INTELLIGENT MULTILATERAL WELL TECHNOLOGY

A Thesis submitted in partial fulfillment of the requirement for the degree of

BACHELOR OF TECHNOLOGY

(Applied Petroleum Engineering)

(Session: 2005 - 09)

Submitted To

University of Petroleum & Energy Studies, Bidholi, Dehradun

Under the able guidance of

Mr. Cecil Antao and **Mr. Vinay Avasthi**

Submitted By

Abhishek Bansal

University of Petroleum & Energy Studies, Bidholi, Dehradun

May 2009

CERTIFICATE

This is to certify that the dissertation report on "**Intelligent Multilateral Well Technology**" completed and submitted to the **University of Petroleum & Energy Studies**, Dehradun by **Mr. Abhishek Bansal** in partial fulfilment of the requirement for the award of degree of Bachelor of Applied Petroleum Engineering is a bonafide work carried out by him under our supervision and guidance.

To the best of our knowledge and belief the work has been based on investigation made by him and this work has not been submitted anywhere else for any other University or Institution for the award of degree/diploma.

Mr. Cecil Antao

(Manager-Technical Services, Baker Oil Tools)

Date: 08-05-09

Mr. Vinay Avasthi

(Assistant Professor, COE, UPES)

Date: 7/5/09

Corporate Office:
Hydrocarbons Education & Research Society
3rd Floor, PHD House,
4/2 Siri Institutional Area
August Kranti Marg, New Delhi - 110 016 India
Ph.: +91-11-41730151-53 Fax : +91-11-41730154

Main Campus:
Energy Acres,
PO Bidholi Via Prem Nagar,
Dehradun - 248 007 (Uttarakhand), India
Ph.: +91-135-2102690-91, 2694201/ 203/ 208
Fax: +91-135-2694204

Regional Centre (NCR) :
SCO, 9-12, Sector-14,
Gurgaon 122 007
(Haryana), India.
Ph: +91-124-4540 300
Fax: +91-124-4540 330

Regional Centre (Rajahmundry):
GIET, NH 5, Velugubanda,
Rajahmundry - 533 294,
East Godavari Dist., (Andhra Pradesh), India
Tel: +91-883-2484811/ 855
Fax: +91-883-2484822

Email: info@upes.ac.in URL: www.upes.ac.in

ACKNOWLEDGEMENT

I would sincerely like to give my thanks to **University of Petroleum & Energy Studies** for giving me an opportunity to work on the project "**Intelligent Multilateral Well Technology**".

I would give special thanks to **Mr. Cecil Antao (Manager-Technical Services, Baker Oil Tools)** for guiding me throughout the project, helping with all the data required and providing valuable support whenever required as mentor.

My sincere sense of gratitude to **Dr. B.P. Pandey (Dean-Emeritus), COE, UPES** for supporting me with his wise guidance and experience.

I would thank **Mr. Vinay Avasthi (Assistant Professor, COE, UPES)** for his support during the completion of the project as an Internal Mentor.

I am also thankful to the other UPES Faculty and library section of University of Petroleum & Energy Studies, without their support and assistance this project wouldn't have been possible.

7/5/09

Abhishek Bansal

B.Tech. (Applied Petroleum Engineering)

University of Petroleum & Energy Studies

Dehradun

ABSTRACT

Multilateral systems provide production from two or more wellbores, while Intelligent Well Systems are designed to control production from multiple zones downhole. The combination of these two complementary technologies can lead to future wells offering maximum reservoir and production efficiency.

Multilateral and Intelligent Well Technologies have been available to the industry for many years. However, it is only recently that wells offering both capabilities have been installed. The risk involved in these technologies had been a major concern considering a combination of the two. However, many of today's multilateral and intelligent well systems have evolved to the point that low risk, highly flexible combinations of these two technologies are fully compatible and feasible in a variety of well situations.

The report highlights the detailed review of each of the Multilateral and Intelligent Well Technologies implemented worldwide for enhanced productivity. The combination of both the technologies has been discussed in detail The Heel – Toe Effect or Pressure Drop calculations in the horizontal well have been discussed which can be resolved using Intelligent Well Technology. A CMG/IMEX simulation model of a reservoir has been made to show the enhanced oil production and reduced water production after the implementation of intelligent completion in the dual opposing multilateral wells.

CONTENTS

LIST OF FIGURES, TABLES & EQUATIONS

ABBREVIATIONS

BHA	Bottom Hole Assembly
CAPEX	Capital Expenditure
DPS	Distributed Pressure Sensing
ECP	External Casing Packer
ESP	Electrical Submersible Pump
HPHT	High Pressure High Temperature
ICD	Inflow Control Device
ID	Inner Diameter
ICV	Interval Control Valve
IQ	Intelligent Quotient
IWS	Intelligent Well System
JIP	Joint Industry Programme
ML	Multi Lateral
MLT	Multi-Lateral Technology
MRC	Maximum Reservoir Contact
MWD	Measurement While Drilling
NPV	Net Present Value
OPEX	Operating Expenditure
ROI	Return on Investment
SAGD	Steam Assisted Gravity Drainage
TAML	Technology Advancement of Multilaterals
TVD	True Vertical Depth
DTS	Distributed Temperature Sensing
DUT	Delft University of Technology
ESP	Electric Submersible Pump
E&P	Exploration and Production
FDP	Field Development Planning
ICV	Inflow Control Valve or Interval Control Valve

ISP	Inflow Switching Process
NPV	Net Present Value
OPEX	Operating Expenditure
SIEP	Shell International Exploration and Production
SSC	Smart Stinger Completion
4D	4-dimensional (3 in space, 1 in time)

NOMENCLATURE

bbl	barrel
B_g	Gas Formation Volume Factor
B_o	Oil Formation Volume Factor
B_w	Water Formation Volume Factor
P	Pressure
q	Flow Rate
g	Acceleration due to gravity
T_x	Transmissibility (in X-Direction)
cp	centipoise
ft	feet
A	Area
L	Length
k_r	relative permeability
k_{rg}	gas relative permeability
k_{ro}	oil relative permeability
k_{rog}	oil gas relative permeability
k_{rw}	water oil relative permeability
lb	pound
md	millidarcy
P	Pressure
psi	pounds per square inch
P_{cog}	Oil-Gas Capillary Pressure
P_{cow}	Oil-Water Capillary Pressure
RB	Reservoir Barrel
R_s	Solution Gas Ratio
SC	Standard Conditions
scf/SCF	standard cubic feet
STB	Stock Tank Barrel

S_w	Water Saturation
S_g	Gas Saturation
Vis_{gas}/μ_g	Viscosity of gas
Vis_{oil}/μ_o	Viscosity of oil
ρ_o	Density of Oil
ρ_g	Density of Gas
ρ_w	Density of Water
φ	Porosity

1. INTRODUCTION

Multilateral and IWS technologies have been deployed in a variety of well profiles, from heavy oil, high pressure gas, underbalanced drilling, conventional oil wells, sub sea and deep water. In all of these applications the technologies have proven their value.

The drivers for using multilateral technology are:

- Production Acceleration
- Increased Recovery Efficiency
- Drilling Cost Optimization
- Reduced Operating cost
- Sustain well inflow (by the prevention of sand ingress into the mother bore and plugging off the production of one leg)
- Reduced deferment of oil (due to logistical restraints, it can take a substantial amount of time to get to the well for remedial action)
- Ensure well integrity (level 3 technology ensures the hole stability and reduces the hazards caused by the dynamic movements of the sand into the well bore)

An intelligent well allows control of flow into or out of the reservoir without physical intervention, with or without downhole sensors and monitoring.

The principal application of intelligent well technology is the ability to actively manage the reservoir recovery process. They can control the distribution of water or gas injection in a well between layers, compartments or reservoirs. They can restrict or exclude production of unwanted effluents from different zones in a production well.

The amalgamation of emerging technologies (intelligent completions, expandable tubulars, advanced drilling and production systems, real-time information flow, downhole factory, etc.) through MLT demonstrates the quantum leap of this technology from discrete MLT hardware to a production system-a leap that will address maximized reservoir understanding, production and control. This will constitute a total production system that will have a revolutionary impact on the energy industry.

2. MULTILATERAL WELLS

A multi-lateral well is a single well with one or more well bore branches radiating from the main borehole. It may be as simple as a vertical well-bore with one sidetrack or as complex as a horizontal, extended-reach well with multiple lateral and sub lateral branches. Multilateral wells require additional initial investment in equipment, but potentially reduce total capital expenditures and development costs as well as operational expenses by decreasing the number of required wells.

(1) Thus, a multilateral well is one in which multiple boreholes or laterals are drilled from a single wellbore and the well can follow different well trajectories: horizontal or deviated.

2.1 MULTILATERAL TERMINOLOGIES

(1) Multilateral Technology uses special terminology which is as follows:

Laterals are wellbores drilled from the main wellbore. Not all multilateral wells are actually horizontal; they may only be deviated.

Branches are wellbores drilled from a horizontal lateral into the horizontal plane.

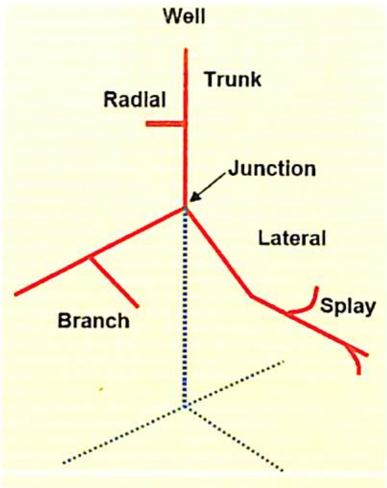
Splays are wellbores drilled from horizontal lateral into the vertical plane. Splays are often called either fish hook or herring-bone.

Junctions are the intersections of the laterals with the main wellbore or of the branches and splays with the lateral. The multilateral junctions have two categories:

- Uncased junctions
- They do not have any casing in the lateral but the main wellbore may or may not have casing either.
- They are more commonly used as it is easier to construct and are less expensive than a cased junction.
- However, they require that the formation be competent so that the borehole wall does not collapse nor the wellbore is filled with sand produced from the formation at the junction.
- Cased junctions
- They have a casing in the lateral that connects to the main wellbore.

- They can be prepared mechanically by proper positioning and cementing or with expandable metals, or by drilling larger holes and installing pre-manufactured junctions.
- They are more expensive to install and hence, are selected where the uncased junctions can't be used.

Figure 1 : Multilateral Well Terminologies (Source: Richard S.)



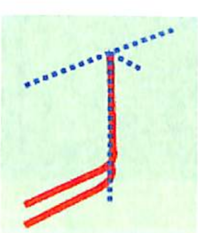
2.2 MULTILATERAL CONFIGURATIONS

(1) The various types of configurations possible by the way the laterals are positioned are:

2.2.1 Stacked Dual Laterals

They are laterals departing from the main wellbore at two different depths and usually intersect two different reservoirs. This type can be used to produce two different zones or produce above and below a permeability barrier.

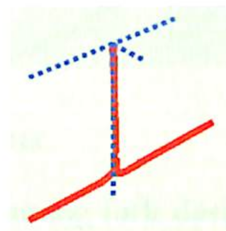
Figure 2 : Stacked Dual Laterals (Source: Richard S.)



2.2.2 Dual Laterals

A dual lateral is a multilateral with two laterals usually in the same reservoir. If the azimuth of the laterals is 180° apart, they are often termed opposed laterals. This doubles the length of the horizontal section.

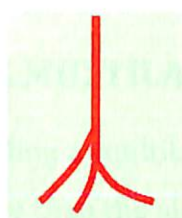
Figure 3 : Dual Laterals (Source: Richard S.)



2.2.3 Crow's foot

It is the drilling of multiple directional wells from a single wellbore in order to drain different parts of the reservoir or different reservoirs.

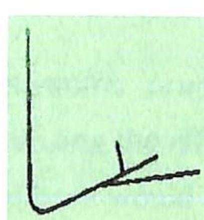
Figure 4 : Crow's Foot (Source: Richard S.)



2.2.4 Branched Multilateral

(2) Laterals are drilled from a horizontal lateral in the horizontal plane.

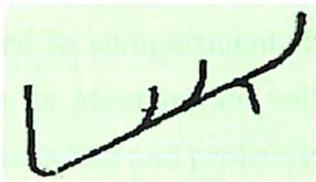
Figure 5 : Branched Multilateral (Source: SPE 39509)



2.2.5 Splayed Multilaterals

Laterals are drilled from a horizontal lateral in the vertical plane.

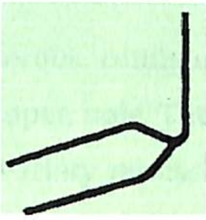
Figure 6 : Splayed Multilaterals (Source: SPE 39509)



2.2.6 Fork Type of Dual Laterals

The shape is that of the symmetric tuning fork design meaning that two horizontal legs would have same direction and TVD.

Figure 7 : Fork Type of Dual Laterals (Source: SPE 39509)



2.3 REASONS FOR DRILLING MULTILATERALS

- (1) The main reason for drilling a multilateral is that the Return on Investment (ROI) for the operator is more than the alternative.
- Multilaterals are more expensive to drill, so production rates have to be higher for a longer period of time to payout the difference.
- Generally, multilateral wells are more effective in low to moderate permeability reservoirs as the cumulative production ratio for these reservoirs is maintained for a longer period of time.
- In higher permeability reservoirs, production interference occurs between laterals at an earlier time reducing the effectiveness of the laterals. Additionally, production in the parent wellbore would be limited by tubing diameter for high permeability wells.

- The economic benefit of MLT is enhancing reservoir flow characteristics, but reducing well construction costs which is a strong incentive for using MLT. A multilateral well can be drilled for 1.2-1.8 times the cost of a single conventional well.
- Multilaterals can be used in compartmentalized reservoirs or reservoirs with varying heterogeneities as Multilaterals will contact more of the producing formation increasing production and probably reserves.
- Additional costs associated with multilateral depends upon the complexity of the multilateral and the cost of individual vertical or horizontal wells. If surface locations or slots (in the case of an offshore platform or subsea template) are not available, then the economics become much more acceptable.

2.4 Multilateral Classification System (TAML Classification)

(1) The multilaterals can have numerous configurations based on whether the main wellbore and laterals are cased or left open hole. These configurations allow installation of a variety of junctions in a well. This variety necessitated development of a classification system for users to compare, differentiate and select the multilateral applicable for their respective requirements.

The TAML (Technology Advancement of Multilaterals) categorizes multilaterals based on the type of junction used. Lateral junctions are a critical element of multilateral completions and can fail under formation stresses, temperature-induced forces and differential pressures during production. Junctions are divided into two broad groups: those that do not provide pressure integrity (Level 1, 2, 3 & 4), and those that do (level 5 &6).

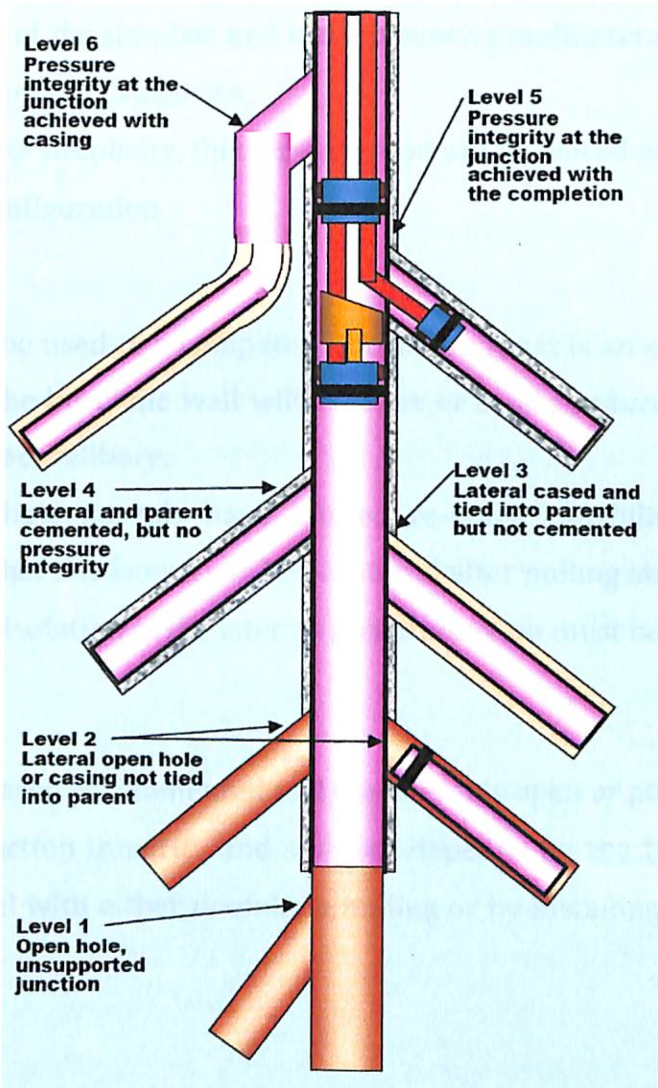
As the level increases, complexity of the junction increases and the cost and risks go up.

The current TAML categorizations comprise the six levels presented below:

- Level 1: Open, unsupported junction
- Level 2: Main (mother) bore cased and cemented; lateral is open
- Level 3: Main bore cased and cemented; lateral is cased but not cemented
- Level 4: Both main and lateral bores are cased and cemented

- Level 5: Junction pressure integrity is achieved with completion (cement is not acceptable)
- Level 6: Junction pressure integrity is achieved with casing (cement is not acceptable)

Figure 8 : Multilateral Classification System (Source: Richard S.)



2.4.1 Level 1

(3) In Level 1, both the main bore and lateral(s) are open (uncased) and the junction is unsupported. The lateral is usually constructed in a consolidated formation from the low side of the well.

Benefits

- (1) It is one of the simplest and least expensive multilaterals and hence, is one of the most common categories.
- Because of its simplicity, this type junction can be placed in any hole size and any wellbore configuration.

Limitations

- It can only be used in a competent formation (as it is an open hole completion), otherwise the borehole wall will collapse or sand produced from the formation will fill up the wellbore.
- The open hole laterals have limited re-entry capabilities and there is no guarantee that any lateral can be reentered after pulling above the junction.
- There is no isolation of the laterals and production must be commingled.

2.4.2 Level 2

(3) The main bore is cased and cemented and the lateral is open or possibly a liner dropped in the lateral. The junction integrity and stability depends on the type of formation. The Junction is constructed with either downhole milling or by installing a pre-milled window joint.

Benefits

- (1) This type of junction is the second most popular multilateral system used today since they can be drilled from an existing vertical well.
- On a new well, the sidetracks can be accomplished with pre-milled window joints.

Limitations

- This junction allows limited reentry capabilities.

- The laterals being open-hole must be located in consolidated formations.
- Also, the laterals are not isolated.
- Reentry is likely but not guaranteed unless some selective completion equipment is used.

In an existing well, it is typically drilled using a whipstock (retrievable) to sidetrack out of the existing casing. The whipstock should be placed in the body of the casing to prevent milling a connection.

The pre-milled windows are much more expensive, more difficult to install, and in some cases, they require drilling a larger hole to accommodate a pre-milled joint. A liner can be dropped off outside the window to case the lateral if desired but the liner does not connect back into the casing of the parent well.

If an orienting packer or liner hanger is placed below the window, a entry nipple can be oriented and placed opposite the window. With this system, thru tubing reentry is possible. During production, the production is commingled and any tools or coiled tubing run in the hole will proceed through the packer.

If entry into the upper lateral is desirable, a deflector is placed in the entry nipple with wireline or coiled tubing. Anything run in the hole will then be deflected into the upper lateral.

Additionally, production from the main wellbore can be isolated by setting a plug in the packer. Production from the lateral can be stopped by placing a sleeve into the entry nipple.

2.4.3 Level 3

(3) The main bore is cased and cemented; the lateral is cased but not cemented. In this system, mechanical integrity at the junction is required but not hydraulic integrity. Intervention and sand control are usually the main design considerations.

(1) This type of junction is created by mechanically tying the lateral to the main wellbore or by installing casing strings in both the laterals and the main wellbore. The level 3 junctions are installed where the formations are not competent at the junction and where water or gas production into the junction is not problematic.

Limitations

- It may or may not have access to both the lateral and to the main wellbore.
- Selective reentry may or may not be possible.
- The level 3 junction can be substantially more expensive depending upon how it is accomplished.

2.4.4 Level 4

(3) The main bore and lateral are both cased and cemented. This type of junction involves running a whipstock, drilling a lateral, and running and cementing a liner in the lateral. The junction is constructed by one of three methods:

- Performing a washover operation that removes the lateral extension and whipstock from the wellbore thereby allowing access to the lower lateral.
- After the liner is placed in the lateral and across the junction, a hole is milled through the liner and whipstock to expose the lower main bore.
- Low-side perforations of the lateral liner and whipstock

Benefits

- (1) The level 4 junction has mechanical integrity, but is assumed to have no pressure integrity. Cement cannot always provide pressure integrity.
- Reentry is possible in most cases through the main bore or through tubing.

2.4.5 Level 5

(3) Pressure integrity at the junction is achieved by using the completion equipment by running tubing and isolation packers (cement is not acceptable). The junction construction here is similar to that in level 4 with the added use of completion equipment to achieve hydraulic integrity at the junction. In addition, packers are placed above and below the junction and in the lateral to provide complete pressure integrity at the junction.
In all at least three packers: lateral isolation packer, main bore completion packer below the junction and a main bore production packer above the junction are required to establish complete hydraulic isolation of the multilateral junction.

(1) However, if a problem develops in the tubular above the packer, the pressure integrity is lost. This type of junction allows access to both wellbores usually through tubing. Another system uses a diverter packer assembly. The liner is run and diverted into the lateral.

It provides both a mechanically supported and hydraulically isolated multilateral completion having full re-entry and production isolation capability into any of the laterals.

Disadvantages

- It is much more expensive and is more risky to run.
- The more complex a system, the more likely there will be a mechanical failure during the installation.

2.4.6 Level 6

(1) In this level, pressure integrity is achieved with the main casing string and additional downhole equipment is required to create the hydraulic integrity of the junction.

There are two types of level 6 junctions: expandable metal junction and splitter.

They are used in new installations only because the expandable metal junction or splitter must be run as part of the casing string.

The expandable metal junction requires under-reaming the hole where the junction will be placed so that the junction can be expanded before setting cement.

The splitter junction requires drilling a much larger diameter hole from the surface down so that the splitter can be run. For this reason, splitters are usually run at shallower depths.

(3) Levels I and II were the earliest form of ML completion and have achieved standardization and popularity in the industry, but are only effective in hard competent formations. The technical complexity for levels 3-6 is far greater.

2.5 COMPLETION COMPLEXITIES REQUIRED/DESIRED

(2) The complexities are:

- Isolation of zones & flow control.
- Hydraulic isolation/ sealing of lateral & mainbore.
- Mechanical connectivity of lateral liner(s) with main bore casing.
- Accessibility into the laterals.

With more completion complexities required/ desired, the ML well application becomes more complex thus increasing the risk of encountering drilling/ completion problems. Hence lesser the completion complexities required/desired, more suitable would be the reservoir for ML application.

2.6 MULTILATERAL TECHNOLOGY APPLICATIONS

(4) The key driver in the application of Multilateral Technology is exploitation of multi target structures. These include compartmentalized, layered, and dispersed structures. The result is field development with fewer wells. On a per-well basis, this appears as accelerated production.

(2)The applications are as follows:

2.6.1 Increased production per platform slot

Multiple lateral wells expose more of the reservoir

2.6.2 More reserves

Many fields are not considered viable on economical basis. Using ML technology, marginally economical fields may become viable

2.6.3 Production from natural fracture systems

There are certain reservoirs which depend exclusively on natural fracture system to produce oil and gas. Multilateral wells greatly increase the probability of encountering and draining different fracture systems. In such cases if fracture system is not capable of economic production, multilateral wells may intersect several fractures and help drain them efficiently.

2.6.4 Efficient reservoir drainage

The use of multilateral wells in a single reservoir can also help in draining the reservoir more efficiently. The laterals can be drilled in different directions, for creating a large reservoir contact area. Therefore, fewer wells are needed to produce the field and in low producing reservoir well productivity increases.

2.6.5 Maximization of Reservoir Contact

(4) To improve well productivity by maximizing reservoir contact, reduce the unit cost of drilling ($/ft) and production ($/STB) and utilize the limited drainage space available between existing wells (A Maximum Reservoir Contact (MRC) well is a multilateral horizontal well with more than five kilometer of total contact with the reservoir rock).

2.6.6 Exploiting reservoirs with vertical permeability barriers

(2) In certain cases, an impermeable barrier blocks the vertical flow of hydrocarbons, between two producing zones. In such cases, dual stacked or dual opposing stacked laterals can be drilled to produce from both the zones.

2.6.7 Improving thin oil zone reservoirs production performance

Depending upon the length of the laterals, the number of laterals, the angle and distance between the laterals a multilateral well may improve productivity and coning behavior compared to conventional horizontal wells.

2.6.8 Economy

The primary reason for drilling a multilateral well is to increase the return on investment through improved reservoir drainage. Field development costs are reduced since fewer wells are required to properly drain the reservoir. Multilateral drilling may therefore allow the development of fields that would otherwise be considered uneconomic.

2.6.9 Reduced Well Cost

Multilateral wells reduce drilling costs because the number of vertical sections required to be drilled is also reduced. Consequently, the costs of casing, well head, cementing and all the various services involved in drilling many vertical holes is saved.

2.6.10 Reduced Time

Also time is money. It takes time to drill the vertical part of a well. Hence time is saved by drilling fewer vertical sections, which is particularly important in offshore developments.

2.6.11 Reduced Capital Cost

Onshore, the use of multiple laterals can reduce number of surface locations, access road and minimizes clean up costs, which reduce overall project cost. Offshore, fewer surface facilities may be necessary, and increasing the drainage area for a fixed number of slots gives greater platform flexibility and allows more extensive field development. The increased production minimizes the number of platforms, cutting investments and operational costs.

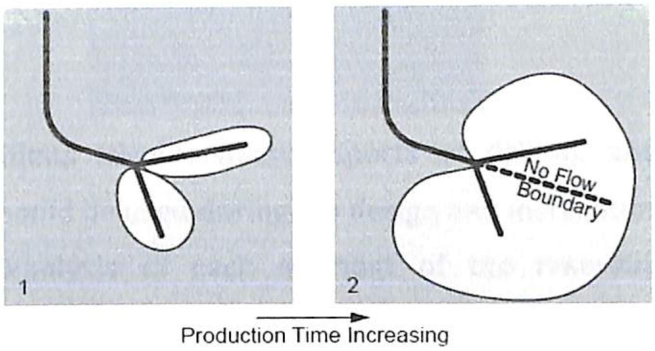
2.7 Factors Influencing the Potential Application of Multilaterals

- (5) There are many constraints in multi-lateral well design related to the operation of sidetracking out of the primary wellbore and the shape of the reservoir(s) targeted by the laterals.
- For example the primary wellbore may be 8.5" hole with a gentle build angle while the sidetrack may be 6" hole with quite a severe build angle due to the small vertical distance between the junction and the reservoir. The laterals may have different lengths and different completions as a result of such geometric constraints.
- Interference may take place between laterals either in the reservoir or in the wellbore.
- If the laterals are being drilled in the same reservoir or in communicating reservoirs, the drainage areas will eventually overlap at later time. In this case,

the resulting drainage area will be less than would be the sum of the drainage areas for the laterals individually.

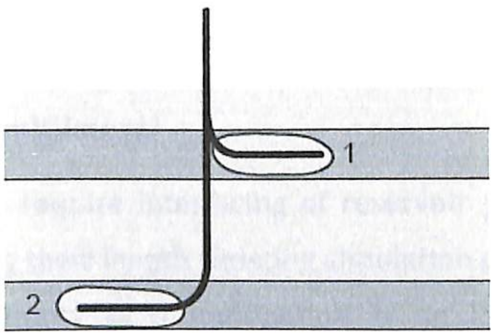
- For low permeability reservoirs the transient period may last for a long time and significant acceleration of production will be achieved before interference effects reduce production.

Figure 9 : Multilateral Interference (Source: Temp)



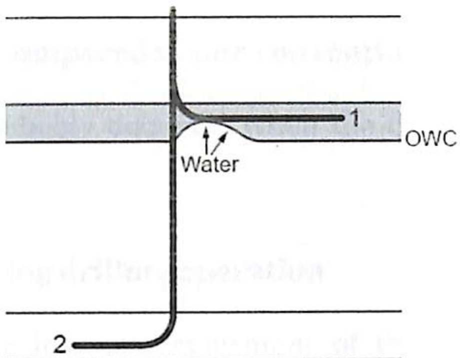
- In non-communicating reservoirs, for example, in a sequence of stacked reservoirs, the same issues arise in a vertical well when deciding whether to perforate two independent flow units. Interference will take place in the wellbore unless a completely independent dual completion has been used.

Figure 10 : Multilateral interference effects in the wellbore (Source: Temp)



- For reservoirs at the same pressure regime commingled production when producing dry oil causes no problem unless severe differential depletion takes place. With the advent of water cut in layer 1 a back pressure will be experienced due to the higher density of the fluid in layer 1 causing undesirable cross flow into layer 2.

Figure 11 : Water Breakthrough affects the performance of both zones in a Multilateral Well (Source: Temp)



Because MLT applications involve many aspects of drilling and production, a total integrated approach should be used during job design and installation. Compatibility issues require a complete analysis of each segment of the reservoir development plan, drilling/completion program and facility design, to optimize technology inter faces at each step.

2.8 LIMITATIONS OF MULTILATERAL TECHNOLOGY

Although ML technology has many advantages and is being progressively adopted in the industry, it has certain limitations which should be kept in mind before its application in a field.

Following are the limitations of ML technology:

2.8.1 Modeling of a multilateral

Modeling of a ML well may require interfacing of reservoir performance and fluid flow behavior in the laterals along their length. Existing simulation packages have limitations in this regard. Pressure continuity in a multilateral is an important factor from well performance standpoint, and thus needs to be considered during modeling.

2.8.2 Problems during production phase

This involves costlier and complicated well-intervention; less than optimum reservoir monitoring/ management. However, intelligent completion systems are presently under development for monitoring and controlling reservoir performance during a well's life cycle with a minimum of well intervention operation.

2.8.3 Increased cost compared to one conventional well

The cost of ML well will probably decrease when the design and drilling techniques are further improved in future.

2.8.4 Higher risk during drilling operation

This relates to the possible loss or impairment of the main wellbore due to drilling problems.

2.8.5 Technology still in development stage

Even if the drilling risks and costs can be minimized, the remaining area of risk is "will the ML well perform sufficiently to justify its cost?"

2.9 SCREENING VARIABLES FOR MULTILATERAL TECHNOLOGY

(6) These are the fundamental criteria from which the multilateral feasibility study should be done.

2.9.1 BUSINESS DRIVERS FOR MULTILATERAL TECHNOLOGY

The following is the list of business drivers, which represent the primary justification for considering the application of the technology:

Cost Reduction

- The purpose of the technology is to reduce CAPEX
- A typical cost reduction model would have the multilateral well contributing up to twice the production, but only 1.5 times the cost of a monobore completion. Similarly, a trilateral may cost twice the monobore completion, but supply up to three times the production.

Increased Reserves

- ` :ditional reserves may be isolated lenses of pay or compartmentalized reservoirs.
- The degree of the compartmentalization will dictate the number of laterals and the wellbore geometry needed to optimally exploit the reservoir.
- Multilateral technology may also allow access to smaller or marginal reservoirs that, if evaluated as separate drilling projects, would be uneconomic.

Accelerated Reserves Production

- Drainage optimization is especially important when price per barrel or OPEX is high.
- Multilaterals implemented under this driver are typically drilled in the same horizontal plane or vertical plane (Kv/Kh low) to accelerate production.
- The laterals can be radially opposed or in any planar configuration which allows for the best aerial drainage.

Slot Conservation/Facilities Cost

- Multilateral technology allows a maximum number of reservoir penetrations with a minimum number of wells.
- The additional penetrations increase the aggregate production per slot, thus reducing capital cost per barrel.

Heavy Oil Reserves

- Steam Assisted Gravity Drainage (SAGD) is a multilateral application whereby the vertical steam injector and the producer are combined into one wellbore (with surface facility modifications) with two horizontal laterals.
- The upper lateral is used as the steam injection well and the lower lateral is used to produce the gravity-drained reserves.

Delineation of Reservoirs

- Fault blocks, channel sands, and multiple formations or targets can be located, logged, plotted, or produced with a minimum number of wellbores.

- Horizontal and vertical extent, drainage area, and volumetric calculations can also be refined through the use of multilateral technology.

2.9.2 COMPLETION SCREENING VARIABLES

The multilateral well, like any drilling project, should be planned from the completion back. Information concerning sand control, water production, drawdown, lifting mechanisms, varying completion scenarios, and production control will assist in the determination of which system is appropriate for the reservoir.

Sand Control

- The design criteria including the level of sand control, the length, and setting mechanism of the liner hanger, the re-entry requirements for stimulation and cleanout, and the running tools/jewelry will be different for each of the available multilateral systems.
- Most multilateral systems available now allow gravel-packing operations in Levels 4 and 5. Level 6 gravel packing operations are also feasible, but generally accomplished in smaller ID environments.

Water Production

- Similar to the sand control issue, planners must decide how water will be produced or handled and when it can be expected.
- The ability to allow for the determination of each lateral's contribution of water may also dictate the appropriate multilateral system.

Production Drawdown

- The most common cause of multilateral failure is junction instability.
- If drawdown pressures are expected to be high, consideration should be given to a multilateral system that ensures production isolation of each lateral.
- Additionally, when the production drawdown equals the frictional pressure drop, no further production increase will be expected.

Lifting Mechanisms

- The implementation of a multilateral may change depending on the type of artificial lift utilized for the multilateral well.
- The multilateral system design must also take into account any future production logging plans as ID restrictions may prohibit all but special clearance "Y" blocks or other such tools used to obtain post-production information.

Completion Design

- The completion design impacts the selection of the appropriate multilateral system. For example, a Level 1 system may be chosen because of cost drivers. However, if the lateral(s) need acid stimulation, re-entry is not guaranteed without a casing bore in which to set a whipstock.
- If the laterals will be used for injection rather than production, the multilateral system chosen could be completely different.
- Also, the multilateral planner must work with the vendor to ensure their objectives are aligned.

Production Control

- The need to know contribution from each lateral will also determine which multilateral system is appropriate.
- Additionally, the optimum multilateral system may have to be designed around conventional "heel-toe" theory. For example, a dual production string completion, whereby one string produces the heel while the other produces the toe, will require a system that will allow for the increased inside diameter required for such a completion.
- Similarly, any dual string producer or injector will require additional planning. The multilateral system must also allow the passage of external casing packers used to control production without damaging the rubber elements.

2.9.3 RESERVOIR SCREENING VARIABLES

The reservoir screening variables pertain to reservoir evaluation including models and simulations, petrophysical properties, and wellbore stability. Inconsistent pore pressure regimes, and anticipated crossflow potential of the laterals also affect the choice and design of multilateral equipment. Other reservoir variables include reservoir geometry and drainage strategy.

Reservoir Evaluation

- A modeling and simulation of the reservoir will aid in the determination of volumetrics, number and length of laterals, flow rates, and tubular requirements.
- Rock mechanics analysis should also be understood or performed in the field where the multilateral candidate is located.
- Classification levels 1- 4 are typically designed (with a few exceptions) for consolidated formations, while levels 5-6 are designed for both, consolidated and unconsolidated formations.

Pore Pressure

- Typically, the first lateral drilled is the last lateral opened for production. It should be isolated with a plug or packer to prevent damage to the completion interval while the other lateral is being drilled. This damage potential is usually caused by inconsistent pressure regimes across the different laterals.
- Ideally, reserves will be produced even if one zone significantly over-pressures the other.
- If packers and tubing strings are not used to separate production, it must be determined whether one zone will overpower the other, whether that dominant zone will be produced up to pressure equalization, or whether the dominant zone will crossflow into the passive lateral.

Reservoir Geometry

- The degree of unit compartmentalization determines the number of laterals in a multilateral project.

- Even within the units, shale stringers, dolomite streaks, or other partial flow barriers further dictate the wellpath design and number of laterals.
- Fracture connectivity also determines the length and number of laterals, and wellpath design.

Drainage Strategy

- The multilateral planner has to consider the drainage strategy of the reservoir based on the field life cycle stage.
- Multilateral technology can be used in all stages of the cycle from appraisal through development, but it is typically used in the development stage.
- Production is usually artificially lifted and/or aided by depletion strategies including steamfloods, CO_2 floods, and waterfloods.
- Intelligent completions technology can be combined with multilateral technology to control, monitor and/or optimize the flow into or out of the wellbore.

2.9.4 GEOLOGY SCREENING VARIABLES

The geology screening variables involve junction and lateral placement with respect to stability, lateral orientation, and wellbore path design. The junction must be optimally placed such that the dogleg severity will not significantly affect the installation of completion equipment, while simultaneously addressing the additional cost of rig time, casing, etc. that will be required as the dogleg severity decreases.

