A TECHNOLOGY PERSPECTIVE AND OPTIMIZED WORKFLOW TO INTELLIGENT WELL APPLICATIONS

A Thesis

by

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ABSTRACT

Today's oil and gas industry is faced with several geographic and economic challenges that have significantly increased the pressure on companies engaged in oil and gas exploration and production. Technical as well as economic challenges like the highly volatile crude oil prices, global competition for depleting resources and pressure from shareholders for return on investment are threatening to the industry. In the quest to address these challenges, operators are continuously seeking advanced technology that could increase production, improve recovery, and minimize cost. Although advanced technology such as 3D and 4D seismic downhole sensors have significantly improved the amount of accessible realtime information, the amount of data is often massive and too complex to accurately analyze.

Within the past decade, significant advances in drilling and completion techniques have been made to enable more active monitoring and control of production wells. Smart well technology, also known as Intelligent Well Completions (IWC), is one of such technologies that integrates permanent downhole sensors with surface-controlled downhole flow control valves, enabling operators to monitor, evaluate, and actively manage production (or injection) in real time. All of this is achieved without any well interventions, thus completely eliminating the risk and economic losses associated with well intervention.

A comprehensive review of smart well technology, as well as real-world case studies will be presented. A case study simulation is performed to evaluate the additional value that is derived by adopting smart well technology. The simulation results clearly indicate that adopting smart well technology significantly reduced field water cut, accelerated the productions time and improved the Net Present Value (NPV) of the project.

Finally, a workflow is presented which can be used to assess to applicability of a given field with multiple producing wells.

DEDICATION

First off, I will like to thank God for granting me the resilience to make it this far in my academic career.

Every challenging work requires self-effort as well as support from others especially those who are close to our heart. I will like to dedicate the efforts of this work to my brother Bayong T. Fombad whose strength and good spirit has always served as a source of inspiration to me, and has challenged me to always put in my best effort in everything I do.

ACKNOWLEDGEMENTS

I will like to use this opportunity to express my deepest sense of gratitude to my advisor Dr. Eduardo Gildin for his full support, guidance and understanding throughout my research study. This thesis work will not be complete without his patience and timely counsel.

I would like to thank Dr. Ding Zhu and Dr. Richard Malak for their willingness to serve on my advisory committee.

I would also like to thank all my friends and colleagues for their support, and recognize the department faculty and staff for providing me with all the resources and a great environment to succeed in my studies.

Finally I will like to extend special thanks to my sweet and loving parents. Their affection and continuous encouragement was very instrumental in all my achievements and for that I am forever grateful.

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INTRODUCTION

1.1 Statement of the Problem and Motivation

Over the last two decades, the oil industry has reveled in a high crude oil price environment and had often mitigated the forecasts of imminent decline in oil production by making new discoveries to replace the produced reserves. However in recent years, there has been a sharp decline in the number of sizable discoveries and the global competition for depleting resources has mounted significant pressure on the industry. As seen in *figure 1*, conventional oil discovery peaked in the 1960's and has steadily declined while oil production has steadily increased.

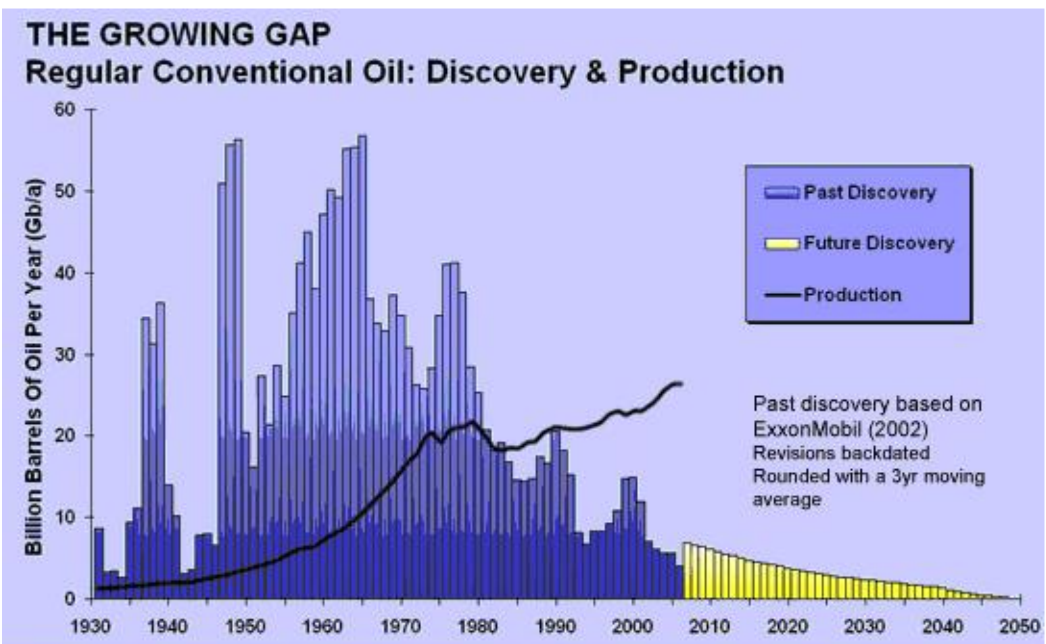

Figure 1: Chart showing decline world conventional oil discovery versus increase production (February 2006 ASPO newsletter**)**

The need for technology that will better improve reservoir control and management, sweep efficiency, and increase recovery is more crucial than it has ever been. The recent volatility and rapid decline in crude prices sent a shock wave of urgency throughout the industry on the need for companies to adapt their technology to the low price environment. This message was continuously echoed by top oil and gas executives from around the world:

In the words of Rex Tillerson, chairman and chief executive officer of ExxonMobil, the industry should expect *"difficult price environment for the next couple of years"* (Rassenfoss, 2015).

"You have to prepare for USD 60 and less......we cut costs by a thirds. Some projects are going away" – Stephen Chazen, President and CEO of Occidental Petroleum (Rassenfoss, 2015).

This message was continuously echoed by other top executives at the 2015 HIS CERAWeek[1] conference in Houston Texas, stressing the need for maximizing production efficiency. Some ways in which companies can reduce cost while improving recovery efficiency include; improving sweep efficiency, reducing water production, minimizing well intervention, accelerating production, properly managing mature fields and reducing capital expenditure (simplifying architecture of well and gas lift operations). Intelligent well technology offers unique capabilities which when properly implemented on the right asset, enable the achievement of all of the aforementioned benefits. This technology offers operators the ability to remotely measure, monitor and control fluid production (or injection) in real time using downhole control devices, without the need of any well intervention. With such control capability, gas can directly

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[1] CERAWeek is an annual energy conference organized by the information and insights Company (HIS) that provides a platform for discussing a range of energy related topics including global economic outlook, geopolitics, energy policy and regulation, and climate change.

be channeled from a gas producing layer to an oil producing layer below in a gas lift operation, thus eliminating the need for a separate compressor facility on the surface for the gas lift operation. Water cut can be remotely measure and problematic layers shut in thus improving production and sweep efficiency. These are just a few of the many applications of smart well technology which will be discussed in more detailed later in this thesis.

The motivation behind this thesis topic is to explore the benefits of smart well technology, and investigate how this technology can be best applied to help operators improve recovery, cut operating/capital cost and remain profitable in this volatile price environment. In this thesis report, the terms smart well technology, intelligent well technology, and intelligent well completions will be used interchangeably.

1.2 Research Objectives

The main objective of this research study is to demonstrate the potential benefits of adopting smart well technology in optimizing production. The ultimate goal was to develop an optimized workflow which can be applied by operators to determine whether or not the application of smart well technology is economically viable for a particular petroleum asset under development. This study used simulator algorithms to find the optimum ICV configuration to minimize water cut and maximize NPV in a field of producing vertical wells. A simulation of the workflow process is performed using the UNISIM-I-D benchmark reservoir. The UNISIM-I-D model was chosen over other benchmark reservoir models like SPE 10, Brugge, Norne and PUNQ because the reservoir geometry and properties best fit the intended study conditions.

The UNISIM-I-D model used in this study contained with 4 producers and 3 injectors, and the analysis was performed using a commercial simulator (Eclipse 100). An economic analysis is then performed to understand the profitability and marginal value of the different options of intelligent well systems. The entire premise of this research study is based on the crucial assumption of reliability of the smart well systems. This is critical as the true value of intelligent well systems can only be realized if the system functionality is maintained over the designed lifetime of the well. So far the current industry players in this technology have been able to demonstrate sufficient reliability in these systems as will be discussed later. *Figure 2* shows the three main components of a smart well system and *figure 3* shows a comparison between the architecture of a conventional producer and a smart producer:

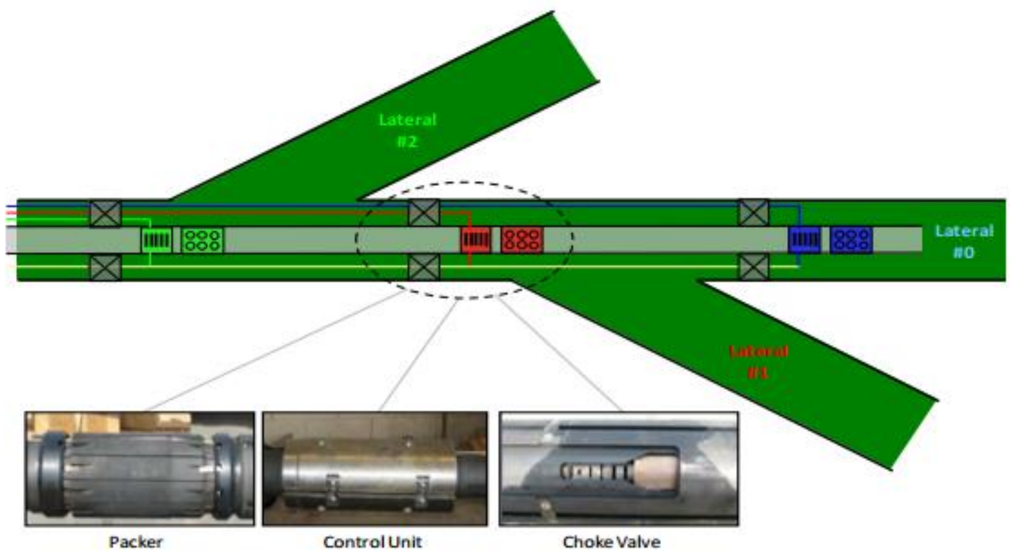


Figure 2: Schematic showing the components of a smart multilateral well. Reprinted from (Dumville, 2008)

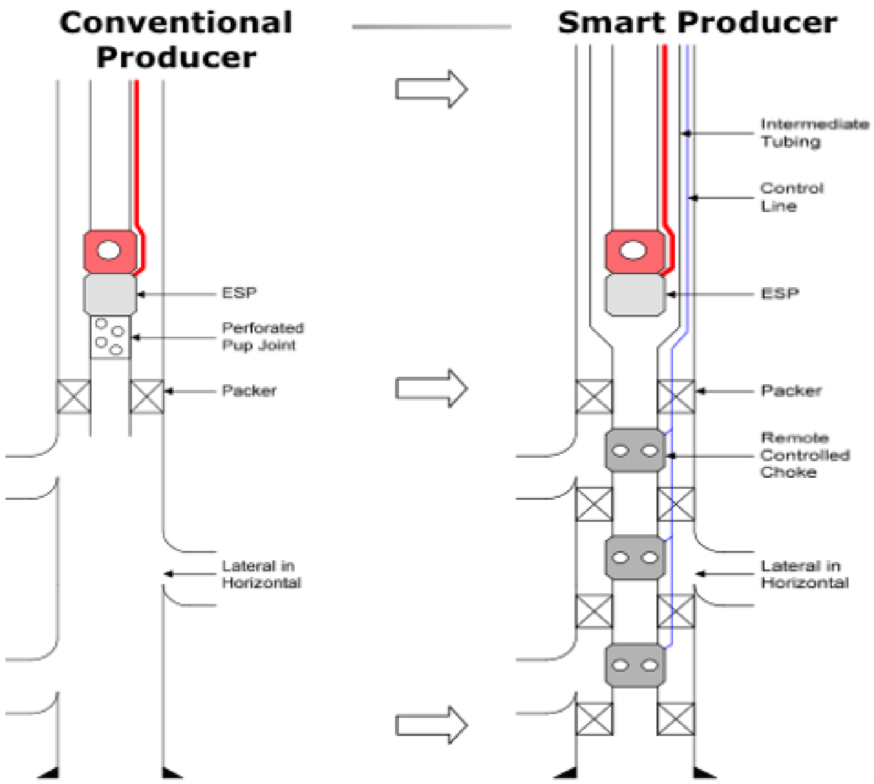


Figure 3: Conventional producer versus a smart producer. Reprinted from (SPEATCE, 2006). Smart completions offer the capability to simultaneously monitor, control and produce from multiple zones.

1.3 Scope of Work and Limitations

The UNISIM-I-D simulation model was used along with a commercial simulator to perform this study. The scope of this work was centered on production control of a successfully installed and reliable smart system. Well design, system installation and well placement were out of scope for this study.

Some of the limitations for this study include:

- Limitation in the amount of downhole control achievable using the commercial simulators.

- Limitations to the extent to which operation costs and unforeseen costs can be incorporated into the NPV analysis
- Lack of real life field reliability data to quantify risk of failure of smart well systems.

1.4 Report Outline

This thesis report is presented in five chapters:

- **Chapter One** presents an overview of the industry challenges and briefly introduces Intelligent (Smart) Well Completions. The motivation for this project, expected outcomes, the scope and the limitations of the work are defined.
- **Chapter Two** provides an in-depth review into the historical development of Intelligent Well Technology, the key industry players and the technology design. The applications, benefits and past field experience are also investigated.
- **Chapter Three** introduces the reservoir system used for this study and outlines the steps taken to simulate the various scenarios using the Eclipse 100 simulation package. The methodology implemented for the sensitivity analysis, and economic analysis are also discussed.
- **Chapter Four** presents and discusses the results obtained from the reservoir simulation exercise.
- **Chapter Five** concludes the research work and provides recommendations for future work related to intelligent well completions.

CHAPTER II

LITERATURE REVIEW

2.1 Overview and Historical Development

Smart well technology also known as intelligent well technology (completions) generally refers to any sort of downhole monitoring system that has the capability of collecting, transmitting and analyzing production data, while providing the capability for remote action control of the production process (PetroWiki, 2015).

Although advancement in computer assisted operations greatly improved reservoir management and recovery, remote monitoring and control of wells was limited to hydraulic and electro-hydraulic control of safety valves up until the late 1980's (PetroWiki, 2015). The only means of obtaining downhole production data (pressure, temperature and flow) was through periodic well intervention-based techniques. This method was certainly undesired as intervention-based logging techniques interrupt production, are costly and stand the risk of logging equipment getting stuck down hole. These issues coupled with the declining production from the first generation of subsea wells in the early 1990's motivated the drive to find better alternative methods of obtaining downhole monitoring and control capabilities. However, it wasn't until 1997 when the first remotely operated hybrid electro-hydraulic well system that had the capability of real-time pressure and temperature measurement, using permanent downhole gauges with flow control devices was installed. This installation was performed on a well at the Saga's Snorre Field in the North Sea (Greenberg, Jerry, 1999). Since this first installation, there have been significant advancement in the development of the technology and it has been highly adopted by large companies like Saudi Aramco and on multiple high stake offshore projects in the North Sea (Hamid, Osman. "Completion optimization for an unconventional reservoir" Saudi Journal of Technolgy, 05th August, 2015. Figure 4 shows a study showing a comparison between smart wells versus conventional wells that were deployed in different developments within the same field. From this study, 48 smart wells achieved the same production target that would require 150 vertical wells (Mubarak, Pham, Shamrani, and Shafiq, 2007).

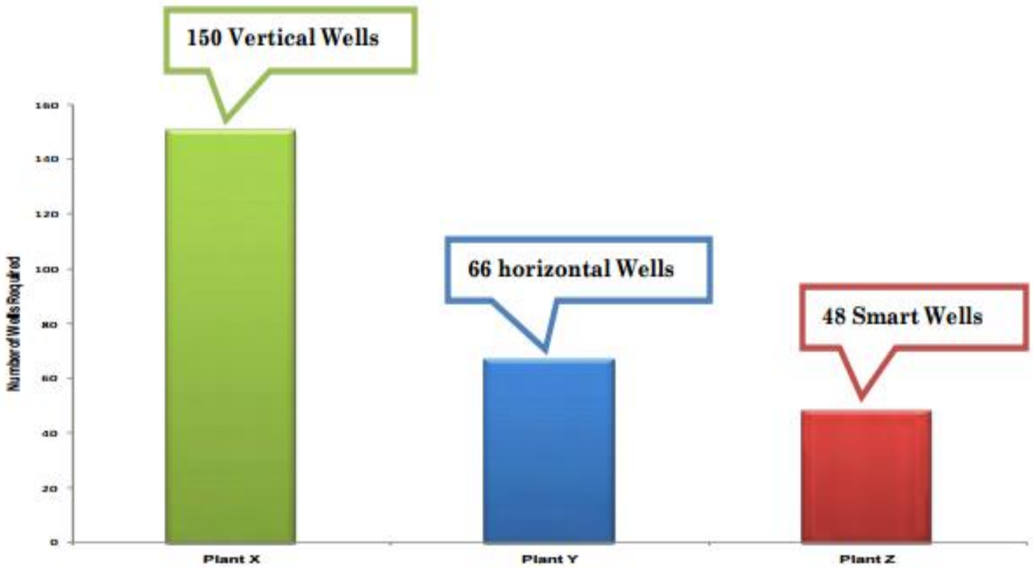


Figure 4: Study comparing number of wells required to achieve production target. Reprinted from (Mubarak et al., 2007)

On the supply side, there are many companies which are heavily invested in the development of intelligent well systems and the various designs and options available in today's market will be discussed in the next section.

2.2 Academic Literature

The increasing demand for limited oil and gas resources has led to a critical need for more efficient production methods that will enable operators increase recovery of fluids in place. Several studies have propose optimization model at every stage of the production process. Traditional research approach of has been to focus on each area of study individually to find better methods of improving a specific problem.

Most of the focus has been on conventional subjects such as well placement, pressure transient analysis of bottom hole pressures and rate measurements, history matching models and recently, fiber optic sensing methods.

Nasrabadi et al presented a literature survey of well placement optimization with focus on topics such as optimization algorithms, reservoir response models, uncertainty and well placement optimization in gas and gas condensate fields (Nasrabadi, Morales and Zhu, 2012).

Similarly, Park et al. presented a multi-objective optimization approach to determine pumping rates and well locations to prevent saltwater intrusion, while satisfying desired extraction rates in coastal aquifers (Park, and Aral, 2004)

Mansoori et al presented a novel approach to the well test (pressure transient analysis) problem by proposing a bilaterally coupled model that utilizes a two-stage method to remove wellbore effects and treat noise on well-head flow measurements (Mansoori, Van den Hof, Jansen and Rashchian, 2015).

Several works have developed optimization techniques for reservoir management. Sampaio et al implemented proposed a hierarchical hybrid optimization framework that performs local optimization by implementing proper orthogonal decomposition (POD) with discrete empirical interpolation method (DEIM). The model employed gradient based techniques and was tested using the UNISIM-I-D benchmark reservoir model (Sampaio, Ghasemi, Sorek, Gildin, and Schiozer, 2015).

Similar work on computational models for reservoir optimization was performed by Jansen (Jansen, 2013). In his work, a gradient-based closed loop reservoir management algorithm is developed based on the optimal control theory.

Volcker et al. presented a numerical method for solution of large-scale constrained optimal control problems using a single-shooting method that computes the gradients using the adjoint method (Volcker, Jorgensen and Stenby, 2011). Volcker et al. also proposed a predictive step size control applied to high order methods for temporal discretization in reservoir simulation (Volcker, Carsten, Jorgensen, and Bagterp, 2010). Finally, in his work on fiber optics, Zinati explored how distributed sensing systems can be used to estimate inflow and reservoir properties (Zinati, 2014).

Unlike the problem specific approach, smart well technology adopts an exhaustive closed loop approach of optimizing the entire production process rather than focusing on distinct production issues. Optimization using smart wells has been applied and tested for both injection and production operations.

Brouwer used the optimal control theory study the dynamic optimization of water flood in a numerical reservoir using smart wells (Brouwer, 2004).
Experimental studies have also been performed to demonstrate how water alternating gas (WAG) operations can be optimized in smart wells (Esmaiel, 2007).

A literature review of smart wells and their applications was presented by Gao et al (Gao, Rajeswaran and Nakagawa, 2007).

The UNICAMP institution has proposed several studies on intelligent well control. Barreto proposed an optimization methodology for assessing control valve wells in the selection of oil production strategy (Barreto, 2007-2014).

Mazo performed a water management analysis through control injection wells in heterogeneous and fractured reservoirs (Mazo, 2009-2013).

2.3 Key Industry Players

Over the past decade, smart well systems have advanced from merely being a prototype technology to becoming a widely acceptable practice in certain field applications. Smart well technology has been highly adopted by large companies like Saudi Aramco and has been successfully implemented on multiple high stake offshore projects in the North Sea. The main industry players involved in the development of smart well systems include Halliburton (Well Dynamics and recently acquired Baker Hughes), Schlumberger and collaborative venture by key industry players know as the Intelligent Well Reliability Group (IWRG). Each manufacture provides unique systems with varying capabilities and the subsequent sections will delve more into these options.

2.3.1 Halliburton

Traditionally, Halliburton's well system research and operation was done under its child company, Welldynamics. With the recent acquisition of Baker Hughes, Halliburton has significantly increased its hold of market share in the smart well technology business (Halliburton press release, July 1st, 2008). The following section will assess the technology offered by Welldyanamics and Baker Hughes.

2.3.1.1 Well Dynamics

Welldynamics introduced the first industry smart well completion in 1997 (Swanger, "WellDynamics Norge awarded North Sea Advanced Well steering Framework agreement by hydro" Business wire, 17th May, 2007) and was fully acquired by Halliburton on July 1st, 2008 (Halliburton press release, July 1st, 2008). According to Welldynamics, a smart well system is defined as "completion consists of some combination of zonal isolation devices, interval control devices, downhole control systems, permanent monitoring systems, surface control and monitoring systems, distributed temperature sensing systems, data acquisition and management software and system accessories, that optimizes well production and reservoir management process by enabling operators to monitor and actively control the reservoir in real time at the sand-face level, all without any mechanical intervention." Welldynamics offers a range of options with varying capabilities for the following system components:

2.3.1.1.1 Interval Control

Interval Control Valves (ICV) provide the capability to control flow into or out of an isolated reservoir layer. Welldynamics offers a wide range of interval control capabilities for example the HS-ICV is designed for deep-water operations and can withstand pressures as high as 15,000 psi and temperatures up to 325 F, while the MCC-ICV is designed to provide incremental flow control over individual reservoir zones ("Interval control valves" Halliburton product services, 2015).

Figure 5: WellDynamics interval control valve. Reprinted from ("Interval control valves" Halliburton product services, 2015)

2.3.1.1.2 Zonal Isolation

In order to have flow control capability, reservoir zones need to be isolated. Welldynamics provides a range of high-performance packers and isolation devices with varying applications. Some of these options include: the HF-1 Packer which can withstand higher loads and pressures than stardard packers, HFP Packer which is designed for deep water and ultra-deep water applications, MC Packer, and Seal Stach Assembly which is used for applications in which packers are either undesirable or cannot be used.

When properly combined, these components results in a fully functional intelligent well system, enabling operators to remotely monitor and control production.

Figure 6: WellDynamics HF-1 Packer (Reprinted from Well Dynamics website)

2.3.1.1.3 Downhole Control Systems (DCS)

Downhole control devices allow operators to control the downhole system components during production, as well as accurately acquire and communicate data back to the surface. The most commonly used control system is the Surface-Controlled Reservoir Analysis and Management System (SCRAMS) ("Downhole control systems" Halliburton product services, 2015). Other DCS capabilities offered by Welldynamics include Accu-Pulse Incremental Positioning Module which provides incremental opening of a multi-position ICV, Digital Hydraulics DCS which uses hydraulic pressure sequencing to control multiple downhole devices, and SmartPlex DCS which is an electro-hydraulic system that enables reliable zonal control of multiple valves.

2.3.1.1.4 Permanent Monitoring Systems (PMS)

Permanent Monitoring Systems are retrievable monitoring devices that provide the capability to measure essential real-time data necessary to make informed decisions. Some of the available PMS options include CheckStream Chemical Injection System, Chemical Injection System, FloStream Venturi Flow Meter, ROC Permanent Downhole Gauges, and SmartLog downhole gauge system.

Figure 7: ROC permanent downhole gauge (Reprinted from Well Dynamics website)

2.3.1.1.5 Surface Control and Monitoring Systems (SCMS)

Surface Control and Monitoring Systems (SCMS) are electrical and hydraulic systems that enable operators to monitor permanent downhole gauges (PDGs), control interval control valves (ICVs), interpret and model data acquired by the system. Some available Welldynamics SCMS systems include Land and Platform Control Systems, Portable Control Systems and Ancillary Equipment, SCADA and Software Applications, Standalone Permanent Monitoring Systems, and Subsea Control and Monitoring Systems.

2.3.1.1.6 Remote Open Close Technology (ROCT)

Remote Open Close Technology (ROCT) is a field-proven technology that eliminates the need for traditional wireline plug and prong equipment, thus reducing risk and saving time otherwise needed to rig-up wireline and associated pressure control equipment. Welldynamics ROCT systems include eRED Ball Valve, eRED-HS Remotely Operated Circulating Valve, and Evo-RED Bridge Plug.

2.3.1.2 Baker Hughes

Baker Hughes intelligent well systems are focused on reducing total cost of ownership (TCO) and optimizing production through advanced downhole data monitoring and remote reservoir zone control. The Baker Hughes intelligent well system capability consists of three main components namely; well monitoring instrumentation, intelligent completion technologies, and automated chemical application ("Intelligent Well Systems", Baker Hughes oilfield services, 2015).

