Screening of Reservoir Types for Decision-Making on the Application of Intelligent Wells

Farhad Ebadi

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Institute of Petroleum Engineering, Heriot-Watt University

Edinburgh, United Kingdom

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Abstract

Intelligent Well systems Technology (IWsT) focuses on delivery and management of production flexibility thorough downhole measurement and control.

This thesis uses a new workflow to develop techniques for decision-making on the application of Intelligent Wells. The value generation capability of Intelligent Wells by using a "show case" of case histories, general experience from operators, etc. is demonstrated. A road map for the rapid screening of a candidate well or field to determine whether it would benefit from evaluation of the IWsT to "Add Value" has been described. It evaluates the suitability of a wide range of reservoir types for IWsT application. This is achieved by a systematic study of a series of generic reservoir scenarios, based on property distributions derived from real field data and operational oilfield models. The geological scenarios were tested and the degree of heterogeneity was systematically increased in order to determine the "Added Value from IWsT" compared to standard well completions.

Results show that IWsT can control uneven, invading fluid fronts that develop along the wellbore length due to permeability differences, reservoir compartmentalisation or different strength of aquifer or gas cap support. Downhole Interval Control Valves (ICVs) are capable of managing wellbore friction effects as well as the above differences in zone pressure along the wellbore. Oil recovery factors improve and co-produced water volumes reduce with proper valve choking, when combined with a correct selection of the ICV location(s) and control zone length. However, the degree of improvement is dependent on the reservoir type (Layered, Faulted, Channelised, etc.) and the distribution of porosity and permeability within it.

A global methodology is developed for initial screening for favourable, geological scenarios for the implementation of IWsT. An IWsT Application Envelope, based on the formation's correlation length (CL) and coefficient of variation (C_V) is described. "IWsT Added Value" has been identified when the C_V, CL_H/WL and CL_V/RT parameter values are such that an uneven fluid front development of sufficient magnitude develops in such a manner that it can be managed by the ICV in order to improve the sweep efficiency OR to allow a greater oil production while meeting well outflow or facility

water or gas handling constraints. The validity of this "Added Value" envelope has been illustrated by its application to a real reservoir modelling case. The combination of the volume of reserves to be developed by the well and the "Added Value" suggested by these screening tools can be used to justify the IWsT project.

ICV placement guidelines for a wide range of well and reservoir scenarios have been presented. The results show that how a good understanding of the reservoir geology is the key to ICV placement. This geological understanding along with appreciation of the reservoir drive mechanism aids prediction of the fluid-front movement towards the wellbore, allowing an optimum placement (number and location) of ICVs along the length of the wellbore for efficient flow control. The interplay of the CV, CL_H and CL_V parameters, well length and the length of the zone to be controlled by each ICV will determine the shape of fluid front development towards the wellbore.

This thesis continues with the study on whether "Proactive" rather than "Reactive" ICV control adds greater value in Single well reservoir models. "Proactive Control" proved particularly successful in highly heterogeneous reservoir scenarios e.g. where a high-permeability streak, channel or fracture intersects the wellbore. Choking too early (being "Too proactive") often results in losing oil as "Good Water" needs to be produced. "Proactive Control" will also add value when reductions in water or gas production are required due to tubing performance or surface facility limitations. Single Well "Proactive Control" requires that the other zone(s) can compensate for the loss of fluid which was being produced from the choked zone(s). Its value will often increase when Artificial Lift is installed. The value of "Proactive Control" is well known in multiple well scenarios, where value creation requires even-flood front management of an injected fluid.

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Nomenclature

IWsT	Intelligent Well system Technology
ICVs	Interval Control Valves
NTG	Net to Gross Ratio
BHP	Bottom Hole Pressure
THP	Tubing Head Pressure
SLP	Sequential Linear Programming
SQP	Sequential Quadratic Programming
GAs	Genetic Algorithms
VOI	Value Of Information
NPV	Net Present Value
STOIIP	Stock Tank Oil Initially in Place
RT	Reservoir Thickness
WL	Well Length
CFD	Computational Fluid Dynamics
PI	Productivity Index
II	Injectivity Index
PDG	Permanent downhole gages
SD	Standard Deviation
$K_{\bar{ar}}$	Arithmetic average
C_V	Coefficient of Variation
CL	Correlation Length
CL_H	Horizontal Correlation Length
CL_V	Vertical equiv mean

μ	Mean
σ	Variance
C_V	Valve flow coefficient (a calibration factor)
G	Specific density of the fluid (water = 1)
Q	Effective flow rate
q	Total flow rate (gallon per minute)
Q_{ax}	Axial flow
Q_{eff}	Effective flow rate
C_D	Discharge coefficient (dimensionless)
A_0	Orifice area
ρ	Fluid density
A	Area upstream of the valve
ΔP	Differential pressure across the valve
N	Number of pairs of data points
OD_t	Outer diameter of the tubing
ID_c	Inner diameter of the casing
d_{eff}	Equivalent diameter
f	Fanning friction factor
L	Length of tubing in the choke segment
v_p	Flow velocity of the mixture through the choke segment
c_u	Unit conversion constant
γ	Dimensionless coefficient for pressure loss mechanism

List of Publications and Presentations by the Candidate

1. F. Ebadi, G.A. Aggrey and D.R. Davies.: "Added Value from Intelligent Well systems Technology" presented at the "IQPC Fields of the Future" International Conference held in Aberdeen, UK, 22 - 23 September 2004.
2. F. Ebadi, D.R. Davies and P.W.M. Corbett.: "Reservoir Management & Improved Recovery using Intelligent Wells" presented at the 4th International Conference on Improved Oil Recovery (13th Oil, Gas & Petrochemical Congress) held in Tehran, Iran, 24 - 26 January 2005.
3. F. Ebadi, D.R. Davies, M. Reynolds and P.W.M. Corbett.: "Screening of Reservoir Types for Optimisation of Intelligent Well Design", Paper SPE 94053 presented at the 14th Europec Biennial Conference held in Madrid, Spain, 13-16 June 2005.
4. F. Ebadi, D.R. Davies and P.W.M. Corbett.: "The Effect of Reservoir Type on the Added Value from an Intelligent Well" presented at the International Petroleum Geoscience Collaboration Conference held in London, UK, 30th Nov.- 1st Dec. 2005.
5. F. Ebadi and D.R. Davies.: "Should Proactive or Reactive Control be Chosen for Intelligent Well Management?", paper SPE 99929 presented at the Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 11- 13 April 2006.
6. F. Ebadi and D.R. Davies.: "Techniques for Optimum Placement of Interval Control Valve(s) in an Intelligent Well", paper SPE 100191 presented at the SPE Europec/EAGE Annual Conference and Exhibition held in Vienna, Austria, 12 - 15 June 2006.
7. F. Ebadi, D.R. Davies, A.R. Gardiner and P.W.M. Corbett.: "Evaluation of Added Value in Reservoir Management by Application of Flow Control with Intelligent Wells" submitted to the Petroleum Geoscience Journal.

Chapter 1 Introduction

While the uptake of Intelligent Well system Technology (IWsT) in our industry was initially much slower than anticipated, actual field well count is now rapidly increasing every year. The development of IWsT is driven by its perceived capability to improve field & well economics by generating increased reserves, improved overall well performance and providing high-performance reservoir/well monitoring. Acceptance levels are nevertheless still hampered by the same major issues that are virtually generic for our industry, regardless of the technology type:

1. Technology Added Value Determination &
2. System Cost and Reliability

If written 3 - 4 year ago, the list would probably begin with the System Reliability and Cost. To-day, after many, well-publicised, successful installations, the industry has turned more and more towards this technology in order to achieve the maximum technical benefit from the application of Intelligent Wells. Development of the IWsT technology and the experience from the initial applications helped the service companies to improve the reliability issues attached to the IWsT hardware while, at the same time, reducing the cost of applying this technology. However, determination and justification of the IWsT Added Value and decision-making on its application still remains a challenging task.

Other authors [1.1, 1.2, 1.3, 1.4] have studied the optimisation of Intelligent Wells or identified well and/or reservoir opportunities where IWsT can "Add Value" [1.5]. This study will, in a new workflow, look at the application of Intelligent Wells in a wide range of reservoir types in order to determine the common or specific "Value Drivers" for this range of reservoir scenarios. This study will develop evaluation and screening tools & determine decision-making factors which could be invaluable for engineers screening the application of Intelligent Wells in a variety of well and reservoir situations.

The study starts with (Chapter 2) by introducing the IWsT and the mechanism of work, different IWsT control systems, its potential "Added Values" and the selection criteria for Interval Control Valves (ICV). It will continue with demonstrating the value generation capability of Intelligent Wells by using a "show case" of case histories drawn from experience gained by operators, etc. The "show case" can be used as a check-list against which the opportunity to create value by IWsT for a particular field case study can be screened.

Many factors should be considered when deciding whether to install IWsT and, more specifically, the numbers and type of flow control and flow monitoring equipment which should be installed in a particular case. Chapter 3 presents a road map with some parameters that should be considered during this process. It is essentially a screening list which can be used as a tool for initial screening and identifying whether the candidate field or well could benefit from this technology. The screening process recognises, evaluates and prioritises candidate wells or fields for completion using IWsT. It does not offer a 100% solution; but is expected to identify those fields that will most benefit from IWsT.

The study continues with evaluating the performance of Intelligent Wells in a wide range of reservoir types. Chapter 4 starts with classification of the reservoir types and a description of reservoir modelling techniques. It will explain how the reservoir models for the evaluation of the performance of Intelligent Wells were generated and how the reservoir/rock properties were distributed in the generic reservoir models constructed.

Chapters 5 and 6 describe the techniques developed for modelling and optimisation of Intelligent Wells. It continues with introducing and evaluating various optimisation techniques followed by describing the available techniques for modelling and optimisation of Intelligent Wells within the Eclipse™ Package [1.6].

Chapter 7 will describe the evaluation procedure and the results of the analysis performed on a wide range of reservoir scenarios that were built and tested to determine if IWsT "Adds Value" compared to installation of a standard well completion. The study was based on the premise that some reservoir types are inherently more suitable for IWsT than others. Situations in which IWsT proved particularly successful are identified. Results will show that IWsT can control uneven, invading fluid fronts that develop along the wellbore due to permeability differences, compartmentalization (of either a sedimentary or a structural origin) and/or due to different strengths of the aquifer/gas-cap pressure support. The longer the completion intervals, the greater the potential for such differences to develop along the wellbore (i.e. from heel to toe). Hence, the greater the potential value that can be achieved by an ICV installation.

Result will show that IWsT "Adds Value" in layered and compartmentalised reservoirs, provided the difference in layer/compartment permeability is sufficient to produce an un-even fluid front progression towards the wellbore. Reservoir permeability heterogeneity is one cause of an un-even fluid front. Multiple aquifers/gas-caps of different strength supporting the production from a number of formation layers in contact with the wellbore are a second cause of un-even fluid fronts developing along the wellbore. IWsT can "Adds Value" in faulted or compartmentalised reservoirs being produced by a horizontal or multilateral well provided there is a difference in reservoir pressure and/or oil/water contact level between the zones. This is true irrespective of the distribution of permeability and porosity if the reservoirs are isolated.

The lessons learned from chapter 7 will be used to develop a selection criterion for improved implementation of IWsT in chapter 8. The results of this chapter will help to screen reservoir types for decision-making on the application of Intelligent Wells.

In chapter 8, in a new workflow, a global screening methodology, for determining when and where not to implement IWsT on the basis of reservoir statistical parameterizations will be described. Development of an IWsT application screening tool that could be applied to every reservoir type would simplify the process of justifying the cost of an IWsT installation. The goal is a decreased risk and uncertainty associated with developing complicated reservoirs. The "IWsT Added Value" screening tool has been created from generic, geological models in which uneven fluid front development was restricted to permeability heterogeneity alone. The concept will be confirmed later in this chapter by its application to a real reservoir scenario.

Chapter 9 will provide optimum ICV placement guidelines for different well and reservoir geometries with a variety of reservoir drive mechanisms. Results from this study will highlight the importance of correct ICV placement. A systematic study of the "Added ICV Value" for a range of reservoir models will be completed. The number of ICVs installed and the zonal length will be varied. Emphasis will be given to studying the more complex (e.g. channelised) reservoir models where prediction of the extent of reservoir layer / zone connection is difficult.

ICV(s) can only balance the advance of a fluid-front if they are correctly placed. A typical example would be their installation across zones showing early water or gas break-though. This allows "Value" being "Added" to the reservoir management process by controlling the unwanted fluid. Optimum ICV placement thus requires prediction of these zones. The extent of reservoir layer / zone connection thus needs to be quantified. In practice, the available information is often limited to (local) information gained from measurement at or very near the wellbore during the well construction operation, together with exploration seismic and (global) reservoir geological studies. The results from chapter 9 can be used as a screening and decision making tool for deciding on the optimum number of the ICV(s) and their placement.

The optimum ICV placement is a function of the choking (optimisation) policy, which itself greatly affects the "IWsT Added Value". Chapter 10 will study scenarios to identify when "Proactive" rather than "Reactive" ICV choking policy can "Add" greater "Value". Reservoir scenarios have been created in which inter-zone connection, permeability contrast between zones, zonal length and other reservoir parameters have been systematically varied. The interaction between the aquifer and reservoir was observed when producing these reservoirs with a horizontal Intelligent Well using a range of "Reactive" and "Proactive" choking policies. An example of successful "Proactive Control" is when the wellbore is intersected by a high-permeability channel. Here, early water or gas breakthrough leads to unwanted fluid being produced along with reduced volume of oil. Too early choking (or being "too Proactive") can result in losing oil as the "Good Water" is also blocked. "Proactive Control" will also be successful when reduced water or gas inflow is required due to tubing or surface handling limitations.

The key factor in a successful Single Well "Proactive Control" is that other zone(s) can compensate for the loss of fluid from the choked zone(s). Its value thus increases when Artificial Lift is installed, allowing increased flow and greater recovery from the well.

The value of "Proactive Control" is well known in conventional reservoir management (i.e. multiple well scenarios). Here, value creation requires even flood-front management of an injected fluid at the field level. There is also the opportunity for other wells to supply extra oil production capacity when a (single) well is choked. The results from this chapter can be used to screen for scenarios suitable for "Proactive Control", increasing the range of Intelligent Well Technology applications.

The fact that IWsT can potentially "Add Value" will not be sufficient justification for its installation. This has to be confirmed by a full economic analysis for the particular case being studied. Economic evaluation as applied to IWsT will be discussed in chapter 11.

The lessons learned from the total study will provide a valuable screening tool for decision-making on the application of Intelligent Wells. However, as in most cases in the Petroleum Engineering of Field Development, further studies for a specific case will often be required for accurate decision-making for a real field case.

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Chapter 2 Literature Review

2.1 What is Intelligent Well system Technology?

Drilling and completion techniques have advanced significantly over the last years. Technology now allows the drilling of the complex, multi-lateral and extended reach wells. This has been complemented by the later development of down-hole inflow control valves, measurement devices and even processing facilities in the wellbore. Such rapid technological development in the field of well construction is aimed at efficiently supporting the need of more cost effective oilfield development.

Intelligent completion techniques have gained a great deal of attention because of their capabilities to improve monitoring and overall well performance in oil and gas field developments. In such multi-zone intelligent-well completions, flow adjusting or Interval Control Valves (ICVs) and monitoring devices are located between zonal isolation packers to control flow into or out of each zone. Figures 2-1 and 2-2 illustrate some of the components of a smart completion.

The "Intelligent Well" is a well with "the ability to install, operate, monitor and control the completion's operation without the need for conventional interventions". Intelligent completions are focused on the delivery and management of production flexibility. The significant benefits of "Intelligent Wells" include:

- ***Increasing the oil recovery*** through better management of reservoirs by making available real time information (continuous online data acquisition) from the downhole producing zones. This helps operators to make decisions on the choke settings required for optimum well performance.
- ***Decreasing the cost of oil production by reducing the number of the both light and heavy well interventions.*** This will not only reduce the life-cycle well cost and increase the value creation, but the reduced intervention frequency also reduces operational risks by removing the need to carry out difficult well operations which potentially compromise well integrity. Safety performance is improved by reducing the exposure of personnel to such operations.

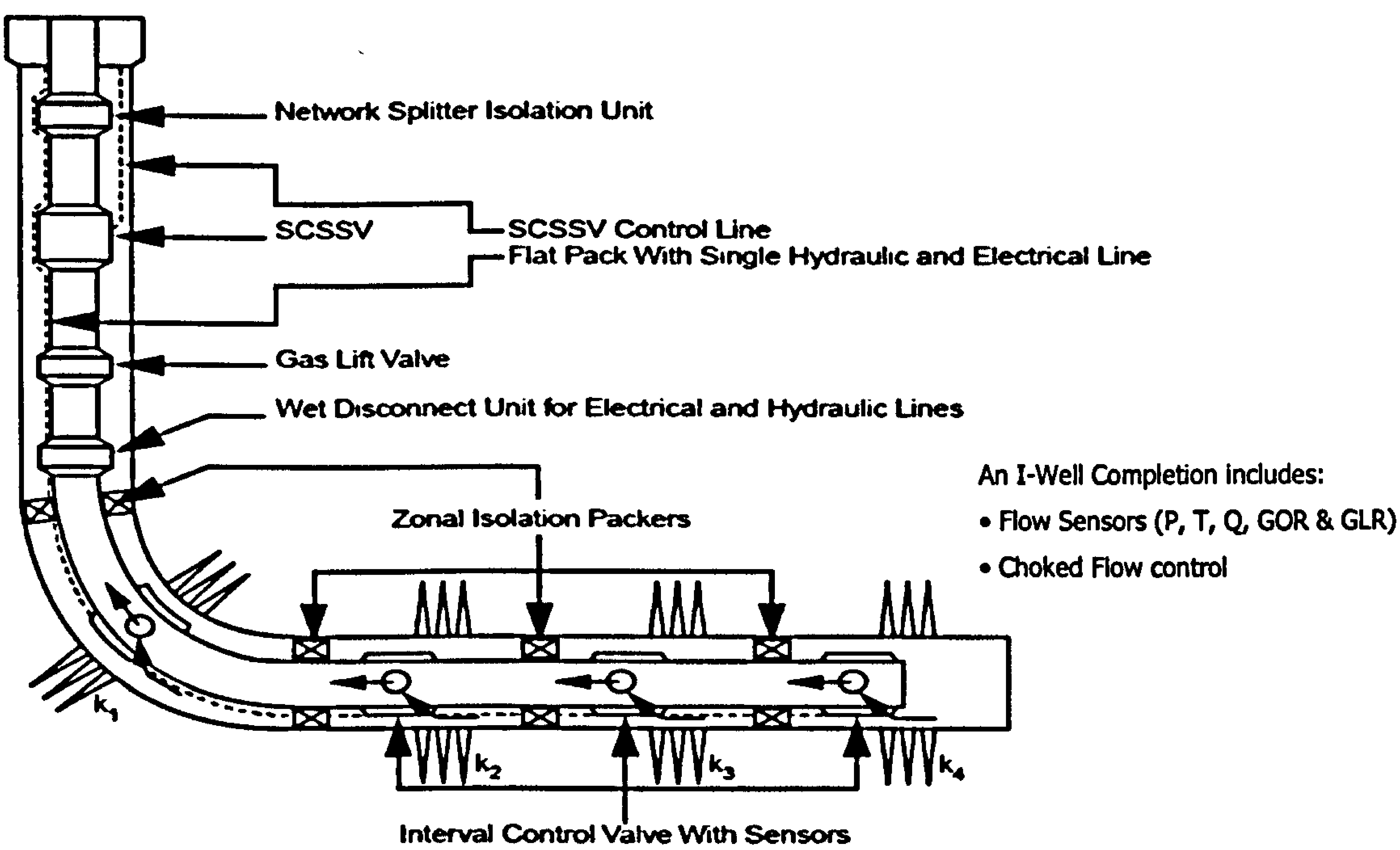


Figure 2-1: A schematic of the Intelligent Well

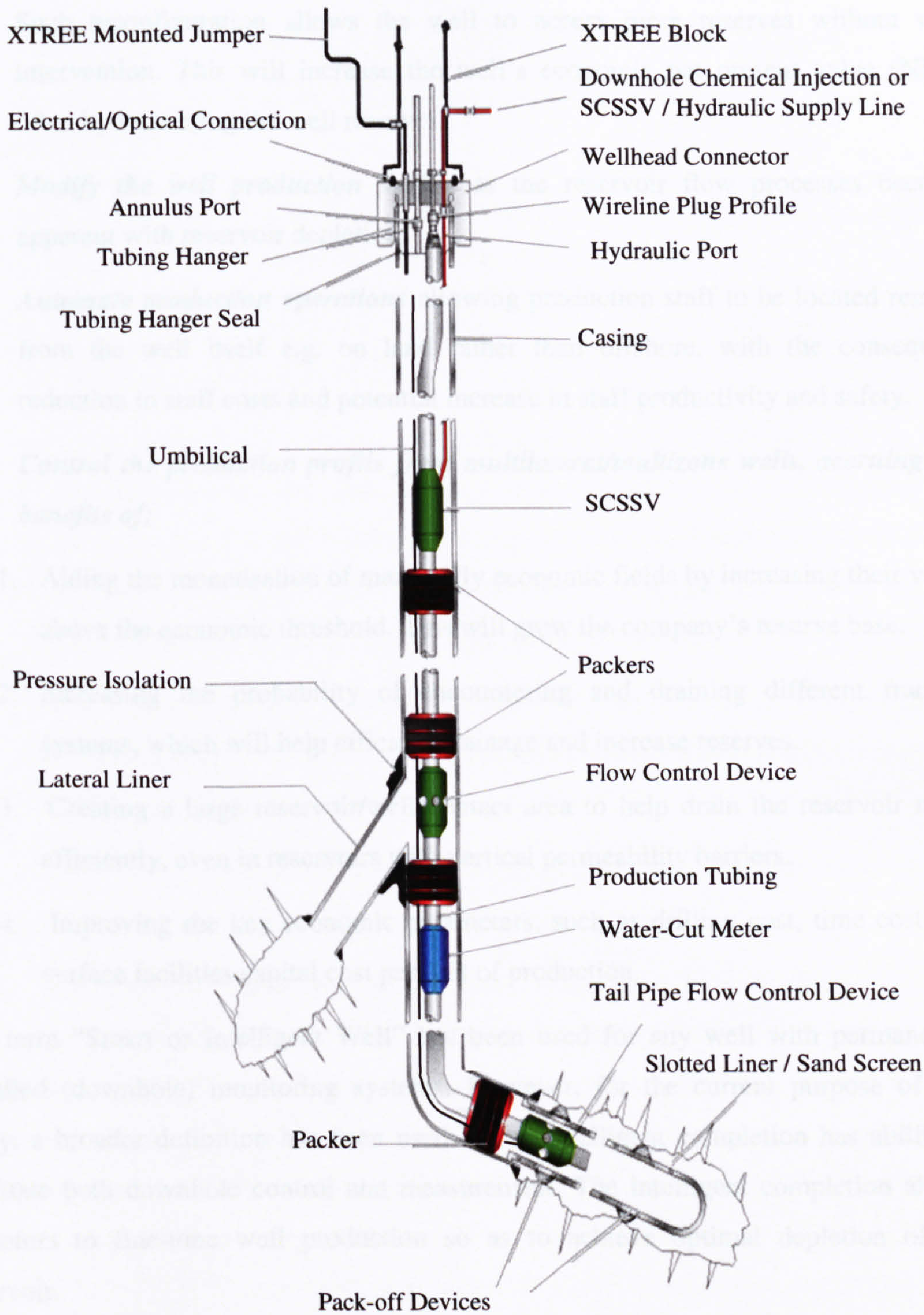


Figure 2-2: Some components of an Intelligent Completion (Courtesy ABBOS)

- ***Allow the operator to reconfigure well architecture*** without well intervention. Such reconfiguration allows the well to access more reserves without well intervention. This will increase the well's economic net present value (NPV) often by increasing the well reserves.
- ***Modify the well production profile*** as the reservoir flow processes become apparent with reservoir depletion.
- ***Automate production operations*** allowing production staff to be located remote from the well itself e.g. on land rather than offshore, with the consequent reduction in staff costs and potential increase in staff productivity and safety.
- ***Control the production profile from multilateral/multizone wells, accruing the benefits of:***
  1. Aiding the monetisation of marginally economic fields by increasing their value above the economic threshold. This will grow the company's reserve base.
  2. Increasing the probability of encountering and draining different fracture systems, which will help efficient drainage and increase reserves.
  3. Creating a large reservoir/well contact area to help drain the reservoir more efficiently, even in reservoirs with vertical permeability barriers.
  4. Improving the key economic parameters, such as drilling cost, time cost and surface facilities capital cost per unit of production.

The term "Smart or Intelligent Well" has been used for any well with permanently installed (downhole) monitoring systems. However, for the current purpose of this study, a broader definition has been used i.e. an intelligent completion has ability to facilitate both downhole control and measurement. The intelligent completion allows operators to fine-tune well production so as to achieve optimal depletion of the reservoir.

2.2 How does Intelligent Well system Technology work?

An "intelligent well" is a well with "the ability to install, operate, monitor and control completions without the need for conventional interventions". It will have some or all of the following attributes:

A Multi-lateral or Multi-zone well producing from one/or more reservoirs, e.g. using of produced gas to accelerate oil production as a form of artificial lift

- *A well producing single or multiple zones into one wellbore*, leading to commingled production from different zones and lateral bores
- *A well with the ability to control the production flow* by a down-hole choke. This is managed through real time monitoring and control of the producing zones using an Inflow Control Valves (ICV) and an optimised sensor distribution for data acquisition and down-hole fluid production measurement. It also has the ability to shut - off water/gas producing zones at the wellbore
- *A well with some form of Artificial Lift installed.* The type of lift used depends on the reservoir and production system requirements. Frequently, an ESP is installed down-hole to lift the produced liquid.
- *A well with downhole separation of water/gas and oil* in the wellbore and re-inject the separated water into a disposal zone

Figure 2-3 shows a simple feedback control system for a well. Outputs of the monitoring system are pressure, oil, gas and water rate, etc. Short-term control (e.g. aiming at keeping the net oil production rate constant) can be made based on these parameters. Long-term control (production forecasting and reservoir management) requires a reservoir model whose validity is checked at regular intervals. Information from production engineering activities such as stimulation, water or gas shut off, etc. can also be used. Well test results, reservoir fluid distribution images from time-lapse seismic or other sources are also used as input to guide the adjustment of the reservoir model.

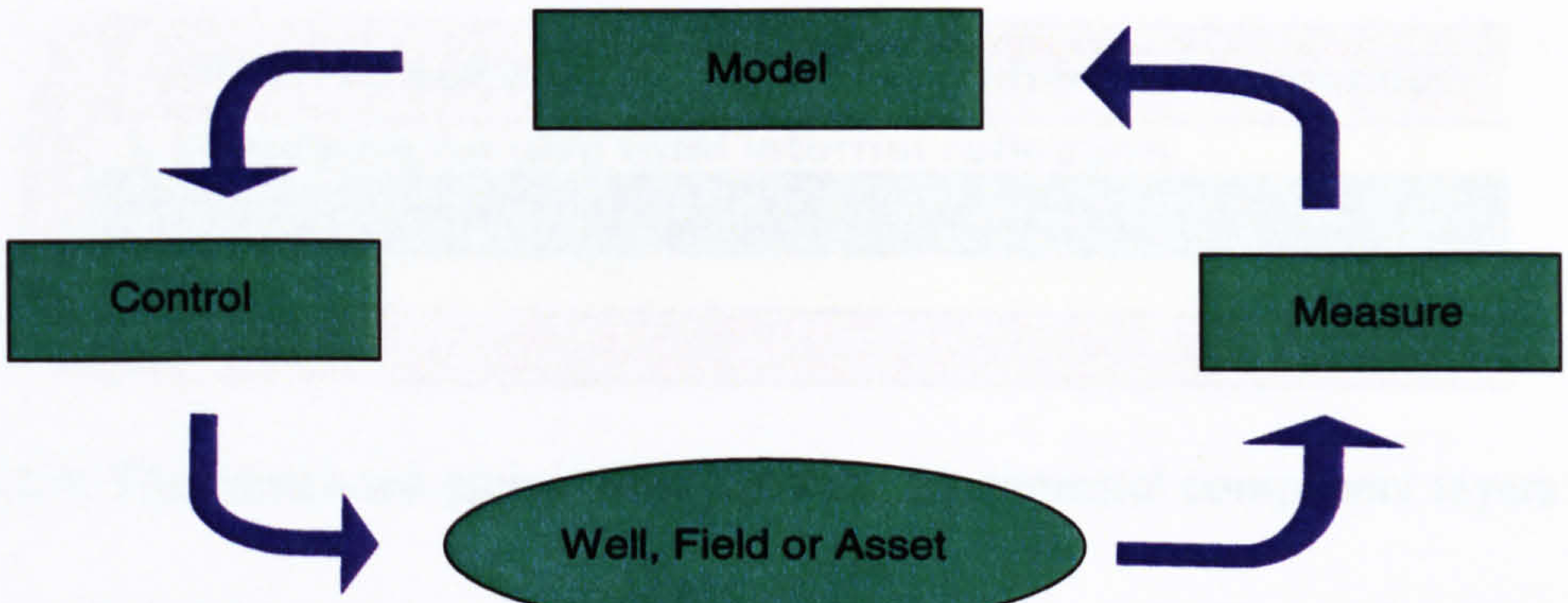


Figure 2-3: Value Loop for Downhole Instrumentation & Control Systems (DIACS)

Complex reservoir simulation is not necessary for all studies. Thus a detailed, well performance model and actual well performance data are sufficient for short-term control of the production process and for flow allocation along the wellbore length. A reservoir model is required for the long-term control of the reservoir process.

Downhole measurements improve the quality of the data compared to measuring devices sited at the surface. Downhole control allows rapid reaction in the case, for example, of water or gas breakthrough.

Electronic sensors have historically been the most widely used permanent downhole monitoring technology. The susceptibility of electrical systems to failure increases at high downhole temperatures. Optical sensing technology now offers an alternative to electronic tools, although the current optical systems do not always deliver the accuracy and resolution of electronic devices.

An optical fiber (Figure 2-4) is a circular waveguide that takes the form of a long, thin strand of glass about the diameter of a human hair (0.125mm). This fiber contains two concentric glass regions with slightly different refractive indices. The refractive index is the ratio of the speed of light in a vacuum to its speed in the glass fiber medium. Most of the light travels through the centre (core). The outer, lower refractive index than the inner region, is called the cladding. Plastic coating and an encasing cable structure protects the optical fiber during installation and operation.

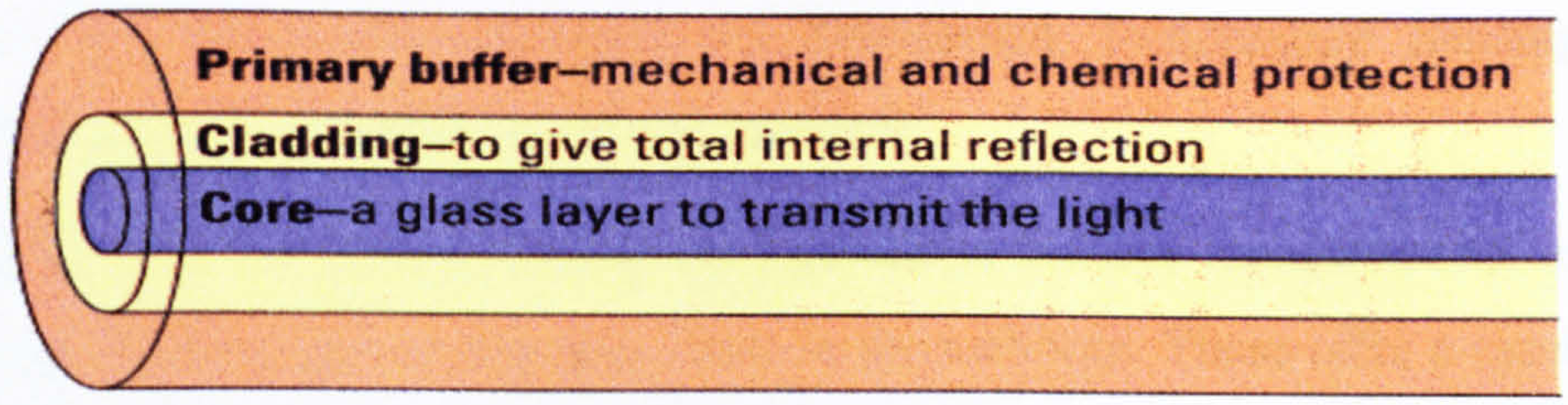


Figure 2-4: The completed optical fiber showing fundamental component layers [2.1]

Two basic optical fiber types exist: single-mode or multi-mode. The main difference is the dimension of the fiber core. A single-mode fiber typically has a core diameter of 0.01 mm, which allows only one mode of light at any time to propagate through the core. Multi-mode fiber has a much larger core (normally 0.05 mm diameter), allowing hundreds of modes of light to move through the fiber simultaneously.

Three components of the optical sensing systems are:

1. The light source, or transmitter, which resides at the surface in an opto-electronic instrumentation package.
2. Single strand or multiple strands of optical fiber wrapped in a protective covering to form a 6 mm diameter cable. This cable is clamped to the completion tubing.
3. The photo-detector in the receiver, also located in the surface instrumentation package, transforms the return optical signal from the fiber and converts it into an electrical signal for transmission through the non-optical portions of a network [2.1].

There are also systems in which a quarter inch tube is attached to the completion and the fiber optic cable is blown in place once the completion process is installed. This is used for the systems in which the fibre forms the measuring device i.e. it does not have to be attached to a downhole measuring device.

Fiber optic sensing systems can be implemented in single-point, multi-point, and continuous distributed sensing configurations (Figure 2-5). In a continuous distributed configuration the entire optical fiber is used as a sensor. The result is a log of the measured quantity along the length of the wellbore. To date, continuous configurations in wells have been used primarily for Distributed Temperature Sensing (DTS). Distributed strain measurements are also possible.

Single-point and multi-point sensing configurations involve measurements at discrete locations along the length of the optic fiber in the wellbore. These offer a much broader range of measured parameters. They also provide higher accuracy, precision and spatial resolution.

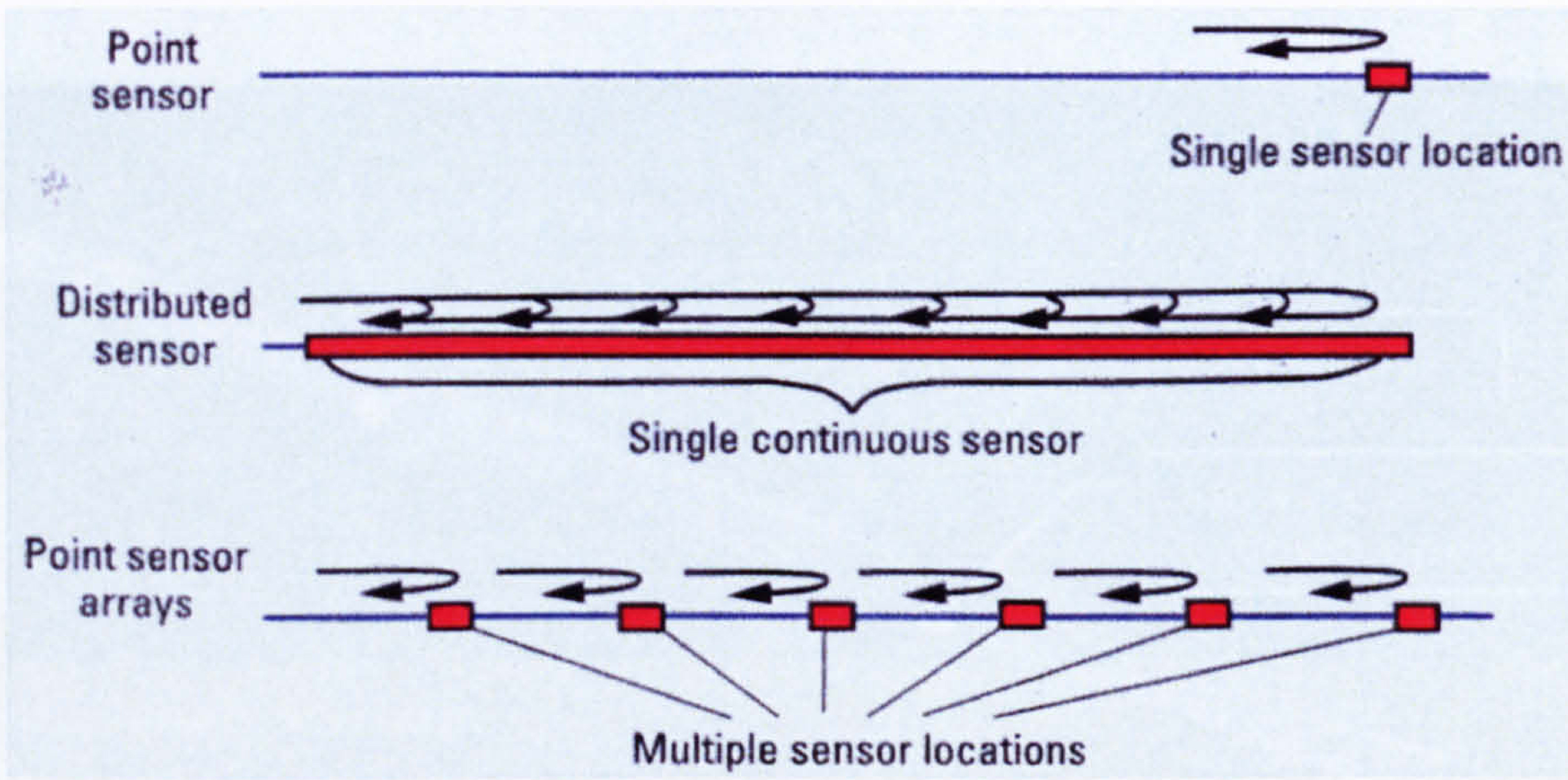


Figure 2-5: Configuration modes for permanent in-well, optical sensing systems [2.1]

In sensing systems, single-mode fibers are normally used because they can maintain spatial, temporal and spectral integrity of each optical signal during longer distances. However, in the case of distributed temperature-sensing measurements (distributed temperature sensing system), multi-mode fibers are most common.

A single optical fibre can be used to measure downhole temperature, pressure, flow rate, and phase fraction. A laser located at surface sends a pulse of light, which is reflected from a series of downhole sensors. There are various techniques used to measure pressure and temperature using optical fibers such as Bragg Gratings for point sensing, Raman Scattering for Distributed Temperature Sensing, etc.

The optical data is obtained and transmitted in real time to a demodulation unit located at the surface, where it is analysed using signal processing techniques. Maximum operating conditions for optical sensors are currently up to 150°C and 20,000 psia.

2.2.1 The Interval Control Valve

The primary objectives for a Downhole Interval Control Valve (ICV) are control, including shut-off, of the *flow-rate* for a producing zone or well lateral while a surface choke typically operates at lower pressures. These lower pressures cause the surface chokes to be exposed to higher velocities and harsher erosional conditions.

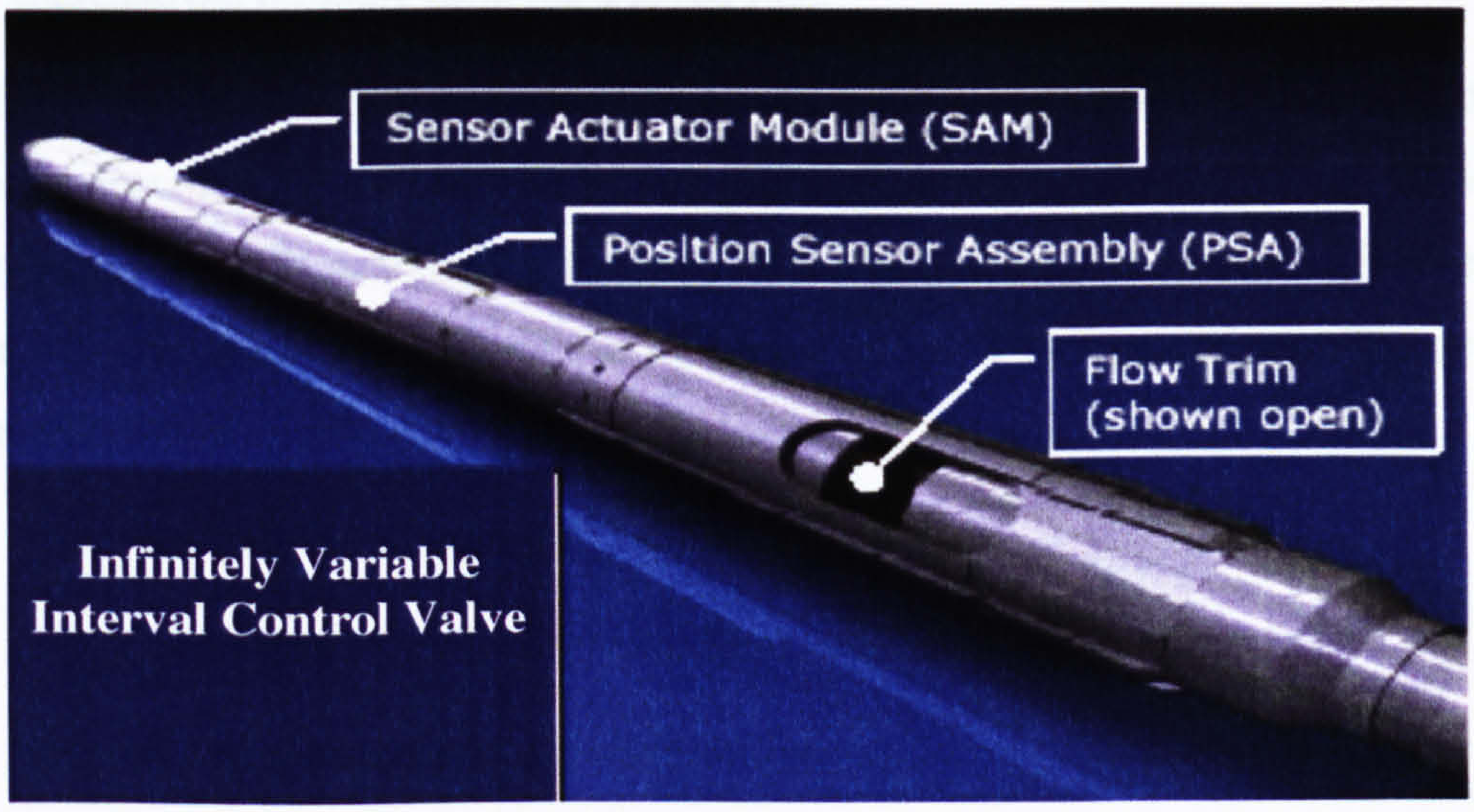


Figure 2-6: An Interval Control Valve (Courtesy of Ippoliti et al [2.1])

Surface chokes, unlike ICVs, not only control the flow rates but are also designed for a large pressure drop so that they can act as a safety device to protect the downstream equipment (with its lower pressure rating than the wellhead and completion).

The sub-critical (normal) operating range of an ICV shows a non-linear relationship between the flow-rate and the differential pressure. Here, the ICV operates in turbulent flow. This can be described by:

$$\Delta P = (Q / C_V)^n \qquad \text{Equation (2.1)}$$

Where ΔP is the differential pressure across the valve, Q is the flow rate, C_V is the valve flow coefficient (a calibration factor), and n is typically between 1.8 and 2.1.

Infinitely variable and Multi-position ICVs are designed to flexibly and accurately control the flow over a wide range of flow rates. At the same time the pressure loss across the valve should be minimised to conserve energy; e.g. fluid flowing at 30,000 b/d with a 200 psi pressure drop across it will consume more than 102 horsepower. This is not only a waste of reservoir energy, but is also a source of equipment wear and tear.

The above equation indicates that:

- The pressure drop may become unacceptably high at high flow rates
- Sensitive control of the flow rate requires a small value of C_V. However, this will increase the pressure drop for a given rate.

The acceptable pressure drop value from a well performance point of view will depend on the reservoir deliverability and the production tubing performance. It will be controlled by the ICV design. The majority of the installed ICVs operate with a pressure drop of less than 100 psi with values of 10 psi or lower being common. The pressure drop employed is usually a compromise between:

- The level of control required
- The acceptable energy loss level to the system and
- The erosion resistance of the valve design

The valve characteristics are a fixed function of the valve design i.e. pressure drop vs flow rate for each valve will be uniquely determined by the valve design and its position in the reservoir-valve-tubing hydraulic circuitry [2.3].

The flow rate through an ICV can be measured using either a conventional test separator at the surface or by a downhole or surface multi-phase flow meter. The technique is to close all ICVs except one, which will be tested. However, the disadvantage of this technique is that the measured flow rate is not representative of the actual flow rate when the well is producing normally with commingled flow from the other zones. This is especially true if the valve is operating under sub-critical flow. Here, the pressure downstream of the valve i.e. inside the tubing, is affecting the behaviour of the valve.

The techniques and correlations used to model the ICV during the reservoir simulation are relatively simple and generic (since one is effectively evaluating the effect of creation of a certain pressure drop across the ICV on the overall well performance).

Translation of this pressure drop value to an actual choke setting requires development of an accurate flow equation. An example of the work required is given below.

2.2.2 Development of an ICV Flow Correlation

Various multi-phase flow equations are being developed to determine the flow rate and phase cuts from measurement of temperature and pressure changes across the ICV [2.4]. One example describes the liquid (incompressible fluid) flow through valve as:

$$q = C_V \sqrt{\frac{\Delta P}{G}} \qquad \text{Equation (2.2)}$$

Where:

q is the total flow rate (gallon per minute)

C_V is the flow coefficient (gallon per minute per psi), This is the water flow rate in gallons per minute at 60 degrees Fahrenheit through a fully open valve, with a pressure drop of 1 psi.

G is the specific density of the fluid (water = 1)

The control valve sizing (liquid flow) equation (Equation 2.2) along with 3D numerical simulation (CFD or Computational Fluid Dynamics) can be used to derive a flow equation for estimating the flow rate of the downhole ICVs:

$$Q = C_D \cdot A_0 \cdot \sqrt{\frac{2 \cdot \Delta P}{\rho \cdot \left[1 - \left(\frac{A_0}{A}\right)^2\right]}} \qquad \text{Equation (2.3)}$$

Where:

Q is the effective flow rate

C_D is the discharge coefficient (dimensionless)

A_0 is the orifice area

ρ is the fluid density

A is the area upstream of the valve

ΔP is the differential pressure across the valve

The discharge coefficient (C_D) was initially introduced to the control valve sizing equation to account for the difference between the orifice area and the vena contracta in addition to the friction pressure loss in the orifice. It is a dimensionless flow coefficient frequently used in numerical flow analysis or modelling. It ranges from zero to one, where the value of one represents an ideal valve with no pressure loss.

C_D is a variable whose value varies in response to changes in the mixture density and composition, valve opening size and pressure drop as well the effect of flow from deeper producing zones. Figure 2-7 shows that the total flow rate (Q_{ax} Total) is a combination of the axial flow (Q_{ax}), fluid produced from deeper producing zones, and the effective flow rate (Q_{eff}), which is coming from the specified zone. CFD is used to evaluate the relation between C_D and the above parameters to enable the flow model to calculate Q_{eff}.

The CFD calculations were validated and tuned using laboratory tests where gas, liquid and gas/liquid mixtures were flowed through a real valve and the pressure drops measured and incorporated into an allocation algorithm to help allocate the production of each ICV in the well continuously.

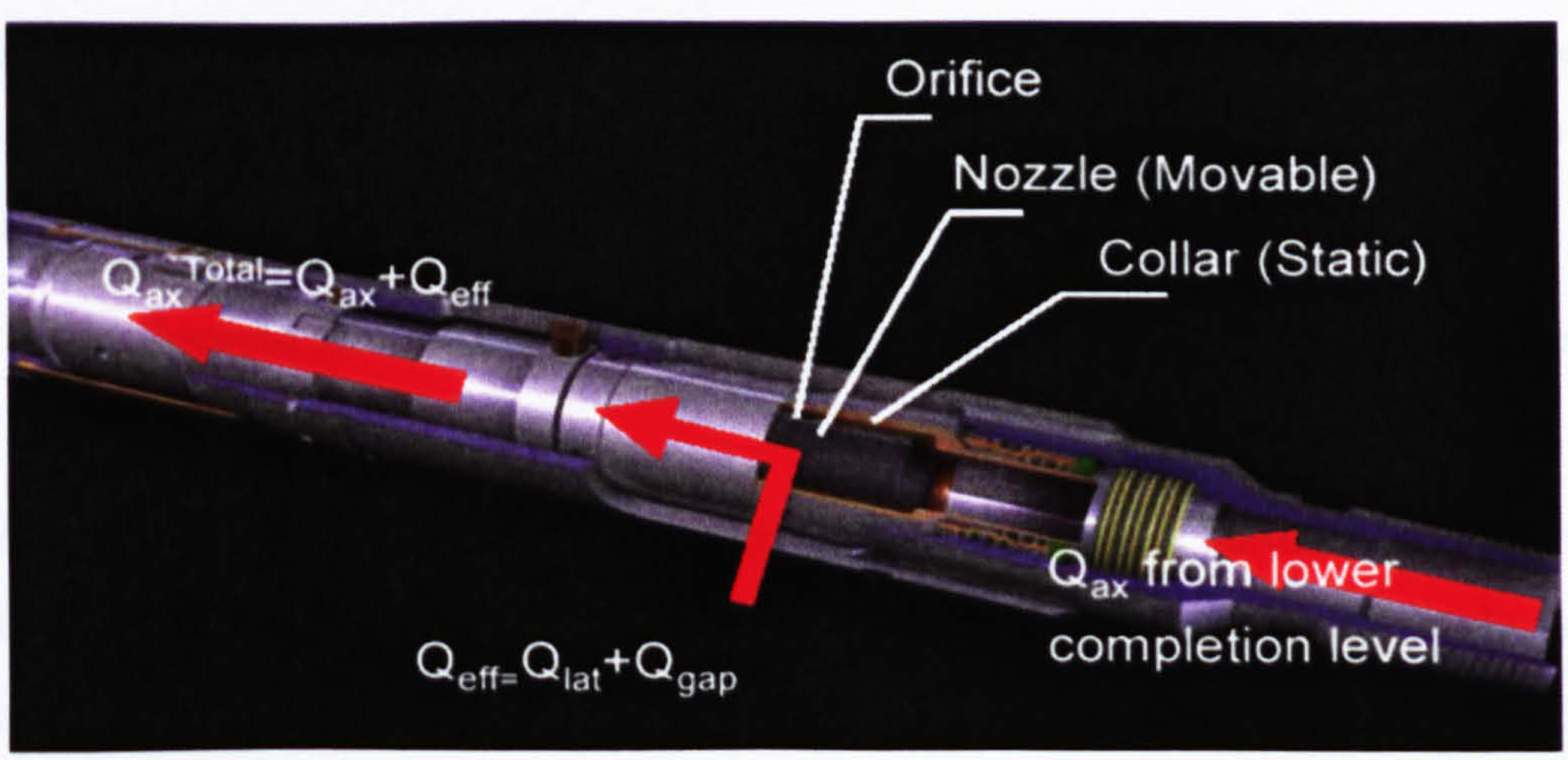


Figure 2-7: Flow Rate Analysis (Courtesy of TEA [2.4])

2.2.3 ICV Selection Criteria

The heart of the "Intelligent" system controlling the flow is the ICV. There are several different types of ICVs. They may simply open and close (on/off valves), have a number up to ten or more fixed positions or may even be infinitely variable. The selection criteria for an ICV for a particular case is based on:

Technical Objectives e.g. on/off valves might be used to counter rapid, unwanted fluid invasion such as water in a fracture. A valve with a limited number of positions can provide simple control at a certain water cut in a multi-zone well while multi-position valves are suited for pressure balancing in high rate, high productivity oil & gas wells.

Reservoir and Fluid Characteristics e.g. reservoir heterogeneity, drive mechanism, size, thickness, aerial extent, reserve estimate, reservoir pressure, etc.)

The existing data and information need to be processed, e.g. target coordinates, completion diagrams, depths and dimension numbers, reservoir pressures and estimated zone Productivity or Injectivity Indices are required prior to the initial screening of potential ICV equipment taking place.

First pass mechanical engineering assessment, e.g. stress analysis, pressure and temperature rating for all the components, material compatibilities and installation feasibility calculations are required next. Logistical issues, drilling and facility requirements, etc need to be confirmed as viable.

Economic Evaluation e.g. cost of control valves and the associated completion versus potential increases in revenue. Other considerations, such as the reduced reliability often associated with more complex equipment should also be considered.

Risk of equipment failure during initial installation and reliability during subsequent years has to be estimated.

Reliability is the most important requirement after getting the initial design right and installed. Little history of the technology is available; proof of, for example, a 90% reliability over 15+ year well life for "average well" conditions will not be available for some years.

The limited existing data, encouraging as it is, may not provide a meaningful picture for the case. The number of variables and their range are so large in reservoirs and wells that every design should be treated as the first; with the past data only showing that others have done it *under different conditions.*

Reliability is a system requirement that reflects the weakest link in the system chain. The reservoir/well environments will always be one of the most important factors determining the reliability. One type of valve may perform better than another in one environment but the reverse may be true for a different environment. The valve design is also as critical as the ICV system objectives, so one cannot simply assume for example an on-off type of valve is more reliable than other types [2.3].

Failure tolerance and Recoverability

Failure will occur. The design, however, should be such that failures of the most likely types are anticipated, and the system can either tolerate them to some degree or recover from them with proven means. As a minimum, mechanical override of the valve functions should be considered. The ability to delay a recovery intervention usually depends on the impact of failure on production. Operational procedures should take into consideration the need to minimise the possibility of leaving an ICV system in a failed condition where immediate well intervention (a workover) is required to recover the situation [2.3].

Robustness in large change in operational environments

Pressure and temperature swings may cause the components to be exposed to greater strains when operated at steady but high values of these parameters. Design should take such worst-case scenarios into consideration. Operational procedures and instructions should recognise the need to manage the more sensitive components; e.g. connections and components subject to erosion so that their operational life is maximised.

Variable duty level including late well life

The two extreme cases expected during valve operation is that it becomes inoperable due to build up of scale. This occurs if the valve is not moved sufficiently frequently in a scaling environment. However, critical component may also wear out due to excessive cycling in an attempt to keep them free of scale. The required duty level to prevent scale buildup should be estimated as part of the design. The valve system capability should be tested, for the preferred downhole environment. This is particularly important for systems that are not likely to be actively used until late in the installation life.

Some of the tools for managing reliability are [2.3]:

- Recognition of common failure modes, when apparent equipment redundancy will not increase reliability.
- The simplest design that meets the functionality requirements is likely to be the most reliable. Use redundancy meaningfully with common failure modes.
- Perform systematic failure investigations to identify the underlying cause of the failure.
- Ensure all suppliers have a suitable quality plan where effectiveness is established auditable and third party inspection process for critical components when necessary.
- Perform reliability testing where appropriate.

Other Considerations

System and valve design

Assessing and documenting the valve design and system performance against the objectives agreed is important. As a minimum, the valve design should be shown to be capable of delivering the control required together with the tubing and all other subsystems at the possible range of reservoir parameters. Spreadsheet models have been found to be suitable here.

E.g. assume that the wellhead pressure, reservoir pressures and Productivity Index (PI) or Injectivity Index (II) and their range are all known, while the tubing including the depths of the valves on the tubing are fixed. As described previously, the hydraulic circuit is uniquely determined for the flow rates and pressure drops throughout the system once the C_V factors of the valves are known. Varying any of the pressures will highlight the sensitivity of the system to that factor while varying the C_V value will show the impact of the valve control. In the event that the C_V factors are not known, orifice equations can be used and the opening area used to estimate the C_V *value.* Over time the equation can be calibrated and adjusted with real valve data.

Integration issues

Integration of disciplines and multiple suppliers into a cohesive project team is prerequisite to success. The integration of Intelligent Well Technology hardware and control systems with other well systems e.g. the subsea wellhead control system, raises many issues. For example, when landing some designs of horizontal trees, a momentary ingress of the external fluids is allowed. This may not be suitable for ICV control systems. Downhole, wellhead and surface facilities may involve both hydraulic and electronic equipment for measurement and control, which have to operate together through a common protocol. Compatibility testing and analysis should include physical, chemical, procedural and other long-term considerations [2.3].

Installation issues

The increase in complexity in terms of the downhole components, controls and interfaces means that experienced, properly trained wellsite team is necessary for installation success. Detailed planning, crew training and practice are critical. Unsuccessful equipment Installation negates all the design effort and investment.

Mechanical requirements

Strength and Dimension etc.

Equipment's mechanical load requirements are usually well understood, but the pressure related loads often need clarification. The specified hydrostatic and differential pressure capabilities must not be confused with the differential pressure level under which the valve can be opened or closed without damaging the seals. Hydrostatic capability is critical for unbalanced hydraulic systems, which work against well pressures (it determines the limit of possible setting depths). However, one can not assume that balanced hydraulic systems are not depth limited by hydrostatics. Changes in reservoir pressure and well measurement operations can exceed the allowable design pressures and forces. Choice of construction materials, particularly for seals and Corrosion Resistant Alloys are required is often determined by the temperature rating.

Dimensional constraints affect both design and installation, e.g. eccentric valves or modules external requires the drift to be checked at the installation stage [2.3].

Erosion/corrosion resistance

Survival of the valve against erosion and corrosion depends on the use of adequate materials and design. Erosion is controlled by solid content, particle characteristics and fluids velocities. The latter are controlled by the flow path geometry. Oxygen, Hydrogen Sulphide, Carbon dioxide and, of course, water are the main causes of corrosion.

Specific erosion tests once the well has been designed are the preferred manner of reliably quantifying the equipment's operational limits.

Compatibility with fluids and chemicals, including seals

Materials used to construct the valve and other components must withstand the reservoir fluids, but also any introduced chemicals used during well treatments throughout the life of the well. Seals must operate without damage for the specified number of cycles at differential pressure levels [2.3].

Flow rate induced vibration

Vibration induced by high flow rates can occur. A suitable (quantitative) qualification test protocol is not yet available. It should cover electronics, hydraulic connections and any other parts where vibration may have negative impact, e.g. loosening, impingement, or even shattering.

Scale resistance and management features

A second qualification specification is required to describe the ICV's ability to manage a certain level of scale build-up without losing functionality.

Injection vs. production ICVs

ICV should be designed with comparable or even larger flow-area than that of the tubing cross-section so that, at fully open position it cause negligible pressure loss.

However, the conditions experienced by an injection ICV are different from those of a production ICV, resulting in different requirements for the valve design. For example, required water injection rates often are higher than liquid production rates, while erosion patterns during production are different from those during injection.

The valve sizing will depend on whether a liquid or gas is being produced or injected. Water Alternate Gas (WAG) injection wells will require that this is for the chosen sizes of the valve opening. This is particularly important if multi-position type valves are used. Similarly, when the valve is used for natural gas lift and behaves as a choke, the sizing is critical to cope with the reservoir pressure changes.

Both electrical and hydraulic systems are available to operate and control the ICV. Simple on/off valves and those with limited number of valve settings can be controlled hydraulically. Though the infinitely variable valves can have electro-hydraulic or electric systems, but they are normally electric motor actuated. The probability of failure in the electrical systems is greater than hydraulic systems as historically the electronics have been more sensitive to high temperatures. Currently many suppliers are focusing on developing the hydraulic flow controls. Electrically operated valves have been installed in some wells, experience shows that their reliability is improving.

2.3 The I-Well as a System

The earlier sections in this chapter described the initial components e.g. ICVs and communication systems. Here I will discuss three complete I-Well systems to illustrate the range of equipment available. They include a simple hydraulic system (Figure 2-8), a more complex hydraulic system (Figure 2-9), an electric system and a combined electro-hydraulic system (Figure 2-10).

2.3.1 Hydraulically Actuated ICV

Figure 2-8 illustrates an ICV, which uses hydraulic pressure to control the production from two zones. Three types of choke setting are possible:

1. Both zones may be closed
2. One zone may be fully open while the other remains closed and

3. Intermediate settings allow preference to be given to one of the zones i.e. as the choke setting on one zone increases in diameter that on the second zone decreases

Such intermediate positions require sensors to indicate how far the valve has been opened so that the selected position can be chosen and/or confirmed. Position estimation is also possible without the installation of downhole sensing by measuring at the subsea or platform control station the volume of fluid required to move the valves. (This approach assumes there is no leakage in the system, but has been proven to work in the field).

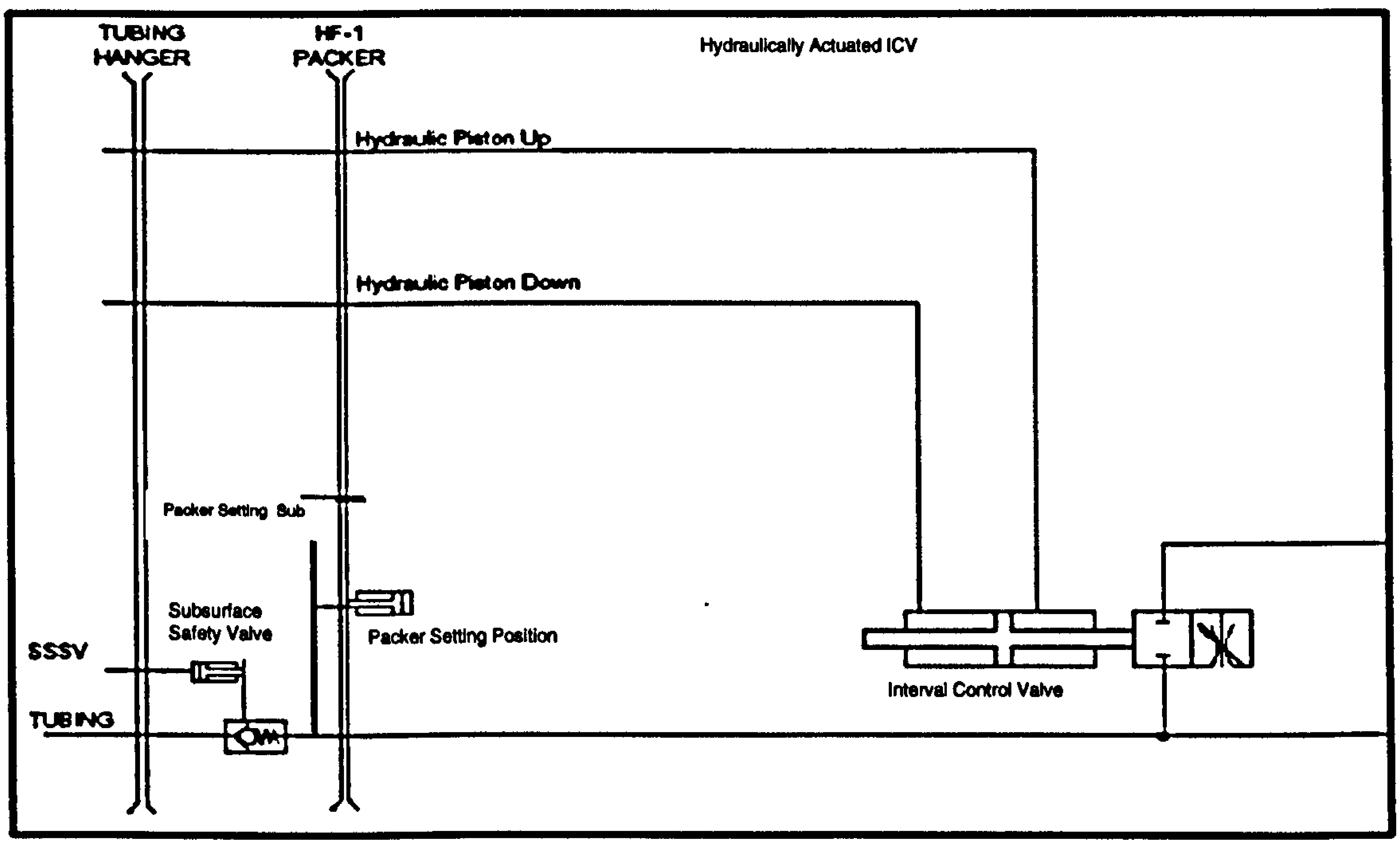


Figure 2-8: Hydraulically Actuated ICV [2.5]

Figure 2-9 shows a more complex system in which solenoid valves are used to direct hydraulic fluid to the open or closed side of the actuated piston. Power and command functions are sent via the instrumentation wire in the flatpack. This particular system contains five solenoid valves – two normally open (to provide hydraulic communication to additional tools), two normally closed (to actuate the valve), and a fifth one that is normally closed (to provide hydraulic power to an auxiliary mechanism such as a packer).

A system containing solenoid valves, although claimed not to be inherently less reliable, is certainly more complex than one without solenoid valves (Figure 2-8).

The advantages and disadvantages of the direct hydraulic option are:

Advantages:

- With the solenoid system, any of several single point electrical failures will render the valves inoperable without intervention.
- The direct hydraulic system is not dependent on electrical components for actuation. The direct hydraulic system requires at least two electrical failures to prevent actuation. This potential increase in reliability has been proven to be the case in the field.
- The direct hydraulic system is less complex and tends to be more cost effective.

Disadvantages:

- Production from more than two independent zones will require additional hydraulic lines, as the system is no longer multiplexed.
- The hydraulic supply to the intelligent completion system is no longer redundant.
- If a subsea pod is used, a direct hydraulic system becomes much more complex than the standard electro/hydraulics module as hydraulic steering would have to be designed to take place in the pod system. While the intelligent completion equipment would be simpler, the intelligent system will have become more complex [2.5].
- A cheaper single line hydraulic system is available which is suitable for controlling a single on/off valve. The hydraulic fluid is vented into the completion at the ICV since only a single control line is installed.

2.3.2 Digital Hydraulic Systems

Digital Hydraulic is a Smart Well Technology completion system that expands the application range of downhole hydraulic equipment. This technology enables independent control of multiple reservoir intervals using the actual hydraulic line system. The digital hydraulics systems send a series of pressure pulses to a downhole "sequencer" which selects the particular ICV that is to be controlled. The control is then with conventional direct hydraulic manner.

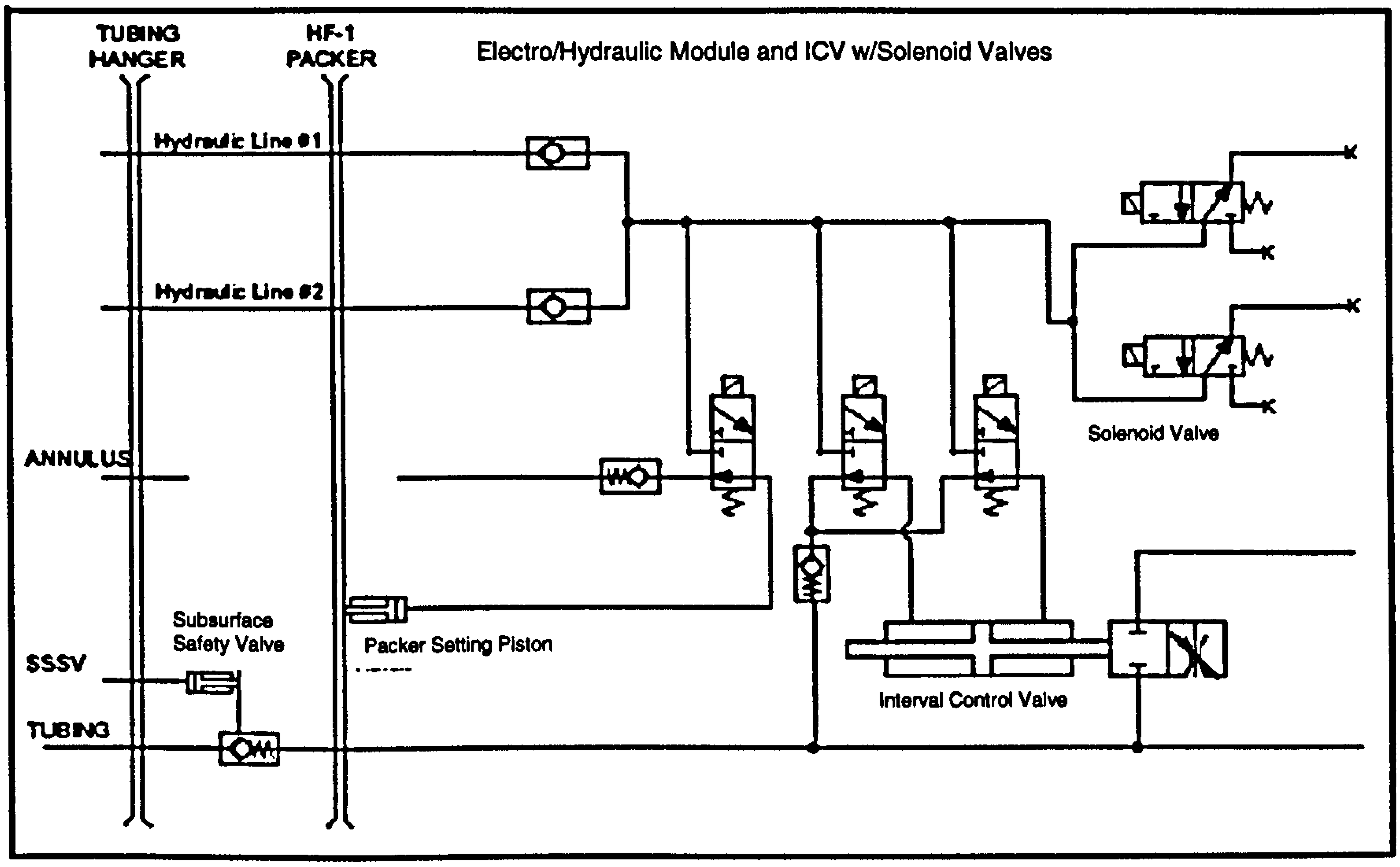


Figure 2-9: Electro/Hydraulic Module and ICV w/Solenoid Valves [2.5]

2.3.3 *Electrically actuated ICV system*

In an electric system the electronics within the ICV will receive and decode the topside initiated request to adjust the choke. This is achieved by activation of the motor which moves the choke inflow aperture to the desired position. Sensors and data acquisition circuits can be designed at the choke, which will provide feedback on the zonal production/injection status (e.g. Pressure and Temperature at the choke inlet and outlet, Phase Cut etc.) to the operator via the communications link. Diagnostic information on equipment condition in service can be provided and redundant electronic modules to ensure maximum system availability can also be housed in the ICV. Electric control allows single line, multi-valve control, which alleviates the problem of the annular space requirement for one or more hydraulic umbilicals [2.6].

2.3.4 A Complex Electro-hydraulically Actuated System

This is a surface-controlled well management system using a computer operated "surface control unit" with specially designed software for bi-directional communication with electronic circuit boards located in each sensor actuator module. The communication is through a multi-drop, permanently installed, instrument wire network that supplies both electric power and allows communication with each downhole sensor or well tool [2.7].

Permanently installed, redundant hydraulic control lines are used to transmit surface-supplied hydraulic power to each sensor actuated module unit (Figure 2-10). The single "surface actuator unit" contains small, low-power solenoid valves which route hydraulic power to position individual tools. A unique electronic signal is transmitted from the "surface control unit" to the selected "surface actuator unit" to position the selected "Interval Control Valve". Circuit boards in the "Surface Actuated Module" unit interpret the signal and operate a solenoid valve that is also located in the "Surface Actuated Module" unit. When the solenoid valve opens, hydraulic pressure acts on a large differential area, hydraulic actuator to move the ICV's choke. Movement of the hydraulic actuator is measured by (redundant) linear-transducers. An electrical voltage indicates the position of the hydraulic actuator to the "Surface Actuated Module" unit and, indirectly, to the position of the choke. This information is transmitted and encoded to the "surface control unit" and the surface computer. When either of the position sensors in the ICV indicates that the desired position has been reached, the downhole circuit board closes the solenoid, and the choke position is set.

The above description is of a "High End" (expensive) intelligent well completion with infinitely variable chokes controlling production from a multi-zone or multilateral well. Such complexity is not always required by the well technical objectives and/or can be supported by the added value from IWsT. Simpler systems are often more appropriate.

The ICV operational means (electrical, hydraulic or electro-hydraulic actuation) can exist together in a system. One of these is selected as primary and the other as secondary or back-up operational mode. In the unlikely event that the primary means undergoes a system failure the back-up mode can be enacted.

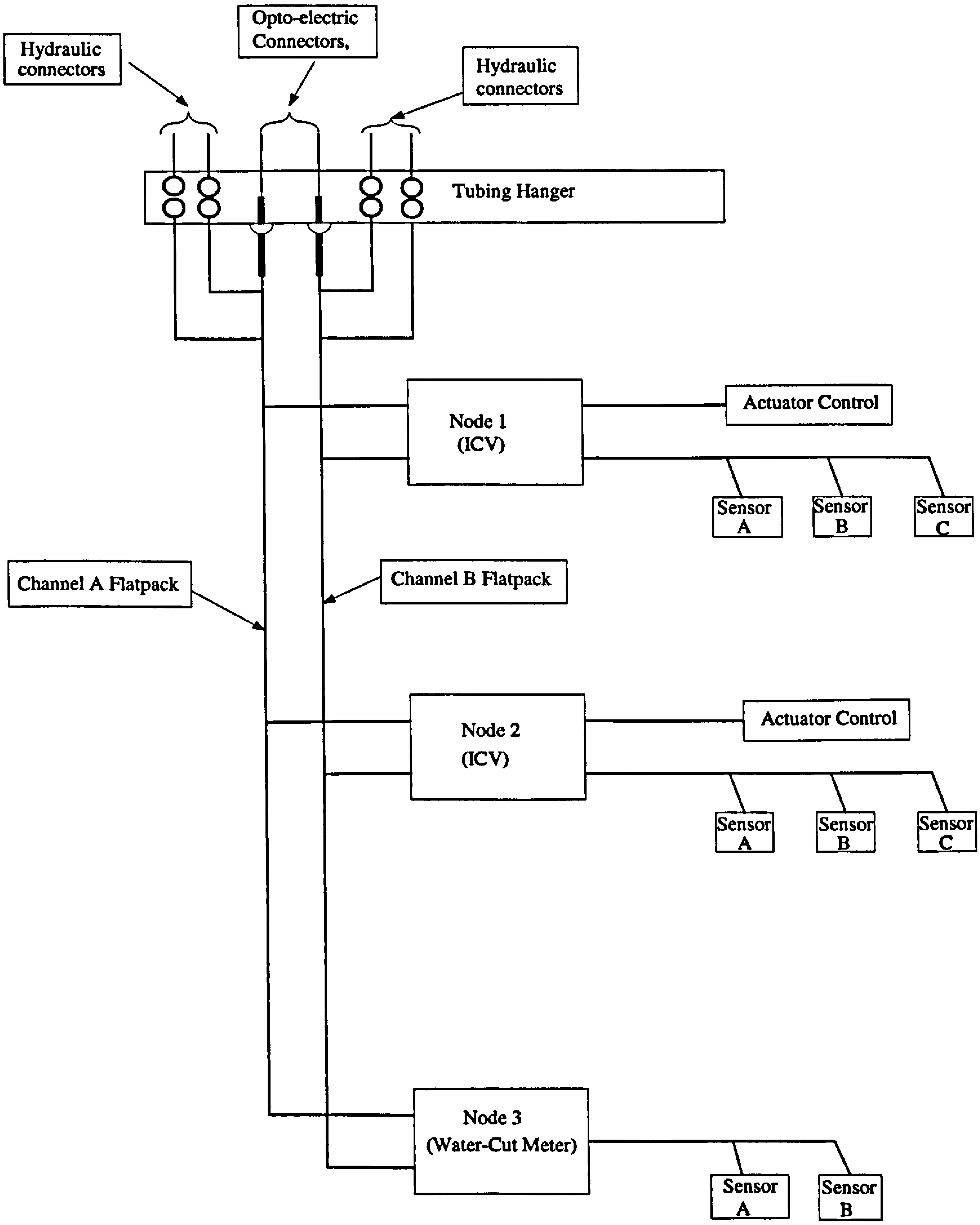


Figure 2-10: Block Diagram for an "Intelligent" Well Communication & Power System

2.4 Where has it been used?

The value generation capability of Intelligent Wells by using a "show case" of case histories, general experience from operators, etc has been demonstrated in this section. The "show case" can be used as a check list against which the opportunity to create value by IWsT for a particular case being studied can be screened.

2.4.1 Where to find IWsT value

A summary checklist based on experience from one large Service Company is as below:

- Increased recovery
- Accelerated production
- Data collection
- Reduced reservoir uncertainty
- Manage recovery & fluid allocation from various zones
- Selective stimulation
- Rapid return to production of shut-in zones as required by operational constraints, etc
- Minimise intervention costs (OPEX)
- Connect several zones of uncertain productivity
- Safety - less people and on-site transport no longer necessary
- Environment - gas/water emissions reduced
- Reduced power for water injection,
- Less spills (but more complicated equipment)

While experience from one large operator showed that small portion of the asset portfolio delivered 80% of the value generation from application of Smart Wells, 50% of the IWsT value was in Ultimate Recovery Increase. However, 80% of Smart Wells were justified to management on Production Acceleration. This latter is easier to quantify and presents immediate, short term benefit in increased production, speeding management approval.

Many important aspects identified that were difficult to quantify e.g. reservoir management issues. Early data gathering combined with the ability to adjust well pattern (need to be able to take action) reduces downside risk during field development.

The operational Value of downhole data is significant. Bringing new/existing well up to full production more rapidly than the normal technique using surface data i.e. the cost of the downhole instrumentation and control system (DIACS) installation can be (partly) justified on the more rapid well clean up and the consequent saving in the rig time. The availability of downhole measurements has frequently been shown to lead to faster than normal well start-up achieved with surface measurements only.

Arrival of gas cone was unnoticed and the well had to be shut in for 5 days. Downhole temperature measurements combined with a suitable model would have identified the early stages of coning/cusping. Production staff require suitable, easy to use monitoring / alarm tools to recognise onset of change situation from continuous data streams.

2.4.2 Where less likely to find IWsT value

Installation of Intelligent Wells may not be justifiable in mature field developments with limited reserve and low rate wells e.g. land operations and large platforms with easy well access. These often show limited scope for value creation since only well optimisation is possible and IWsT completions may excessively increase project cost.

However, availability of low cost IWsT completion equipment has increased the market and widened the range of potential economically justifiable completions, though this is not true when multilateral completions require separate control and / or there are specific reservoir fluid scenarios. It should be remembered that Infill Drilling / Sidetracking is a competitor to Intelligent Wells.

2.5 Published Examples of Intelligent Well Application

2.5.1 Accelerate Production by commingling stacked pay

IWsT by commingling stacked pay manages the (possibly tilted) oil rims with different thickness in multiple fault blocks from a single wellbore. Figure 2-11 illustrates the commingling production from separate sands using an intelligent well [2.8]. It meets the regulatory need for zone allocation when combined with downhole flow / phase-cut meters. Accuracy of downhole flow rates is normally sufficient to allow approval to co-produce zones where single completions would normally be required.

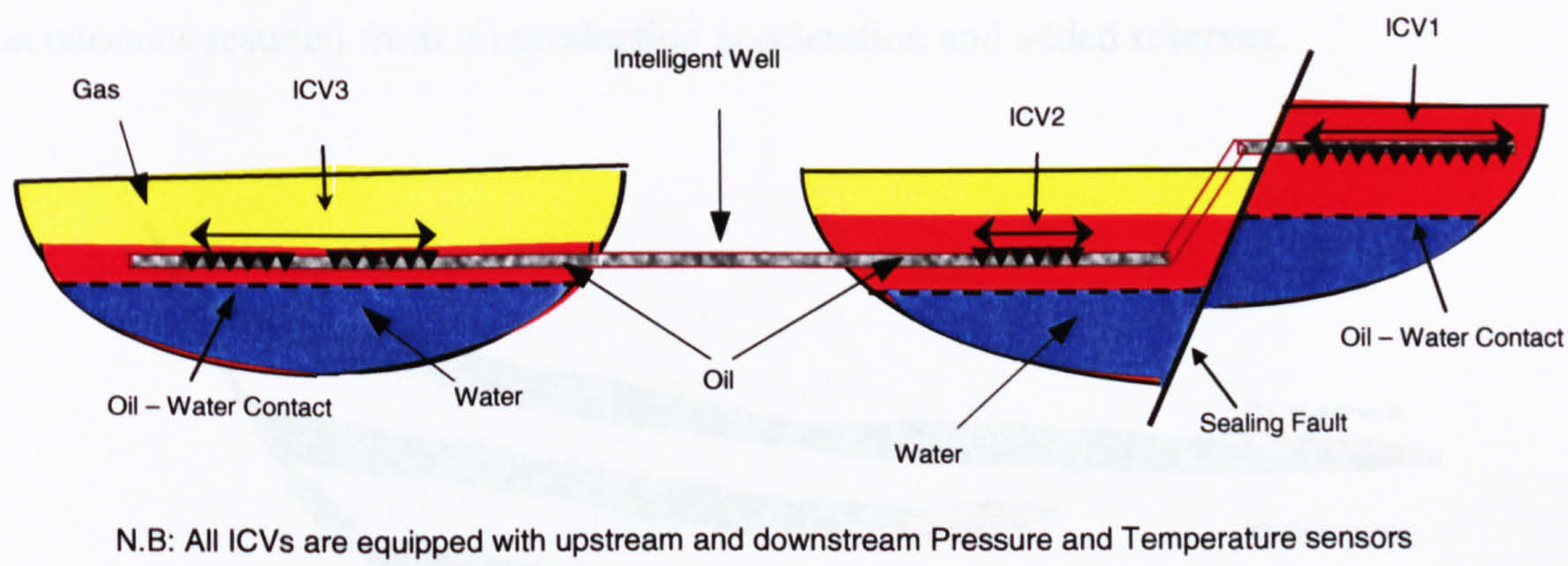


Figure 2-11: Commingling production from several sands

2.5.2 Optimization of Reservoir Management of a deepwater Gulf of Mexico Field

Figure 2-12 shows a schematic of a deepwater Gulf of Mexico field that consists of several stacked sandstone reservoirs that were separated by shales [2.9]. Intelligent Well system Technology applied in this field resulted in optimizing the management of a field through controlled commingling of production and increased flexibility to make operational changes.

The use of IWsT resulted in the original estimates of production potentials to be surpassed. The cost-saving resulted from the elimination of rig intervention, both for re-completing the well or the drilling of further laterals in late well life. Improved project economics resulted from oil production acceleration and added reserves.

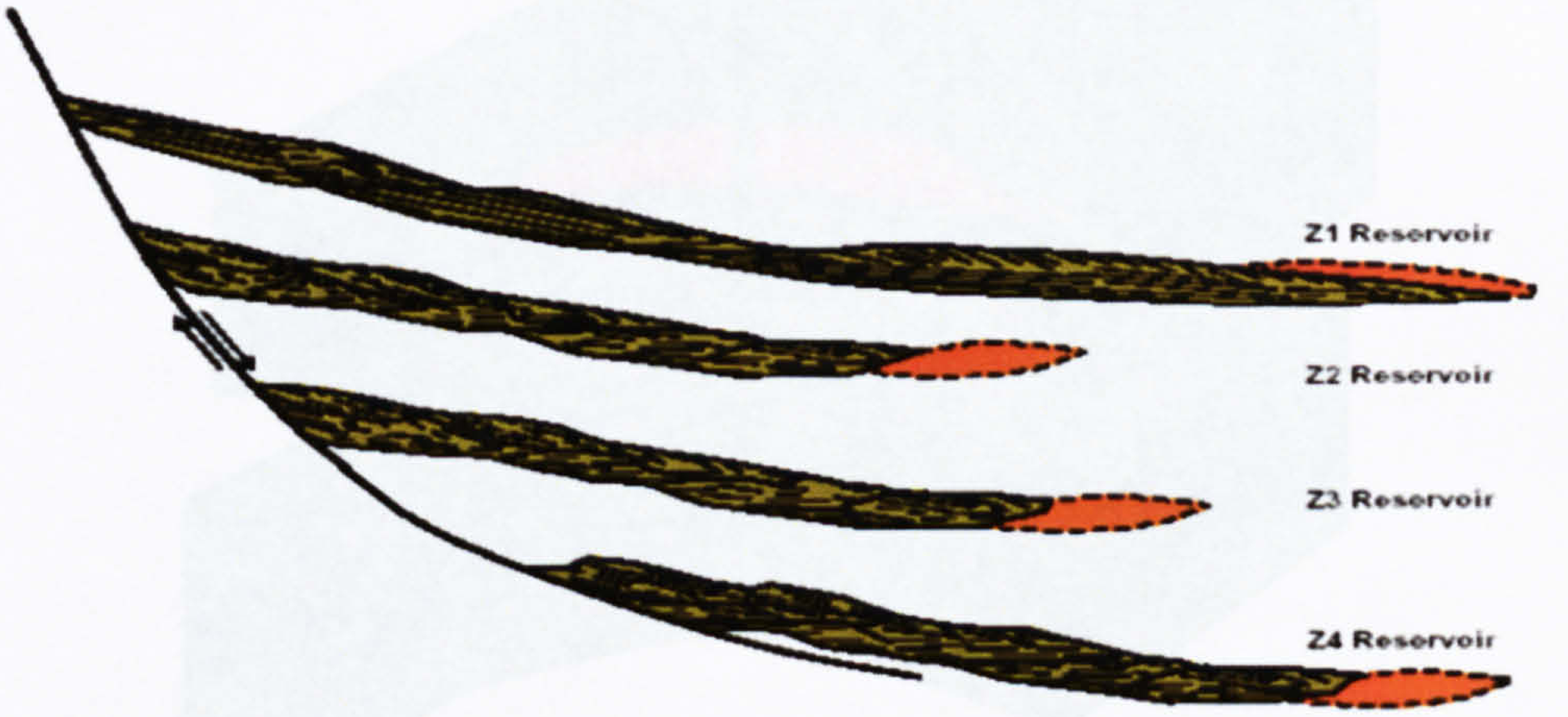


Figure 2-12: Four reservoirs intersected by a well [2.9]

2.5.3 Gas Dump flooding

The drilling of a well with deep gas production and (shallower) injection will:

- Increases Ultimate Recovery
- Saves on Compressors
- May save drilling extra injection well
- Internal (dump) flood for fluid sweep or reservoir pressurisation
- Increased reserves by production from Multilaterals completed in separate reservoirs

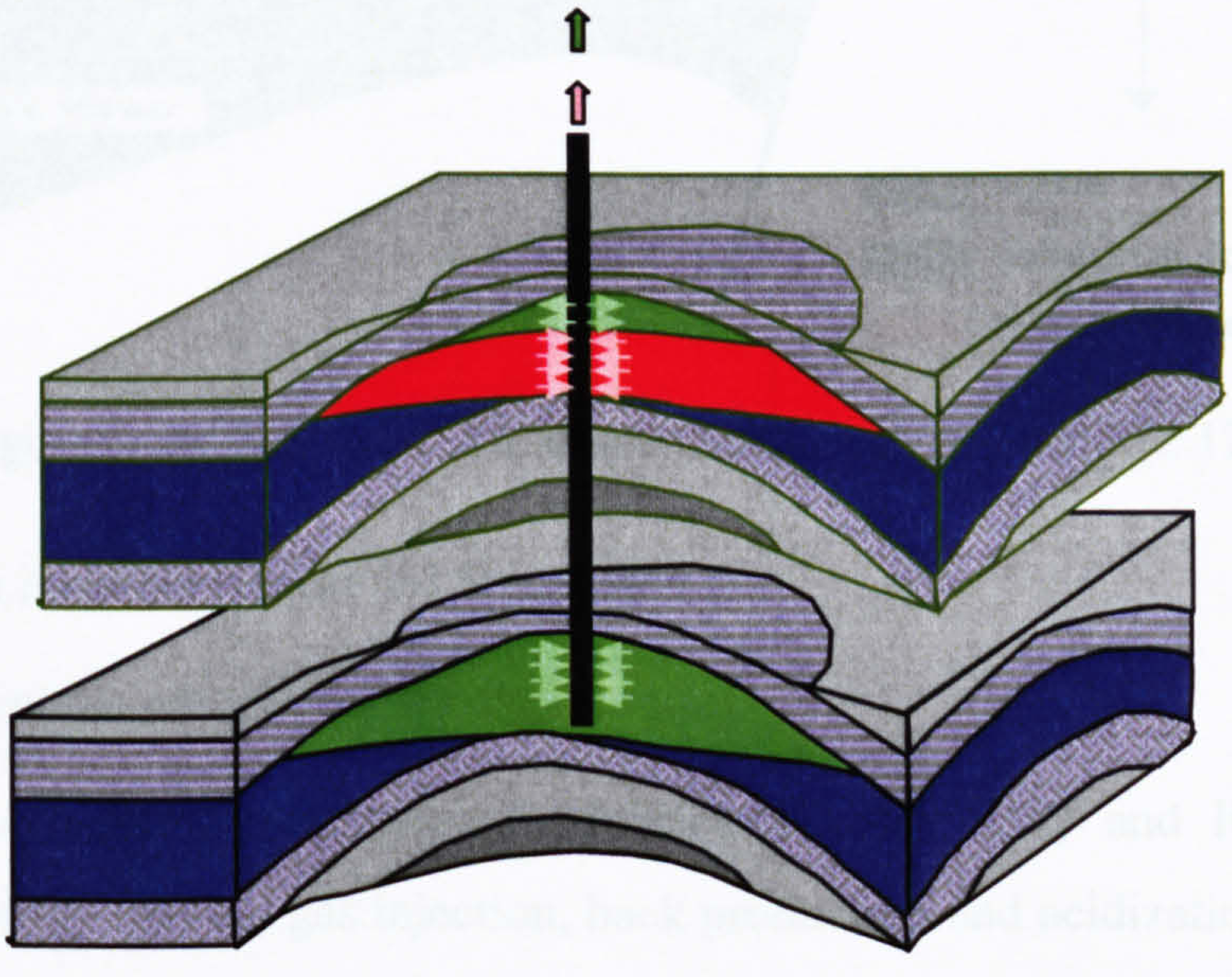


Figure 2-13: Pressure maintenance through controlled gas dump flooding [2.10, 2.11]

2.5.4 Intelligent Internal Gas Injection Wells Revitalise a Mature Field

Figure 2-2 shows reservoirs that are located in an alternating sequence of shallow marine sands and sealing shales at a depth of 1800-2000 m SS [2.12].

The AV reservoirs (Figure 2-2) are undergoing a gas drive from a large secondary gas cap. The AV pressure has declined from 190 bar in 1972 to about 70 bar in 1999 resulting in low production rates and lift problems.

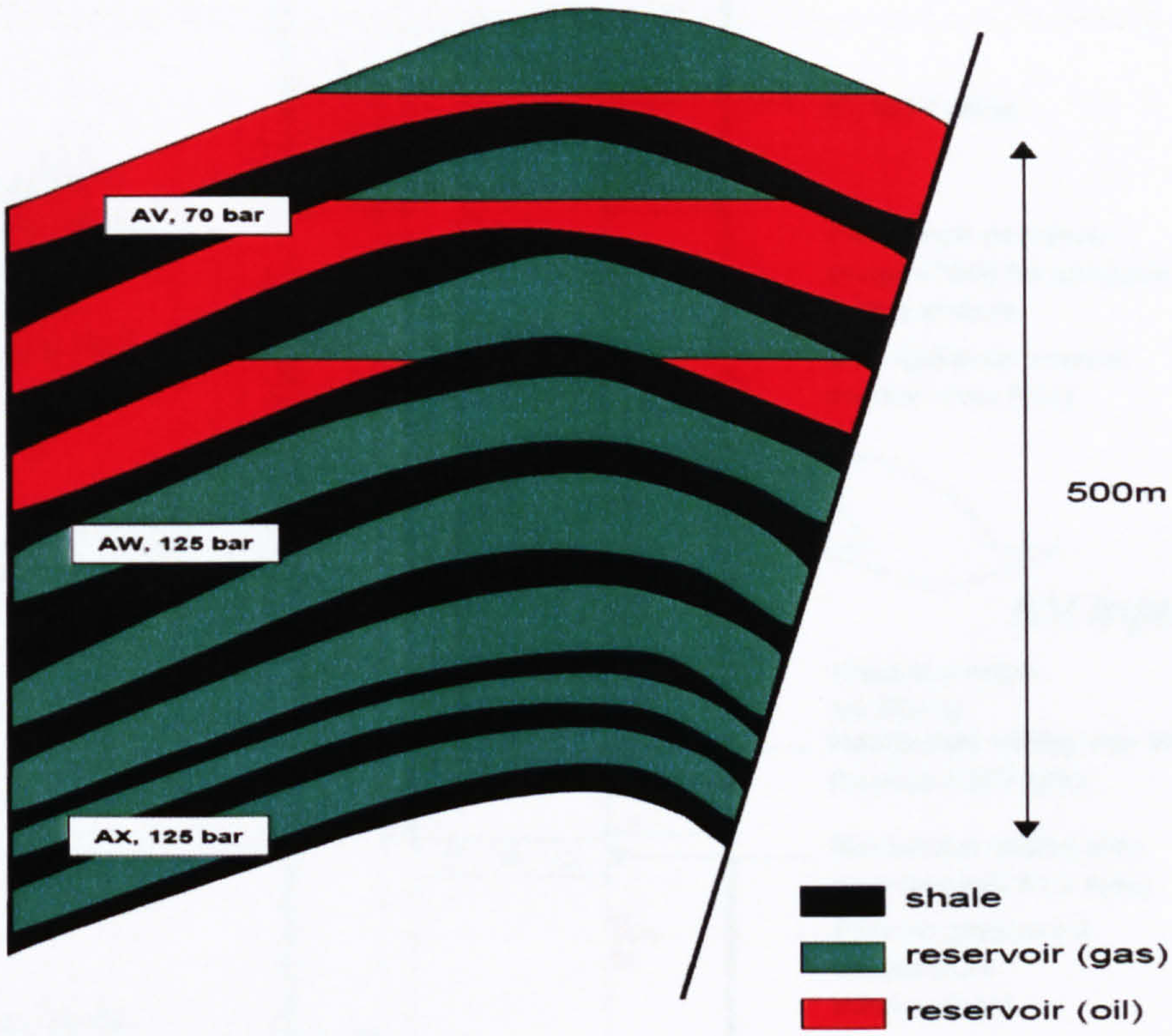


Figure 2-14: Schematic cross-section through reservoir [2.12]

The completion installed (Figure 2-15) included a:

- Long openhole gravel pack for sand control.
- Surface controlled mini-hydraulic lubricator valve (LV) and ICV for on/off control of the internal gas injection, back production and acidization of AV sands without Wireline Intervention.
- Permanent downhole gages (PDG) to monitor pressure drop in the tubing for gas injection rate calculation and to monitor the reservoir pressure if the zones are shut in.
- Mechanical redundancy is available if the ICV, etc fails.

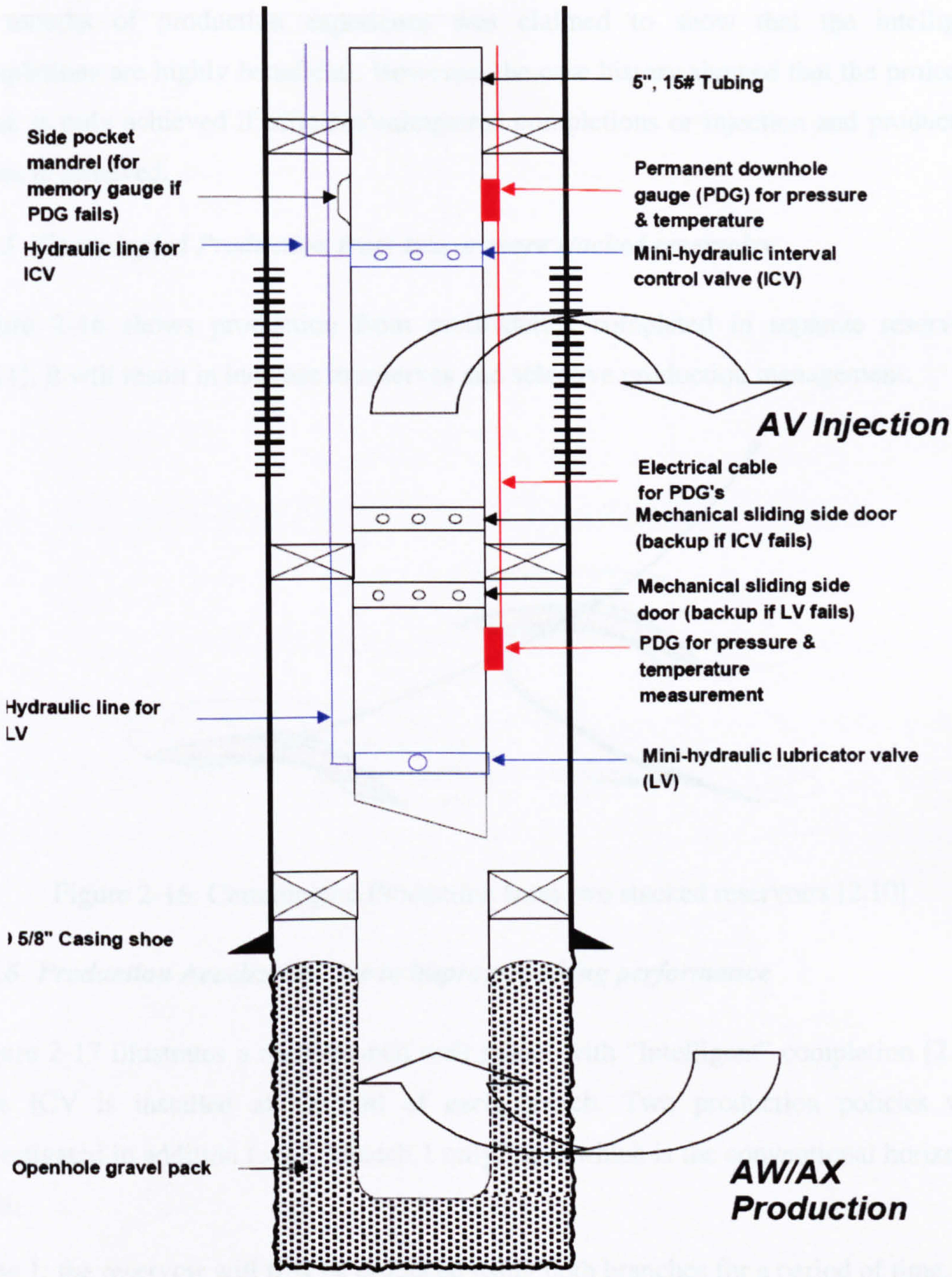


Figure 2-15: Well Diagram [2.12]

Installation of the above completion caused deliberate cross flow of gas from deep AW/AX gas reservoir into the gas cap of the overlying oil reservoirs. This achieved reservoir pressure maintenance without any surface facilities.

17 months of production experience was claimed to show that the intelligent completions are highly beneficial. However, the case history showed that the projected value is only achieved if efficient/unimpaired completions or injection and production zones is achieved.

2.5.5 Commingled Production from two or more stacked reservoirs

Figure 2-16 shows production from multilaterals completed in separate reservoirs [2.11]. It will result in increase in reserves and selective production management.

