optimization of production rates according to market values and increasing reserves with reduced CAPEX.

One thing needed to be clearly understood that multilateral technology is a reservoir development technology rather than a drilling technology. Bundle of screening variables which we have to consider for a technical and economic feasibility study of any multilateral project are discussed below in detail.

All the Screening variables mentioned below come in consideration during planning, design and execution of a multilateral project in general. Type of multilateral well, drilling methods, selection of completion type and junction level is thus decided by evaluating these variables.

Success of a multilateral project demands dedicated efforts and input from all the technical disciplines and vendors during planning, design and execution phase.

3.3.1 Reservoir Evaluation

Determination of volumes, number of laterals, flow rates and tubular requirements are obtained by reservoir simulation models.

Reservoir evaluation must include analysis of dominant verses passive lateral production. If production from both laterals is not isolated then dominant flow will overpressure the other. This will cause reduction of cumulative production that will be less in comparison to production from two separate wells.

3.3.2 Multilateral Economics

Since economics is the primary driver for any business decision, risk analysis is taken in the next step. Risk factors can be better understood in terms of potential economic impact.

Multilateral well will be feasible economically if it meets the following two criteria.

- Absolute cost of the multilateral well. Oil/Gas production rate should be sufficient to pay off the design expenses.

- Relative cost and production rate of multilateral well vs horizontal wells. Ratio of production from multilateral to production from horizontal wells should be greater than the ratio of multilateral well cost to horizontal wells cost for a specific field application. Hence, Flow rates and cumulative production forecast will be an input for predicting multilateral economic feasibility.

There are few factors which makes it difficult to estimate the exact cost for a multilateral well. Risks involved in multilateral wells is a main factor, and thus should be included in well drilling cost. Other contributing factors are, the various levels of multilateral design complexity, the drilling methods applied and number of laterals to drill.

An approximate cost estimation of a multilateral will be

ML cost= *cost of drilling laterals+ Cost of side track or Casing exit+ Junction Cost*

Cost for Drilling laterals and sidetrack cost is usually constant depending on the laterals trajectories and reservoir targets to penetrate. However, junction cost is dependent on the type of junction level selected and additional equipment for its construction.

Although the reservoir is considered as the biggest driver of the multilateral project, tangible and intangible cost savings also supplement and can easily provide the additional justification for proceeding with a multilateral solution (Hogg 2005).

3.3.3 Geological Considerations

Lithology of the formations dictate the junction depth and lateral wellbores placement with respect to stability. Junction thus need to be placed in non-reactive and stable formations.

Analysis of Rock mechanics is much needed as it affects the cost of the multilateral system. Rock mechanics contributes a lot especially during junction level selection. The type of junction levels like level 1 to 4 can be used in consolidated formations while higher Levels like 5 and Level 6 can be used both in consolidated or unconsolidated formations, depending upon the other defining factors.

3.3.4 Production Drawdown

Pressure drawdown by which each lateral will produce is also a drawdown against the junction installed, hence protection against that drawdown pressures at the junction area further defines the level of multilateral junction and the construction cost associated with that system. Level 1-3 junction will have drawdown acting directly on the formations. Therefore, expected pressures, rock strength and lithology are the basic design factor for the junction.

3.3.5 Technical Consideration

One of other technical considerations while thinking of a multilateral well, is the choice of premilled or downhole milling system for drilling laterals. Table below shows that which system for multilateral can be selected on the basis of different considerations.

Table 2: Considerations for downhole milling or premilled systems

Considerations	Downhole milling system	Premilled system
Drilling Sequence flexibility	Restricted to bottom up	Yes
Primary casing must be oriented	Not possible	Yes
Ease of Debris management	Low	Yes
Precision of window direction	less	High

3.3.6 Multilateral junction Level Selection

Bundle of considerations take part in the selection of preferred multilateral system. E.J Idiodemise and A.Dosunmu, have made a selection matrix for junction selection, as shown below in the table. Here in the table, “High’ dictates as most suitable against mentioned consideration/requirements, while ‘low’ dictates the least suitable.

Table 3: Matrix for junction level selection[1]

Junction Type ⟹	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6
Flow Segregation	Low	Low	Low-med	Medium	High	High
Slotted Liner/Screen	Low	Low	High	High	High	High
Commingled Flow	Low	Low	Medium	Medium	High	High
Rig Less Reentry	Low	Low	Medium	Medium	High	High
Ease of Construction	High	High	Medium	Medium	Low	Low
Low cost	High	High	High	Medium	Low	Low
Open hole lateral	High	High	High	Medium	Low	Low
Fractured Carbonate	High	High	High	Medium	Low	Low
Unconsolidated	Low	Low	Medium	Medium	High	High
Sand control	Low	Low	Medium	Medium	High	High
Pressure Integrity	Low	Low	Medium	Medium	High	High
Hole Stability	Low	Low	Medium	Medium	High	High
Pressure rating	Low	Low	Low	Medium	High	Med-High
ID restriction avoidance	Low	Low	High	Low	Low	Low

3.4 Risks involved in multilaterals

For sure, increased complexity in design and execution of multilateral project results in increased risk. Chances of failures are higher when constructing single junction (two legs) as compared to construction of two junctions (three legs) in a single well. Complexity of operations has increased with the innovative and intelligent completion systems now used for multi-junction wells. Which in turn has high level of operational risks. Two of the major risks involved are junction stability and accessibility problems into the laterals during drilling phase and at later time.

[1] A model for completion selection for multilateral wells by R.J.Idiodemise and A.Dosunmu, 2007.

In general junction stability and laterals drift limitations are considered to be main risks involved in multilaterals, which are discussed in details here below.

3.4.1 Junction stability and connectivity

Collapse of junction is one of the major causes of multilateral project failure. Junctions are critical to the effectiveness of multilateral completions. These completion components can fail when subjected to high formation stresses, temperature induced forces and differential pressures during production.

Milled window is generally a weak structure, if its size is not small enough relative to parent wellbore geometry. However in general, a window, as large as possible, is milled through the casing wall, to allow passage of BHAs and completion tools for the laterals. Here we should not ignore the stability of junction. Connectivity between the laterals at junction is thus very important for junction integrity over well life.

During construction of junction, number of trips should be reduced as much as possible to prevent any mechanical damage. Tension and Compressive loads transmitted to the junction while running liner, can also alter the geometry of junction.

Deflection of casing wall at window (C-Ring) shown below in figure is relatively thin and reacted to formation loads. Thus desired junction geometry can deteriorate with excessive loads and migration of formation solids occur.

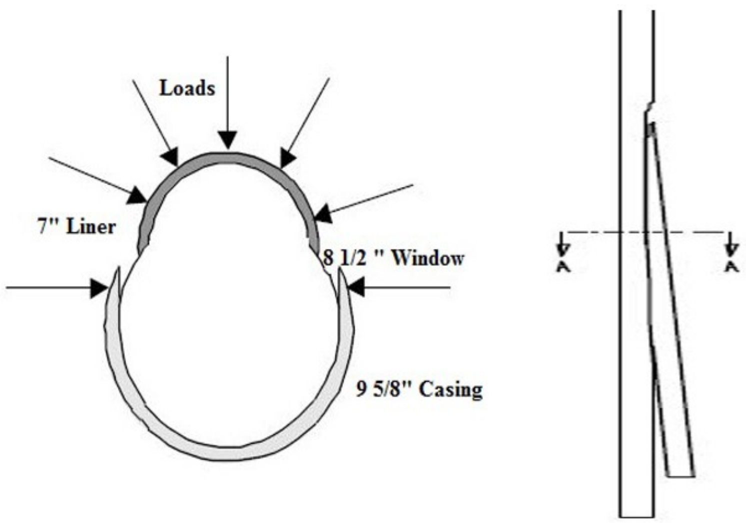

Figure 11: Radial deflection of thin Casing wall at window Point.

Those junctions which are placed in unstable formations are more likely to cause junction collapse, as compared to junctions placed in competent rock, which has shown no structural failure of the junction. For a competent and stable formation, connectivity is thus not an issue. If cement is used to strengthen the junction, its placement and recipe is very important like in Level 3, Level 4 and level 5. Level 6 technology has no such risk of junction instability.

The above discussion is all about the junction failure during drilling process, which is typical failure for a multilateral well. The other factor which can also contribute for junction instability later in production phase is Pressure drawdown. For higher production drawdown, production isolation of both laterals is required.

If the formation in which junction is placed is not competent, the excessive loads and stresses will cause the collapse of formation at junction area. In return, unsupported junction tends to move into the main borehole, causing reduced drift diameter of the main borehole for future interventions.

The figure below shows the cross sectional view of the moving in of lateral liner/Junction equipment at junction area due to excessive loads.

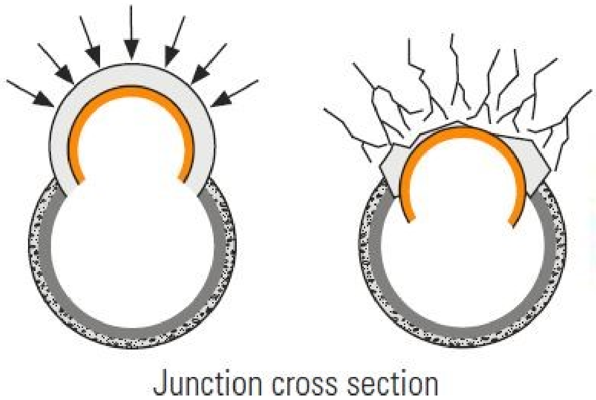

Figure 12: Unsupported junction moves into the main wellbore[1]

It has been observed through various studies that the junction stability highly depends on the relative orientation of junction with respect to regional in-situ stresses. The junction will be much more stable when the major principal stress in the cross sectional plane aligns with the center to center line (Joise Fraija, Herve Ohmer, Tom pulick, 2002).Typically, where the overburden is the largest among all other in-situ stresses, the junction will be most stable when the center to center plane is vertical, with almost horizontal both main bore and lateral. The figure below illustrates the stability of junction with respect to orientation.

[1] New aspect of multilateral well construction by Joise Fraija, Herve Ohmer, Tom pulick, 2002

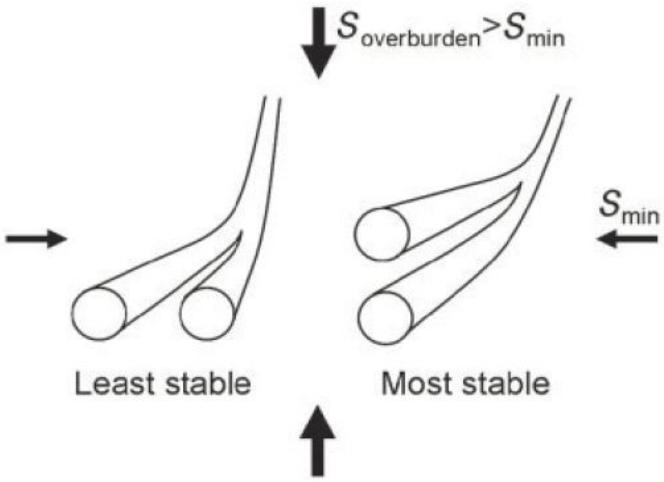

Figure 13: Multilateral junction stability and junction orientation[1]

Apart from the consolidated formation for junction to be placed, generally by the reduction of angle between the two opposed laterals, junction gets more stable (k. Goshtasbi.., 2014). Also the junction is more stable in higher inclinations. Therefore, ideal case for exiting casings for lateral drilling, is to have some inclination in parent bore at exit point[2].

3.4.2 Lateral drift limitations

Casing exit involves the risk of inability to drift tools down into the lateral borehole. This type of risk usually evolves when we cannot manage to position lateral borehole diverter in accurate axial and oriented position with respect to casing exit. Too low or too high positioning of kick off ramp and rotationally non-aligned diverter will cause choking off the lateral borehole. Axial position and rotational orientation of ramp thus need to be 100% aligned with the exit window to avoid lateral drift limitations.

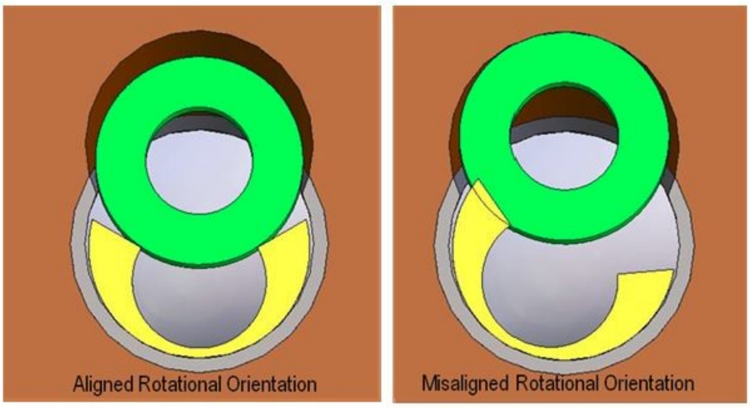

Figure 14: Lateral drift limitations associated with rotational orientation

[1] Fluentes et al.1999; Hoang et al.2004; Hoang and Abousleiman 2008.

[2] Discussion with multilateral expert (from multilateral solutions.UK).

Major risks which are associated especially with the installation of proposed system for Sawan 12 dual lateral, are discussed during description of its installation procedures in later chapters.

3.5 Reliability of multilateral technology

One of the cited reasons by most of the operators, for not putting multilateral technology into practice for developing their fields, is the high level of risk, both economic and technical. In Multilaterals, risk or failures usually referred to loss of one lateral or loss of junction, therefore meaning loss of the both (lateral and main borehole). I would like to mention here the results and findings from the recent and only known study on the reliability of multilateral technology by Halliburton Team. Through this analysis, my intentions are to show that multilateral technology is no more risky and is reliable for application. According to their study, by analyzing installation of over 822 junction installations worldwide, the overall success rate was 96 percent as shown in figure below.

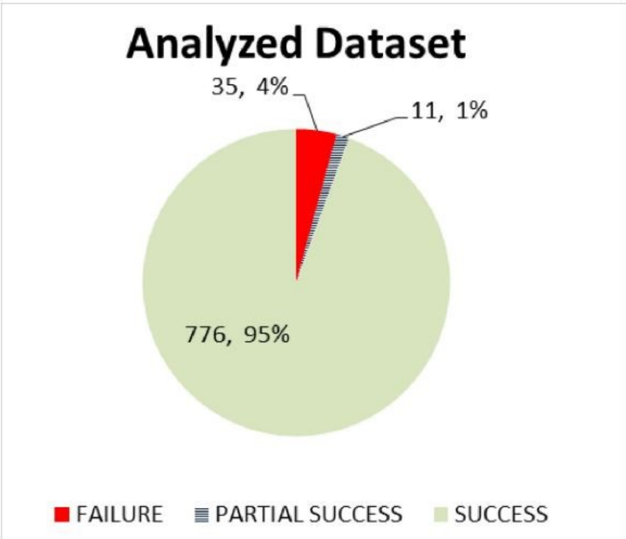

Figure 15: Analyzed dataset categories for multilateral reliability. [1]

[1] Overcoming the perceived risk of multilateral wells, Ben Butler, Andreas Grossmann, Joe Parlin and Chet Sekhon; Halliburton, 2015.

The reliability which refers to the successful multilateral well construction, has improved over time and is 98.2 % for the recent five years. The Graph below shows that how much industry has improved over time, to successfully construct and complete multilateral junction.

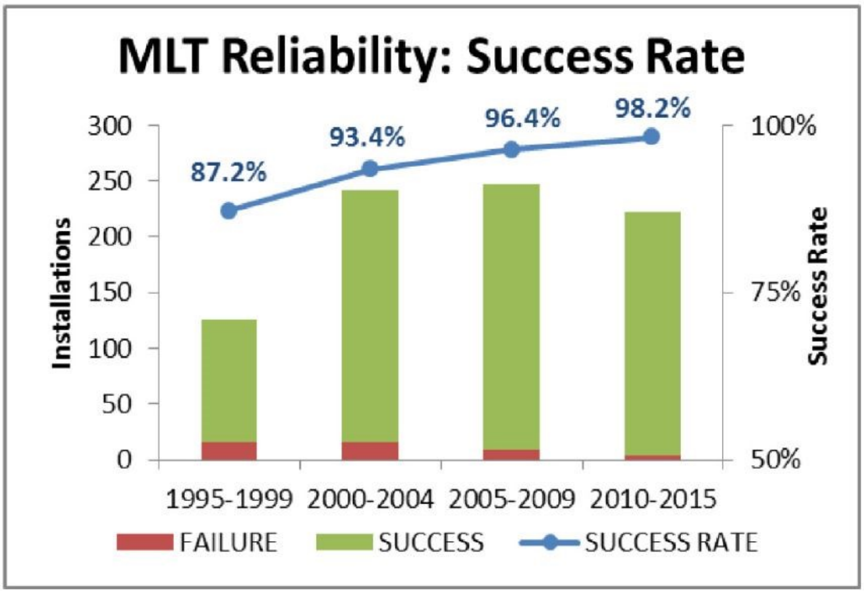

Figure 16: Multilateral Historical success rate.[1]

A literature search has shown that the multilateral technology is as reliable as other accepted well construction and completion technologies. The relative comparison with other well completion technologies is shown below in the table. This comparison is not intended to show exact quantitative results (Ageh et al.2010, Armentor et al.2007, Capderou and Dilorenzo 2012, Ismail and Geddes 2014).

Table 4: Comparison of various well completion technologies[2]

Technology	Reliability	Remarks
Expandable sand screens	84%	More than 350 applications
Intelligent wells	86%	Electronics failures most prevalent
Sand control	93-100%	Various techniques reported for more than 2200 wells
Multilaterals	96%	Data set of 822 junctions
Open Hole gravel pack	97%	121 wells

[1,2] Overcoming the perceived risk of multilateral wells, Ben Butler, Andreas Grossmann, Joe Parlin and Chet Sekhon; Halliburton, 2015.

4 SAWAN 12- DUAL LATERAL WELL DESIGN

4.1 OMV Sawan Gas field

Sawan Gas field is located in North East of Sindh Province of Pakistan (Figure 17). The first well was drilled and completed back in 1997 and a total of 16 wells have been drilled and completed till date.

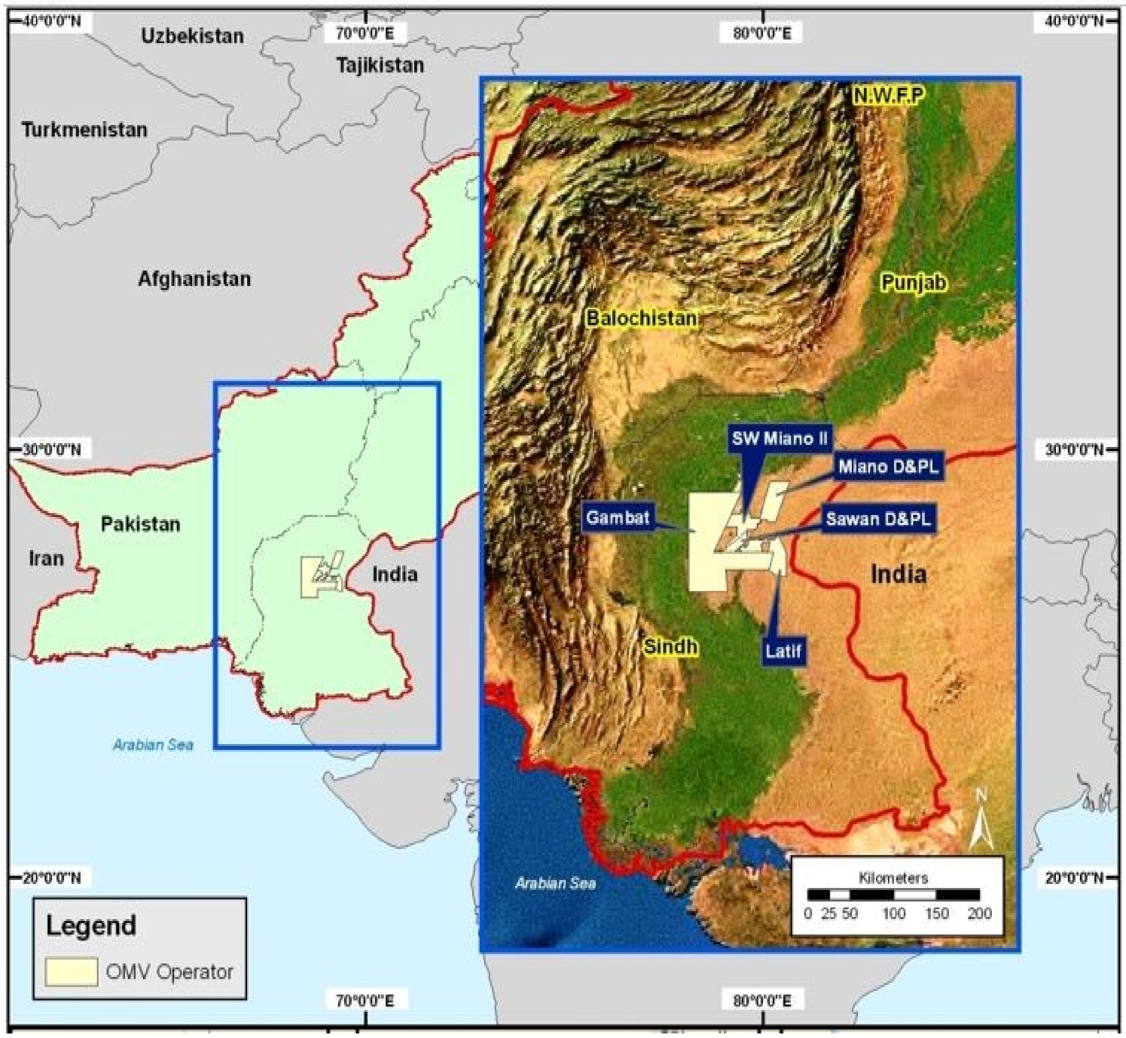

Figure 17: location map of OMV fields in Pakistan[1].

[1] Extracted from OMV Well Reports.

4.2 Well- Sawan 12

Sawan 12 was drilled and completed on 24 April 2010. Sawan 12 was commissioned to central processing plant and production was started on 20th of December 2012. Production rate was about 1.5 MMscf. WGR test was conducted in November 2013 and the gas rate was 0.30 MMscf having water production of 324.4 BPD, with WGR value of over 1000. On 30th September 2015, well was shut off and surface facilities were removed, due to low gas and high water production. Completion and X-mass tree is installed and well is shut off. Final production was 0.010 MMscf of gas per day.

4.2.1 Location

Sawan-12 is located about 2.10 km west of Sawan-6, 3.73 km SW of Sawan-4 and 5.37 km from Sawan CPP. Sawan 12 is located in sand dune area in south west of Sawan airstrip and is 67m above mean sea level.

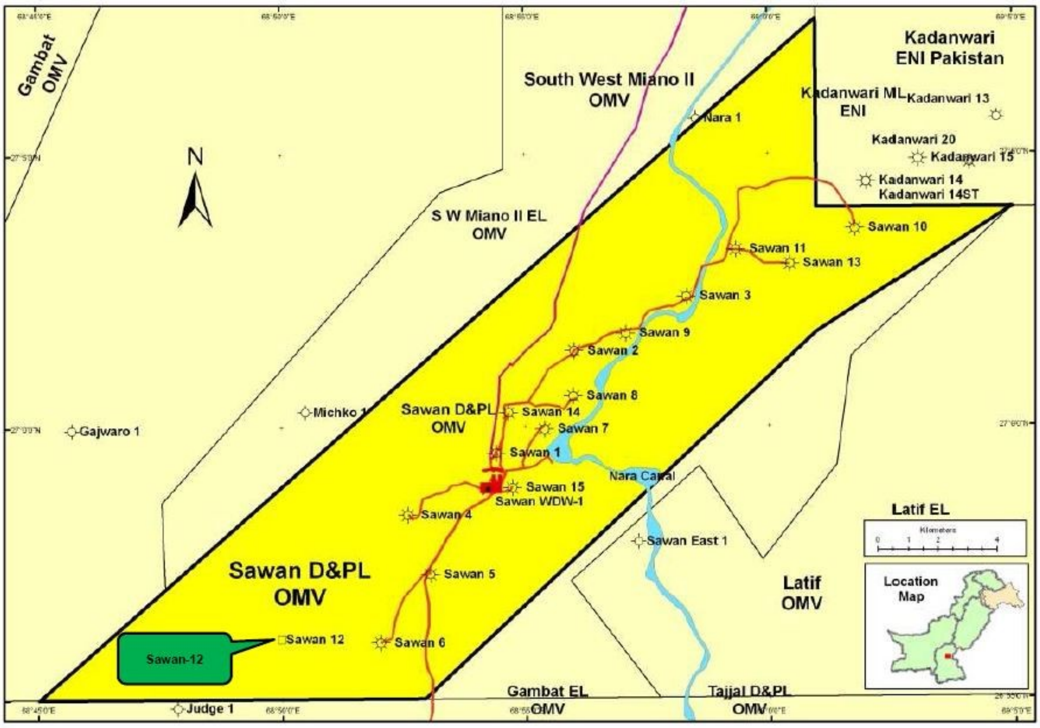

Figure 18: Well Sawan-12 surface location map[1].

[1] Image provided by Geological Department, OMV Pakistan.

4.2.2 Formation Summary

Both the laterals of proposed well is kicked off from **Goru formation (Upper Goru MB and lower Goru Shale)**. The lithology of the formations which was considered for junction placement and those drilled through to reach the well TDs is summarized in details here below.

4.2.2.1 Ranikot Formation

The Ranikot Formation is composed of mix lithology that includes Shale with intercalation of Limestone in the upper part followed by Sandstone and claystone cycle and in the lower part, the Sandstone is the dominant lithology.

The heterogeneity in the lithology makes it difficult to drill through due to frequent change in rock types. The hardness of the Ranikot formation is lithology dependent. The behavior of the Sandstone is occasionally abrasive in nature which is harder to drill.

