ECONOMIC EVALUATION OF SMART WELL TECHNOLOGY

A Thesis

by

ABDULLATIF A. AL OMAIR

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2007

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Richard Startzman
Committee Members,	W. John Lee
	Wayne Ahr
Head of Department,	Stephen A. Holditch

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ABSTRACT

Economic Evaluation of Smart Well Technology. (May 2007)

Abdullatif A. Al Omair, B.S., The University of Tulsa

Chair of Advisory Committee: Dr. Richard A. Startzman

The demand of oil and gas resources is high and the forecasts show a trend for higher requirements in the future. More unconventional resource exploitation along with an increase in the total recovery in current producing fields is required. At this pivotal time the role of emerging technologies is of at most importance.

Smart or intelligent well technology is one of the up and coming technologies that have been developed to assist improvements in field development outcome. In this paper a comprehensive review of this technology has been discussed. The possible reservoir environments in which smart well technology could be used and also, the possible benefits that could be realized by utilizing smart well technology has been discussed.

The economic impact of smart well technology has been studied thoroughly. Five field cases were used to evaluate the economics of smart well technology in various production environments. Real field data along with best estimate of smart well technology pricings were used in this research. I have used different comparisons between smart well cases and conventional completion to illustrate the economic differences between the different completion scenarios.

Based on the research, I have realized that all the smart well cases showed a better economic return than conventional completions. The offshore cases showed a good economic environment for smart well technology. Large onshore developments with

smart well technology can also provide a lucrative economic return. These situations can increase the overall economic return and ultimate recovery which will assist in meeting some of the oil demand around the globe.

DEDICATION

This work is dedicated

To my parents for their constant support through out my life to achieve this goal;

To my beloved wife, Nouf, and my beautiful daughter, Nourah, for all the sacrifice they gave during the time I was away from them during my studies. I tell them that we can enjoy this together and reunite forever. To all my brothers and sisters, thanks for all the support you provided for me and my family during my studies.

ACKNOWLEDGEMENTS

I wish to express my sincere appreciation to the following members of my graduate advisory committee for their contribution and continuous support to accomplish this research.

Thank you to the chairman of my graduate advisory committee, Dr. Startzman, for his constant support and continuous guidance during this research

Thank you to Dr. John Lee and Dr. Wayne Ahr for serving as members of my advisory committee and for the knowledge I gained from them.

I would like to thank my fellow friends at the Harold Vance Department of Petroleum Engineering that made my stay here a memorable one.

Thanks also to faculty and staff of the Harold Vance Department of Petroleum Engineering at Texas A&M University for providing the facilities and accommodations to conduct my research.

Finally, I would like to thank Saudi Aramco for giving me this opportunity to pursue my degree. I appreciate the chance they gave me to come to the best school in the world.

TABLE OF CONTENTS

CHAPTER Page

LIST OF FIGURES

FIGURE Page

FIGURE Page

LIST OF TABLES

TABLE Page

TABLE Page

CHAPTER I

INTRODUCTION

1.1 Motivation

The demand of energy has been rising steadily in the past few years as shown in figure 1.1. Sources of hydrocarbons are still abundant around the globe. Many of these resources are harder to produce than the reserves being produced currently. Another important challenge in this current situation is to maximize recovery at a profitable rate.

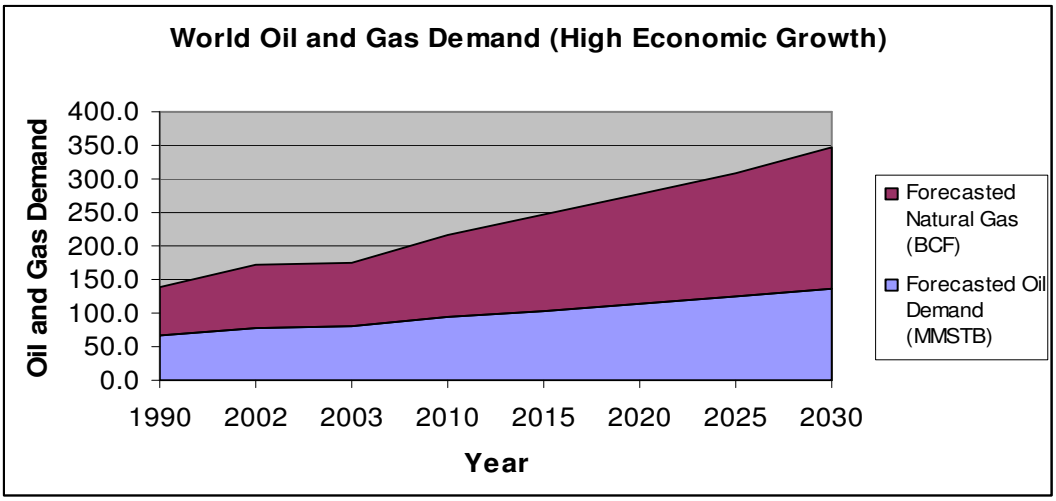

Figure 1.1: Hydrocarbon World Demand under High World Economic Growth (EIA[1])

The positive aspect of this situation is that the technology is progressing as those reserves get more challenging to produce. Many petroleum engineering technologies have been developed in order to ease the production of new reservoir.

This thesis follows the style of *SPE Journal*.

Slanted and horizontal well technology was developed in the early 1920's but was rarely used until the 1980's. However with the technology advancement in the industry horizontal wells are not uncommon anymore.

The industry has a tendency of being careful with new technologies till the technology is proved both theoretically and operationally. The change usually takes place in more than one aspect i.e. production, drilling and reservoir strategies. However, adapting some of the new technologies will be a must in order to produce the resources in the best manner that will yield profit to these companies. Saudi Aramco[2] has indicated a steady increase in technology use with time. The author emphasized on the role of technology advancement in order to produce the more challenging resources available around the world as shown in figure 1.2.

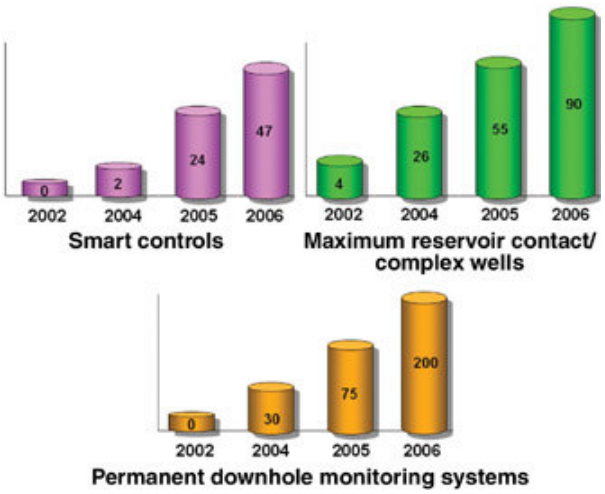

Figure 1.2: New Technologies Role in Saudi Arabian Fields (courtesy of Saudi Aramco[2])

One of the new technologies that have emerged in the past 10 years is what is called "Smart Well Technology" or "Intelligent Well Technology". The main driver for this technology is the emergence of horizontal and multi-lateral wells around the world.

The main aspect of the smart well technology is the ability to control flow from many laterals or zones utilizing down-hole control valves.

1.2 Research Goals

The goals of this research are the following:

1. Review the current state of smart well technology.
2. Evaluate the economic factors of fields developed with smart well technology.
3. Create solid conclusions in the economic viability of smart well technology in the different oil field environments.

1.3 Organization of Thesis

This thesis is organized in five chapters, including this introduction. Chapter II will give an overview of smart well technology. Topics such as the industry's definitions, possible applications, and the possible benefits of smart well technology will be discussed in this chapter. Chapter III will focus in the available economic models for smart well technology development. Chapter IV will investigate five field cases developed using smart well technology. Economic evaluations of this project will be carried out to evaluate the technology's economic viability. Chapter V contains the conclusions and the recommendations of this study.

CHAPTER II

SMART WELL TECHNOLOGY OVERVIEW

2.1 Definitions

In this chapter, I will state the definition of "smart or intelligent well" as stated in the industry.

2.1.1 Schlumberger's Definition

A well equipped with monitoring equipment and completion components that can be adjusted to optimize production, either automatically or with some operator intervention[3]. Figure 2.1 shows the dynamic process of the Schlumberger model.

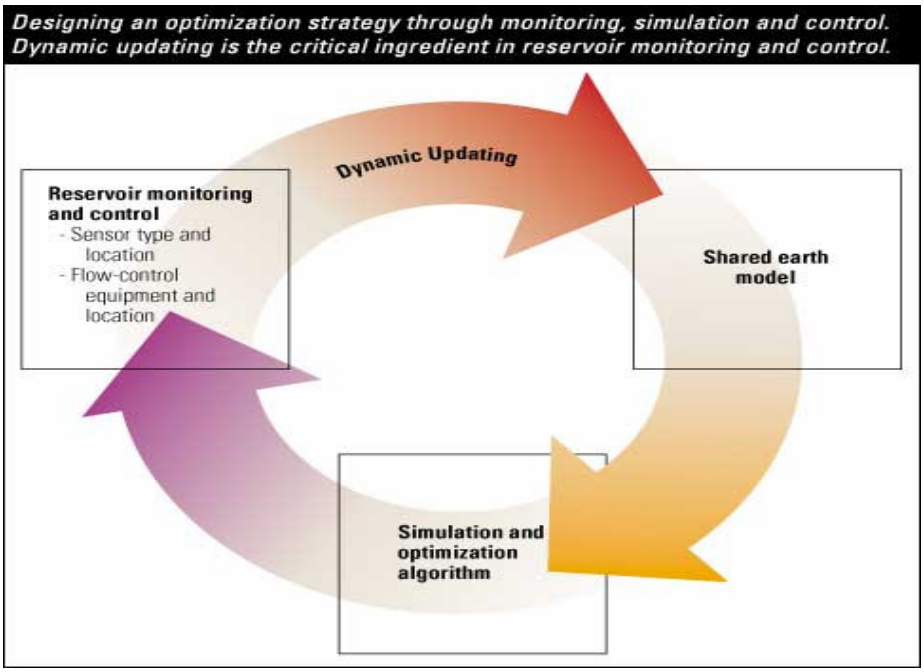

Figure 2.1: Schlumberger's Model for Smart Well Technology Process (courtesy of Schlumberger[4])

2.1.2 WellDynamics' Definition

WellDynamics defines a smart well as a well that combines a series of components that collect, transmit and analyze completion, production and reservoir data, and enable selective zonal control to optimize the production process without intervention[5] as shown in figure 2.2.