Junction and Lateral Placement

- Junctions should be placed in non-reactive, stable lithologies close to the pay zone and allow a minimal dogleg wellpath design. This does not mean that the junction must necessarily be placed in shale. Epoxies and resins can be pumped into sands to strengthen the junction area.
- The dogleg severity of the wellpath also determines the entry point into the zone of interest which, in turn, impacts the amount of reservoir that will be accessible at the heel of the well. That is, the longer dogleg exposes less reservoir at the heel and vice versa.

- All multilateral systems (Levels 3-6) have a dogleg design limit through which their equipment can be run; therefore every effort should be made to determine the optimum junction placement depth.

Water/Gas Coning Potential

- Water and gas coning potential can be minimized using multilateral technology.
- Multilaterals have been used to simultaneously produce the heel and the toe of a long horizontal section.
- Proper alignment of the pump inlet in each lateral can significantly delay the onset of early water or gas.

Lateral Length

- Effective lateral length, especially in high permeability, high rate reservoirs is defined by production drawdown and the frictional pressure drop along the lateral.
- The impact of understanding the variable rock properties with respect to multilateral technology is essentially cost versus production rate.
- Understanding and mapping this variability will also impact the flow contribution in any lateral wellbore.

2.9.5 DRILLING SCREENING VARIABLES

Though multilateral technology is a reservoir technology, the drilling department has the responsibility of coordinating inputs into a viable project. The screening criteria that must be evaluated include the system design, which must address junction stability and debris management, the two most common causes of failure in a multilateral implementation.

Junction Stability

- The number of laterals is the number of potential stability problems and the stability of the wellbore defines the type of junction and the appropriate multilateral system.

- Junction collapse is one of the two major causes of multilateral failure, and any analysis of multilateral systems must cautiously study and risk-weight this variable.
- The cement can be foamed or densified for strength and cement recipes include components such as polypropylene or nylon fibers, latex, etc., for strength and plasticity.
- Reservoir issues such as crossflow, commingling requirements, junction placement, and pressure differentials (across the junction and between zones) combined with cement design and production related issues such as drawdown, combine to make this screening variable the most important drilling variable.
- Level 6 technology virtually eliminates the risk associated with this particular screening variable.

Debris management

- Second only to junction failure, the mismanagement of debris accounts for a high percentage of incomplete multilateral implementations.
- Mud systems must be tested extensively to ensure that the carrying capacity of the fluid will overcome the slip velocity of long and angular metal cuttings.
- As with junction stability, Level 6 technology virtually eliminates the risk associated with this particular screening variable.

Re-entry Requirements

- The classification, level, and cost of the optimum system depend in part on the operator's plans for re-entry.
- The junction with the least risk, cost, and complexity (Level 1) has only a limited capability for re-entry due to a lack of casing in the main wellbore, while the other levels allow the installation of a whipstock or other deflection device in the main wellbore casing.
- Re-entry criteria includes anticipated water production, anticipated remedial interventions for stimulation, cleanup, etc., potential for enhanced recovery (i.e. steam, water, CO_2, etc.), cost, mechanical risk and complexity, and more.

Well Control

- Complete isolation of a drilled and/or completed lateral while working on another lateral is essential to prevent well control problems.
- Lack of isolation creates much more complicated well control scenarios including kicks, crossflow, and/or damage to the production zone of a completed lateral.
- Isolation can be accomplished with a packer run through the bore of a liner hanger or set in the main bore casing string. This variable is especially important when considering underbalanced multilateral operations.

Tubular Limitations

- Most systems are built around standard 9-5/8" or 7" systems, but 13-3/8" systems are now becoming more commonplace, especially in the surface casing splitter technologies.
- Cost, availability, and standard operating practices make this screening variable important for selection of the optimum multilateral system. It determines the size and classification of multilateral system.

Wellbore Stability

- Stability of the wellbore is not only critical around the junction, but throughout the lateral drilling process.
- Mud systems must not only be designed to prevent reaction with the junction area, but also to keep the wellbore open. This includes changeovers from drilling fluids to completion fluids, which may remove the filter cake across the junction.

Vendor Equipment

- The multilateral system selection depends on an evaluation of all the variables (especially junction stability and debris management) and ensuring that the driver for the technology is met.
- Also, care should be taken to ensure that in any one operation or procedure, a minimum number of experimental or untried tools is used.

Vendor Dependability

- The operator must feel confident that the vendor will ensure the placement of the best project personnel, equipment, management and engineering support, and will openly discuss the plans, objectives, day-to-day operations, and mistakes along the way. This is especially important if the implementation does not go as planned.

2.9.6 GENERAL SCREENING VARIABLES

General screening variables include a thorough evaluation of the drivers for multilateral technology. Additionally, regulatory requirements and pre-existing alliance commitments will impact the decision of which classification and system is appropriate for the field.

Multilateral Drivers

- Slot conservation, expedited reserves, additional reserves, multiple pay zones, commingling design, and cost reduction are the primary drivers for multilateral technology and these drivers should be evaluated first.

Regulatory Requirements

- An understanding of the regulatory requirements involves consideration of commingling restrictions, well control, and zonal isolation.
- This variable may have to be evaluated after the drivers for multilaterals are understood. For example, choosing a Level 1 multilateral system would not be appropriate for an area where the regulatory agencies prohibit commingling of production.

Contingency Planning

- Contingencies must be in place to handle cost overruns, reservoir uncertainty, and mechanical failure.
- Contingency planning involves both mechanical and budgetary contingencies. Funding should reflect the state of the technology, the experience of the vendor, and the success rates of the application.

Risk Management

- Peer reviews/assists will allow diverse perspectives on the project, which could generate new ideas and suggestions for improvements.
- Consortiums or JIPs such as TAML can also assist in the minimization of mechanical risk. Economic risk can be minimized through the use of quantitative risk analysis to gain a better understanding of reserves, cash flows, and operations reliability.
- Risk or cost/benefit and decision models with sensitivity analysis should also be used to minimize overall economic risk.

Management Commitment

- Management has the responsibility to ensure that the driver(s) and objectives for multilateral technology are met, whether it be reduction in CAPEX, slot conservation, accelerated reserves, etc.
- Management also has to show aggressive support for asset managers who take on projects that carry risk.

2.10 MULTILATERALS AS A RESERVOIR DEVELOPMENT TOOL

(7) Essentially multilaterals give options: options to pursue targets just outside economic reach, options that improve the value of a reservoir, options that allow the developer to mitigate reservoir risks and uncertainties.
Reservoir value enhancement comes to play in the following ways:

2.10.1 Mitigating Reservoir Heterogeneity

There are very few fields in the world that contain uniform, thick, homogeneous reservoirs. Heterogeneities, whether vertical or horizontal, are created by depositional, geologic, and tectonic forces. Even thin shale or permeability barriers can disrupt fluid flow and the recovery of valuable reserves. Enhancing the value of a reservoir in these formations comes to play in facilitating more complete drainage by traversing or connecting these various reservoirs with multilateral wells.

2.10.2 Improving Sweep Efficiencies

Advanced drainage architectures can also be employed in improving sweep efficiencies by delaying water/gas breakthrough through lowered drawdown pressures and better drainage patterns. Not only can these drainage patterns delay water or gas breakthrough, but they can also help to mitigate sand control problems by lowering fluid velocities. These types of drainage architectures are also useful in low reservoir-energy or low-pressure support situations.

2.10.3 Enhancing Production of Difficult-to-Produce Fluids by Increasing Reservoir Exposure

Difficult-to-produce reservoir fluids can be defined as either heavy, viscous fluids (heavy oil) or as more mobile fluids in very tight formations (e.g., tight gas). Bores in reservoirs containing difficult-to produce fluids are by far the most popular multilateral application. Essentially production involves taking the well bore to the hydrocarbons instead of bringing the hydrocarbons to the well bore.

2.10.4 Time

The element of time can also come in to play in several ways. One, by enabling access to more reserves while area production facilities still remain economical; two, by keeping wells above the economic limit longer thereby aiding better recovery factors.

2.10.5 Rate Acceleration

Multilateral wells have been shown to have the potential for higher production rates than conventional or horizontal wells. More branches allow for more reservoir contribution. Tying together multiple, independent reservoirs allows for early production of secondary reserves.

2.10.6 By-Passed Reserves

An interesting application for mature fields can be the opportunity for development of marginal reserves. These reserves — either small accumulations or difficult to reach accumulations — can be made economic through lower cost per barrel development designs. Lower cost per barrel development designs can even have the effect of increasing bookable reserves in certain fields.

2.10.7 Adding Exploration Targets

Exploration programs can also benefit from the use of multilateral technology. Multiple exploration targets can be reached with various laterals, and the well bore can be kept for future developments. The ability to add risky exploration targets to known in-fill development projects is a beneficial option. This option can help to inexpensively delineate known reservoirs or take a look at new "bright spots".

2.11 MULTILATERAL WELL PLANNING CONSIDERATIONS

(3) Some of the important considerations in planning a multi lateral well are:

- Drilling methods
- Junction design
- Well control issues
- Drilling issues
- Milling problems
- Completion requirements
- Multi-lateral requirements
- Abandonment

2.12 FLOW CONTROL AND ISOLATION OF LATERAL

To isolate the flow from lateral to the main bore can be done using various methods for e.g. using sliding sleeves, external casing packer and hydraulically sealing lateral etc.

2.12.1 Sliding Sleeves

This is a mechanical device with hole or slot which can be covered or uncovered by mechanically or hydraulically moving a sleeve inside the sliding sleeve sub.

Operation:

- Normally opened and closed using wireline - either up or down shift to open

- Coiled tubing used in highly deviated wells above 60°
- Pump open sleeves are available but wireline or coiled tubing is required to close ports

Advantages

- Tried and tested technology
- Integral landing people nipple profile for running of various tools
- Isolation sleeves can be run to shut off production if sliding sleeve fails to isolate on closure
- Flow control and sand control can be built in sizes up to 7"

Disadvantages

- Will not allow re-entry of lateral
- Downward jarring is limited in highly deviated wells
- Reliability is an issue (newer sealing materials may reduce problem)
- Requires up to 1900 lbs to move sleeve
- Seal failure due to sand

2.12.2 External Casing Packer

External casing packers (ECP's) have long sealing elements (up to 40') and afford a seal in the open hole. Inflatable external casing packers can be run on slotted pipe or wire-wrapped screen type liners. Once inside the hole, to inflate the ECP, a combination tool is located across the port, shearing the break off plug and fluid pressure is then applied.

A typical inflation pressure is 1250 psi Inflation fluids can be:

- Drilling fluids
- Completion fluid
- Cement
- Epoxy is proposed for future use

Advantages

- Ability to seal and isolate in open hole

Disadvantages

- The main disadvantage of an ECP is its reliability. Reliability depends on:
    - Failure of sealing element or non return valve

- Cement if used to inflate. excess can contaminate screens or
- Can cause formation damage. Cement expands and then contracts
- On setting causing micro channeling
- ECP's can be bypassed by flow through formation

2.13 TECHNOLOGY REVIEW

2.13.1 SCHLUMBERGER

RapidConnect System

(8) Schlumberger RAPID*—Reliable Access Providing Improved Drainage— products include the RapidConnect* multilateral completion system which provides superior junction stability and strength, improved drainage, and excellent mechanical integrity with built-in lateral access. It provides a simple, low risk system with running procedures that reduce the number of trips into the hole. The two main components, the template and the connector, lock together downhole to provide the connectivity at the junction. The resulting junction is particularly well suited to multilateral applications in unstable formations. The RapidConnect junction also uses a selective through-tubing assembly, set in the template profile, with selective access for logging or remedial work.

Reservoir flexibility-

Due to the overall strength of the connection, the RapidConnect system can be utilized in unstable formations. The junction can be set either above the reservoir to allow access to multiple layers or faulted blocks, or in the reservoir to allow multiple branch access to the same reservoir.

Applications-

- New and reentry wells
- High-Pressure High-Temperature (HPHT) Wells
- Gravel-Pack Option
- Heavy Oil Reservoirs
- Laminated Reservoirs
- Commingled Production

Benefits-

- Strong and Retrievable junction
- Stable access for the life of the well
- Reentry capability

Figure 12 : RapidConnect Multilateral System (Source: Schlumberger)

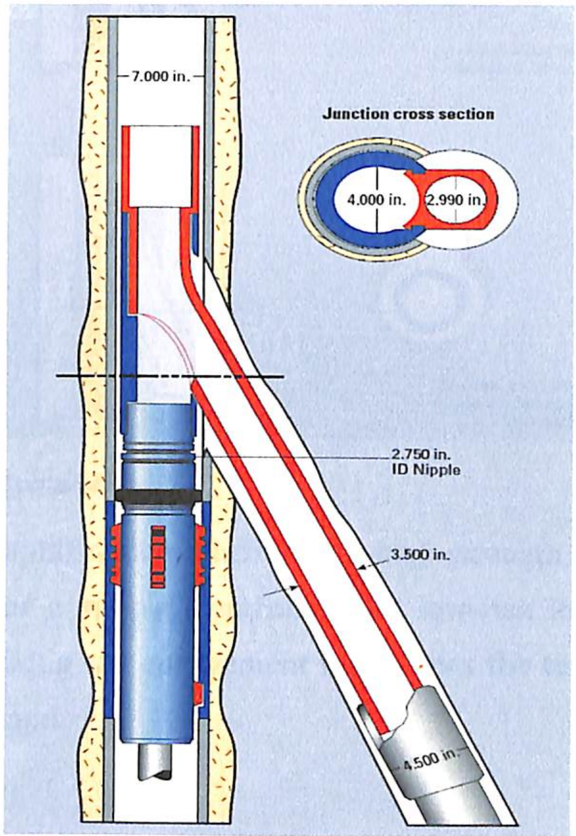
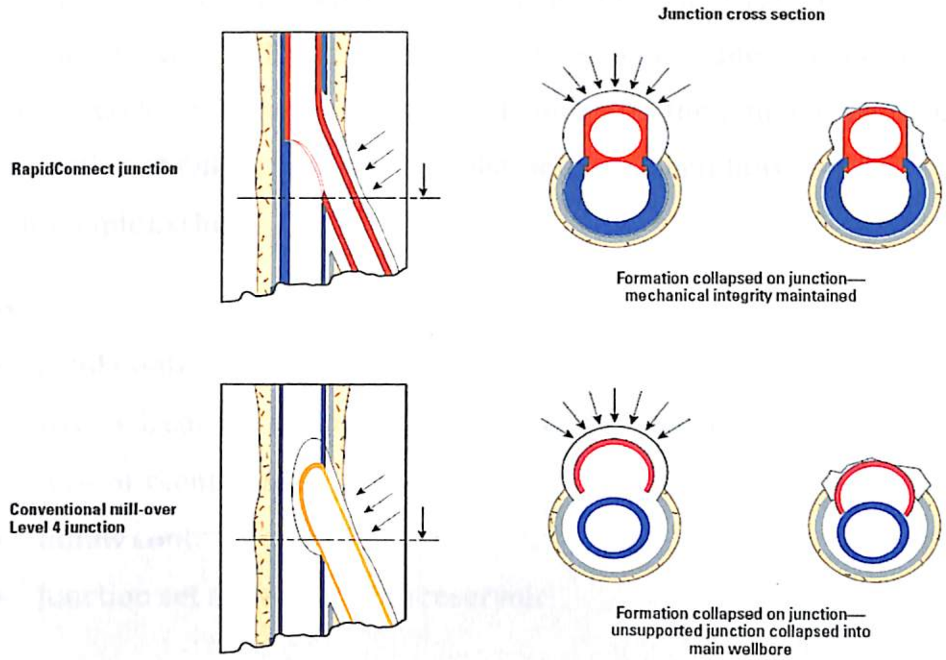


Figure 13 : RapidConnect Junction Integrity (Source: Schlumberger)



RapidExclude Multilateral Completion

(9) The Schlumberger RapidExclude junction is a high-strength junction for multilateral completions. Designed for a simple, controlled and low-risk installation, RapidExclude features a continuous locking rail engagement that allows the template and connector to act as a single barrier to sand.

Reliable access-

The high-strength RapidExclude junction provides a full-size drilling diameter, through 9 5/8-in. casing with a large size completion and intervention diameter. The junction design is an evolution of the proven RapidConnect system, to provide sand exclusion at the junction. RapidExclude assures access for the life of the well and improved reservoir drainage.

Reservoir versatility-

RapidExclude junction gives reservoir managers an additional tool for layered, compartmentalized and faulted reservoirs. If individual reservoir compartment reserves are subeconomic, a risk-managed system with the RapidExclude junction assures overall economic project NPV.

With a systematic quantitative risk assessment to identify the best location, the RapidExclude junction can be used for wells with different pressure regimes requiring inflow control or infill well drilling in mature assets. RapidExclude provides stability with a lateral exit in unstable shale cap rock and sand control at the junction with an exit in the reservoir. Formation stability, sandface completion design and flow control options are all supported with RapidExclude.

Applications-

- Sand Control
- Layered, compartmentalized and faulted reservoirs
- New or reentry wells
- Inflow control
- Junction set above or in the reservoir

Benefits-

- Full-size drilling diameter—through 95/8-in. casing
- Large-size completion diameter
- Improved reservoir drainage
- Junction stability
- Inflow control options
- Infill drilling in mature assets
- Junction collapse strength to 2500 psi

Figure 14 : RapidExclude Multilateral Completion (Source: Schlumberger)

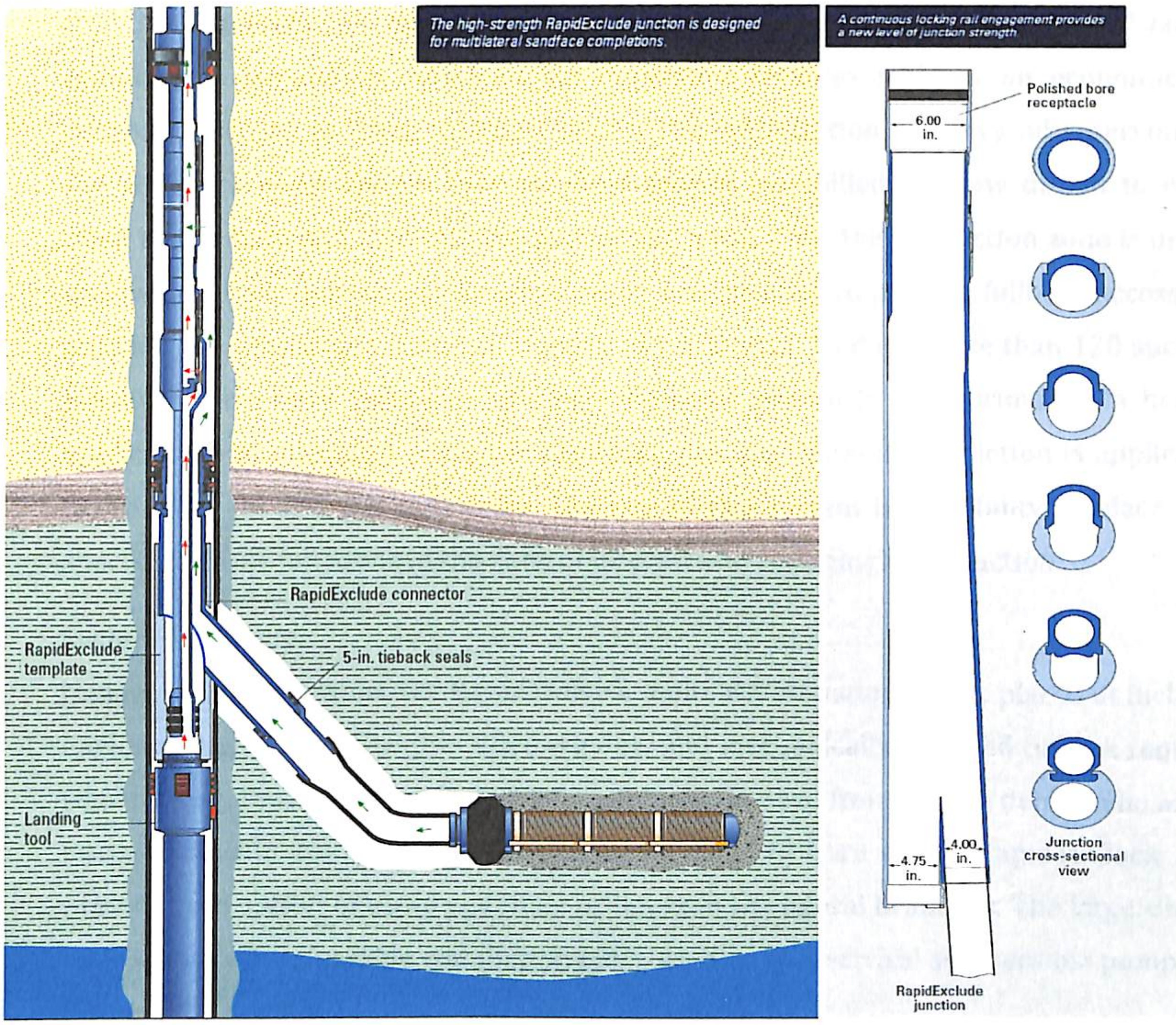
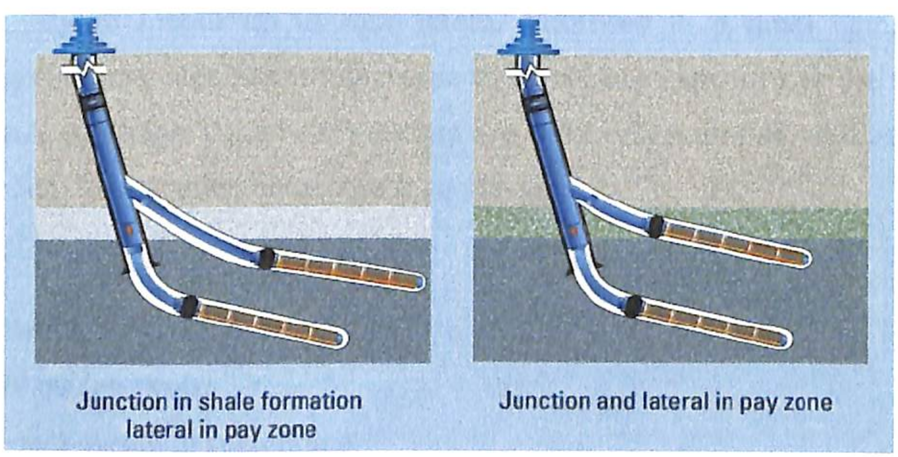


Figure 15 : Junction can be placed either above the reservoir or in the reservoir (Source: Schlumberger)



Rapid TieBack Quad System

(10) The Schlumberger RapidTieBack* quad system is a member of the RAPID* family of multilateral completion solutions. Its innovative features make it an economical and reliable approach to using multilaterals for the optimization of heavy oil reservoirs. The RapidTieBack quad system uses the field-proven pre-milled window design to exit the main casing bore and drill into the production zone. Once the production zone is drilled, a mechanical liner tieback and internal sleeve are installed to provide fullbore access at the junction for subsequent selective reentry of the lateral. To date, more than 120 successful junctions have been installed. Although the quad system is used primarily in heavy oil applications to maximize reservoir exposure, this multilateral completion is applicable in many other oil and gas reservoirs. The key to this system is the ability to place closely spaced multiple junctions in the zone of interest and commingle production.

System versatility-

In new well applications, the RapidTieBack multilateral system can be placed at inclination angles as high as 90°. The premilled window and mechanically installed tieback require no steel milling, thus reducing the risk of equipment damage from milling debris. The multiple lateral branches can be selectively accessed. The big bore of the RapidTieBack system provides the option of using openhole or liners in the lateral branches. The large-diameter liner sleeve allows passing completion tools, such as an electrical submersible pump (ESP), through the junction.

Reservoir flexibility-

With the flexibility to install up to four lateral branches in a quad completion, the RapidTieBack system can significantly increase the wellbore exposure of the reservoir to improve reservoir drainage. Other applications are tight reservoirs as well as viscous oil reserves where maximum reservoir access is required.

Applications-

- New wells
- Heavy oil reservoirs
- High-inclination branch points

- Large-diameter completion tools
- Junction set in reservoir
- Access to lateral required

Benefits-

- No casing and liner milling with premilled window
- Mechanical tieback for lateral reentry access without washover operations
- Maximized reservoir exposure: multiple large-diameter lateral branches
- Inner sleeve liner placement for the life of the well
- Big-bore access for tools through the junction

Figure 16 : Rapid TieBack Quad System (Source: Schlumberger)

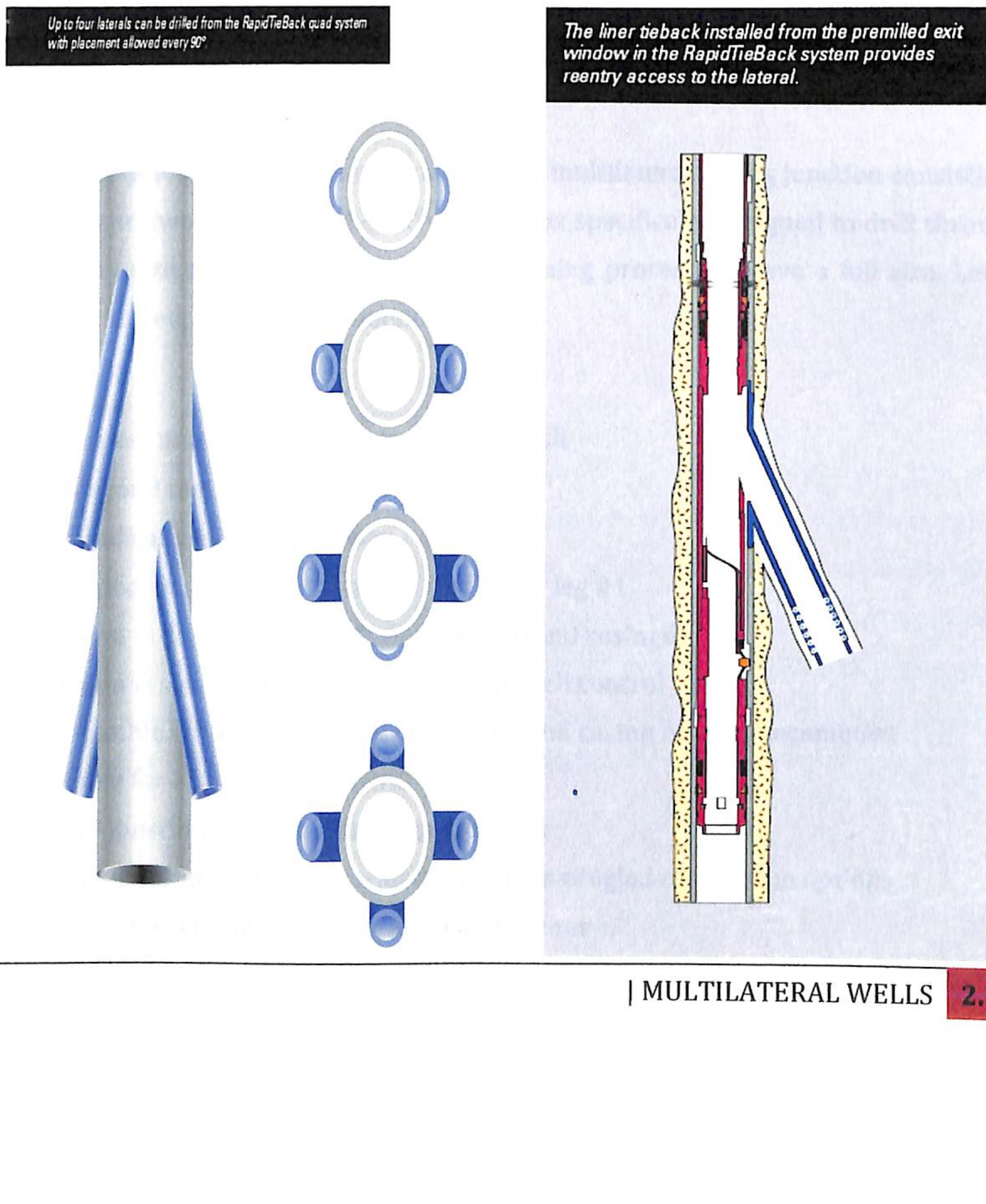
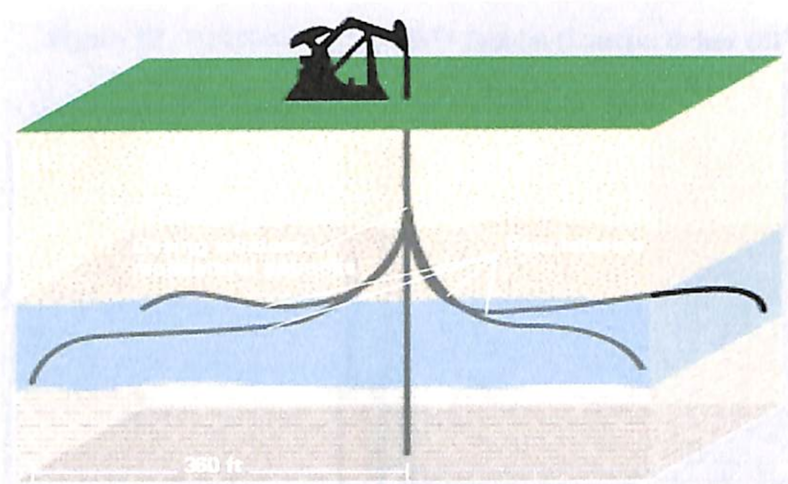


Figure 17 : Quad Multilateral Completion for Cyclic Steam Injection (Source: Schlumberger)



2.13.2 BAKER OIL TOOLS

FORMation Junction™ System

(11) The FORMation Junction™ is a manufactured multilateral casing junction consisting of a main bore and two cased branches. The system is specifically designed to drift through a smaller casing size and using a downhole reforming process, achieve a full size, Level 6 hydraulically sealed, multilateral junction.

Advantages-

- Minimizes multilateral well construction risk
- Milling and metal debris are eliminated
- Hydraulically isolated junction
- Extended length of casing can be run below leg #1
- Junction is deployed through smaller hole and casings
- Junction is sealed from the formation for well control
- Compatible with conventional cementing and casing running techniques
- Suitable for extended reach drilling
- Install junction and defer drilling of laterals
- Completion flexibility by way of dual or commingled completion options
- Compatible with Intelligent Well™ completions

- Selective re-entry into either leg of tubulars

Figure 18 : FORMation Junction™ System (Source: Baker Oil Tools)

Stackable Splitter™ System

(12) The Stackable Splitter™ is a manufactured Level Six multilateral system that allows two or more laterals to be constructed and completed from a common wellbore. Designed for wellbores that require high burst and collapse ratings, the Splitter is also suitable for high-pressure casing frac applications. A unique diverter system designed for the Splitter is dressed at surface to locate and latch in the selected Splitter. Flexible completion options allow the Stackable Splitter™ to be completed as an annular dual, a single monobore completion with commingled production or as a single commingled completion.

Advantages-

- Minimal multilateral well construction risk
- Milling and metal debris are eliminated

- High-pressure / high-temperature applications
- Splitters can be stacked for three or more laterals from one wellbore
- Inlet to the splitter is the same size as the outlets
- Splitter is sealed from the formation for well control
- Compatible with conventional cementing and casing running techniques
- Install splitters and defer drilling of laterals
- Completion flexibility
- Compatible with Intelligent Completions™
- Selective reentry into either leg of tubulars

Figure 19 : Stackable Splitter™ System (Source: Baker Oil Tools)

2.14 MULTILATERAL TECHNOLOGY: THE FUTURE

(13) There are many applications for MLT that have yet to be vigorously pursued, such as the use of MLT in exploration wells, mitigating geologic risks and navigating non-heterogeneous reservoirs. Exploration targets could be easily delineated with laterals, while access to the mainbore is maintained. The impact of geologic uncertainty can be minimized by the ability to re-drill to other positions if the original target is not as anticipated. The effects of smaller than expected reservoir drainage patterns can be reduced by putting in more "straws", effectively draining otherwise by-passed reserves. As in Niche markets such as Coal Bed Methane fields that will require dewatering and gas production from increased access through the coal seams. In some cases geologic and reservoir risk can be reduced by cost effectively multiplying the potential reservoir penetrations, i.e. taking a "shotgun" approach to reservoir development.

The future grows brighter for MLT because of its synergistic influence on other emerging technologies. The amalgamation of emerging technologies (intelligent completions, expandable tubular, advanced drilling and production systems, real-time information flow, down-hole factories, etc.) through MLT demonstrates the quantum leap of this technology from discrete MLT hardware to a production system, a leap that will address maximized reservoir understanding, production and control. This will constitute a total production system that will have a tremendous impact on the energy industry.

3. INTELLIGENT WELLS

3.1 Overview

Intelligent Wells (Smart Wells or Intelligent Well Completions, or some other such variation on this theme) can be defined as one which requires *no workover* or other *intervention* to *monitor* and *control* reservoir performance.

To achieve these ends, intelligent wells feature:

- Sensors installed downhole to constantly *monitor* wellbore characteristics in real-time
- Remotely controlled downhole valves or sleeves to *regulate flow* in one or more productive zones
- Downhole separation and re-injection to reduce water production costs at the surface
- Potential application of downhole gas compression

A well should have certain characteristics to be considered intelligent:

- Controlling flow from one or more intervals
- Capable of gathering production information
- Capable of using production information to make informed decisions that have a positive impact on a field's Net Present Value.

Most of the wells are subjected to numerous interventions for data acquisition. The cost of these interventions can mount up to become a single largest expense over life of well. Intelligent completions offer an alternative to many foreseeable interventions. The scope of intelligent wells covers *monitoring, analyzing, responding and optimizing* downhole flow. IQ of completions depends on degree of automation installed. The combination of electrical and fiber optics sensors along with connectors and downhole controls like hydraulic sleeves have significantly contributed to flexibility and improved well economics.

A number of Intelligent Well systems use electronics or fiber optics to detect and measure downhole fluid flow, reservoir pressure and temperature. Downhole flow is controlled from the surface, by way of hydraulic, electric, or electro-hydraulic actuation of downhole valves or sleeves which produce or shut-in pay zones.

Some Intelligent Wells also go a step beyond downhole sensing and flow control by providing basic downhole production processing. These wells have the means to separate water from the production stream, and re-inject it into downhole formations. By reducing the amount of water, which must be treated at the surface, some operators have been able to achieve a reduction in the size of their production platforms while also reducing the risk of surface water pollution.

The working concept of "intelligent" completions does not imply a capability for automated self-control or optimization (a concept sometimes called the *Automated Oilfield*). Overall, an Intelligent Well enables the operator to better manage their reservoir through the process of:

- Monitoring: measuring downhole parameters referenced to depth, time, and events taking place in the well or reservoir
- Analyzing: validating and comparing data to performance models of the well or reservoir
- Responding: remotely operating downhole flow control devices when changes in data are attributed to a particular problem or event
- Optimizing: pro-actively fine-tuning adjustments to downhole flow

3.1.1 Justification of Intelligent Wells

Initially, the primary justification for installing intelligent completions was to mitigate the costs of intervention. However, as intelligent well technology evolved, the industry began to improve its record on implementation and reliability. At the same time, the operators gained experience in managing their intelligent completions, and were able to realize the economic potential of reservoir optimization and improved recovery that comes from direct control of wellbore production.

By providing a system for real-time reservoir management, intelligent well technology can help the operator to recover additional reserves, assign production and determine the course of future field development (i.e., drill additional wells or change production/injection profiles). In fields that allow commingled production, the ability to manage pressures in different producing intervals allows the operator to achieve quicker payback on the well. In many such wells, this technology translates to a 2% - 15% increase in recoverable reserves.

The Benefits of an Intelligent Completion to the operator are given in Table 1.

Table 1- Intelligent Completion Benefits to the Operator

Maximizing and accelerating production	This includes commingling and reservoir management capabilities such as selective choking of individual zones, preventing cross-flow between producing zones, improving injection efficiency, and reducing water cut during long-term production.
Minimizing and eliminating intervention	This includes reducing the need for logging, maintenance, workover, and other such activities; associated benefits are derived from eliminating the cost of acquiring an intervention rig and the cost of lost production during intervention, along with reduced risks to health, safety and the environment.
Accelerating cash flow	Through optimal production, managing pressures, and minimizing costs of intervention, the operator ultimately achieves a faster payout

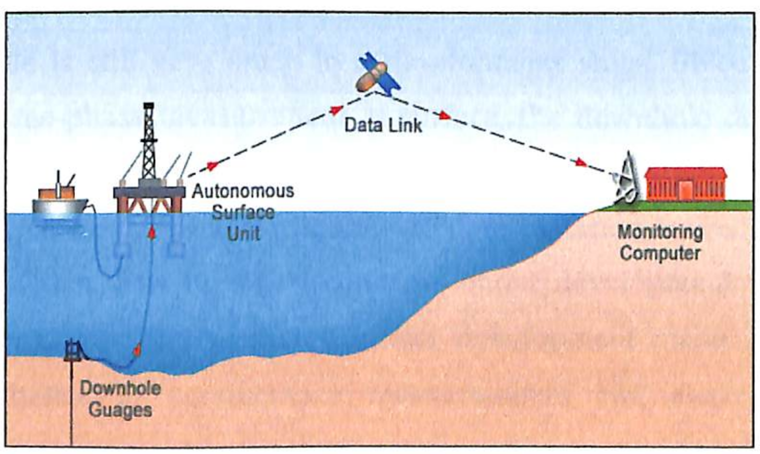
3.1.2 Basic System Architecture

In broad terms, a basic intelligent completion will consist of:

- **Downhole sensors** to measure such variables as temperature, pressure and flow
- **A surface acquisition system** to collect the data measured downhole
- **A data transmission link between the production facility and monitoring system** to control and monitor the data.