4.2.2.2 Goru formation

The Goru formation is divided into two members, the Upper Goru and the Lower Goru Member. The contact between these members grades from marl to siltstone and claystone.

4.2.2.3 Upper Guru Member

The Upper Guru member mainly composed of Marl. The upper part of the formation entirely consists of homogeneous lithology with minor streaks of limestone. The middle and lower part of the formation mainly composed of Marl with intercalation of limestone and occasional thick beds of shale. The formation is firm to moderately hard and mostly the penetration rate remains stable due to the homogeneous nature of the rocks.

4.2.2.4 Lower Guru Member

The Lower Goru Member of the Goru Formation is divided into three distinct intervals, namely Lower Goru Shale Interval, “D” Interval and “C” Interval. The shale interval dominantly consists of interbedded claystone and siltstone. The rock type is hard in nature and mostly drilling is smooth through the section.

For formation’s summary and parent wellbore (Sawan 12) casing shoe depths, see appendix at the end of this report.

4.2.2.5 Target Formation

D-interval of Lower Goru formation is assumed to be the target layer. However, C-interval sands are the real prospect or primary target formation. The thickness of the D-sand layer is 65 to 70 meters. In the upper part, “D” Interval mainly consists of fine sandstone graded to siltstone, interbedded with shale. In the lower part, sandstone and shale are interbedded with claystone. The hardness is dependent upon the sand quality. The nature of sand in Sawan-12 is silty, therefore the rock is moderately hard. Horizontal section of both the laterals must be drilled along the middle of the layer, as D-sands are considered for its hydraulic fracturing. The figure below shows that, planned horizontal well path is through the middle of D-sand.

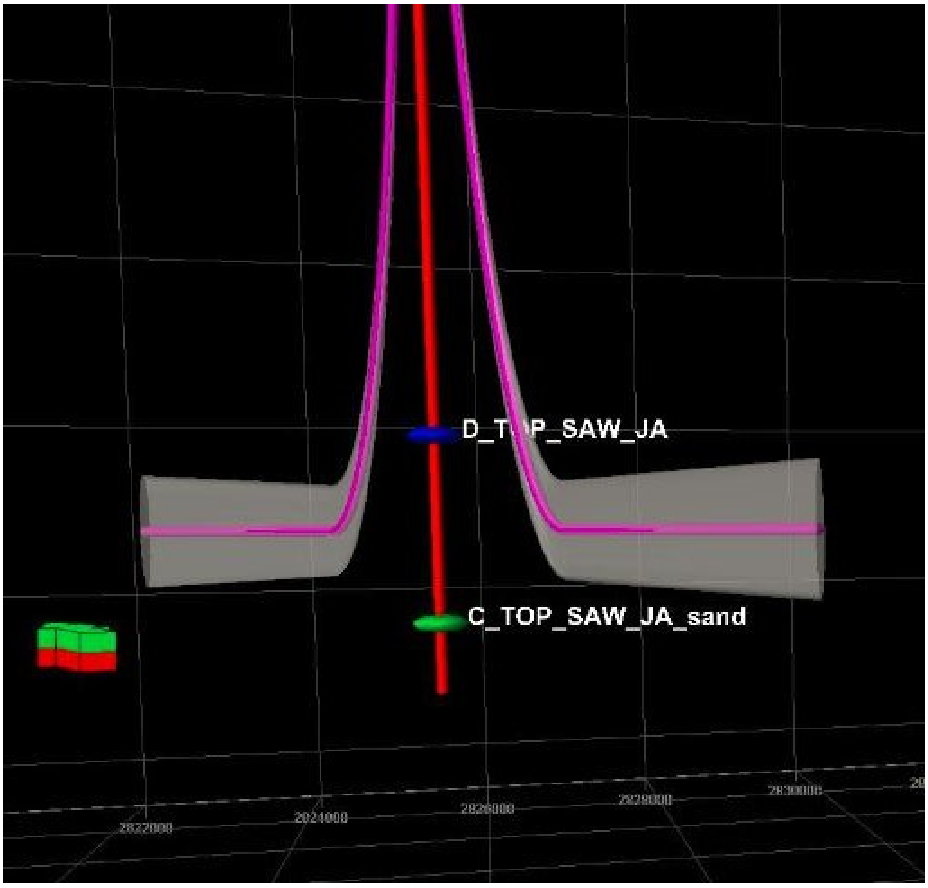

Figure 19: Horizontal sections of Sawan 12 dual lateral, within the D-interval sands.[1]

4.3 Conceptual Well Design of Sawan-12 DL

For this particular Case of Sawan 12-DL, we have to sidetrack first from the Sawan 12 to drill a new mother borehole, as targets are being assumed within D-interval Sand. Originally Sawan 12 is drilled through and perforated in C-interval Sands, which is the original drilling prospect. As here the project focuses on the technical aspect of dual opposed laterals from Sawan 12, the sidetrack to have a new mother borehole in desire azimuth is required for making it dual opposed lateral.

[1] Image Created with Petrel (2014).

While designing of multilaterals, Construction of multilateral junction and completion strategies are the differentiators between multilateral wells and conventional wells. If two or more wellbores are producing at the same time from different pay zones or compartmentalized reservoirs, having different pressures, then these reservoirs have to be isolated from each other.

Designing the multilateral well involves analysis of lithology encountered and reservoir characteristics in advance. Well Design thus depends on the criteria defined by geology of the area, geometry and production criteria. The brief overview of screening variables and criteria for type of multilateral well as well as junction level, has been mentioned earlier in previous chapter.

4.3.1 Optimum Junction Depth

Junction Location of a multilateral well depends on the geological parameters because stability of junction relies on the formation strength where it is placed. So, for optimum junction depth, one has to consider characteristics of lithology encountered, keeping in mind the required wellbore geometry to reach the desire targets.

As there is direct correlation between inclination at the end of build section, DLS and reservoir exposure thus Junction placement is defined by the DLS, economic variables and reservoir exposure. Multilateral systems from Level 3 to Level 6 have a dogleg design limits through which their tools can be run. Some reservoirs having low pressure need some kind of artificial lift so, here Junction should be placed deep enough that the reservoir can lift fluids up to the downhole pump. Therefore, efforts and time should be dedicated towards planning of an optimum junction depth.

4.3.1.1 Drilling Method

If final targets are assumed to be known, desire Lateral length for horizontal section also defines the position of junction in main wellbore. So for attempting to reach predetermined targets, drilling methods used for horizontal well drilling are Short radius, medium radius and long radius depending on the build rate from the vertical section to horizontal section. The radius of curvature of the wellbore trajectory will decrease with the increase of build rate and vice versa.

For long radius, build rate ranges in between 2^{e} to 6^{e} per 100 ft. And more than 4000 ft. can be drilled horizontally after reaching 90^{e} of inclination. Build rate range for medium and short radius wellbores are 8^{e} to 20^{e} per 100 feet and 1^{e} to 3^{e} per feet respectively. Another drilling method for marginal fields is ultra-short radius with build angle of 100^{e} per 30m to 250^{e}/30m.

For Sawan 12-DL each lateral is of long radius with an average build rate between $2\text{-}5^{e}$ per 30 meters. After placing junction within Upper Goru MB formation and heel and toe targets are assumed to be known, coordinates were then put in the Landmark software to get the desire build rate for each lateral. Kick off and casing exit depth is mentioned later in table.

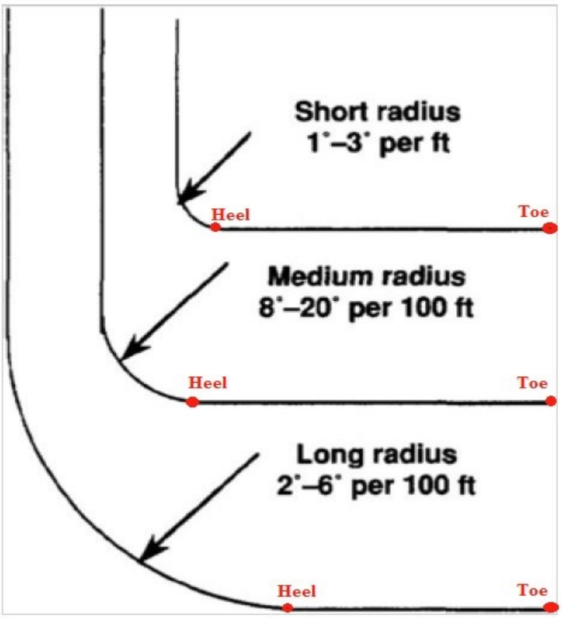

Figure 20: Drilling methods for horizontal wells[1]

For multilaterals lot of other limitations are there while choosing short, medium or long horizontal wellbores. These limitations include selection of completion type and possibility of logging measurements for each drilling methods as shown in the table below.

Table 5: Limitations associated with various drilling methods[2]

Drilling Methods	Completion Possible	Logging Measurements
Ultra short radius	Perforated tubing/gravel pack	Not possible
Short radius	Open hole, slotted liner	Not possible
Medium radius	Open hole, slotted liner, perforated liner	Possible
Long radius	Slotted liner selective completion using cemented perforation	Possible

4.3.2 Trajectory Planning for Sawan 12-DL

Here in the case of Sawan 12-DL, we have formations named as Ranikot FM, Upper Goru MB, and Lower Goru Shale. The characteristics of all these formations as described earlier in previous chapter reveals that we have Upper Goru MB formation as the stable one, to be considered for junction and KOP for the lateral borehole.

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[1] Petrowiki.

[2] Model for completion selection for Multilateral, SPE 111884

Well geometry while considering ease to drill directionally to reach given heel and then to toe points within the D-Interval, has justified the junction placement in Upper Goru MB formation. So, both laterals of well Sawan 12-DL will fall in the category of long radius horizontal wells if considered separately. In conclusion, the smaller DLS allows a wider array of tools, BHAs, logs and artificial lift equipment to drift through. However, higher cost of extra rig time, casing costs and cost for other tangibles need to be considered while economic evaluation of the project. The figure below shows the trajectory of the Sawan 12-Dual lateral.

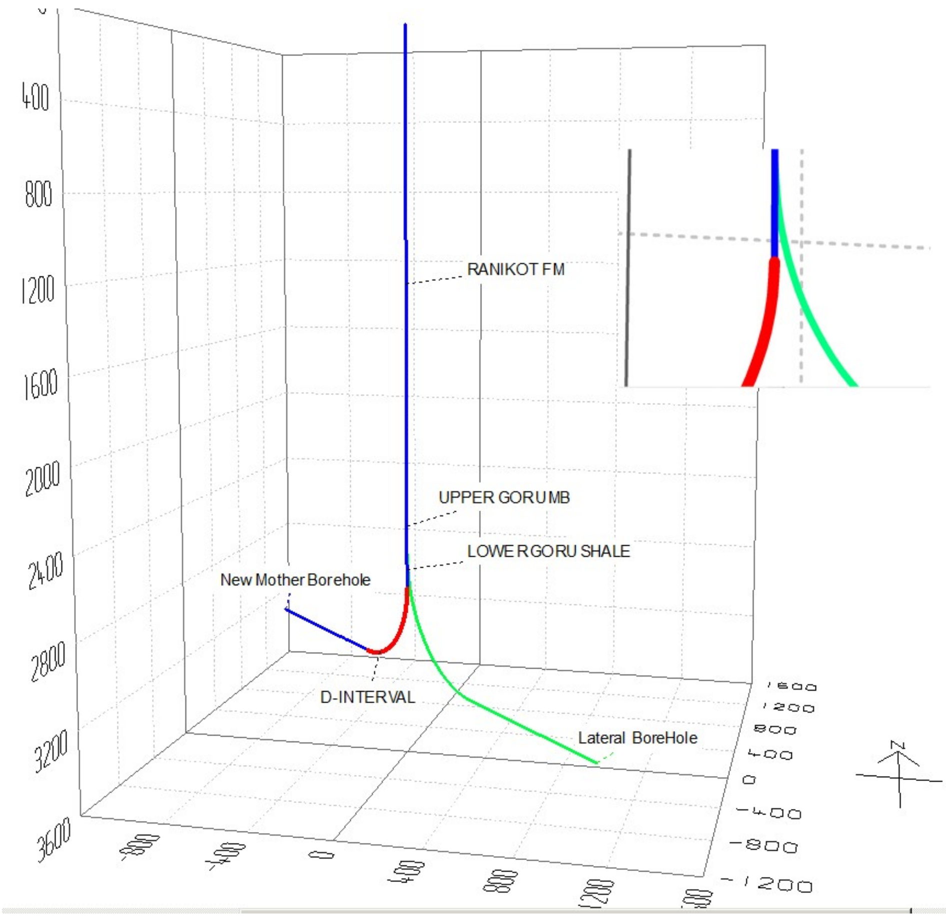


Figure 21: Trajectory of Sawan 12-DL[1]

[1] Created with Landmark Software-Compass

Table 6: Trajectory parameters for Sawan 12-DL

Description	Mother Borehole	Lateral Wellbore
KOP/Top of window	2760m MD	2565m MD
Azimuth	314.78°	134.78°
Average Build Rate	4.21° /100ft	2.86° /100ft
Build Section	651.88m MD	958.19m MD
End of Build	3411.88m MD	3523.19m MD
Horizontal Section	1000m	1000m
Total Measured Depth	4411.88m	4523.19m
TVD	3175m	3175m

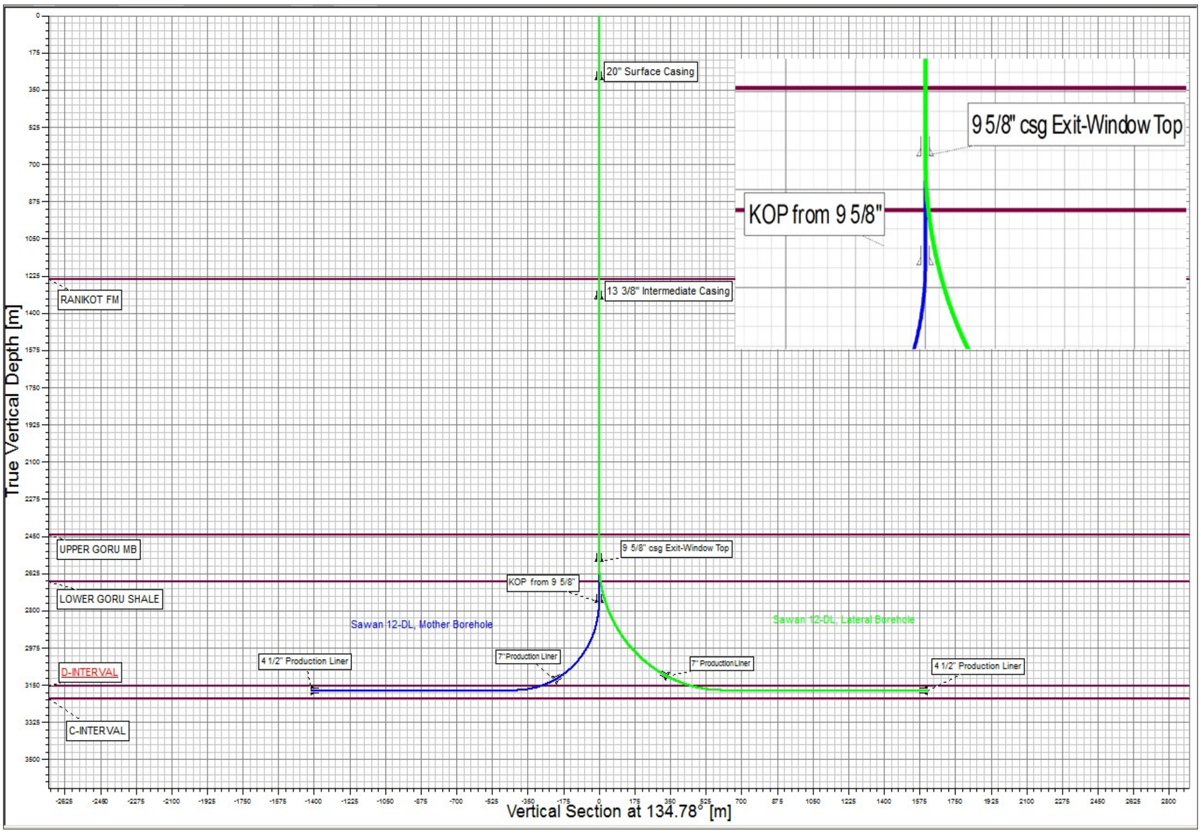


Figure 22: Vertical section view of Sawan 12-dual lateral[1]

[1] Created with Landmark Software-Compass

4.3.3 Casing Design

The surface and 13-3/8” casing will remain same for both the laterals as from Sawan 12 Casing scheme, as they are already run and cemented. 9-5/8” casing exit depth and lower liners shoe depth is different for both the laterals.

20” Casing and 13-3/8” Casing, are set in the top of Ghazij and Ranikot formation respectively. The mother borehole is kicked off out of 9-5/8” casing at measured depth of 2760m MD, while for lateral 9-5/8” casing is exited from 2565m MD.

7” liner of both the Mother borehole and lateral leg is set in lower part of the lower Goru shale of Goru formation, to isolate formation above the reservoir section, as shown in figure below. 4-1/2” liner lap to 7” liner is kept 100m in each case. 7” Casing scheme for both the laterals is also given below in the tables.

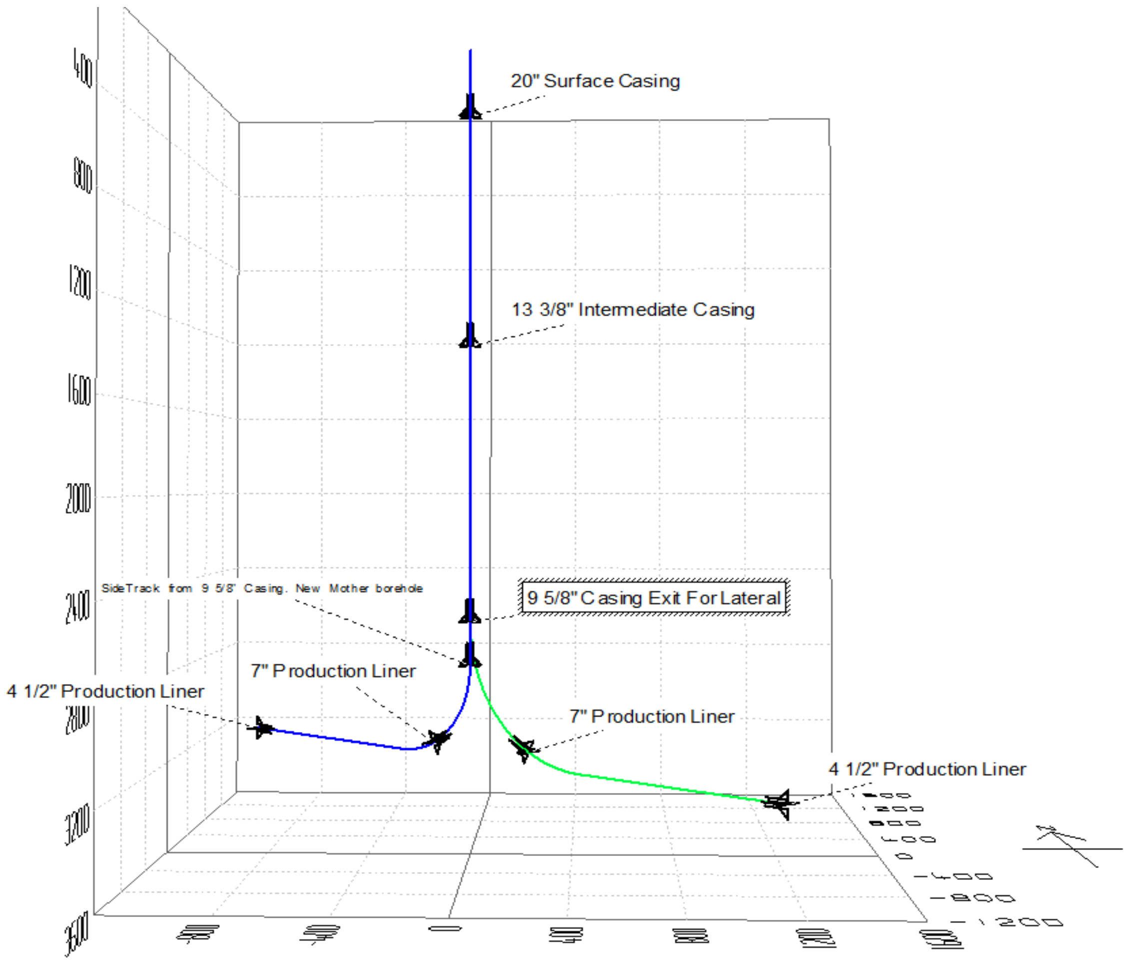


Figure 23: Sawan 12-Dual lateral illustrating casing shoes depths

Table 7: Casing scheme for Mother borehole

Casing Scheme- Mother Borehole							
	OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)		
					Hanger	Shoe	TOC
1	20"	Surface	Casing	26.000	76.00	300.00	76.00
2	13 3/8"	Intermediate	Casing	17.500	76.00	1330.00	76.00
3	9 5/8"	Production	Casing	12.250	76.00	2760.00	76.00
4	7"	Production	Liner	8.500	2660.00	3210.00	2660.00
5	4 1/2"	Production	Liner	6.000	3110.00	4411.88	

Table 8: Casing scheme for Lateral borehole

Casing Scheme, Lateral Borehole							
	OD (in)	Name	Type	Hole Size (in)	Measured Depths (m)		
					Hanger	Shoe	TOC
1	20"	Surface	Casing	26.000	76.00	300.00	76.00
2	13 3/8"	Intermediate	Casing	17.500	76.00	1330.00	76.00
3	9 5/8"	Production	Casing	12.250	76.00	2565.00	76.00
4	7"	Production	Liner	8.500	2525.00	3240.00	2620.00
5	4 1/2"	Production	Liner	6.000	3140.00	4523.19	

4.3.3.1 Casing design Philosophy

The casing design and selection of materials is determined by different factors which includes High bottom hole temperature of about 330°F. The loads (axial, external and internal) are also considered while designing the 7” and 4-1/2” liners where required. Loads include Displacement to gas, gas kick profile, tubing leak, injection down casing, full/partial evacuation, running in Hole, stimulation surface leaks, pressure test, drill ahead and cementing the 7” liner.

4.3.3.2 Design Criteria

The designing criteria are followed as per OMV standards, mentioned in the OMV Well Engineering standards for casing design. The table below shows the design parameters.

Table 9: Design criteria for casing design

Pipe Body		Connection	
Burst:	1.100	Burst/Leak:	1.100
Axial		Axial	
Tension:	1.500	Tension:	1.500
Compression:	1.500	Compression:	1.500
Collapse:	1.100		
Triaxial:	1.250		

The minimum safety factors obtained through selection of appropriate liner strings and connections types for both the wellbores are enough to meet the design criteria.

Table 10: Liner Strings Summary for mother Borehole

Strings Summary- Mother Borehole

String	OD/Weight/Grade	Connection	MD Interval (m)	Drift Dia.	Minimum Safety Factor (Abs)			
					Burst	Collaps	Axial	Triaxial
Production Liner	7", 29.000 ppf, L-80	Tenaris Blue	2660.00-3210.00	6.059	1.82	1.33	4.17	1.85
Production Liner	4 1/2", 15.100 ppf, P-110	Tenaris Blue	3110.00-4411.88	3.750	3.41	2.68	4.24	1.93

Table 11: Liner Strings Summary for Lateral Borehole

Strings Summary-Lateral Borehole

String	OD/Weight/Grade	Connection	MD Interval (m)	Drift Dia. (in)	Minimum Safety Factor (Abs)			
					Burst	Collapse	Axial	Triaxial
Production Liner	7", 29.000 ppf, L-80	Tenaris Blue	2525.00-3240.00	6.059	1.94	1.32	3.93	1.85
Production Liner	4 1/2", 15.100 ppf, P-110	Teraris Blue	3140.00-4523.19	3.750 A	3.69	2.68	3.74	1.95

Furthermore Von Mises Simulation is done for casing design of each wellbores. The plot below shows all the loads are within the tri-axial load limits.

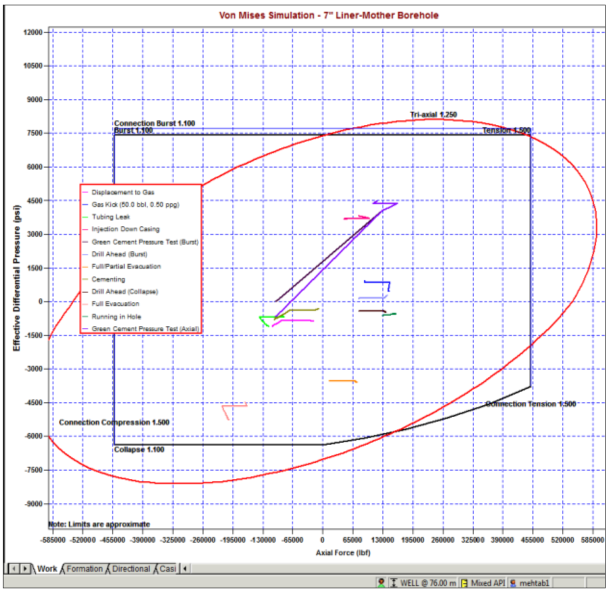


Figure 24: Design limits of 7" liner (mother bore)

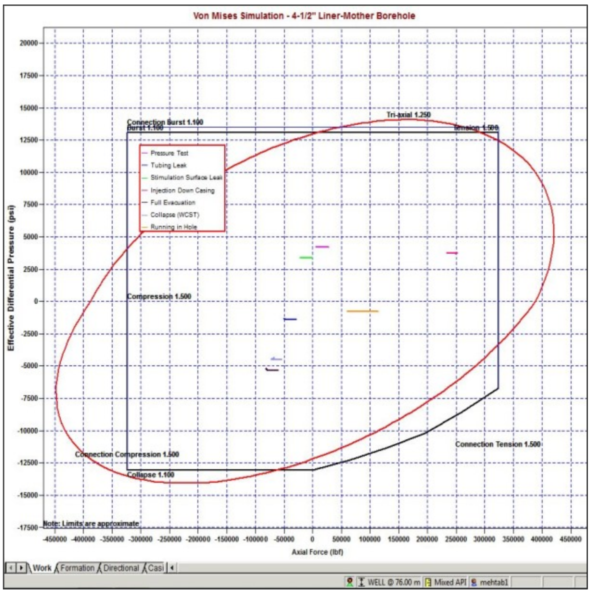


Figure 25: Design limits of 4-1/2" liner (mother bore)

The above and below mentioned graphs clearly illustrates that the recommended liner strings for each case can bear all those acting loads.