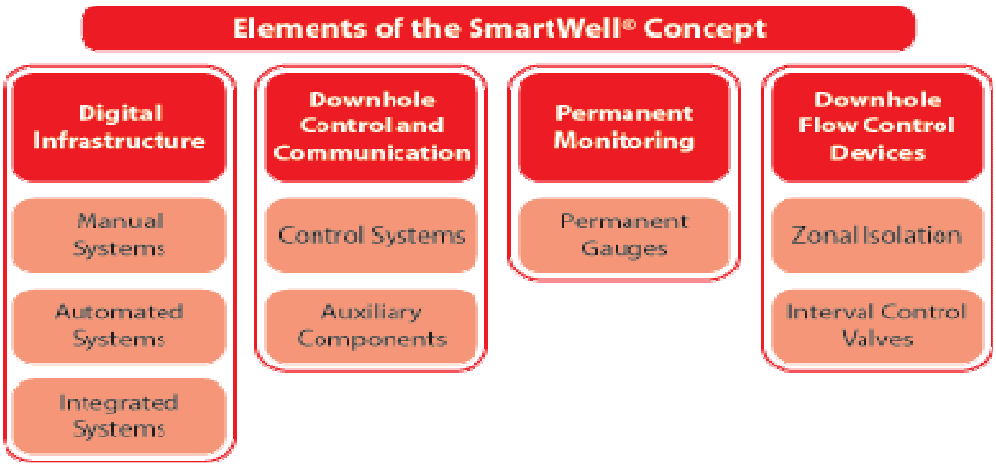

Figure 2.2 WellDynamics Elements of Smart Well Technology (*Courtesy of WellDynamics*[5])

2.1.3 Intelligent Well Reliability Group (IWRG) Definition

The intelligent Well Reliability Group (IWRG) defines an intelligent well as a well equipped with means to monitor specified parameters (e.g. fluid flow, temperature, pressure) and controls enabling flow from each of the zones to be independently modulated from a remote location (eg at the wellhead, or a nearby offshore platform, or a distant facility)[6].

2.1.4 Baker Hughes' Definition

Baker Hughes defines an intelligent well as implementation of fundamental process control downhole. Intelligent wells enable surveillance, interpretation and actuation in a continuous feedback loop, operating at or near real-time[7].

2.1.5 Definition Discussion

Many other companies have different organization of the word but the base definition is the same. However, the main question to be asked is these wells smart? The answer is simply not yet. Merriam-Webster dictionary defines intelligence as the ability to learn or understand or to deal with new or trying situations. The systems being installed around the world have very significant advantages than regular completions but they can not learn nor deal with any situation yet. For the sake of this study I am going to reference this technology as smart well technology (SWT).

2.2 Possible Applications of Smart Well Technology

As mentioned above, the main features of SWT is to provide the ability to control downhole fluid intake from reservoir while monitoring the pressure and temperature of the reservoir. As in any other technology in different industries, SWT should be utilized in areas with viable applications. Glandt[8] has discussed the reservoir management applications of the smart wells from an operator point of view. The paper discussed the prospects that could be possible fits for smart well technology. The following are the reservoir opportunities that the author discuses in his paper:

2.2.1 Optimal Sequential Production

In many fields reservoir are stacked on top of each other and wells usually cut through these banks. Many government agencies and reserves owners will not allow commingled flow and will require sequential production. In this case the well will be produced from one reservoir only tell the well reaches its economic limit and then it will be plugged and the next reservoir will be perforated and produced. This might result in long periods of time where the reservoirs are producing at a low rate till the economic limit and abandonment. However, smart wells could be deployed in such wells where alternations between productions from different reservoirs could be utilized to accelerate production from the reservoirs without the need for abandoning a reservoir to produce the other.

2.2.2 Commingled Stacked Pay

Achieving the maximum possible commingled rate (tubing restriction) of a well in stacked reservoirs is a lucrative project that would return high net present values for the well. However, differences in reservoir pressure and regulatory rules limit the possibility of achieving this goal. Smart well technology provides possible method to produce commingled reservoir in a sound engineering manner. Pressure balancing utilizing downhole chokes will allow the reservoirs to be co-produced without cross-flow and fluid loss. Produced volumes could be allocated utilizing production logging, geochemical fingering and individual pressure and rate calculations from each reservoir. These values can be reported to government agencies and should be utilized in reservoir simulation studies.

2.2.3 Oil Rims in Single Compartments

Horizontal wells have been very effective in thin oil rims gas and water zones. However, the production of such wells declines rapidly as soon as water or gas breaks through in well. Installing a inflow control valves in different locations along the horizontal section might help shut-off the unwanted effluent.

2.2.4 Oil Rims in Compartmentalized Reservoirs

Wells that are planned to produce different thin oil rims form different zones can utilize smart well completions to control flow from different zones. As producing zones get excessive gas or water production, these zones could be shut-in utilizing the downhole valves.

2.2.5 Drive-Recovery Processes

Many of fields in the world utilize some type of pressure support processes to recover hydrocarbons. Some of these drives are natural such as the gas cap or a strong water aquifer; other processes are designed by engineers to help support the pressure. Secondary recovery mechanisms include water flooding, gas injection, steam injection and polymer floods. However, these processes sometimes affect producing wells by having excessive injected fluid production through reservoir heterogeneities such natural fractures and super permeable zones.

2.2.6 Flow Profiling

Distributed temperature sensing technology is a part of smart technology (fiber optics) that could be used to provide an idea of flow profiles along the tubing. It could be used

to detect flow behind pipe and crossflow. This technology could be deployed in areas where production profiling is expensive or suspect.

2.2.7 Intelligent Multilaterals

Multilateral wells in the same formation have been proven to increase well productivity at a lower unit development cost. Maximum reservoir contact (5 Km of contact) wells have been developed in many fields and are showing great results. However, the possibility of unwanted effluent premature breakthrough in one of the laterals is strong. The premature breakthrough can adversely affect the whole well's productivity. Inflow control valves could be deployed in such wells to detect the lateral affecting the flow and remedial action could be taken.

2.2.8 Fluid Transfer for Sweep or Pressurization

The process of dump flooding has been used in the industry for a long time. The basic concept of such process is to utilize higher pressure gas or water zones to pressure up the producing formation to assist pressure maintenance. This method is economically sound due to the lack of injection surface facilities and the injection fluid cost. The main flaw in such process is the lack of control of the amount of the volumes being transferred from the high pressure zone into the producing zone. Smart well technology can provide operator some leverage on the amount of fluids being transferred. Downhole chocking is the only possible method to control the amount of fluids being injected.

2.2.9 Intelligent Waterflooding in Partially Fractured Reservoirs

Water injection is a common method of secondary recovery process or pressure maintenance practices in oil fields around the world. In many partially fractured reservoirs many injectors encounter natural fractures in the wellbore. These fractures could act as a pathway for water and might lead it the oil producing well. The water might load the well with water leading to premature rate decline. Smart valves could be installed along the path of the injector (segments), which leads to adequate identification of the thieve zone. This zone then could be controlled by the downhole valve and better injection efficiency could be obtained.

2.2.10 Auto Gas Lift

Oil producing wells usually intercept other reservoirs that contain an active gas cap. Smart well technology could be deployed in such setting and use the gas from the upper reservoir to lift the oil in the producing zone. Inflow control valves can control the amount of gas being used to lift the oil to meet the gas lift design standards.

2.2.11 Swing Producers

The author discusses a very interesting swing producer layout employing smart well technology. In this project an oil producer that utilizes auto-gas lift system where a gas zone is perforated and the gas is used to lift a deeper oil zone. However, gas production demands increase in certain times of the year. Utilizing the smart completion, the gas could be produced to surface instead of the oil and the gas demands could be met.

2.2.12 Other Possible Uses

The author mentioned some technically sound situations where smart well technology could be deployed in the future. Connector well is a concept that suggests connecting reserves from a different formation to an active well without installing any surface facilities. This idea is designed for offshore projects and should help reduce the cost of development by reducing the number of platforms.

Downhole production testing is a concept that explores the possibility of flowing a prospect formation to a depleted formation. Smart completion will allow measuring the average rate of production without the need to flow the well to surface. This concept is both practical and environmentally friendly. Smart abandonment is another application that the author explored in his review. In essence, smart abandonment concept suggests the installation of downhole monitoring systems for wells to be abandoned. The pressure and temperature data could be used in reservoir simulation studies and sweep monitoring projects. Many oil companies have adopted this concept in their reservoir monitoring wells.

Downhole geophones could be installed with permanent downhole monitoring system to provide reservoir imaging data. These repeatable seismic data should assist reservoir engineers and geologists in monitoring the sweep efficiency of the enhanced recovery technique.

2.3 Possible Benefits of Smart Wells

Smart well technology as noted in the section above has many applications in the oil industry. These applications can yield many operational and economic benefits. In the next section I will speak about the possible benefits of smart well technology.

2.3.1 Accelerated Production

One of the important aspects of current hydrocarbon production strategies is to accelerate the production from proved reserves. As oil prices reach record highs and the future market conditions are almost impossible to predict, acceleration of production will yield the best NPV for the project. Smart well systems can play a vital role in accelerating production especially in multi-layer reservoirs.

Commingled production from different reservoirs in the same well can be detrimental to the ultimate recovery. Crossflow and fluid dumping from different zones will cause unflattering recovery values. Drilling different wells to produce these zones can be very costly and will require high initial development cost. However, wells equipped with inflow control valves (smart wells) can produce different layers without reservoir communication.

A case study in the North Sea was developed by WellDynamics Company to investigate the possibility of accelerating the production of a two reservoir field[9]. Two simulation studies were performed to compare the regular zone by zone (conventional) production to avoid crossflow. The second simulation run was developed to illustrate the production profile by utilizing the smart well technology. Figures 2.3 and 2.4 show the results of the simulation.

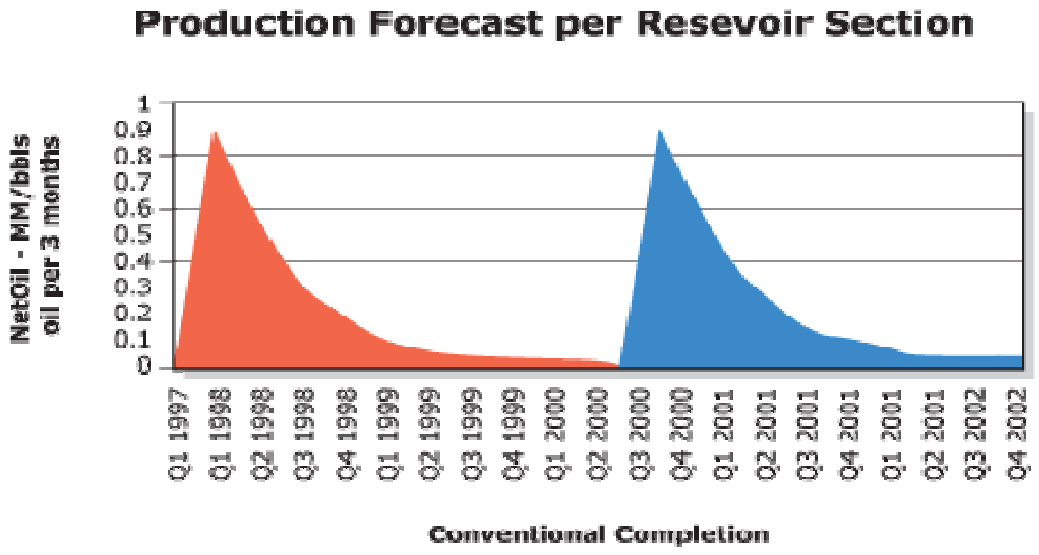

Figure 2.3: Production Forecast for Producing Each Reservoir By Itself (courtesy of WellDynamics)[9]