The Figure 20 shows the basic design of an intelligent well.

Figure 20- An Intelligent Well System Design



3.2 Equipments Used

3.2.1 Permanent Downhole Gauges

The permanent downhole gauges were already in use long before the term "Smart Well" became fashionable used to measure pressure and temperature.

Most used are sensors using *resonating quartz crystals:* the resonance frequency of the electrically excited crystals is a function of pressure and temperature. Recent advances include the development of *electric resonating diaphragms* which have the advantage of having no electronics down hole, and *fibre brag grating* technology which does away with electronics altogether and uses fibre optics for measurement and data transmission to surface.

3.2.2 Distributed measurement of pressure and temperature

A recent development is distributed temperature sensing (DTS). DTS employs a thin glass fibre optical cable running along the entire length of the well. Using the effect that light sent through the cable scatters with characteristics depending on the local temperature, it is possible to obtain a very accurate (0.1 degree) temperature profile along the entire well. An effective way of installation of DTS is through pumping it down through a U-tube ¼ inch control line that was run with the completion. The value of DTS measurements to interpret reservoir inflow has yet to be confirmed. A next step in distributed sensing is likely to be distributed pressure sensing (DPS).

3.2.3 Flow rate and composition meters

Its use in downhole is still very much in a development stage. Given the difficulties to obtain accurate three-phase measurement at surface, the downhole developments make take a while before they reach the stage of routine application. An exception is the use of venturi meters, which can be used for liquid rate determination in wells with inclinations up to 30 degrees. Other flow metering concepts under development include fibre brag grating technology. Compositional meters under development make use of gamma ray absorption, capacitance or conductance measurements and electromagnetic helical resonators.

Information on *downhole flow rate* and *composition* can, to a limited extent, be inferred from downhole temperature and pressure measurements in combination with surface measurements. Also, the use of downhole inflow control valves allows for the determination of flow rates from individual well intervals through closing all intervals but one and using surface measurements only ("well testing by exception").

3.2.4 Reservoir imaging

In addition to direct or indirect downhole measurement of primary production variables (pressure and flow rates), there are several developments to obtain reservoir information from other sources during the producing life of a field. Most notably is the use of *"4-dimensional" (4D) seismic*, also known as *time lapse seismic*, to achieve a picture of fluid front movements in the reservoir through observation of the differences in seismic images over time.

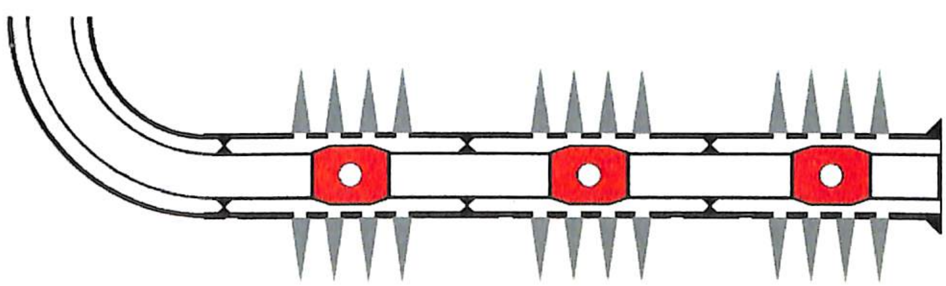
Other developments, although much more in their infancy, are reservoir drainage imaging with the aid of *continuous resistivity measurements* in a well bore or between well bores, or through listening to *micro-seismicity* (cracking) around the well bore with downhole geophones.

Yet another possibility is the use of downhole control valves to perform "*on-line well tests*", i.e. to infer information from the reservoir response to deliberately disturbed inflow into the well bore.

3.2.5 Flow and Pressure Control Devices

Downhole flow and pressure control can be achieved through the use of *interval control valves (ICVs)*.

Figure 21- Well with three perforated intervals completed with ICV's



In Figure 21, a well is completed with a perforated casing and equipped with tubing extending below the production packer (also referred to as an *extended stinger*). The well is divided in intervals with the aid of packers between the tubing and the casing, and each interval is equipped with a remotely controllable ICV. All the major service companies can provide this functionality, and various levels of sophistication – and costs - can be achieved. At the high end of the scale are electrically controlled continuously variable ICVs with pressure and temperature measurements and valve position feedback at each valve. The typical cost of such a valve is in the order of 0.5 million $.

Cheaper solutions employ valves that have a limited number of discrete valve opening settings, or can just switch between open and closed (on/off valves). In addition to electrically powered system, hydraulic systems are available.

ICVs can also be applied to wells completed with a slotted liner or a sand screen instead of a cemented casing, although this will usually lead to communication behind the casing between the intervals. Furthermore, ICVs installed in the main well bore of a multi-lateral well can be used to control inflow from branches. Obviously, the concept can also be used to control outflow from injections wells, or even cross flow between different zones in a single well bore.

3.2.6 Downhole processing equipments

The biggest development effort in downhole processing is currently in downhole water separation with the aid of cyclones. In combination with an inverted electric submersible pump (ESP) this allows for downhole re-injection, with the potential for a dramatic reduction in water production to surface. No full-field implementations have been performed to date, but several pilot tests are ongoing around the world.

Another potential future application of downhole processing is downhole gas compression.

3.2.7 Communications and power supply

Further smart well hardware developments are in the field of power and data transmission.

Signals from downhole measurement devices to surface and vice versa are, at present, sent mainly electrically or optically (via glass fibre). Recently, several experimental systems for cable-less communications have emerged.

Downhole Fiber Optics

Downhole fiber optics are based on proven technology, developed by the tele-communications industry and tested under extreme conditions imposed on transoceanic communication lines. Fiber optic cables use hair-thin fibers to transmit light over long distances. These fibers, with diameters measured in microns (10^{-6} meters), guide the light from the up-hole light source to the sensor, and back to the receiver.

Fiber optics provide a versatile means of taking downhole measurements, and several methods have been implemented for measuring physical phenomena using fiber optic sensors. The conceptual basis of fiber optic measurement is fairly simple. First, a beam of light is sent through a length of optical fiber. This light wave can be characterized by any of a number of measurable parameters, such as wavelength, intensity, phase, or polarization. As the light wave travels down the length of optical fiber, it may be affected by some external force such as temperature, or pressure, or some other such factor of interest (called the *measurand*). The magnitude of that *measurand* is inferred from the amount of change exhibited by the light wave *parameter*. In this way, for instance, a pressure reading can be obtained by measuring the intensity of a beam of light.

Fiber optic systems have proven to be relatively impervious to harsh downhole conditions, owing to a number of common inherent characteristics:

- No downhole electronics
- No moving parts
- Low component counts
- High stability
- Chemical inertness

Power to downhole control equipment is currently provided electrically or hydraulically.

Experimental developments are in the area of batteries which can sustain downhole temperatures, and downhole power generation (e.g. micro turbines driven by the production flow).

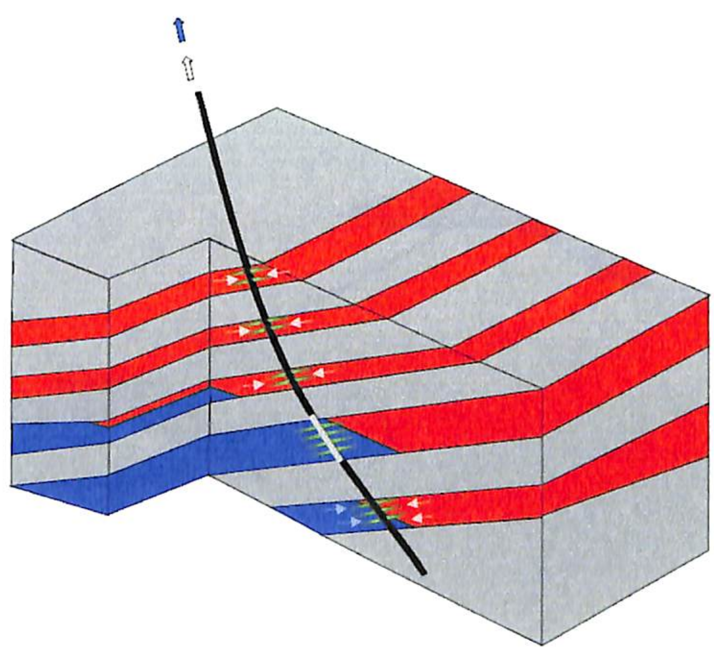
3.3 Current applications

3.3.1 Water or gas shut-off

A first example of the use of smart well technology is depicted in Figure 22. A reservoir with water drive and strong horizontal barriers is drained with a single well with perforated intervals in each separate reservoir layer. Water breakthrough in the layers does not occur simultaneously because of permeability differences. Using a completion with an on-off ICV in each interval, well segments can be shut off when water breaks through, thus reducing the amount of water to be processed at surface and preventing early lift-die out of the well.

Detection of the water could be done, in theory, by using the results from pressure and temperature sensors at the ICVs. In practice, it will probably be sufficient to assess the effect of closure of each ICV on the water production of the well at surface. A similar solution could of course be used to shut off early gas influx. In terms of measurement and control, this example relates to daily production optimization, as well as to asset management.

Figure 22- Control of Water Breakthrough in a Layered Reservoir

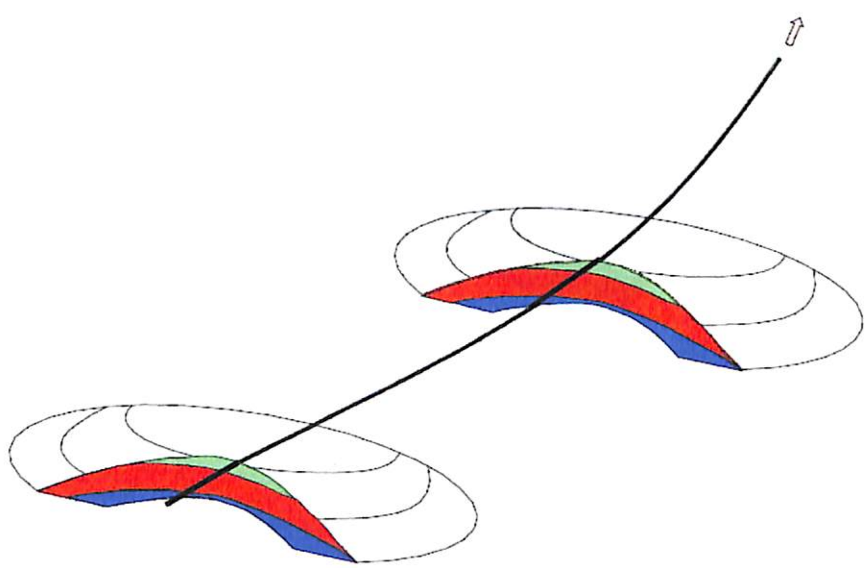


3.3.2 Commingled production

A second example is the use of ICVs to allow commingled production from zones with different pressures, through choking the inflow from the highest pressured zone with a continuously variable ICV, to avoid cross-flow to the lowered pressured zone; see Figure 23.

The alternative, conventional, scenario would be to sequentially produce the two zones, through shifting of a sleeve on wire line or coiled tubing, or through work over and re-perforation of the well. The major value of the smart well solution is in case of accelerated production, or, if production is restricted at surface, then maintaining a constant production plateau. Additional benefits are the absence of a work over, which is particularly attractive for sub-sea wells, and the possibility to produce commingled in cases were zonal pressures are equal, but where government regulation require accounting of production from different zones. In the latter case some means of flow measurement, either directly or "inferred" is necessary.

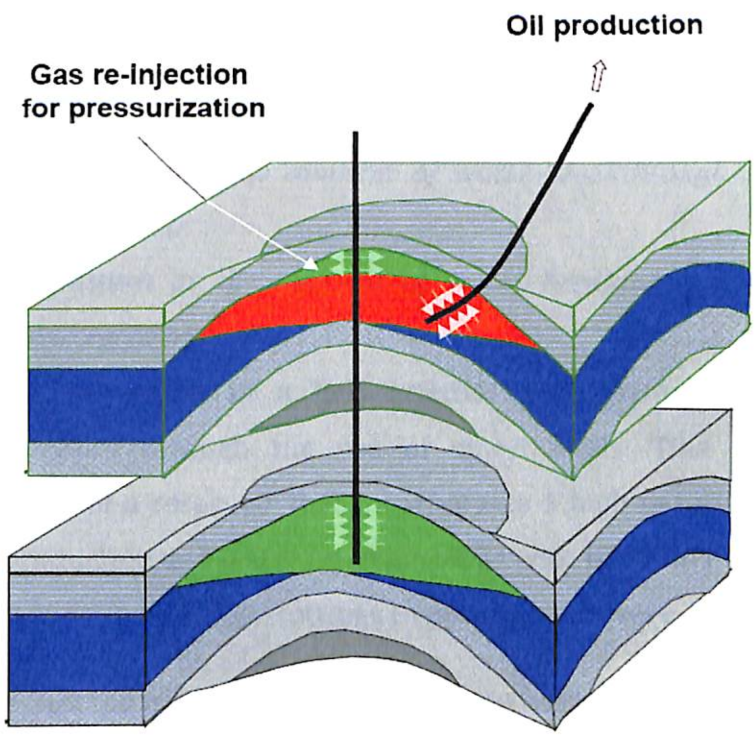
Figure 23- Comingled Production from two stacked reservoirs



3.3.3 Gas dump flooding

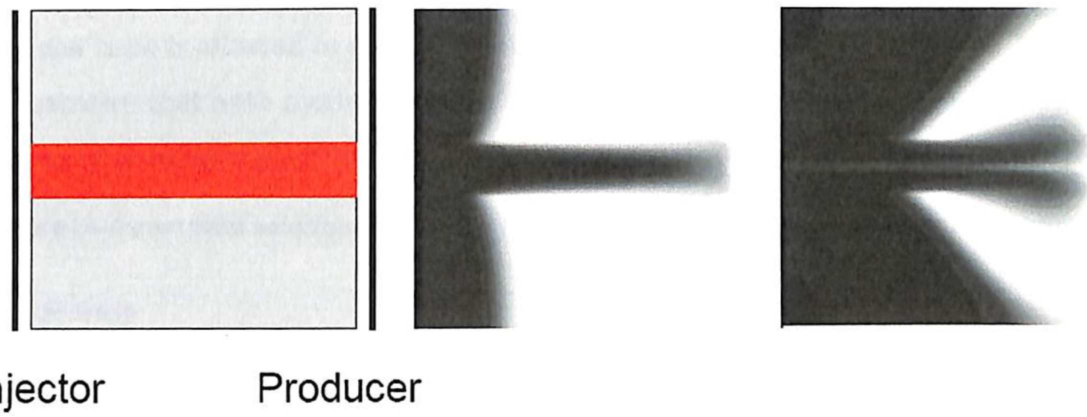
Figure 24 shows an example where a smart well is used to connect an oil reservoir with weak gas cap drive to an underlying gas reservoir with a higher pressure. Pressure sensors and a continuously variable ICV at the injection interval allow control of the "gas dump flood". In this example, a second well is used to drain the oil. Alternatively, the oil could be produced trough the same well as used for the internal gas injection, using a concentric or parallel dual completion solution.

Figure 24- Pressure maintenance in an oil reservoir through controlled gas dump flooding



3.3.4 Improved reservoir drainage

Figure 25- ***Improved water flooding of a reservoir with a highly permeable streak***



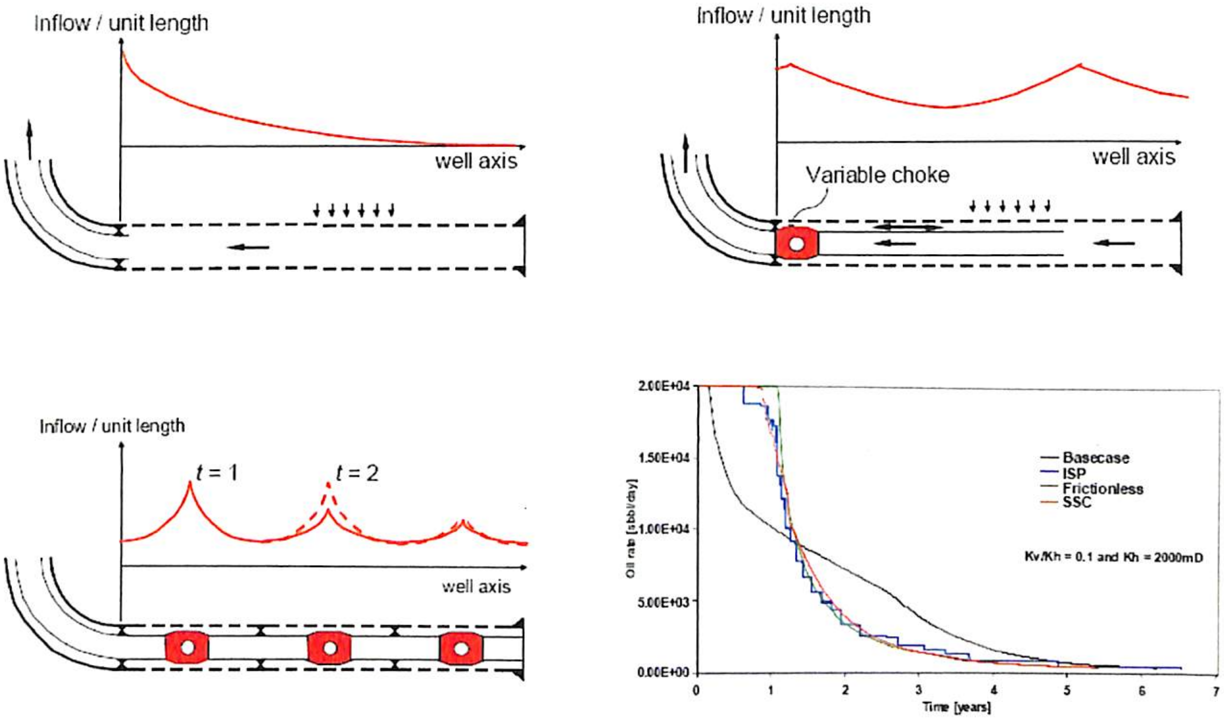
Left: top view of the reservoir with a pair of parallel horizontal injection and production wells.
Middle: Displacement pattern at the moment of water-breakthrough using conventional wells; black = water; white = oil.
Right: Displacement pattern at the moment of water breakthrough using smart wells, revealing a much higher recovery.

Figure 25 displays the results of a first attempt to improve ultimate recovery in heterogeneous reservoirs through the use of smart wells. This particular example simulates the drainage of a reservoir that incorporates a high permeable streak, using a pair of horizontal production and water injection wells with ICVs. An intuitive optimization algorithm was used to control the ICV settings to optimize recovery.

3.3.5 Counteract the effect of pressure drop in horizontal wells

Figure 26 (top left) illustrates the occurrence of a very uneven inflow along the axis of a horizontal well, caused by frictional pressure drop in the well bore resulting in a higher draw down at the heel than at the toe. This typically occurs for large-diameter, high rate wells producing from highly permeable reservoirs. As a result the well is prone to early water or gas breakthrough at the heel, and the effectiveness of the well near the toe is strongly reduced. Figure 26 (top right and bottom left) display two conceptual solutions to counteract this effect. The first one, the smart stinger completion (SSC), employs an extended stinger with one continuously variable ICV at the heel to flatten the draw down profile, and thus the inflow profile. The second method, the inflow switching process (ISP), uses a number of on/off ICVs to regularly move the point of highest draw down along the well bore. Once water or gas has broken through, that particular interval is shut off and the water or gas cone is allowed to recede before re-opening of the interval. Figure 26 (bottom right) illustrates that both methods result in an oil production behavior almost identical to that in case of an ideal well without pressure drop.

Figure 26-Smart Well solutions to combat frictional pressure drop in horizontal well bores



Top left: A conventional horizontal well, displaying decreasing inflow from heel to toe because of pressure drop along the well bore.

Top right: The smart stinger completion (SSC).

Bottom left: The inflow switching process (ISP).

Bottom right: Cumulative oil production as a function of time. The solitary line represents production for a conventional completion. The three lines close together represent production using the SSC, the ISP and production from a conventional well without pressure drop (i.e. the ideal situation).

3.4 Candidates

Wells where intervention would be difficult, or subject to ultra high re-entry costs are prime candidates for Intelligent Completions.

Wells that are fairly remote (a long distance from shore, for instance), or are inaccessible (deepwater, subsea completions), are also good candidates. Not just for deepwater wells, Intelligent Well systems also fill a niche in shallow-water, subsea wells. The cost of most subsea wells will be cheaper than those requiring surface facilities, but only if intervention can be avoided. Intervention costs, in terms of rig time and lost production, can negate the savings of a subsea tieback.

Intelligent completions can improve the economic picture for fields whose small reserve base can't support the infrastructure or intervention costs. For example, fields that hold only marginal economic promise may depend on multilaterals and downhole flow control devices to eliminate intervention costs while improving productivity and recovery. Thus intelligent completions provide an opportunity to produce reservoirs that would not otherwise be economically viable. The range of Intelligent Well candidates may include:

- Extended-reach wells
- Highly deviated wells
- Multilateral wells
- Dry-tree wells
- Wells with multiple production and/or injection zones

Basically, most wells that have producing intervals beyond the technical limits or reliability limits of conventional through-tubing slick-line and/or coiled tubing operations would probably make good candidates.

3.5 Reliability and Environmental Modeling

Reliability is the major point of concern for any permanent downhole monitoring system. Since the typical life of a producing reservoir spans at least 5 - 10 years, any permanent monitoring system will be expected to serve as long as the useful life of the reservoir.

It has already been established that the downhole environment tends to be hostile to electronic components. A study of some 900 downhole pressure and temperature systems traced approximately 40% of the failures to electronic components. In another study, that number was put at over 49%.

The failure of downhole electronic components points to problems at the chip and circuit-board level, such as inter-metallic growths, wire resonance in high vibration applications, electro-migration, and dielectric breakdown. The heat and vibration usually serve to magnify the severity of an otherwise minor flaw. Assembly related flaws, such as inter-metallic impurities in solder and metal migration in traces, are exacerbated at high temperatures. Vibration or shock can promote fatigue in solder joints and cracking failures in printed circuit board components.

Therefore, all downhole components must be designed and built to withstand each of several environmental stresses that they will encounter.

3.6 Examples of Intelligent Well Systems

Table 2- Intelligent Well System Examples

Desired functionality	System Components	Valve Example	Advantage
Access to zones below an electric submersible pump (ESP) in a land well	Surface-controlled sliding sleeve	InForce™ HCM Remote Controlled Sliding Sleeve	Economic method of achieving open/ close functionality
Multi-zone selective flow control in offshore or deepwater application	Multiple surface-controlled sliding sleeves and feed through packers	InForce™ HCM-Plus Remote Controlled Sliding Sleeve (Hydraulic)	Open/Close functionality with additional system features
Pro-active production management	Multi-position choking valves, hydraulic switching devices, feed through packers and modified completion components	InForce™ HCM-A Remote Controlled Choke (Hydraulic)	Discreet choking functionality in multi-drop application
Fully Integrated Intelligent Completion System	Infinitely variable choking valves, venturi-style mass flow meter, feed through packers, downhole wet-disconnect anchor, expansion joint, subsea connectors, and topside and subsea controller	InCharge™ Intelligent Completion System (Electric)	Infinitely variable choking valves with integrated sensors and only one wellhead penetration.

3.7 Simulation of an Intelligent Well

(14)It is crucial to be able to model and understand the impact on the field of the technology prior to installation. By modelling the entire system the ideal completion design and field location are evaluated, whilst the reservoir response to the variable choke is predicted for the life of the well. The economic value of the technology can now be understood. Previous attempts at modelling intelligent wells have crudely adjusted either perforation skin, or near wellbore permeability, to mimic the choking effect. However, the challenge is to firstly, develop a model which correctly predicts the fluid and pressure distribution throughout the completion as well as across the reservoir for each choke orifice, and then to apply the model as a reservoir management tool.

The challenge for a reservoir engineer in modelling an intelligent well is to model the change in inflow through the perforated sections for a change in choke at a specific time. In attempting to do this, the engineer usually has a limited number of options.

3.7.1 Options to model Intelligent Well

Changing Skin or Permeability Thickness Product

Model the intelligent completion as a single well and vary the **skin** or **permeability-thickness product adjacent to each perforated section.** Whilst this certainly will change the inflow into the well, it does not accurately model the actual choking process and no longer honors the completion or reservoir properties. An additional concern is that with this approach each perforation (which is treated as a simulation grid cell) is choked, rather than the perforated section upstream of the choke. How much each perforation is choked becomes extremely difficult to predict, particularly when the choke is located away from the perforated section (i.e. at a multilateral junction above the reservoir), or when the produced fluid composition is continually changing.

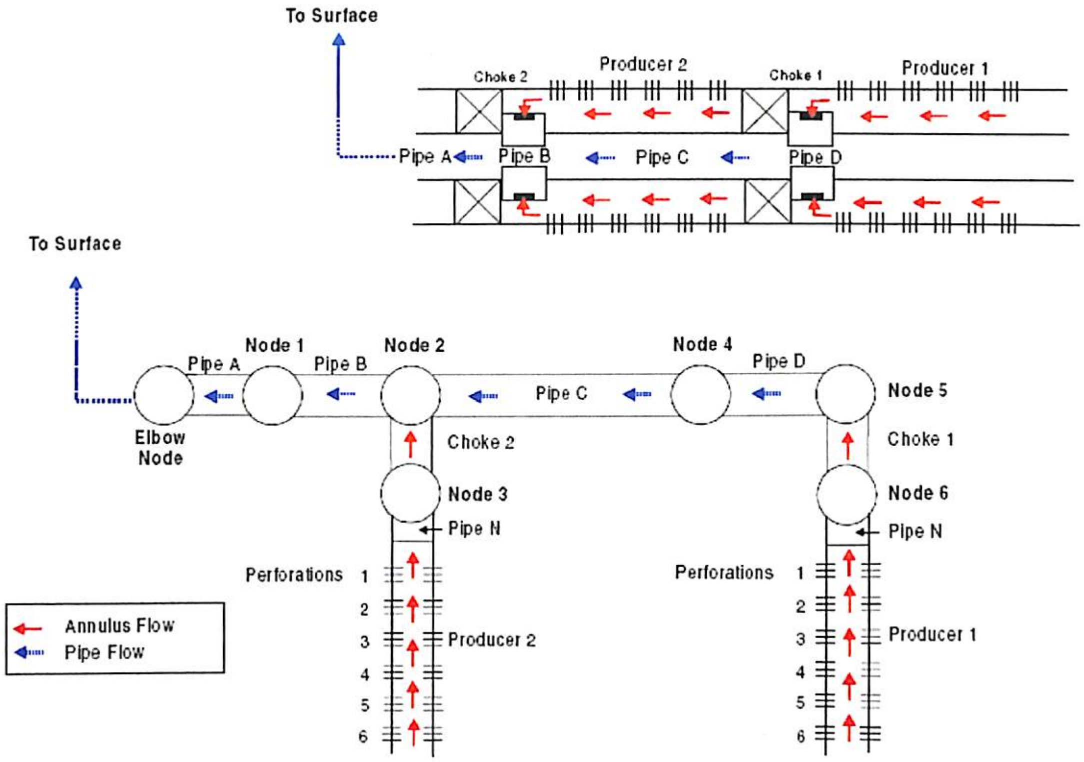
Adjusting Production Rate

A second option is to model **each choked perforated section as a separate well.** Each section is choked by either manually specifying the **production rate** of each well, or by allowing the production rate to be automatically determined from known restrictions and target criteria. In this case each perforated section inflow is correctly allocated based on the well production rate. However, as the wells are modelling a single intelligent completion, they must satisfy a common flowing bottom hole pressure (FBHP) at the junction point. The engineer must therefore manually adjust the well production rates to satisfy this common FBHP throughout the entire simulation; an almost impossible task. One additional problem is that, as neither incorporates a choke model, it is difficult to relate the observed field FBHP at the choke inlet and outlet to the FBHP's predicted by the simulation model. Fine tuning of a field choke based on a simulation prediction is therefore likely to be cumbersome.

The Network Model

The Network Model is represented in the figure below. By combining two separate wells with a surface network and incorporating a **variable choke at the heel** of each well, a dual choke intelligent well is modelled. The attraction of a choked network model is that it simulates the FBHP and multiphase flow distribution in an intelligent well, both within the annulus and tubing, for any choke position. Production from each choked section and perforation is allocated accordingly. In addition, the network model defines tubing and equivalent annulus lengths, I.D.'s, roughness factors and pipe flow correlations. Choke I.D.'s are specified at any time. The network is extremely flexible and can model a wide range of intelligent well applications purely by adjusting or incorporating new components.

Figure 27- The Network Model



The Choke Model

The Perkins' choke models is one of the flow devices available in the Surface Pipeline Network (SPN) module within Landmark Graphics' VIP reservoir simulator. The choke model can handle multi-phase flow in either the upstream or downstream direction. Given the total mass flow rates, temperature, tubing ID, choke ID, and the entry pressure, the model determines the pressure drop across the choke and indicates as to whether the flow rate is critical or sub-critical. For each choke the engineer specifies a choke correlation which relates the choke settings to the corresponding choke ID's. Then, at any time, the engineer can specify the choke setting for each choke in the network.

3.8 Technology Review

3.8.1 BAKER OIL TOOLS

Hydraulically Actuated Sliding Sleeve

(15) The Baker HCM™ hydraulically actuated sliding sleeve is based on proven technology originally developed for Baker's manually operated sliding sleeves, which have been performing reliably since 1990. The HCM hydraulic sliding sleeve is actuated from the surface by pressurizing either of two hydraulic control lines. These two control lines operate on a balanced hydraulic chamber, to actuate the "inner sleeve" of the downhole device. When pressure is applied to the "open" line, the "return" line surface valve remains open to atmospheric pressure in the hydraulic reservoir. Once shifting pressure is achieved, the inner sleeve begins to travel, exposing the equalizing slots momentarily until the valve is fully open.

To slide the sleeve closed, pressure must be applied to the "return" line while the "open" line remains open to the hydraulic reservoir. As one line is pressurized, the other line serves as a balanced line, displacing a pre-determined amount of hydraulic oil to the surface, thus providing a positive indication that the sleeve has successfully opened or closed.

The HCM Sliding Sleeve is a key component in Baker's *InForce* Intelligent Well System, which also includes permanent downhole gauges and isolation packers. The *InForce* system uses multi-feed through packers to accommodate control line passages, which allows for placement of multiple sliding sleeves. Control lines are protected by a unique cover plate that protects up to six ¼-inch lines from side load and flow erosion. The number of penetrations at the wellhead can be minimized by letting multiple sliding sleeves share the same "close" hydraulic line. Hydraulic control of the InForce system can be manual or automated, using valves and actuators linked to a SCADA control unit.

Electrically Actuated Infinitely Variable Choke

Baker's *InCharge*™ Intelligent Well System is strictly all-electric, with electronic gauges downhole, and an electric motor to drive each infinitely variable choke. By providing an infinitely variable capability, this choke allows the operator to fine tune production, rather than simply opening or shutting off a zone. Baker calls their infinitely variable choke and electric motor combination an *Intelligent Production Regulator* (IPR).

The *InCharge* system uses a common epoxy-filled twisted pair conductor to transmit electrical power and addressable digital signals to each IPR in the well. Once a particular IPR is addressed, the electrical power drives its motor to adjust the choke to any position specified by the operator. A single wellhead penetration, for a ¼-inch (0.635cm) control line, allows the operator to monitor and control up to 12 zones in a single well, and up to 12 wells from a single In*Charge* Surface Control System. This PC-based control system allows multiple target zones to be selectively brought on stream or shut off at will. Incharge system using a common epoxy filled twisted pair conductor to twisted pair conductor to transmit electrical power and addressable digital signals to each Intelligent Production Regulator. Together infinitely variable and electric motor called Intelligent Production Regulator. It can provide up to twelve zone monitoring and control. The automated control system allows multiple target zones to be selectively brought on stream or shut off at will.

Advantages of Incharge are as follows-

- All-electronic, simple design
- Eliminates hydraulics from subsea dynamic systems
- Single-penetration control line
- Infinitely variable chokes allow selective control of flow rates from individual zones
- All terminations, bypasses, feedthroughs, and splices are engineered within reliable, conventional completion components

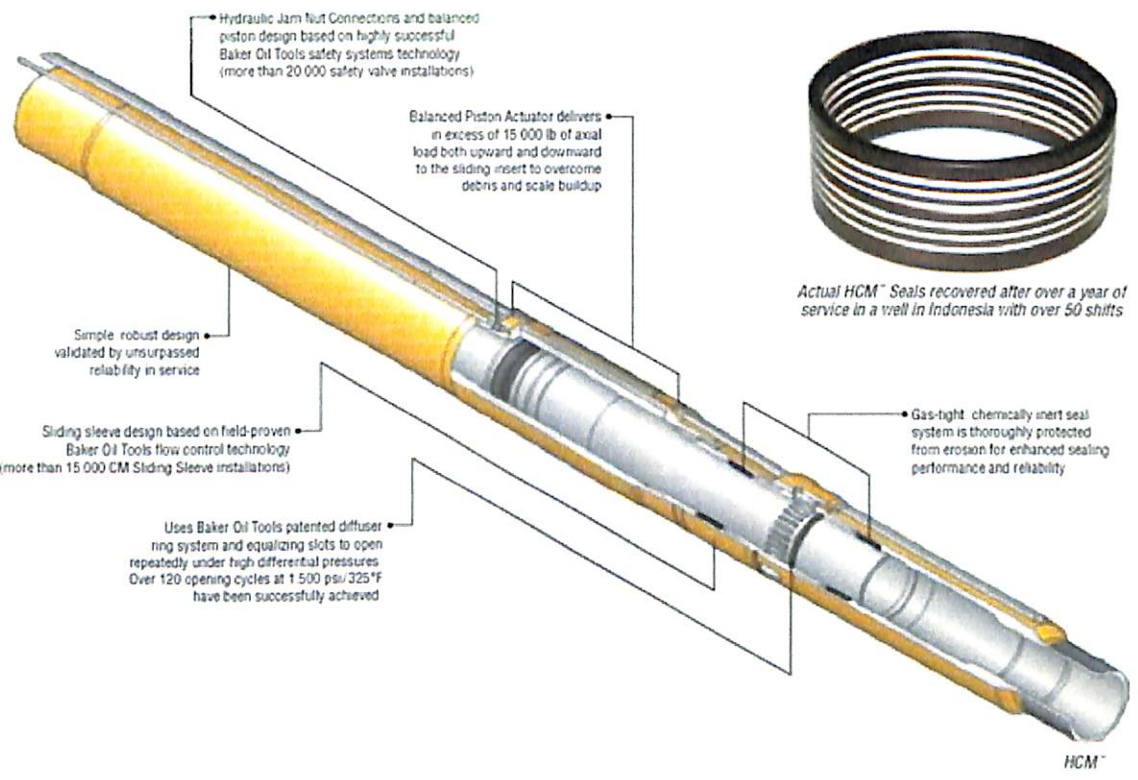
InCharge is the first intelligent completion system to use electrically powered and controlled valves and infinitely variable chokes.

It has been designed with all terminations, bypasses, feedthroughs, and splices engineered within reliable, conventional completion components. As a result, operators can achieve downhole monitoring and control without compromising proven completion designs and techniques.

The InCharge system monitors real-time measurements of pressure, temperature and flow at the sandface level(s) in both tubing and annulus. The system's infinitely variable chokes allow selective control of flow rates from individual zones. By managing production and/or injection conditions in real time and selectively controlling individual zonal flow rates, an operator can ensure continuous well optimization in response to changing conditions downhole. Flow contribution can be properly allocated, water and gas breakthrough can be controlled, and multiple target zones can be pre-completed to be selectively brought on stream or shut off at will from the InCharge PC-based control system.

The InCharge system is equally applicable to vertical, deviated and horizontal wells, completed on land or offshore, from platforms or subsea. One aspect of the InCharge system that is particularly valuable to subsea operators is the single control line that penetrates packers and wellhead. Combining power transmission, command and control, and data transmission in a single, ¼-in. penetration delivers simplicity without sacrificing functionality. From this control line, the operator can monitor and control up to 12 zones in a single well, and up to 12 wells from a single InCharge Surface Control System.

Figure 28- HCM Remote Controlled Hydraulic Valves



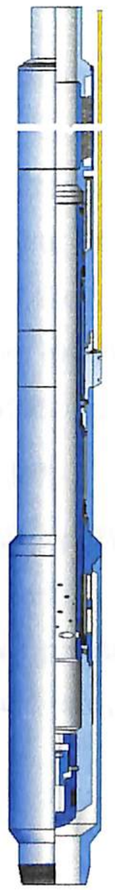
3.8.2 SCHLUMBERGER

(16) Schlumberger's tubing-retrievable flow control valves (TRFC) provide the foundation for their approach to downhole flow control in intelligent completions. These valves use proven technology based on Camco's surface-controlled subsurface safety valves. Schlumberger makes electric (TRFC-E), as well as hydraulic (TFRC-HN) flow controllers.