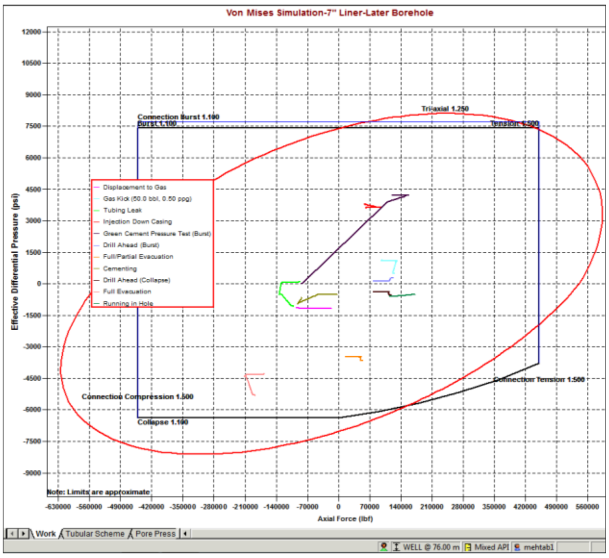


Figure 26: Design limits of 7" liner (lateral bore)

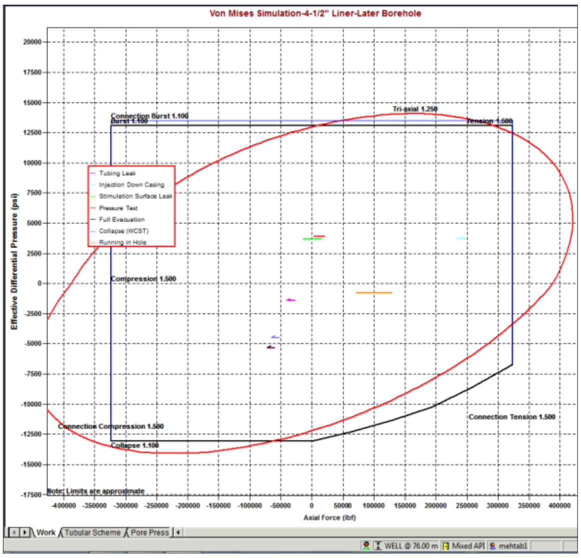


Figure 27: Design limits of 4-1/2" liner (lateral bore)

4.3.4 Hydraulics Summary

To evaluate the rig operational hydraulics, Landmark WELLPLAN Hydraulics module is used. By using this module, bit hydraulics is optimized, minimum flow rate required for hole cleaning and maximum flow rate limit to avoid flow turbulence is determined.

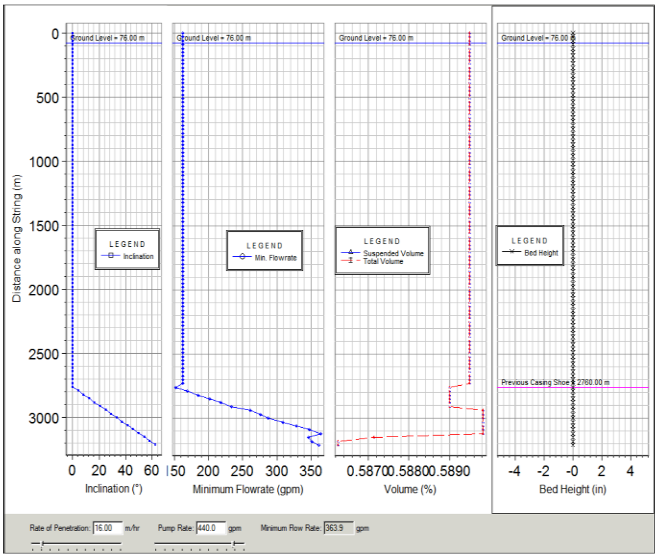
String and BHA is selected mostly the same as used in earlier sidetracks and horizontal wells. The approach was to understand and give an overview of the hole cleaning, while considering pressure limitations at surface. Simulation is done while changing flow rates and bit nozzle sizes. Fluid rheology is also assumed up to average values in each case from final well reports. The Rate of penetration is assumed to be practically achieved, as average values are taken for the same formations, from the daily drilling reports of offset wells. Flow rate value is selected while analysis of graphs showing minimum flow rates required against desire rate of penetration, pressure limitations on the surface and hole cleaning with zero inches bed height, especially in horizontal section, where cuttings tend to settle down on bottom edge.

The hydraulic summary is given in the table below, while few of the graphs regarding hole cleaning, pressure losses chart showing also ECD, is given below in figures for each case of both the laterals. Well schematics for each case are given in appendix B, at the end of document.

Table 12: Hydraulics Summary for both the laterals

Bit Size (in)	Nozzles (1/32”)	TFA (in^2)	Fluid PV (cp)	Fluid YP ($lb/100ft^2$)	Flow (GPM)	SPP (Psi)	Bit Pressure loss (Psi)	Bit (HIS)	BIF (lbf)	Nozzles Velocity (ft/sec)
Mother Borehole										
8.5	5×12	0.552	20	29	440	1785	566.99	2.6	565.2	255.6
6	2×10 4×11	0.525	18	26	310	1873	295	2	277	190
Later Borehole										
8.5	3×16	0.589	16	24	450	1675	532	2.5	560.7	245.3
6	4×10 2×11	0.492	22	29	280	2700	300.70	1.8	267.3	182.4

4.3.4.1 Mother Borehole: Case 1: 8-1/2” Hole



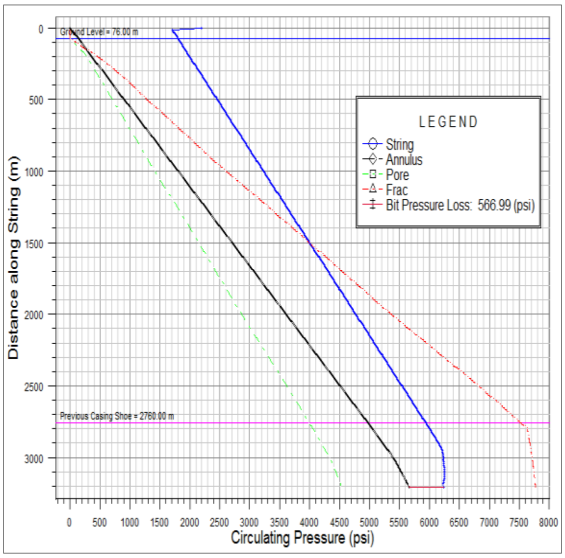
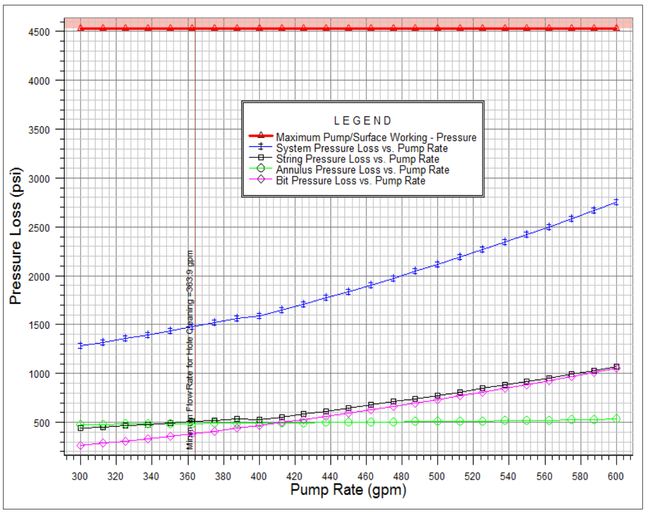


Figure 28: 8.5’’ Hole, Cutting Transport Operational

Figure 29: 8.5’’ Hole, Circulating Pressures

Inclination through 8-1/2” hole, minimum flow rate required, percentage of suspended volume and bed height is shown in the above left side graph. The zero inch bed height reveals efficient hole cleaning. The difference in string pressure and annulus pressure at the end of string length is the bit pressure loss, whose value is mentioned above in the table. Graph also reveals that the annulus pressure is in between the pore and fracture pressure curves of the formations.



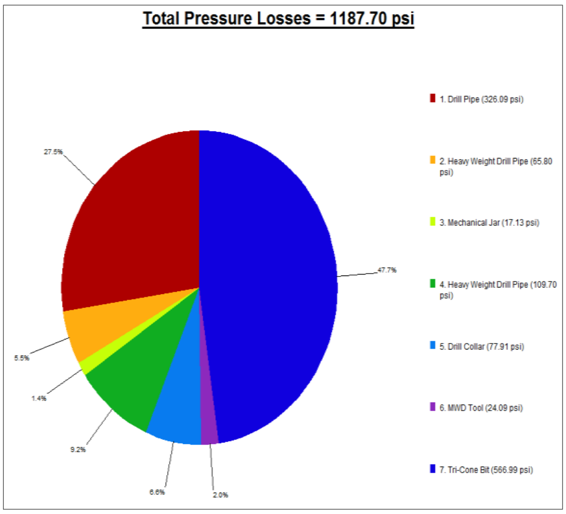
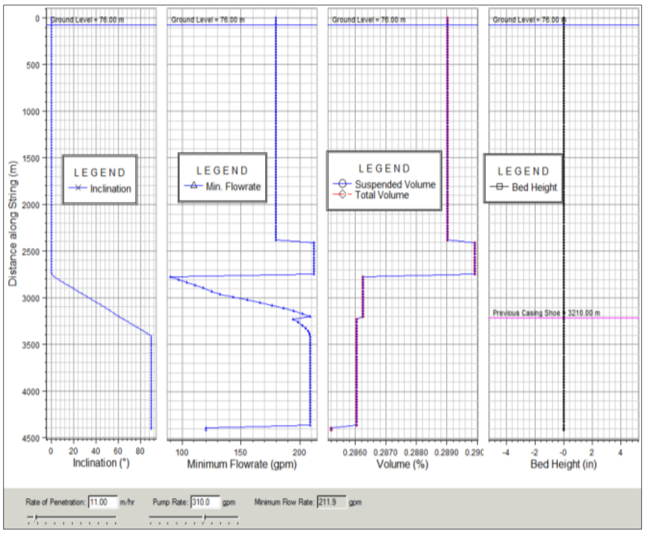


Figure 30: 8.5“Hole, Pump rate vs Pressure Losses

Figure 31: 8.5“Hole, Drill String Pressure Losses

The graph above shows the minimum flow rate required for hole cleaning and pressure losses at different places associated with different flow rates. While in the right side, pie chart shows the breakdown of string pressure losses due to different components of drill string.

4.3.4.2 Mother Borehole: Case 2: 6" Hole



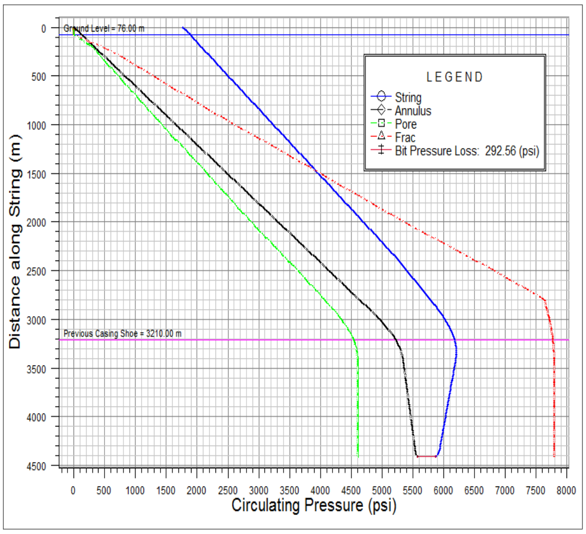
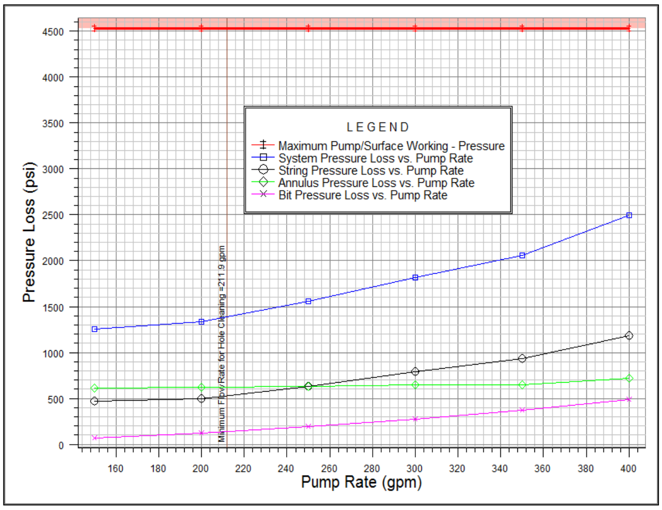


Figure 32: 6"Hole, Cutting Transport Operational

Figure 33: 6"Hole, Circulating Pressure

For horizontal section, hole cleaning is difficult as compared to vertical or inclined wells. This is due to the settling of cuttings at the lower side of the hole. Zero bed height value justifies the good hole cleaning. In the right side graph, curves shows that we are not exceeding fracture pressures of the formations and have higher annulus pressure than formation pore pressure, meeting requirements of having desired overburden pressure.



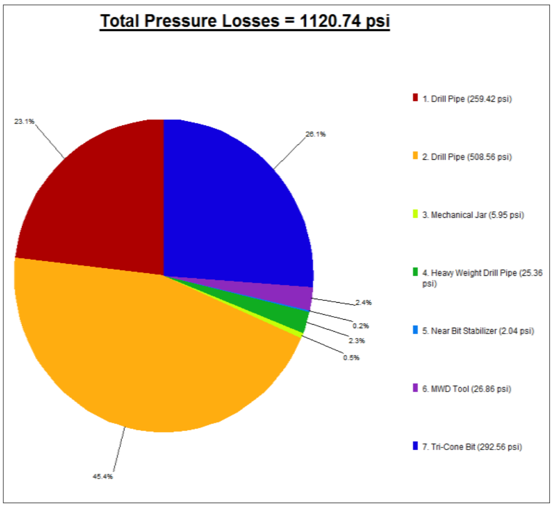
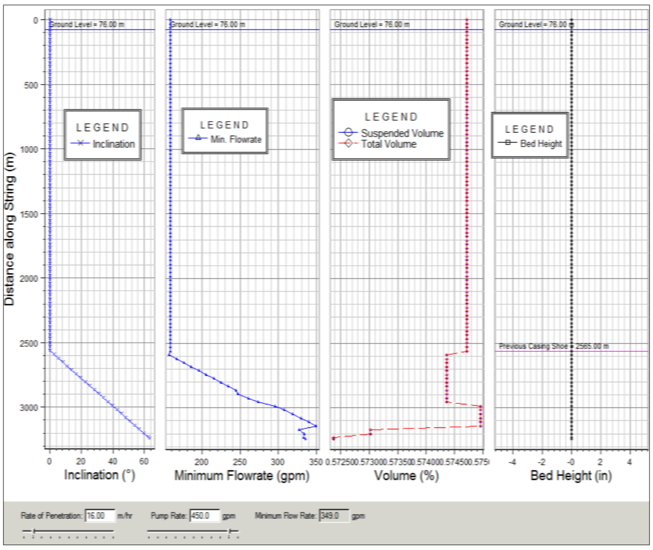


Figure 34: 6"Hole, Pump rate vs Pressure Losses

Figure 35: 6"Hole, Drill String Pressure Losses

The left side graph above, shows the minimum flow rate required for hole cleaning and pressure losses at different places associated with different flow rates. While in the left side, pie chart shows the breakdown of string pressure losses due to different components of drill string.

4.3.4.3 Lateral Borehole: Case 1: 8-1/2” Hole



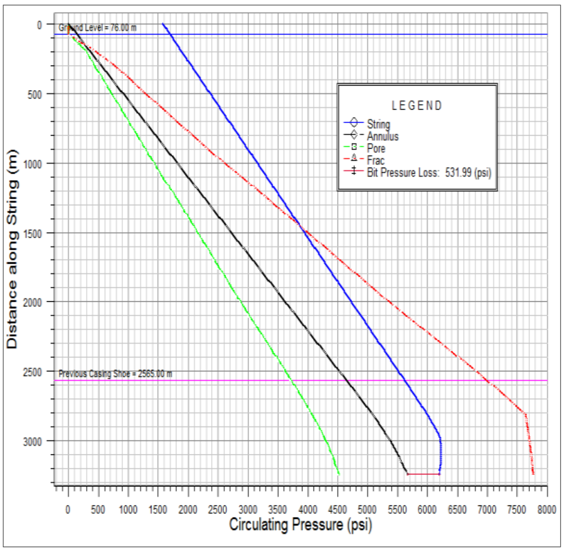
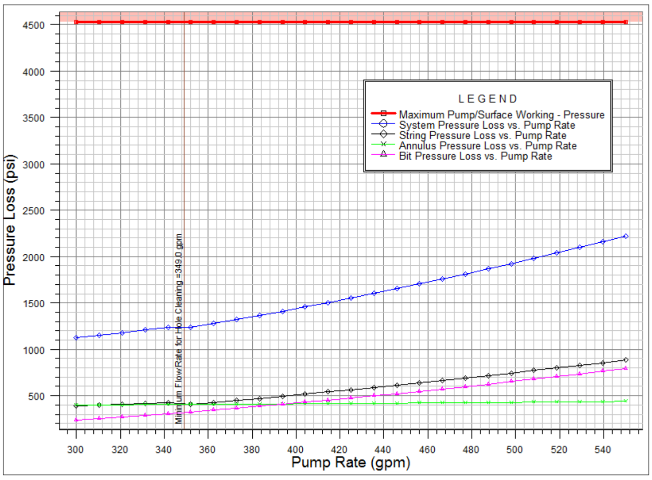


Figure 36: 8.5“Hole, Cutting Transport Operational

Figure 37: 8.5“Hole, Circulating Pressures

For the lateral borehole, inclination, minimum flow rate and bed height is given. Graph reveals zero inch bed height, so there are no hole cleaning issues in 8-1/2” hole. The above given right side graph shows the circulating pressure.



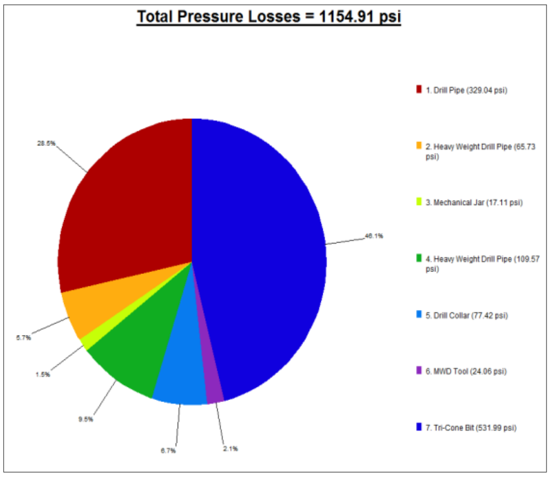
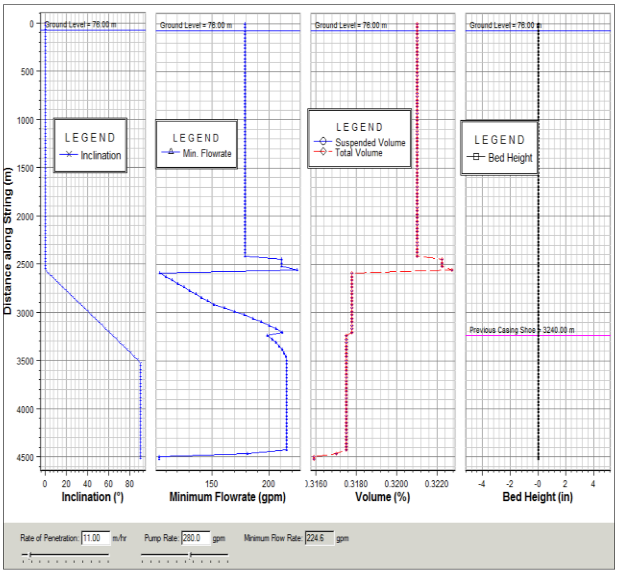


Figure 38: 8.5“Hole, Pump rate vs Pressure Losses

Figure 39: 8.5“Hole, Drill String Pressure Losses

The left side graph above shows the minimum flow rate required for hole cleaning and pressure losses at different places associated with different flow rates. While in the left side, pie chart shows the breakdown of string pressure losses due to different components of drill string.

4.3.4.4 Lateral Borehole: Case 2: 6” Hole



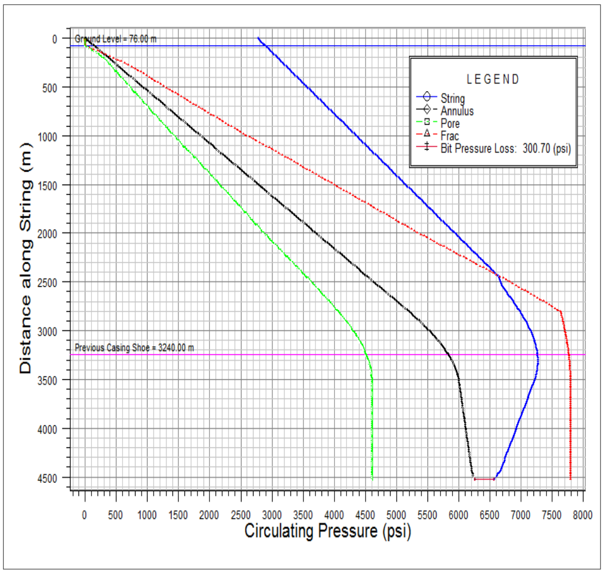
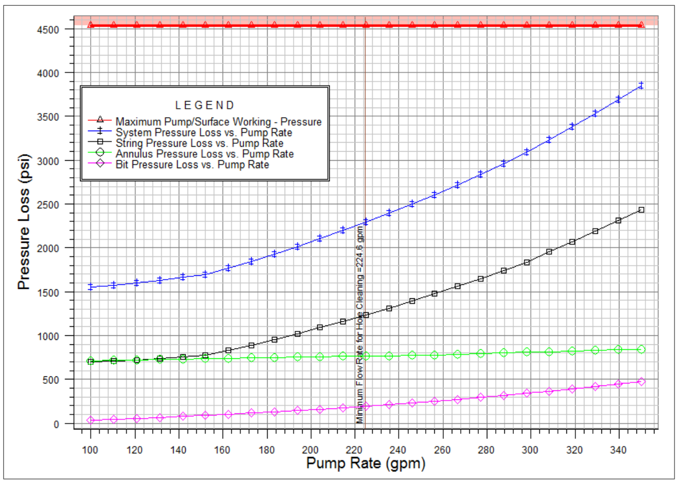


Figure 40: 6“Hole, Cutting Transport Operational

Figure 41: 6“Hole, Circulating Pressures

Mostly, hole cleaning is given much consideration while drilling horizontal sections, and thus did so to achieve zero bed height values at all inclinations, as shown in graph above right side.



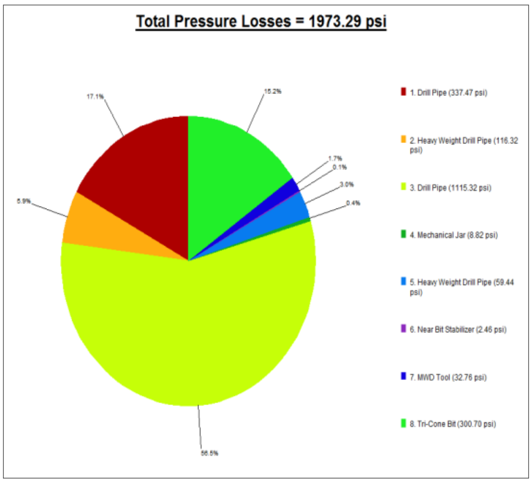


Figure 42: 6“Hole, Pump rate Vs Pressure Losses

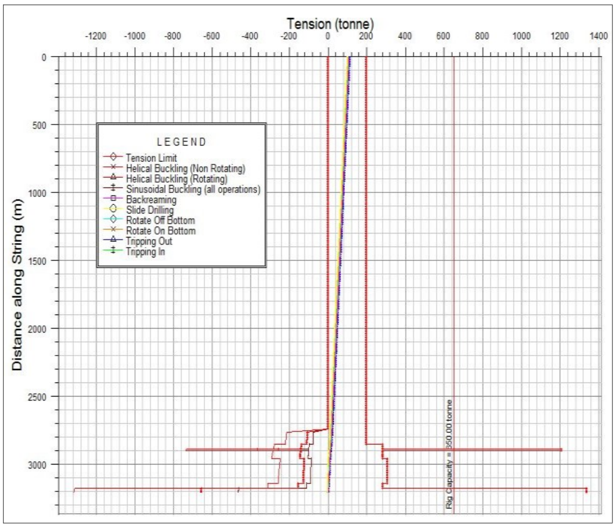
Figure 43: 6“Hole, Drill String Pressure Losses

The left side graph above, shows the minimum flow rate required for hole cleaning and pressure losses at different places associated with different flow rates. While in the left side, pie chart shows the breakdown of string pressure losses due to different internal diameter of drill string components for 6” Hole of lateral borehole.