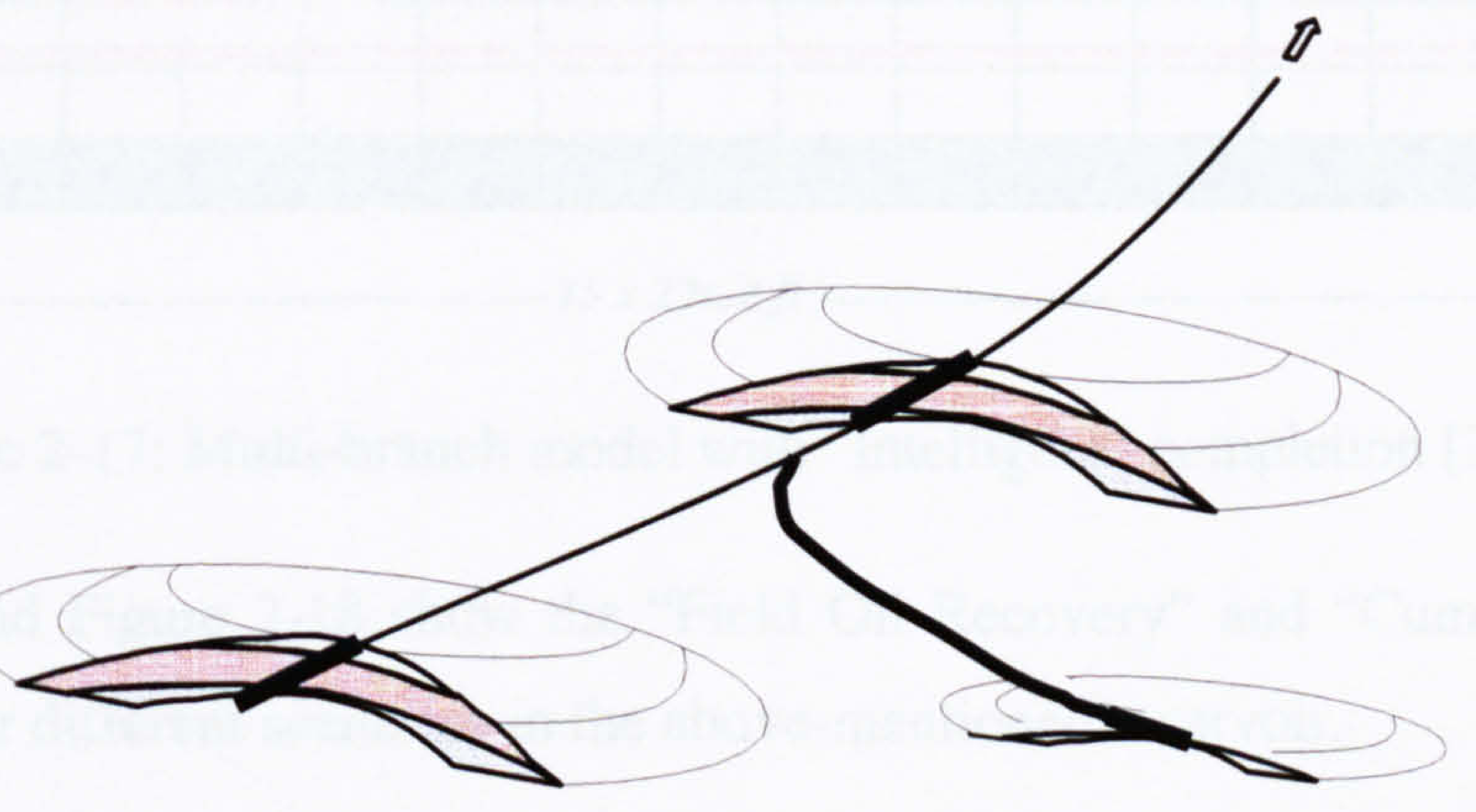


Figure 2-16: Commingled Production from two stacked reservoirs [2.10]

2.5.6 Production Accelerated due to improved tubing performance

Figure 2-17 illustrates a multi-branch well model with "Intelligent" completion [2.13]. One ICV is installed at the end of each branch. Two production policies were investigated in addition to the "branch 1 only" case which is the conventional horizontal well:

Case 1: the reservoir will first be produced using both branches for a period of time. The upper ICV will then be closed to halt production from the upper lateral (Branch 2).

Case 2: first produces the reservoir by the upper branch (Branch 2) only; followed by changing the production zone to the lower branch (Branch 1) alone

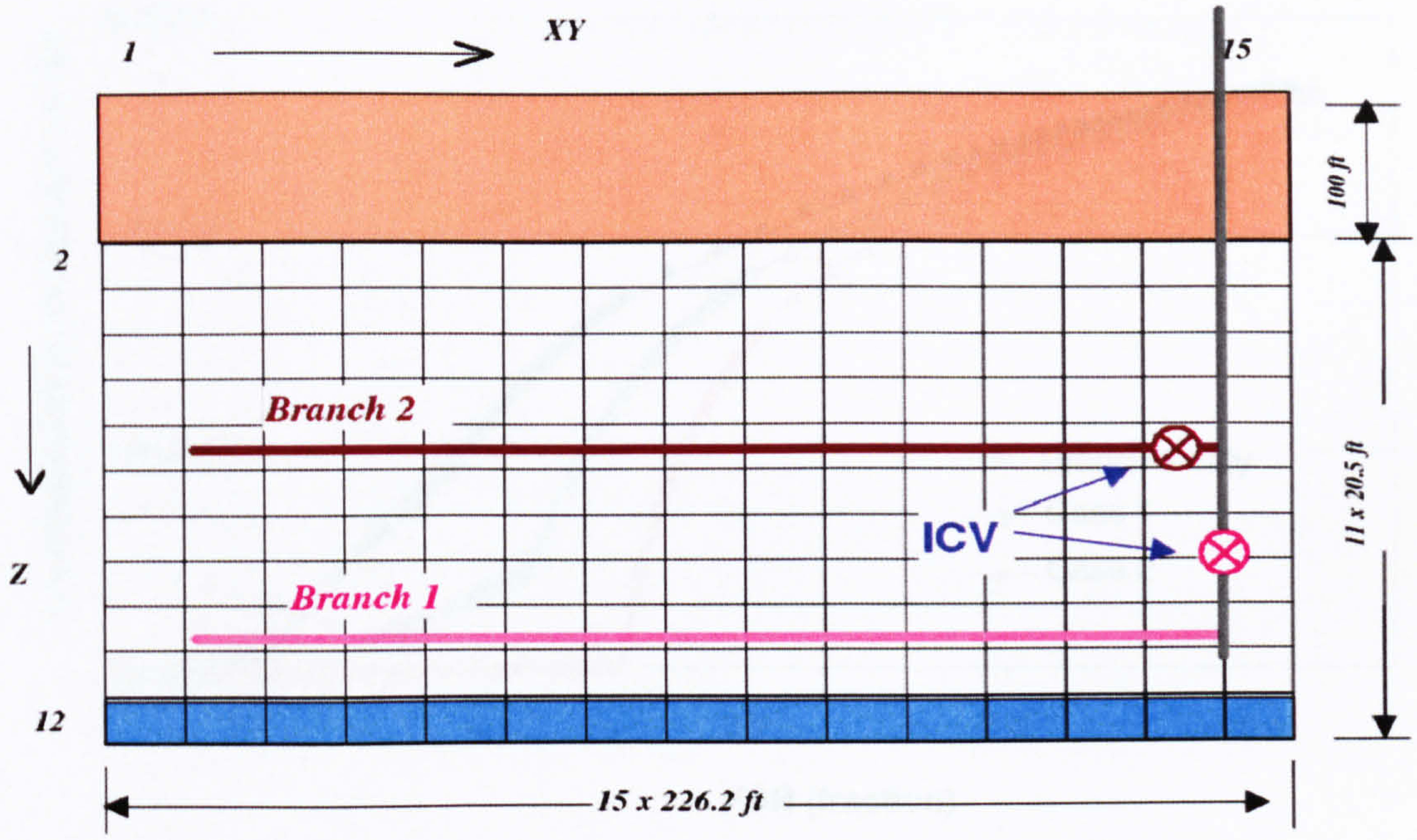


Figure 2-17: Multi-branch model with "Intelligent" completion [2.13]

Figure 2-17 and Figure 2-18 show the "Field Oil Recovery" and "Cumulative Water Production" for different scenarios in the above-mentioned reservoir.

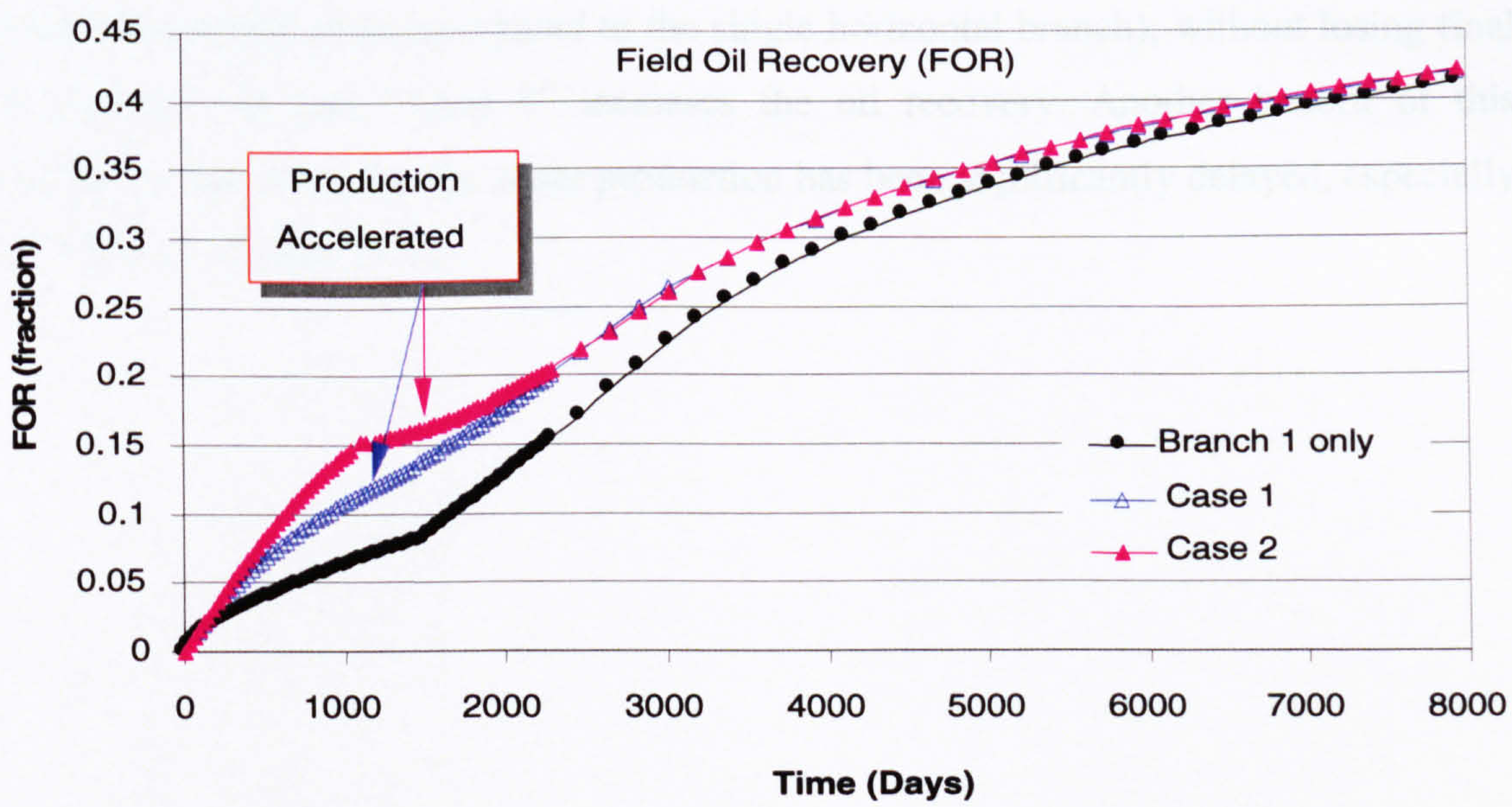


Figure 2-18: Production accelerated due to improved tubing performance [2.13]

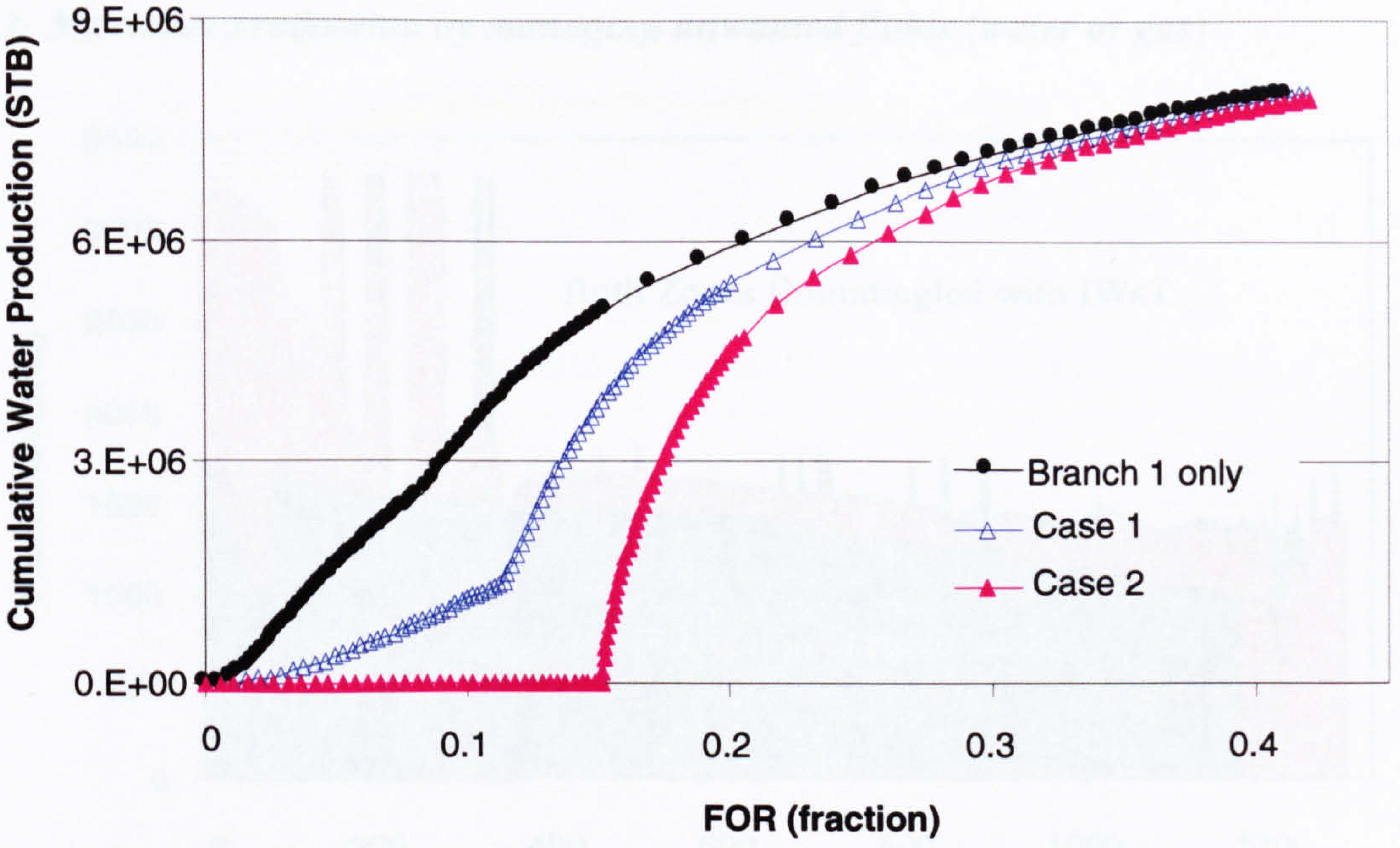


Figure 2-19: Delayed Water Production [2.13]

Figure 2-18 shows that both production policies achieve the sought for early oil production acceleration (compared to the single horizontal branch); without losing final oil recovery. In fact, "Case 2" increases the oil recovery. Another benefit of this completion option is that the water production has been significantly delayed, especially for "Case 2" (Figure 2-19).

2.5.7 Maximise production by managing unwanted fluids (water or gas)

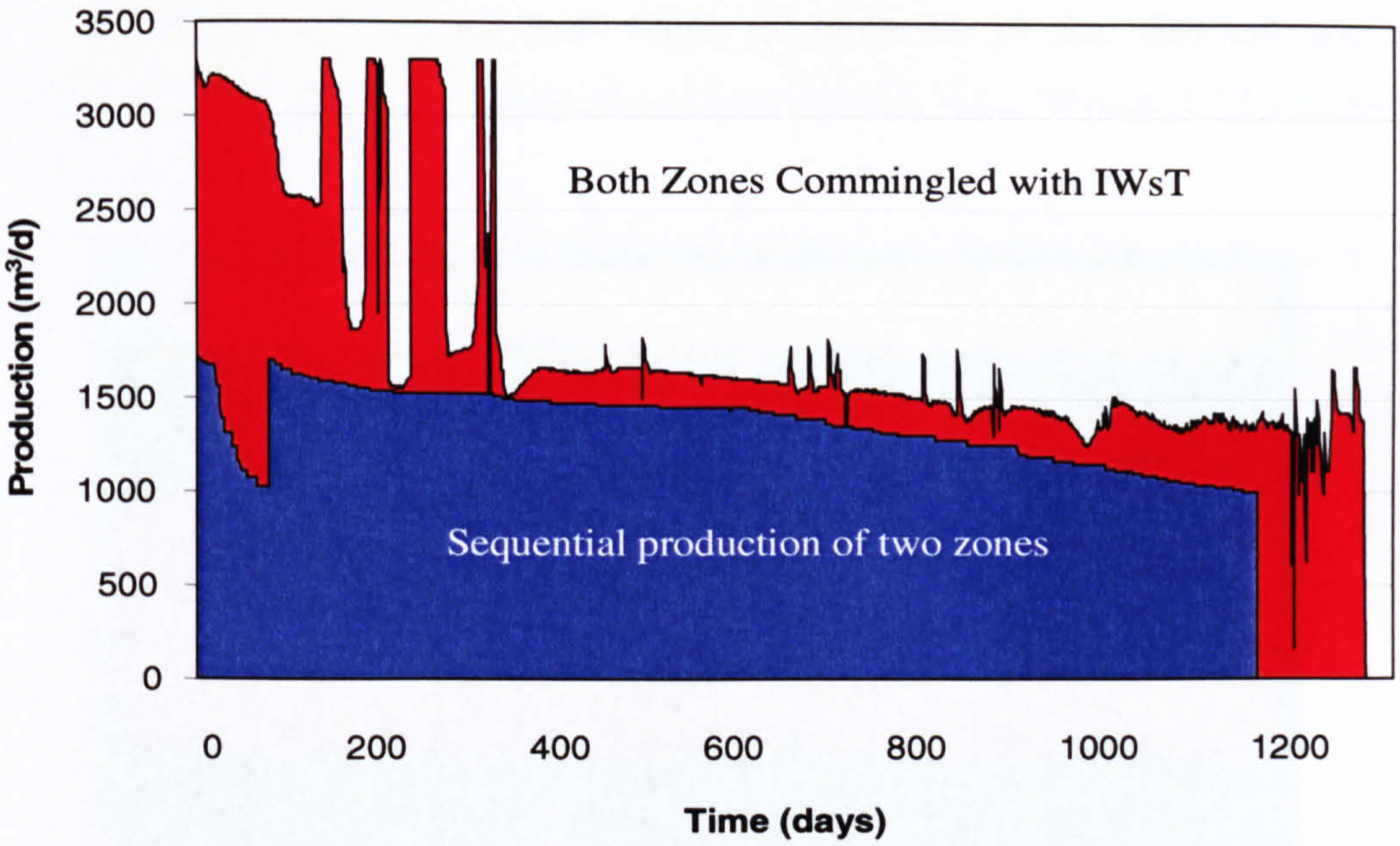


Figure 2-20: Managing unwanted fluids [2.14]

Figure 2-20 clearly demonstrates the effect of ICVs on improving recovery when commingled production with IWsT is considered. Both the well's life and production increases when compared to producing the two zones subsequently.

2.5.8 Internal gas lift to optimise tubing performance

Figure 2-21 shows a horizontal well which produces an oil rim. Conventional well completion was only able to produce the oil rim for 180 days (Figure 2-22). Well died due to water coning.

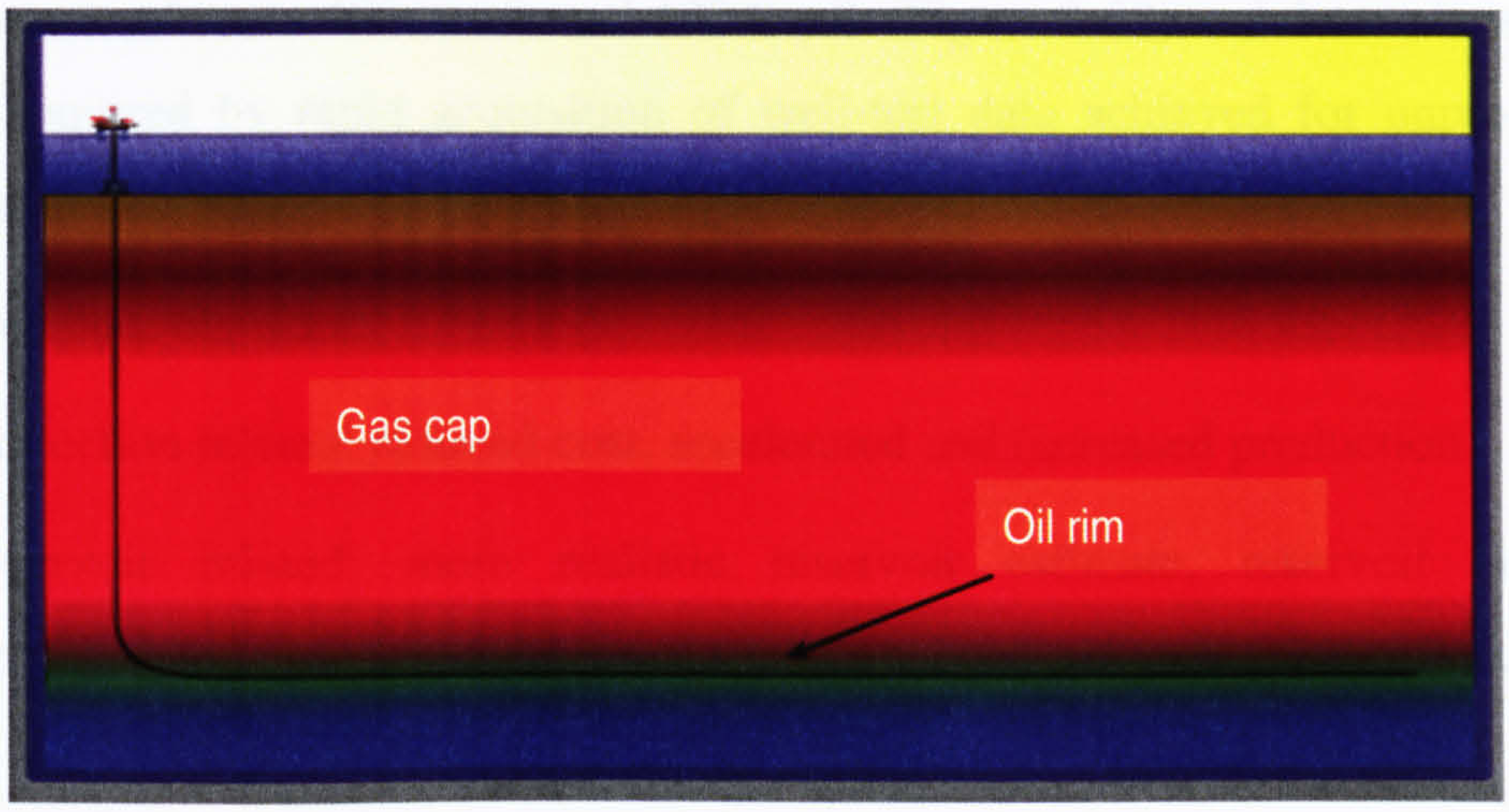


Figure 2-21: A horizontal well producing an oil rim [2.14]

Figure 2-22 shows that controlled natural gas lift by controlled choking the inflow from the gas cap improved the tubing performance. The well produced for more than 6 years.

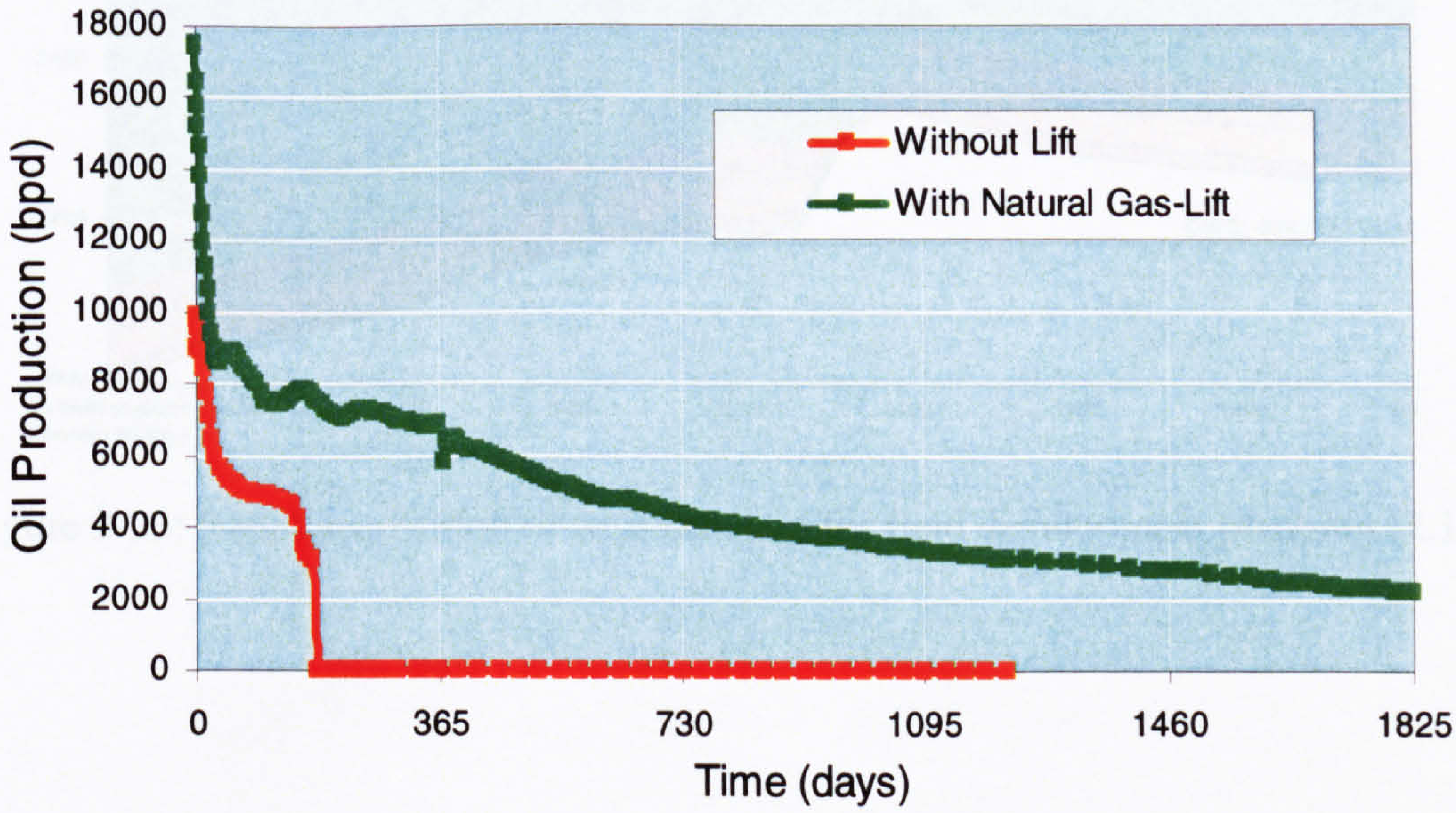


Figure 2-22: Internal gas lift improved the well performance [2.14]

2.5.9 Data acquisition

Figure 2-23 shows the well 34/7 completed in Snorre field [2.15]. The well objectives were primarily to produce the upper Statfjord oil and secondarily the lower Statfjord oil. Installation of the well resulted in obtaining early information about the degree of fault sealing between blocks 400 North and 400 South (Figure 2-23) and determines if 1 or 2 injectors required by rapid acquisition of well-test data achieved for unproved field development planning.

The proven benefits were:

- Production related: reduced cost, accelerated and increased production.
- Reservoir related: more realistic reservoir estimate, reservoir boundaries identified and optimum position of the future injection well(s) identified.

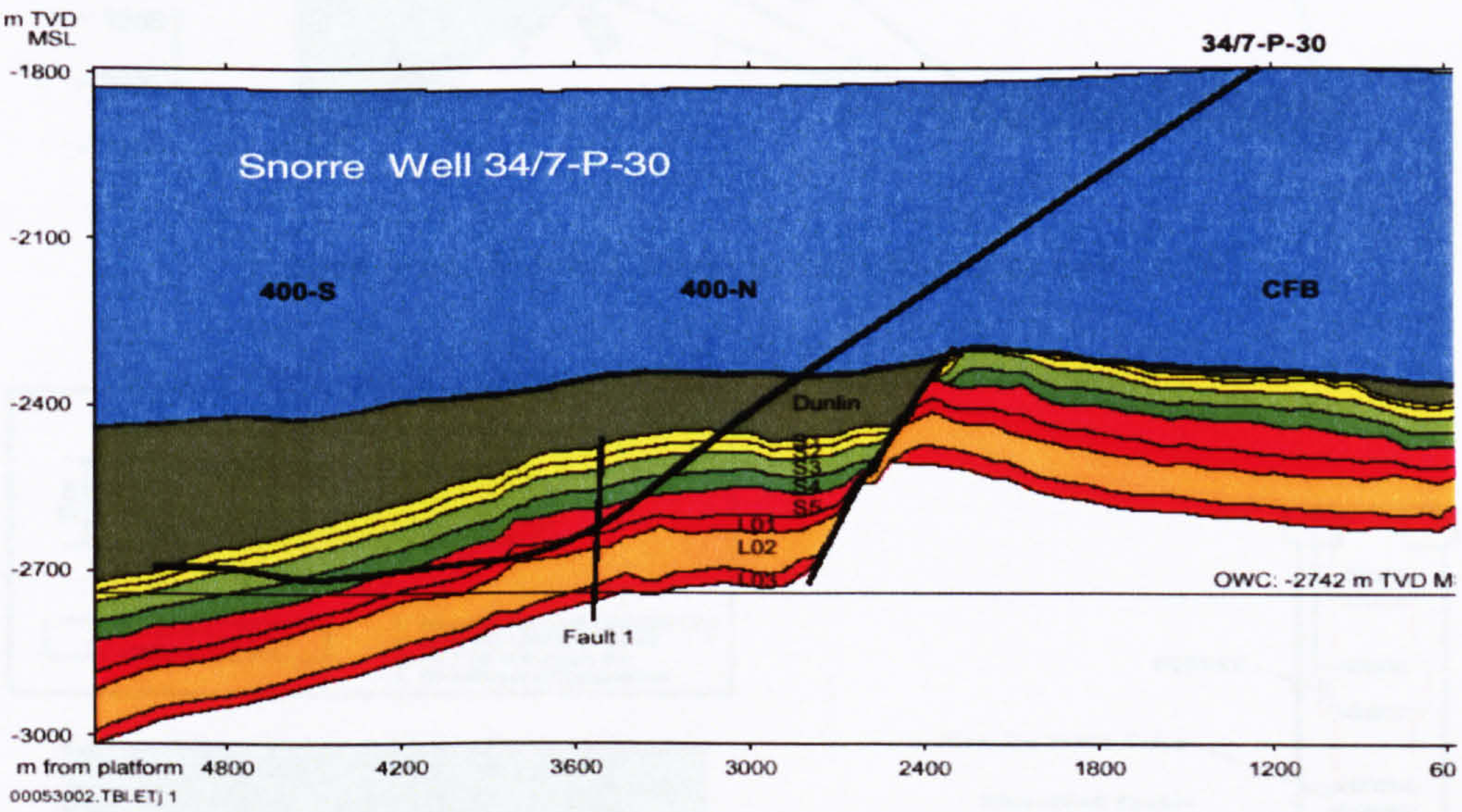


Figure 2-23: Rapid acquisition of well-test data for field development planning [2.15]

2.5.10 IWsT in fractured reservoirs

Figure 2-24 shows a cross-section of reservoir down the side of a Salt Diapir showing the reservoir layers and the main fractures. The reserves are mostly contained in fractured chalk. Presence of the fractures controls the well inflow.

Four ICVs were installed along the production interval. The completion interval was divided into 4 zones of equal length since the detailed fracture production performance, location and pattern was unknown (Figure 2-25).

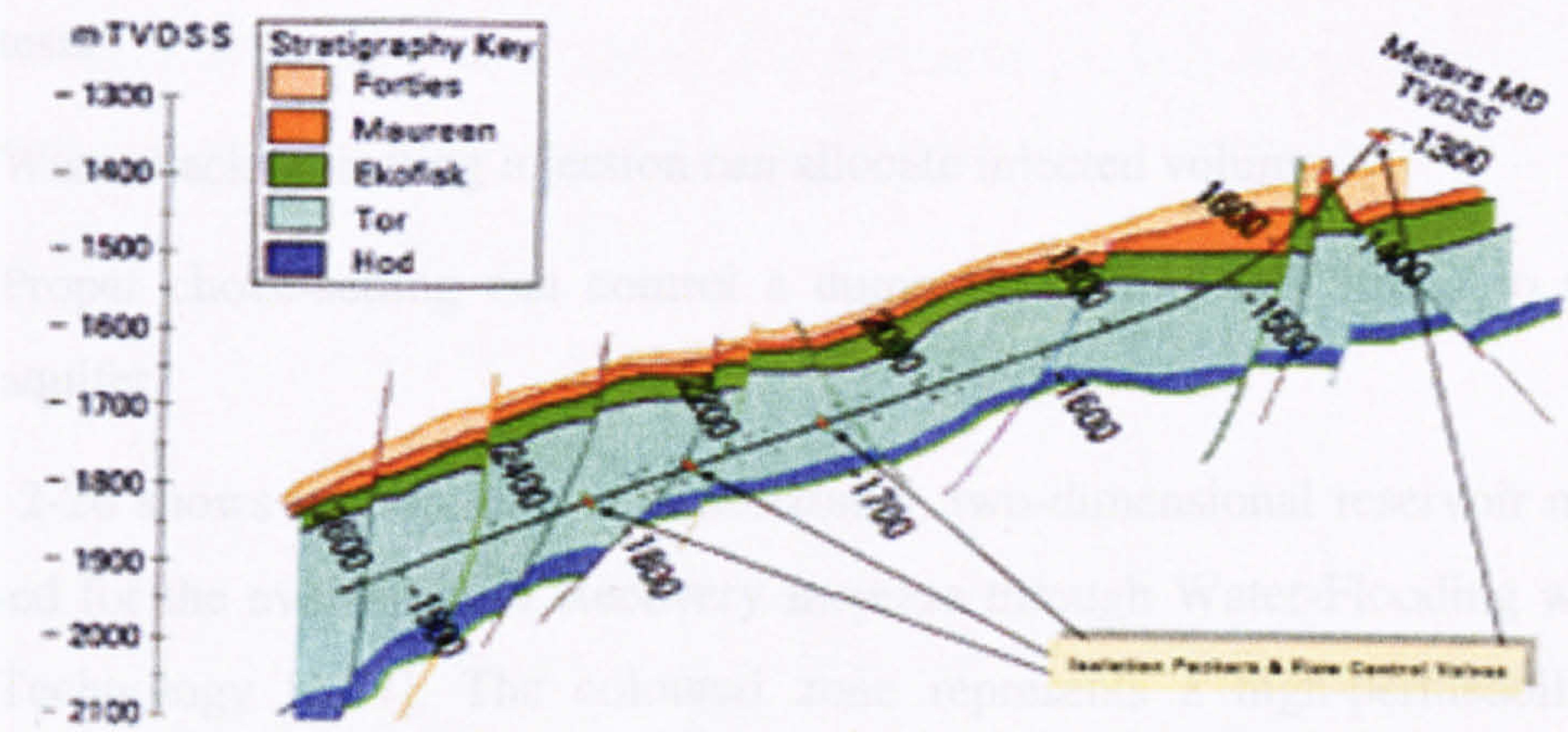


Figure 2-24: Machar Field in central North Sea [2.16]

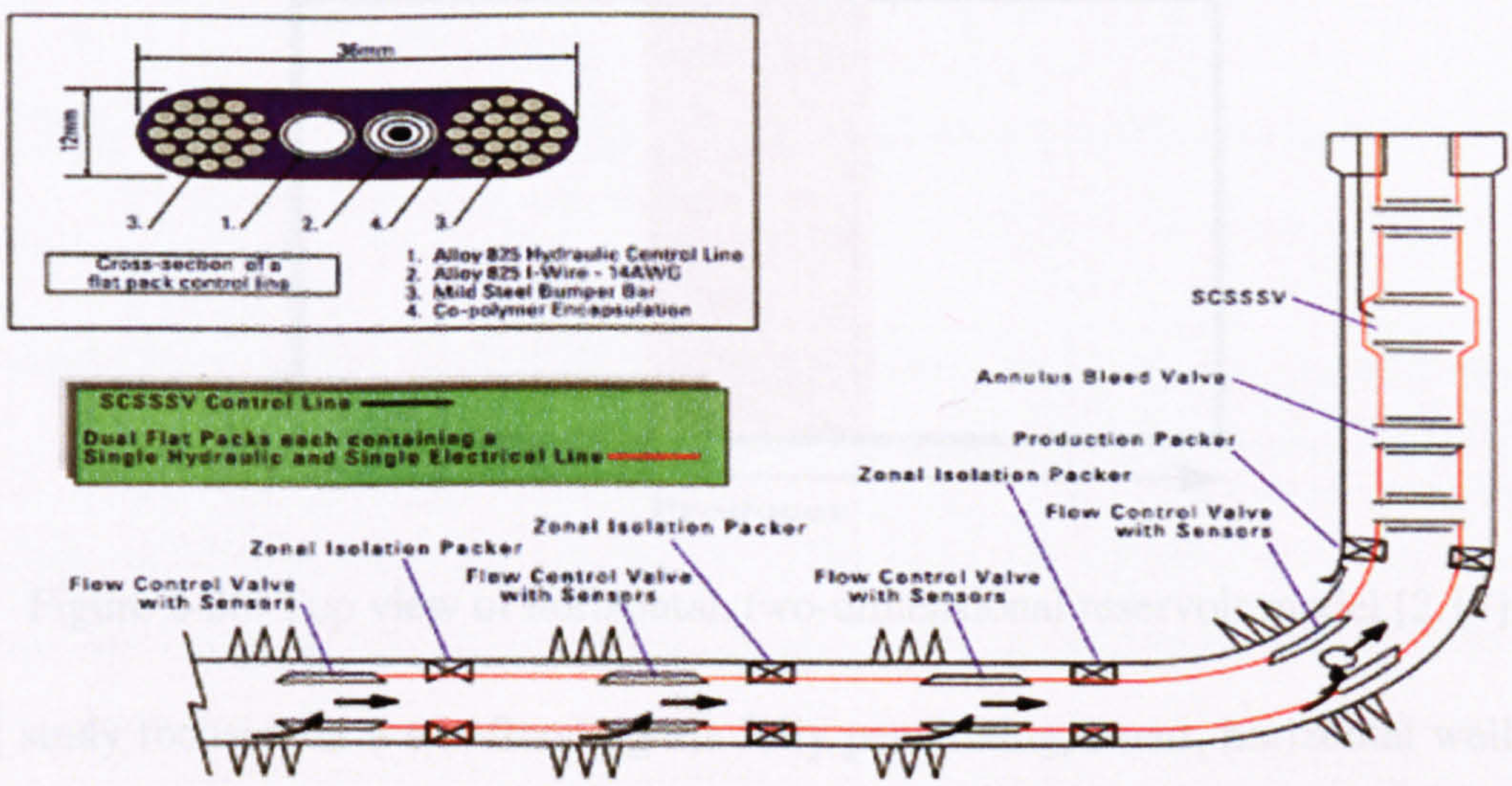


Figure 2-25: Schematic of Smart Completion Showing the General Layout of Control Valves, Packers and Flat-Pack Control Lines [2.16]

2.5.11 More Effective Management of Injectors

The primary purpose of using Smart Injectors is to achieve selective (controlled) injection into two or more zones with pressure incompatibilities. Inclusion of downhole instrumentation allows them to recognise:

- The presence of sealing or leaking faults between zones
- Connection between zones that the well traverses
- Water allocation between zones can be quantified by carrying out interference tests
- Warm-back on halting injection can allocate injected volumes
- Proper choke-setting can control a dump flood from the Strong to the Weak aquifer

Figure 2-26 shows the top view of a horizontal, two-dimensional reservoir model that was used for the evaluation of Recovery Increase through Water-Flooding with Smart Well Technology [2.17]. The coloured zone represents a high-permeability streak perpendicular to the injector and the producer.

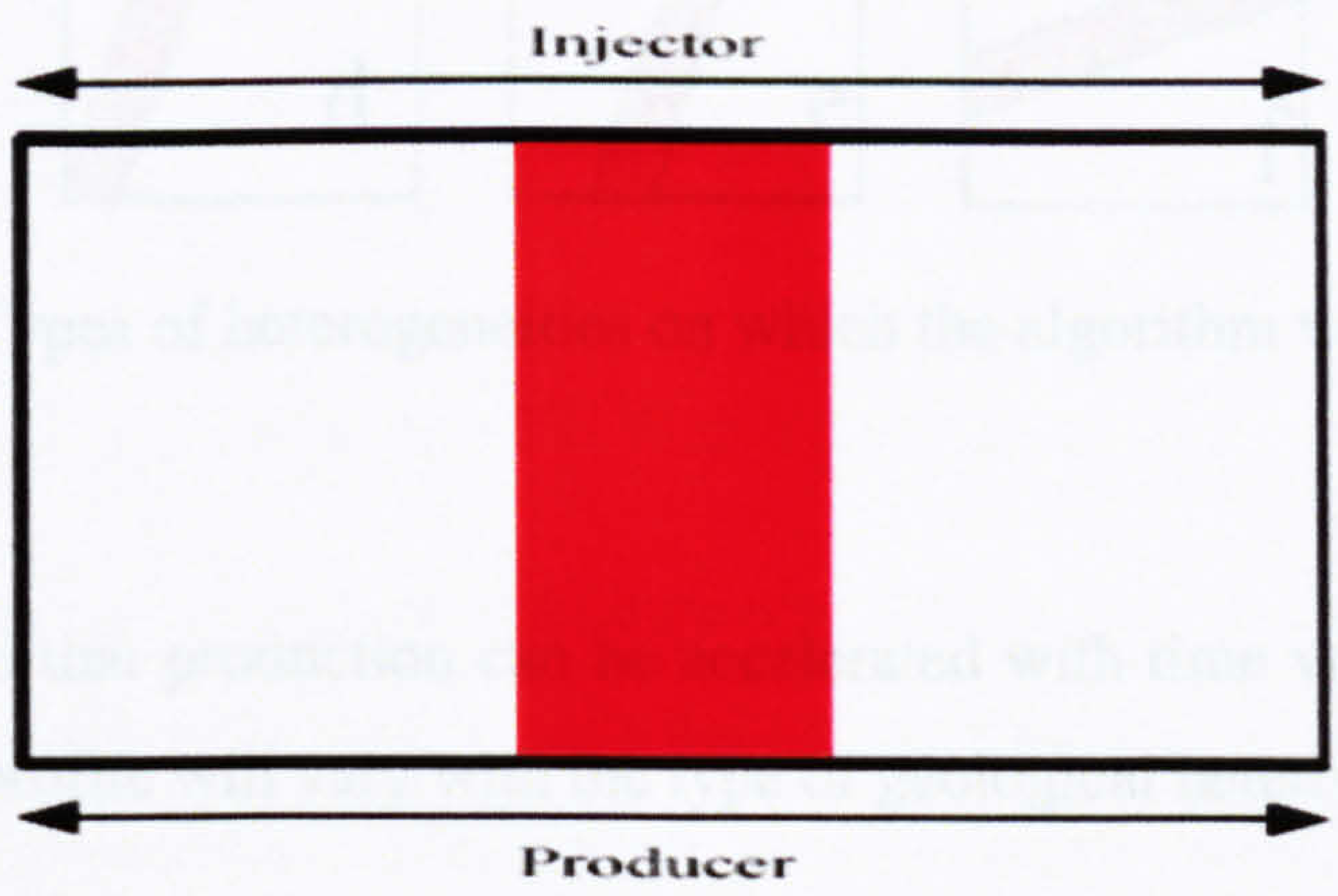


Figure 2-26: Top view of horizontal, two-dimensional reservoir model [2.17]

This study focused on water-flooding via fully penetrating, smart, horizontal wells in a reservoir with simple, large-scale geological heterogeneities.

The study showed that the water-flood could be improved by changing the well injection profiles according to simple algorithms that move the flow paths away from the high permeability zone in order to delay water-breakthrough in the producer.

The general principle behind optimization was to reduce as much as possible the difference in the "time of flight" for water flowing from the injector to the producer along different flow lines.

Orientation of the geological heterogeneity is very important. The water flow-path is affected by the presence of the high permeability streaks. Early-water breakthrough does not occur if the high permeability streak orientation is (near) perpendicular to that of the shortest distance between the wells providing these streaks extend over the full width of the reservoir (Figure 2-27f).

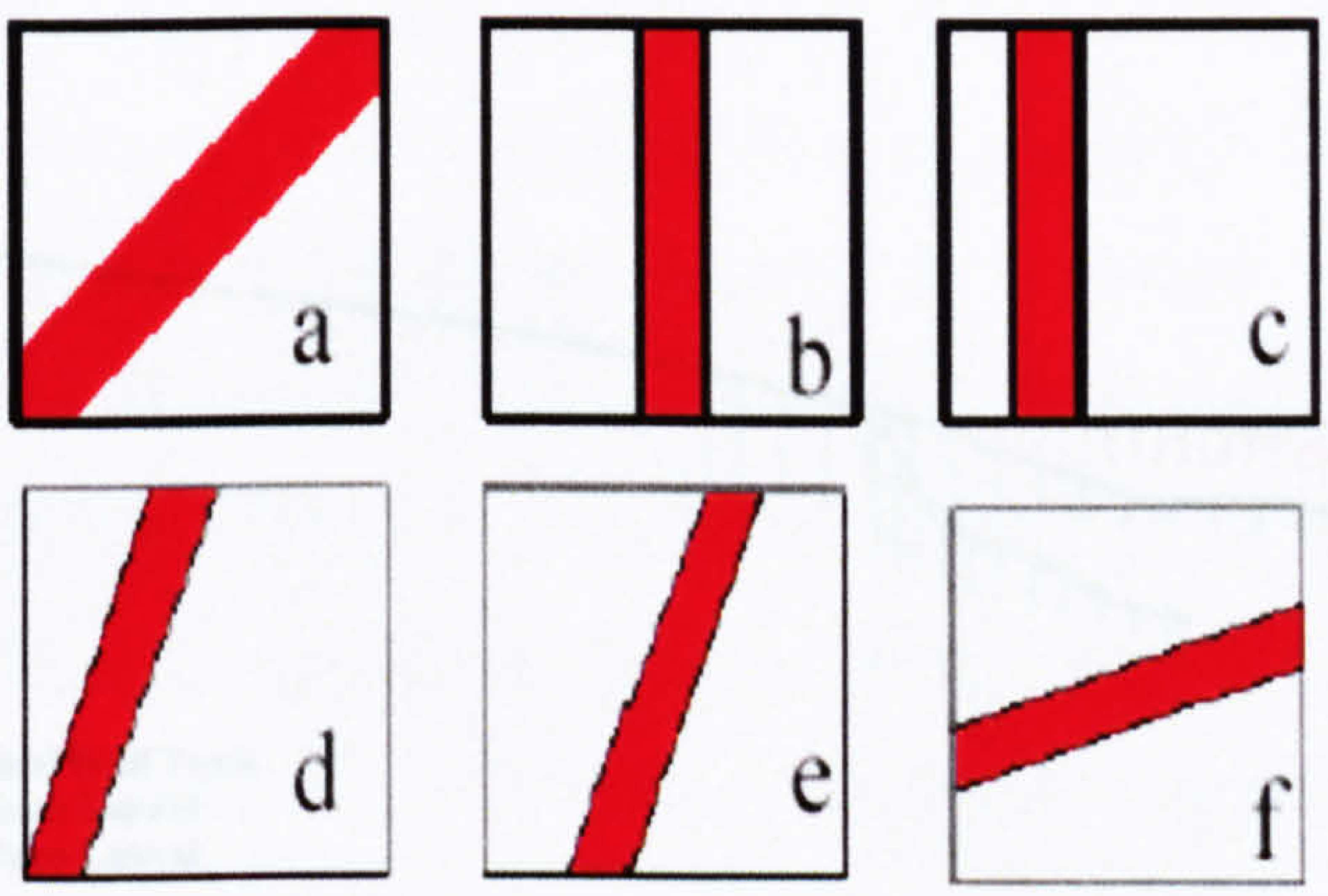


Figure 2-27: Types of heterogeneities on which the algorithm was tested [2.17]

The results showed that production can be accelerated with time varying flow profiles. The optimal flow profile will vary with the type of geological heterogeneity

In a large number of cases the optimisation algorithm was successful in improving the ultimate recovery. The extent of improvement varied considerably, from 0% to 20%, with a consequent delay in water breakthrough. The more a reservoir is prone to early water breakthrough the greater the potential improvement from the optimisation.

2.5.12 Controlling the production of laterals with different pressure

Figures 2-28 and 2-29 show the schematic of an Intelligent Multilateral Well in the Sherwood Formation [2.18].

The field is under strong water drive; hence the faulted sections of the field are prone to early water production. The wells are equipped with ESPs to allow well production at high water-cut and to enhance recovery.

Well M-2, which was drilled in 1994, went to a high water-cut in 1997 and was abandoned in 1998. The original completion was abandoned and a dual lateral sidetrack drilled to reach two reservoir targets. Two ICVs were installed to control the production of the high-rate, high water-cut, northern lateral. A third ICV was used to control production from the southern lateral.

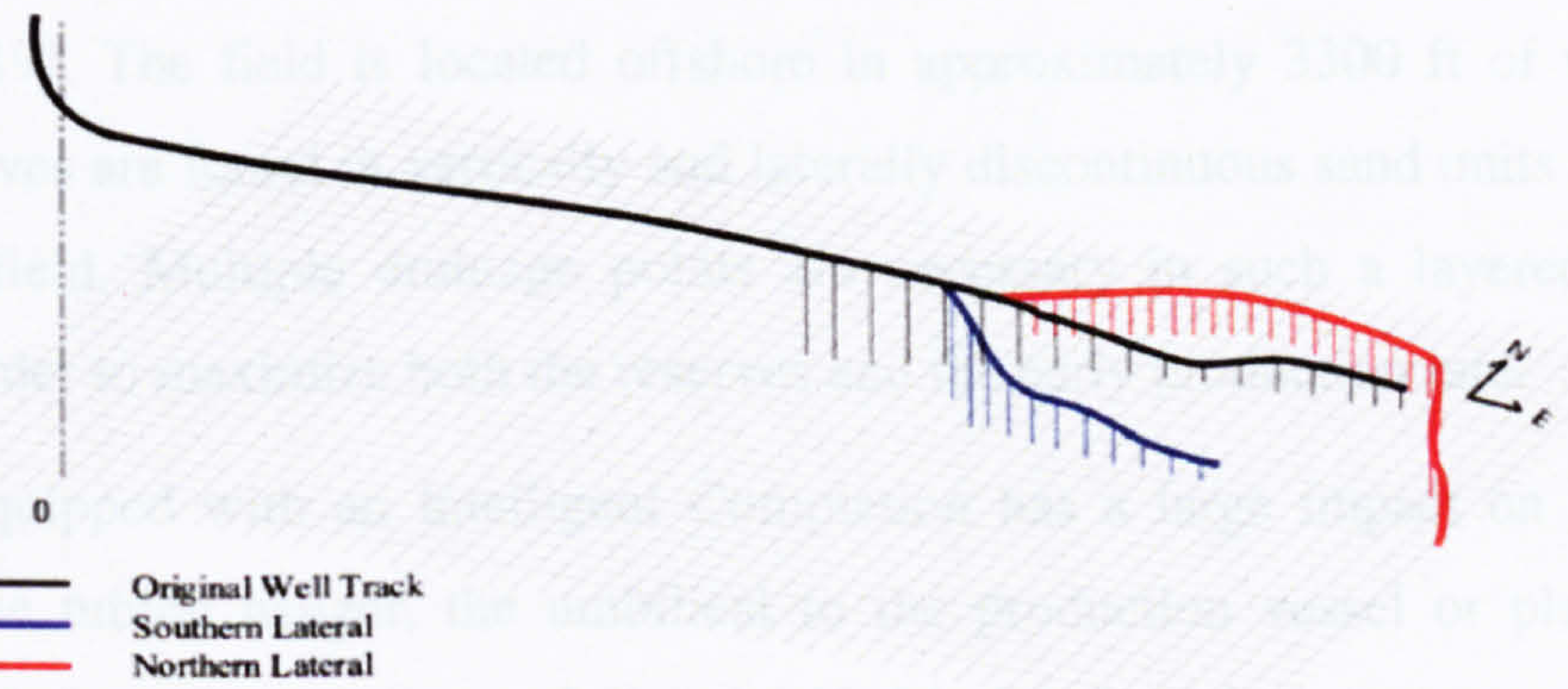


Figure 2-28: Well Track [2.18]

Interference was observed during simultaneous production of the two laterals. The production strategy called for maximum total net oil production. The lower water-cut, southern lateral is produced at the highest possible rate (un-choked) while choking production from the high water cut northern lateral.

An extra 0.5 MMSTB oil production is attributed to the use of intelligent completion technology in the M -2 well has increased the recovery by to date. Reservoir simulation with segmented wellbore model allowed determination of the choke settings advantages to production. The near-wellbore simulator helped for fine-tuning the management of an individual (intelligent) well in the centre of a developed field.

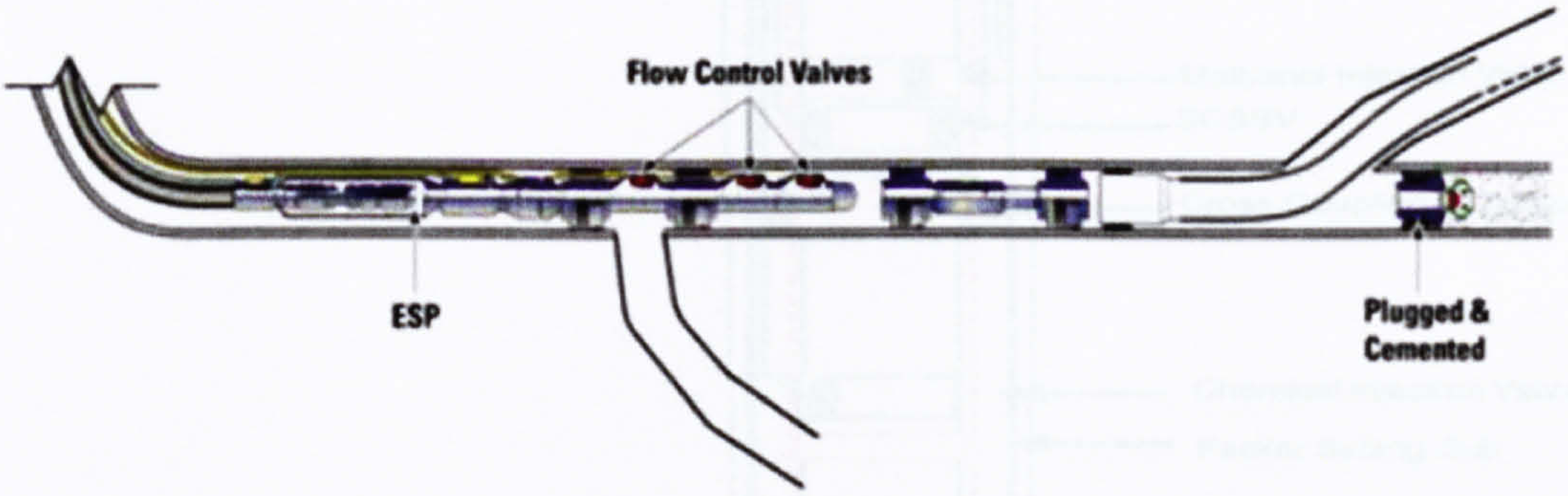


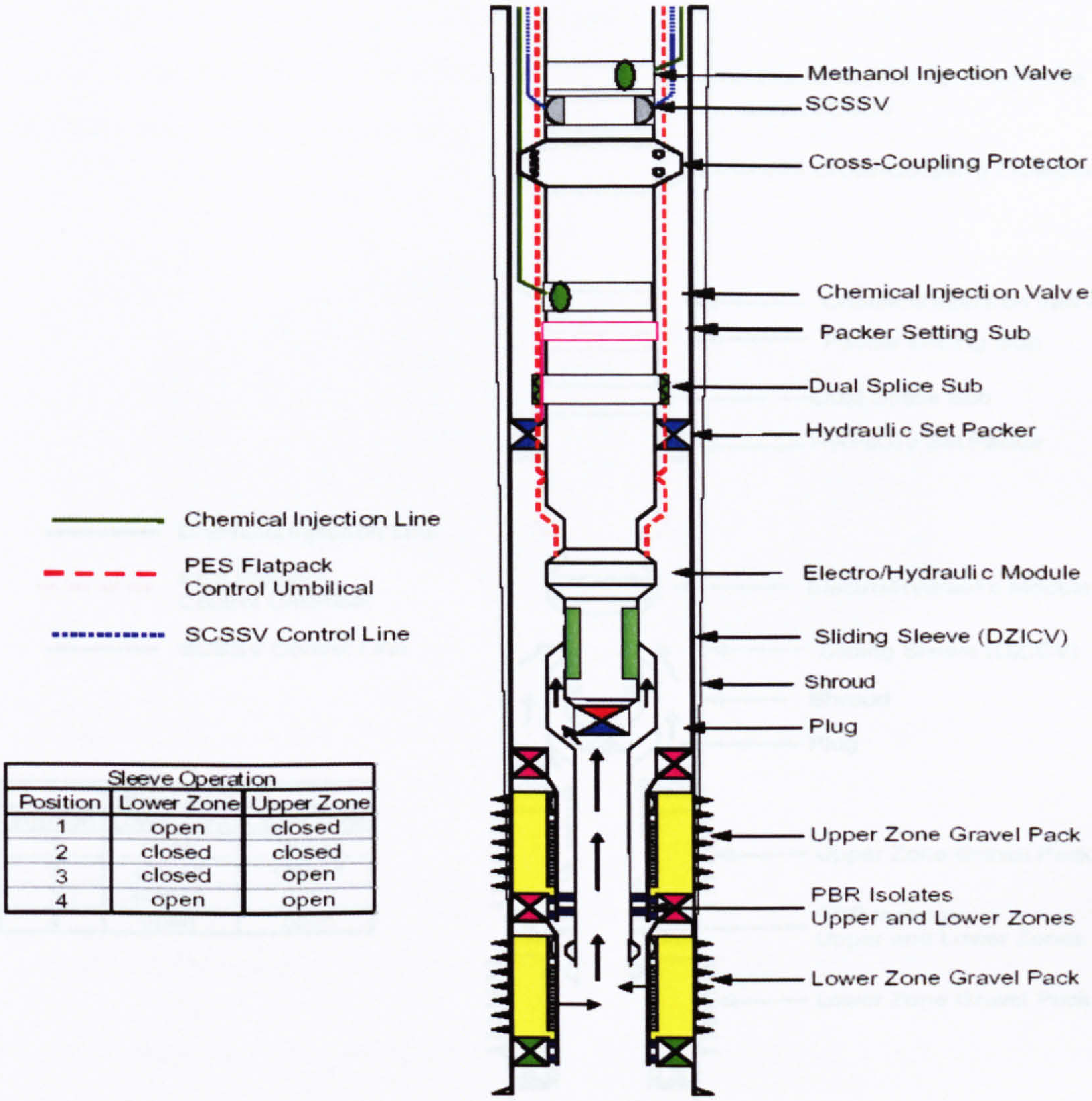
Figure 2-29: Well configuration at lateral junction [2.18]

2.5.13 IWsT in a field with vertically and laterally discontinuous sand units

Figures 2-30 and 2-31 show the first Intelligent Completion installed in the Gulf of Mexico [2.19]. The field is located offshore in approximately 3300 ft of water. The field's reserves are found in vertically and laterally discontinuous sand units distributed across the field. Multiple drainage points are necessary in such a layered reservoir system in order to maximize both the reserves and the early production rate.

The well equipped with an Intelligent Completion has a large impact on the subsea interface, the tubing hanger, the umbilical to the production vessel or platform, the topsides and the permanent completion itself. Modified surface instrumentation and well operation procedures are also required. I.e. all these components need to be considered as a system from the point of view of design and construction.

Detailed testing programmes (integration, stack up, installation and functionality) were designed and implemented during the design and manufacturing stages so as to eliminate the discovery of preventable installation problems when the (expensive) rig was running the equipment into the well itself.

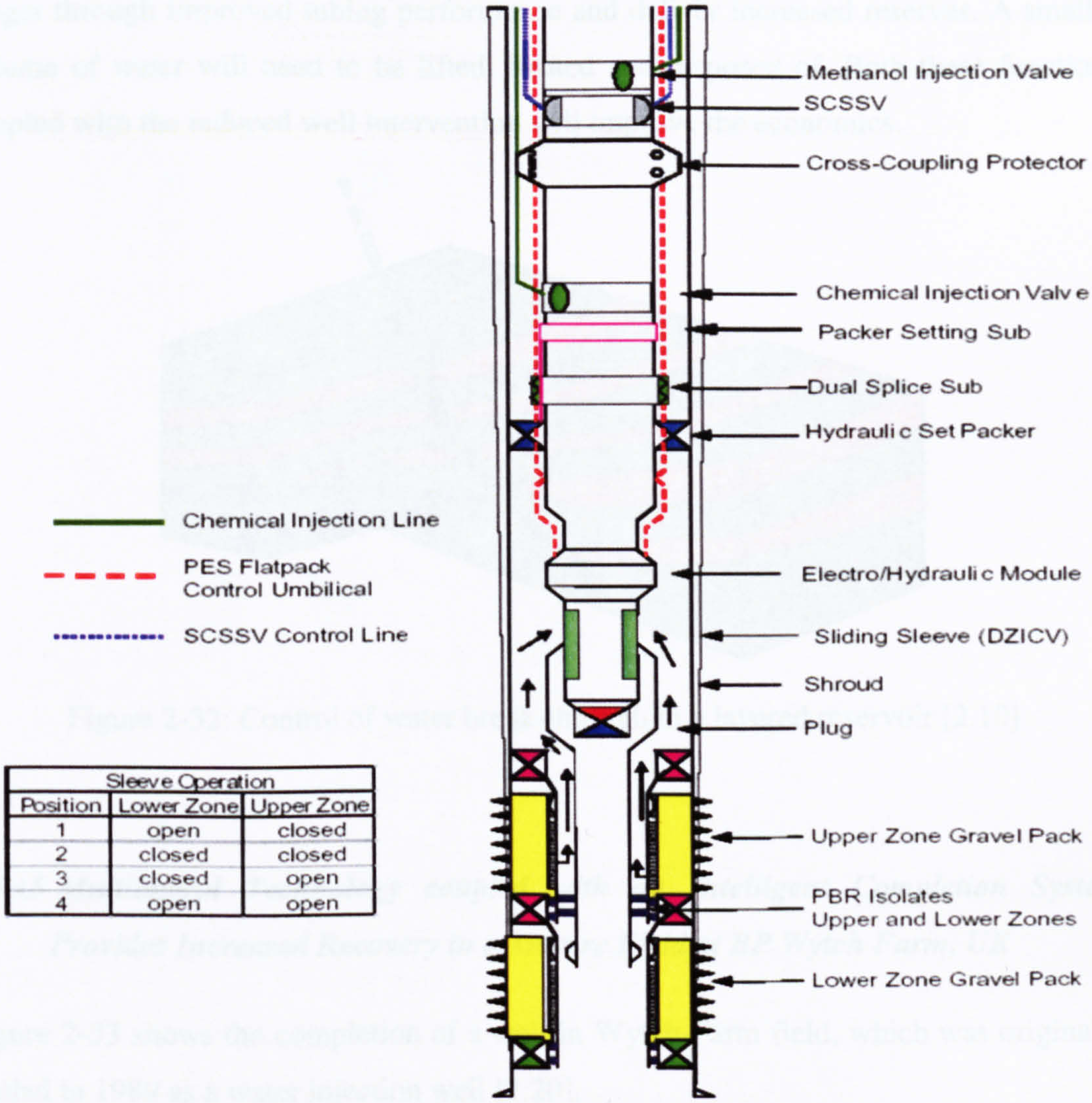


Sleeve Operation		
Position	Lower Zone	Upper Zone
1	open	closed
2	closed	closed
3	closed	open
4	open	open

Figure 2-30: Intelligent completion, lower-zone production [2.19]

The conclusions drawn from this case history were that:

- The elimination of planned well intervention enhanced the field economics. The incremental increase in profitability is the value of IWsT.
- Early, in-depth planning is required to effectively interface the multiple systems involved, especially when different vendors supply these.
- Proper coordination of all parties involved with the completion is critical to project success.



Sleeve Operation		
Position	Lower Zone	Upper Zone
1	open	closed
2	closed	closed
3	closed	open
4	open	open

Figure 2-31: Intelligent completion, upper-zone production [2.19]

2.5.14 Control of water break-through in a layered reservoir

Figure 2-32 shows a field with multiple reservoirs separated by horizontal shale barriers. The field drained with a single well, which has been perforated in each reservoir layer. Each layer may have its own aquifer; hence water break-through does not occur simultaneously in all the layers due to aquifer strength and permeability differences between the layers. Flow from each layer, when water breaks through, can be controlled by installing an ICV in each layer i.e. the well will now stay on production longer through improved tubing performance and deliver increased reserves. A smaller volume of water will need to be lifted, treated and disposed of. Both these functions coupled with the reduced well intervention will improve the economics.

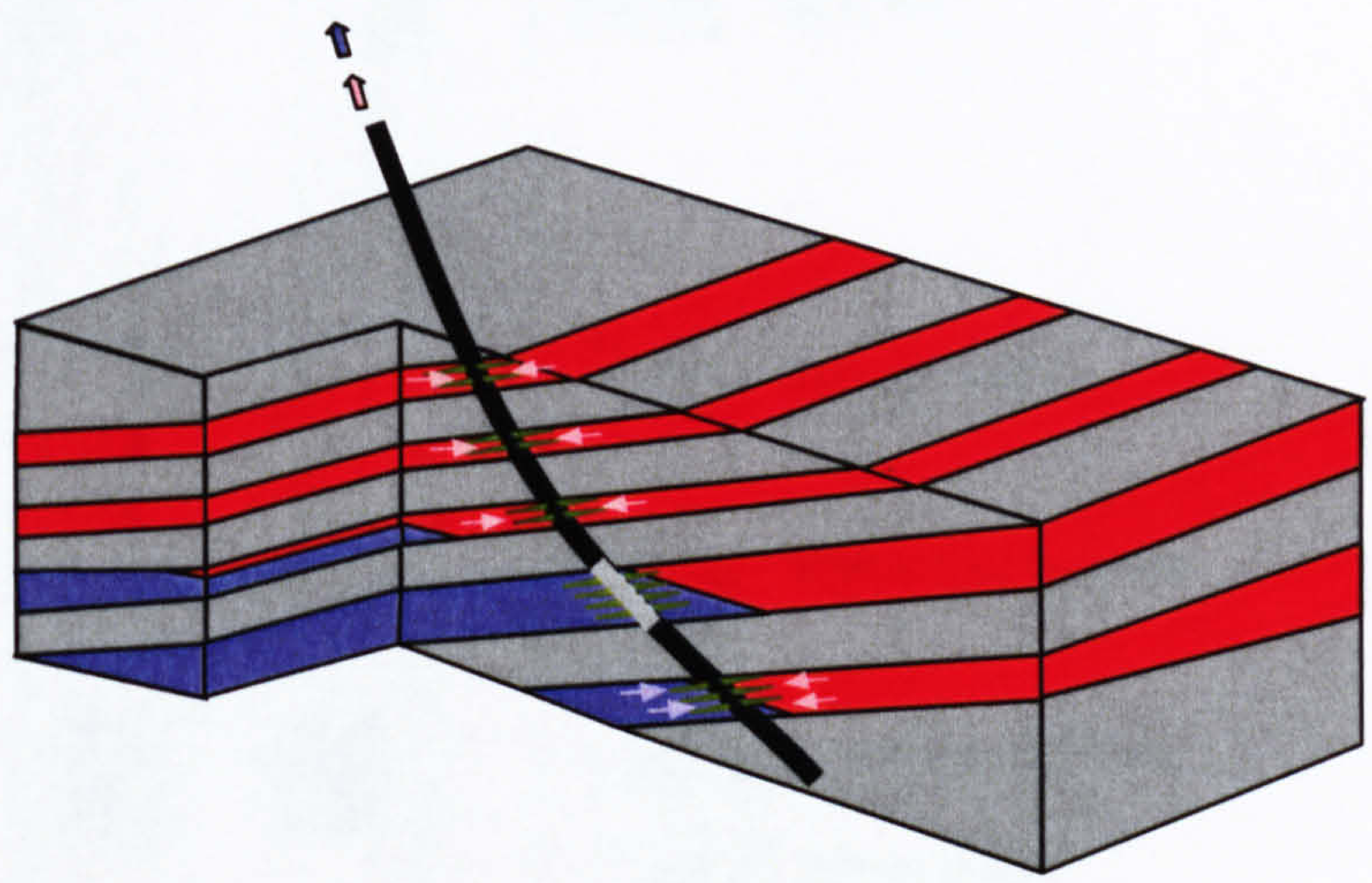


Figure 2-32: Control of water break-through in a layered reservoir [2.10]

2.5.15 Multilateral Technology coupled with an Intelligent Completion System Provides Increased Recovery in a Mature Field at BP Wytch Farm, UK

Figure 2-33 shows the completion of a well in Wytch-Farm field, which was originally drilled in 1989 as a water injection well [2.20].

Figure 2-34 shows the new converted well, which high-angle lateral will improve water-flood performance, gaining additional production from adjacent wells.

Later the main-bore will be perforated to recover bypassed reserves. However, there is a high probability of producing excessive water. The new lateral will also be produced to recover any oil.

The well will be converted to water injection into the new lateral only once the well has watered out. The intelligent completion allows these changes to be made from surface without intervention.

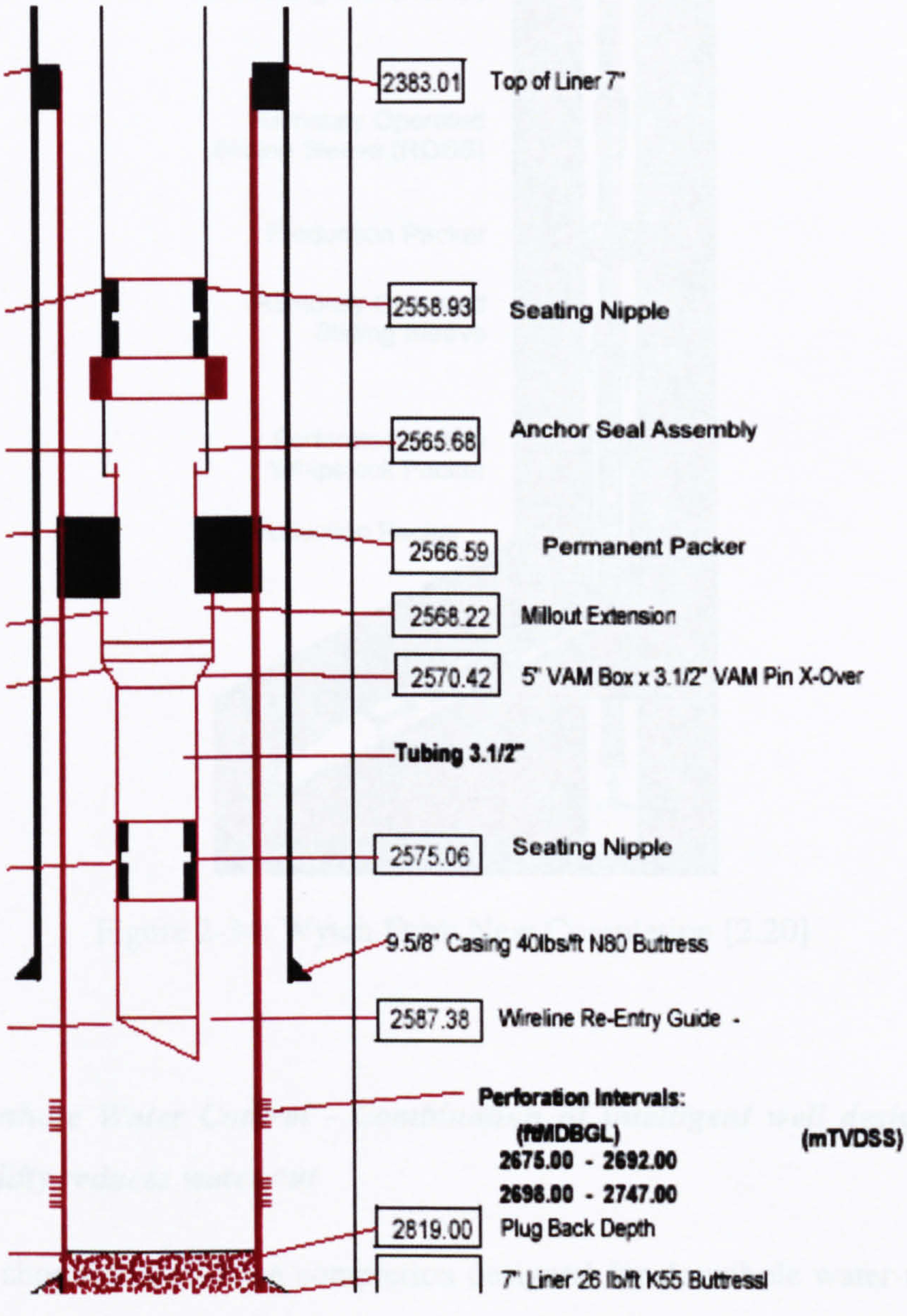


Figure 2-33: Wytch Farm Old Completion [2.20]

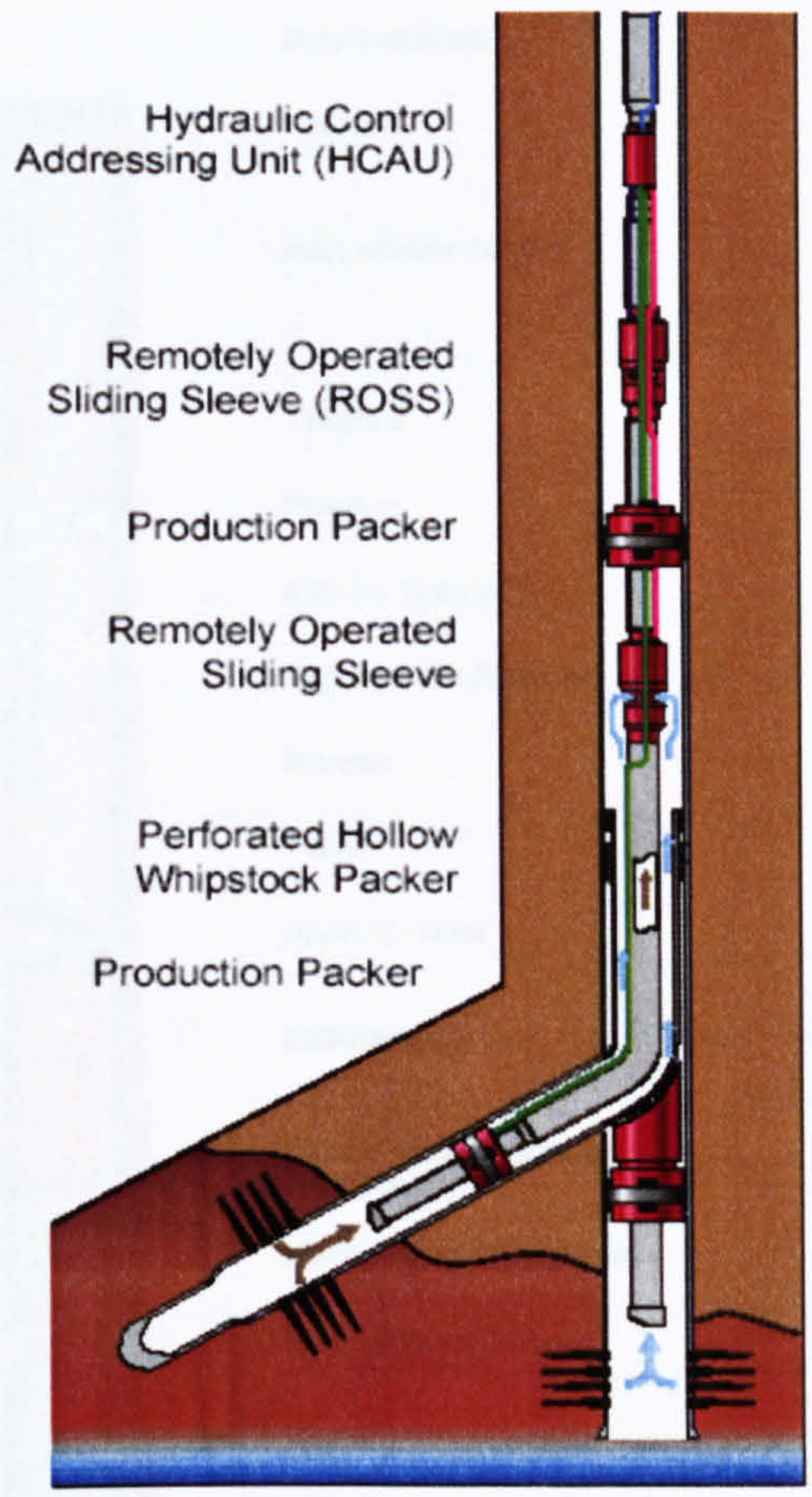


Figure 2-34: Wytch Farm New Completion [2.20]

2.5.16 Downhole Water Control - Combination of intelligent well design and ESP flexibility reduces water cut

Figure 2-35 shows a multi-zone completion designed for downhole water management in the Douglas Field [2.21], which has limitations on handling water at surface.

New design (Figure 2-35) is capable of isolating water production from middle or upper reservoir intervals, with continued production from other layers.

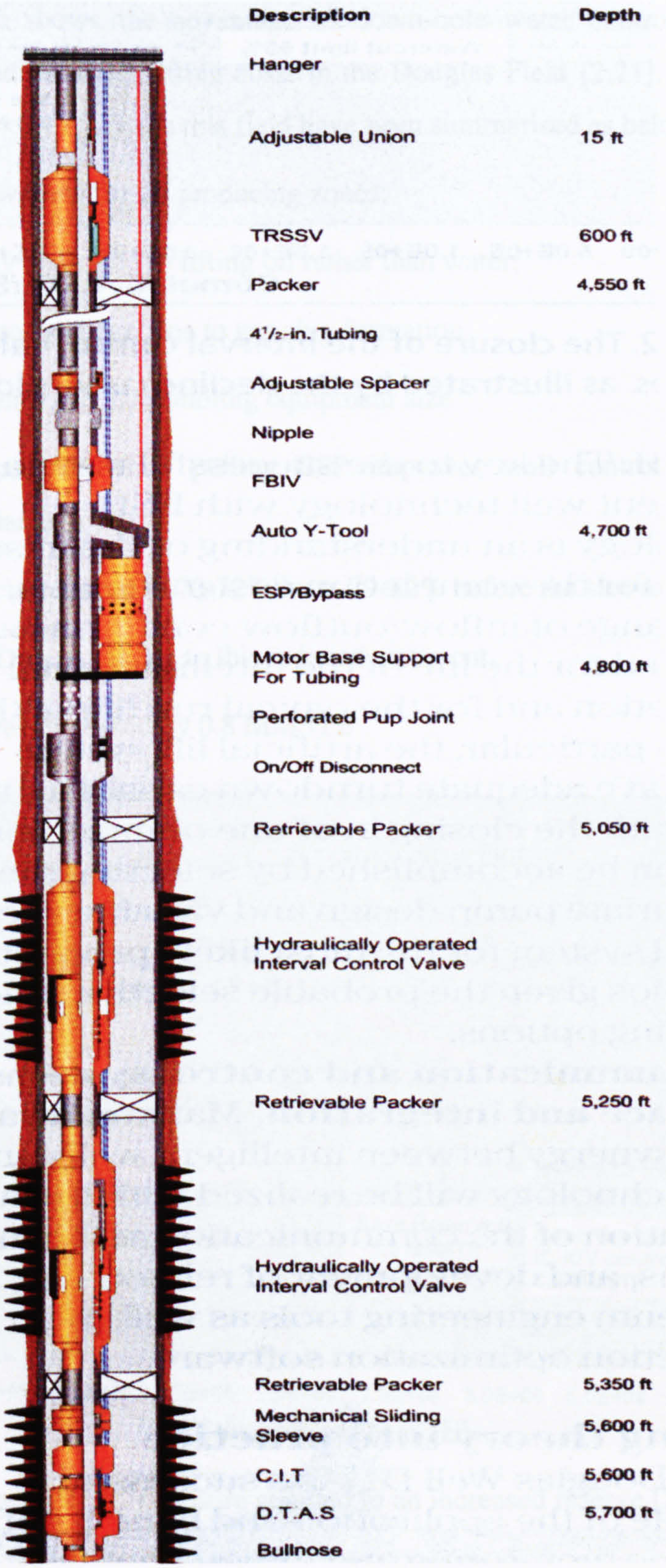


Figure 2-35: The multi-zone completion was designed with isolation packers between each zone and ICVs to shut off production from high water cut intervals [2.21]

- Figure 2-36 shows the advantage of down-hole water control on increasing recovery and reducing lifting costs in the Douglas Field [2.21]. The benefits of the application of ICVs in this field have been summarised as below:
- Greater drawdown for oil producing zones;
- More energy dedicated to lifting oil rather than water;
- Reduced wear-and-tear due to gas slug formation
- Reduced pump and gas handling equipment size
- Sand-face shut-in while pulling ESP improves well control and minimises formation damage
- The water-cut reduced to 70-72% from 79-82% before the sleeve was closed.
- 1200 STB/D extra oil due to this reduced water cut.
- Well reserves increased by 0.8 MMSTB

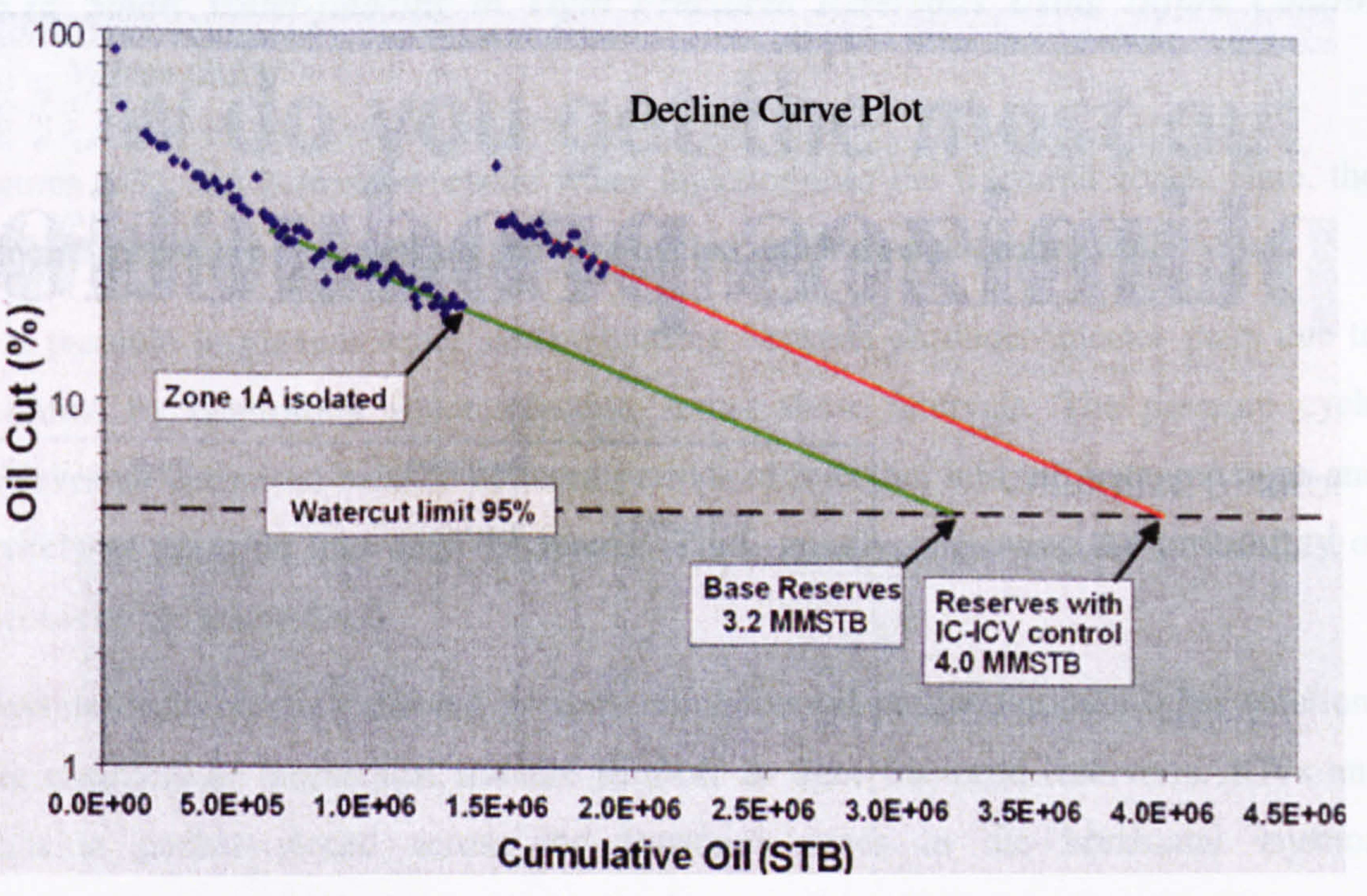


Figure 2-36: ICV closure resulted in an increased reserve [2.21]

2.5.17: ICVs and engineered diversion of stimulation treatments [2.22]

Using the isolation capabilities of the intelligent completion, several intervals were sequentially treated.

- ICVs divert the acid from one zone to the next.
- This can be done on-the-fly or in a more controlled manner using multiple treatment stages.

Limited entry perforating provided the method of diversion necessary to effectively treat each perforation within each completion interval. Availability of real-time multizone downhole pressure and temperature data provided several fascinating opportunities to view downhole mechanisms.

The stimulation was verifiably very successful in treating all the fracture clusters and a high productivity well resulted.

2.5.18 Smart Water-flooding in Tight Fractured Reservoirs Using Inflow Control Valves [2.23]

Figures 2-37 and 2-38 show cyclic water injection into the fractured zones. Here, the selected intervals of the well are pressure-cycled rather than the entire well.

It is possible to prevent water short-circutting between producer-injector pairs due to fractures by controlling water injection across these intervals. The pressure cycle achieves an optimised balance between periods of injection into the fractured zone and periods of injection into only the matrix. Thus, greatly improving the probability of success of the water-flood.

Pressure cycle control achieved greater cumulative oil production over other solutions like chemical or mechanical fracture shut-off in tight fractured reservoirs. ICVs and isolation packer placed across the fractured zones in the horizontal injector. Conventional completion is installed in the horizontal producer.

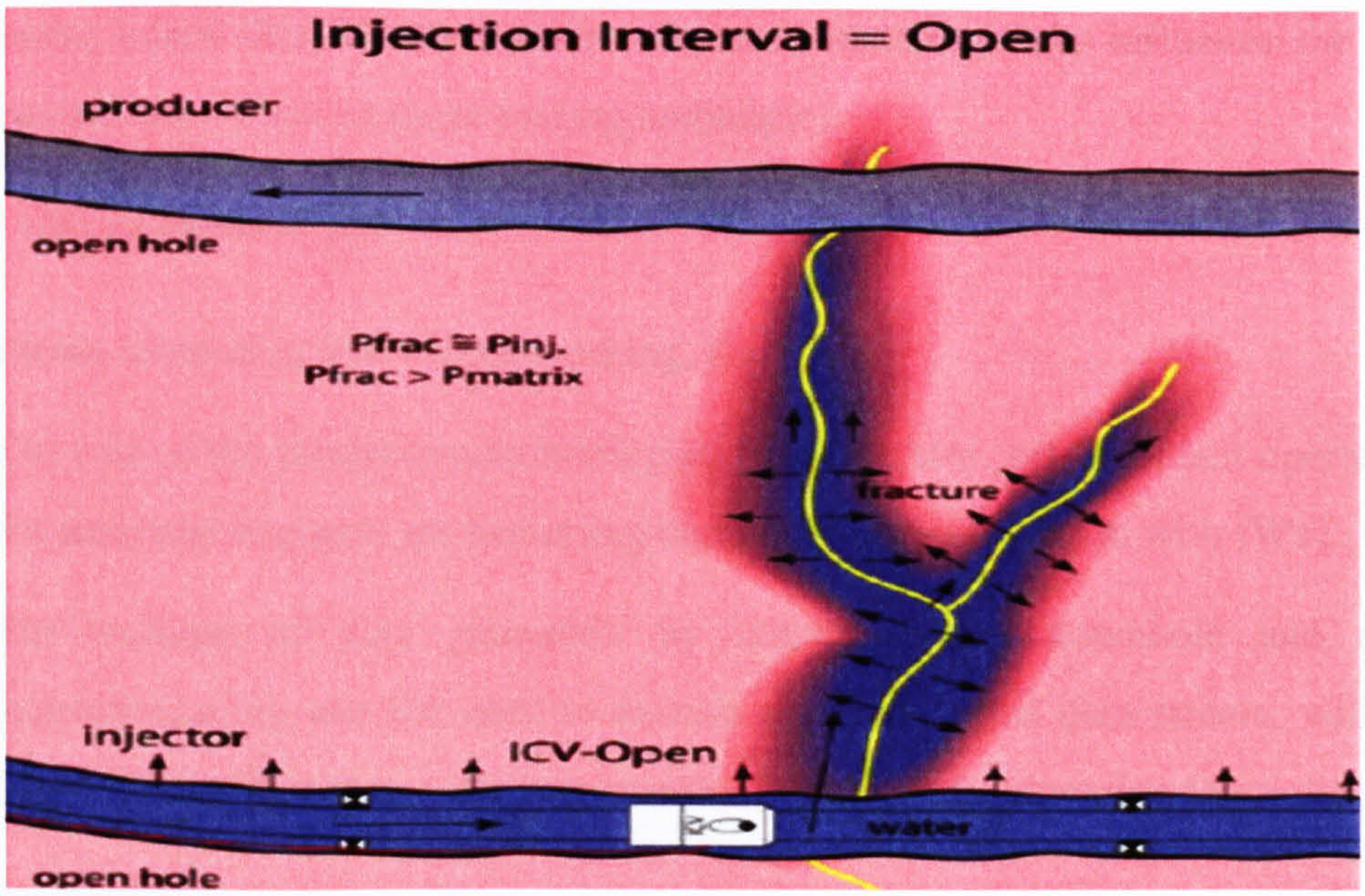


Figure 2-37: A horizontal well pair intersected by a contained fractured zone. ICV allows cyclic water injection into the fractured zone [2.23]

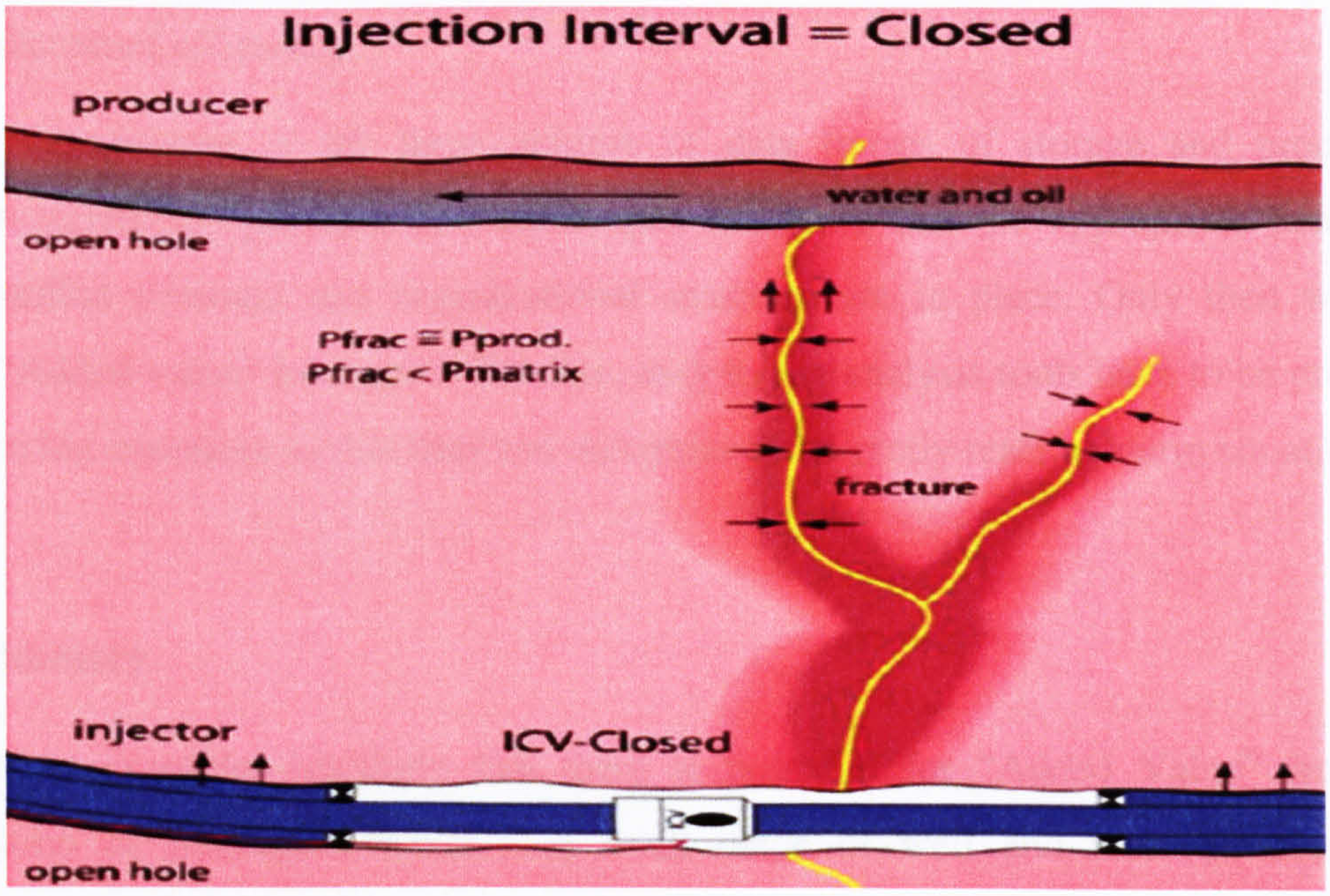


Figure 2-38: The ICV closed so the water injection occurs only via the matrix [2.23]

During water-flooding operations, water-cut is monitored in the producer and ICVs operated. The ability to control flow into the fractured zone via ICVs results in both increased sweep efficiency and decreased water production.

The relative injectivities of the fracture zone and matrix greatly influence the design (and effectiveness of the pressure cycling technique).

2.5.19 Management Issues

IWsT allows more effective way of working, i.e.:

- The role of the production technologist, field operator, process plant operator and the reservoir engineer are becoming combined into one person with IWsT.
- The volume of data generated by comprehensive downhole and surface instrumentation, and the need to extract value from this data stream, will break down the traditional barriers between the Petroleum Engineering Disciplines.

Data availability:

- Data combined with models have the ability to identify a preferred state for ICVs. This leads to more efficient control of wells and reduced operational cost & increased efficiency.
- Management of the large volume of data (terms of storage and processing requirement) presents new challenges to ensure that the appropriate hardware, skilled personal and organizational structure are in place. Only then will the "Added-value" be reaped. Suitable, easy to use analysis tools have to be provided to the operators so that they can recognize & correctly react to alarm situations.

2.6 Summary

The above examples highlight that there is potential for "Added Value" from the application of Intelligent Wells in a wide range of well and reservoir scenarios. However, a methodology for decision-making on the application of Intelligent Wells in different situations is required.

The next chapter will discuss the parameters, which needs to be evaluated for screening and initial decision-making on the application of Intelligent Wells.

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Chapter 3 Rapid Screening Techniques for Decision- Making on the Application of "Intelligent Well systems Technology

3.1 Introduction

Many factors should be considered when deciding whether to install IWsT and, more specifically, the numbers and type of flow control and flow monitoring and equipment that are suitable for a particular case. In this chapter, a road map with some parameters that should be considered during this process has been described. It is essentially a screening list which can be used as a tool for initial screening and identifying whether the candidate field or well could benefit from this technology.

The evaluation of the incremental revenue and cost – the value generated - resulting from implementing IWsT can be carried out using various financial techniques of differing levels of complexity. There are many input data that often contain a large uncertainty in their value which are required to carry out the evaluation.

The screening process may be sufficient to identify the best solution for a particular case, especially when the degree of risk and uncertainty is low. However, further evaluation work will be required before making the final decision if the process identifies a high degree of risk. This high degree of risk could be due to the uncertainty in the data quality and/or in the data interpretation.

3.2 Rapid Screening Techniques

The Rapid Screening Techniques described here are an extension of the field development screening methodology extended to include IWsT. It is essentially a screening checklist, which will help to identify the wells, or fields, which could benefit from further study.

3.2.1 The Screening Process

The screening process recognises, evaluates and prioritises candidate wells or fields for completion using IWsT. It does not offer a 100% solution; but is expected to identify the fields that will most benefit from IWsT. The screening process is based on a series of steps:

a) Why IWsT is being considered? (Defining and assessing the technical and economic objectives of IWsT.)

The objective may be to:

- Decrease intervention costs, delay water/gas production,
- Increase drainage efficiency (reserves/well ratio),
- Improve oil recovery/waterflood performance (Manage water injection/ production profile within well),
- Manage geological risk,
- Ensure even production along complete (horizontal) well length,
- Manage performance of multiple laterals or
- Decrease the number of wells required e.g. produce simultaneously from multiple reservoir zones with incompatible pressures etc.

A particular IWsT installation may often have multiple objectives. These objectives may have different requirements for the performance of the installed hardware: they may even be contradictory. (See chapter 2.5 for a "Show Case of IWsT Added Value Generation".)

b) Analyse and survey existing field information e.g. geology, geophysics, well logs, historical production, etc. to understand how many objectives can be met in terms of technical feasibility and acceptable risk.

This includes questions such as:

- Can the optimum, long horizontal section be drilled without difficulty?
- Can the minimum borehole diameter needed for installation of Interval Control Valves and the control system be provided?
- How is the increased risk of more complicated completions to be balanced against the potential for enhanced value?
- What is the reliability of the ICV and/or control system?
- What aspect of the ICV and/or control system failure should be evaluated?
- Can current well objectives be met or is a compromise solution needed to minimise the risk to a suitable level?

An economic and reliability evaluation package, which addresses all these issues, has been developed in our JIP, this will be further discussed in chapter 11 (Economic Evaluation of Intelligent Wells).

c) Identify and evaluate well design criteria and resulting alternative strategies.

This includes questions such as:

- What are the well or field production and/or injection requirements?
- What degree of control is required? (Open/shut or fully variable ICV or an ICV with a limited number of preset valve opening settings.)
- What reliability is required?
- Are provisions for mechanical redundancy required?
- Are there any artificial lift requirements?

- What types of sensors are required to provide the basic data for the well/field diagnostic requirements?
- Are special well clean-up arrangements required? E.g. sand etc. may erode the ICV's choke or prevent its operation
- Do sand control measures need to be installed? What type is more suitable?
- What are the operational environment conditions? (Temperature, Pressure, Produced Fluid Composition, etc.)
- What construction materials should be employed for the ICV (produced corrosive fluids, etc)
- How will the flow assurances issues be solved? (potential deposition and inhibition requirements to control asphaltene, wax, hydrate, scale etc)
- What mitigation measures need to be taken to ensure ICV operation when scaling condition are forecast?
- What is the planned intervention frequency and expected project life?

d) Evaluate the identified design options

This stage consists of a number of steps:

1. **Predict the Reservoir performance for Intelligent Well Evaluation:** A check-list of the detailed parameters, which should be considered for decision-making on a range of reservoir types, has been produced. The evaluated reservoir types include:

- Faulted/Compartmentalised Reservoirs
- Stacked Sands
- Naturally Fractured Reservoirs
- Thin reservoirs
- Viscous Oil Reservoirs
- Mature Reservoirs

The performance of Intelligent Wells in a wide range of reservoir types has been systematically evaluated (chapters 7 and 8). This identifies those reservoir types that yield greater value from Intelligent Wells.

2. **Predict the well/field performance from model scenarios:** a long-term simulated reservoir performance is often the best option. Extensive reservoir simulation studies have been performed for many real (intelligent) wells and fields. When evaluating a particular case it must always be remembered that the quality/accuracy of the model controls how representative the prediction will be.
3. **Estimate the costs:** Drilling, completion, production, intervention and other costs need to be calculated and compared with the equivalent costs for the conventional well design case. Reductions in pipeline, surface facility, platform, well intervention costs in the intelligent completion can be included as this can be a significant contributor to the value increase along with the improved recovery and project acceleration benefits.
4. **Analyse the risk related to each phase of the project:** Realistic figures for reliability are required to ensure that proper life-cycle cost figures are generated.
5. **Model the economic performance of the well/field:** The appropriate risked, economic indices e.g. Net Present Value, Real Options, etc should be used. The tools detailed below provide both deterministic and stochastic evaluation models. They allow a direct comparison of various choking policies and failure frequencies.