Hydraulically Actuated Choke

The TRFC-HN hydraulic model can be further subdivided into two models: the TRFC-HN-LP for tubing production, and the TRFC-HN-AP for annular production. A single 0.25-in hydraulic control conduit from the surface is used to actuate the choke section of the tool by way of pressure cycles that incrementally shift the valve to 11 different positions, ranging from fully open to fully closed. These systems are for completions where severe erosion is expected.

Figure 29 : TRFC-HN-LP Tubing Retrievable Flow Control Valve



Electrically Actuated Choke

The TRFC-E uses a dedicated electronic surface system to adjust the downhole choke. The TRFC-E provides precise flow control within 1% of full-scale travel Infinite adjustment of the integral choke. Operating current comes from a single electric cable permanently attached to the outside of the tubing. The TRFC-E, which is mounted on the tubing, can be installed in multiple-unit completions for a fully automated reservoir monitoring and control system. An electric downhole system allows the operator to monitor the position of the valve, and to open the valve to an infinite number of positions. The TRFC-E minimizes the number of wellhead penetrations, and by using the Schlumberger power and telemetry bus architecture, it can be connected to the same control line as other reservoir monitoring and control devices, such as permanent gauges and tubing-retrievable flow controllers. With a dedicated Internet connection, this system can be controlled remotely from any location in the world.

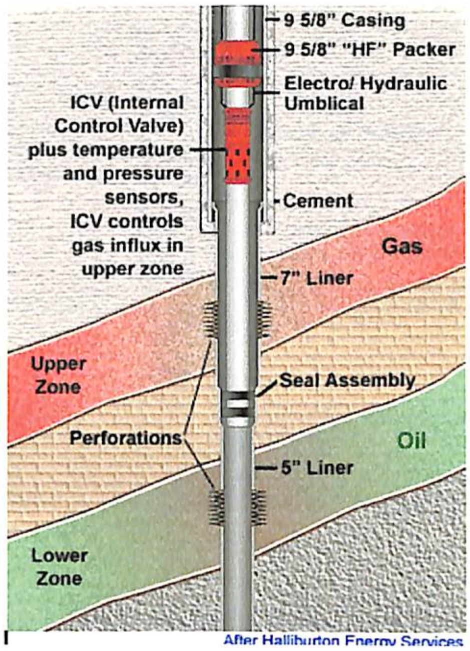
3.8.3 HALLIBURTON/PETROLEUM ENGINEERING SERVICES/WELLDYNAMICS

(17) During the late 1990s, Petroleum Engineering Services, Ltd (PES) of Aberdeen, developed a hydraulically actuated sliding sleeve, called the Interval Control Valve. Their intelligent well technology attracted the attention of Halliburton, which acquired PES in 2000. In 2001, WellDynamics was formed out of a joint venture between Halliburton and Shell Technology Ventures to capitalize on the intelligent completion expertise shared by its parent companies. The IV-ICV is now marketed by WellDynamics as part of their SCRAMS® (Surface Controlled Analysis and Management System) completion system.

Infinitely Variable-Interval Control Valve (IV-ICV™)

The Infinitely Variable-Interval Control Valve (IV-ICV™) is an electro-hydraulic variable choke designed for high-pressure drop, severe cavitation applications. The choke is a tungsten carbide, caged-sleeve design that provides a metal-to-metal seal. Locking dogs also enable the tool to fully close and seal without maintaining hydraulic pressure. An example installation is as shown.

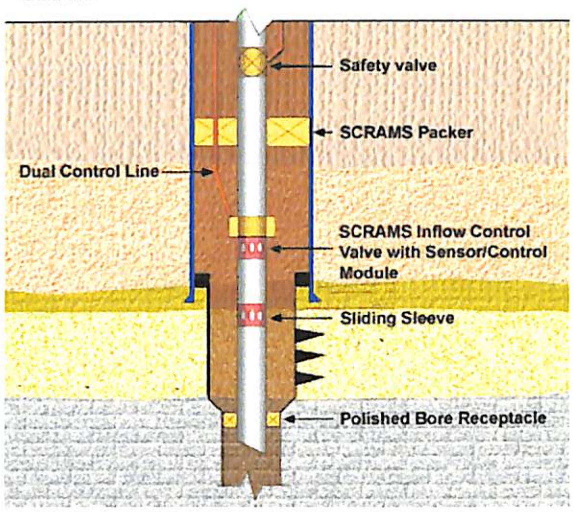
Figure 30 : Example Installation of ICV



From the Surface Control Unit, the operator can monitor, control, and communicate with downhole tools and sensors to make small, incremental changes in the flow area. Integral to the valve is a state-of-the-art Sensor Actuator Module (SAM) that monitors internal and external pressure of the valve and controls the position of the IV-ICV. Fine control of the hydraulics used to actuate the choke is achieved through an Accupulse accumulator system. This system accumulates and dispenses the exact quantity of hydraulic fluid required to overcome fluid compressibility and temperature variations commonly found at the end of thousands of feet of hydraulic line.

The IV-ICV is a key component in WellDynamics SCRAMS® completion system. This system features complete redundancy - from the twin encapsulated umbilicals taking hydraulic and electrical power from surface, to the infinitely variable downhole chokes and pressure gauges. The SCRAMS system is electro-hydraulic and can control up to 127 addressable downhole devices.

Figure 31 : SCRAMS® Completion System Installation



Mini-Hydraulic System

The Mini-Hydraulic System can control multiple downhole flow control devices, using just a single dedicated hydraulic line for each device. Tools with more than one operating mode or position may be adapted for use with this system including tubing-mounted ball valves and sliding sleeves. The Mini-Hydraulic system can also be used with devices constructed with two-way piston (open/close) actuators to provide force in either direction in response to differential pressure across the piston.

The Mini-Hydraulic system operates in the range of 10,000 to 20,000 lbs. of force, for driving the flow control device in either direction. These high driving forces ensure reliable operation to overcome friction when environmental conditions such as scale and corrosion build up over time.

Digital Hydraulic System

The Digital Hydraulic System is a closed-loop control system that transmits digital (binary) code over the hydraulic control lines to command the SmartWell suite of downhole tools. The digital hydraulic concept uses the logical presence or absence of pressure to communicate between the surface controller and downhole tools, such as on /off interval control valves or variable interval control valves.

This system only uses three hydraulic lines, but by applying pressure to different combinations of these lines, an operator can independently control up to six different downhole devices.

4. INTELLIGENT MULTILATERAL WELL TECHNOLOGY

4.1 Need for Intelligent Completions in Multilateral Wells

(18) Multilateral wells offer a cost-effective method of extending contact with the pay zone in single reservoirs and accessing different reservoirs in a multi-reservoir field. Yet multilaterals face challenges from potential early water or gas breakthrough in any of the branches, cross flow and difficulty in accurately allocating production from each branch. Intelligent Well Systems mitigate these challenges and enhance the value of multilateral wells by providing independent monitoring and control of the different branches.

4.2 Influence of High Pressure Drops

A high pressure drop along the horizontal well length is possible in the case of high viscosity fluids such as heavy oils and tar sands. High pressure drop is also possible for light oils if flow rates are in excess of a few thousand barrels per day, i.e., flow rates of the order of 10, 000 to 30, 000 RB/day. Such high rates are possible only in high-permeability reservoirs where permeability is of the order of 1000 md or more. In these reservoirs, pressure drawdown from the reservoir to the well bore can be very small, and can be comparable to pressure drop through the horizontal wellbore. In such cases, beyond a certain length, drilling a longer well would not yield any additional production.

In reservoirs with gas and water coning problems, an excessive pressure drop through the wellbore may enhance the tendency of gas and water to cone rapidly at a point of minimum pressure in the horizontal well, i.e., at the producing end of the wellbore.

As noted earlier, a large pressure drop through the horizontal section would occur mainly in high-permeability reservoirs. In such reservoirs, flow rates are not restricted by well productivity, but rather by flow-string pressure drop limitations. In such high-productivity reservoirs, the reason for drilling a horizontal well should be critically reviewed. In high-permeability reservoirs, water and gas coning problems are minimal. In these reservoirs, a horizontal well can be drilled to reduce coning and enhance oil cuts, but the gain in performance by drilling horizontal wells instead of vertical wells will not be as significant as in a low-permeability reservoir.

4.2.1 Remedies to Minimize High Wellbore Pressure Drops

Several different steps can be taken to minimize pressure drop through the wellbore.

1. High pressure drop occurrence is mainly due to turbulent flow in the wellbore. To minimize the wellbore pressure drop, it is desirable to have laminar flow through the wellbore, or at least to have the minimum possible flow velocities through the wellbore. One way is to consider drilling the largest possible size hole. For example, in the case of a medium-radius well, one can drill as small as a 4.5" hole to as large as 9.5" hole. In the case of a long-radius well, one can even drill a 12.25" hole. After choosing the largest possible hole size, one can also choose the largest possible liner sizes that can be safely inserted in a hole without getting stuck. For a given production rate, by increasing the well diameter two fold, the pressure drop can be reduced by at least thirty-two-fold. This is because, at least for single phase flow, the pressure drop is inversely proportional to the fifth power of the diameter [$\Delta p \propto 1/d^5$].
2. Pressure drop along the well length can be minimized by controlling fluid production rates along the well length. This can be accomplished by manipulating the area open for fluid entry into a wellbore, if the well is to be completed using a slotted or predrilled liner, one can vary the hole or slot sizes along the well length so as to minimize pressure drop along the well length. In the case of a cemented hole, one can change not only shot density, but also perforated interval length to minimize pressure drop along the length.
3. In a high-permeability formation, where pressure drop through a horizontal wellbore is comparable to the reservoir pressure drawdown, a gravel pack will probably be used to complete the well. In such cases, if the well is completed with a perforated liner, then fluid entry points into the wellbore, i.e. slots should be placed as far apart as possible. This will let the gravel pack act as a "choke" for each slot and facilitate maintaining minimum pressure drops along the well length.

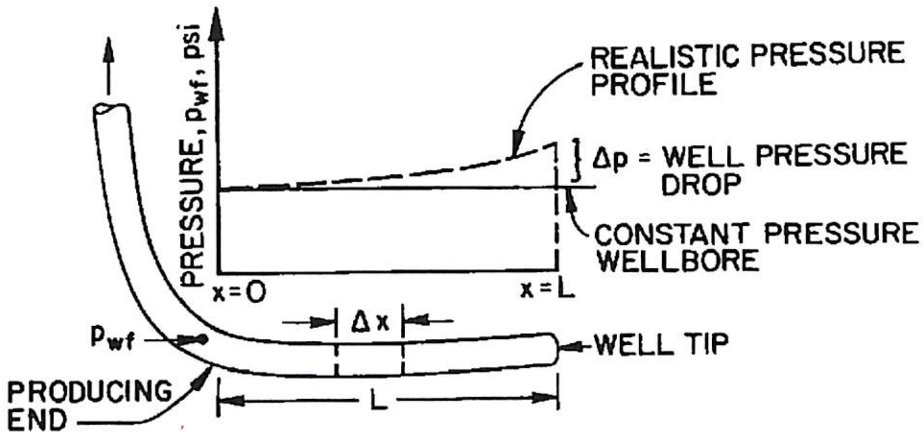
Thus, if wellbore pressure drop is found excessive, then in the well planning stage an appropriate completion scheme can be designed to minimize wellbore pressure drop.

Hence, before finalizing horizontal-well drilling and completion plans, it maybe worthwhile to calculate wellbore pressure drop.

4.2.2 Pressure Drop through a Horizontal Well

The heel to toe effect is a result of the friction pressure drop causing a variable draw-down along the well. In the heel of the well, the fluid meets less resistance compared to the fluid from the toe, because this fraction is also exposed to friction pressure drop along the length of the completion interval.

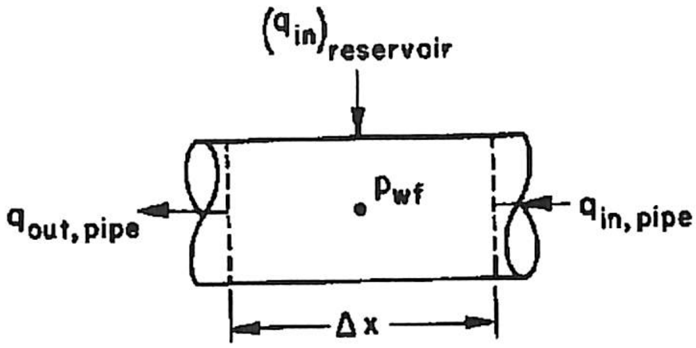
Figure 32- Schematic Diagram of pressure loss along the well length



$$\frac{dp}{dl} = \left(\frac{dp}{dl}\right)_{gravity} + \left(\frac{dp}{dl}\right)_{friction} + \left(\frac{dp}{dl}\right)_{acceleration}$$

Equation 1- Pressure drop calculation in a pipe

Figure 33- Schematic Diagram of Pressure Loss and Flow Relationships between Reservoir and Pipe Flow



Where dp represents pressure drop and dl represents incremental length. Assuming gravity and acceleration terms negligible in a horizontal section of pipe and the flow is fully developed, the equation reduces to,

$$\frac{dp}{dl} = \left(\frac{dp}{dl}\right)_{friction} = \frac{-f_m \rho v^2}{2 g_c d}$$

or

$$\Delta p = \frac{-f_m \rho v^2}{2 g_c d}$$

Equation 2- Single phase pressure drop through a pipe

Where f_m = friction factor, dimensionless

ρ=density of fluid, lbm/ft^3

v= velocity of fluid, ft/s

g_c= gravitational constant, 32.2 lbm-ft/(sec^2-lbf)

d= diameter of pipe, ft

Δp= pressure drop, lbf/ft^2

l= Well Length, ft

Equation 2 can be re written as follows for single phase flow of oil through a horizontal wellbore.

$$\Delta p = (1.14644 \times 10^{-5}) \frac{f_m \rho q^2 l}{d^5}$$

Equation 3- Single phase flow of oil through a horizontal well bore

Where f_m= Moody's friction factor, dimensionless

ρ=density of fluid, gm/cc

q= flow rate at reservoir conditions, RB/day

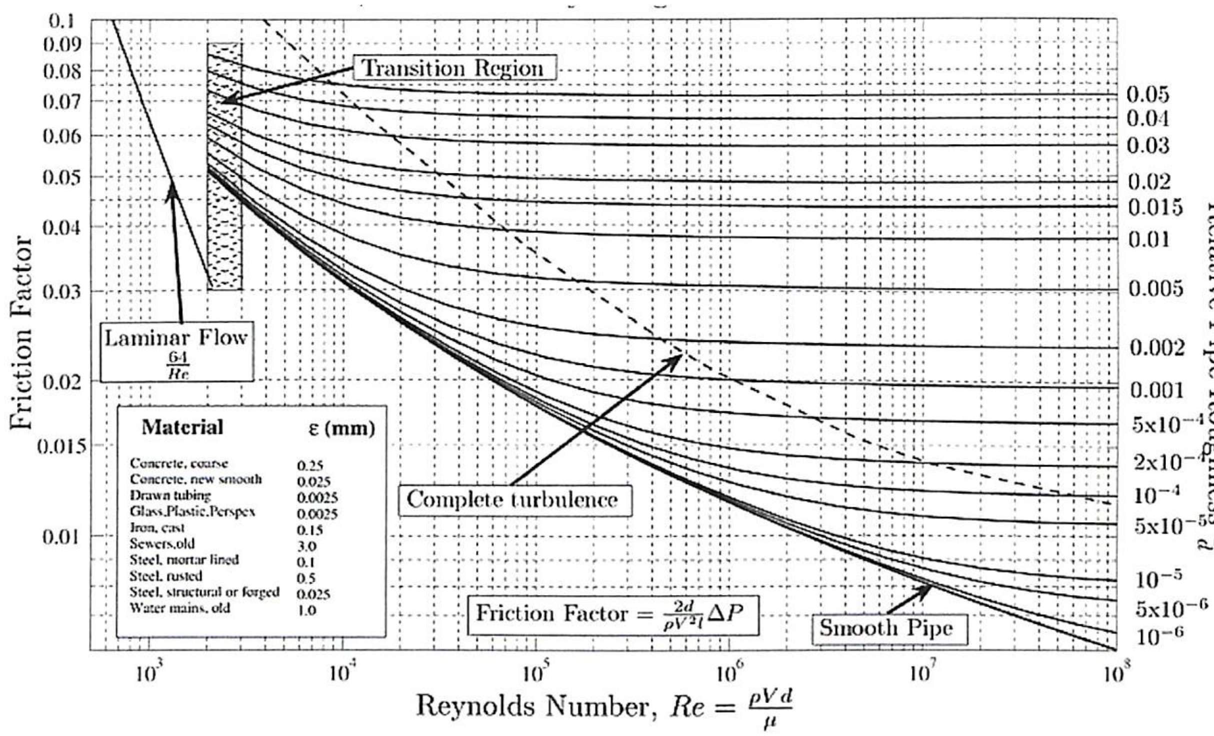
l= Horizontal length, ft

d= Internal pipe diameter, inches

Δp= pressure drop, psia

In Equation 3, the pressure drop is defined as a positive quantity along the flow direction.

Figure 34- Moody's Friction Factor Chart



The friction factor depends upon flow regime, i.e. whether flow is laminar or turbulent. In turbulent flow, the friction factor strongly depends upon pipe roughness, e/d. For flow through a circular pipe, laminar flow occurs when the Reynolds number (Re) is less than 2300. Thus

- For laminar flow: $Re < 2300$
- For turbulent flow: $Re > 4000$
- For transition region: $2300 < Re < 4000$

Where, Re = Reynolds number = $\rho dv/\mu$

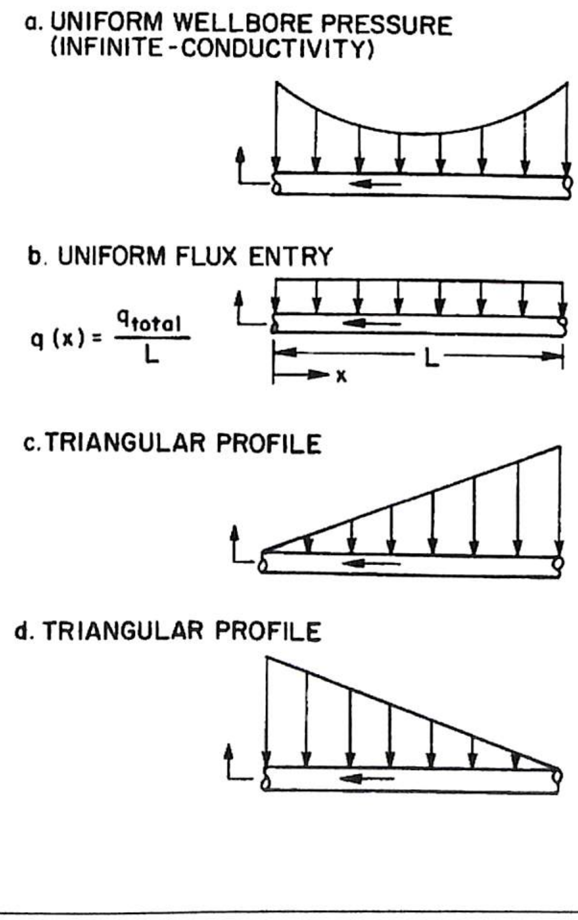
An optimum well length can be calculated by considering pipe pressure drops and reservoir production rates for the changing drawdown along the well length.

In practice it is important to estimate pressure drop along the well length. This pressure drop not only has impact on the production behavior of the well, but also influences well completion and well profile design.

4.2.3 Influence of Fluid Entry profile on Pressure Drop

Pressure drop through a horizontal wellbore depends upon the fluid entry profile. The uniform flux profiles assumes same amount of fluid entry per unit length of the horizontal well. Depending on the well boundary conditions either infinite conductivity or uniform flux, different flow profiles for the fluid entry into the wellbore are possible. Several other fluid profiles are possible depending upon the reservoir heterogeneity along the well length and pipe frictional pressure drop.

Figure 35- Fluid Entry Profiles in the Horizontal Well



Case 1- Uniform Flow Distribution Figure 35 (b)

$$q(x) = \frac{q_{total}}{l}$$

Case 2- Flow Distribution linearly increases Figure 35 (c)

$$q(x) = \frac{2xq_{total}}{l^2}$$

Case 3- Flow Distribution linearly decreases Figure 35 (d)

$$q(x) = \frac{2(l-x)q_{total}}{l^2}$$

4.3 Operating Philosophy and Control of Intelligent Well Completion

(19)Integrating intelligent well completion with multi-lateral well technology provides a tremendous opportunity to understand reservoir behavior and take proactive actions to maximize hydrocarbon recovery. However, the anticipated benefits are achieved only if proper control processes are implemented. The control processes involve the establishment of practical operating philosophy which is tied to the main reason of implementing the technology. The control actions have end goals such as optimizing recovery process.

Optimizing recovery process with multi-lateral intelligent well system requires understanding downhole mechanisms. This in-turn requires the need to install necessary downhole equipment that will provide the information that will be used to dictate the control process. Adequate downhole equipment is a necessary but not sufficient condition to achieving an optimized control process. Other equipment, such as surface control units and module, will have to be integrated with the completion system. In addition, project personnel must be trained to develop competence and skill to manage the technology. The system ownership with respect to decision making and implementation must also be clearly defined.

There are really no hard and fast rules relating to selecting the number and kind of downhole equipment for a multi-lateral intelligent well system, though, adequate understanding of the main drivers and experience from similar applications will help in selecting a fit for purpose system. The control process is often driven by a decision module managed by an applicable optimization routine. For instance, when trying to optimize zonal production contribution from different segments of a multi-lateral IWC, the settings of the downhole valves must be determined based on downhole information such as pressure, temperature, fluid properties, fluid volumes, etc. The well and reservoir will then respond to the implemented controlled actions. The response time depend on several parameters. The implemented optimization routine will depend largely on the anticipated response time. A feedback control process is effective in managing a fast response system. For slow loop processes, such as optimization of recovery from a reservoir, feed forward control process must be considered. The process relies on the ability to accurately model and predict the response of a system or process to a perturbation or change in parameters.

The surface control unit offers the flexibility for remote control of flow control devices and monitoring of reservoir data. It also offers the capability to collect, consolidate and distribute downhole sensor data and surface facilities equipment related to the management and analysis of the reservoir. The unit can take many forms depending on application environment and operator requirements. This could vary from fully automated system requiring minimal human interference to manual portable system. It is important that appropriate system is selected to meet the control expectations. As an example, a movable manual portable surface system should not be expected to provide a feasible solution to an application that requires real time reservoir monitoring and management. Such application will benefit most from an automated surface control unit.

4.4 Downhole Flow Control

The optimization of inflow performance in long horizontal open hole completions involves several challenges. One is the formation damage and well clean-up. Another is the heel – toe effect caused by flow friction in the pipe, resulting in risk of gas or water coning in the heel and limited drainage from the toe. Due to such effects, horizontal wells may suffer from reduced PI and reserves left behind.

The introduction of Inflow Control Device (ICD) technology has proved to significantly increase the recoverable reserves from many fields. The ICD provides a controlled pressure drop which is a function of the flow rate. This restricts high producing zones and thus stimulates low producing zones, resulting in:

- Improved well clean-up reducing the effect of formation damage caused by the drilling of the well.
- Equalizing the flux along the well path, giving reduced coning effects.
- Reduced annular flow. This reduces the risk of sand production behind the screen and subsequent plugging or erosion.

4.4.1 ICD and ICV

(20)**ICV (Interval Control Valve)** is a downhole flow control valve which is operated remotely (from the surface) through a hydraulic, electric or electro-hydraulic actuation system. They are used, for example, to actively control inflow from (or injection to) multiple completion intervals (zones) in a common reservoir or different reservoirs.

ICD (Inflow Control Device) is a passive flow restriction mounted on a screen joint to control the fluid flow path from the reservoir into the flow conduit. An ICD's ability to equalize the inflow along the well length is due to the difference of the physical laws governing fluid flow in the reservoir and through the ICD. Each provider of this technology has a unique design for the pressure drop creation. These currently include: Nozzles, Orifices, Tubes and Helical and Labyrinth Channels. The size of the ICD's restriction is set prior to or at the time of well completion. Options for later adjustment of the flow restriction's diameter are not currently available without intervention. Despite this, ICDs have been installed in hundreds of wells during the last ten years and are now considered to be a mature, well completion technology.

Development of ICV/ICD

The drivers that gave rise to the development of the ICV and ICD technologies were quite different. The first ICV applications were to allow the controlled, commingled production of multiple reservoirs via a single flow conduit; while ICDs were developed to counteract the "heel-toe" effect discussed above. The application area of both technologies has increased dramatically since these early applications. Reservoir studies and subsequent field experience have confirmed the value of both ICD and ICV application to mitigate inflow or injection imbalance and to optimize well and field management.

ICD-ICV Comparison Framework

The reasons behind the choices made are summarized as follows:

1. ***Uncertainty in reservoir description*** – ICVs prove to deliver higher recovery and reduced risk compared with ICDs due to its ability to adjust to unforeseen circumstances.
2. ***More flexible development*** – ICVs have more degrees of freedom than ICDs, allowing more flexible field development strategies to be employed. Both proactive and reactive control can easily be applied with an ICV while real time optimisation can only be achieved with an ICV.
3. ***Number of controllable zones*** – The maximum number of ICVs installed in a single completion to date is six. On the other hand, the number of ICDs which can be installed in a horizontal section is only limited by the number of packers, cost and/or drag forces limiting the reach of the completion string.
4. ***Inner flow conduit diameter*** – The larger flow conduit diameter gives the ICD an advantage over ICV since the ICV's reduced inner flow conduit diameter increases the "heel-toe" effect compared to an ICD for comparable borehole sizes.
5. ***Formation permeability, fluid phases, production/injection rates & productivity variation*** – Both ICVs & ICDs are capable of equalizing the inflow from (or outflow to) heterogeneous reservoirs. ICD application in low permeability reservoirs greatly reduces the well productivity unlike ICVs. A high ICD strength may be needed to achieve a high level of inflow uniformity which in turn may reduce the overall well productivity or injectivity. However, simultaneous analysis of other parameters such as fluid phases along with the formation permeability is often required to decide which of the two technologies to select:
   - The appropriate degree of inflow equalization must be determined in cases where complete inflow uniformity is not required. E.G. when the distance between the wellbore and the original or an invading fluid front varies significantly along the wellbore length.
   - Both ICVs and ICDs can equally be used to manage produced oil and gas or injected gas flow distribution. However, ICDs are more useful in reducing

volumes of associated gas cap gas or water production while ICVs may require frequent actuation (i.e. application of a controller at short time intervals) to manage the high associated gas production rates.

- Oil-water emulsions can form due to the shear created by high velocity fluid flow within an advanced completion incorporating a small diameter flow restriction. This emulsion causes the fluid's viscosity to increase and hinder the well's outflow performance.
- The pressure drop/liquid flow rate relationship is largely linear across the reservoir and quadratic across the ICD or ICV. The ratio of these pressure drops and the subsequent flow rate is the main factor in the ICD and ICV completion's design. However, unlike ICVs, the fixed nature of ICD completions makes its "equalization" efficiency highly dependent on the operating flow rate. This efficiency will decrease if the well operates at a lower flow rate from the design flow rate.
- ICD completions can control many intervals within a zone as well as a number of zones of varying productivity along the wellbore. The limit to such completion is the minimum ICD restriction size that can practically be applied with the minimum risk of erosion, plugging or emulsion creation potential. ICV completions are limited by the number of valves that can be installed in a single completion.

6. ***Value of information*** – Indications of gas and water influx or rate allocation is an advantage which can be gained in both ICV and ICD completions when equipped with appropriate gauges. Recently, fibre optic for Distributed Temperature Sensing (DTS) was also installed in an ICD completion. However, the value of information from ICVs can be increased due to the ability to remotely control the flow rate of individual zones in addition to measuring data. This gives ICVs the advantage over ICDs.
7. ***Multilateral well applications*** – ICVs can currently only be installed in the well's mother bore due to limitations of available control umbilical technology to connect to both the mother bore and laterals at the junction. ICDs can be installed to equalize

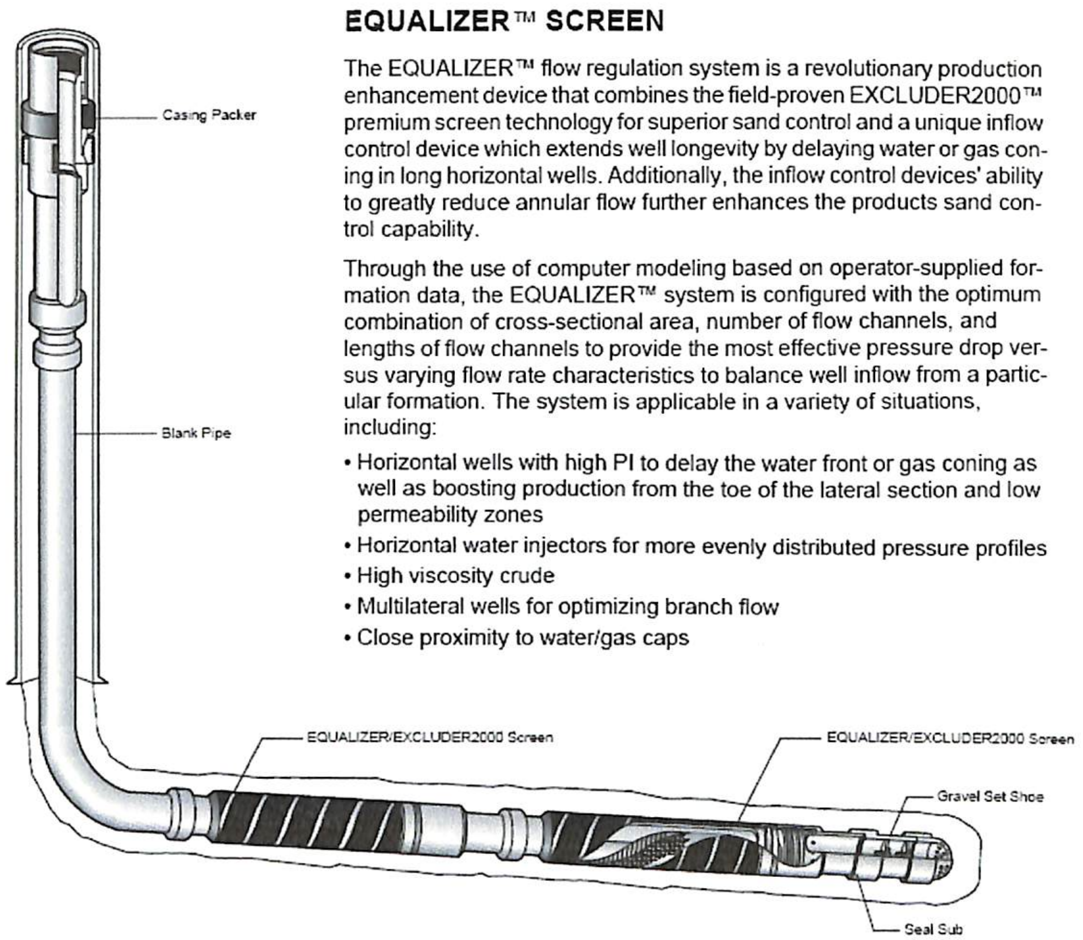
the flow within individual laterals. This difference in applicability leads to integration of both technologies for optimum completion of multilateral wells.

8. ***Multiple reservoir management*** – Both ICVs & ICDs have been applied to equalize the inflow from multiple layers within a single reservoir or multiple reservoirs. The optimum choice between these two technologies for a particular well will depend on the specific reservoir, fluid and completion architecture. However, ICVs have been proven to optimally control the commingled production and prevent the cross flow between multiple reservoirs. ICVs also allowed gas and water transfer between different layers for sweep improvement and pressure support ICDs have a limited capability to perform these tasks

4.4.2 ICD's for Multilateral/Horizontal Wells

(15)Equalizer™

Figure 36- Equalizer



EQUALIZER™ SCREEN

The EQUALIZER™ flow regulation system is a revolutionary production enhancement device that combines the field-proven EXCLUDER2000™ premium screen technology for superior sand control and a unique inflow control device which extends well longevity by delaying water or gas coning in long horizontal wells. Additionally, the inflow control devices' ability to greatly reduce annular flow further enhances the products sand control capability.

Through the use of computer modeling based on operator-supplied formation data, the EQUALIZER™ system is configured with the optimum combination of cross-sectional area, number of flow channels, and lengths of flow channels to provide the most effective pressure drop versus varying flow rate characteristics to balance well inflow from a particular formation. The system is applicable in a variety of situations, including:

- Horizontal wells with high PI to delay the water front or gas coning as well as boosting production from the toe of the lateral section and low permeability zones
- Horizontal water injectors for more evenly distributed pressure profiles
- High viscosity crude
- Multilateral wells for optimizing branch flow
- Close proximity to water/gas caps

Features

- Vector Weave Inner Membrane Provides Increased Inflow Area - Membrane inflow area is comparable to that of a formation face. A single layer of tightly woven steel membrane provides uniform pore throat openings, helping to form a more permeable filter cake. Additionally, particle flow is redirected to minimize erosion.
- Vector Shroud Protects Screen – Protects against damage from wellbore fragments during installation. Once the well is producing, the shroud design redirects flow to minimize erosion from formation materials.

- Incorporates a special end adapter (ICD) which uses a helical channel as a restrictive element to impose a pressure distribution along the entire length of the wellbore.

Figure 37- Equalizer Screen

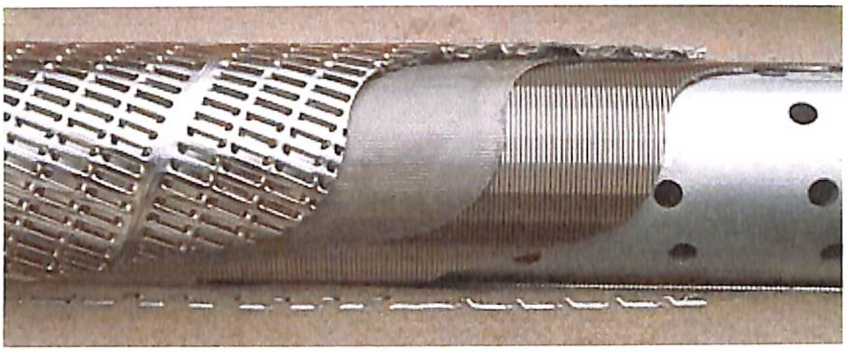
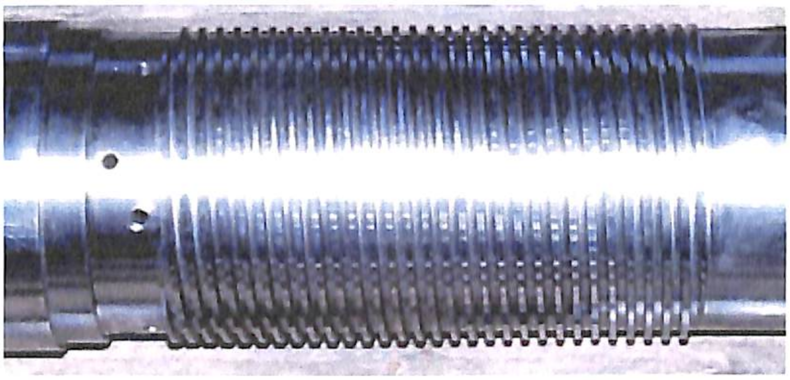


Figure 38- Helical Flow Channel ICD



- Mathematical modeling allows system to be configured with precise combination of cross sectional area and length of channels to provide optimal pressure drop versus flow rate characteristics to balance well inflow, based on a particular set of information data.
- Helical flow channels (as opposed to orifice) are less prone to erosion or plugging.
- Frictional effects - Equalize pressure drawdown seen by the reservoir. Non-uniform reservoir - Optimize drawdown seen by different reservoir sections.

Designing Data

The data required to design the Equalizer for a particular well is as follows:

- Screen Size

- Number of ICD units in the completion interval. (There can be one or two ICDs per joint of Screen)
- Type of base pipe holes: drilled holes or kill filter slots.
- Reservoir conditions:

Average pressure, P_R

Temperature, T_R

- The ICD flowing pressure differential and total flow rate per ICD
- Oil

Formation volume factor, B_o

Flow rate per ICD

At reservoir conditions:

  - Oil viscosity
  - Oil density

- Gas

Fraction free gas relative to oil

Formation volume factor, B_g

Flow rate per ICD

At reservoir conditions:

  - Gas viscosity
  - Gas density

- Water

Fraction water relative to oil

Formation volume factor, B_w

Flow rate per ICD

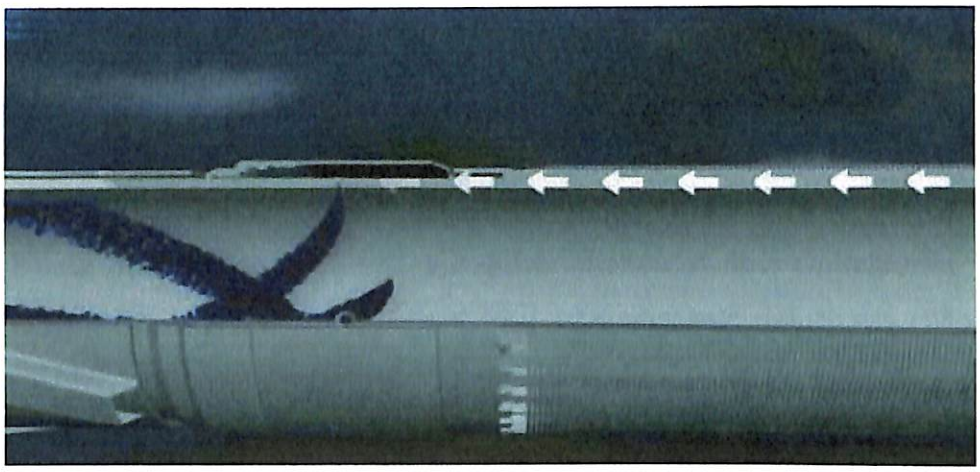
At reservoir conditions:

  - Water viscosity
  - Water density

4.5 Optimum ICD Completion Design

(21) The ICD's are designed to normalize inflow distribution. It may therefore be deduced an ICD completion designed to counteract friction from produced fluid along the wellbore, will also have a beneficial effect on well cleaning. On the upstream side, the choke apparatus is connected to a sand screen. The ICD provides a controlled pressure drop which is predominately a function of the flow rate.