4.3.5 Torque and Drag

Torque and drag analysis has been done for both the boreholes using landmark software package. Result from a total of four cases are shown below graphically. During this analysis, effective tension, side forces, fatigue ratios, buckling limits, Hook Loads and torque is evaluated and optimized for smooth operations. Friction factors for cased hole and Open hole are considered to be 0.25 and 0.30 respectively as default values (system generated).

4.3.5.1 Mother Borehole: Case 1: 8-1/2” Hole



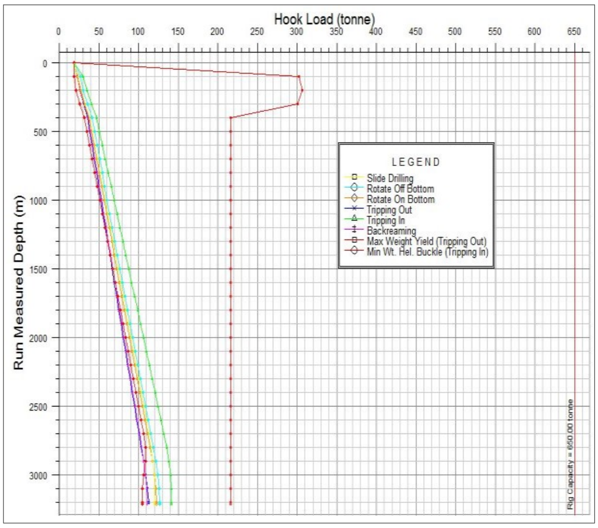
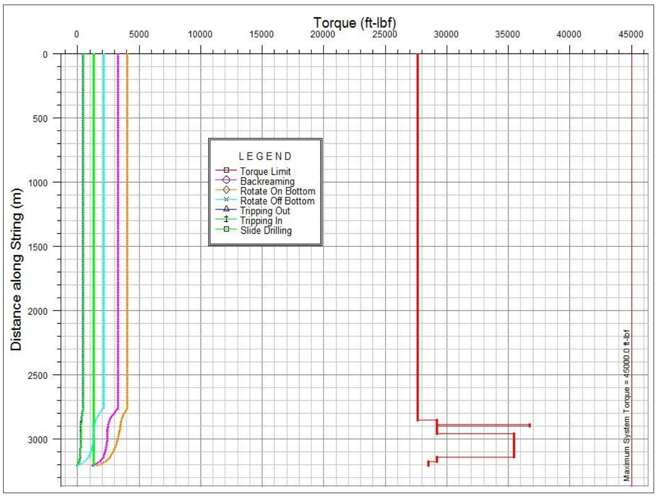


Figure 44: Effective tension vs distance along string

Figure 45: Hook Load vs Run MD

From the graph above, it can be clearly seen that tension in string does not exceeds the limits and is not in compression to cause buckling. On the right side graph reveals the hook loads along with run measured depths. Maximum weight on bit for helical and sinusoidal buckling is 20.8 tons and 20.3 tons respectively.



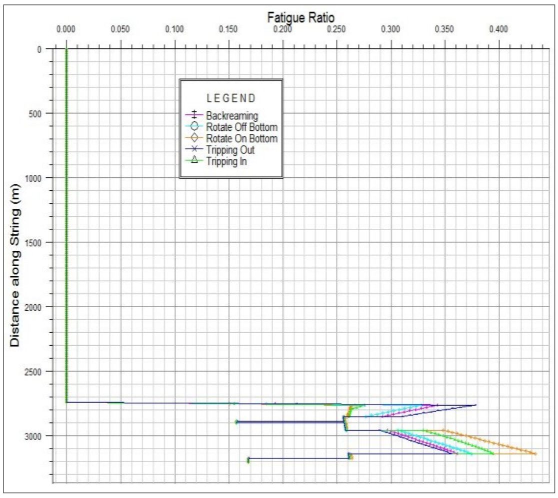
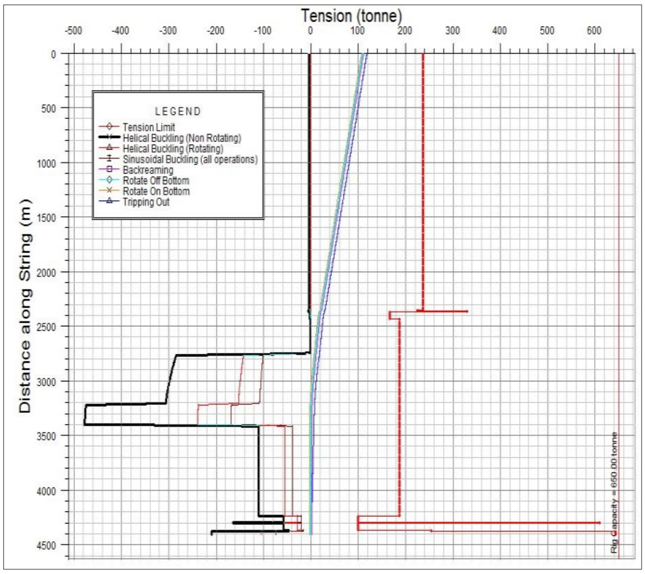


Figure 46: Torque vs Distance along string

Figure 47: Fatigue Ratio vs Distance along string

The right side graph shows the torques generated from different operations while right side illustrates the fatigue ratio in the string for this hole section.

4.3.5.2 Mother Borehole: Case 2: 6" Hole



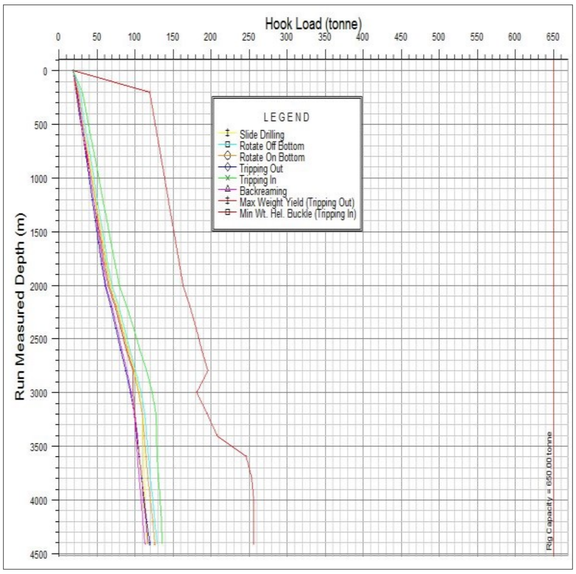
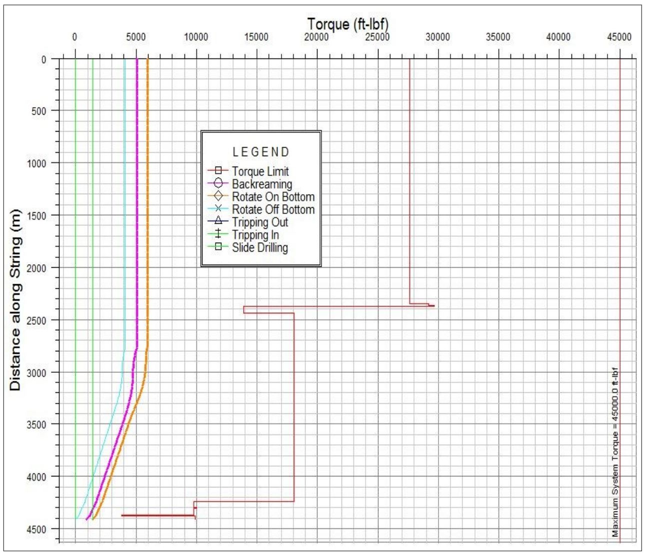


Figure 48: Effective tension vs distance along string

Figure 49: Hook Load vs Run MD

From the graph above, it can be clearly seen that tension in string does not exceeds the limits and is not in compression to cause buckling effect. On the right side graph reveals the hook loads along with run measured depths. Maximum weight on bit for helical and sinusoidal buckling is 10.8 tons and 11.3 tons respectively.



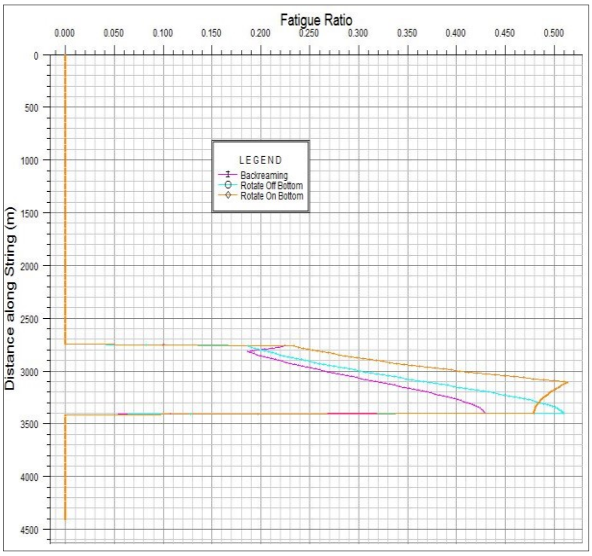
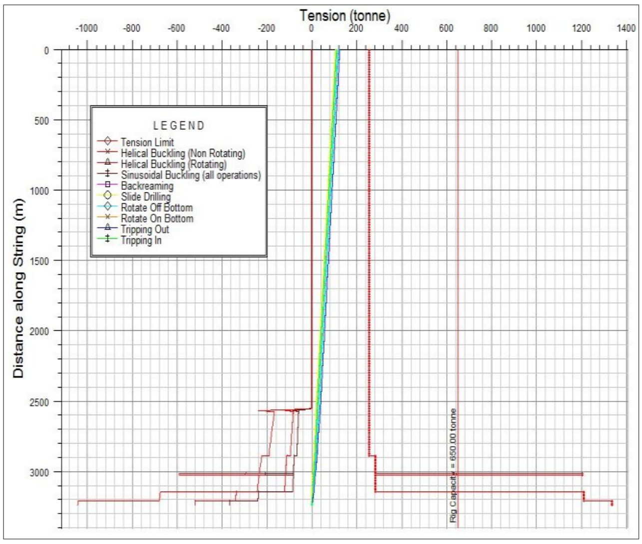


Figure 50: Torque vs Distance along string

Figure 51: Fatigue Ratio vs Distance along string

The right side graph shows the torques generated from different operations while right side illustrates the fatigue ratio in the string for this hole section.

4.3.5.3 Lateral Borehole: Case 1: 8-1/2” Hole



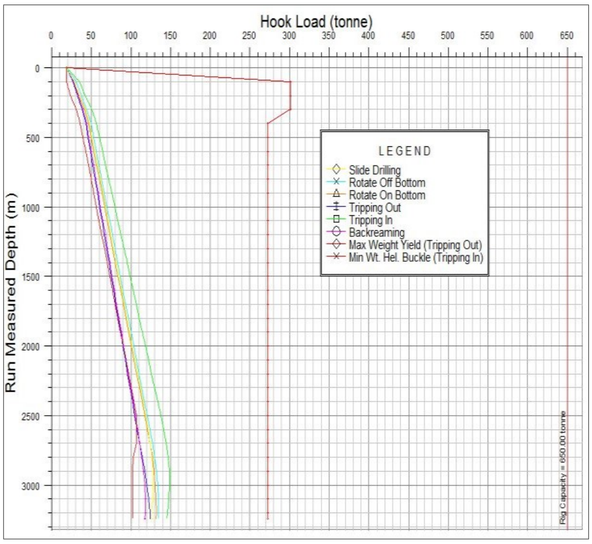
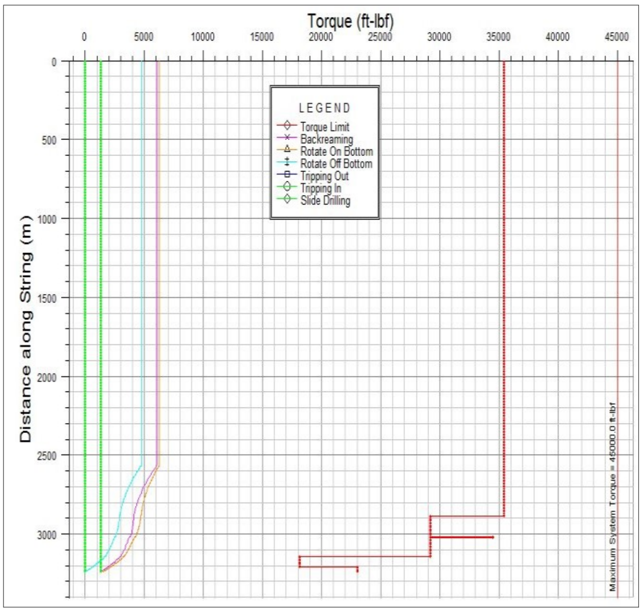


Figure 52: Effective tension vs distance along string

Figure 53: Hook Load vs Run MD

From the graph above, it can be clearly seen that tension in string does not exceeds the limits and is not in compression to cause buckling effect. On the right side graph reveals the hook loads along with run measured depths. Maximum weight on bit for helical and sinusoidal buckling is 31.5 tons and 30.06 tons respectively.



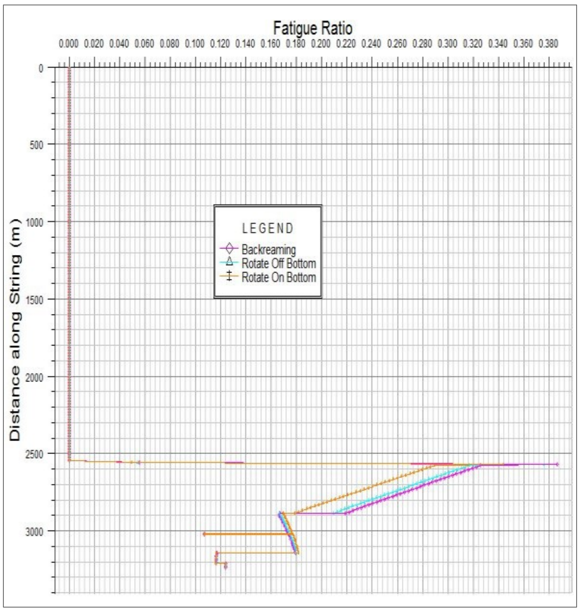


Figure 54: Torque vs Distance along string

Figure 55: Fatigue Ratio vs Distance along string

The right side graph shows the torques generated from different operations while right side illustrates the fatigue ratio in the string for this hole section.

4.3.5.4 Lateral Borehole: Case 2: 6” Hole

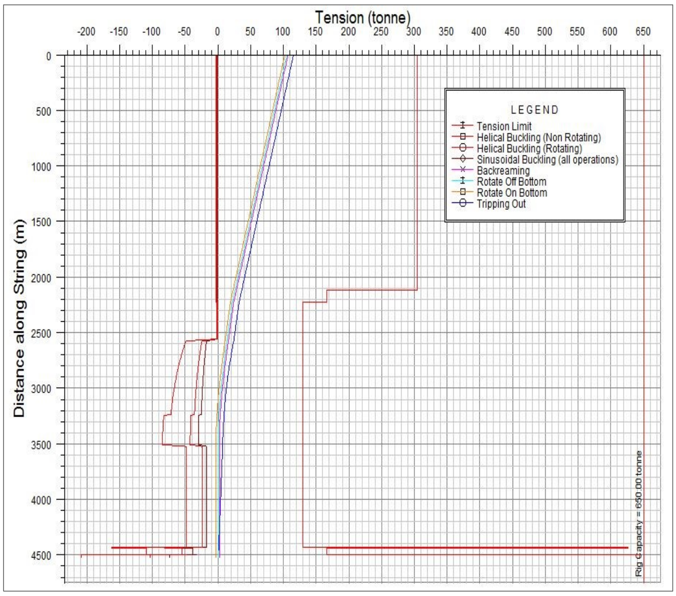


Figure 56: Effective tension vs distance along string

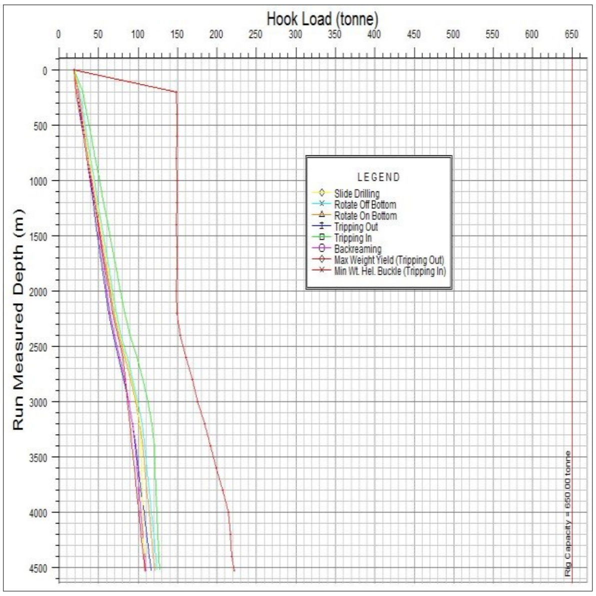


Figure 57: Hook Load vs Run MD

From the graph above, it can be clearly seen that effective tension in the string does not exceeds the limits and is not in compression to cause buckling effect. On the right side graph reveals the hook loads along with run measured depths. Maximum weight on bit for helical and sinusoidal buckling is 15.4 tons and 15.1 tons respectively.

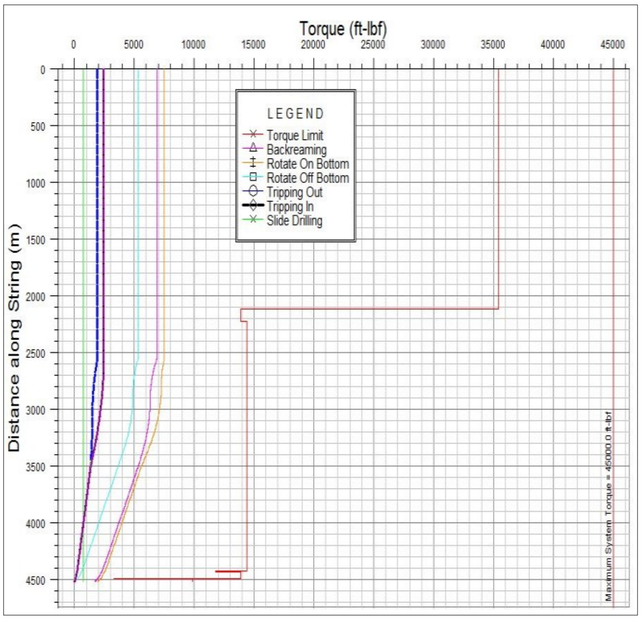


Figure 58: Torque vs Distance along string

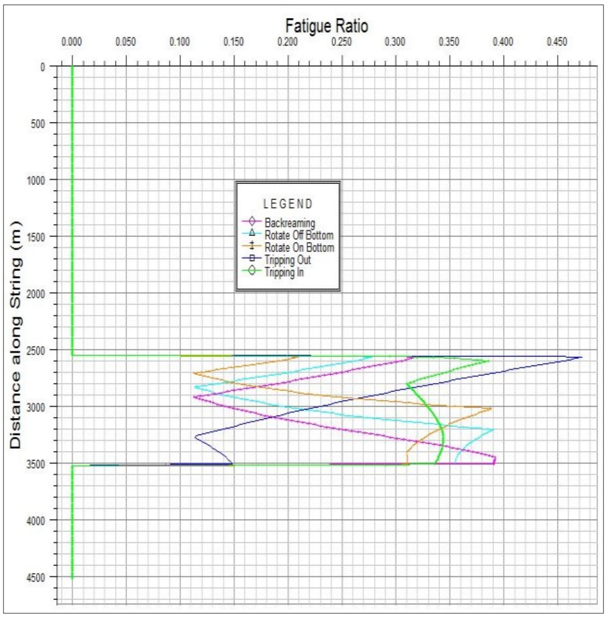


Figure 59: Fatigue Ratio vs Distance along string

The right side graph shows the torques generated from different operations while graph on the right side illustrates the fatigue ratio in the string for this hole section.

4.3.6 Drilling Unit

A Schlumberger Rig 225 is being considered to be hired for drilling Sawan 12 dual lateral. The same rig has also been used for drilling Sawan North Horizontal 1. The rig specifications are mentioned here below.

Table 13: Drilling Unit Specifications

Classification	Land rig, Diesel Electric powered
Max. Drilling Depth	25000 ft.
Static Hook Load Capacity	600 tons
Substructure / Derrick Height	30 ft. / 152 ft.
Crown Block Rating	800 tons
Travelling Block rating	650 tons
Max. Hook/Elevator Load	650 tons
Drawworks	Gardner Denver (GD 2100 E)
Top Drive	IDS 9S
Rotary Table	Continental Emsco
Master/Kelly Bushing	Varco
Stand Pipe Pressure rating	5000 psi
Mud Pumps	3 x 1600 HP (Triplex)
Mud Tank Capacity	2900 bbl.
Shakers	3 x hyper pool shakers
Desander	Derrick 16 cones, 1000 GPM
Mud Cleaners	Derrick FLC 2000
Mud Gas Separator	Schlumberger Eng. [Vertical Vacuum Type]
Rig Power System	4 x CAT 3512 TA (1435 HP Each)
Electricity Generators	4 x CAT SR4 (1750 KVA Each)
BOP Stack [Bag-type]	21-1/4“2K, 13-5/8“5 K
[Ram-type]	20-3/4” 3K, 13-5/8” 10 K
Choke Manifold	4-1/16”, 2-1/16”, 3-1/16” – 10K Cameron Type 4-1/16” – 10K Hydraulic Choke
Accumulator Unit	Koomey

5 Sawan 12-Dual Lateral well construction

5.1 Multilateral system

5.1.1 Objectives

Different service providers offers a variety of multilateral systems with different junction construction methods. As discussed briefly in the previous chapters, the selection of junction level and multilateral system depends on the various factors as shown in selection matrix. Here in this case, the task was to select the preferred multilateral system available in market which can cope up with the requirements of the Sawan 12-Dual lateral well.

Selection criteria for multilateral system is defined by the objectives discussed here below to meet integrity and business goals of Sawan 12 dual lateral.

1. Accessibility to both the laterals for fracturing both the legs back to back.
2. 10K Psi rating multilateral junction system for fracturing job.
3. Re-entry possibilities with slick line and coil tubing, once the well is completed and producing.
4. Field proven track record of the multilateral system.

Few of the multilateral systems offered by different vendors like weatherford, Baker Hughes, Halliburton and Schlumberger, are overviewed here below one by one.

5.2 Weatherford's multilateral system

Weatherford offers MillThru™ Level 4 Multilateral System for new and reentry wells. The description of the system is as under.

The Weatherford's MillThru Level 4 multilateral system with PakLatch reentry creates a Level 4 junction with large-diameter access to both the lateral and main bores. Overlapping concentric strings, combined with cement, create a junction with maximum support. This system uses standard casing exit equipment to create a lateral window. A PakLatch permanent packer assembly is installed in the main bore, and a self-aligning QuickCut™ whipstock is latched into the packer at the desired azimuth. To create the lateral access window, a routine casing exit is performed.

Conventional methods are used to drill, case, and cement the lateral liner. The MillThru milling assembly is then run in the well and mills an access window through the lateral liner overlap at the junction and back into the main bore. An optional re-entry deflector, with flow-activated anchoring system, is used for selective re-entry of multiple laterals with the ability to pass safely through multiple orientation packers.

In this system, a separate junction equipment is not used, which lowers the cost. However, a separate milling job for the milling lateral liner at the junction area is required to access main borehole. The figure below illustrates the concept of the system and table shows the system specifications.

Another system from Weatherford is named as StarBurst level 4 multilateral system, it creates cemented junction with full liner access to the lateral. Later for production from mother borehole, cemented liner at the junction area and hollow whipstock installed below the junction in mother borehole is perforated. The figure below is the schematics of the system.

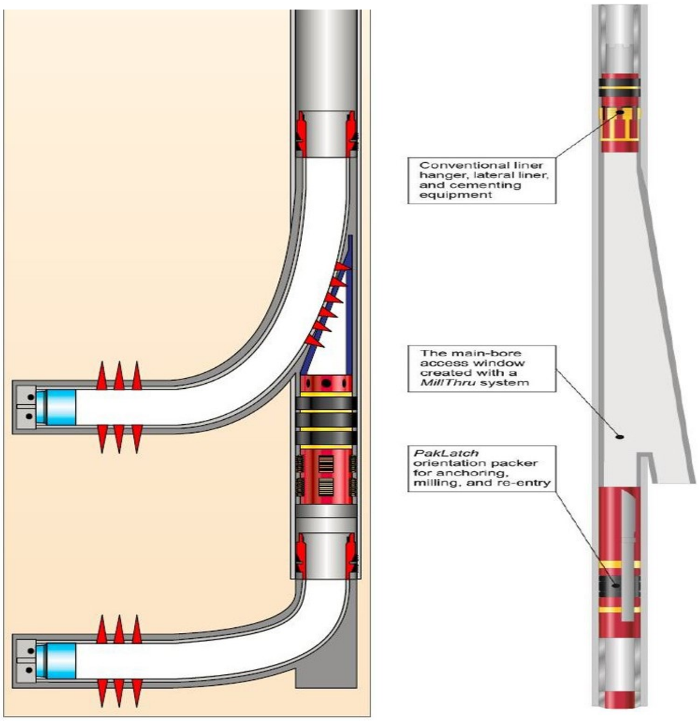


Figure 60: Weatherford's StarBurst and MillThru multilateral system[1]

Table 14: Weatherford's MillThru Level 4 multilateral system specifications[2]

System size	9 5/8 in.
Liner weight	40 to 53.5 lb/ft
Maximum OD, packer body	7 in. (178 mm)
OD, packer gauge ring	23 to 29 in. (584 to 737 mm)
Minimum ID, packer/O-riser	8.25 in. (210 mm)
Maximum differential pressure, packer	5,000 psi (344.7 bar)
Maximum temperature	275°F (135°C)
Snap-in force, packer milling latch	>5,000 lbf (2,224 daN)
Snap-out force, packer milling latch	100,000 lbf (44,482 daN)
Calculated dogleg severity of the liner through the casing exit window	10.2° per 100 ft (30.4 m)
Mainbore window	6 to 6.3 in. (152 to 160 mm)
Maximum mill OD	6.125 in to 6.3 in (155.6 to 160 mm)
Torque rating, packer/O-riser	10,000 lb/ft (13,558 n•m)
Torque rating, system	10,000 lb/ft (13,558 n•m)

[1, 2] Weatherford's re-entry-services/multilateral-systems

5.3 Halliburton's MillRite® Milled Exit Multilateral System

Halliburton offers systems with both milled and premilled window systems. Considering milled window system particularly, MillRite® Milled Exit Multilateral System which can be used to have level 2 and level 4 multilateral system, while ReFlexRite® Milled Exit Isolated tieback Multilateral is a System which provides TAML Level 5 junction for pressure integrity. In shale and tight gas plays, it is possible to fracture each leg of multilateral well without compromising the integrity of the junction. For high-pressure stimulation, the MillRite Junction installation system with a Junction Isolation Tool hydraulically isolates the junction from fracturing pressures allowing high-pressure and high volume fracturing operations to take place, enabling a TAML Level 2 constructed junction to be completed as a temporary Level 5. The system specifications are given as below.