There are many advantages in performing a reservoir simulation study. Perhaps the most important, from a commercial perspective is the ability to generate oil and gas production profiles cash flow predictions for a range of different exploitation options. Further, it offers the required flexibility to study the performance of the field under defined production conditions. Simpler techniques, like material balance, are useful for evaluating the reservoir drive mechanisms but are not suited for reservoir forecasting.

A reservoir simulation model requires a lot of data. It is based on a 3D numerical geomodel which depicts the reservoir structure and geometry and the spatial distribution of flow units, barriers and other reservoir structural elements. Such a model is the basic building block for understanding reservoir volumes and field performance. However, lack of basic reservoir data and the significant engineering resources required to build the model, along with the time constraints imposed by management during which a well proposal has to be developed, often result in well designs being made without the benefit of such a model. Thus, although there are many advantages for doing reservoir simulation study, frequently alternative, simpler methods based on conventional petroleum engineering practice may be used instead.

An example methodology could be as follows:

- STOIIP could be estimated from a geomodel or by simple calculations based on well drainage area, porosity, saturation, net to gross, gross rock volume, formation volume factor, etc
- Recovery factor is estimated by experience and comparison with similar reservoir analogues
- Lift curves can be determined on the base of well or formation (specific) Productivity Index, reservoir and surface pressures, well length, tubing diameter, etc
- Production forecast can be estimated using spreadsheet calculations by incorporating experience, risk and uncertainty as appropriate. The capabilities and the predicted survivability profiles of the different types of conventional and I-well completion equipment are included here.

An example of how the above methodology could be applied is shown below:

(i) Reservoir 1 developed by a conventional well

STOIIP (from geomodel) $=10 * 10^6$ bbl

Recovery (based on our understanding of the reservoir and analogues) = 0.35

Reserves $= 0.35 \times 10 * 10^6 = 3.5 * 10^6$ bbl

Productivity Index (PI) of different parts of the field may have been determined by exploration well tests (drill-stem tests, build-up or drawdown tests, etc) or estimated from well log and core data. Separate estimates of the well PI in different parts of the field can be made or an average well PI value calculated (by assigning different weighting to different PI values on the base of probability of occurrence).

Reservoir Depletion Rate is determined on the basis of experience and our understanding of the reservoir. This determines the number of wells to be drilled, the production rate necessary to meet the production plan and the reserve requirements for each well necessary to deliver an economic project.

Thus for dry oil production as occurs in the initial stages of field development:

If $P_{reservoir}$= 2200 psi, $P_{bottom\text{-}hole}$ = 1700 psi & PI = 40 bbl/day/psi then:

ΔP = 500 psi & Q = ΔP*PI = 500 psi*40 bbl/day/psi =20,000 bbl/day

Assume: Reserve = 2 billion barrels = 2000 million barrels

Assume: Drainage rate per year = 10%

$$\text{Daily depletion} = \frac{2*10*10^9}{100*365} \sim 548{,}000 \text{ bbl/day}$$

No, of wells = 548000/20000 ~ 28

Well performance during the second and subsequent years can be predicted based on simple outflow performance calculations derived from estimates of the wellhead and reservoir pressures and water cut development

Well production, reservoir 1 only (bbl/day):

Year 1	Year 2	Year 3
15000	12000	10000

(ii) Reservoir 2 developed simultaneously with the help of IWsT

An appraisal well is drilled to reach a second deeper target. This well discovers reservoir 2 situated below reservoir 1. Management request the use of IWsT to increase the field production rate using the same number of wells. A lower decline rate during the second and third years is expected for reservoir 2 wells.

Well production, reservoir 2 only (bbl/day):

Year 1	Year 2	Year 3
20000	18000	16000

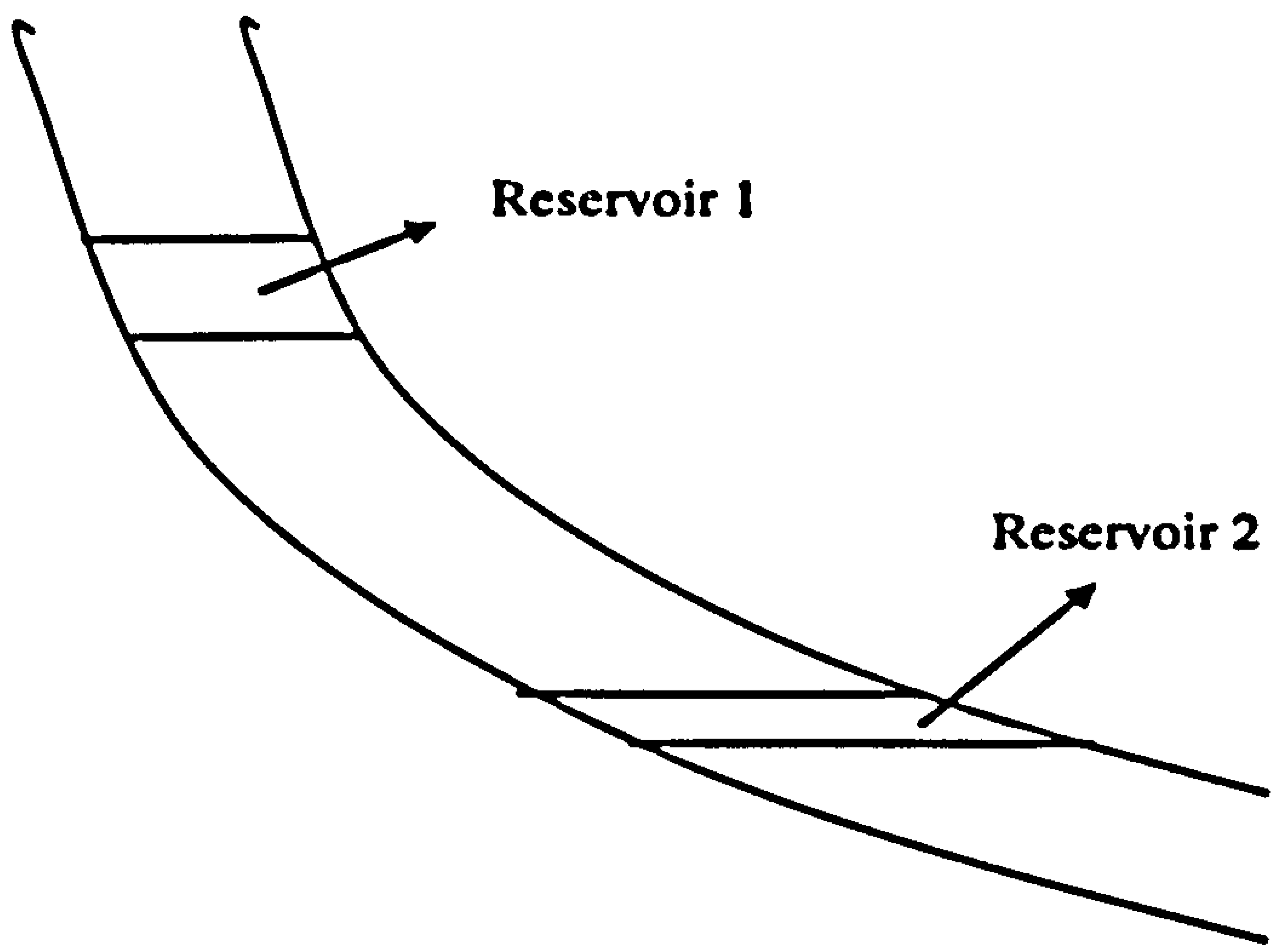


Figure 3-1: A Schematic of Reservoirs A & B

Reservoir 2 is deeper, laterally more extensive, thinner and carries a greater drilling and geological risk compared to reservoir 1. However, the production rate from this reservoir is greater than for reservoir 1 with an expected PI of 40 bbl/day/psi. A dry oil production rate greater than 20,000 bopd can thus be estimated.

Deciding which reservoir is to be produced first requires a series of economic and risk calculations to be made for the case that the production plan is to produce the reservoirs sequentially one after the other.

The methodology used in the reservoir/ case history can be extended to include IWsT. The expected production rate for the "Intelligent Well" producing simultaneously from both zones is estimated using the same methodology. (N.B. remember that suitable changes have to be made to the well completion e.g. tubing and production casing diameter, etc. to accommodate the greater production)

Well production rate when reservoirs 1 and 2 producing simultaneously (bbl/day):

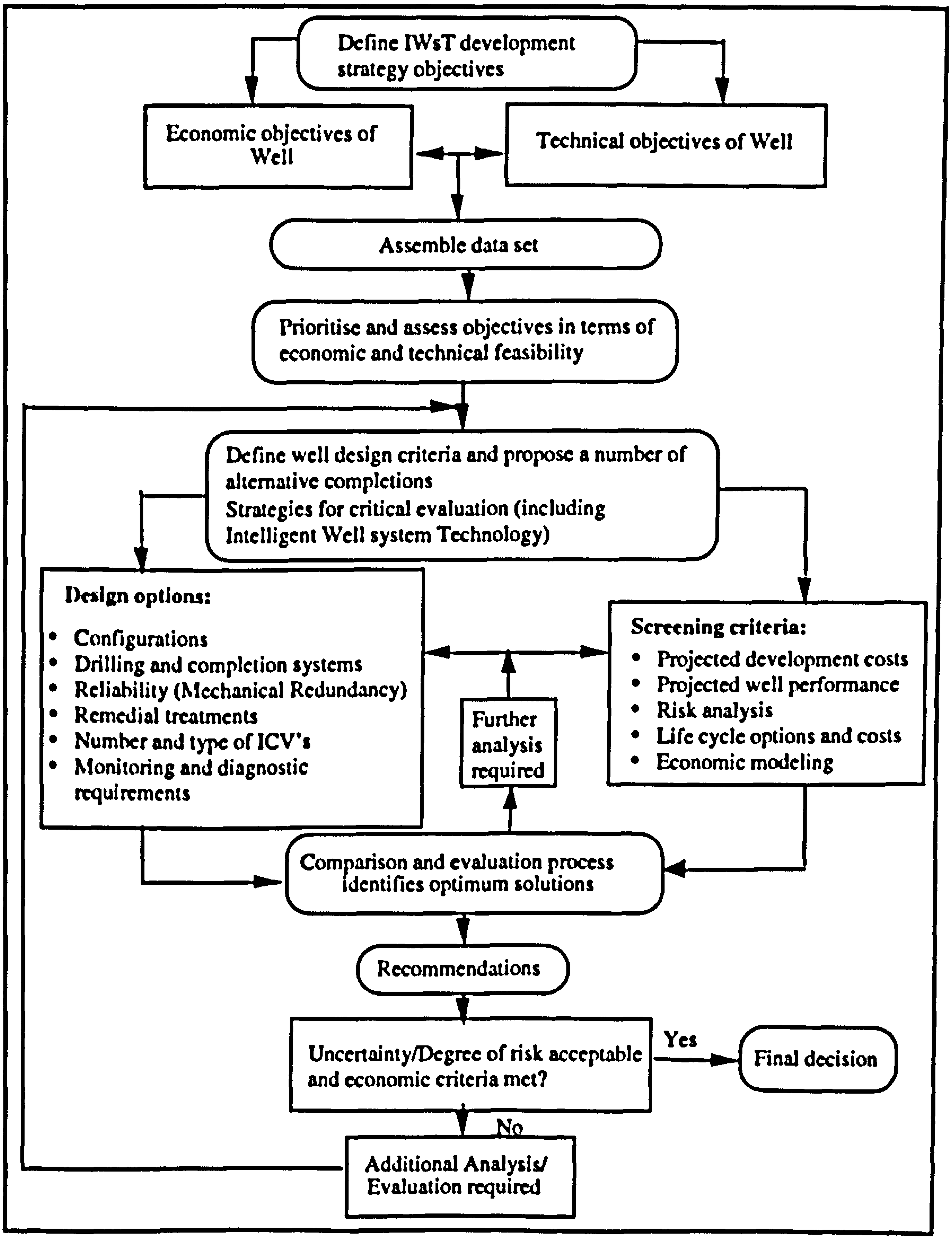
Year 1	Year 2	Year 3
31000	28000	25000

As mentioned earlier, the (equipment and installation) costs, the capabilities and the risked survivability profiles of the different types of I-Well completion equipment e.g. a direct hydraulic or an electric system; need to be factored into the production forecast. The survivability profile can be derived from actual field data or from a reliability analysis.

The above simple method provides the production forecast against which the profitability of IWsT can be analysed. It is essentially the conventional method for rapid production scenario analysis. The advantage of this method is that it is very simple and does not need complicated reservoir simulations. The disadvantage of the above method is that, it mostly based on available experience from analogous reservoirs and is very dependent on our understanding of the reservoir(s) being studied.

The next page shows a flow chart which summarises the development process for Intelligent Well systems.

3.2.2 Flow Chart for Intelligent Well systems development



3.3 Critical Screening Parameters

The basic critical screening parameters are:

- Reservoir characteristics (Fluid and Geological Properties)
- Well design/ and drilling constraints
- Production constraints (Managing Fluids)
- Development costs and well economics

These parameters are often sufficient for generic cases. In specific reservoir studies other local factors will no doubt be included. Reservoir types that have been considered as candidate for IWsT are:

- Faulted/Compartmentalised Reservoirs
- Stacked Sands
- Naturally Fractured Reservoirs
- Thin reservoirs
- Viscous Oil Reservoirs (particularly thin and aerially extensive reservoirs)
- Mature Reservoirs

N.B. IWsT application is not limited to the above reservoir types - it is a generic technology.

The above reservoir types are studied in detail in the following pages. The criteria used and the parameters analysed illustrate the factors that need to be considered for these specific reservoir types.

3.4 Generic Screening Parameters

Reservoir Characteristics →

- Reservoir thickness, size, areal extent
- Degree of faulting (Permeability barriers/ seals)
- Fluid properties,
- Reservoir pressure
- Drive mechanism
- Mobility ratio
- Degree of heterogeneity
- Reservoir dynamics

→ Consider:

- Well position/path in the reservoir
- Well length & completion type
- Effects on well production rate
- Well drainage area
- In heterogeneous reservoirs (e.g.: channel sands) IWsT could be very useful. Number of ICV's depends on heterogeneity
- Heterogeneous reservoirs which have high (water/oil) mobility ratio are a good candidate for IWsT as they experience water breakthrough early in well life.

Economic Considerations →

- Equipment selection
- System complexity
- Maintenance
- Redundancy
- Intervention
- Risk & safety
- Type of well (subsea/dry tree)
- Cost versus benefit
- Investment rate
- Product price (oil, gas, etc)

→ Consider:

- Cost of different drilling and completion scenarios
- Cost of possible IWsT installation problems (Increased installation time, loss of the ICV's or control system, etc)
- IWsT reduces the need for intervention (refer to production considerations below)
- Number of conductor slots necessary/ available separator & platform size (IWsT can reduce slot requirements, water & gas production. Hence smaller separator & platform is needed)
- Monte Carlo simulation & other economic methods

Well Design/ Drilling Constraints →

Drilling:

- Hole Size
- Formation Damage
- Directional Drilling
- Operational Stability
- Mechanical Limitation
- Etc.

→ Consider:

- Length of the well
- Stability and zonal isolation requirements at junction
- Type of completion-system, to be run.
- Drilling system and drilling fluids specification.

Production Constraints →

Operation and control

- Tubing Outflow limitation
- Pressure maintenance
- Monitoring and measuring
- Well life
- Intervention possibility
- Capacity of gathering pipelines
- Surface facilities constraints

→ Consider:

- Reservoir/Fluid management consideration
- Water and gas handling facility constraints
- Export constraints (pipeline capacity, product quality, etc)
- Optimum production rate
- Future production logging requirements
- Future workovers (IWsT reduces the need for workover) Light interventions be carried out using Wireline or Coiled Tubing (Well Tractors can help in horizontal sections)
- Stimulation and artificial lift capabilities
- Complexity and cost of completion equipment
- ICV size (if needed)
- Degree of control and hydraulic integrity required (separate zones need reliable zonal isolation)

3.5 Case Specific Screening Parameters

3.5.1 Stacked Sands (& Separate Accumulations)

Number of Layers →	• Design becomes more complex by increasing the number of zones/layers (reservoirs with separate pressure regimes) to be modelled separately →	• IWsT can manage water/gas production from each zone • Number of zones is initial suggestion for number of ICVs, subsequently reduced by practical and cost considerations
Fluid/ Pressure Differences between Layers →	• Drilling Problems • Crossflow, lost circulation • Clean up problems with low pressure layers →	• IWsT by implementing ICVs can control the flow from high-pressure layers, improving the recovery and production from low pressure layers • Automatic internal gas lift possible
Fluid Compatibility →	• Scale, wax, etc. production due to mixing different layer's fluids →	• Necessity of separated production should be reviewed. • Review efficiency of chemical control (scale inhibitors, etc.) of mixed fluids. If successful IWsT is an option
Thickness of Layers →	• Increasing the layer thickness reduces the incremental benefits of IWsT compared to other options. • (The incremental benefits are more obvious in thin reservoirs.) →	• In thick reservoirs multilateral wells, particularly dual laterals are the better option. ICVs can be used to manage the gas/water production from laterals • Management of thin oil rims by IWsT can prevent early gas/water breakthrough
Highly Variable Permeabilities across Completion Interval →	• Optimal production/recovery from low permeability layers is difficult using conventional wells →	• Coring and (Wireline) logs while drilling give information on localised permeability variations. • Production from high permeability zones could be adjusted by ICVs
Distance between Layers →	• Could affect KOP of the well. • Is an important factor in selecting the well type (conventional, horizontal, multilateral or smart well) →	• Layers close together have reduced drilling costs. • In reservoirs with separate accumulations, multilateral wells, preferred. ICVs can manage the gas/water production from each lateral or within the lateral

3.5.2 Faulted Reservoirs

Number of Fault Planes, Geometry and Spatial Distribution →	• Multiple access to different fault blocks →	• IWsT manages simultaneous production from separated blocks. • Base number of ICVs is the number of fault blocks.
Pressure Difference between Blocks & Fault Sealing →	• Fluid loss to faults and low pressure blocks during drilling • Geological risk – difficulty of remaining within reservoir sand when traversing between fault blocks. • Problems reduced if pressure equalisation has occurred across fault blocks →	• Prediction of the degree of sealing and pressure difference between the blocks • IWsT (in both Injectors and producers) by utilising ICVs for choking the high-pressure blocks, can produce the reservoir blocks optimally. • Automatic gas lift might be possible
Fluid Compatibility and Flow Assurance →	• Scale, wax, etc. production due to mixing different layer's (block's) production if producing separate reservoirs • Evaluate sand production potential control →	• Evaluate reservoir fluids incompatibilities (scale, asphaltene) due to fluid mixing in wellbore. • Chemical control (scale inhibitors, etc.) allows IWsT installation
Fault Reactivation and Subsidence →	• Could squeeze the well (casing/tubing becomes oval) or shear the well casing • Integrity and safety of the well compromised →	• Observed in areas with tectonically active faults, near salt (domes), soft formations, etc. • Risked economic calculations necessary. Potential reduced reliability of more expensive IWsT completion should be considered
Nearness of Different Layers (or Different Fault Blocks) →	• Could affect turning radius and KOP of the well. • Could cause operational/ well design problems, when the blocks are far apart • Geological risk →	• The more adjacent the blocks (or layers), the better candidate for IWsT installation • Slanted/ complex path wells are an alternative to multi-lateral wells, with ICVs when appropriate.

3.5.3 Naturally Fractured Reservoirs

Frequency of Fractures, their Connectivity, Spacing, Orientation, Clustering and Extent →	• Essential information • In some reservoirs fractures are the production conduits, in other ones they are to be avoided as they connect to water and/or gas zones →	• Often only limited knowledge of distribution is available. • Number and location of ICV's can be based on known fracture location. • Adjust well completion design, at short notice, if possible • Orientate well path perpendicular to fracture orientation for maximum inflow • If connectivity of fractures is good the number of wells will decrease, providing they don't produce unwanted fluids.
Flow Characteristics →	• Fracture and matrix permeability. • Transmissibility of fractures. • Connectivity • Inflow and outflow curves. →	• ICVs can control inflow of unwanted fluids from the zones affected If some of the fractures are connected to water zone/gas cap • Lower drawdown is required than for conventional wells
Closure of Fractures →	• Decreased or lost production →	• Production strategy (drawdown and pressure depletion) management • If the problem is due to fracture blocking, remediate by stimulation acid or propped hydraulic fracturing
Fracture Conductivity →	• Affects production, drilling and completion aspects →	• Drilling losses often identify fracture location • Production method/strategy and rate of depletion is a direct function of fracture conductivity. • Mud system used, cementation issues, clean up, stimulation, etc.
Drive Mechanism →	• Water Drive. • Gas Cap Drive. • Gravity Drainage. • Etc. →	• Determine number of wells, their location in the reservoir, distance to water/gas, well standoff, etc. • Reservoir drive mechanism aid to decide on the necessity of Installing IWsT. (Gas cap and water drive reservoirs are candidate for this technology)

3.5.4 Viscous Oil Reservoirs (Particularly thin and laterally extensive reservoirs) ($13^{\circ}<API<25^{\circ}$)

Oil Specific Gravity →

- Reservoir contains viscous oil

→

- IWsT controls drawdown (ICV can control drawdown in the zone prone to water/gas coning) and manages secondary recovery process (fluid fronts)
- Relative permeabilities of different fluids in the reservoir need to be known if the fluid front to be managed based on modelling results.
- Install flood front monitoring techniques (Field-wide 4D seismic, interwell acoustic tomography, deep reading resistivity tools)

Production Technique →

- Position of the wells and their arrangement in the reservoir.
- Completion size
- Well complexity and configuration

→

- Design fit-for-purpose completion for reservoir and fluid conditions/ well inflow and outflow performance
- Complexity of the well should be justified. Identify need for artificial lift and design well with suitable completion size
- Installing IWsT on long horizontal wells can help optimal production from the reservoir; extra value needs to be confirmed.

Drive Mechanism →

- Water Drive.
- Gas Cap Drive.
- Gravity Drainage.
- Etc.

→

- Determine number of wells, their location in the reservoir, distance to water/gas, well standoff, etc.
- Reservoir drive mechanism aid to decide on the value of IWsT. (Gas cap and water drive reservoirs are candidate for this technology)

Drawdown →

- High drawdown from a short length well in viscous oil reservoirs increases the risk of coning and sand production.

→

- Optimise well length to reduce the drawdown.
- ICVs control drawdown when coning and high drawdown problems occurs (proactive preferred to reactive) - install downhole monitoring systems

3.5.5 Mature/Depleted Reservoirs

Quantity and Location of the Remaining Producible Oil (Degree of Depletion) →	• Reservoir considerations (areal extent, etc) • How uniform is the pressure depletion? • Dynamic reservoir known parameters (pressure, oil saturation, etc.)? →	• Identify target zones with sufficient remaining reserves for economic recompletion • Complex completions required if conventional completions can not produce the remaining oil • Multilateral wells increase well reserves. ICV manages the gas/water production from each lateral or within the lateral.
Drive Mechanism & Productivity Index →	• Water Drive. • Gas Cap Drive. • Gravity Drainage. • Drawdown • Etc. →	• Determine number of wells, their location in the reservoir, distance to water/gas, well standoff, etc. • Predict volume of unwanted fluids during the future field life.
Drilling and Completion Constraints →	• Excessive overbalance drilling related problems (losses, impairment, etc.) • Underbalanced completion techniques can give higher productivity completions • IWsT minimises workover requirements →	• Select suitable particulate containing fluids or use underbalanced techniques to minimise damage • Formation stability needs to be preserved • The preferred technique should preserve formation stability. • IWsT minimises well intervention. • Multilateral wells with monitoring and control systems maximise reserves per well and manage unwanted fluids
Surface Facilities Constraints →	• Platform size • Free slots available • Water and gas handling capacity →	• Excessive water/gas managed by IWsT

Chapter 4 Geological Modeling

4.1 Classification of Reservoir Types

Identifying the type of reservoir where the IWsT can be applied is an important step in evaluating its application. Intelligent Completions are not always a guarantee for success. The key question, to be answered in the development of this technology, is to identify when the added functionality actually adds value. Knowing where to apply this technology begins with reservoir characterization - a crucial stage in reservoir management. A useful tool for this stage is the classification of reservoirs.

Weber *et al* [4.1] classified reservoir architecture and scale as a function of reservoir type leading to a recommendation of an appropriate well density. This scheme is restricted to the larger scale elements in sandstone reservoirs and does not take into account the fluid properties or the drive mechanisms. They proposed grouping reservoirs into three types: Layer Cake, Jigsaw Puzzle and Labyrinth Reservoirs. This reservoir architectural typing controls the nature of the most appropriate primary field development pattern for each reservoir type. A similar conceptual tool will be developed during this study, which evaluates a range of reservoir architectures based on their potential for "Adding IWsT Value".

Layercake Reservoir type – these are very extensive sandstone packages which show no major discontinuities or changes in rock properties, such as permeability in the horizontal direction. The layer boundaries coincide with major changes in properties or baffles to flow in the vertical direction. In each layer, variation in vertical permeability is gradual in a lateral sense.

Jigsaw Puzzle Reservoir type – this type of reservoirs are sandbodies that link together in a complex fashion. Low - or non-permeable units may occasionally be embedded in the reservoir. Internally, some units may have very heterogeneous properties. Non-permeable baffles may also exist between superimposed sandbodies. Major discontinuities in rock properties can also occur between sand-units.

Labyrinth Reservoir type – these are the most complex arrangements of sand pods and lenses. In cross-section, the reservoir commonly appears discontinuous. Detail correlations are only possible where the well spacing is small. The sand continuity is often directionally dependent. Accurate three-dimensional reservoir models are rarely possible; a probabilistic modelling technique is usually required.

Tyler and Finley [4.2] in their classification considered the combined effects of architecture, expressed as a function of lateral and vertical heterogeneity using the large US database available to the Bureau of Economic Geology in Austin, Texas. The recovery efficiency was then related to this matrix. They were also able to relate unrecovered oil as a function of depositional environment and drive mechanism.

4.2 Heterogeneity

Reservoir heterogeneities can vary from small to large-scale geological features.

Heterogeneity is controlled by the following factors (modified from Weber, 1986; Schenk, 1988, 1992) [4.1].

- Laminae, (such as thin mudstone layers and calcite-cemented intervals)
- Vertical and lateral distribution of facies, and and interbedding characteristics of different rock types.
- Sedimentary structures

- Geometry of Sandstone bodies
- Baffles and low permeability rocks such as shale
- Influence of diagenetic history on porosity and permeability
- Faulting and fracturing of the reservoir

These features are significant to fluid-flow because they cause the flood-front (the boundary between the displacing and displaced fluids) to distort and spread as the displacement proceeds. However, fluid properties e.g. the density difference between the displacing and displaced fluid (or mobility ratio) also significantly affect the shape of the flood-front towards the wellbore.

Reservoir heterogeneities also relate to indirect geological parameters such as relative permeability, PVT properties, aquifer strength and the development strategy. This is often a response to rock-fluid interaction during the displacement process.

4.3 Reservoir Modeling

A reservoir model is able to predict the distribution of hydrocarbons and flow properties within generic reservoir types. Synthetic geologic architecture and/or property distributions can be obtained from field data, which possess a number of desirable geological features and conditioned to observations. The internal makeup of a reservoir provides a framework of connectivity and continuity flow of the fluids through the reservoir rock. Typical reservoir heterogeneities, such as faults, reservoir geometry and the spatial distribution of flow units and barriers can be represented.

A reservoir model can also be probabilistic. It tries to predict reality by logical relations; but it is limited by our perception, knowledge and understanding of reality and does not necessarily represent reality. It is, however, the best calculated guess. In the past, reservoir models have often consisted of more or less homogeneous packages of superimposed layers which are best described as a layer cake type of reservoir [4.1].

However, in reality this is often not the case. Reservoirs are not uniform because they have variable properties. A sandstone reservoir with a range of porosity and permeability values cannot be described as uniform. Reservoirs are not homogeneous if they consist of different rock types e.g. A fining upward system in a clastic reservoir has a different texture - coarser grain sands at the base from the finer grain sands at the top (Figure 4-1). Hence, such deposit is not homogeneous and certainly not random; it is structured in a systematic way.

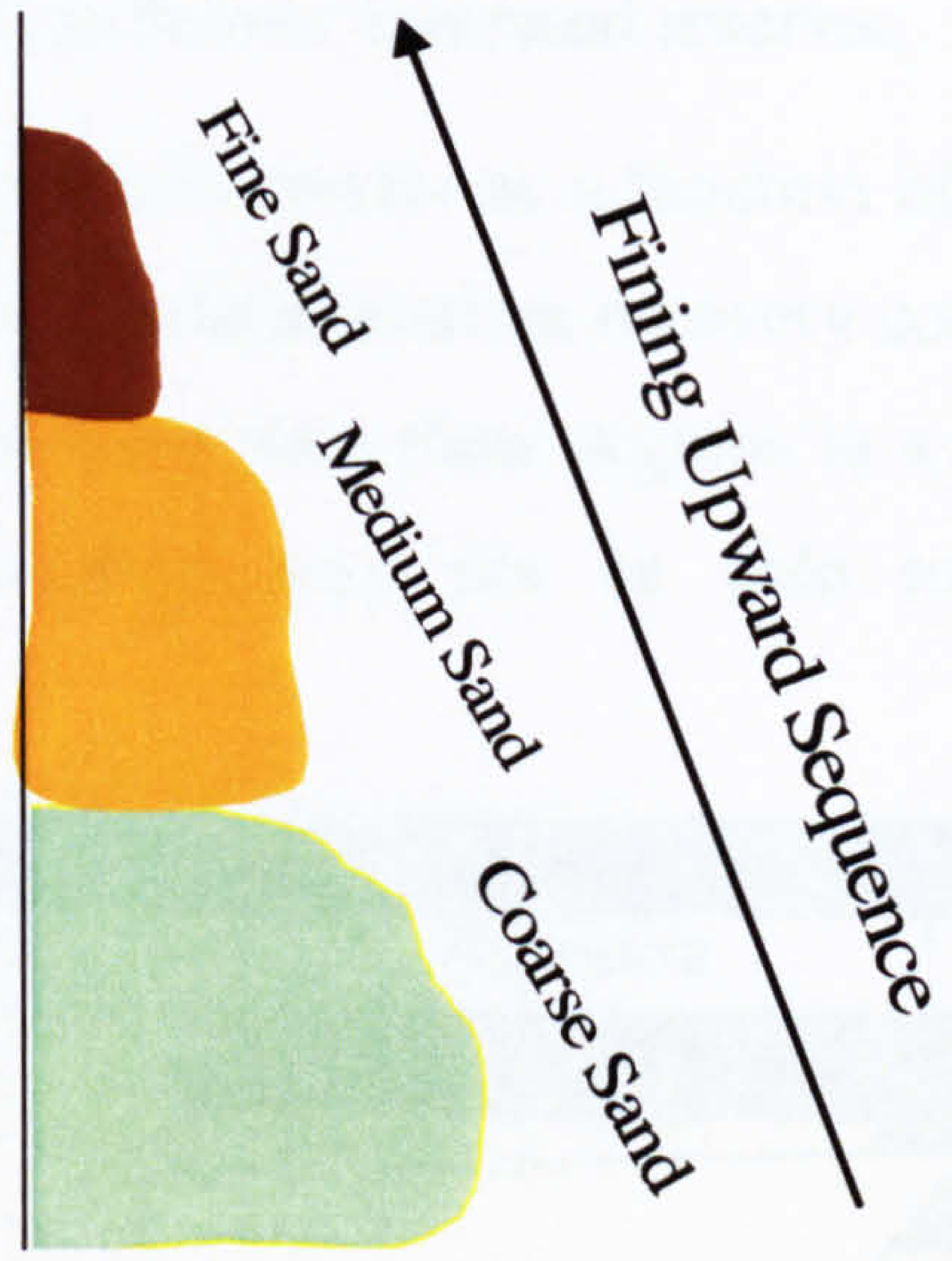


Figure 4-1: Simple model of fining-up reservoir unit

Reservoirs are heterogeneous because processes from which they were formed cause their intrinsic properties to vary in space. The process of reservoir modelling starts with collation and interpretation of field data from which a depositional model is derived. The detailed correlation between wells is a function of well spacing and reservoir complexity.

For this project, two simulation models of North Sea 'Brent Group' type reservoirs were made available by the sponsors. It was not possible to determine the original input facies models and patterns because only the coarse scale, upscaled grid cell model was supplied. The focus was, therefore, to obtain generic reservoir types from the existing simulation models and to capture the effects of upscaled heterogeneity on the reservoir displacement processes. However, these data were not respected during every phase of the study i.e. the data used for many systematic studies, throughout the project, were purely synthetic. Using relatively simplistic, synthetic data will result in a better understanding of the driving factors and will able easier generalisation of the results to a wide range of reservoir scenarios.

As mentioned earlier, identifying the reservoir type(s) where IWsT has the potential to deliver the greater value is an important step in its application. One would instinctively expect that the application of IWsT to systems with a complex geological architecture, where recovery is low, oil is bypassed and where optimum well placement is a complex process, to have the potential to deliver increased reserves.

Figure 4-2 shows the heterogeneity matrix as a function of flow units. It highlights the areas of matrix which have lower hydrocarbon recovery compared to other areas. IWsT is capable of managing production from these regions in a cost-effective way. Standard completions (and infill drilling) may not be able to produce these reservoirs economically.

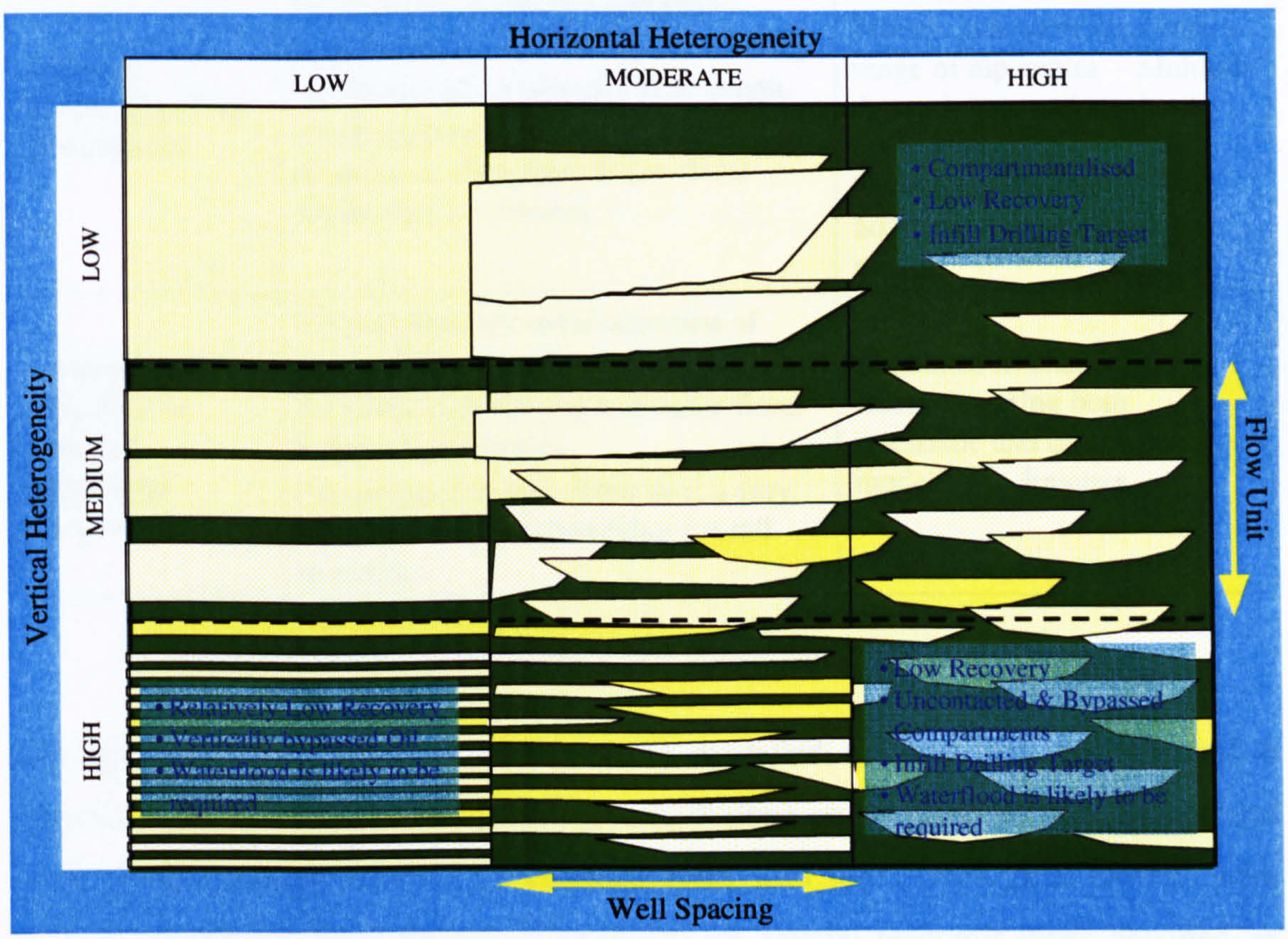


Figure 4-2: Heterogeneity Matrix showing recovery (adapted from Tyler and Finley) [4.2]

Table 4-1 summarises the reservoir types and their analogues used during the course of this study. The reservoir scenarios were deliberately kept relatively simple so as to help the comparison between the cases and allow a better understanding of the driving factor, which determine the "Added Value" from the Intelligent Wells.

Reservoir Types	**Characteristics**	**How they simulated**
Aeolian, Shallow Marine (Barrier Bar, Beach)	Massive thick sandbodies, normally several km long. Fairly homogeneous and extensive sandbodies.	Simulated as a uniform permeability (or limited range of permeability), single reservoir.
Layered Submarine Fan (Turbidite)	Interbedded sandstones and shales. Sandbodies are often thick and laterally continuous up to several km in length. Heterogeneity in the horizontal direction is often low. Water-flood application is common.	Simulated as layered reservoirs Models give structures with a range of dip angles - Multiple deterministic and stochastic realisations of a heterogeneous and homogeneous, inclined model.
Channel Sands (Braided or Stacked individual channels)	Vertical and horizontal accretion of sandbodies. Targeted infill drilling and water-flood redesign is common. The connectivity of channels is a very important factor determining overall recovery.	Simulated as channel sand reservoirs using both stochastic and deterministic modeling techniques.

Table 4-1: Generic reservoir units which simulated at this study

Having identified the types of reservoir to be modelled, the next step was to establish the rock types in each reservoir. This usually is done on the basis of rock quality and porosity/permeability relationship obtained from well logs. Geological models were built using porosity/permeability relationships for several reservoir types obtained by analysis of two real North Sea reservoir simulation models (Figure 4-3). The approach used for obtaining rock types was based on grouping the ranges of permeability values into different rock classes of real fields after extraction from the simulation grid. The pore volume of the total system was kept constant. Hence, total porosity was kept constant.

The Tarbet and Etive formation data (Table 4-2) were used to produce synthetic models. The average permeability data from Etive formation (Table 4-2) were used to create average permeability models. In addition, a range of realisations of a heterogeneous (Etive type) reservoir model using the actual Etive permeability data were also generated.

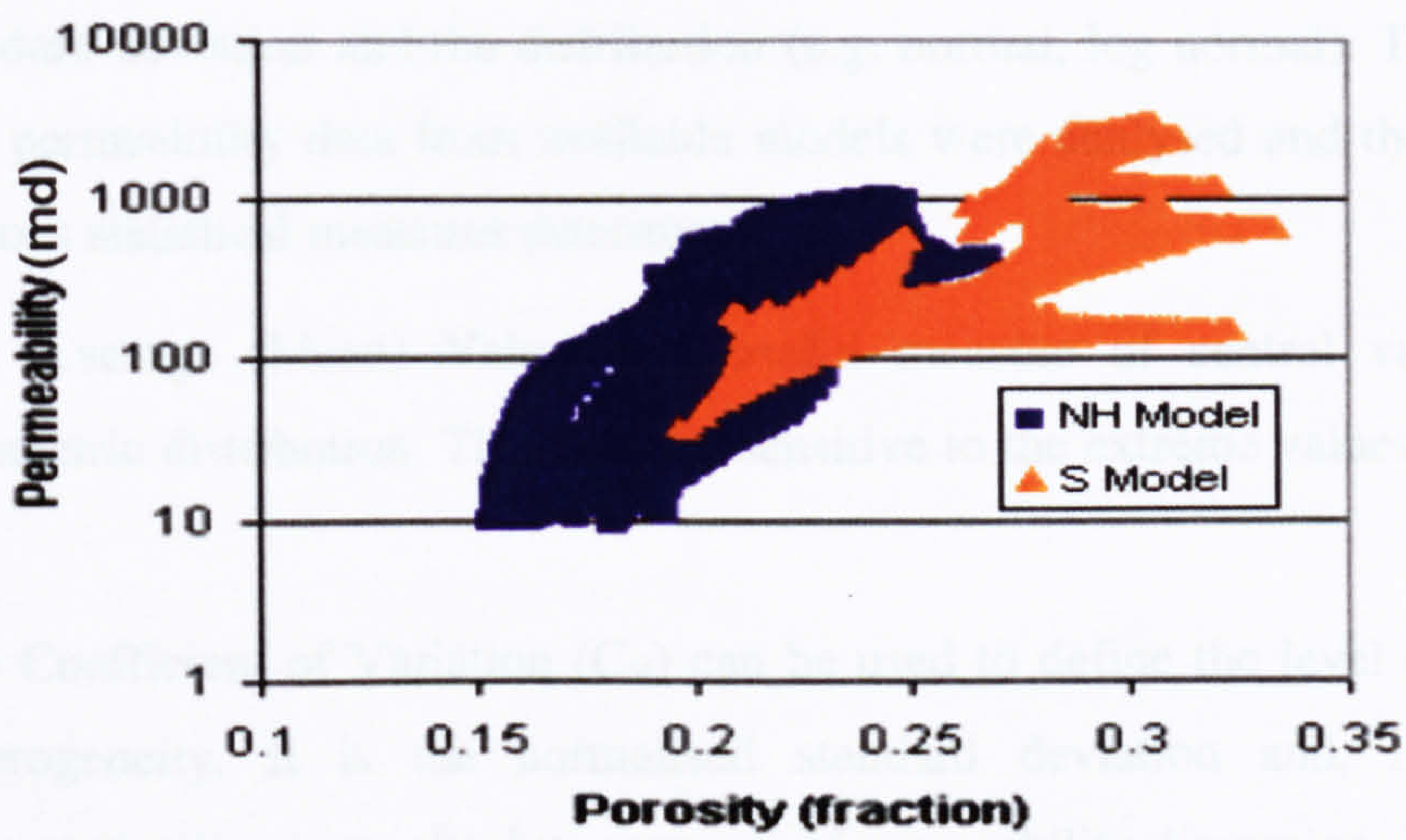


Figure 4-3: Porosity-Permeability plot for the NH and S field models

Model (Based on real field data)	Porosity	Permeability (mD)			Net to Gross
		X	Y	Z	
Tarbet	0.268	188	188	56.4	0.84
Etive	0.215	2119	2119	635	0.94

Table 4-2: Reservoir properties used in the average permeability model

A uniform vertical to horizontal permeability ratio (K_v/K_h) of 0.3 was used in the models. It represents a moderate degree of sub-cell anisotropy (heterogeneity). Variation in the (K_v/K_h) ratio was also studied since this ratio could be much lower depending on the amount of shale in the sand bodies.

4.4 Geological Statistics

1. Geological statistics provides a quantitative summary of geological observations. It is used to describe the spatial variability of reservoir properties and the spatial correlation between related properties. The distributions of geological observations are described by several parameters such as the mean, standard deviation and the distribution (e.g. normal, log normal). The porosity and permeability data from available models were analysed and the following various statistical measures determined:

2. The Average (Mean) Value is a useful measure of central values for a symmetric distribution. This value is sensitive to the extreme values in the data set.

3. The Coefficient of Variation (C_V) can be used to define the level of reservoir heterogeneity. It is the normalised standard deviation and, in reservoir characterisation, is an absolute measure of permeability dispersion. It is defined as: $C_V = SD / \bar{K}_{ar}$ Equation (4.1)

where SD, the Standard Deviation, is the positive square root of variance. It is usually the best measure of spread; being the root mean square of the differences from the mean value ($\bar{K}_{ar}$).

$$SD = \sqrt{\frac{\Sigma \left(K - \bar{K}_{ar}\right)^2}{n}}$$ Equation (4.2)

$\bar{K}_{ar}$ is the arithmetic average of the measured values of horizontal permeability.

C_V will extensively be used throughout this thesis for the study of the heterogeneity and the IWsT Added Value. Formation variability can be classified by using the C_V value [4.3, 4.4].

Increasing Heterogeneity

k=constant	$C_V \leq 0.5$	$0.5 < C_V < 1.0$	$C_V \geq 1$
"Uniform"	"Homogeneous"	"Heterogeneous"	"Very Heterogeneous"

Figure 4-4 shows a model with a small C_V value (= 0.3) while Figure 4-5 shows the relative frequency of permeability values in this model. A wide range of permeability values (0.01-10,000 mD) was chosen to be distributed using a modelling package (chapter 4.7) in this box model. However, the distributed permeability values in Figure 4-5 cluster around the Mean permeability value (Mean = 5000md) i.e. the deviation from the Mean is small. This is due to the low value of C_V (= 0.3) which resulted in a small deviation from the average permeability.

Figure 4-6 shows a model with a large C_V value (= 0.76) while Figure 4-7 shows the relative frequency of permeability values for this model. Large C_V values increase the range of permeability values appear in the model and results in an increase in the heterogeneity.

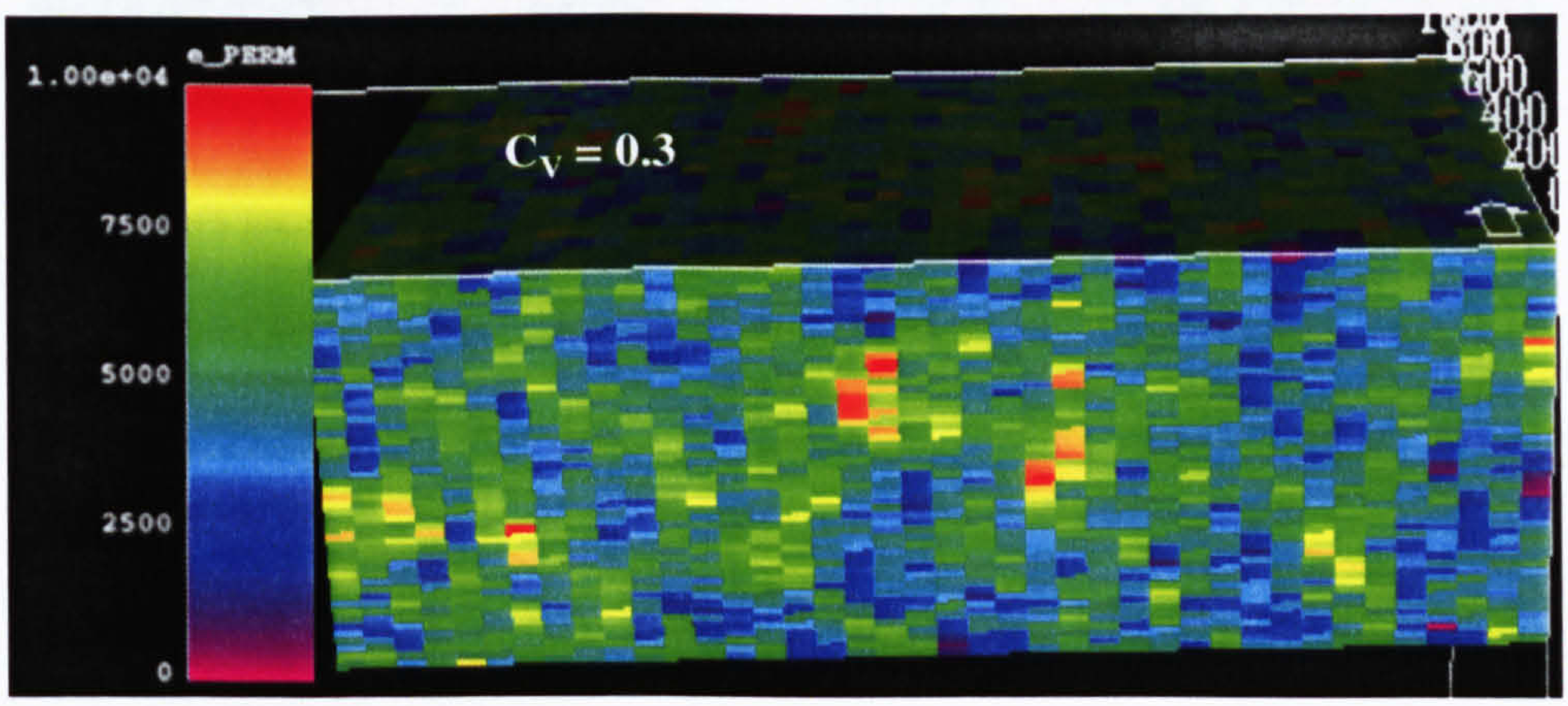


Figure 4-4: Permeability distribution in a reservoir model when $C_V = 0.3$

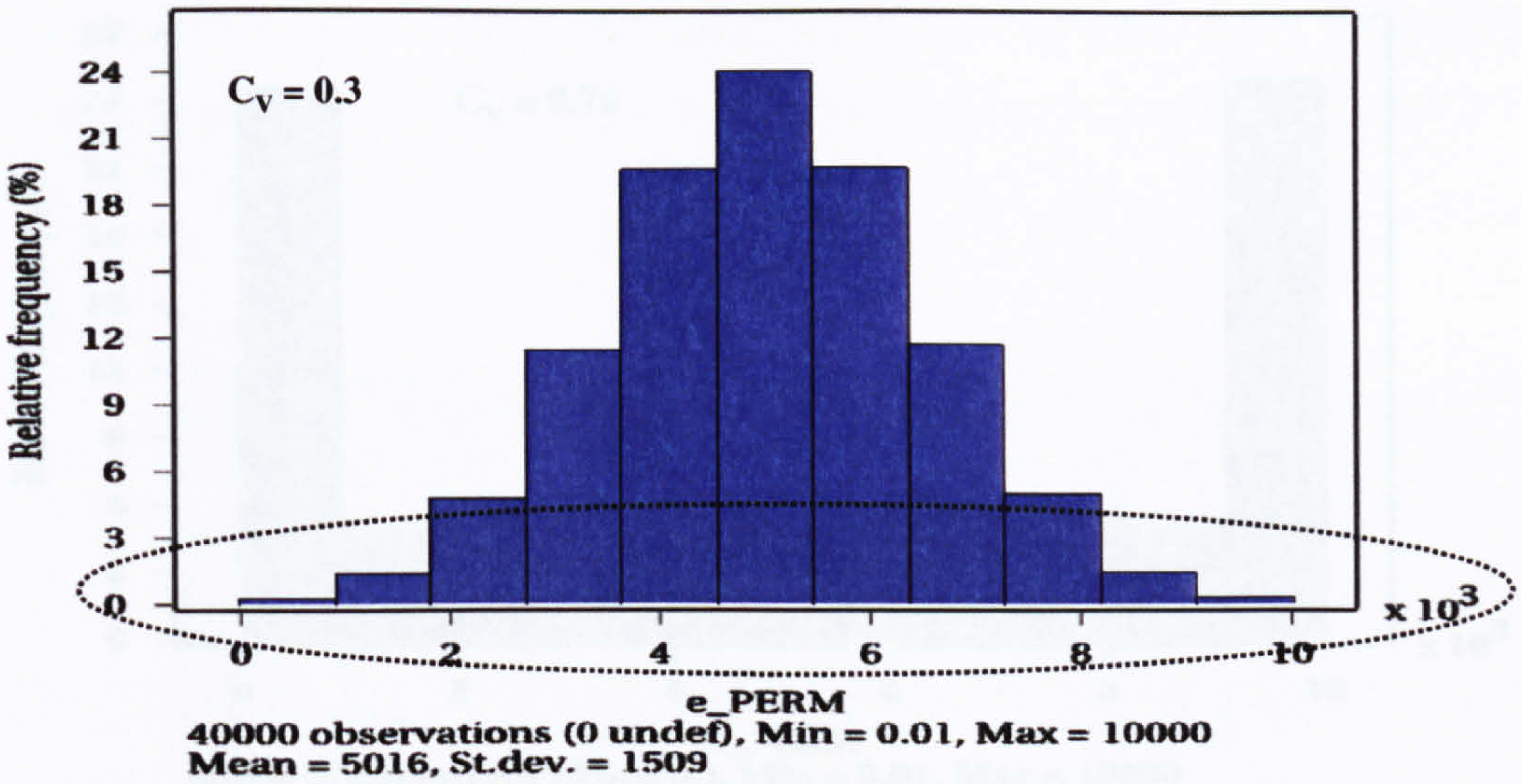


Figure 4-5: Relative frequency of permeability values in the model shown in Figure 4-4

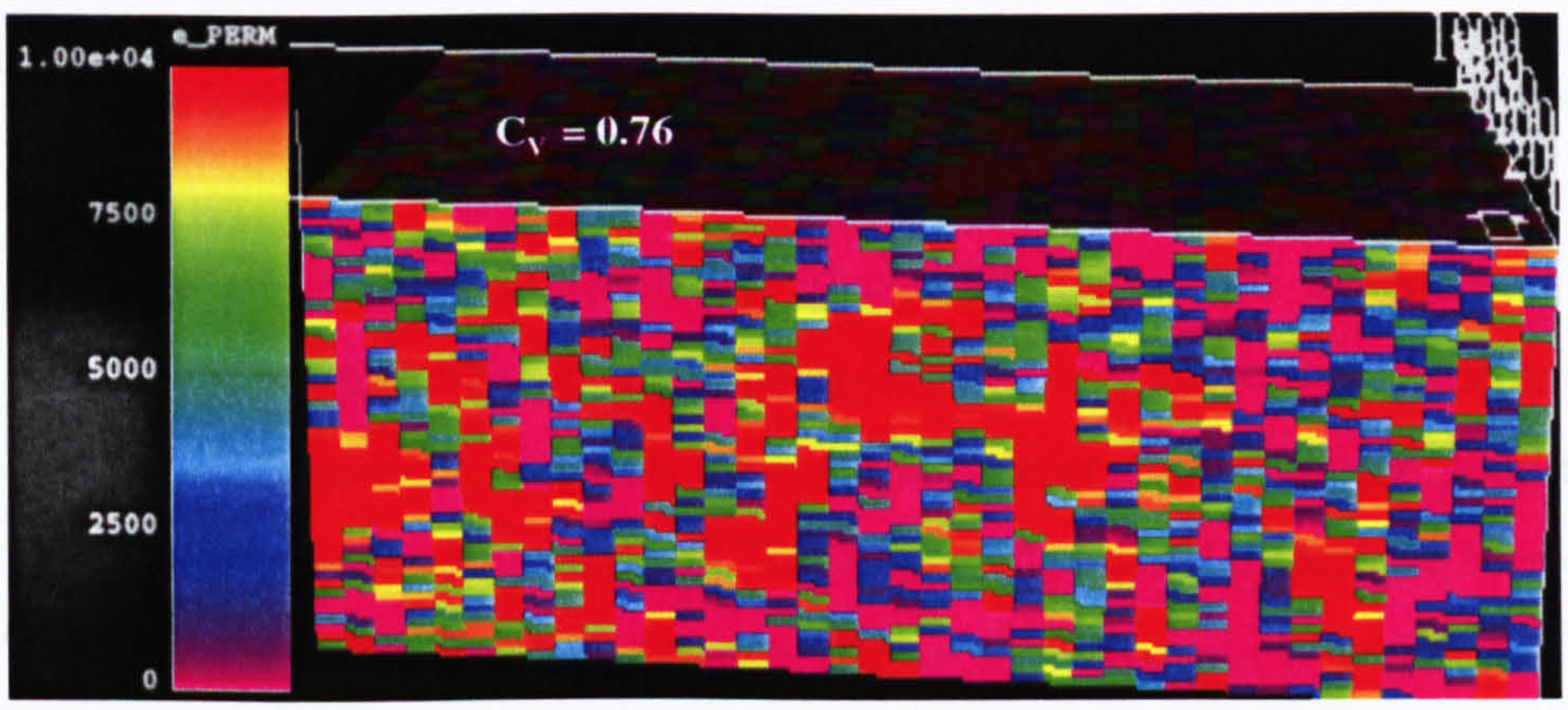


Figure 4-6: Permeability distribution in a reservoir model when $C_V = 0.76$

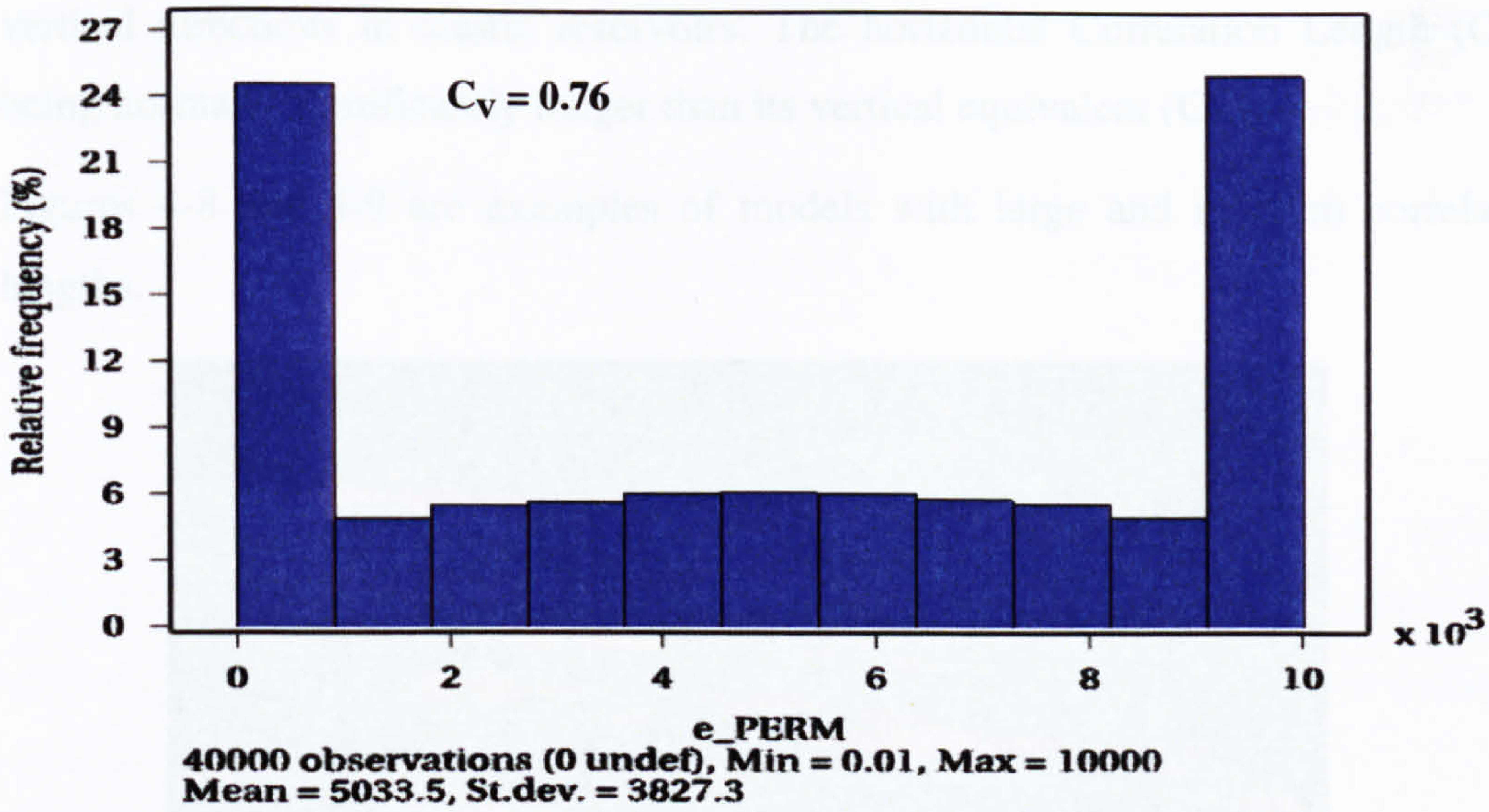


Figure 4-7: Relative frequency of permeability values in the model shown in Figure 4-6

4. The Variogram is a statistical technique used to quantify the spatial continuity of a variable as a function of distance and direction. It can also be defined as a measure of geological variability versus distance. The counterpart of the variogram in object-based methods is the size and shape specifications of the geological objects. It, therefore, reflects our understanding of the geometry and continuity of reservoir properties. The expected squared difference between two data values separated by distance (h) is the variogram; while half of the variogram is the semi-variogram.

$$\gamma(h) = \frac{1}{2N(h)} \sum_{i=1}^{N(h)} \left(k(i) - k(i+h)\right)^2 \qquad \text{Equation (4.3)}$$

In this case N is the number of pairs of data points and *k(i)* and *k(i + h)* are the data of any two points separated by a *lag* (the distance between the points, *h*).

The Variogram concept will be extensively used in this study through the parameter Correlation Length (CL). CL is the distance from a point over which a physical property is correlated with the initial value at any particular point. Values for the property at distances beyond the correlation length become random with respect to the initial, starting value. CL normally has different values in the horizontal and vertical directions in clastic reservoirs. The horizontal Correlation Length (CL_H) being normally significantly longer than its vertical equivalent (CL_V).

Figures 4-8 and 4-9 are examples of models with large and medium correlation lengths.

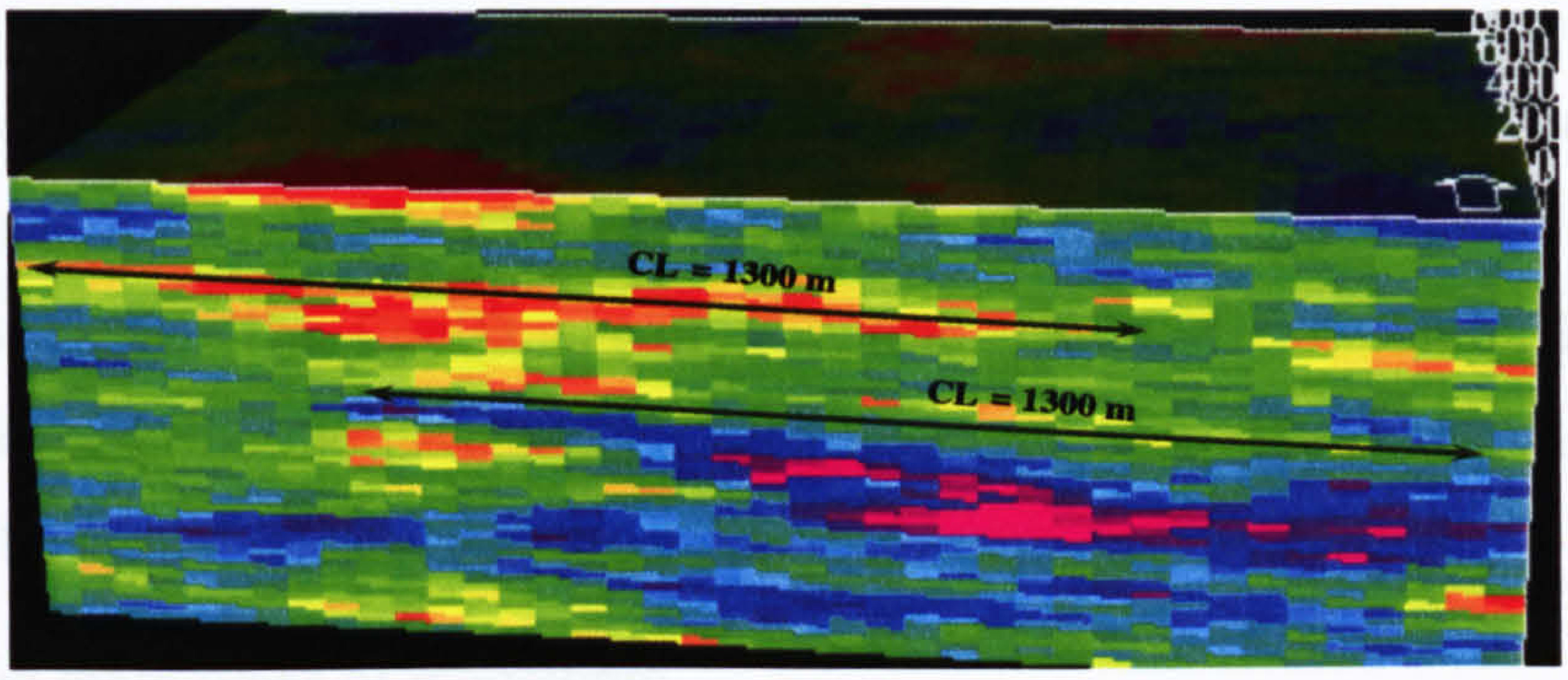


Figure 4-8: Model showing a large horizontal Correlation Length (CL_H = 1300 m)

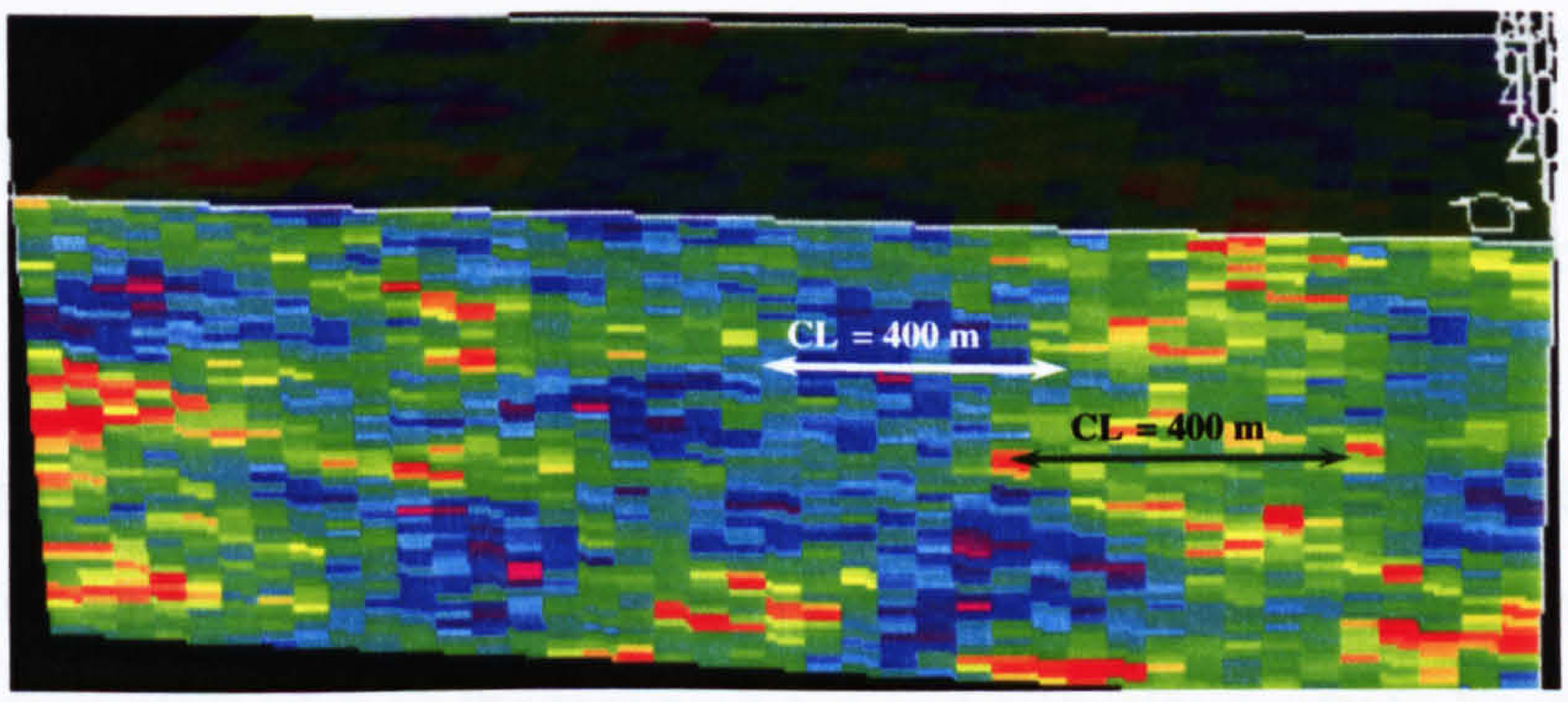


Figure 4-9: Model showing a medium horizontal Correlation Length (CL_H = 400 m)

4.5 Stochastic and Deterministic Modeling

Stochastic modelling is a process whereby different synthetic geologic models are generated from the same input data. It is based on the geological phenomenon that representation of a given set of circumstances may or may not result in exactly the same outcome each time. Stochastic modelling offers the possibility of producing a variety of multiple realisations which all fit the available information about the field and its basic data.

Stochastic modelling and simulation of a reservoir with geostatistics is an effective quantitative and systematic geostatistical method to model reservoir heterogeneities.

Multiple realisations can be produced that all have a similar quality of "fit" to the same basic data. The internal makeup of a reservoir provides a framework of connected fluid-flow pathways throughout the reservoir. A reservoir model tries to capture reality by logical relationships, but it will always be limited by our knowledge and understanding of reality.

Each particular probabilistic model generated using a geostatistical modelling technique is one realisation consistent with the "best guess" parameterisation of a particular geological scenario. The Coefficient of Variation (C_V) and Correlation Length (CL) were used to describe the permeability and porosity heterogeneity. General scenarios can be built by systematically varying these parameters.

There are two main types of modelling:

i) Discrete or Object-based Models: describe geological features of a discrete nature e.g. locations and dimensions of sandbodies; distribution and sizes of shales suspended in sands; distribution, orientations and lengths of fractures and faults; and facies definition. Examples of discrete model are truncated random functions and two-point histograms.

ii) Continuous or Cell-based Models: describe phenomena that vary continuously e.g. rock properties such as permeability, porosity, residual saturation, seismic velocities and dimension parameters such as the reservoir top and oil/water contact. Each point in the reservoir space or area has one distinct value for the variable of interest. A continuous model describes:

- Mean level, or possible lateral or vertical trends for that variable,
- Variability around the mean,
- How strongly neighbouring points tend to have similar values (correlation) and
- The co-variation of the variables under study i.e. how the knowledge of one variable enhances prediction of the others.

Continuous models fall within the framework of geostatistics. Key concepts used here are random functions and (Gaussian) random fields.

Deterministic, petrophysical modelling interpolation using upscaled well log data was used to assign property values to cells that were penetrated by the wells. Stochastic petrophysical modelling generates multiple, equiprobable realizations of the reservoir heterogeneity within the reservoir layers between the wells.

Stochastic modelling technique was used to capture large-scale heterogeneity level and could be extended to include the finer detail geology if required.

4.6 Potential Use of Intelligent Wells in Generic Reservoir Types

Intelligent Well systems Technology can be applied where conventional production management methods are challenged. The reservoir types classified in Table 4-1 have been explained in more detail and simpler form (engineering) below:

4.6.1 Layered Reservoirs

Vertical permeability variation of layered reservoirs has a considerable impact on water drive performance. Permeability differences within the layers have significant impact on recovery process, especially when high permeability streaks are present. An important consideration in the vertical sweep behaviour is the connectivity or cross flow between the layers. Figure 4-10 shows possible layering scenarios that may exist.

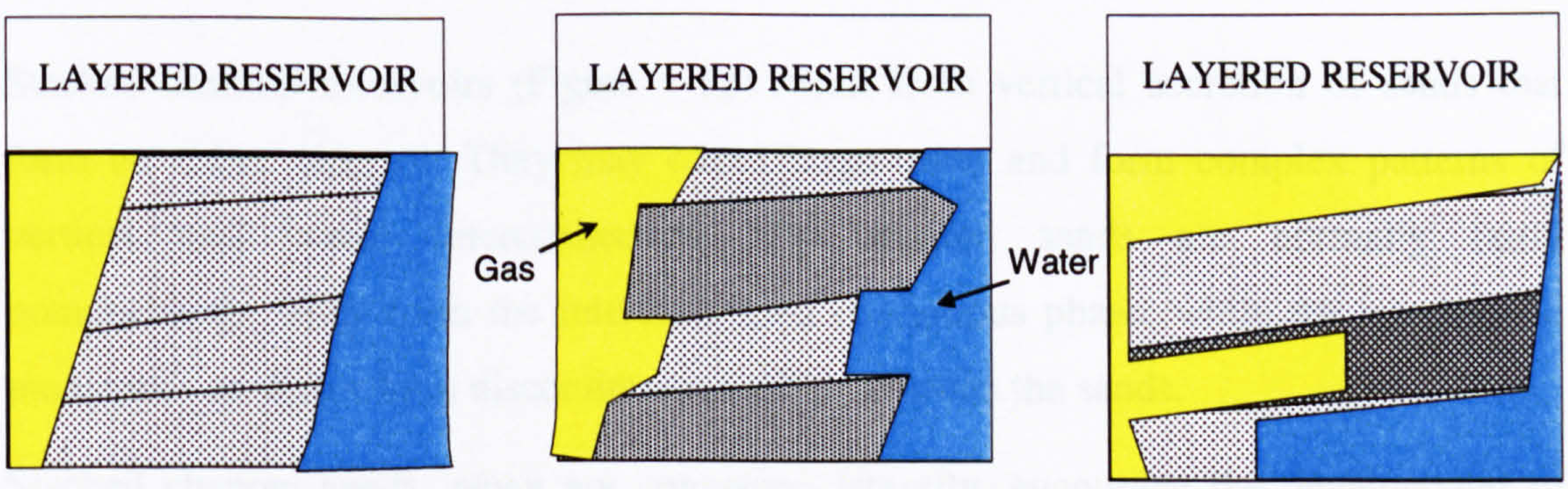


Figure 4-10: Fluid fronts in layered reservoirs

Dipping layered reservoirs with strong aquifer support usually can be drained by perforating intervals in the layers using a completion with an ICV in each separate layer. Production from that layer can then either be choked back or be shut off when water or gas breaks through.

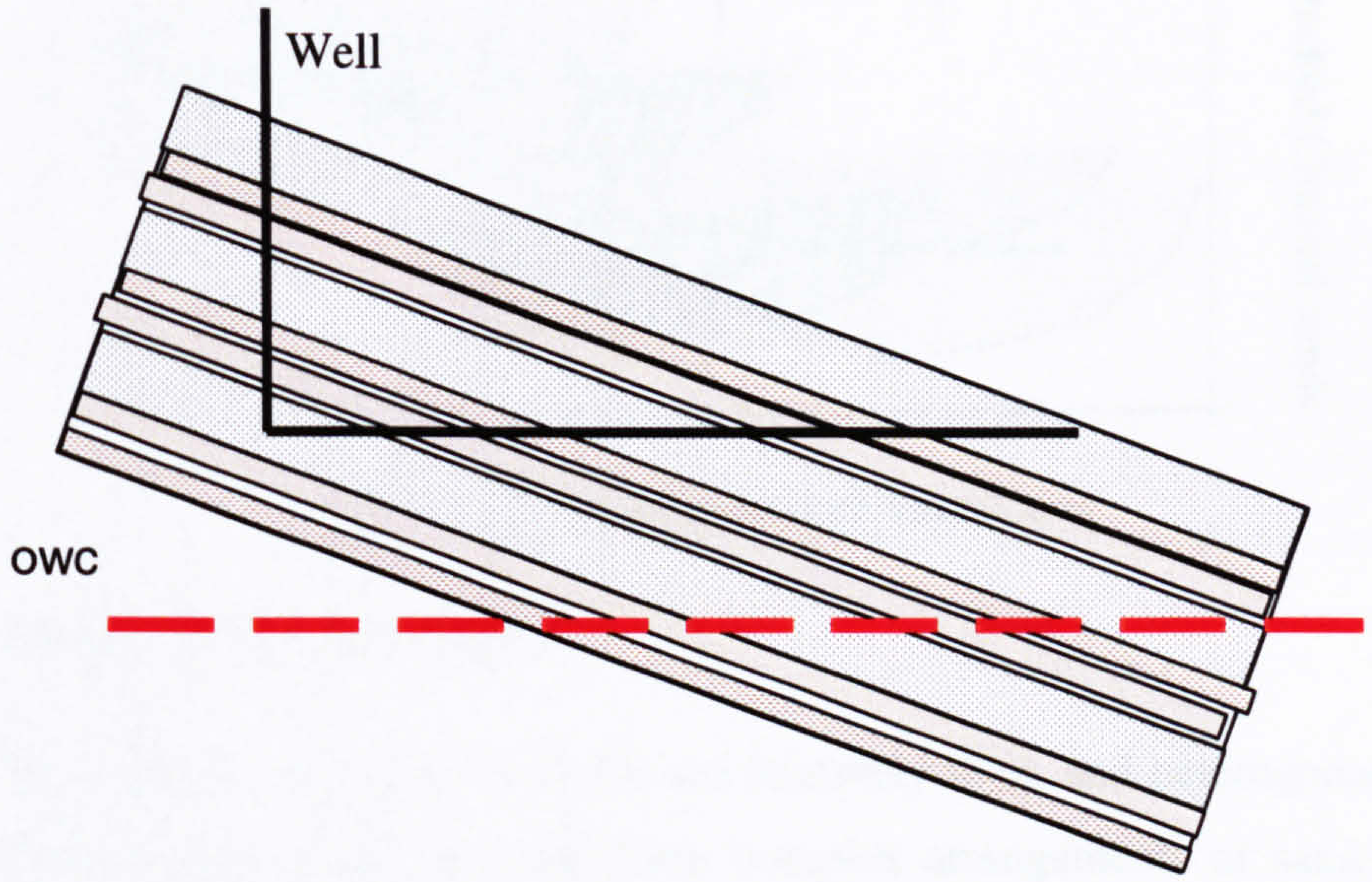


Figure 4-11: Geometry of dipping layers and horizontal wells

4.6.2 Stacked Channel Reservoirs

Stacked channel reservoirs (Figure 4-12) result from vertical accretion of sands that form an entire channel. They may cover large areas and form complex patterns of vertical and lateral interconnection. The stacked sands are normally fairly homogeneous. They form the interconnected continuous phase; while the interbedded mudstones or shales form discontinuous baffles between the sands.

Stacked channel sands, when not connected laterally, encourage the development of different pressure regimes in the sands during depletion. The sandbodies with different pressure regimes could be produced simultaneously using IWsT. This will result in a cost-effective and optimal depletion of the reservoirs.

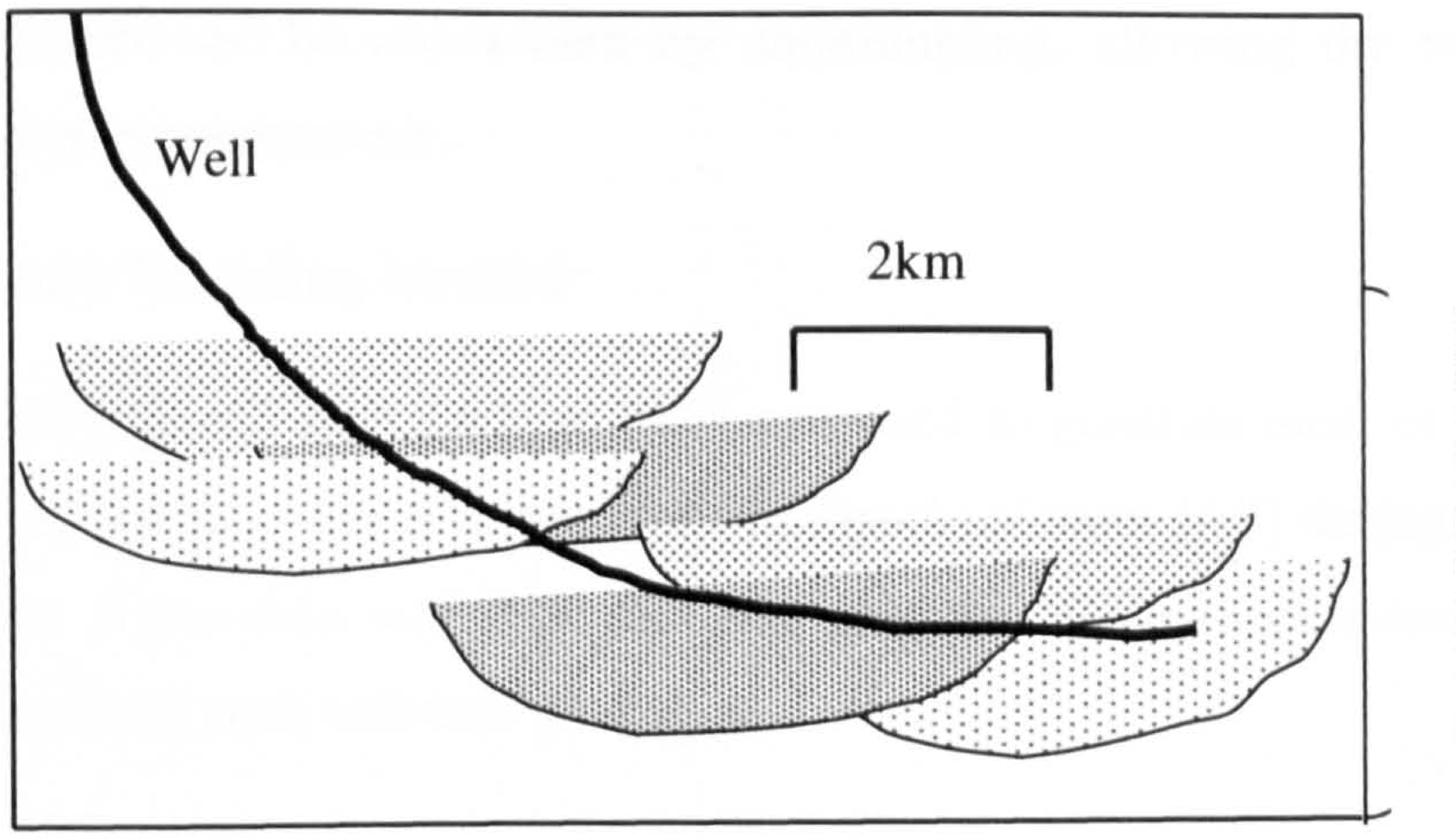


Figure 4-12: Stacked channel sandstones

4.6.3 Isolated Channel Reservoirs

The isolated channel sands (Figure 4-13) are relatively thick and heterogeneous. They occur as deep narrow sandbodies and form complex arrangements of sand pods and lenses. The sands appear to be discontinuous when viewed as a vertical cross-section. This complex arrangement, as in the stacked sands, encourages different pressure regimes to develop during depletion.

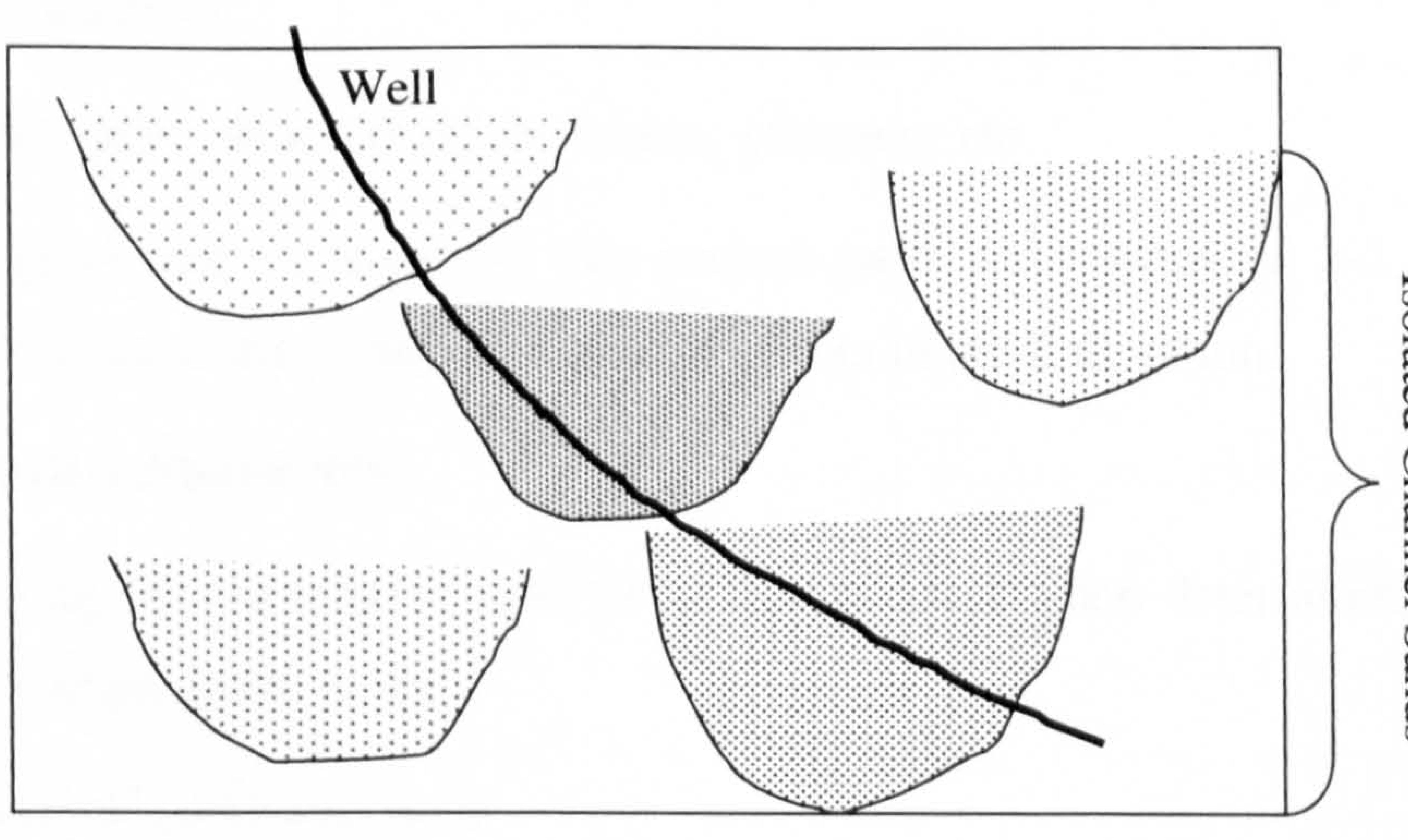


Figure 4-13: Isolated channel sandstones

IWsT can be used to increase the production efficiency from both isolated and stacked channel sand reservoirs by managing the different pressure regimes e.g. the production from such sands can be accelerated by commingling, allowing the tubing outflow performance to be maximised.

4.7 Stochastic Modeling Method

Roxar IRAP/RMS software package [4.6] was used to generate most of the stochastic models. Some models were also generated in Petrel software [4.7] during the last phase of the project. A common workflow for generating the 3D geomodels consisting of two stages was used for both software packages:

Stage 1:

Build a framework (container) and a 3D grid in which property modelling can be done. This stage requires the following inputs:

Horizons: depth (or time)

These are used as bounding surfaces for the 3D volume (known as zone in IRAP/RMS). The porosity and permeability maps for a North Sea field model were imported into the IRAP-RMS package as surfaces and used to generate the 3D volume for some of the models. Other reservoir models generated for this study had purely synthetic properties, as mentioned earlier.

Grid layout: information about resolution, geometry etc

The geological models used for this project have dimensions of 2-3 km in the X direction, 1-2 km in the Y direction and 30 - 80 m in the Z direction.

Representative Model Size

The following considerations were taken into account when determining the required size for a representative model.

- Length of horizontal well
- Maximizing computational efficiency
- Recovery efficiency objective
- Production control

Stage 2

The next stage, which is modelling properties and heterogeneity, is very important for the reservoir description and evaluation of Intelligent Wells. The property distribution affects the shape of fluid front progression towards the length of the wellbore and, therefore, the "Added Value" from the Intelligent Wells. It involves facies modelling (object-based), petrophysical modelling (cell-based) and finally, simulation grid design and upscaling. However, the facies modelling stage was missed out and only the stochastic petrophysical modelling was performed since the data available for this project were reservoir simulation models. In addition, a range of object-based, channelised models were generated without respecting the real data. The IRAP/RMS package requires the following when creating stochastic, petrophysical models:

- The **Distribution** of the variable to be modelled is required. The Gaussian distribution for a continuous variable, such as porosity and permeability, is given as:

$$f(x) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-(x-\mu)^2 / 2\sigma^2} \qquad \text{Equation (4.4)}$$

The mean (μ) and the variance (σ) are used to obtain the distributions.

- The **Variogram** of the variable to be modelled: Common descriptive statistics (e.g. Mean, Average and Standard Deviation) and the histograms fail to identify, let alone quantify, the textural difference between different data sets. Common descriptive statistics and histograms do not incorporate the spatial locations of data. The variogram is a quantitative descriptive statistic that can be graphically represented in a manner which characterizes the spatial continuity (i.e. roughness) of a data set. The experimental variogram is the squared difference between all pairs of sample values calculated and plotted against separation distance. The concept of variogram has been widely used through this study via the Correlation Length (CL) parameter (this was explained earlier in this chapter). The systematic study of the IWsT "Added Value" in chapter 8 is based on the systematic variations of the CL and C_V parameters.

- **Correlation**: It is necessary to determine the correlation between the variables when modelling more than one variable. In this study, porosity and permeability were correlated in the majority of model scenarios, though in some realisations only one variable – permeability - was modelled and porosity was assumed uniform.

4.8 Modeling a Layered Reservoir

Each layer in layered reservoirs would generally not show any major changes in property over a long distance in the horizontal direction, while showing significant changes over short distances in the vertical direction. A variogram model with long correlation length in the horizontal direction was used for stochastic modelling of layered reservoirs to define spatial continuity for variables such as the permeability. A shorter correlation length was used in the vertical direction. The highly layered appearance of the resulting reservoir can be seen in Figure 4-14.

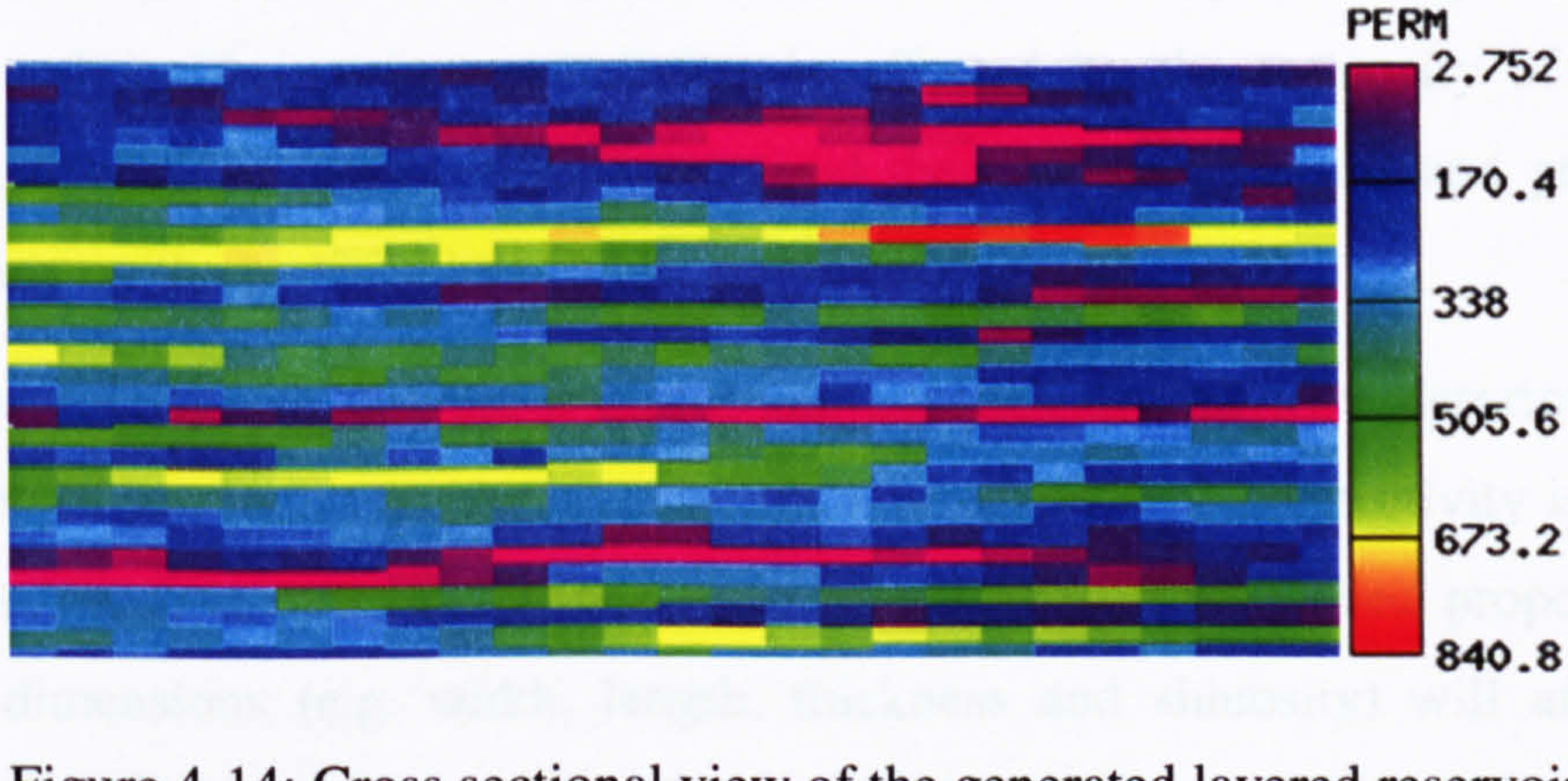


Figure 4-14: Cross sectional view of the generated layered reservoir

4.9 Modeling a Stacked and Isolated Channel Sand Reservoirs

Extensive stacked channel sand reservoirs often show no major changes in properties over a long distance in the horizontal direction. Hence, a variogram model was used to define the long spatial continuity for permeability (large CL value) in order to model a channel reservoir using a stochastic (cell-based) modelling technique. The property change in the vertical direction may not be as significant as in a layered reservoir. A longer range, correlation was therefore used (Figure 4-15).

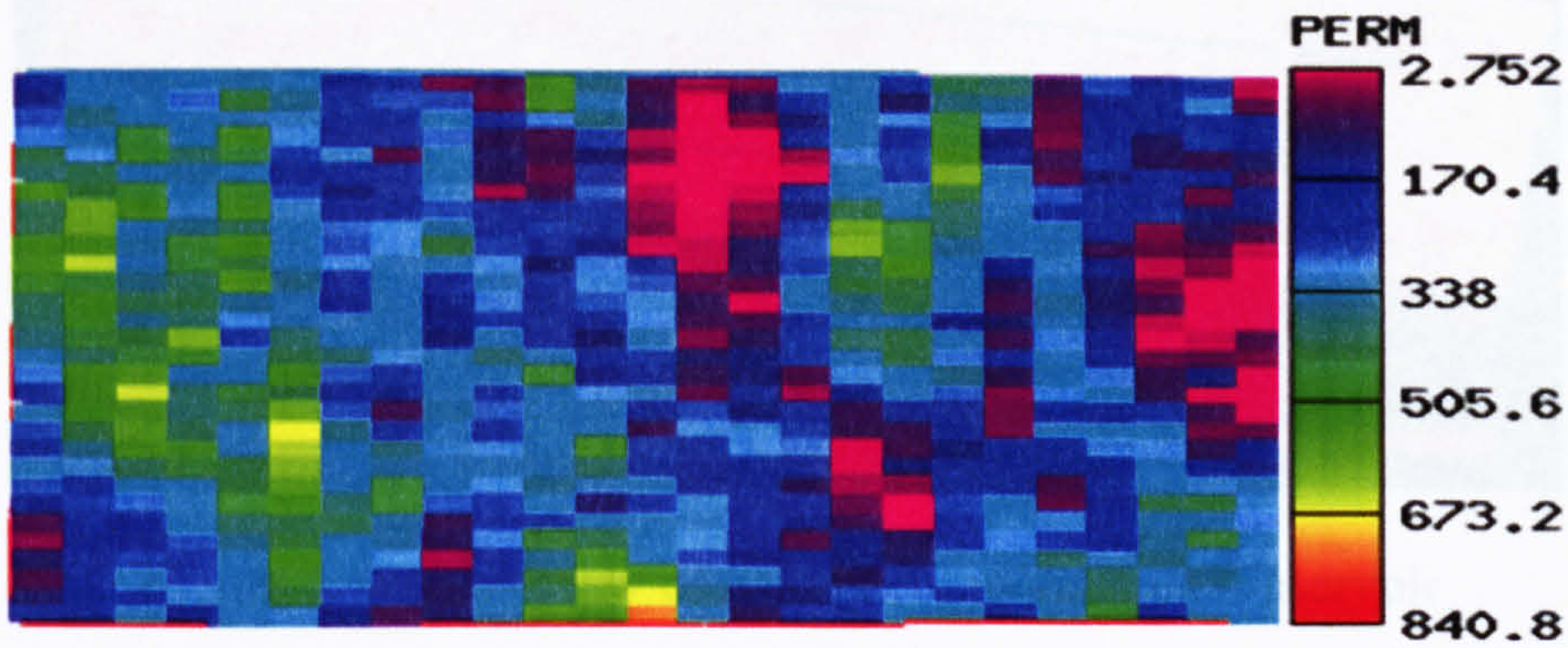


Figure 4-15: Cross sectional view of a cell-based (pixel-based) Stacked Channel reservoir

Figure 4-16 shows a channelised model, which has been generated using an object-based modeling technique in the IRAM/RMS geological modeling package. Connectivity of the channels is a very important factor determining the fluid front performance. Dynamic connectivity relates to the connectivity of fluid pathways in the reservoir and, unlike static connectivity, is affected by the tortuosity of connected pathways, flow rates, well configuration, and the capillary, viscous and gravitational forces acting on the hydrocarbon fluids.

Static connectivity can provide a useful and geologically intuitive description of the distribution of geobodies or pay units within a reservoir. The connectivity is related to depositional architecture, and hence depositional processes. Facies proportions and geobody dimensions (e.g. width, length, thickness and sinuosity) will affect facies connectivity. Within the reservoir, the connectivity of pay facies is the principal geometric control on the effective dynamic properties [4.8].

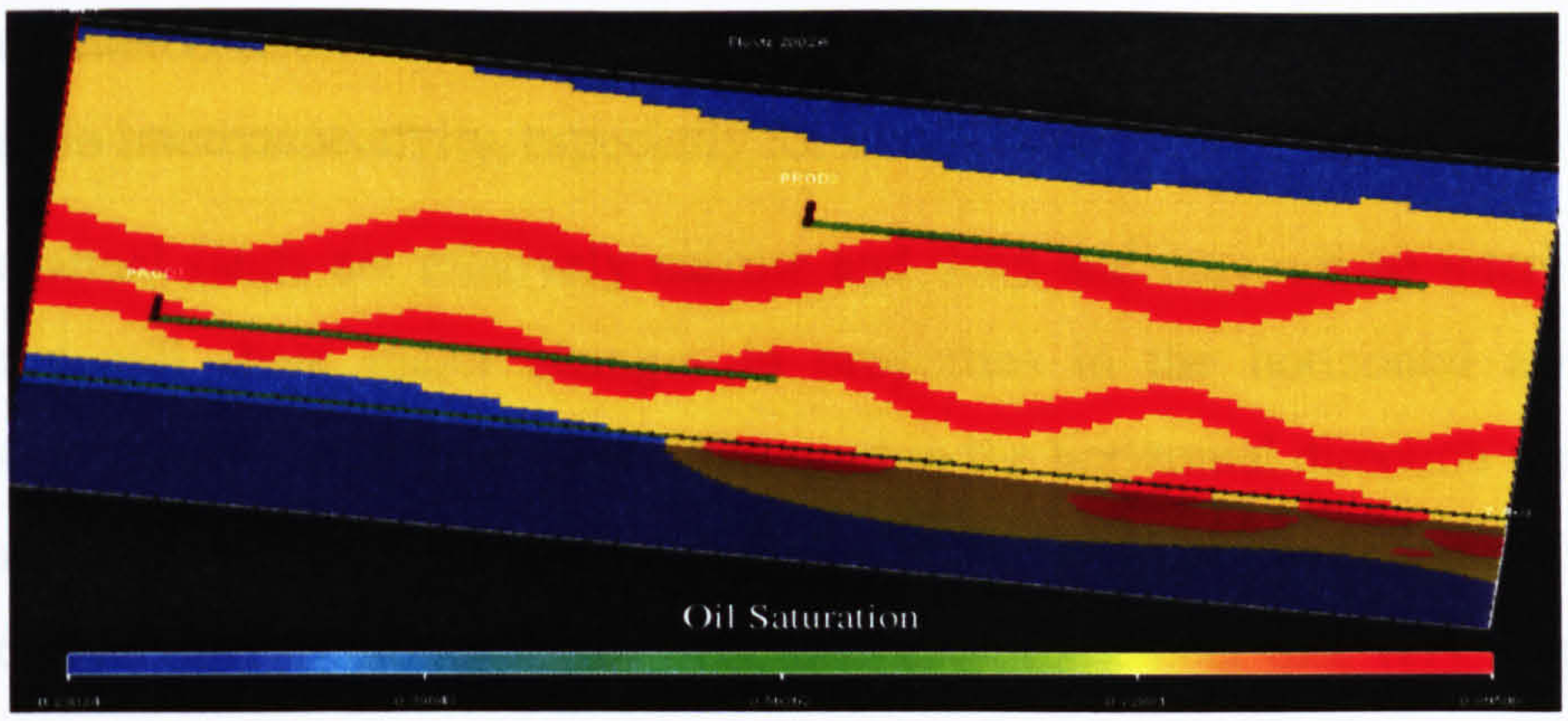


Figure 4-16: Top view of an object-base channel reservoir

The Nabis software developed by the Genetic Units Project in Heriot-Watt University [4.9] helps geologists visualise and quantify connected geobodies in 3D geological models. It has applications in characterising geological architecture, defining static connectivity and estimating dynamic flow response, well optimisation (spacing, vertical, horizontal, inclined), ranking model realisations in sensitivity studies and comparisons of facies models with outcrop analogue data.