2.3.1.2.1 Intelligent Well Systems (IWS)

Baker Hughes IWSs include Cased-Hole and Open-Hole Feed through Packers, Hydraulic Flow Control Devices, and Surface Control Systems.

- Bakers Feed through Packers accommodate tool control lines while maintaining fluid control and zonal isolation. The Premier removable packer and the Pace remover packers are suited for cased-hole applications, while the MPas and the REPacker are suited for open hole applications.

Figure 8: Baker Hughes cased hole (left) and open hole (right) flow control devices (Reprinted from Baker Hughes website)

- Hydraulic Flow Control Devices enables flow control in multiple zones without intervention for both production and injection operations. Available options include HCM-A adjustable choke, InForce HCM-A GL, HCM-S, and HCM Plus valves, which offer multi-position adjustable control capability for varying production environments ("Hydraulic Flow Control Devices", Baker Hughes oilfield services, 2015).
- Surface control systems are the "heart and brain" of intelligent well completions that make it possible to control flow without the need for well intervention. Two options

exist for the InForce surface control system (SCS); the standard SCS which is a pneumatically driven and manually operated SCS designed for simple completions. The other option is the fully-automated SCS which has a built in programmable logic controller (PLC) and is used alongside the supervisory control and data acquisition system (SCADA), in more complex completion configurations that require remote operation (“Surface control systems”, Baker Hughes oilfield services, 2015).

2.3.1.2.2 Well Monitoring Instrumentation

Baker Hughes well monitoring portfolio includes electronic, fiber–optic and Electronic Submersible Pump (ESP) monitoring systems. These systems offer operators the capability to obtain real-time pressure, temperature, flow, fluid density, vibration, acoustic and wellbore stress data that help minimize operational risk and overhead costs (“Well Monitoring Solutions”, Baker Hughes oilfield services, 2015).

- The ESP monitoring system is marketed around improved performance, reliability, reliable downhole data acquisition and extended run life. This is achieved by providing optimum drawdown, thermal cycling and preventing pump-off. The current available portfolio of ESP monitoring systems include WellLIFT N, WellLIFT H, WellLIFT HP, WellLIFT E, SureVIEW, and SureSENS systems. The SureVIEW and SureSENS systems are designed for high pressure and high temperature applications.
- The Electonic Well Monitoring systems include SureSENS permanent gauge systems, SureFLO flow measurements systems, and the StageWatch retrievable gauge systems. Each of these systems have multiple options of variable capabilities, depending on the application.

2.3.2 Schlumberger

The Schlumberger definition of intelligent completions is a system that “incorporates permanent downhole sensors and surface controlled downhole flow control valves, enabling operators to monitor, evaluate, and actively manage production (or injection) in real time without any well interventions.” Schlumberger’s inventory for intelligent well technology includes; Intellizone Compact Modular Multizonal Management System (ICMMMS), Downhole Flow Control Valves (DFCV), Zonal Isolation, Permanent Monitoring Systems (PMS) and Multitrip connectors (“Intelligent Completions”, Schlumberger Services & Products).

- The ICMMMS integrates an advanced design and production modeling engine, a completion module and a remote operating system in a single compact unit. The system reduces the number of hydraulic lines required while maintaining the capability to control the same number of valves. Valve position is controlled from a surface control system programmed with control logic.
- Downhole flow control valves include on/off, multiposition, annular and inline flow control valves that can either be operated manually, automatically or remotely. Several design options of flow control valves (FCV) are available for a wide range of applications. These include; TRFC-HD Multiposition FCV, TRFC-HN Single Line Multiposition FCV, TRFC-HB Binary position FCV, and WRFC-H Wireline-Retrievable FCV.
- Zonal isolation

  Schlumberger multiport parkers are designed to prevent fluid loss, enhance safety and protect against formation damage in multizone wells. The XMP Premium MultiPort and MRP-MP MultiPort series are tubing-conveyed, hydraulically set retrievable packers, and are designed for hydraulic control and electric conduit applications. The Quantum Multiport packer is also hydraulically set and is designed for bypass applications.
- Permanent monitoring systems integrate advanced permanent downhole measurement systems with surface data acquisition systems to enable real time remote well monitoring capability. The Schlumberger PMS catalog is divided into Permanent downhole gauges and Distributed Measurement Systems
  - Permanent Downhole Gauges provide for “highly accurate, stable, and reliable point measurements of pressure, temperature, flow rate, and fluid density.” These

include Pressure and Temperature gauges, FlowWatcher Flow Rate, Fluid Density and PT Monitoring System.

  - The Distributed Measurement Systems include fiber-optic temperature sensing systems, temperature and pressure gauges that provide information on the location, time and reason for any changes in flow. These systems include the WellWatcher Neon DTS & PT Gauge System, WellWatcher BriteBlue Multimode DTS Fiber, and WellWatcher Flux Digital Temperature Array and PT Gauge system.

- Schlumberger's Hydraulic Line Wet Mate (HLWM) multitrip connector system provides operators the ability to install intelligent completion assemblies in the lower completions while maintaining communication with the upper completions

2.4 Technology Design and Mechanism

As a result of the need to increase productivity and maximize efficiency, extended-reach and multilateral horizontal wells are increasingly being used as a means of achieving increased reservoir contact. These complex wells provide several advantages such as increasing the available drainage area, improving well productivity, optimizing sweep efficiency, and delaying water or gas breakthrough. Augmented reservoir contact enables operators to achieve similar production rates as conventional wells using less drawdown pressure (Ellis et al, 2010).

However, in complex and highly heterogeneous reservoir systems, such complex wells are accompanied by high risk and uncertainty if not designed and managed properly. In some reservoirs with extended reach wells, the heel-toe effect is a common issue which often leads to an early end of a well productive life, leaving back undisplaced reserves. The heel-toe effect is a situation in which significantly higher drawdown pressures are experienced at the heel that at the toe of a horizontal well, leading to unequal inflow along the well path (Ellis et al, 2010). As a result of higher drawdown (and consequently flow) in the heel, water or gas breakthrough is accelerated in this region leading to an early end of well productive life. Carbonate reservoirs are especially vulnerable to this condition as they tend to have higher levels of heterogeneity (Ellis et al 2010). The figures below presents a visual demonstration of heel-toe effect in a horizontal section, and a possibly remedy by using ICDs.

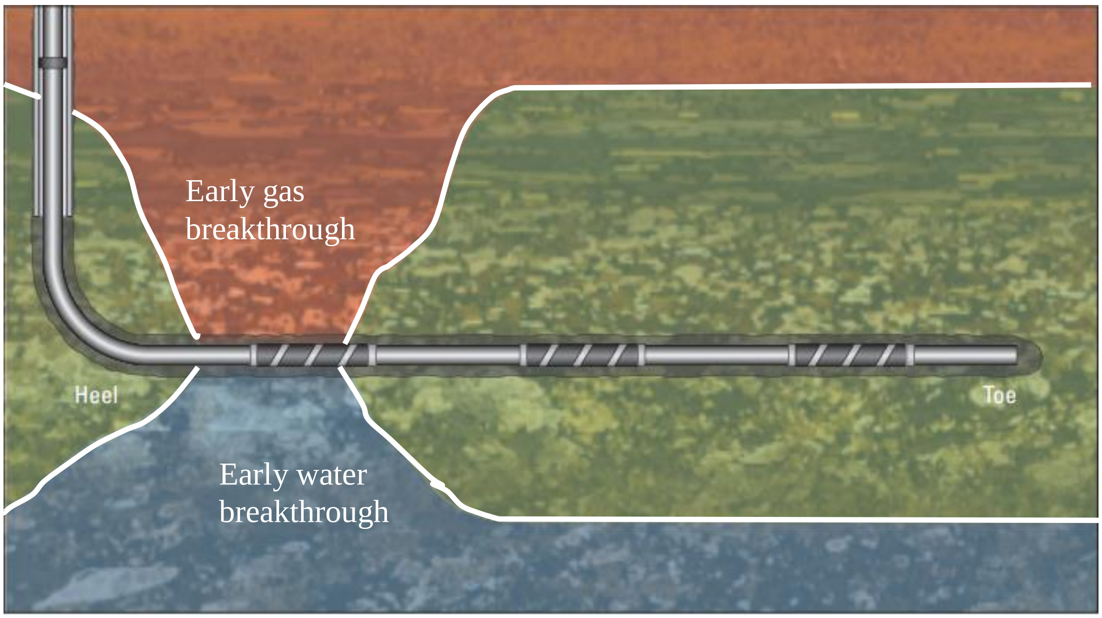


Figure 9: Heel-toe effect - Drawdown is significantly higher at the heel than at the toe in extended-reach horizontal wells due to pressure losses (frictional and velocity) along the wellbore, leading to early breakthrough of water (blue) or gas (red). This leads to an early end of the productive well life, leaving back undisplaced oil (oil). Adapted from (Ellis et al 2010)

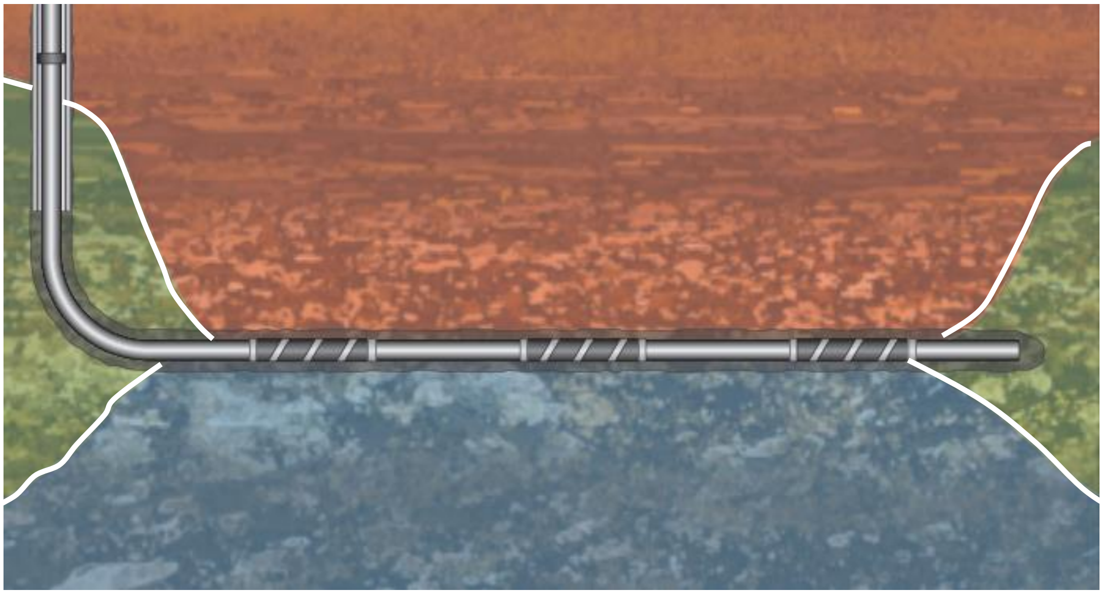


Figure 10: Image showing how inflow control devices regulate flow from problematic zones, leading to uniform flow of oil along the formation, while delaying the flow of water and gas. Adapted from (Ellis et al, 2010)

It is therefore critical to thoroughly understand and have adequate control over each producing zone in the reservoir. In this section, the three main methods through which remote zonal control is achieved will be presented and discussed.

2.4.1 ICD

Inflow control devices (ICD) are passive components of a well completion which are used to optimize production by creating a uniform inflow profile along the entire section of a horizontal well. This is achieved by creating flow restrictions on high flow-rate zones (and of highly mobile phases), while simultaneously stimulating flow low producing zones (and of less mobile phases). This restriction controls the flow of the different phases by varying the pressure drop as needed. Liquid flow in porous media is usually in the laminar flow regime, resulting in a linear relationship between flow velocity and pressure drop. However, the flow across ICDs lies in the turbulent regime (high Reynolds number), therefore the flow velocity-pressure relationship is quadratic. The ICD changes the flow regime from Darcy radial flow within the reservoir to a restrictive pressure drop flow across the ICD (Ellis et al 2010). Several type of ICDs exists, based on the method of achieving this pressure drop.

2.4.1.1 Nozzle (Orifice) Type ICD

Nozzle type ICDs contain orifices with preset diameters through which fluid flows to provide a pressure drop. The pressure drop is a function of the flow rate and the fluid properties and is determined by the friction against the channel surface as fluid is forced to flow through (Ellis et Al, 2010). Nozzle type ICDs are self-regulating and operate independently of the formation heterogeneity or the fluid composition (water, or gas). As stated earlier, nozzle type ICD's function based on fluid flow rates which are determined by fluid properties (viscosity and density). In the event of an early breakthrough in a highly permeable production zone, more mobile fluids like gas and water flow into the wellbore at higher velocities than oil. This raises the friction on the surface of the channels as the fluids force their way through, increasing the backpressure at that point. As a result, the entry of formation fluid into the well bore in that high-permeability zone is slowed down, preventing water and gas from being produced before valuable oil reserves in less permeable zones. This ultimately increases the sweep efficiency, thus improving oil recovery. The ICD's resistance is to flow is determined by the dimensions of the nozzles and this is set before installation and cannot be adjusted without recompletion once installed downhole.

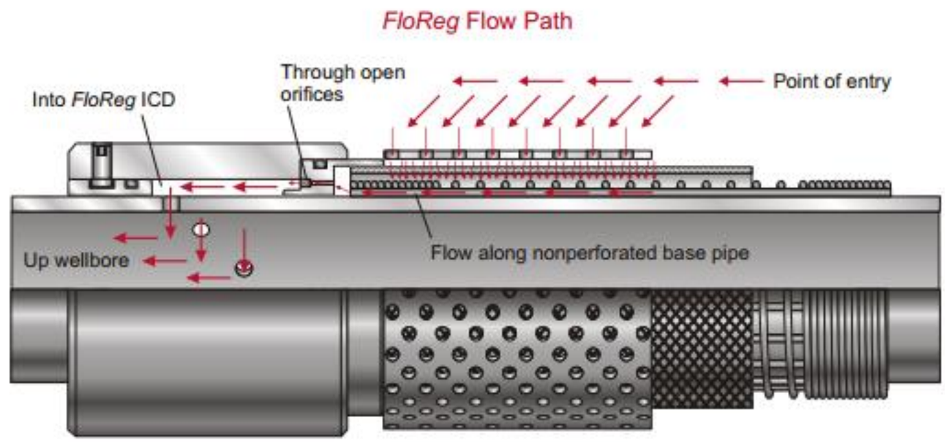


Figure 11: Nozzle type ICD. The red arrows represent fluid flowing from the formation through screens and along the annulus between the screens and pipe. It then enters the production tubing through a restriction.
(Reprinted from Oilfield Review, Winter 2010)

2.4.1.2 Helical-channel ICD

Helical devices have a slightly different design but function in the same way as nozzle-type ICDs. Fluid flows through channels with preset length and diameter, through a tortuous pathway. This creates friction on the surface of the channels as fluids flow through, resulting in a pressure drop at the point of entry. Depending on the fluid velocity, the restrictive backpressure created will vary proportionally. Similar to nozzle type ICDs, the restrictive pressure created is a function of the channel dimensions and cannot be adjusted after downhole installation.

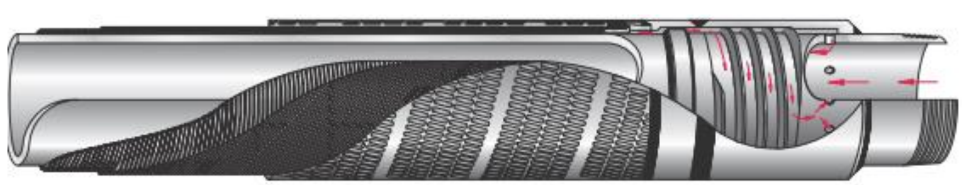


Figure 12: Channel type ICD (Reprinted from Oilfield Review, Winter 2010)

2.4.2 ICV

As the name suggests, Inflow Control Valves (ICV) are downhole flow-control valves which are remotely operated from the surface by hydraulic, electric or a hybrid (electro-hydraulic) actuation system (Al-Khelaiwi et al. 2010). This is a key component of intelligent well systems as ICVs have the ability to choke or completely shut off fluid flow from the reservoir into the wellbore. The ICV system consists of five main components; the control valve itself, gauges to monitor flow, surface control equipment, control lines and connectors itself (Al-Khelaiwi et al. 2010). Detail of the different modifications of ICVs readily available on market were presented in the "key industry players" section. Generally there are two main configurations of ICVs, with several variations in between;

2.4.2.1 Simple On/Off ICV

On/off ICVs are restricted to two modes of operation; the "on" positions where fluids are allowed to flow freely without restriction into or out of the well bore. The "off" position is the other end of the operation and when activated, fluids are completely restricted and flow into or out of the wellbore is completely shutoff.

2.4.2.2 Variable Control ICV

Variable control valves are more advanced and operationally complex than the simple on/off ICVs. Variable control ICVs provide operators the ability to remotely choke fluid flow into or out of the wellbore. The valve position can be adjusted to several positions to obtain the desired fluid flow rates. This is the main difference between ICVs and ICDs as unlike with ICDs, the diameter of the downhole flow path for an ICV can be adjusted without intervention. This capability is especially valuable for production management from multiple producing zones of different permeability into the same wellbore.

In order to fully realize the value of an ICV it must be designed to achieve four main functions (Rahman et al. 2012):

- The sealing technology must be robust enough to handle all loading and unloading events for the entire operational life of the well
- Maintain pressure balance during operation
- Withstand and maintain tension and compression integrity of the completion
- Provide capability for quantifying fluid flow characteristics

To improve efficiency, ICVs are often equipped with monitoring devices to proactively detect water or gas breakthrough early enough to remotely initiate the choking of the unwanted fluids. The zonal location on where the ICV is place in the reservoir system is a critical parameter that requires close collaboration and input from geologists to be thoroughly understood. ICVs should be places in zones where early water and gas breakthrough are most probable.

2.4.3 Sliding Sleeves

Sliding sleeves have been the tradition method used to selectively shut off unwanted fluid (water or gar) production (Erlandsen and Omdal 2008). Operational, sliding sleeves are similar to on/off ICVs, strictly providing zero or full restriction of fluid flow into or out of the wellbore. However, although proven to be robust sliding sleeves are economically limited as well intervention is required to access and operate (open or shut) the device. This limitation historically led to the continuous improvement of the design and eventually the development of ICVs.

2.5 Passive versus Active Inflow Control Completion

Fluid flow control in smart wells can be either passive or proactive. The development of smart completions and advancement of smart well technology components like ICVs have enabled operators to go from traditional passive/reactive production to more active/proactive control. Sliding sleeves and ICDs restrict influx of unwanted fluids like water and gas upon breakthrough however, these devices are limited by the fact that they only provide full flow or restriction capabilities and the flow paths cannot be adjusted once deployed downhole. With more advanced technology like ICVs, proactive production techniques such as imposing a pressure profile along the well bore based on down-hole measurements are possible (Jansen, 2001). The imposed pressure profile and reservoir models can be continuously updated during production to improve recovery efficiency. Nevertheless, full realization of such potential requires the development of robust computational tools to enable the continuous revision of conventional production scenarios. Several studies have been proposed on closed loop reservoir management to enable continuous optimization during production (Jansen, 2013), Bjarne et al. (2011) and Sarma (2006).

Several works have developed optimization techniques for reservoir management. Sampaio et al implemented proposed a hierarchical hybrid optimization framework that performs local optimization by implementing proper orthogonal decomposition (POD) with discrete empirical interpolation method (DEIM). The model employed gradient based techniques and was tested using the UNISIM-I-D benchmark reservoir model (Sampaio, Ghasemi, Sorek, Gildin, and Schiozer, 2015).

Similar work on computational models for reservoir optimization was performed by Jansen (Jansen, 2013). In his work, a gradient-based closed loop reservoir management algorithm is developed based on the optimal control theory.

Several studies on reservoir optimization using intelligent well control have been presented by the UNICAMP institution. Barreto proposed an optimization methodology for assessing control valve wells in the selection of oil production strategy (Barreto, 2007-2014). Mazo performed a water management analysis through control injection wells in heterogeneous and fractured reservoirs (Mazo, 2009-2013).

Equipped with the right personnel and resources, the value of proactive production methods can be fully realized and production efficiency significantly improved.

2.6 Application of Smart Well Technology

As discussed in the previous sections, smart well technology has the potential of significantly improving reservoir control and management, sweep, and recovery efficiency. However, the profitability of Smart Well Technology and extent to which it enhances fluid production is highly dependent on the inherent reservoir properties. From experience, highly heterogeneous reservoirs with variable fluid delivery from each zone have proven to be suitable for the application of Smart Well technology. Research studies have been performed to show that recovery can be significantly increased by changing reservoir management from a 'batch-type' to a closed loop near-continuous model-based control activity (Jansen, 2013).

In this section, the possible application of smart well completions will be discussed to further demonstrate the value proposition. It is assumed that the field under investigation has been properly assessed and confirmed to be suitable for the application of the technology.

2.6.1 Intelligent Injection

Maintaining pressure support is critical to hydrocarbon recovery and achieving target production rates. In the absence of natural pressure support such as aquifers or a gas cap, many oil fields rely on injection to provide the required pressure for the drive mechanism to occur. However, the injection flow profile is rarely uniform, especially in naturally fractured carbonates (Schlumberger Middle East & Asia Reservoir review, 2007). In such reservoir systems, the high permeability contrast between the natural fractures and the matrix cause most of the injected fluids to be captured by high permeability streaks, significantly leading to uneven injection profiles and poor sweep efficiency *(Figure 13).*

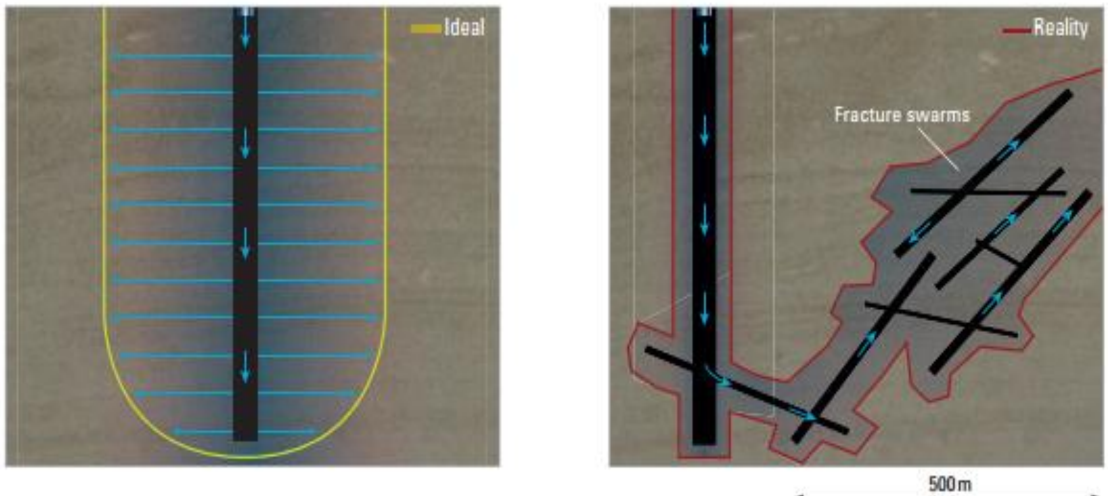


Figure 13: High permeability contrasts between natural fractures and the matrix can significantly lead to uneven injection profiles. Reprinted from (Schlumberger Middle East & Asia Reservoir review, 2007)

For such highly heterogeneous reservoirs, intelligent completion systems such as the Shclumberger ResInject can regulate the injection rate along the well bore to create a more even injection profile. The ResInject is a nozzle type ICD as described in earlier sections. Fluids enter pass through the nozzles into the reservoir, creating a pressure drop which is calculated by the nodal analysis software. The nozzles self-regulate to reduce the injection of fluids into theft zones (high-permeability streaks), at the same time increasing the injection into low permeability zones. This advanced operational control allows operators to simultaneously manage multiple injection zones, achieve more uniform injection profiles, delay water break through and ultimately increase oil recovery.

2.6.2 Intelligent Gas Lift

Operators rely on gas lift to increase oil production rates in heavy oil production operations or to enable “dead” wells to flow. Traditionally, gas compression facilities pump gas from the surface down the annulus of the well which then changes the flow properties of the oil downhole, reducing hydrostatic head and thus enabling higher flow rates to be achieved. This process requires substantial capital investment equipment (pumps, compressors etc.) for the surface facility.

In reservoir systems with a gas cap, intelligent completions can help eliminate the capital investment required for the surface facility in a traditional gas cap operation. In an intelligent gas lift operation, the gas-bearing zone can be completed and equipped with an intelligent well system. This allows the lift gas to be produced and bled into the production tubing at a controlled rate through the downhole flow valves (Schlumberger Middle East & Asia Reservoir review, 2007). Intelligent gas lift is also commonly referred to as auto, in situ or natural gas lift. If executed well, intelligent gas lift generates additional value by completely eliminating the cost, risks and platform load requirements associated with surface gas compression facilities, providing a means of controlling gas coning, and eliminating the need for interventions to place traditional gas lift equipment.