Table 15: Halliburton's MillRite multilateral system specifications[1]

TAML Level 2 / 4			
System Casing Size	7 in. 177.8 mm	7 in. 177.8 mm	9-5/8 in. 244.5 mm
Casing Weight Range	26-29 lb/ft 38.69-43.16 kg per m	32 lb/ft 47.62 kg per m	43.5-53.5 lb/ft 64.73-79.62 kg per m
Lateral Liner Type	Drop Liner/Cemented Liner		
Lateral Hole Size	6 – 6 1/8 in. 152.4 - 156 mm	5-7/8 in. 149.2 mm	8-1/2 in. 215.9 mm
Lateral Liner Size	4-1/2 in. 114.3 mm	4-1/2 in. 114.3 mm	7 in. 177.8 mm
Lower Mainbore Access	Full gauge 6.059 in. 153.9 mm	Full Gauge 5.969 in. 151.6 mm	Full Gauge 8.525 in. 216.5 mm

5.4 Schlumberger multilateral systems

The different TAML Level systems offered by schlumberger are given below in the table.

Table 16: Multilateral systems offered by Schlumberger

Multilateral Junctions				
	TAML 2	TAML 3	TAML 4	TAML 5
7-in casing	RapidAccess RapidMSS	RapidTrip RapidTieBack RapidConnect	RapidTieBack	RapidX
9 5/8-in casing	RapidAccess	RapidTrip RapidConnect RapidXtreme	RapidXtreme	RapidXtreme RapidX
10 3/4-in casing	None	RapidXtreme	None	RapidX

[1] Halliburton Sperry drilling services/multilateral systems

The RapidConnect TAML 3 multilateral junction has a continuous locking rail that provides ultrahigh junction stability and strength. System features include a continuous locking rail that acts as an effective sand barrier.

The two main junction components are the template and the connector. These lock together to provide sand exclusion at the junction. This junction provides formation stability at the casing exit and is most suited for unstable, cap rock or in-reservoir applications. The figure below illustrates the concept of the system.

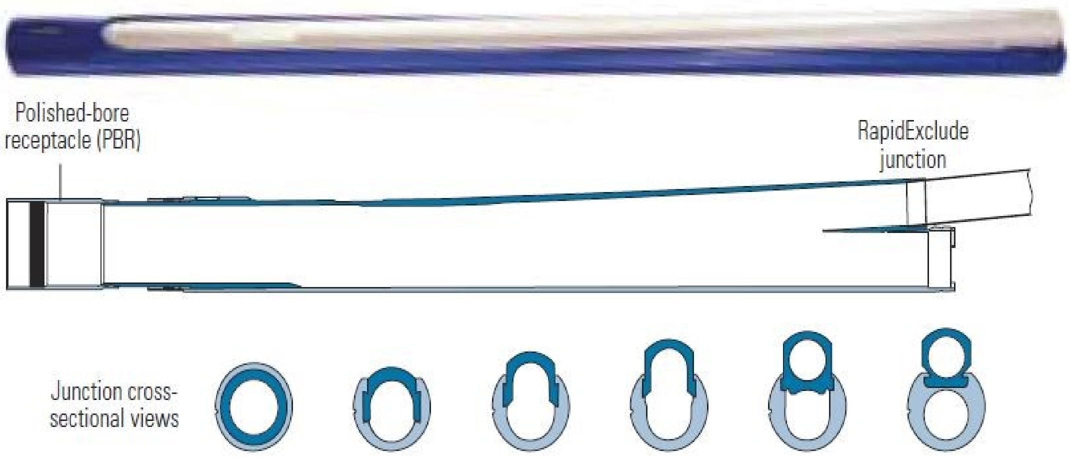


Figure 61: Schlumberger RapidConnect system with template and the connector[1]

Table 17: Schlumberger, RapidConnect TAML 3 multilateral system specifications[2]

Casing size, in	7	9⅝	10¾
Casing weight, lbm/ft [kg/m]	23, 26, 29, 32, 35 [38.69–47.62]	40–53.5 [59.52–79.6]	55.5 [82.58]
Lateral hole, in [mm]	6.125 [155.6]	8.5 [215.9]	9.5 [215.9]
Lateral ID, in [mm]	3.50 [88.9]	3.958 [100.5]	3.958 [100.5]
Main bore ID, in [mm]	4.00 [101.6]	4.421 [112.29]	4.421 [112.29]
Collapse resistance,† psi [kPa]	1,500 [5,080]	2,500 [17,237]	2,500 [17,237]
Window type	Milled casing exit	Milled casing exit	Milled casing exit
TAML level	3	3	3
Sand exclusion, u	Not available	40	40
†Burst and collapse pressure ratings.			

[1, 2] Schlumberger services and products, multilateral systems.

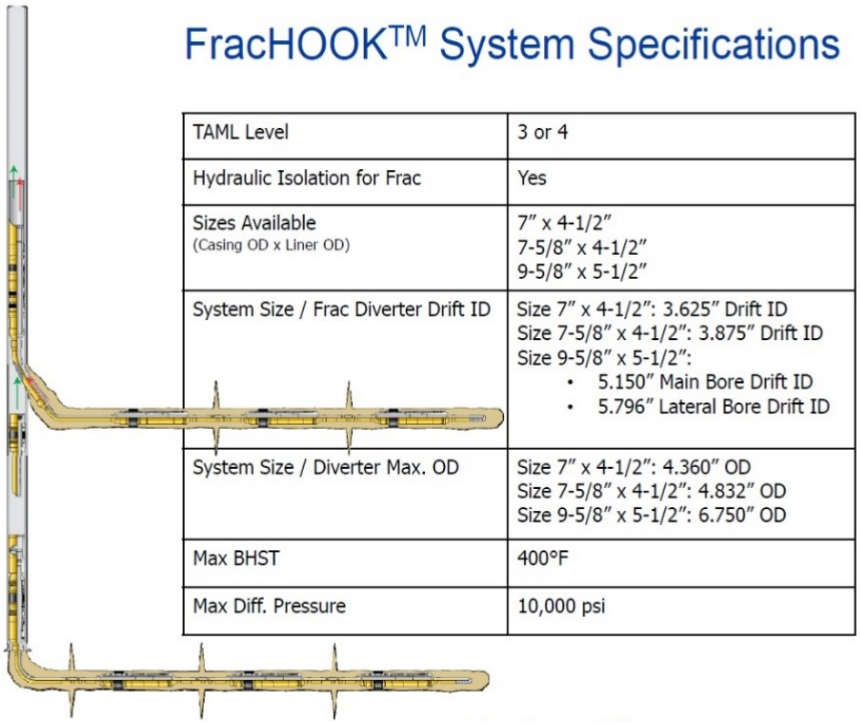
5.5 Baker Hughes FracHook™ multilateral System:

FracHook™ multilateral System is TAML Level 3 or Level 4 Multilateral system with integrated multi-stage fracturing completions. The Baker Hughes FracHook™ multilateral fracturing system provides selective, high-pressure fracturing capabilities of all laterals. Some of the common applications are open hole completions, cemented liners, and slotted liners, depending on the formation and desired completion method.[1]

Features and Benefits

- Mechanical and hydraulic isolation to each lateral
- Maintains large IDs to both laterals
- Can use current multi-stage fracturing techniques
- Casing fracturing or tieback frac-string options
- Field proven technology
- Multiple completion methods

Table 18: Baker Hughes FracHook™ multilateral System specifications[1]



FracHOOK™ System Specifications

TAML Level	3 or 4
Hydraulic Isolation for Frac	Yes
Sizes Available (Casing OD x Liner OD)	7″ x 4-1/2″ 7-5/8″ x 4-1/2″ 9-5/8″ x 5-1/2″
System Size / Frac Diverter Drift ID	Size 7″ x 4-1/2″: 3.625″ Drift ID Size 7-5/8″ x 4-1/2″: 3.875″ Drift ID Size 9-5/8″ x 5-1/2″: • 5.150″ Main Bore Drift ID • 5.796″ Lateral Bore Drift ID
System Size / Diverter Max. OD	Size 7″ x 4-1/2″: 4.360″ OD Size 7-5/8″ x 4-1/2″: 4.832″ OD Size 9-5/8″ x 5-1/2″: 6.750″ OD
Max BHST	400°F
Max Diff. Pressure	10,000 psi

[1] Baker Hughes product and services, multilateral systems

Components:

- Multilateral Junction Equipment

    "S-3" HOOK Hanger

- Diverters

    Lateral Bore Frac-Diverter

    Main Bore Frac-Diverter

- Seal Bore Packer
- Multi-Stage Fracturing Systems (Frac-Point or Plug & Perf)

The proposed multilateral junction system for Sawan 12-Dual Lateral is this system. As it meets all the required objectives of Sawan 12 Dual Lateral well. Therefore, a detailed description of equipment along with the track record of the system is given below.

5.5.1 HOOK Hanger System

The Baker Hughes HOOK Hanger™ system combines simple design and operational efficiency to deliver reliable multilateral junctions for widely used TAML Level 3, 4 and 5 completions. HOOK Hanger system provides mechanical support for junctions that join cased and cemented main bores with laterals in wells for either commingled or dual production. The system is worldwide field proven with over 400 installations as of 2009 (Baker Hughes). Till date installations and statistics of the system is also given later in this chapter.

Hook Hanger has a premilled window, when run and oriented downhole, aligns in such a way that premilled window faces towards main borehole, as shown in figure below.

Figure 62: Hook Hanger with premilled window

Patented HOOK Hanger technology can be used in TAML Level 3 to 5 completions and can accommodate lateral inclinations ranging from 0 to 90 degrees. In wells where extended-reach drilling is required, the system can be installed and cemented, and drilling operations can be continued through the HOOK Hanger and the liner shoe.

HOOK Hanger™ system is TAML Level 3 or Level 4 multilateral junction that provides mechanical support and re-entry capability to all laterals. Few of the features of the systems are as under.

- It locates into a casing exit window
- Installation is similar to a conventional liner
- Multiple completion options for the laterals
- A TAML Level 5 multilateral junction possible with specialized completions equipment such as Frac-Diverters or the Dual Seal Module

Detailed installation procedure is given later in the chapter, however typical procedure is as under[1].

1. The lower lateral is drilled and completed through the casing shoe.
2. A one-trip WindowMaster whipstock system with bottom trip anchor is run in position to drill the upper zone and set on the liner hanger.
3. The casing window is cut and the upper lateral is drilled to TD.
4. The whipstock is retrieved.
5. The Hook Hanger assembly is made up, run into the casing and landed in the casing exit window. The system's hook engages with the lower part of the casing exit window to hang the lateral liner system off the main bore casing.
6. The well is now ready for final completion and production.

1 https://www.youtube.com/watch?v=FEodS4OAbuA (Tag: Hook Hanger Final)

The figure below illustrates the concept of exiting Hook Hanger along with lateral liner, out of main bore casing.

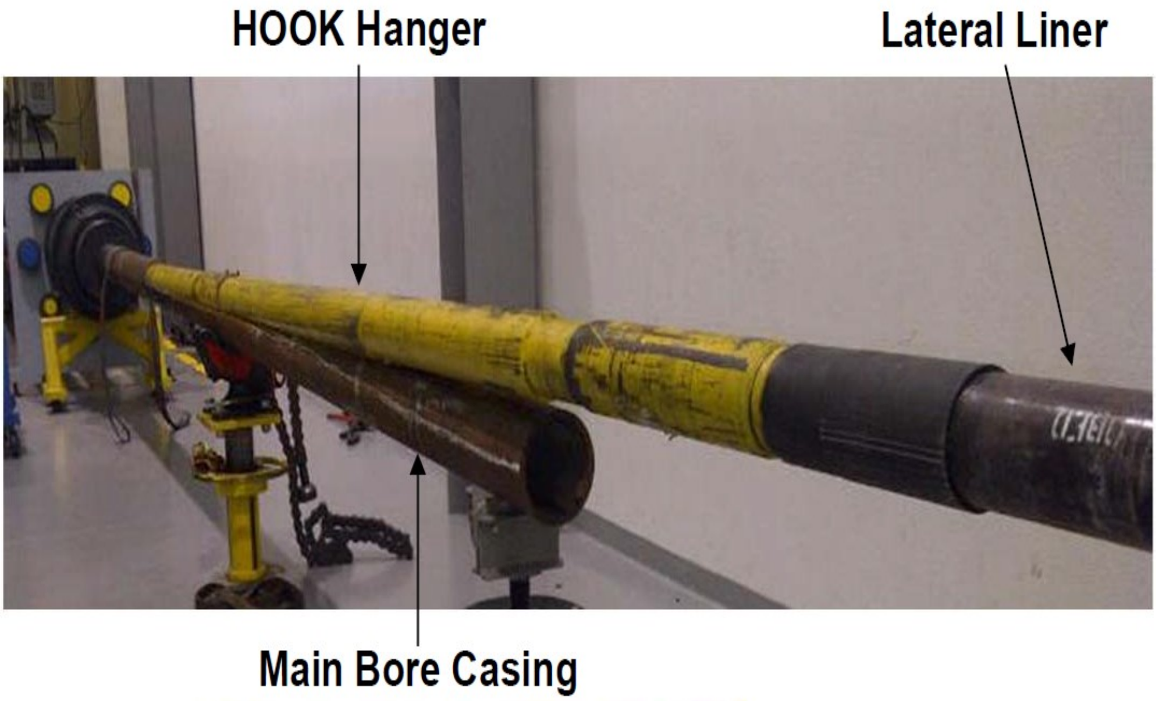


Figure 63: Illustration of Hook Hanger with lateral liner

5.5.2 Frac-Diverters

Hydraulic isolation to the laterals is achieved with frac-diverters. Each lateral leg has a unique diverter that provides both mechanical and hydraulic isolation. The frac-diverters are specifically sized to allow for balls to be dropped during hydraulic fracturing with the Frac-Point system or any other same fracturing system, passing of setting tools and perforating guns, mills for removing ball seats or composite plugs, and allow shifting tools to pass if re-closeable sleeves are installed.

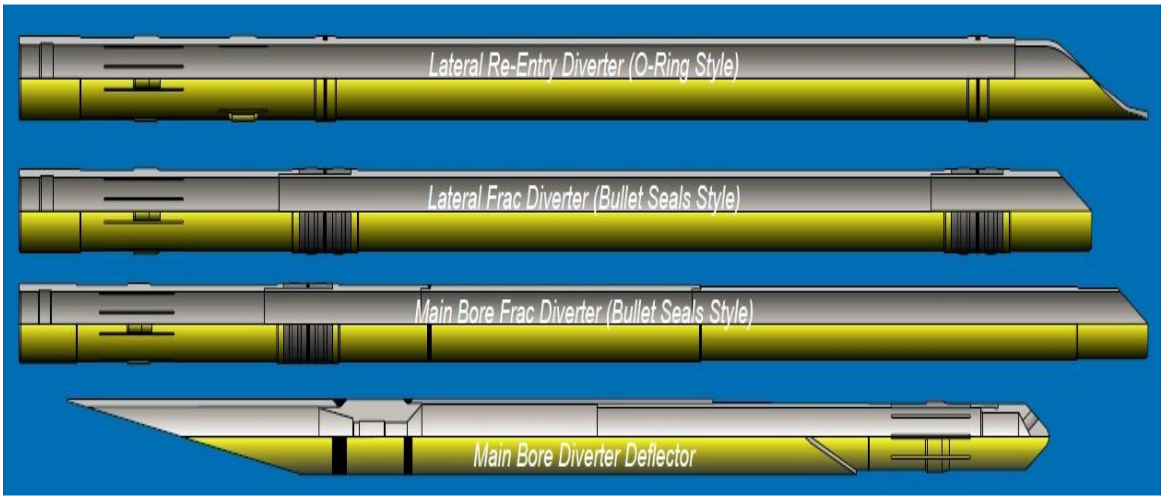


Figure 64: Frac-Diverters for FracHOOK Hanger System

The FracHook multilateral system allows access to multiple sections of a formation for increased production, and can be commingled or selectively produced. Over the life of a well, it may become necessary for workover operations to be conducted. The diverters which are unique to each lateral as shown in figure above, give positive access for common remediation techniques and may even be used when re-stimulation is desired.

The above described FracHOOK hanger system is multilateral system which is considered to best suited for Sawan12-dual lateral. The reason to choose this system is that, it look like fit for purpose here, as the operator requirements for having 10K Psi pressure rating at the junction while considering fracturing of both the laterals.

All equipment data and images shown are the courtesy of Baker Hughes. Few of the information is gathered directly from the concerned personals from the Baker Hughes, while part of it, is gathered from external open resources.

5.5.3 Track record of Hook Hanger multilateral system

The chosen multilateral system is reliable having field proven track record as statistics are given here below. Reliability of overall multilateral wells has also been discussed with reference of Halliburton team research work, the only and known study about the reliability of multilaterals, in chapter 3 of thesis report.

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Figure 65: Reliability of Hook Hanger system

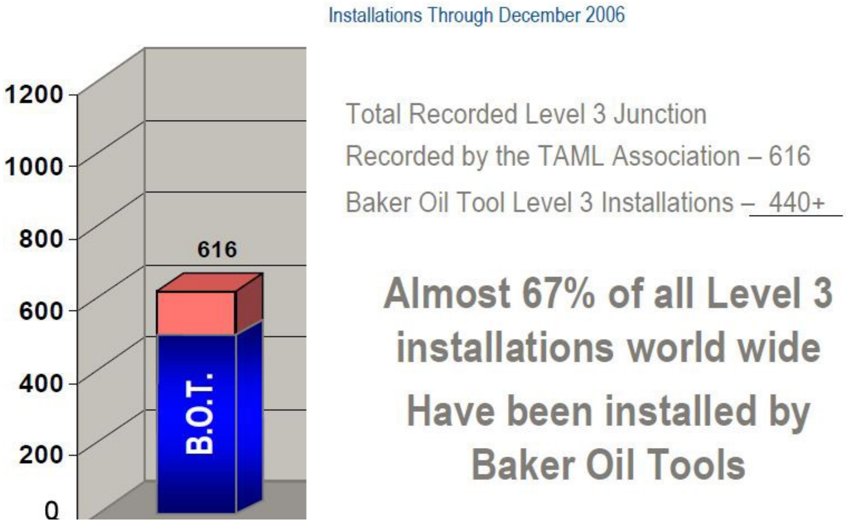


Figure 66: TAML Level 3 statistics worldwide till 2009

The statistics of Baker Hughes FracHOOK Hanger system since 2009 is shown above while statistics of Baker Hughe's Hook Hanger system installations till date is given in the table.

Table 19: Combined Multilateral Database since 2009

2009 to date ML Database						
DATE	COUNTRY	Onshore/Offshore	HOOK HANGER TYPE	HOOK HANGER SIZE	INCLINATION	TAML Level
July 2, 2009	USA	Onshore	B-Hook	4.5" x 7".00	65	3
July 9, 2009	Norway	Offshore	HydraSplit	7" x 4" x 4"	81	5
July 23, 2009	USA	Onshore	B-Hook	4.5" x 7".00	65°	3
August 15, 2009	USA	Onshore	B-Hook	4.5" x 7.00" (23lb)	65	3
April 13,2010	Norway	Offshore	HydraSplit	7" x 4" x 4"	71	5
May 6, 2010	USA	Onshore	B-Hook	4.5" X 7.00"	5º	3
May 15, 2010	USA	Onshore	B-Hook	4.5" x 7.00" (20lb)	0º	3
May 23, 2010	USA	Onshore	B-Hook	4.5" X 7.00"	0º	3
May 31, 2010	USA	Onshore	B-Hook	4.5" x 7.00" (20lb)	0º	3
July 1, 2010	USA	Onshore	B-Hook	4.5x7.0	0	3
July 1, 2010	Canada	Onshore	B3 HH	4.5x7.0		4
July 8, 2010	Canada	Onshore	B3 HH	4.5x7.0		4
August 24, 2010	USA	Onshore	B-Hook	4.5"x7.00" (20lb)	0º	3
September 1, 2010	USA	Onshore	B-Hook	4.5x7.0	85.5	3
September 1, 2010	Canada	Onshore	B3 HH	4.5x7.0		3
September 8, 2010	USA	Onshore	B-Hook	4.5"x7.00" (20lb)	4°	3
September 23, 2010	USA	Onshore	B-Hook	4.5"x7.00" (23lb)	0º	3
October 8, 2010	USA	Onshore	B-Hook	3.5" X 5.5"	0º	3
October 13, 2010	USA	Onshore	B-Hook	4.5"x7.00" (20lb)	0º	3
October 27, 2010	USA	Onshore	B-Hook	4.5" x 7.00" (23lb)	86º	3
November 1, 2010	USA	Onshore	Frac Hook	4.5" x 7"		4
November 2, 2010	USA	Onshore	Frac Hook	4.5" x 7"		4
November 3, 2010	USA	Onshore	Frac Hook	4.5" x 7"		4
January 17, 2011	Canada	Onshore	C HH	5.5x8.625		3
April 2, 2011	Norway	Offshore	Form 5 SBD	7" x 5" x 5"	43	5
April 16, 2011	USA	Onshore	B-Hook	4.5"x7.00" (20lb)	0	3
April 25, 2011	USA	Onshore	B-Hook	4.5"x7.00" (20lb)	0	3
May 5, 2011	USA	Onshore	B-Hook	4.5"x7.00" (20lb)	0	3
May 17, 2011	USA	Onshore	B-Hook	4.5"x7.00" (20lb)	0	3
July 9, 2011	Norway	Offshore	HydraSplit	7" x 4" x 4"	80	5
August 26, 2011	USA	Onshore	B-Hook	4.5" x 7.00" (20lb)	0	3
September 4, 2011	USA	Onshore	B-HOOK Pos. 1	4.5" x 7.00" (20lb)	0	3
September 8, 2011	USA	Onshore	B-HOOK Pos. 2	4.5" x 7.00" (20lb)	0	3
September 19, 2011	USA	Onshore	B-HOOK Pos. 1	4.5" x 7.00" (20lb)	0	3
September 24, 2011	USA	Onshore	B-HOOK Pos. 2	4.5" x 7.00" (20lb)	0	3
September 27, 2011	USA	Onshore	B-Hook	4.5"x7.00" (20lb)	0	3
November 20, 2011	Norway	Offshore	HydraSplit	7" x 4" x 4"	80	5
April 30, 2012	Norway	Offshore	HydraSplit	7" x 4" x 4"	73	5
August 25, 2012	Canada	Onshore	C HH	5.5" x 8.625"		3
September 2, 2012	Canada	Onshore	C HH	5.5" x 8.625"		3
September 28, 2012	Canada	Onshore	C HH	5.5" x 8.625"		3
October 23, 2012	Canada	Onshore	C HH	5.5" x 8.625"		3
January 24, 2013	Canada	Onshore	C HH	5.5" x 8.625"		3
March 14, 2013	Canada	Onshore	C HH	5.5" x 8.625"		3
March 27, 2013	Canada	Onshore	C HH	5.5" x 8.625"		3
June 25, 2013	Canada	Onshore	C HH	5.5" x 8.625"		3
July 14, 2013	Canada	Onshore	C HH	5.5" x 8.625"		3
August 21, 2013	Canada	Onshore	C HH	5.5" x 8.625"		3
September 5, 2013	Canada	Onshore	C HH	5.5" x 8.625"		3
September 9, 2013	Canada	Onshore	B-3 HH	4.5" x 7"		3
October 30, 2013	Canada	Onshore	C	5.5" x 8.625"		3
December 20, 2013	Canada	Onshore	C HH	5.5" x 8.625"		3
January 18, 2014	Canada	Onshore	C HH	5.5" x 8.625"		3
July 7, 2014	Canada	Onshore	C HH	5.5" x 8.625"		3
July 02, 2015	Norway	Offshore	Combo SBD	7" x 4" x 4"	89	5
October 01, 2015	Norway	Offshore	HydraSplit	7" x 4" x 4"	84	5
January 19, 2016	Norway	Offshore	HydraSplit	7" x 4" x 4"	84	5
May 13, 2016	Norway	Offshore	HydraSplit	7" x 4" x 4"	63	5

Reentry to boreholes is considered to be a luxury if a multilateral well has. This system itself provides the reentry system of 10K Psi rating for future fracturing job, meeting Sawan 12 Dual lateral well objectives.

5.6 Sequence of Operations for Sawan -12 DL Construction

Here below is the sequence of operations for drilling laterals from Sawan 12 and construction of the dual lateral well. Those operations which are more focused towards drilling of upper lateral and junction construction, are described in details. First of all, current well profile is needed to be shown, to give an insight that how Sawan 12 well profile look like, as given below.