Nabis was used to compare the relation between connectivity of channels and the shape of fluid front towards the wellbore. The optimum placement of ICVs along the length of the wellbore and hence, the "Added Value" from an Intelligent Well requires prediction of the shape of fluid front towards the wellbore. This will be discussed further in chapters 8 and 9.

A range of sensitivities were also performed on the Sinuosity, Wavelength, Thickness of sandbodies and Net to Gross Ratio (NTG) in the above model (Figure 4-16). However, a NTG of 30 % was used for the base case model (Figure 4-16). This was due to the study performed by Guest et al [4.8] which suggested that net-to-gross ratio (NTG) was the main control on connectivity, with ratios of approximately 25% representing the change from largely amalgamated sandbodies to smaller, discrete sandbodies. Above approximately 25% NTG, other parameters, such as channel dimensions, sinuosity and channel direction, had little influence on connectivity, but it was suggested that these parameters have a greater influence at lower NTG values. Thickness and width of sandbodies interconnectivity increases with NTG. Increased channel sinuosity produces an increase in interconnectivity, especially for low NTG (e.g. NTG equal to 10%).

Isolated channel sands are relatively narrow and deep and may not be interconnected; hence, they will show major changes in properties in the horizontal and vertical directions. A shorter correlation length was used in the horizontal direction and a longer correlation length in the vertical direction in order to model such reservoirs using stochastic modelling techniques. However, one must remember that very large vertical correlation values rarely occur in real formations.

4.10 Summary

This chapter explained the description and methodology used for generation of the reservoir models, which were used for this study. The technique used for modelling and optimisation of Intelligent Wells in the reservoir models will be described in the next chapter.

4.11 References

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4.6 Roxar IRAP/RMS software package, version 7.2, Roxar.

4.7 Petrel software, version 2004, Schlumberger.

4.8 J. Guest, A.R. Gardiner and J. Clark.: "3D interconnectivity analysis, illustrated by reservoir models of low to intermediate net-to-gross fluvial systems", Genetic Units Project, Institute of Petroleum Engineering, Heriot-Watt University, UK, January 2002.

4.9 Genetic Units Project (GUP): A joint industry project (JIP) accomplished at the Institute of Petroleum Engineering, Heriot-Watt University, UK, 2002.

Chapter 5 Intelligent Wells Modeling

5.1 Introduction

The methodology used for generating a wide range of reservoir models to be used for evaluation of their suitability for Intelligent Wells application, was described in the previous chapter. The methodology used for modelling Intelligent Wells in the reservoir models, using the Eclipse™ Package capabilities is presented in this chapter [1.5]. The following sections 5.2 and 5.3 are the adopted version of the work produced by the Heriot-Watt University Intelligent Well Research Group [5.2].

5.2 Modeling of Horizontal Wells

The fraction of the total pressure drop across a conventional vertical or deviated well completion due to friction is normally small due to the relatively short length of the completion. The situation is different in horizontal wells, the length of the perforated section extending over a thousand or more metre. For high / low velocities the frictional component of the total pressure drop over the completion length can be significant; resulting in a variable drawdown over the length of the perforated section. This will have a direct affect on the production per unit length at different points along the wellbore, potentially leading to a large variation in the well's inflow performance along its length. In fact, it has been realised for a number of years, that in high productivity wells where the well drawdown has a similar magnitude to the frictional pressure drop, there comes a point at which extending the length of the horizontal well will not increase the well production i.e. the pressure in the wellbore is equal to the reservoir pressure at all wellbore locations beyond this critical point.

Well inflow effects can be included in numerical reservoir simulation by splitting the completion zone into a number of segments, typically one segment for every reservoir grid that the well passes through. Holms [5.3] first reported the use of this so-called multi segment wellbore option when he studied the interaction of the reservoir with the multi segment model of a horizontal well containing an interval control valve (ICV).

5.2.1 The Multi Segment Well Model

The wellbore is divided into an arbitrary number of segments in the multi-segment well model. The appropriate number of segments will obviously depend on the degree of accuracy with which the well is to be modelled. For example, a separate segment may be placed adjacent to each reservoir grid block in which the well is completed. It is also possible for a segment to accept flow from more than one reservoir grid block. Additional segments may be used to represent unperforated lengths of casing. However, each well segment has only one value of pressure, which is used to calculate the drawdown at the connection between the well and the reservoir grid block.

5.2.2 The Pressure Drop Calculation

The multi-segment well model, as implemented in the Eclipse™ reservoir simulator [1.5], offers a choice of three methods for calculating the pressure drop across each segment. These are:

1. *A homogeneous flow model,* in which all phases flow with the same velocity.
2. *A simple 'drift flux' flow model,* which allows the phases to flow with different velocities.

3. *Interpolating a pre-calculated pressure drop table*. Here, pressure loss data as a function of outlet pressure, flow rate, water fraction and gas fraction are supplied in the form of a Vertical Flow Performance (VFP) table.

5.2.3 The Top Segment of the Multi-Segment Well

The topmost segment of the multi-segment well should be located as close as possible to the producing formation while being above:

1. All the completion intervals connecting the reservoir grid to the well.
2. Any well (lateral) branch junctions.

Computationally, it is more efficient to obtain the pressure losses between this top segment and the tubing wellhead by use of a VFP lookup/interpolation table. The alternative, to include a series of segments extending up the tubing to the wellhead, generates a much greater computing overhead. Thus the top segment corresponds to the well's bottom hole reference depth while the top segment's pressure is regarded as the well's Bottom Hole Pressure (BHP).

5.2.4 Segment Structure

A multi-segment well can be considered as a collection of segments arranged in a gathering network or tree topology. A single-bore well will, of course, just consist of a series of segments arranged in sequence along the wellbore. A multi-lateral well will have a series of segments along its main stem, while each lateral branch, consisting of a series of one or more segments, connects at one end to a segment on the main stem. Figure 5-1 shows such a segment structure for multi-lateral well while Figure 5-2 shows the alternatives connection flows from the reservoir grid to the segments.

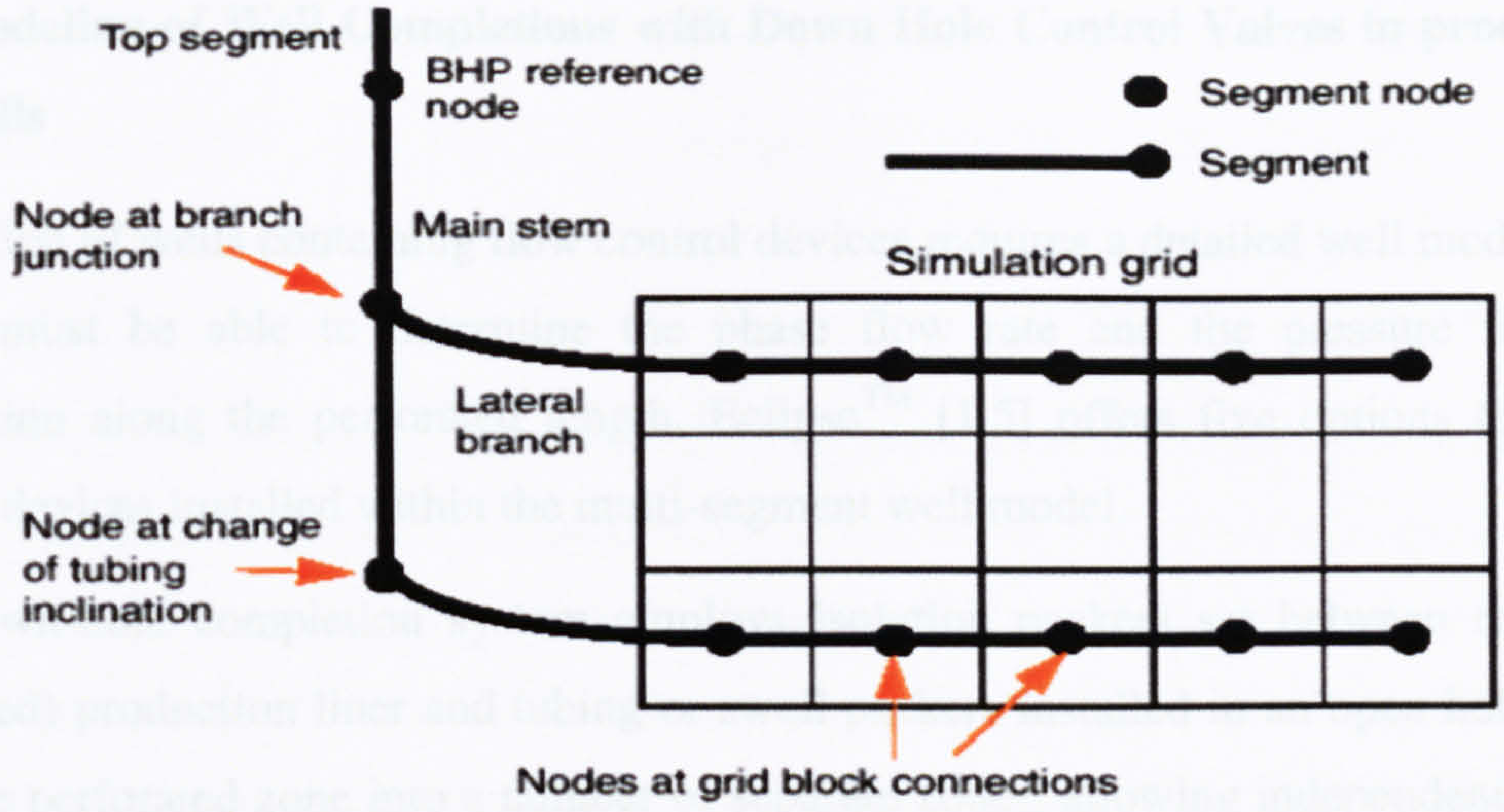

Figure 5-1: A multi-lateral, multi-segment well [1.5, 5.2]

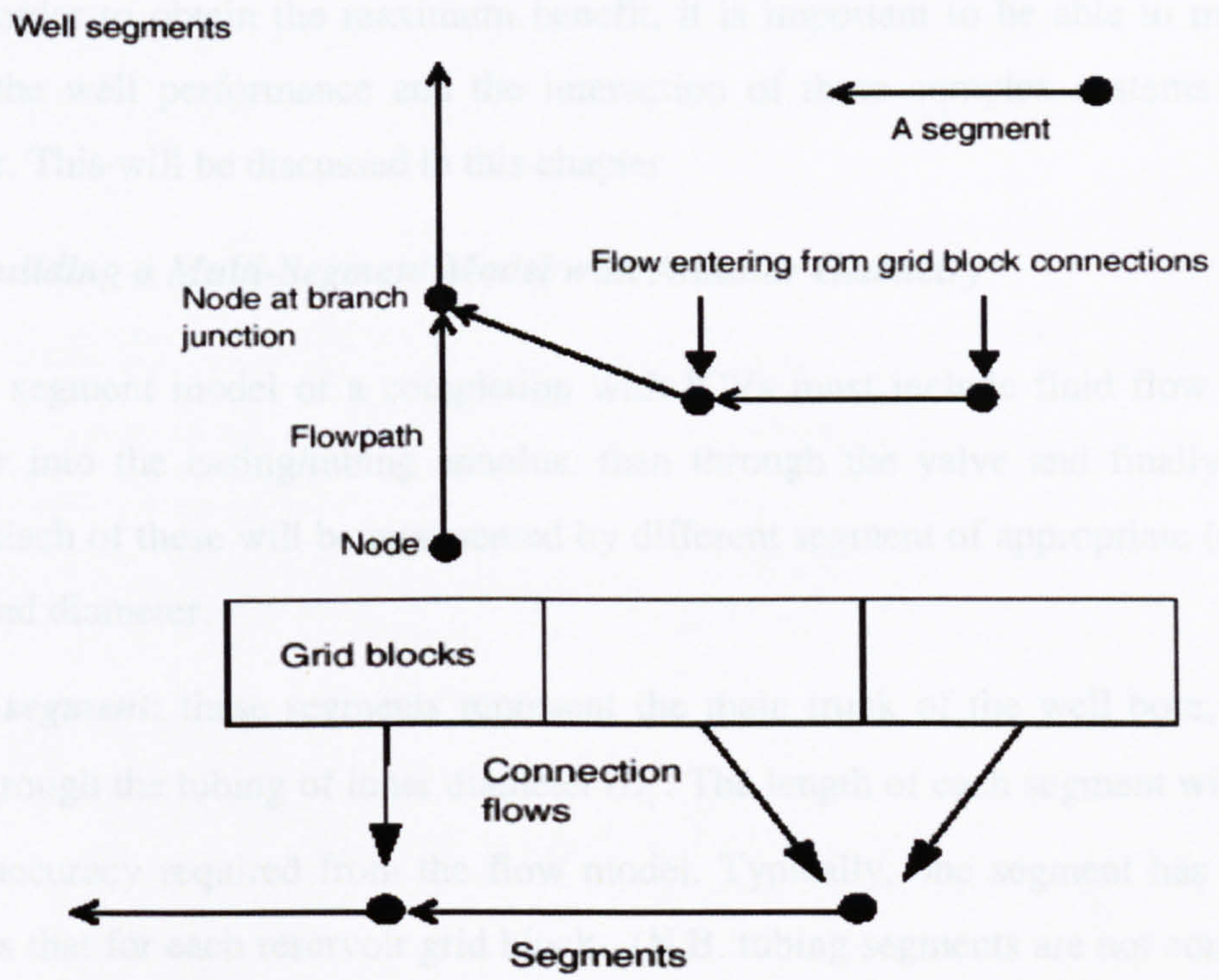

Figure 5-2: Alternative connection flows from the reservoir grid to the segments [1.5, 5.2]

5.3 Modeling of Well Completions with Down Hole Control Valves in production wells

Simulation of wells containing flow control devices requires a detailed well model. This model must be able to determine the phase flow rate and the pressure for each connection along the perforated length. Eclipse^{TM} [1.5] offers five options to model control devices installed within the multi-segment well model.

The down-hole completion system employs isolation packers set between the (well cemented) production liner and tubing or swell packers installed in an open hole. They split the perforated zone into a number of separate zones, allowing independent control of the inflow from each zone. The mechanical installation of this more complex completion is difficult, time consuming and more prone to error than the equivalent conventional completion. Such "intelligent" completions are more expensive to install and, in order to obtain the maximum benefit, it is important to be able to model and predict the well performance and the interaction of these complex systems with the reservoir. This will be discussed in this chapter

5.3.1 Building a Multi-Segment Model with Annular Geometry

A multi segment model of a completion with ICVs must include fluid flow from the reservoir into the casing/tubing annulus, then through the valve and finally into the tubing. Each of these will be represented by different segment of appropriate (different) length and diameter.

Tubing segment: these segments represent the main trunk of the well bore, the flow being through the tubing of inner diameter ID_t. The length of each segment will depend on the accuracy required from the flow model. Typically, one segment has the same length as that for each reservoir grid block. (N.B. tubing segments are not connected to the reservoir).

The Annulus segment: the annulus is divided into a number of sections with the exit being controlled by an ICV. The "equivalent diameter" of the annular cross section, d_{eff}, can be calculated from the outer diameter of the tubing (OD_t) and the inner diameter of the casing (ID_c). The pressure drop in the annulus is calculated from:

$$d_{eff} = \sqrt{(ID_c)^2 - (OD_t)^2} \qquad \text{Equation (5.1)}$$

The Interval Control Valve segment: The ICV segment is the connection between the annulus and the tubing. It is best modelled based on the actual physical properties of the valve; its length is thus equal to the valve's length; as is the diameter and the roughness. The performance of the choke is usually modelled using a Choke Discharge Coefficient (C_V), the value of which is determined by model tests carried out by the manufacturer or operator. A change in the valve segment's property allows the Eclipse™ modeler to reduce or increase the flow across the valve.

Figure 5-3 shows the actual well configuration while Figure 5-4 illustrates how the multi-segment model is used to simulate flow from the reservoir in to the annulus segment and then through the one of the two valve segments into the tubing.

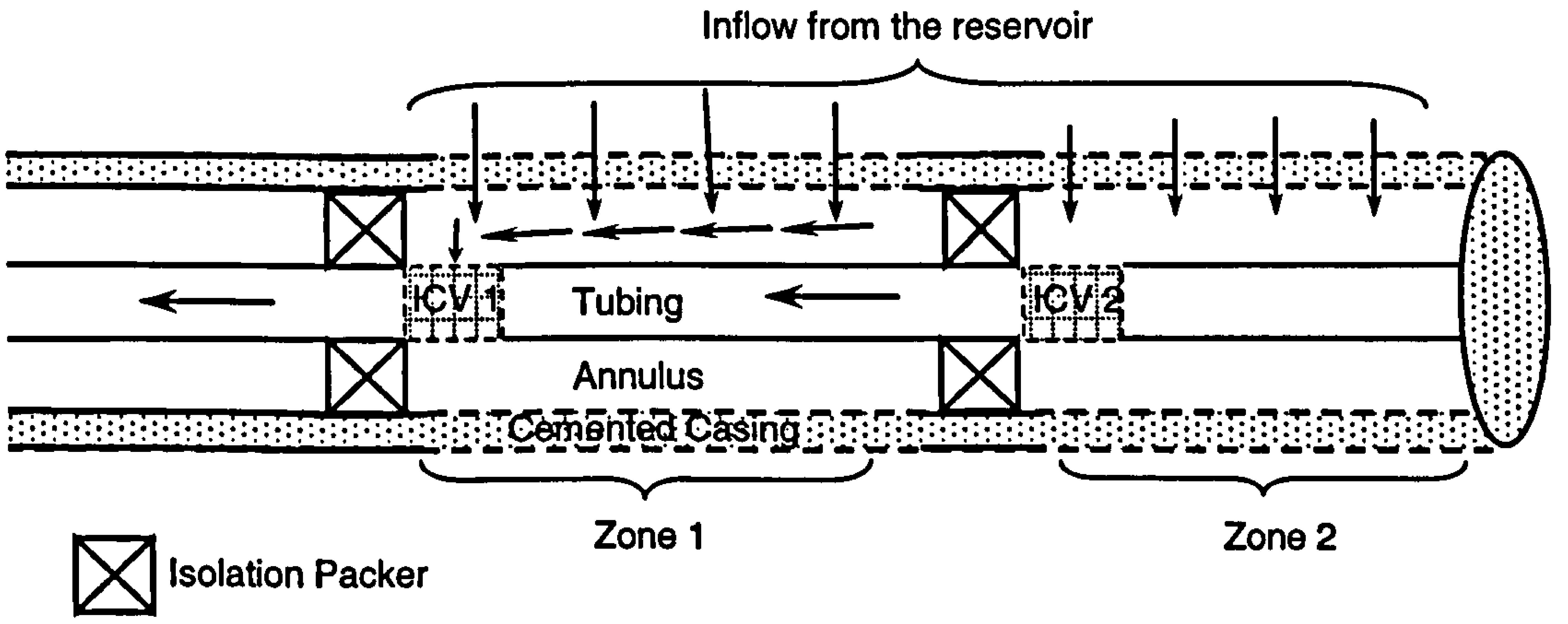

Figure 5-3: The Well Configuration

Figure 5-4 shows the segment configuration number for the above horizontal well when modelled in a three-phase reservoir completed with two ICVs. The wellbore is divided to two separate zones. ICV1 controls the connection between segments 2 and 12 while ICV2 controls the connection between segments 6 and 7.

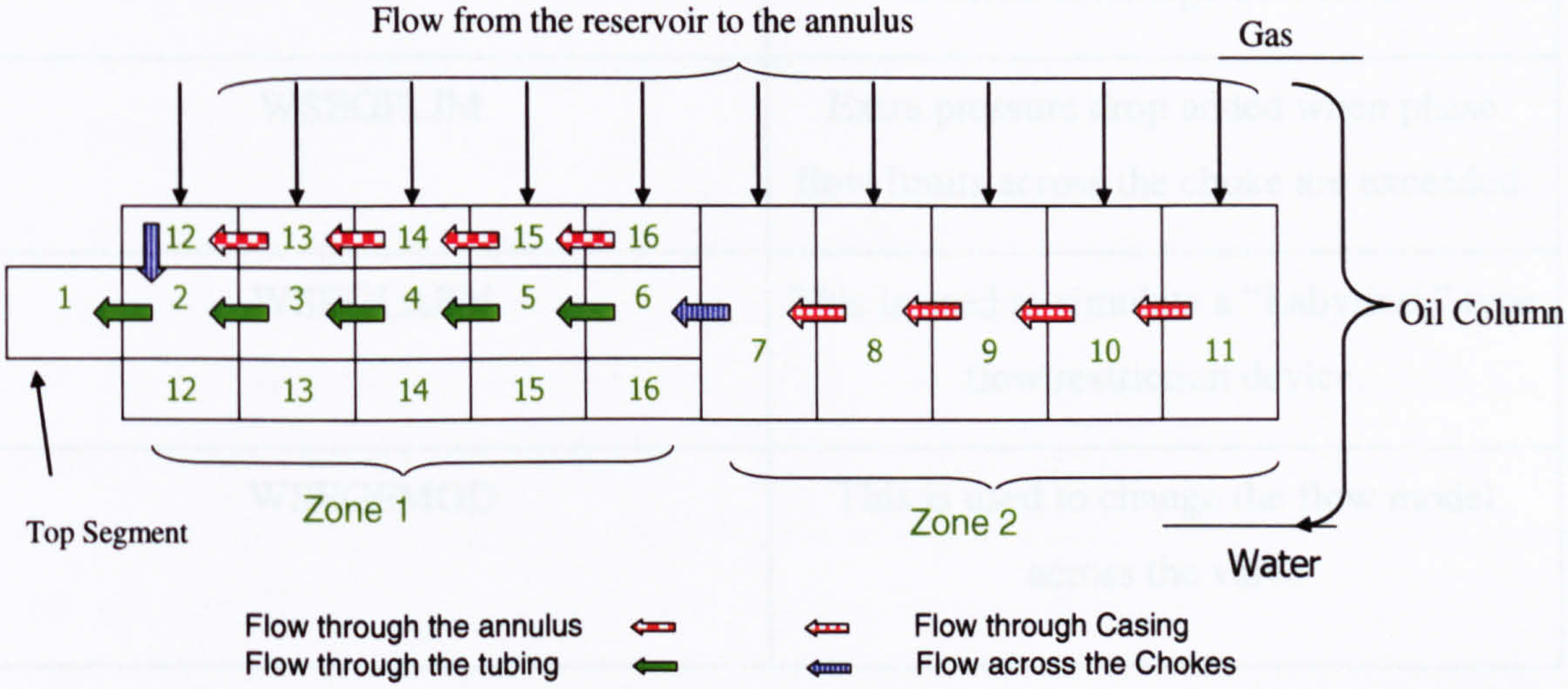

Figure 5-4: Flow connection for a well completed with two ICVs

5.3.2 *Options Available in Eclipse^{TM} to Model Inflow Control Devices*

Table 5-1 summarises the keywords associated with Intelligent Well modelling when using the Eclipse^{TM} reservoir simulation package.

As explained earlier in section 5.2.2 the multi-segment well model uses different methods for calculating pressure drop across each segment - the segment representing the valve is not an exception. Eclipse will automatically use the homogenous model in which there is no slip between the phases if none of these options are specified.

Keyword	Description
WSEGTABLE	The segments will take their pressure drop calculations from a pre-calculated table
WSEGVALVE	A homogenous flow model is used, using a choke discharge coefficient
WSEGFLIM	Extra pressure drop added when phase flow limits across the choke are exceeded.
WSEGLABY	This is used to simulate a "Labyrinth" type flow restriction device.
WSEGFMOD	This is used to change the flow model across the valve

Table 5-1: The keywords available in Eclipse to model ICVs

1. The pressure loss across individual segments can also be obtained from a VFP table (keyword WSEGTABL)
2. The pressure loss across individual segments can also be calculated from a built-in model of a particular flow control device (keywords WSEGVALV, WSEGFLIM, WSEGLABY and WSEGFMOD).
3. Segments not specified in keyword WSEGTABL, WSEGVALV, WSEGFLIM, WSEGLABY or WSEGFMOD, will use the default flow model which is set when defining the segment structure using the WELSEGS keyword.

These five options available within Eclipse 2002 are described in greater detail below:

1. Pressure drops calculations from VFP tables (WSEGTABLE keyword)

This keyword obtains the pressure losses across the valve segment by interpolation within a pre-calculated table. The tables are in the same form as the VFP tables, which have been used for many years to calculate the tubing performance of production wells.

These are entered in the SCHEDULE section with the keyword VFPPROD. These standard VFP tables give the Bottom Hole Pressure (BHP) as a function of the flow rate, the Tubing Head Pressure (THP), the water and gas fractions, and, optionally, the Artificial Lift Quantity (ALQ).

When applied to a well segment, the BHP should be interpreted as the segment's nodal pressure (i.e. the segment's inlet pressure), while the THP should be interpreted as the pressure at the node of its neighboring segment towards the wellhead i.e. the segment's outlet pressure.

The Eclipse™ package of programs uses the program VFPi to produce a VFP table, which can be based on a number of flow performance models. This model incorporates both the critical (when the flow rate is independent of the pressure drop across the choke) as well as the sub-critical flow regime (when the flow rate increases with pressure drop). The effects of varying choke diameter can also be incorporated into the table by use of the ALQ variable. VFPi can thus be used to create a table of pressure losses across several different choke diameters for a range of flow rates and phases ratios. The diameter of the choke is represented by the ALQ variable (in the appropriate units). The selected ALQ definition for this purpose should be 'BEAN'. It is thus possible to model the effects of varying the choke diameter at any time in the simulation by changing the look-up ALQ value of the VFP table (this is the eighth item in the keyword WSEGTABL).

2. Pressure Drops Calculations Using the Built-In Model (WSEGVALV keyword)

This keyword ensures that a specified segment will have its pressure drop calculations made using a built-in model to represent sub-critical flow through a valve with a specified throat cross-section area.

This imposes an additional pressure drop in the segment due to flow through a constriction with a specified cross-sectional area. The pressure drop across the device is calculated using a homogeneous model for sub-critical flow through a pipe containing a choke. The total pressure loss (δP_{total}) across this segment is made up of the sum of two components:

1. The pressure loss across the choke (δP_{choke}) and

2. And that across the pipe ($\delta P_{pipe.fric}$)

$$\delta P_{total} = \delta P_{choke} + \delta P_{pipe.fric} \qquad \text{Equation (5.2)}$$

$$\delta P_{pipe.fric} = 2c_u f \frac{L}{ID_t} \rho v_p^2 \qquad \text{Equation (5.3)}$$

Where:

f is the Fanning friction factor.

L is the length of tubing in the choke segment.

v_p is the flow velocity of the mixture through the choke segment

c_u is a units conversion constant [1.5]

N.B. The valve segment's length is short, hence pressure loss due to acceleration and hydrostatic pressure changes due to changes in elevation can be ignored.

δP_{choke} accounts for the effect of the choke. It is calculated as:

$$\delta P_{choke} = c_u \left(\frac{\rho v_c^{\,2}}{2C_v^{\,2}} \right) \qquad \text{Equation (5.4)}$$

Where:

c_u is a units conversion constant [1.5]

ρ is the density of the fluid mixture

v_c is the flow velocity of the mixture through the constriction

C_v is the (dimensionless) flow or discharge coefficient for the valve. This value is supplied by the valve manufactures.

ID_t is the internal diameter of the tubing into which the choke has been built, is usually less than the diameter of the remainder of the tubing that makes up a multi-segment well e.g. a well is completed with a 6-in ID production liner across the completion interval together with a 9 5/8 OD casing to surface. Typically a 6-in ID tubing would be installed to the surface and 3.3-in ID tubing across the completion interval.

v_c and v_p depend on the respective cross-section areas of the choke and the tubing and the local total volumetric flow rate, Q_m, of the mixture through the segment,

$$Q_m = v_c A_c = v_p A_p \qquad \text{Equation (5.5)}$$

Where A_c and A_p refer to the choke and tubing cross sectional area respectively.

3. Limiting the Flow by Increasing the Segment's Friction Pressure (WSEGFLIM keyword)

A 'flow-limiting valve' is modelled with this option. This device limits the flow rate of oil, water or gas (at surface conditions) through a segment once it reaches a specified maximum value. This is achieved by sharply increasing the frictional pressure drop across the segment for flow rates exceeding the specified limit.

The device can be used to:

1. Limit the production of water and/or gas through a section of tubing
2. Control the distribution of production or injection between the various completion zones or between the branches of a multilateral well.
3. Prevent branch-to-branch cross flow in a multilateral well.

The frictional pressure drop across the segment is calculated as:

$$\delta P_{fric} = \delta P_1 + \delta P_2 \qquad \text{Equation (5.6)}$$

where

$\delta P_1 = A_1(Q_1 - Lim_1)$ when $(Q_1 > Lim_1)$ and $\delta P_1 = 0$ when $(Q_1 < Lim_1)$

$\delta P_2 = A_2(Q_2 - Lim_2)$ when $(Q_2 > Lim_2)$ and $\delta P_2 = 0$ when $(Q_2 < Lim_2)$

The (A_n) terms are coefficients which, if sufficiently large, will provide a steeply increasing pressure drop once the (Q_n-Lim_n) term is positive. The Q_n terms represent the flow rate of the chosen phase (oil, water, gas or liquid) through the segment (for convenience this rate is calculated at surface conditions). The Lim_n terms represent the chosen specified limiting values, representing production flows. It is thus possible to limit the flow of two phases using one valve segment. The pressure drop term is zero if the flow limits are not exceeded {i.e. (Q_n - lim_n) is negative} in all cases. The hydrostatic and acceleration pressure drop components are calculated in the usual way using homogeneous flow model across segment i.e. slip between the phases is not allowed.

An alternative is to assign a negative value to the *Lim* term. The pressure drop term now impedes negative flow when its magnitude increases beyond this limit - it does not prevent positive flows. Thus:

$$\delta P_n = A_n (Q_n - Lim_n) \qquad \text{when} \qquad (Q_n < Lim_n < 0) \qquad \text{Equation (5.7)}$$

Thus negative limits can be used to limit flow in injection well branches, while small negative flow limits can be used to restrict cross-flow in production wells.

4. The Use of a "Labyrinth" to Control the Flow (WSEGLABY keyword)

"Labyrinth" controls the inflow profile along the well by imposing an additional pressure drop between the sand face and the tubing (Figure 5-5). The device essentially acts as a fixed choke for each completion zone.

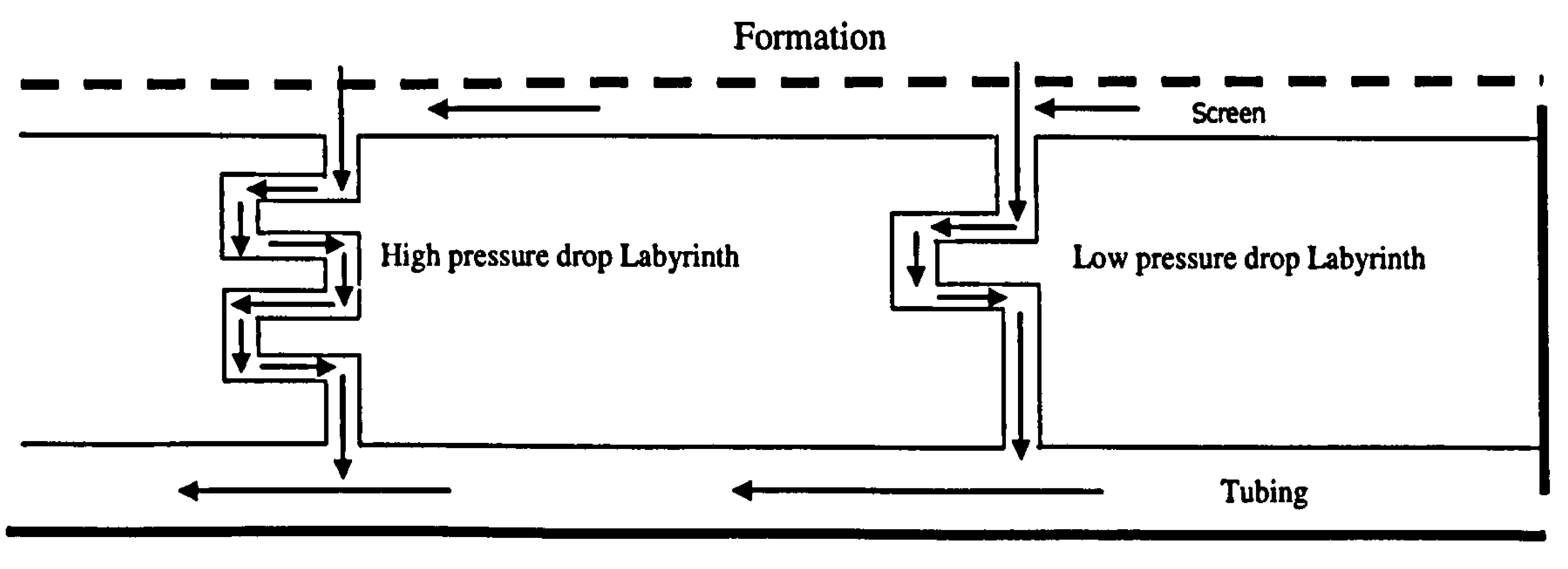

Figure 5-5: "Labyrinth" well configurations [1.5]

The device is placed around a section of the tubing and diverts the fluid flow from the formation into a series of small channels before it enters the tubing. The additional pressure drop that it imposes depends upon the length of the flow-path through the system of channels. This is pre-adjustable at the surface. A series of labyrinth devices with different channel settings can be placed along the length of the well or lateral e.g. to reduce the variation in drawdown along the (horizontal) well. It was initially designed for high rate wells producing low viscosity fluid from very productive formations. It's use is now being extended to more wells producing more viscous oil. This scenario results in the frictional pressure drop along the tubing being significant compared to the draw down across the formation.

The pressure drop across the device is calculated as:

$$\delta P_{total} = \delta P_{form} + \delta P_{fric} \qquad \text{Equation (5.8)}$$

δP_{fric} is the standard expression for the homogeneous flow frictional pressure loss through the channel system,

$$\delta P_{fric} = 2C_u f \frac{L}{ID_l} \rho v^2 \qquad \text{Equation (5.9)}$$

f is the Fanning friction factor.

ID_l is the internal diameter of each channel.

L is the effective length of the channel system

c_u is a units conversion constant [1.5]

δP_{form} accounts for geometric effects and pressure loss through the inlet section of the channel system, (including the pre-packed screen) and the corresponding channel outlet (including the kill filter). It is calculated as:

$$\delta P_{form} = C_u (\gamma_{inlet} + (N_c - 1)\gamma_{labyr} + \gamma_{outlet})\rho v^2 \qquad \text{Equation (5.10)}$$

γ is a dimensionless coefficient for each pressure loss mechanism

N_C is the 'configuration number' of the device, which determines the length of the channel flow-path through the labyrinth

ρ is the density of the fluid mixture

v is the fluid flow velocity of the mixture through the channel

C_u is the unit conversion constant [1.5]

5. Specify the Segment's Multi-Phase Flow Model (WSEGFMOD keyword)

This keyword identifies which flow correlation should be used to model multi-phase flow and in the calculation of the pressure losses within an individual segment. The choices are a Homogeneous Flow Model [1.5], in which all the phases flow with the same velocity, and a Drift Flux Model [1.5], which allows slip between the phases and can result in countercurrent flow (dense and less dense phases flowing in opposite directions) at low flow rates.

5.4 Comparison of different keywords to model choke performance

5.4.1 Difference in modelling the Surface chokes and ICVs

Inflow Control Valves and surface chokes have similar objectives and functions. However, the difference in construction results in different flow behaviour. The major factors influencing the flow behaviour of ICVs are:

1. The flow from the lower intervals (ICVs), which is not present in the surface chokes.
2. The fluid flow path prior to the valve opening. In other words, the influx of fluid from the reservoir has to flow through the annular space between the casing and tubing (or valve outer surface) prior to entering the opening of the ICV. This will introduce some disturbance to the flow.
3. The higher pressure values in the reservoir and wellbore will effect the fluid properties. This, in turn will influence the volumetric flow through the ICV (the determining factor for critical or sub-critical flow).

These effects can be accounted for by varying the C_D (the discharge coefficient) value used in the pressure drop calculation according to the flow conditions.

5.4.2 The Discharge Coefficient C_D

Only two ICV modelling keywords (WSEGVALV and WSEGLABY) allow for direct specification of a specific value for C_D during the simulation modelling itself (this is required for reliable modelling of the ICV behaviour and prediction of the flow rate). C_D can only be specified once in WSEGTABL, when the VFP table is generated, and cannot vary during the simulation run. This might cause errors in the calculated flow rate and the behaviour of the ICV. In contrast, WSEGFLIM does not allow any control over the C_D value.

5.5 Comparison between different keywords

A study was performed [5.2] to compare the different keywords when modelling the choke performances and the behaviour of an ICV. WSEGVALV and WSEGLABY showed similar characteristics to the sub-critical flow behaviour of surface chokes. They allowed for alteration of C_D value and maybe used to simulate sub-critical flow through ICVs.

Use of WSEGTABL showed inconsistent behaviour compared to WSEGVALV and WSEGLABY when simulating sub-critical flow with Sachdeva's model [5.4]. It showed an increasing pressure drop across the ICV with decreasing liquid flow rate. This behaviour can occur in chokes when the cross-sectional area of the constriction is reduced to restrict the flow. The WSEGFLIM keyword maintains the specified (constant) flow rate by continuously changing the frictional pressure drop across the ICV. This can be achieved in real ICVs by continuously altering the cross-sectional area of the valve constriction. (Note that the pressure drop across the valve remains constant as long as the limiting phase flow rate remains constant).

The conclusions and recommendations for which keywords to use were [5.2]:

1. The WSEGVALV and WSEGLABY can be used to simulate a sub-critical flow through ICVs. However, it should be noted that the C_v (C_D) value should be changed in accordance to the ICV opening diameter and to the flow rates. The mechanism of altering C_D should be based on fluid dynamics modelling studies or experiments performed on the ICV.
2. Utilizing Sachdeva [5.4] model in WSEGTABL keyword to simulate sub-critical flow is not recommended due to the inconsistent behaviour of the model and the ability to alter the C_D value.
3. WSEGFLIM keyword can be used to model a continuously adjustable ICV with a previously set flow rate and a critical flow through the ICV.

5.6 Choice of modeling keyword

The Eclipse^{TM} functionality, as explained above, was used for modelling the Intelligent Wells in the generated reservoir models. For pressure drop calculations across the choke, the WSEGVALV keyword was used throughout all simulations for consistency and ease of comparison of the result. This keyword allows exact and detailed definition, modelling and modification of the valve characteristics, which will provide the opportunity to perform a range of sensitivities on the valve characteristics.

5.7 Summary

This chapter showed how the Intelligent Wells can be modeled and the chosen ICV settings applied. The modeling methodology was kept constant throughout the study for ease of comparison of the results.

The next chapter will review a range of techniques which could be applied for the optimisation of Intelligent Wells.

The results of the study for the evaluated models will be discussed in chapter 7.

5.8 References

5.1 Eclipse 100 Reference Manual, GeoQuest (2004a).

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5.3 J.A. Holmes, T. Barkve and Q. Lund.: "Application of Multi-segment Well Model to Simulate Flow in Advanced Wells" paper SPE 50646 presented at the SPE European Petroleum Conference held in The Hague, The Netherlands, 20-22 October 1998.

5.4 R. Sachdeva, Z. Schmidt, J. Brill, and R. Blais.: "Two-Phase Flow Through Chokes", paper SPE 15657 presented at the SPE Annual Technical Conference and Exhibition, New Orleans, LA, October 5–8, 1996.

Chapter 6 Intelligent Wells Optimisation

6.1 Introduction

The technique used for the modelling of Intelligent Wells in the reservoir models for Intelligent Wells application was described in the previous chapter. This chapter starts with a review of a range of techniques available for optimisation of Intelligent Wells and continues with the description of the optimisation capabilities within the Eclipse™ Package [6.1].

6.1.1 How Does Mathematical Optimisation Modelling Work?

The steps to be taken for completing an optimisation problem could be summarised as below:

1. Structure the problem
2. Translate the problem into mathematical language

- There is no specific tool or standard for it and different interpretations/ translations of a problem can result in different answers

3. Select or develop an appropriate solver. Solve the problem

- Solver could be mathematical algorithms or numeric mathematics, however there is no standard approach or tool for it

4. Interpretation and validation

6.1.2 Mathematical Modeling and Optimisation Building Blocks

- Data (Actual Situation and Requirements, Control Parameters)

  e.g., number of sites, unit capacities, demand forecasts,

- model (variables, constraints, objective function)

  e.g., how much to produce, how much to ship, (decision variables, unknowns)

  e.g., mass balances, network flow preservation, capacity constraints

  e.g., max. contribution margin, min. costs, yield maximization

  e.g., NPV, oil recovery, ICV Placement

- Optimisation algorithm and solver

e.g., Simplex algorithm, Sequential Quadratic Programming (SQP), outer approximation...

- Optimal solution (Suggested Values of the Variables)

  e.g., production plan, unit-connectivit, optimum ICV choking...

6.2 Linear & non-linear Optimisation Algorithms

Linear Expressions

Linear optimisation involves expressing the constraints in terms of a series of linear expressions. These expressions are then used to discover the optimal, or best, solution to achieve a given objective. Solution of a problem using linear programming requires the following steps to be performed. These are illustrated below and shown in Figure 6-1.

1. Construct a mathematical model of the problem detailed in Figure 6-1 (this is an essential).
2. Graph the expressions derived from the constraints and plot the area of feasibility ($A>12$, $0<B<20$, $A+B<40$, $2A + B > 40$, $5A + 8B > 160$)
3. Draw the feasibility function (the shaded area in Figure 6-1).

4. Minimise the objective function as follows:

   - Superimpose on the graph a profile line representing the objective function ($C = 25A + 25B$). This has been drawn in Figure 6-1 for C = 400, C = 850 and C = 1000.

   - Draw parallel lines to objective function and identify the minimum of the C value (point K) that falls within the feasibility polygon.

Figure 6-1 presents the above steps. It shows the feasibility polygon which satisfies all limitations. Point K is the minimum value of the objective function that falls within the feasibility polygon minimises the objective function. It correspond to C = 636.

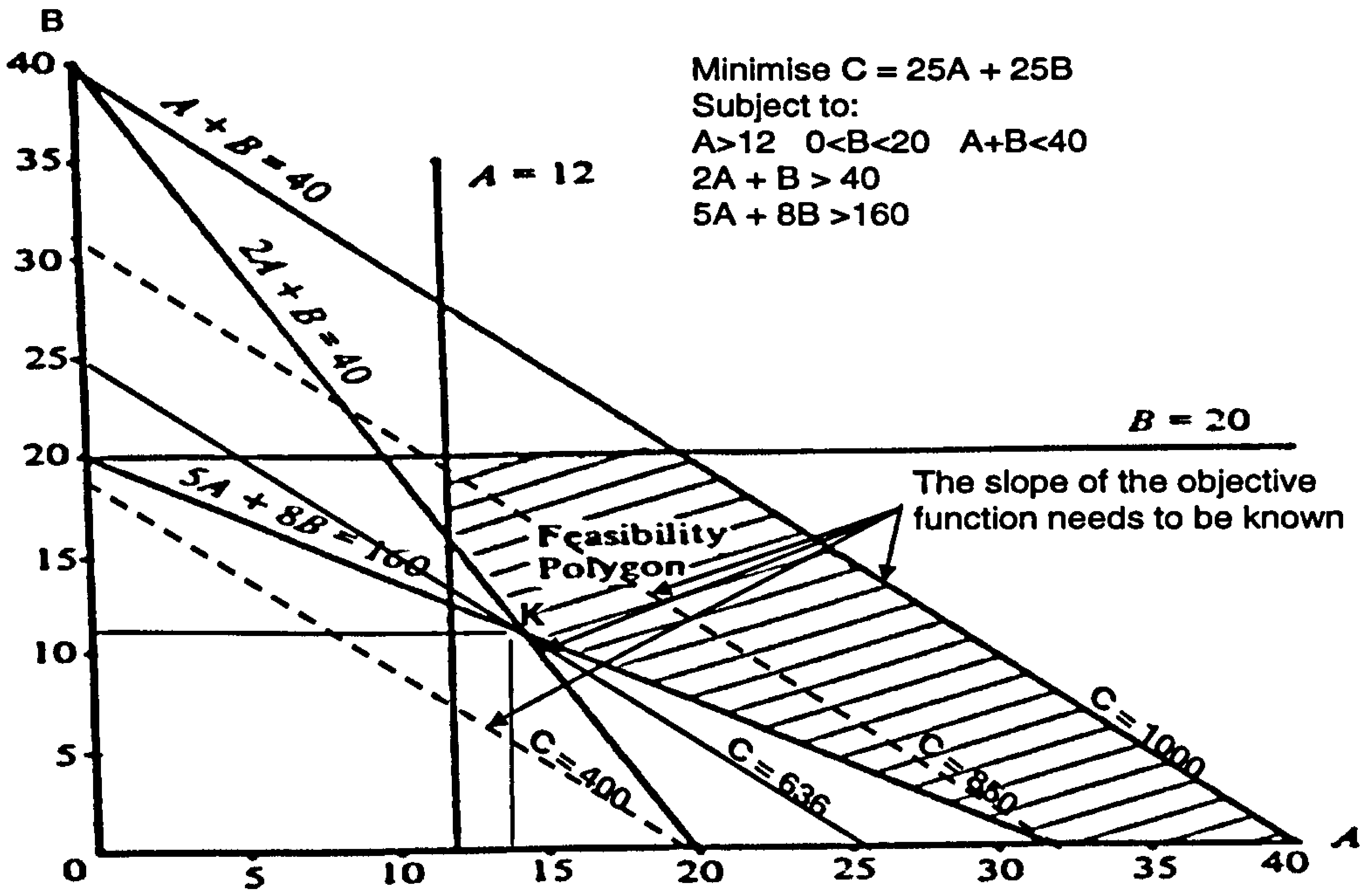

Figure 6-1: Linear Expression of an Optimisation Problem

6.3 Linear Programming: Simplex Method

The Simplex Method applies Detached Coefficients to linear programming. Matrices are used for solving simultaneous equations by applying the rules of row transformation to the entire matrix so as to change the coefficient matrix in to a unit matrix.

This method can not cope with inequalities. I.e. the model needs to be transformed to a system of equalities by introducing extra parameters. The technique is illustrated below.

e.g.: Maximise A= 4x+3y subject to:

$$\left.\begin{array}{r} 4x+y \leq 90 \\ 2x+y \leq 50 \\ x+y \leq 40 \\ x \geq 0 \\ y \geq 0 \end{array}\right\} \text{ becomes } \left\{\begin{array}{l} 4x+y+a=90 \\ 2x+y+b=50 \\ x+y+c=40 \\ x \geq 0, y \geq 0 \\ a \geq 0, b \geq 0, c \geq 0 \end{array}\right.$$

Solving the matrix with the above rules gives the following results:

$$\begin{array}{c} \left[\begin{array}{ccccc|c} 4 & 1 & 1 & 0 & 0 & 90 \\ 2 & 1 & 0 & 1 & 0 & 50 \\ 1 & 1 & 0 & 0 & 1 & 40 \end{array}\right] \\ \begin{array}{cccccc} \uparrow & \uparrow & \uparrow & \uparrow & \uparrow & \uparrow \\ x & y & a & b & c & \text{Quantity} \end{array} \end{array}$$

6.4 Gradient Methods, Non-linear Programming

Many problems can not be formulated as linear equations, Non-linear techniques being then required. The function to be optimised can be considered as a surface in three dimensional space. Gradient methods (first & second order) often use to identify the gradients and to drive search direction towards a minimum or maximum point. Techniques to avoid being trapped in local rather than global minima (Figure 6-2) are required. Further Petroleum Engineering variables are often poorly defined. It then becomes necessary to carry out sensitivity studies employing (all combinations) of possible ranges for these variables. This becomes a very time consuming, and computer intensive operation.

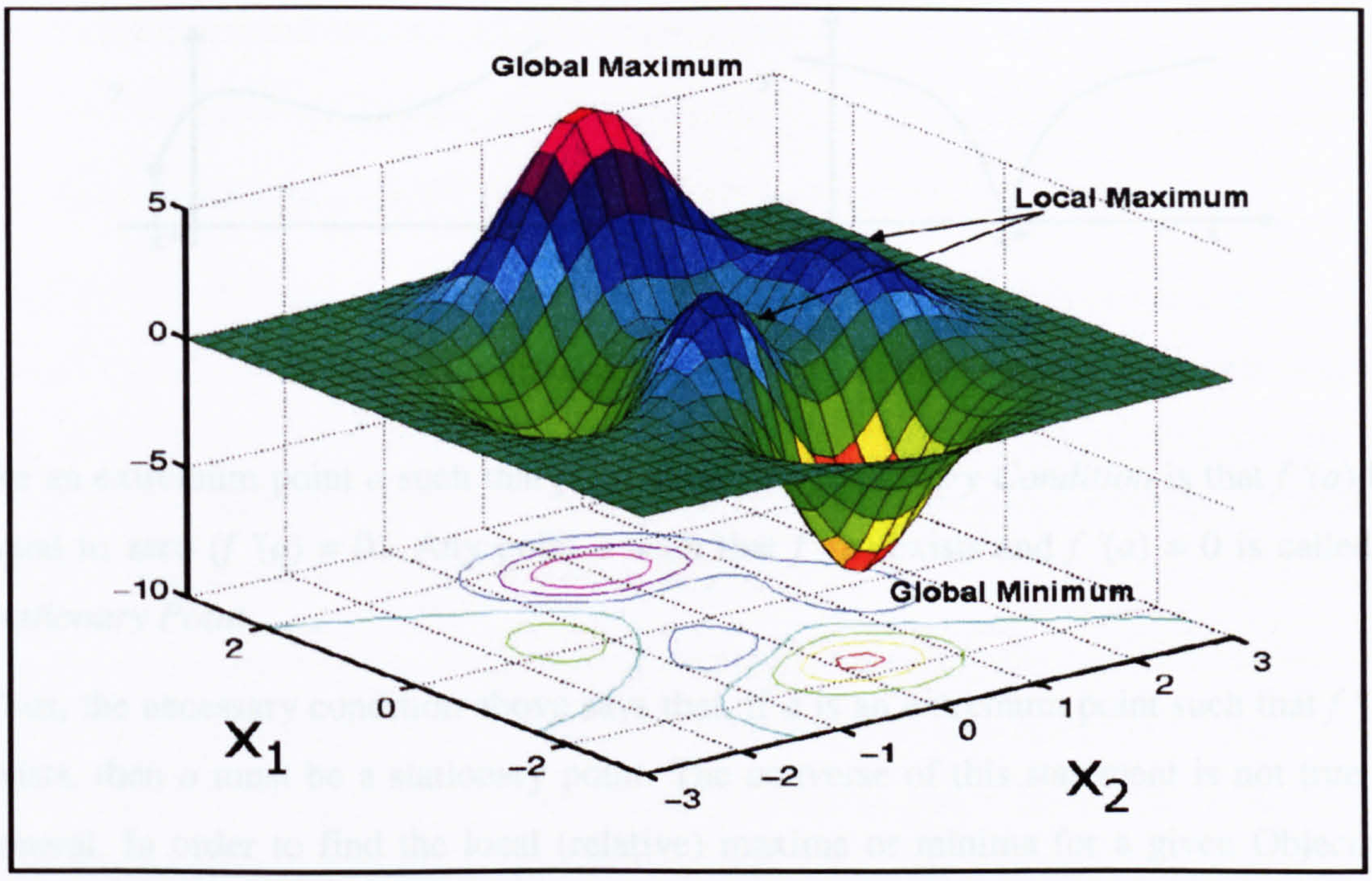

Figure 6-2: Local & global minimum and maximum of a function [6.3]

6.4.1 Basic concepts of gradient optimisation

f(x*) is said to be the global (absolute) maximum of f if f(x*) ≥ f(x) for all x in the domain of f. Two examples are shown in Figure 6-3.

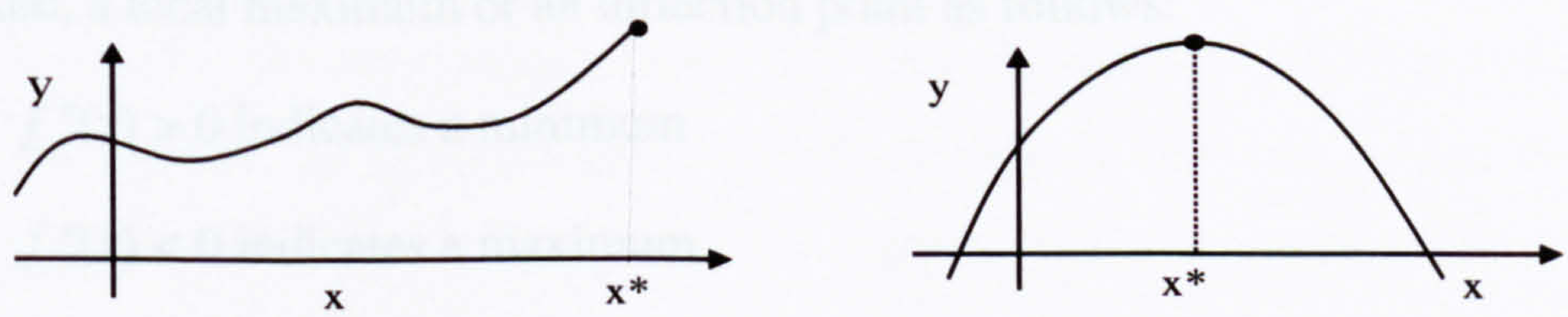

Figure 6-3: Global maximum is x*

Conversely, f(x*) is said to be the global (absolute) minimum of f if f(x*) ≤ f(x) for all x in the domain of f. (see Figure 6-4 for two examples)

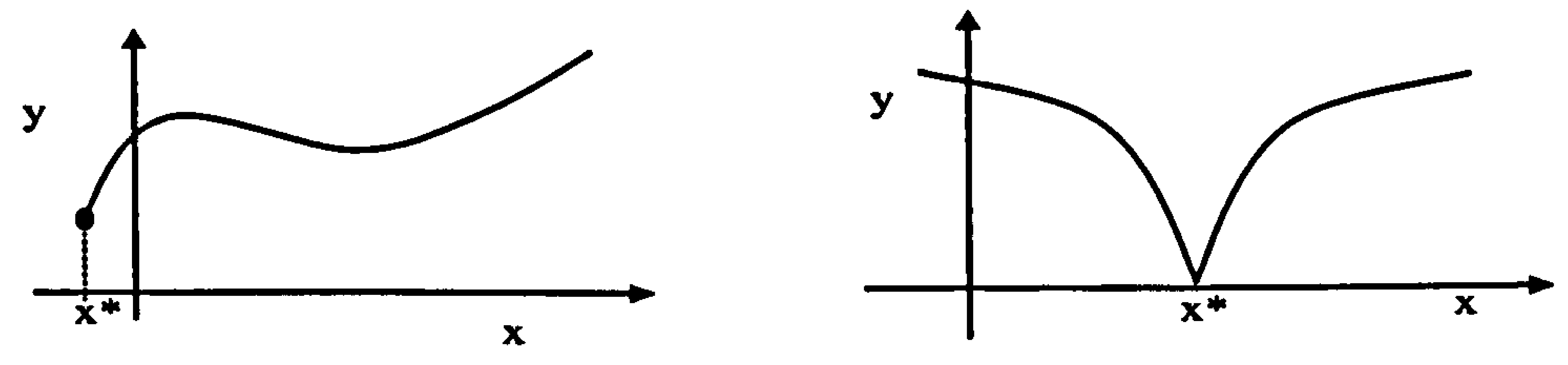

Figure 6-4: Global minimum is x* in these graphs

For an extremum point a such that $f\,'(a)$ exists the *Necessary Condition* is that $f\,'(a)$ be equal to zero ($f\,'(a) = 0$). Any point a such that $f\,'(a)$ exists and $f\,'(a) = 0$ is called a *Stationary Point.*

Thus, the necessary condition above says that, if a is an extremum point such that $f\,'(a)$ exists, then a must be a stationary point. The converse of this statement is not true in general. In order to find the local (relative) maxima or minima for a given Objective Function, f, (assume scalar functions f of one variable). Function f is *Unconstrained* when any $x \in R^3$ is acceptable whereas it is *Constrained* when minimize f on a subset of space .

The condition for a minimum or maximum of a function is that the first derivative ($f\,'(x) = 0$). The sign of the second derivative then determine whether we have a local minimum, a local maximum or an inflection point as follows:

$f\,''(x) > 0$ indicates a minimum

$f\,''(x) < 0$ indicates a maximum

$f\,''(x) = 0$ indicates an inflection point

Search procedures often find local minimum rather than the global minimum, since this can be hard to find, depending on where the search algorithm starts from. One option is to find as many local minimum as possible and then to compare their values to find the global minimum.

The basic concepts of gradient optimisation are well developed. The oil industry literature refers to the use of many different techniques, such as Newton-like & Quasi-Newton Method, Linearization Method and Optimal Algorithms (Optimal Control

Theory), these have been used for optimisation of sweep efficiency, enhanced oil recovery and many other applications.

6.5 Sequential Linear and Quadratic Programming

As with all optimisation techniques, a mathematical model (MM) of the system to be solved has to be constructed. MM consists of a number of equations and inequalities that encompass the solution of the process and incorporates the constraints and the objective function. The latter identifies the process to decide which solution to return to if more than one solution fulfils the constraints.

The methodology proceeds iteratively and builds a linear approximation to the original mathematical model (the proxy model). It also measures how well the solution to the linear approximation fulfils the non-linear constraints and whether the value of the objective function has stopped changing (this latter is a convergence check).

The main weakness of the Sequential Linear Programming (SLP) technique is that a linear approximation may be a poor description of the full model of the system if the full model is highly non-linear. I.e. there is a large error between the exact solution of the full equations and the linear "guesstimate" derived from the proxy model.

Experience, shows that SLP can be sufficient for well & choke performance model analysis as these are often second order equations. Sequential Quadratic Programming (SQP), by contrast assumes the existence of continuous first and second derivatives. SQP is thus more exact than SLP, but the resulting equations are more difficult to solve.

Example: Use of the Quadratic Gradient approach for Intelligent Well Optimisation

There are only two directions in which any valve setting can move; the ICV used in an Intelligent Completion can then be either incrementally opened or incrementally closed.; hence the gradient information basically provides this direction. The nature of the problem thus suggests use of a gradient based optimisation algorithm.

The problem can be defined mathematically as: $\max f(x),\ 0 < xi < 1$

Where f is the objective function and x is the valve setting at time i between 0 (valve fully closed) and 1 (valve fully open).

For each time period i, the device settings are optimised for the remaining simulation period. The gradient vector is calculated repeatedly until the entire simulation period is covered.

6.6 Search methods

Direct solution of the complex objective functions is not possible. Therefore, search methods are employed to identify the optimum value with a minimum number of computations. It minimises the optimisation criterion based on the information about the criterion itself. They are useful for simple cases with few parameters; however, more complex cases require many iterations. Computation time will rapidly increase unless a refined procedure is used to target the calculation around the optimum value. Such procedures will set up an initial search of the parameter space and look for good data-fit regions (Figure 6-5 a). One search method, the Neighbourhood Search Algorithm [6.4], then selectively samples the good data-fit regions and generate refined models in these regions (Figure 6-5 b). This is subsequently further refined to identify areas of optimum values (Figure 6-5 c & d).

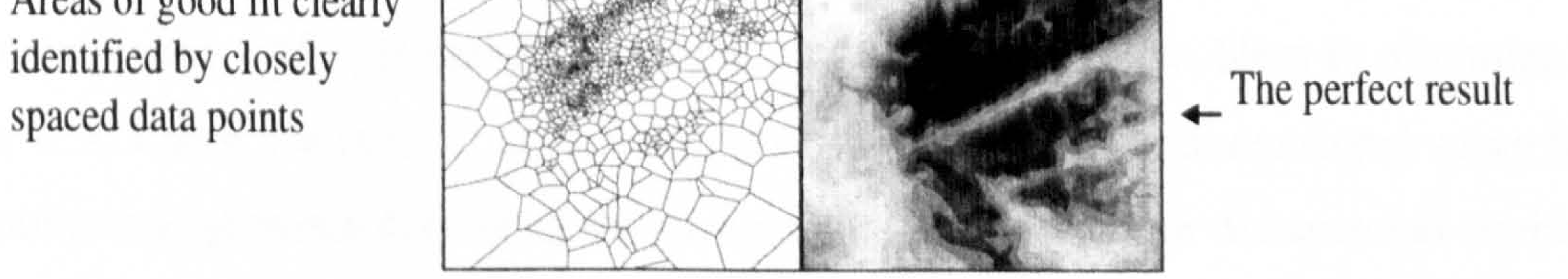

Figure 6-5: The process followed by the Neighbourhood Search Method [6.4]

6.6.1 *Mathematical Background for Search Methods*

The function f is unimodal, if there exists some x* (to be identified) such that f(x) is strictly decreasing in x for x < x*, and strictly increasing in x for x > x*. The point x* is then both the unique local and the unique global minimum [6.2].

Let us assume that the problem P is defined by P: minimize f(x) in $x \in [a; b]$. Note that the possibility that f is either increasing or decreasing over the entire interval [a; b] is allowed. In such a case the minimum solution, x*, will occur at a or b. The more usual possibility that x* is some interior point within the interval [a; b] is also allowed. We have not required f to be differentiable and no gradient information is required.

The basic idea behind search methods is illustrated as follows:

Suppose that, at any stage, we know that the minimum x lies in some interval [x1; x2] contained within [a; b]. Choose two further points x3, x4 within this interval such that x1 < x3 < x4 < x2. If f(x3) ≤ f(x4), it follows from the unimodality of f that x* necessarily lies within the interval [x1; x4], while if f(x3) ≥ f(x4), it similarly follows that x* necessarily lies within the interval [x3; x2].

In both these cases we have narrowed our search to a smaller interval. Also we have already evaluated the function f at a point in the interior of this interval. Thus, starting with the interval [a; b], we may proceed iteratively to home in on x* with just one new function evaluation being required at each iteration [6.2].

We will now extend these ideas to Multi-dimensional Optimisation.

Assume the multi-dimensional unconstrained minimization problem P: minimize f(x) in $x \in X$ where x = (x1,.......,xn) and where X is a subset of n-dimensional space R^n. The numerical problem here is much harder than that for the one dimensional problem we described above. Indeed, nearly all algorithms take for granted the ability to perform a line search, i.e. to find the minimum of the function f in any given direction within the region X. The procedures for solving these problems again work best when the objective function f is unimodal with respect to movements in all such directions (as defined in previous section) and has a unique global minimum. The complexity of the optimization increases rapidly with the number of dimensions, **n**, of the problem.

These are analogous to the simple search procedures used for one-dimensional problems. Again, there is no need for **f** to be differentiable, the function, f(x), and no gradient information is required. Solutions to this type of problems require further assumptions and wider search space. One example is the Nelder-Mead simplex method, on of the most commonly used techniques. It uses the same search method concept as those described above.

6.7 Stochastic methods

The search direction in stochastic methods is determined by a random number generator in combination with a stochastic strategy based on the weighting of the parameters for the object function. Examples of stochastic methods are Genetic Algorithms and Neural Networks. This method does not require calculation of the gradient, however many iterations are needed to find the solution. This can be computationally expensive.

6.7.1 Simulated Annealing

Simulated Annealing [6.5] is a solution technique in which a Monte Carlo simulation is used to find the most stable orientation of a system. Their method mimics the procedure used to manufacture the high-strength glass. The glass is heated to a sufficiently high temperature so that it becomes a liquid i.e. molecules that make up the glass can move relatively freely. The temperature of the glass is then lowered sufficiently slowly so that at each temperature glass molecules can adopt the most stable orientation. The atoms are then able to "relax" into the most stable orientation if the glass is cooled slowly enough. This slow cooling process is known as *annealing*, here the method is known as Simulated Annealing.

For our purposes the “high temperature” can be simulated by incorporating a large percentage of random steps within the process. This percentage of random steps is reduced as the temperature is lowered.

A Simulated Annealing optimisation starts with a Monte Carlo simulation at a high temperature. This means that a relatively large percentage of the random steps that result in an increase in the energy will be accepted. After a sufficient number of Monte

Carlo steps, or attempts, the temperature is decreased. The Monte Carlo simulation is then continued. This process is repeated until the final temperature is reached.

6.8 Genetic Algorithms

Genetic Algorithms (GAs) are computer-based random search techniques based on natural evolution [6.5]. GAs are a stochastic technique, but they differ in fundamental ways from other stochastic optimisation methods. Monte Carlo methods use an unguided, random search while the individuals in the population guide the genetic algorithm search. GAs have the ability to make radical jumps in the search space if they improve the fitness of an individual, while simulated annealing makes only incremental moves in the search space.

Gradient based optimisation methods e.g. SLP or SQP are typically based on the "hill climbing" methodology. The direction of search towards a maximum or minimum is defined by the direction of steepest ascent or descent toward a maximum or minimum respectively. The drawback of this type of approach is its tendency to become trapped in a local minima. GAs avoid this by using a randomised search procedure rather than deterministic rules. Therefore the possibility of becoming trapped in a local minima is less than with other techniques [6.6].

GAs have been used for a wide range of search and optimisation problems. They can solve the optimisation of complex and noisy objective functions, which present difficulties to traditional optimisation methods.

Another important advantage of GAs is the capability of handling many parameters. E.g. full-field reservoir simulation models requires the estimation of many parameters with resulting huge computational cost. GAs also work with a population of solutions rather than only one solution, making them suitable for parallel computing.

Complex formulations and numerical calculations used by steepest descent or other optimisation methods often cause convergence errors making them difficult to implement. GAs use comparatively simple calculation techniques, making them easier to implement than some other techniques. However, they do require a careful design for encoding of variables, selection of individuals, deciding what operators are applied and how the offspring enter the population.

GAs also have been described as having an internal memory since they make use of all previous iterations. This is particularly important when the misfit (difference between the actual value and the estimated value) function is expensive to evaluate; as is the case for reservoir history matching. They have been shown to have the potential to find an ensemble of models that sample the good data-fitting regions of parameter space. This is the main reason that GAs have become popular for uncertainty quantification.

A simple GA works by randomly generating an initial population of solutions (a generation), then moves from one generation to another by breeding new solutions. The traditional breeding process involves objective function evaluation and three operators; reproduction, crossover and mutation. Reproduction copies an individual from one generation to the next, crossover combines features from two or more parents to produce one or more children and mutation makes small local changes.

GAs have been applied to a wide range of petroleum engineering problems e.g. pipeline optimisation, porosity and permeability predictions and seismic waveform inversion and, more recently, they have been involved in the problems, which require generation of multiple history matched reservoir models. Table 6-1 compares different optimisation algorithms.

Method	Description	Example algorithms	Strength	Weakness	Applications
Stochastic methods	Search direction is determined by random number generator combined with a stochastic strategy based on the value of the object function.	Simulated Annealing Evolutionary algorithms (genetic, neural networks)	No gradient calculation Parallel computing Non–smooth objective functions Avoids local minima.	Many iterations (computationally expensive) Training of network	Sasim (GSlib)
Search methods	Minimise the optimisation criterion based only on information about the criterion itself	Nelder-Mead Simplex, Hooke-Jeeves, Implicit Filtering	No gradient calculation Good when gradient is inaccurate	Slow, many iterations	Simple case with few parameters
First order (gradient)	Uses gradient to drive search direction (often with approximation to 2nd derivative – Hessian matrix)	Steepest descent Quasi-Newton methods Gauss-Newton Levenberg-Marquardt (LM)	Sensitivity (gradient information) is valuable. Good convergence	Steepest descent slow to converge Generating sensitivity parameters is time consuming	Parameter estimation, history matching for rock and fluid properties
Second order	2nd derivative calculated at each iteration	Newton method	Fast convergence	2nd derivative cannot be calculated numerically	Function optimisation
Constrained optimisation	Design must fulfil additional constraints	LM (Gauss-Newton + trust region)	Smooth optimisations with 1st derivative	As 1st and 2nd order problems	History matching

Table 6-1: Comparison of different Optimisation Techniques [6.3]

6.9 Manual optimisation approach adopted

A review of the optimisation techniques indicates the need for the proper application of optimisation techniques and, therefore, dependency of the results of the analysis on the applied optimisation technique. The techniques explained above, have been used for optimisation of Intelligent Wells by several authors [6.9, 6.10, 6.11], however the nature of the ICV optimisation problem is mainly a gradient optimisation. Work is going on the automatic optimisation of ICVs using improved gradient techniques (adjoint, etc).

In this study, in order for better understanding of the underlying parameters affecting the added value from Intelligent Wells and also due to the lack of a reliable automatic optimiser for setting of ICVs at the time of study, the available manual optimisation techniques in the Eclipse™ package were used. However, it was found to be a time-consuming process and required testing many ICV settings in order to find the optimum policies.

Though the optimum ICV setting(s) calculated on the basis of the manual optimisation might not be the absolute optimum, however, it was judged suitable for the purpose of this study. It is planned that the ICV action will be optimised and compared in a similar manner. Determining the absolute optimum "Added Value" was not the objective of this study.

6.10 ICV Setting Optimisation in Eclipse Package

Reservoir simulation is used to evaluate the field performance over a number of years. In the real world, each production zone can be controlled from the surface by monitoring the zone's phase flow. Adjustments are made to the valve setting at regular intervals, either based on measurements made by pre-installed sensors monitoring that particular zone's performance or by estimating the zone production by shutting all the zones sequentially and evaluating the changes in total well flow rate. The aim is to achieve the same effect within the Eclipse™ simulation by optimizing the valve setting so as to increase oil production and decrease the produced water and gas (i.e. increase production rate and, hopefully, total recovery).

6.10.1 Using of the WECON Keyword to Simulate an On/Off Valve

The WECON keyword acts as an On/Off choke. It can be used to shut off a single reservoir/well connection or group of connections when their production exceeds a specified limit. This approach is not optimum, if one wants to re-open that connection again or if one only wants to choke the flow back to certain limit and does not want to close the connection completely.

This keyword was originally developed for use with an Eclipse™ conventional well model (i.e. without the multi segment well option). It allows the user to specify a limit (e.g. maximum water cut) for the well or for the reservoir/well connection. The simulator will automatically take action if the well or the connection exceeds this limit. This action also has to be specified. A number of actions are possible. For example, if the well water cut exceeds the specified value, then the highest water cut reservoir/well connection will be shut in. This keyword can be used in conjunction with the COMPLUMP keyword so that a group of reservoir/well connections will all be shut in at the same time i.e. simulating several reservoir/well grid blocks forming the zone controlled by a particular ICV.

WECON keyword is thus easy to use; however, the chosen segment is fully closed (On/Off effect only, no progressive choking and no re-opening in the same run).

6.10.2 Use of ACTIONS Keyword to Set up Valve Setting Rules

This keyword allows the user to set up rules for the segment representing the valve using one of the triggering conditions in Table 6-2. The specified "Action" will take place if the segment exceeds this limit. This "Action" changes the segment's properties, using one of the valve modeling keywords described earlier. It is also possible to specify the time that these actions should be carried out e.g. once per month.

1. WSEGTABLE allow the user to change the valve setting based on the choke size used in the VFP table.
2. WSEGFLIM or WSEGMULT can be used to apply extra pressure drop on the segment representing the valve.
3. WSEGVALVE can be used to choke back the segment representing the valve by changing the cross sectional area of the segment.

"Action" keywords were widely used throughout this study for optimisation of ICV setting. It allowed easy comparison and evaluation of the results on a similar basis.

Keyword	Description
SOFR	Segment oil flow rate
SWFR	Segment water flow rate
SGFR	Segment gas flow rate
SGOR	Segment gas oil ratio
SOGR	Segment oil gas ratio
SWCT	Segment water cut
SWGR	Segment water gas ratio
SPR	Segment pressure
SPRD	Segment pressure drop
SOHF	Segment oil holdup fraction
SWHF	Segment water holdup fraction
SGHF	Segment gas holdup

Table 6-2: The quantity to which the triggering condition applies

6.11 Summary

This chapter showed how the performance of Intelligent Wells can be optimised. The available optimisation methodologies were surveyed and the decision made to use manual optimisation techniques throughout the study for ease of comparison of the results.

The results of the study for the evaluated models will be discussed in the next chapter.

6.12 References

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Chapter 7 The Performance of Intelligent Wells in a variety of Reservoir Types

7.1 Introduction

This chapter will describe the evaluation procedure and the results of the analysis performed on a wide range of reservoir scenarios that were built and tested to determine if IWsT adds value compared to standard well completions.

Situations in which IWsT proved particularly successful will be identified. Lessons learned will be used to develop a selection criterion for improved implementation of IWsT in the next chapter. The results of this chapter will help to identify the optimum optimisation technique for each reservoir type.

The study was based on the premise that some reservoir types are inherently more suitable for IWsT than others. Glandt [7.1] identified well and reservoir opportunities where IWsT can potentially "Add Value". This thesis will be looking at the "Value Drivers" for some of these scenarios in greater detail.

7.2 Methodology

A range of reservoir models, built using IRAP-RMS and Petrel standard industry software packages, were used as the basis for simulation studies of the following reservoir scenarios:

1. A uniform permeability, single reservoir (Figure 7-2)
2. Multiple, stochastic realisations of a heterogeneous, single reservoir without faulting or reservoir dip (Figure 7-4)
3. A faulted reservoir with transmissive and sealing faults and a range of Oil-Water contacts and Reservoir Pressures (Figure 7-6)
4. Multiple deterministic and stochastic realisations of heterogeneous, inclined and layered reservoirs with a range of dip angles (Figure 7-11 and Figure 7-15)
5. A channel sand reservoir (Figure 7-26 & Figure 7-27)

All reservoir models were 2-3 km in the X direction, 1-1.5 km in the Y direction and 30-80 m in the Z direction. Simulation grid dimensions were 50 m*50 m*1 m in the X, Y and Z directions respectively. The permeability distribution was chosen so as to be representative of appropriate real reservoir cases. The two phase (oil + water) relative permeability curves assigned to each grid cell were related to the cell's absolute permeability on the basis of the following formulas [7.2].

$$S_n = \frac{S_w - S_{wc}}{1 - S_{or} - S_{wc}}, \qquad k_{rw} = c_3 S_n^{e3},$$

$$S_{wc} = c_1 + m_1 \log_{10}(k_{abs}),$$

$$S_{or} = c_2 + m_2 \log_{10}(k_{abs}), \qquad k_{ro} = c_4 (1 - S_n)^{e4},$$

Relative k Parameters	Water-Wet	Intermediate-Wet	P_c Parameters	Water-Wet	Intermediate-Wet
c_1	0.6	0.6	c_5	3.0	3.0
m_1	-0.165	-0.165	c_6	0.0	-2.0
c_2	0.3	0.3	e_5	0.0	0.4
m_2	0.0	0.0	e_6	0.6667	0.6667
c_3	0.3	0.4	e_7	1.0	0.4
e_3	3.0	3.0	e_8	1.0	0.6667
c_4	0.85	0.85	S_1	1.0	0.55
e_4	3.0	3.0	S_2	1.0	0.56

Table 7-1: Values of the parameters for defining the relative permeability and capillary pressure curves

The majority of the studies involved realatively stable displacement of the oil by the water (oil/water viscosity ratio $\approx$ 1.3) i.e. any uneven fluid front development was due to geological heterogeneity only. An active analytical aquifer was also connected to the reservoir model to provide pressure support.

In the simulations, fluid was produced from the reservoir models by a long horizontal well placed in the centre of the model in X and Y directions and near top in the Z direction, the well's position being kept constant for all reservoir types. ICV(s) were mainly placed in the high permeability areas of the wellbore [7.3]. The well was completed either with or without IWsT and the results compared. The well model was built using the multi-segment option available in Eclipse™ commercial black oil simulator [7.4]. Figure 7-1 is a schematic diagram of a three-zone, well completion discussed in the previous chapter.

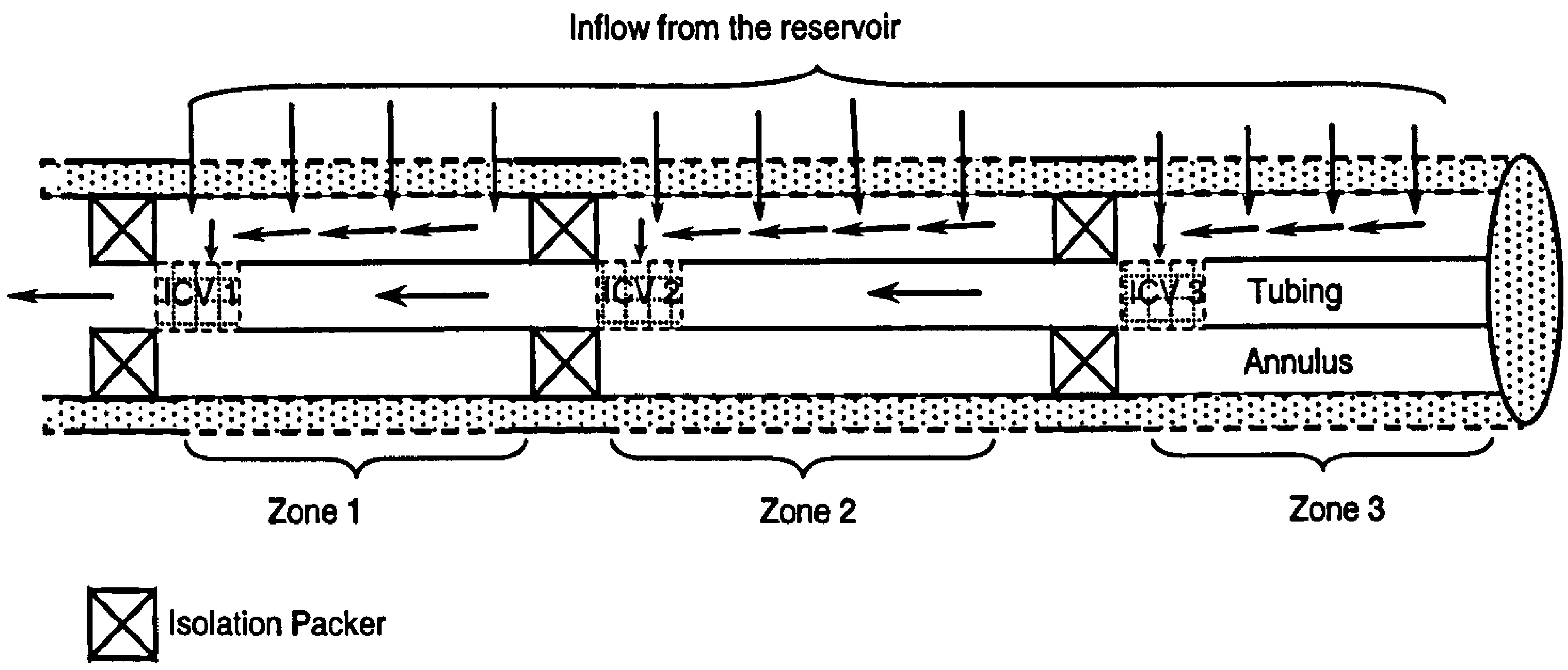


Figure 7-1: The typical intelligent well configuration

Manual optimisation techniques, [7.5] have been applied to control the ICVs. The active aquifer maintained reservoir pressure to a sufficiently high value that ICV control of the fluid front was possible throughout the simulation period. Performance of the well with and without IWsT has been compared as a function of the reservoir type. The "Added Value of IWsT" was based on any increase in the model reservoir's cumulative oil production with a managed IWsT completion. This value was compared with production from an equivalent well with the ICV in the fully open position i.e. to simulate a completion with the same tubing geometry (the difference in oil production for the case of fully open ICV and the case with no ICV was insignificant). Complex value criteria and detailed well design optimisation studies were not considered so as to simplify the above comparison and allow better understanding of the role of the underlying parameters affecting the performance of the Intelligent Wells (the "Value Drivers").

7.3 Analysis of results with respect to Reservoir Type

7.3.1 Constant Permeability Reservoir

Installing ICVs in a homogeneous model (Figure 7-2) can delay early water breakthrough and increase the well's producing lifetime. In the simulation runs, oil recovery was increased and water production reduced by optimum ICV operation (choice of ICV choke diameter). Table 7-2 summarises the reservoir properties used in the homogeneous models based on the real field data and Table 7-3 summarises the simulation results for this reservoir model. Figure 7-3 is an example of the main, identified source of "Added Value" for this reservoir type. The IWsT-enabled well continues producing while the well without ICV(s) dies due to inadequate tubing performance. The improved tubing performance due to management of the water influx allows the well to remain on production longer, recovering more oil. This value could be further increased when the field water handling limitations have been reached. Similarly, value can be achieved by limiting gas production when the producing gas-oil-ratio has to be constrained to maximum value.

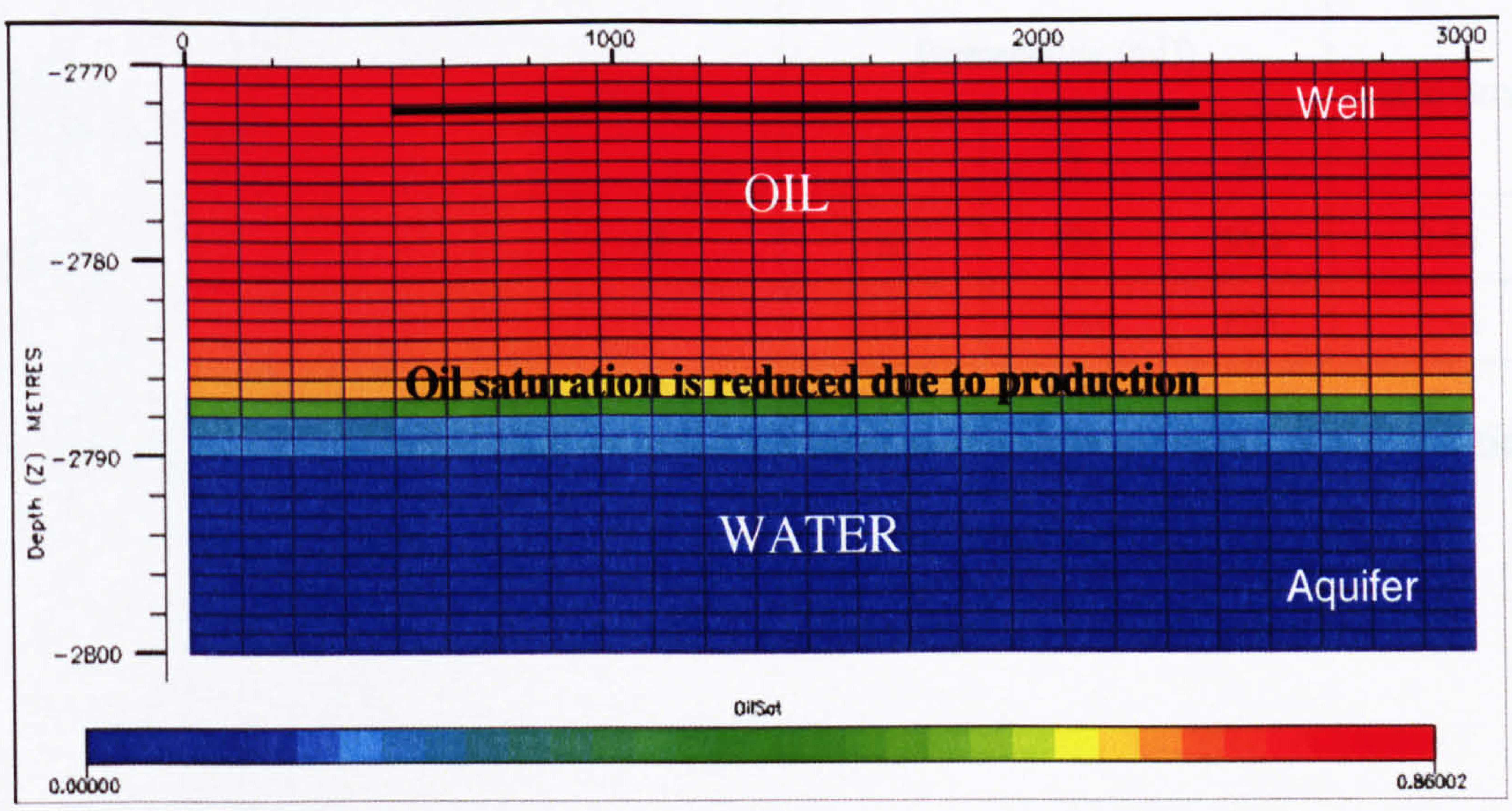


Figure 7-2: A homogeneous model

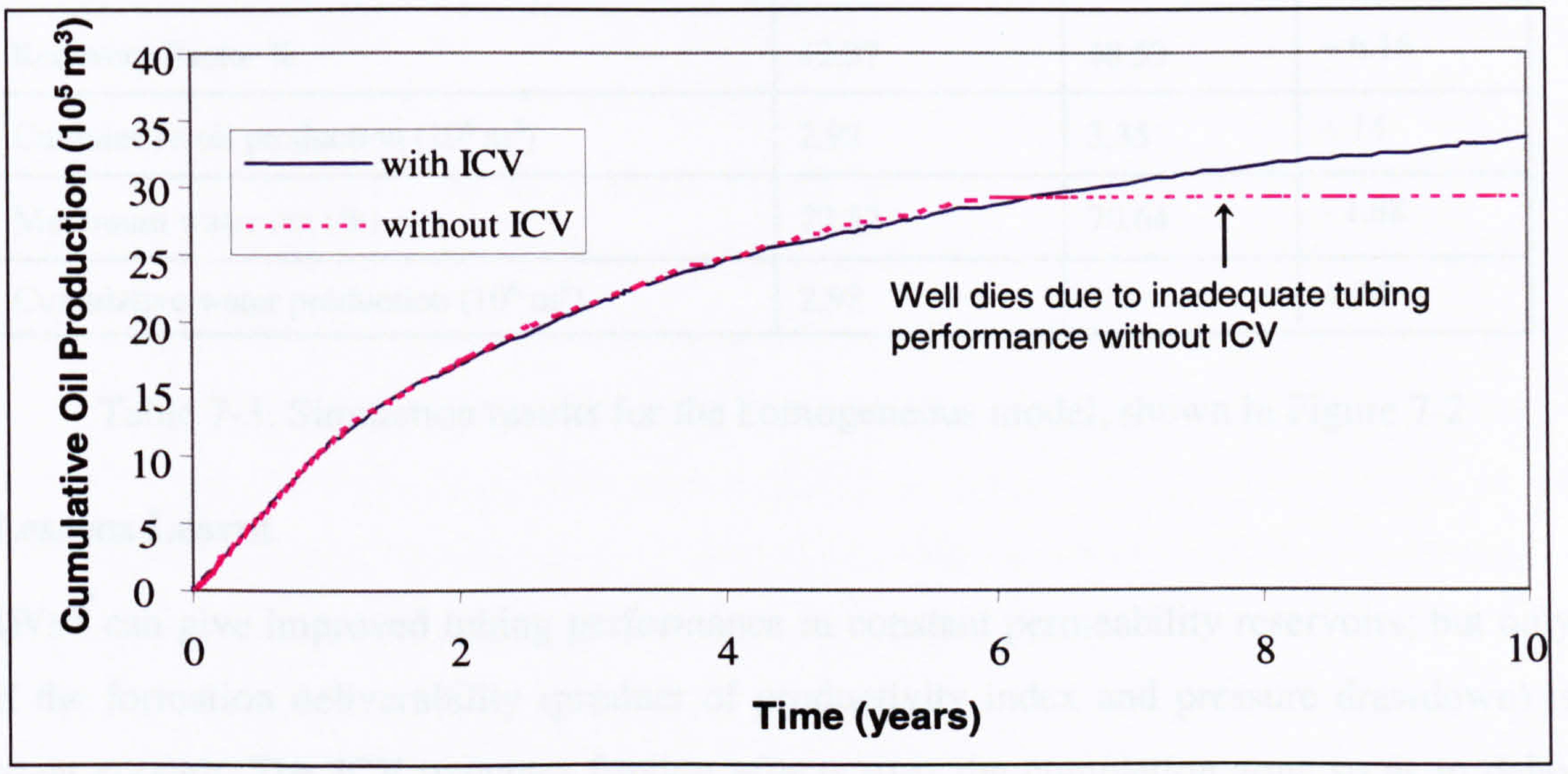


Figure 7-3: Cumulative oil production with & without ICV in a homogeneous model

Model (Based on real field data)	Porosity	Permeability (mD)			Net to Gross
		X	Y	Z	
Tarbet	0.268	188	188	56.4	0.84
Etive	0.215	2119	2119	635	0.94

Table 7-2: Reservoir properties used in the homogeneous model based on the real field data

Base Case	Without ICVs	With ICVs	% Change
STOIIP (10^6 m^3)	6.9	6.9	
Recovery Factor %	42.37	48.53	+ 6.16
Cumulative oil production (10^6 m^3)	2.92	3.35	+ 14
Maximum water cut (%)	72.52	70.64	- 1.88
Cumulative water production (10^6 m^3)	2.98	3.7	+ 24

Table 7-3: Simulation results for the homogeneous model, shown in Figure 7-2

Lessons Learnt

IWsT can give improved tubing performance in constant permeability reservoirs; but only if the formation deliverability (product of productivity index and pressure drawdown) is great enough. The ICV manages friction effects over the completion zone so as to delay gas or water breakthrough at a single point along the well length. However, installation of IWsT in these reservoir types may not to be economically justified if the completion zone is short, since an uneven fluid front of sufficient dimensions may not develop along the perforated length of the wellbore.

Improved tubing performance is a very significant source of value. However, it is outside the scope of this paper since it is case specific and can, in principal, be managed by conventional production management practices. The examples discussed in the remainder of this paper will concern cases where the tubing performance is not the limiting factor i.e. we will concentrate on "Added IWsT Value" stemming from the improved management of reservoir displacement due to geological heterogeneity.

7.3.2 Stochastic realisations of a heterogeneous reservoir

Multiple, stochastic realisations were generated of a heterogeneous, single reservoir with no faulting or reservoir dip. The same modelling methodology and comparison technique were applied, except that a series of "equi-probable" realisations was generated. Figure 7-4 illustrates the permeability distribution in the x-y plane along the wellbore for two realizations. The fluid front progression, and hence the "Added Value", will be significantly different for these two realisations. Figure 7-5 highlights how the "Added Value" for IWsT varies from one realization to another. The percentage change compared to the average recovery from wells without IWsT is plotted for all realisations. Both the "Added IWsT Value" and the recovery from the conventional well depend on the details of the reservoir permeability distribution relative to the well position.

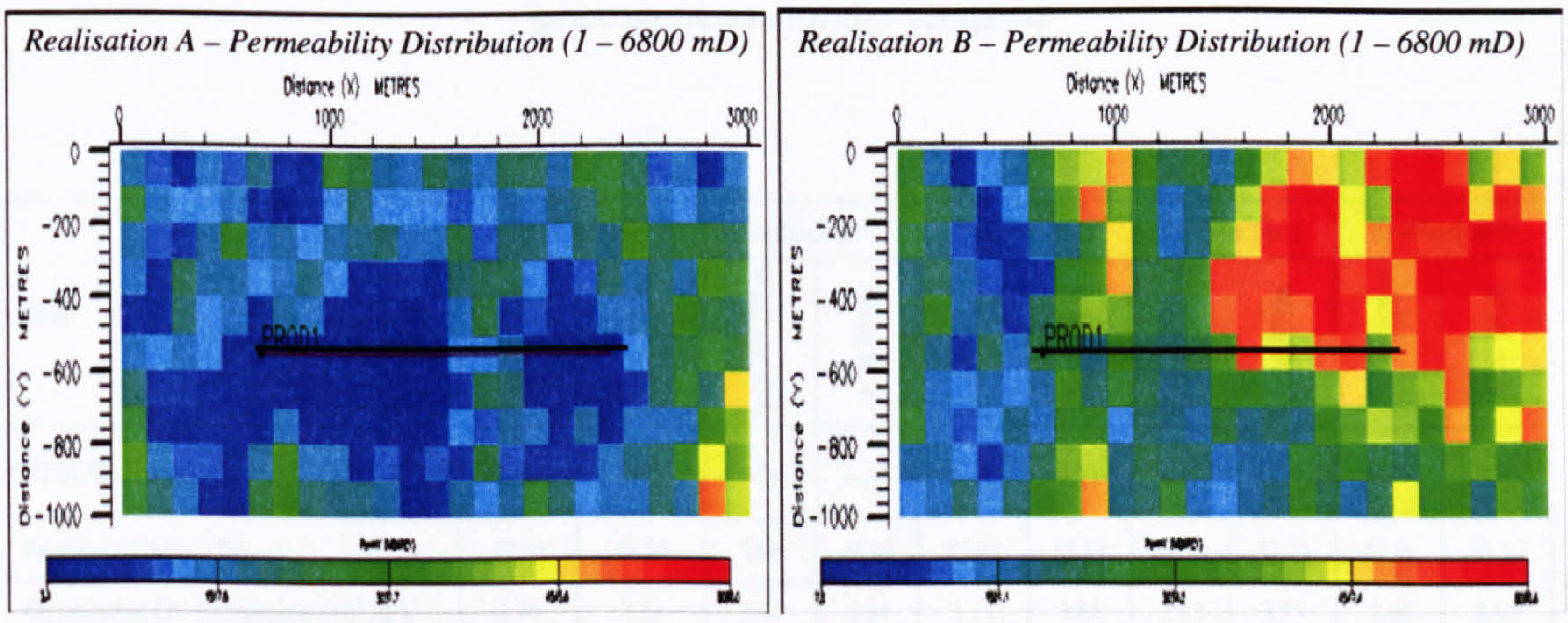
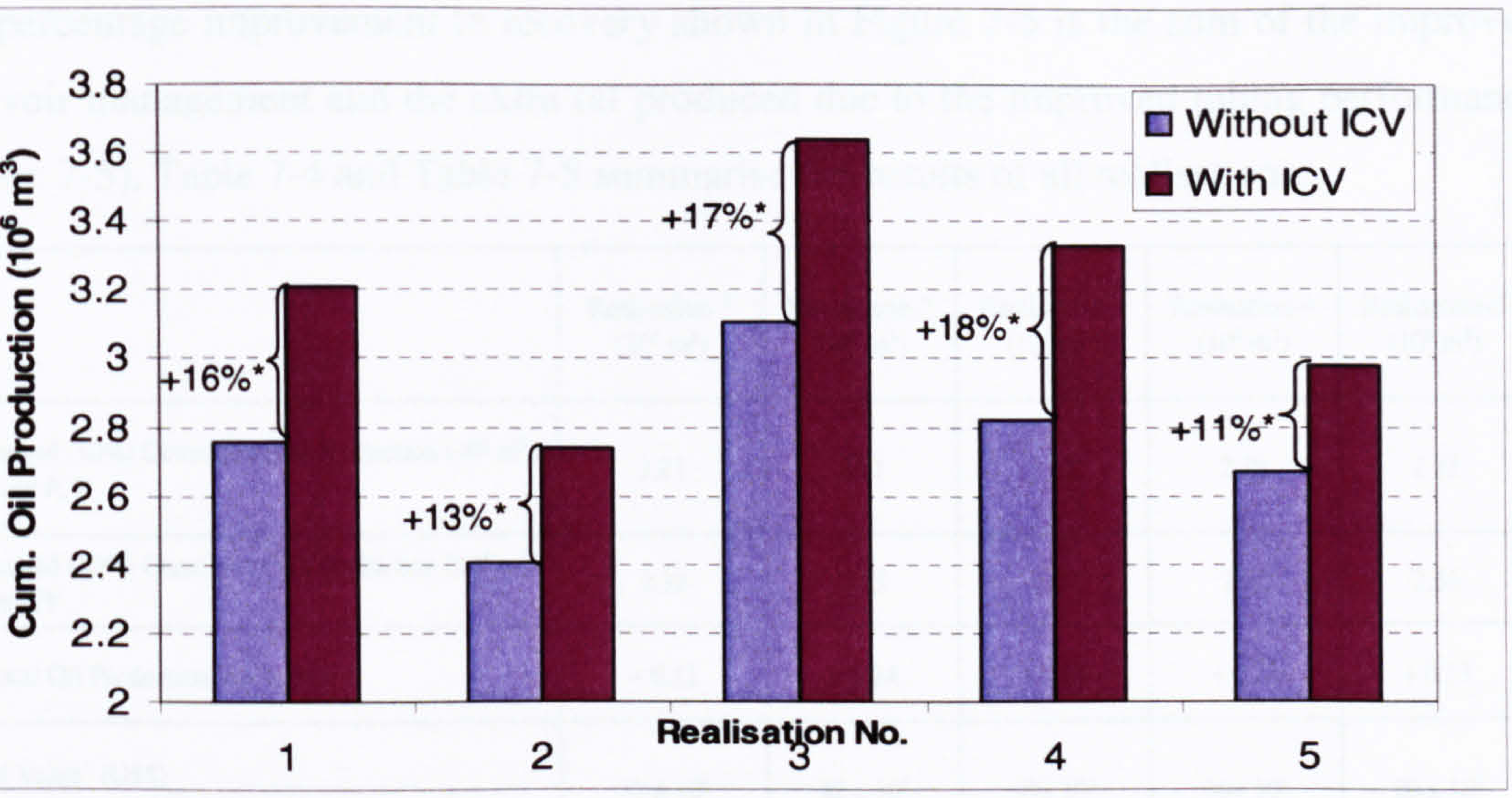


Figure 7-4: Permeability distribution in the x-y horizontal plane of the well for two realisations



* % recovery improvement with IWsT

Figure 7-5: Cumulative oil production with & without ICV for different realizations of a heterogeneous model scenario

Case	Realisation-1		Realisation-2		Realisation-3		Realisation-4		Realisation-5	
	Without	With ICV	Without ICV	With ICV	Without ICV	With ICV	Without ICV	With ICV	Without ICV	With ICV
STOOIP (10^6 m^3)	6.43	6.43	6.24	6.24	6.77	6.77	6.39	6.39	6.23	6.23
Recovery Factor (%)	43.06	49.97	38.6	43.98	45.93	53.81	44.23	52.12	42.86	47.87
Cumulative Oil Production (10^6 m^3)	2.76	3.21	2.41	2.74	3.11	3.64	2.82	3.33	2.67	2.98
Increase in Recovery (%)	+ 6.91		+ 5.38		+ 7.88		+ 7.89		+ 5.01	
Water cut (%)	73.38	72.34	75.53	73.85	71.37	71.06	72.63	71.77	75.33	73.48
Cumulative Water Production (10^6 m^3)	2.76	3.43	3.3	3.67	2.29	3.27	2.82	3.38	3.08	3.47
Increase in Cumulative Water Production (%)	+ 24		+ 11		+ 42		+19		+ 12	

Table 7-4: Comparison of different realisations of a heterogeneous (Etive type) reservoir

The percentage improvement in recovery shown in Figure 7-5 is the sum of the improved reservoir management and the extra oil produced due to the improved tubing performance (Figure 7-5). Table 7-4 and Table 7-5 summarise the results of all realisations.

