MATERIAL BALANCE APPLICATION FOR BROWNFIELD DEVELOPMENT

A Thesis Presented to the Department of Petroleum Engineering

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MASTER OF SCIENCE IN PETROLEUM ENGINEERING

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ABSTRACT

The need to re-develop one of the Brown fields located in the Niger Delta area of Nigeria was necessitated by the fact that there are still three undeveloped reservoirs in the field.

A total of six stacked reservoirs, A100 to A600 (all oil bearing with associated gas) were penetrated between 8552 ftss and 10652 ftss by APV-1 well. Reservoir blocks A200 and A600 are the largest in the field accounting for 77% of the total field STOIIP. The well was completed with a Two String Multiple (TSM) on the two levels, with the short string producing from the A200 reservoir and the long string producing from the deeper A600 reservoir, A300 behind the sleeve.

The purpose of this research is to identify the best developmental plan to produce the reservoirs, either with a TSM completion or with a Smart well completion based on the economics. There are many single well fields in the Niger Delta area of Nigeria that have not been optimally produced, hence this study seeks to maximize the life of this field.

The reservoirs were simulated and production forecast carried out amounted to 14.55 MMstb for a period of 16 years.

After economic analysis was performed, the Net Present Value for the TSM and the Smart well completion were US $MM 241.9 and 248.88 respectively and an Internal Rate of Return of 155% and 202% respectively, hence the Smart well development plan is recommended.

Keywords: reservoir blocks, Two String Multiple, reservoir development plan, economic analysis

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I am grateful for all the daily miracles and the grace that GOD bestowed on me throughout my stay at AUST. My gratitude and thanks go especially to the following individuals and friends:

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- My family, for all their support throughout my stay at AUST.
- And, all my colleagues and friends in the Petroleum Engineering Stream and the AUST community at large.

DEDICATION

I sincerely dedicate this thesis to God Almighty for seeing me through it all.

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CHAPTER ONE

1.0 BACKGROUND

Petroleum reserves are declining, and fewer noteworthy discoveries have been made in recent years (Abdus, 1990). The need to increase recovery from the vast amount of remaining oil and to compete globally require healthier reservoir management practices (Abdus et al, 1994).

However, technological developments in all areas of petroleum exploration and exploitation, along with fast increasing computing power, are providing the tools to better develop and manage reservoirs to maximize economic recovery of hydrocarbons (Abdus, 1990).

A reservoir's life begins with exploration, which leads to discovery; reservoir delineation; field development; production by primary, secondary and tertiary means; and abandonment (Figure. 1.1).

Sound reservoir management is the key to successful operation of the reservoir throughout its entire life. It is a continuous course, unlike how the baton is passed in traditional E&P organizations (Abdus et al, 1994).

Reservoir Management is all about excellence in the Operate phase of an E&P project life cycle. This is the only phase (Operate) that earns income, to provide the return on investment and it is the longest of the four (4) E & P business phases (Exploration, Appraisal, Development and Operate) spanning decades. (Shell WRM Operational Excellence, 2010).

Complete reservoir management requires the use of both human and technological resources for maximizing profits (Abdus et al, 1994). It requires good coordination of geologists, geophysicists, production, and petroleum engineers to advance petroleum exploration, development, and production. Also, technological advances and computer tools can facilitate better reservoir management as well as enhance economic recovery of hydrocarbons. Even a small percent increase in recovery efficiency could amount to significant additional recovery and profit. These incentives and challenges provide the motivation to sound reservoir management.

Reservoir simulation is the way by which one uses a numerical model of the geological and petrophysical characteristics of a hydrocarbon reservoir to analyze and predict fluid behavior in the reservoir over time. In its simple form, a reservoir simulation model is made up of three parts: (i) a geological model in the form of a volumetric grid with face properties that describes the given porous rock formation; (ii) a flow model that defines how fluids flow in a porous medium, typically given as a set of partial differential equations expressing conservation of mass or volumes together with suitable closure relations; and (iii) a well model that describes the flow in and out of the reservoir, including a model for flow within the well bore and any coupling to flow control devices or surface facilities (Lie, 1994).

Figure 1.: Reservoir life process (Abdus et al, 1994).