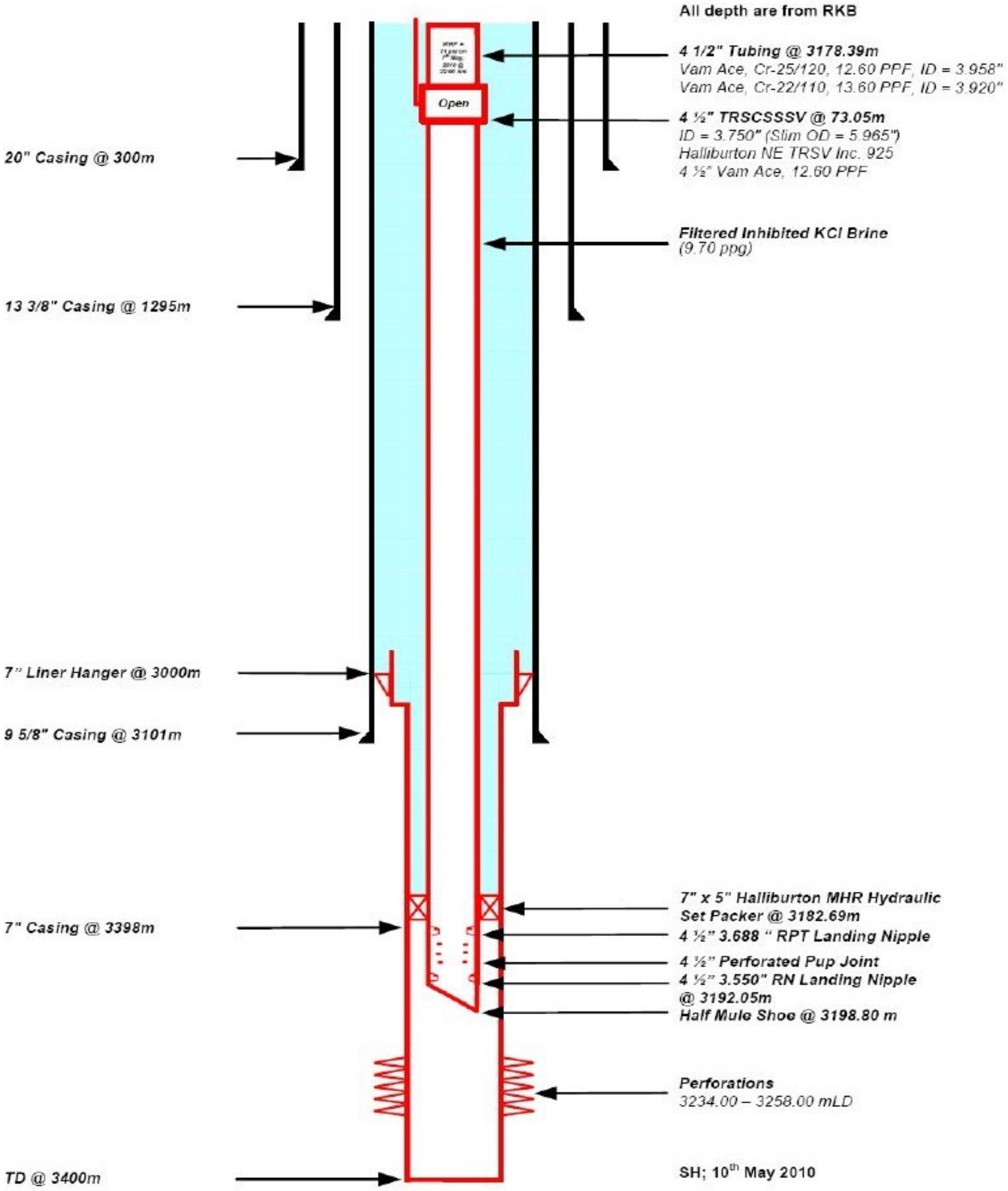


Figure 67: Sawan-12, current Well Profile

Sequence of operations are as under for construction of Sawan 12 dual lateral.

A) Abandonment Part

1. Kill Well
2. Remove Tubing
3. Place 2 Cement Plugs in main borehole
   - One across perforations and one up in 9-5/8” casing below 2760m.

B) Mother Borehole Construction

1. Drill Window, Kick off @2760m MD.
2. Drill 8-1/2” Hole to 3210m MD (3127m TVD).
3. Run 7” Liner and cement it.
   - Top of Cement is 2660m MD
4. Drill 6” Hole to TD 4411.88m MD (3175m TVD).
5. Run 4-1/2” frac-liner with Open Hole Packers and ten Ball Activated Frac-Sleeves.
   - Hang Liner @3110m
6. Run Seal Bore packer (with tie back seals and with ceramic disk of 10k Psi rating).
   - Set Seal Bore Packer @2630m

C) Lateral Borehole Construction

1. Run Whipstock with milling Assembly and set it @2630m MD.
2. Drill 8-1/2” window and POOH, Top of Window @2565m MD.
3. Drill 8-1/2” Hole to 3270m MD (3123m TVD).
4. Retrieve Whipstock Assembly.
5. Run 7” Liner and Hook Hanger with drilling diverter latched into Hook Hanger.
   - Liner shoe @3240m MD (3110m TVD)
6. Cement 7” Liner up to approx. depth of 2620m MD.
7. Drill 6” Hole to TD, 4523.19m MD. (3175m TVD)

8. Run 4-1/2” Frac-Liner with Open Hole Packers and ten Ball activated Frac-Sleeves. Hang the Liner @3140m MD.
9. Retrieve Drilling Diverter.
10. Install Lateral Borehole Frac-Diverter.
11. Run pumping String and fracture the horizontal section.
12. Clean the Lateral Wellbore.
13. Fill Wellbore with Brine of approximate 9.6 ppg.
14. Run 4-1/2” Liner extension
15. Retrieve Lateral Frac-diverter

D) Mother Borehole Fracturing

1. Install Mother Bore Diverter.
2. Rupture the disk Mechanically
3. Run Pumping string and Fracture the Mother borehole
4. 4-1/2 Liner extension and tie back into tie back seals of SBP.
5. Clean the mother borehole
6. Pump Brine
7. Retrieve Mother Bore Diverter.

E) Final Completion

8. Run Upper Completion. Set packet Approx.@2500m.
9. Rig up Coil Tubing unit and surface well testing facilities to lift the well while pumping of Nitrogen.
10. Allow the well to flow and test both the laterals.

5.7 Lateral Borehole Construction

5.7.1 Installation of Seal Bore Packer

To shut off main borehole a seal bore packer is needed to be installed in 9-5/8” casing @2630m, to exit casing above that, as shown in figure below.

Seal Bore packer will be permanent to the main borehole casing. Seal Bore Packer has two main functions:

- Provides place for whipstock system to locate
- Creates lower seal on main borehole diverter

Run tieback seals below seal bore packer to sting into lower liner top PBR (Polish bore receptacle). Seal bore Packer must be run on B-2 setting tool, it allows packer to be tested. A ceramic disk having rating of about 10k Psi is considered to be installed in the packer to seal off mother borehole. Later on this ceramic disk can be ruptured mechanically to access mother borehole.

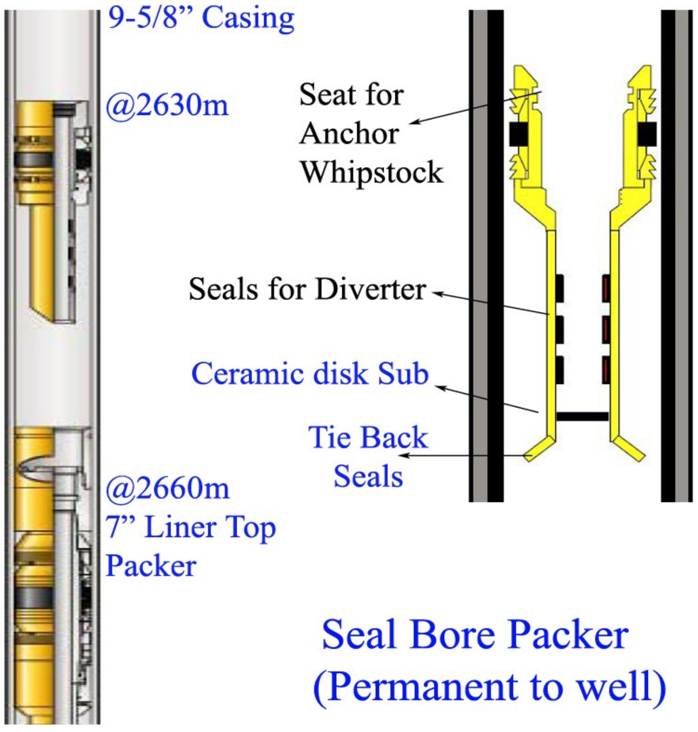


Figure 68: Illustration of Seal Bore Packer in 9-5/8” casing

5.7.2 9-5/8" Casing Exit and 8-1/2" Window Milling

The lower lateral is isolated and now window can be created by existing 9-5/8" casing of parent borehole for drilling another lateral. Things to consider while casing exit are as follow:

While milling a window, we have to avoid couplings and centralizers, the window should be created out from a complete joint of casing. This makes the Kick off point decision very critical. The formation at KOP should be consolidated and strong enough not to collapse, or wash out during window milling and drilling operations.

The centralizer scheme with concerned depth in previous casing is shown below, as to avoid them while choosing the location for exiting casing.

Table 20: Sawan-12, 9-5/8" Casing Tally.

Jt.#	Jt. Length (m)	In Hole Depth (m)	Joint WT (ppf)	Centralizer
27	11.62	2789.25	47	Bow
28	11.45	2777.80	47	
29	11.38	2766.42	47	
30	11.50	2754.92	47	
32	11.48	2731.84	47	Bow
36	11.50	2686.08	47	
37	11.43	2674.65	47	Bow
38	11.43	2663.22	47	
39	11.32	2651.90	47	
40	11.50	2640.40	47	
42	11.45	2617.52	47	Bow
46	11.50	2571.70	47	
47	11.27	2560.43	47	Bow

The table above shows that we don't have any centralizer placed around casing joints of our concerned depths (Highlighted).The proposed system for this operation is the Baker Hughes WindowMaster whipstock system. The anchor and spacer joints can be set on seal bore packer installed below in 9-5/8" casing. Milling a long enough window is needed to reduce the Dog Leg Severity of future downhole tools or BHAs that will pass through the window.

5.7.2.1 WindowMaster Whipstock system

The milling BHA should be designed to provide enough down weight so that the shear bolt can be fatigued. The shear bolt rating varies for different systems. Milling BHA for WindowMaster Whipstock system will be mainly consists of following tools (bottom to top). Unloader seal sub, Bottom trip anchor, shear disconnect, debris cup, Generation 2 One trip window cutting system (Whipstock and milling bit, MWD, running tools), as shown in figure below.

Whipstock face angle is of 2.1º to sidetrack from main borehole. Bottom trip anchor or BTA is used to anchor the whipstock in place in order to permit sidetracking operations. BTA can run in with Baker Hughes windowMaster one trip system. After running in hole, whipstock orientation is achieved by MWD or UBHO orientation method. Pumps are started and MWD sends signals to the surface. With the whipstock with desire orientation, the set down weight activates the anchor to set whipstock in place. This helps to avoid rotational movement of whipstock during operations. 8-1/2" Window now can be drilled.

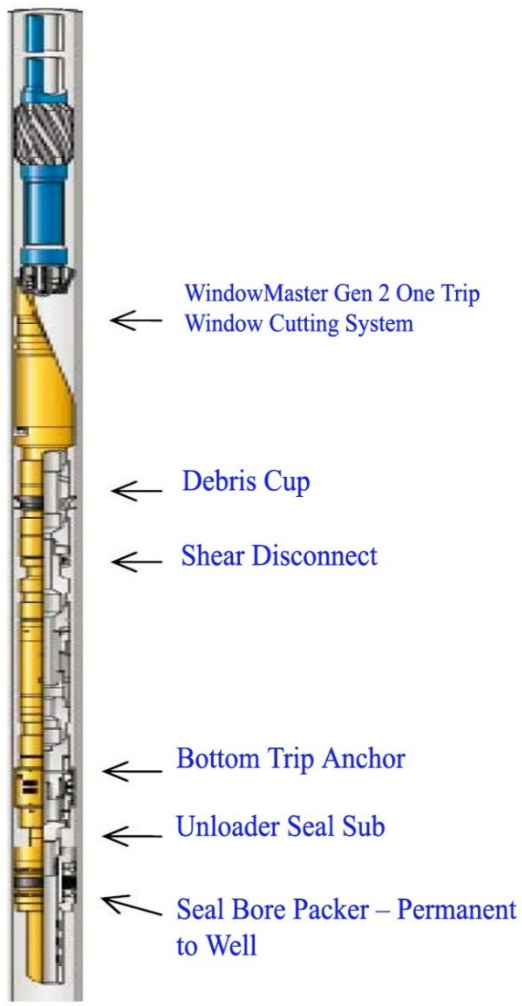


Figure 69: Baker WindowMaster Whipstock system

Final 8-1/2” window with at least 25 ft. of rat hole is needed to provide tangent section to allow Hook Hanger to locate in window, as shown in figure below.

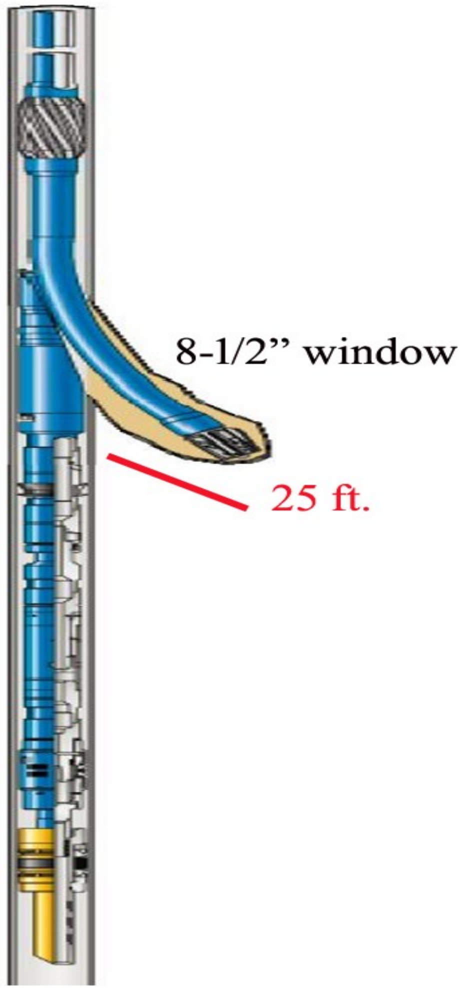


Figure 70: 8-1/2” milled window for lateral borehole

5.7.2.2 Debris Management

Debris management is considered to be among the highest risk associated while executing multilateral project. Operators has reported that one third of the multilateral completion failures are due to the debris left in the wellbores. As said by Ron Barker, “the industry is finally recognizing that just circulating the wellbore to remove debris is not enough”.

Before running Whipstock, hole should be cleaned from any debris and conditioning the hole is much needed with required milling mud.

Casing scrapers are usually run to check any potential problem in the casing. Removal of SWARF[1] cuttings during milling will have a great impact on the success of this milling job.

If steel cuttings are not removed quickly and efficiently then downtime due to bird nesting can become a severe issue. Bird nesting occurs whenever a large number of cuttings accumulate in an area in the annulus or in the surface equipment. Periodic cleaning of flow line is important for proper cutting removal.

It is better to place viscous pill from top of packer to casing exit point to prevent debris from falling down to some extent. However, debris cup installed with whipstock system will prevent falling down of metal cuttings. On shaker’s possum belly, magnets may be placed to recover metal pieces which will flow up in the mud return line.

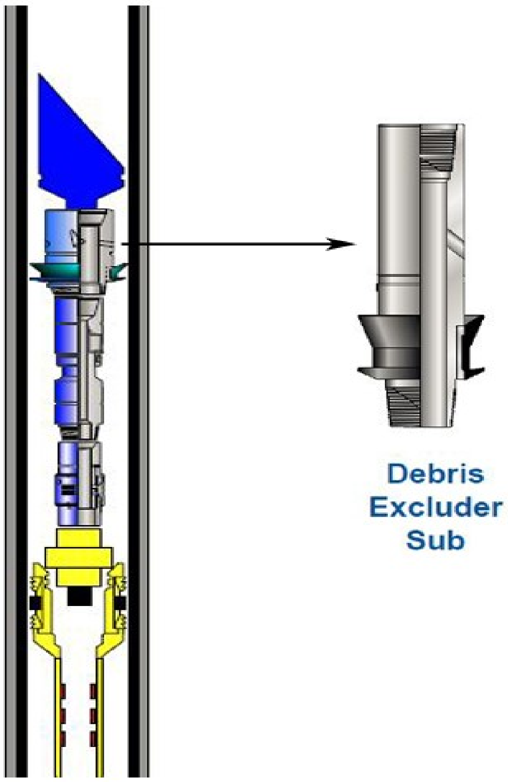


Figure 71: Debris excluder sub installed with whipstock system

[1] Fine chips or filings of stone, metal, or other material produced by a machining operation

5.7.2.3 Milling contingency

If the penetration rate falls below expectations for the time spent on milling, POOH, replace mill and continue milling. The milling ROP will vary greatly on well factors such as cement quality behind casing, casing quality and WOB transfer amongst other factors.

While milling 9-5/8” casing to create window for lateral drilling will produce lot of SWARF cuttings that need to be circulated out. If Debris left in the junction area, it may jeopardize the system. Debris cup attached to WindowMaster whipstock system, will help to capture the debris which will fall down during milling operations.

The major tasks which must be assessed for any well while sidetracking from it, are summarized below.

- Choosing the location of sidetrack
- Selection of sidetracking equipment (whipstock, milling assembly etc.)
- Conditioning the well for sidetracking
- Exiting the casing and drilling rat hole
- Running in of drilling assembly to drill till target depth
- Retrieving the sidetracking equipment

Choosing the location of sidetrack is critical. Wellbore conditions like casing condition, surrounding formation and inclination must be considered while selecting location for sidetrack, because they may have adverse effects on the performance of downhole equipment. Keeping in mind the targets and dogleg severity, type of formation (based on drillability) should also be considered while deciding the depth of sidetrack.

The casing from surface to window point, need to be in good condition. Obstructions and deformations in main borehole casing can cause insecure setting of whipstock or movement of milling assembly, which in return will result crooked or lost window.

Prior to running whipstock or milling assembly, running casing scrapper is advised to identify potential problems. Cement bond log is useful to determine the cement condition behind the casing at window depth. As far as inclination is concerned, vertical or near vertical wells present very difficult situation to sidetrack away from the mother borehole. In this case, careful selection of milling assembly and whipstock is needed and it should be designed in such a way that it can easily build angle away from the whipstock. Evaluation of bending stresses, forces and departure for each component of the milling assembly is needed for desire results.

5.7.3 Drilling of 8-1/2” lateral Hole

After pulling out of hole milling BHA, make up drilling BHA and assembly and run in hole to drill 8-1/2” to 3270m MD. While 7” liner shoe is planned to be at 3240m MD, the extra 100 ft. or 30m rat hole is required to ensure the hook will land in window before shoe tags the bottom. The below figure illustrates the concept.

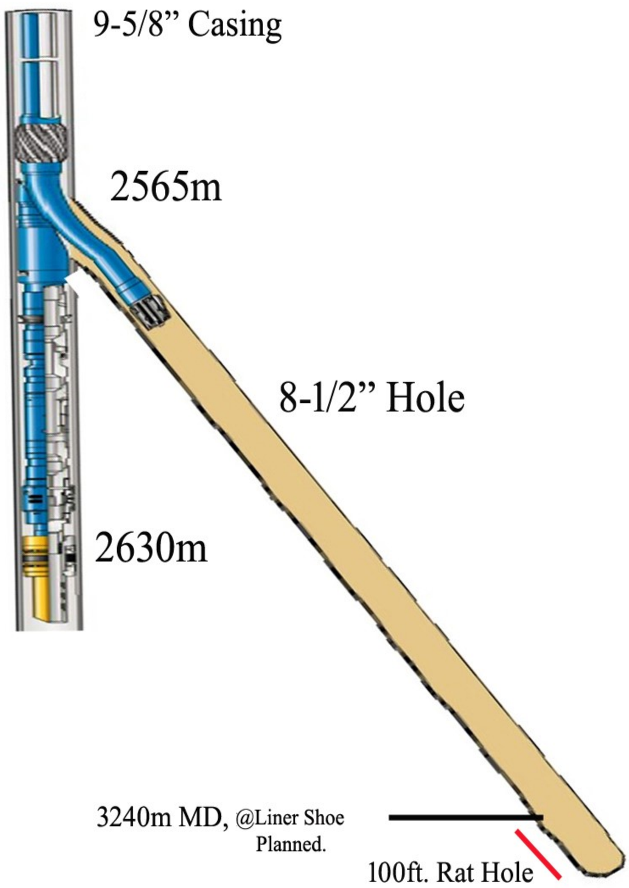


Figure 72: Illustration of drilling 8-1/2” lateral Borehole

After drilling 8-1/2” Hole, POOH to retrieve whipstock which is anchored into seal bore packer. For retrieving the whipstock system, run the solid lug tool into the hole till whipstock slot depth. Either UBHO or MWD can be used to align correctly this tool with the whipstock. The jets built in the solid lug tool, will clean out the debris in the whipstock slot. The tool is then latched into the retrieval slot. The whipstock is then pulled from the wellbore. The retrieval tool is shown in figure below.

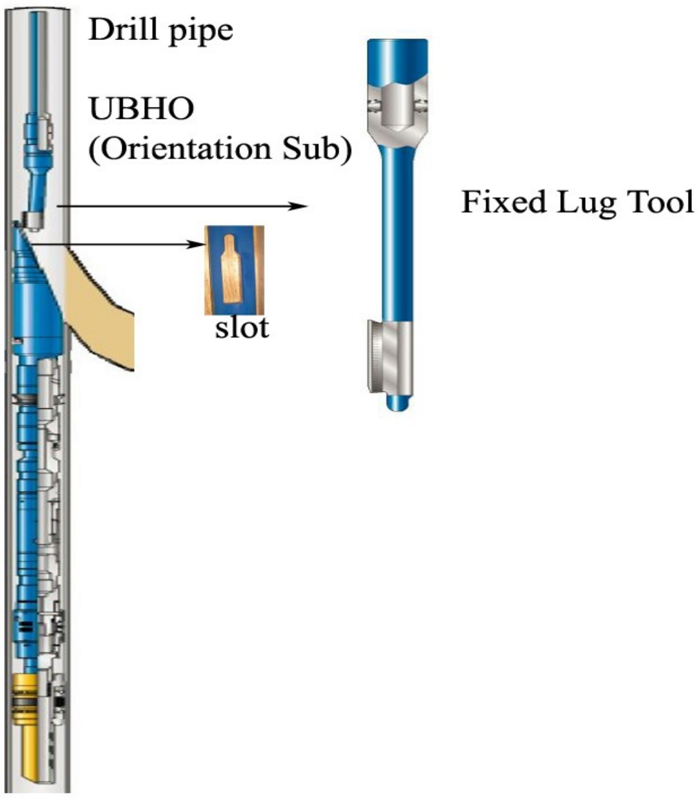


Figure 73: Whipstock retrieval system

5.7.4 Running of 7” Lateral Liner with Hook Hanger

The following procedure is needed to run lateral liner and install Hook Hanger as a junction equipment.

- Run the bent joint, liner shoe track, 7” liner, tension lock swivel, Hook hanger with drilling diverter already latched into it, into the well.

The bent sub is used at the bottom of the liner just behind the liner shoe to access lateral window for liner and Hook Hanger Assembly, as whipstock system is retrieved earlier.

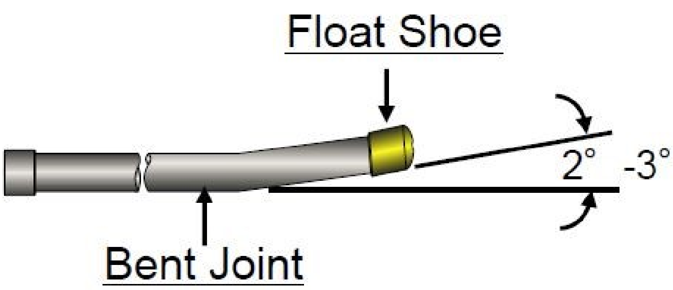


Figure 74: Bent joint for exiting window

- Tag Seal Bore Packer with float shoe and spot high viscous pill across junction area.
- Before the Hook Hanger assembly reaches the window, approx. 30ft above window. The assembly is picked up or down to record pick up and slack off weights.
- Pick up and access lateral with Bent joint. Pick up and turn in ¼ increments if necessary.

5.7.4.1 Orienting and Aligning Hook Hanger with exit window

There are three methods to align the Hook Hanger with the casing exit window.

- In the first method, risk of damaging the packing element or hanging the slips in the casing exit, is eliminated while using a liner packer. It is recommended here to add one joint of pipe between the packer and Hook Hanger, so that the packer does not go out of the casing exit while picking up and down assembly several times while setting the Hook Hanger. This method is effective but needs lot of experience of this specific job.
- Another method is to use surface read out gyro. It can be used as a contingency, it is the simple method to orient the Hook Hanger in the casing exit window. Factors here to consider are gyro operational time and hole conditions.
- Using MWD, is the most accurate and fast method to orient and align the Hook Hanger. MWD is used below the HR setting tool.