Case	Realisation-1 (10^6 m^3)	Realisation-2 (10^6 m^3)	Realisation-3 (10^6 m^3)	Realisation-4 (10^6 m^3)	Realisation-5 (10^6 m^3)
Discounted (10%) Cumulative Oil Production (10^6 m^3) - *Without ICV*	2.21	2.01	2.62	2.39	2.23
Discounted (10%) Cumulative Oil Production (10^6 m^3) - *With ICV*	2.32	2.15	2.87	2.62	2.36
Increased Oil Production due to ICV	+0.11	+0.14	+0.25	+0.23	+0.13
Added Value* (US$) (Oil price assumed US$25/ bbl. Net)	17 x 10^6	22 x 10^6	39x 10^6	36x 10^6	20 x 10^6

Table 7-5: Comparison of different realisations of a heterogeneous reservoir

In the remainder of this work we will exclude the improved tubing performance issues (lower pressure drop in the tubing and, therefore, longer well life) and study ONLY the improvement in recovery due to improved reservoir sweep efficiency.

Lessons Learnt

IWsT gives better recovery in the majority of cases studied. It is able to take advantage of the opportunities created by the permeability heterogeneity to manage an invading fluid front. The recovery – and the magnitude of the "Added Value" – is thus a function of the distribution of porosity and permeability in the reservoir. This is especially true for the distribution near the wellbore.

Later studies will show that the magnitude of the "Added Value" will be affected by the presence of flow-barriers within the reservoir. Examples of such barriers are the presence of faults, (clay or shale) low permeability layers or the juxtaposition of sands of different permeabilities.

7.3.3 Faulted Reservoir

Figure 7-6 shows a simple faulted reservoir with two different oil/water contacts and zero transmissibility between the two compartments. IWsT can be used to balance the production from the two zones by installing a separation (isolation) packer (Figure 7-1) at the interface of the two formations. Water production from zone 2 will start much earlier than from zone 1 (Figure 7-7). Choking the production from zone 2 at 40% water cut allows an increased total oil rate, for a constant total liquid production rate, since zone 1 is producing dry oil.

Many faulted reservoir models with a stochastic distribution of porosity and permeability, plus different pressure regimes in the compartments have been studied, Figure 7-9 being one of the more complex models used. All these models showed "Added Value" from IWsT.

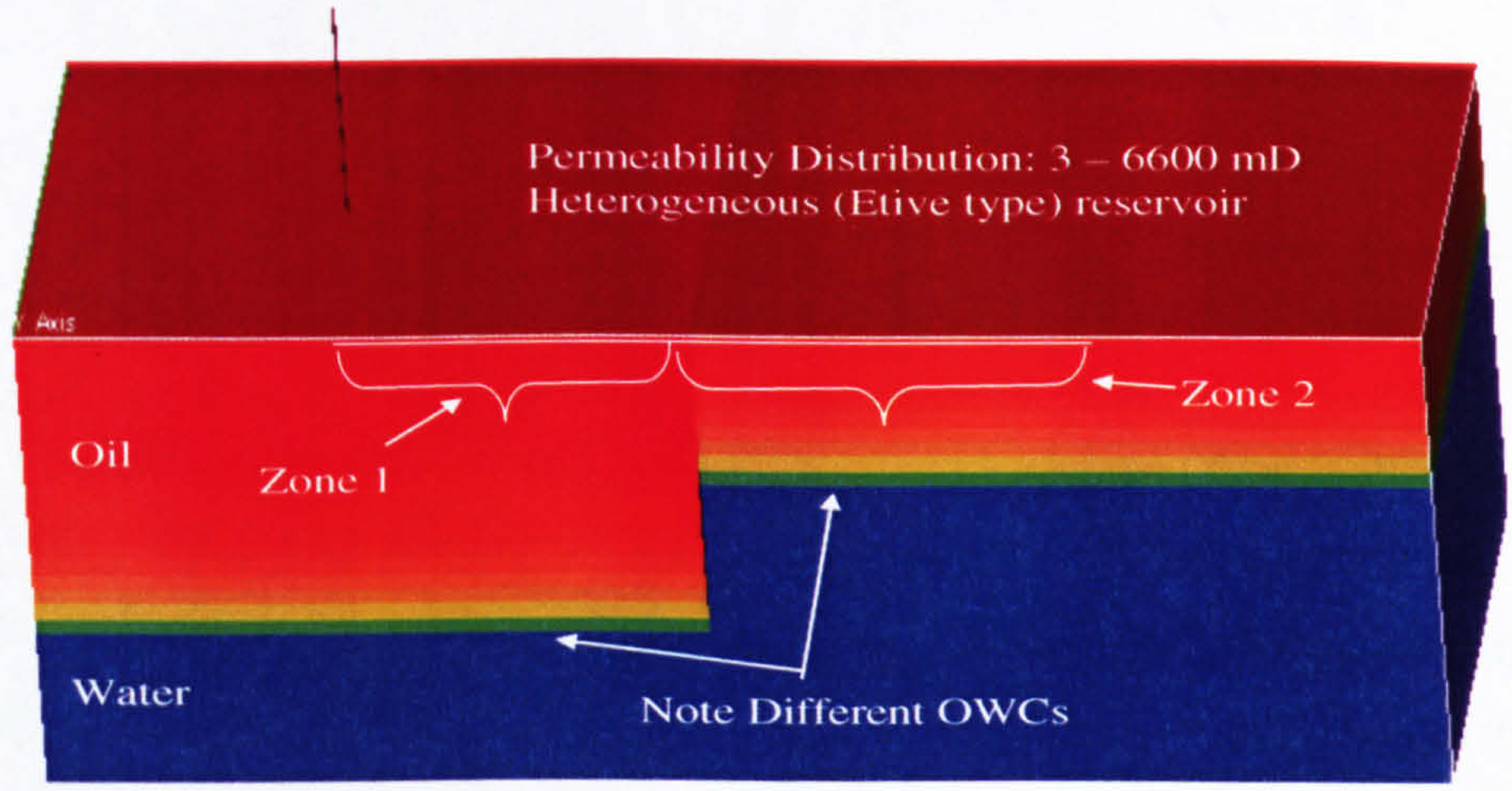


Figure 7-6: Faulted Reservoir with different Oil Water Contacts (OWCs)

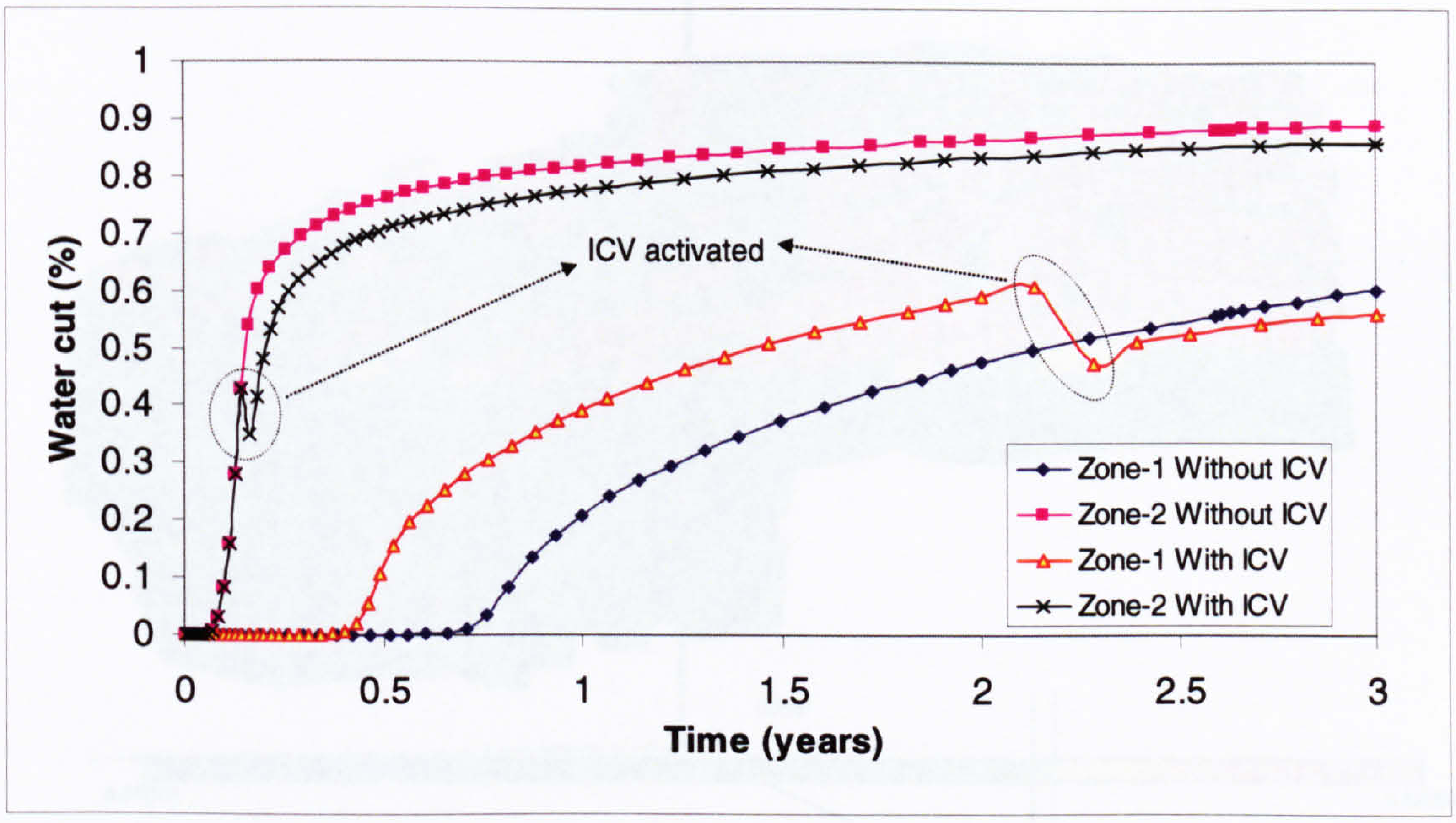


Figure 7-7: Water Cut with & without ICV for zones 1 & 2

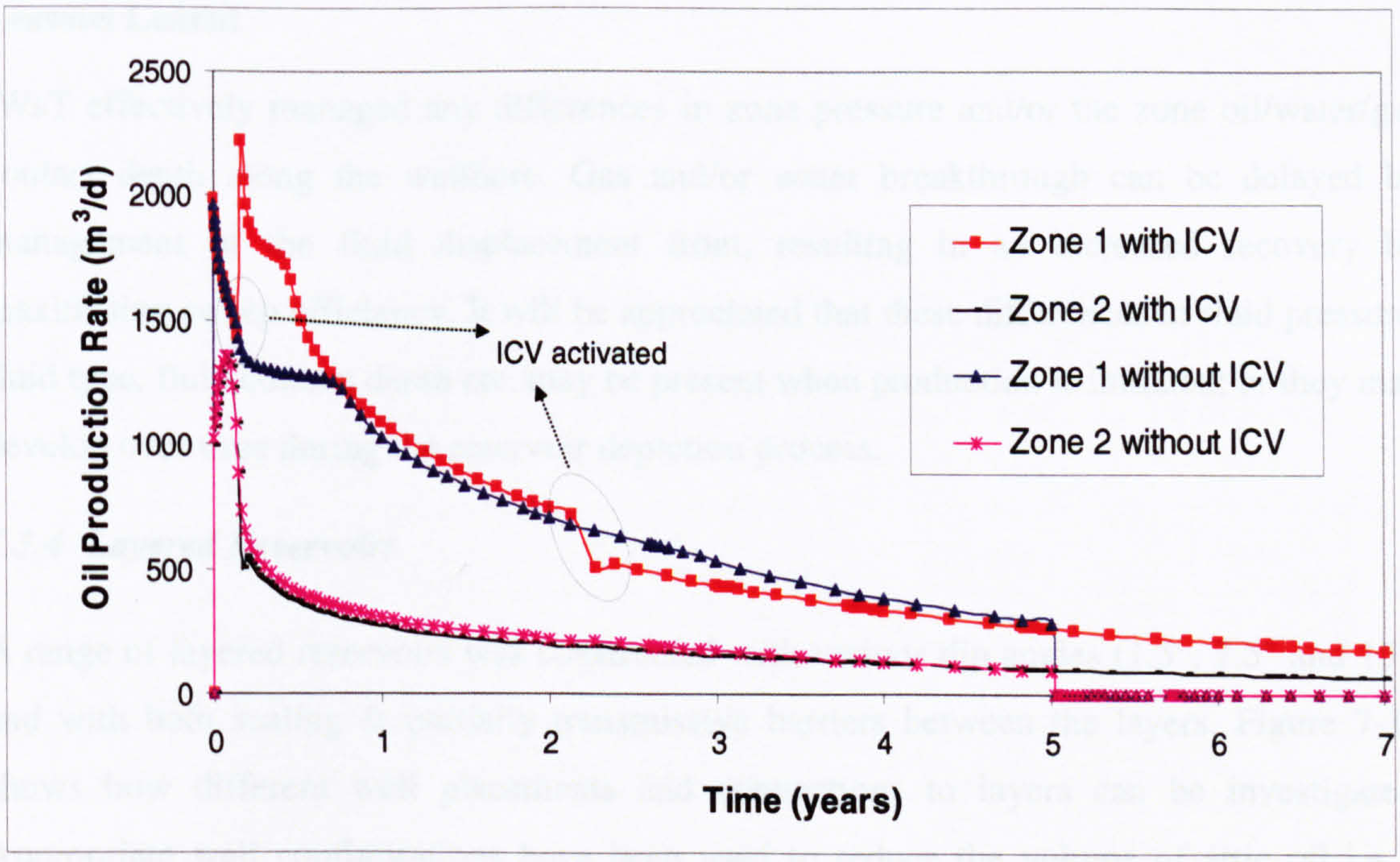


Figure 7-8: Oil production rate with & without ICV for zones 1 & 2

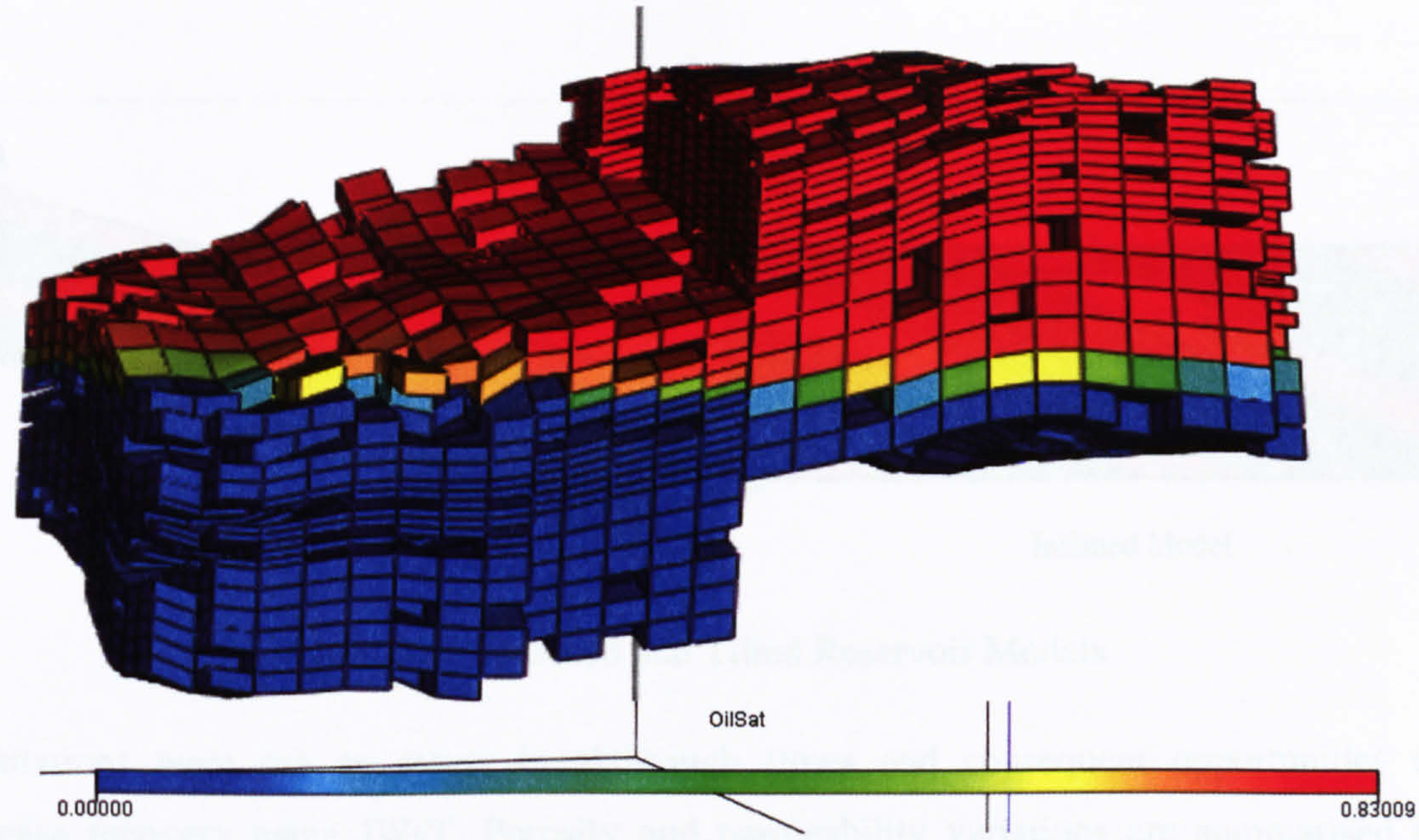


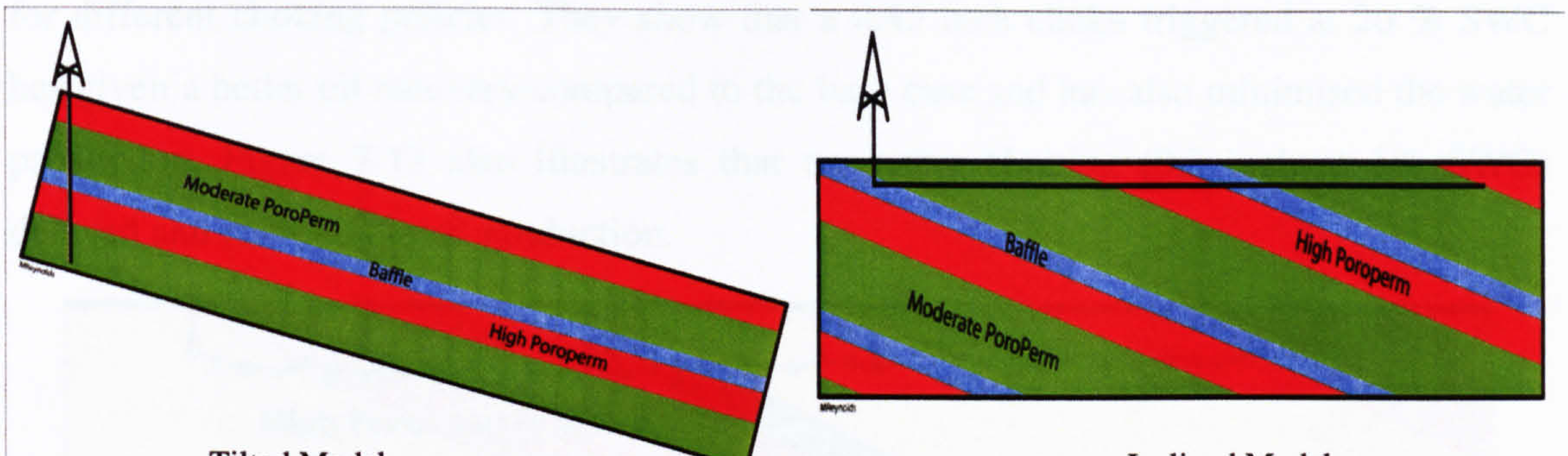
Figure 7-9: A Complex Faulted Reservoir Model which showed "Added Value" from IWsT

Lessons Learnt

IWsT effectively managed any differences in zone pressure and/or the zone oil/water/gas contact depth along the wellbore. Gas and/or water breakthrough can be delayed by management of the fluid displacement front, resulting in an increased recovery by maximising sweep efficiency. It will be appreciated that these differences in fluid pressure, fluid type, fluid contact depth etc. may be present when production is initiated; or they may develop over time during the reservoir depletion process.

7.3.4 Layered Reservoirs

A range of layered reservoirs was constructed with various dip angles (1.5°, 7.5° and 15°) and with both sealing & partially transmissive barriers between the layers. Figure 7-10 shows how different well placements and connections to layers can be investigated. Appropriate well configurations have been used to reduce the volume of attic oil i.e. a vertical well in a tilted formation and a horizontal well in an inclined formation.



Tilted Model　　　　Inclined Model

Figure 7-10: Inclined and Tilted Reservoir Models

Simulations were run to assess breakthrough times and consequent opportunities to increase recovery using IWsT. Porosity and permeability variations are summarised in Table 7-6. These models are analogous to reservoirs with well developed layers e.g. shallow marine sheet sandstones, amalgamated fluvial sandstones, turbidite sands, etc. As previously, a horizontal well was placed near the top of the model. Figure 7-11 is a simple example of this type of inclined layer model. In this case, a single ICV managed early water breakthrough in the high permeability layer.

Layer	Permeability in X & Y direction	Permeability in Z direction	Porosity (constant)
High Permeability	1000 mD	500 mD	23 %
Low Permeability	5 mD	2.5 mD	15 %
Very Low Permeability (Shale)	0.1 mD	0.05 mD	10 %

Table 7-6: Porosity/permeability values used in the Figure 7-11 layered model

Figure 7-12 (an enlarged version of the right hand side of Figure 7-11) shows how extra recovery is achieved by IWsT from the high and medium permeability layers. Figure 7-13 and Figure 7-14 show the improvement in oil production and reduction in water production for different choking policies. They show that a 0.45 inch choke triggered at 20 % SWC has given a better oil recovery compared to the base case and has also minimised the water production. Figure 7-13 also illustrates that excessive choking (0.3 inch at 1% SWC) delayed and reduced the oil production.

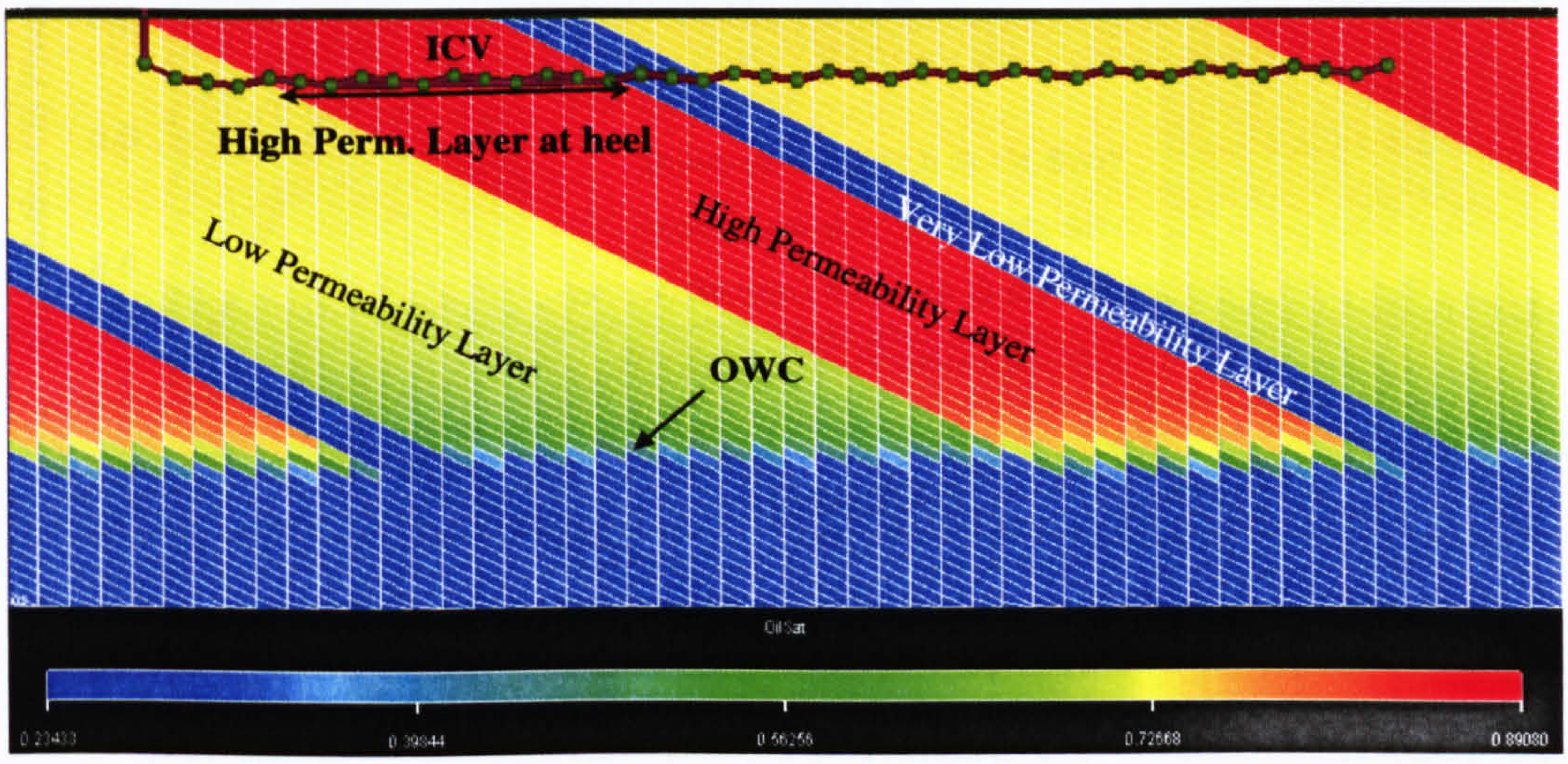


Figure 7-11: A single ICV manages the high permeability zone in a horizontal well producing a 38 m thick and 2.5 km long sand body dipping at 1.5°

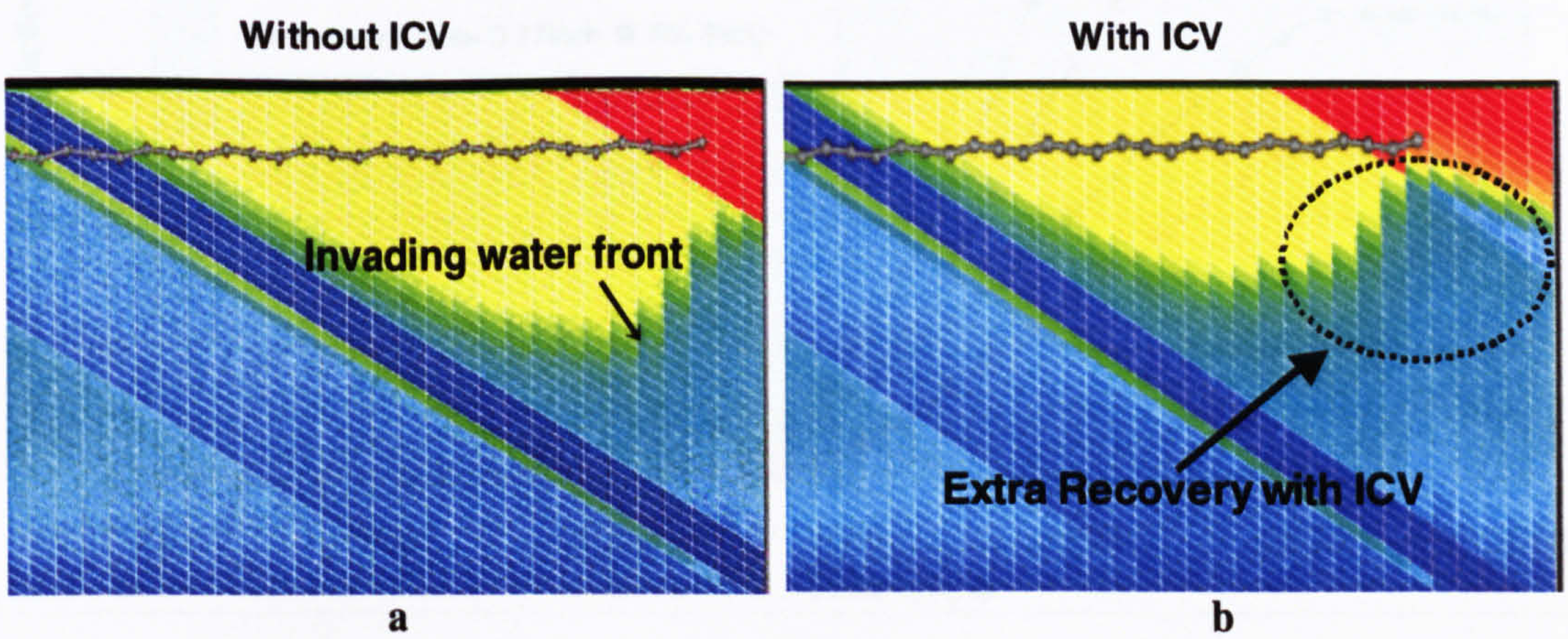


Figure 7-12: An inclined, layered model with low permeability layer at the toe of well (Figure b shows where extra oil recovery occurs compared to Figure a at a particular simulation time)

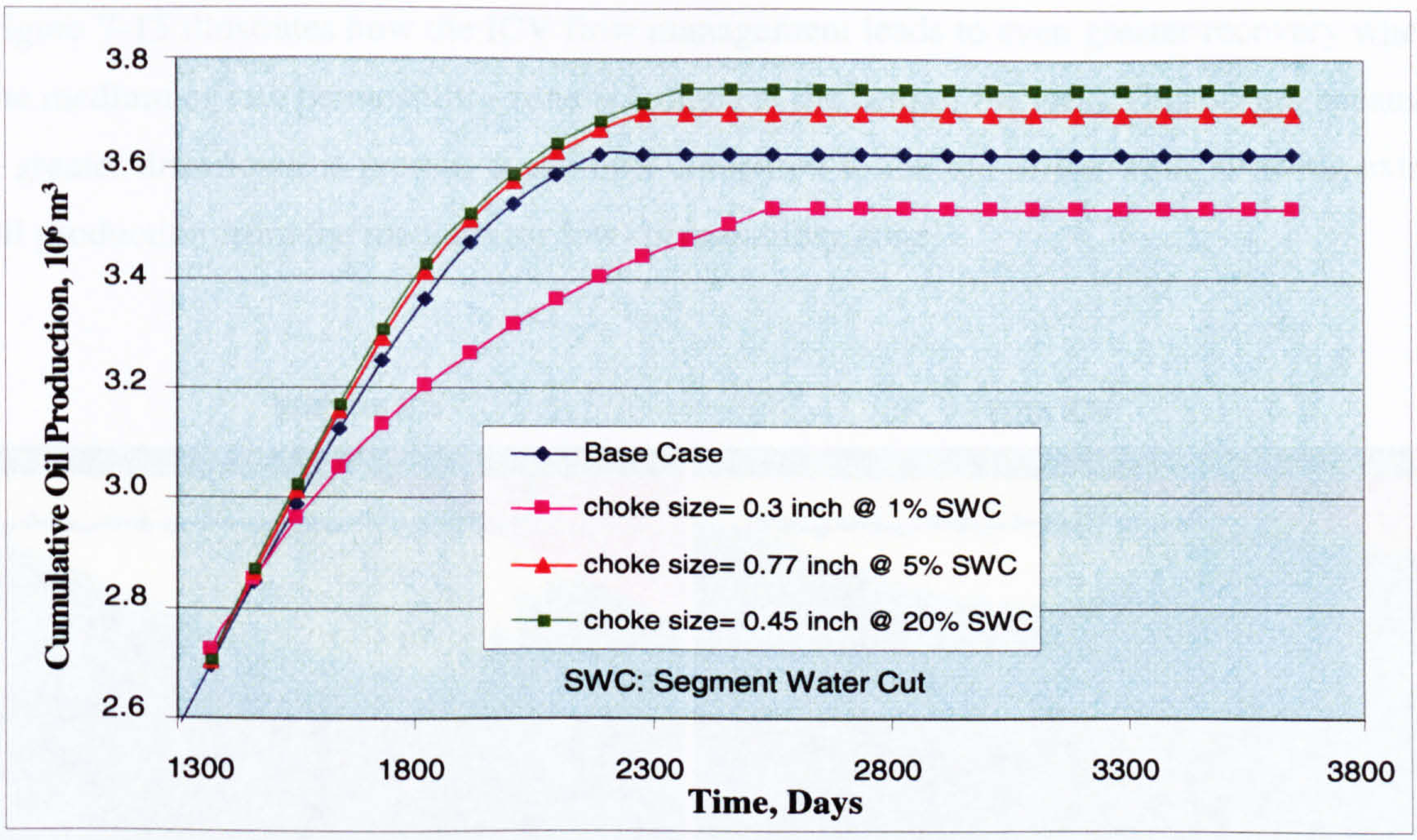


Figure 7-13: Cumulative oil production versus time

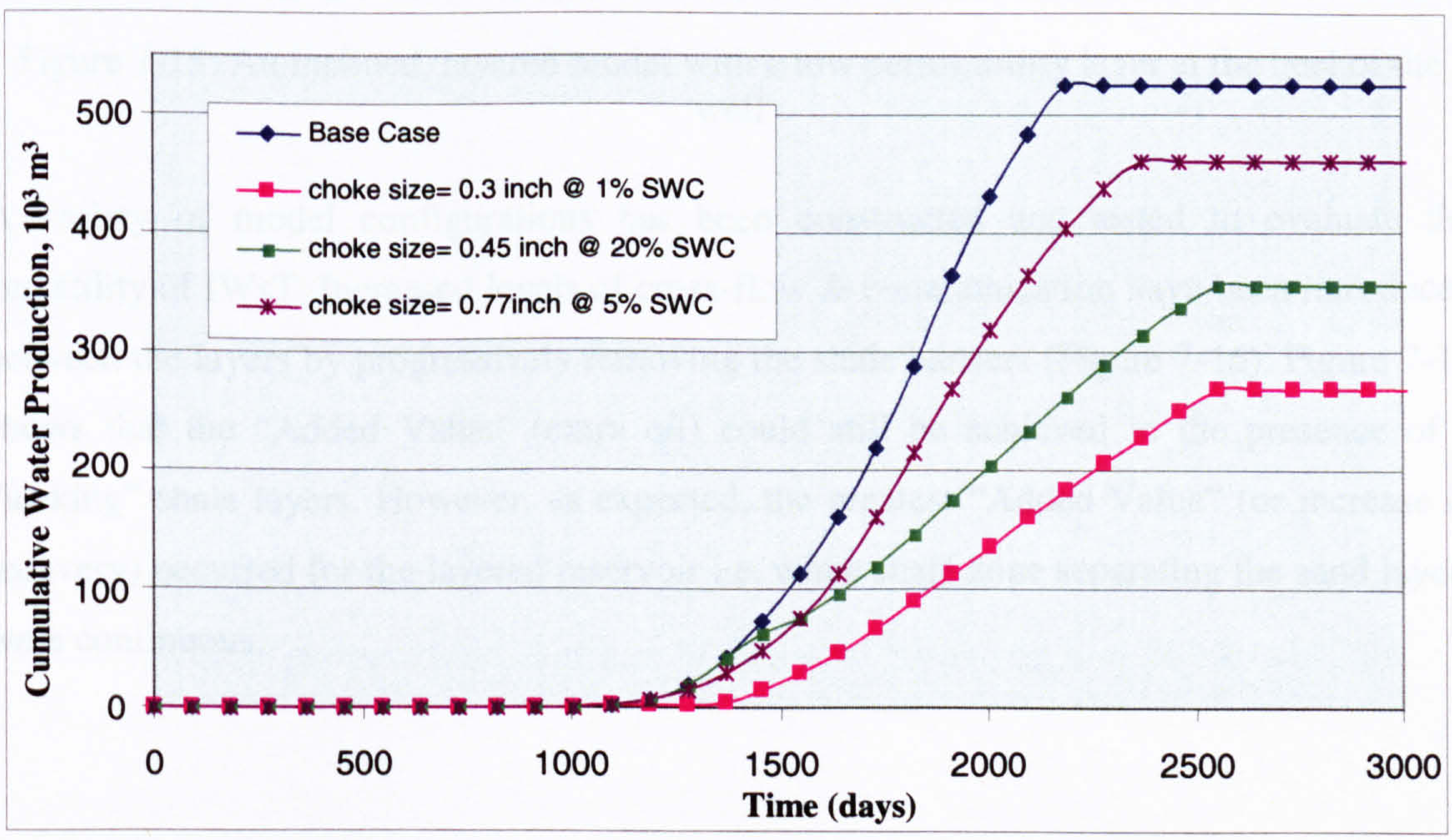


Figure 7-14: Cumulative water production versus time

Figure 7-15 illustrates how the ICV flow management leads to even greater recovery when the medium or low permeability zone is located at the heel of the well. This occurs because a greater drawdown is present at the heel compared to the toe of the well; allowing extra oil production from the medium (or low) permeability zone.

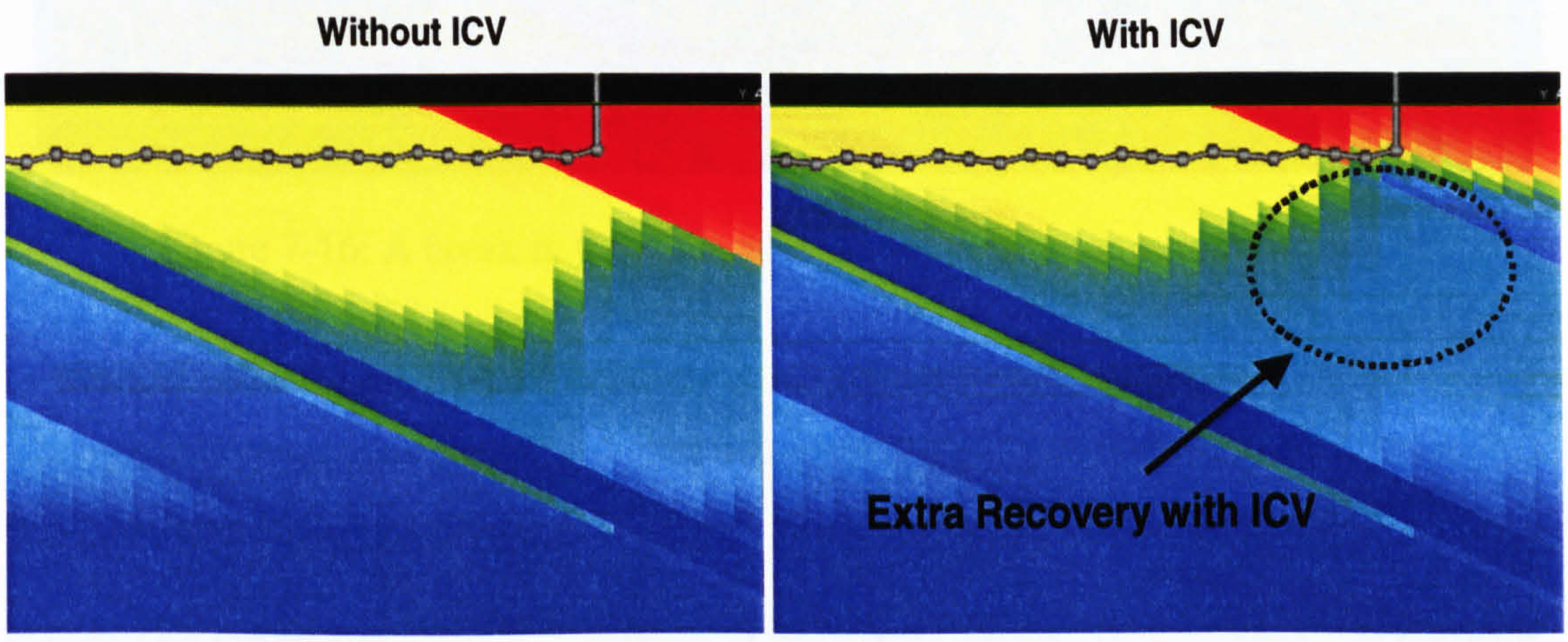


Figure 7-15: An inclined, layered model with a low permeability layer at the heel of the well

A variety of model configurations has been constructed and tested to evaluate the versatility of IWsT. Increased levels of cross-flow & communication have been introduced between the layers by progressively removing the shale barriers (Figure 7-16). Figure 7-17 shows that the "Added Value" (extra oil) could still be achieved in the presence of a "leaking" shale layers. However, as expected, the greatest "Added Value" (or increase in recovery) occurred for the layered reservoir i.e. when shale zone separating the sand layers were continuous.

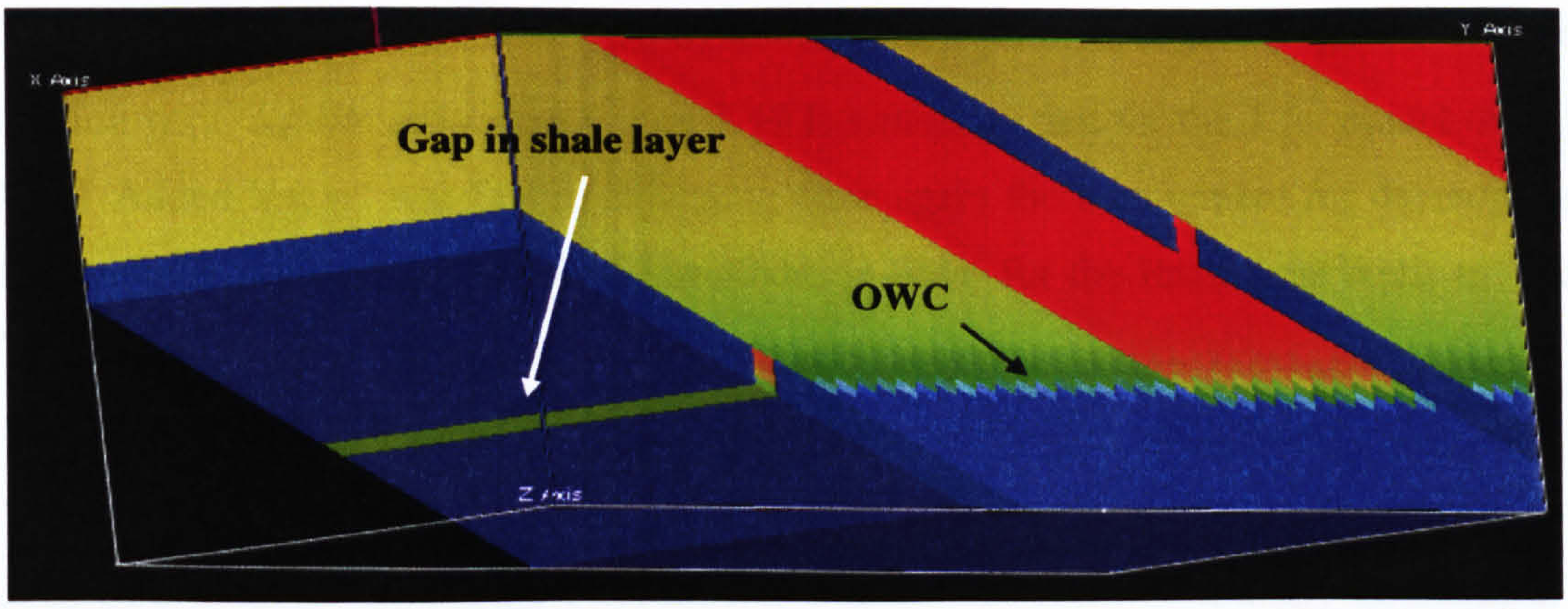


Figure 7-16: A break in the shale allows communication across the model

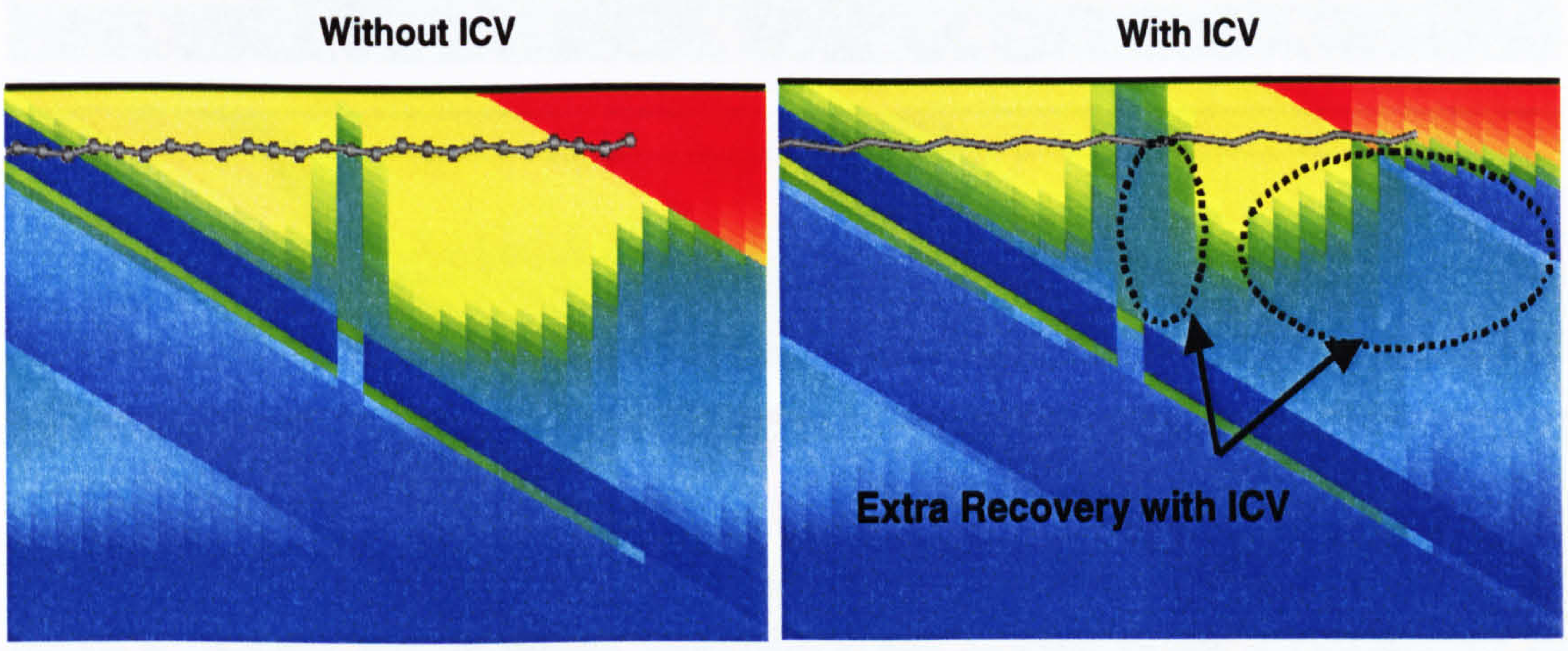


Figure 7-17: The ICV in the high permeability sand was still able to delay channelised water breakthrough

Figure 7-18 shows that all layers in 7.5^{o} and 15^{o} dip models have strong aquifer support; however, the low permeability layer in 1.5^{o} dip model does not have direct contact to the aquifer. This was the main source for development of an uneven fluid front towards the wellbore in the 1.5^{o} dip model. An even fluid front and, therefore, limited "IWsT Added Value", was observed for the 7.5^{o} and 15^{o} dip formations.

This phenomenon was further studied by altering the aquifer strengths (Figure 7-19). The situation w.r.t. aquifer support in Figure 7-19 is similar to that for the 1.5° model. A high "IWsT Added Value" was found, indicating once again the requirement for development of an un-even fluid front towards the wellbore in order for the Intelligent Wells to "Add Value".

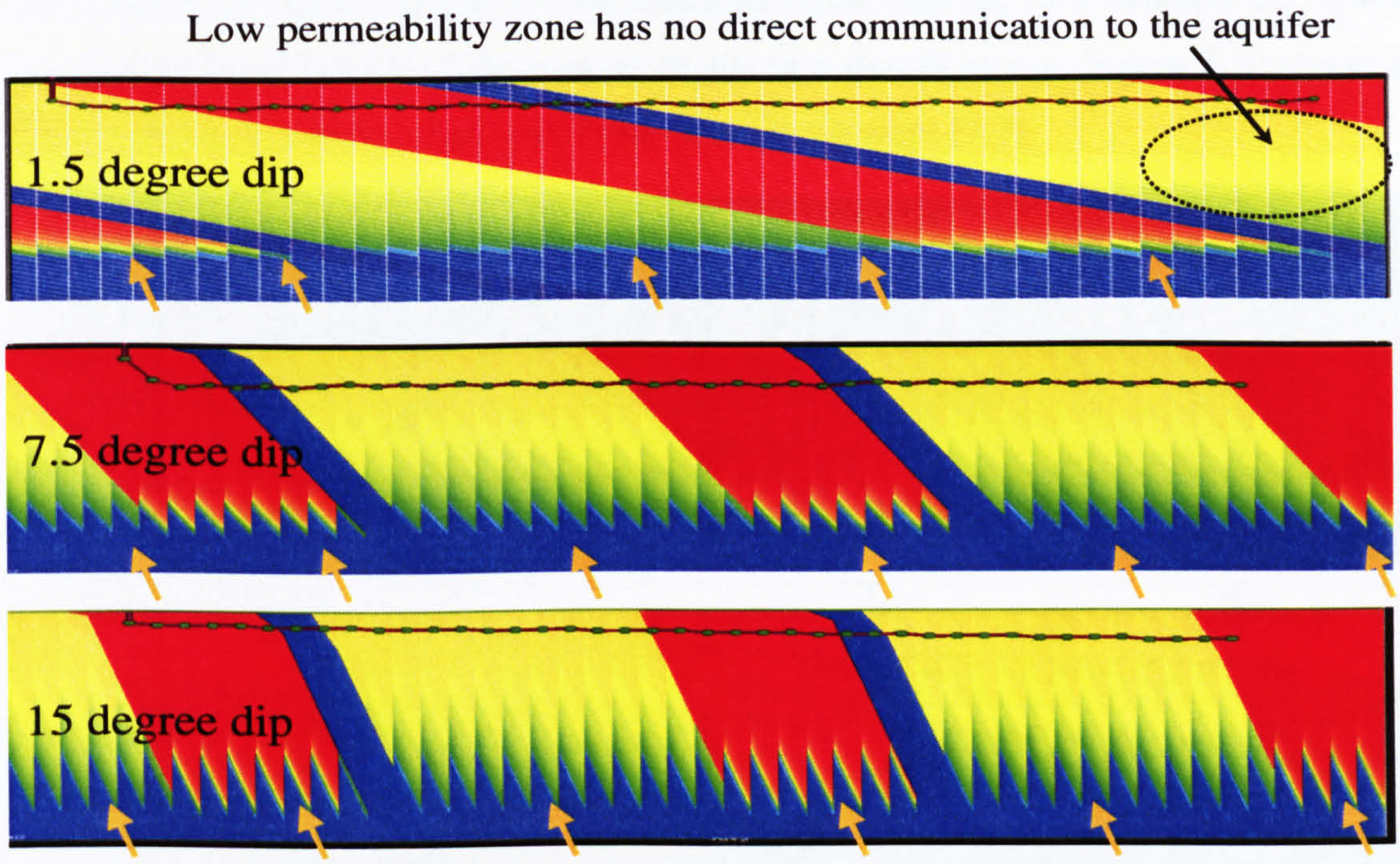


Figure 7-18: Aquifer support for different reservoir scenarios

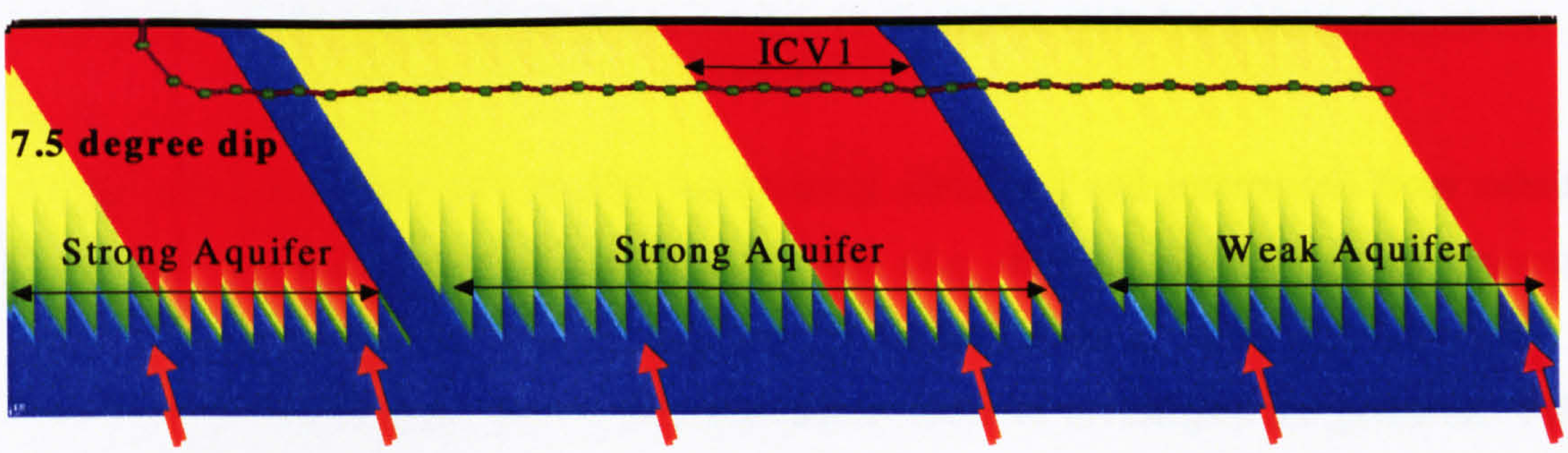


Figure 7-19: Modified aquifer support for the 7.5° dip model

IWsT Application in Stratigraphic Trap Reservoirs

A stratigraphic trap is created when a reservoir rock terminates in an updip direction because of the depositional limit of a porous bed, a change in lithology, or a loss of permeability. Any of these factors will prevent further movement of the migrating petroleum, thus creating a stratigraphic trap. Two types of major genetic traps that have been identified in reservoirs are stratigraphic and structural traps. A stratigraphic trap accumulates oil due to changes in rock character rather than the rock structure i.e.: it is not due to faulting or folding of the rock as occurs in a structural trap. Figure 7-20 shows the basic differences between these two types of reservoir traps [7.7].

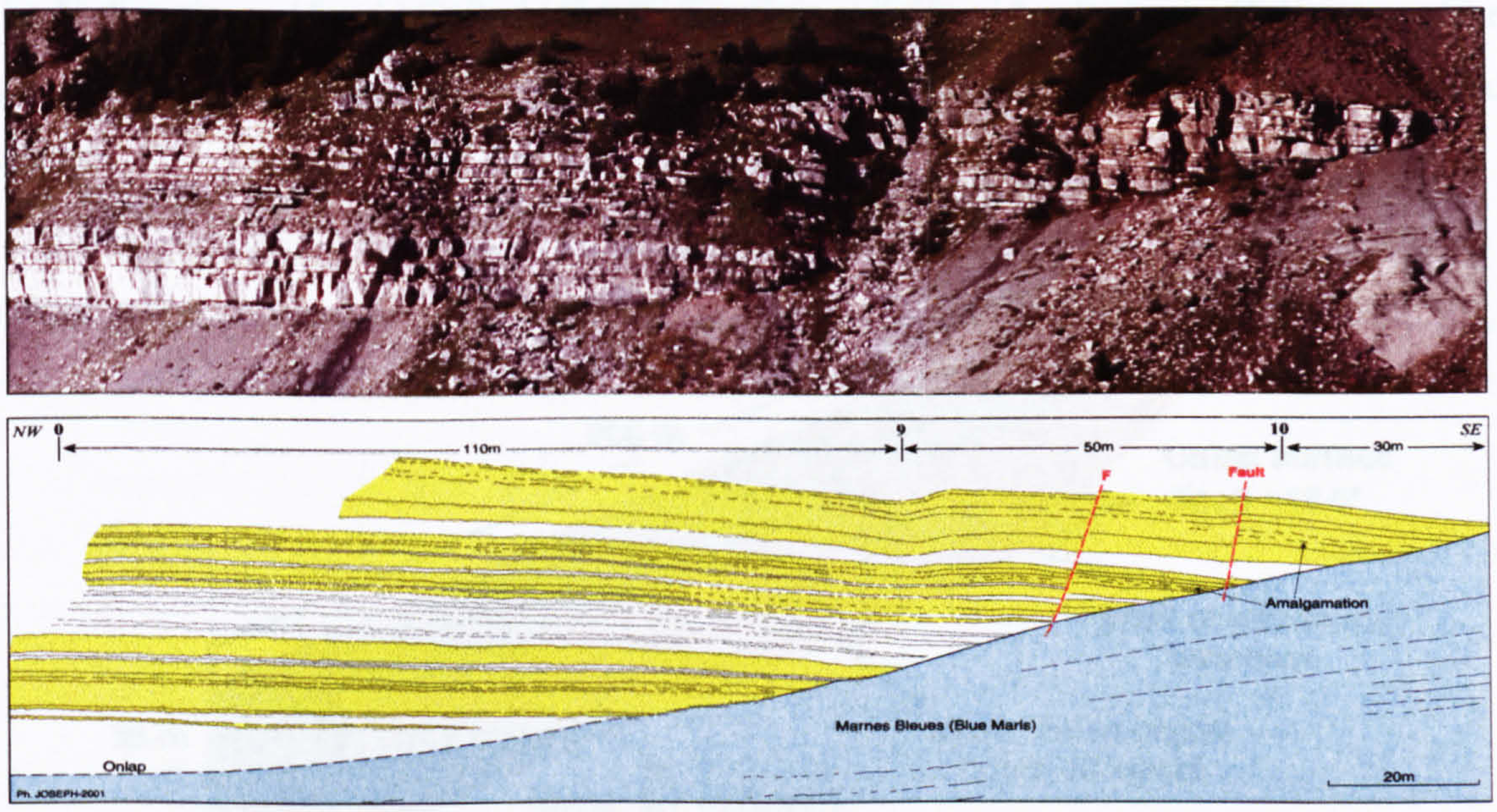


Figure 7-20: Example of simple onlap in a stratigraphic reservoir (Annot Sandstone, Chalufy) [7.7]

Stratigraphic trap reservoirs maybe inaccurately identified and interpreted from seismic. Petroleum exploration and production activities (e.g. drilling) in this type of reservoirs often involve greater measure of risk and uncertainty than in other reservoir types. A reservoir simulation study has been conducted in order to investigate the potential "IWsT Added Value" in the stratigraphic trap reservoirs in terms of maximising oil recovery compared to the recovery that can be achieved from the conventional completions. A wide range of sensitivities w.r.t the degree of shale discontinuity and reservoir sands properties were performed in order to investigate the performance of IWsT in scenarios with different levels of geological heterogeneity. The impact of well locations (within the stratigraphic trap reservoir) on the potential "IWsT Added Value" compared to the conventional well completions was also investigated.

Figure 7-21 shows a three-dimensional onlap stratigraphic trap developed in a layered reservoir. This model was used by the Genetic Units research project at the Institute of Petroleum Engineering in Heriot-Watt University [7.7]. The model had 150 grid cells in the X directions, 15 grid Cells in the Y direction and 50 grid cells in the Z direction. The grid cells were divided into ten layers of sands, each separated vertically by thin bedded shales.

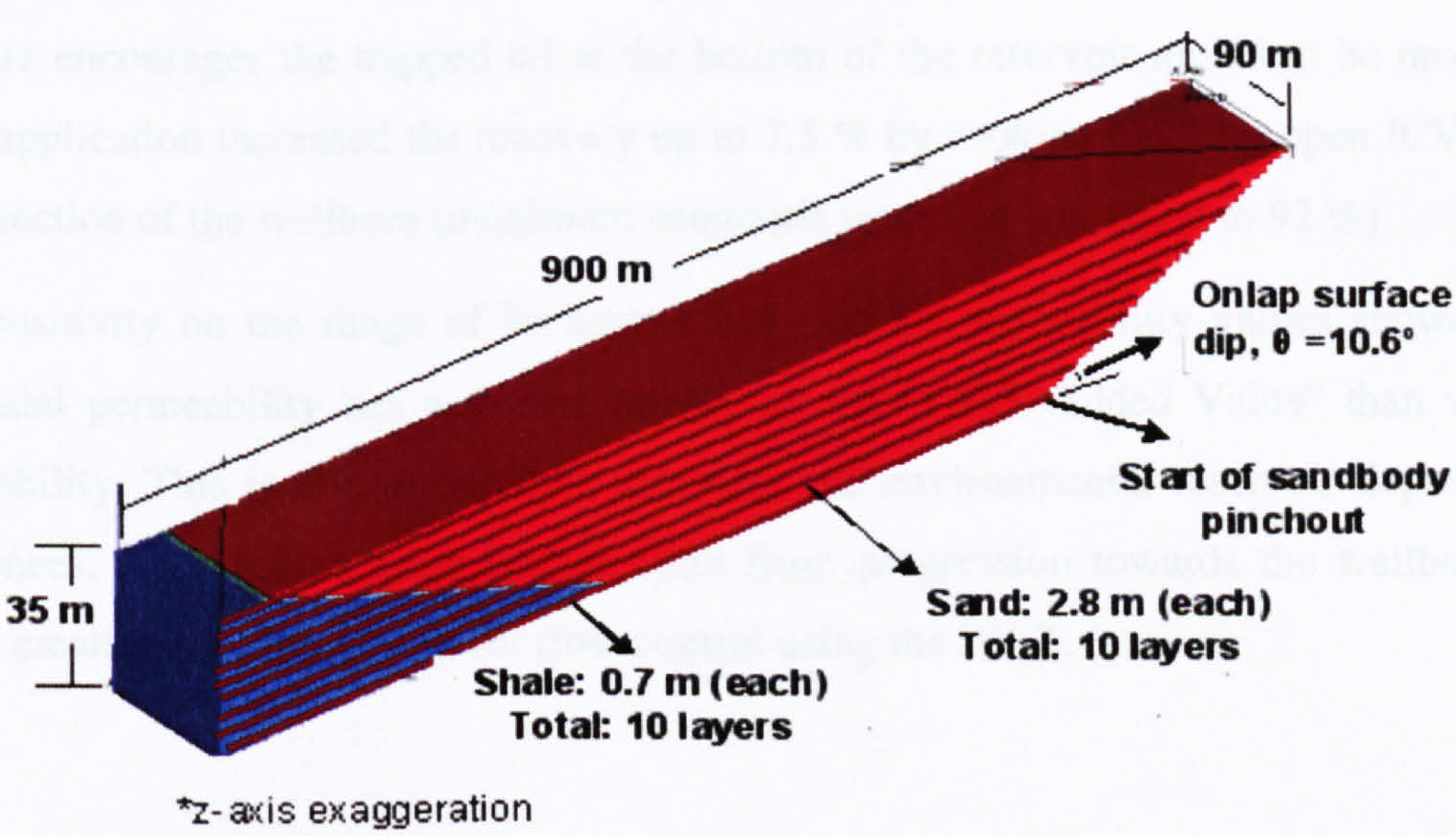


Figure 7-21: Reservoir simulation model used for this study

The onlap surface had a 10.6° dip from the horizontal plane. The cells beyond the onlap were inactive. The reservoir sediments were assumed to have been deposited in a turbidite environment, which resulted in very low shale and moderate sands permeability. The sand and shale had a permeability of 500 mD and 0.01 mD and a porosity of 0.2 % and 0.01 %

respectively. The term "shale" here represents a very low permeability layer. However, in practice; the shale layers in stratigraphic trap reservoirs could have a zero permeability (complete seal). The reservoir pressure was supported by an edge aquifer as shown in Figure 7-21.

Figure 7-22 shows the oil recovery with conventional completion for different well placements scenarios on the onlap surface. It shows that the oil trapped updip of the well decreased as the well moved up the structure (Figure 7-22 a - d). However, the volume of oil trapped down-dip increased. The objective in conventional well placement is to minimise the total volume of unswept oil. The scenario C (Figure 7-22) showed the highest recovery amongst the others.

Figure 7-23 shows how the IWsT was capable of improving the recovery and sweep efficiency at different simulation time-steps for scenario C. Choking the top sections of the wellbore encourages the trapped oil at the bottom of the reservoir model to be produced. IWsT application increased the recovery up to 7.5 % by choking the fully open ICV at the lower section of the wellbore (maximum economic water cut was equal to 92 %).

The sensitivity on the range of horizontal and vertical permeability values showed that horizontal permeability has a greater impact on the "IWsT Added Value" than vertical permeability. This is due to the flow direction and environmental reservoir depositional differences, leading to a more uneven fluid front progression towards the wellbore and hence, creating the opportunity for flow control using the IWsT.

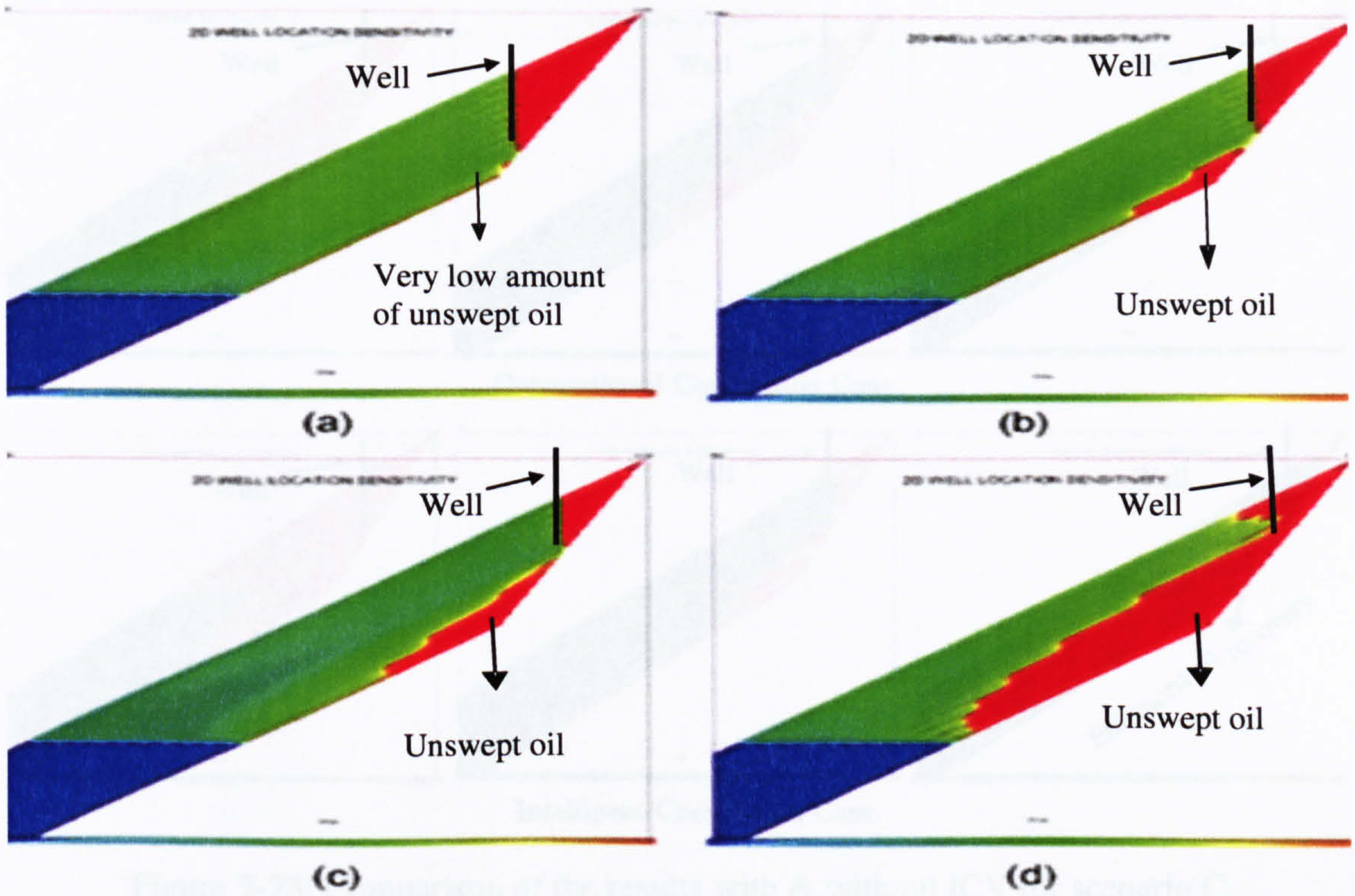


Figure 7-22: Comparison of the oil recovery with conventional completion for different well placements scenarios on the onlap surface

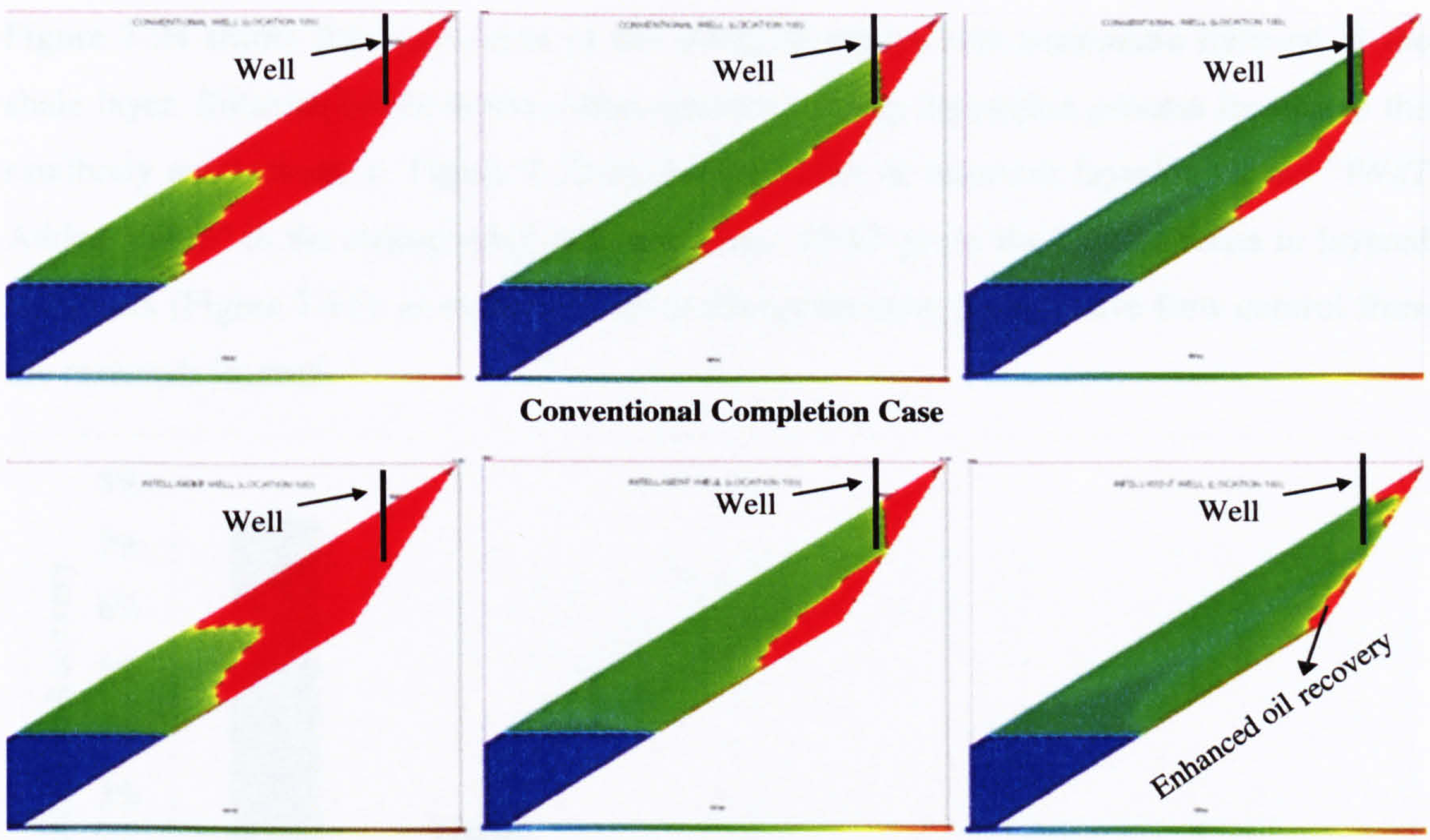


Figure 7-23: Comparison of the results with & without ICV for scenario C

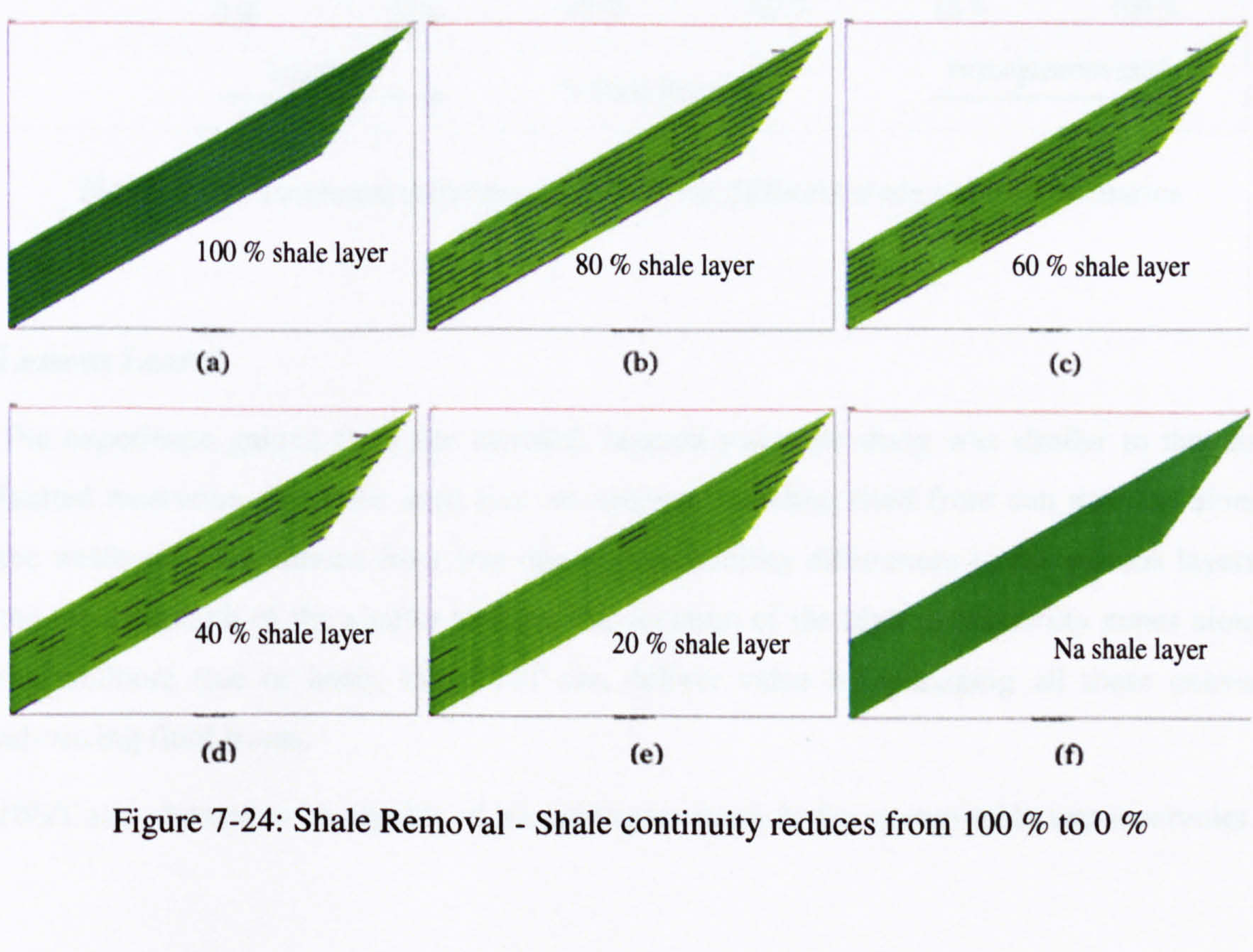


Figure 7-24: Shale Removal - Shale continuity reduces from 100 % to 0 %

Figure 7-24 shows the realisations of the reservoir model with systematic removal of the shale layer. Siltstone (shale layers) often removed during deposition process leading to the sandbody amalgamation. Figure 7-25 shows the effect of reservoir layering on the "IWsT Added Value" in the stratigraphic trap reservoirs. IWsT gives the highest value in layered reservoirs (Figure 7-25), as expected, due to the opportunity for selective flow control from the reservoir layered.

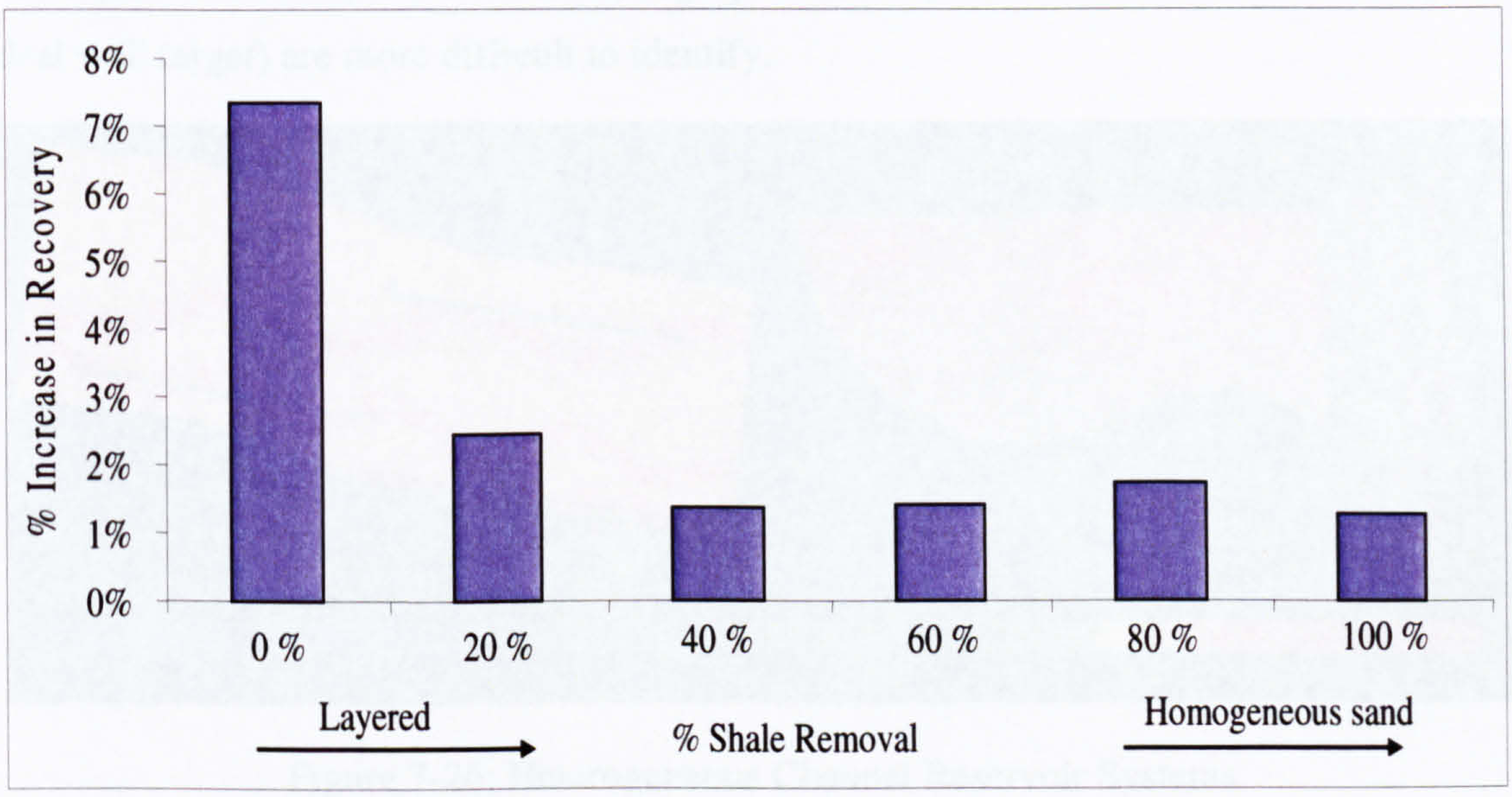


Figure 7-25: Increased recovery with IWT for different shale removal scenarios

Lessons Learnt

The experience gained from the inclined, layered reservoir study was similar to that for faulted reservoirs. We have seen how an uneven, invading fluid front can develop along the wellbore. This uneven front was due to permeability differences in the various layers, the local strength of the aquifer support, the location of the high permeability zones along the wellbore (toe or heel), etc. IWsT can deliver value by managing all these uneven advancing fluid fronts.

IWsT also showed to be capable of improving recovery in the stratigraphic trap reservoirs.

7.3.5 Heterogeneous Channel Reservoir Systems

A turbidite channel complex consists of turbidite channels (high net-to-gross & high permeability sand bodies) confined to a discrete "fairway" (a moderate to low net-to-gross sediment volume) set within a background dominated by shale or siltstone (Figure 7-26). The channel complex is a relatively easy drilling target that can be identified using seismic techniques. However, the individual, high-permeability channels within the fairway (the ideal well target) are more difficult to identify.

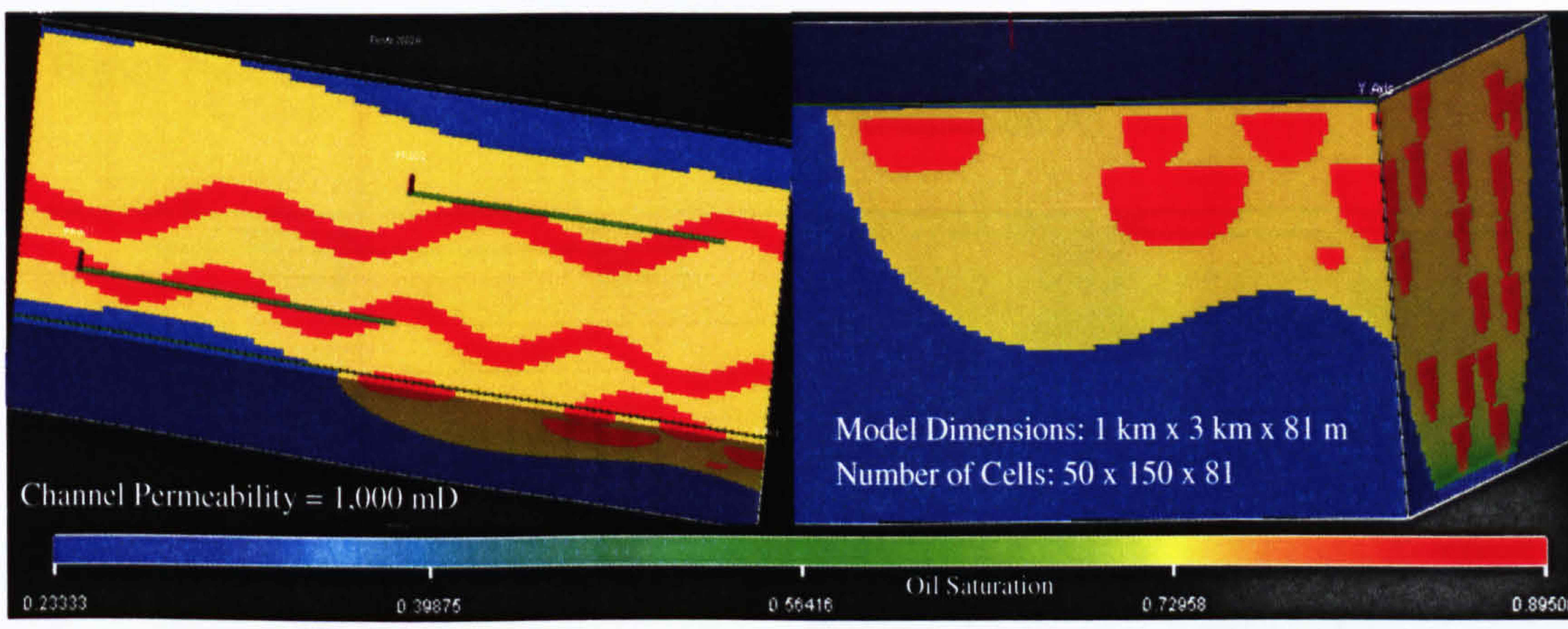


Figure 7-26: Heterogeneous Channel Reservoir Systems

Figure 7-27 shows a long horizontal well, located in the centre of a turbidite model. It is connected to four turbidite channels which are themselves in connection with other high permeability channels. Two ICVs have been used to control the production from the high permeability layers. Figure 7-28 shows an intelligent well completed in a second realisation of this type of reservoir. This particular model shows an even better IWsT performance.

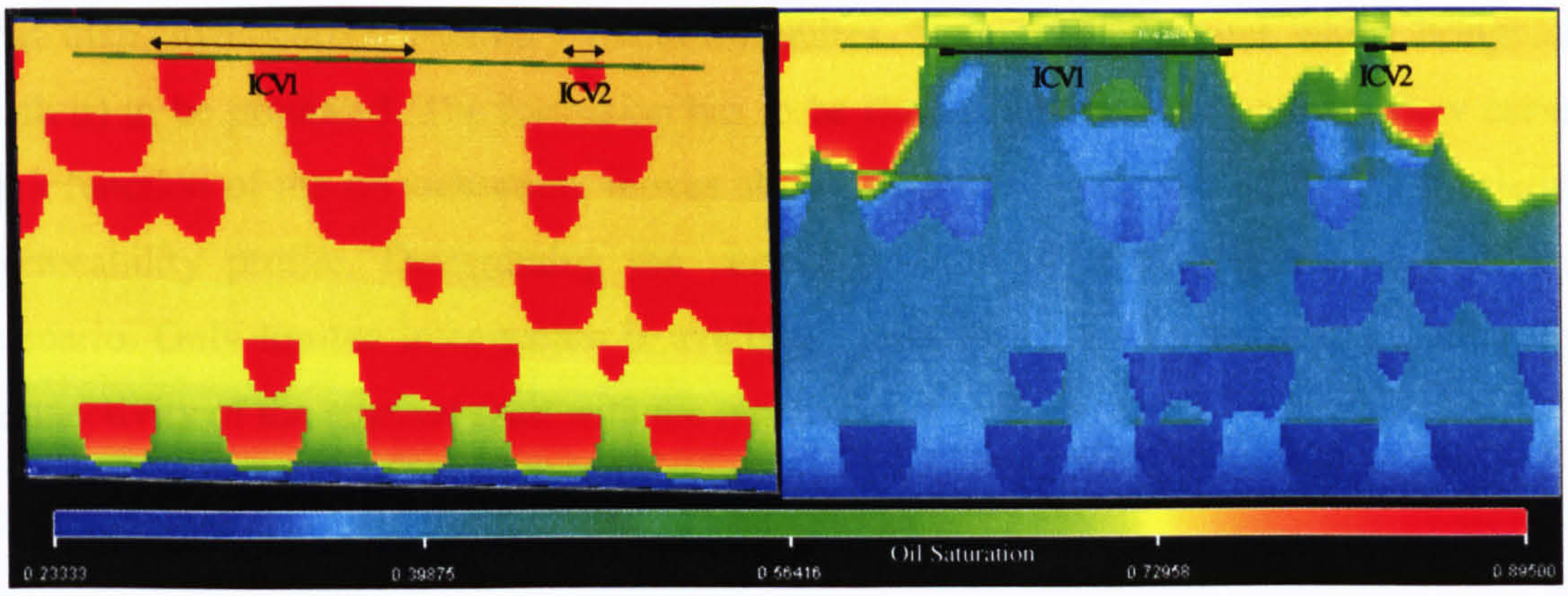


Figure 7-27: Front view of ICVs position and fluid displacement in a Heterogeneous Channel Reservoir (Realisation A)

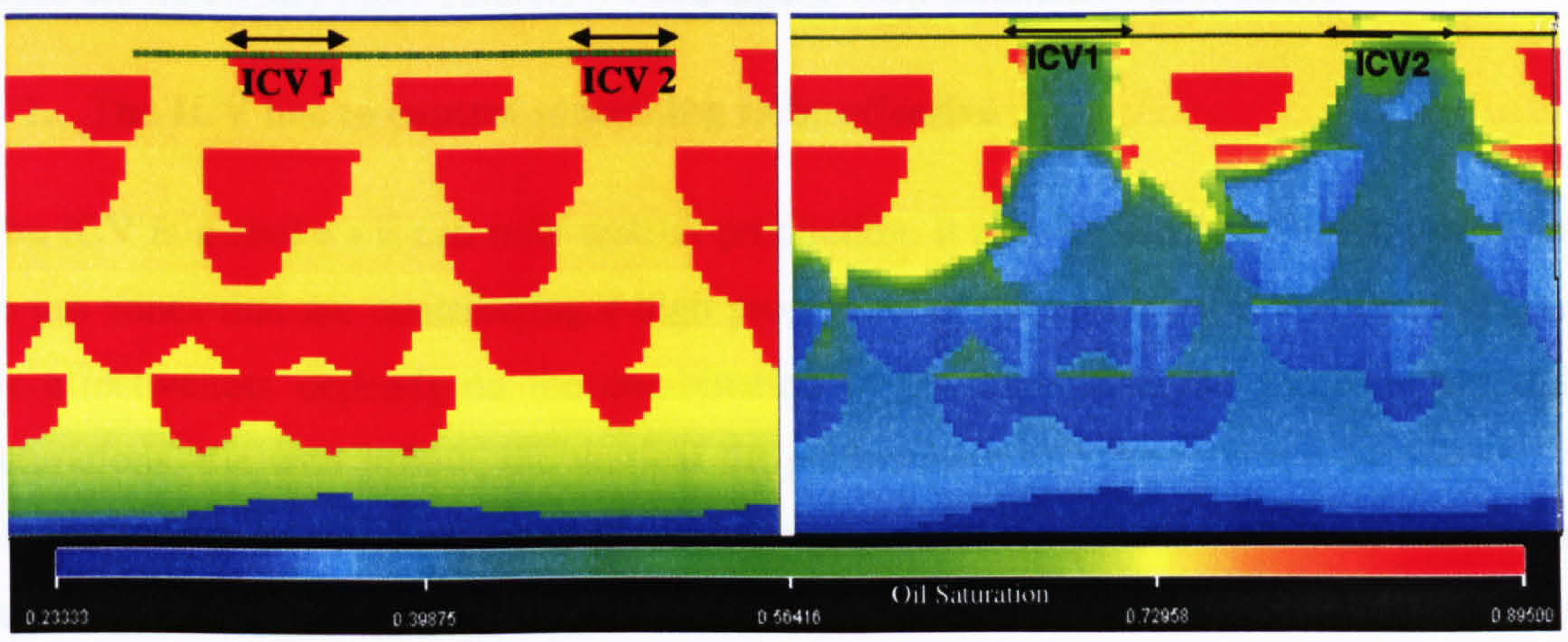


Figure 7-28: Front view of ICVs position and fluid displacement in a Heterogeneous Channel Reservoir (Realisation B)

Lessons Learned

Well Performance depends on the location of the well with respect to the high permeability channels and the extent of the connectivity between these channels. These features control the local gas or water breakthrough time. The effectiveness of the ICV depends on its ability to improve reservoir sweep efficiency, while maintaining a sufficiently high well deliverability (i.e. the well's production targets can be met). It must also be remembered that high, hydrocarbon recovery fraction requires "good" water (water which brings oil with it) to be produced. The formation has to be flushed so that the fractional flow curve, as a function of the oil saturation, moves along Dake's "long corner" [7.6] of the relative permeability profile. Determining the correct position of ICV(s) is not easy in this scenario. Only limited information is available, prior to the well's completion, about the connectivity of the channel sand with the remainder of the reservoir.

7.4 Conclusions

IWsT has been shown to be capable of managing geological variability and thus coping with geological uncertainty in a wide range of reservoirs. It has shown that some reservoir types are inherently more suitable for Intelligent Well installation than others.

1. The ICV has to control something to be effective

The ICV is a choke - it can only restrict production. It may be used for shutting off water or gas zones that are contributing a high proportion of the unwanted fluid (water or gas). Its effectiveness depends on the combination of the local reservoir pressure and fluid saturations, the well inflow, the vertical lift performance and the reservoir heterogeneity. "Good" water has to be flushed through the formation to produce oil from zones with sufficient remaining oil saturation. "Bad" water from already flushed zones should be shut off. Other factors that have a major impact on well performance are the well's Productivity Index and the well's Production Target. The choking of an ICV can only achieve short term, field management objectives if another completion zone can produce extra oil so that the well's target oil production rate is still achieved. This choking effect can, at least partially, be compensated by the installation of Artificial Lift.

2. An ICV can control uneven, invading fluid fronts

Uneven fronts develop along the wellbore due to permeability differences, compartmentalization (of either sedimentary or structural origin) and/or due to different strengths of the aquifer/gas-cap pressure support. The longer the completion intervals, the greater the potential for such differences to develop along the wellbore (i.e. from heel to toe). Hence, the greater the potential value that can be achieved by an ICV installation.

IWsT adds value in layered and compartmentalised reservoirs provided the difference in layer/compartment permeability is sufficient to produce an un-even fluid front progression towards the wellbore. Reservoir permeability heterogeneity is one cause of an un-even fluid front. Multiple aquifers/gas-caps of different strength supporting the production from a number of formation layers in contact with the wellbore are a second cause of un-even fluid fronts developing along the wellbore.

IWsT can add value in faulted or compartmentalised reservoirs being produced by a horizontal or multilateral well provided there is a difference in pressure or oil/water contact level (Figure 7-6) between the zones. This is true irrespective of the distribution of permeability and porosity in the isolated reservoirs.

It is clear that there is the potential for IWsT "Added Value" if the reservoir has one of the above characteristics (e.g. layered or compartmentalised). However, real reservoirs will normally have a more complicated distribution of permeability and porosity. This will be studied further in the next chapter.

3. **Oil Recovery from a Horizontal Well is strongly influenced by the permeability distribution immediately around the wellbore**

Added Value for IWsT in a Horizontal Well is a function of the permeability distribution around the wellbore and the optimum placement of ICVs along the completion length.

The recovery improves with correct choice of the number and location of the ICVs within the wellbore. This study suggests that ICVs should be installed in the high permeability areas on the basis of information (logging, cuttings etc.) gained during drilling. This will be studied in details in chapter 8.

In this study, generic models were used and various aspects simplified for practical necessity (including size of models, size and number of grid blocks, fluids, contacts, aquifers, economics and other engineering control methods). In "real life" studies these issues will have to be further considered.

The presence of faults or other forms of compartmentalisations that can give rise to different pressure regimes, fluid contacts and other forms of uneven fluid front movement towards the wellbore will also lead to "Added IWsT Value".

The fact that IWsT can potentially "Add Value" will not be sufficient justification for its installation. This has to be confirmed by a full economic analysis for the particular case being studied.

7.5 Summary

Intelligent Well systems Technology (IWsT) can deliver and manage the production flexibility thorough downhole measurement and control.

Results show that IWsT can control uneven, invading fluid fronts that develop along the wellbore length due to permeability differences, reservoir compartmentalisation or different strength of aquifer or gas cap support. Downhole Interval Control Valves (ICVs) are capable of managing wellbore friction effects as well as the above differences in zone pressure along the wellbore. Oil recovery factors improve and co-produced water volumes reduce with proper valve choking, when combined with a correct selection of the ICV location(s) and control zone length.

However, the degree of improvement is dependent on the reservoir type (Layered, Faulted, Channelised, etc.) and the distribution of porosity and permeability within it. Guidelines for optimum placement of ICV location within the planned completion zone are discussed.

In the next chapter a new workflow will be used to evaluate the suitability of a wide range of reservoir types for IWsT application on the basis of reservoir statistical parameterization. A global methodology will be developed for initial screening for favourable geological scenarios for the implementation of IWsT.

7.6 References:

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Chapter 8 A Methodology for Evaluating the suitability of a Reservoir Type for IWsT using Reservoir Statistical Information

8.1 Introduction

In the previous chapter the effect of different reservoir heterogeneity and geometries on the IWsT performance was determined. It was showed that intelligent wells could "Add Value" in a wide range of reservoir types. Developing a screening tool for evaluating the suitability of a Reservoir Type would simplify the process of justifying the cost associated with an IWsT installation. This will result in decreased risk & uncertainty associated with developing complicated reservoirs.

Reservoir heterogeneity has a very important role in fluid-front performance and IWsT "Value Generation". The Intelligent Well can control uneven, invading fluid-fronts that develop along the length of the wellbore. The uneven fluid front could be due to permeability differences, reservoir compartmentalisation, different strength aquifer/gas cap support, etc. A review of the lessons-learned of the applicability of IWsT in various reservoir types from the previous chapter can help clarify the way forward:

8.1.1 Layered Reservoirs

IWsT adds value in this reservoir type (Figure 8-1) provided the difference in layer permeability is sufficient to produce an un-even fluid front progression towards the wellbore. Reservoir permeability heterogeneity is one cause of an un-even fluid front. Multiple aquifers/gas-caps of different strength supporting the production from a number of formation layers in contact with the wellbore are a second cause of un-even fluid fronts developing along the wellbore.

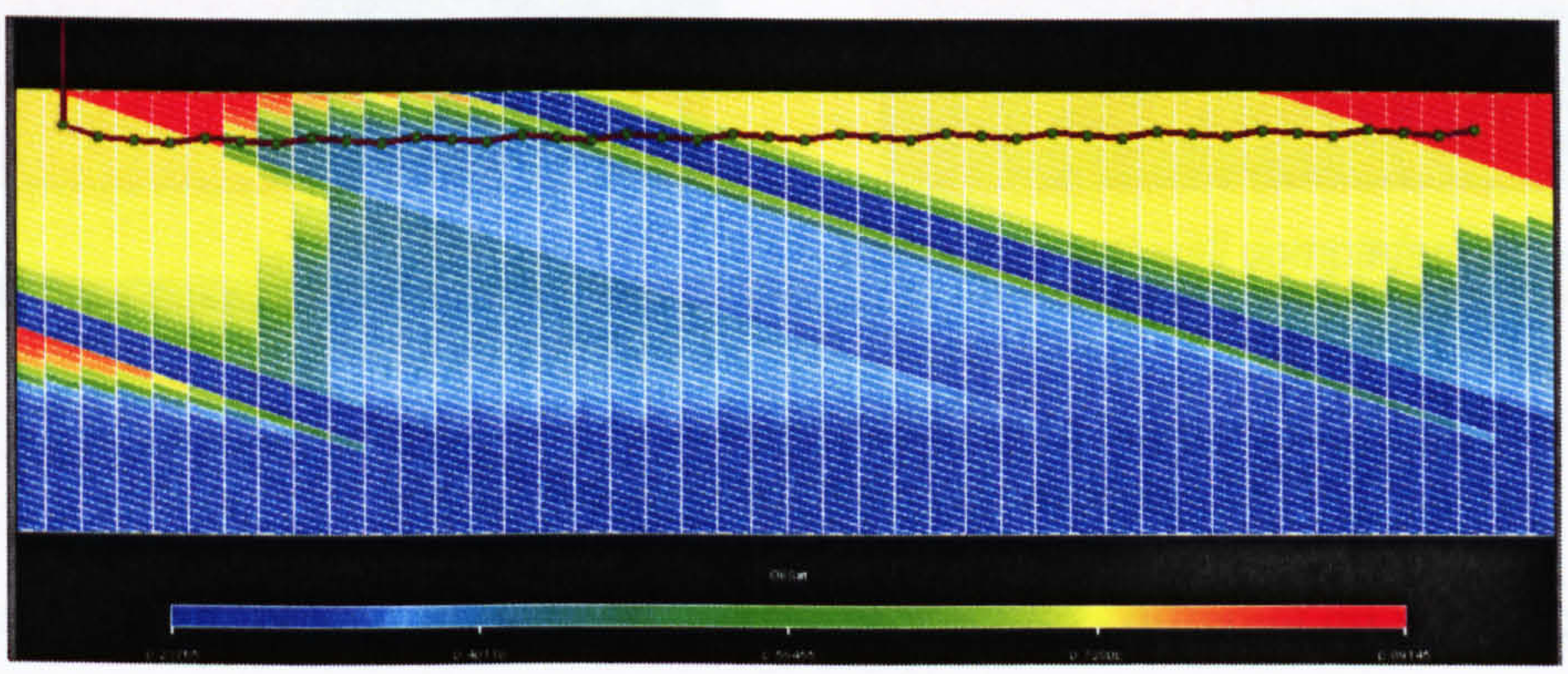

Figure 8-1: A layered reservoir with high and low perms layers

8.1.2 Compartmentalised Reservoirs

IWsT can "Add Value" in faulted or compartmentalised reservoirs being produced by a horizontal or multilateral well. This is also true when there is a difference in pressure or oil/water contact level (Figure 8-2) between the zones. This is true irrespective of the distribution of permeability and porosity in the isolated reservoirs.