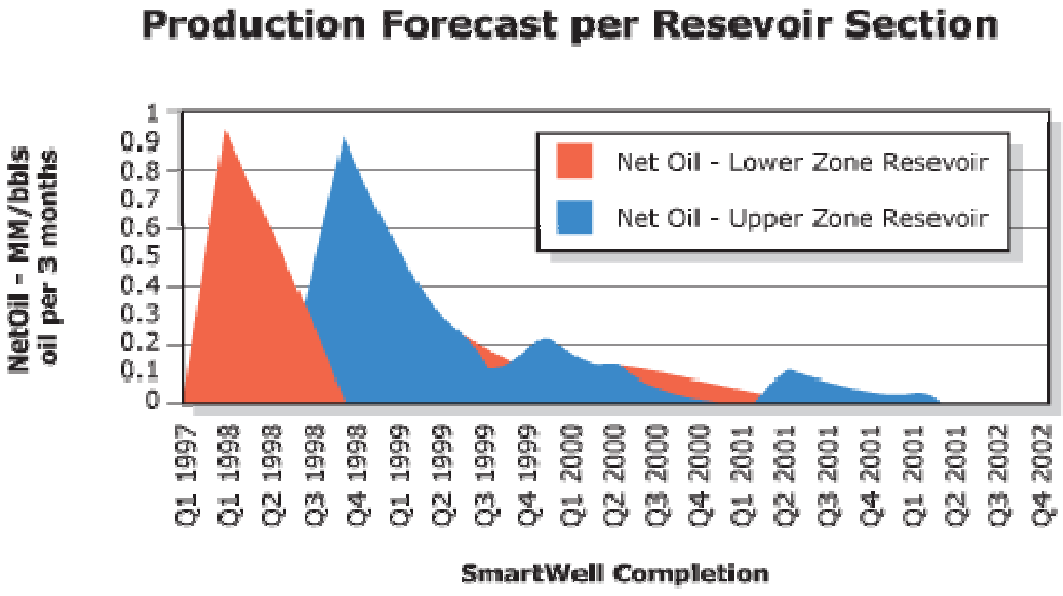

Figure 2.4: Production Forecast for Commingled Production Utilzing Smart Well Technology (courtesy of WellDynamics)[9]

2.3.2 Increase Ultimate Recovery

As energy demands increase rapidly, the goal of energy companies is to maximize ultimate recovery in an economically sound manner. Many hurdles meet the industry when trying to maximize ultimate recovery while operating under the economic limit. Intervention costs such as workovers, coil-tubing operations and other production enhancing operations are the main reasons for limiting the increase ultimate recovery. However, the new SW technology minimizes the future costs associated with intervention and reduce the safety issues that can be costly for operators. Maximum ultimate recovery for current producing fields and future development will be an important driver in the future oil demands.

A case study offshore Brunei was used to determine the applicability of smart well technology[10]. The simulation results indicate that both accelerated production and maximizing ultimate recovery were realized.

2.3.3. Reduction in Capital Expenditure

Reduction in capital cost can be categorized as the most important aspect of SW technologies. In the profit driven environment that oil and gas companies operate under, maximizing NPV is the main driver for any development project. The time value of money concepts implies that high capital expenditures will delay the payback period along with an overall reduction of NPV[9]. However, the applications under which CAPEX could be reduced are specific and it is not a global application. The specific viable applications will be discussed in section 4.1.

2.3.4 Reduction in Operating Expenditure

Operating expenditure (OPEX) is one of the most important aspects that control the economic visibility of the project. High OPEX will yield a high abandonment rate which will shorten the project life. I believe that SWT can help in reducing OPEX in some certain environments. Reducing the number of wells, less intervention (workovers) can be achieved by developing suitable fields with SWT technology which might reduce the OPEX costs[9].

2.3.5 Reduce Risk

During the research of SWT technology, many companies elected to use the term reduce operational risk. I will just use the phrase "Reduce Risk" to account for both operational risk "safety" and reservoir uncertainties. In terms of safety, SWT suitable fields may require smaller number of wells than conventional fields. The possible reduction of number of wells should reduce the risk of having safety problems that might cause operational failure. The risk of having operation problems in smart wells is present but the risk discussed in this section is the overall well drilling and completion risk.

The second type of risk reduction is associated with reservoir uncertainties[9]. This type can be linked to multi-lateral wells with many uncertainties in the reservoir such as fractures, faults and super-k zones. Inflow control valves (ICV) can eliminate pre-mature fluids breakthrough that might reduce the productivity of the well and affect production from other laterals in the well.

2.4 Design Criteria

As displayed in the definitions section, the main components of a smart well are the permanent downhole monitoring system along with the inflow-control valve (ICV). The permanent downhole monitoring system (PDHMS) provides the valuables real time or (near real time) pressure measurement of the zones. To date only one (PDHMS) could be installed in a single well in a location above of all downhole valves and zones. This limits the collecting of pressure data up and down stream from the inflow-control-valve. Service companies are working on providing pressure measurement down and upstream from each downhole choke valve.

Nodal analysis is a main factor in assessing the size of the valve and the tubing in smart well design[11]. Reservoir properties such as productivity index and expected rate govern the design size. If the smart well design contains more than one formation, all the formations properties should be used to design the best combinations of valves to provide best production or injection results.

Figures 2.5 and 2.6 are some results of field design:

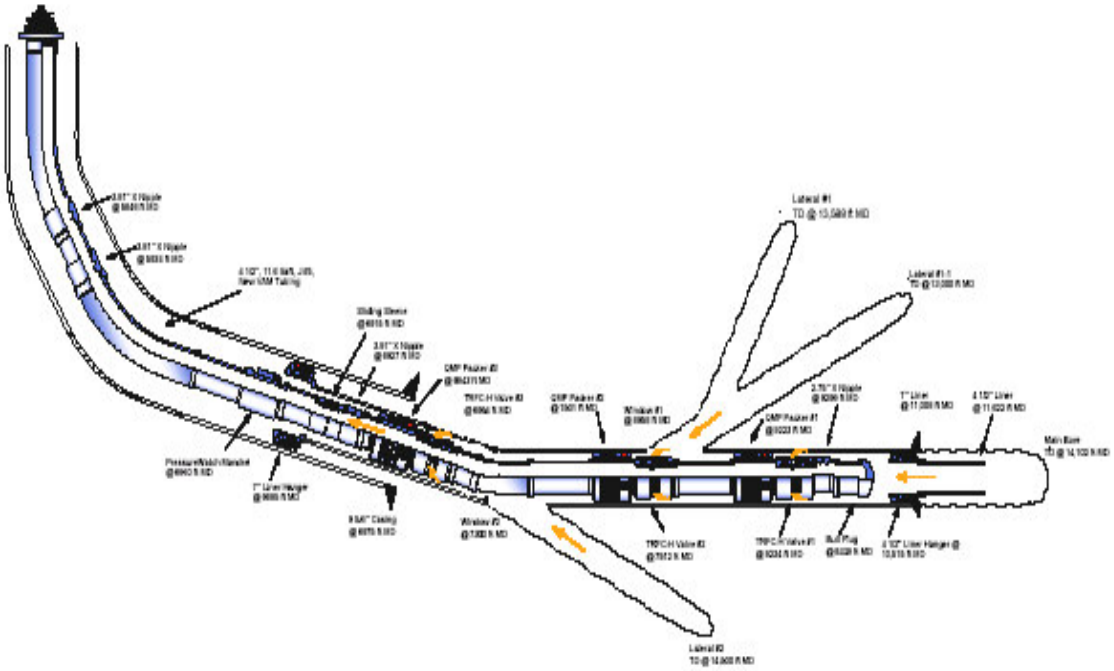

Figure 2.5: Example of a Smart Well Completion Layout

The following are the field results of the above illustrated well:

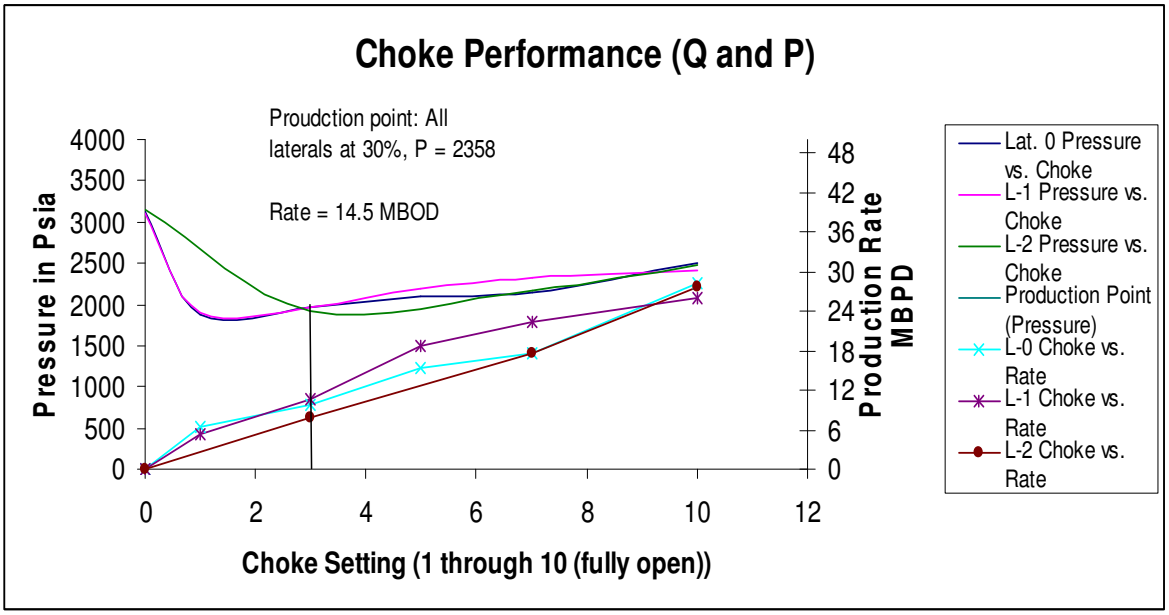

Figure 2.6: Well's Rate Based on Smart Choke Settings

Such tests indicate the productivity of each lateral and optimum rate could be found utilizing different combinations of choke settings or even shutting-in poor laterals that reduce that productivity of the well.

CHAPTER III

ECONOMIC MODELS FOR SMART WELL TECHNOLOGY

Petroleum projects as any business development project should be technically and economically feasible to be executed. Every project has to be thoroughly checked and many scenarios should be run and the best project to meet the company goals should be selected. Many oil companies select development projects based on the best economic outcome of the projects (maximizing NPV). However, some oil companies have different goals in field development projects such as maximizing ultimate recovery, reducing water production or minimizing intervention cost and many other goals.