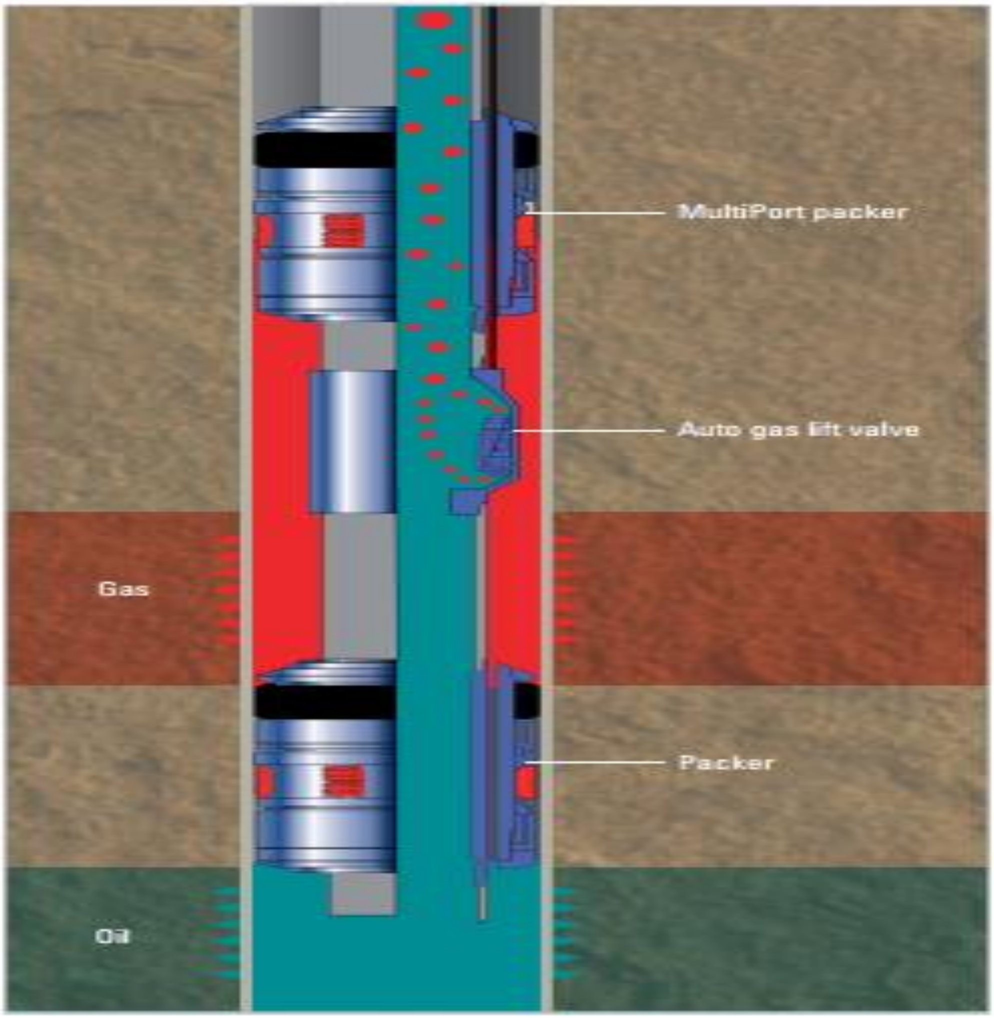


Figure 14: Gas from the overlying gas cap (red) in bled into the production tubing to reduce the hydrostatic head of the oil (green) and increase flow rate. Reprinted from (Schlumberger Middle East & Asia Reservoir review, 2007).

2.6.3 Optimal Reservoir Management (Water or Gas Shut-off)

The value of an oil well depends on how much oil can be recovered after all the related cost inquired to produce the oil have been accounted for. A big part of the expense for every producer is the cost to treat and dispose of the produced water. In highly heterogeneous reservoir systems with high permeability contrast, horizontal barriers and strong water drive, early breakthrough can significantly increase the amount of water produced. High water production rates can lead to the early end of life of a well due to the high cost of water treatment, leaving behind undisplaced hydrocarbons. Using smart well technology, early water breakthrough can be detected using the temperature and pressure sensors in the downhole ICVs. Excessive water production can be controlled by completely shutting off or choking zones that breakthrough early. This can also be applied to control early gas influx into the well in situations where a gas drive (gas cap) is present and gas production is not desired (Schlumberger Middle East Reservoir Review, 2007).

Figure 15: Optimal reservoir management using intelligent well technology to improve oil production in the event of early water or gas breakthrough. Reprinted from (Emerson News release, May 4, 2009)

2.6.4 Commingled Production

It is not uncommon to have reservoir systems in which several production zones, each with different pressures are stacked on each other. Such pressure differences can lead to cross flow during production from the high pressured to lower pressured zones. The conventional way of working around this issue will be to produce sequentially. This could be achieved by either shifting a sleeve on a wire line (or coiled tubing), or through work over and reperforation (Jansen, 2001). Work overs can be significantly more expensive especially in deep water operations where time saving is a critical factor. Additionally, government regulations in some areas require that production from each zone be independently accounted for, making it a challenge when there is uncontrolled cross flow between layers.

Using smart well technology, commingled production can be achieved by choking the flow from high pressured zones to avoid cross flow to low pressured zones (Jansen, 2001). This allows vertically stacked layers with different pressure profiles to be simultaneously produced, while adhering to regulation. Additional benefits include accelerated production and eliminating the need of work overs, both of which significantly add production value especially in deep water operations.

2.6.5 Flow Profiling

Collecting and understanding flow profile data of a well is critical for developing accurate reservoir models. Well testing is one of the most common methods used to evaluate well conditions and reservoir characteristics (Paino et al., 2004). However, well testing is expensive as it is time consuming and usually involves interrupting normal production. Also, conventional methods are risky as trips need to be made to deploy equipment downhole for data collection. This also interrupts production making the data collection very expensive and sometimes inadequate due to limits on how long production can be interrupted. Smart completions are equipped with permanent downhole pressure sensors, thus the need for making trips or interrupting production is eliminated. Live pressure data can be constantly collected during production. Additionally, fiber optic technology which is integrated with smart well technology enables the operators collect temperature data and thus have a better understanding of the flow profile along the production tubing. Cui et al. proposed a diagnosis for multiple fracture stimulation in Horizontal Wells by Downhole Temperature Measurements (Cui and Zhu, 2014).

2.6.6 Dump Flooding

Dump flooding is a recovery enhancement technique that has been practiced in the industry to reduce capital and overhead costs associated with traditional water flooding by injection. The concept of dump flooding utilizes pressure from gas or water zones to improve sweep efficiency and maintain the reservoir pressure. Submersible pumping systems (ICDs) installed downhole in the wellbore are used to redirect water from an acquifer or gas from a gas cap along an isolated pathway into the main reservoir system. This method minimizes the costs associated with surface injection facilities, which are needed in conventional flooding methods. Similarly, the use of ICVs provides the operator with sufficient control to maximize the leverage of the external pressure source. The example in figure 9 shows a gas flood operation where a smart well is used to connect an oil reservoir with weak gas cap drive to an underlying gas reservoir with a higher pressure (Jansen, 2001). Pressure sensors and variable control ICVs are used at the injection interval to channel gas from the high pressure gas reservoir and displace oil in. This process is referred to as “gas dump flooding”. A second well is used to drain the displaced oil thereby maximizing the recovery from the under pressured oil reservoir.

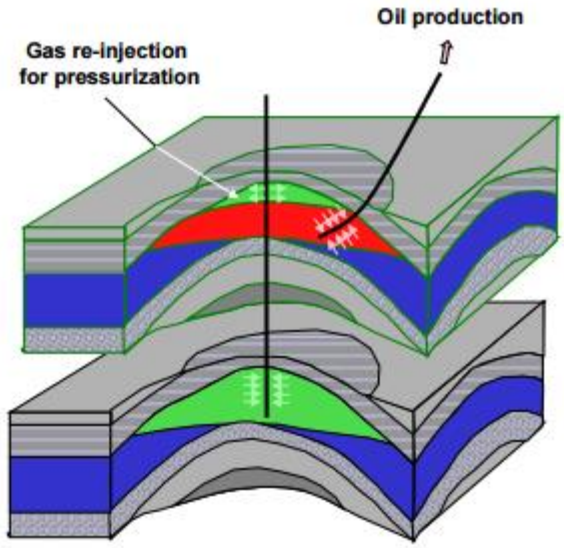


Figure 16: Gas dump flood process showing oil displacement using gas re-injected from a high pressure gas reservoir. Reprinted from (Jansen, 2001)

2.6.7 Reservoir Characterization

Proper reservoir characterization is critical for accurate reserves estimation and optimal reservoir management. Improper reserve estimation is not only embarrassing to the engineers but could be costly to a company's reputation and financial position. Additionally, without proper reservoir characterization, it becomes challenging for engineers to properly manage the reservoir to obtain optimum production. Intelligent well completions provide real time downhole data which can be used to update production models and reduce reservoir uncertainty.

Naldrett *et al* investigated the case where temperature profiles measured by an intelligent completion was used to determine the production interval and the production rate from each layer. This was achieved by comparing the measured temperature profile with the geothermal gradient (Naldrett et al, 2005).

Intelligent completions provide data which enables more accurate reservoir modeling/characterization and optimizes future operations.

2.7 Benefits of Intelligent Wells

The previous section have presented evidence on the potential benefits of optimal application of Smart well technology. Smart well technology becomes even more valuable in deepwater and subsea operations which are more technically challenging and expensive. Some benefits of Intelligent Well Technology include;

- Accelerated production through well controlled comingled production
- Reduction in amount of water produced.
- Reduction in Capital Expense (CAPEX). Reduces the need for surface facilities, extra wells and intervention procedures.
- Reduced Operating Expense (OPEX)
- Decreases reservoir uncertainty by improving reservoir characterization.
- Maximizes sweep efficiency leading to higher Ultimate recovery
- Extends well life while maintaining production peak
- Reduction in rig downtime
- Downhole ICVs enable automated flow regulation during production and provide remote control capabilities
- Improves reservoir model optimization by providing real time measurements
- Minimizes need for personnel presence at well site and thus reduces risk of accidents

The design and modeling smart well technology is a dynamic process that requires critical fit-for-purpose analysis before implementation. The simulation performed in this thesis will demonstrate how smart well completions can be used to accelerate production while significantly reducing the amount of water produced. Accelerated production translates to lower operating costs and minimizes the need for personnel presences on site. The less time spent by personnel on the rig, the lower the opportunity of work related accidents.

Minimizing water cut reduces treatment and disposal costs, and highlights optimized sweep efficiency. Lower fluid capacity needs translate to lower capital and operating cost requirements.

Furthermore, the simulated cases will demonstrate the optimal case where water production is minimized while oil production is maximized.

2.8 Real World Case Studies

Although a relatively new technology, smart well completion technology has been tested and applied to several real world projects to mitigate a wide mix of production problems. This section will discuss some of the documented cases in which intelligent well systems were adopted to optimize production.

- The application of smart well completions to the Agbami deepwater field (offshore Nigeria) was adopted to provide real time monitoring and control necessary to optimize field recovery and performance. Despite the complex stratigraphy and high reservoir uncertainty, field production was increased by approximately 10 million BOPD due to the adoption of smart well technology (Collins and Neuber, 2012)
- Saudi Aramaco has been one of the major industry adopters of smart well technology. An intelligent SCADA (Supervisory Control And Data Acquisition) system was adopted in the Ghawar Field (on the Haradh Increment-III) in Saudi Arabia (Mubarak, Phan, Shamrani and Shafiq, 2007). The implementation of smart completions to this field significantly reduced the amount of onsite monitoring by engineers, maintained peak production, and significantly reduced water cut.
- Adoption of smart well technology was also responsible for the optimal asset development of the Nakika field (deepwater Gulf of Mexico) with minimum number of wells (Chacon, McCutcheon, Schott, and Arias, 2007). Due to the

faults and salt zones, data collection through imaging was expensive and challenging. This challenge was mitigated by the capability of real time data measurement and control. The results were a reduction in uncertainties, improved production efficiency and a significant reduction in field development costs.

- Another field application of smart well technology is in the operations of the Nothern Business Unit (NBU) of Shell UK in the North Sea (Akram, Hicking, Blythe, Kavanagh, Reijinen and Mathieson, 2001). Nine fields that produce 400 thousand barrels of oil equivalent per day were equipped with smart well technology. For the mature assests, the key benefits derived were optimization of oil production, zonal water management and more cost-effective gas capacity management.
- The first ever application of smart well technology in the Gullfaks field (offshore Norway) was also analyzed and documented (Lie and Wallace, 2000).
  Production was significantly accelerated due to comingled production which was previously impossible, and the data from downhole sensors helped to optimize reservoir characterization.

CHAPTER III

SIMULATION WORKFLOW AND METHODOLOGY

3.1 Introduction

As discussed in the previous chapters, the design and modeling of smart well technology is a dynamic process that requires critical fit-for-purpose analysis before implementation. The properties of the field under study must be thoroughly assessed to ensure that it is suitable for the application of smart well technology. Reservoir pressure profile, size, depths of fluid contacts and production zones, reservoir fluid types and recoverable reserves, reservoir heterogeneity (porosity and permeability), operating environment (onshore versus offshore), well type (production versus injection), well geometry, target rates and recovery methods are some of the factors that must be deliberated and analyzed to determine whether or not the reservoir is suitable for the application of smart well technology. Jansen proposed a closed loop reservoir management model that performs due diligence to analyze compatibility be a reservoir model and automated control (Jansen, 2013). A similar closed loop reservoir study was proposed by Gildin et al. in their work on developing Low-Order Controllers for High-Order Reservoir Models and Smart Wells (Gildin, Klie, Rodriguez, Wheeler, and Bishop, 2006)

Once the technical analysis is completed and applicability is established, an economic analysis must be performed. Comparing the marginal increase in cost to the marginal increase in revenue should provide a quick estimate on the economic feasibility of implementing the technology. Increased cost are a result of increased capital and operational expense while revenues increase due to improved recovery, savings in rig time and reduced water production.

The following sections will describe the reservoir system and discuss the methodology that was used in simulating the smart well operation.

3.2 Reservoir Simulation

3.2.1 Reservoir Simulation Overview

In this section, a brief overview of the fundamental equations and numerical methods that are implemented in reservoir simulation will be presented. A simple single phase black oil model will be employed to understand the fluid flow behavior in porous reservoir media. This is for illustration only as we employ a more complicated multiphase model in the case study simulation. The equations and methods presented are based on the textbook by Ertekin et al.[23].

3.2.1.1 Deriving the General PDE's that describe the Fluid Flow for a Reservoir

The mass balance equation for single phase flow is given by the continuity equation:

$$\frac{\partial}{\partial t}(\phi\rho) = -\nabla\cdot(\rho\boldsymbol{u}) - \tilde{q} \qquad (01)$$

Where ϕ is porosity, ρ is the fluid's density, $\boldsymbol{u}$ is fluid's velocity and $\tilde{q}$ is the source/sink term as mass flow rate or volumetric flow rate per control volume (for injector $\tilde{q} < 0$ and for producer $\tilde{q} > 0$).

The velocity term $\boldsymbol{u}$ is define by Darcy's Law as:

$$\boldsymbol{u} = -B_c\frac{1}{\mu}\mathbf{k}(\nabla p - \gamma\nabla z) \qquad (02)$$

Where $\mathbf{k}$ = *permeability in darcy units*

$B_c = Transmissibility\ conversion\ factor = 1.127$

∇p = *pressure drop in psi/ft*

$\gamma = phase\ gravity \left[\frac{psi}{ft}\right] = \gamma_c . \rho . g$

$\gamma_c = gravity\ conversion\ factor = 0.21584 * 10^{-3}$

g = gravitational acceleration = 32.174 ft/s^2,
∇z = *the elevation of each point with respect to a determined reference level [ft/ft]*

μ = *phase viscosity in centipoise*

Substituting equation (02) in (01), yields the general porous media flow equation for a single phase flow problem:

$$\frac{\partial(\phi\rho)}{\partial t} = \nabla \cdot \left(B_c \frac{\rho}{\mu} \mathbf{k} (\nabla p - \gamma \nabla z) \right) - \tilde{q} \qquad (03)$$

Incorporating the formation volume factor B and incorporating it into equation (03) yields:

$$\frac{\partial}{\partial t}\left(\frac{\phi}{B}\right) = \nabla \cdot \left(B_c \frac{\mathbf{k}}{\mu B} \left(\nabla p - \frac{B^o \rho^o}{B} \gamma_c g \nabla z \right) \right) - \frac{1}{B^o \rho^o} \tilde{q} \qquad (04)$$

Where: $$\rho = \frac{B^o}{B} \rho^o \qquad (05)$$

B^o and ρ^o are the formation volume factor and density at reference pressure,

respectively.

The mass flow rate term can be rewritten as volumetric flow (q) by:

$$q = \frac{\tilde{q}}{\rho} \qquad (06)$$

Introducing the term , $B^0 = 1, \& \ b = \frac{1}{B}$ and substituting equations (05) and (06) in equation (04) yields:

$$\frac{\partial}{\partial t}(\phi b) = \nabla \cdot \left(\frac{\mathrm{B_c kb}}{\mu} (\nabla p - \rho^0 . \gamma_c . b . g \nabla z) \right) - q \qquad (07)$$

Depending on the fluid system, equation (07) can be solved as follows:

For incompressible fluids, the formation volume factor B is constant, thus $\frac{\partial}{\partial t}\left(\frac{\phi}{B}\right) = 0$.

This yields:

$$\nabla \cdot \left(\frac{\mathrm{B_c k}}{\mu B} \left(\nabla p - \frac{B^o \rho^o}{B} \gamma_c g \nabla z \right) \right) = \frac{q}{B} \qquad (08)$$

Implying that the pressure profile keeps the same over the domain regardless of time.

Unlike the case for incompressible fluids, the fluid properties are not constant for slightly compressible fluids. The following assumptions derived from Taylor series expansion are acceptable for slightly compressible fluids:

$$\rho = \rho^o e^{c_f (p - p^o)} \approx \rho^o \left[1 + c_f (p - p^o) \right] \qquad (09)$$

$$\frac{1}{B} = \frac{1}{B^o} e^{c_f (p - p^o)} \approx \frac{\left[1 + c_f (p - p^o) \right]}{B^o} \qquad (10)$$

$$\phi = \phi^o e^{c_R(p-p^o)} \approx \phi^o[1 + c_R(p - p^o)] \tag{11}$$

Where c_f is the fluid compressibility, c_R is the rock compressibility, ϕ^o is porosity at the reference pressure, p^o. Applying these equations to (03), while ignoring conversion constants gives:

$$\phi\frac{\partial\rho}{\partial t} + \rho\frac{\partial\phi}{\partial t} = \nabla\cdot\left(\frac{\rho}{\mu}\mathbf{k}(\nabla p - \rho g\nabla z)\right) - \tilde{q} \tag{12}$$

$$\left[\phi\frac{\partial\rho}{\partial p} + \rho\frac{\partial\phi}{\partial p}\right]\frac{\partial p}{\partial t} = \nabla\cdot\left(\frac{\rho}{\mu}\mathbf{k}(\nabla p - \rho g\nabla z)\right) - \tilde{q} \tag{13}$$

$$[\phi\rho c_f + \rho\phi^o c_R]\frac{\partial P}{\partial t} = \nabla\cdot\left(\frac{\rho}{\mu}\mathbf{k}(\nabla p - \rho g\nabla z)\right) - \tilde{q} \tag{14}$$

$$\rho\phi\left[c_f + \frac{\phi^o}{\phi}c_R\right]\frac{\partial P}{\partial t} = \nabla\cdot\left(\frac{\rho}{\mu}\mathbf{k}(\nabla p - \rho g\nabla z)\right) - \tilde{q} \tag{15}$$

$$c_t = \left[c_f + \frac{\phi^o}{\phi}c_R\right] \tag{16}$$

$$\rho\phi c_t\frac{\partial P}{\partial t} = \nabla\cdot\left(\frac{\rho}{\mu}\mathbf{k}(\nabla p - \rho g\nabla z)\right) - \tilde{q} \tag{17}$$

Defining the volume of each grid block as $V_i = \Delta X \text{ x } \Delta Y \text{ x } \Delta Z$, and multiplying equation (07) by V_i yields:

$$V_i\frac{\partial}{\partial t}(\phi b) = V_i\nabla\left(\frac{B_c kb}{\mu}(\nabla p - \rho^0\gamma_c bg\nabla z)\right) - Q\,, \tag{18}$$

$$where\ Q = qV_i$$

Discretization of the LHS of equation (18) can be achieved by implementing the forward difference scheme described in Ertekin et al.[23] as follows:

$$V_i \frac{\partial}{\partial t}(\phi b) = \frac{\mathrm{V_i}\left[(\phi b)^{(n+1)} - (\phi b)^n\right]}{\Delta t}$$

This can be expanded as follows:

$$V_i \frac{\partial}{\partial t}(\phi b) = \mathrm{V_i}\left[C_f b^0 \phi^{(n+1)} - b^n \phi^0 C_R\right] \frac{p^{n+1} - p^n}{\Delta t} = \mathrm{V_i}\left[C_R b^{n+1} \phi^0 - b^0 \phi^n C_f\right] \frac{p^{n+1} - p^n}{\Delta t} \tag{19}$$

Assuming an incompressible fluid system $\phi^0 = \phi^{n+1} = \phi^n$

$$\mathrm{V_i}(\phi b)\left(C_f + C_R\right)\frac{p^{n+1} - p^n}{\Delta t} = \mathrm{V_i}(\phi b).C_t\frac{p^{n+1} - p^n}{\Delta t} = \mathrm{V_i}C_i\frac{p^{n+1} - p^n}{\Delta t}, \tag{20}$$

$where\ C_i = C_t(\phi b)$

To analyze the right hand side (RHS), consider the definition of the following terms:

$$\gamma_t = \gamma_c \rho g b \qquad \& \qquad \lambda = B_c k \frac{b}{\mu}$$

Then the RHS of equation (18) can be discretized spatially as follows:

$$\mathrm{V_i}\nabla\left(\frac{\mathrm{B_c kb}}{\mu}(\nabla p-\rho^0\gamma_c bg\nabla z)\right)-Q=V_i\left[\frac{\partial}{\partial x}\left(\lambda\left(\frac{\partial}{\partial x}P-\gamma_t\frac{\partial}{\partial x}z\right)\right)+\frac{\partial}{\partial y}\left(\lambda\left(\frac{\partial}{\partial y}P-\gamma_t\frac{\partial}{\partial y}z\right)\right)+\frac{\partial}{\partial z}\left(\lambda\left(\frac{\partial}{\partial z}P-\gamma_t\frac{\partial}{\partial z}z\right)\right)\right] \tag{21}$$

Expanding each term in equation (21) and applying block centered discretization, while assuming average properties, λ(k, B and μ) between grids yields:

$$V_i\left[\frac{\partial}{\partial x}\left(\lambda\left(\frac{\partial}{\partial x}P-\gamma_t.\frac{\partial}{\partial x}z\right)\right)\right]=V_i\left[\frac{1}{\Delta x}\left(\lambda_{i+\frac{1}{2}}\left(\frac{\partial}{\partial x}P\right)_{i+\frac{1}{2}}-\lambda_{i+\frac{1}{2}}(\gamma_t)_{i+\frac{1}{2}}\left(\frac{\partial}{\partial z}z\right)_{i+\frac{1}{2}}+\lambda_{i-\frac{1}{2}}.(\gamma_t)_{i-\frac{1}{2}}\left(\frac{\partial}{\partial z}z\right)_{i-\frac{1}{2}}-\lambda_{i-\frac{1}{2}}\left(\frac{\partial}{\partial x}P\right)_{i-\frac{1}{2}}\right)\right] \tag{22}$$

$$=V_i\frac{1}{\Delta x}\left[\lambda_{i+\frac{1}{2}}\frac{1}{\Delta x}(P_{1+1}-P_i)-\lambda_{i-\frac{1}{2}}\frac{1}{\Delta x}.(P_i-P_{i-1})-\lambda_{i+\frac{1}{2}}(\gamma_t)_{1+\frac{1}{2}}\frac{1}{\Delta x}(z_{i+1}-z_i)+\lambda_{i-\frac{1}{2}}(\gamma_t)_{i-\frac{1}{2}}\frac{1}{\Delta x}(z_i-z_{i-1})\right] \tag{23}$$

Factorizing $\frac{1}{\Delta x}$ and substituting $V_i = \Delta X \text{ x } \Delta Y \text{ x } \Delta Z$ yields:

$$=\frac{\Delta y\Delta z}{\Delta x}\left[\lambda_{i+\frac{1}{2}}(P_{1+1}-P_i)-\lambda_{i-\frac{1}{2}}(P_i-P_{i-1})-\lambda_{1+\frac{1}{2}}(\gamma_t)_{1+\frac{1}{2}}(z_{i+1}-z_i)+\lambda_{i-\frac{1}{2}}.(\gamma_t)_{i-\frac{1}{2}}(z_i-z_{i-1})\right] \tag{24}$$

The same logic can be applied for the ‘j’ and ‘k’ directions to arrive at the full 3D equation below;

$$V_i\left[\frac{\partial}{\partial x}\left(\lambda * \left(\frac{\partial}{\partial x}P - \gamma_t.\frac{\partial}{\partial x}z\right)\right)\right] =$$

$$\frac{\Delta y \Delta z}{\Delta x}\left[\lambda_{i+\frac{1}{2},j,k}.(P_{1+1,j,k} - P_{i,j,k}) - \lambda_{i-\frac{1}{2},j,k}.(P_{i,j,k} - P_{i-1,j,k}) - \lambda_{i+\frac{1}{2},j,k}.(\gamma_t)_{i+\frac{1}{2},j,k}.(z_{i+1,j,k} - z_{i,j,k}) + \lambda_{1-\frac{1}{2},j,k}.(\gamma_t)_{1-\frac{1}{2},j,k}.(z_{i,j,k} - z_{i-1,j,k})\right] \quad +$$

$$\frac{\Delta x \Delta z}{\Delta y}\left[\lambda_{i,j+\frac{1}{2},k}.(P_{1,j+1,k} - P_{i,j,k}) - \lambda_{i,j-\frac{1}{2},k}.(P_{i,j,k} - P_{i,j-1,k}) - \lambda_{i,j+\frac{1}{2},k}.(\gamma_t)_{i,j+\frac{1}{2},k}.(z_{i,j+1,k} - z_{i,j,k}) + \lambda_{i,j-\frac{1}{2},k}.(\gamma_t)_{i,j-\frac{1}{2},k}.(z_{i,j,k} - z_{i,j-1,k})\right] +$$

$$\frac{\Delta x \Delta y}{\Delta z}\left[\lambda_{i,j,k+\frac{1}{2}}.(P_{1,j,j+1} - P_{i,j,k}) - \lambda_{i,j,k-\frac{1}{2}}.(P_{i,j,k} - P_{i,j,k-1}) - \lambda_{i,j,k+\frac{1}{2}}.(\gamma_t)_{i,j,k+\frac{1}{2}}.(z_{i,j,k+1} - z_{i,j,k}) + \lambda_{i,j,k-\frac{1}{2}}.(\gamma_t)_{i,j,k-\frac{1}{2}}.(z_{i,j,k} - z_{i,j,k-1})\right] \tag{25}$$