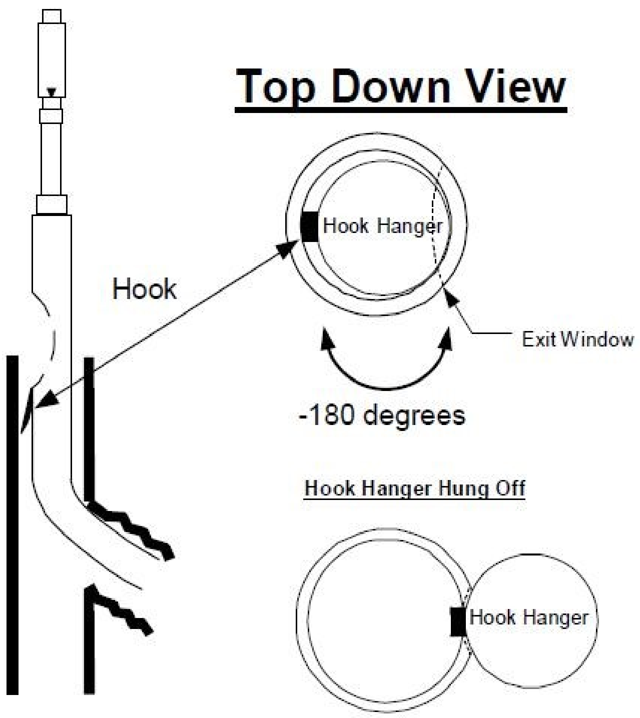


Figure 75: Proper Alignment of Hook Hanger with casing exit window

- After properly aligning the Hook Hanger, The assembly is then lowered, until rail system and hook contacts the window profile.

- Land Hook Hanger in window with 10K lbs. weight

- If Hook does not land, pick up 30 ft. above and rotate ¼ turn, lower it again to land.

- Double check the orientation of the hook hanger, after it is aligned.

Upon landing, the pre-milled window will automatically orientated to the main borehole as shown in figure below.

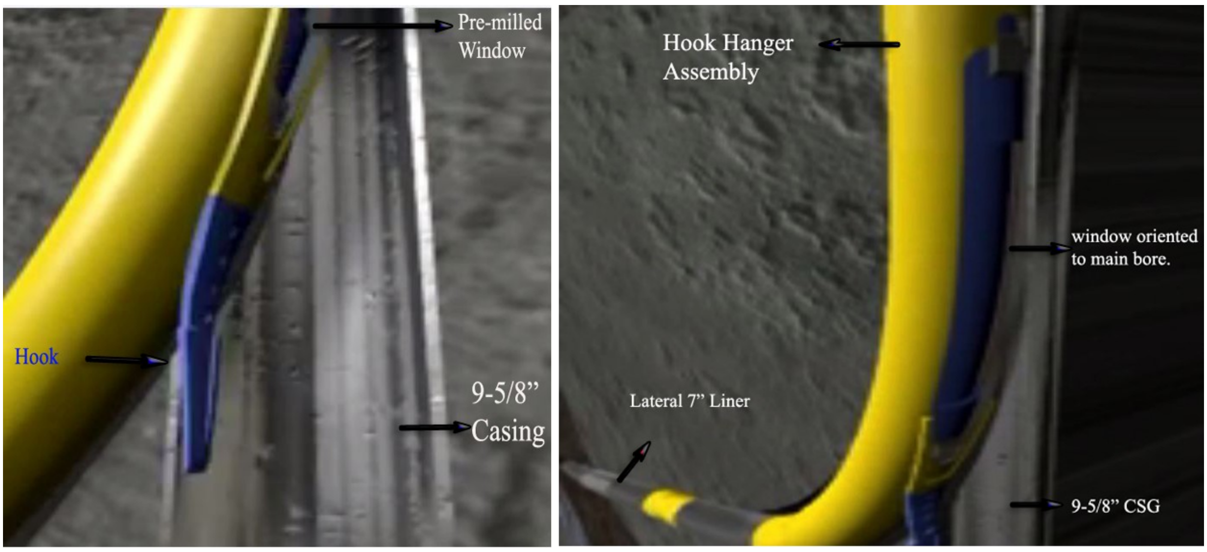


Figure 76: Pre-milled window of Hook Hanger oriented to main borehole[1]

The next step is to anchor the Hook Hanger and liner assembly to the main borehole casing.

As in the case, drilling diverter is installed for drilling ahead 6” Hole, Hook hanger must be held securely to bear high snap out loads of the diverters, thus it is recommended to use liner packer with hold down system. The anchoring of Hook hanger and liner assembly is described below.

A ball is dropped from the surface through drill string and seats in pump out ball seat sub located just below the HR setting tool. Applied pressure releases Collate on the HR setting tool which allows upward movement of the entire running assembly. When the dogs on the packer setting dog sub reaches the top of the HR setting sleeve, they extend outwards. After pick up and slack off weights are recorded, downward movement causes the dogs to contact top of the HR setting sleeve.[1]

[1] https://www.youtube.com/watch?v=FEodS4OAbuA (Tag: Hook Hanger Final)

Continuous downward movement activates the slips on the hold down assembly causing them to bite into the casing, anchoring the Hook Hanger and liner assembly to the main borehole casing. The entire running assembly is then removed out of the hole.

5.7.5 Cementing of 7” Lateral Liner

The above figure illustrates the Hook hanger with no diverters installed. As mentioned earlier, we have pre-installed drilling diverter in Hook Hanger, so that we can drill ahead 6” Hole.

It is decided not to cement 7” liner up to the junction area to get the TAML level 4 system, due to the associated risk of high debris and not being able to retrieve drilling diverter out from hook Hanger. Hence, 620m of 7” liner is thus proposed to cement, leaving the junction area un-cemented (Sawan 12 DL, TOC of 7” lateral Liner = 2620m MD). Doing so, will help us to achieve successful Level 3 multilateral junction system. However, for cementing the liner up to junction area to achieve Level 4 junction is possible. For Level 4 junction, the thickening time of the lead slurry (covering junction area) should be much higher, so that it can be circulated out of hole later.

5.7.6 Drilling Ahead 6” Hole

With partially cemented 7” liner, Hook hanger and drilling diverter installed in Junction equipment, drilling assembly can now be run in Hole through drilling diverter and we can drill ahead 6” Hole of lateral borehole to TD 4523.19m MD.

Drilling diverter is rated enough to allow cementation but not fracturing. Drilling diverter has O-Ring seals and thus not recommended to use for fracturing job. It has pressure rating of 4300 Psi. So for fracturing job later on, we need to retrieve drilling diverter and to install frac-diverters. Drilling diverter can be retrieved out of hole with liner running tool assembly, if lateral diverter retrieval (LDR) tool is used. It can also be left in well and retrieved at a later time with hydraulic GS spear.

5.7.7 Frac-Diverters

The use of frac-diverters along with detailed specifications of the system is already discussed earlier along with tool description. In 9-5/8” Casing, OD and Drift ID of the frac-diverters is given as under:-

Diverter’s maximum OD	6.750 in
Drift ID Main Borehole Frac-Diverter	5.150 in.
Drift ID Lateral Borehole Frac-Diverter	5.796 in.

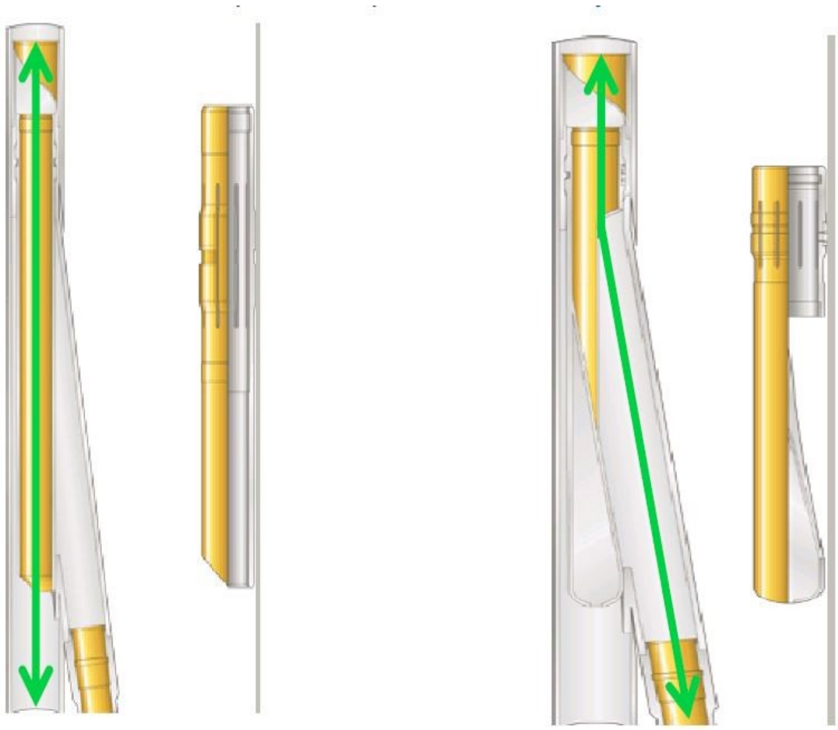


Figure 77: Frac-Diverters used with Hook Hanger System

5.7.7.1 Installation and retrieval of Frac-diverters

The work string, the HHD running and retrieving tool and the main bore diverter are run into the hole. Once inside the Hook Hanger, the helical profile on the nose of the main bore diverter contacts a meeting profile just below the Hook Hanger window. This causes the diverter ramp to turn and automatically align with the opening to the main borehole. At the same time, collate on the top of the diverter, latches into the profile and anchors it to the hook hanger. The pumps are started and differential pressure causes the HHD tool collate to release from the main borehole diverter, allowing retrieval of the HHD tool from the well.

Diverters must be run on threaded pipe or coil tubing. They cannot be run on wireline. The running procedure for landing the lateral reentry diverter is the same to main bore reentry diverter. With the lateral diverter landed, Coil tubing or standard work string can be used to perform clean out, stimulation or other workover operations.

If there are issues getting main bore diverter out of Hook hanger, then we can run diverter deflector. For that, Main bore diverter is retrieved with GS spear. If well is under pressure, then we must be able to snub or lubricate the diverter plus the running tool assembly. Typically means being able to snub or lubricate up to 70 ft. then on second trip, retrieve diverter deflector.

In order to retrieve lateral diverter, the HDD tool is run into the well and latched into the profile in the lateral diverter. The lateral diverter and the HHD tool is then retrieved from the wellbore. The required weight to snap-out Diverters is about 12000 lbs. while snap-in with 12000 lbs. is enough.

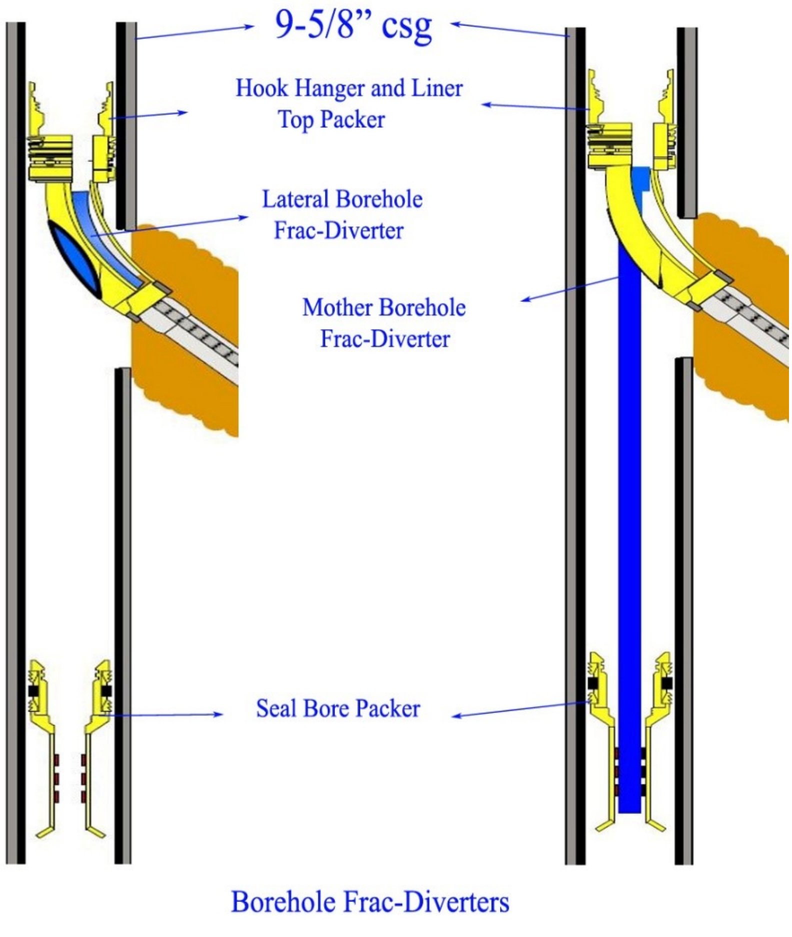


Figure 78: Illustration of Frac-Diverters installed in Hook Hanger downhole.

5.7.8 Hydraulic Fracturing of Horizontal Sections

Tight gas reservoir is defined as, “reservoir that cannot be produced at economic flow rates or recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by use of horizontal wellbore or multilateral well bores”.[1]

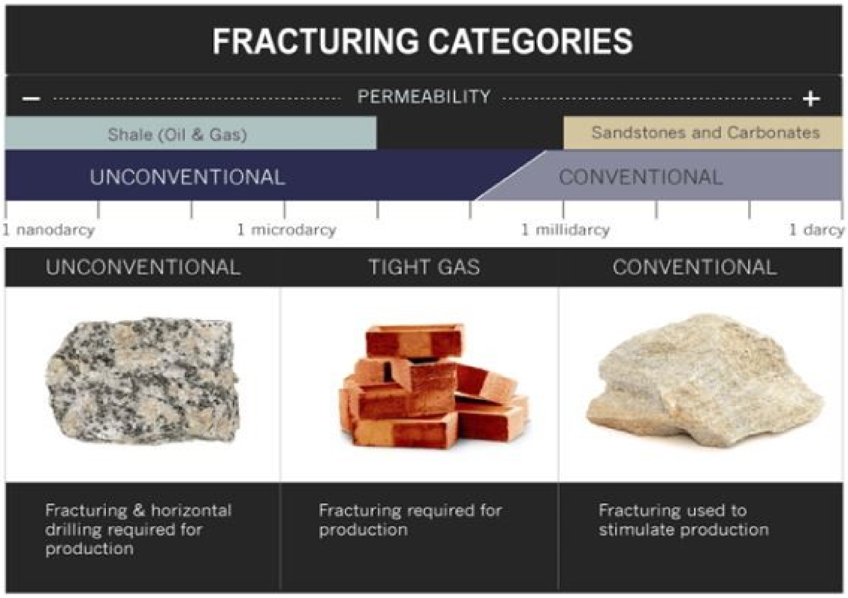


Figure 79: Fracturing categories, (Image Credit: Oil Pro)

Presence of natural fractures in tight gas reservoirs cause problems while fracturing hydraulically. The problem caused may be due to the ability of natural fractures to open and allow fluid leak-off during the pressure processes. As a result, pressure losses occur and create shorter fractures than desired.

Subsurface D-Interval of Sawan field region is a tight gas layer, hence multistage fracturing of horizontal section of each laterals is considered while selecting multilateral system and during conceptual design of Sawan 12 Dual lateral. Both the laterals have horizontal section of 1000 meters in D-interval. 10 stages fracturing, having distance of 100m in between two stages is considered. As suggested by the Operator, the preferred technique was to use ball activated sleeve system for multistage fracturing of the horizontal section.

The 4-1/2” frac-liner completion in 6” Hole in both the laterals thus mainly consists of open hole packers, ball activated sleeves, liner joints and liner top packer with PBR, as shown in figure below. For hydraulic fracturing using this technique, services of Baker Hughes or PackerPlus can be received. A conceptual estimated cost for fracturing job and services is also included in the total well cost estimates.

[1] Holditch, S. A. (2006). Tight Gas Sands, SPE journal paper.

The multilateral system is compatible with any of the hydraulic fracturing techniques currently used in the industry. Ball activated fracture sleeves system, is considered to be used for the hydraulic fracturing of Sawan 12 dual lateral as per OMV Pakistan recommendations.

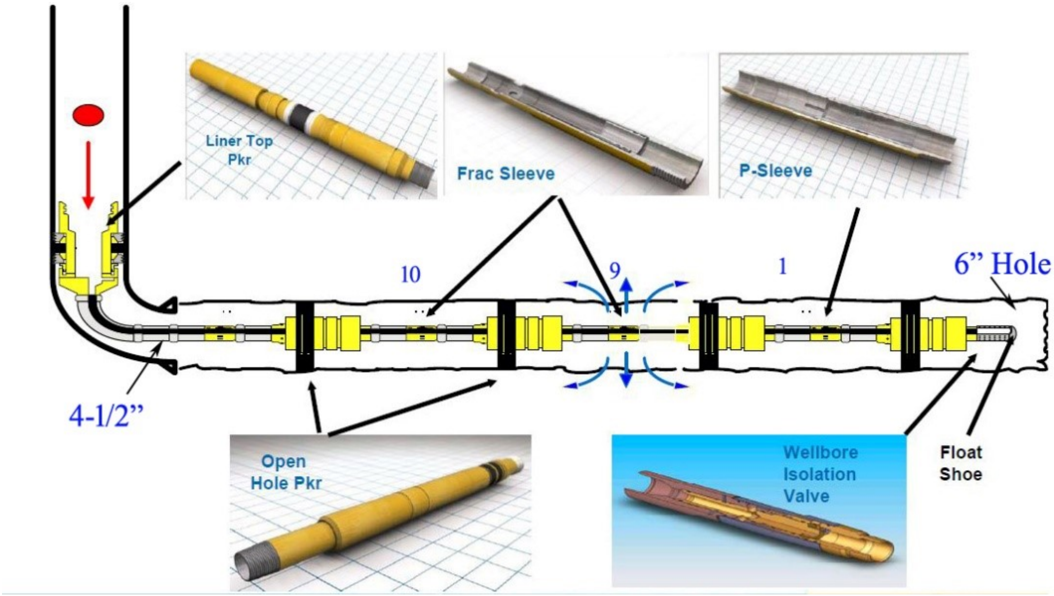


Figure 80: Illustration of Sawan 12-DL horizontal section completion

5.7.9 Producing the well

After fracturing and cleaning out both the legs, the well is ready to produce. Upper completion now can be installed for commingled production. For that, a packer on tubing is run and set above liner top at about 2500m, as shown in figure below.

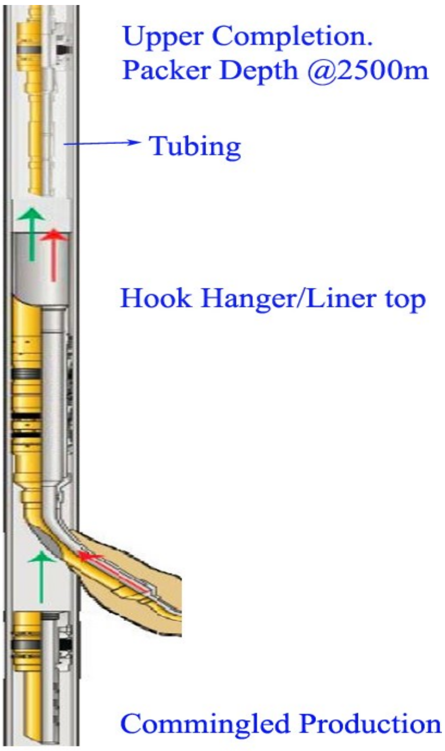
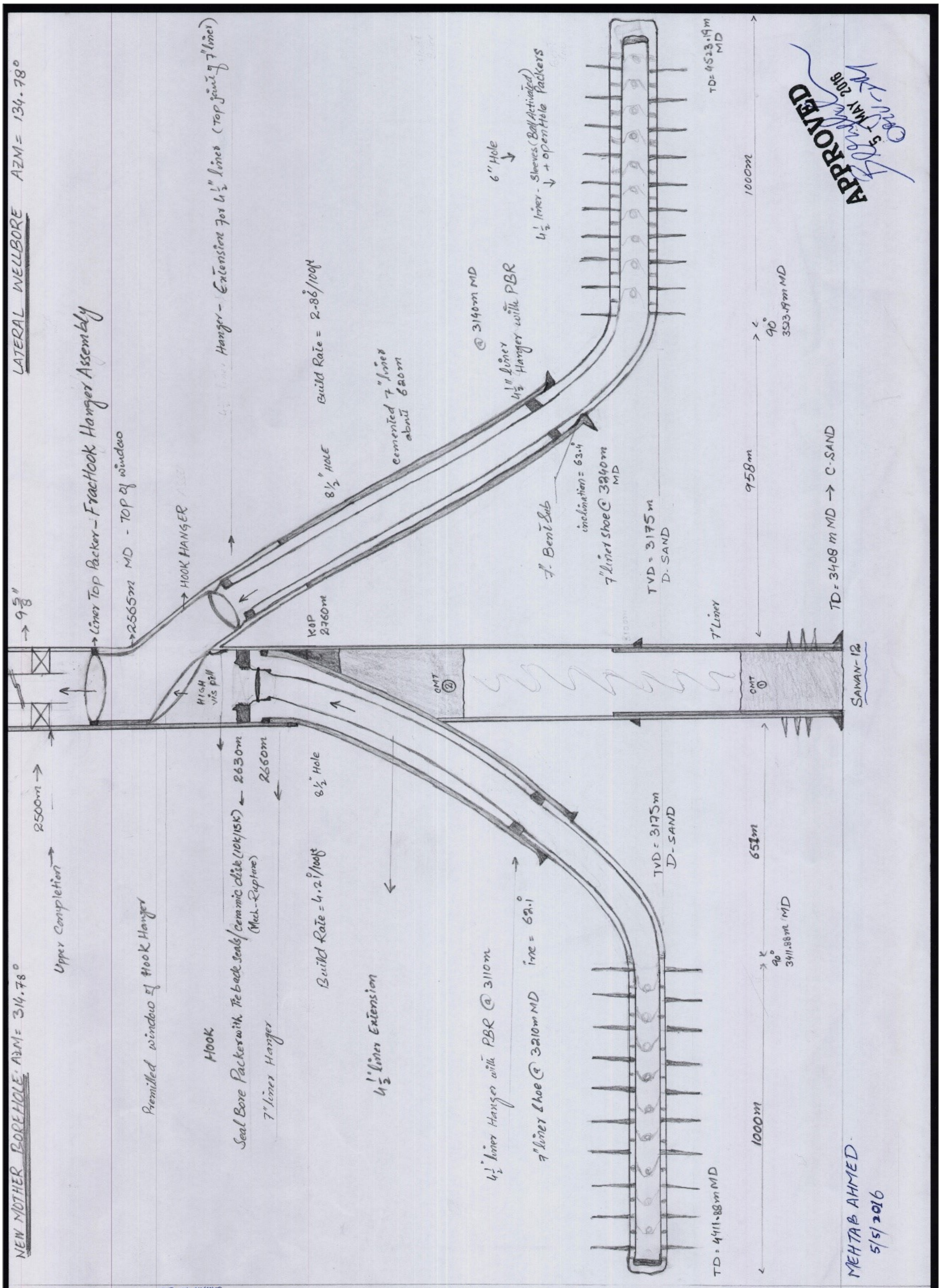


Figure 81: Illustration of final completion at junction

5.7.10 Final well profile of SAWAN 12-DL

Figure 82: Final well Sketch, Sawan 12-Dual Lateral[1]



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[1] Pencil work by Hand.

5.8 Well Cost

A conceptual cost estimate is done for the proposed dual lateral well according to OMV current conceptual drilling cost model, which is based on actual contracts in place with service providers.

Cost estimates of Sawan 12-Dual Lateral is 21.62 MM$. Here, mother borehole cost is 11.58 MM$ while cost for Lateral borehole is 10.03 MM$**.** The table below shows the estimated costs for different well types.

Table 21: Estimated cost for Sawan 12-DL, HW and New Well

Well Type	**Mother Borehole Cost (MM$)**	**Lateral Borehole Cost (MM$)**	**Estimated Total well Cost (MM$)**
Sawan 12 Dual Lateral	11.58	10.03	21.62
New Dual Lateral	14.798	10.03	24.83
Two Horizontal wells	14.798 + 14.798		29.596

The total rig time on location required for each well, site preparations, drilling of first three sections (casing, cementing, fluids, bit and downhole tools), are the major contributing factors for the differences between all three above estimated costs.

The Table given later in this chapter summarizes the cost breakdown. Al the values are taken from the database of OMV past development well's costs (Horizontal/Side track costs).

The cost differences and time duration for each operation is given later under the heading 'cost comparison and savings'.

Table 22: Sawan 12 Dual lateral well Cost breakdown[1] **(K$)**

Costs (Average Values-Offset)	Sawan 12 Mother bore	Sawan 12 Lateral	Total Cost Sawn 12 Dual Lateral	New Horizontal Well
Location & Land	180		180	842
20" (m)	0		0	300
$/m	600		600	600
13 3/8" (m)	0		0	1330
$/m	220		220	220
9 5/8" (m)	0		0	2760
$/m	200		200	200
7" (m)	550	**670**	1220	580
$/m	120	**120**	240	120
4 1/2" (m)	480	**570**	1050	480
$/m	70	**70**	140	70
Fracsleves (10 pcs)	**1000**	**1000**	**2000**	**1000**
Sum Casings	1099.6	**1120.3**	2220	2128
Acessories Wellheads & Junction	250	**390**	640	210
Rigmove	600		600	600
Spreadreate Rig/Energ/Supervision	45.808	45.808	92	46
Spread cost	**2551.5**	**1713.2**	**4265**	**3376.1**
Days on Location	56	**37**	93	74
Directional Drilling & LWD	600	**600**	1200	600
Mud &Solid Control & Water	400	**400**	800	687
Cementing	132	**110**	242	232
Drill bits &Downholetools	164	**164**	328	264
Coring & Logging	400	**400**	800	400
Cont. Dry Hole. 5%	318.9	**244.9**	564	466.9
Subtotal Dry Hole	**6696.0**	**5142.4**	**11838**	**9806**
Completion LLI	294	**294**	588	390
Completion services	605	**605**	1210	605
Cont. Completion 5%	45	**45**	90	50
Subtotal Completion	**944**	**944**	**1888**	**1045**
Stimulation, Cleanup	**3948**	**3948**	**7896**	**3948**
Total K$	**11587.662**	**10034.096**	**21621.758**	**14798.293**

[1] Created with MS Excel 2013.