In smart well projects standard petroleum engineering economics practices are used to evaluate projects. Many authors have written about ways to find the value of smart well completions and possible ways to assess their value prior to starting the projects.

3.1 Gai Model

Gai[12] has discussed the challenges and the difficulties that surround the measurement of smart well benefits. The author elaborated on different industrial points of view in regarding the benefits and the set backs that affect the overall values of smart well technology. The end product that the author proposed was a models that encounters options and risk analysis. Figure 3.1 is the proposed flowchart of the value assessment method proposed by the author:

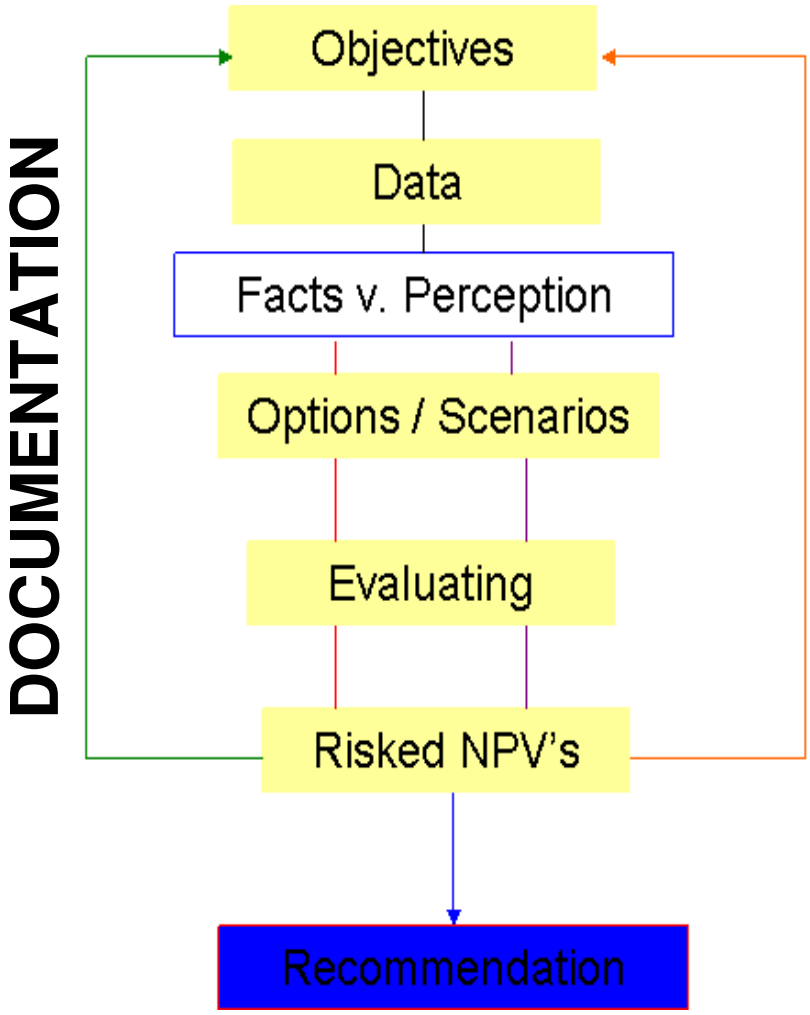

Figure 3.1: Flowchart of the Smart Technology Value Assessment Method (Reproduced from SPE 77941)[12]

This method is a process that is carried out in several steps with many scenarios in order to find the best economic case. The author proposes a very interesting and logical method to examine the applicability and the profitability of smart well technology in new field developments.

3.2 Sakowski, Anderson and Furui Model

Sakowski et.al[13] have explored the possible impact of smart well on the economics of field developments. The main idea discussed in this paper is the possible incremental NPV increase by utilizing smart well technology over conventional completions. This method as in the previous one uses reservoir simulation data and then economical data are generated based on the reservoir model. Figure 3.2 is a flowchart of this method:

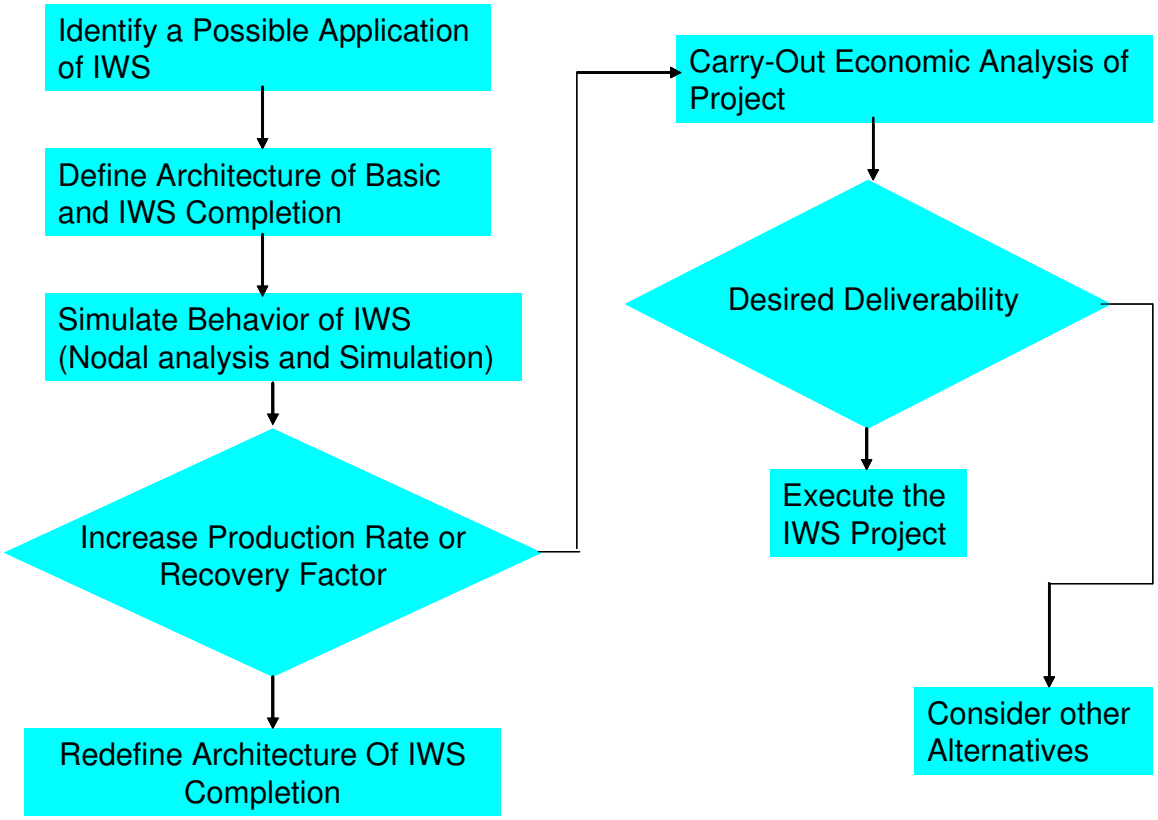

Figure 3.2: **Reservoir and Economical Analysis Processes for Smart Well Completion (Reproduced From SPE 94672)[13]**

The model described above is simple and fluid and complies with most of the project analysis methodologies. Completion architecture and reservoir simulation models

are the main drivers in this model. Most of project should carry out similar analysis prior to selecting development type.

Both methods discussed above are great ways to generate different scenarios and their probable economic outcomes. Reservoir simulation, nodal analysis and cost data should be accurate, and reliable. Reservoir simulation is the least accurate of the other data but nevertheless it is still a great tool to estimate the rate of the development project.

In this next section I will take the task of reviewing fields already developed by smart well technology. Different scenarios will be suggested to draw a solid comparison between the SWT and the regular completions scenarios.

CHAPTER IV

ECONOMIC REVIEW OF ACTUAL FIELD CASES

4.1 Giant Field Development of Onshore Carbonate Field

Haradh-III field is part of the great Ghawar field in Saudi Arabia. The reservoir geology along with the completion design is discussed in a paper by Afaleg *et.al*[14]. I will discuss the geology of the reservoir along with the reasons for smart completion applicability in the field.

The Arab-D reservoir is a carbonate reservoir overlain by an anhydrite layer. The reservoir is divided into four zones according to rock quality. The top zone is referred to as zone-1 and it is a thin low porosity zone. The rock is predominately dolomitic lime grainstone.

Zone-2 is separated from zone-1 by a thin anhydritic dolomite layer. Zone-2 is subdivided into two sub-zones zone-2A and zone-2B. Zone-2A is a high porosity and high permeability rock that is composed of skeltel-peloidal lime grainstones. The quality of the rock in zone-2A worsen upward with lower permeability and porosity with burrowed packstone and dolomitized mudstones. Vugs are common in the quality parts of zone-2A which capitulate super-permeable zones.

Zone-2B follows zone-2A and its lower part show moderate porosity and permeability of stromatoporoid rudstone to floatstone with a a wackestone/packstone matrix. This rock then improves upward to a high prosity/permeability skeletal-peoloidal packstone to grainstone at the bottom to a burrowed packstone at the top. The uppers zones usually show higher presence of dissolution vugs that cause local super-

permeability zones. Zones 3 and 4 show lower quality rock with low permeability and it is observed that the zones have high abundance of natural fractures due to the drap folding of the reservoir.

The fluid flow characteristics of the reservoir indicate that the combination of the super-permeable streaks along with the natural fractures will have a significant role in the reservoir recovery processes. The fluid flow mechanisms were discussed thoroughly in the paper by Pham *et al*[15]. The main concept to be understood in this reservoir is that the reservoir is not a naturally fractured reservoir but it is a reservoir with fractures.

Super-permeable zones act as productivity enhancers when the one phase (oil) is being produced (Figure 4.1). However, as water moves upward in the reservoir and reaches the super-permeable zone it acts as a productivity detractor and most of the time causes the well to die (Figure 4.2).