Where $A_x = \Delta Y \text{ x } \Delta Z, A_y = \Delta X \text{ x } \Delta Z \text{ and } A_z = \Delta X \text{ x } \Delta Y$

To write the equation (22) in terms of transmissibility the following transmissibility terms for block centered grids are defined:

$$T_{i\pm\frac{1}{2},j,k} = \lambda_{i\pm\frac{1}{2},j,k}\frac{Ax}{\Delta x} = B_c.\frac{1}{(B.\mu)_{i+\frac{1}{2}}} * \frac{k_{i\pm\frac{1}{2}}.A_x}{\Delta x} \tag{26}$$

Where $T_f = Flow\ transmissibilty = \frac{1}{(B.\mu)_{i+\frac{1}{2}}}, and$

$T_g = geometric\ transmissibilty = \frac{k_{i\pm\frac{1}{2}}.A_x}{\Delta x}$, and

$$T_g = 2.B_c\left[\frac{(k_x.A_x)_i * (k_x.A_x)_{i+1}}{(k_x.A_x)_i \Delta x_{i+1} * (k_x.A_x)_{i+1} \Delta x_i}\right]$$

$$for\ non\,uniform\ grid\ systems$$

$k_{i\pm\frac{1}{2}}$ is the permeability at the grid interphase defined by taking the harmonic average of the adjacent grid block center permeabilities as follows;

$$k_{i+\frac{1}{2}} = \left(\frac{1}{k_i} + \frac{1}{k_{i\pm1}}\right)$$

The properties $(\mu)_{i+\frac{1}{2}}$ and $(B)_{i+\frac{1}{2}}$ can be computed via one of two methods;

a. Taking average properties

$$\mu_{i+\frac{1}{2}} = \frac{\mu(P_i) + \mu\left(P_{i\pm\frac{1}{2}}\right)}{2}\ and\ B_{i+\frac{1}{2}} = \frac{B(P_i) + B\left(P_{i\pm\frac{1}{2}}\right)}{2}$$

b. Computing the properties at an average pressure

Define an average pressure $P_{i+\frac{1}{2}} = \frac{P_i + P_{i\pm\frac{1}{2}}}{2}$,

then

$$\mu_{i+\frac{1}{2}} = \mu\left(P_{i\pm\frac{1}{2}}\right), and\ B_{i+\frac{1}{2}} = B\left(P_{i\pm\frac{1}{2}}\right)$$

The transmissibility sum term is defined as:

$$\sum T_{i,j,k} = T_{i\pm\frac{1}{2},j,k} + T_{i,j\pm\frac{1}{2},k} + T_{i,j,k\pm\frac{1}{2}} = T_{i\pm\frac{1}{2}} + T_{j\pm\frac{1}{2}} + T_{k\pm\frac{1}{2}} \tag{27}$$

Now the gravity terms for x, y, and z directions can be lumped together as follows:

$$G_x = \frac{A_x}{\Delta x}\left[\lambda_{i+\frac{1}{2},j,k}(\gamma_t)_{i+\frac{1}{2},j,k}\left(z_{i+1,j,k} - z_{i,j,k}\right) - \lambda_{i-\frac{1}{2},j,k}(\gamma_t)_{i-\frac{1}{2},j,k}\left(z_{i,j,k} - z_{i-1,j,k}\right)\right] \tag{28}$$

$$G_y = \frac{A_y}{\Delta y}\left[\lambda_{i,j+\frac{1}{2},k}(\gamma_t)_{i,j+\frac{1}{2},k}\left(z_{i,j+1,k} - z_{i,j,k}\right) - \lambda_{i,j-\frac{1}{2},k}(\gamma_t)_{i,j-\frac{1}{2},k}\left(z_{i,j,k} - z_{i,j-1,k}\right)\right] \tag{29}$$

$$G_z = \frac{A_z}{\Delta z}\left[\lambda_{i,j,k+\frac{1}{2}}(\gamma_t)_{i,j,k+\frac{1}{2}}\left(z_{i,j,k+1} - z_{i,j,k}\right) - \lambda_{i,j,k-\frac{1}{2}}(\gamma_t)_{i,j,k-\frac{1}{2}}\left(z_{i,j,k} - z_{i,j,k-1}\right)\right] \tag{30}$$

$$G_{i,j,k} = G_i + G_j + G_z \qquad \text{Where } \gamma_t = \gamma_c \rho g b$$

Restating equation (18):

$$V_i \frac{\partial}{\partial t}(\phi b) = \mathrm{V_i}\nabla\left(\frac{\mathrm{B_c kb}}{\mu}(\nabla p - \rho^0 \gamma_c b g \nabla z)\right) - Q \text{ ,} where\ Q = qV_i$$

Now substituting the discretized schemes into the above equation yields:

$$\mathrm{V_i}.C_i * \frac{p^{n+1} - p^n}{\Delta t} + G_{i,j,k} + Q = \sum T_{i,j,k} P_{i,j,k} + T_{i+\frac{1}{2},j,k}.P_{i+\frac{1}{2},j,k} + T_{i-\frac{1}{2},j,k}.P_{i-\frac{1}{2},j,k} + T_{i,j+\frac{1}{2},k}.P_{i,j-\frac{1}{2},k} +$$
$$T_{i,j,k+\frac{1}{2}}.P_{i,j,k+\frac{1}{2}} + T_{i,j,k-\frac{1}{2}}.P_{i,j,k-\frac{1}{2}}$$

$$\mathrm{V_i}.C_i \frac{p^{n+1} - p^n}{\Delta t} + G_{i,j,k} + Q = \sum T_{i,j,k} P_{i,j,k} + T_{i+\frac{1}{2}} P_{i+\frac{1}{2}} + T_{i-\frac{1}{2}} P_{i-\frac{1}{2}} + T_{,j+\frac{1}{2}} P_{j-\frac{1}{2}} +$$
$$T_{k+\frac{1}{2}} P_{k+\frac{1}{2}} + T_{k-\frac{1}{2}} P_{k-\frac{1}{2}} \tag{31}$$

Rewriting in general terms yields the following linear system:

$$T_p = B\frac{dp}{dt} + G_{i,j,k} + Q \quad (32)$$

$$T_p = \sum T_{i,j,k}P_{i,j,k} + T_{i+\frac{1}{2}}P_{i+\frac{1}{2}} + T_{i-\frac{1}{2}}P_{i-\frac{1}{2}} + T_{,j+\frac{1}{2}}P_{j-\frac{1}{2}} + T_{k+\frac{1}{2}}P_{k+\frac{1}{2}} + T_{k-\frac{1}{2}}P_{k-\frac{1}{2}}$$

$$\mathrm{B} = \mathrm{V_i}.C_i$$

Tp = Heptadiagonal transmissibility NxN matrix since for any point, there are 7 unknown pressures

N = I x *j* x *k*
Tp is multiplied by an Nx1 pressure matrix. The order sequence is such that i elements are swept through first
(i = 1,2,…N), then j elements, and finally k elements. B is an NxN matrix, and G and Q are Nx1 matrices.

The Peaceman well model is used to calculate the flow rates. The equations implemented are defined as follows:

$$r_{oxy} = (\frac{1}{2} * e^{-\pi}\left(\Delta\mathrm{X}^2\left(\frac{KY}{KX}\right)^{0.5} + \Delta\mathrm{Y}^2\left(\frac{KY}{KX}\right)^{0.5}\right)^{\frac{1}{2}} = 0.147 * \left(\Delta\mathrm{X}^2\left(\frac{KY}{KX}\right)^{0.5} + \Delta\mathrm{Y}^2\left(\frac{KY}{KX}\right)^{0.5}\right)^{\frac{1}{2}} \quad (33)$$

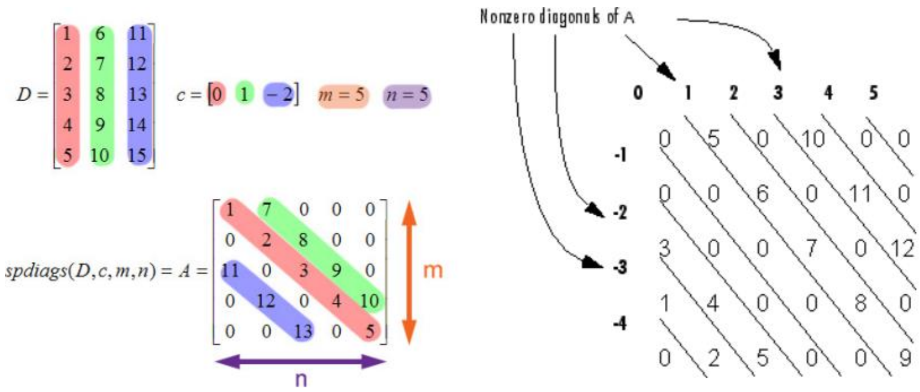
The well index (WI) is defined as:

$$WI = \frac{2\pi * \Delta\mathrm{Z} * \sqrt{\mathrm{KX} * \mathrm{KY}}}{\mu\mathrm{In}\left(\frac{\mathrm{roxy}}{\mathrm{rw}}\right) + s} \quad (34)$$

$$Q = \frac{WI * (P(t) - Pwf)}{B(P) * \mu(P)} \quad (35)$$

Where P changes with time, and B and density change with pressure.

The following numbering sequence is used to construct the sparse transmissibility matrix



In order to exhaust every gridblock the following sparsing index is used in the 3D matrix

Diagindx = [-i x j, -i, -1, 0, 1, i, i x j], where

i = number of gridblocks in x-direction
j = number of gridblocks in y-direction
k = number of gridblocks in z-direction

The matrix system of equations can be solved by applying either the implicit (backward in time) scheme or the lagging coefficient scheme.

- Implementing the **Implicit (Backward in time)** Scheme

$$\left(\frac{\partial P}{\partial t}\right)_i^{n+1} = \frac{P^{n+1} - P^n}{\Delta t} \ldots\ldots compute\ at\ n+1$$

$$T^{n+1}P^{n+1} = B^{n+1}\left(\frac{P^{n+1} - P^n}{\Delta t}\right) + G_{i,j,k}^{n+1} + Q^{n+1}$$

$$(T^{n+1} - \frac{1}{\Delta t}B^{n+1})P^{n+1} = -\frac{1}{\Delta t}B^{n+1}P^n + G_{i,j,k}^{n+1} + Q^{n+1}$$

$$(T^{n+1} - \frac{1}{\Delta t}B^{n+1})P^{n+1} + \frac{1}{\Delta t}B^{n+1}P^n - G_{i,j,k}^{n+1} - Q^{n+1} = 0$$

$$(T + B)\backslash(B \times P + G + Q) = P^{n+1}$$

Intelligent Well Technology provide the capability to control the flow rates (Q) and downhole pressures (P).

3.2.2 Reservoir Simulation Benchmarks

The UNISIM-I-D benchmark reservoir model was used for the simulation case studies. This reservoir model is created and managed by the UNISIM group (a collaboration between UNICAMP and CEPETRO) (Gaspar, Maschio, Santos, Avansi, Filho and Schiozer, 2013). The UNISIM-I-D model was chosen over other benchmark reservoir models like SPE 10, Brugge, Norne and PUNQ because the reservoir geometry and properties best fit the intended study conditions.

The simulation was modified using Petrel and ran using the Schlumberger Eclipse 100 simulator. The main benefits highlighted by the simulations runs performed are the water breakthrough management and production optimization capabilities obtained by adopting Smart Sell Technology. The value proposition of the technology is measured using three key parameters; **reduced water production, economic oil production rates (favorable NPV) and rig time saving.**

More details on the simulators and the reservoir description will be presented in the sections below.

3.3 UNISIM-I-D Benchmark Model

The UNISIM-I-D model is a carbonate reservoir based on the Namorado field located offshore in the presalt Campos Basin in Brazil. Discovered in 1975 by the 1-RJS-19 wildcat in 166m water. The heterogeneous properties of the model makes it an ideal candidate for simulating intelligent well operations.

The UNISIM-I-D model is described on a regular Cartesian grid with a total of 93,960 grid cells. The reservoir model has global dimensions of 8061 x 5772 x 995 (meters) or

26447 x 18937 x 3264 (feet), and a fine scale grid cell size (*NI* x *NJ* x *NZ*) of 81 x 58 x 20. There are 20 producing zones (layers) with an average reservoir permeability in the x, y, and z directions (Kx, Ky, and Kz) of 125.9 md, 125.9 md, and 48.96 md respectively.

The reservoir is divided into two regions with a water oil contact (WOC) of 3100m in region 1 and 3174m in region 2. The average reservoir pressure is 327.1 bars with and initial water saturation of 0.44 and an initial oil saturation of 0.56.

There are 4 production wells namely; *NA1A*, *NA2*, *NA3D* and *RJS19*, and 3 injectors; *INJ003*, *INJ005 and INJ006*. The producers are operated under a maximum liquid rate constraints of 3000 m^3/day while the injectors provide pressure support for oil displacement and are operated under a 343.2 bar bottom hole pressure (BHP) constraint. Production begins on June 1st 2013 and ends on May 28th 2028 (15 years). A detailed reservoir description is provided in the table below.

Table 1: UNISIM reservoir description

Field property	Value
Global Dimensions	
Model length (DX)	8061 m
Model width (DY)	5772 m
Model height (DZ)	995 m (-3861.39 m to -2866.56m)
Grid cells (*NI* x *NJ* x *NZ*)	81 x 58 x 20
Total number of grid cells	93,960
Average Porosity	0.1295 (0 to 0.3)
Average Net To Gross NTG	0.7558
Average PERMX (md)	125.9 (1 to 1190)
Average PERMY (md)	125.9 (1 to 1190)
Average PERMZ (md)	48.96 (1 to 1190)
Average Initial Reservoir pressure (bars)	327.1 (250 to 349.9)
Initial Field Oil in Place (standard m^3)	1.2999E08 (1.09E9 bbl)
Initial Field gas in Place (standard m^3)	1.474778E10 (5.208E9MCF)
Average Initial Water Saturation (06/02/2013)	0.44
Average Initial Oil Saturation (06/02/2013)	0.56
Water oil contact – WOC (m)	Region 1 = 3100, Region 2 = 3174
Gas oil contact – GOC (m)	Region 1 = 1000, Region 2 = 1000

Figure 17 shows the oil saturation profile of the reservoir after 15 years of production. The varied saturation profile clearly highlights the heterogeneity of the reservoir. The saturation ranges from 0.0 (purple) to 0.9 (yellow).

Figure 18 to 19 show the permeability (PERM X) and porosity profiles respectively. These highlight the heterogeneity of the UNISIM-I-D reservoir.

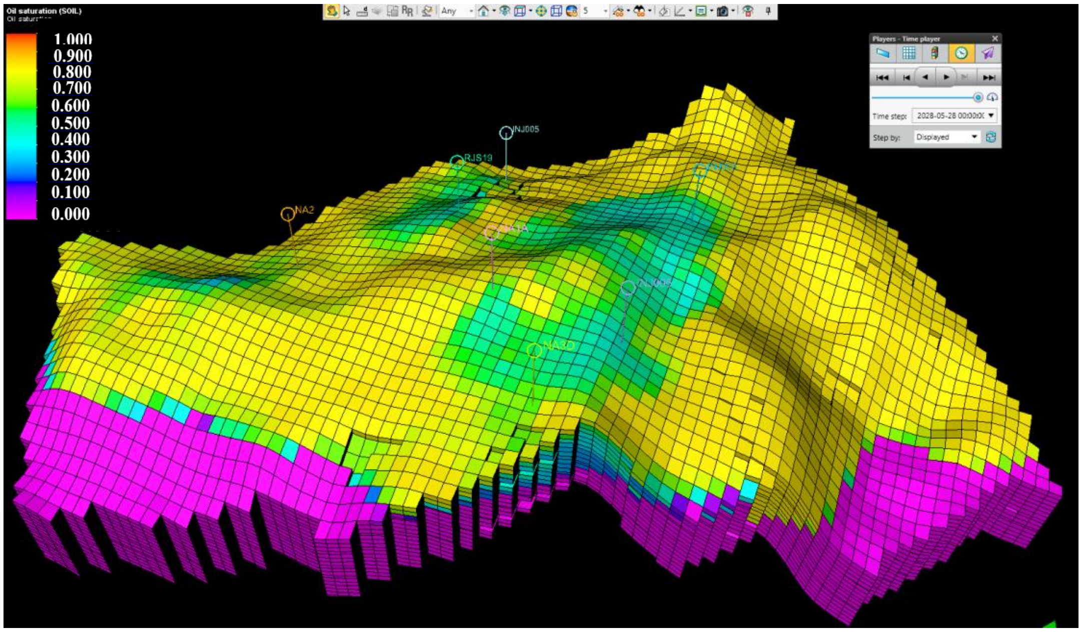


Figure 17: Oil saturation profile on 05/28/2028

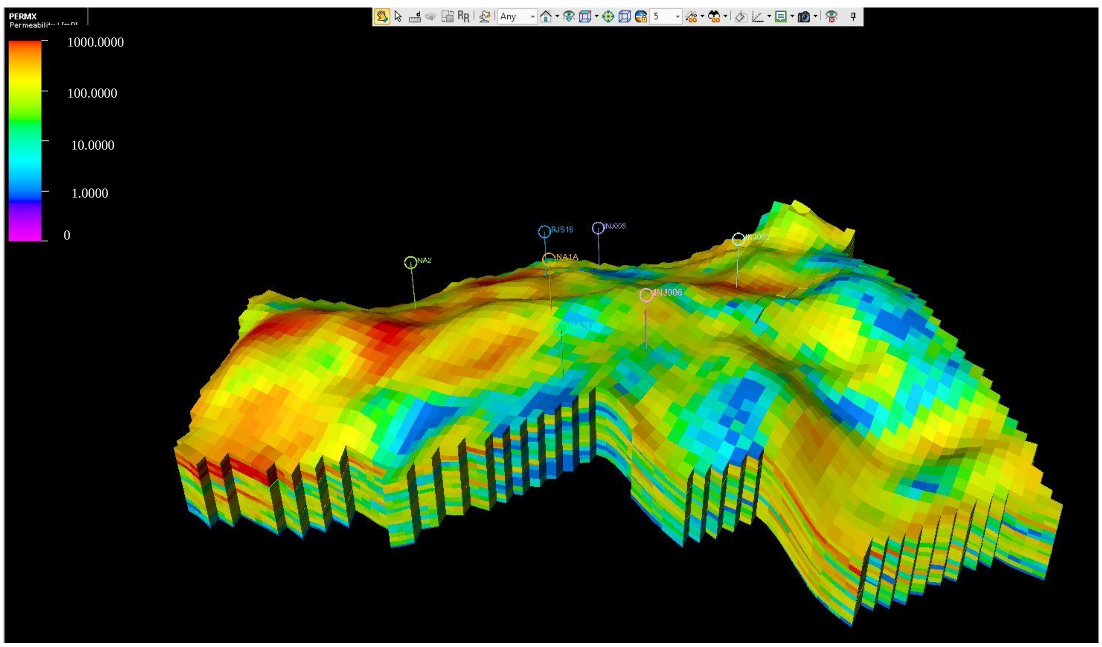


Figure 18: Average permeability (PERM X) profile. The permeability varies from 1 (blue) to 1190 (red).

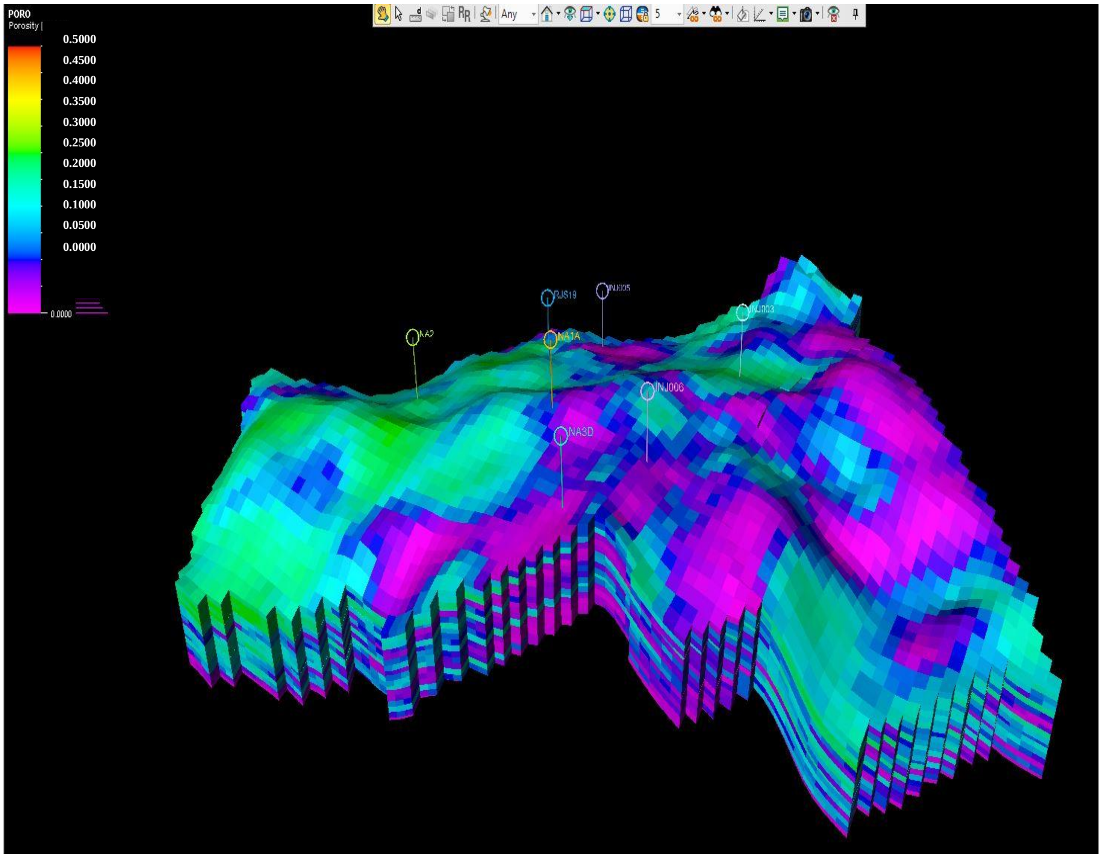


Figure 19: Average reservoir porosity profile**.** Porosity varies from 0 (purple) to 0.3 (green).

3.3.1 Simulation with Commercial Reservoir Simulators

A commercial simulator (Eclipse 100) was used for all the simulation runs in this study. As discussed in *section 3.2.1*, the multiphase Blackoil simulator applies finite difference (fully implicit) techniques for numerical computation on the reservoir model. Unlike compositional simulators (for example Eclipse 300, and CMG STARS/GEMS) that incorporates changes in phase compositions, black oil simulators assume that oil and gas phases can be represented as independent components whose properties can only change with temperature and pressure. The composition does not change through time.

The simulation workflow is a batch process that requires an input data file. This is a text file containing keywords that fully describe the model (reservoir description, fluid and rock properties, initial conditions, wells, flow rates etc.). The data file is divided into sections each containing keywords with a particular purpose. The keywords of reservoir properties like permeability and porosity, as well as other simulator commands are simulator specific and differ for different commercial simulators. The various sections can be created in separate text files and compiled in the main input data file using the INCLUDE keyword. Table 2 uses the Eclipse simulator to describe the different sections in a commercial simulator input data file.

Table 2*:* Input data file sections in Eclipse simulator describing structure of input files used in commercial simulators. Adapted from (Schlumberger Eclipse reference manual, 2014)

RUNSPEC	Describes general model characteristics. Includes keywords to define phases (Oil, gas, water), number of grid blocks in I, J, and K (DIMENS), simulation start time, well dimensions, fault dimensions etc.
GRID	Defines the geometry of the simulation grid and assigns basic rock properties (porosity, absolute permeability and net-to-gross ratios) to each grid cell. Grid properties are used to calculate pore volumes, midpoint depths and inter-block transmissibilities.
EDIT (Optional)	Enables modification of the GRID section data (pore volumes, block center depths, transmissibility, diffusivities etc.)
PROPS	Contains pressure and saturation dependent properties of the reservoir fluids and rocks (PVT and SCAL properties).
REGIONS (Optional)	Subdivides the reservoir into regions. Saturation functions (relative permeability & capillary pressure), PVT properties (FVF, fluid densities, and viscosities), fluids in place and other properties are calculated for computational grids in each region.
SOLUTION	Initialization of the model. Initial pressures, saturations, and compositions are defined.
SUMMARY (Optional)	Specifies variables that should be written in summary files. Output for requested variables is written each time step and can be used for line plots
SCHEDULE	Specifies the operations to be simulated (well controls and constraints, rate data, flow correlations, time step and termination).

3.4 Methodology/Test Cases

Four simulation cases were ran by modifying the data input file for each case. A baseline case was first ran where all the production wells were operated for 15 years without any water production control. The next case that was simulate highlighted traditional water management methods with limited water control capability. Finally, two intelligent modifications were simulated to demonstrate different strategies of water management. Each case is described in more details later in this report.

The results of the simulated cases were analyzed against the decision drivers chosen for this project namely; water production, economic oil production rates (favorable NPV) and rig time saving. An NPV is then performed for each case and sensitivity analysis is done to understand the effect of variables on the project NPV.

Finally, a work flow process is proposed which can be applied to any project with different decision drivers.

3.4.1 Base Case Scenario

A base case simulation model run was performed at initial conditions before any intelligent control was applied. This model provides a baseline against which to measure the marginal improvements gained by adopting intelligent well control. The control mode and constraints for all wells were set under the SCHEDULE section with the producers operating under a maximum liquid production rate of 3000 m^3 (25,159 barrels) and minimum BHP of 35.3 bars (512 psi). The injectors were set to inject water at a maximum BHP of 343.2bars (4978 psi) and all the wells produced continuously for 15 years.