5.8.1 Time vs Depth curve

A Time vs Depth curve has been generated for Sawan 12 dual lateral well, to have a look on the number of days required to drill and complete the Sawan 12- dual lateral well, as shown here below. The Blue colored line in the curve reveals the time spent by operations for mother borehole construction while red line is for Lateral Borehole.

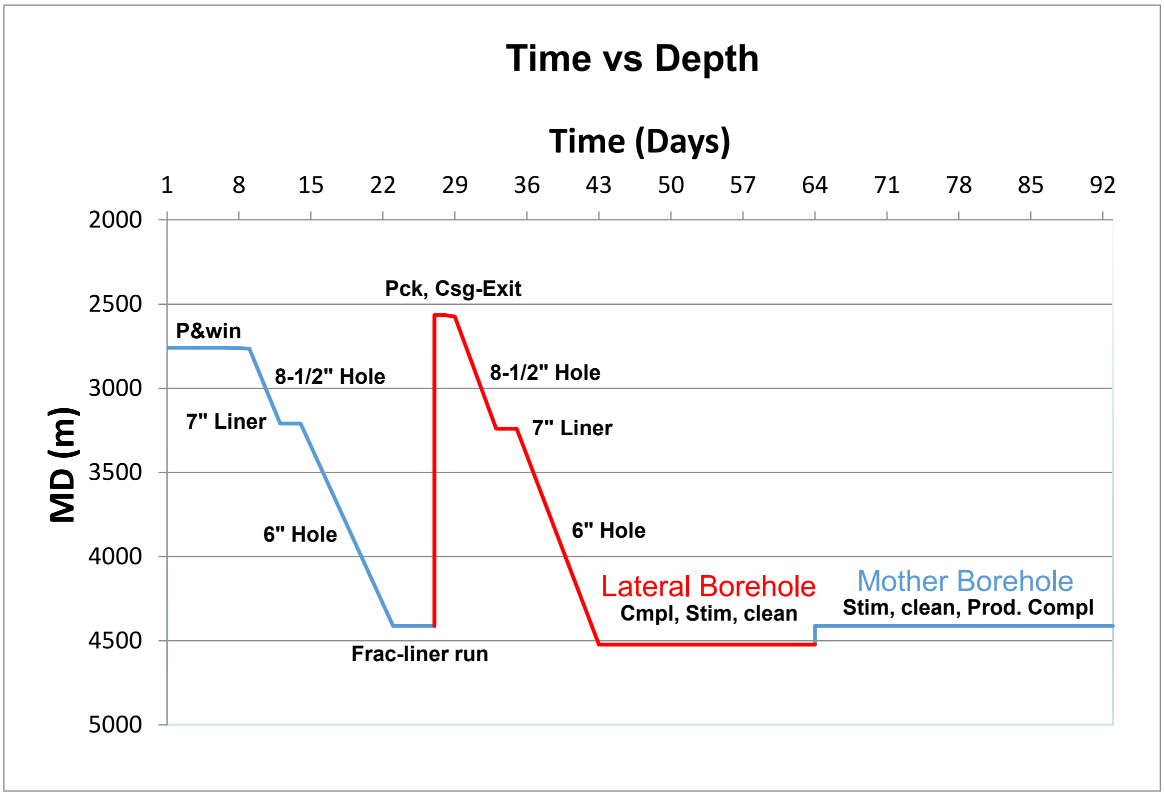


Figure 83: Time vs Depth curve for Sawan 12-Dual lateral[1]

In the curve, initial flat time of about 7 days shows the time consumed for killing of the existing well Sawan 12, tubing retrieval, placement of two cement plugs in parent borehole for mother borehole construction.

For diverter Installation, Retrieval and final production completion run, a service rig can also be used instead of having same drilling rig on site for so long time during stimulation, CT cleaning and final completion run. However, as per OMV Pakistan suggestions, the same Rig (225) on location till the final completion of the well, is considered, which lead to have a bit increased of Rig on location time as well as spread cost.

As the presence of Rig at location till the end is considered for diverter installations for reentry into the boreholes for Hydraulic fracturing job and final completion run, which leads to have 93 rig days on site in total as shown in figure above.

[1] Created with MS Excel 2013.

Spread cost is estimated to be 45808 $ per day. The number of Rig days on location for Sawan 12 dual lateral is 93 in total, in which 56 days are dedicated for mother bore and 37 days for lateral borehole. 14 days of Fracturing job and 4 days of CT cleanup is included for each lateral. 6 days for well testing is included in mother bore construction time. Final completion run and rig release time of 2.9 days is also included in mother borehole duration. All these durations are shown in above figure as flat blue and red lines at the end of curve for mother borehole and lateral bore respectively.

Rig days on location for construction of single horizontal well or mother borehole for new dual lateral well are 74, and are calculated as follows.

(Mother borehole time of Sawan 12 Dual lateral + drilling of first three sections) – Parent wellbore abandonment time.

$$(56 + 25) - 7 = 81 - 7 = 74 \text{ Days}$$

An average ROP of 7-9 m/hr. is considered for drilling of 6” and 8-1/2” hole section respectively while calculating drilling time for wellbores, as assumed from the bit performance reports for the same formations drilled for Sawan 12, as shown in figure. However, ROP values of 11 m/hr. and 13 m/hr. are used while engineering design of both the laterals on Landmark software package.

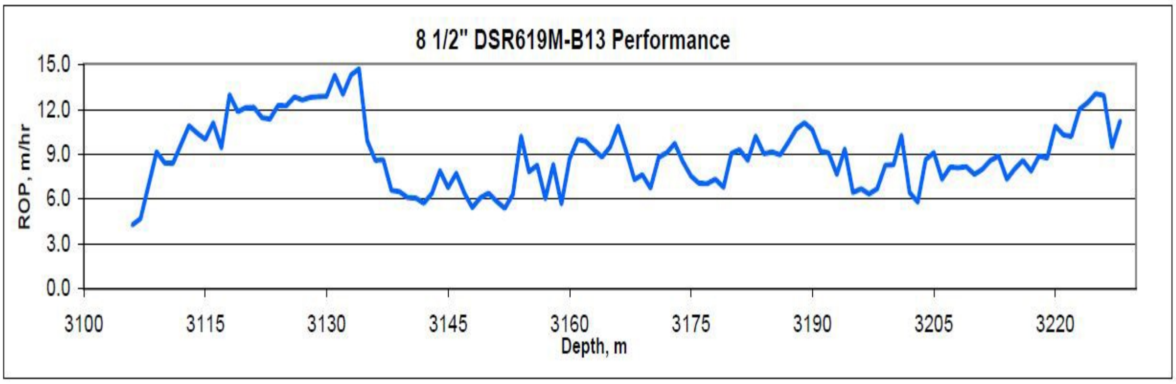


Figure 84: Bit Performance 8-1/2” hole section (Sawan 12 Final report-Operations)

5.8.2 Cost Comparison and Savings

The graph below summarizes the cost comparison of Sawan 12-DL with two separate horizontal wells and with a new dual lateral well. The detailed description of cost comparison along with time duration for each operation is described later to see that where the difference come from and how much we saved this amount.

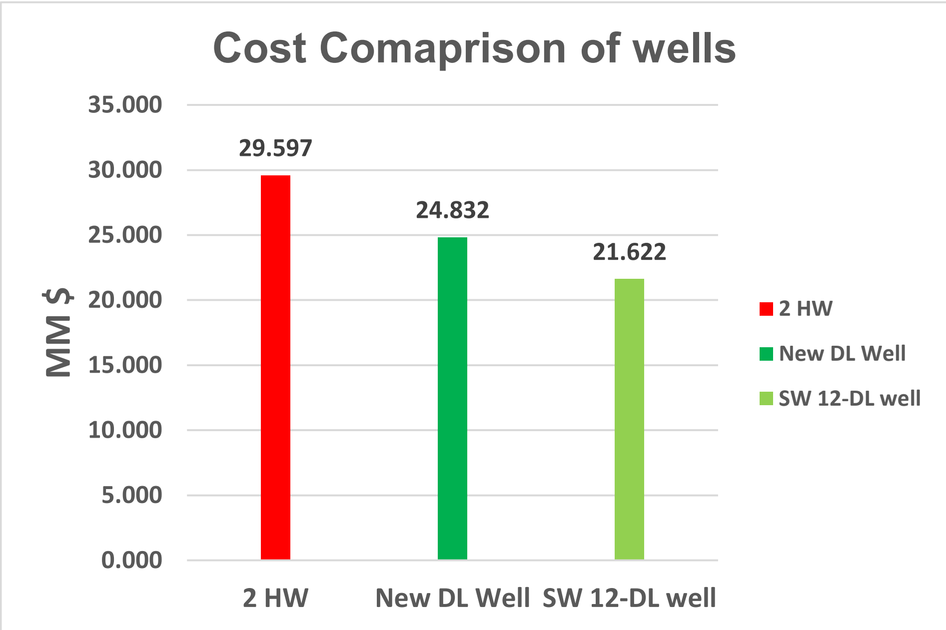


Figure 85: Cost comparison of Dual laterals Vs Horizontal well

While cost comparison, Initial site preparations, drilling of first three sections (casing, cementing, fluids, bit and downhole tools), junction/diverter equipment and fracturing sequence contributes a lot in the cost differences. Cost for two horizontal wells as well as new dual lateral well is also estimated while considering hydraulic fracturing of both the laterals with ball activated fracture sleeve system. Here below statements justify the cost values given in above table 22.

- Location and site preparation cost for new wells is 842K$ while for Sawan 12 dual lateral is considered 180K$, as location is already prepared.
- Casing cost per meter for each section is given above in the table, as average values from previous development wells. Casing costs for first three sections is not included in Sawan 12 dual lateral, as they are already cased.
- The cost of Junction Equipment (Hook Hanger) is included in lateral wellbore, which is 230K$ and Frac-diverter's cost of 40K$ each is included in mother bore hole cost. The price for junction equipment also differs with respect to region where they need to be shipped.

- Rig move cost of 600K$ is added to Sawan 12 mother bore cost and is not included for lateral borehole.
- The Rig cost (Spread rate) is also constant in all the cases, as taken average values from OMV wells cost report summary and is 46K$/day. We can still save a bit more Spread cost associated with long stay of Drilling rig on location, if we hire work over rig for frac diverter installation/retrieval and final completion run. As per OMV Pakistan suggestions, Slb Rig (225) is considered to be on location till final completion run which made the total Rig days of 93 for Sawan 12 dual lateral and 74 days for each new horizontal wells.

Table 23: Rig Daily Spread Cost

SPREAD COST (K$)	
Rig Day rate	23800
Energy	6000
Catering	2500
Supervision	6100
HSSE	2057
Logistics	2027
HO & RFS	1000
Rental Equipment	1351
Wastes disposal	973
Total (K$)	**45808**

- Cost of Directional drilling and tools is same for all the cases as all the wells are directional and horizontal.
- Cost of mud, water and solid control for drilling the new horizontal well is considered to be 687K$, while for Sawan 12 dual lateral, its value is reduced to 400K$, as the first three sections are already drilled.
- For cementing, 232 K$ is cost for new well, for mother bore the cost is assumed to be 132K$ which is the result of excluding cost of cementing first three sections and adding cost of placing two cement plugs in parent wellbore. Cementing cost for the lateral wellbore is further reduced as there is no cement plugs cost, no first three sections and cementing only part of 7” liner keeping junction area un-cemented.
- Cost of Drill bits and downhole tools is also reduced to 164K$ for mother and lateral well bore, While it costs 264K$ for drilling a new single horizontal well.
- Coring and logging cost is same in each case.
- A contingency of 5% is placed for dry hole cost and completion cost in each case, as per OMV Pakistan suggestions.
- Cost of 10 Frac-sleeves and 4-1/2” liner cost is included in casing costs while other completion jewelry is included in cost mentioned above in the table.

- About 3.948 MM$ is considered to be fixed for stimulation/cleaning of the horizontal section for each of the well bores, as calculated independently shown below in table.

Table 24: Hydraulic fracturing conceptual cost estimate

Conceptual Cost Estimate - 1000 m Horizontal - 10 Fracs							
Lower Completion cost (K$)							
Sleeve & OHP - per set					100	x10	1000
Liner - 1100 m 15.2 ppf					62	$/m	69
Linerhanger							120
Subtotal							**1189**
Frac-string cost (K$)							
Packer							120
Frac-tubing - 15.2 ppf 3230m Avg.					62	$/m	200.26
Fracture 15k							100
Subtotal							**420.26**
Fracking cost (K$) - 10 Frac ,14 days of work							
Fracservice							
Mob/Demob					80		
Dayrate Equipment	15000	$/day	14	days	210		
Dayrate People	5000	$/day	18	days	90		
				Total	**380**		
Frac-proppants	150000	lbs/frac	10	Fracs	1500	Klbs	
	0.8	$/lb	1500	klbs	**1200**		
Chemicals	1500	bbl/frac	10	Fracs	15000	bbls	
	90	$/bbl	1500	bbls	**1350**		
Water	0.5	PKR/lit	79.5	PKR/bbl	0.795	$/bbl	
Frac	15000	bbl					
Cleanup	2000	bbl					
Disposal	5000	bbl					
Total Water cost (K$)	22000	bbl	0.795	$/bbl			**17**
Subtotal Proppants/water/Chemicals					**2567**	**K$**	
Total Frac-service					**2947**	**K$**	
Coiled Tubing					200	K$	
Well testing					380	K$	
				Total	**580**	**K$**	
Total Fracturing cost (K$) - Without Tubing & Lower Completion							**3947.8**

Table 25: Savings from Sawan 12-DL, in comparison to two horizontal wells

Well Types for comparison	Savings
Sawan 12 dual Lateral compared to Two Horizontal Well	7.975 MM$
Sawan 12 dual lateral compared to New Dual Lateral Well	3.21 MM$

The reduced CAPEX in drilling a dual lateral well as compared to two separate wells to get the same reservoir exposure, justifies the implementation of multilateral drilling in Pakistan.

6 Conclusions

One thing is now clearly understood that multilateral technology is a reservoir development technology rather than a drilling technology.

One cannot deny from the reduced CAPEX and savings involved in practicing multilateral drilling as compared to separate drilling projects for developing a specific field, as proved in the cost comparison of the proposed dual lateral for Sawan 12 with two separate wells. However, technical complexities of the multilateral systems and operational risks are needed to be evaluated in terms of economics to clearly justify the design and implementation of multilateral well.

As the technical complexities and risks involved in execution of multilateral project is very high, it demands significant amount of input and cooperation from all the technical disciplines during planning and all the project phases. The recommendations and suggestions while installation of the proposed design are mentioned within the procedures of specific operation. For a successful multilateral project, vendors and service companies should be involved at the earliest as possible during planning.

In the literature part, the only known study about the reliability of multilaterals is also included to motivate multilateral implementation in Pakistan. The result has shown that this era of proven junction construction methods and completion systems available in market, have reduced the operational risks involved in execution of a multilateral project.

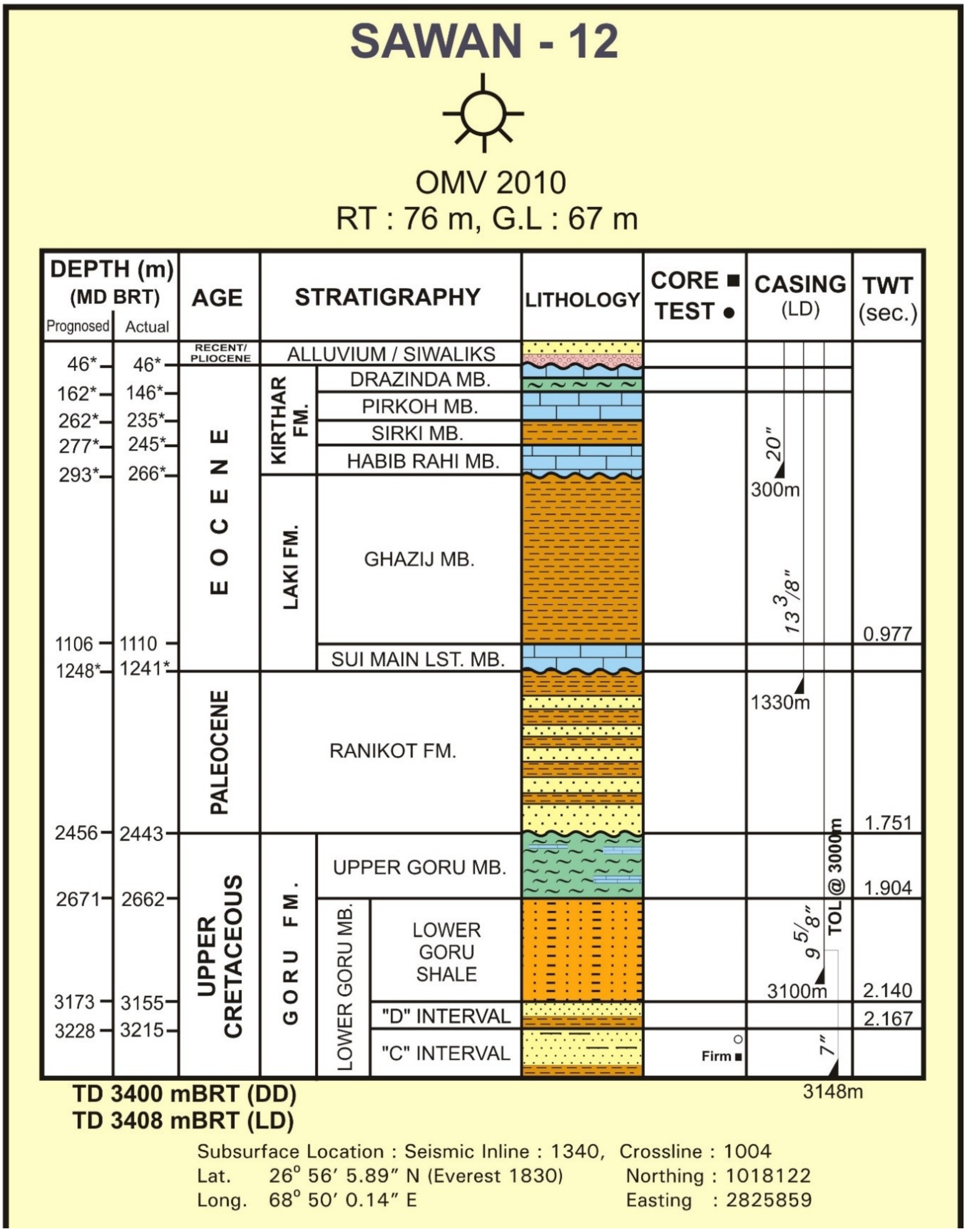
From technical standpoint, the proposed design is feasible. However, strong justification and input from reservoir department with realistic production performance forecasts, is needed for its implementation on the Sawan field. The objectives of the project to provide a generalized study and concept of multilaterals along with the conceptual design of dual lateral well for Sawan Gas field of Pakistan, has been met.

Abbreviations

ML	Multi-Lateral
TAML	Technical Advancement for Multilaterals
DL	Dual Lateral
HW	Horizontal well
SBP	Seal Bore Packer
TD	Total Depth
SPP	Stand Pipe Pressure
OH	Open Hole
CH	Cased Hole
CPP	Central Processing Plant
CAPEX	Capital Expenditures
OPEX	Operational Expenditures
SW	Sawan (Gas Field)
MM $	Million Dollars
BTA	Bottom Trip Anchor
SCF	Standard Cubic Feet
TFA	Total Flow Area
DLS	Dog Leg Severity
BIF	Bit impact Force
UBHO	Universal BoreHole Orientation
TOC	Top of Cement
DHFC	Downhole Flow Control
GPM	Gallon per Minute
LDR	Lateral Diverter Retrieval
WGR	Water Gas Ratio
CT	Coil Tubing
ECD	Equivalent Circulating Density
MWD	Measurement While Drilling
WOB	Weight on Bit
PBR	Polished Bore Receptacle

Appendix A

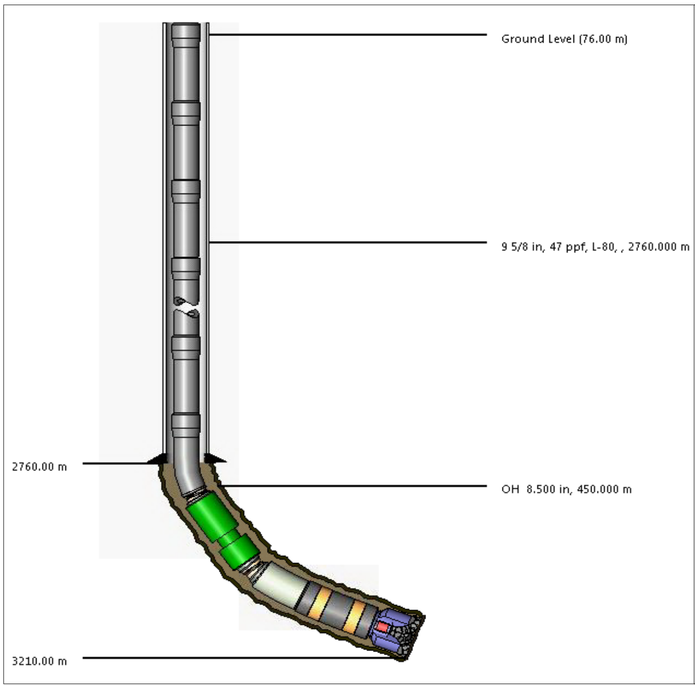
OMV (PAKISTAN) **Well Summary**



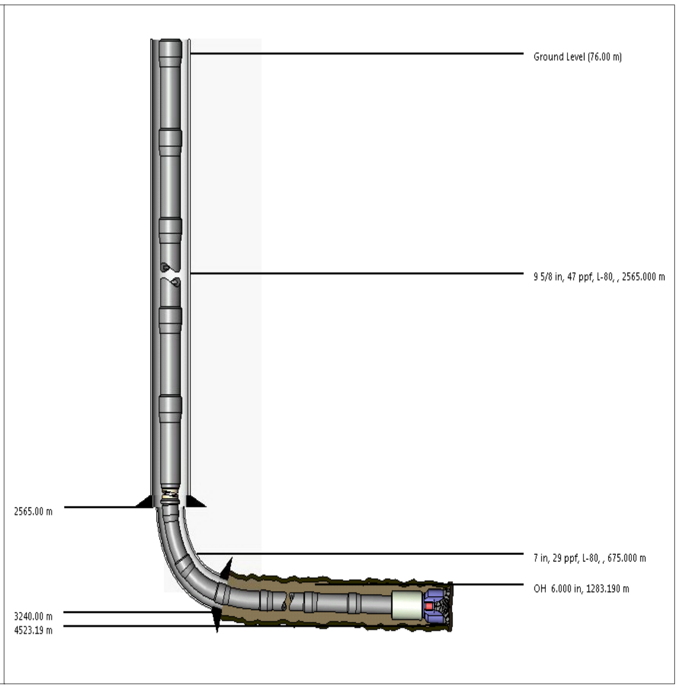
Appendix B

Well Schematics:

Mother borehole

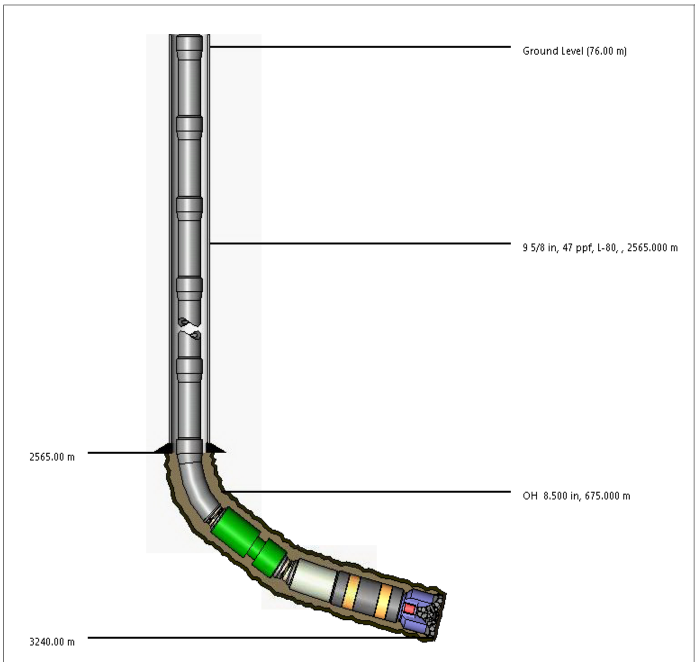


8-1/2" Hole

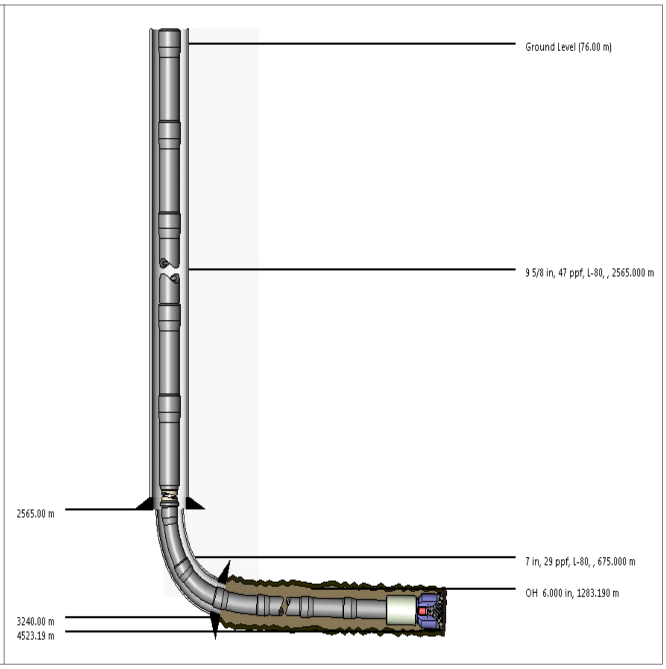


6" Hole

Lateral Borehole:



8-1/2" Hole



6" Hole

Appendix C

Sawan-12
Estimated Pore Pressure and Fracture Gradient