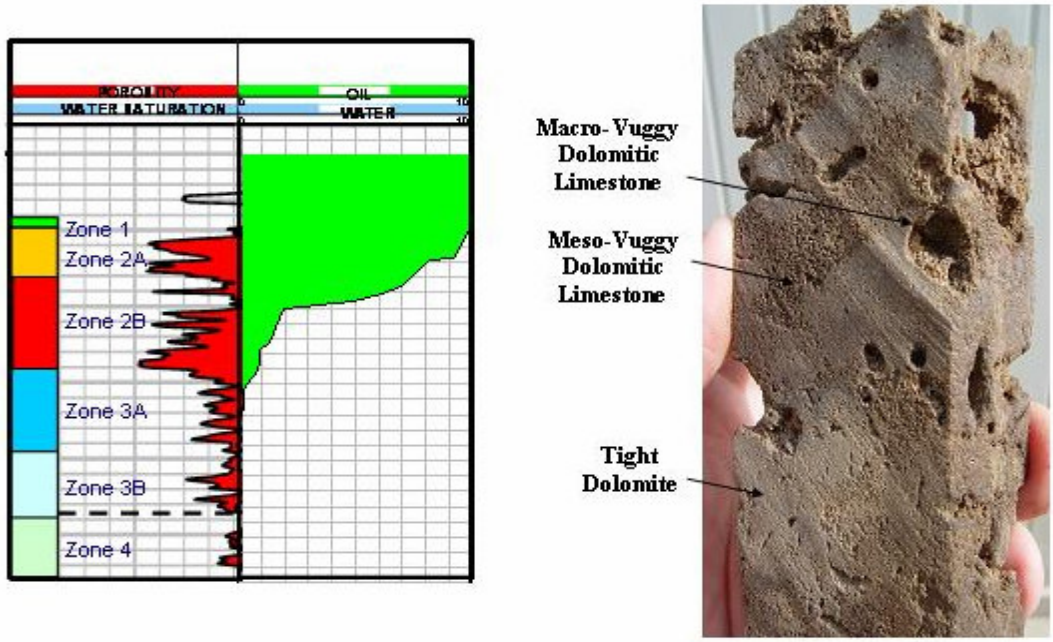

Figure 4.1: Super-Permeable Zone Acts as a Productivity Enhancer[15]

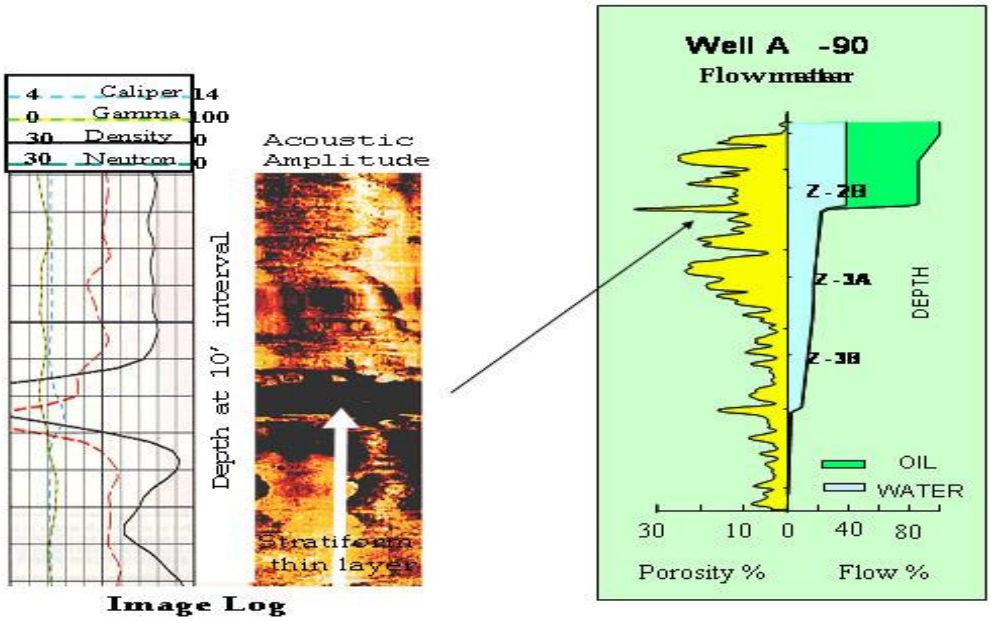

Figure 4.2: Super-Permeable Zone Acts as a Productivity Detractor[15]

The same analogy can be transformed for vertical fractures in the reservoir. Horizontal wells have shown high production rates after intersecting fractures but as soon as injection water has reached the bottom of the reservoir and connected with the vertical fracture the productivity of these wells had decreased with high water cuts (Figure 4.3).

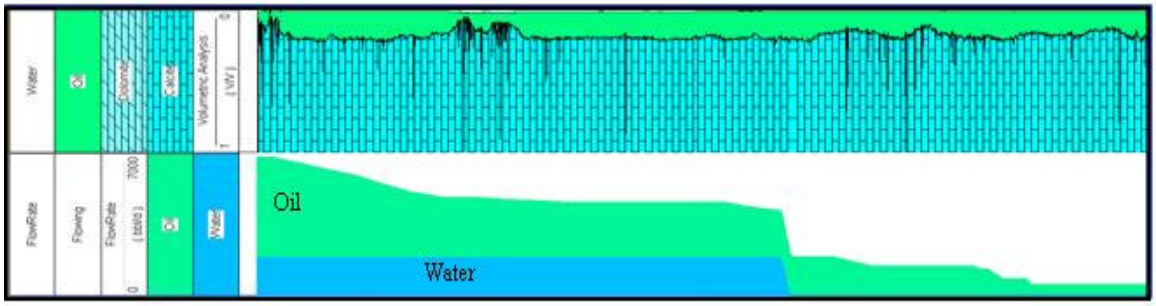

Figure 4.3: Horizontal Well Intersecting Vertical Fracture[15]

4.1.1 Development Scenarios and Economic Analysis

The field could be developed in several completion strategies such as vertical, horizontal and multi-lateral developments. The large field is planned to be produced at 300,000 BBL/day[16]. Vertical, horizontal and multi-lateral development scenarios were prepared from early trial wells and table 4.1 indicates their requirements.

Table 4.1: Haradh Field Requirements for Full Field Development.

Type	Rate/well STB/D	Number of Well Required for Field Development
Vertical	1,100	280
Horizontal	3,500	80
MRC	10,000	32

Maximum reservoir contact (MRC) wells consist of three laterals with a minimum of 5 kilometers of reservoir contact. However, the reservoir's geology necessitates the installation of downhole control valves to control fluids inflow from each lateral.

4.1.2 Economic Requirements

The field is planned to be produced at 300,000 STB/D, hence the income out of the field will be the same. In such projects the main controllable factor is to reduce the capital expenditure to maximize the economic outcome of the project. The costs of the previously mentioned development scenarios will be examined to find the lowest development cost. Table 4.2 reveals the average costs of drilling and tie-in.

Table 4.2: Haradh Field Wells' Drilling Costs Data.

Type	Cost/Well, $
Vertical	1,200,000
Horizontal	2,800,000
Smart	5,700,000

The formula used for the calculation of the cost development cost is;

$$\text{Cost} = (\#\text{Of Wells} * \text{Cost}/\text{Well}) + (\#\text{Of Wells} * \text{Tie-in Cost}) \ldots\ldots\ldots\ldots\ldots\ldots 4.1$$

The results of these calculations are shown in table 4.3:

Table 4.3: Final Development Costs for all Scenarios for the Haradh Field.

Type	CAPEX, Million $	Relative Cost to Vertical Development
Vertical	546	1
Horizontal	284	0.52
Smart	206.4	0.38

The high cost of vertical well development was a result of the high number of wells and surface tie-ins required to operate the field under the required rate. Horizontal well development indicated a 50% savings from the vertical development due to the less well and surface requirements. Maximum reservoir contact wells equipped with smart well technology showed the cheapest results of the other types.

4.2 Commingled Production for an Offshore Nigerian Field

The Garben field is located in the Nigerian delta near the developed Usari field[17]. The field consists of seven reservoirs with many uncertainties due to the bad seismic data and lack of wells drilled in the area. All the reservoirs are sandstones with heavy faulting in the area.

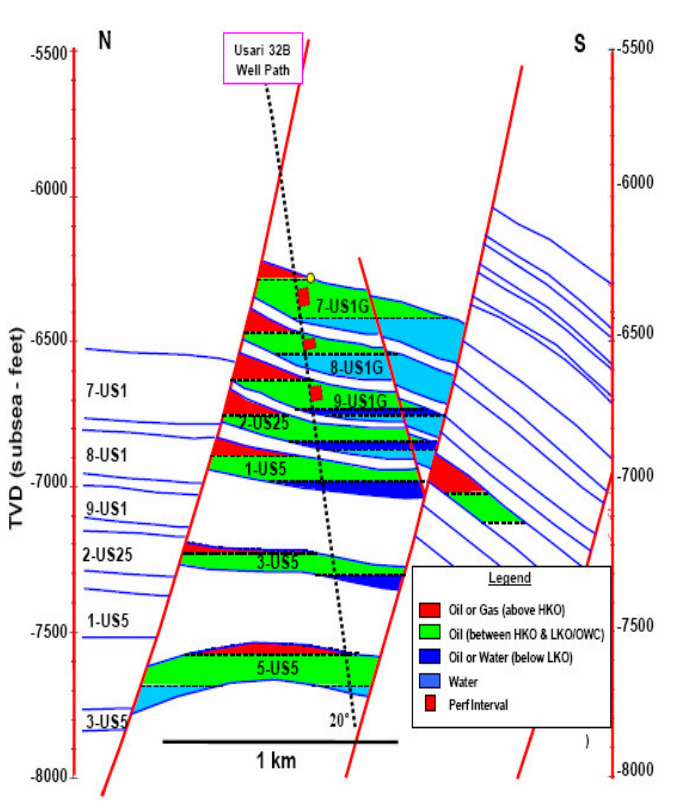

Figure 4.4: Garben Field General Geology (After Brock *et al*)[17]

As indicated in figure 4.4 the reservoirs are small and only require three wells for development for all seven reservoirs. The first well was drilled to produce three reservoirs under commingled flow with smart well completion.

The three reservoirs were tested separately utilizing the smart well completion and test results are illustrated in figure 4.5:

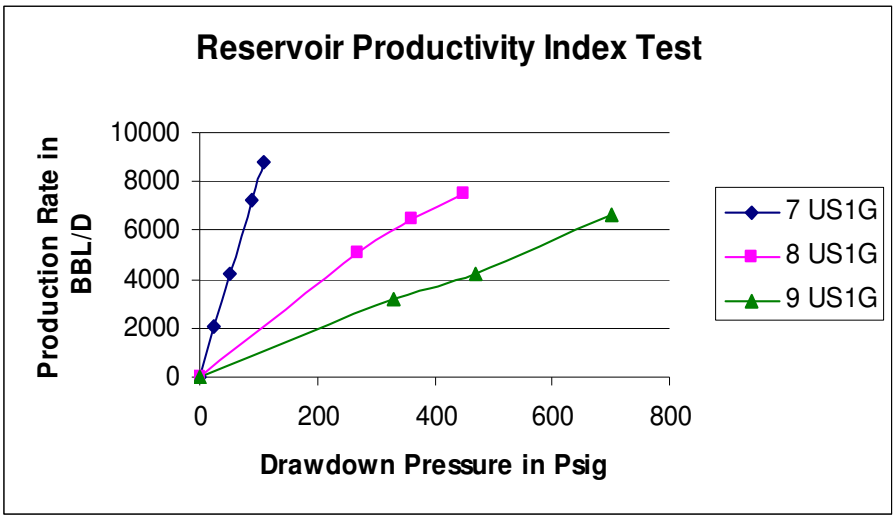

Figure 4.5: Garben Field's Reservoirs Productivity Tests (Reproduced From SPE 101021)[17]

The production tests indicated that the productivity indexes of the reservoirs are shown in table 4.4:

Table 4.4: Productivity Index Values for Each Reservoir.