3.4.2 Conventional Water Management Operation

The next simulation run was performed to model conventional operation methods to manage water breakthrough without intelligent technology. In this case, the wells were operated under the same constraints as the base case model. However in addition, the producers were set to a maximum water cut of 70%. Once this water cut threshold is reached for a particular producer, the well is shut-in and assumed uneconomic. Similar to the base line case, this mode of operation provides a reference against which to measure the gains of adopting Smart Well Technology.

3.4.3 Intelligent Well Modifications

Two modes of intelligent control were simulated namely: ON-OFF control and Feedback ON-OFF control. Unlike the baseline and conventional water management case, the intelligent modifications employ downhole monitoring and control of each production layer. The goal is to optimize production by accelerating and maximizing oil production, while minimizing water production. Down hole control was simulated by installing the Inflow Control Devices (ICD) discussed in chapter 2 around the tubing. The device achieves flow control by imposing an additional pressure drop between the sandface and the tubing. The device diverts fluid inflowing from the formation through a sand screen and then into a spiral before it enters the tubing. Figure 20 shows a sample well architecture with several perforation zones and downhole spiral ICDs installations in each zone.

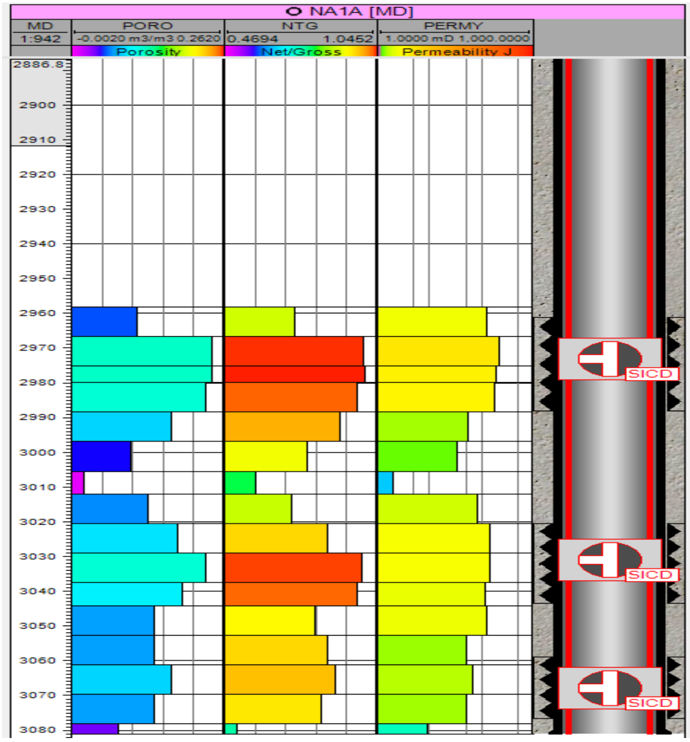


Figure 20: Graphic showing spiral ICD installation

The pressure drop across the device is calibrated to account for the varying density and viscosity of reservoir fluid flowing through the device. The pressure drop is defined in *equation (36)* and is proportional to the second power of the flow rate through the ICD (Schlumberger, 2009).

$$\delta P = \left(\frac{\rho_{cal}}{\rho_{mix}} \cdot \frac{\mu_{mix}}{\mu_{cal}}\right)^{\frac{1}{4}} \cdot \frac{\rho_{mix}}{\rho_{cal}} \cdot K \cdot q^2 \tag{36}$$

where

$\rho_{cal} =$ the density of the fluid used to calibrate the ICD

$\rho_{mix} =$ the density of the fluid mixture in the segment at local conditions

$\mu_{cal} =$ the viscosity of the fluid used to calibrate the ICD

$\mu_{mix} =$ the viscosity of the fluid mixture in the segment at local conditions

$K = \frac{^{a}SICD}{\rho_{cal}}$ the base strength of the ICD, with dimension of inverse area squared

$^{a}SICD =$ strength of the SICD

$q =$ the volume flow rate of the fluid mixture through the ICD at local conditions

$q =$ flow rate through ICD $*$ device length dependent scaling factor

$\rho_{mix} = \alpha_o.\rho_o + \alpha_w.\rho_w + \alpha_g.\rho_g$

$\alpha_{o,w,g} =$ volume fraction of the free oil, water, gas phases at local conditions

$\rho_{o,w,g} =$ density of the oil, water, gas phases at local conditions

$\mu_{mix} = (\alpha_o + \alpha_w) \,.\, \mu_{emul} + \alpha_g + \mu_g$

$\mu_g =$ gas viscosity at local conditions

$\mu_{emul} =$ viscosity of the oil $-$ water emulsion at local conditions

The emulsion viscosity is a function of local phase volume fractions in the well segments. The two functional forms are low water in liquid fractions, μ_{wio} (continuous phase is oil) and high water in liquid fractions, μ_{oiw} (continuous phase is water) (Schlumberger, 2009) and are defined by equation (37) and (38).

$$\mu_{wio} = \mu_o \cdot \left(\frac{1}{1 - \left(\frac{0.8415}{0.7480} \cdot \alpha_{wl} \right)} \right)^{2.5} \tag{37}$$

$$\mu_{oiw} = \mu_w \cdot \left(\frac{1}{1 - \left(\frac{0.6019}{0.6410} \cdot \alpha_{ol} \right)} \right)^{2.5} \tag{38}$$

$\mu_o =$ oil viscosity at local conditions

$\mu_w =$ water viscosity at local conditions

$\alpha_{wl} = \dfrac{\alpha_w}{(\alpha_w + \alpha_o)}$ local water in liquid fraction

$\alpha_{ol} = \dfrac{\alpha_o}{(\alpha_w + \alpha_o)}$ local oil in liquid fraction

3.4.3.1 ON-OFF Control

The ON-OFF operation mode was simulated by constantly monitoring all the producing layers against a set upper limit water cut threshold. The water cut threshold was set to 50% and production constraints imposed such that once the water cut of a producing layer exceeds the threshold, that layer is completely shut. This two mode operation simulates a simple On/off ICV discussed in chapter 2. The intelligent modification for this operation mode was performed using the CECON keyword. The CECON keyword monitors production at each grid block with a connection to the wellbore against the set proxy model (watercut in this case) (Schlumberger reference manual, 2014). Once proxy model condition is violated, the set action is applied. The possible actions include completely shutting off the connection or setting it to auto mode, where the connection is continuously checked every time step against the set threshold condition.

3.4.3.2 Feedback ON-OFF Control

The Feedback ON-OFF control mode is a slight modification to the ON-OFF control mode described above. In this mode, the overall well water cut was continuously monitored during production against a specified upper limit water cut threshold. The water cut threshold was set to 50% and production constraints imposed such that once the well water cut threshold is violated, the most offending producing layer in that well is completely shut. Just like the ON-OFF control case, this operation mode simulates a simple On/Off ICV with a slight modification to the control strategy. The intelligent modification for this operation mode was performed using the WECON keyword. Unlike the CECON keyword that monitors each downhole grid block connection, the WECON keyword checks the entire well production against the set proxy model condition (Schlumberger reference manual, 2014). Once proxy model condition is violated on the well, the simulator checks each downhole producing layer connection and the desired action is applied on the most problematic layer connection. Similar to the CECON keyword, the possible actions include completely shutting off the connection or setting it to auto mode, where the connection is continuously checked every time step against the set threshold condition.

3.4.3.3 Variable Control

The variable control mode simulates a variable control ICV. This provides the operator the capability of setting the ICV valve at multiple positions between the fully open (ON) and fully closed extremes (OFF) in order to choke the flow from producing zones. This is a more sophisticated mode of fluid control and for simplicity was not simulated in this work. However, Eclipse offers various options for accommodating such strategies based on user requirements.

The WCUTBACK and WSEGSICD keywords should be explored for more information on this mode of control. The WCUTBACK keyword monitors each downhole producing layer against a set watercut threshold. Once this threshold is violated, the user can choke the flow from the problematic layer. The user has the option to choke the flow as a factor of the total liquid production rate, the total water production rate or the total oil production rate (Schlumberger reference manual, 2014).

The WSEGICD keyword allows the user to manually design a downhole ICD as described in *section 3.6*. The user specifies the perforation zone across which the ICD is installed, the ICD strength and the ICD length, which determines the pressure drop imposed by the ICD across the perforations (Schlumberger reference manual, 2014).

3.5 Sensitivity Analysis

Sensitivity analysis on variable reservoir parameters is important in any reservoir simulation to understand the best and worst case scenario. Understanding price sensitivity before making the decision on whether or not to adopt intelligent technology in a field is critically important in today's environment of volatile oil prices.

Traditional approaches to sensitivity analysis can be implemented by simple perturbation of the variable parameters one at a time, followed by running the new model and observing the change in reservoir response with the change in the parameter. A tornado plot can be generated for all the variable parameters to observe the most sensitive parameters. Impact of parameters like labor, cost of equipment/raw materials, well dimensions, crude price have a direct impact on the return of investment and should be properly analyzed before implementing a project.

For this study, a simple sensitivity study was performed to understand the economic feasibility of Smart well technology on the UNISIM-I reservoir model. The study was simplified by narrowing down the sensitivity study around two parameters: Oil price and water cut. The results of this study will be presented for each simulation case later in the results section of this report.

3.6 Economic Evaluation

A modified NPV model was adopted to evaluate the economic value of adopting Smart Well Technology to the UNISIM-I reservoir model. A fixed discount rate of 10% was used in the conventional NPV formula below.

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_o \tag{39}$$

Where

$C_t = net\ cash\ inflow\ during\ period\ =\ Revenue - (OPEX + Royalty + Tax)$

$Revenue\ (\$) =\ Oil\ price\ \left(\frac{\$}{bbl}\right) * Cumulative\ oil\ (bbl) - water\ disposal\ cost\ \left(\frac{\$}{bbl}\right) *$

$Cumulative\ water\ (bbl)$

$C_o = total\ upfront\ investment\ costs$ (CAPEX)

$r = discount\ rate$

$t = number\ of\ time\ periods\ (t = 1\ to\ T)$

The capital expense (C_o) for the project include upfront drilling and completion cost. A default drilling cost of $10 MM was assumed for each well. Completion cost was assumed to be $2 MM per well and this value was scaled up by a factor of 1.3 for intelligent completions.

Operating expenses (OPEX) are necessary for the daily field operations and can be either fixed or variable. A default value of $20,000 per well was assumed for fixed OPEX in the NPV analysis while variable OPEX like water treatment was calculated assuming

\$1.5 per barrel of water produced. This along with royalties and taxes feed into the C_t term in the NPV equation. A fixed royalty of 10% (charged on gross revenue) and a tax rate of 30% (on net earnings) was assumed.

Several studies have been performed to understand the economic impact of smart well technology. Conventional analysis have mostly utilized the traditional NPV equation describe in *equation 39*. Sakowski et al analyzed the impact of smart well systems on total economics of field developments using this method (Sakowski, Anderson, and Furui, 2005). Addiego-Guevara et al performed a similar economic study using the conventional NPV method in their work on the insurance value of intelligent well technology (Addiego-Guevara, Jackson, and Giddins, 2008).

Although the traditional method NPV analysis incorporates the key economic parameters, it fails to capture some of the intrinsic value provided by smart well completions. As discussed in *section 2.6*, one of the possible benefits of Smart Well technology is accelerated production. One of the goals of this thesis study was to optimize the conventional NPV analysis by proposing a technique that captures the value derived through accelerated production. To achieve this goal, the conventional NPV equation (*equation 39*) was modified and a new term, Value of Time Savings (VTS) was introduced.

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_o + VTS \tag{40}$$

The Value of Time Savings term (VTS) is simply defined as a cumulative sum of operating expenses and other expenses that are saved through the adoption of smart well technology, which will otherwise be incurred as cost if the field was produced using conventional techniques. Daily operations costs also known as lifting costs include fixed costs like labor and transportation costs, as well as variable costs like facilities costs, separation costs, and other unforeseen costs. By accelerating production, rig time is saved and daily operation costs are minimized or completely eliminated. This cost savings is captured in the VTS term in the proposed NPV model.

For simplicity, only operating expenses were captured in the Value of Time Savings term although more complex analysis could be performed to consider other factors, depending on the desired level of detail. The method used in this study was a simplistic method where by a constant added value of $20,000 was gained per day saved in production time. However, a more realistic model will need to capture saved costs and discount these values throughout the period of time saved. The risk associated by implementing intelligent controls, the opportunity costs and the risks associated with alternate investments should also be captured. Pedersen et al. proposed a risk model for alternative investments (Pedersen, Page and He, 2014).

A summary of the field economic parameters showing the costing strategy is presented in table 3.

Table 3: Field economics

PARAMETER	***UNIT PER WELL***	***FIELD TOTAL****
DRILLING COST ($)	10 MM	40 MM
COMPLETION COST ($)	2 MM	8 MM
TOTAL FIXED CAPEX ($)	12 MM	48 MM
COST OF INTELLIGENT COMPLETION ($)	0.3*Completion cost = 600,000	2.4 MM
COST OF DOWNHOLE SENSORS	3 MM	12 MM
TOTAL COST OF SMART WELL ($)	15.6 MM	62.4 MM
FIXED OPEX ($)	20,000	80,000
OIL PRICE ($)	50	
ROYALTY (%)	10	
DISCOUNT RATE (%)	10	

*Injector wells were not included in the field total calculations as they were strictly implemented for water drive. However these cost can be easily added if required and will not impact the results as the injectors in this study are not equipped with ICDs and will represent a constant fixed cost across all 4 simulated scenario

Figure 21 is a chart of the proposed workflow process for choosing and adopting smart well systems on a project.

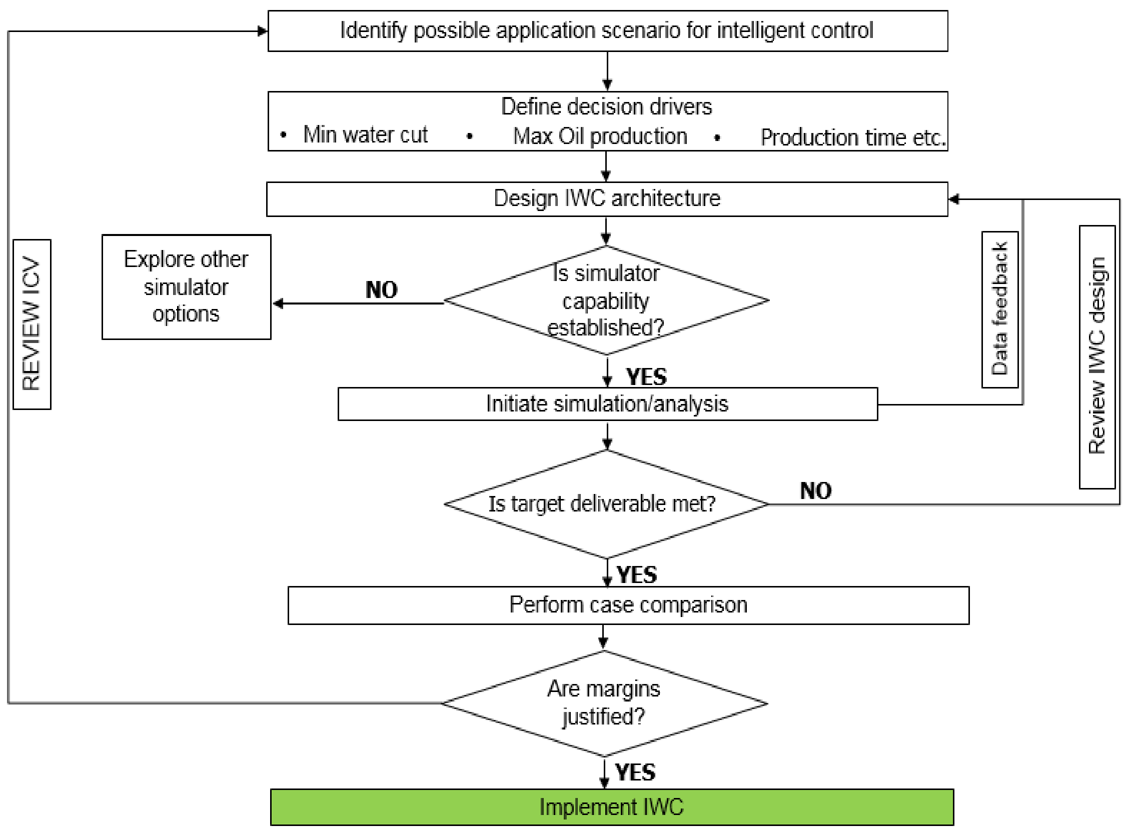


Figure 21: Work flow process used to select smart well technology

The workflow begins with the identification of potential applications for Intelligent Well Technology. This could be a new asset, a mature asset, onshore or offshore projects, or any other potential application. Once the potential application is identified, the decision drivers need to be defined. Decision drivers refer to the benchmark factors through which the benefits of intelligent control are quantified. Decision drivers include objective functions like Minimizing watercut, increasing oil production by a defined threshold, or maximizing NPV against alternative investments. It should be noted that the decision drivers are neither mutually exclusive nor constant. NPV for example is a function of water production as well as oil production. The decision drivers will also change from project to project and will vary depending on the operator.

Once the decision drivers are established, the ICV architecture is designed. The design of ICV is discussed in section 3.4.3.

The next step is to identify a simulator that is applicable to the simulation task and has the capability to offer downhole monitoring and control. Several simulators should be explored and a balance between cost and efficiency should be sought. The simulation process is then initiated and the analysis of the results is performed. Each decision driver is checked to see if the target deliverables are met. If the target deliverables are not met, the ICV design should be reassessed. During the simulation process, data is continuously fed back into the design process to improve the reservoir model and better characterize the reservoir.

If the target deliverables are met, the must be justifiable to proceed. Justification for a target deliverable will depends on the personnel performing the analysis as well as the benchmarks of the operating enterprise. For example, an engineer onsite may consider minimizing field watercut as a good justification while a project manager may use NPV as a justification. The level of decision making will eventually determine the measure of justification. If the project is not justifiable, the applicability of ICV to the project in question needs to be reviewed. If the target is justified, then ICV technology should be adopted.

CHAPTER IV

RESULTS AND DISCUSSIONS

4.1 Overview

The results obtained from the base case, traditional water management operation, and intelligent modification simulation models will be presented in this chapter. As previously stated, the interest in this simulation work is oil production, and therefore gas production data is not included in the output plots. The three main metrics used to quantify the marginal value of adopting smart well technology are oil production (NPV), water production (watercut) and time savings (accelerated production). The focus of this work was therefore to build a proxy model that will maximize oil production and, simultaneously minimize water production.

4.2 Base Case Scenario

The base case simulation model run was performed at initial conditions before any intelligent control was applied. This model provides a baseline against which to measure the marginal improvements gained by adopting intelligent well control. The control mode operated the producers under a maximum liquid production rate of 3000 m^3 (25,159 barrels) and minimum BHP of 35.3 bars (512 psi). The injectors were set to inject water at a maximum BHP of 343.2bars (4978 psi) and all the wells produced continuously for 15 years.

The simulation results for the base case scenario are presented in *figures 22* to *24*. *Figure 22* shows the daily oil, gas and water production rates. It can be observed that daily water production surpasses daily oil production rate starting from year 7. This highlights the need for water management to optimize the production process. *Figure 23* shows the cumulative oil, water and gas production. Beginning from year 4, the amount of water produced increases exponentially while the amount of oil and gas decreases. This increase in water production is again highlighted in *figure 24* by the increase in field watercut.