Figure 39- Screen with ICD



The screen design is based on the fluid flowing through a filtering media and into a drainage layer. The drainage layer allows the fluid to flow from the filter media into the base pipe perforations in a conventional screen or into the ICD housing which is normally located at the end of the screen jacket.

The ICD net effect is to restrict high productivity segments while increasing flow in the low productivity segments. Balance in flow is achieved by breaking the horizontal length into flow compartments using zonal isolation devices (packers and constrictors). The heel generally tends to dominate flow (if everything else is equal) to the total exclusion of the remainder of the lateral. The heel compartment will usually require choking back in order for the remainder of the lateral to be given a chance to flow. Under certain conditions, fracture or high permeability zones may be completely blanked out by blank pipes and straddled by packers or choked back with few ICD's per compartment, especially if mainly gas or water is expected from this compartment. If a limited amount of production is required from this compartment, then a nominal number of equalizers are required. For non-ICD wells, the toe section usually shows little or no contribution to flow due to heel to toe effect, especially if reservoir pressure is lower than at the heel. There are cases where it may be desirable to reduce contribution to flow from this section to retard water breakthrough, especially when it is higher pressure than the toe or if it is heavily fractured and underlain by water or overlain by gas.

ICDs are needed in selective wells which meet the following criteria:

- High differential pressure between the heel and the toe.
- High permeability or flow contrast between the various compartments.
- Fractured horizontal wells.
- Horizontal wells overlain by gas zones or underlain by water zones and sometimes both.
- Long horizontal sections

All wells falling in the above categories require balance of flow contribution along the lateral that leads to improve volumetric sweep efficiency and defers gas cusping/water coning to sustain oil production and improve recovery.

ICDs Benefits in Horizontal Wells:

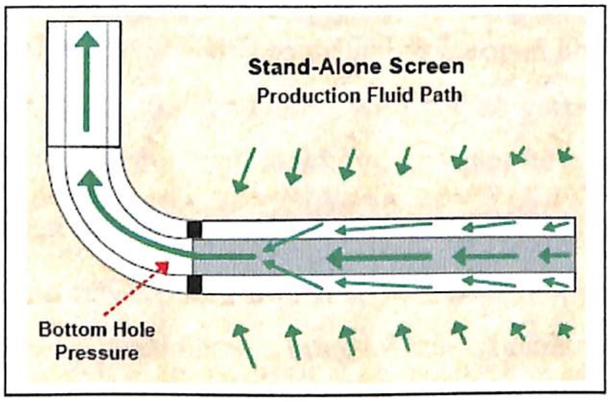
- Improve the ultimate recovery by having uniform depletion from the targeted zones.
- Maximize the production from low permeability sands.
- Extend well life by controlling the pressure drawdown and delay water breakthrough.
- Control sand production.
- Balance the flow along the well path, thereby reducing coning effects.
- Improve well cleanup by reducing the effect of formation damage caused by drilling mud[3].
- Reduce annular flow. This reduces the risk of sand production behind the screen and subsequent plugging or erosion.

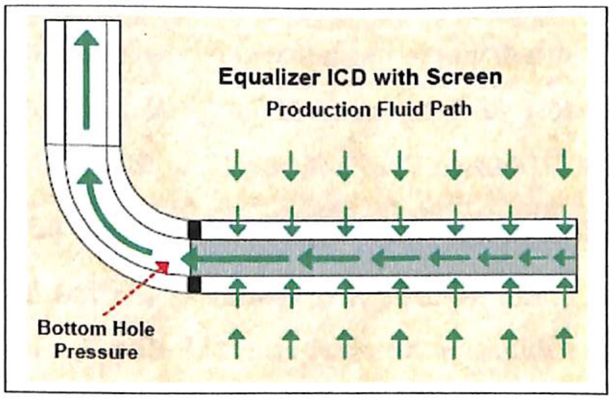
Before running the ICD screens, OBM (Oil Based Mud) should be conditioned and tested using a PST (Production Screen Tester) to confirm that the fluid will flow back through the screens without causing screen plugging.

4.6 Offshore North Sea Case History

(22) The concept to develop Inflow Control Devices originated with Norsk Hydro in the mid 1990's for application in the Troll Field. Inflow control technology was jointly defined and developed with Baker Oil Tools resulting in the EQUALIZER™ ICD integrated with sand screens as shown in Figure 41 and Figure 42. In the 1980's, Troll was considered to be a gas field with production from the thin oil layer deemed uneconomical. With development of drilling systems to drill extended horizontal laterals and the development of inflow control technology, Troll is now one of the largest oil producing fields in Norway. EQUALIZER™ is the first completion system to successfully create a uniform production profile along the entire length of a horizontal wellbore as well as provide sand control via integration with sand screens. Prior to the development of Equalizer, it is well documented that in long horizontals, the majority of the produced fluid is produced from the first one third of the well that is closest to the heel (casing shoe) with the remaining of the interval contributing very little. To date, over 120 wells in the North Sea have utilized Equalizer ICD's integrated into sand screens to balance production inflow along the lateral length, prevent coning of water and gas, and provide well life sand control without gravel packing.

Figure 40-Schematic of Production Fluid Profiles Identified During Flow Testing with and without Equalizer ICD's

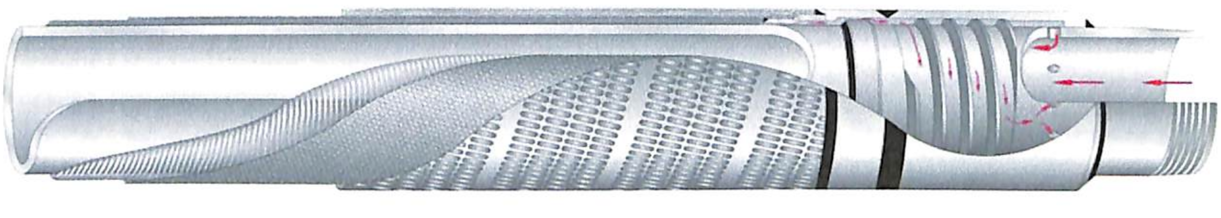




Troll oil is produced from a high permeability sandstone formation with a thin oil layer and both water and gas contacts. In order to effectively improve economic oil recovery, it is necessary to maximize reservoir contact via horizontals while minimizing the potential for coning water or gas into the production stream. One of the longest lateral sections to be completed achieved a length of 11,894 ft (3619 meters) of open hole for the M-22 well in the Troll Field. Numerical modeling and reservoir simulation were utilized to achieve a design that would control inflow from the reservoir and ensure that the entire length of the interval is producing while minimizing the influx of undesired fluids such as water and/or gas into the wellbore at or near the heel (casing shoe).

Figure 41-The Equalizer™ Inflow Control Device Integrated with a Debris Filter for Application in Carbonate Formations

Figure 42-Cut-a-Way View of the Equalizer™ ICD Integrated with a Premium Excluder2000 Sand Screen and Production Flow Paths



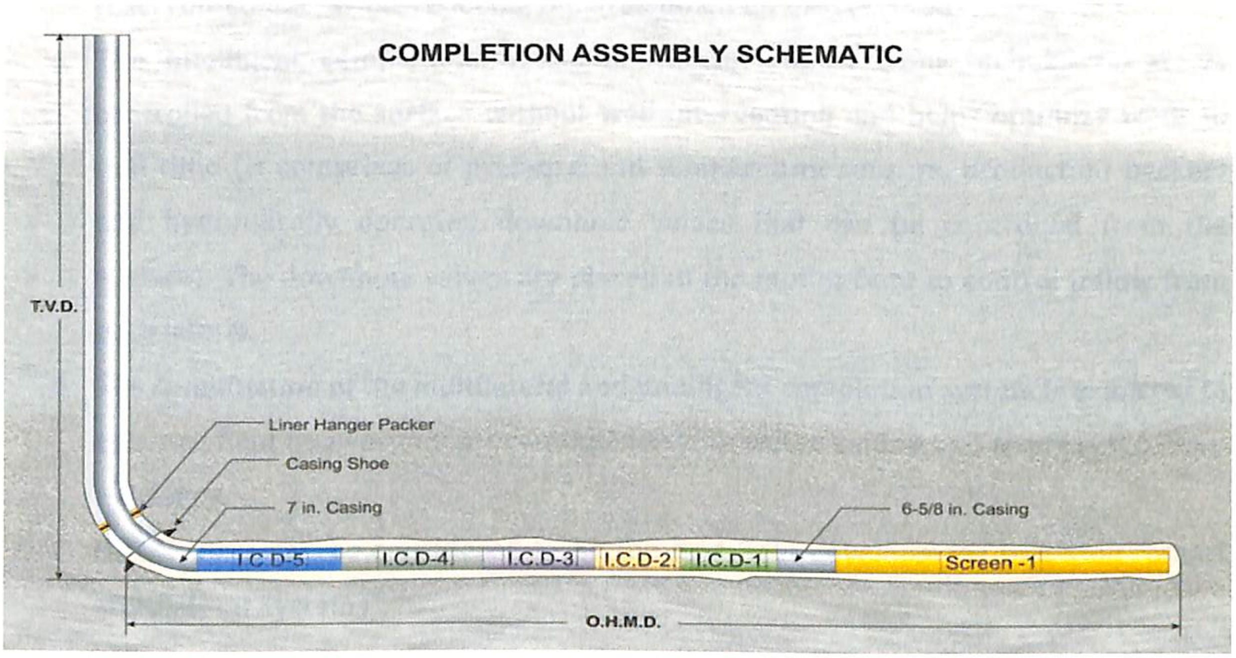
M-22 Well and Completion Description

The M-22 oil well was drilled as an open hole extended reach horizontal to a total depth of 18,113 ft (5521 meters) with a true vertical depth of 5177 ft (1578 meters) for Norsk Hydro in the Troll Field and an open hole lateral length of 11,894 ft (3619 meters). The open hole was completed with 279 joints of 250 micron EXCLUDER2000™ stand alone sand screens and EQUALIZER™ In-Flow Control Devices as shown in Figure 43. The ICD screen assembly was hung-off from the bottom of a 7" x 10-3/4" non-rotating, hydraulic set Flex-Lock Liner Hanger with a 7" x 10-3/4" Model ZXP liner top packer inside 10-3/4" casing. The ICD's were positioned along the horizontal open-hole section to balance and effectively control the production inflow along the entire open-hole section. To achieve optimum well production, the inflow control devices were numerically modeled to determine appropriate placement and drawdown as listed in Table 3 and illustrated in Figure 43.

Table 3-M-22 ICD Design for Balancing Inflow in the 11,894 ft Open Hole Lateral

	# of joints	Screen Type	Pressure Distribution
Screen - 1	115	Excluder	0
I.C.D. - 1	23	Equalizer	0.2 Bar
I.C.D. - 2	20	Equalizer	0.4 Bar
I.C.D. - 3	33	Equalizer	0.8 Bar
I.C.D. - 4	39	Equalizer	1.6 Bar
I.C.D. - 5	49	Equalizer	3.2 Bar

Figure 43-Troll M-22 with 279 Joints of 250 Micron Excluder2000 and Equalizer ICD Screens in a 11,894 ft Horizontal Section

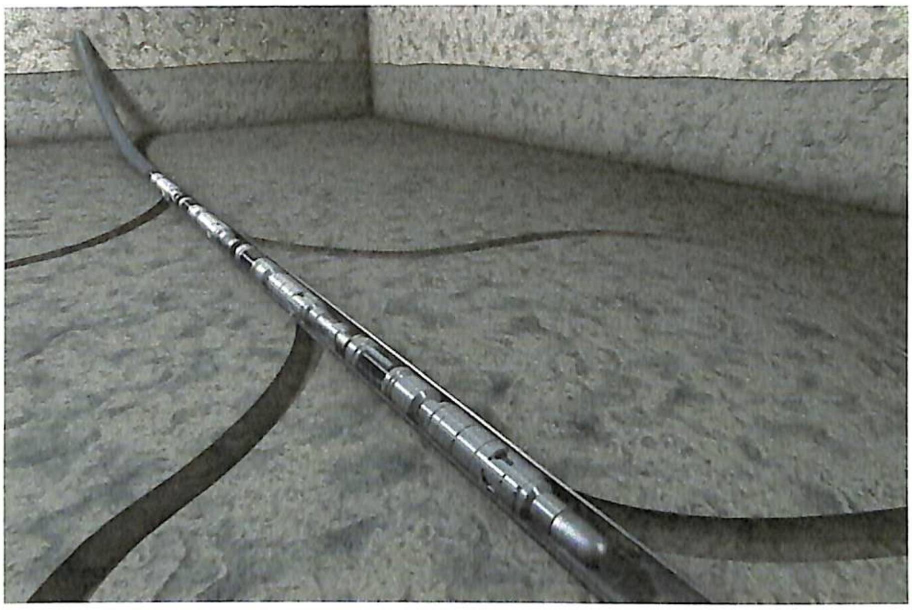


4.7 CASE HISTORIES

4.7.1 CASE HISTORY 1 (Intelligent Multilateral MRC Wells in Haradh Inc-3)

- (23) Haradh Increment-3 (HRDH Inc-3) is the southernmost part of the greater Ghawar Field.
- HRDH Inc-3 development, commissioned in March 2006, has added significant volumes to Saudi Aramco's daily production capacity.
- The development has 73 wells comprising of 28 water injectors, 13 observation and 32 producers. 28 of the 32 producers are intelligent completions in multilateral wells.
- The Maximum Reservoir Contact (MRC) wells with multilateral systems improve the reservoir contact while reducing the drawdown on the reservoir.
- The intelligent completion system allows the inflow from each lateral to be controlled from the surface without well intervention and helps optimize wells in real time (It comprises of pressure and temperature sensors, production packers and hydraulically operated downhole valves that can be controlled from the surface). The downhole valves are placed in the motherbore to control inflow from each lateral.
- The combination of the multilateral and intelligent completion system is expected to enhance field recovery by preventing/delaying water coning and improving sweep efficiency.
- HRDH Inc-3 can be considered to be the first field development based on "Smart Multilateral Systems"

Figure 44 : Illustration of the Intelligent Completion inside the mainbore of a multilateral well to isolate and control inflow from each lateral



Drilling Operations

- The producer wells were drilled with three or four laterals depending on the location of the well. Each of the laterals has around 4,000 ft of reservoir contact and the average reservoir contact for each well is over 14,000 ft. A 300 m separation was kept between laterals for efficient drainage.
- The TAML Level-2 multilateral windows were set at 300 m separation based on reservoir studies and evaluation of inter-lateral interference (TAML Level-2 multilateral systems with cased and cemented motherbore and openhole laterals were selected due to the presence of consolidated rock at the junction points).
- The hydraulic set whipstock with packer is run in conjunction with the tri-mill and measurement while drilling (MWD) assembly. The whipstock was run, oriented to the upper quadrant, and window milled in one trip.
- The initial section of the 6 1/8" openhole lateral was drilled with motor and changed to RSS as friction increases.

Smart Laterals

- The all-hydraulic smart well system was selected due to its higher reliability and track record.

- The smart well systems consist of hydraulically operated, surface controlled downhole chokes. These chokes have 10 discrete positions.
- The choke sizes were designed to meet the flow rate during the life of the well.
- The downhole control valve is positioned using the AccuPulse™ choke systems that dispenses a fixed volume of fluid in each pressure cycle and opens the choke by one position. This has the ability to close the choke from any position in one pressure cycle.
- Hydraulic set retrievable packers were used to provide the isolation between the laterals. These packers have control line ports with isolation fitting to pass the control lines.
- The smart well equipment was selected based on the expected well conditions and flow rates. The completion consists of 3 ½" tools for the lower laterals and 5½" tools for the upper lateral. 7" tubing was used for 6,000 ft in the top section to allow future ESP installation inside the 7". This will enable the ESP to be installed and retrieved without affecting the smart well completion.

Production Operations of the Intelligent Wells

- The downhole valves for each lateral enabled each of the laterals to be unloaded independently and flow tested.
- All the wells in Haradh Inc-3 are producing currently and the smartwell systems are functional.
- The downhole chokes are set as per the well conditions and production requirements, some of the wells are being produced from individual laterals, while the rest are being commingled.
- The permanent downhole gauges provide real-time data on well and reservoir conditions, and the generated data are being used for production and reservoir management decisions on an ongoing basis.
- The intelligent completions at HRDH Inc-3 provide the operator with a high level of flexibility in producing the wells. For example, laterals may be individually produced until the reservoir pressures enable commingling without cross flow.

- Laterals with high water or gas may be choked back and other suitable zones opened to compensate.
- Intelligent well configurations also enable the operator to quickly respond to reservoir uncertainties by reconfiguring inflow into the tubing. The laterals are being individually tested to develop a procedure to optimize the production.

Conclusion

- Technologies like multilaterals, intelligent completions, rotary steerables, geosteering and deep image LWD have been successfully integrated in Haradh Inc-3 field development.
- Adoption of best practices and lessons helped to reduce the non-productive time and improved drilling performance by over 70 % in some drilling sections.
- The maximum reservoir contact wells with higher productivity than conventional wells have helped reduce development cost.
- The capability to commingle multiple laterals in HRDH Inc-3 significantly reduced the well count and potential for intervention, enabling an economic development project.

4.7.2 CASE HISTORY 2 (Ecuador Intelligent Well)

- (24) An intelligent well system with remote-controlled adjustable downhole chokes played a key role in enabling commingled production from multiple zones in a single well for the first time in Ecuador.
- The IWS helped an operator improve the economics of a field in Ecuador, while gaining significant incremental production.
- Six intermediate choking settings between fully open and fully closed must be selected, from an infinite range, by machining a single component of the tool prior to tool installation.
- The choking settings are established based on reservoir studies and nodal analysis to achieve a number of objectives: maximized oil production; reduced total water cut at the surface; improved final oil blend quality; sand control; avoidance of crossflow and consequent production losses; compliance with

regulatory production restrictions; and production above the bubble point to avoid gas at the pump intake.

Nodal Analysis

- The nodal analysis helps the operator and intelligent completion provider determine whether chokes are needed for the well and, if so, the optimum settings for the chokes.
- Input parameters for the nodal analysis include completion configuration, fluid properties, productivity indexes (PI), wellhead pressures, formation pressures, and ESP size/type.
- The base case for the nodal analysis in this application intelligent completion assumed two zones commingled with no downhole chokes to regulate flowing bottom hole pressures.
- The objective was to determine uncontrolled commingled production capability and flowing pressure at a given ESP operating frequency, as well as any potential for cross-flow between zones.
- The base case nodal analysis also considered various water cuts to simulate increases in water production over time.
- The operator provided a requirement for maximum pressure drawdown in each zone to ensure that pressure was maintained above bubble point as well as a requirement for maximum production rate from the lower zone.
- The base case analysis showed that cross-flow was not a concern when producing commingled, but that the maximum drawdowns were not achievable for each zone with just an ESP.
- The nodal analysis was then performed with the intelligent well system in place to simulate production rates and pressures at various choke settings in each zone to optimize production at current water cuts.
- By increasing the water cuts, the analysis could simulate reduction in water production that could be achieved by choking.

- In order to decrease water production, oil production will also be decreased, so the analysis was used to balance the gain in incremental commingled oil production with the decrease in overall water production.
- Based on the well data provided by the operator, choking was required in the lower zone, but not the upper zone. However, uncertainties with the upper zone data prompted the operator to run chokes in both zones for added flexibility.
- The "ideal" choke setting was selected to regulate drawdown and production from the lower zone in order for the ESP to produce more oil from the more prolific upper zone.
- The "ideal" setting was 1% of the full open flow area of the choke, and this was expanded upon to determine the other five settings of the multi-position choke which turned out to be 2%, 3%, 6%, 9%, and 12% of the full open flow area.
- The nodal analysis data was provided to the ESP supplier for proper sizing of the ESP. Relevant data included commingled flowing pressures and production rates.

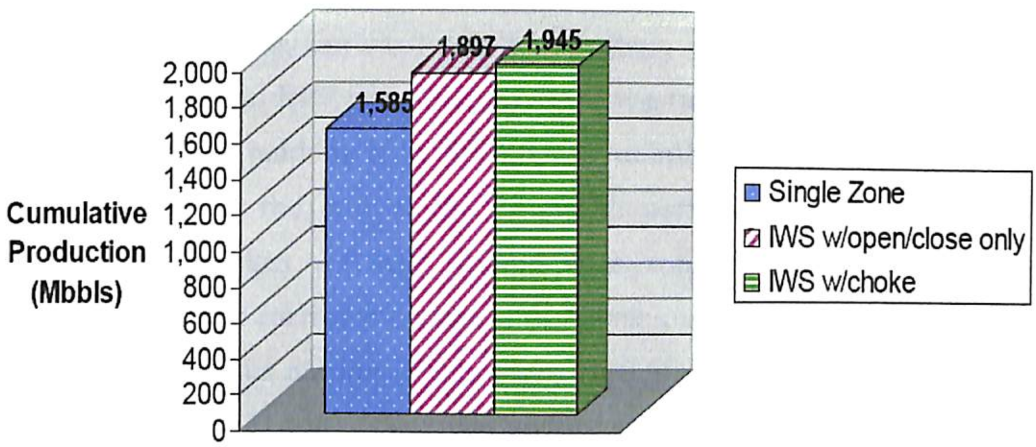
Reservoir Simulation

- The reservoir simulation model was built and used to model the "long-term" performance of the intelligent well over the estimated 2-year run life of the ESP.
- After the initial construction of the model, history matching was performed to match the model to the historical performance of the well.
- Once the simulation model had been validated against past performance, the simulator could be used to make forecasts of future production for multiple different completion types.
- The first simulation run was of the initial base case single zone completion. In this case, the well produces a total of 1,585,000 bbls of oil over a two-year period. Although initial production from the upper zone is quite prolific, water coning from the upper zone does lead to a decline in oil production over the two-year period of the model.
- The second simulation run considered a commingled completion using an intelligent well. In this case, an intelligent well system is used to commingle both

zones while independently monitoring pressure, flow and water cut from each zone. In this case, additional production is brought in from the lower zone that increases the overall production of the well. Over the course of two years, this completion will yield 1,897,000 bbls of oil: an incremental 312,000 bbls (19.2%).

- Lastly, the case deploying downhole chokes to optimize drawdown across both zones was considered. In this case, the upper zone is choked back continuously through the life of the model. Initial production is lower, as demonstrated by the nodal analysis, but more reserves are ultimately captured. In this case, it is estimated that 1,945,000 bbls of oil will be produced over the 2-year period. This is an incremental 360,000 bbls (22.7%) over the base case and 48,000 bbls over the IWS with open/close valves only.

Figure 45 : Cumulative Production of IWS Completion at 2 years for Ecuador Field Example

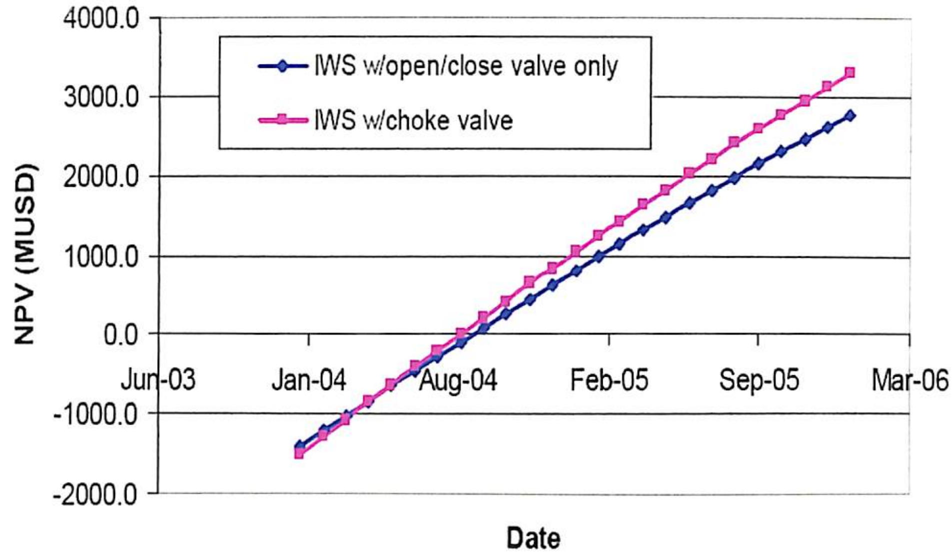


Economic Analysis

- In order to ultimately determine the best completion option for this well, a time value of money economic calculation was run.
- This analysis balances the incremental production of the intelligent well to the incremental investment required for the additional functionality.
- To simplify the analysis, an incremental economic analysis was performed. Rather than considering the economics of the entire wellbore and completion, the incremental analysis only compares the investment decision of using a conventional completion versus an intelligent well.

- The basic economic parameters used in the analysis are as follows:
  - Discount Rate – 15%
  - Oil Price – 20 USD/bbl
  - Handling Cost – 5 USD/bbl
    - Total Intelligent Well Completion Cost (Includes IWS equipment, incremental ESP costs, wellhead modification, rig time, miscellaneous expenses, etc.)
    - With Open/Close Valves only - $1,400,000
    - With Choking Valves - $1,500,000
  - The first economic case considered was the incremental net present value (NPV) of the intelligent well with open/close valves versus the base case conventional completion.
  - In this case, an incremental investment of $1,400,000 was considered for the total cost to deploy the Intelligent Well System.
  - The incremental NPV over time for this investment is shown in Figure 15. The investment is paid back in full after 8 months and reaches a total NPV of $2,770,000 by the end of the 24-month period. The IWS completion with downhole chokes was the second case considered. In this instance, the intelligent well carries the same investment costs plus the incremental cost of the choke versus an open/close valve. In this case, payback occurs one month earlier (Month 7) and the cumulative NPV at the end of 24 months is $3,316,000. This is an incremental NPV of $544,000 over the previous case that utilized open/close valves only. So, although the incremental production gain of deploying chokes appears to be minor, there is significant economic benefit as a result of this additional functionality.

Figure 46 : Incremental Net Present Value of IWS Completion Optons for Ecuador Field Example



Results

- The intelligent completion described above made it possible for the first time in Ecuador to accelerate production goals with fewer wells by commingling production from multiple zones.
- The first well is currently producing commingled from two zones, gaining incremental production of 3,500 barrels/day of oil over the previous single-zone ESP completion.
- Based on the successful installation and results from this well, two identical intelligent completion systems were installed in the same field in 2004.
- Prior to installation of the IWS, the well was producing approximately 3,500 bbl/day of oil. After a successful IWS installation, in early November 2004, oil production increased to approximately 6,500 bbl/day.
- At this stage, it is still too early to fully determine the economic benefit of the intelligent well installations in this field. However, the initial incremental production benefits have been significant and many more IWS wells are planned in the field to maximize the economic benefit of this new technology.

5. CMG-IMEX SIMULATION

5.1 Introduction to IMEX

(25)IMEX is a full-functionality black oil reservoir simulator, which incorporates all functionality required for full-field simulation studies. IMEX has the ability to accurately model complex heterogeneous faulted structures, primary and secondary recovery processes, including horizontal and multilateral wells, and reservoir subsidence. IMEX also forms an integral part of the Petroleum Experts GAP and Neotec FORGAS products, for analysis of surface network systems, as well as having its own network modeling abilities.

IMEX models multiple fluid systems as well as multiple rock types, for stacked reservoir environments. Users can incorporate very complex geological structures utilizing geostatistical or stochastically derived reservoir parameters. As well, users can calculate various reservoir properties or parameters using a very sophisticated calculator to derive values based on the users own mathematical functions.

A range of gridding options are available in IMEX, including block-centered and corner-point geometry, Cartesian, radial and irregular grids. Enhanced resolution around wells or in other areas of the reservoir where rapid flow is occurring can be provided through multi-level LGR's. MPFA (multi-point flux approximation) gridding is also available for improved accuracy in areas with complex geology, or where highly skewed non-orthogonal grids exist.

IMEX incorporates one of the most elaborate and sophisticated means of modelling naturally or hydraulically fractured reservoirs. Within IMEX, the user can select one of four different fracture models, including dual-porosity and/or dual-permeability, allowing for accurate simulation of matrix-fracture fluid transfer in a fractured reservoir system. The fracture models allow vertical movement of fluids through individual matrix blocks and transient effects through large block systems.

IMEX can be coupled with comprehensive surface facilities models, GAP and FORGAS, enabling accurate forecasting and scheduling of the entire field from reservoir to pipelines and gathering stations to the facilities. The link to GAP also allows multiple IMEX reservoirs to be optimized simultaneously through the surface network system..

IMEX uses an adaptive implicit solver for optimal solution, accuracy, and computational speed. This is further enhanced by the black oil formulation and ability to run in 2, 3, or 4 phases.

The following is a list of specific functionality that enhances **IMEX** modelling ability:

- Local Grid Refinement
- Four separate Dual Porosity/Dual Permeability systems (fractured reservoirs)
- Geo-mechanical modeling capability including subsidence output
- Polymer flood model
- Solvent flood model
- Pseudo-Miscible flooding
- Gas Lift Optimization
- Surface network model
- Multi phase non-Darcy flow
- Vertical Flow Performance and Sophisticated Wellbore Model
- Vertical, horizontal, deviated and multi-lateral well configurations
- Full range of complex water and gas recycling and injection controls

The following is a list of fluid types that IMEX supports:

- Dry Gas
- Wet Gas
- Condensates
- Volatile oils
- Saturated oils with gas cap
- Under-saturated oils
- Heavy oils

The following is a list of production mechanisms that IMEX supports in both fractured and non-fractured reservoirs:

- Primary depletion (including rock compaction and dilation effects)
- Water flood (with or without polymer) including aquifer functions
- Immiscible gas injection
- Miscible gas injection

- Water Alternating Gas (WAG)

IMEX can also be used to model well tests and the performance of hydraulic fractures, as well as more standard full field and single well models.

5.2 Equations Used

5.2.1 Darcy's Law

Equation 4- Equations used to calculate flow rate

$$q = \frac{k * A * \nabla P}{\mu}$$

$$q_o = \frac{k * k_{ro} * A * \nabla P_o * \rho_o}{\mu_o * B_o}$$

$$q_o = \frac{k * k_{ro} * A * (\frac{\Delta P_o}{L}) * \rho_o}{\mu_o * B_o}$$

$$q_o = \frac{(k * A/L) * k_{ro} * A * \nabla P_o * \rho_o}{\mu_o * B_o}$$

$$q_o = \frac{T_x * k_{ro} * \nabla P_o * \rho_o}{\mu_o * B_o}$$

Any of the above equations are used to calculate the flow rate from each grid block to the perforations depending upon the availability of the type of data.

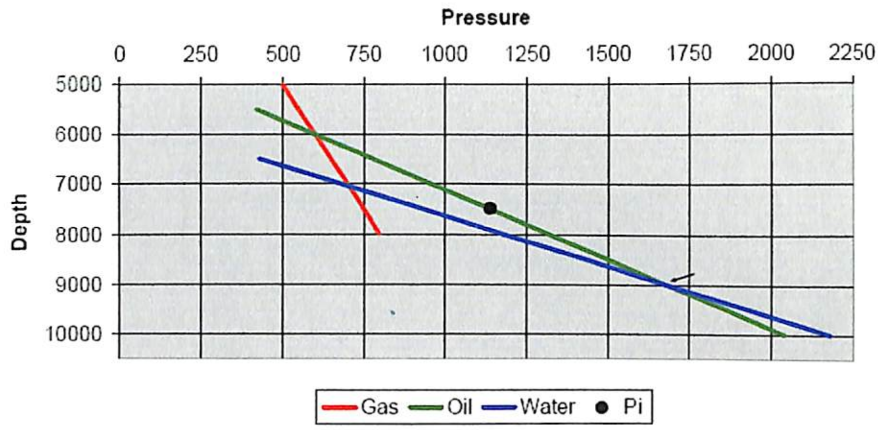
5.2.2 Simulation Calculations

The following calculations are done for each of the grid block:

- Gross Rock Volume (GRV): DX*DY*DZ
- Mid-Point Depth: Calculated from depth and DZ
- Pore Volume:
  - DX*DY*DZ*NTG*PORO
  - DX*DY*DZNET*PORO
  - GRV*NTG*PORO
- Transmissibility in X-Direction: K_{AVG}*AREA/MID-POINT DISTANCE
- Phase Pressures (O,W,G): The steps for its calculation are as follows-
  - The pressure is defined at a given depth.

- The pressure of that phase is computed for each grid block using phase density at reservoir conditions.
- At the gas-oil or oil-water contacts, the pressure of the remaining phases (generally water and gas) is calculated from the capillary pressure defined at these contacts.
- The pressure of these other phases is then calculated for each grid block using water and gas phase densities at reservoir conditions.

Figure 47- Phase Pressures



- Phase Densities (O,W,G) at reservoir conditions:
  - $\rho_W^{res} = \rho_W^{SC}/B_W$
  - $\rho_g^{res} = \frac{\rho_g^{SC}}{B_g} + rs * \rho_o^{SC}/B_g$
  - $\rho_o^{res} = \frac{\rho_o^{SC}}{B_o} + RS * \rho_g^{SC}/B_o$

  The surface densities of oil, water and gas are user defined. The formation volume factors B_o, B_w and B_g as well as RS and rs are user defined values as functions of pressure (input as PVT Data).
- Initial Equilibrium
  - $\Delta P_{OIL} = \Delta D * \rho_o^{res} * g$
  - $\Delta P_{WAT} = \Delta D * \rho_W^{res} * g$
  - $\Delta P_{GAS} = \Delta D * \rho_g^{res} * g$
- Capillary Pressure:
  - $P_{COW} = P_O - P_w$ (user defined at OWC)

- $P_{CGO} = P_G - P_O$ (user defined at GOC)

- Capillary Pressure v/s Saturation:

  For each grid block P_{COW} and P_{CGO} are calculated from above equations and from the input capillary pressure v/s saturation curve, the water and gas saturations are calculated for each grid block.

- Equation of Continuity:
  - Inflow – Outflow = Accumulation

  Inflow and Outflow calculated from darcy's law

  - $\sum K_{RO} * K * AREA \frac{\frac{\Delta\varphi_{OIL}}{L}}{\mu_O * B_O} + \sum Q_{O,WELLS} = PV * \left(\left(\frac{S_O}{B_O}\right)_t - \left(\frac{S_O}{B_O}\right)_{t-1}\right)$

5.3 Description

The simulation of a sample reservoir using two cases was done on CMG-IMEX Simulator (To see the data file refer to Annexure A).

The description of the simulation model is as follows:

- The reservoir has 9*9*15 blocks (i.e.1215 blocks) in I*J*K directions with Cartesian Geometry. BLACK OIL Model is used.
- It is a three phase model with Gas, Oil and water present in the reservoir.
- The model has no fractures, no faults, no shale present and single porosity exists in the reservoir
- The permeability in I direction is given in Table 4. The permeability in J direction is same as in I direction. The Z Permeability is 0.1 times to that in I direction.

Table 4- Permeability in I direction

I	J	K	Permeability I (md)
1:9	1:9	1	35.0
1:9	1:9	2	47.5
1:9	1:9	3	148.0
1:9	1:9	4	202.0
1:9	1:9	5	90.0
1:9	1:9	6	418.5
1:9	1:9	7	775.0
1:9	1:9	8	60.0
1:9	1:9	9	682.0
1:9	1:9	10	472.0
1:9	1:9	11	125.0
1:9	1:9	12	300.0
1:9	1:9	13	137.0
1:9	1:9	14	191.0
1:9	1:9	15	350.0

- Rock Compressibility is $6*10^{-6}$ /psi and reference pressure is 8327 psi
- Gas Oil Contact is at depth of 9061 feet and Oil Water Contact is at a depth of 9209 ft (The top depth of reservoir is 9000 feet).

The porosity in the reservoir is given in Table 5.