Reservoir	Productivity Index, STB/D/psi
9-US1G	20
8-US1G	9
7-US1G	85

4.2.1 Economic Analysis

The main concept applied in this project to calculate the smart well cost and compare it to the development cost of the three wells (one well per reservoir). The first year of production for the smart well is provided. The expected rates for the single reservoir wells will be calculated using the productivity index values for the reservoirs along with the operational drawdown.

$$Q_{reservoir} = PI_{reservoir} * Drawdown \quad \text{.....} 4.2$$

Tables 4.5 and 4.6 show the production results for the two cases:

Table 4.5: All Wells Are Producing at a Drawdown of 120 psig.

Month	Qsmart, STB/D	Qus7g, STB/D	Qus8g, STB/D	Qus9g, STB/D
1	12,400	10,080	1,129	2,354
2	12,000	10,080	1,129	2,354
3	11,500	10,080	1,129	2,354
4	11,000	10,080	1,129	2,354
5	11,000	10,080	1,129	2,354
6	11,000	10,080	1,129	2,354
7	11,000	10,080	1,129	2,354
8	11,000	10,080	1,129	2,354
9	11,000	10,080	1,129	2,354
10	11,000	10,080	1,129	2,354
11	11,000	10,080	1,129	2,354
12	11,000	10,080	1,129	2,354

Table 4.6: Smart Well Producing at 120 psig and all the Other Wells Are Producing at a Drawdown of 200 psig.

Month	Qsmart, STB/D	Qus7g, STB/D	Qus8g, STB/D	Qus9g, STB/D
1	12,400	16,800	1,882	3,923
2	12,000	16,800	1,882	3,923
3	11,500	16,800	1,882	3,923
4	11,000	16,800	1,882	3,923
5	11,000	16,800	1,882	3,923
6	11,000	16,800	1,882	3,923
7	11,000	16,800	1,882	3,923
8	11,000	16,800	1,882	3,923
9	11,000	16,800	1,882	3,923
10	11,000	16,800	1,882	3,923
11	11,000	16,800	1,882	3,923
12	11,000	16,800	1,882	3,923

The wells are being produced at constant rate due to the low pressure drawdown from the reservoir. This low drawdown is selected to avoid early water and gas breakthrough from aquifer and the gas cap. The aquifer and the gas will not be a big

factor unless the wells are being overproduced which will cause water and gas encroachment through conning.

The completion time data along with the price estimates of drilling and smart well completion equipment were used to calculate the cost of the smart well. The same concept was used to calculate the cost of the conventional wells.

$$COST_{Smart} = [\$_{smartequipement}] + \left[\left(\$/day\right)_{rig} * Drilling time (days)\right] + [Well Equipement Cost] \quad .....4.3$$

$$COST_{Regular} = \left[\left(\$/day\right)_{rig} * Drilling\ time\ (days)\right] + [Well\ Equipement\ Cost] \quad .....4.4$$

The time of smart completion installation was incorporated in the drilling time calculation. Tables 4.7 and 4.8 illustrate the factors taken into account for the cost calculations:

Table 4.7: Drilling and Completion Time Breakdown for the Garben Field.

Well Type	Drilling Time, Days	Completion Time, Days
Smart well	40	40
Regular Well	40	19

Table 4.8: Cost Data for the Garben Field.

Rig Cost, $/Day	95,000
Well's Equipment Cost, $	3,000,000
Smart Completion Cost, $	1,700,000

The calculations showed that a smart well will cost **19.3** Million dollars and a regular well for one reservoir will cost **15.6** Million dollars. Due to the lack of information of the wells' future performance net present value could not be performed. Furthermore, to normalize the comparison between the smart well and the three wells

other economic factors were used. The concepts of dollars spent per barrel produced after one year along with the payback period were used. The operating expenditures were assumed to be 10% of the income of the wells' production. The results found are illustrated in figure 4.6 and table 4.9:

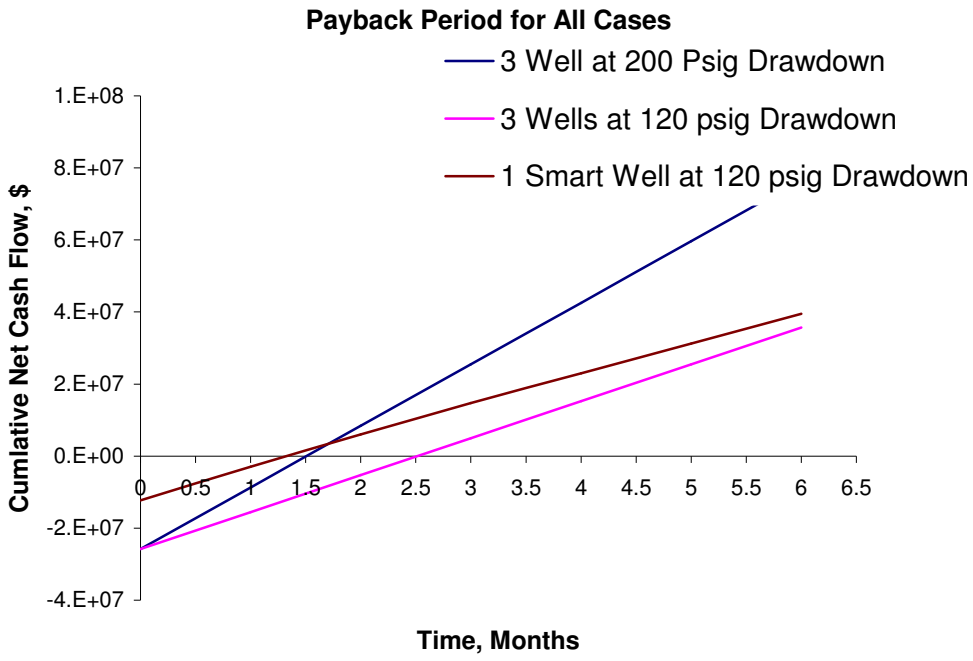

Figure 4.6: Pay Back Period for All Development Scenarios in the Garben Field

Table 4.9: Cost per Barrel Produced for all the Development Scenarios for the Garben Field.

case	$ spent/bbl produced	payback period, months
smart well	**5.5**	**1.3**
3 wells at 120 psi drawdown	**7.7**	**2.5**
3 wells at 200 psi drawdown	**5.6**	**1.5**

The results indicate that smart well completion provide cheaper cost per barrel produced when compared to conventional completion in this case. However, this does not mean that NPV analysis should agree with these results. Moreover, the ultimate recovery may not be higher for the smart well.

4.3 Multi-Lateral Well Overlain by a Gas Cap Offshore Norway

The Oseberg Field is located offshore Norway in the North Sea[18]. This field is considered a giant field with access of 3 billion barrels in place. The Tarbert, Ness and the ORE formations make up the good reservoir quality zones for the field. The well in focus in this study was drilled in the Ness formation. Sand channels are present in the formation which confines the communication between quality rock sections in the reservoir.

4.3.1 Why Smart Well Technology?

The field was initially developed on deviated well technology. However, with the long production history in the field the oil column shrunk from 200 ft to 20-40 ft. The deviated wells have experienced high GOR as the gas-oil contact got deeper in the reservoir. Therefore, horizontal wells were introduced to the field to mitigate the gas encroachment problem and avoid high water cuts from the water aquifer.

However, as production continued the horizontal wells were also experiencing access gas production. Therefore, multi-lateral wells with smart completion were suggested as a solution to continue production without access gas production. Laterals with high gas oil ratio can be restricted or shut-in while other laterals can be still produced from the same well.

The well that is being examined in this study is a four-lateral horizontal well in the Ness formation. A smart well completion was installed in this field as a mean of controlling unwanted fluids when necessary. Initial production tests indicated access gas production from well (all laterals open). The ICVs were adjusted to minimize the gas production which might increase the water production. After several test a certain combination of ICV positions showed a smaller GOR from the well along with oil production increase. Figure 4.7 shows the results of the smart well case against the conventional well:

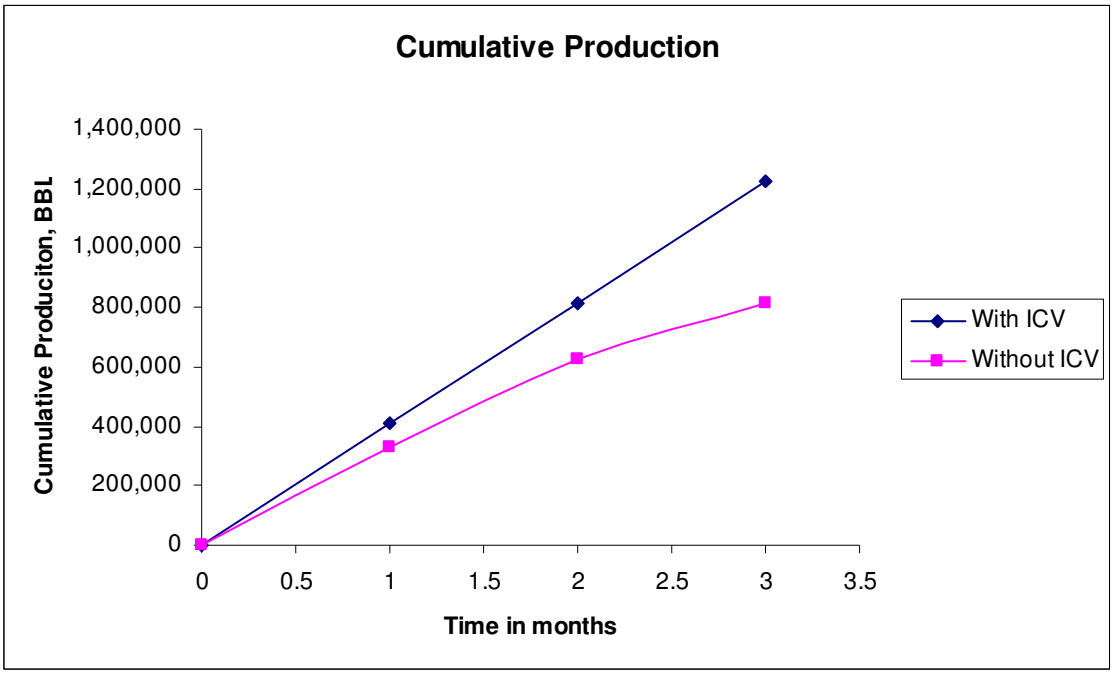

Figure 4.7: Cumulative Production History for the Osberg Field (Reproduced from SPE -62953)[18]

4.3.2 Economic Analysis

The results of the wells production tests will be used to create an economic comparison between the smart well and a multi-lateral well without any inflow control option. The

method used in this case is similar to the method used in the Nigerian field discussed earlier. The first three months of production will be used to create the dollars spent bbl produced.

The cost data along with the drilling time analysis are given in tables 4.10 and 4.11:

Table 4.10: Drilling Time Estimates for the Osberg Field.

Well Type	Time, Days
Multi-Lateral	**70**
Multi-Lateral With Smart Completion	**80**

Table 4.11: Drilling Cost Estimates for the Osberg Field.