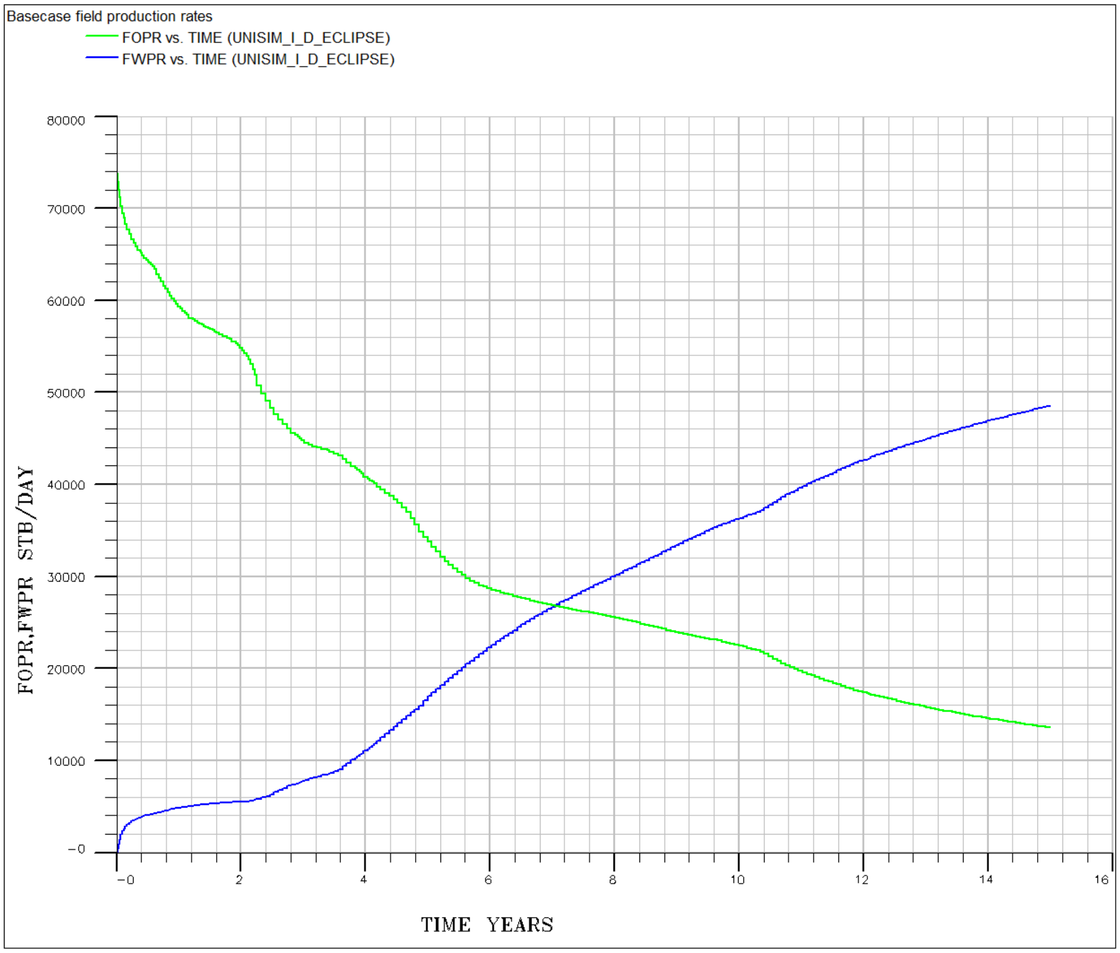


Figure 22: Base case field production rates

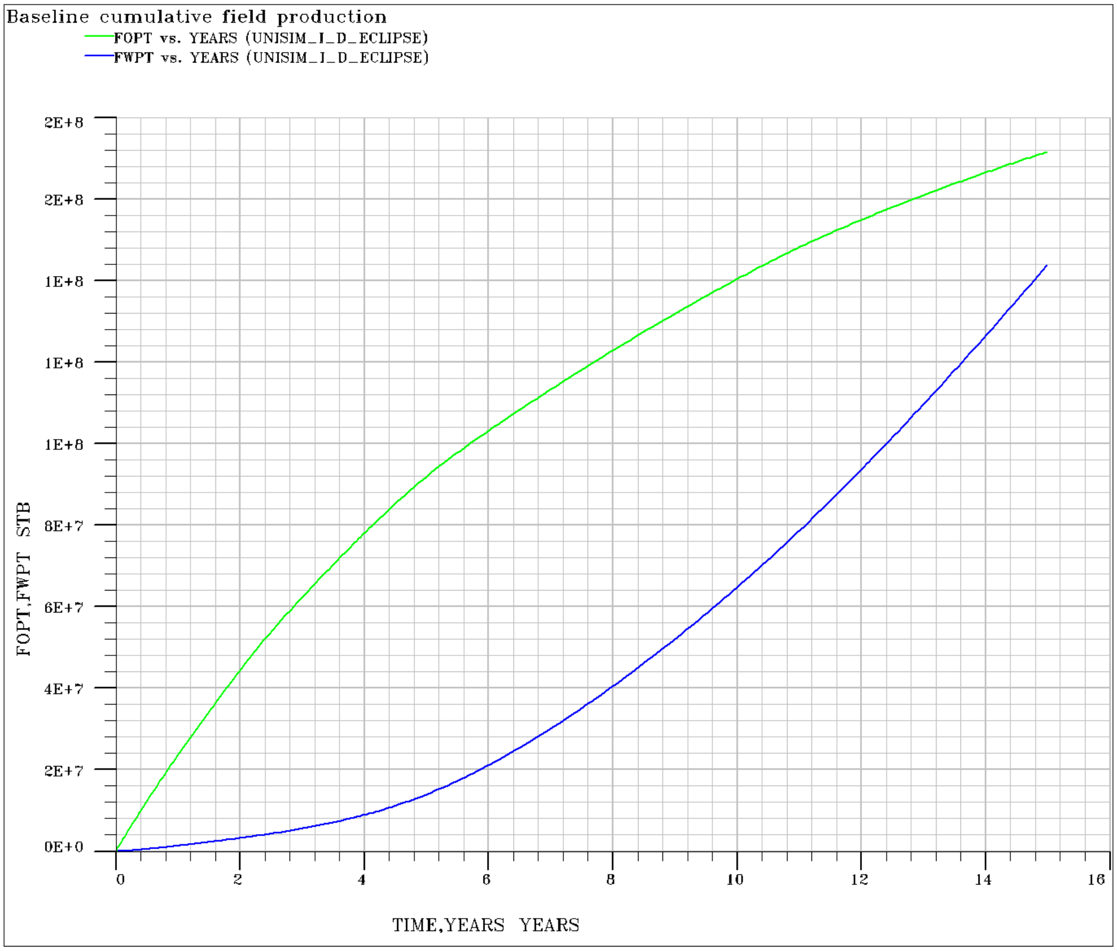


Figure 23: Base case cumulative field production rates

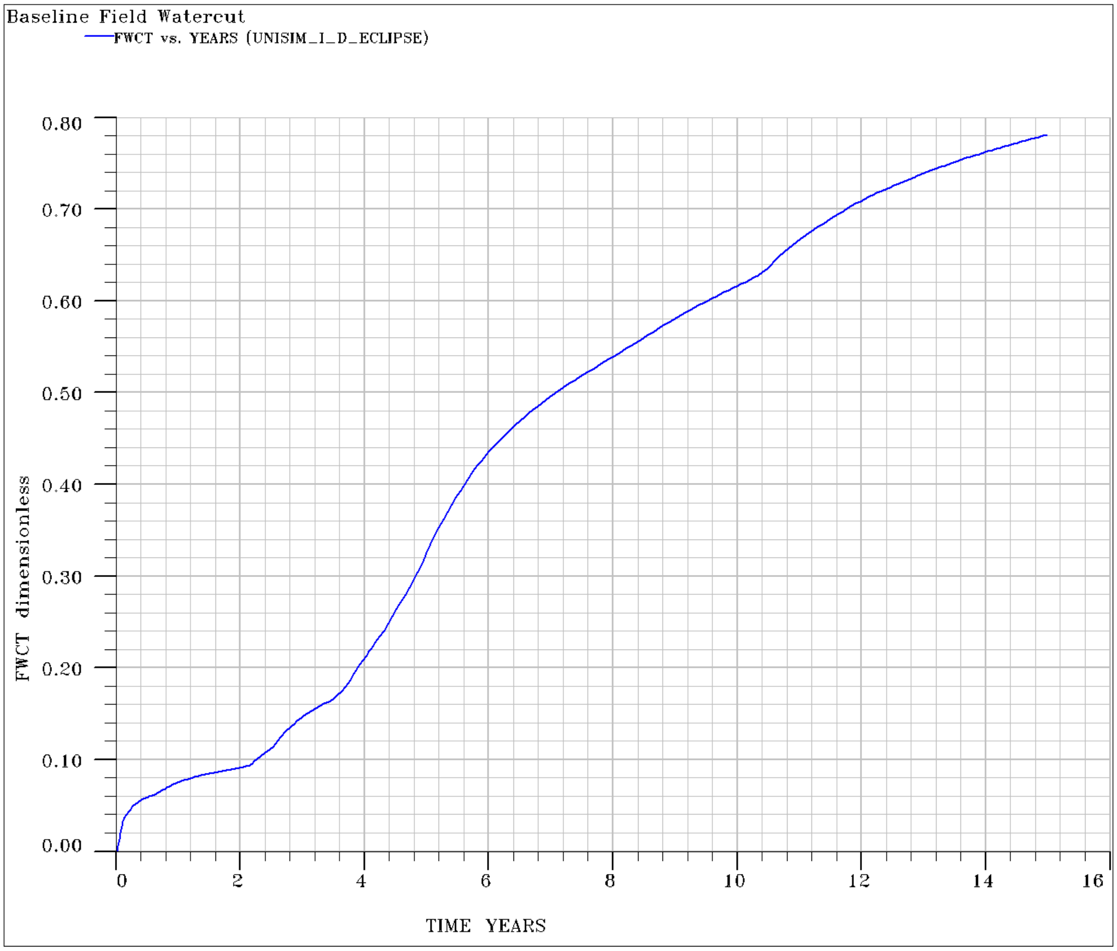


Figure 24: Base case field water cut

4.3 Conventional Water Management

This simulation run was performed to model conventional operation methods to manage water breakthrough without intelligent technology. The wells were operated under the same constraints as the base case model. However in addition, the producers were set to a maximum water cut of 70%. Once this water cut threshold is reached for a particular producer, the well is shut-in and assumed uneconomic. Similar to the base line case, this mode of operation provides a reference against which to measure the gains of adopting Smart Well Technology.

The simulation results showing a comparison between the base case scenario and the conventional water management case are presented in *figures 25* to *27*. *Figure 25* shows the daily oil, and water production rates. It can be observed that the conventional water management case results in slightly lower oil production rates starting in year six. However, the rate of water production is significantly reduced compared to the baseline case. This highlights the optimization of the production process when water management is applied. *Figure 26* shows the cumulative oil, and water production and highlights the reduction in water production achieved by applying water management. Finally, *figure 27* shows the reduction in field watercut from 78% in the baseline case to 52% in the conventional water management case.

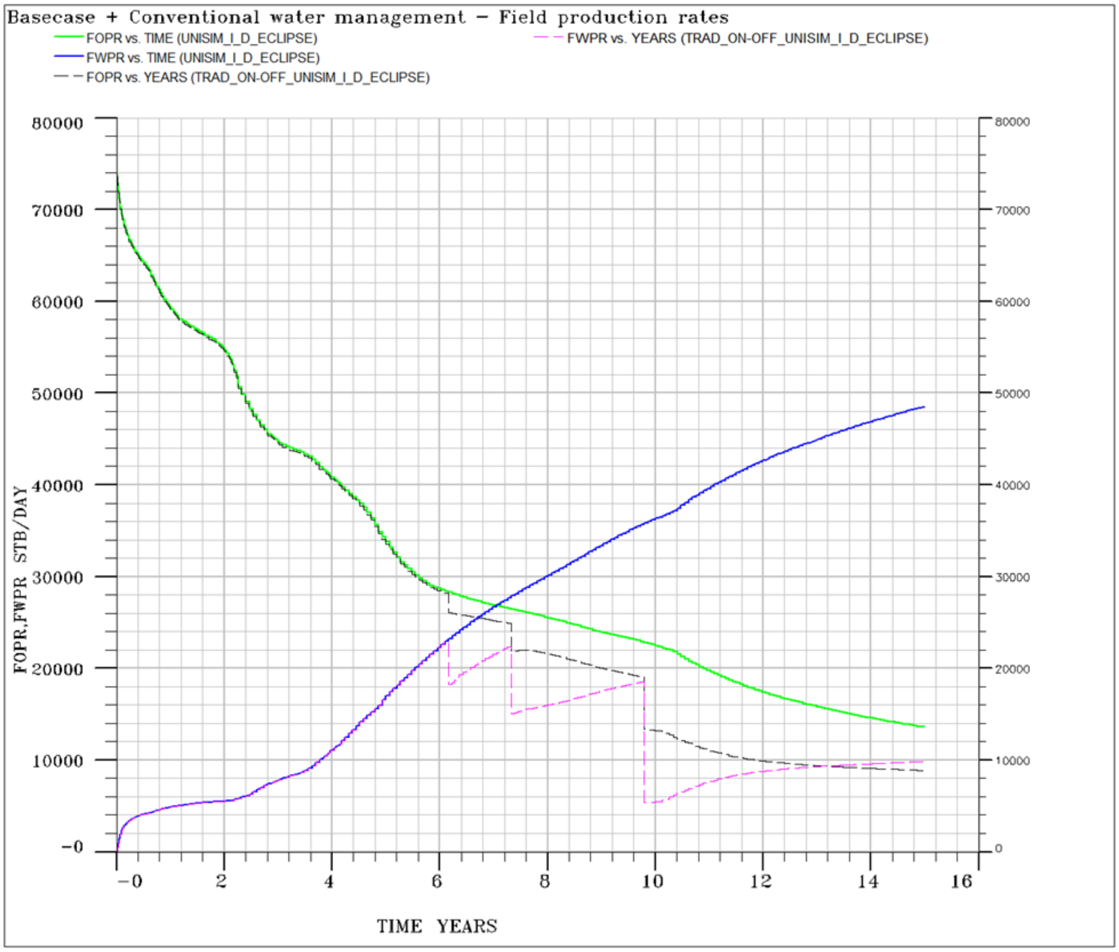


Figure 25: Field oil and water production rates - Baseline case versus conventional water control

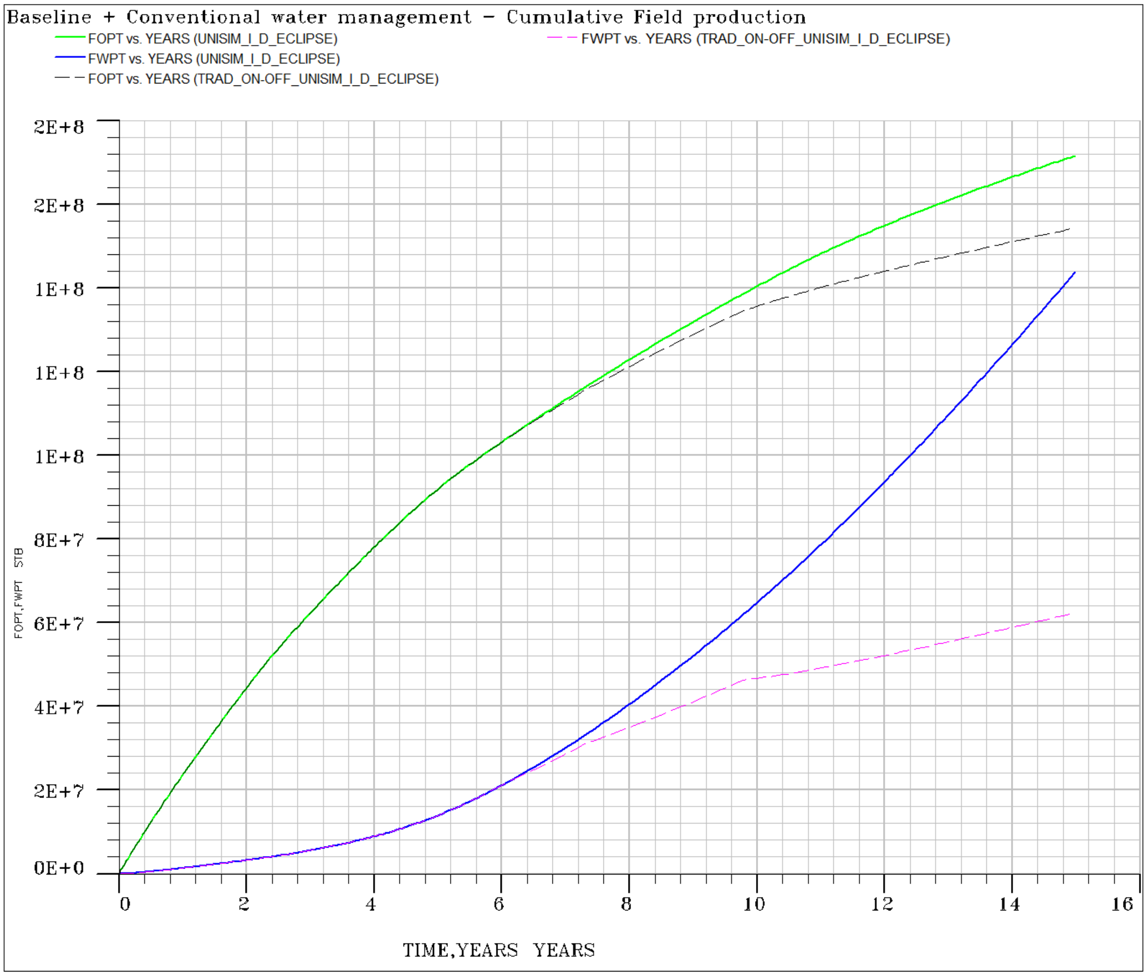


Figure 26: Cumulative field production rates - Baseline case versus conventional water control

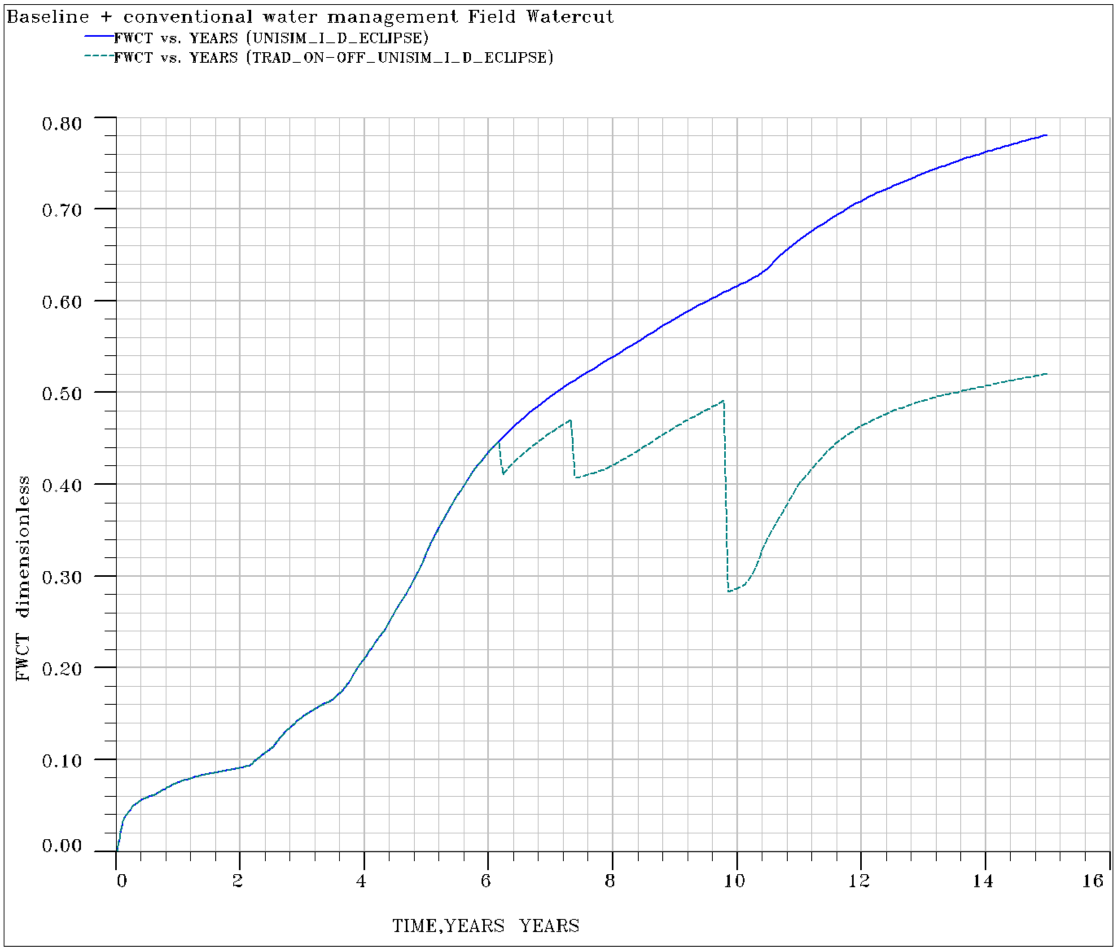


Figure 27: Field water cut comparison - Baseline case versus conventional water control

4.4 Intelligent Well Modifications

Two modes of intelligent control were simulated namely: ON-OFF control and Feedback ON-OFF control. Unlike the baseline and conventional water management case, the intelligent modifications employ downhole monitoring and control of each production layer. The goal is to optimize production by accelerating and maximizing oil production, while minimizing water production.

4.4.1 ON-OFF Control

The ON-OFF operation mode was simulated by constantly monitoring all the producing layers against a set upper limit water cut threshold. The water cut threshold was set to 50% and production constraints imposed such that once the water cut of a producing layer exceeds the threshold, that layer is completely shut.

The simulation results showing a comparison between the base case scenario, the conventional water management case, and the ON-OFF layer control case are presented in *figures 28* to *30*. *Figure 28* shows the daily oil, and water production rates. It can be observed that the ON-OFF layer control case results in slightly lower oil production rates starting in year six. However, the rate of water production is significantly reduced compared to the baseline and the conventional water management case. This highlights the optimization of the production process when water management is applied using smart well completions. *Figure 29* shows the cumulative oil, and water production and highlights the reduction in water production achieved by applying downhole layer control. Finally, *figure 30* shows the reduction in field watercut from 78% in the baseline case to 31.9 % in the ON-OFF layer control case.

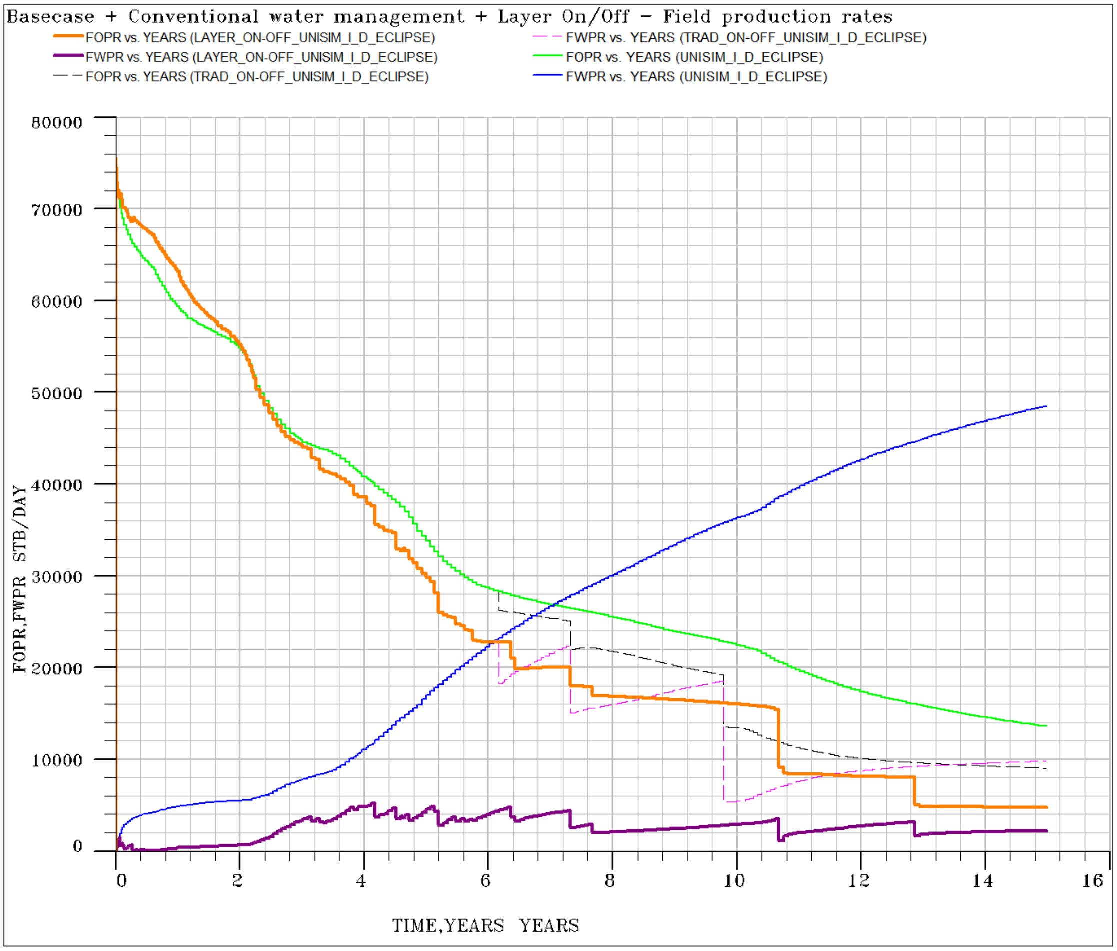


Figure 28: Field production rates - Baseline, conventional water control, and ON-OFF intelligent control

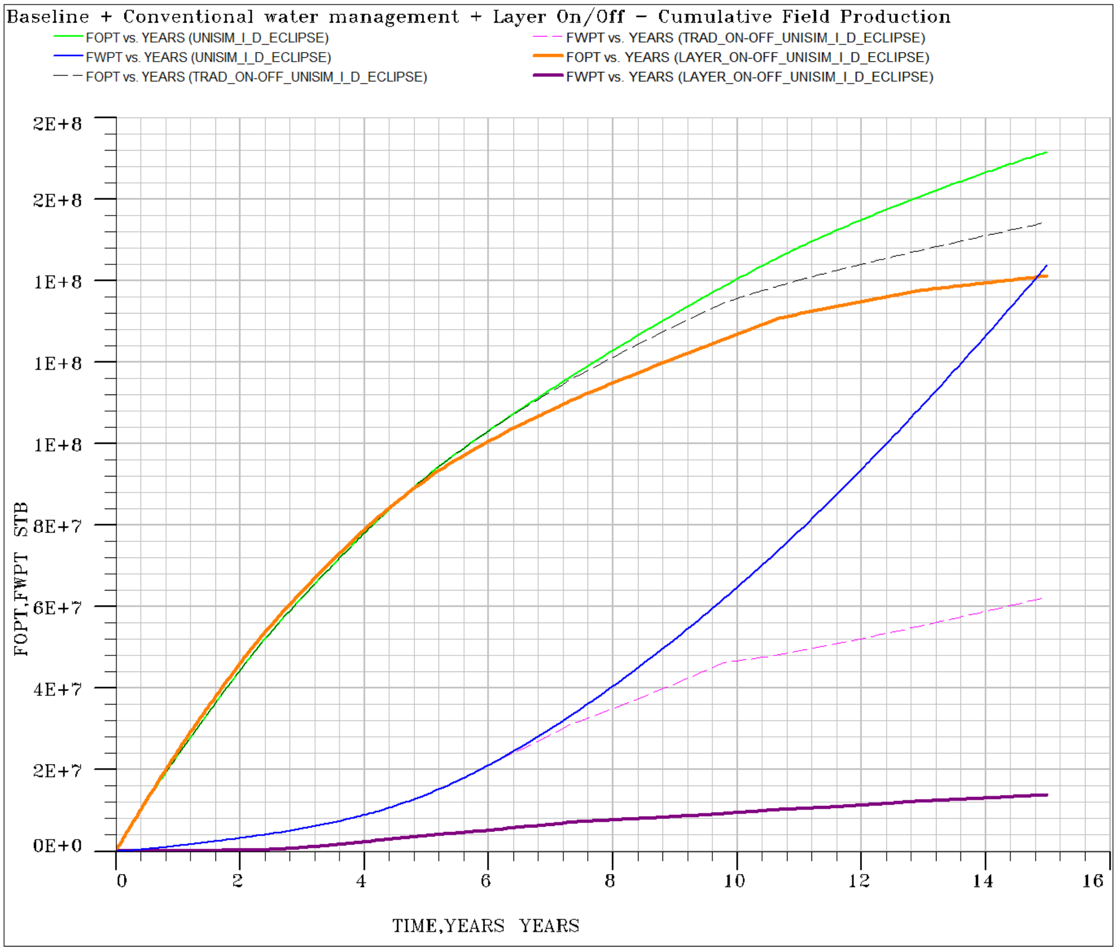


Figure 29: Cumulative production rates - Baseline, conventional water control, and ON-OFF intelligent control

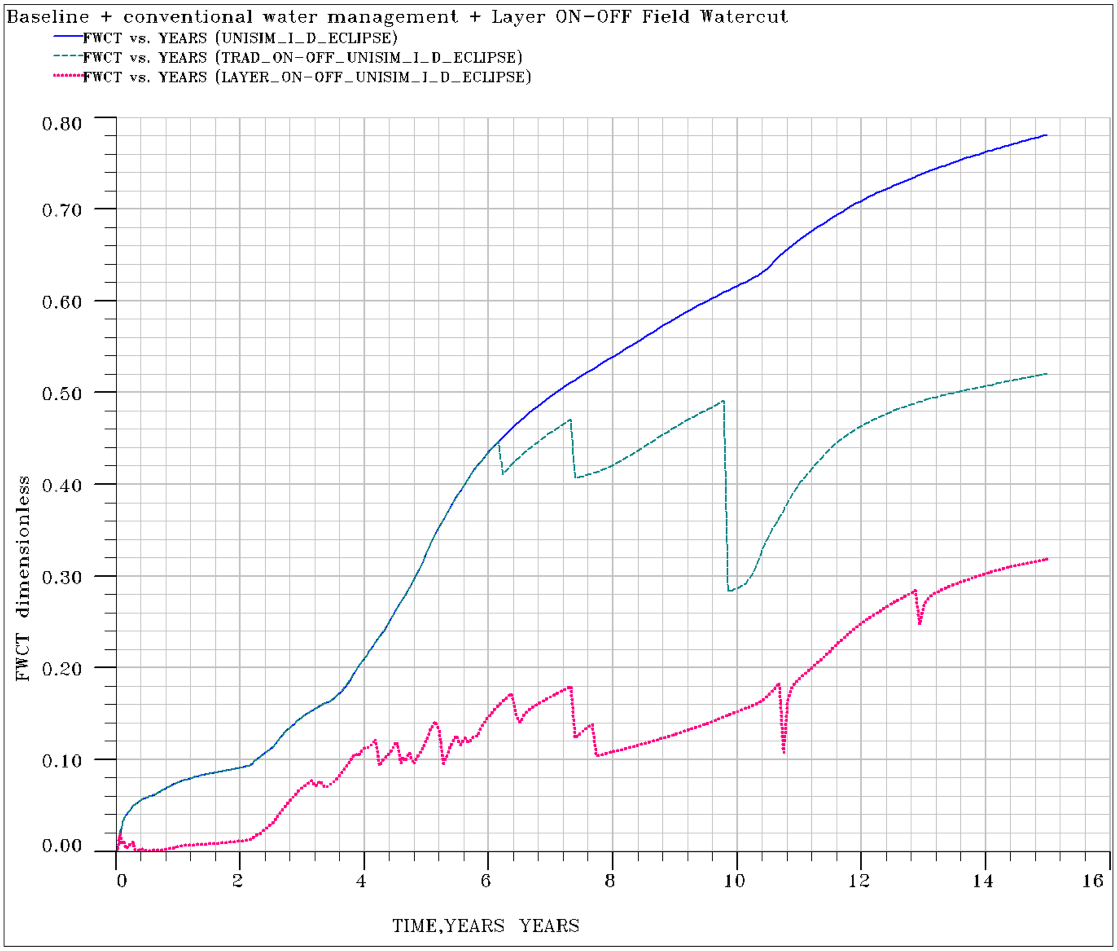


Figure 30: Field water cut comparison

4.4.2 Feedback ON-OFF Control

The Feedback ON-OFF control mode is a slight modification to the ON-OFF control mode described above. In this mode, the overall well water cut was continuously monitored during production against a specified upper limit water cut threshold. The water cut threshold was set to 50% and production constraints imposed such that once the well water cut threshold is violated, the most offending producing layer in that well is completely shut. Just like the ON-OFF control case, this operation mode simulates a simple On/off ICV with a slight modification to the control strategy.