Reservoir Management approaches have been used over the years to make optimal decisions in terms of improving production and maximizing the life of the reservoir. This concept is applied in this study for optimization of the Niger Delta field using MBAL simulation.

1.1 STATEMENT OF PROBLEM

Petroleum reserves are dwindling, and fewer significant discoveries have been made in recent years. Hence, the need to effectively maximize recovery from the huge amount of remaining oil.

1.2 AIM

The aim of this study is to maximize the life of the field, with a key focus on Reservoir Management/developments strategies.

1.3 OBJECTIVE OF STUDY

The study objectives include:

- Allow the field to flow without any work over
- Work over 3 Reservoirs by completing with Two String Multiple(TSM)
- Work over 3 Reservoirs (Intervals) by completing with Smart well
- Economic Analysis of the field development plans.

1.4 SCOPE OF THE STUDY

This project involves maximizing the value of a Niger Delta field.

- The reservoirs were modelled with MBAL software and all assumptions of tank model apply
- Parameters inputted are for the field of study; Geological data, Petrophysical data, Reservoir data, etc.
- Economic Analysis was done using oil price of $48.16 and a gas price of $2.07.

1.5 MOTIVATION FOR THE STUDY

I strongly believe that this study will enable me to integrate the basic Petroleum Engineering principles acquired in school, with industry best practices and thus equip me with a holistic knowledge (Sub-surface) of the E & P business.

CHAPTER TWO

2.0 LITERATURE REVIEW

The petroleum industry has advanced from an initial period of unrestrained production, through a period of maximum production controlled by government constraint into a period of declining production where companies plan to make the most profits based on the current management environment. The industry has now moved into a period of challenge. Industry must admit that a substantial amount of oil and gas will remain unrecovered unless enhancements are made in reservoir management or development practices (Wiggins and Startzman, 1990).

Petroleum reservoir management is an area that has created significant discussion within the industry in recent years as assets have declined, prices have fluctuated and companies have begun to realize the necessity for comprehensive planning in reservoir development.

A comprehensive understanding of the petroleum reservoir management process is vital to the proper development and exploitation of oil and gas reserves (Wiggins and Startzman, 1990).

2.1 RESERVOIR MANAGEMENT

There are several definitions of reservoir management as there are authors on this topic. The fact that there have been so many attempts, and that there is still no generally accepted definition of the term emphasizes what reservoir management is within the industry (Sawabini and Sawabini, 1997).

Reservoir Management is all about excellence in the Operate phase of an oil and gas project. It is the foundation for long-term value maximization and is critical for all development and optimization decisions, managing existing assets, ensuring the delivery of remaining reserves and production (Shell EP, 2010).

Petroleum reservoir management is the application of state-of-the-art technology to a known reservoir system within a given management environment. Reservoir management can be said of as that set of operations and judgments, by which a reservoir is identified, measured, produced, developed, watched and evaluated from its discovery through depletion and final abandonment (Wiggins and Startzman, 1990).

Figure 2.1 shows the components of the idea of reservoir management. A reservoir is managed for a particular reason and that reason is accomplished within the management environment using the existing tools and technology (Wiggins and Startzman, 1990).