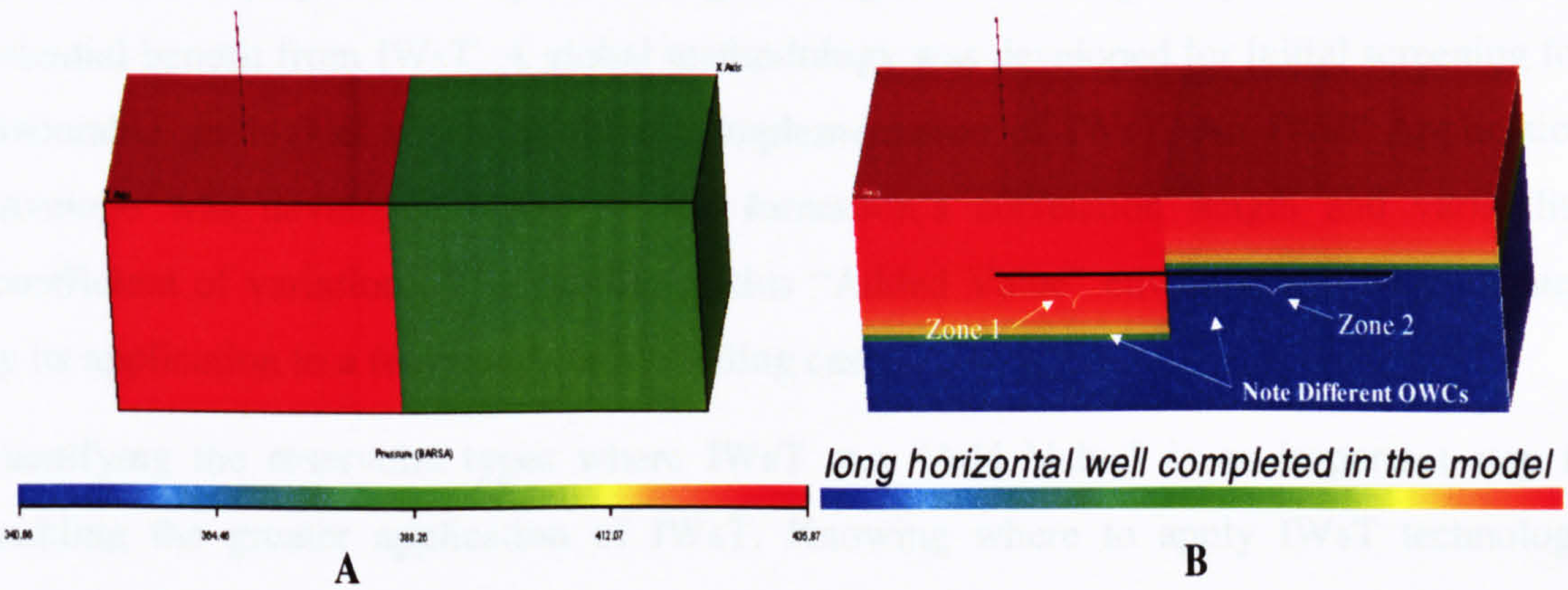

Figure 8-2: Faulted reservoir models
A: Sealing fault - Two different reservoir pressures
B: Sealing fault present initial or after some production - different oil water contact

It is clear that there is the potential for IWsT "Added Value" if the reservoir has one of the above characteristics (e.g. layered or compartmentalised). However, real reservoirs will normally have a much more complicated permeability and porosity distribution. It is, therefore, necessary to develop a methodology, which could be applied to every reservoir type. This will be discussed in this chapter. It is clear that if the reservoir has one of the above characteristics (e.g. layered or compartmentalised) it has a much higher chance of benefiting from IWsT.

8.2 Methodology

An easy-to-use tool for recognising "Added Value" is not available in the case of a single sand reservoir with a complex permeability and porosity distribution as explained above. It was therefore decided to carry out a study in which the reservoir heterogeneity was systematically varied. This heterogeneity is measured using the Geologist's "Coefficient of Variation" and "Correlation Length". A range of realisations of a reservoir model have been created by systematically increasing the degree of heterogeneity and evaluating the potential benefit from IWsT. A global methodology was developed for initial screening for favourable geological scenarios for the implementation of IWsT. An IWsT Application Envelope was developed based on the formation's correlation length and variability (coefficient of variation). The validity of this "Added Value" envelope will be illustrated by its application to a real reservoir modelling case.

Identifying the reservoirs types where IWsT can "Add Value" is an important step in enabling the greater application of IWsT. Knowing where to apply IWsT technology begins with reservoir characterization - a crucial stage in reservoir management.

Some twenty models (2 km x 1 km x 50 m) were generated using the previously described, stochastic modelling technique. Grid cells showing the same permeability (0.01 - 10,000 mD) and porosity (0.1 - 0.4) ranges used previously were distributed throughout the models. The degree of formation heterogeneity was increased systematically by changing the Coefficient of Variation (Cv) and the Correlation Length (CL).

Production from a 1450 m horizontal well, placed in the centre, near the top of the model, completed with and without IWsT, was modelled. The ICV(s) were placed across high permeability zones present along the wellbore. The same optimisation and evaluation techniques for ICV management discussed earlier were applied. The models were run with a conventional completion to identify those values of C_V and CL where un-even fluid fronts could develop. The ICVs were then operated to control front invasion and to quantify the potential "Added Value".

The degree of formation heterogeneity was altered systematically by changing the values of the C_V and CL parameters. The CL parameter was made dimensionless by dividing CL_H by the Well Length (WL) [8.8] and CL_V by the Reservoir Thickness (RT). The range of model parameters used for the generated models was such that they fully explored the CL_H/WL versus C_V and the CL_V/RT versus C_V spaces (Figure 8-3 and Figure 8-4).

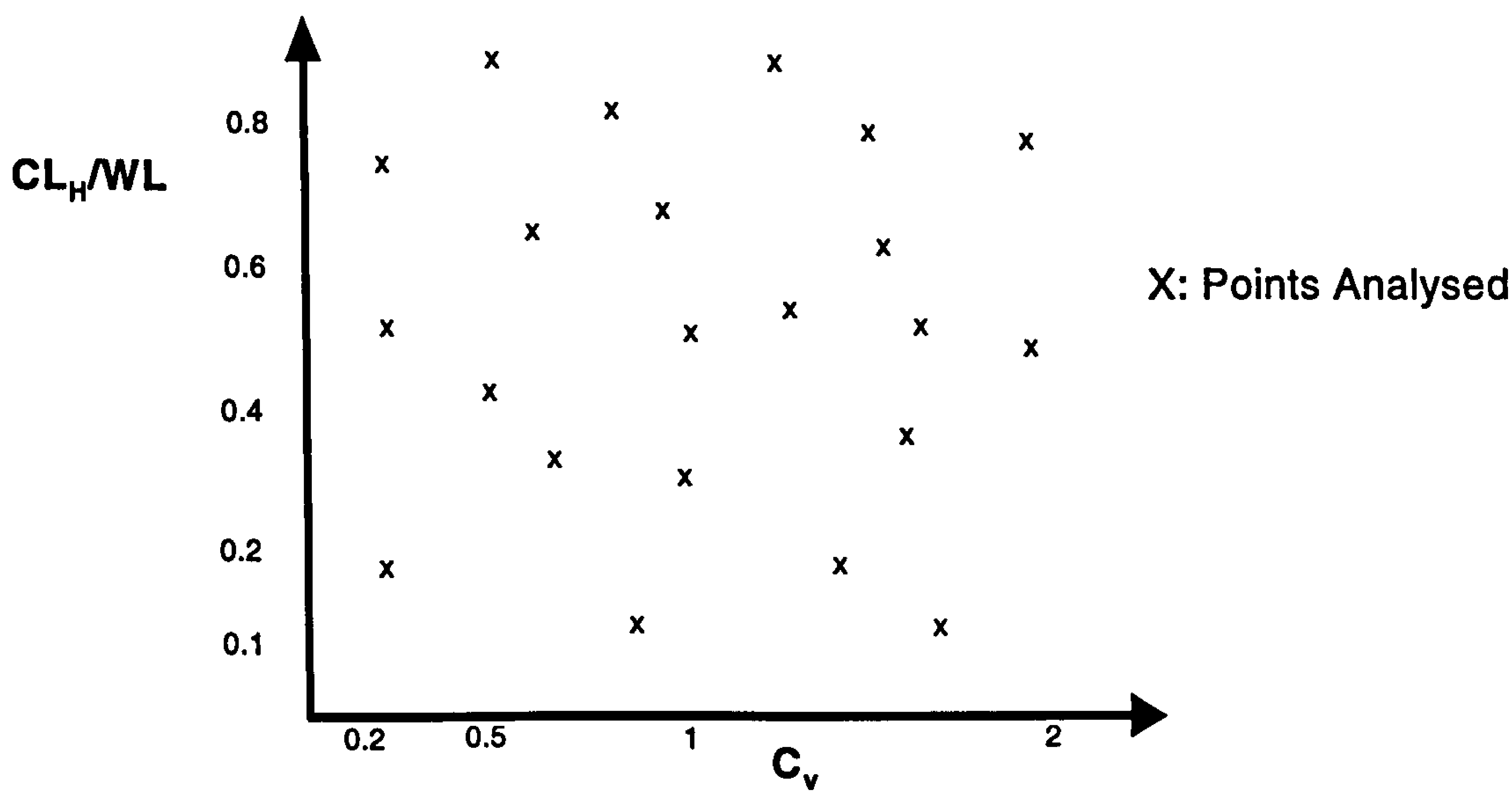

Figure 8-3: Cases selected for analysis within the dimentionless horizontal Correlation Length vs Coefficient of Variation space

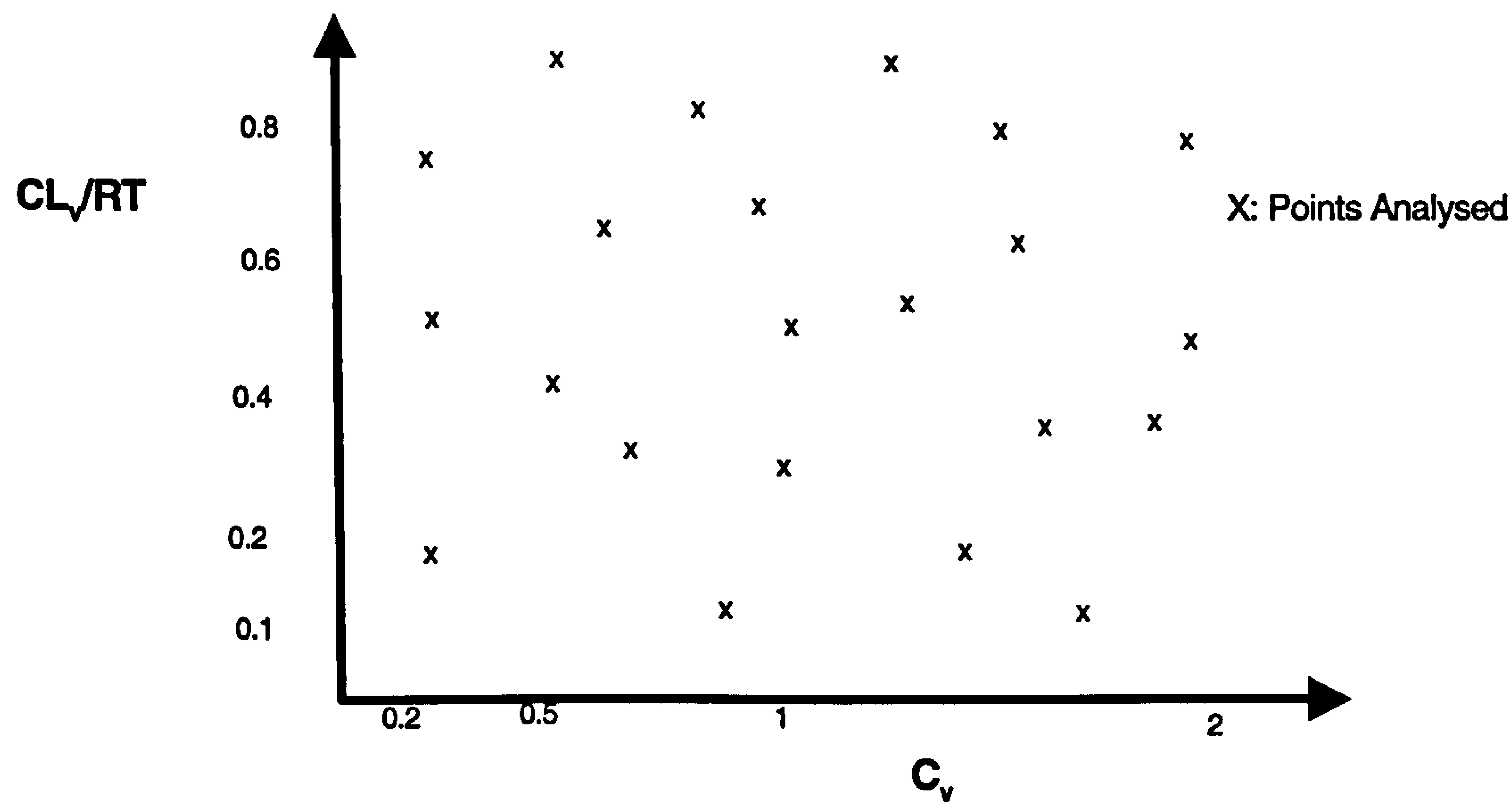

Figure 8-4: Cases selected for analysis within the dimentionless vertical Correlation Length vs Coefficient of Variation space

A range of sensitivity analysis was performed in order to confirm and generalize the above results:

Sensitivity to Permeability range: The range of permeability values in the models was reduced from 0.01 - 10,000 md (mean 5,000 md) to 0.01 - 4,000 md (mean 2,000 md) and 0.01 - 2,000 md (mean 1,000 md). Results obtained were essentially the same for both model sets for constant Cv, CL_H/WL and CL_V/RT values.

Sensitivity to grid size: The size of grid cells in the models was reduced from 40 m * 40 m * 1 m to 25 m * 25 m * 1 m and the same modelling and optimisation methodology applied. No unexpected changes in model performance were detected. The maximum recovery difference for the base case was 1%, while the Intelligent Wells showed the same range of improvement (0.2 - 2 %, depending on the well location, detailed distribution of reservoir properties, etc.) as observed previously.

8.3 Results

1. An increase in C_V increases the scatter and the range of permeability values present in the model. An increase in CL_H or CL_V allows similar permeability values to be grouped together. The unevenness of the fluid front progression, and hence those areas that will allow an Intelligent Well to show value, can be expected to be a function of C_V, CL, WL and RT.
2. Models with a C_v value of less than 0.3 and a (CL_H/WL) value of 0.2 showed an even fluid front development. Figure 8-5 shows a model with a CL of 800 m (0.55 * WL) in the X and Y directions and 15 m (0.3 * RT) in the Z direction. It has a C_v value of equal to 0.77 and (CL_H/WL) of equal to 0.55. This model showed a slightly uneven fluid front development towards the wellbore (Figure 8-6).

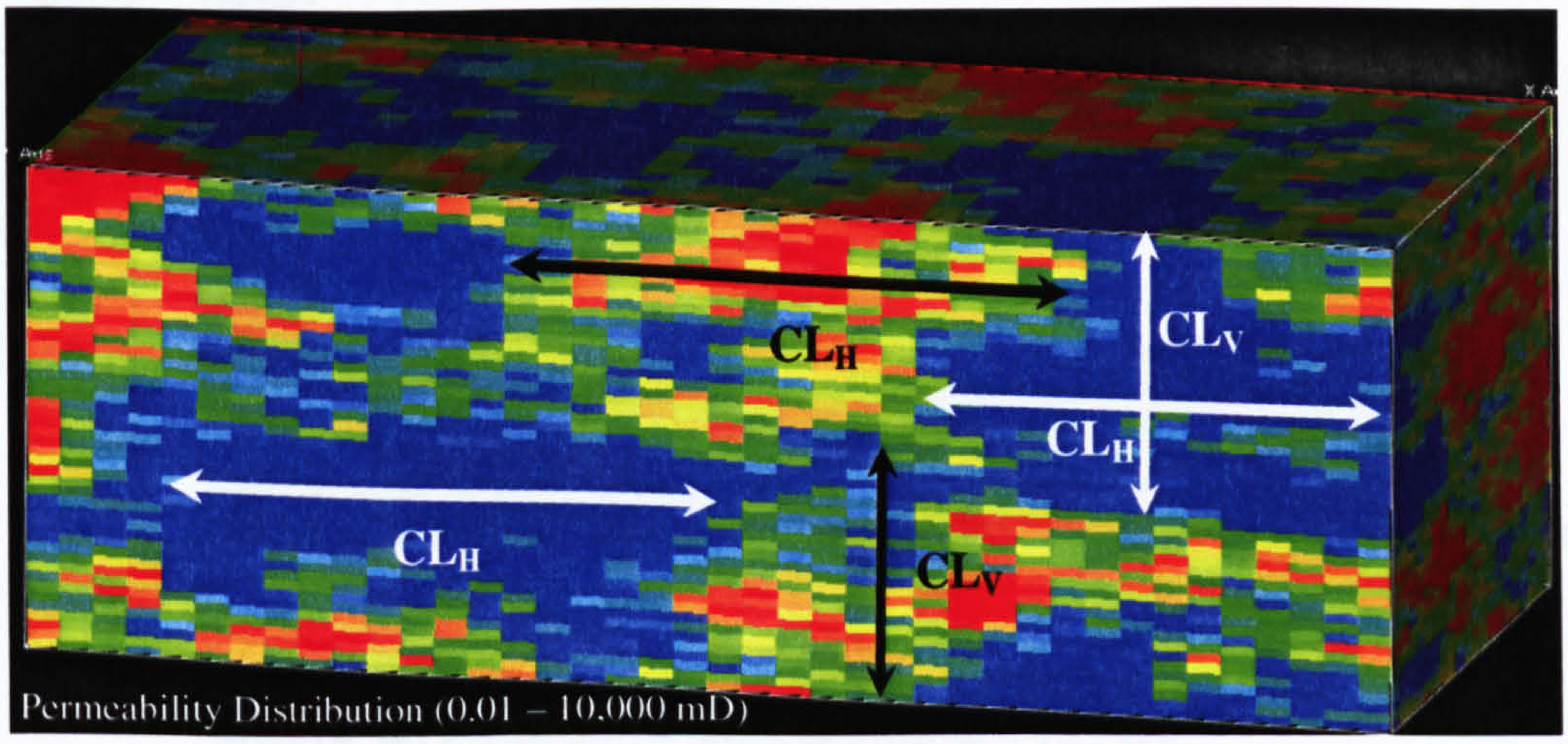

Figure 8-5: CL_H and CL_V illustrated for a model showing slightly uneven fluid front development in Figure 8-5

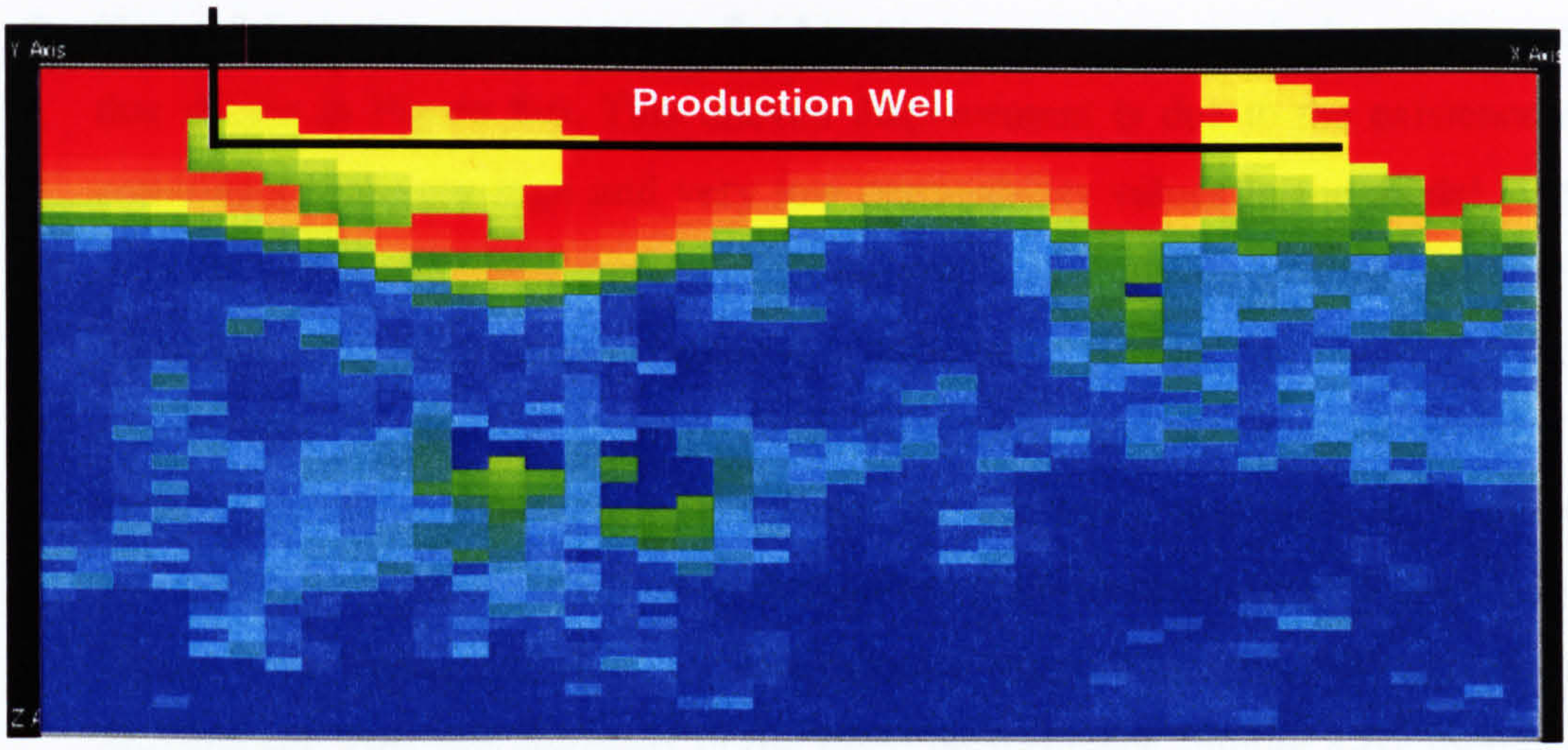

Figure 8-6: Fluid Front Invasion for the model shown in Figure 8-5

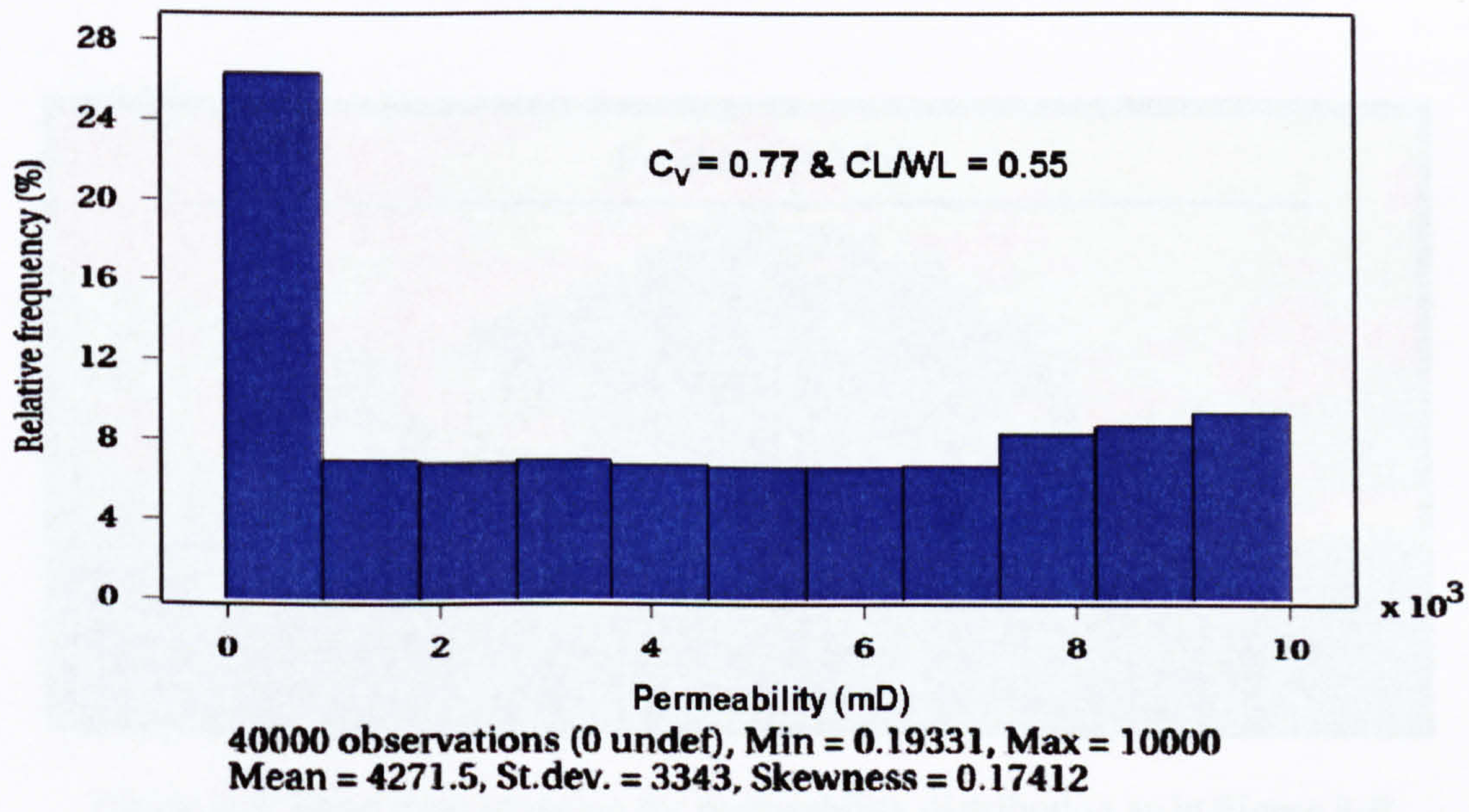

Figure 8-7: Relative frequency of permeability values in the model shown in Figure 8-5

3. Figure 8-8 shows a more uneven fluid front progression towards the wellbore than that shown in Figure 8-6. This uneven displacement is due to the existence of a combination of very high and very low permeability values in the model (Figure 8-9). This results in development of an uneven fluid front towards the wellbore for a suitable correlation length. Figure 8-7 is the same plot for the Figure 8-5 model where only a slightly uneven fluid front development was observed. The systematic studies reported here defined the necessary minimum differences in permeability values for creation of the uneven fluid front (compare Figure 8-6 and Figure 8-7). Figure 8-7 shows a less extreme (more homogeneous) permeability distribution. This was reflected in the flood performance (Figure 8-6), though this latter will also depend on the CL_H and CL_v values.

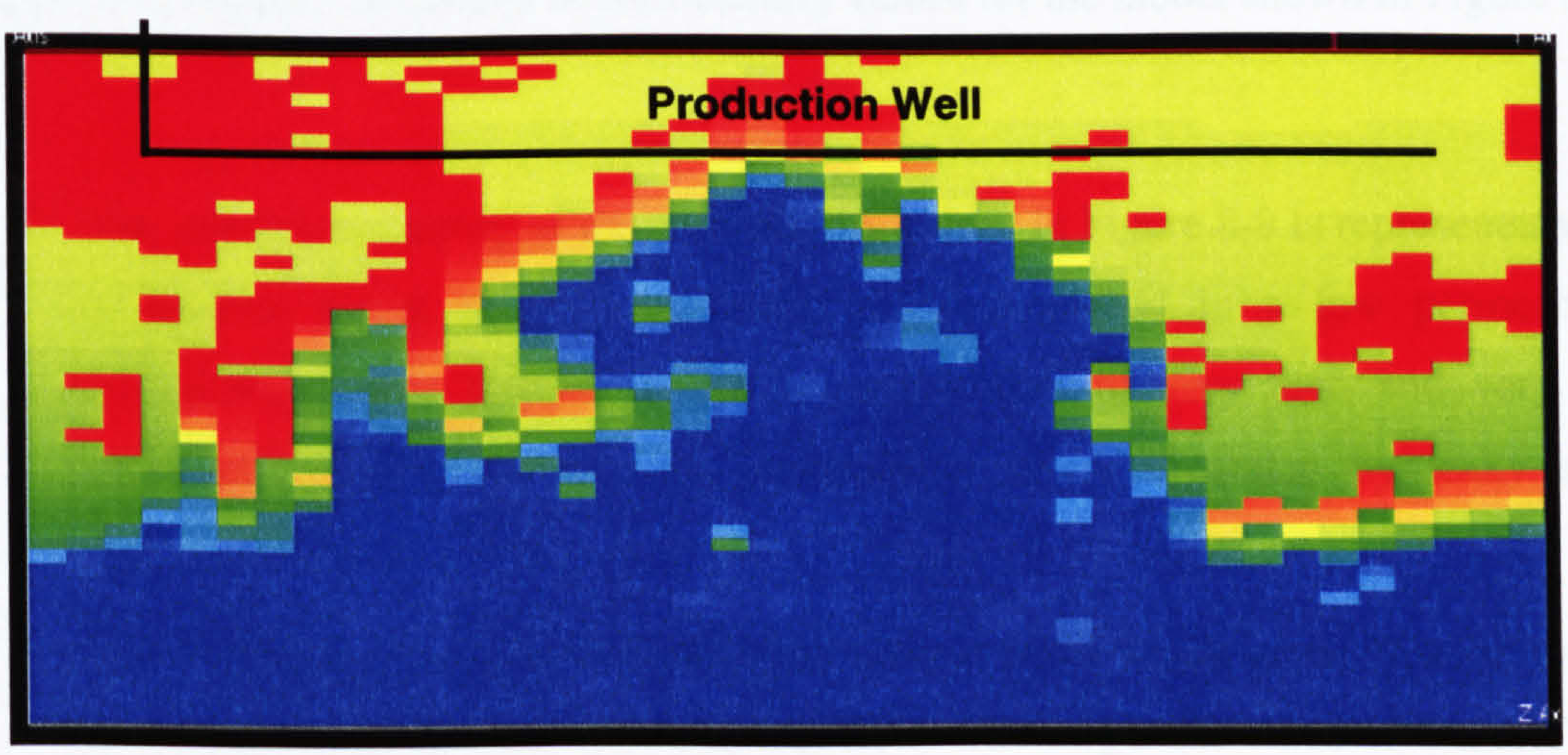

Figure 8-8: Fluid front invasion for permeability distribution as in Figure 8-9

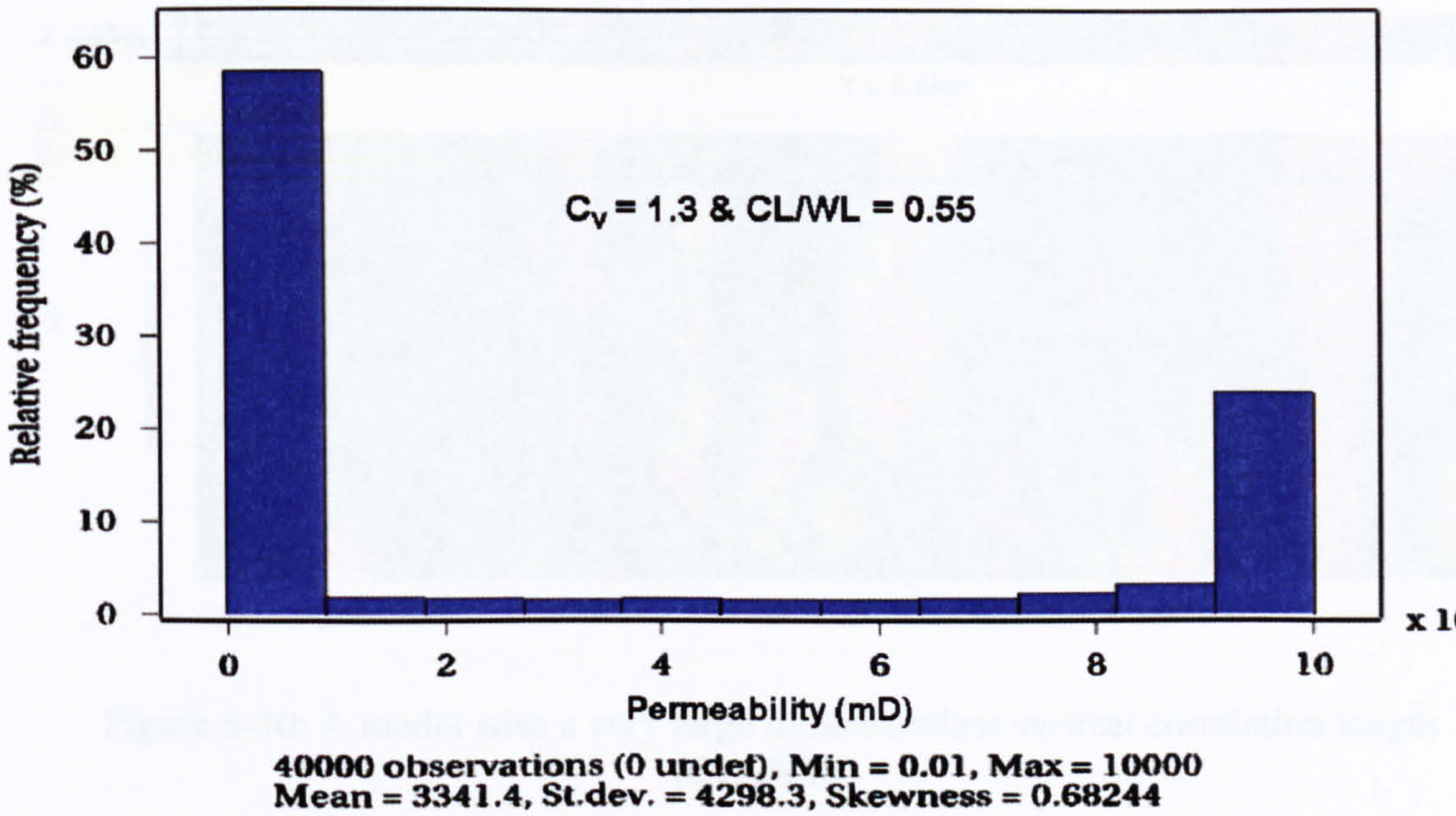

Figure 8-9: Relative frequency of permeability values for the model shown in Figure 8-8

4. The relative frequency of the permeability values in Figure 8-9 is representative of a channel model (high permeability channels placed in a low permeability background) or a layered model (a combination of very high and very low permeability layers or of high permeability layers separated by leaky shale barriers).

5. The minimum correlation length in the vertical plane which gives "Added Value" is a function of the reservoir thickness (RT). The larger the value of CLv/RT, the higher the chance of early water breakthrough in the high permeability zones i.e. uneven fluid fronts form and progress towards the wellbore (Figure 8-10). In practice, CL_V/RT values greater than 0.5 rarely occur in real formations, unless there is a significant formation dip.

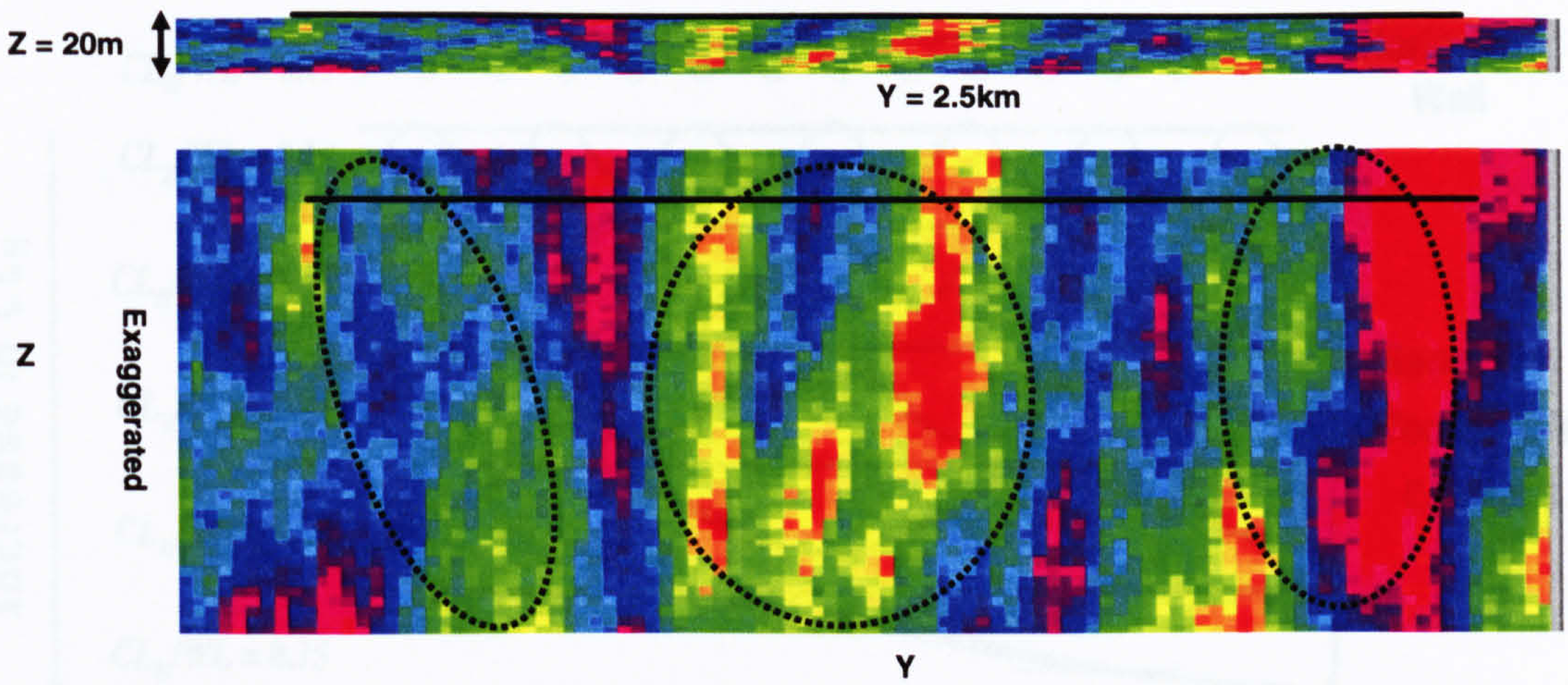

Figure 8-10: A model with a very large dimensionless vertical correlation length (CL_V/RT)

6. Simulation results show that the interplay of C_V with the dimensionless parameters CL_H/WL and CL_V/RT is the key factor. Uneven fluid fronts develop when these parameters interact so that adjacent model grid cells can be grouped into similar permeability values (e.g. Figure 8-5). Figure 8-11 shows how the interaction of the horizontal and vertical correlation length affects the shape of the fluid invasion front as it moves towards the wellbore. Hence the optimum number of ICVs required for effectively controlling this "unevenness" in the fluid-front movement will be controlled by these static reservoir properties.

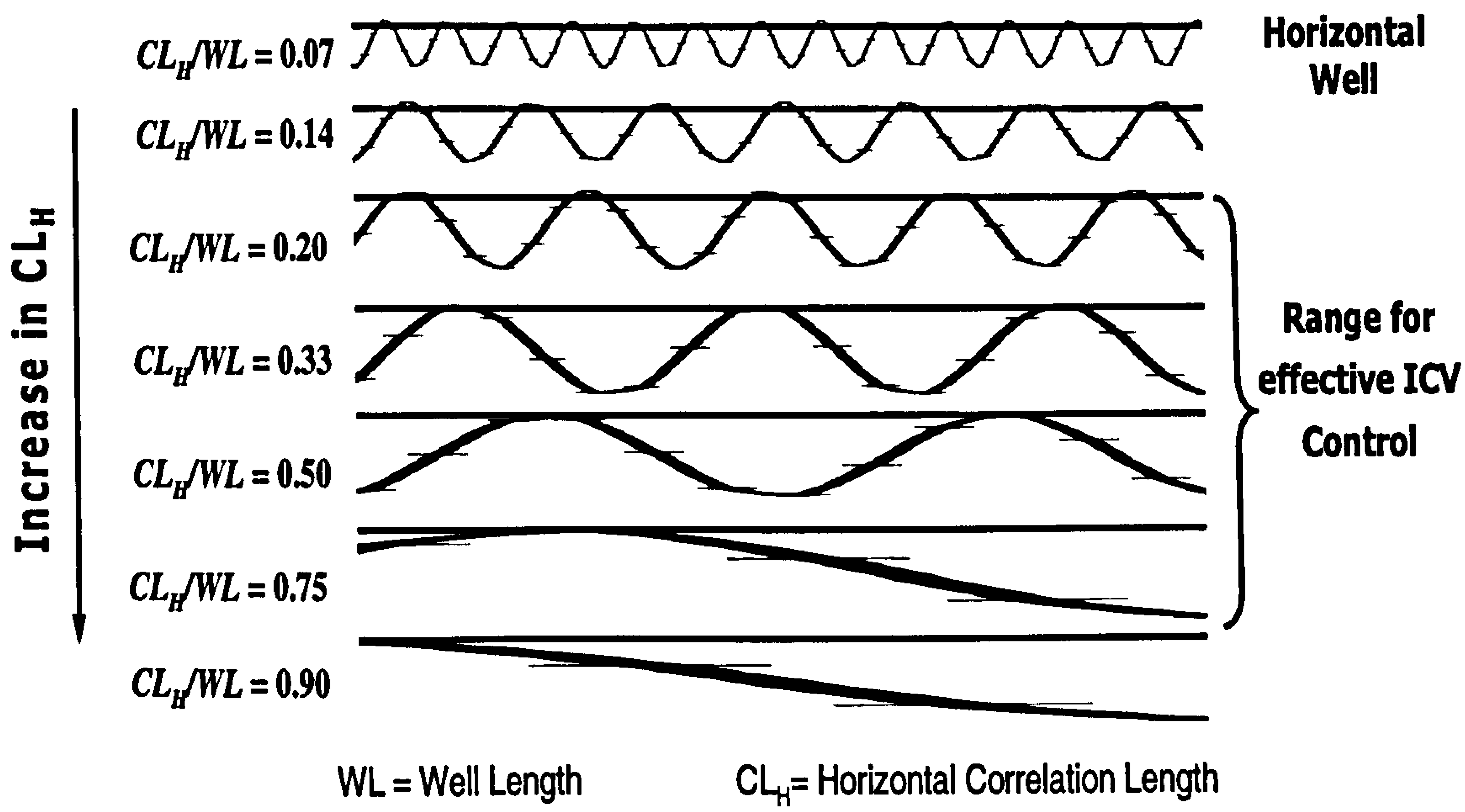

Figure 8-11: Representation of fluid-front progression towards the wellbore for stable Oil/Water displacement in heterogeneous systems

Figure 8-12 shows the results of analysis of the cases selected within the dimentionless horizontal Correlation Length vs Coefficient of Variation space. The figure indicates that some areas of the space show higher Added Value for Intelligent Wells than others.

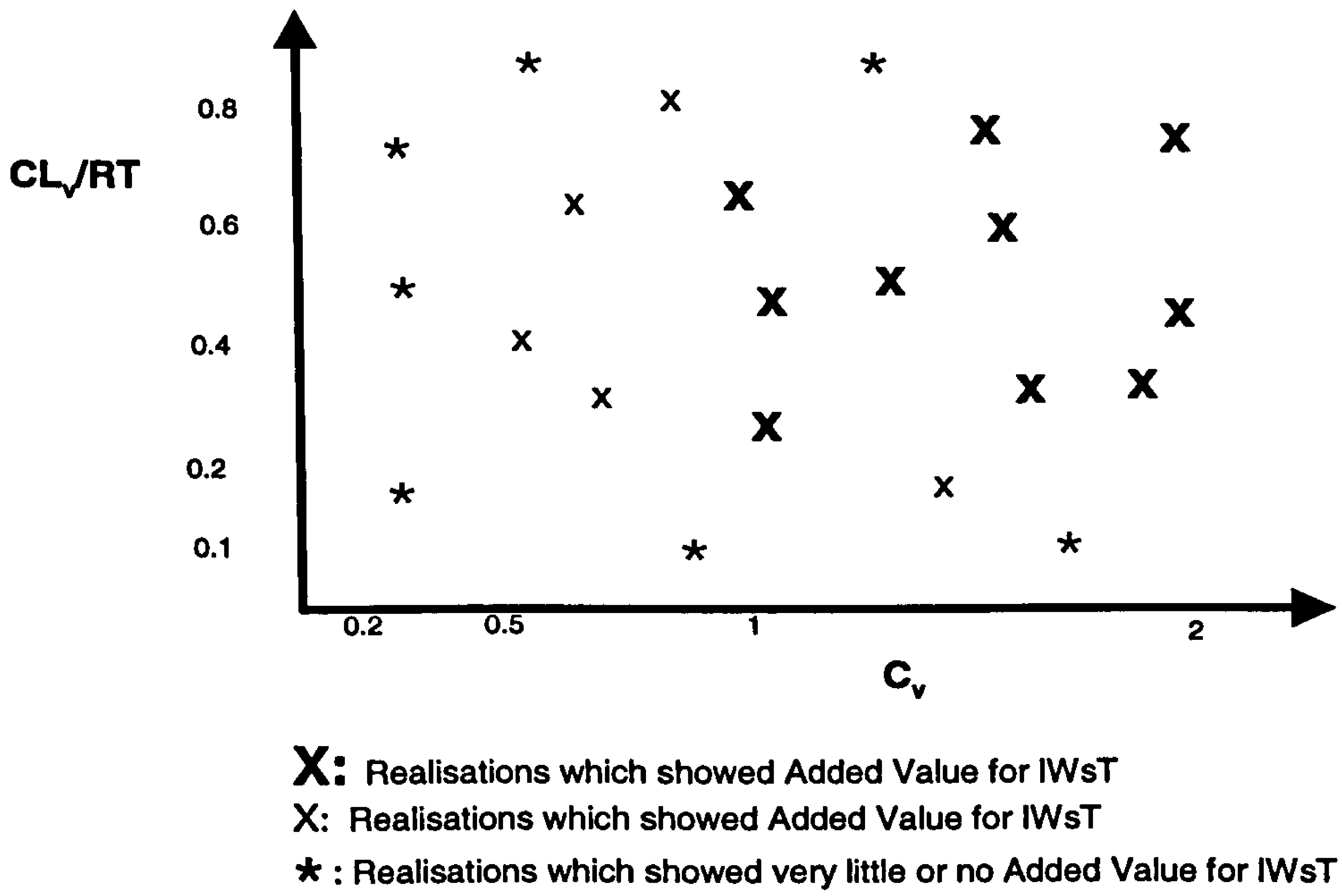

Figure 8-12: Results of analysis of the cases selected within the dimentionless horizontal Correlation Length vs Coefficient of Variation space

Lessons Learned

The analysis of the above results is summarised in Figure 8-13 and Figure 8-14. These figures illustrate an "Added Value" from IWsT Application Envelope for a horizontal well producing a low viscosity Oil/Water system. A similar plot can be developed for other fluid systems e.g. Gas and Water, etc. Figure 8-13 evaluates the IWsT application based on reservoir permeability and heterogeneity only, NOT Fluid Mobility. It is because a low Mobility Ratio (= 1.3) was used in the study. High viscosity oil reservoirs will give a more uneven fluid front and increased chance of early water breakthrough. Hence, the IWsT value area increases (Figure 8-15 is the equivalent figure for a high viscosity oil system). Further, the position and extent of the transition zone shown in Figures 8-13 and 8-15 will depend on a detailed economic analysis for the particular case being studied.

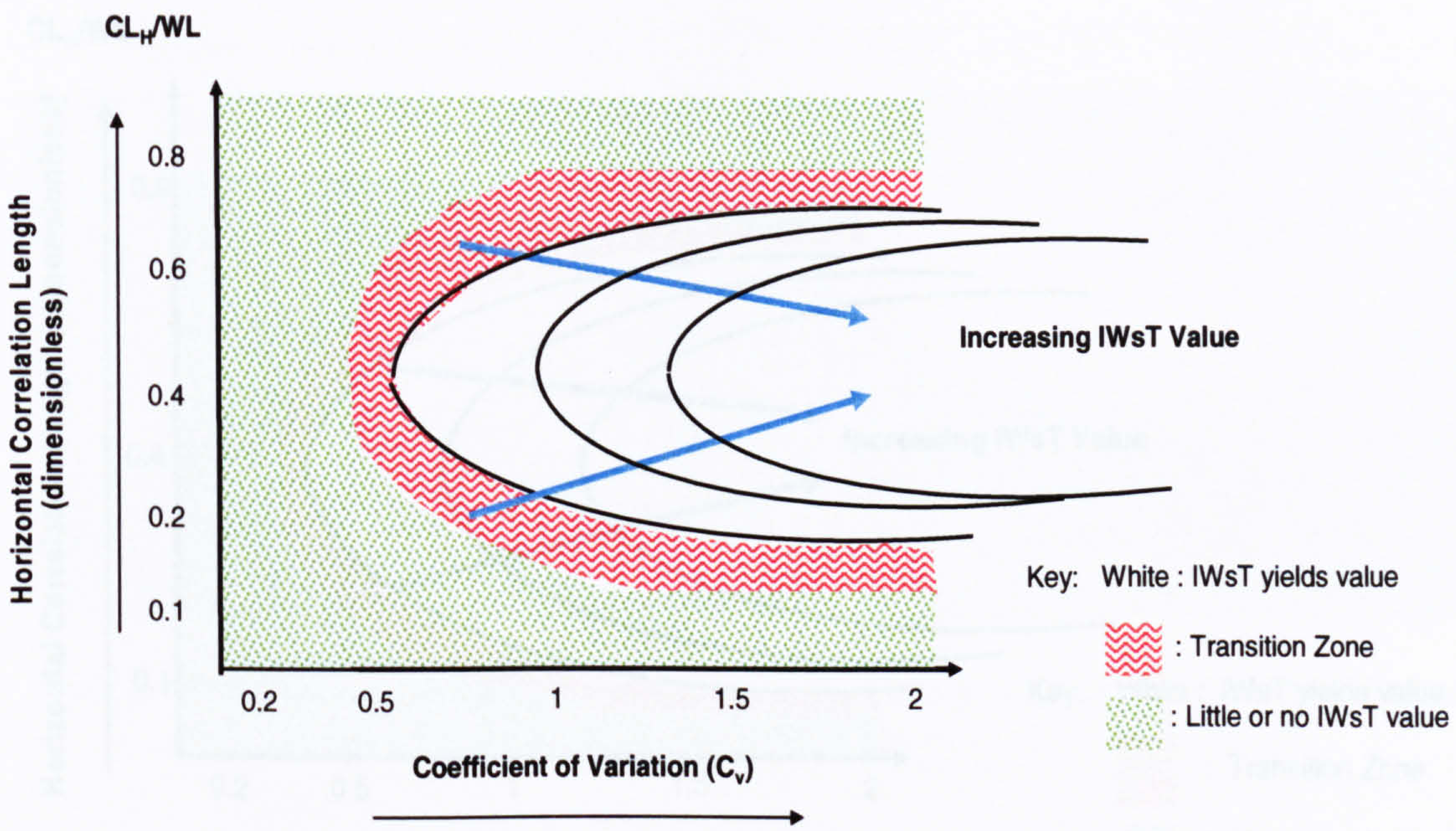

Figure 8-13: IWsT Application Envelope for a low viscosity Oil/Water System

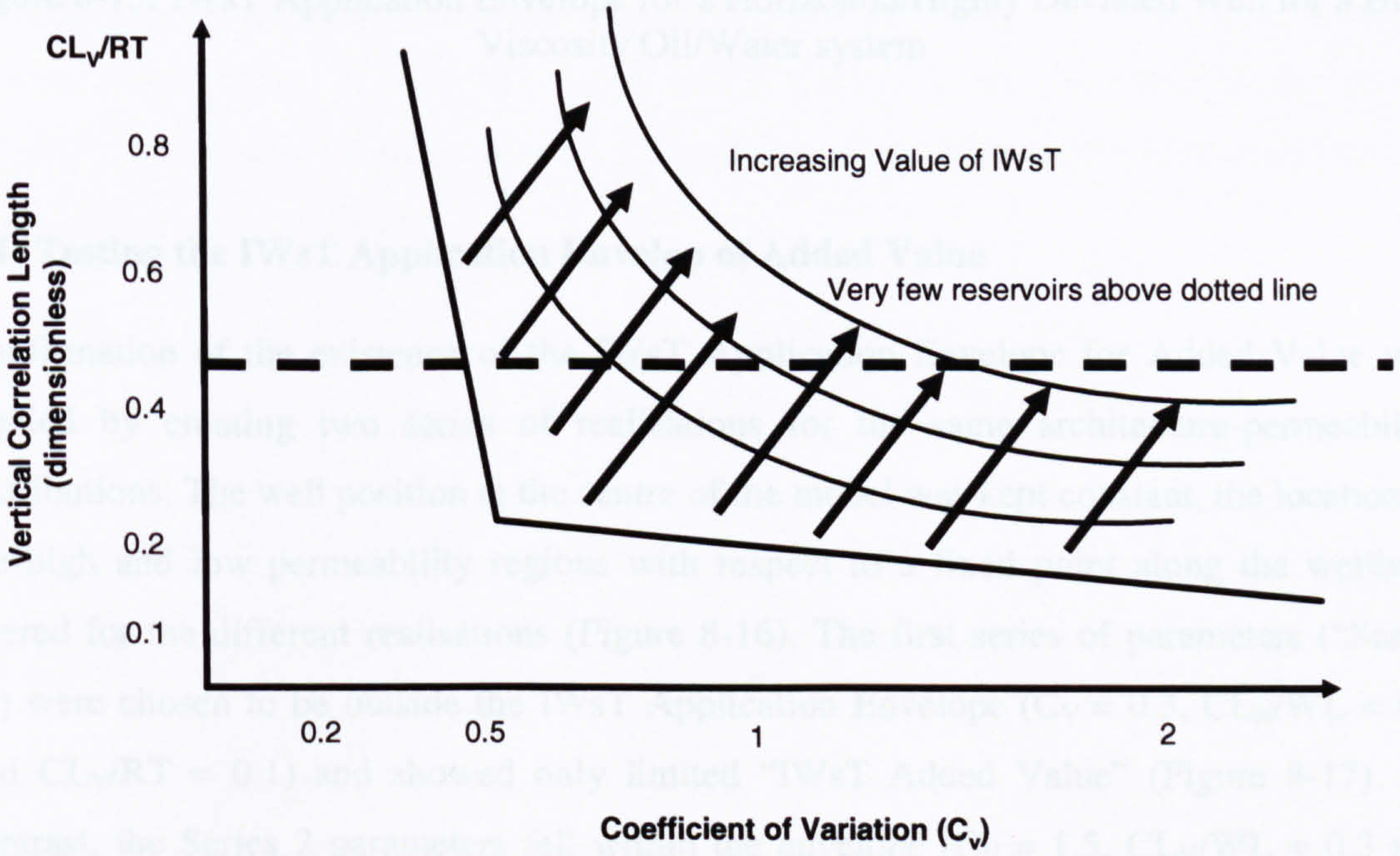

Figure 8-14: IWsT Application Envelope for a low viscosity Oil /Water system

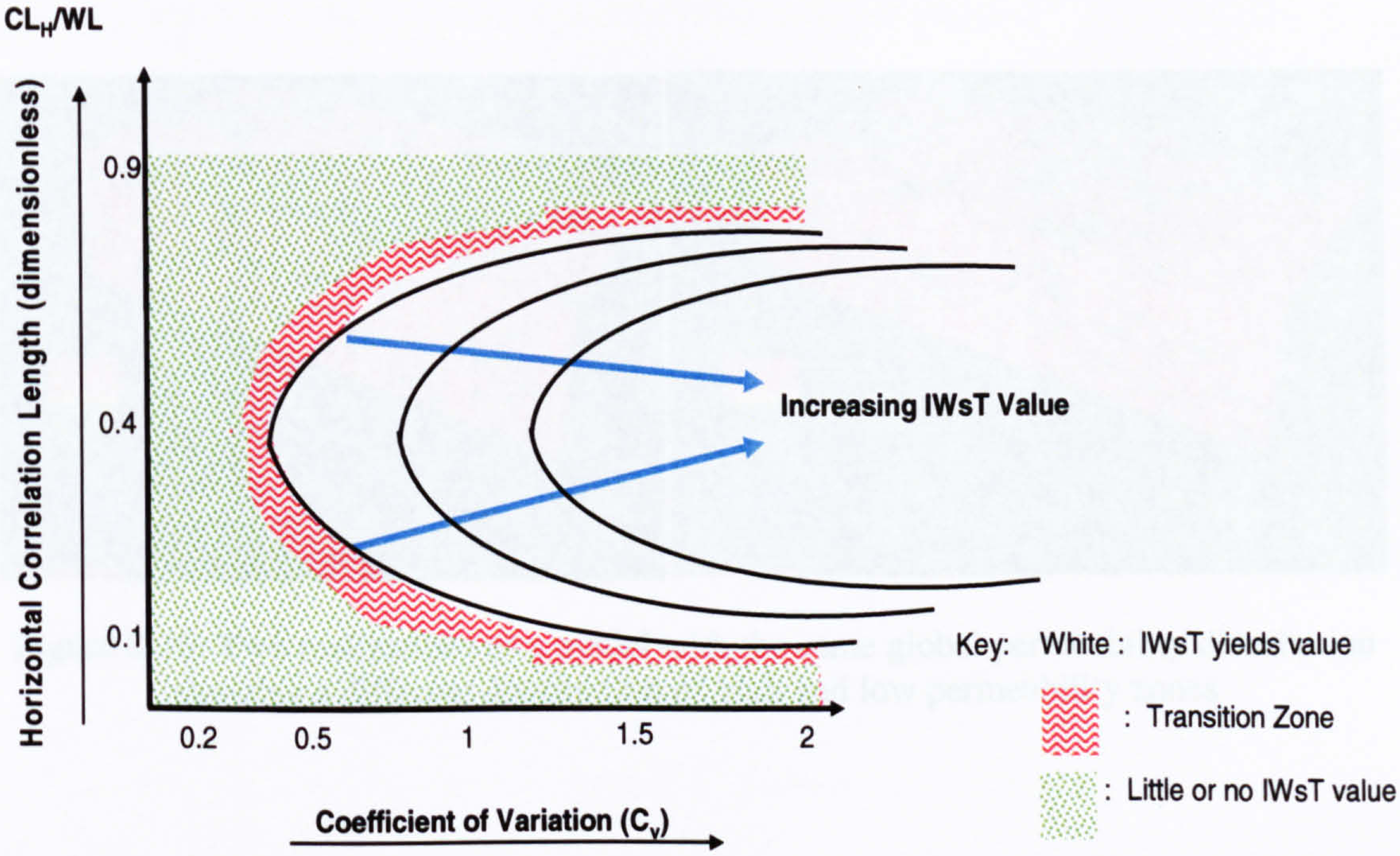

Figure 8-15: IWsT Application Envelope for a Horizontal/Highly Deviated Well for a High Viscosity Oil/Water system

8.4 Testing the IWsT Application Envelop of Added Value

Confirmation of the existence of the IWsT Application Envelope for Added Value was studied by creating two series of realisations for the same architecture-permeability distributions. The well position at the centre of the model was kept constant, the location of the high and low permeability regions with respect to a fixed point along the wellbore altered for the different realisations (Figure 8-16). The first series of parameters ("Series 1") were chosen to be outside the IWsT Application Envelope ($C_V = 0.3$, $CL_H/WL = 0.1$ and $CL_V/RT = 0.1$) and showed only limited "IWsT Added Value" (Figure 8-17). By contrast, the Series 2 parameters fell within the envelope ($C_V = 1.5$, $CL_H/WL = 0.3$ and $CL_V/RT = 0.4$).

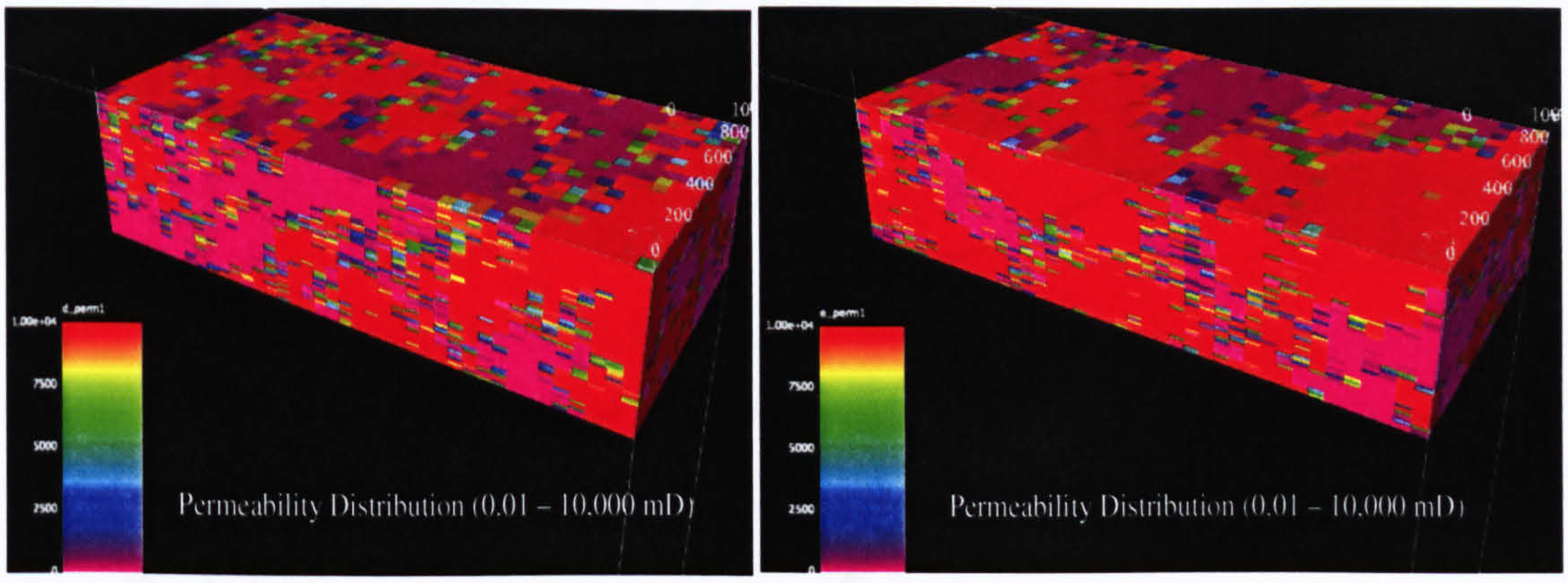

Figure 8-16: Two realizations of a model with the same global permeability distribution showing a different distribution of high and low permeability zones

Varying fluid-front performance at the wellbore was observed in the different realisations. As expected, all the series two realisations showed development of an uneven fluid-front and an "IWsT Added Value". The extent of the "Added Value" depended on the model details for that particular realisation i.e. the grouping of the high and low permeability grid cells relative to the wellbore.

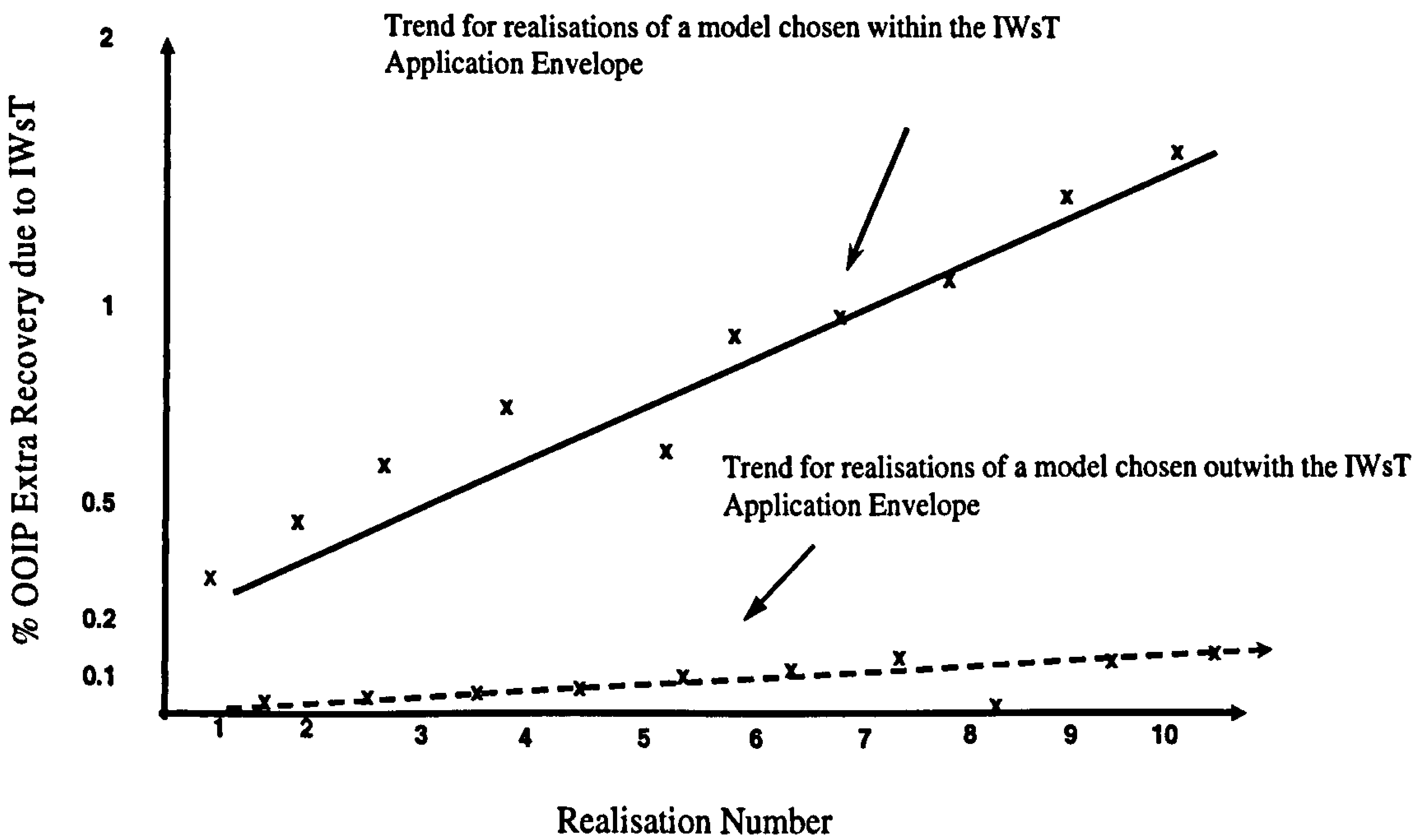

Figure 8-17: Added Value for both models within and outwith the IWsT applicability zone (NB: realisations are ordered from lowest to highest extra value due to IWsT)

The following discusses the significance of Figure 8-17:

1. "Added Value" of IWsT for each realisation was compared to its corresponding (no ICV case) base-case i.e. the base-case was not constant and varied with the particular realisation.

2. The well position was kept constant at the centre of the model. It therefore means that for some realisations well position was not optimum (i.e. well was not seeing the movement of an uneven, fluid front movement directly, even though it existed within the model.)

3. The methodology used for placement of the ICVs within each model was that it should cover any high permeability areas of the wellbore and that the selected zone lengths should not be too short and that the zone length should be as similar as

possible. The number of ICVs varied between 2 and 4 for different realisations, depending on the expected shape of any uneven fluid-front development.

4. Further studies [8.5] performed on the optimum placement of ICVs confirmed that the optimum number of ICVs is a function of the "unevenness" in the flood-front as it moves towards the wellbore. The fluid-front progression schematic (Figure 8-11) can be used as a tool for decision-making on the optimum number of ICVs required along the length of the wellbore in a complex reservoir. Thus, an increased number of independently moving, uneven fluid fronts moving towards the wellbore will require a greater number of ICVs for effective flow control.

5. The added value of IWsT for each realisation may, therefore, have been affected by non-optimum position and number of ICVs. However, realisations with parameters chosen from inside the IWsT Application Envelope gave higher value for IWsT compared to those chosen from outside the IWsT envelope, provided the ICVs were choking the correct sections of the wellbore. Realisations in which "Added Value" of IWsT was highly affected by non-optimum position and number of ICVs have been ignored in Figure 8-17. The choking (optimisation) policy was kept constant for all realisations to simplify the comparison; however, this will also affect the optimum "Added Value" of IWsT for various realisations.

6. The "Added Value" for an IWsT is dependent on the number and location of the ICV controlled zones. Too many valves lead to unnecessary and excessive cost as well as the potential for reduced reliability. Too few valves will not provide sufficient flexibility for efficient control.

7. A minimum degree of un-even fluid-front progression is required before effective ICV control "Adds" sufficient "Value" to justify the costs and risks involved in installing this technology.

8.5 Application of the "IWsT Added Value Screening Tool" to a Simulation Model of a Real Reservoir

The application of intelligent completions in a braided fluvial reservoir model of a real field case was evaluated to confirm the applicability of the "IWsT Added Value" screening tool, as well as to extend the catalogue of reservoir types tested. The opportunity was also taken to illustrate the role of the well's productivity index by exploring the value of artificial lift.

Two full-field reservoir models (Figure 8-18) using both Pixel based (Model A) and Object based (Model B) modelling technology were prepared from a field data set used in master's students projects. In this case, the details of the model building are not relevant as we are testing the application in a "real" field simulation model rather than the field itself. More details of the modelling approaches used are given by Zheng *et al* [8.11]

Single well, sector models of the equivalent reservoir volumes (Figure 8-19) were extracted and different realisations created by systematically changing the C_V & CL values. A 2km horizontal well equipped with ICV(s) was inserted into the models. It could be produced either by natural flow or by Artificial Lift to determine the "IWsT Added Value" for both cases.

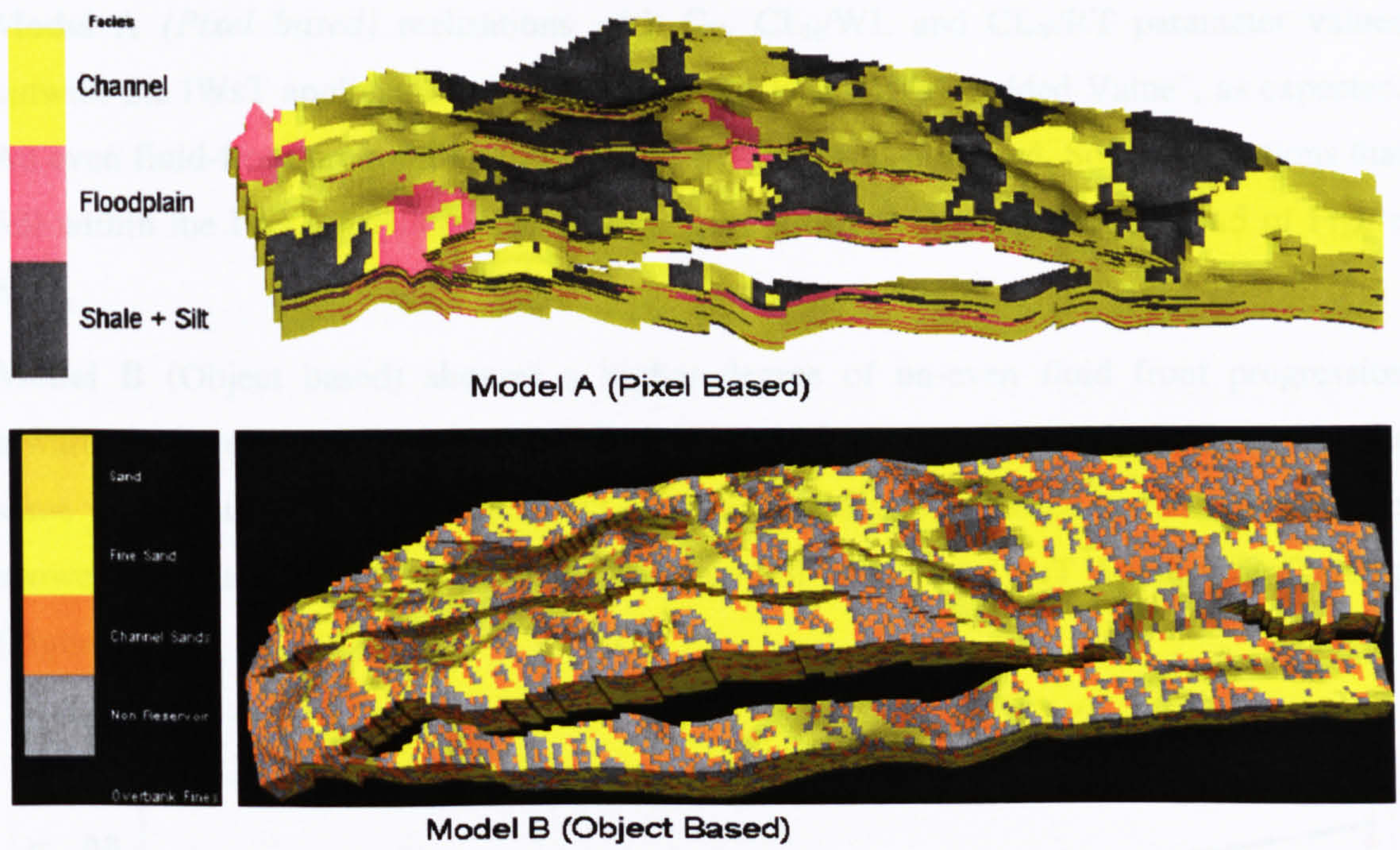

Figure 8-18: The Field Models used for the test in a real field model

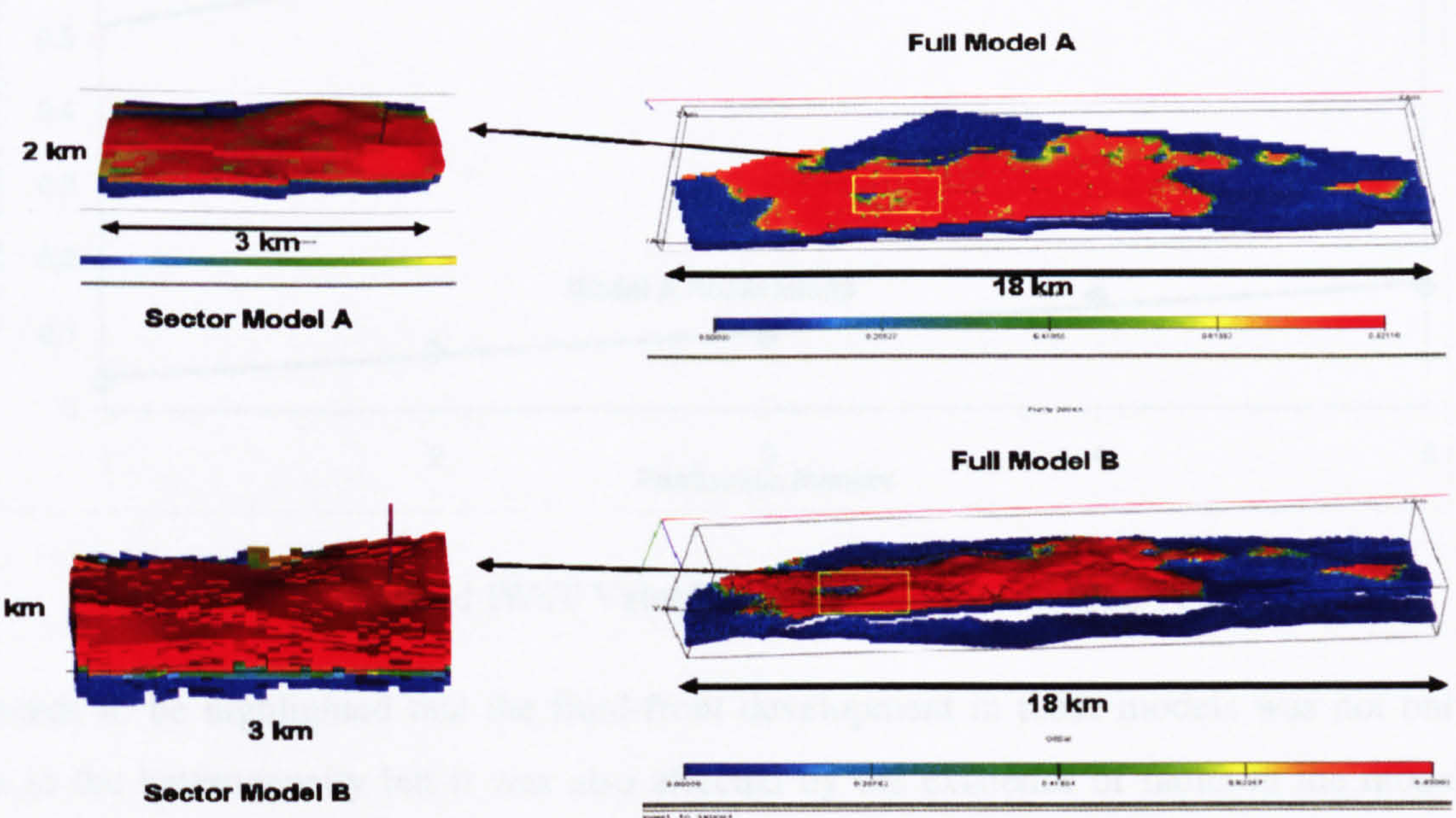

Figure 8-19: Sector models were extracted from the full field model at the same locations

Model A *(Pixel based)* realisations with C_V, CL_H/WL and CL_V/RT parameter values outwith the IWsT applicability envelope showed little "IWsT Added Value", as expected. An even fluid-front progression towards the wellbore was observed. Some realisations that fell within the IWsT Application Envelope gave greater value e.g. realisation 5 of Figure 8-20.

Model B (Object based) showed a higher degree of un-even fluid front progression towards the wellbore than observed for the equivalent model A realisation (i.e. for the same value of the C_V, CLH/WL and CL_V/RT parameters). IWsT used in these models thus showed a greater "IWsT Added Value" as they fell within the IWsT Application Envelop (Figure 8-20).

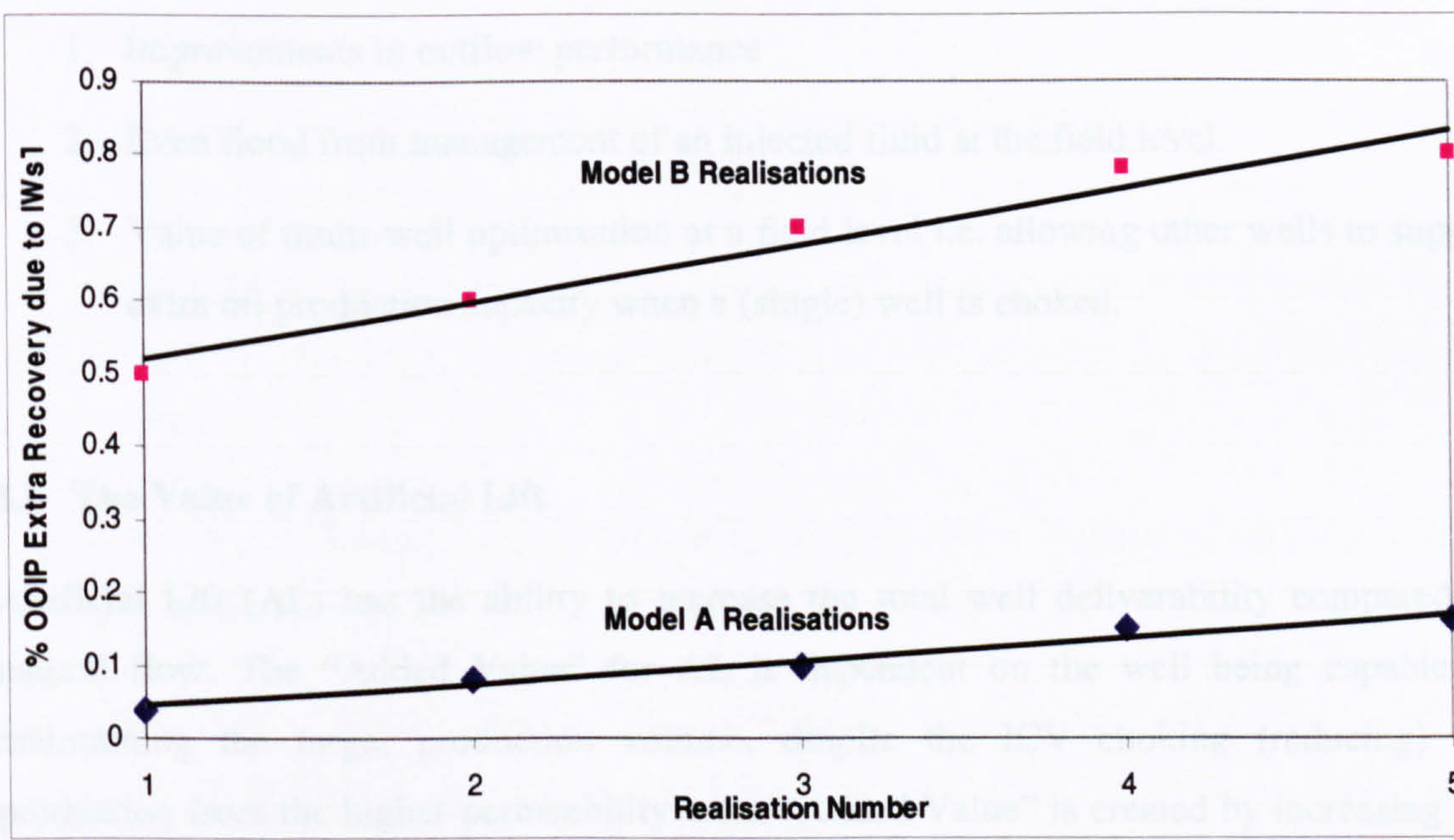

Figure 8-20: "Added IWsT Value" for realisations of Models A and B

It needs to be highlighted that the fluid-front development in these models was not only due to the heterogeneity but it was also affected by the existence of faults in the model. The effect of faults could either increase or decrease the produced unevenness due to the heterogeneity, depending on the position of the faults compared to the high and low permeability groups within the different realisations. This is the reason that we see realisation 4 from model A, which fell just within the envelope and was expected to give a slightly higher recovery, actually achieved a low recovery. Similarly, realisations of model B, which are mainly in the envelope, show a lower degree of improvement.

However, in general, the results confirm the validity of the IWsT envelope.

The scale of improvement shown in Figure 8-20 seen by IWsT in these studies may appear small. This is due to the nature of study, which evaluates the performance of a single well in a sector model of limited volume. This is because we have been studying ONLY the role of geological heterogeneity, ignoring the following effect of improvements in recovery that can be very beneficial:

1. Improvements in outflow performance
2. Even flood front management of an injected fluid at the field level
3. Value of multi-well optimisation at a field level i.e. allowing other wells to supply extra oil production capacity when a (single) well is choked.

8.6 The Value of Artificial Lift

Artificial Lift (AL) has the ability to increase the total well deliverability compared to natural flow. The "Added Value" for AL is dependent on the well being capable of maintaining the target production volume, despite the ICV choking (reducing) the production from the higher-permeability zone. "Added Value" is created by increasing the drawdown opposite the (un-choked) low permeability zones, hence increasing recovery. AL will also add value if it allows the well to flow for a longer period of time than is achieved under natural flow.

In our case AL did accelerate production but, the total recovery with IWsT was only slightly increased due to the limited size of the sector model and the relatively good sweep efficiency shown in all cases,

8.7 Conclusions

IWsT has been shown to be capable of managing geological variability and thus coping with geological uncertainty in a wide range of reservoirs. A global screening methodology has been developed for determining where and where not to implement IWsT.

1. **An IWsT Application screening tool has been developed**

"IWsT Added Value" has been identified when the C_V, CL_H/WL and CL_V/RT parameter values are such that an uneven fluid front development of sufficient magnitude develops in such a manner that it can be managed by the ICV in order to improve the sweep efficiency OR to allow a greater oil production while meeting well outflow or facility water or gas handling constraints.

The combination of the volume of reserves to be developed by the well and the "Added Value" suggested by these screening tools can be used to justify the IWsT project.

The fact that IWsT can potentially "Add Value" will not be sufficient justification for its installation. This has to be confirmed by a full economic analysis for the particular case being studied.

2. **The "IWsT Added Value" Screening Tool has been applied to a real reservoir simulation study**

The "IWsT Added Value" screening tool was created from generic, geological models in which uneven fluid front development was restricted to permeability heterogeneity alone. The concept was confirmed by application to a real reservoir scenario.

The presence of faults or other forms of structures that can give rise to different pressure regimes, fluid contacts and other forms of uneven fluid front movement towards the wellbore will also lead to "Added IWsT Value".

3. **Added Value for IWsT in a Horizontal Well is a function of the permeability distribution around the wellbore and the optimum placement of ICVs along the completion length.**

The recovery improves with correct choice of the number and location of the ICVs within the wellbore. This study suggests that ICVs should be installed in the high permeability areas on the basis of information (logging, cuttings etc.) gained during drilling. Zone length should not be too short and their lengths should be as similar as possible. This reduces the uncertainty in the direction of the flood-front movement towards the wellbore due to the complex reservoir geology.

4. **The Evaluation of the IWsT Added Value is Sensitive to the Modelling Approach**

In this study, generic models were used and various aspects simplified from practical necessity (including size of models, size and number of grid blocks, fluids, contacts, aquifers, economics and other engineering control methods). These issues will have to be further considered in a "real life" study. Another issue in this study is the modelling approaches selected. A comparison of the pixel and object based models in the same field suggested that the choice of model type may also have an impact on the evaluation of IWsT Added Value. Object based models are inherently more heterogeneous and will hence show greater value from IWsT.

Identification of the technique which best captures a particular geology is beyond the scope of this thesis.

8.8 Summary

Development of a global screening methodology for determining where and where not to implement IWsT was discussed in this chapter. Chapter 9 will provide optimum ICV placement guidelines for different well and reservoir geometries with a variety of reservoir drive mechanisms. The results reported in the next chapter can be used as a screening and decision making tool for deciding on the optimum number of the ICV(s) and their placement.

8.9 References

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Chapter 9 Techniques for Optimum Placement of Interval Control Valve(s) in an Intelligent Well

9.1 Introduction

Chapters 2 discussed how the application of Intelligent Well Technology is rapidly increasing. Its development being driven by its perceived capability to improve field & well economics by generating increased reserves, improved overall well performance and providing high-performance reservoir/well monitoring. IWsT improves well and field performance management by combining zonal production control using ICVs with the installation of flow monitoring devices. The "Added Value" for an IW is dependent on the number and location of the ICV controlled zones. Too many valves lead to unnecessary and excessive cost as well as the potential for reduced reliability. Too few valves will not provide sufficient flexibility for efficient control.

An Intelligent Well has the ability to control the flow at the bore or the zone level by a down-hole choke or ICV. This choking operation is managed through Real-Time monitoring [9.1] using an optimised distribution of sensors for data acquisition (e.g. temperature and pressure). New sensors allow for down-hole, fluid-production rate and phase cut measurement. It thus has the ability to recognise the presence of, and then shut off, water/gas producing zone at the zone or the bore level.

There are three main types of ICVs in terms of the style of control: two position valves, multiple step valves and infinitely variable valves. The two position ICV is either fully open or fully closed. The multiple step ICVs are constructed to various designs with typically 4 to >10 steps for the choke settings as it changes from the fully open to the fully closed position. The infinitely variable ICV has the flexibility to provide optimum control (always assuming that it was placed to cover the most appropriate sections / length of the wellbore). Not surprisingly, variable ICVs are more expensive and require more sophisticated control algorithms than the simpler types of ICV.

The ICV is arguably the heart of the Intelligent Well. However, decision-making on the most profitable application of ICVs i.e. their placement and, operation to optimally manage production presents many challenges, especially for complex reservoirs. It must be remembered at all times that ICV is, due to its nature, a choke. Thus in-appropriate choking will result in reduced well deliverability. In this case there will be an almost inevitable loss of oil production if well deliverability is constraining the field production. However, an optimally placed and managed ICV can greatly improve the performance of an Intelligent Well and "Add Value" to the Reservoir Management System. Further, an Intelligent Completion has a smaller size tubing than a simple completion when installed in a given diameter drilled well. The resulting reduced outflow performance may further limit the wells outflow performance.

It was showed in chapters 7 and 8 that a minimum degree of un-even fluid-front progression needs to be present in order for effective ICV control to be able to "Add" sufficient "Value" to justify the costs and risks involved in installing this relatively new technology. ICV(s) can balance the fluid-front provided they are placed correctly. A typical example would be their installation across zones showing early water or gas break-though. This allows "Value" being "Added" to the reservoir management process by controlling the unwanted fluid. Optimum ICV placement requires prediction of these zones. The extent of reservoir layer / zone connection thus needs to be quantified. In practice, the available information is often limited to (local) information gained from measurement at or very near the wellbore during the drilling of the well, together with exploration seismic and (global) reservoir geological studies.

A systematic study of the "Added ICV Value" for a range of reservoir models has been completed. The number of ICVs installed and the zonal length were varied. Emphasis was given to studying the more complex (e.g. channelised) reservoir models where prediction of the extent of reservoir layer / zone connection is more difficult.

This chapter provides optimum ICV placement guidelines for different well and reservoir geometries with a variety of reservoir drive mechanisms. Results from this study highlight the importance of correct ICV placement. The results can be used as a screening and decision making tool for deciding on the optimum number of the ICV(s) and their placement.

9.2 Methodology

Chapter 7 of this thesis described the performance of Intelligent Wells located in a variety of well and reservoir types and operated with a range of choking policies [9.1, 9.3]. It showed that a minimum degree of "unevenness" of fluid-front movement towards the wellbore is required for the Intelligent Well to be able to "Add Value" to the Reservoir Management Process [9.1]. The process underlying this guideline is exemplified in Figures 9-1 and 9-2. The development of this "unevenness" in the fluid-front movement towards the wellbore was related to the reservoir statistical parameters of Correlation Length (CL) and Correlation of Variation (C_V). A reservoir-type Application Envelope identifying the reservoir geology that was most likely to allow for Intelligent Well "Added Value" was derived from this work [9.1].

Figure 9-1 illustrates two reservoir models with a medium and a long horizontal Correlation Length (CL_H). Figure 9-2 shows how the interaction of the horizontal and vertical correlation length affects the shape of the fluid invasion front as it moves towards the wellbore. Hence the optimum number of ICVs required for effectively controlling this "unevenness" in the fluid-front movement will be controlled by these static reservoir properties.

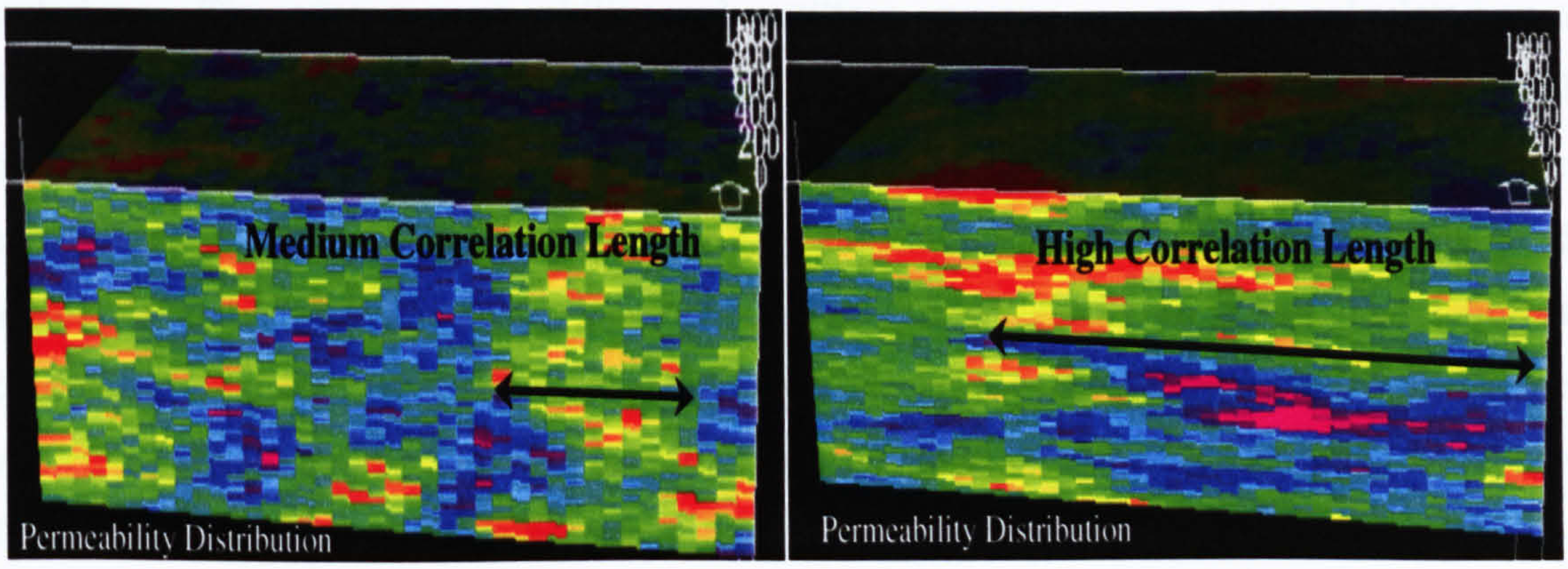

Figure 9-1: The Correlation Length Concept

This chapter summarises the ICV placement considerations developed from the lessons learnt from a range of systematic studies, that have been performed on a wide range of generic, reservoir types.

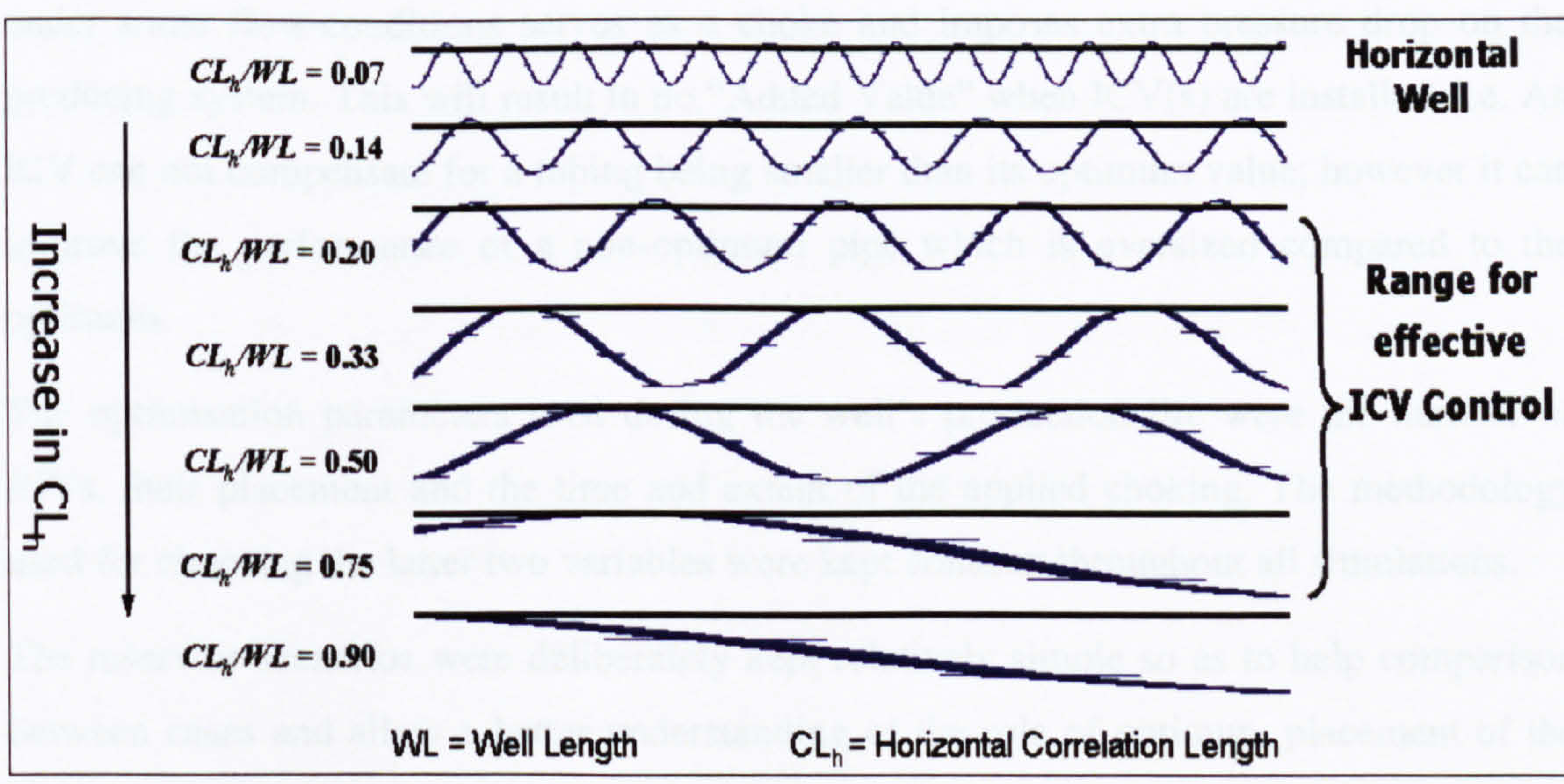

Figure 9-2: Fluid-Front Progression towards the wellbore

The reservoir models used in this study had a size of 2 - 3 km in the X direction, 1 km in the Y direction and 30 - 80 m in the Z direction. Different ranges of permeability values were distributed in the models by employing both deterministic and stochastic modelling techniques. The relative permeability and capillary pressure curves were calculated as a function of the absolute permeability based on Pickup, G., et al's work [9.4]. Manual optimisation techniques [9.1, 9.3, 9.5, 9.6], as provided by the Eclipse simulator package capabilities [9.7], were used for the control of the ICVs. The ACTION keyword was used to specify a field condition (e.g. a water-cut limit) for triggering an action. The action is carried out by a specific well model segment which represents the ICV installed within the well. The WSEGVALV keyword designates the appropriate segment within the well. The flow-regime in the valve is sub-critical. Hence an additional pressure drop is generated in this segment on choking the ICV to a reduced cross-sectional area (Ac). However, other system limitations e.g. well target rate and wellhead pressure, can under some conditions, constrain the choking effect. This is due to the system performance which can provide the target rate even with the reduced choke size. This indicates that the original choke size was not properly optimised. It is worth nothing that non-optimum choice of pipe diameter under some flow-conditions serves as a choke and imposes extra pressure drop on the producing system. This will result in no "Added Value" when ICV(s) are installed. I.e. An ICV can not compensate for a tubing being smaller than its optimum value; however it can improve the performance of a non-optimum pipe which is oversized compared to the optimum.

The optimisation parameters used during the well's production life were the number of ICVs, their placement and the time and extent of the applied choking. The methodology used for choosing the latter two variables were kept constant throughout all simulations.

The reservoir scenarios were deliberately kept relatively simple so as to help comparison between cases and allow a better understanding of the role of optimum placement of the ICVs on the "Added Value" from the Intelligent Well. In all cases the performance of the well was compared with production from an equivalent well with the ICV permanently in the fully open position (the base case). This was done to ensure that production from the same, basic completion design was compared in all cases. A range of sensitivities were performed on the number of ICVs and the length of the wellbore being controlled by each ICV.

N.B. Work has been already published on the development of automatic ICV choking algorithms [9.8, 9.9]. Other papers developed techniques to optimise both the ICVs' location as well as its operation. E.g. Kharghoria, A. et al [9.10] studied the application of Inflow Control in a horizontal well subject to a bottom-water drive. They discretized the valve inflow-area into a number of steps from fully open to fully closed as well as discretizing the length of the well into 18 grid-blocks. They illustrated the solutions of setting-only, placement-only and solving of the combined problem using exhaustive simulations, simulated annealing and conjugate-gradient methods.

9.3 Results

The rules chosen for detailed optimum ICV placement will be a function of the level of information available and the confidence that the engineer has in the data and the modelling tool employed. A Reservoir Simulator can be a reliable option to help select ICV placement providing extensive reservoir information is available to validate the simulator. For example, it is often used to validate the re-completion of a well as an I-Well or to justify the drilling of extra infill wells. Reservoir simulation identifies those areas of the wellbore where early water or gas breakthrough can be expected. The simulator thus provides a platform with which to perform sensitivities on the number and position of the ICVs. The optimum number(s) and locations(s) for installation of ICVs should be chosen so as to sufficiently control the "unevenness" of the invading fluid-front (a technical issue); while at the same time minimising the investment in extra ICVs and associated equipment (an economic factor). However, carrying out this optimisation process can be a time consuming operation with a high cost is attached to it.