Figures 31 to *33* show a comparison of all the simulation cases. *Figures 31* and *32* show that the two intelligent modification cases produced the minimum amount of water, with the ON-OFF layer case being the most effective. As observed in *figure 33*, the field watercut went from 78% in the baseline case, to 52% in the conventional water management case. Adopting smart well control reduced the field watercut to 49% in the Feedback ON-OFF case to 31% in the ON-OFF layer control case. These results clearly highlight the benefit on minimizing field water production achieved by adopting smart well control.

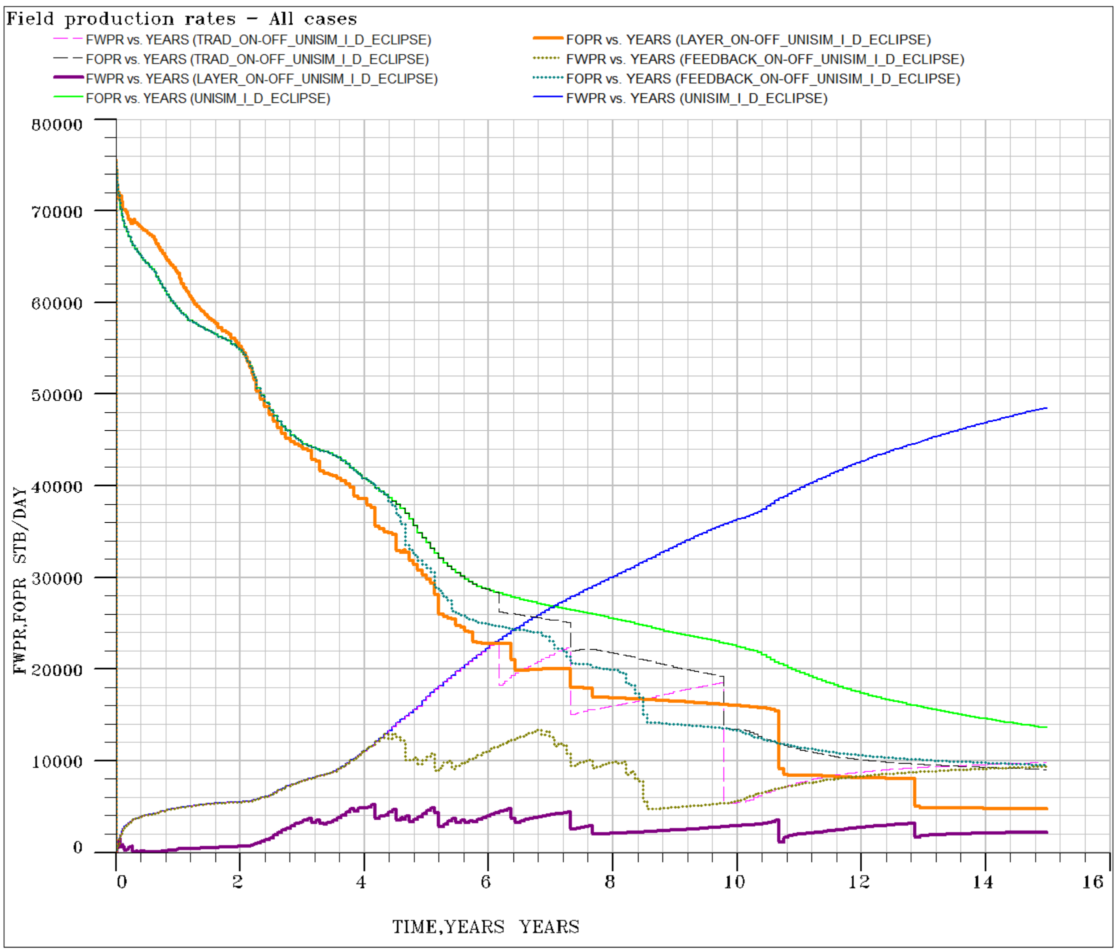


Figure 31: Field production rates - All cases

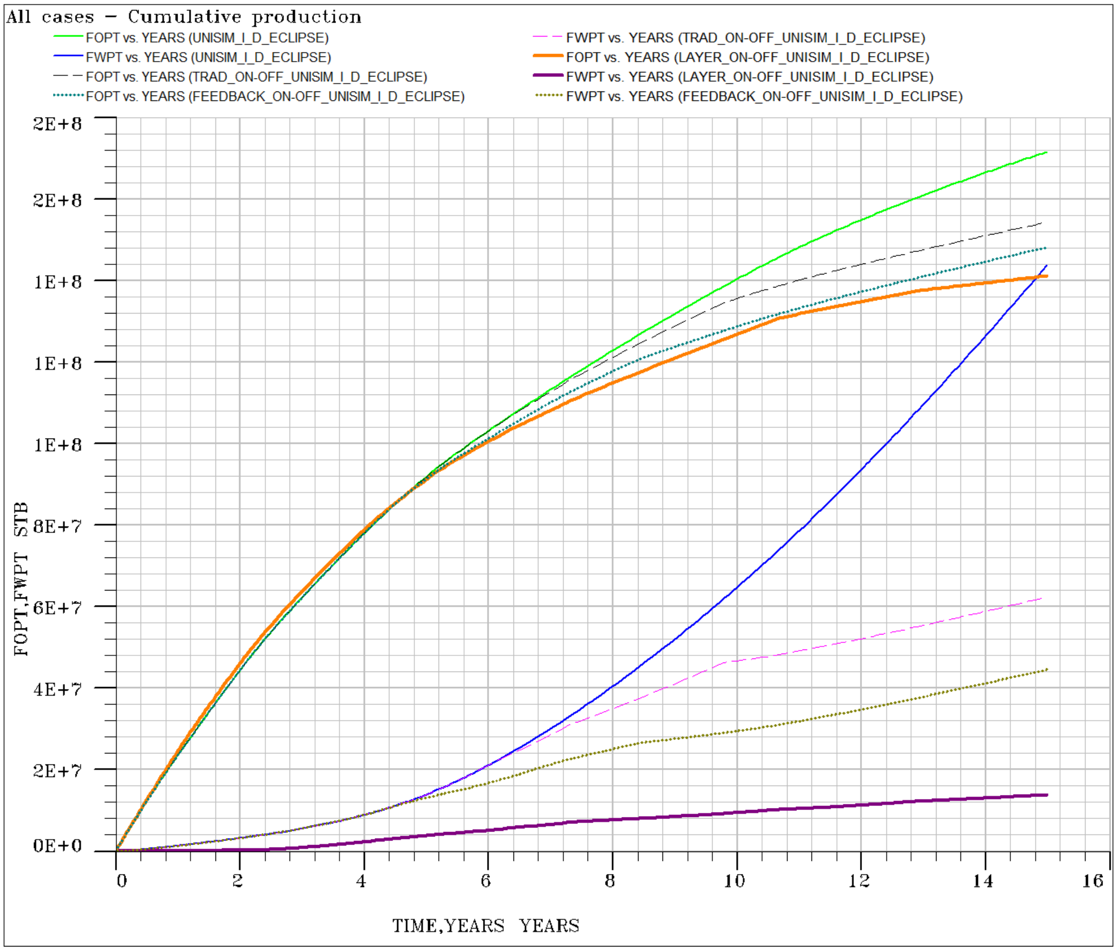


Figure 32: Cumulative field production - All cases

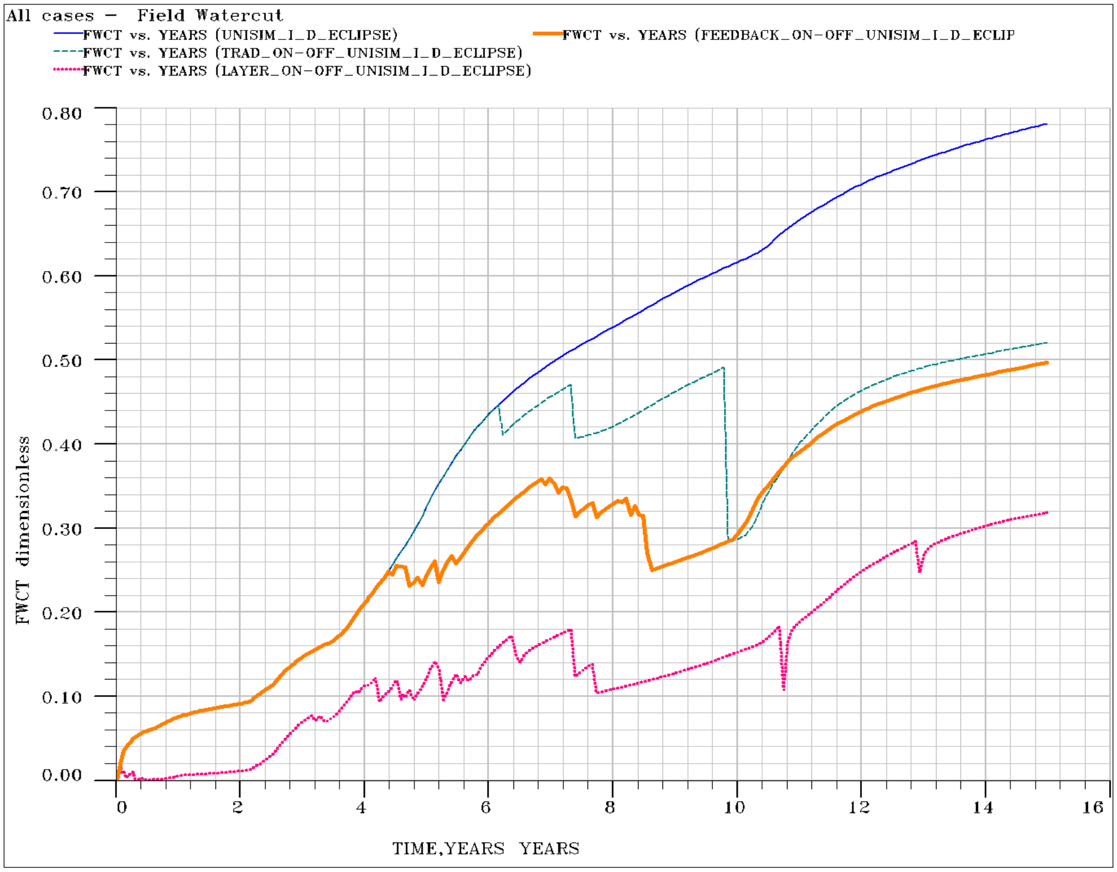


Figure 33: Field water cut comparison - All cases

4.5 Well Analysis

The optimization in production is evident from the field data analysis when considering the decision driver of minimizing water production. To observe the production acceleration benefit, it is necessary to analyze the individual well data.

Figures 34, 36, and 37 show the time required by each simulation case to achieve total oil and water production in well NA1A, NA3D, and RJS19 respectively. In all three wells, it can be observed that the two intelligent modification cases (Feedback ON-OFF and Layer ON-OFF) produced for the least amount of time. Although production time was significantly shorter in the cases with smart completions, economic levels of oil production were achieved. Additionally, the amount of water was significantly reduced by adopting smart well completions.

Figure 35 shows the production data for well NA2. This highlights an optimal case in which the benefits of smart well completions are fully realized. Adopting ON-OFF layer control results in the least amount of water produced, the fastest oil production rate and the highest cumulative oil production.

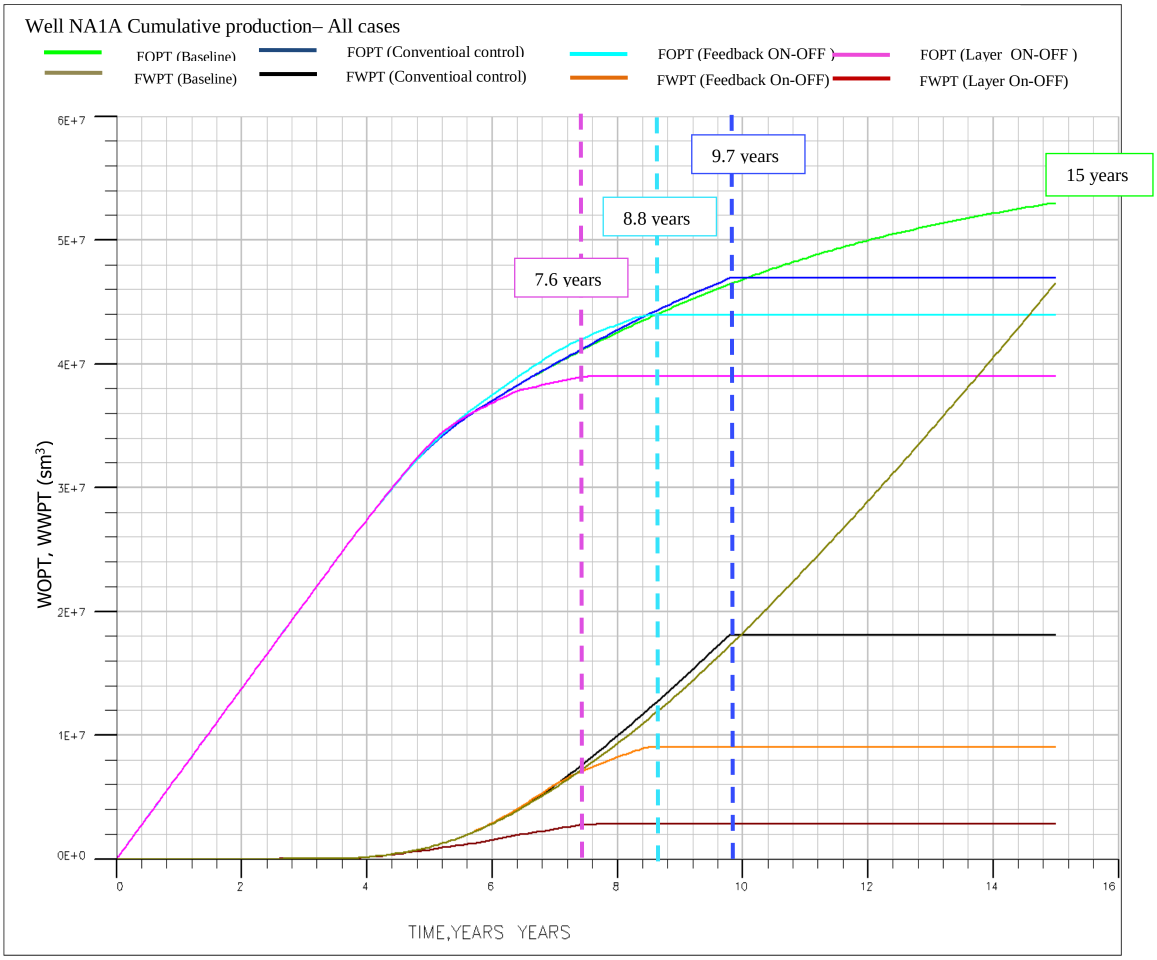


Figure 34: Cumulative production rate analysis of well NA1A showing production times each simulation case

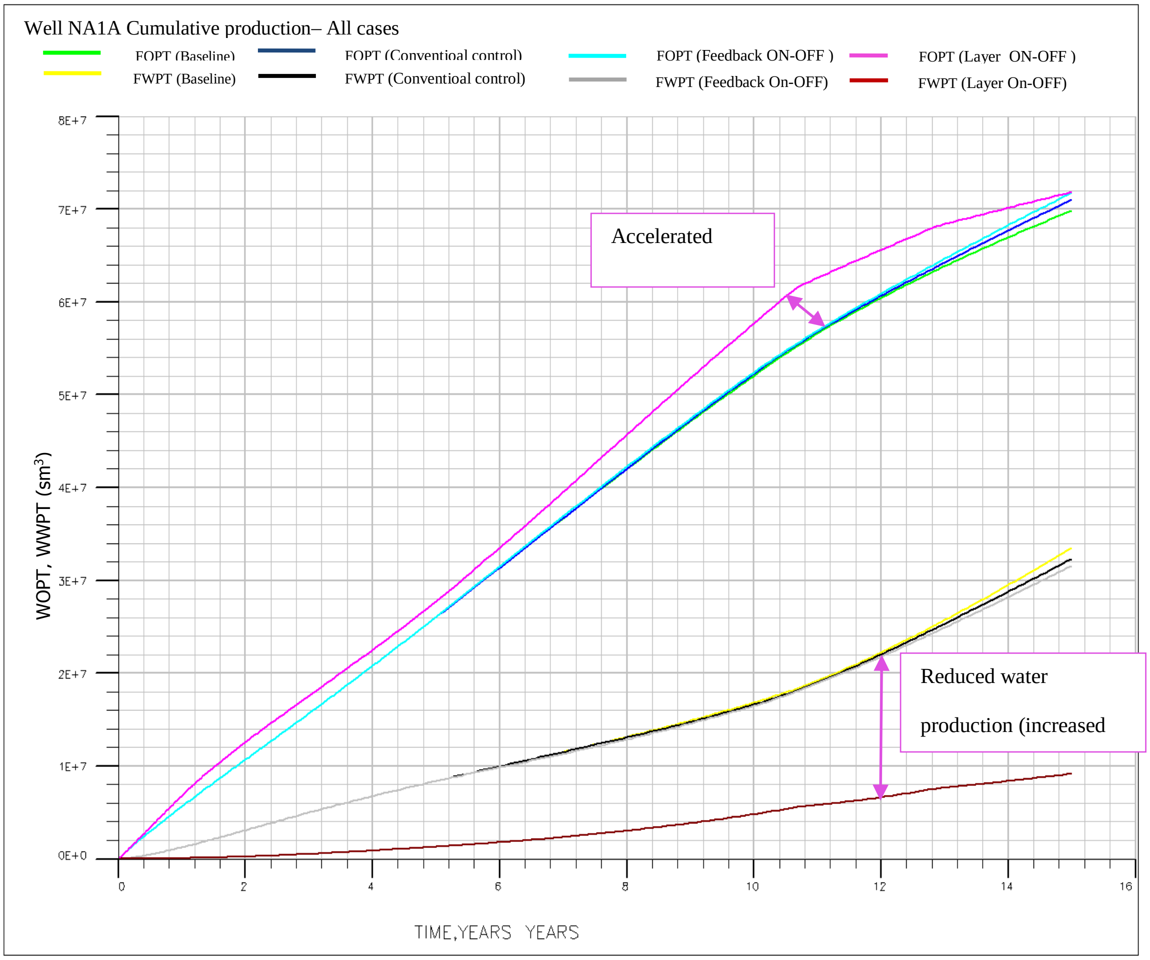


Figure 35: Well NA2 cumulative production showing benefits of intelligent control

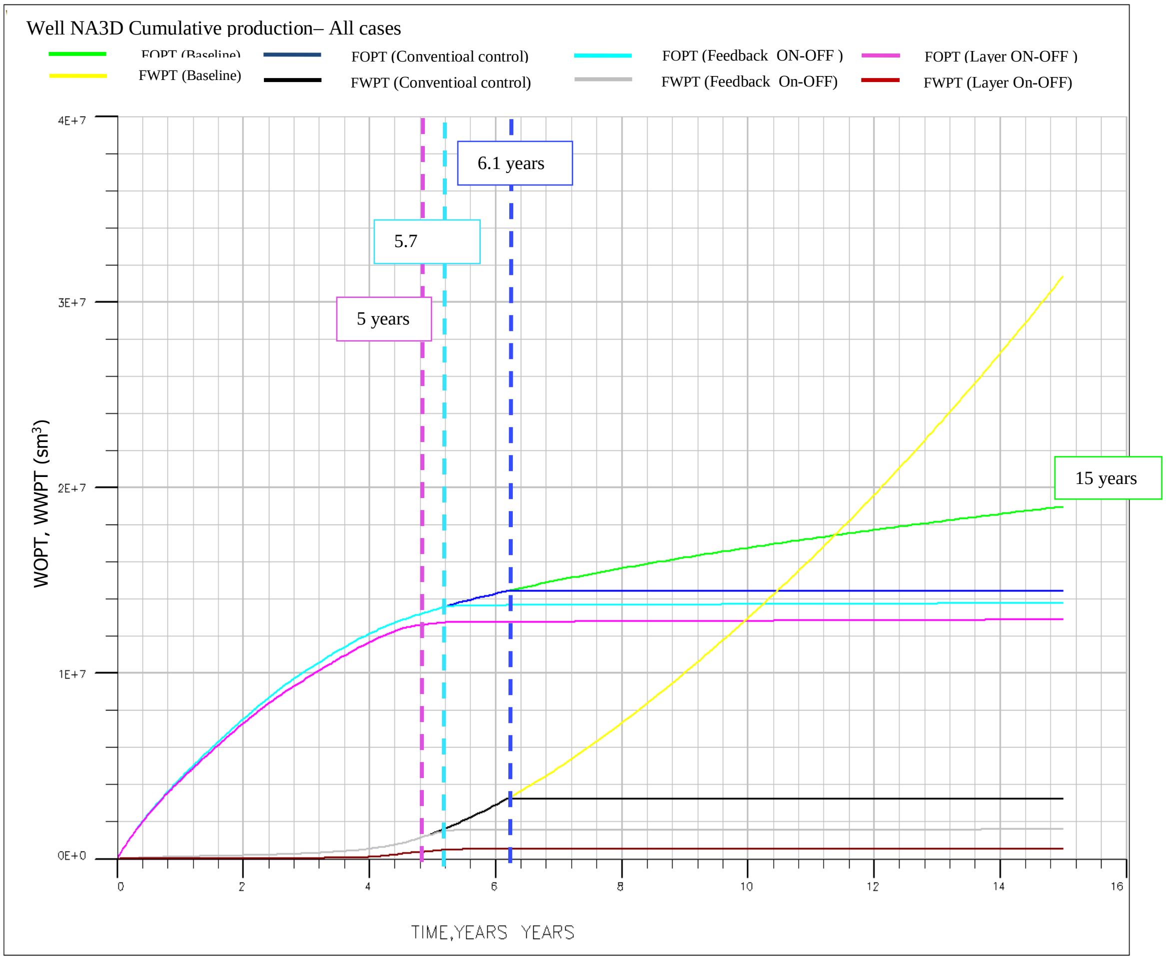


Figure 36: Well NA3D cumulative production showing accelerated production benefit of intelligent completions

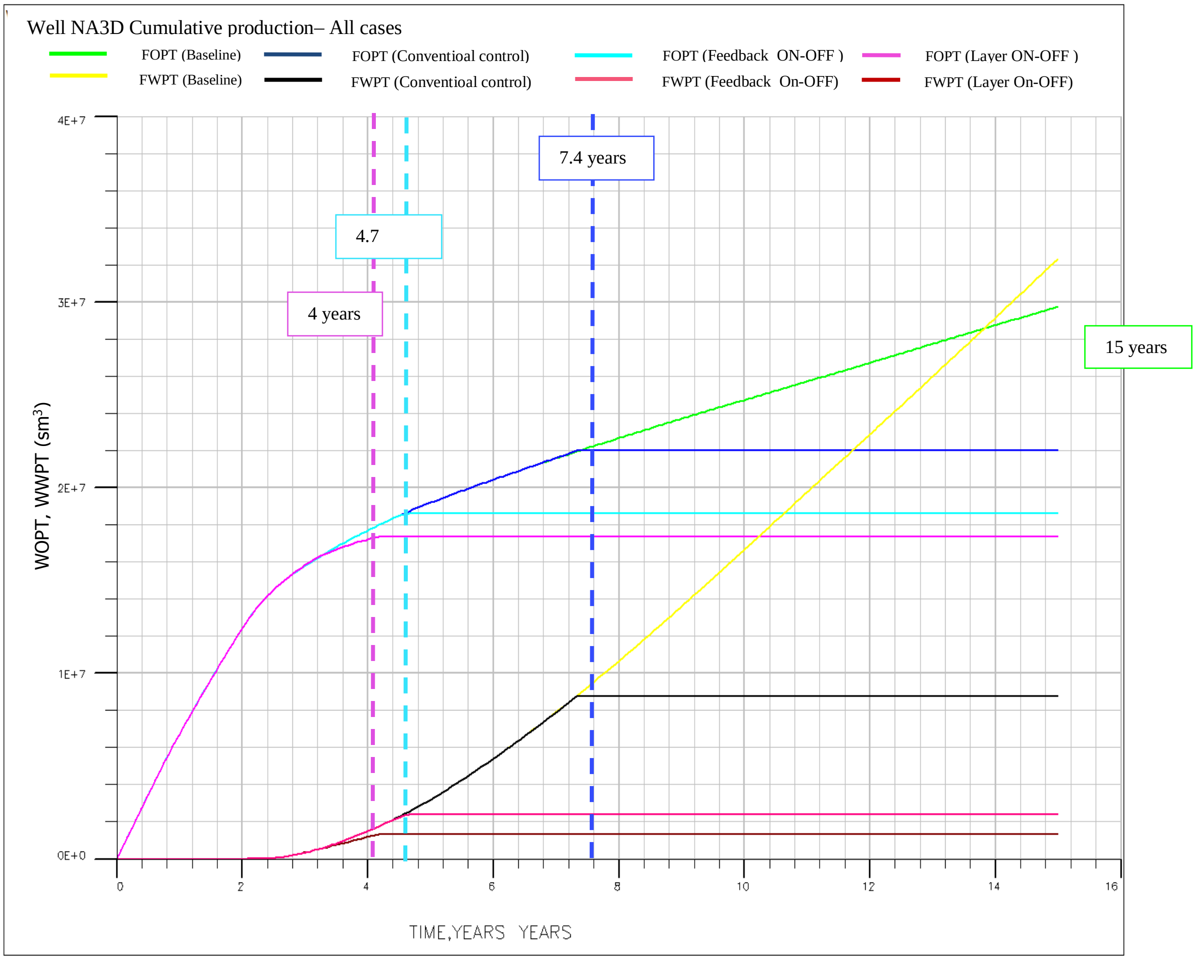


Figure 37: Well RJS19 cumulative production demonstrating optimized production

4.6 Summary

The field data clearly highlights the advantages of adopting intelligent well technology when water production/disposal capacity is a critical parameter. A comparison of the cumulative oil and water production for all four simulated cases is presented in *figure 32* above. In the baseline case, all the wells operate for 15 years without any controls to minimize water production. As expected this case resulted in the highest field water production (78.1 % water cut) and the highest cumulative oil produced. Obviously, coping with such high volumes of water require significant purification/disposal capabilities which increase operation cost and risk. This high level of water production also implies that the marginal amount of oil produced by operating all the wells for the entire project life is significantly low. Operators must therefore consider all these factors before deciding to operate using such a strategy.