Table 5- Layer Wise Porosities

I	J	K	Porosity (%)
1:9	1:9	1	8.7
1:9	1:9	2	9.7
1:9	1:9	3	11.1
1:9	1:9	4	16
1:9	1:9	5	13
1:9	1:9	6	17
1:9	1:9	7	17
1:9	1:9	8	8
1:9	1:9	9	14
1:9	1:9	10	13
1:9	1:9	11	12
1:9	1:9	12	10.5
1:9	1:9	13	12
1:9	1:9	14	11.6
1:9	1:9	15	15.7

The description of the given simulation model in terms of fluid properties are as follows:

- Density of Oil is 49.99 lb/ft^3, Density of Gas is 0.050 lb/ft^3 and Density of Water is 68.60 lb/ft^3.
- Water Formation Volume Factor is 1.054, water compressibility is $3.57*10^{-6}$/ psi, viscosity of water phase at reference pressure of 8327 psi is 0.241 cp.
- Oil Compressibility is $1.3687*10^{-5}$/psi.
- Pressure Dependence of Oil Viscosity (Oil Viscosibility Factor) is $4.6*10^{-5}$cp/psi.
- Reservoir Pressure is 3600 psi and is equal to the Bubble point pressure.
- The operating conditions for well are as follows:
- Maximum Surface Oil Rate is 1000 STB/day.
- Maximum Surface Gas Rate is $2*10^6$ SCF/day.
- Minimum Bottom hole pressure is 1000psia

The oil properties in terms of Gas Formation Volume Factor (B_g) are given in Table 6.

Table 6- Oil and Gas Properties

P (Psi)	R_s (scf/STB)	B_o (RB/STB)	B_g (RB/scf)	Vis $_{Oil}$ (cp)	Vis $_{Gas}$ (cp)
14.7	0.0	1.062	0.166667	1.040	0.0080
264.7	90.5	1.150	0.012092	0.975	0.0096
514.7	180.0	1.207	0.006289	0.910	0.0112
1014.7	371.0	1.295	0.003195	0.830	0.0140
2014.7	636.0	1.435	0.001613	0.695	0.0189
2514.7	775.0	1.500	0.001294	0.641	0.0208
3014.7	930.0	1.565	0.001080	0.594	0.0228
4014.7	1270.0	1.695	0.000811	0.510	0.0268
5014.7	1618.0	1.827	0.000649	0.449	0.0309
9014.7	2984.0	2.352	0.000386	0.203	0.0470

- The Water Oil Relative Permeability (K_{rw}) Data is given in Table 7.

Table 7- Water Oil Relative Permeability Data

S_w (Water Saturation)	K_{rw}	K_r	P_{cow} (Capillary Pressure)
0.20	0.000	1.00	7.00
0.25	0.000	0.715	5.41
0.30	0.003	0.492	4.12
0.35	0.010	0.323	3.09
0.40	0.024	0.201	2.30
0.45	0.047	0.117	1.71
0.50	0.081	0.065	1.30
0.55	0.129	0.035	1.03
0.60	0.192	0.022	0.88
0.65	0.274	0.017	0.80
0.70	0.376	0.012	0.78
0.75	0.500	0.00	0.78
0.80	0.600	0.00	0.77
0.85	0.700	0.00	0.71
0.90	0.800	0.00	0.59
0.95	0.900	0.00	0.36
1.00	1.000	0.00	0.00

- The Liquid Gas Relative Permeability Data is given in Table 8.

Table 8- Gas Oil Relative Permeability Data

S_g (Gas Saturation)	K_{rg}	**K_{rog}**	**P_{cog} (Capillary Pressure)**
0.00	0.000	1.000	0.00
0.07	0.001	0.690	1.26
0.13	0.004	0.454	1.92
0.20	0.014	0.282	2.18
0.26	0.034	0.163	2.22
0.33	0.067	0.088	2.25
0.39	0.116	0.045	2.44
0.46	0.184	0.025	3.01
0.52	0.275	0.018	4.13
0.59	0.391	0.013	6.00
0.65	0.536	0.000	8.82
0.68	0.614	0.000	10.50
0.71	0.699	0.000	12.43
0.74	0.791	0.000	14.65
0.77	0.892	0.000	17.17
0.80	1.000	0.000	20.00

Rock-Fluid Properties data

Figure 48-Solution Gas Ratio and Oil Formation Volume Factor vs Pressure

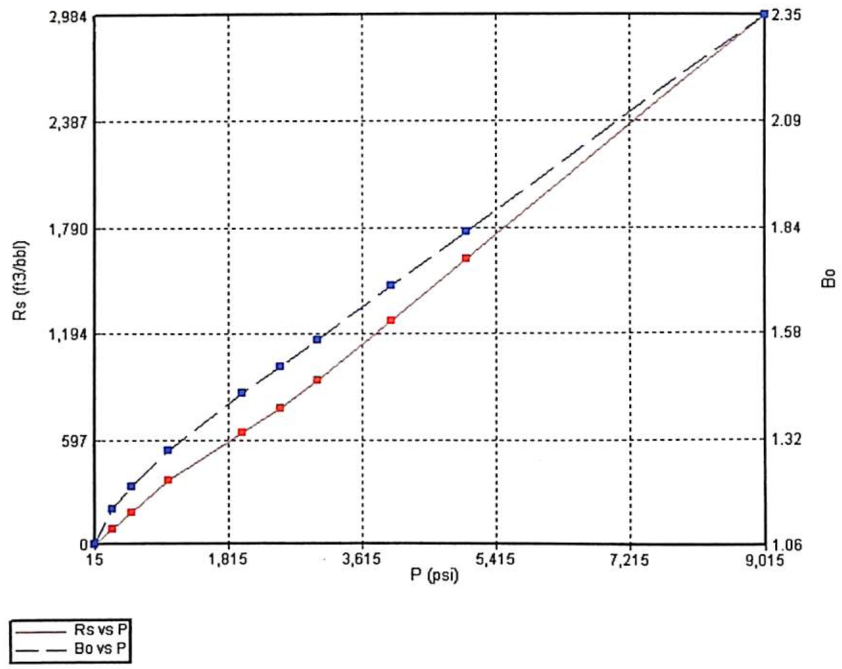


Figure 49- Gas Formation Volume Factor vs Pressure

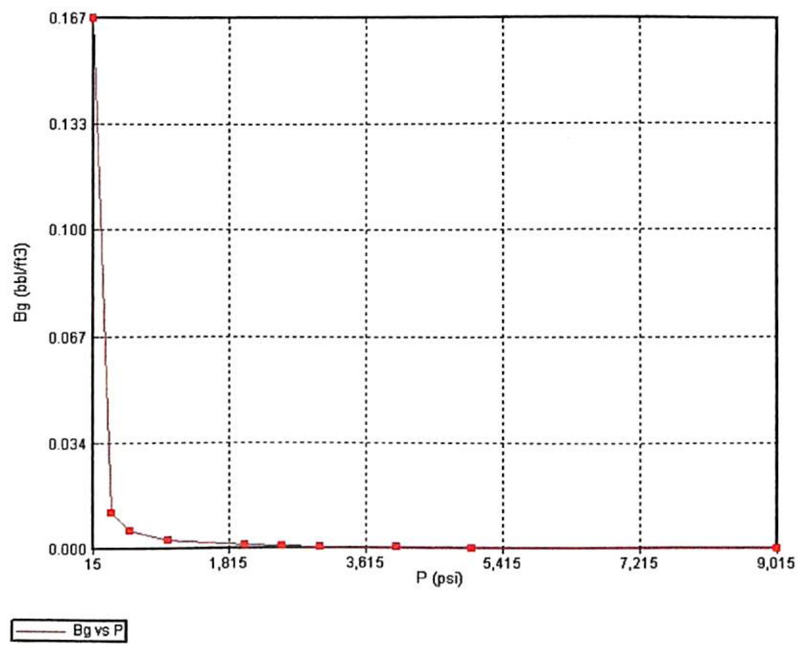


Figure 50- Oil-Gas Capillary Pressure vs Gas Saturation

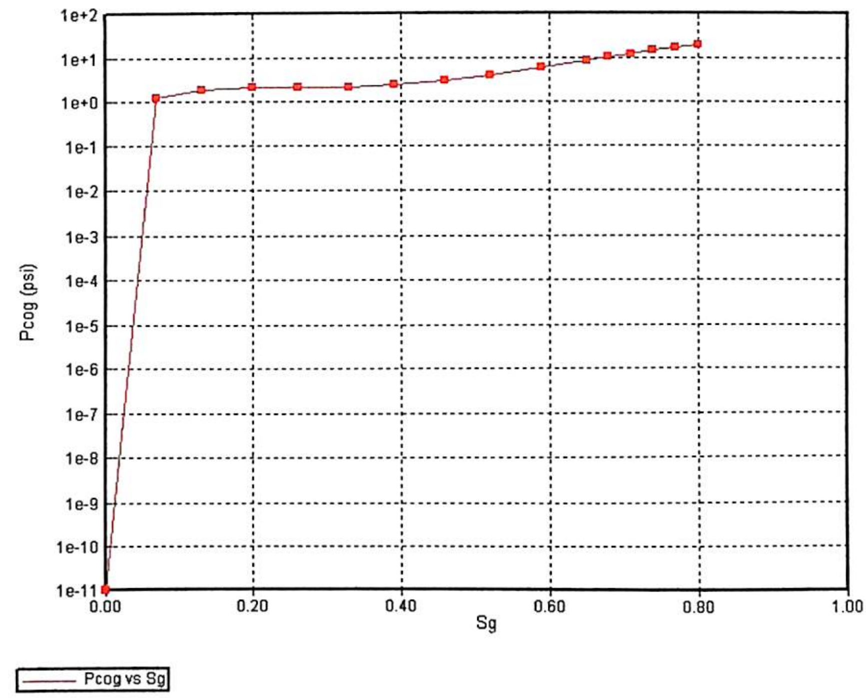


Figure 51- Water Relative Permeability and Oil- Water Relative Permeability vs Water Saturation

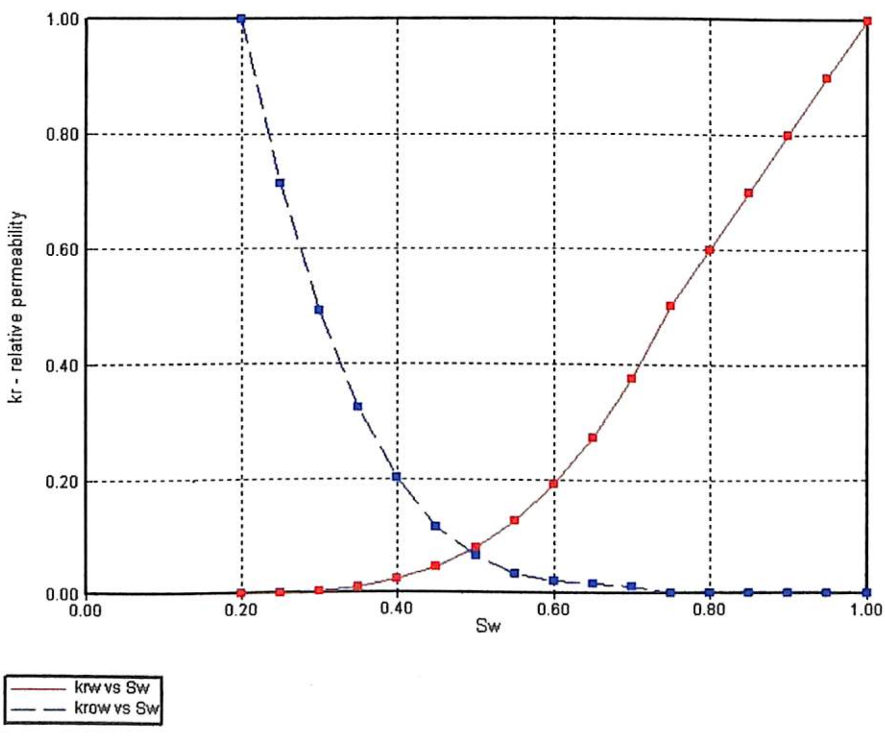


Figure 52- Gas Relative Permeability and Oil-Gas Relative Permeability vs Gas Saturation

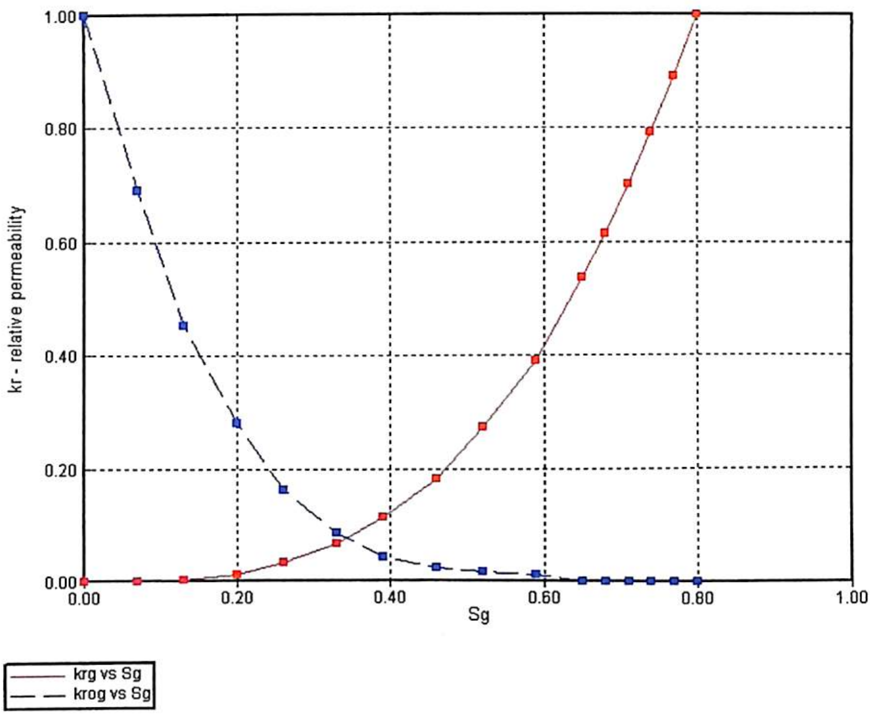


Figure 53- Oil-Water Capillary Pressure vs Water Saturation

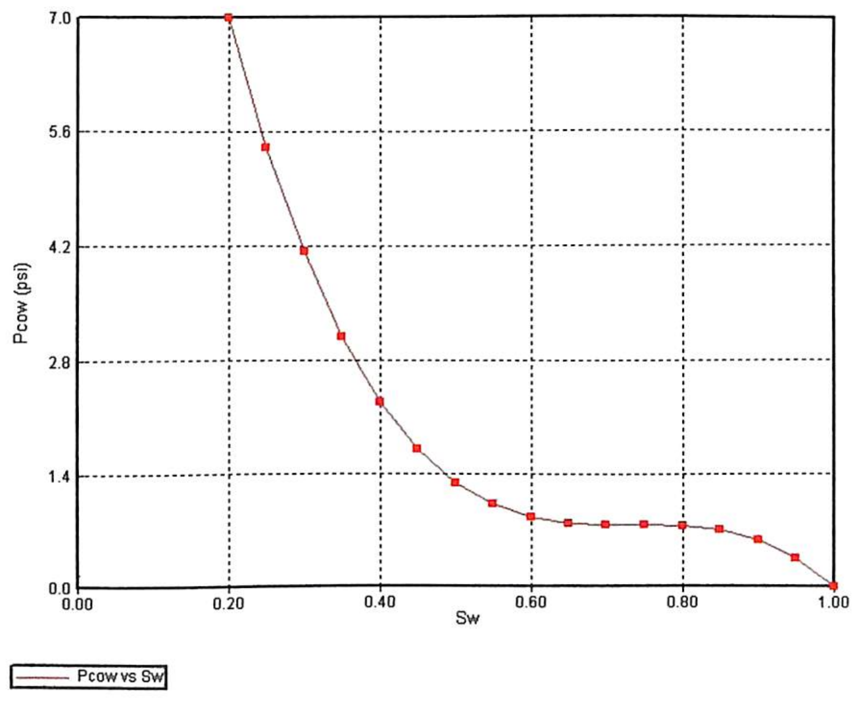


Figure 54- Three Phase Relative Permeability

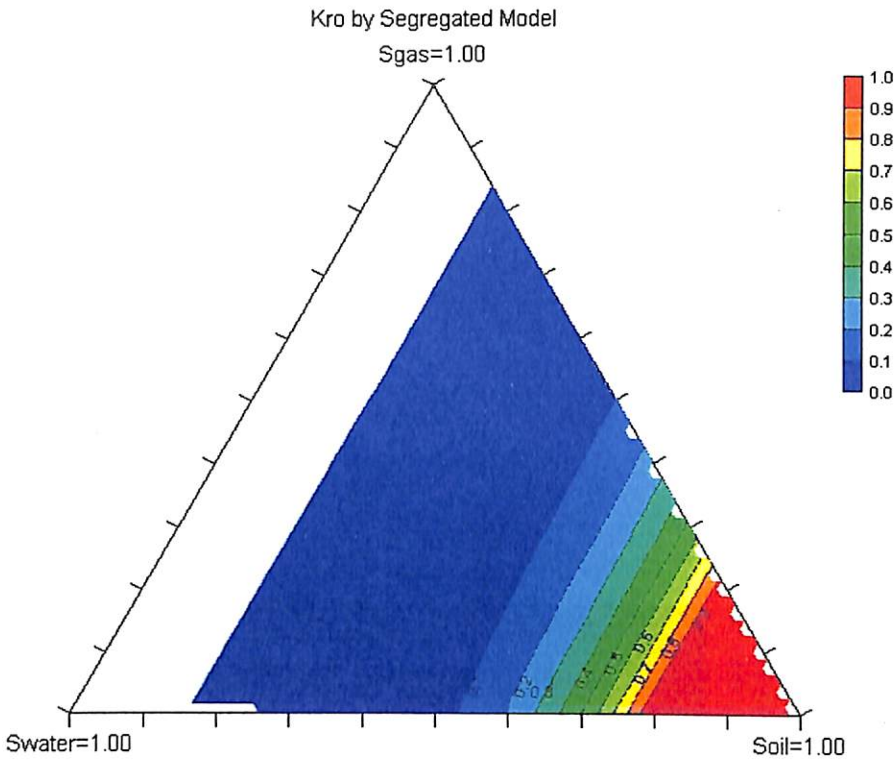
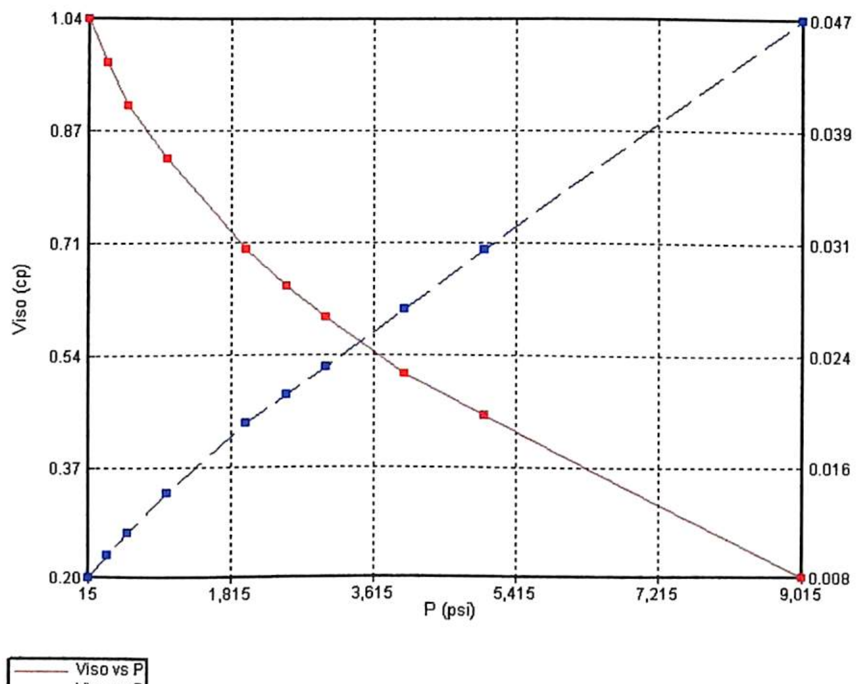


Figure 55- Viscosity of Oil and Gas vs Pressure

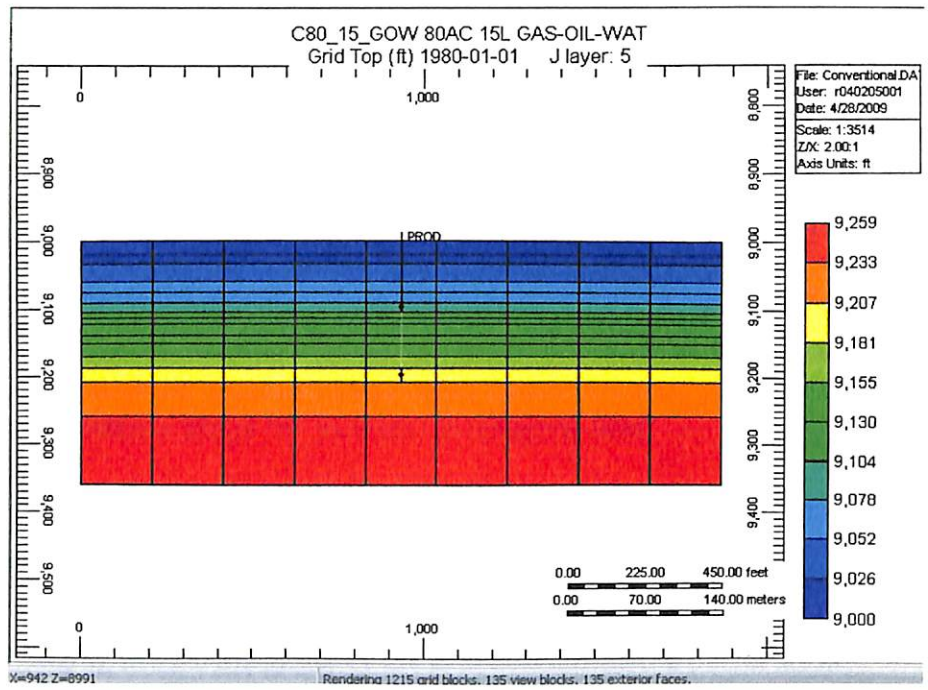


5.4 Conventional Vertical Well vs. Intelligent Well

A vertical well was taken as a producer for the above mentioned reservoir.

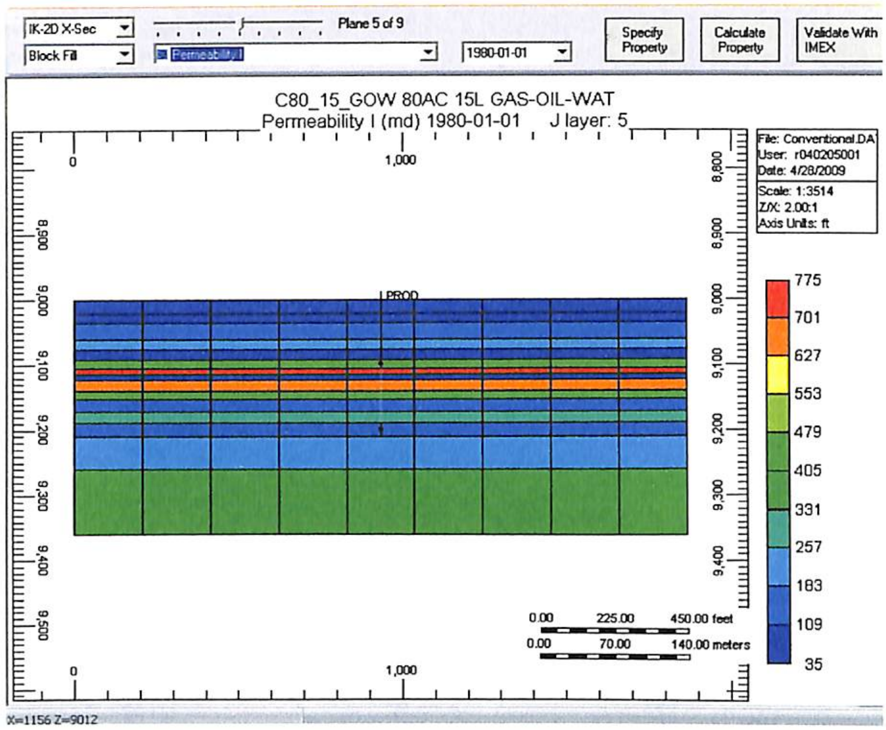
- The perforations in the vertical well have been done in the 6th and 13th layer i.e. in grids (5, 5, 6) and (5, 5, 13).
- The layer 13 is just above the water-oil contact.
- The reservoir grid along with depth of each layer in shown in the Figure 56.

Figure 56- J-K section view of the vertical well



- The permeability in I-Direction is equal to the permeability in J-Direction. The J-K section view shown in Figure 57 gives the permeability in I-Direction for each layer.

Figure 57- J-K Section View for I-Permeability



5.4.1 Simulation Steps for Vertical Intelligent Well

To implement the intelligent technology or flow control device in the above well, we change the permeability to mimic the choking effect. The choking effect can be shown in two ways:

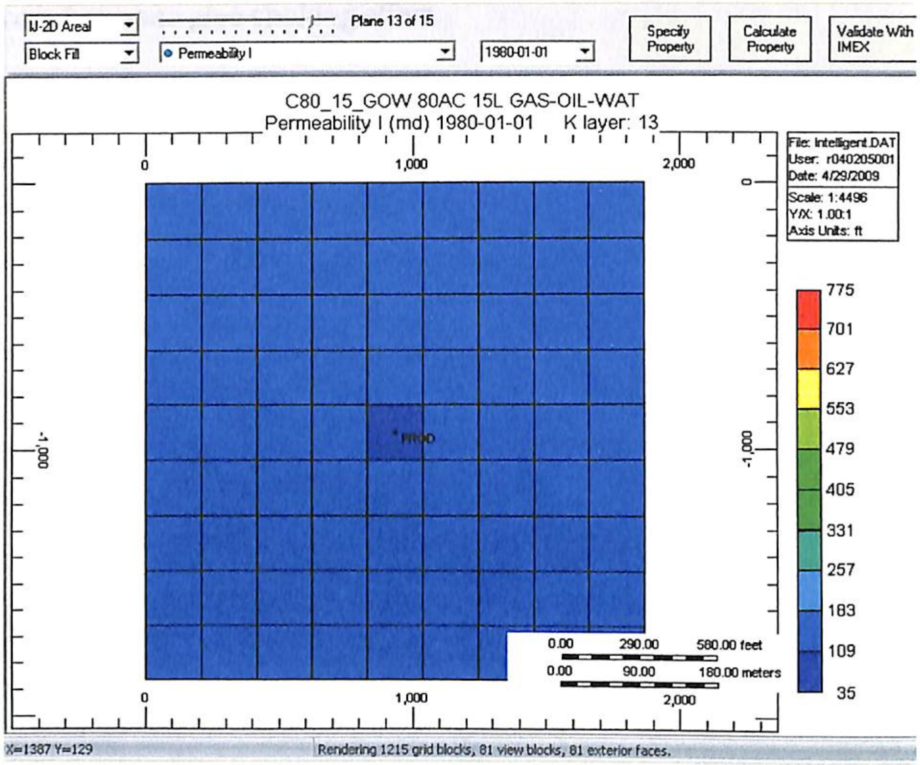
1. By changing the permeability of the grid containing the perforation
2. By changing the permeability around the well-bore

Both of the above cases will give different results. Here, we will use the first case, i.e. by changing the permeability of the grid containing perforation.

This is done in the following manner:

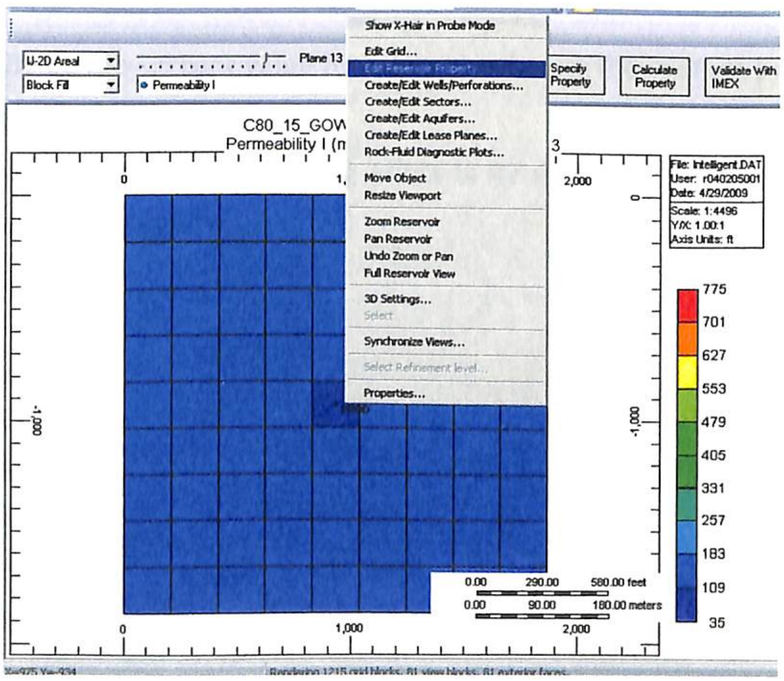
- Go to the areal view (1J-2D Areal) and select the property 'Permeability I'.
- Now select the plane where perforation is located/ grid property is to be changed. Here we select layer 13, as the perforation located just above the Water Oil Contact is to be selected.

Figure 58- Permeability Modification of Perforated Grid



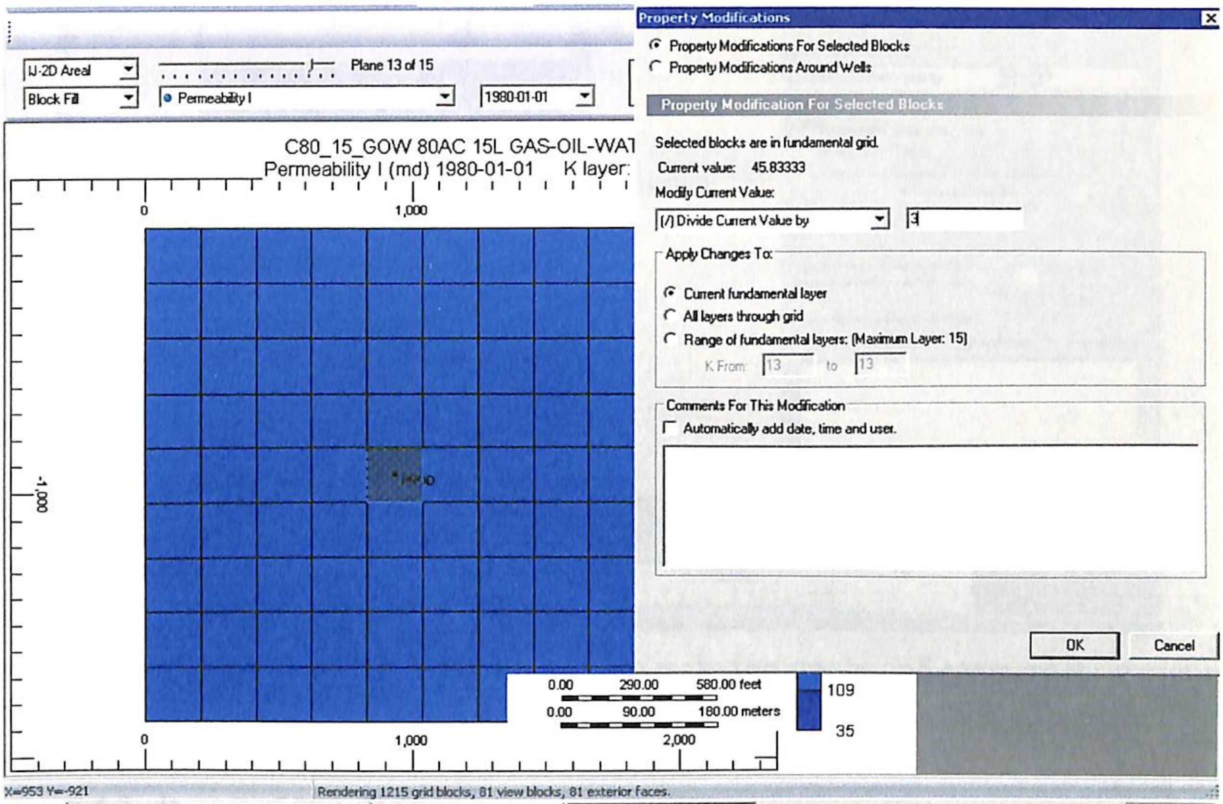
- Now, right click on the perforated grid and select edit reservoir property.

Figure 59- Editing Reservoir Property



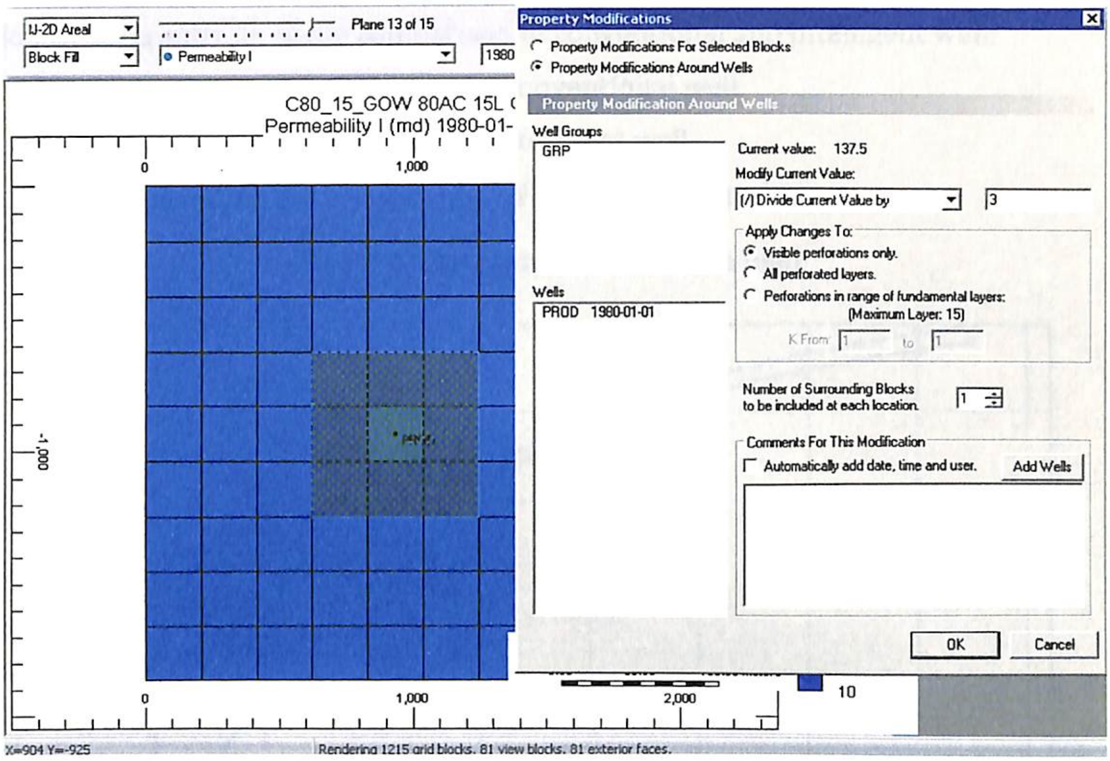
- Now change the permeability by dividing the current value by any value higher than 1 so as to give choking effect.

Figure 60- Property Modification for selected grid blocks



- Here we divide the current value by 3 so as to change the current permeability from 137.5 md to 45.833 md.
- Another way to create the choking effect is by changing the permeability around wellbore as shown in Figure 61.

Figure 61- Property Modification around Wellbore



- We now use the CMG- Result Graph to make the graphs and compare the various parameters.

5.4.2 Result of Simulation

The following conclusions were drawn by observing and analyzing the graphs.

1. An increment of 38, 000 bbl of was shown in the Cumulative Oil Recovery at standard conditions.
2. The Cumulative water production was decreased by 1, 60, 000 bbl.
3. The water cut was decreased from 0.47 to 0.42.
4. The oil rate was increased but not appreciably
5. Water rate was decreased appreciably.

The above observations prove the benefit of using the Inflow Control Device in a conventional vertical well.