N.B. The development of a reliable, general, automatic optimisation algorithm that can work with a detailed well performance model linked to the reservoir model to optimise the location and the timing and extent of the ICV operation has not yet been developed. Further, trustworthy reservoir simulations are not available for many oil and gas fields. In these cases the available data is limited to knowledge of the Reservoir Geology from analogue studies, exploration seismology and the information gained during the drilling of the well e.g. from drill cuttings, wireline logs, etc.

Optimum ICV placement, as it can be deduced from the above, requires that the extent of the connection between the various reservoir layers to be quantified. The following ICV placement guidelines were developed during this study for a range of well and reservoir scenarios:

9.3.1 Performance of a Vertical or Slightly Deviated Well Producing a Single Reservoir

Vertical or slightly deviated production wells are frequently used for fields where reservoir flow is controlled by the following drive mechanisms, either singly or in combination:

1. Depletion (gas cap may form in the late production period)
2. Gas Cap drive
3. Bottom Water drive
4. Edge Water Drive

The placement of ICV(s) in such wells is relatively easy, provided the reservoir is being produced under the first three reservoir drive mechanisms. This is because fluid coning and cusping will, in many cases, override effects attributed to Reservoir Heterogeneity when it comes to controlling the position of water or gas breakthrough within the producing well's completion. Hence ICVs should be placed at the top or the bottom of the oil zone in a reservoir being produced under water or gas cap drive mechanism respectively. This is controlled by the reservoir parameters (permeability plus height above the Oil Water Contact) and the well production parameters (flow rate). Variable rather than on/off ICVs may deliver extra Value compared to well intervention. However, application of ICVs depends on the relative cost of the ICV and the intervention options. Installing more ICVs, either at the top or the bottom (depending on the reservoir drive mechanism) gives greater control and a reduced loss in oil zone deliverability (permeability thickness) when a valve shuts. However, the number of ICVs depends on economics (the required value of the ratio of the "Added Value" / "Increased Costs" is a factor that will be determined by the company's investment criteria), the production plan, the thickness of the reservoir, the oil volume originally in place and many other reservoir parameters. The same methodology could be applied for a vertical well producing a reservoir under depletion drive, the ICVs should be placed at the top of the reservoir provided the "Added Value" for ICVs is justified. (It is realised that a lot of these considerations represent good reservoir engineering practice.)

ICV placement is a much more complex task if the vertical well is producing oil from a reservoir operating under an Edge Water drive. Figure 9-3 shows a well completed in a reservoir when production is controlled by this edge water drive mechanism. The water invasion front is perpendicular to the direction of gravity. This dilutes the effect of the Reservoir Heterogeneity which mainly operates in a horizontal plane in this model. Generalising our results and defining an Intelligent Well application envelope as a function of the reservoir description parameters is thus more difficult in this case. I.e. the un-evenness of the fluid-front movement towards the wellbore is affected by extra parameters such as gravity, injection rate and pressure.

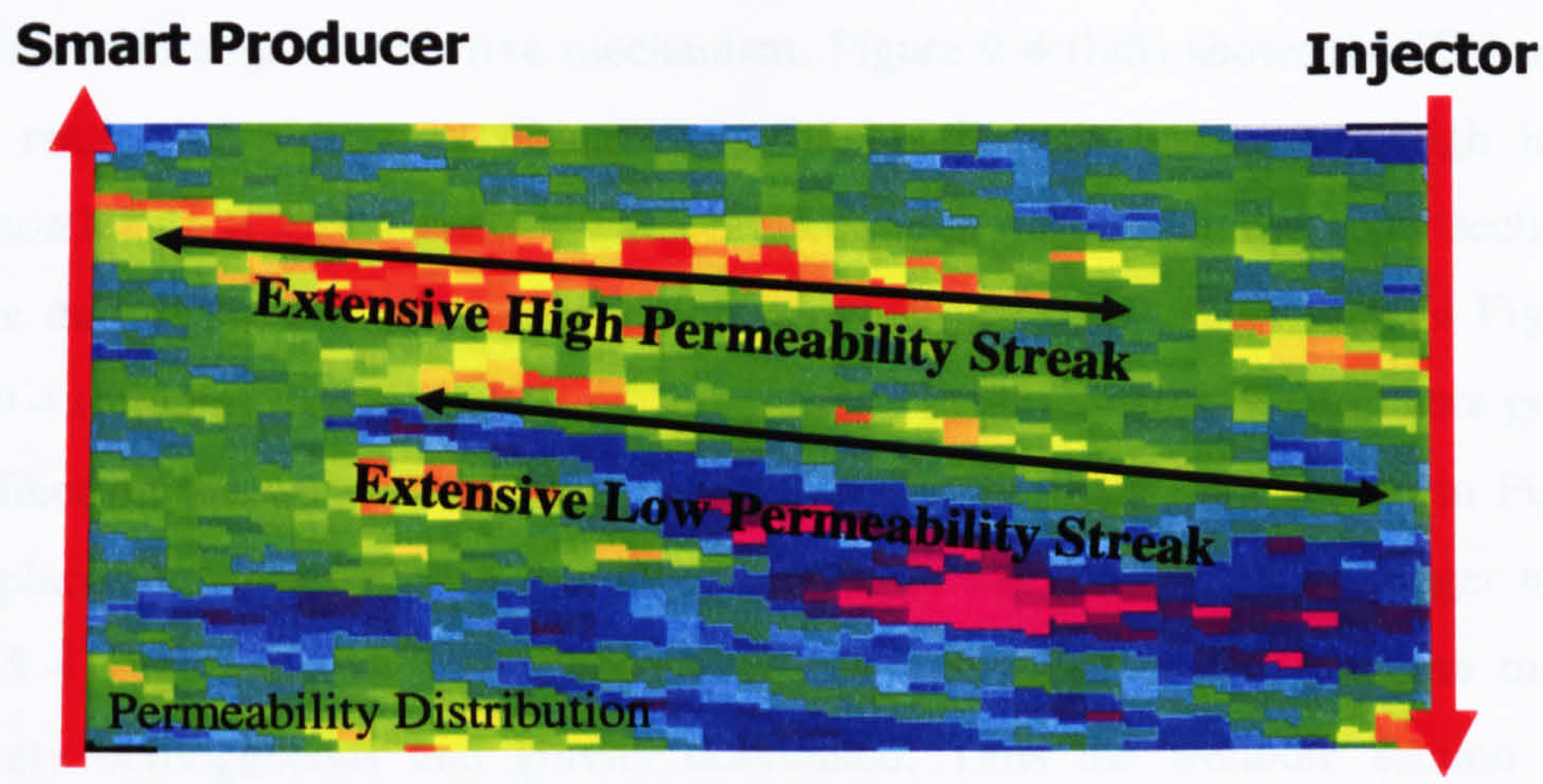

Figure 9-3: A Reservoir with a high horizontal correlation length producing with an Edge Water Drive showing a high and low permeability streks have developed

A range of realisations of this reservoir model with different levels of heterogeneity were created by changing the formation's Correlation Length (CL) and Coefficient of Variation (C_V) [9.1]. Increasing the horizontal correlation length (CL_H) will increase the extent of the horizontal layering within the reservoir. Hence there is a greater chance for early water breakthrough and more opportunity for flow control using ICVs with the larger CL_H. The critical value of CL_H is a function of the distance between the injector and producer, the CL_V and C_V parameters, the injection rate and pressure and many other parameters. The larger the vertical correlation length (CL_V), the greater the opportunity for gravity to have an effect. I.e. the progression of the water flood front towards the wellbore is delayed and the opportunity for flow control using ICVs is reduced. However, flood-front progression rate is also a function of the CL_H, i.e. increasing the CL_H reduces the effect of the CL_V and hence the reduced effect of gravity on the flood front movement towards the wellbore. The smaller the C_V, the more homogeneous the model and the greater the effect of gravity on the flood front movement towards the wellbore.

The number of ICVs and their placement were sensitized in the above-mentioned realisations. Figure 9-4 illustrates ICV Placement scenarios for a vertical well completed in a reservoir with edge water drive mechanism. Figure 9-4 (left) shows the ICV placement for the realisation shown in Figure 9-3. This realisation has a very high horizontal correlation length (CL_H); therefore water breakthrough occurred at the upper section of the wellbore due to the existence of the high permeability streak (best seen in Figure 9-3). Figure 9-4 (middle) shows the ICV placement for a medium value of CL_H; here gravity has more effect on the water front progression than for the realisation shown in Figure 9-3. Hence placement of an ICV at the upper section of the wellbore is no longer necessary. Figure 9-4 (right) shows ICV placement for a low value of CL_H i.e. the model was effectively homogeneous and gravity dominated. Thus the wellbore section requiring control by ICVs is even shorter and is concentrated towards the bottom of the wellbore.

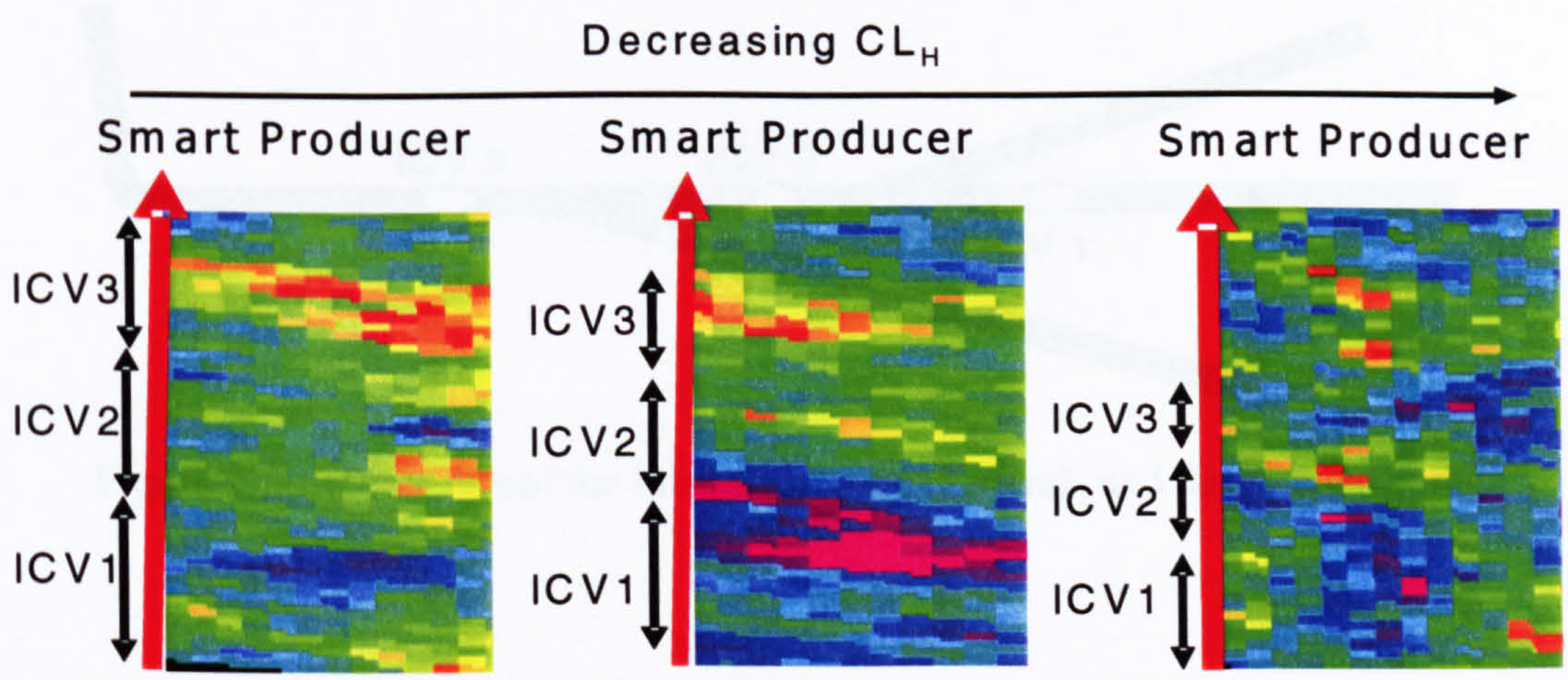

Figure 9-4: ICV Placement scenarios for a vertical well completed in reservoirs with an edge water drive mechanism

The exact length of the wellbore to be controlled by an ICV and the optimum number of ICVs is very case dependent and needs to be economically justified. However, it is a function of (CL_H / Injector to producer Wells' Separation) and (CL_V / Height of Zone). This can be seen in Figure 9-2 and will be further explained in section 9.3.3.

9.3.2 *Performance of a Vertical, Deviated or Horizontal Well, Commingling Multiple, Compartmentalised or Layered Reservoirs*

Figure 9-5 shows a multilateral well. The laterals and mother-bore may produce from the same reservoir or from multiple reservoirs. Current technology limits ICV placement to control flow from the mouth of the laterals and not from different sections within a lateral. The ICVs are placed within the mother-bore in such a manner that separate control of each lateral is achieved. However, the same methodology of ICV placement in the mother-bore could be applied to the laterals when development of this technology allows.

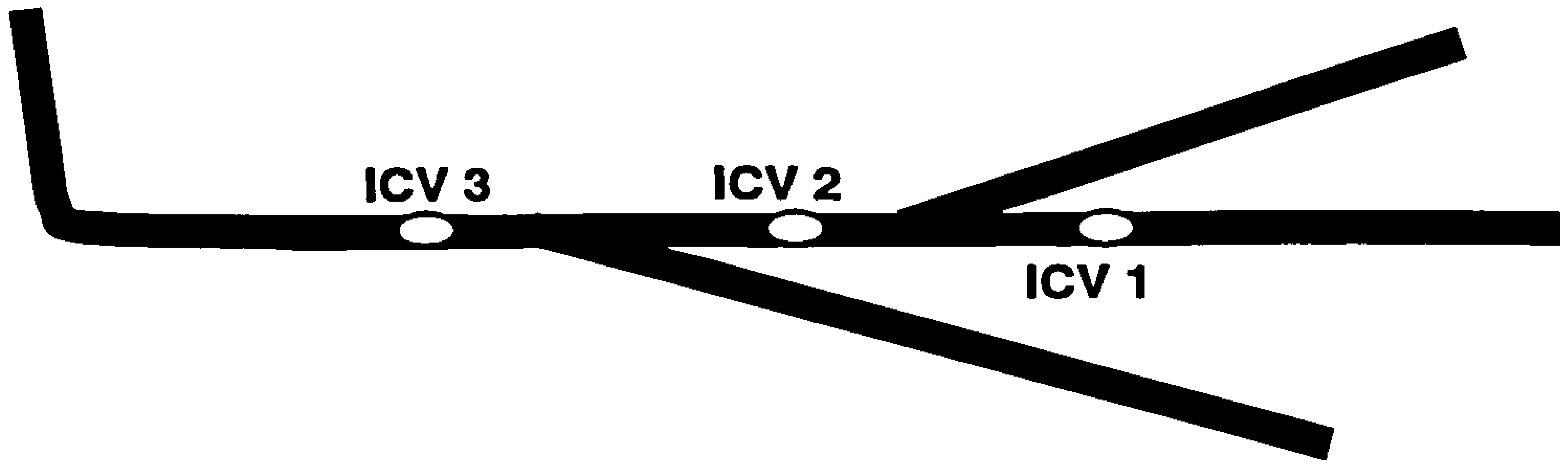

Figure 9-5: ICVs Control the Production from Laterals and the mother-bore

Figure 9-6 shows a gas auto-dump-flood. This is a similar case to the above except that the perforated zone now replaces the lateral. Figure 9-7 shows the complex completion that is necessary for controlled separate production of the lower gas and oil zones followed by controlled production from the oil zones and controlled gas injection from the lower zone to the upper production zone. ICV placement, in this case, is simplified by the fore-knowledge of the length of the wellbore to be controlled by the ICV (the vertical height of the oil and gas zones).

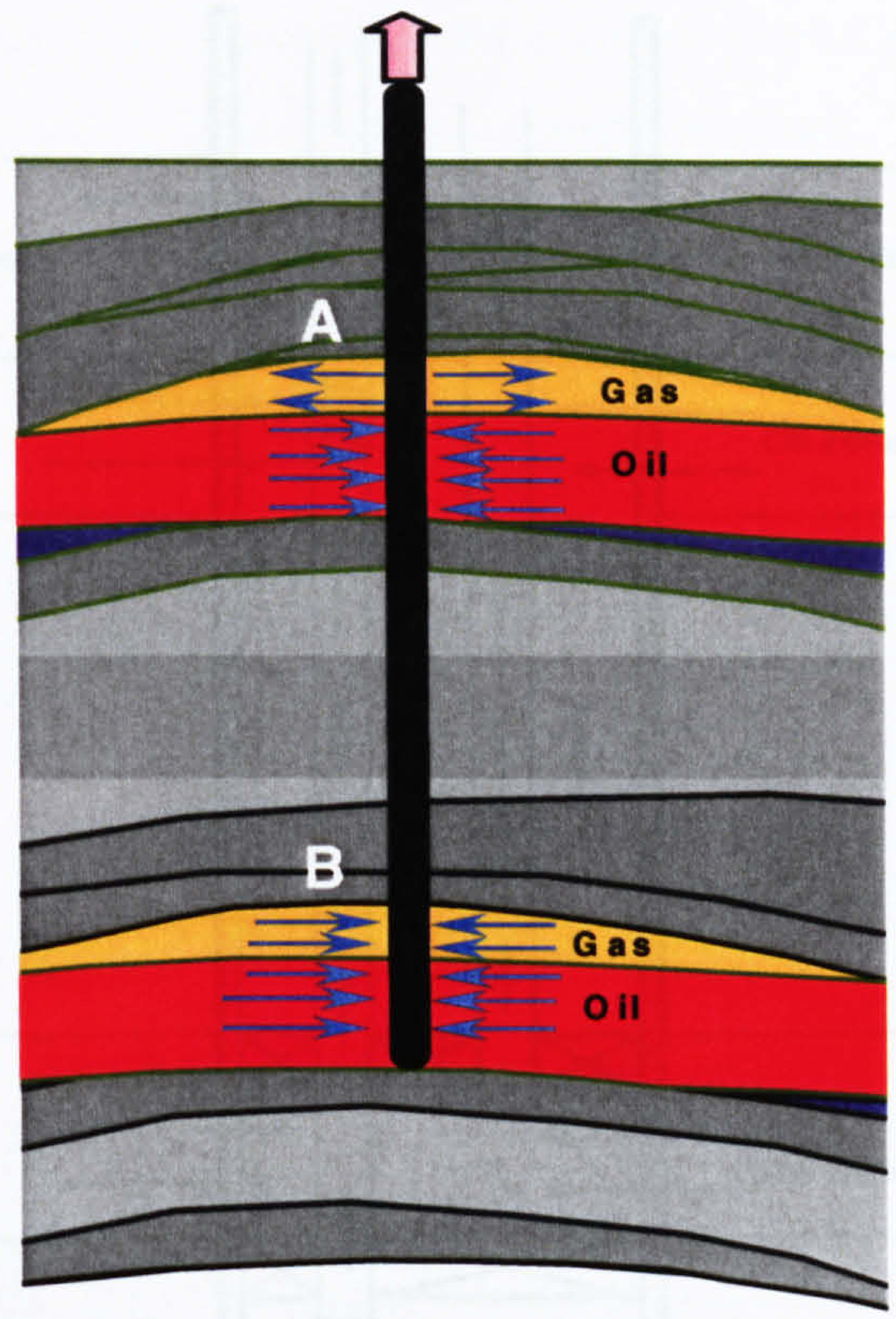

Figure 9-6: ICVs used for manage an Auto-Gas Dump Flood from zone B to A and to manage oil production from zones A and B

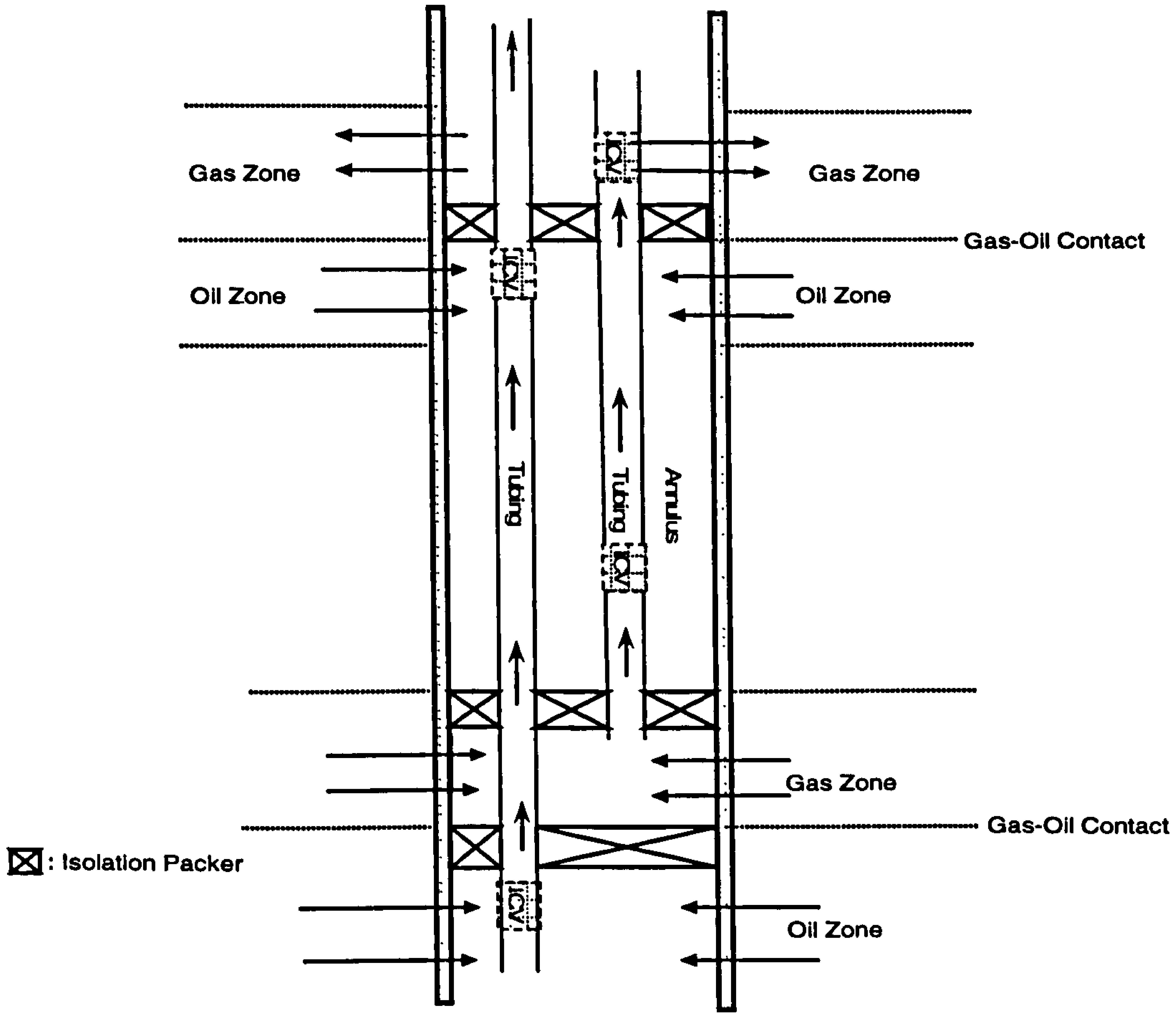

Figure 9-7: Separate production of the lower gas and oil zones followed by controlled production from the oil zones and controlled gas injection from the lower zone to the upper production zone

Figure 9-8 shows a model of a reservoir with tilted sand layers with varying permeability. Previous work with this type of model had confirmed that, as expected, choking of the high permeability layer encourages greater production from the low permeability layers as well as increasing total recovery. Choking the high permeability layer reduced water production at the well level, allowing a better sweep efficiency in the low permeability zone. This will result in a longer plateau oil production rate and an increase in the recovery, providing the well is outflow rather than inflow limited. ICVs therefore should be placed so as to be able to control the high permeability layers / zones or compartments.

Other examples which fit in this category include scenarios when a well produces from multiple fault blocks or when it commingles production from different reservoirs.

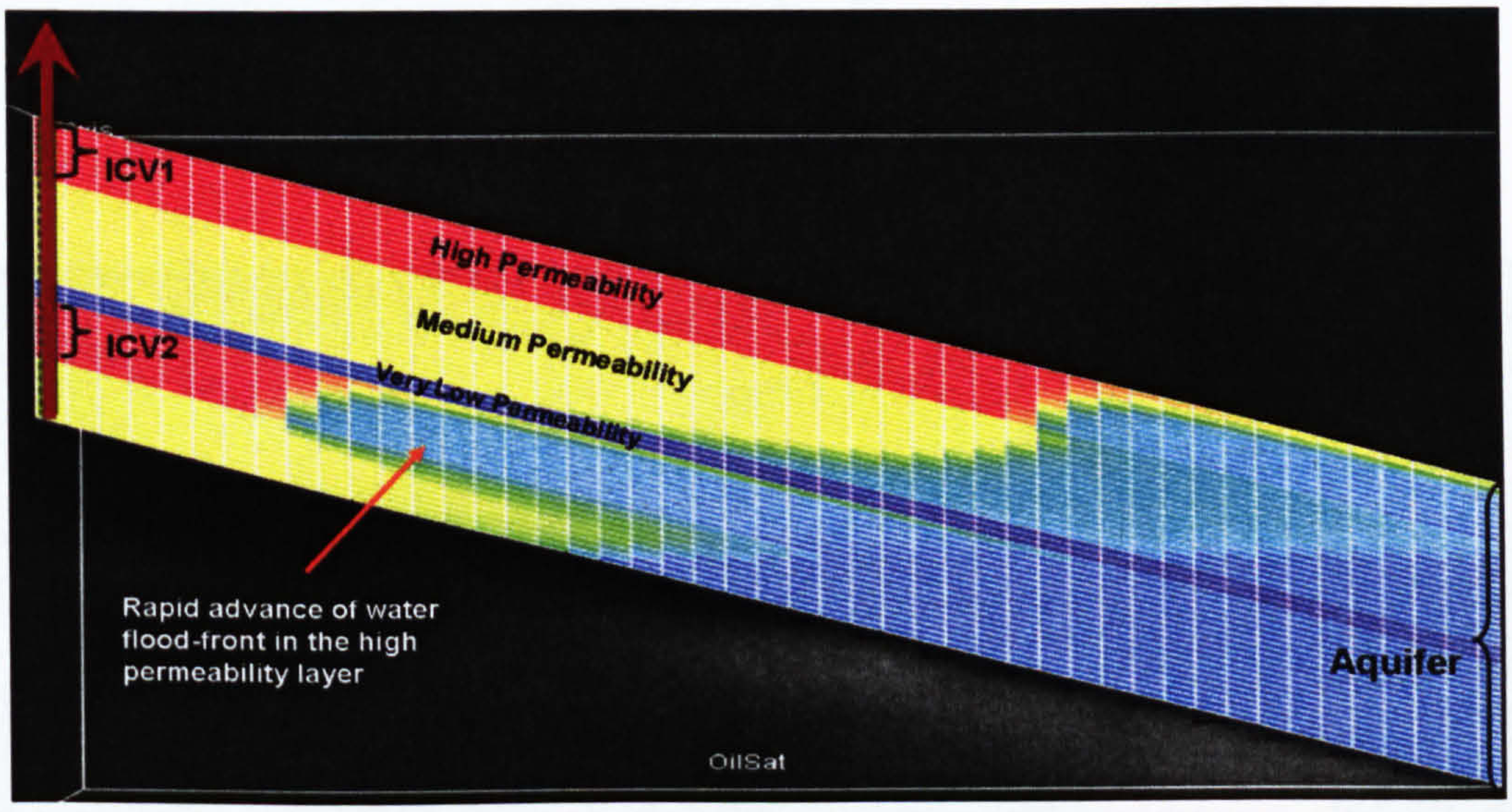

Figure 9-8: ICVs control production from a tilted Layered Model

Annular packers have to be placed at the separation point of the different reservoir zones, layers or compartments. A single ICV is sufficient if "even" fluid-front movement towards the wellbore occurs in each compartment / layer is assumed. However, multiple ICVs within each reservoir may be justified if the well section is long enough and / or sufficiently large reservoir heterogeneity is suspected. However, in a similar manner to that discussed previously, economic justification for increasing the number of ICVs will be required.

9.3.3 Performance of a Horizontal Wells producing Complex Geology (e.g. Channelised, Aeolian, Shallow Marine sands)

Figures 10-9 and 10-10 show a horizontal well completed in a specific realisation of a stochastic and a deterministic channel sand model respectively. Here optimum ICV placement is not obvious in these cases due to the uncertainty in the extent of connection between the high permeability channel sands. The sands are of limited vertical and horizontal extent and the shape of fluid front toward the wellbore is difficult to predict.

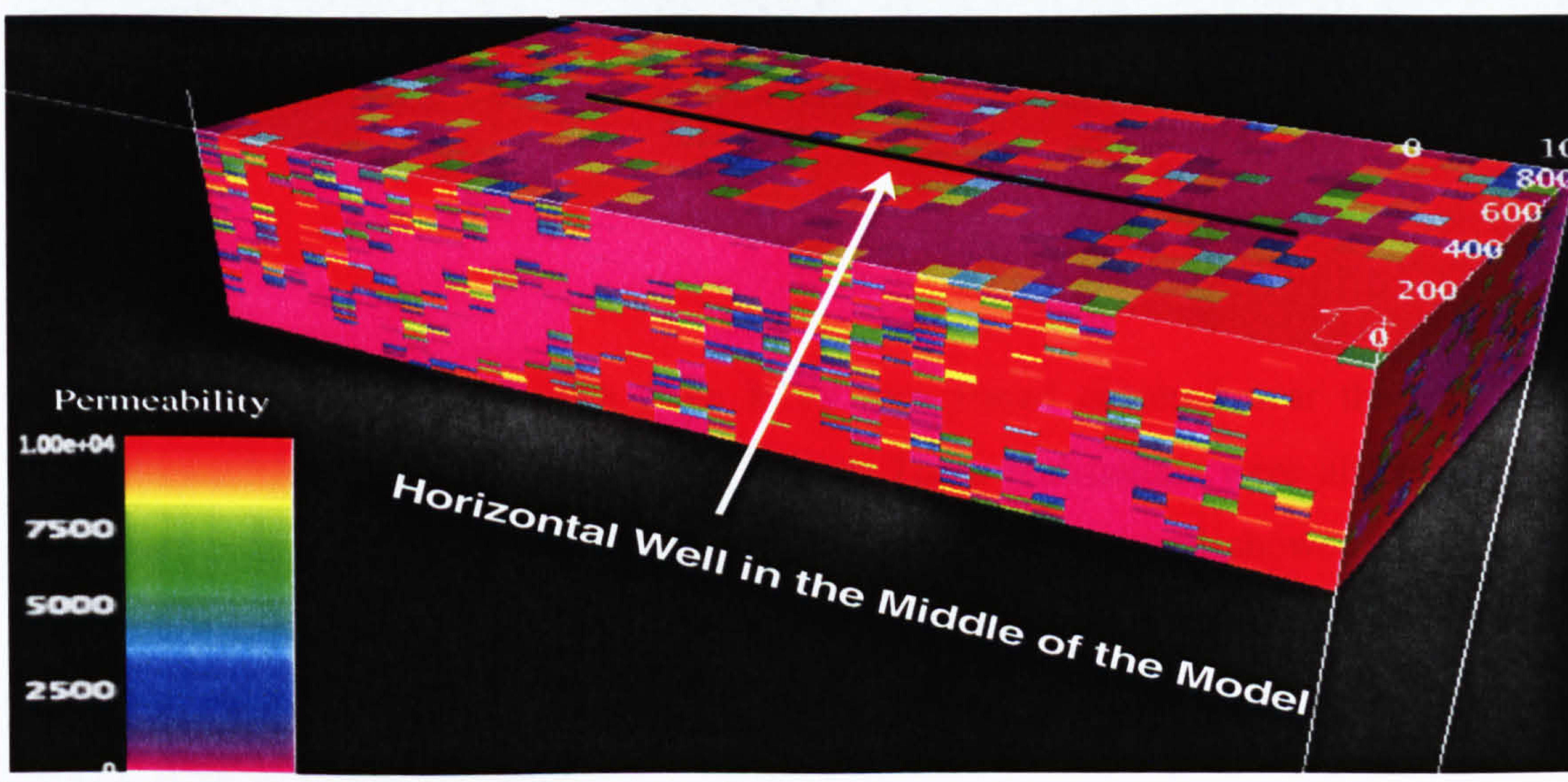

Figure 9-9: A Stochastic, Channel Sand Model of a reservoir

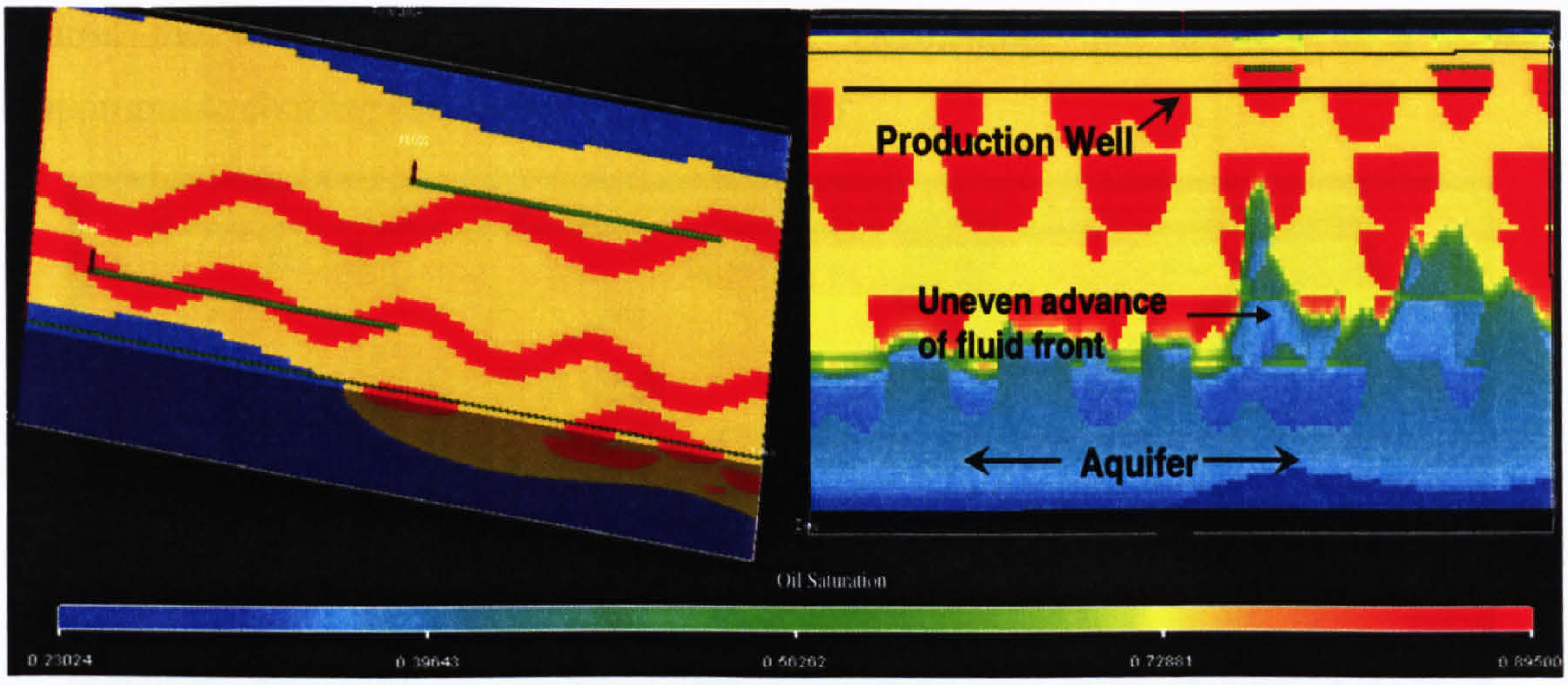

Figure 9-10: A Deterministic Channel Sand Model

Part A:

A horizontal well equipped with three ICVs was placed centered near the top of the reservoir in 8 realisations of a reservoir model. These realisations were all chosen from inside the IWsT applicability envelope (chapter 8), hence they all showed the expected "uneven" fluid front progression towards the wellbore. A strong aquifer was also connected to the reservoir model. The optimisation and comparison methodologies were similar to those discussed earlier.

The majority of the realisations delivered a positive "IWsT Added Oil Value". The magnitude of this "Added Value" varied between 0.2 - 1.2 % STOOIP for the different realisations. The "Added Value" was a function of the relative position of the well and of any high permeability channels intersecting the wellbore. This occurred because these channels were the cause of the early water-breakthrough providing the opportunity for flow control using ICVs. However, negative values for IWsT were also observed (- 0.1 to - 0.6 % STOOIP) in a few instances. These occurred when the separation point between the ICV zones was such that the main oil-producing zones were also choked when attempting to control the water production (Figure 9-11). {Remember that an ICV is a choke; inappropriate choking can reduce oil production.}

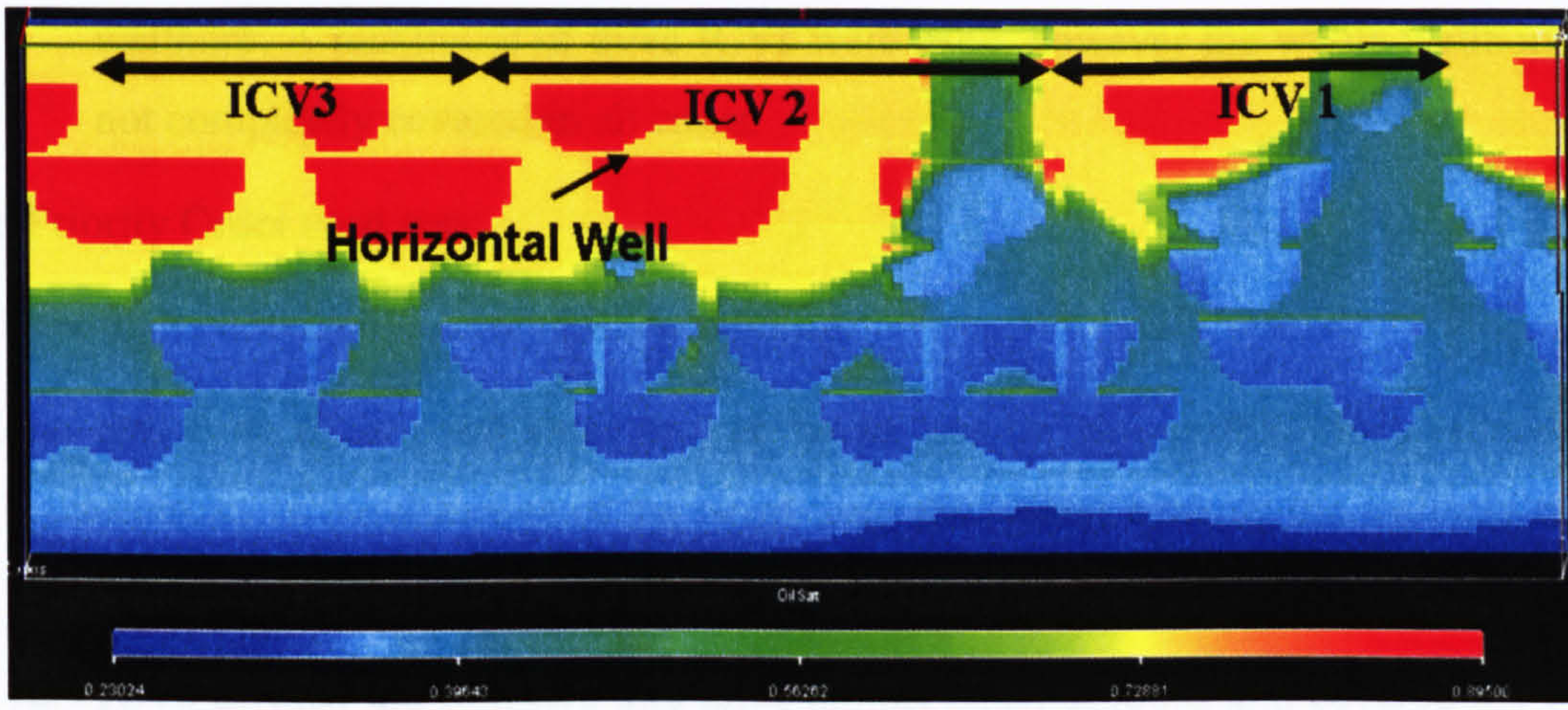

Figure 9-11: Choking ICV2 reduced total well oil production as well as delaying water ingress

Part B:

The results from part A proved that the Added Value for flow control using ICVs is a function of the relative position of the well and the position and extent of any high permeability channels intersecting the wellbore since they were the cause of early water breakthrough, as the other reservoir parameters were kept constant. It is necessary to choose a realisation which shows the opportunity for flow control using ICVs in order to perform sensitivities on the optimum position of the ICVs along the length of the wellbore. A geological model realisation was chosen with the CL & C_V values such that "Added Value" was expected from the IWsT application envelope had been chosen. Further, the well was positioned to give "Added Value" due to its position with respect to the high and low permeability zones. A range of sensitivities were then performed in which the length of the zone being controlled by an ICV was varied. The optimisation and comparison methodology was similar to that used earlier.

The rules used for placing the ICV zone lengths were as follows:

1. ICVs are located across zones of high permeability thickness as observed at the wellbore. A maximum of three ICVs were used, however the whole wellbore was not completely covered in all cases.

The Priority Order used was:

Cover high permeability area of the wellbore

Zone length to be not too short and to be as similar as possible. This reduces the uncertainty in the direction of the flood-front movement towards the wellbore due to the complex reservoir geology

2. ICVs divided the wellbore into three almost equal sections and covered the whole wellbore. Sensitivities were performed on the length of the section that each ICV controls, varying from 20% to 70% of the wellbore.

Realisations, in which one ICV choked a long zone that was the main contributor to the oil production, gave less "Added Value", as expected. Covering the whole wellbore with ICVs, instead of limiting them to some sections only, reduced the uncertainty in the "Added Value". This occurred because choking policy was able to react to the "surprises" stemming from the complex reservoir geology. However, higher "Added Value" was achieved for some realisations in which ICVs mainly choked the high permeability-thickness zones that were observed at the wellbore compared to the scenarios in which the ICVs controlled the complete wellbore.

Installing an increased number of ICVs gives greater control; reducing the loss in the oil zone permeability-thickness when a particular valve shuts. The optimum number of ICVs is a function of the "unevenness" in the flood-front as it moves towards the wellbore (Figure 9-12). Increasing the number of independently moving, uneven fluid-fronts moving towards the wellbore requires a greater number of ICVs for effective flow control. This is a function of the parameters (CL_H /Well Length) and (CL_V / Height of Zone) (Figure 9-12).

However, the number of ICVs also depends on economics (Incremental Value Increase from an extra ICV versus the cost of installing and operating that ICV).

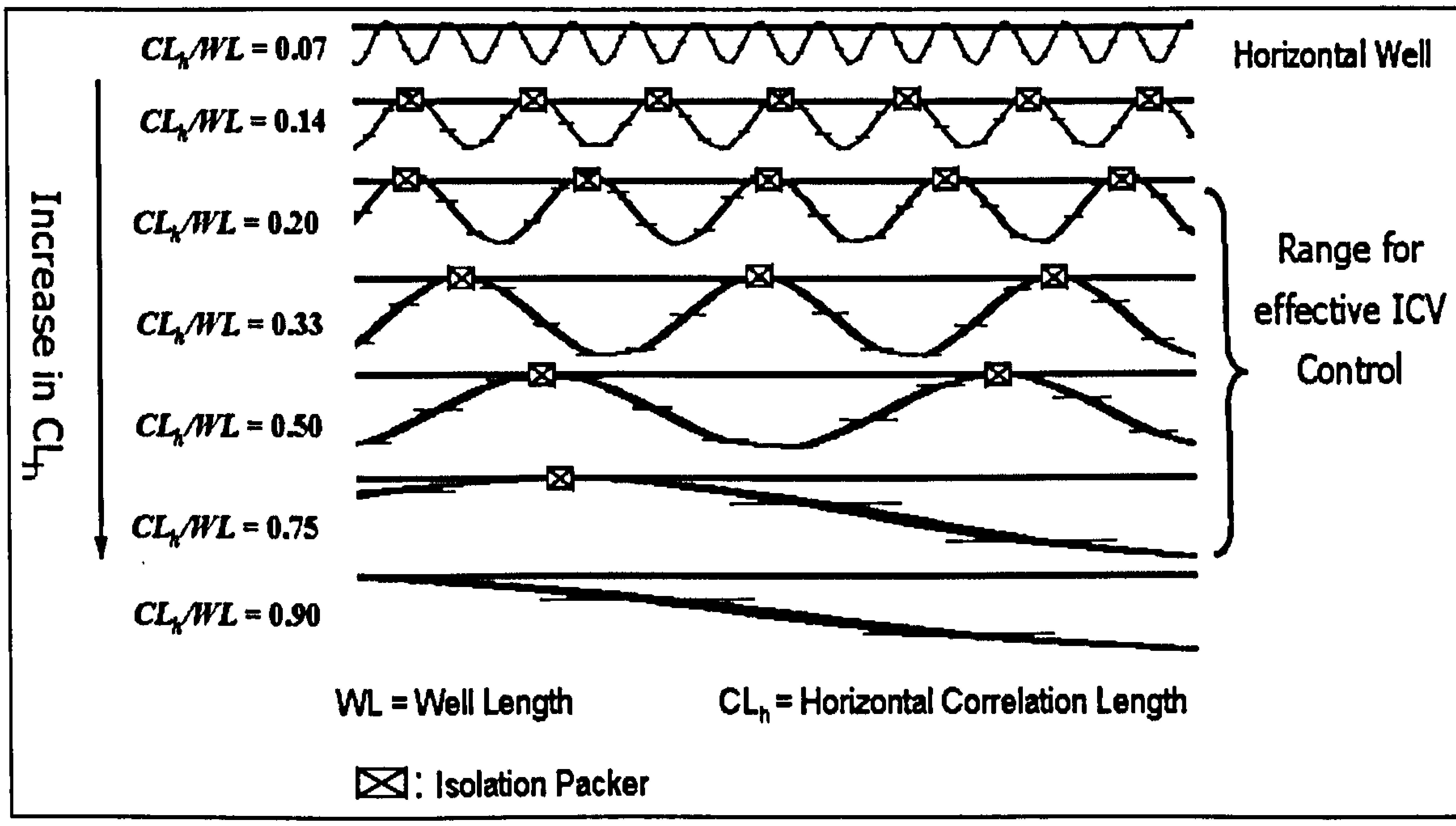

Figure 9-12: A greater number of independent, uneven fluid-fronts moving towards the wellbore require a greater number of ICVs

Results show that optimum ICV placement rules vary from one reservoir type to another. This is due to the variation in the shape of the fluid-front moving towards the wellbore which is a function of reservoir type.

It should be noted that many other parameters affect the results e.g.:

1. **The Optimisation Technique:** only manual optimisation techniques were used in this study. A more complex choking policy may affect the results and possibly add more "Value" by compensating for the reduced flexibility created by an ICV being placed in a slightly inappropriate position. It was decided to keep the optimisation policy constant for all realisations since this would have affected the optimum placement of ICVs along the length of the wellbore and complicate the comparison of the results.

2. **The reservoir modeling techniques:** The rate of the fluid- front movement towards the wellbore is a function of the reservoir type. This fluid-front movement is also a function of the degree to which the model is representative of the real reservoir, but also of the way we build the reservoir model. Both of these features can greatly affect the results.

3. **Other system parameters** such as the water injection rate, the strength of aquifer, the well control parameters and many other production system limitations that affect the performance of the combined well and reservoir models.

The role of the assumptions made and the resulting uncertainty needs to be taken into consideration when generalizing the results from this study in section 9.3.

9.4 Conclusions

ICV placement guidelines for a wide range of well and reservoir scenarios have been discussed.

1. This chapter has shown how a good understanding of the reservoir geology is the key to ICV placement. This geological understanding along with appreciation of the reservoir drive mechanism aids prediction of the fluid-front movement towards the wellbore, allowing an optimum placement (number and location) of ICVs along the length of the wellbore for efficient flow control.
2. The interplay of the C_V, CL_H and CL_V parameters, well length and the length of the zone to be controlled by each ICV will determine the shape of fluid front development towards the wellbore.
3. The fluid-front progression schematic (Figure 9-12) can be used as a tool for decision-making on the optimum number of ICVs required along the length of the wellbore in a complex reservoir. This figure gives a simple, but realistic, impression of the shape of fluid-front movement towards the wellbore.
4. ICV placement rules vary from one reservoir type to another. They are affected by many reservoir parameters. This thesis provides a geological framework within which the performance of the well can be more easily understood.
5. Despite the general geological understandings, there will always be uncertainty in most practical cases when deciding the optimum placement of the ICVs.

9.5 Summary

ICVs placement guidelines for a range of well and reservoir scenarios was developed and discussed in this chapter. However, the optimum ICV placement is a function of the choking (optimisation) policy as well, which itself greatly affects the "IWsT Added Value". The choking policy was mainly kept constant for all realisations in this study in order to simplify the comparison between the various cases. However, this will also affect the optimum "Added Value" of IWsT derived from the various realisations. This will be discussed in the next chapter which evaluates the application and suitability of "Proactive" and "Reactive" control for Intelligent Well Management.

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Chapter 10 Application of "Proactive" and "Reactive" Control for Intelligent Well Management

10.1 Introduction

Multi-zone, intelligent-well completions contain appropriate monitoring devices located between zonal isolation packers. They control the flow into or out of each zone with Interval Control Valves (ICVs). Intelligent Well (IW) Technology combines zonal production control using Interval Control Valves (ICVs) together with installation of appropriate flow monitoring devices to improve well and field performance management. Zonal flow control can maximise produced oil value, minimise unwanted fluids or a combination of both objectives.

Managing the future reservoir performance based on correct decision taking requires a model that accurately reflects the behavior of the reservoir system. Common reservoir management objectives are to reduce risk, increase production and reserves, maximise recovery and minimise capital and operating costs. IWsT has been shown to be capable of managing geological uncertainty (chapters 7 and 8) [10.1]. Operating at or near real-time allows operators to fine-tune the performance of the whole production system by reconfiguring the well's completion system. The ultimate goal for this continuous monitoring of the reservoir is to implement a proactive reservoir management technique [10.2].

The "Added Value" from an Intelligent Well depends on the optimum implementation of well control. It is best applied in a suitable reservoir [10.1] with an appropriate measurement and control system for the ICVs included as part of the well's completion. In this chapter the impact of two, different, IWsT well management policies on the reservoir performance will be examined. This chapter will help determine which technique should be chosen when specifying the requirements for an effective, Intelligent Well management system.

The objective of zonal flow control using ICVs is to maximise the oil production and/or NPV, minimise the unwanted fluid productions or a combination of these objectives. ICVs are normally activated on the basis of the breakthrough time of unwanted fluids (water or gas). The activation policy can be either "Reactive" or "Proactive". "Proactive Control" is defined in this chapter as choking of the ICV(s) before water or gas breakthrough is observed at the wellbore. "Reactive Control" is choking the ICV(s) after water or gas breakthrough has occurred at the well level.

I have already shown the application and performance of "Reactive ICV Control" in a wide range of generic and real reservoir types (chapters 7 and 8) [10.1, 10.3, 10.4]. Brouwer et al. [10.5] presented a study in which the optimisation technique focused on reducing the difference in time of flight from the injector to producer in a water flood environment. Their method involved manipulating the well segment's productivity index (PI) to maximise total well production. Yeten et al. [10.6] presented a general method for the optimisation of a well equipped with ICVs. Their method entails the use of an optimisation tool based on a conjugate gradient algorithm. This optimisation tool was linked to a commercial reservoir simulator containing a wellbore flow model capable of modeling ICVs. Their optimisation approach required that the simulation be divided into a number of optimisation steps. The valve settings were optimised for each time period. Their method was applied to examples involving vertical wells in a layer-cake reservoir and multilateral wells in a complex channelised reservoir. It proved possible to improve cumulative oil recovery using a defensive ("Proactive") control methodology. Aitokhuehi et al. [10.7] combined IW optimisation on the basis of Yeten et al.'s work and history matching techniques. Use of multiple history matched models provided improved results in some cases.

In this penultimate chapter of the thesis the effectiveness of the "Proactive" and "Reactive" ICV Control will be compared.

It was shown in chapters 7 and 8 that a minimum degree of un-evenness of an invading fluid front is needed for effective ICV control. This chapter studies scenarios to identify when "Proactive" rather than "Reactive" ICV choking policy can add greater value. Reservoir scenarios were created in which inter-zone connection, permeability contrast between zones, zonal length and other reservoir parameters were systematically varied. The interaction between the aquifer and reservoir was observed when producing these reservoirs with a horizontal IW using a range of "Reactive" and "Proactive" choking policies.

An example of successful "Proactive Control" is when the wellbore is intersected by a high-permeability channel. Here, early water or gas breakthrough leads to unwanted fluid being produced along with reduced volume of oil. Too early choking (or being "too Proactive") can result in losing oil as the "Good Water" is also blocked. "Proactive Control" will also be successful when reduced water or gas inflow is required due to tubing or surface handling limitations.

The key factor in successful Single Well "Proactive Control" is that other zone(s) can compensate for the loss of fluid from the choked zone(s). Its value thus increases when Artificial Lift is installed. Lowering of the flowing bottom hole pressure allows an increased flow or it allows ICV control when the natural flow rate from the well was uneconomic.

The value of "Proactive Control" is well known in multiple well scenarios. Here, value creation requires even-flood front management of an injected fluid at the field level. Multiple well scenarios allow other wells to supply extra oil production capacity when one or more well(s) are choked.

The results from this chapter can be used to screen for scenarios suitable for "Proactive Control", increasing the range of Intelligent Well Technology applications.

10.2 Potential Value of "Proactive" Control

"Proactive" reservoir management can add value by optimising reservoir performance at the "Field Level" by developing an even flood-front along the length of the wells in the reservoir. This chapter will evaluate the effectiveness of "Proactive Control" on a "Single Well Basis" rather than the "Field Level". "Proactive reservoir management Control" requires a greater knowledge of the reservoir than that required for "Reactive Control". This arises from the need to optimally control the distance of the water or gas flood front from the wellbore as a function of time and fraction of the original oil-in-place recovered within the well's drainage area.

10.3 Model Construction

Figure 10-1 shows a cross-sectional view of the basic reservoir model, used for creation of the scenarios to be studied. It is a 3D model with 3 distinct layers. It has 20 grid elements in X-direction, 50 elements in Y-direction and 116 elements in Z-direction (total 116000 grid cells). Each grid cell is dimensioned 50 x 50 x 1 m in the X, Y and Z directions respectively. Table 10-1 summarises the porosity and permeability values used.

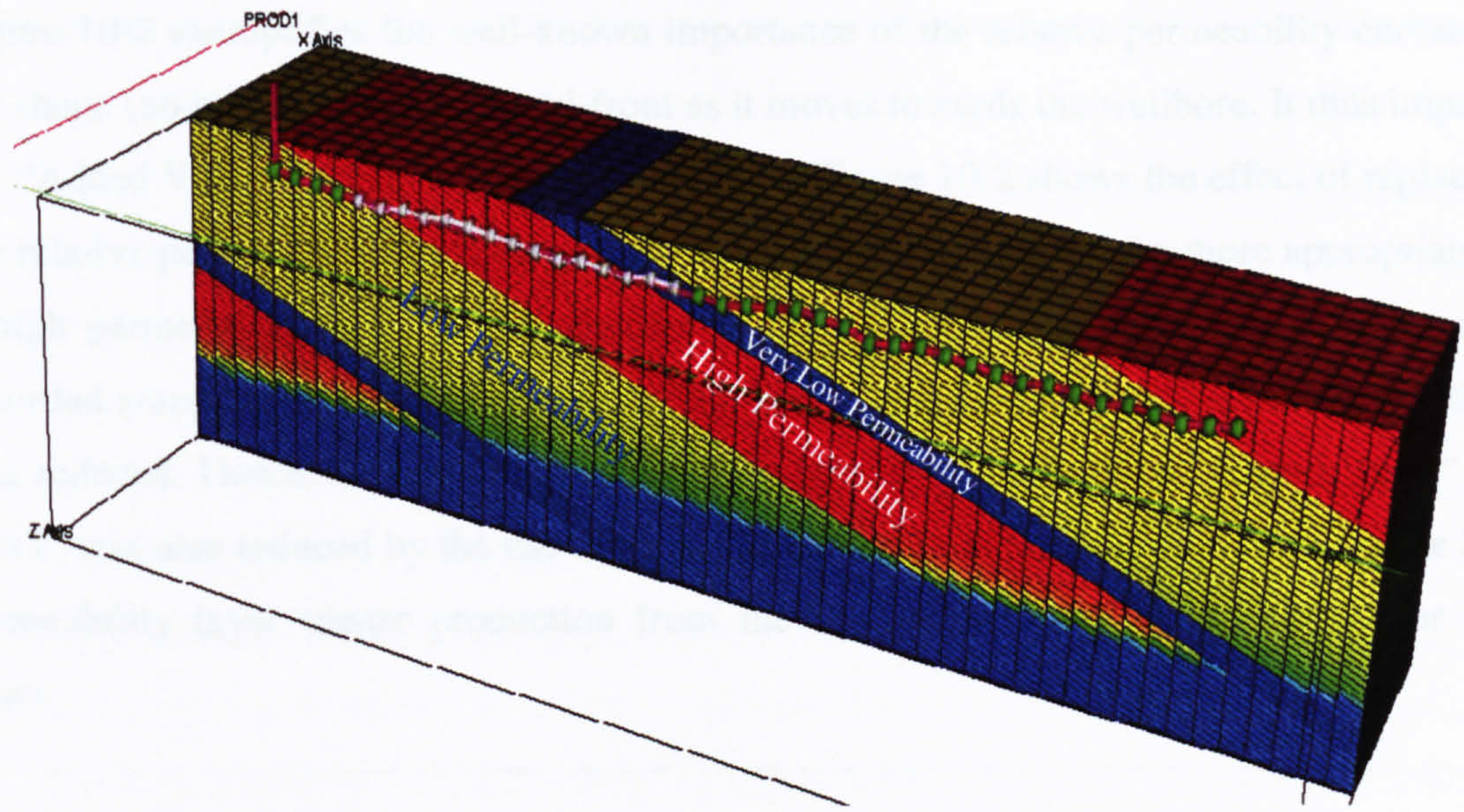

Figure 10-1: A Schematic of the Reservoir Model

Layer	Permeability (X & Y directions) md	Permeability (Z direction) md	Porosity (Fraction)
High Permeability	1000 mD	500 mD	0.23
Low Permeability	5 mD	2.5 mD	0.20
Very Low Permeability (Shale)	0.1 mD	0.05 mD	0.1

Table 10-1: Permeability/Porosity for the reservoir model

The "Added Value" for an Intelligent Well has been shown to be a function of the un-evenness of the movement of the fluid-front towards the wellbore [10.1]. Many parameters affect the fluid front's movement – the fluid properties, relative permeabilities among others are of great importance. In this study the relative permeability and capillary pressure curves were calculated as a function of the absolute permeability based on Pickup et al's work [10.8].

Figure 10-2 exemplifies the well-known importance of the relative permeability curves on the shape (un-evenness) of the flood-front as it moves towards the wellbore. It thus impacts the "Added Value" from Intelligent Wells [10.1]. Figure 10-2 shows the effect of replacing the relative permeability curve for the low permeability layer with one more appropriate to a high permeability zone. A 5% increase in the oil recovery for the "no ICV" case is recorded since the un-evenness shown by the flood-front as it moved towards the wellbore was reduced. Hence the opportunities for flow control, and hence the "Added Value" for IWsT, was also reduced by the use of inappropriate relative permeability curve for the low permeability layer (faster production from the low permeability layer resulted for this case).

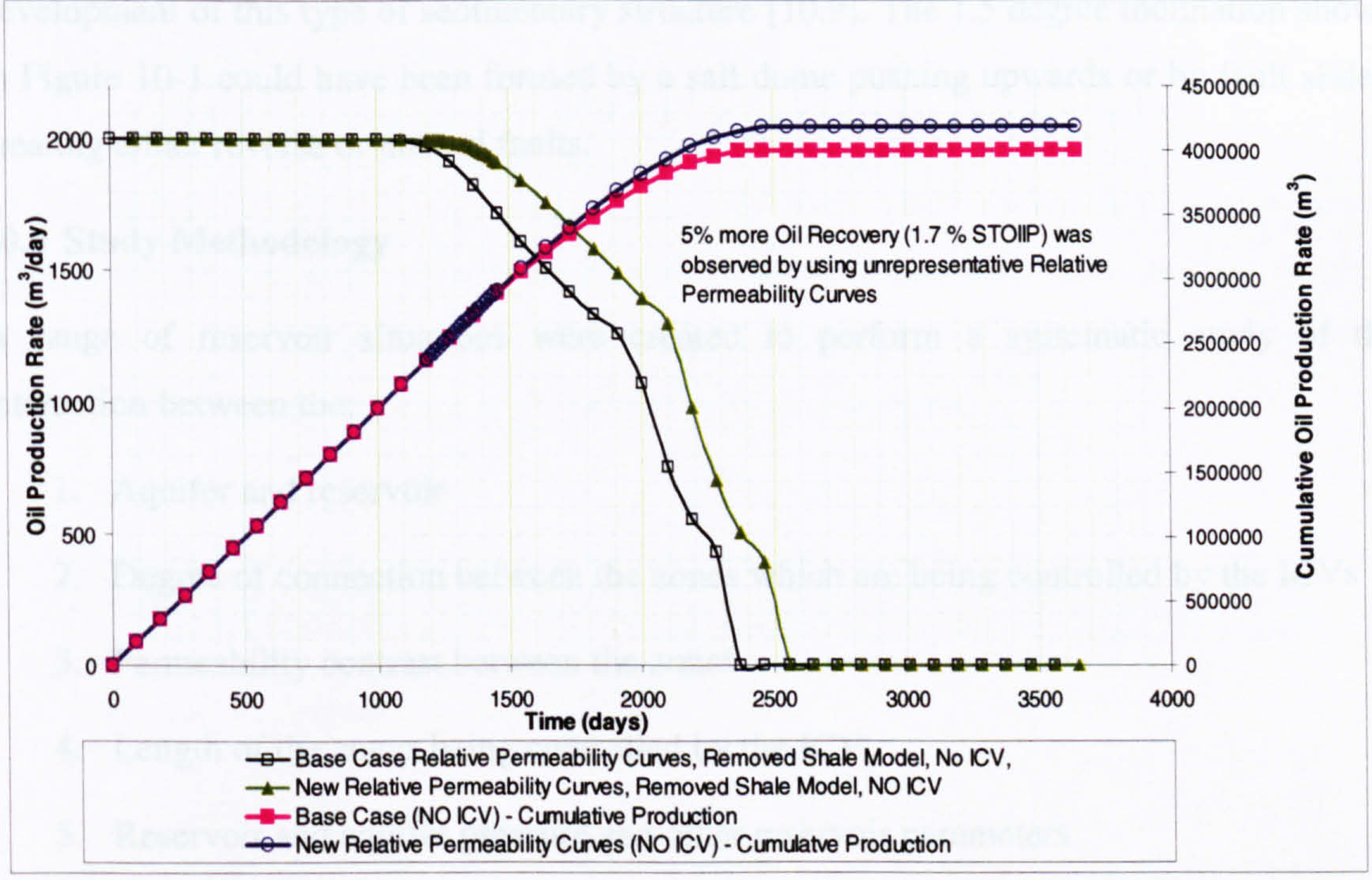

Figure 10-2: The Importance of the choice of Relative Permeability Curve

Inappropriate relative permeability curves can increase or decrease the "Added Value" for Intelligent Wells, depending on how they affect the shape of the flood-front as it moves towards the wellbore. It is also a function of the number and the position of the ICVs along the length of the wellbore.

The generic geological model used for this study (Figure 10-1) is based on a sequence of sandstone deposition events in a deep-water, marine environment with interbedded sand, silt and mud. These sediments could have been deposited in highly turbulent sediment flow from the sediment source. The sand bodies consist of two distinct layers – a high permeability sandstone with a permeability of 1000 mD and a low permeability sands of 5 mD permeability. The stratigraphic trap was formed from the deposited shale and mudstone layers (0.1 mD), the latter being formed during periods of low energy flow. Continued sediments transport, bedform migration and sediment deposition leads to the development of this type of sedimentary structure [10.9]. The 1.5 degree inclination shown in Figure 10-1 could have been formed by a salt dome pushing upwards or by fault slides; creating either reverse or normal faults.

10.4 Study Methodology

A range of reservoir situations were created to perform a systematic study of the interaction between the:

1. Aquifer and reservoir
2. Degree of connection between the zones which are being controlled by the ICVs
3. Permeability contrast between the zones
4. Length of the zones being controlled by the ICV
5. Reservoir and aquifer pressure and other reservoir parameters
6. The reservoir models were chosen so that the degree of un-even fluid front needed for effective control could be observed.

Manual optimisation techniques [10.1, 10.3, 10.4] for reactive and proactive control, as provided by the Eclipse^{TM} simulator package capabilities [10.10], have been applied for the control of the ICVs. The ACTION keyword was used to specify a field condition (e.g. a water cut limit) for triggering an action. The action is carried out by a specific well segment, which in our case represents a valve in the segmented well. The WSEGVALV keyword designates the appropriate segment within the well. The flow-regime in the valve is sub-critical, hence an additional pressure drop in the segment due to flow is imposed when the ICV action is triggered. The valve constriction has a specified cross-sectional area (Ac). The optimisation parameters used during the well's production life were the number of ICVs, the ICV flow diameter, choking time and the choking policy ("Reactive" or "Proactive" Control).

The reservoir scenarios were deliberately kept relatively simple so as to:

1. Help comparison between cases and
2. Allow a better understanding of the role of the "Reactive" versus "Proactive" control on any changes in the "Added Value" from an Intelligent Well.

In all cases performance of the well with both of these IWsT modes was compared with production from an equivalent well with the ICV permanently in the fully open position (the base case). The well flow rate was controlled at a target liquid rate of 2,000 m^3/day. Table 10-2 shows the range for each sensitivity parameter studied.

Sensitivities	Minimum	Maximum
Water Cut at which the ICV triggered (Reactive Control)	1%	30%
ICV Choke Size	0.000025 m^2 (0.2 inch ID)	0.001 m^2 (1.4 inch ID)
Reservoir Pressure	370 bars	500 bars
Choking Time for Proactive Control (Days before water breaks through)	9 days	821 days

Table 10-2: The range of sensitivities performed

Previous work with this type of model (chapter 7), confirmed that, as expected, choking of the high permeability zone encourages greater production from low permeability layers. This occurs because the well's production was not outflow limited; being controlled by the total liquid rate. This can result in delayed water breakthrough at the well level, allowing better sweep efficiency in the low permeability zone. Figure 10-3 shows the presence of trapped oil in the reservoir when producing it with a conventional well.

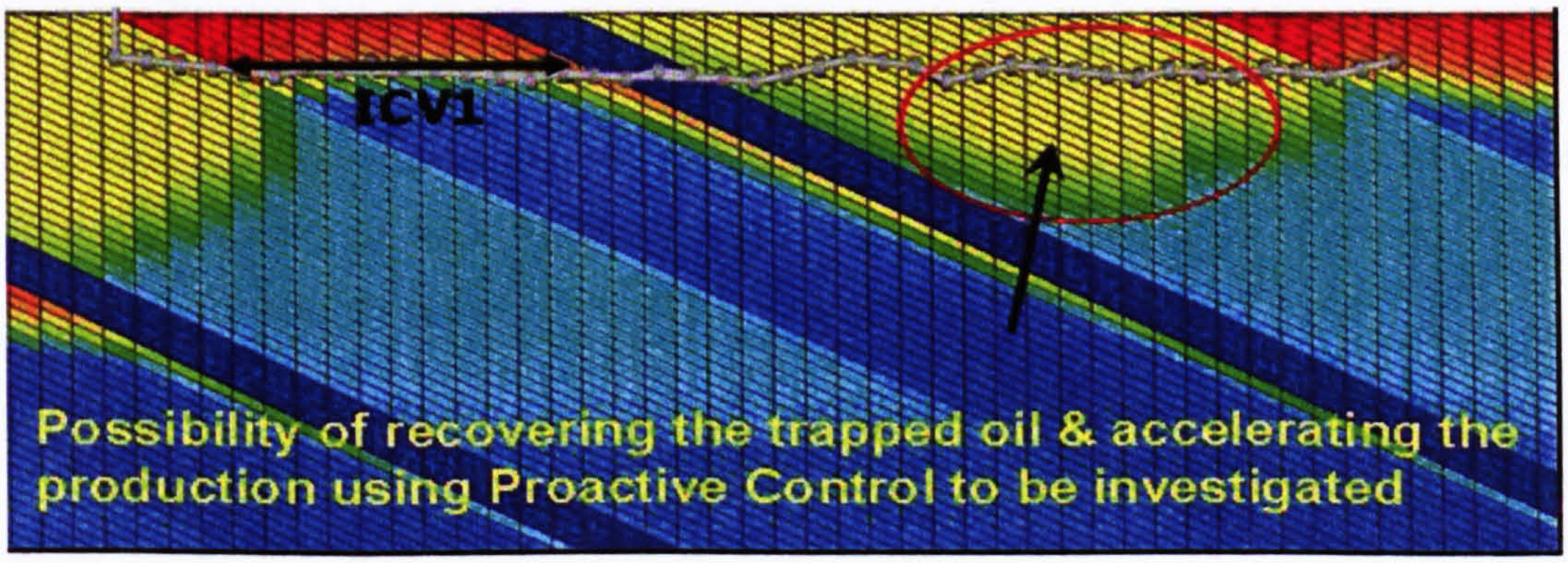

Figure 10-3: A slice of the model showing trapped oil by producing the reservoir with a conventional well

ICV1 was placed across the complete high-permeability layer. The well (or zone) length it controls was kept constant for all sensitivities studied. The model was modified during the latter parts of the study (Figure 10-10 and Figure 10-13). A second ICV (ICV2) was also introduced to control the water break-through at the very end of the well (Figure 10-13). The well (or zone) length controlled by ICV2 was kept constant for all scenarios.

10.4.1 Choking Policies

The choking policies for Reactive Control allowed changing the water cut at which choke action was triggered. Different choking policies were examined:

1. Single choke action. Here the choke size stayed constant for the remainder of the well's life after the single choking event.

2. Two control actions optimally spaced. The choke size was reduced to a certain diameter initially and then made reduced again later in the well's life when the water cut became too high.

A wide range of sensitivities were performed to identify the optimum values for ICV size and triggering time within the above policies.

Similar choking policies have been studied for "Proactive Control".

1. Single control action for the ICV so that choking took place some time before the water broke-through into the well.
2. Two control actions, one was set before water breakthrough ("Proactive") while the second one was "Reactive" with choking later in the field life to curb an excessive water cut.
3. Three control actions, one control action was "Proactive", occurring before the water breakthrough time, while the final two took place later on ("Reactive").

The complexity of the manual optimisation was increased systematically during the study to allow development of a better understanding of the performance of "Proactive" control on a "Single Well" Basis.

10.5 Results and Analysis

Figure 10-4 is an overview of the models studied and the simulations performed.

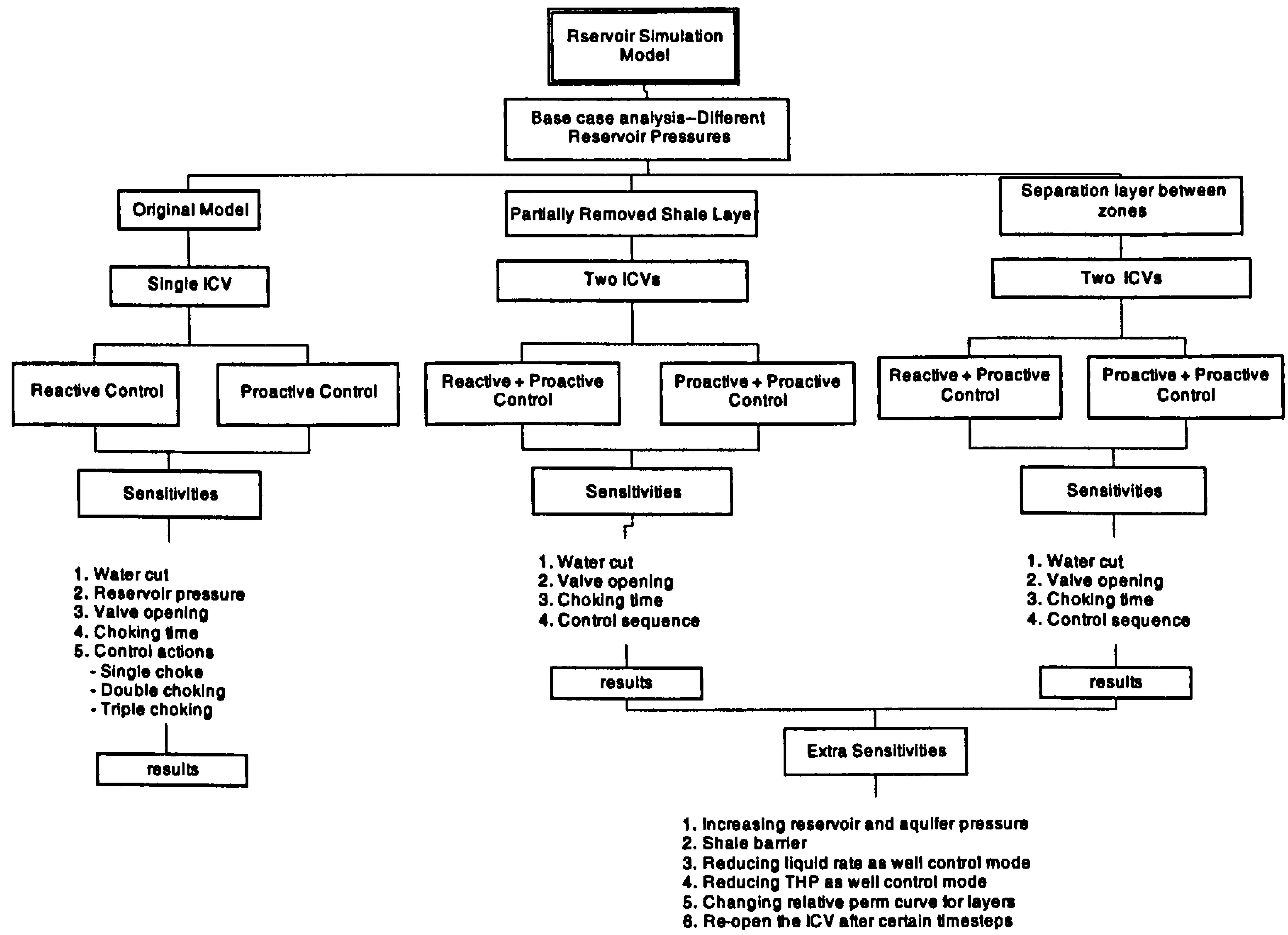

Figure 10-4: An overview of the simulations and sensitivities performed

10.5.1 The Original Model

Figure 10-5 compares the performance of "Proactive" and "Reactive" Control with the base case. "Proactive Control" accelerated the production and increased recovery by 6.2 %. This was slightly (0.3%) better than when a "Reactive Control" policy was employed.

Optimum "Proactive" Control required choking of the ICV 175 days before water breakthrough occurred at the wellbore. "Proactive Control", increasing production from the low permeability layer to such an extent that the plateau period was extended compared to the base case. The low permeability zone now experiences a later water break-through.

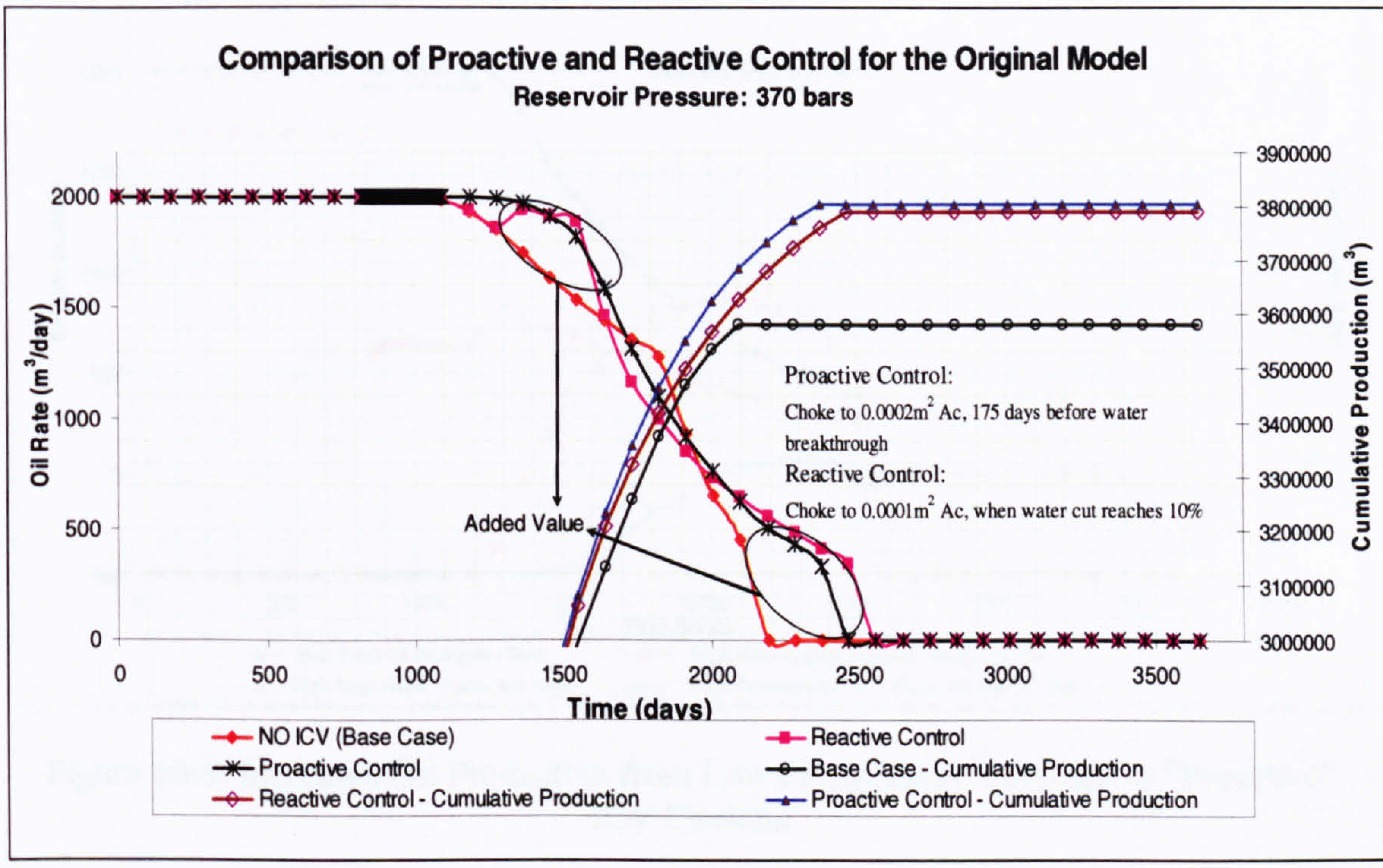

Figure 10-5: Comparison of Proactive and Reactive Control for the original model

Figure 10-6 depicts the oil flow rate at the ICV controlling the flow from the high permeability layer. Extended production at the plateau rate was achieved despite choking the high permeability zone that had previously produced 85% of the well's production. The net result was an improved recovery from the reservoir.

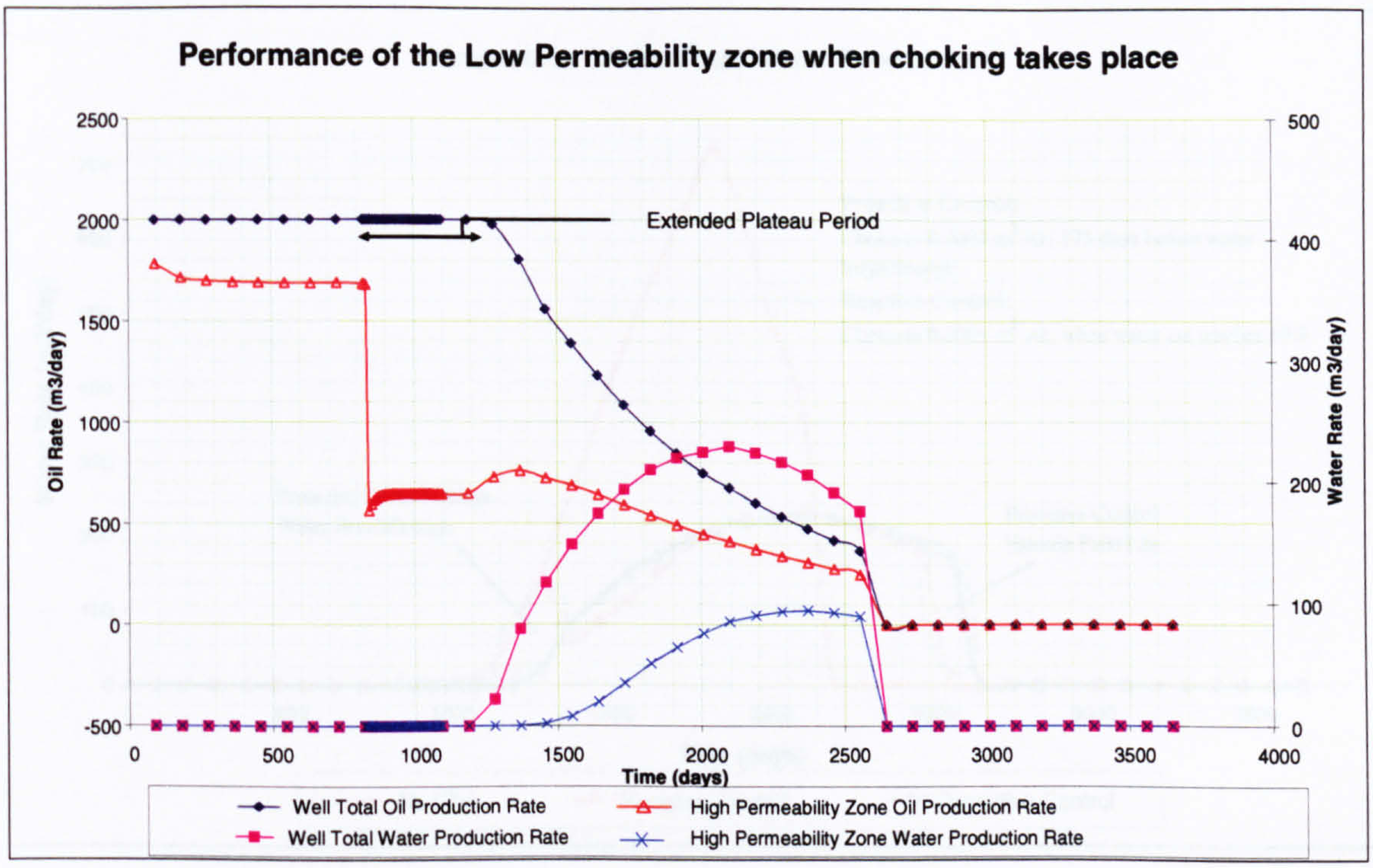

Figure 10-6: Increased Oil Production from Low Permeability Zone due to "Proactive" ICV Choking

Figure 10-7 illustrates a significant (40 %) reduction in water production compared to the base case. "Proactive Control" will normally delay water breakthrough and reduce the cumulative water production compared to the "Reactive Control". (Remember, the ICV is a choke!). The magnitude of the difference in recovery between these policies will depend on the particular choking policy chosen and the case being studied.

N.B. Both "Reactive" and "Proactive" Control can be highly successful when reduced water or gas inflow is required due to tubing or surface handling limitations. "Proactive Control" will be preferred under some scenarios as it both reduces and delays the total volume of unwanted fluid produced.

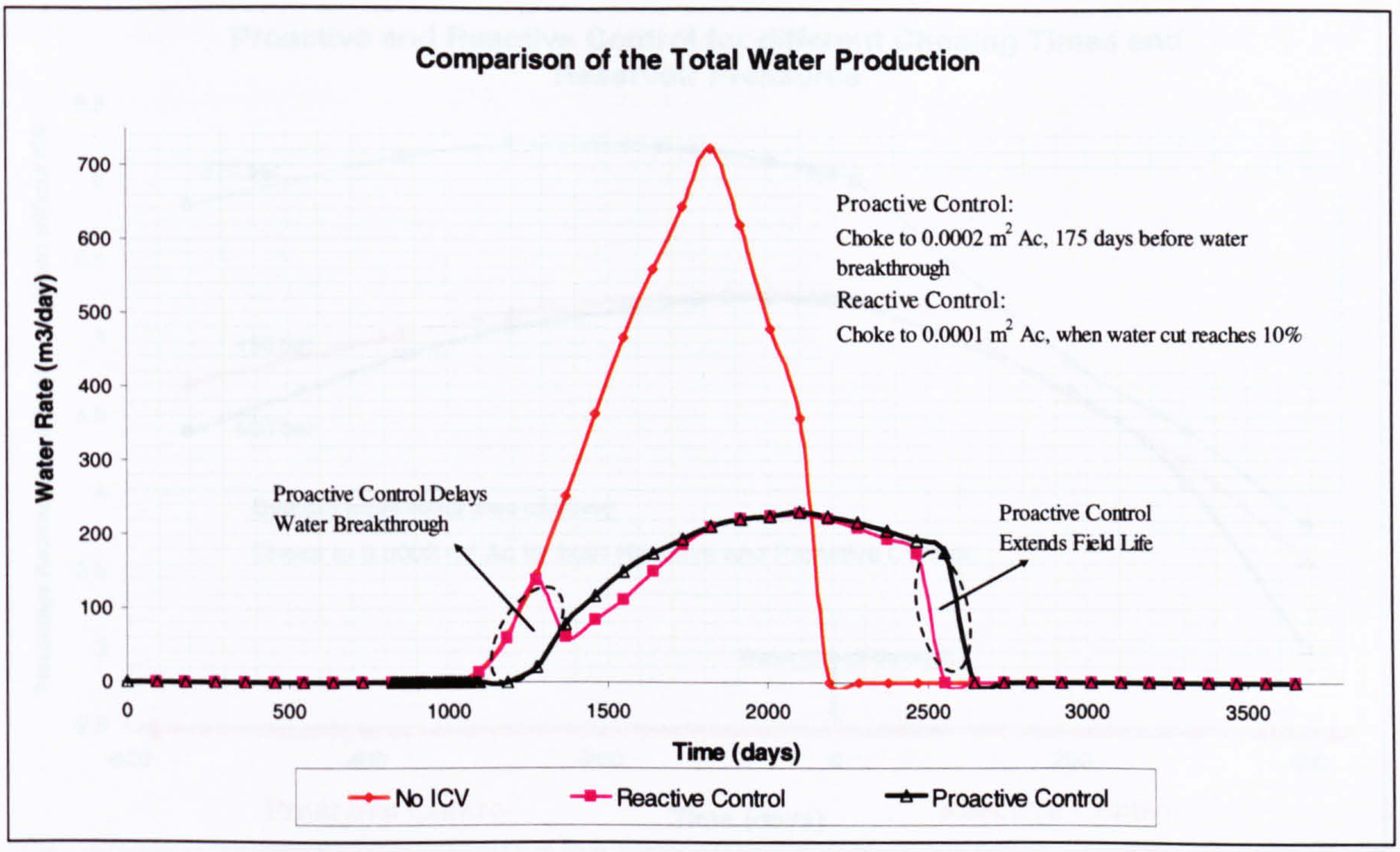

Figure 10-7: Comparison of the Total Water Production for the original model

Figure 10-8 compares the performance of both "Proactive" and "Reactive" control for a wide range of choke trigger times and Reservoir Pressures. It illustrates how choking too early, or being "too-Proactive", will result in a loss of oil. The optimum choke triggering time for "Proactive Control" in this study is between 150 to 200 days before water breakthrough for a reservoir pressure of 370 bars. The optimum severity of the choking to be applied will vary with the time (before water-breakthrough) that the choke action is triggered. Choking later implies that a slightly more severe (reduced diameter) choke is required for optimum performance. However, in this example the difference is small and the "Added Value" of "Proactive" compared to "Reactive" control remained approximately constant.

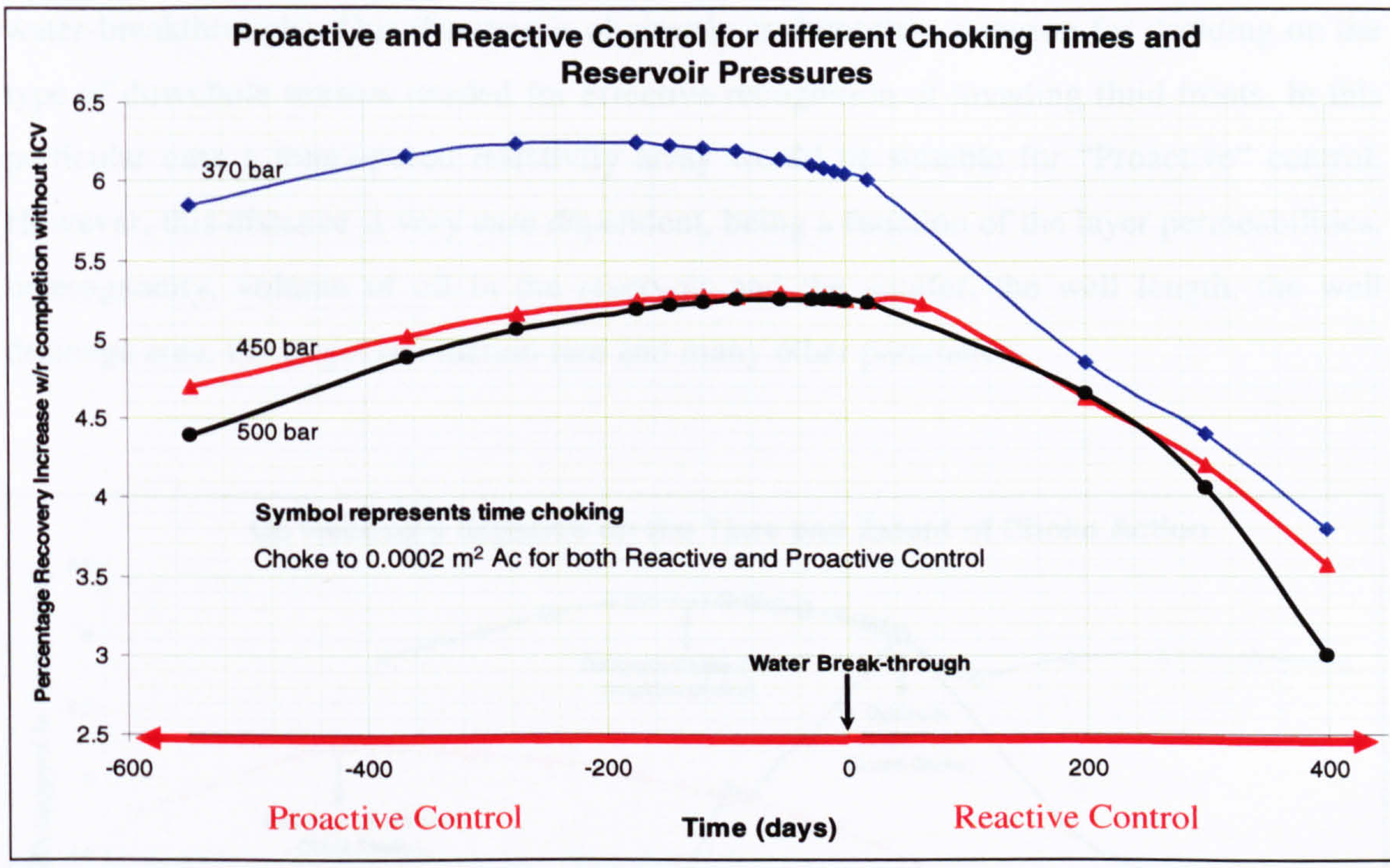

Figure 10-8: Performance of Proactive and Reactive Control for different choking times and reservoir pressures

The amount of choking, or the internal diameter of the ICV, was kept constant at each of the trigger times shown in Figure 10-8. This was done to aid comparison of the results However, a wide range of sensitivities were performed on the choking severity for each of the trigger times illustrated in Figure 10-8.

Figure 10-8 also illustrates the choke trigger times for different reservoir pressures supported by a constant aquifer pressure. It shows that the lower reservoir pressures gave a higher value for IWsT. The greater pressure differential between the reservoir and the aquifer pressures implies that a greater pressure support is available. This creates an earlier, more un-even, fluid-front movement towards the wellbore. Hence, there will be more opportunities for flow-control; and a higher "Added Value" from IWsT.

The distance of the invading oil/water flood front from the wellbore was 10 meters in the above example of effective "Proactive Control" (ICV trigger time of 175 days before water-breakthrough). This distance is obviously an important criterion for deciding on the type of downhole sensors needed for effective recognition of invading fluid fronts. In this particular case a long-spaced resistivity array would be suitable for "Proactive" control. However, this distance is very case dependent, being a function of the layer permeabilities, heterogeneity, volume of oil in the reservoir and the aquifer, the well length, the well drainage area, the target production rate and many other parameters.

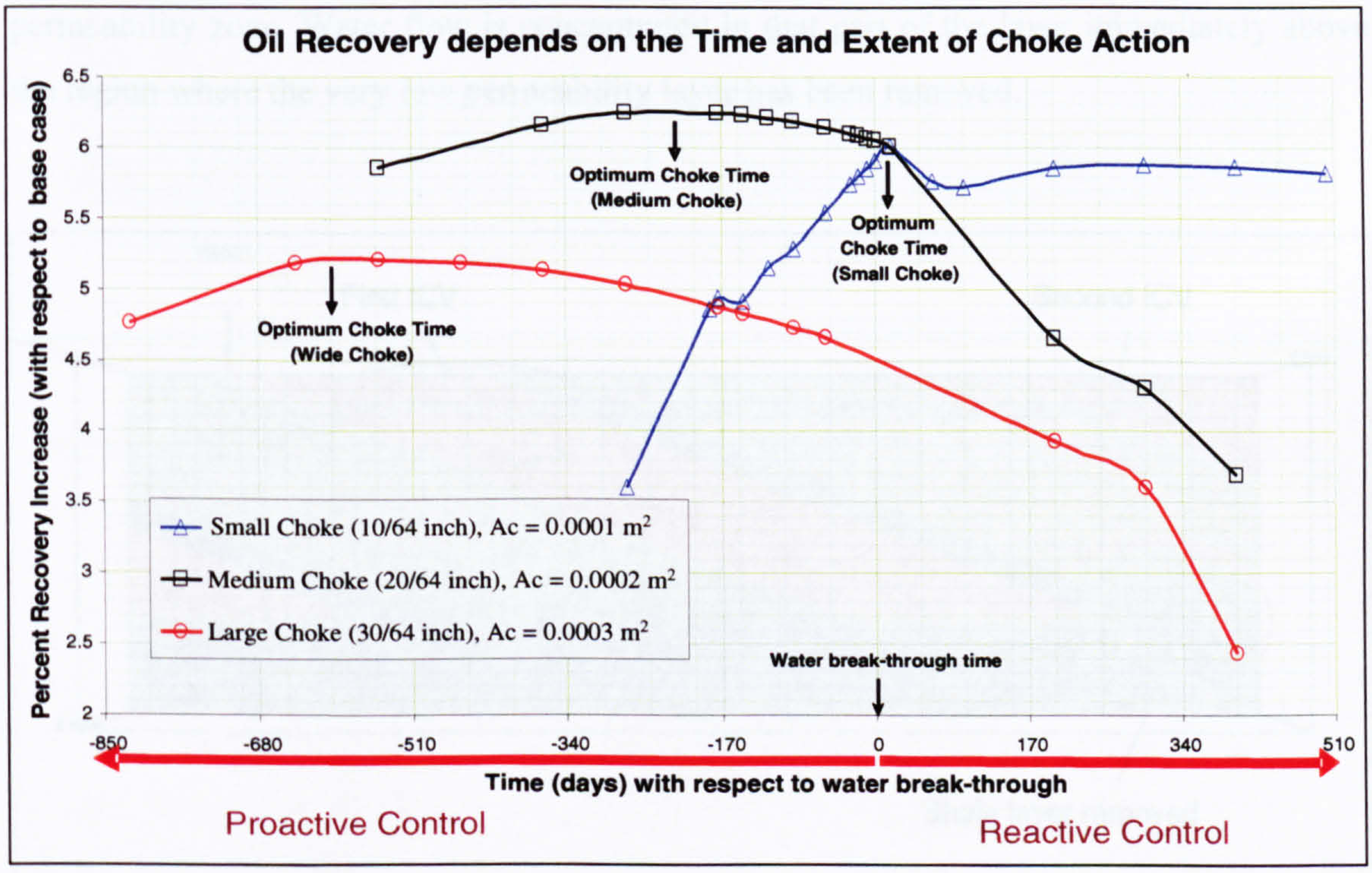

Figure 10-9: Oil Recovery depends on the time and extent of choke action

Figure 10-9 shows that optimum earlier "Proactive" choking requires use of a larger choke. Too early (or "too Proactive") choking looses oil ("Good Water" is blocked). Figure 10-9 shows that medium choking applied 200 days before water breakthrough gives optimum recovery. For some other cases it was found that combined actions – both "Proactive" and "Reactive Control" – is the best option.

10.5.2 Modification of the aquifer support by Partial Removal of the very Low Permeability Layer

Figure 10-10 shows the cross-section of the Figure 10-1 model which has been modified by partial removal of the very low permeability layer at the bottom right of the reservoir. This was done in order to modify the aquifer support to the layers by creating greater communication between the layers. Fluid front performance in Figure 10-11 illustrates how the aquifer water on the right-hand side of the model no longer supports the complete low-permeability zone. Water flow is concentrated in that part of the layer immediately above the region where the very low permeability layer has been removed.

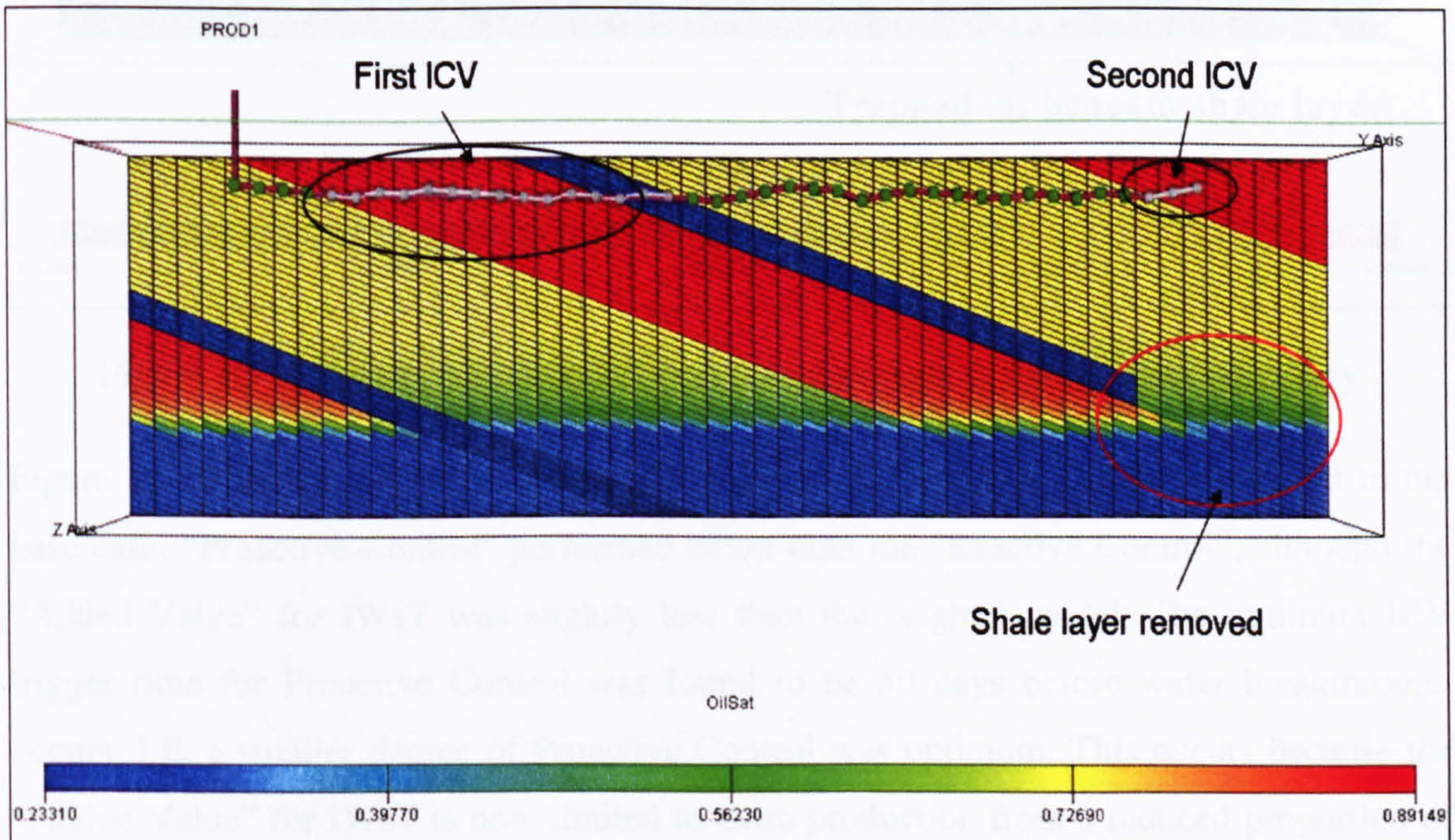

Figure 10-10: Partial removal of shale barrier creates communication between the compartments

Insufficient pressure support is now given to the low permeability layer. It is no longer able to compensate for the loss in fluid production from the high-permeability zone when the ICV controlling the high-permeability zone is triggered.