The conventional water control case was simulated by shutting in any well once the well water cut surpassed the threshold value of 70 %. Compared to the baseline case, field water cut decreased by 33% from 78.1 % to 52%. In addition, cumulative oil production reduced by 10%, although it should be noted that this control strategy operated on fewer wells than the baseline case. Only 3 wells were operational in the 6th and 7th year of production, while 2 wells were producing in the 8th and 9th year. Finally for the last 5 years of production, only 1 well was operational. This therefore a more efficient production strategy, relative to the baseline case as the extra cost and risks associated with operating all 4 producers are avoided. The operator must therefore consider such savings when choosing on a production strategy, rather than rely on absolute values of oil produced.

Two cases of intelligent modifications were simulated; the feedback ON-OFF control and the layer ON-FF control. In the feedback ON-OFF case the well water cut was first checked against a set threshold, after which the most offending layers were shut in when the threshold violated. For the layer ON-OFF case, the water cut threshold was applied directly to each producing layer and once violated, the offending layer was shut in.
Compared to the baseline case, the feedback ON-OFF control resulted in a 37% drop in field water cut (from 78.1% to 49.6%) and a 13.6% reduction in cumulative oil production. This case also operated fewer wells than the conventional oil control case (3 wells in 2018, 2 wells from 2018 to 2021, and 1 well from 2022 to 2028).

The layer ON-OFF control case operated the least number of wells through the production life (see summary data below). Compared to the baseline case, the layer ON-OFF case resulted in a 59% reduction in field water cut (from 78.1% to 31.9%) and a

17.7% reduction in cumulative field oil production. The summary data is presented is the tables below.

Table 4: Summary of field data

Simulation case	**Baseline**	**Conventional water control**	**Feedback ON-OFF control**	**Layer ON-OFF control**
FOPT (MSTB)	27,273.110	24,532.250	23,548.380	22,432.530
FWPT (MSTB)	22,845.440	9,919.755	7,087.498	2,198.612
FWCT	78.1 %	52.0 %	49.6 %	31.9 %

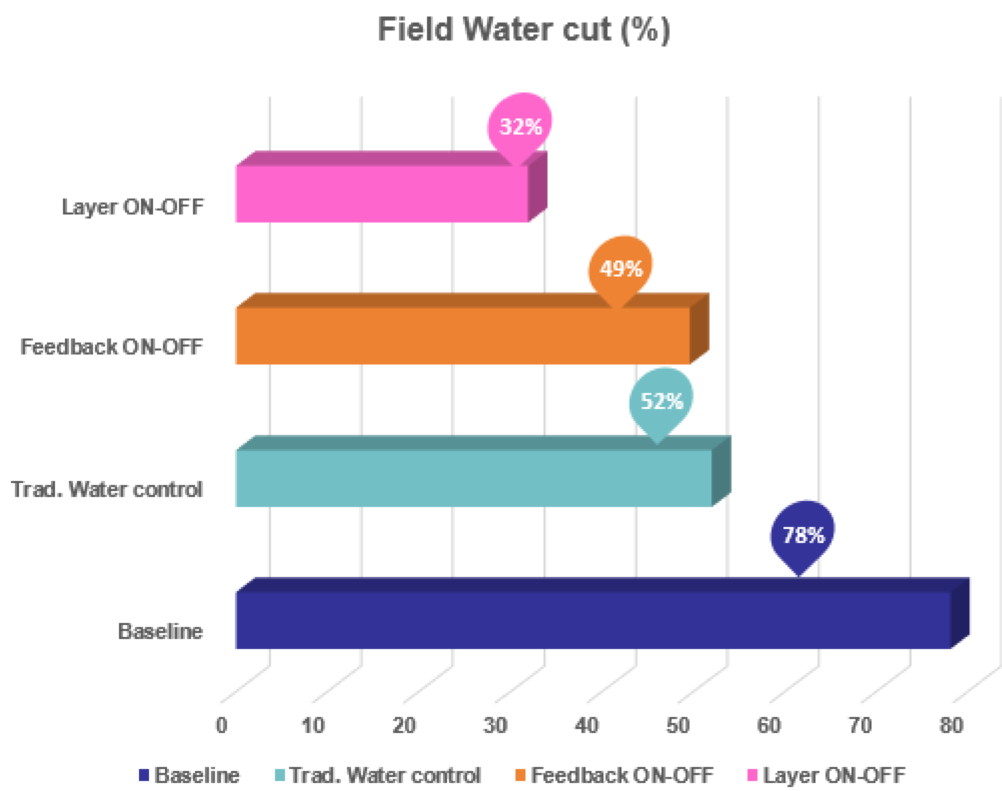


Figure 38: Field water cut comparison for all simulation cases

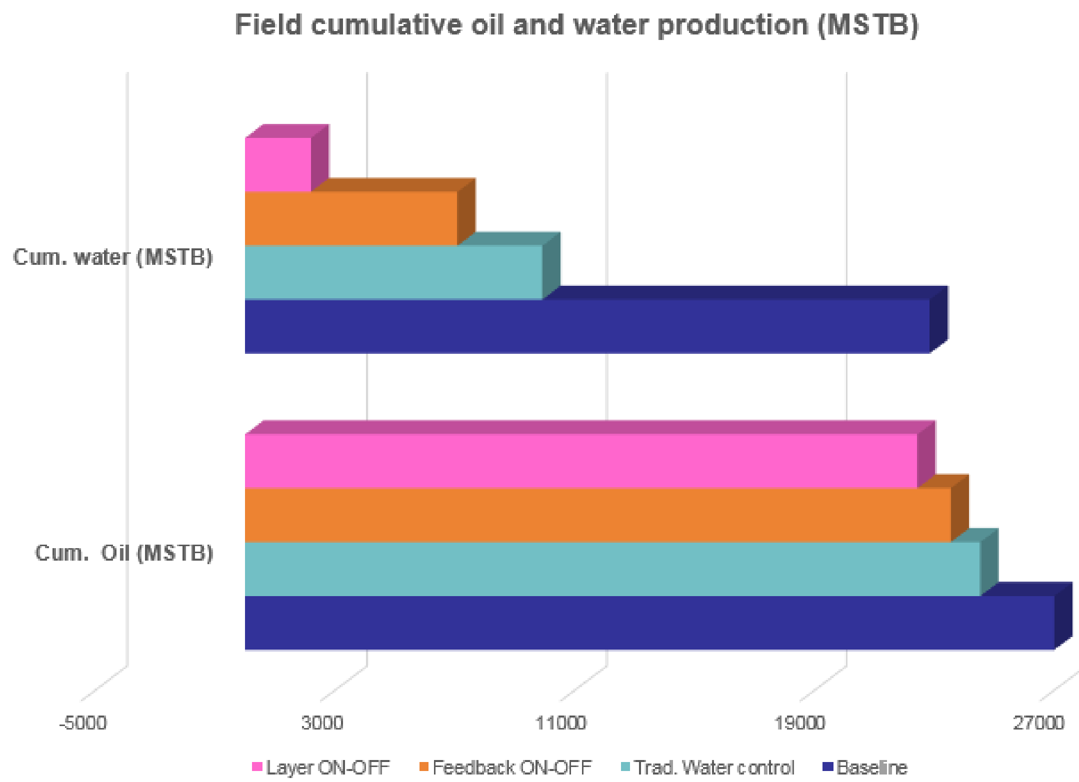


Figure 39: Cumulative oil production comparison for all simulation cases

Table 5: Summary of well data

Well	Control	Water (sm^3)	Oil (sm^3)	Water (bbl)	Oil (bbl)	Time to produce (years)
NA1A	Feedback	1.43E+06	6.99E+06	1.20E+07	5.86E+07	8.8
	Layer	4.46E+05	6.20E+06	3.74E+06	5.20E+07	7.6
	Trad	2.88E+06	7.46E+06	2.42E+07	6.25E+07	9.7
	Baseline	7.36E+06	8.43E+06	6.18E+07	7.07E+07	15.0
NA2	Feedback	5.00E+06	1.14E+07	4.19E+07	9.55E+07	15.0
	Layer	1.45E+06	1.14E+07	1.22E+07	9.57E+07	15.0
	Trad	5.11E+06	1.13E+07	4.29E+07	9.46E+07	15.0
	Baseline	5.31E+06	1.11E+07	4.45E+07	9.30E+07	15.0
NA3D	Feedback	2.52E+05	2.19E+06	2.11E+06	1.84E+07	5.7
	Layer	8.31E+04	2.05E+06	6.97E+05	1.72E+07	5.0
	Trad	5.10E+05	2.29E+06	4.28E+06	1.92E+07	6.1
	Baseline	4.98E+06	3.02E+06	4.18E+07	2.53E+07	15.0
RJS19	Feedback	3.84E+05	2.96E+06	3.22E+06	2.48E+07	4.7
	Layer	2.11E+05	2.76E+06	1.77E+06	2.32E+07	4.0
	Trad	1.39E+06	3.49E+06	1.17E+07	2.93E+07	7.4
	Baseline	5.13E+06	4.72E+06	4.30E+07	3.96E+07	15.0

The direct benefits of adopting intelligent well technology (for example reduced water production) are clearly visible from looking at the field data however, the individual well data must also be analyzed to fully realize the added value of the technology. From *Table 5* above it can be observed that smart well technology significantly accelerates the oil production rate, at the same time significantly decelerates water production. For example analyzing the data for well NA3D indicates that in 5 years, the layer ON-OFF case produces 68% of the cumulative oil produced by the baseline case in 15 years. This implies that in the 10 additional year of production in the base case model, only an additional 32% of cumulative oil was achieved. In addition, the layer ON-OFF case for this same well produced 98.3% less water that the baseline case. This is a significant optimization of production efficiency. Besides the gains in efficiency, the value of time savings also include minimizing unforeseen risk associated with extended production, labor cost, other unforeseen expenses, risk of down time and emergency incidents.

Additional benefits of adopting smart well technology can be observed by analyzing the data for well NA2. This well produced for all 15 years in all the simulated cases. However, the layer ON-OFF control case significantly optimized production resulting in the highest amount of cumulative oil and the least amount of cumulative water produced. This reflects an optimal scenario where smart well technology should be implemented.

Operators must perform such analysis when deciding production strategy. This workflow enables engineers to identify which wells are most suitable (add the most value) for adopting smart well technology.

4.7 Economic Analysis

The NPV model described in *equation 30* was used to compare the economic value of the different simulation cases. As seen in *figure 36* below, both intelligent modifications (Feedback ON-OFF and layer ON-OFF) were the most profitable cases. It should be noted that only the cumulative oil and water produced, fixed capital investment (well cost, sensors cost and intelligent completion costs), daily operation costs and other direct cash flows were used in this NPV analysis. However, indirect benefits of adopting intelligent well technology like minimized risks, labor cost, downtime and other unforeseen expenses are not quantified in the results presented in the graph below. Therefore, the value of intelligent technology is high underestimated when relying solely of measureable benefits and this must be considered.

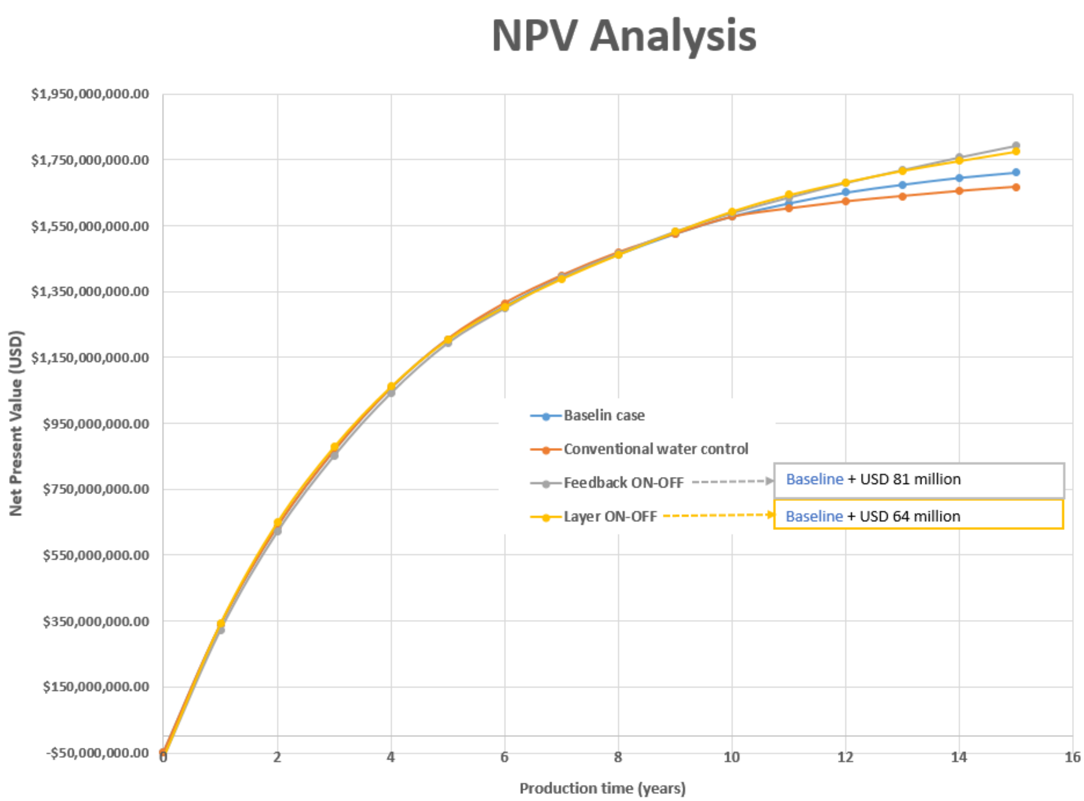


Figure 40: NPV analysis of all four simulation cases

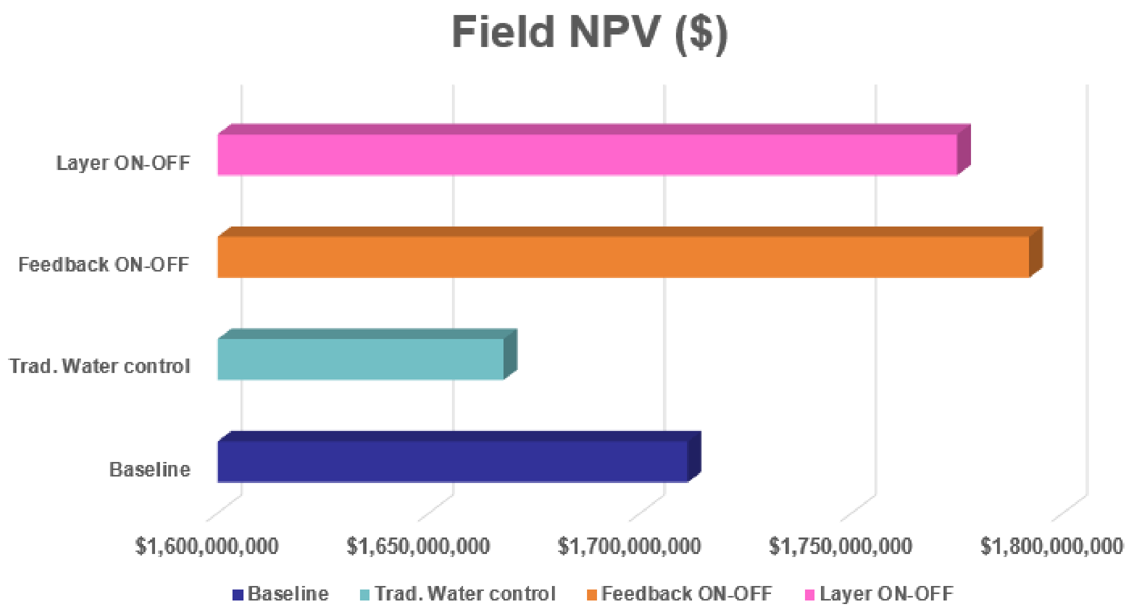


Figure 41: Field NPV comparison for all cases

4.8 Sensitivity Analysis

A sensitivity study was performed to understand the effect on both oil price and the cost of capital (discount rate) on the project NPV. *Figure 40* shows the sensitivity of NPV to oil price and *figure 41* shows the sensitivity of NPV to the discount rate. As observed in the plots, NPV is high sensitive to oil price and almost insensitive to the discount rate. As expected, the higher the oil price, the more profitable the project.

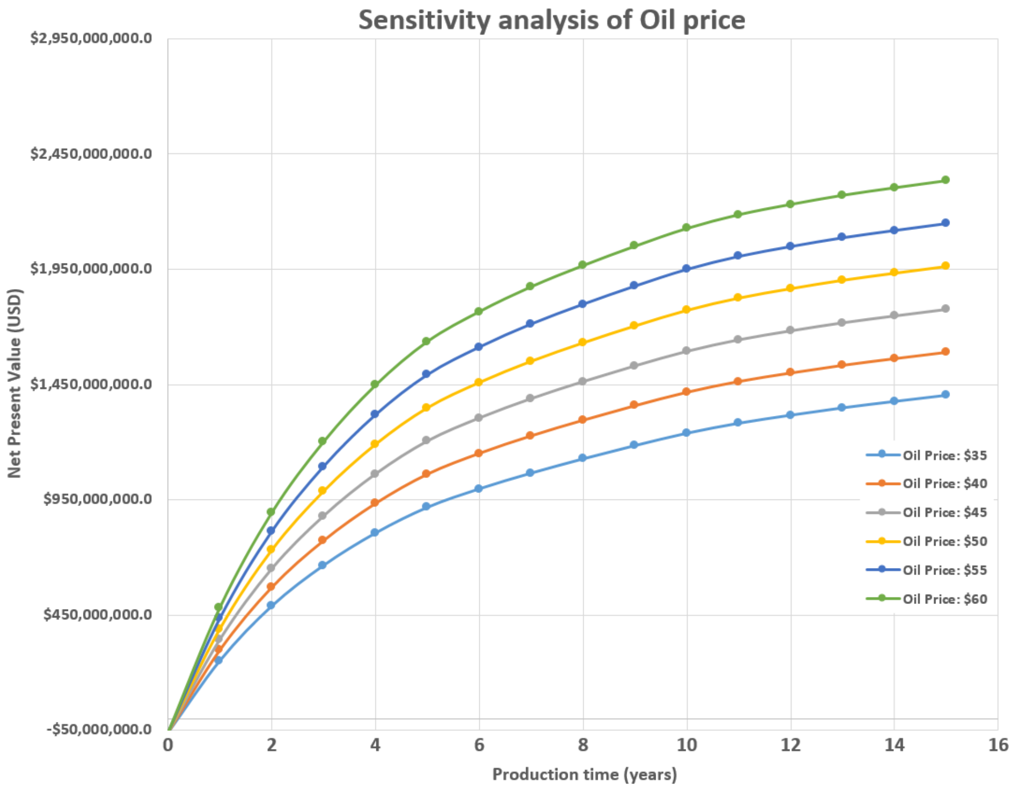


Figure 42: Sensitivity analysis of oil price

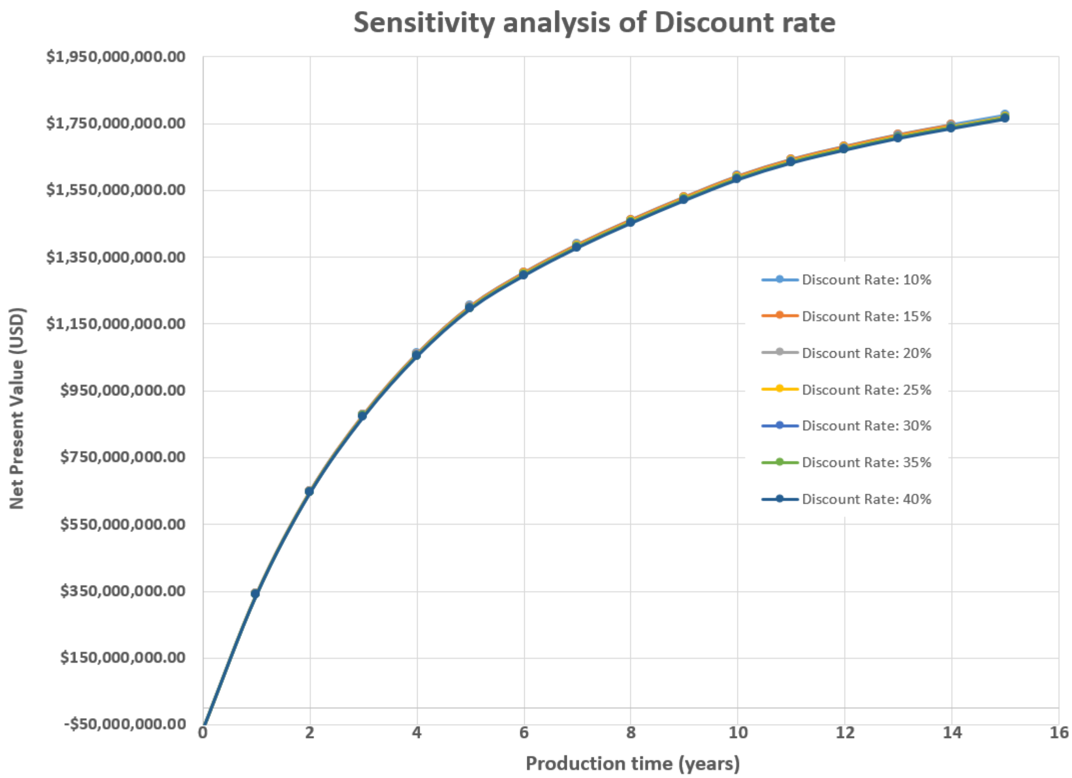


Figure 43: Sensitivity analysis of discount rate

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

This thesis has successfully investigated and developed a hierarchical closed loop workflow process for production optimization of field with multiple vertical wells. Although, the process was studied using the UNISIM-I-D reservoir model, it can be applied during the field development stage to any field to access the applicability of intelligent well technology.

The results demonstrate strong value derived from the adoption of intelligent downhole control in this project. *Figures 38*, *39* and *41* clearly show that the three decision drivers for this project were met. Field water cut was significantly reduced from 78.1 % in the baseline case to 31.9% in the Layer ON-OFF, and oil production was economic in the cases where intelligent modifications were adopted leading to the highest NPV forecasts. The NPV forecasts presented do not include some variable factors like savings in labor costs and unforeseen risk associated with extended production and therefor the NPV values for the intelligent modifications could be higher.

It is important to note that the decision drivers are not fixed and could be different for different operators. The weighted value of each decision driver could also vary from project to project therefore it is critical that the decision drivers should be properly assessed and clearly defined at the start of the analysis.

The sensitivity analysis also demonstrated that oil price is a key variable that must be thoroughly examined and forecasted before making the decision to adopt intelligent well technology. As seen from the UNISIM-I-D model study, a significant benefit of intelligent well technology is production timesaving due to accelerated production and this could be of significant value especially in low oil price environments.

Lastly, it should be noted that the intrinsic value in intelligent well systems is highly dependent on the reliability of the technology. This installed system must perform a minimum throughout the productive life of a well without the need for well interventions for system performance related issues. The major players (Schlumberger, and Halliburton (Weahtherford and Baker Hughes) have demonstrated the capability to deliver reliable systems that meet this critical requirement. The reliability and value of the systems continue to be demonstrated as real time production data is collected. The benefits of intelligent well systems are significant and continue to be proven in several major fields. The widespread adoption of this technology is therefore encouraged and inevitable, especially in the low crude oil price environment of recent years.

5.2 Recommendations

Based on this research study, the following recommendations are suggested:

- Pre-development or re-development evaluations to assess the benefits of adopting smart well technology are encouraged. Highly heterogeneous formations that are susceptible to early breakthrough of unwanted fluids are prime targets for this technology.
- Further research and field data collection should be dedicated to improve operator confidence in the reliability and benefits of intelligent well systems.
- Intelligent well technology should be promoted in other non-producing applications like smart injection, and dump flooding to improve efficiency and minimize facilities costs.
- More research effort should be dedicated to better incorporate simulation capabilities of intelligent well systems to commercial software. Integrating intelligent well simulation with other commercial simulator applications could add more value to understanding the full impact on the entire project.

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APPENDIX

Table 6: Summary section keywords

KEYWORD	**DESCRIPTION**
EXCEL	requests that the run summary output should be written in a format that can be easily imported into Excel
COPR	Completion Oil Production Rate
COPT	Completion Oil Production Total
CWPR	Completion Water Production Rate
CWPT	Completion Water Production Total
WOPR	Well Oil Production Rate
WOPT	Well Oil Production Total
WWPR	Well Water Production Rate
WWCT	Well water Cut
FOPR	Field Oil Production Rate
FOPT	Field Oil Production Total
FWPR	Field Water Production Rate
FWCT	Field water Cut
FOE	Field Oil Efficiency (recovery efficiency %)