Rig Cost, $/Day	**95,000**
Well's Equipment Cost, $	**3,000,000**
Smart Completion Cost, $	**2,200,000**

The results of the economic review revealed that the smart well completion has a cheaper cost per barrel produced than the conventional multi-lateral completion. Also, more reserves have been exploited in the production time period. Furthermore, the payback period is slightly quicker for smart well completion than the multi-lateral well. Figure 4.8 and table 4.12 show the economic analysis from this field.

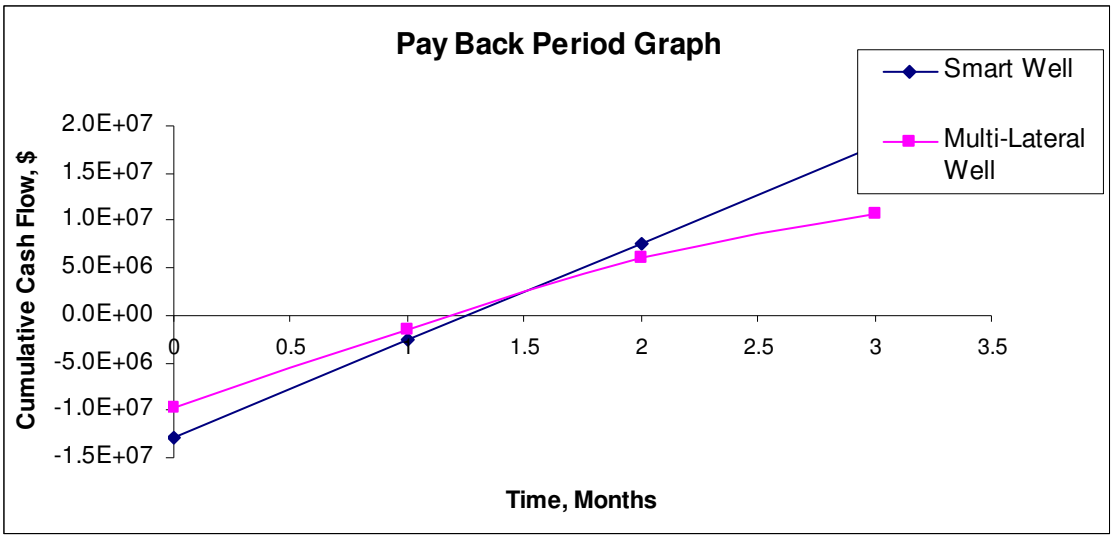

Figure 4.8: Pay Back Period Graph for the Osberg Field

Table 4.12: Cost per Barrel Produced for all the Development Scenarios for the Osberg Field

case	$/bbl produced	payback period, months
smart well	11	1.25
multi-lateral well	14	1.2

4.4 Multi-Lateral Well Under Pattern Injection Offshore Norway

The Gullfaks South Statjford field is located offshore Norway. The limestone reservoir has low permeability and is the fluid type if light oil[19]. Multi-lateral wells in an injection-production pattern were introduced to seize the pressure decline in this mature field. However, the water cut started increase in the field with some wells reaching 99% WC and a field wide average of 75%.

The smart completion was suggested to restore productivity in some of the high water cut producers. A four-lateral horizontal well was picked as a trial well to check the

applicability of smart completion in the filed. The well was initially drilled as a four-lateral horizontal on a producer-injector pattern. A workover was performed to install the downhole control valves in this well. The smart completion revealed that two laterals are producing mostly water without any oil. These laterals were then shut-in and productivity was restored to the well.

4.4.1 Economic Analysis

This field presents itself as a very interesting case because of the long production history with smart well completion. I have chosen to run three completion installation cases with different oil price scenarios. The first case consists of the actual production and completion history. The second case will assume that the smart completion was installed after the well was drilled. However, the production will be back to production after two and a half year as the operated can quickly detect the ineffective laterals by the use of smart well testing.

The third case will assume that the well was abandoned after three years of production without any remedial actions. The production profiles of the three cases are shown in figure 4.9-4.11.

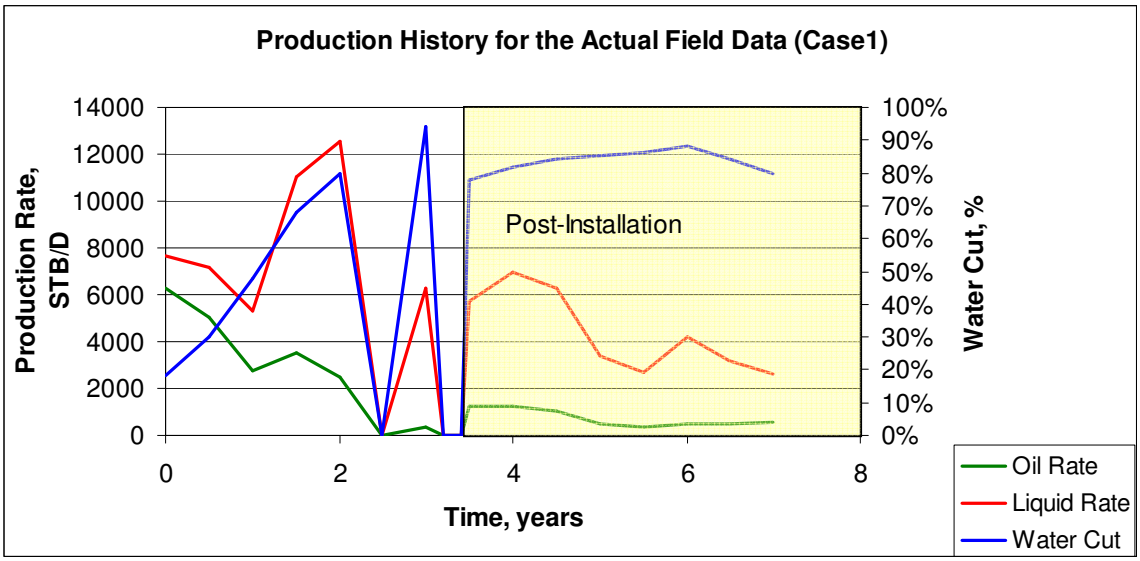

Figure 4.9: Production History for the Smart Well in GullFaks Field (Reproduced from SPE-102982)[19]

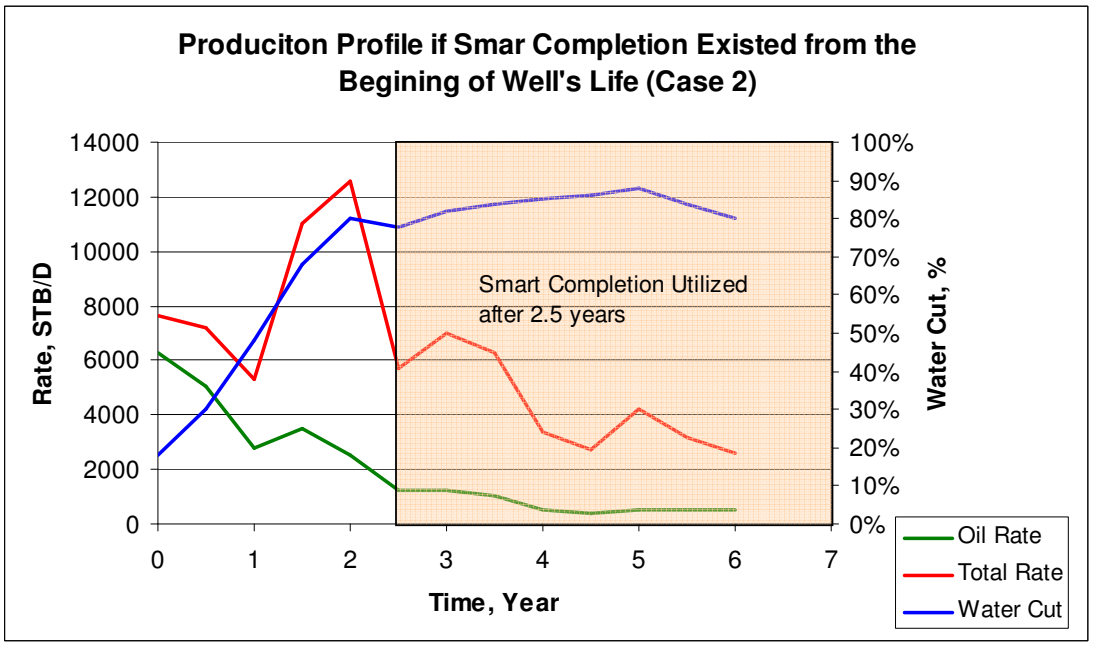

Figure 4.10: Expected Well's Rate if Smart Well is Used after 2.5 Years

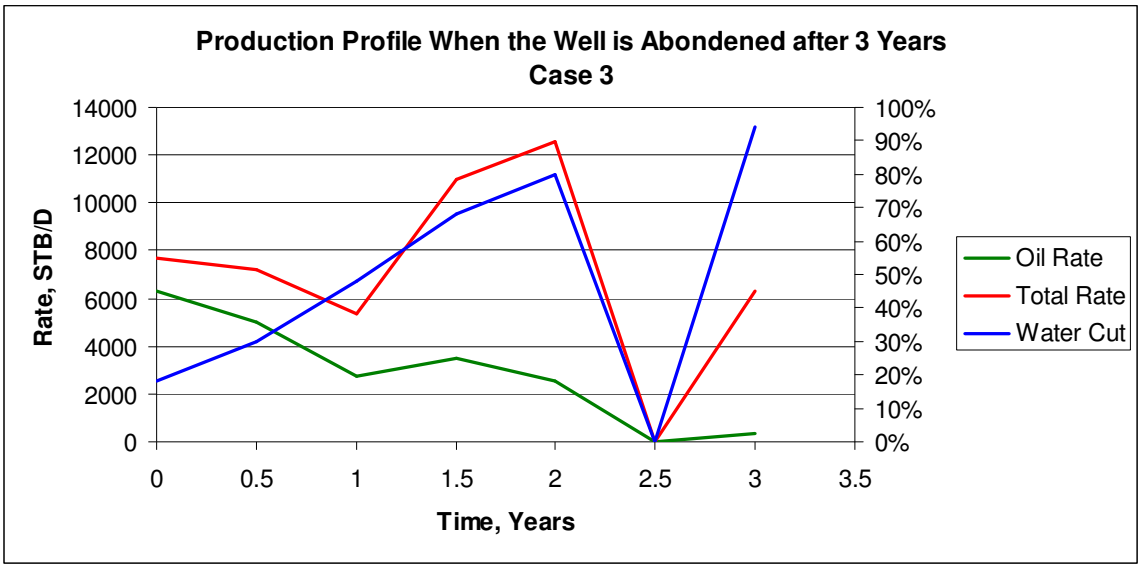

Figure 4.11: Production Rate if the Well was Abandoned after 3 Years

Simple net present value analysis will be used to determine the economic values of these projects. These projects are all assumed to reach economic limit. Table 4.13 will illustrate the economic factors used in this study. These three cases will be run for three oil price scenarios to investigate the role of oil price in the economics of this project.

Table 4.13: Estimated Rig Time and Cost Data for the GullFaks Field.