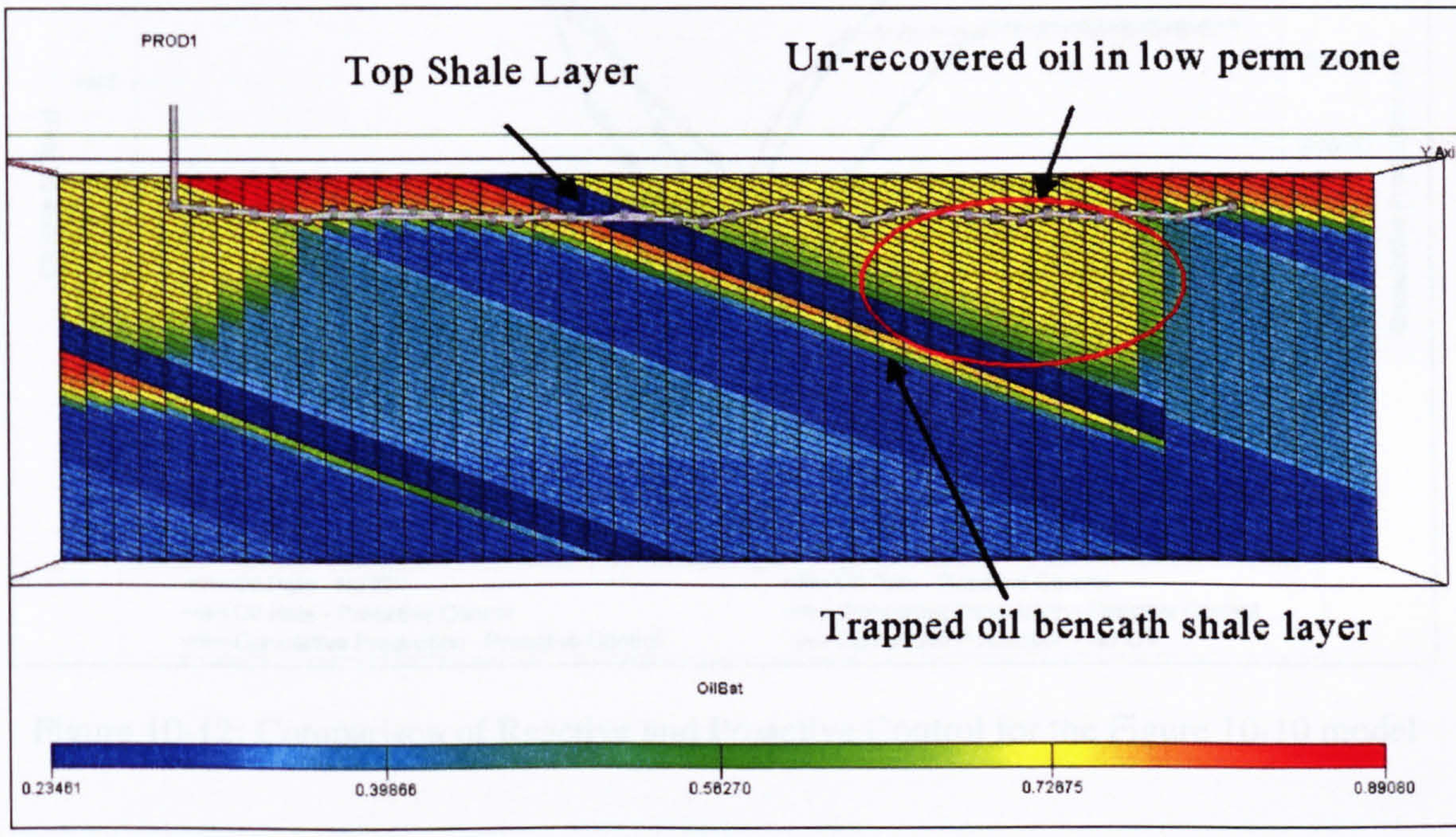

Figure 10-11: Communication between compartments reduces sweep efficiency

Figure 10-12 shows the performance of Proactive and Reactive Control compared to the base case. "Proactive Control" performed better than the "Reactive Control", although the "Added Value" for IWsT was slightly less than the original model. The optimum ICV trigger time for Proactive Control was found to be 50 days before water breakthrough occurs. I.E. a smaller degree of Proactive Control was optimum. This occurs because the "Added Value" for IWsT is now limited to extra production from a reduced proportion of the low permeability zone, the full potential of which could not be exploited due to lack of aquifer support.

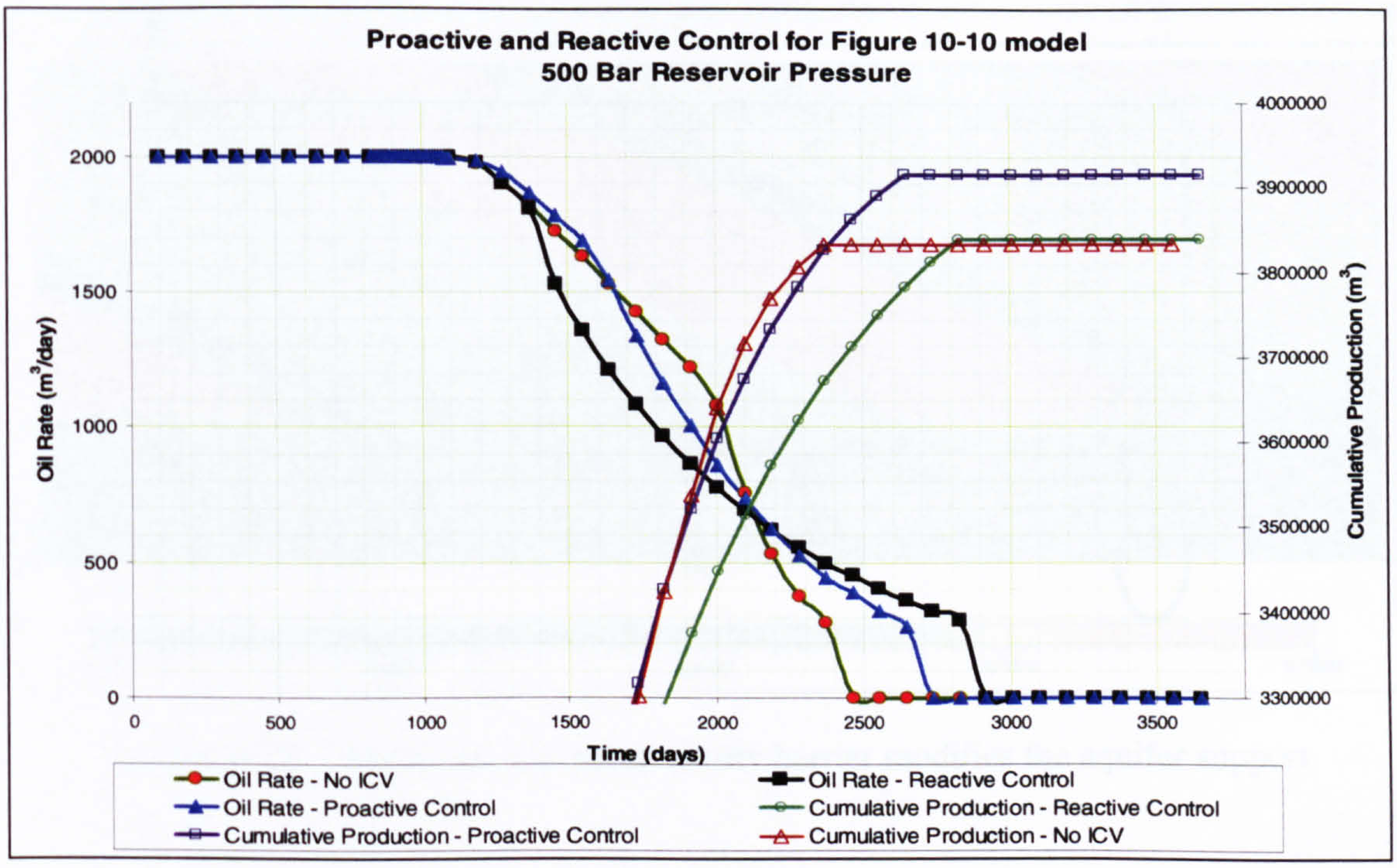

Figure 10-12: Comparison of Reactive and Proactive Control for the Figure 10-10 model

10.5.3 Addition of a Permeability Barrier to modify the Aquifer Support

Figure 10-13 shows modification of the aquifer support by addition of a permeability barrier. Figure 10-14 illustrates how the water flood is now restricted to the high permeability layer, resulting in the low permeability layer suffering a low sweep efficiency. A second ICV was introduced to control water production flow from the far right section of the model (ICV2 in Figure 10-13). "Reactive", "Proactive" and "Mixed Mode" choking (a combination of both "Reactive" and "Proactive" control) were studied for both ICVs.

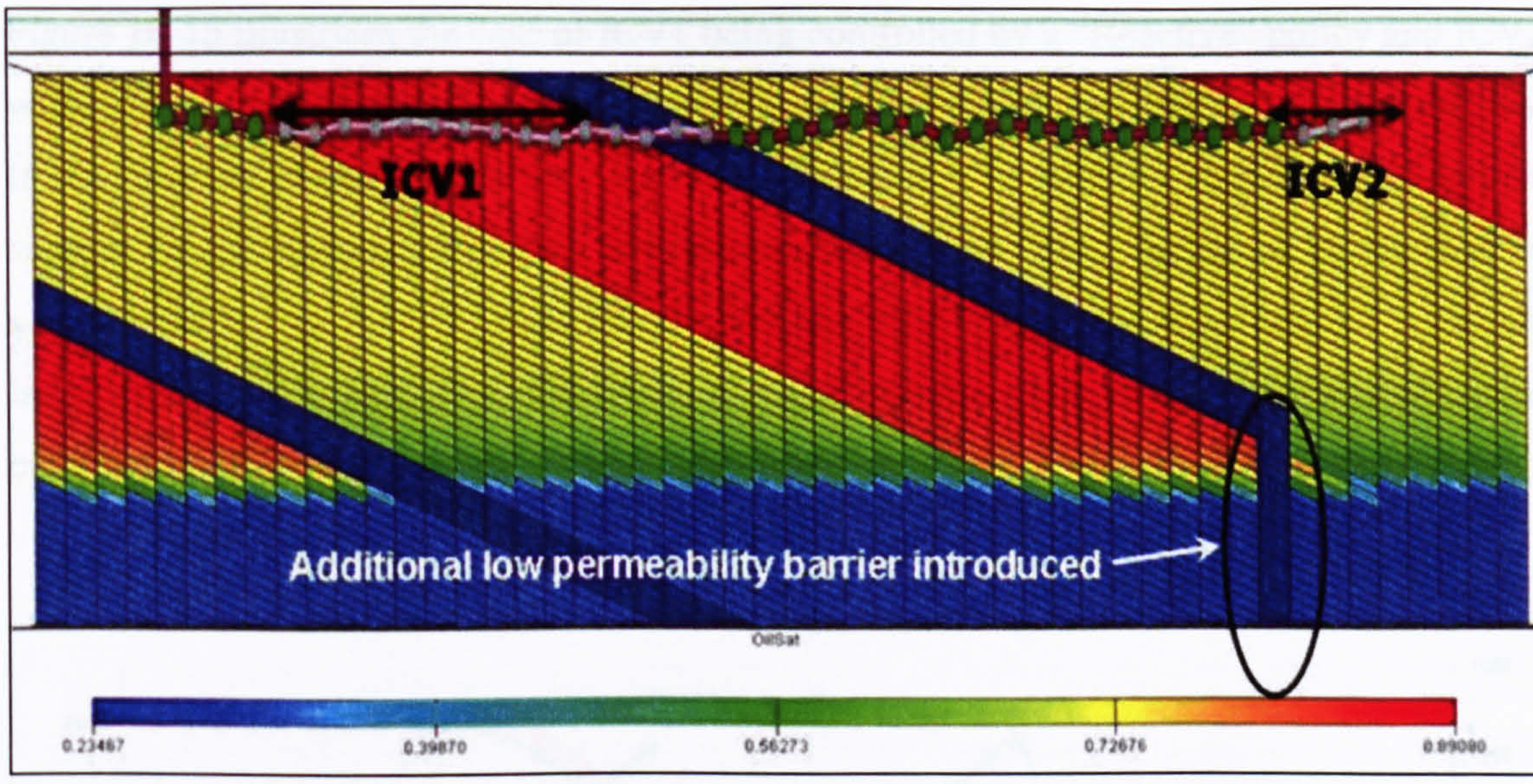

Figure 10-13 : Additional low permeability barrier modifies the aquifer support

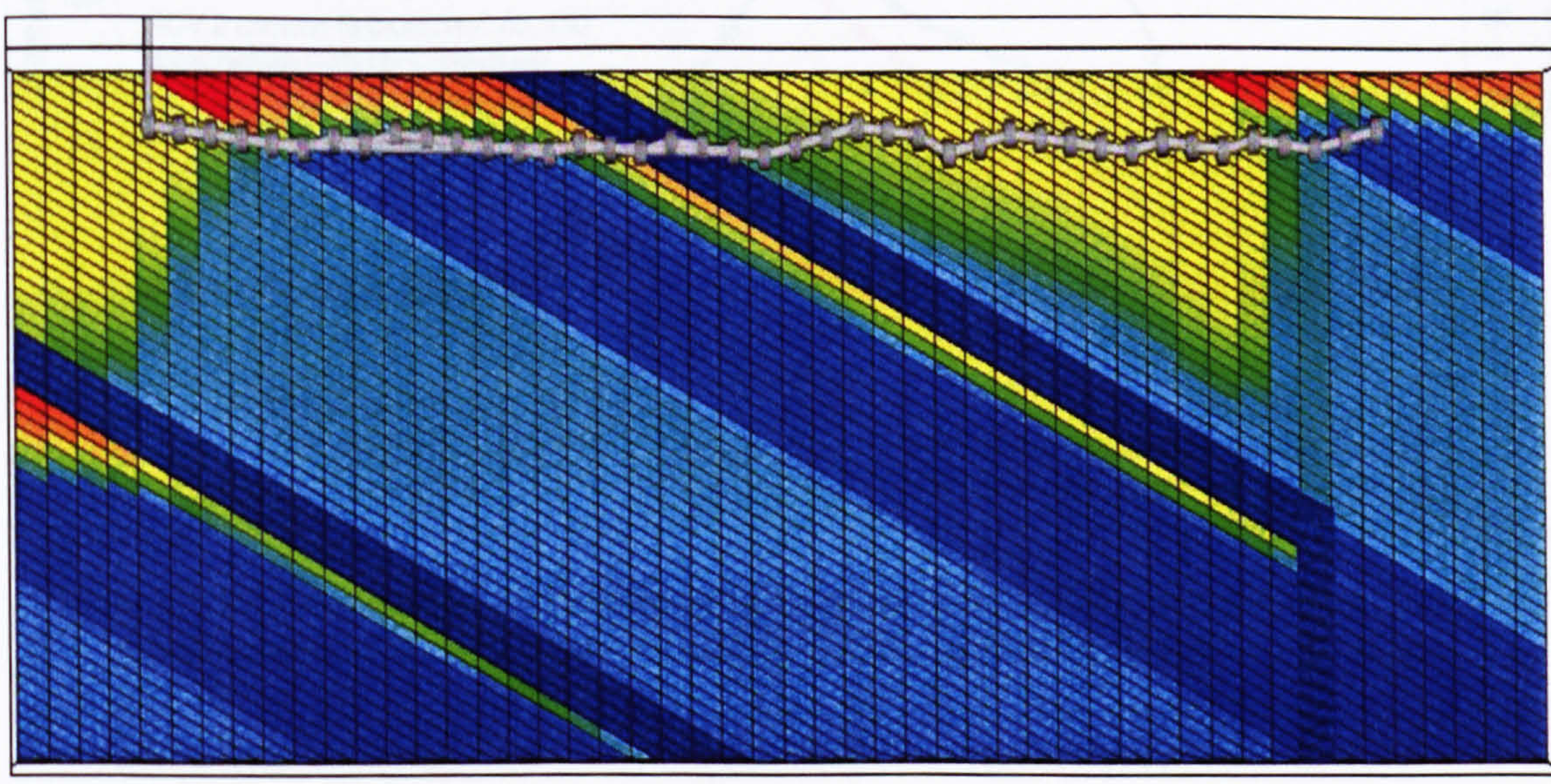

Figure 10-14: Only a slight increase in the sweep efficiency is observed compared to Figure 10-11

Figure 10-15 illustrates the case of ICV1 being controlled by a "Reactive" policy and ICV2 with a "Proactive" Policy. The performance is compared with the case of fully open ICVs. In this case the oil production was unaffected by the ICV control due to the limited aquifer support to the trapped oil in the low permeability layer. N.B. Increased production to compensate for the loss of produced oil when the ICV is triggered was required from this layer in the above scenarios. However, a slight improvement in recovery was observed compared to Figure 10-11.

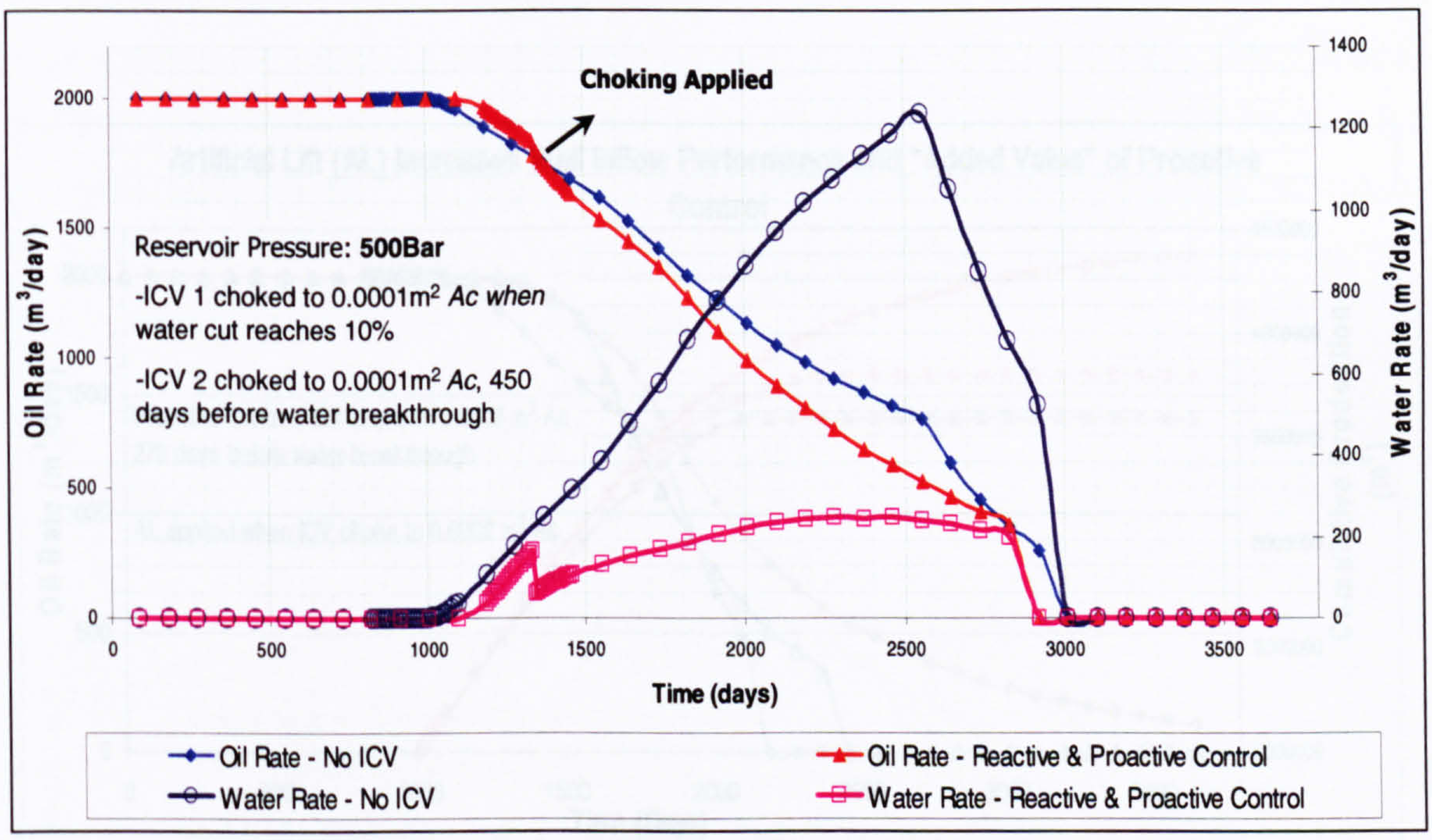

Figure 10-15: Comparison of Reactive and Proactive Control for the modified model 2 – Combination of Reactive and Proactive Control applied to Figure 10-13 model

Figure 10-15 records a substantial reduction in water production despite this lack of success in increasing oil production.

10.5.4 Artificial Lift Installation compensates for the lack of aquifer support

Figure 10-16 shows the performance of a well equipped with Artificial Lift (AL). The ICV choking action in the high permeability layer was triggered 270 days before water break-through. AL was applied at the same time as this "Proactive ICV choke Control" of the flow from high permeability layer. The AL improved the well inflow performance, encouraging extra production from the low permeability layer. An increased "Added Value" of 22 % extra recovery was achieved for "Proactive Control" compared to the "no ICV + no AL" case (Figure 10-16).

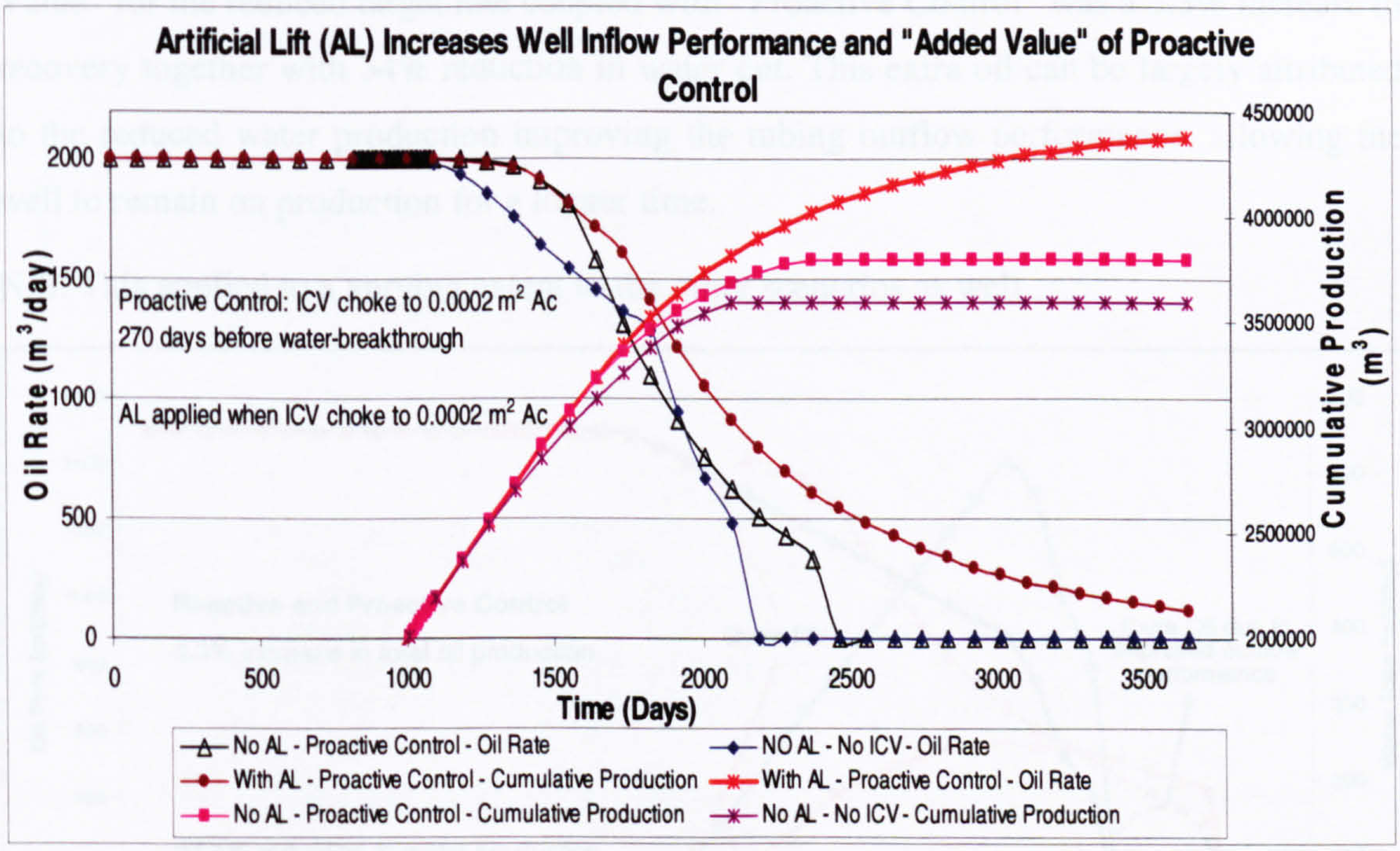

Figure 10-16: Application of Artificial Lift with Proactive Control

10.5.5 Reduced Target Liquid Rate

The lack of efficient aquifer support was identified as the main cause for the limited "Added Value" from ICV control in the above scenarios. The requirement for aquifer support was therefore reduced by lowering the well's target rate.

Figure 10-17 shows the performance of the well completed in the Figure 10-13 reservoir model after reduction of the target liquid rate from 2,000 m^3/day to 1,500 m^3/day. The low permeability layer is now able to compensate for the loss of oil production from the high permeability layer when its flow was reduced by "Proactive" Control of the ICV. (N.B. This compensation was not possible with a well target rate of 2,000 m^3/day). The "Added Value" for the reduced target rate coupled with "Proactive Control" was a 3.3% increase in recovery together with 34% reduction in water cut. This extra oil can be largely attributed to the reduced water production improving the tubing outflow performance, allowing the well to remain on production for a longer time.

N.B. This applied to a varying extent to the other scenarios as well.

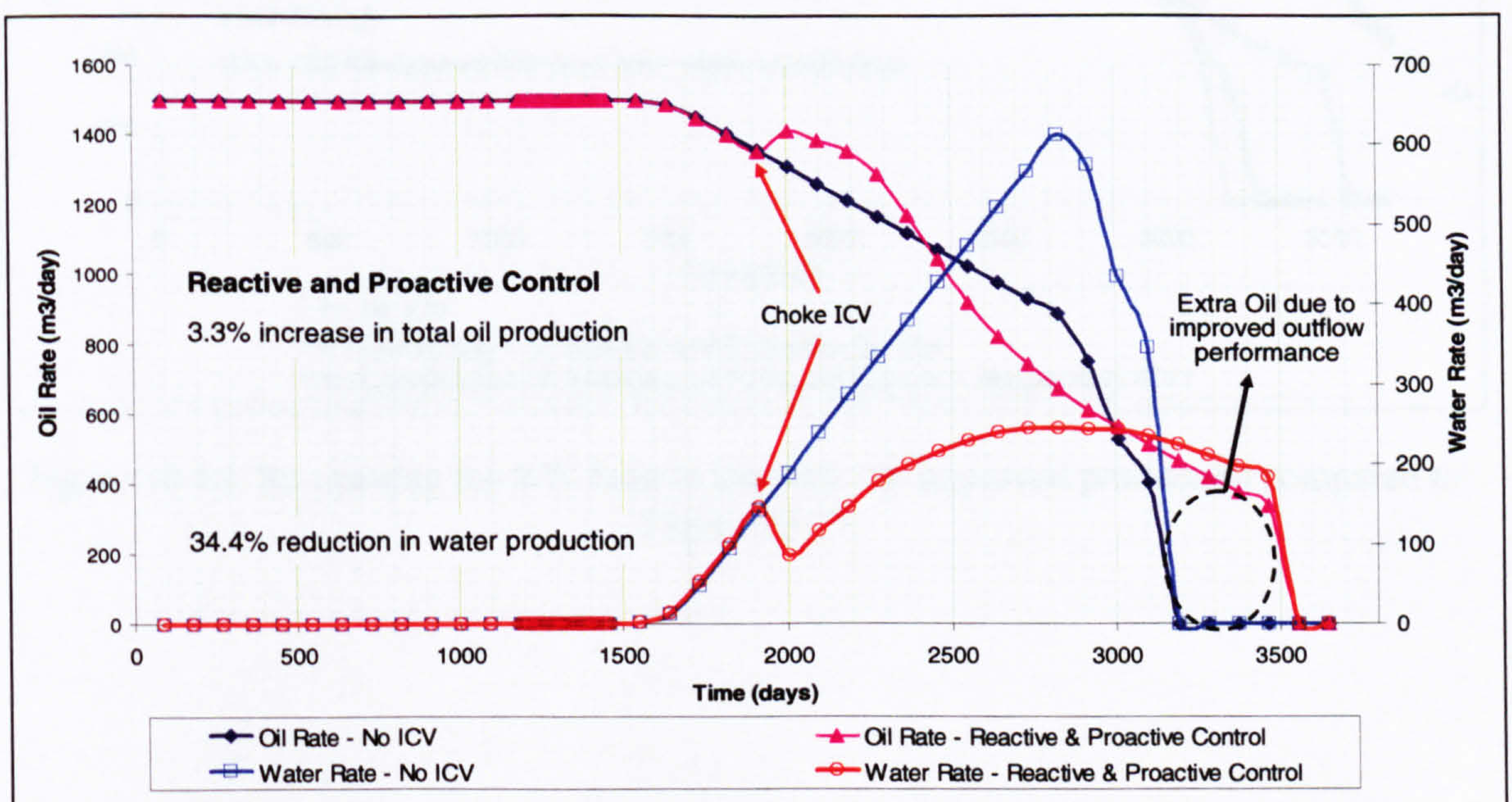

Figure 10-17: Reduced Well Target liquid rate for the Figure 10-13

10.5.6 Re-open the ICV Later in Field Life Improves Well Deliverability

Figure 10-18 shows the performance of the well for the reduced target rate of 1500 m^3/day. Both ICVs were re-opened later in the field life. This scenario was chosen to illustrate that very significant volumes of unswept oil remained in the model that could be recovered by a more complex choking policy in the mature phase of the well life.

Increased oil production (rather than reduced water production) can thus only be achieved when excess well deliverability exists.

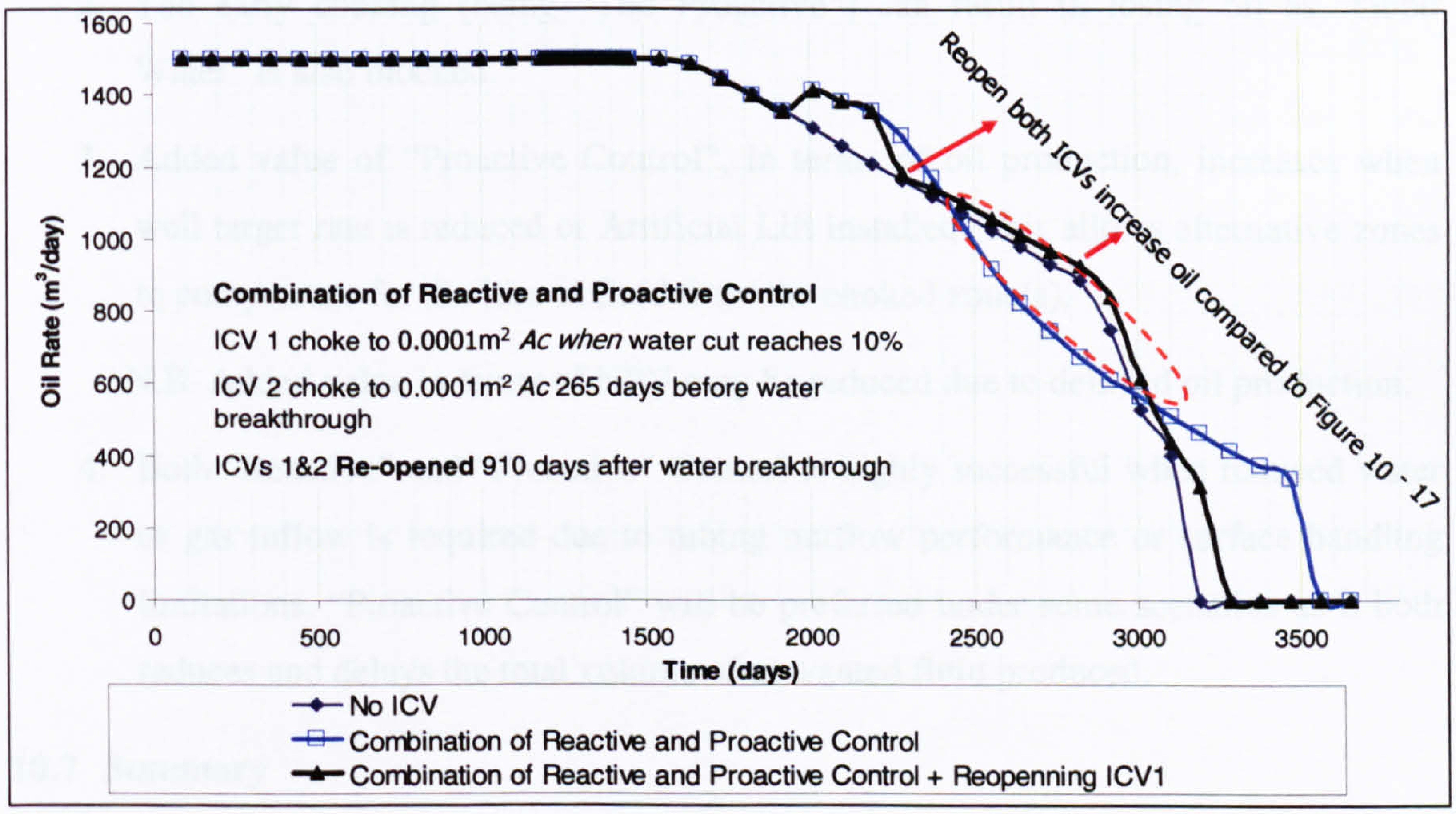

Figure 10-18: Re-opening the ICV later in the well life improved production compared to Figure 10-17

10.6 Conclusions

The key learning from this chapter with the objective to identify successful Single Well "Proactive Control" scenarios is that:

1. Alternative production zone(s) must be able to compensate for the loss of fluid from the choked zone(s). Knowledge of the parameters effecting the movement of the fluid-front (e.g. permeability distribution, strength of the aquifer support at all points within the model etc.) is required when preparing an "Added-Value Statement" for IWsT.

2. Too early choking (being "Too Proactive") can result in losing oil as "Good Water" is also blocked.

3. Added value of "Proactive Control", in terms of oil production, increases when well target rate is reduced or Artificial Lift installed. This allows alternative zones to compensate for the loss of fluid from the choked zone(s).

   N.B. Added value in terms of NPV may be reduced due to delayed oil production.

4. Both "Reactive" and "Proactive" Control is highly successful when reduced water or gas inflow is required due to tubing outflow performance or surface handling limitations. "Proactive Control" will be preferred under some scenarios as it both reduces and delays the total volume of unwanted fluid produced.

10.7 Summary

The performance of Reactive and Proactive control was evaluated in this chapter. The previous chapters together present the factors which should be considered and evaluated when deciding on the application of Intelligent Wells. However, the "Added Value" from Intelligent Wells requires to be economically justified. The economic evaluation of the Intelligent Wells will be discussed in the next chapter.

10.8 References

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Chapter 11 Economic Evaluation

11.1 Introduction

The objective of screening a (field) development for IWsT application is to identify opportunities to improve the value of the well and/or the project. IWsT completions are more expensive than conventional completions (on a well basis), but should only be used when the overall investment efficiency increases. IWsT will often reduce the capital expenditure (on a field bais) through an innovative Intelligent Field Development strategy.

A successful IWsT application is likely to accelerate oil and gas production often by extending the plateau period of the production profile. However, most benefits come through the enhancement of post-plateau production (note that simulation models that do not adequately capture the geological complexity will predict that this stage may not be reached for many years).

The value of implementing IWsT is the difference in Net Present Value (NPV) of the (oil) revenue and costs resulting from the IWsT installation compared to a conventional development, once allowance has been made for risk and reliability issues connected to IWsT. The evaluation of the incremental cost and revenue are, however, complex. There are many input data required, some of which contain a large uncertainty in their value.

Figure 11-1 illustrates the Intelligent Completion evaluation process. A model of how the (intelligent) completion is input into the reservoir simulator (or other tools) is required. The well path and cost are determined via the conventional drilling planning process. The production profile may now be generated by combining the reservoir model with the well performance lift curves, etc. for a range of input data that fully reflect the uncertainty in the reservoir description. The value from the (Intelligent) completion installation can now be determined using the chosen financial technique; the result being checked to see if it is an optimum result that meets the company's economic criteria.

Sharma et al [11.1] showed how the technical and non-technical issues concerned with evaluating the overall risks involved with choice of (IWsT) functionality can be combined. They used Real Options analysis for quantification of value creation by Intelligent Wells as discounted cash flow (DCF) models do not adequately value the benefits of operational flexibility, and thus often understimate the value of IWsT (i.e. the benefits of real-time monitoring and control).

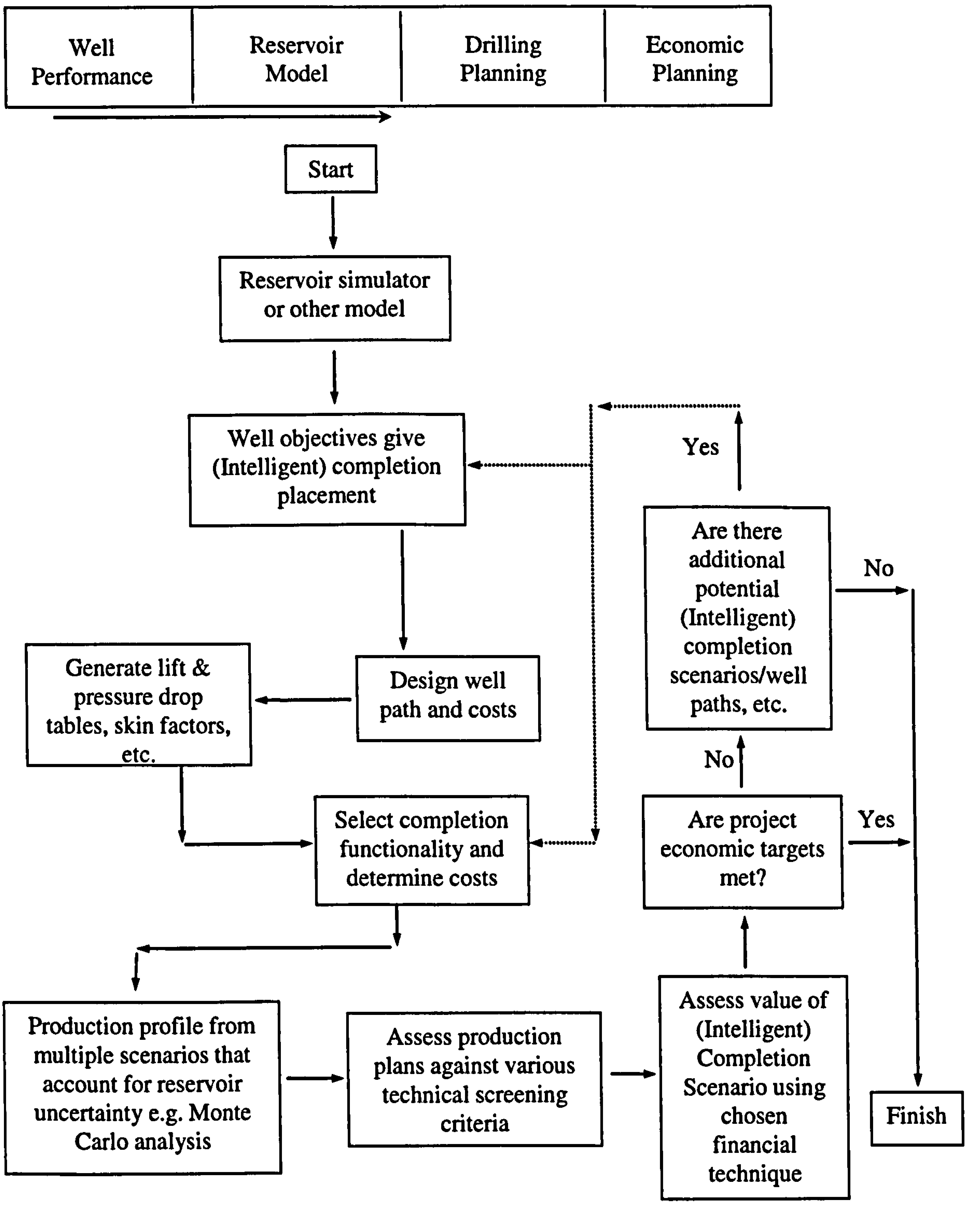


Figure 11-1: Intelligent Completion Evaluation Process

The following is a brief discussion of the financial evaluation methodology that can be used to analyse the benefits of IWsT.

11.2 Cash Flow Analysis (Net Present Value)

Conventional Discounted Net Cash Flow (DNCF) analysis is the most commonly applied economic evaluation tool. It represents the net cash flow or the difference between the expected revenue and cost on yearly basis over the project lifetime, discounted to a common point in time. Discounted Net Cash Flow takes in account the depreciation in time value of money. The sum of the all predicted annual cash flows (discounted to a common point in time) over the project lifetime is the Net Present Value (NPV) of project.

It may be represented by the following equation:

$$NPV = \frac{A_0}{(1+i)^0} + \frac{A_1}{(1+i)^1} + \frac{A_2}{(1+i)^2} + ... + \frac{A_n}{(1+i)^n}$$

Where:

A = Project net cash flows, defined by project

i = Discount rate, specified by company policy (may vary over life of project)

n = 0, time of origin

If the NPV is positive, the required rate of return is likely to be earned, and the project should be considered. If it is negative, the project should be rejected.

Table 11-1 summarises economic metrics that are used in financial analysis.

Indicator	Unit	Refers to	Comments
Net Present Value	£ million	Value	Requires a discount rate and reference date.
Profit to Investment Ratio	Ratio	Investment Efficiency	For low risk projects a positive value is often acceptable. For high risk projects it should be close to unity.
Time to Pay Back	Years	Timing, risk	Length of time invested capital is at risk.
Cost per Barrel	£/barrel	Benchmark	Useful for comparison with similar developments.
Internal Rate of Return	%	Investment Efficiency	Not suitable for use in analysing incremental investments because of sign change in incremental cash flows.

Table 11-1: Some Economic Metrics

There are significant risks and uncertainty involved in IWsT projects as mentioned above. The uncertainty could be due to Intelligent completion installation failure, future ICVs' operation failure and/or conventional risks such as future changes in the product price, tariffs, fixed opex and also technical reservoir characteristics.

IWsT installation will require a higher capital cost equipment and additional rig-time and possibly higher fixed operating cost (operating cost of downhole control and monitoring system and increased expenditure on IT systems for data storage and analysis). However, IWsT may reduce the surface facilities size (reduced unwanted fluids production), the variable operating costs (number of staff, etc.) and the future intervention costs. It often increases the well production rate & reserves and improve the recovery, as discussed in the previous chapters.

Sensitivity analysis is one of the best ways to evaluate and present the effects of these changes and the impact of uncertainty on their individual values. It indicates the worst and best possible outcomes by changing one or more parameters. But it neither points out the range of possible outcomes nor quantifies this probability of occurrence. The discount factor used is normally dictated by corporate policy. It is, therefore, might be necessary to consider stochastic approches for a more comprehensive analysis.

11.3 Expected Value

The Expected Net Present Value (ENPV) is the basic criterion for incorporating the concept of probability and risk. Normally most of the decisions taken under the condition of uncertainty have more than one possible monetary outcome. The expected value is the product of the probability of occurrence of a particular outcome and the estimated "value" if that outcome occurs. The "value" can be expressed in various ways: monetary profit or loss, opportunity loss, preference or utility values based on associated profit or loss, etc.

The ENPV is thus the product of the discounted value of a successful event (NPV_S) multiplied by the probability of achieving success (P_S) plus the product of the discounted value of an unsuccessful event (NPV_f) multiplied by the probability of failure (P_f).

It can thus be presented as:

$\sum_i (NPV)_i P_i = (NPV)_1 P_1 + (NPV)_2 P_2 + \ldots\ldots + (NPV)_n P_n$ N.B. $(P_S + P_f = 1)$

Some of the terms in above equation will be positive (representing successful outcomes) and some of them will be negative (representing failure).

11.4 Decision Tree Analysis

Virtually all important business decisions are made under conditions of uncertainty. The decision-maker must choose a specific course of action among those available to him, even though the consequences of some, if not all, of the possible courses of action will depend on the events that can not be predicted with certainty.

Decision-making under uncertainty implies that there are at least two possible outcomes that could occur if a particular course of action is chosen. For example, when the decision to test a seismic anomaly with a risky well is made, it is not known with certainty what the outcome will be. Even if the well is successful in discovering a large new oilfield, it is not certain what the ultimate value of the reserves will be. In fact, petroleum exploration has frequently been given the distinction of being the "classic example of decision making under uncertainty" [11.2].

Most prospects involve only a single decision that is made at time zero. This single decision would be, for example, "drill," or "farm out," etc. Once the decision is made there are no later contingencies or decision options with which the decision-maker becomes involved. For these types of decision choices, the procedures of making expected value (EV) computations are completely adequate. However, there are certain decision alternatives of a more complex nature that can not be analysed by a simple EV computation. Consider IWsT, the immediate decision choices are to Install or not install the "Intelligent Completion". But if the decision-maker decides to install IWsT, then there is another decision regarding what type of IWsT to install (the level of complexity) and, later, what to do if an installation problem is experienced while the well is being completed.

These types of decisions require our thinking to be modified with respect to the expected value concept. The analysis involves constructing a diagram showing all the subsequent chance events and decision options that are predicted.

The advantage of this form of analysis is that:

- All contingencies and possible decision alternatives are defined and analysed in a consistent manner.
- Such an analysis provides a better chance for consistent action in achieving a when a series of decisions have to be made.
- Any decision, no matter how complicated, can be analysed by the method.

- The entire sequential course of action is set out prior to the initial decision.
- The decision tree can be used to follow the course of events. At any decision node, if the conditions have changed, the remaining alternatives can be re-analysed to develop a new strategy from that point forward.

Decision trees can also be helpful to analyse the Value Of Information (VOI) that might be missing but could be acquired (through a possibly costly process). VOI will be discussed in section 11.7.

11.5 Construction of a Decision Tree

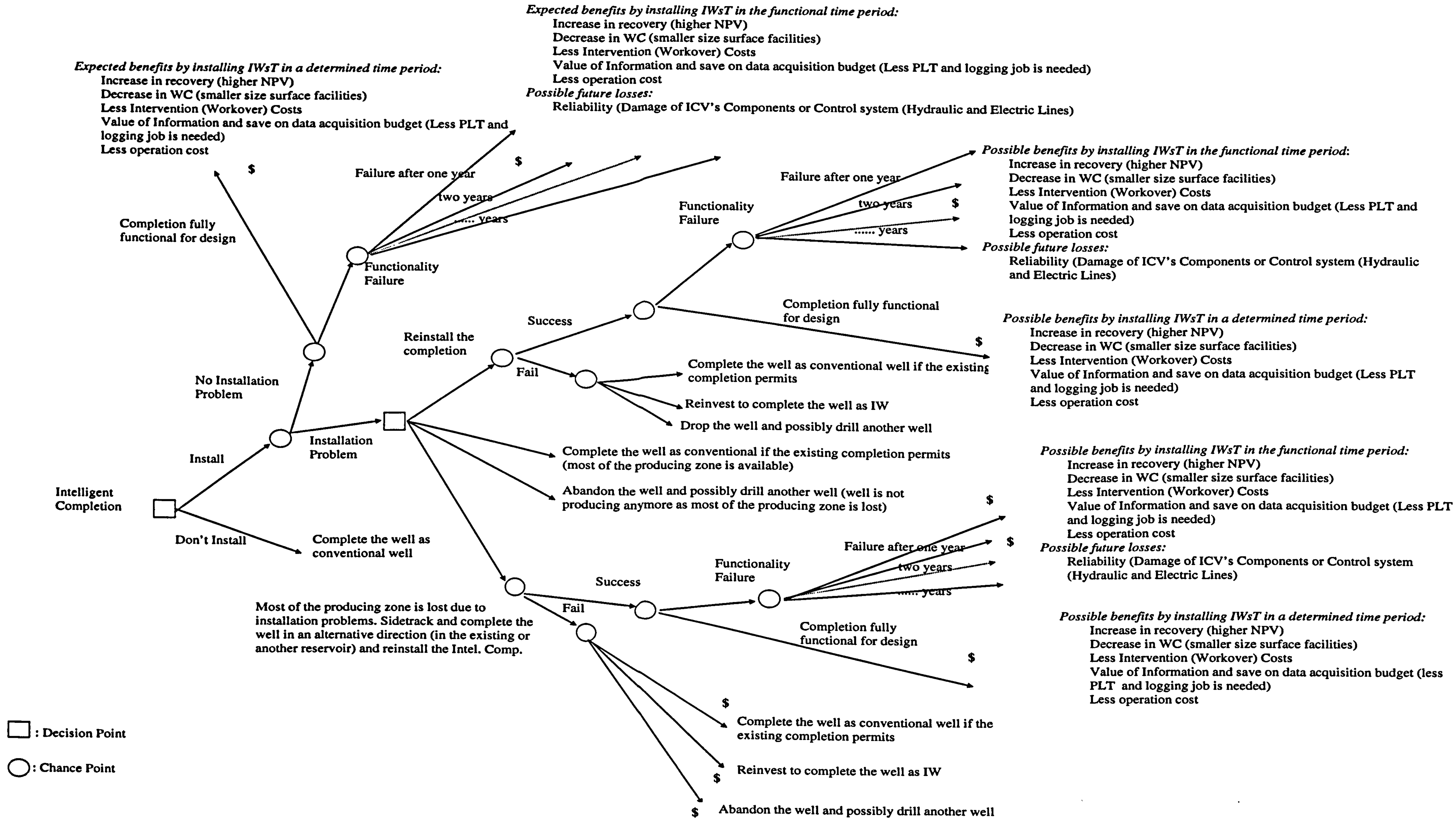
The following steps should be followed for evaluating the IWsT by application of decision analysis.

1. Structuring and deconstructing the problem into its underlying components, including the possible problems of intelligent completion installation.
2. Assessment of the possible outcomes.
3. Assessment of risk and uncertainties for all the stages leading to the outcomes. It includes determining the probability and costs of different outcomes, such as reinvesting to complete the well as IW in the case that installation problems are experienced.
4. Constructing a spread sheet, based on a decision tree(s).
5. Sensitivity analysis and assessment of the value of additional information to help finalise the decision.
6. Strategy selection

The following decision tree demonstrates possible events that may occur when deciding to install the IWsT. Installation may be carried out without any problem, or difficulties maybe encountered. The possible future benefits are listed if the installation proceeds without problems. If an installation problem is experienced, the future outcomes should be reanalysed. This stage represents another decision-making process in which each decision results in a different Expected Value (EV). Some possible future decisions and the expense in reaching the final benefits are shown in the decision tree (Table 11-2).

It is necessary that all possible outcomes be evaluated so that a risked income profile can be generated e.g. what are the benefits if IWsT is no longer operable after 5 years? Such possibilities need to be included in the decision tree.

Setting the correct probability for each event is of vital importance at chance points, since all future cost calculations are a function of the probability of that event occurring. Often, quantitative data is not available to allocate the correct probability to decision points and engineering judgement has to be employed.



In this decision tree the phrase "Install Intelligent Completion" means installing all the system components e.g. monitoring systems, etc.

Table 11-2: Example Calculation of IWsT Expected Value

Decision trees also provide a platform for more detailed decision analysis, such as Monte Carlo Simulations, estimation of the Value Of Information, Portfolio Analysis etc.

11.6 Monte Carlo Simulation

Monte Carlo simulation packages are commercially available at a low cost. In Monte Carlo simulation, the results of a specific operation are calculated thousands of times based on variations in the input values taken from a predefined distribution for each variable. It is a method for incorporating the effect of uncertainty in the evaluation process by providing a probability-value relationship for all the significant variables. It is obviously key to estimate the correct input data distribution curve of the range of probabilities for these variables.

The Monte Carlo analysis process is started by a random number generator, which chooses a specific value for each variable. The chance that this input value is chosen by the program is described by the input distribution for that data element. Values for each variable are generated and the resultant answers to the mathematical operation are calculated. The process is repeated many thousands of times and the resultant answers contain the complete range of probable solutions. The answer can be expressed in the form of a cumulative probability distribution curve [11.3].

11.7 Value Of Information (VOI)

Information is valuable only if it has the potential to change a decision! The VOI is the difference between the expected benefits from a series of outcomes for scenarios with and without extra data being acquired and acted upon. On the other hand, it is also the (opportunity) loss of (potential) income that would occur if a decision was made in the absence of this information. It is often difficult to quantify the opportunity loss value before the project design has been finalised. However, the risk of opportunity loss and the "expected loss" can be calculated. This is useful for decision making on information gathering. If the expected loss is high, then the decision-maker may decide that there is value to be generated by acquiring more information. If it is low, the value of the information may be less than the cost of acquiring it [11.4].

Analysing the value of information is one of the important evaluation processes for IWsT. Here "VOI" has two meanings:

1. It is information gathered during planning stage by spending money and time on different parts of study (doing reservoir simulations, economic evaluation, running seismic, etc.)
2. It is the value of information gathered using the possibly installed measuring devices (gauges, sensors, etc) in downhole intelligent completion during well production.

Designing an IWsT project based on limited information would tend to reduce the chance of an economic project unless the benefits are clear cut e.g. reducing the number of subsea wells producing from a series of stacked reservoirs. However, decision tree process coupled with Monte Carlo analysis can be used to assign a value and a probability function to extra incomes from IWsT when information is being acquired and acted upon. Similarly, possible losses (costs) when this information is not gathered can be investigated. This process allows the VOI to be quantified.

Sensitivity analysis of the VOI identifies the key risks and probabilities that must be managed to enhance the project robustness/value and to help ensure that it is delivered.

Once IWsT projects have been installed in the ground, the value of data e.g. acquired by monitoring devices installed as part of an intelligent completion, along with the associated oil production response, should be evaluated and the data stored in a database. The availability of such a high quality database will increase confidence in the predicted future performance of Intelligent Completion and will help to reduce the uncertainty in the project profitability.

11.8 Portfolio Analysis

Portfolio analysis is a technique for assembling optimum portfolio projects, which will maximise the economic return while minimising the overall risk failure i.e. not achieving that target. It is a method to find the least risky combination of independent options to reach any given level of expected return. Therefore, portfolio management combines the evaluation of expected value (e.g. using Monte Carlo Simulation) with analysing the effect of diversification (i.e. if the outcome of one project is dependent on that for another project the diversification will be less).

An important pre-condition for the Portfolio Theory is to identify if, and how, the projects are dependent. Or, expressed in other words, to determine how the success or failure of one project can affect the outcomes of other projects. For example, suppose that one was considering investing in projects, which involved drilling exploration wells in one or more potential accumulations that are expected to be filled from the same hydrocarbon source rock but isolated from each other. Then these projects are clearly not independent, since a lack of hydrocarbon generation from the source rock would cause both endeavours to fail. The simplest example of statistical dependence is correlation, which may be either positive or negative. The correlation is positive when a given outcome for one project increases the chance of the same outcome for the second project, thereby diminishing diversification. Conversely, a correlation is negative when a given outcome for one project decreases the chance of the same outcome; thereby enhancing diversification [11.5].

The goal in portfolio management is to spread investments across many opportunities while seeking out negative correlations and avoiding positive ones. Statistical dependence can come from a variety of sources. The economic outcomes of two sites close to one another may be positively correlated through geological similarities, such as draining the same reservoir rock or relying on the same hydrocarbon source or sealing rock. Two widely separated sites, on the other hand, would have little or no geological correlation and would therefore be more diversified.

When designing an IWsT installation there is normally more than one possible option. Outcome depends on what level (cost) of technology is installed and what the resulting well objectives are e.g. acceleration and reduced Workover costs, optimised reservoir management, etc. Sharma et al [11.1] described the mathematics involved in implementing portfolio theory and reports the availability of commercial software to carry out the process. However, specialised portfolio analysis software is required to implement this procedure.

The above description summarised the economic evaluation techniques which can be applied for justification of the cost of IWsT, however, in general, no advantages resulting from the use of the more complex portfolio analysis approach compared to the more familiar economic analysis techniques described in this chapter.

A piece of software (based on Excel spreadsheet) was developed with the help of Martin O'donnell [11.6], which has implemented the above techniques for IWsT cost evaluation. The software was further developed in the JIP by George Aggrey [11.7] to include the reliability issues associated with the Intelligent Wells.

Appendix A illustrates the software.

11.9 References

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Chapter 12 Conclusions and Areas for Future Research

12.1 Conclusions

The lessons learned from this study could be used as a valuable tool for decision-making on the application of Intelligent Wells. The whole concept of Intelligent Well system Technology has been introduced throughout the thesis. The value generation capability of Intelligent Wells using a "show case" of case histories, general experience from operators, etc. has been demonstrated. The "show case" can be used as a check list against which the opportunity to create value by IWsT for a particular case can be screened. A road map for the rapid screening of a candidate well or field to determine whether it would benefit from further study of IWsT has been described. It is essentially a screening list which can be used as a tool for initial screening and identifying whether the potential benefit of a candidate field or well could derive from this technology. Techniques for reservoir and Intelligent Wells modeling & subsequent optimisation in a variety of reservoir types have been evaluated. This resulted in understanding of the "Driving Parameters" which affect the IWsT Added Value.

The following conclusions were drawn from this study:

1. IWsT has been shown to be capable of managing geological variability and thus coping with geological uncertainty in a wide range of reservoirs. It has shown that some reservoir types are inherently more suitable for Intelligent Well

installation than others e.g. those that inherently lead to an uneven invading fluid front progression towards the wellbore.

2. Results show that ICV has to control something to be effective. The ICV is a choke - it can only restrict production. It may be used for shutting off water or gas zones that are contributing a high proportion of the unwanted fluid (water or gas). Its effectiveness depends on the combination of the local reservoir pressure and fluid saturations, the well inflow, the vertical lift performance and the reservoir heterogeneity. "Good" water has to be flushed through the formation to produce oil from zones with sufficient remaining oil saturation; whilst "Bad" water from already flushed zones should be shut off. Other factors that have a major impact on well performance are the well's Productivity Index and the well's Production Target. The choking of an ICV can only achieve short term, field management objectives if another completion zone can produce extra oil so that the well's target oil production rate is still achieved. This choking effect can, at least partially, be compensated by the installation of Artificial Lift.

3. Results show that an ICV can control uneven, invading fluid fronts that develop along the wellbore due to permeability differences, compartmentalization (of either sedimentary or structural origin) and/or due to different strengths of the aquifer/gas-cap pressure support. The longer the completion intervals, the greater the potential for such differences to develop along the wellbore (i.e. from heel to toe). Hence, the greater the potential value that can be achieved by an ICV installation.

4. IWsT adds value in layered reservoirs provided the difference in layer/compartment permeability is sufficient to produce an un-even fluid front progression towards the wellbore. Reservoir permeability heterogeneity is one cause of an un-even fluid front. Multiple aquifers/gas-caps of different strength supporting the production from a number of formation layers in contact with the wellbore are a second cause of un-even fluid fronts developing along the wellbore.

5. IWsT can add value in faulted or compartmentalised reservoirs being produced by a horizontal or multilateral well provided there is a difference in pressure or oil/water contact level between the zones. This is true irrespective of the distribution of permeability and porosity in the isolated reservoirs.

6. In this study, generic models were used and various aspects simplified for practical necessity (including size of models, size and number of grid blocks, fluids, contacts, aquifers, economics and other engineering control methods). In "real life" study these issues will have to be further considered.

7. A global screening methodology has been developed for determining where and where not to implement IWsT. "IWsT Added Value" has been identified when the CV, CL_H/WL and CL_V/RT parameter values are such that an uneven fluid front development of sufficient magnitude develops in such a manner that it can be managed by the ICV in order to improve the sweep efficiency OR to allow a greater oil production while meeting well outflow or facility water or gas handling constraints. The combination of the volume of reserves to be developed by the well and the "Added Value" suggested by these screening tools can be used to justify the IWsT project. This has to be confirmed by a full economic analysis for the particular case being studied.

8. The "IWsT Added Value" Screening Tool has been applied to a real reservoir simulation study. The "IWsT Added Value" screening tool was created from generic, geological models in which uneven fluid front development was restricted to permeability heterogeneity alone. The concept was confirmed by application to a real reservoir scenario. The presence of faults or other forms of compartmentalisations that can give rise to different pressure regimes, fluid contacts and other forms of uneven fluid front movement towards the wellbore will also lead to "Added IWsT Value".

9. The Evaluation of the IWsT Added Value is Sensitive to the Modelling Approach. In this study, generic models were used and various aspects simplified for practical necessity (including size of models, size and number of grid blocks, fluids, contacts, aquifers, economics and other engineering control

methods). In "real life" study these issues will have to be further considered. Another issue in this study is the modelling approaches selected. A comparison of the pixel and object based models in the same field suggested that this may also have an impact on the evaluation of IWsT Added Value. Object based models are inherently more heterogeneous and will hence show greater value from IWsT. Which technique best captures a particular geology is beyond the scope of this paper.

10. Added Value for IWsT in a Horizontal Well is a function of the permeability distribution around the wellbore and the optimum placement of ICVs along the completion length. The recovery improves with the correct choice of the number and location of the ICVs within the wellbore. This study suggests that ICVs should be installed in the high permeability areas of the wellbore on the basis of information (logging, cuttings etc.) gained during drilling. Zone length should not be too short and their lengths should be as similar as possible. This reduces the uncertainty in the direction of the flood-front movement towards the wellbore due to the complex reservoir geology.

11. ICV placement guidelines for a wide range of well and reservoir scenarios have been presented. The results show that how a good understanding of the reservoir geology is the key to ICV placement. This geological understanding along with appreciation of the reservoir drive mechanism aids prediction of the fluid-front movement towards the wellbore, allowing an optimum placement (number and location) of ICVs along the length of the wellbore for efficient flow control. The interplay of the CV, CL_H and CL_V parameters, well length and the length of the zone to be controlled by each ICV will determine the shape of fluid front development towards the wellbore.

12. The fluid-front progression schematic (Figure 9 -12) can be used as a tool for decision-making on the optimum number of ICVs required along the length of the wellbore in a complex reservoir. This figure gives a simple, but realistic, impression of the shape of the fluid-front movement towards the wellbore. ICV placement rules vary from one reservoir type to another, being affected by

many reservoir parameters. This thesis provides a geological framework within which the performance of the IWsT well can be more easily understood.

13. Despite the general geological understandings, there will always be uncertainty in most practical cases when deciding the optimum placement of the ICVs.
14. In order for a Single Well "Proactive Control" scenario to be successful it is necessary that the alternative production zone(s) be able to compensate for the loss of fluid from the choked zone(s).
15. Too early choking (being "Too Proactive") can result in losing oil as "Good Water" is also blocked. Added value increases when well target rate is reduced or Artificial Lift installed. This allows alternative zones to compensate for the loss of fluid from the choked zone(s).
16. Both "Reactive" and "Proactive" Control is highly successful when reduced water or gas inflow is required due to tubing outflow performance or surface handling limitations. "Proactive Control" will be preferred under some scenarios as it both reduces and delays the total volume of unwanted fluid produced.
17. Knowledge of the parameters effecting the movement of the fluid-front (e.g. permeability distribution, strength of the aquifer support at all points within the model etc.) is required when preparing an "Added-Value Statement" for IWsT.
18. The "IWsT Added Value" needs to be economically justified. The process for justification of the extra cost of the Intelligent Wells has been explained in this thesis.

12.2 Considerations

The role of the assumptions made and the resulting uncertainty needs to be taken into consideration when generalizing the results from this study. Despite the general geological understandings, there will always be uncertainty in most practical cases when deciding on the application of IWsT.

Some parameters that affect the results are as below:

1. The Optimisation Technique: only manual optimisation techniques were used in this study. A more complex choking policy may affect the results and possibly add more "Value" by compensating for the reduced flexibility created by an ICV being placed in a slightly inappropriate position. It was decided to keep the optimisation policy constant for all realisations since this would have affected the "Added Value" from IWsT and complicate the comparison of the results.

2. The reservoir modelling techniques: The rate of the fluid-front movement towards the wellbore is a function of the reservoir type. This fluid-front movement is also a function of the degree to which the model is representative of the real reservoir, but also of the way we build the reservoir model. Both of these features can greatly affect the results. The cases included in this thesis are meant to be illustrative, and not exhaustive.

3. Other system parameters such as the water injection rate, the strength of aquifer, the well control parameters and many other production system limitations that affect the performance of the combined well and reservoir models.

4. The "IWsT Application Envelopes" in chapter 8 have been developed for a horizontal well producing a flat reservoir with the bottom drive aquifer. The IWsT application zone in the envelopes will slightly vary if the well is not horizontal, the reservoir is not flat or there is an aquifer attached to the reservoir. These features can affect the shape of the flood front development towards the length of the wellbore and hence the "Added Value" from an Intelligent Well.

5. The majority of this study was performed on the two phase flow (oil and water) reservoir models. The presence of gas can result in a different shape of flood front progression towards the wellbore compared to the oil/water systems due to the high mobility of gas. This will affect the "IWsT Application Envelope" and the "Added Value" from Intelligent Wells in different well and reservoir types.
6. The boundaries of the "IWsT Application Envelopes" will vary depending on the company's rate of return policy and their acceptable risk and uncertainty. The "IWsT Application Envelopes" in this study do not include the risk of IWsT components' installation failure. This needs to be taken into consideration when screening different reservoir types for IWsT application against these tools.

12.3 Areas for Additional Research

Areas of uncertainty and the required considerations have been mentioned at the previous section (section 12.2) and at each chapter as well. Major issues are considered in the following review of further work.

- The results of this study show that a good understanding of the reservoir geology is the key to optimum ICV placement and the resulting "Added Value" from IWsT. The optimum ICV placement requires the prediction of the fluid-front movement towards the wellbore. The prediction of the fluid-front movement towards the wellbore requires prediction of extent of the connection of the layers/zones connected to the wellbore. Building on the results from this study to develop techniques for prediction of the fluid front movement towards the wellbore would be invaluable in optimum placement of ICVs along the length of the wellbore and the resulting "Added Value" from IWsT. The deliverable will be reservoir characterization techniques for prediction of the fluid-front movement towards the length of the wellbore customised for screening of reservoir types for application of the Intelligent Wells and optimum placement of ICVs along the length of a wellbore.

- The systematic study of the IWsT application (chapters 7 and 8) could be extended to include oil/gas and oil/gas/water systems with different well and reservoir geometries. In an oil/gas system provided the reservoir pressure is supported by gas injection then the shape of fluid-front movement towards the wellbore will be affected by the presence of gas & possibly less dependent on the permeability distribution and the reservoir heterogeneity i.e. it is expected to show un-even fluid front for less heterogeneous models as well. It is due to the high gas-mobility and gas miscibility in the oil. A wider IWsT Application Envelope is, therefore, expected.

  In a three phase flow environment, as we are concerned about the shape of the fluid-front movement towards the wellbore, provided the reservoir pressure is being supported by the water, the gas should not much affect the shape of the fluid-front towards the wellbore though a gas-cap exist as well. This is because the fluid-front is mainly affected by the water flood i.e. gas will not be the dominant factor. However, the presence of gas will affect the ICV choking policy and will possibly make the optimum ICV choking more difficult. The methodology and results of this thesis can be applied to a gas/oil system with a limited error. However, the boundaries of the "IWsT Application Envelope" for a gas/oil system will possibly be different than that for an oil/water system. IWsT is expected to "Add Value" in a wider range of the envelope (includes less heterogeneous scenarios as well) due to the high mobility values of the gas. Further studies are required to confirm these ideas.

Appendix A

Economic Evaluation Software – Illustration

1. Define the following parameters, which are built in the software as a base case values, as in Figures 1 and 2.

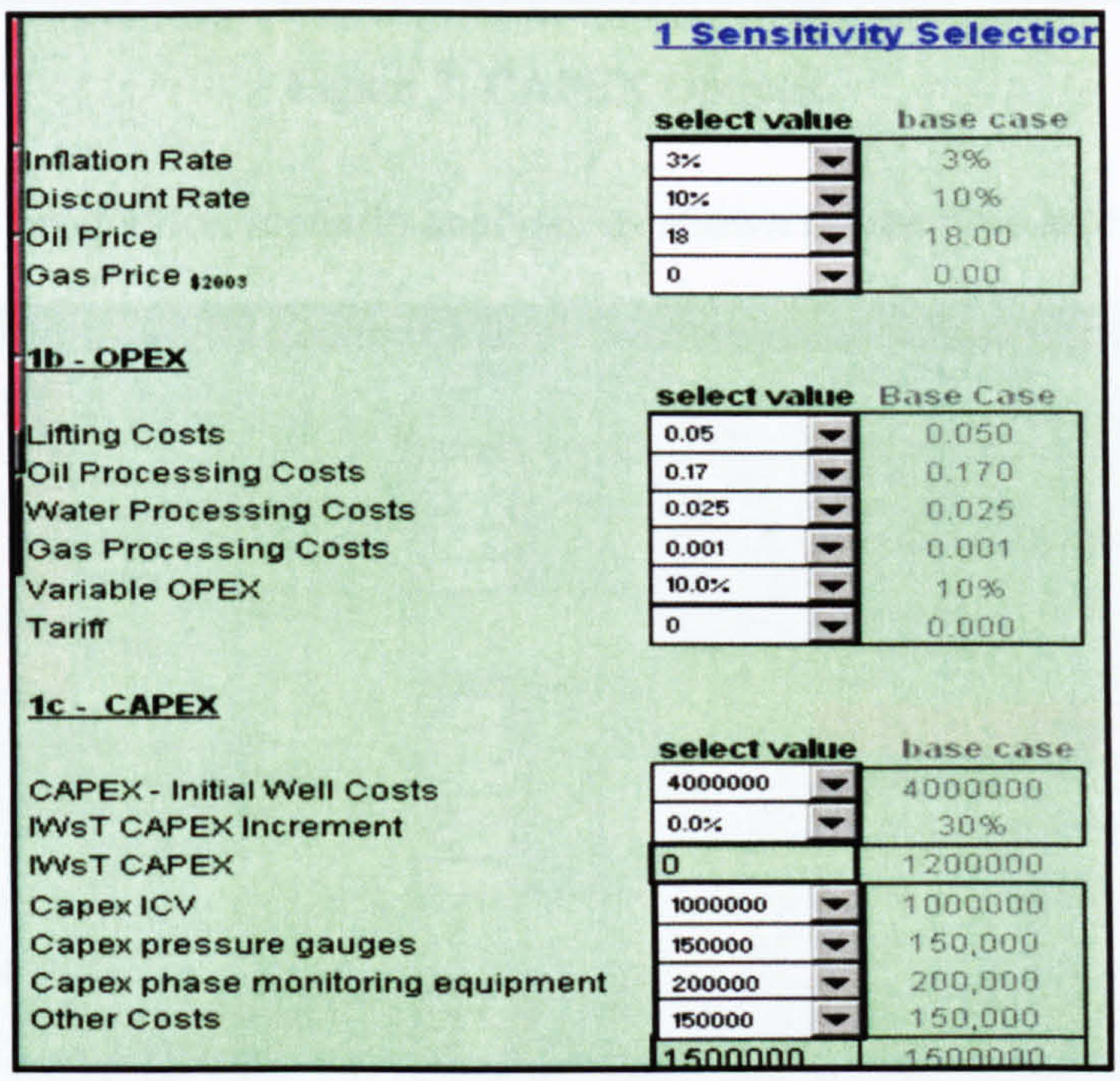

Figure 1: Sensitivity on input data

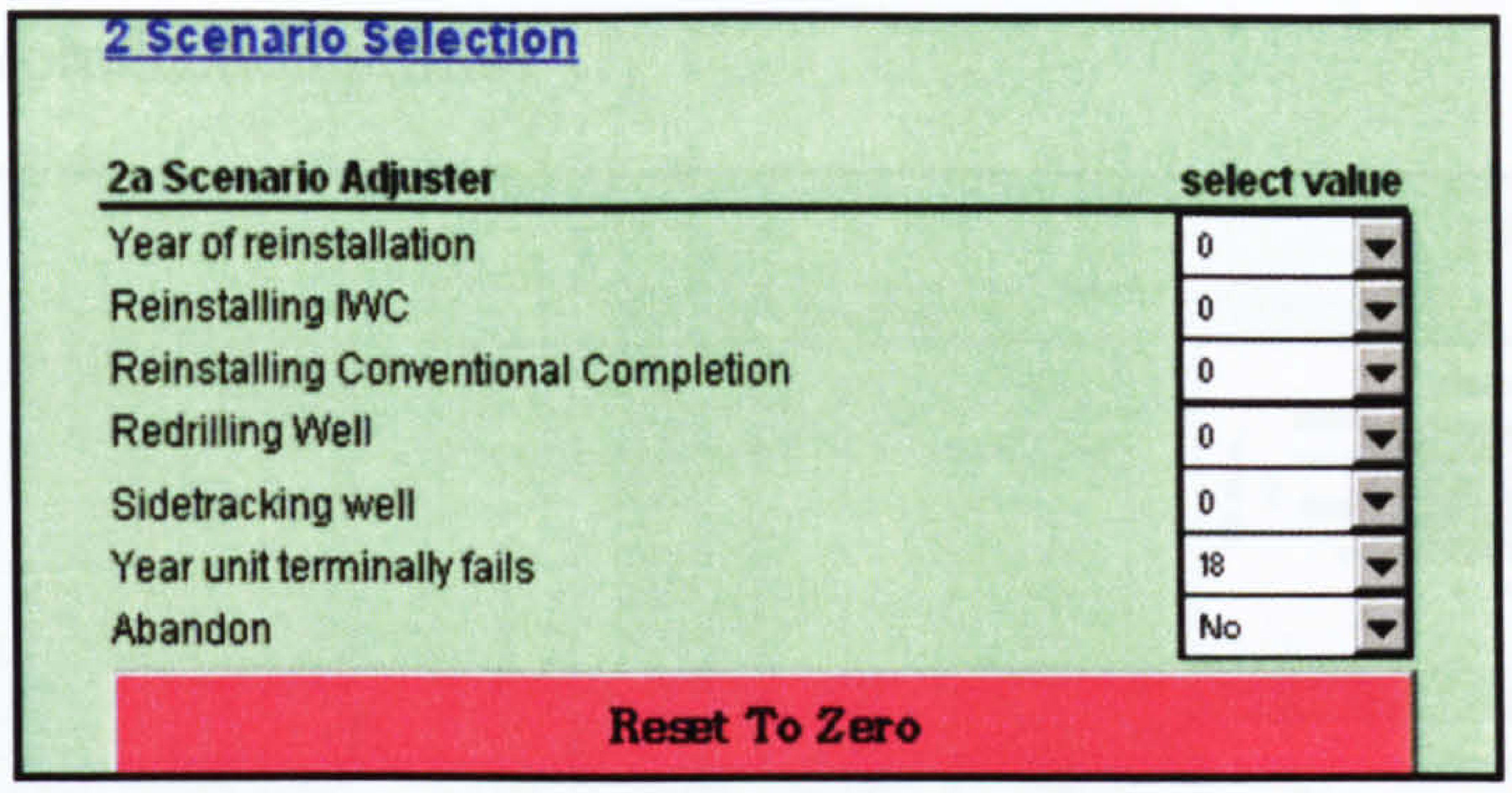

Figure 2: Scenario selection - Sensitivity input data

2. Choose the Fixed or Proportional CAPEX option as in Figure 3.

Figure 3: CAPEX Options

3. Activate production scenario analyser as shown by the blue arrow.

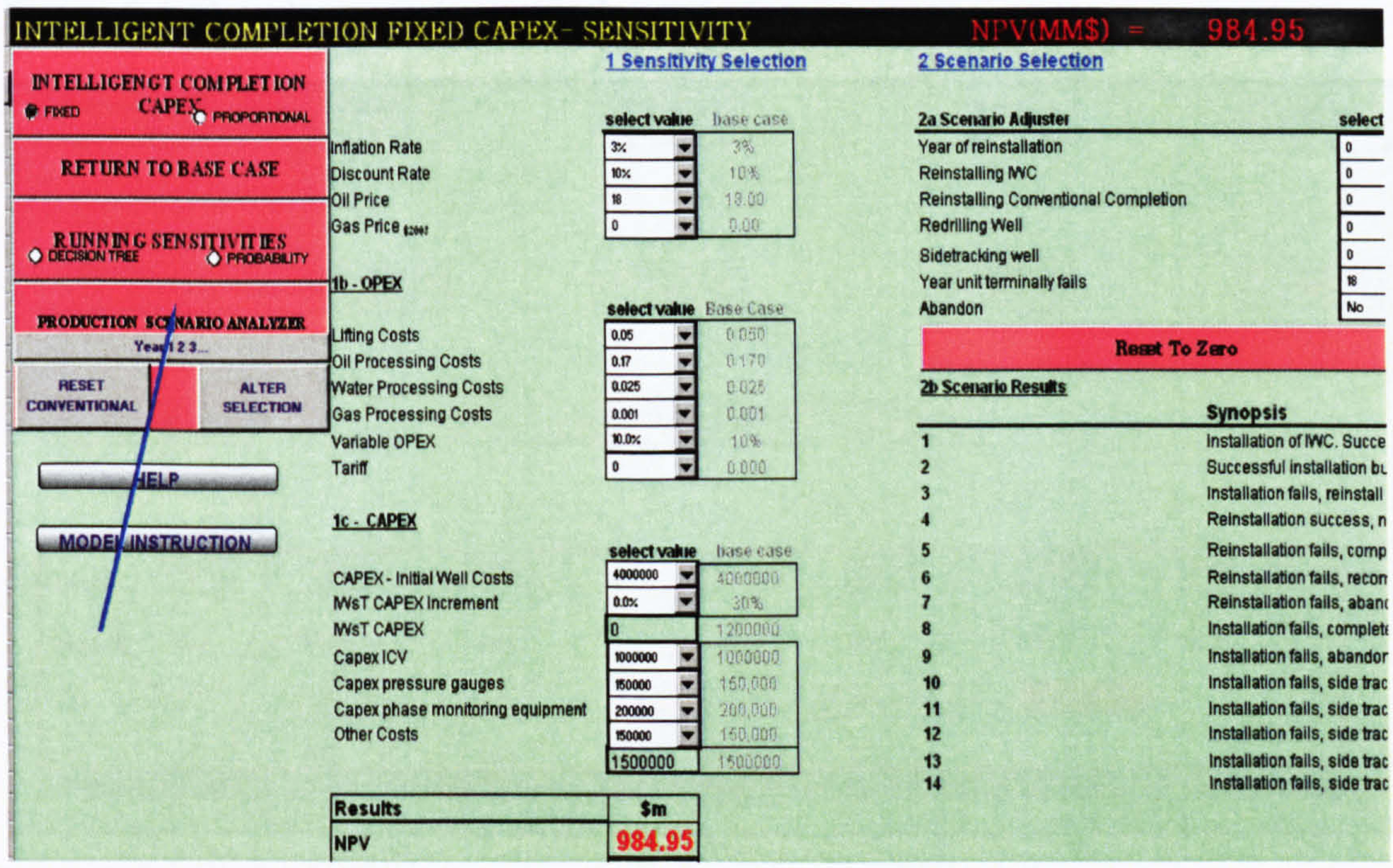

Figure 4: Production Scenario Analyser.

4. Choose a production profile

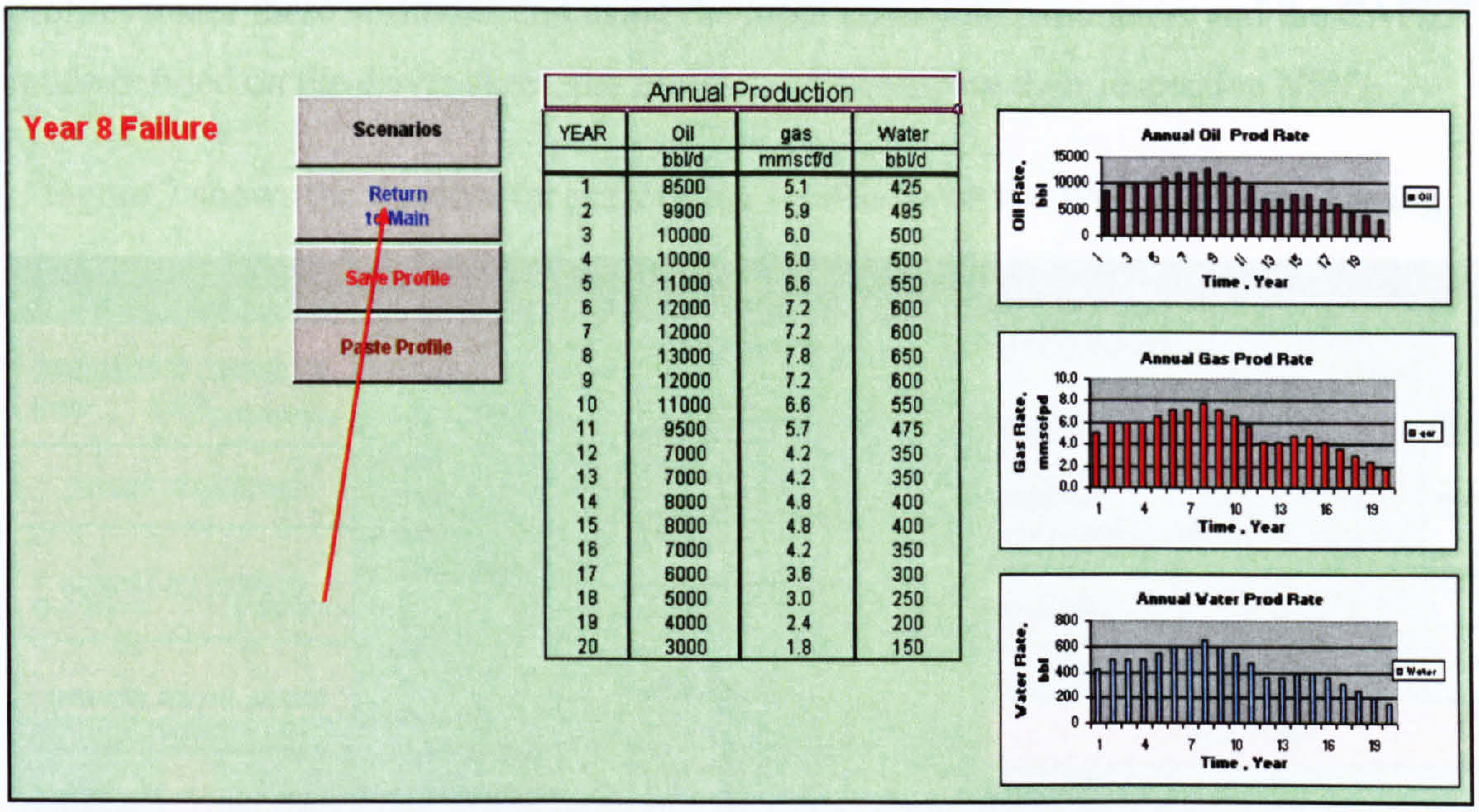

Figure 5: Production Profile Page

The software enables to carry out a wide range of sensitivities.

Figure 6 depicts the scenario comparison window.

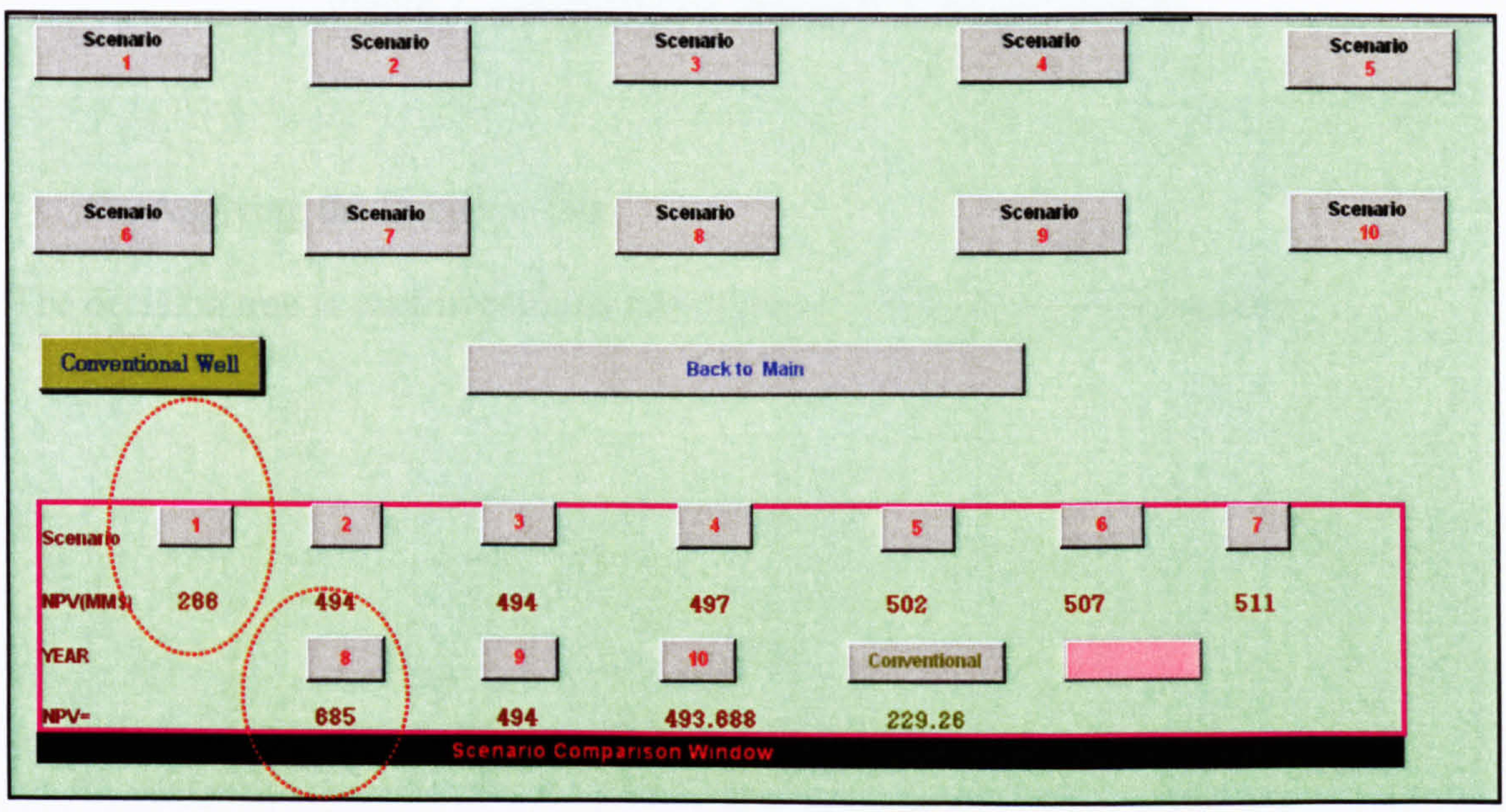

Figure 6: Scenario Comparison Window

Activating the buttons in the scenario comparison window automatically loads the saved profiles under these scenarios and using the input economic parameters and the CAPEX mode defined on the driver sheet, the program will compute their respective NPVs.

Figure 7 shows the window for performing sensitivity on the IWsT Cost and Timing

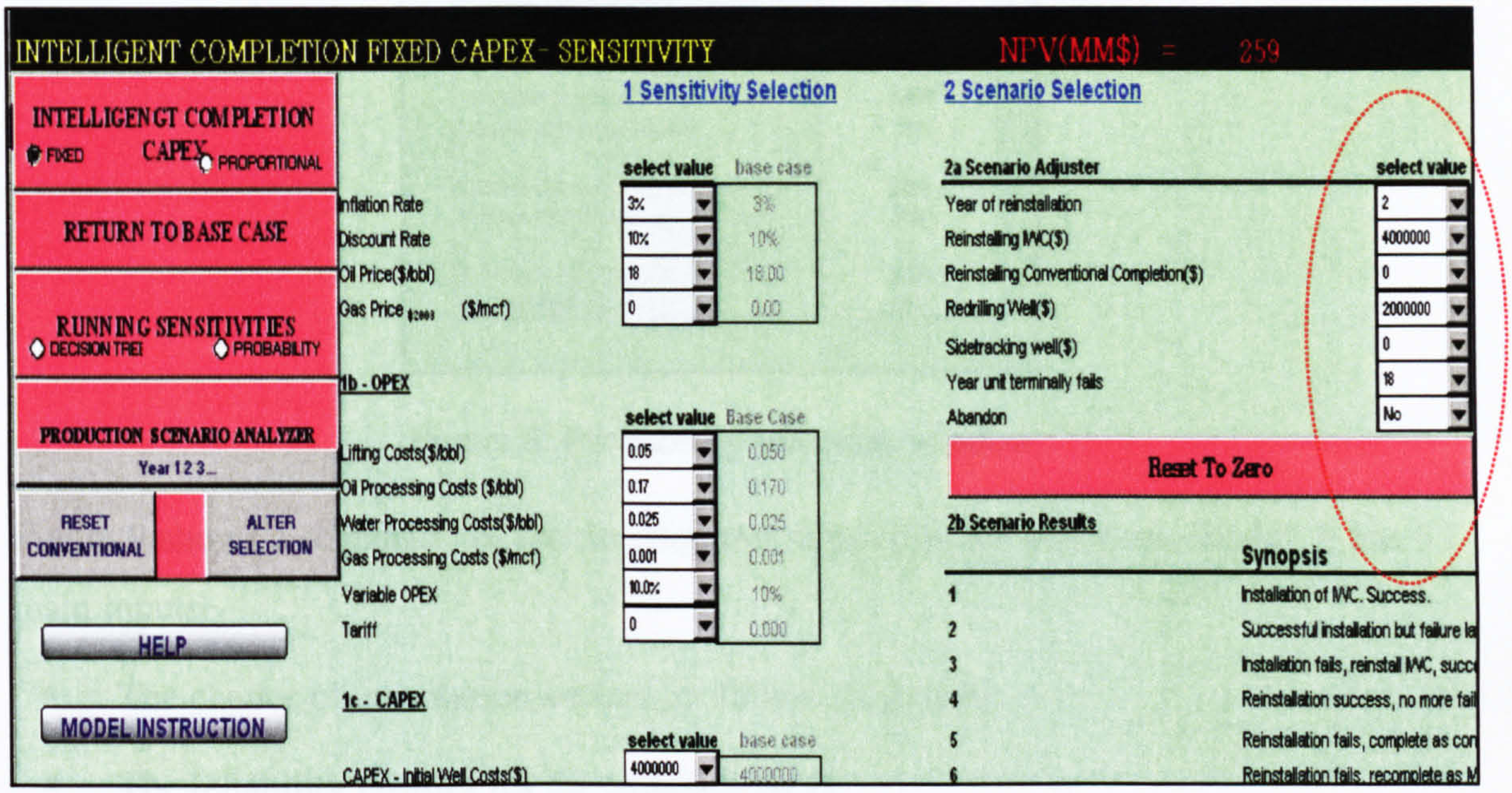

Figure 7: Sensitivity on the IWsT Cost and Timing

5. Applying the Decision Tree.

The decision tree is used to estimate the expected value of the IWsT project.

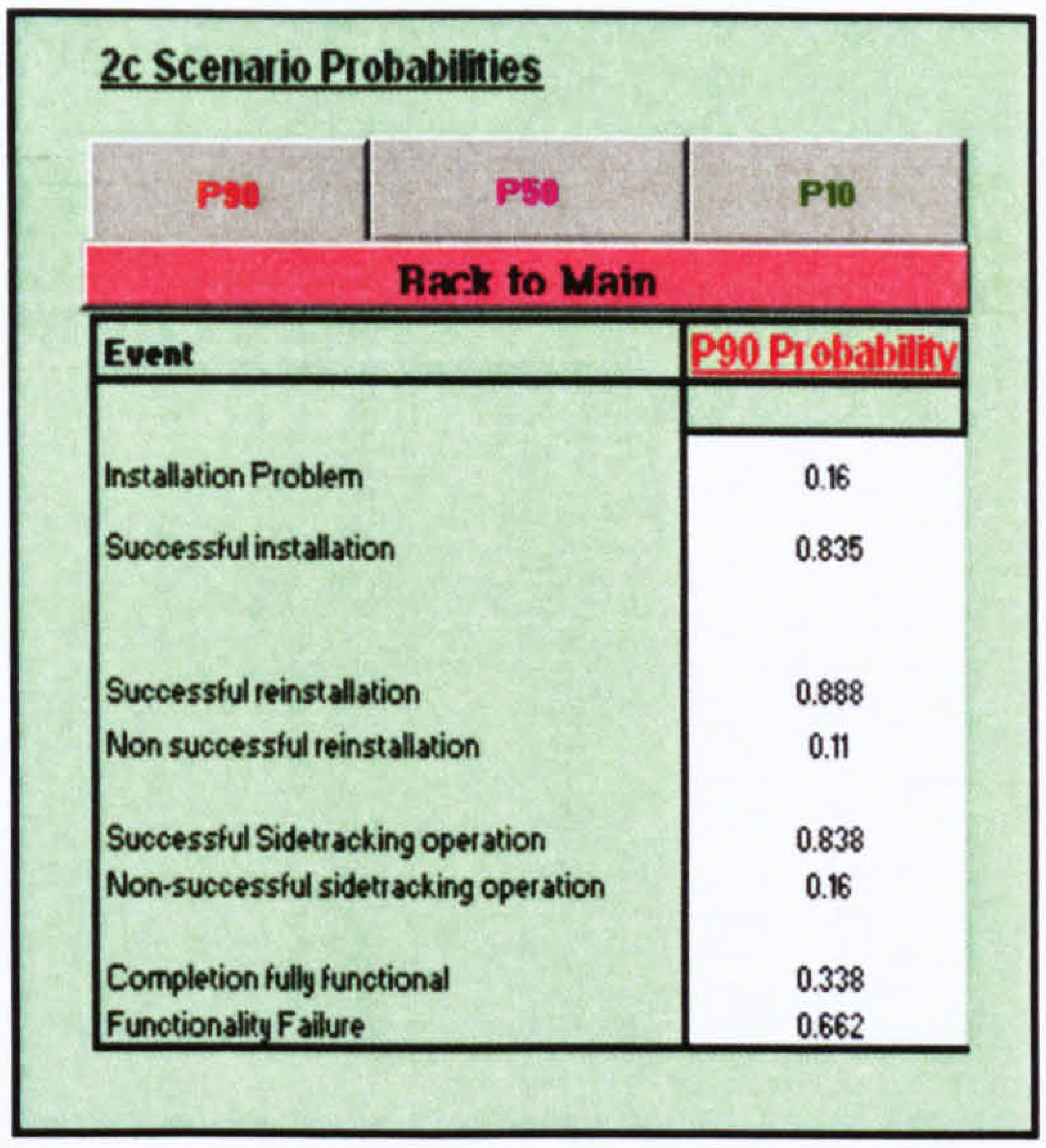

Figure 8: Probability selection window

Figure 9 shows a schematic of the decision tree applied in the economic model. It has 3 main inputs:

- The chance of installation success or failure (Figure 8)
- The reliability profiles for the installed IWsT
- Computed deterministic NPV for the various project combinations.

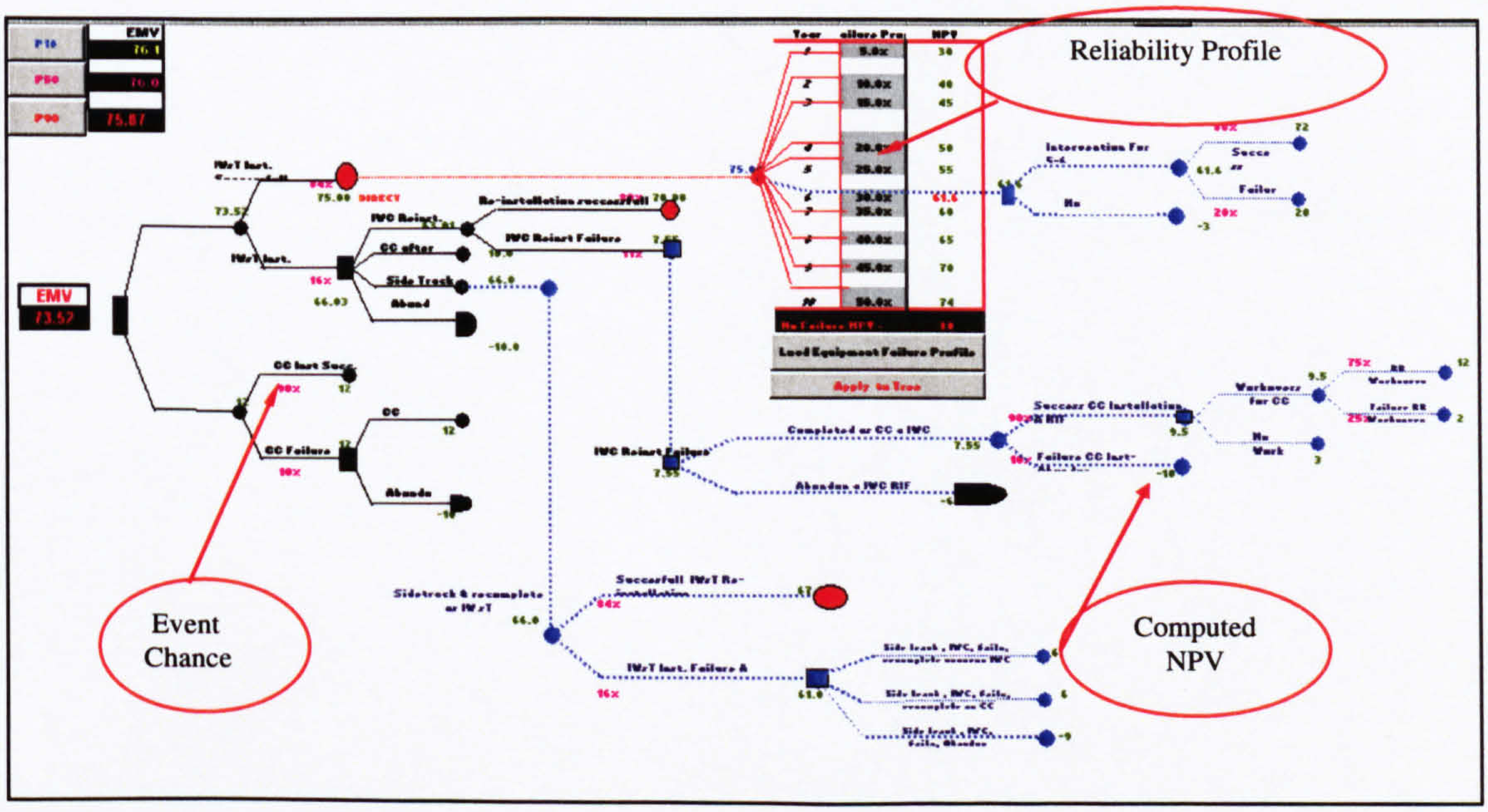

Figure 9: The Decision Tree