5.4.3 Graphs

The following graphs show the comparison of conventional and intelligent well:

1. The blue color curves indicates the conventional well
2. The red color curves indicates the intelligent well
3. Difference properties are shown by a single red colored curve

Figure 62- Cumulative Oil Production (bbl)

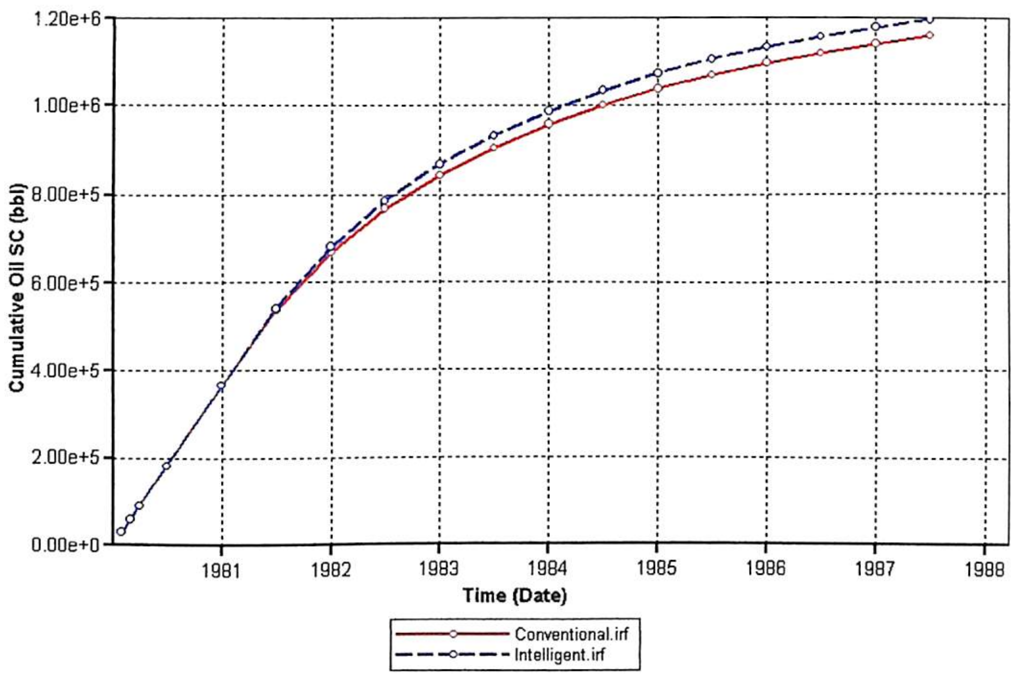


Figure 63- Cumulative Oil Difference (bbl)

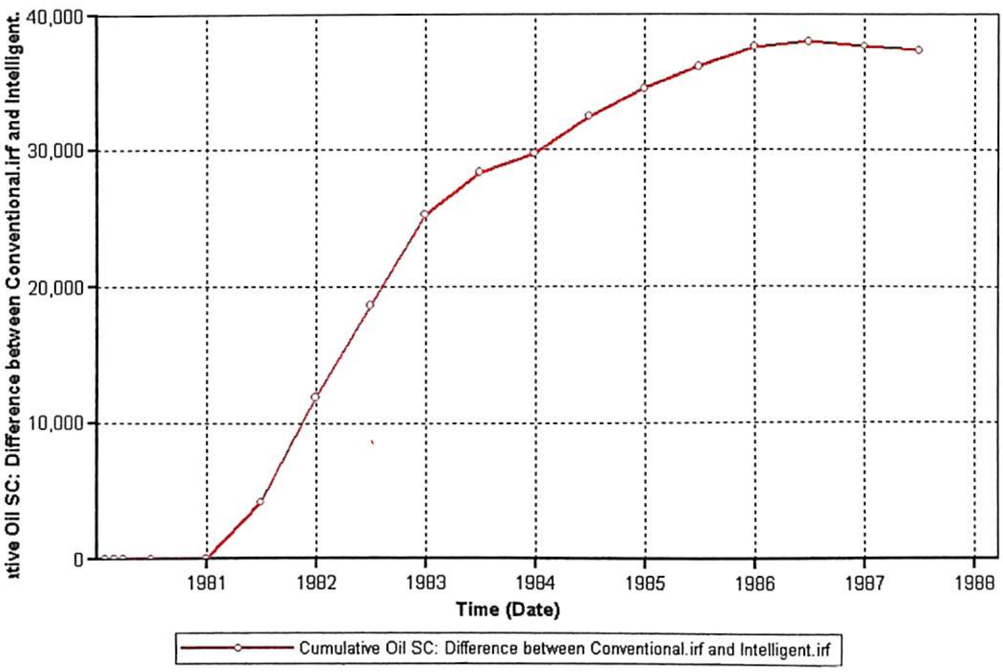


Figure 64- Cumulative Water SC (bbl)

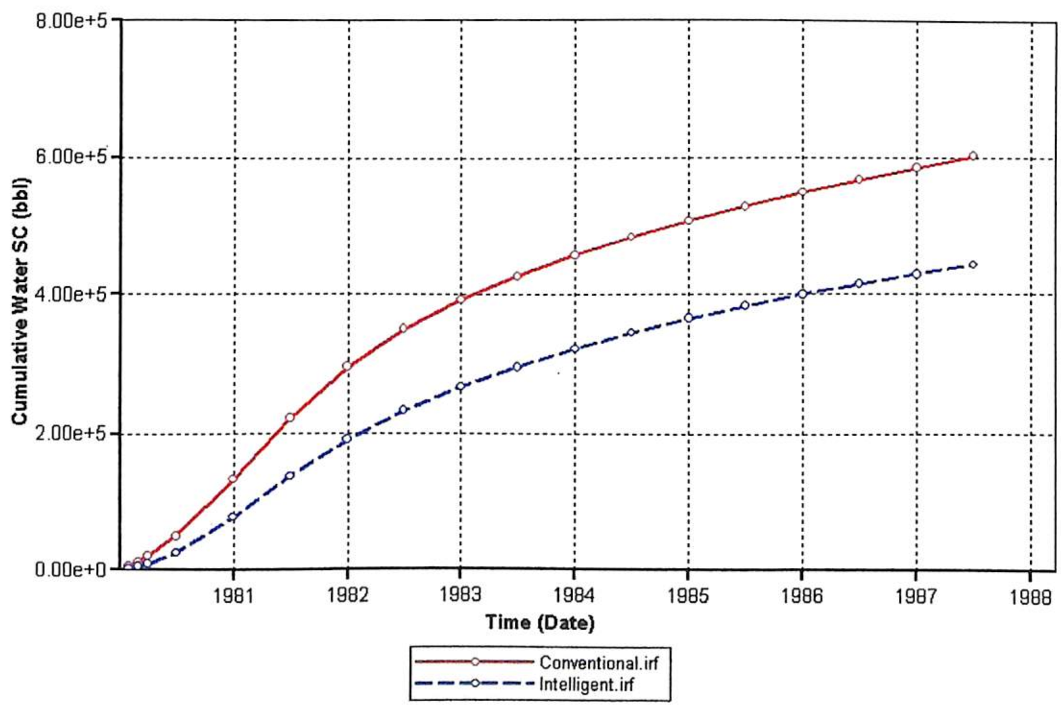


Figure 65- Cumulative Water Difference (bbl)

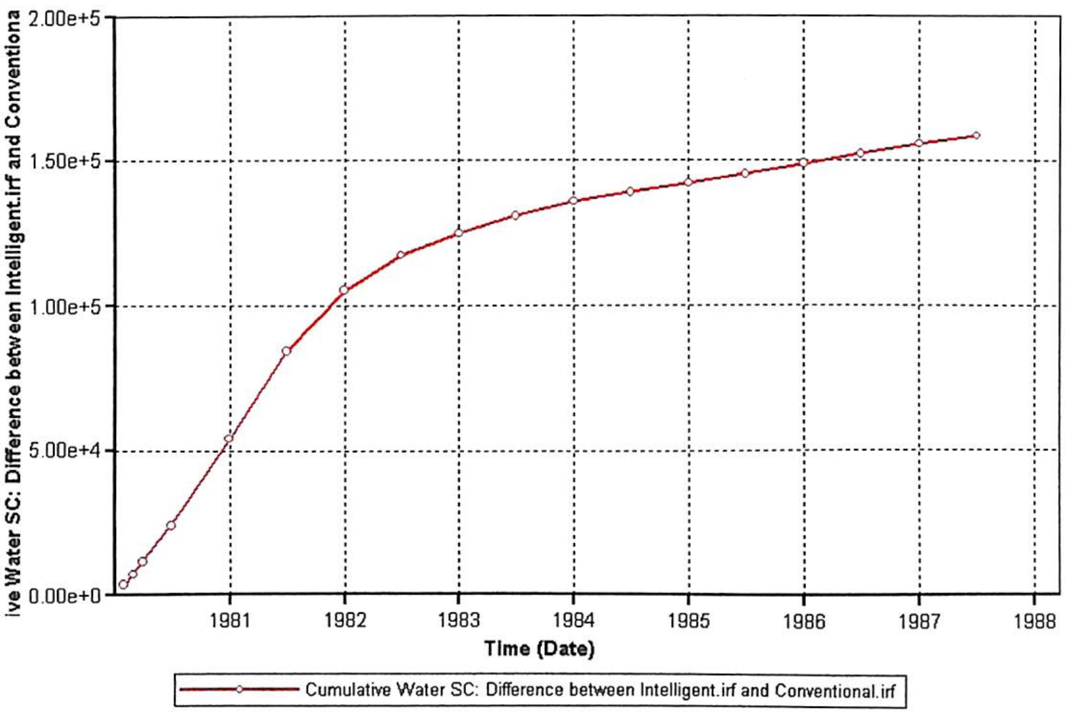


Figure 66- Oil Rate SC (bbl/day)

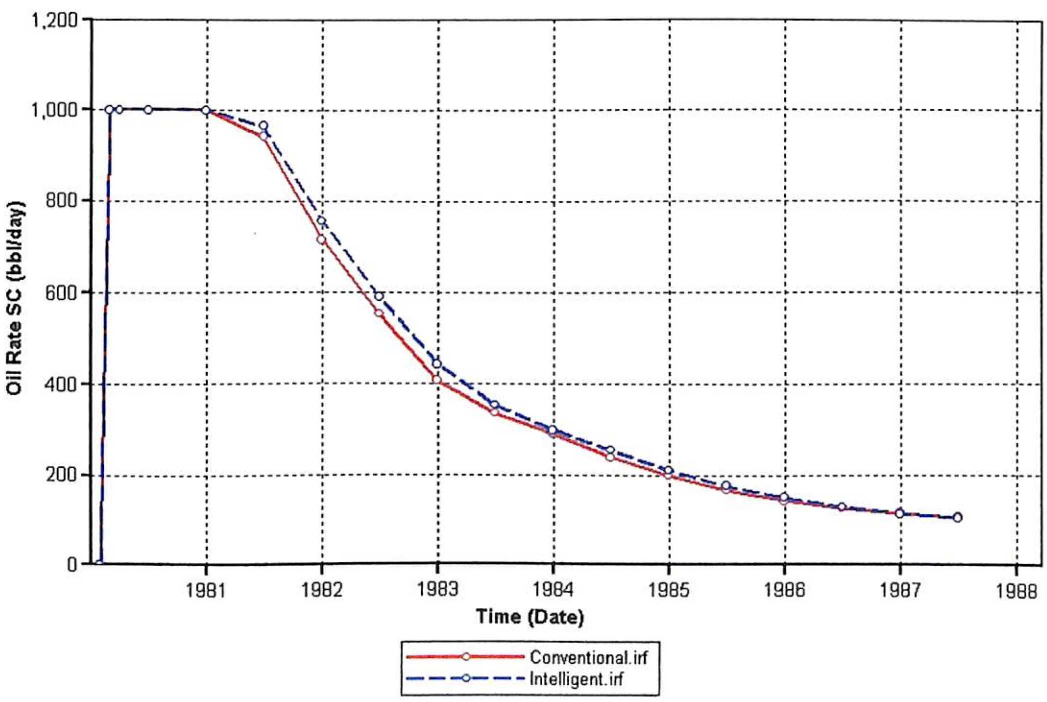


Figure 67- Oil Rate Difference (bbl/day)

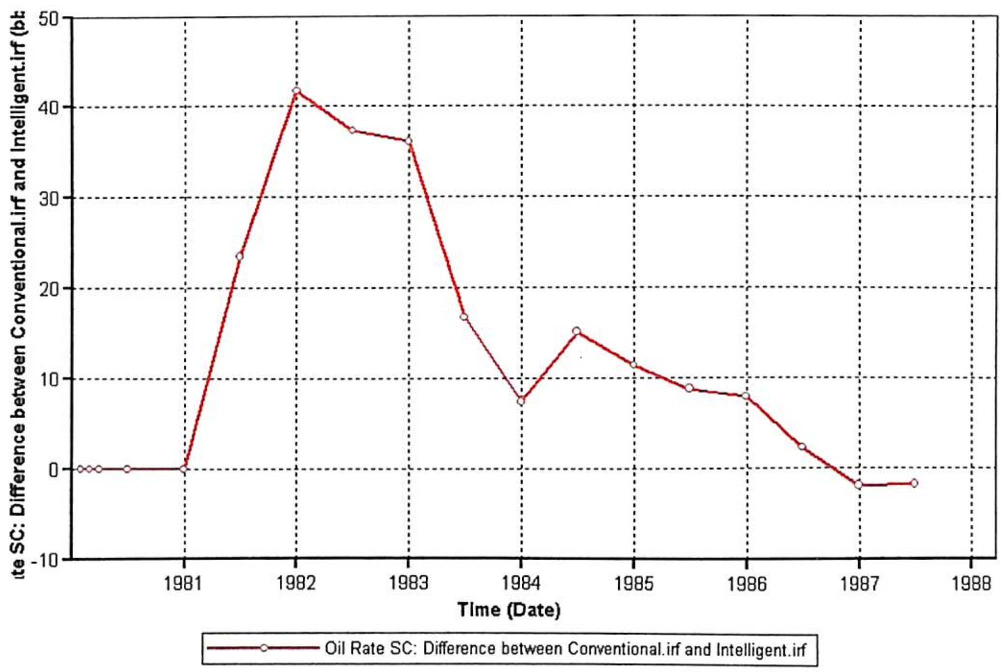


Figure 68- Water Rate SC (bbl/day)

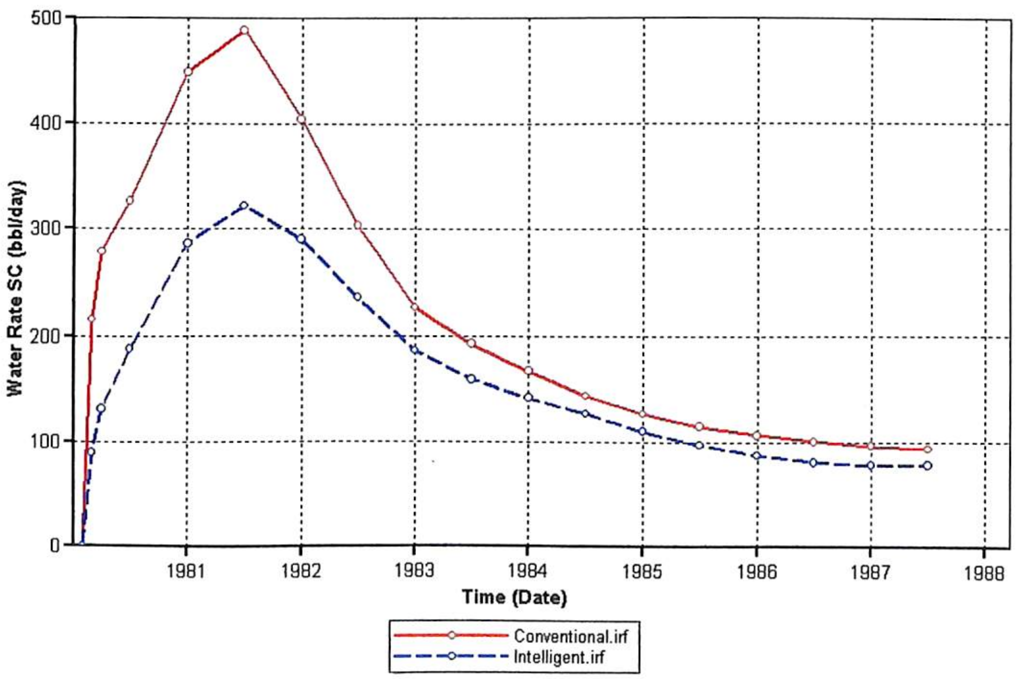


Figure 69- Water Rate Difference (bbl/day)

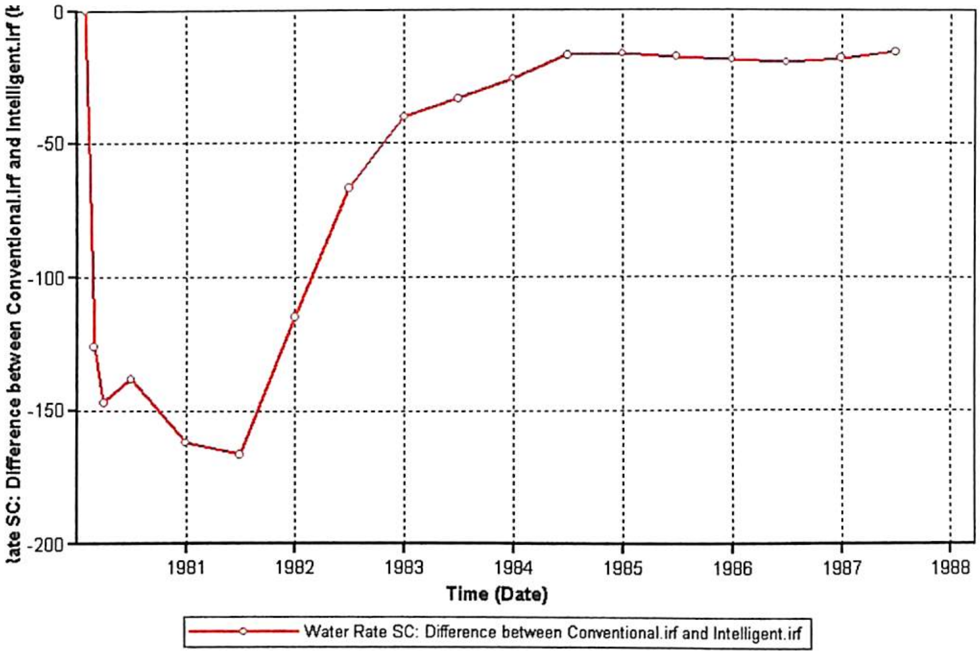
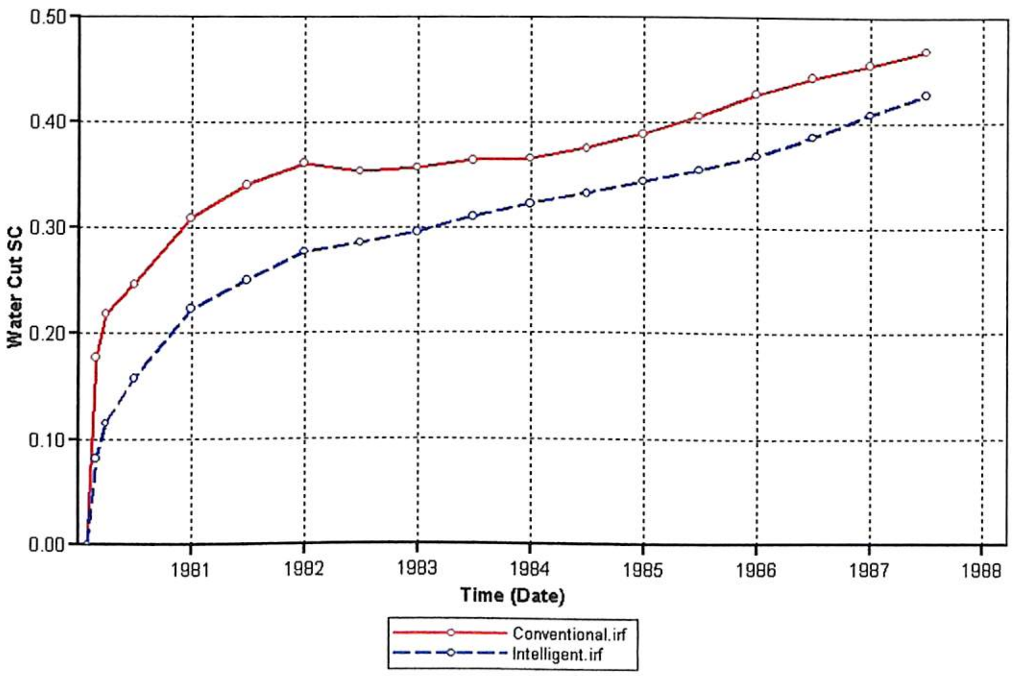


Figure 70- Water Cut SC

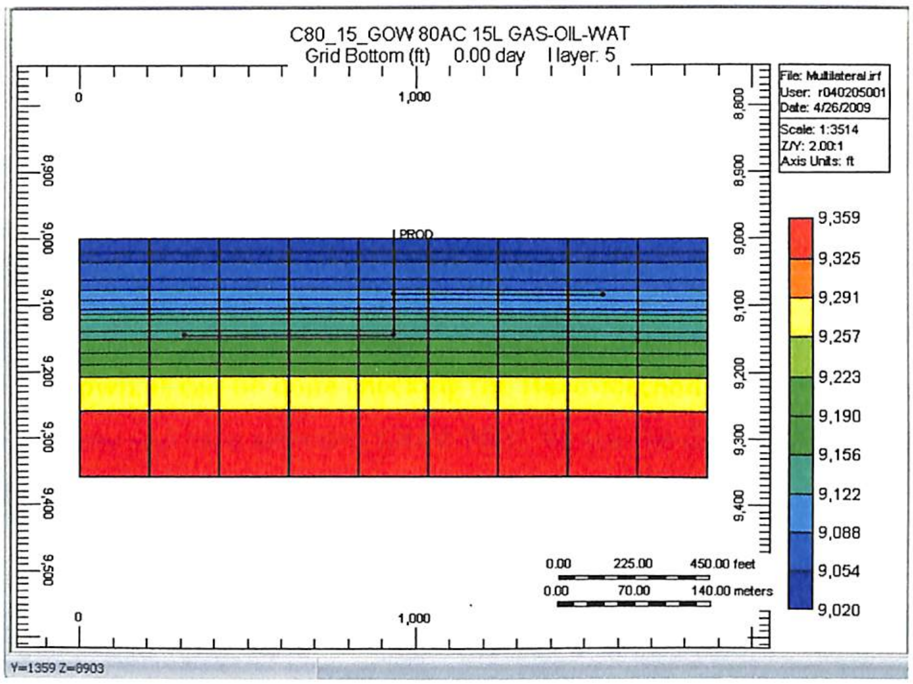


5.5 Multilateral Well vs. Intelligent Multilateral Well

A multilateral well with dual opposing laterals was taken as producer for the reservoir.

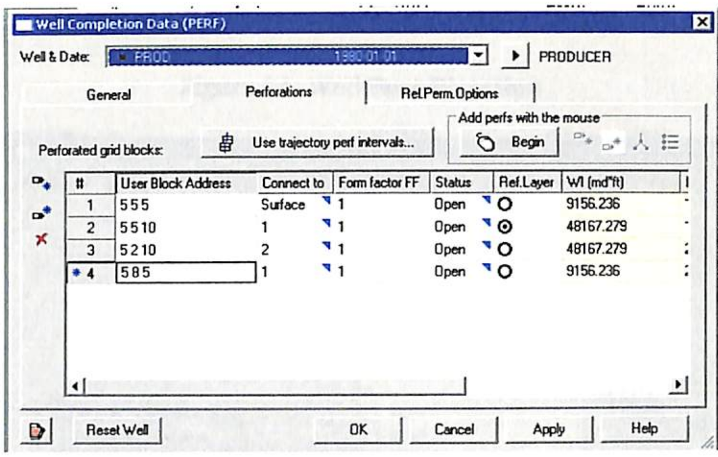
- Two perforations were done in each of the lateral of the multilateral well in the 5th and 10th layer.

Figure 71- J-K Section View for Multilateral Well



- The perforations for lateral in 5th layer were done in grids (5, 5, 5) and (5, 8, 5).
- The perforations for lateral in 10th layer were done in grids (5, 2, 10) and (5, 5, 10).

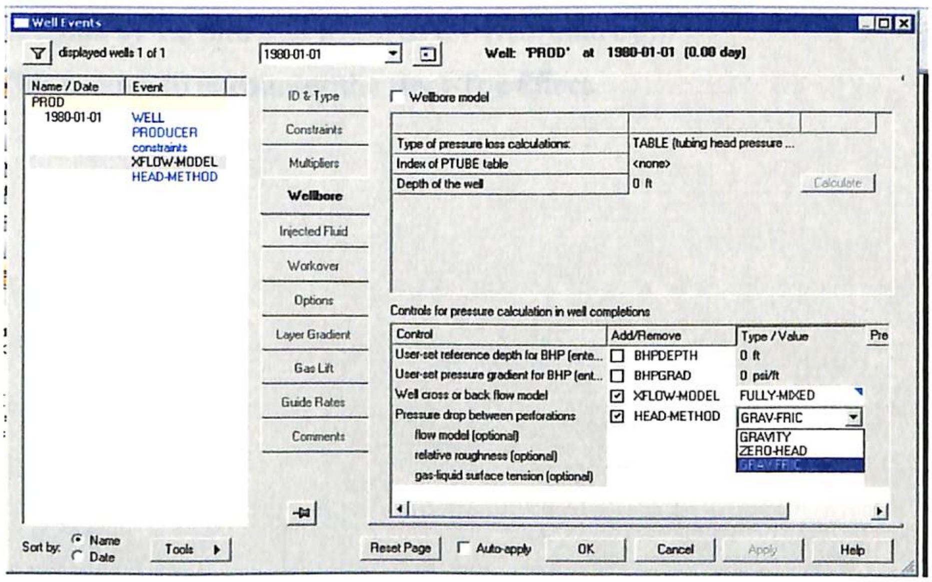
Figure 72- Perforations in Multilateral Well



5.5.1 Simulation Steps for Intelligent Multilateral Well

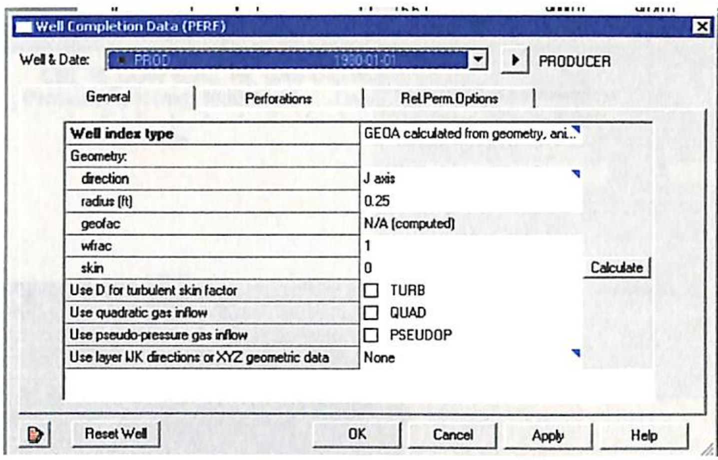
To correctly show the behavior of a multilateral well, the pressure drop due to friction is essential to be shown. It can be done checking the Head-Method in the Wellbore Tab of the Well Events window and then selecting GRAV-FRIC. To see the data file refer to Annexure A at the end of report.

Figure 73- Pressure Drop due to Friction



Another important change required is to change the well bore direction so as to correctly model the flow behavior and flow direction. The direction can be changed to J- Axis (meaning well bore is parallel to J-Axis) by selecting General Tab in the Well Completions Data (PERF) window.

Figure 74- Well Bore Direction



The simulation steps for Intelligent multilateral well are similar to that of Vertical Intelligent Well. The difference being that here we modify the K-Permeability instead of I-Permeability since the flow into the well occurs from K- Direction. Here also we implement Flow Control in the lower lateral only.

- Divide the current value of the K-Permeability of the perforation towards the Toe side by 1.5 and that towards the Heel side by 3.
- This is done to encounter the Heel-Toe Effect.

Figure 75- Permeability Modification at Toe

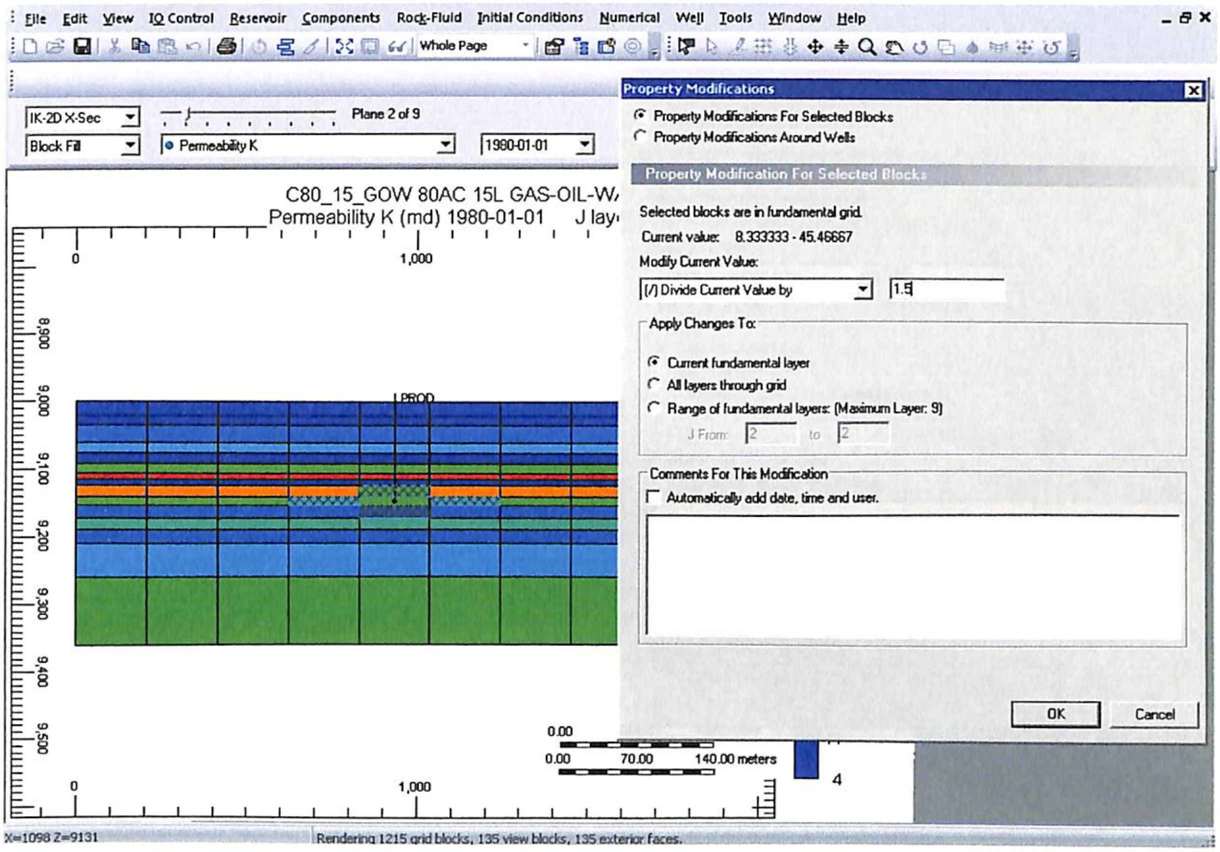
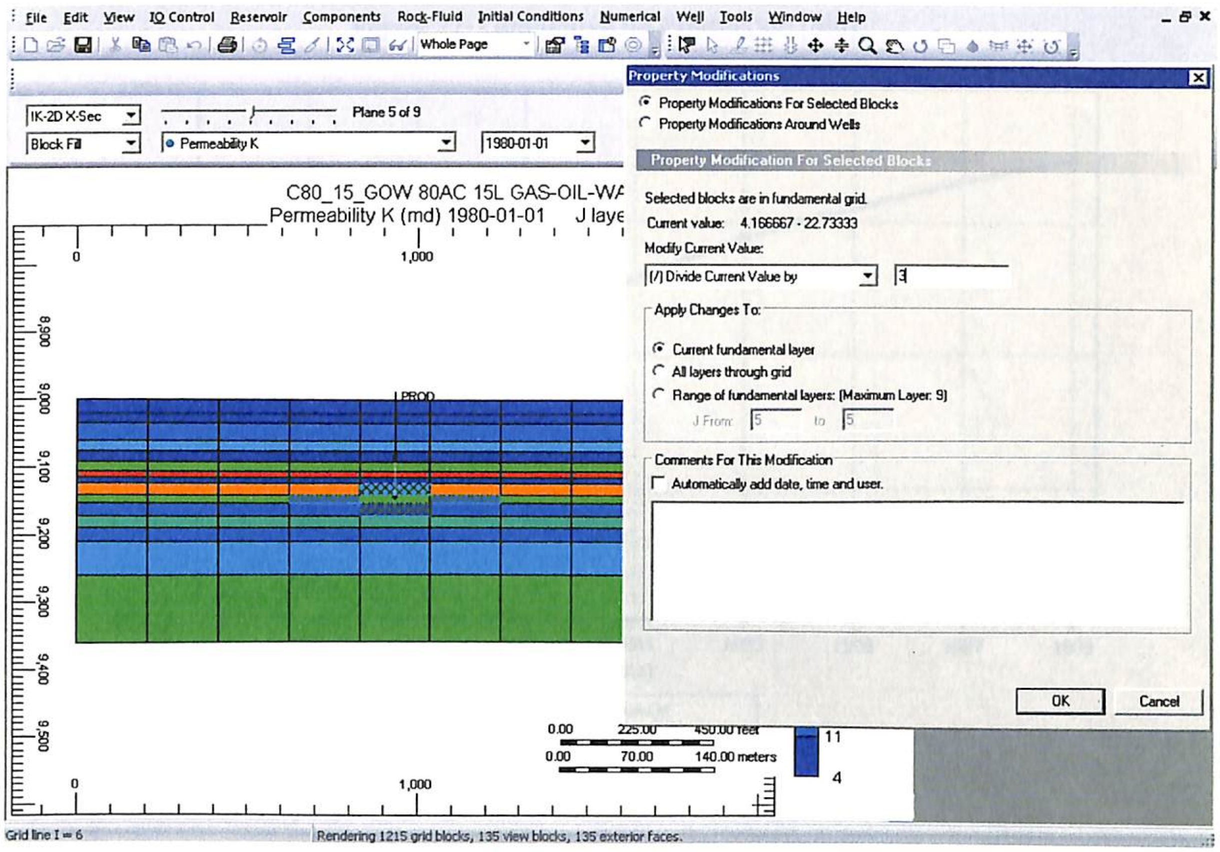


Figure 76- Permeability Modification at Heel



- We now use the CMG- Result Graph to make the graphs and compare the various parameters.

5.5.2 Result of Simulation

The following conclusions were drawn by observing and analyzing the graphs.

1. An increment of 1, 200 bbl of was shown in the Cumulative Oil Recovery at standard conditions.
2. The Cumulative water production was decreased by 11, 000 bbl.
3. The water cut was decreased from 0.14 to 0.12.
4. The oil rate was increased but not appreciably
5. Water rate was decreased appreciably.

The above observations prove the benefit of using the Inflow Control Device in a Intelligent Multilateral Well.