Rig Rate, $/Day	95,000
Drilling Time, Days	90
Workover Time	10
Well Equipement Cost, $	3,000,000
Smart Completion Cost, $	2,200,000
Water Treatement Cost, Cents/BBL	50.0
OPEX,% of Revenue	5%
Discount Rate	10%

A sample calculation for the first case under 40 $/BBL is shown in table 4.14 to show the methodology of the calculations[20].

Table 4.14: Sample NPV Calculation for Case 1 and Oil Price of 60 $/bbl.

Time, Years	CAPEX	Produced Oil, STB	Produced Water, STB	Income, MM$	OPEX, MM$	Profit, MM$	NPV, $
0	11,550,000					-11.55	-11.55
1		1,715,357	1,583,407	102.92	5.94	96.98	88.17
2		1,072,098	1,905,952	64.33	4.17	60.16	49.72
3		352,261	2,850,111	21.14	2.48	18.65	14.01
4	4,150,000	258,511	2,091,591	15.51	1.82	9.54	6.52
5		321,629	1,516,253	19.30	1.72	17.57	10.91
6		183,788	1,177,606	11.03	1.14	9.89	5.58
7		187,234	982,980	11.23	1.05	10.18	5.22
						Project NPV, $ =	168.58

The results of the calculations indicated that the installation of the smart completion will improve the economic outcome of the well. Furthermore, the ultimate recovery will be more if the completion is installed.

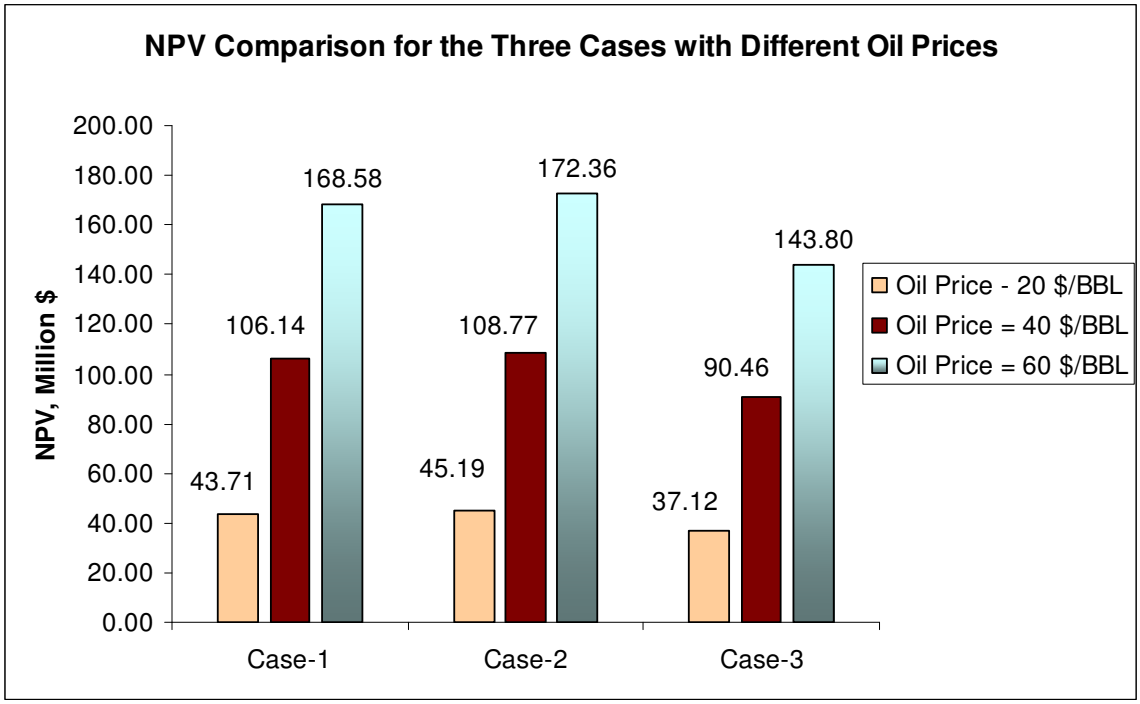

Figure 4.12: NPV Analysis for the Three Development Scenarios under Different Oil Prices

The analysis suggests (as shown in figure 4.12) that the oil price plays a pivotal role in the decision making process for smart well installation. The high oil price case showed the better results which suggests that the higher the price the more attractive the

installation. It has to be noted that the project could have not put the well back in production which will reduce the overall NPV of the project. However, risk is a part of the petroleum industry and in this case the project has returned a good increase in the NPV.

4.5 A Small Onshore Field Development in the Middle East

The AH field is an onshore field with two carbonate commercial reservoirs. Some of the reservoir properties are significantly different in the two reservoirs. Table-4.15 illustrates the complete reservoir properties for both formations.

Table 4.15: AH Field Reservoir Properties.

Reservoir	K	H
Depth, ft	8,400	9,800
Khoriz, md	290	100
h, ft	80	100
KH, md-ft	23,200	10,000
μ, cp	1.70	0.75
Bo, BBL/STB	1.06	1.19
ϕ, %	21	19
Kv, md	26	25
API	28	35
Pressure, psi	4,140	4,843

The field is expected to be produced at a plateau of 100 MSTB/Day. The reservoirs are different in size as illustrated in figure 4.13.

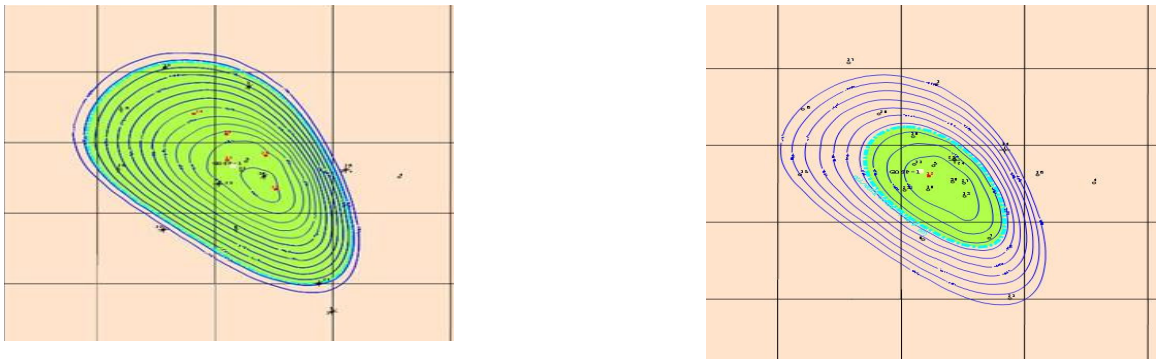

Figure 4.13: H and K Reservoir Structure Map

The Babu and Odeh[21] method was used to calculate the expected rates of the horizontal well cases.

$$q = \frac{\sqrt{k_y k_z}\, b\left(\bar{p} - p_{wf}\right)}{141.2 B_o \mu \left[\ln\left(\frac{A^{0.5}}{r_w}\right)\right] + \ln C_H - 0.75 + s_R + s} \quad \text{.....4.5}$$

The multi-lateral wells calculations were also estimated using the Babu and Odeh model. However, the junction pressure where the two reservoir fluids met had to be equalized. Tables 4.16 and 4.17 show the expected rates for all the cases run in this study.

Table 4.16: Expected Rates for Horizontal Well Designs.

Design	*500 m Well*		*750 m Well*		*1 Km Well*	
Reservoir	*Rate, STB/D*	*Pth, psi*	*Rate, STB/D*	*Pth, psi*	*Rate, STB/D*	*Pth, psi*
K	8911	586	12500	485	16800	430
H	8000	586	11000	900	14900	778

Table 4.17: Multilateral Well Production Rate Prediction.

Pjunction	**3340**	**psi**
Rate	**22,500**	**STB/D**
Pth	**685**	**psi**

4.5.1 Economic Analysis

Utilizing the above mentioned production predictions the following development scenarios were found (table 4.18).

Table 4.18: Number of Wells Required for Field Development.

Well Type	*500 m Well*		*750 m Well*		*1 Km Well*		Smart Well	
Reservoir	K	H	K	H	K	H	Both	H
Number of Wells	2	10	2	7	2	5	2	4

The number of wells for K reservoir was limited to two wells due to the small size of the reservoir. Two commingled wells equipped with smart well completion along with four H reservoir wells were chosen for the smart well development plan. The commingled wells were equipped with smart completion to control the flow from each reservoir.

The average drilling costs were collected from fields nearby the AH field. This data was used to compile the capital expenditure values for the development scenarios. The results are tabulated in tables 4.19 and 4.20.

Table 4.19: Estimated Drilling Cost per Well.

Well Type	*500 m Well*		*750 m Well*		*1 Km Well*		Smart Well
Reservoir	K	H	K	H	K	H	Both Reservoirs
Cost/Well, MM $	2.80	3.00	2.90	3.10	3.00	3.20	5.50

Table 4.20: Overall Development Costs for All Scenarios.

Well Type	*500 m Well*	*750 m Well*	*1 Km Well*	*Smart Well*
Drilling Cost, MM$	35.60	27.50	22.00	24.20
Tie-In Cost, MM $	9.00	6.75	5.25	4.50
CAPEX, MM $	44.60	34.25	27.25	28.70

The calculations indicate that the best development scenario is the 1 Km horizontal wells for both reservoirs. The smart well scenario does provide a good development cost but it is still not the most economic scenario. This higher cost is caused by the low number of conventional wells required to develop this small field.

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

On the basis of this research I have come up with following conclusions:

1. The actual field data for smart well technology suggests a greater economic return than conventional completion.
2. Smart well technology economics are dependent on oil prices. In many instances, the installation looks more attractive as the oil price increases.
3. Offshore multi-laterals and commingled pay production projects are excellent environments for smart well technology implementations.
4. Smart completion wells cost in average 35% more than conventional drilling in offshore development. They cost 48% more in onshore developments.
5. The cost of the smart completion in smart wells is in average 15% of the well's total cost in offshore developments. In onshore developments it usually averages 28% of the total well's cost.
6. Smart multi-laterals can provide a significant capital expenditure reduction.
7. Smart well technology can increase the development cost in small onshore fields with limited number of wells.

5.2 Recommendations

Based on this research, the following recommendations are suggested:

1. The implementation of pre-development or re-development trial tests are encouraged for smart well completions.
2. Smart well technology should be used in multi-lateral wells that are developed in high geological risk areas.
3. Evaluate the economic impact of smart wells that do not produce any oil, such as, smart injectors and dump flooding wells as more data is collected.

NOMENCLATURE

SWT Smart Well Technology

NPV Net Present Value

WC Water cut, %

STB Stock-Tank-Barrel

C_H Shape Factor

B_0 Oil Volume Formation Factor, BBL/STB

h Net thickness, ft

S_r Partial Penteratoin skin

S Skin Factor

k Reservoir permeability (horizontal if not denoted), md

k_z, Permeability in the Z-Direction, md

z_y Permeability in the y-Direction, md

p_{avg} Average reservoir pressure, psi

p_{wf} Flowing bottomhole pressure, psi

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