5.5.3 Graphs

Figure 77- Cumulative Oil Production (bbl)

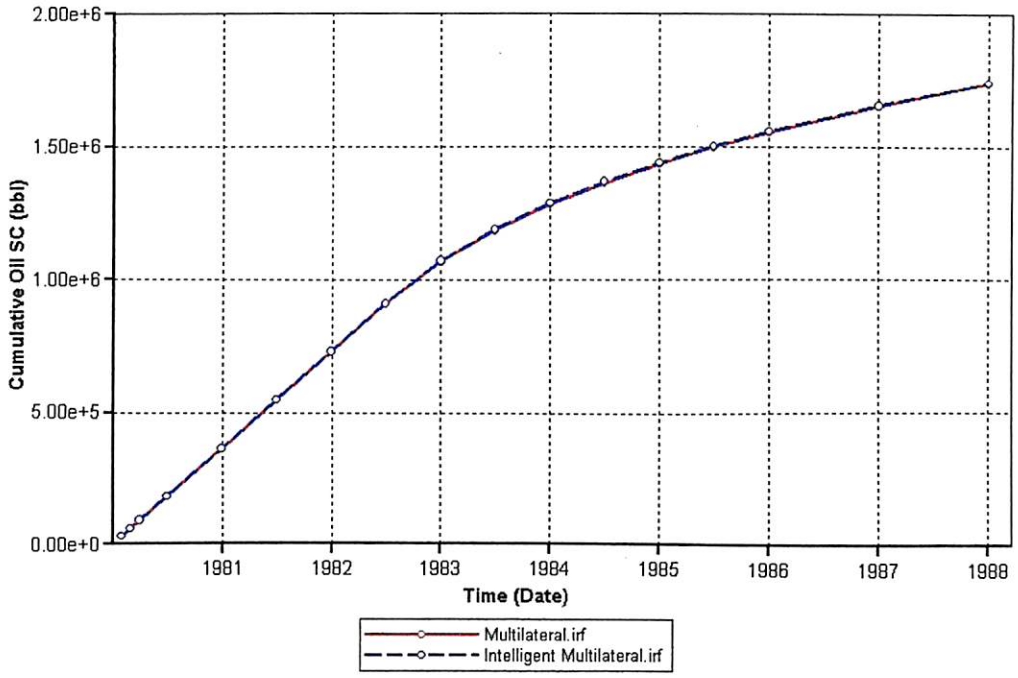


Figure 78- Cumulative Oil Difference (bbl)

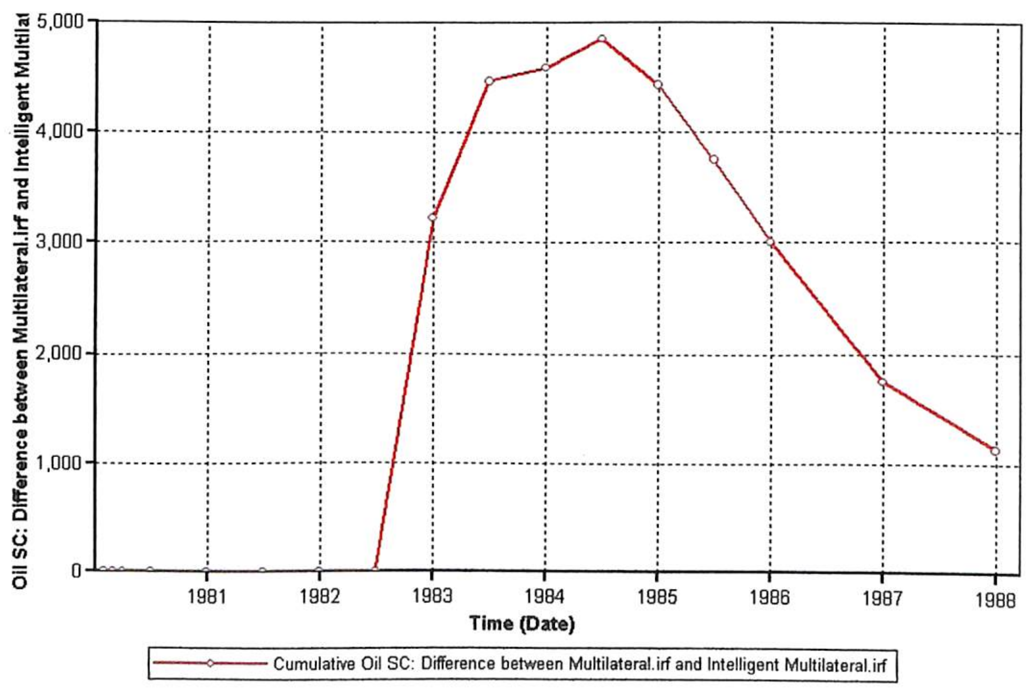


Figure 79- Cumulative Water SC (bbl)

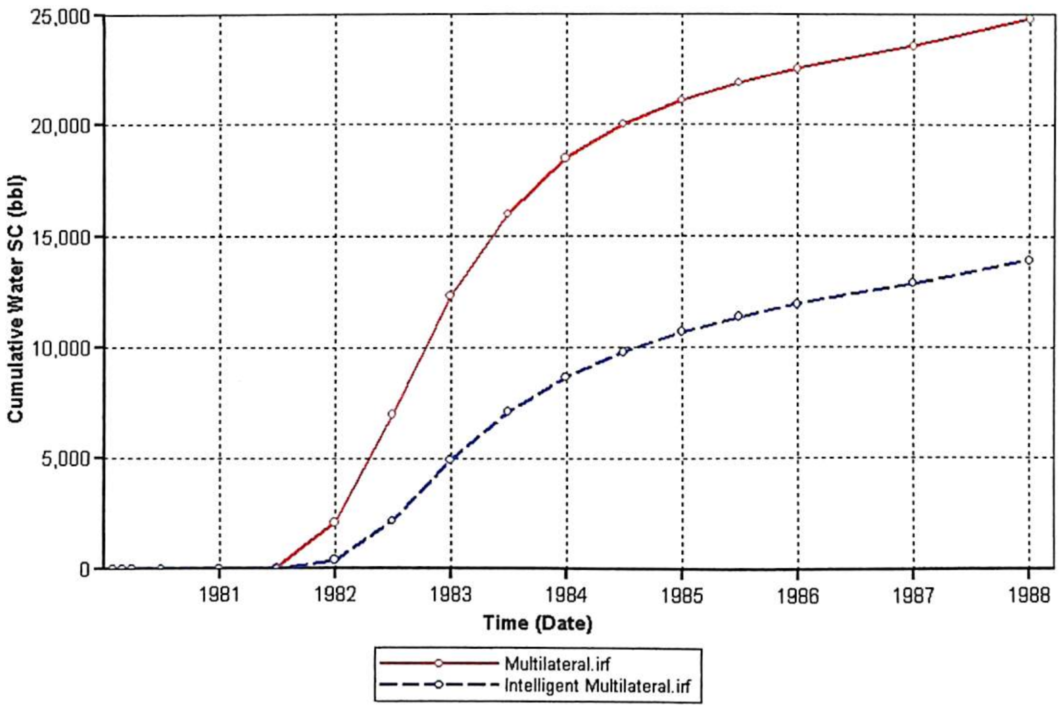


Figure 80- Cumulative Water Difference (bbl)

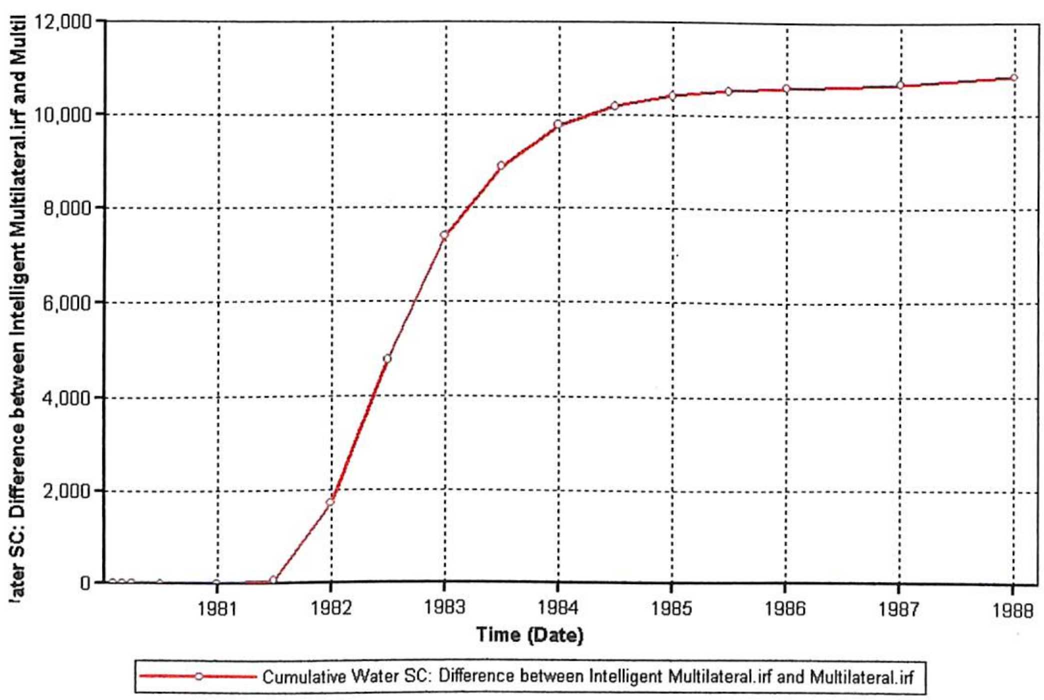


Figure 81- Oil Rate SC (bbl/day)

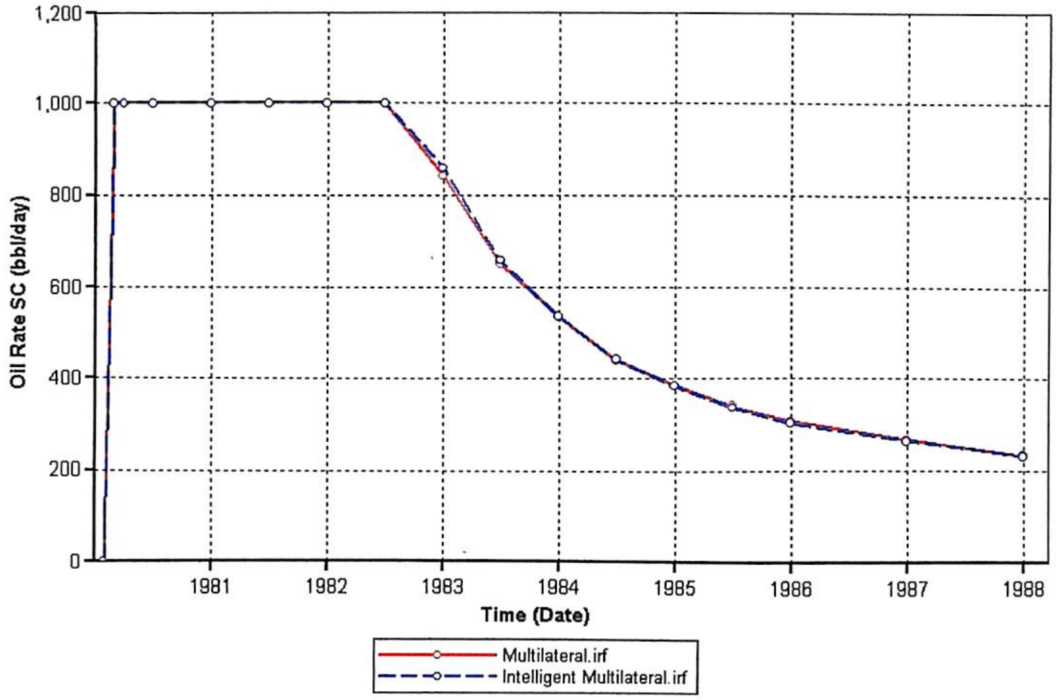


Figure 82- Oil Rate Difference (bbl/day)

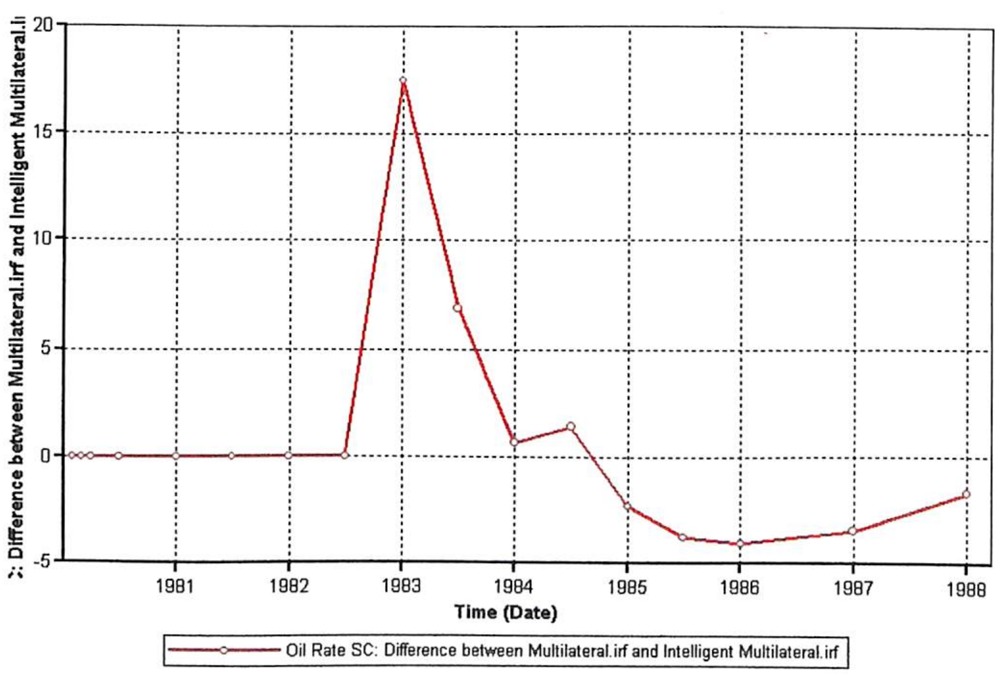


Figure 83- Water Rate SC (bbl/day)

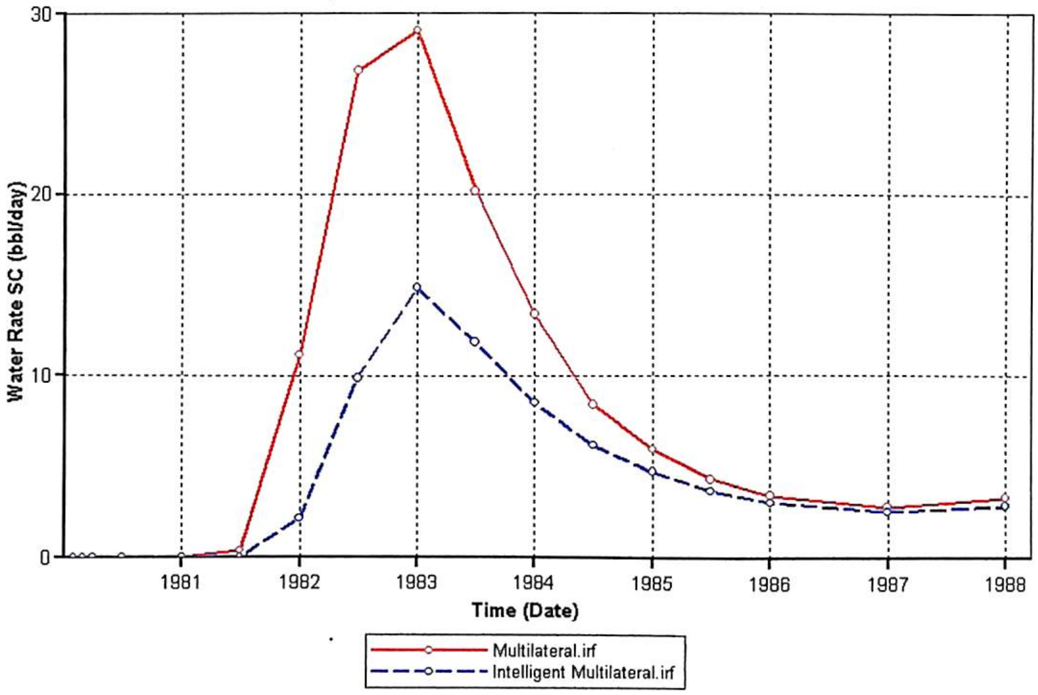


Figure 84- Water Rate Difference (bbl/day)

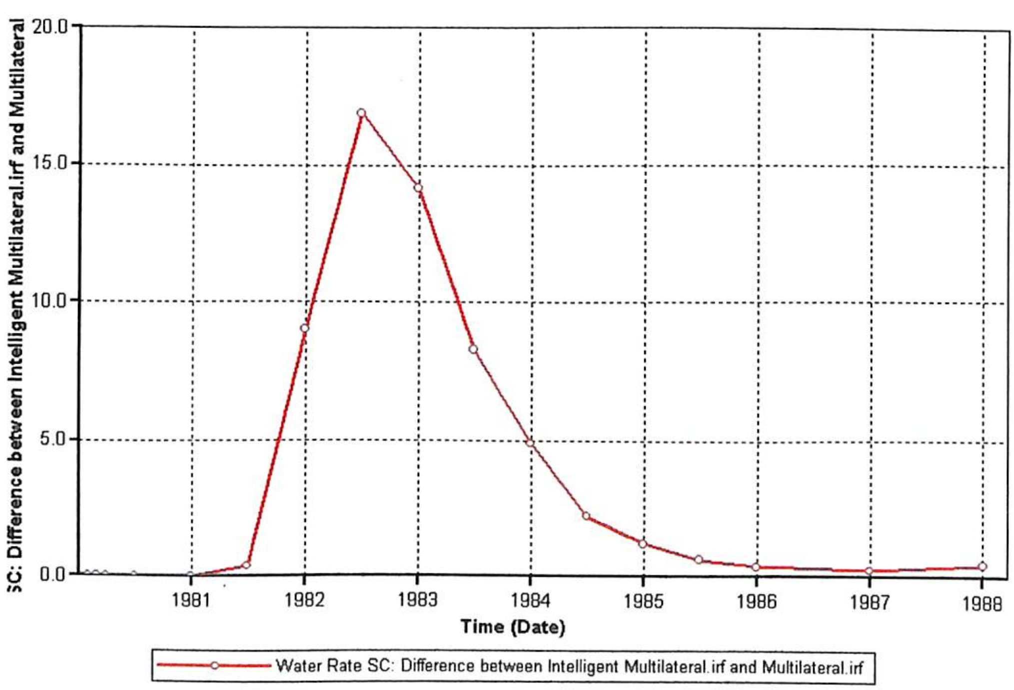
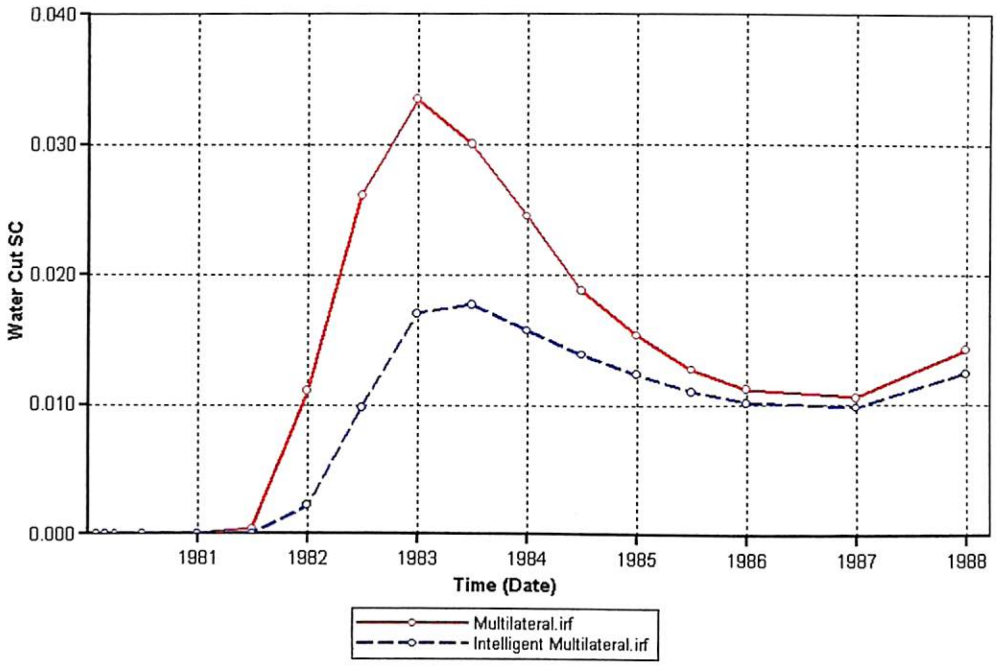


Figure 85- Water Cut SC



6. CONCLUSION

1. Multilateral Wells provide maximum reservoir contact for increased productivity or injectivity and improved recovery factors.
2. An intelligent well is capable of accelerating reserve recovery and reducing cumulative water production in a layered reservoir with respect to a conventionally completed well.
3. The intelligent well systems incorporated in multilateral wells help in mitigating the challenges of early water or gas breakthrough in any of the branches, cross flow and difficulty in accurately allocating production from each branch, thereby enhancing the value of multilateral wells by providing independent monitoring and control of the different branches without costly well intervention. This increases the flexibility of the field development plan.
4. This involves many aspects of drilling and production, therefore, a total integrated approach needs to be used during job design and installation. Compatibility issues require a complete analysis of each segment of the reservoir development plan, drilling/completion program and facility design, to optimize technology inter faces at each step.
5. Hence, it is essential to accurately model an intelligent completion within the reservoir if the performance of the well is to be predicted and the well is to be ideally managed throughout its life. Only then its economic value can be understood.

The conclusions drawn from the **CMG Simulation Model** used are:

1. The Model confirmed that the Inflow Control Devices have a significant effect on the control of Water Production.
2. The Oil Production also increases to a certain extent. However, further optimization of the Inflow may be required.
3. Heel-Toe effect can be efficiently controlled.
4. An economic analysis is essential to prove the effectiveness and economic viability of the Intelligent Well Technology.

The model quantifies the incremental benefit of the intelligent completion employed in the Multilateral Well Technology.

7. RECOMMENDATIONS

- Further optimization of the Inflow may be required at heel and toe.
- Relationship between the production and the choking effect can be made by taking several cases to use optimum reduction factor for permeability in the simulation model.
- Real time monitoring implementation in simulation will give more realistic results.

BIBLIOGRAPHY

1. **Richard S. Carden, Robert D. Grace.** Horizontal and Directional Drilling Manual. Tulsa, Oklahoma : Petroskills, 2007, pp. 6-28, 6-29.

2. *Multilaterals: An Overview and Issues Involved in Adopting This Technology.* **Vij S.K., SPE, Narasaiah S. L., Walia Anup, SPE, and Singh Gyan, SPE, Oil and Natural Gas Corporation Limited.** New Delhi, India : SPE, 17-19 February, 1998. SPE 39509.

3. **Rabia, Hussain.** Well Engineering and Construction. pp. 549-569.

4. *Optimizing Maximum-Reservoir-Contact Wells: Application to Saudi Arabian Reservoirs.* **Hussain A., SPE, Kumar A. , SPE, Garni S.A. , SPE, and Shammari M.A., SPE, Saudi Aramco.** Doha, Qatar : International Petroleum Technology Conference, 21-23 November, 2005. IPTC 10395.

5. **Temp.** Pro Tech JP Ch 1 A/W. *Production Technology I.* s.l. : Heriot-Watt University, pp. Ch-13, Page 18-34.

6. *Screening Variables for Multilateral Technology.* **Brister Ray, SPE, Chevron Petroleum Technology Company.** Beijing, China : SPE, 2000. SPE 64698.

7. *Multilateral Technology as a Creative Reservoir Development Strategy for New and Mature Fields Alike.* **Oberkircher Jim, Halliburton Energy Services.** Melbourne, Australia : SPE, 8-10 October, 2002. SPE 77826.

8. **Mac_CDBurner.** RapidConnect Multilateral Completion System. *Schlumberger.* [Online] http://www.slb.com/media/services/completion/multilaterals/rapidconnect.pdf.

9. **Schlumberger.** RapidExclude. *Schlumberger.* [Online] http://www.slb.com/media/services/completion/multilaterals/rapidexclude.pdf.

10. Rapid TieBack Quad System. *Schlumberger.* [Online] http://www.slb.com/media/services/completion/multilaterals/rapidtieback.pdf.

11. FORMation Junction System. *Baker Oil Tools.* [Online] http://www.bakerhughesdirect.com/cgi/bot/resources/ExternalFileHandler.jsp?bookmarkable=Yes&path=private/BOT/public/multilaterals_expandables/multilateral_systems/formation_junction/index.html&channelId=-546906737.

12. Stackable Splitter System. *Baker Oil Tools.* [Online] http://www.bakerhughesdirect.com/cgi/bot/resources/ExternalFileHandler.jsp?bookmar

kable=Yes&path=private/BOT/public/multilaterals_expandables/multilateral_systems/stackable_splitter/index.html&channelId=-546906744.

13. *Boon or Bane? A Survey of the First 10 Years of Modern Multilateral Wells.* **Oberkircher Jim, Smith Ray,Halliburton Energy Services,Thackwray Ian,Woodside Energy Ltd.** Denver, Colorado, U.S.A. : SPE, 5-8 October, 2003. SPE 84025.

14. **Thompson I.M., SPE, Sarkar R., SPE, Halliburton Energy Services Inc. and Parker E.D.,SPE, Landmark Graphics.** *Predicting the Reservoir Response to Intelligent Wells.* Paris, France : SPE, 24-25 October, 2000. SPE 65143.

15. Baker Oil Tools Product Catalogue. s.l. : Baker Oil Tools.

16. TRFC-HN AP and TRFC-HN LP hydraulic flow control valves. *Schlumberger.* [Online] http://www.slb.com/content/services/completion/intelligent/trfc_hh_ap_lp.asp?.

17. Halliburton Product Catalogue. s.l. : Halliburton.

18. BOT-04-6197_IWS Applications_brochure_web.indd. *Intelligent Solutions for Reservoir Management.* s.l. : Baker Oil Tools.

19. *Intelligent-Well Technology Reduced Water Production in a Multilateral Oil Producer.* **A. Ajayi, SPE and M.R. Konopczynski, SPE, WellDynamics Inc.** SPE 102982.

20. *Advanced Wells: A Comprehensive Approach to the selection between Passive and Active Inflow Control Completions.* **F.T. Al-Khelaiwi, V.M.Birchenko SPE Heriot Watt University and M.R. Konopczynski, SPE, WellDynamics.** IPTC 12145.

21. *Best Cleanup Practices for an Offshore Sandstone Reservoir with ICD Completions in Horizontal Wells.* **Ali M. Shahri, Khalid Kilany, Drew Hembling, J. Eric Lauritzen, SPE/Saudi Aramco, Varma Gottumukkala, Olusegun Ogunyemi/Schlumberger, Oscar Becerra Moreno/Baker Oil Tools.** SPE 120651.

22. *New Technology Applications to Extend Field Economic Life by Creating Uniform Flow Profiles in Horizontal Wells: Case Study and Technology Overview.* **Eugene E. Ratterman, SPE, Baker Oil Tools, Benn A. Voll, Baker Oil Tools, Jody R. Augustine, SPE, Baker Oil Tools.** OTC-17548.

23. *Drilling and Completing Intelligent Multilateral MRC Wells in Haradh Inc-3.* **Fahad Al-Bani and Ahmad Shah Baim, SPE, Saudi Aramco, and Suresh Jacob, SPE, WellDynamics Inc.** Amsterdam, The Netherlands : SPE/IADC Drilling Conference, 20-22 February, 2007. SPE/IADC 105715.

24. *Using Economic and Production Evaluation Methodologies to Expedite Commercialization of Intelligent and Multilateral Wells.* **X. Ramos, Occidental Exploration & Production Co., and A. Anderson, SPE, S.A. Sakowski, SPE, and C. Hogg, SPE, Baker Oil Tools.** Jakarta, Indonesia : SPE, 5-7 April, 2005. SPE 93859.

25. **Soni, Y.S.** Clas Notes-Reservoir Modeling and Simulation. s.l. : UPES, 2008.

26. *Smart Wells.* **Jansen, J.D.** s.l. : SPE, 2001.

27. **Sada D. Joshi, Ph.D.** *Horizontal Well Technology.* Tulsa, Oklahoma : Pennwell Books, 1991. pp. 379-420.

28. *Case Study: The Application of Inflow Control Devices in the Troll Oil Field.* **Knut H. Henriksen, SPE, Baker Oil Tools, Eli Iren Gule, SPE, Hydro ASA and Jody Augustine, SPE, Baker Oil Tools.** SPE 100308.

29. *Inflow Control Device and Near-Wellbore Interaction.* **T. Moen, SPE, Reslink AS, and H. Asheim, SPE, NTNU.** SPE 112471.

30. **Settari, Aziz &.** *Petroleum Reservoir Simulation.* London : Applied Science Publishers, 1979.

ANNEXURE A

```
*TITLE1
'C80_15_GOW 80AC 15L GAS-OIL-WAT'
*TITLE2
'NO FRAC, NO FAULTS, NO SHALES'
*INUNIT *FIELD
*DIM *MAX_LAYERS 15
** CONTROL THE FREQUENCY OF VARIOUS OUTPUTS
*WPRN *WELL *TIME
*WPRN *GRID *TIME
*WPRN *SECTOR *TIME
*WPRN *ITER *BRIEF
*WSRF *WELL *TIME
*WSRF *GRID *TIME
*WSRF *SECTOR *TIME
** SPECIFY ITEMS FOR VARIOUS PRINTOUTS
*OUTPRN *WELL *ALL ** ALSO *BRIEF, *RESERVOIR, *LAYER *NONE
*OUTPRN *GRID *SO *SW *PRES *SEAWF ** ALSO *ALL, *EXCEPT, *NONE
*OUTPRN *TABLES *ALL ** ALSO *NONE
*OUTPRN *RES *ALL **PV *SECTOR *DI *DK ** THESE ARE INIT CONDITIONS AT T=0
*OUTPRN *WELL-SECTOR *SORT-WELL-NAME
*OUTPRN *WELL-SECTOR *SORT-WELL-NUM ** THIS MAY BE REDUNDANT
*OUTSRF *WELL *DOWNHOLE
*OUTSRF *WELL *BLOCKP *ON
*OUTSRF *WELL *LAYER *ALL *DOWNHOLE
*OUTSRF *GRID *SO *SW *PRES *FLUXSC *STRMLN *SEAWF ** ALSO *ALL, *EXCEPT,
*NONE
*OUTSRF *RES *ALL ** OR *NONE THESE ARE INIT CONDITIONS AT T=0
*OUTSRF *SPECIAL 1 1 1 *SG
*XDR *OFF ** OR MAKE IT *ON FOR EXPORTABLE BINARY FILE
```

```
****************************************************************************
**          *GRID
****************************************************************************
*GRID  *VARI 9 9 15
*KDIR *DOWN
*DI *IVAR
9*207.418
*DJ *JVAR
9*207.418
*DK *KVAR
20  15  26  15  16  14  2*8  18  12  19  18  20  50  100
*PERMI *IJK
1:9  1:9   1    35.0
1:9  1:9   2    47.5
1:9  1:9   3   148.0
1:9  1:9   4   202.0
1:9  1:9   5    90.0
1:9  1:9   6   418.5
1:9  1:9   7   775.0
1:9  1:9   8    60.0
1:9  1:9   9   682.0
1:9  1:9  10   472.0
1:9  1:9  11   125.0
1:9  1:9  12   300.0
1:9  1:9  13   137.5
1:9  1:9  14   191.0
1:9  1:9  15   350.0
*MOD
 5:5   2:2   9:9   / 2
 4:4   2:2  10:10  / 2
 6:6   2:2  10:10  / 2
```

5:5 2:2 11:11 / 2
5:5 5:5 9:9 / 2
4:4 5:5 10:10 / 2
6:6 5:5 10:10 / 2
5:5 5:5 11:11 / 2
5:5 2:2 9:9 / 2
4:4 2:2 10:10 / 2
6:6 2:2 10:10 / 2
5:5 2:2 11:11 / 2
5:5 2:2 9:9 * 4
4:4 2:2 10:10 * 4
6:6 2:2 10:10 * 4
5:5 2:2 11:11 * 4
5:5 5:5 9:9 * 2
4:4 5:5 10:10 * 2
6:6 5:5 10:10 * 2
5:5 5:5 11:11 * 2
PERMJ EQUALSI * 1
*POR *ALL
81*0.087 81*0.097 81*0.111 81*0.16 81*0.13 162*0.17
81*0.08 81*0.14 81*0.13 81*0.12 81*0.105 81*0.12
81*0.116 81*0.157
*PERMK *ALL
81*35 81*47.5 81*148 81*202 81*90 81*418.5
81*775 81*60 81*682 81*472 81*125 81*300
81*137.5 81*191 81*350
*MOD **PERMK KV/KH=0.1
1:9 1:9 1:15 * 0.1
5:5 5:5 9:9 / 2
4:4 5:5 10:10 / 2
6:6 5:5 10:10 / 2

```
5:5   5:5   11:11  / 2
5:5   2:2    9:9   / 4
4:4   2:2   10:10  / 4
6:6   2:2   10:10  / 4
5:5   2:2   11:11  / 4
5:5   5:5    9:9   * 2
4:4   5:5   10:10  * 2
6:6   5:5   10:10  * 2
5:5   5:5   11:11  * 2
5:5   5:5    9:9   / 3
4:4   5:5   10:10  / 3
6:6   5:5   10:10  / 3
5:5   5:5   11:11  / 3
5:5   2:2    9:9   * 4
4:4   2:2   10:10  * 4
6:6   2:2   10:10  * 4
5:5   2:2   11:11  * 4
5:5   2:2    9:9   / 1.5
4:4   2:2   10:10  / 1.5
6:6   2:2   10:10  / 1.5
5:5   2:2   11:11  / 1.5
**$ Property: Pinchout Array  Max: 1  Min: 1
**$  0 = pinched block, 1 = active block
PINCHOUTARRAY CON        1
CPOR 0
*DTOP
81*9000
**$ Property: NULL Blocks  Max: 1  Min: 1
**$  0 = null block, 1 = active block
NULL CON        1
```

```
** CAN ALSO USE [*DEPTH-TOP] OR [*PAYDEPTH] OR [*DEPTH *TOP or *CENTER i j k value]
*CROCKTYPE 1
*CCPOR 0.000006
*CPRPOR 8327
****************************************************************************
**          *MODEL
****************************************************************************
*MODEL *BLACKOIL
*DENSITY *OIL 49.99   **NEED TO ADD OIL DENSITY
*DENSITY *GAS 0.050
*DENSITY *WATER 68.60
*PVT *BG 1          **NEED TO ADD OIL PROPERTIES
** P      Rs     Bo      Bg       VIS_O    VIS_G
 14.7     0.0   1.062   0.166667   1.040   0.0080
 264.7    90.5   1.150   0.012092   0.975   0.0096
 514.7   180.0   1.207   0.006289   0.910   0.0112
1014.7   371.0   1.295   0.003195   0.830   0.0140
2014.7   636.0   1.435   0.001613   0.695   0.0189
2514.7   775.0   1.500   0.001294   0.641   0.0208
3014.7   930.0   1.565   0.001080   0.594   0.0228
4014.7  1270.0   1.695   0.000811   0.510   0.0268
5014.7  1618.0   1.827   0.000649   0.449   0.0309
9014.7  2984.0   2.352   0.000386   0.203   0.0470  ** bO CAHNGED FROM 2.357  TO 2.352
*REFPW 8327
*BWI 1.054
*CW 0.00000357
*VWI 0.241
*CVW 0
*CO  1.3687E-5 ** ADD OIL COMPRESSIBILITY
```

```
*CVO  4.6000E-5  ** ADD OIL VISCOSIBILITY FACTOR
******************************************************************************
**        *ROCKFLUID
******************************************************************************
*ROCKFLUID
*KROIL *SEGREGATED    ** ADD 3-PHAE KRO OPTION AND O-W AND G-O TABLES
*RPT 1
*SWT
** SW  KRW  KR  PCOW
0.200 0.000 1.000 7.00
0.250 0.000 0.715 5.41
0.300 0.003 0.492 4.12
0.350 0.010 0.323 3.09
0.400 0.024 0.201 2.30
0.450 0.047 0.117 1.71
0.500 0.081 0.065 1.30
0.550 0.129 0.035 1.03
0.600 0.192 0.022 0.88
0.650 0.274 0.017 0.80
0.700 0.376 0.012 0.78
0.750 0.500 0.000 0.78
0.800 0.600 0.000 0.77
0.850 0.700 0.000 0.71
0.900 0.800 0.000 0.59
0.950 0.900 0.000 0.36
1.000 1.000 0.000 0.00
*SGT
** SG  KRG  KROG  PCGO
0.00   0.000 1.000 0.00
0.07   0.001 0.690 1.26
0.13   0.004 0.454 1.92
```

```
0.20    0.014  0.282  2.18
0.26    0.034  0.163  2.22
0.33    0.067  0.088  2.25
0.39    0.116  0.045  2.44
0.46    0.184  0.025  3.01
0.52    0.275  0.018  4.13
0.59    0.391  0.013  6.00
0.65    0.536  0.000  8.82
0.68    0.614  0.000  10.50
0.71    0.699  0.000  12.43
0.74    0.791  0.000  14.65
0.77    0.892  0.000  17.17
0.80    1.000  0.000  20.00
*****************************************************************************
**          *INITIAL
*****************************************************************************
*INITIAL
*VERTICAL *DEPTH AVE *WATER OIL GAS  ** THIS CARD MODIFIED
*REFDEPTH 9061
*REFPRES 3600
*DWOC 9209      ** REPLACE DWGC BY DWOC
*DGOC 9061      ** ADD DGOC
*PB *CON 3600.0  ** ADD INITIAL BUBBLE POINT PRESSURE
*****************************************************************************
**          *NUMERICAL
*****************************************************************************
*NUMERICAL
*DTMAX 365.0
*DTMIN 0.1
*****************************************************************************
**          *RUN
```

```
*****************************************************************************************
*RUN
*DATE 1980 1 1
GROUP 'GRP' ATTACHTO 'FIELD'
*DTWELL 1
**$
WELL 'PROD' ATTACHTO 'GRP'
PRODUCER 'PROD'
OPERATE  MAX  STO  1000.  CONT REPEAT
OPERATE  MAX  STG  2e+006  CONT REPEAT
OPERATE  MIN  BHP  1000.  CONT
**$        rad  geofac  wfrac  skin
GEOMETRY  J  0.25  0.37  1.  0.
PERF  GEOA  'PROD'
**$ UBA     ff  Status  Connection
  5 5 5   1.  OPEN    FLOW-TO  'SURFACE'
  5 5 10  1.  OPEN    FLOW-TO  1  REFLAYER
  5 2 10  1.  OPEN    FLOW-TO  2
  5 8 5   1.  OPEN    FLOW-TO  1
XFLOW-MODEL 'PROD' FULLY-MIXED
HEAD-METHOD 'PROD' GRAV-FRIC
*DATE 1980 2 1
*DATE 1980 3 1
*DATE 1980 4 1
*DATE 1980 7 1
*DATE 1981 1 1
*DATE 1981 7 1
*DATE 1982 1 1
*DATE 1982 7 1
*DATE 1983 1 1
*DATE 1983 7 1
```

*DATE 1984 1 1

*DATE 1984 7 1

*DATE 1985 1 1

*DATE 1985 7 1

*DATE 1986 1 1

*DATE 1987 1 1

*DATE 1988 1 1

*STOP

RESULTS SPEC 'Permeability I'

RESULTS SPEC SPECNOTCALCVAL -99999

RESULTS SPEC REGION 'All Layers (Whole Grid)'

RESULTS SPEC REGIONTYPE 'REGION WHOLEGRID'

RESULTS SPEC LAYERNUMB 0

RESULTS SPEC PORTYPE 1

RESULTS SPEC EQUALSI 1 1

RESULTS SPEC STOP