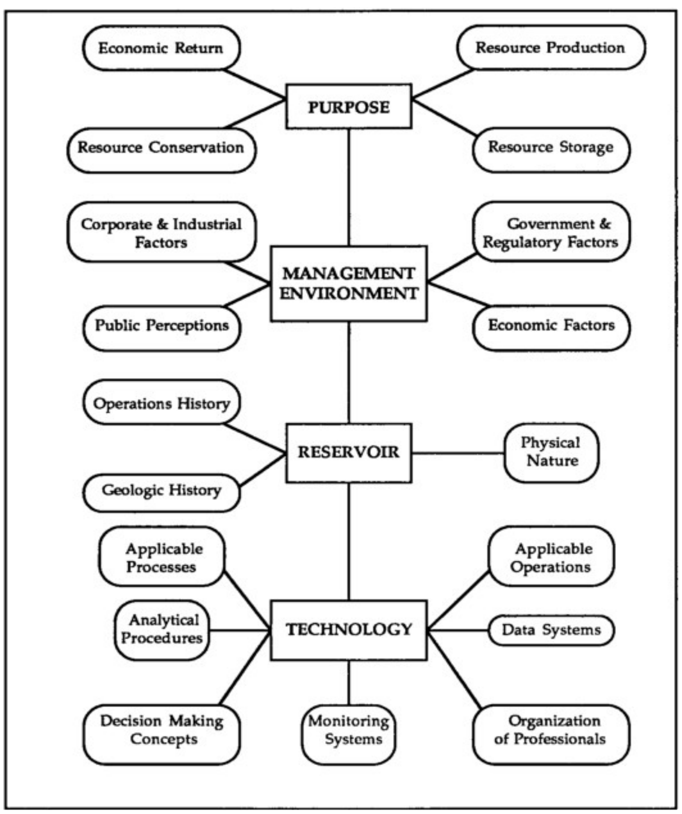


Figure 2. : Components of Reservoir Management (Wiggins and Startzman, 1990).

2.1.1 Fundamentals of Reservoir Management

Reservoir management is not simply the creation of a development plan but rather an all-inclusive, integrated strategy for reservoir exploitation.

Reservoir management requires three basic components; reservoir knowledge, environmental management, and available technology. When these are combined, decisions can be made and a strategy developed for realizing management goals. Without a proper understanding of these components, effective management cannot be accomplished, hence a comprehensive plan for achieving management goals cannot be developed (Wiggins and Startzman, 1990).

2.1.1.1 Reservoir Knowledge

Knowledge of the system being managed has numerous dimensions. Firstly, knowledge of the system, a petroleum reservoir is an accumulation of hydrocarbons trapped within a single hydrodynamically-connected geological environment. This general knowledge includes an understanding of fluid movement, rock properties, phase behavior and other basic knowledge (Wiggins and Startzman, 1990).

The second dimension of reservoir knowledge provides information about the macroscopic nature of the reservoir. This includes reservoir fluid content, size and variability; geologic province, formation and environment of deposition; the type of rock, depth, pressure and similar general information. The third dimension provides detail on a microscopic level such as reservoir morphology, porosity, fluid saturations, matrix content, capillary pressure relationships, relative permeability data, rock characteristics, and Pressure-VolumeTemperature (PVT) relationships among many others.

The fourth dimension of reservoir knowledge is its history, the events which have taken place during the operation of the reservoir which includes what wells have been drilled, how they were completed, what type of well stimulation has occurred, amounts of fluids produced or injected and any other data that pertains to the reservoir.

2.1.1.2 Environmental Management

It deals mainly with social and economic factors. This may include factors such as lease ownership, government conservation, safety and environmental regulations, market demand for petroleum products, availability of funds, equipment and personnel and the importance attached to reservoir management by a particular organization.

2.1.1.3 Technology

This technological knowledge includes all knowledge that may be generic to the behavior of reservoirs, knowledge that may be specific to an individual reservoir and knowledge that may be derived from other fields of technology (Wiggins and Startzman, 1990).

It also includes the types of techniques and operations that may be used to study or be performed on a reservoir. Methods for acquiring data, monitoring techniques, diagnostic and analytical procedures, modeling techniques and any other concepts which pertain to the handling of reservoir data and its use for determining a condition, a reservoir process or a course of action are examples of this type of knowledge (Wiggins and Startzman, 1990).

2.1.2 The Reservoir Management Plan

A Reservoir Management Plan, in written form, will improve communications and allow all personnel, including drilling, production, geological, reservoir and field, to focus on a common goal. The size of the plan, the amount of detail and frequency of revision will depend on the significance of the reservoir and the commitment of management to the planning process. A simple, carefully constructed reservoir management plan might suffice for the one well reservoir while a complex and complicated plan might be required for a large, multi-well reservoir. Though the approach to reservoir management should begin with the planning of the first exploratory well, reservoir management principles can be implemented at any time in a reservoir's life. The point is that every reservoir deserves sound reservoir management and a written plan is almost essential to assure sound reservoir management (Wiggins, 1990).

2.2 MATERIAL BALANCE EQUATION

The material balance equation (MBE) has long been recognized as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance. The MBE, when properly applied, can be used to:

- Quantifying different reservoir parameters such as hydrocarbon in place, gas cap size etc.
- Determine the presence, type and size of an aquifer, encroachment angle, etc.
- Estimate the depth of the gas/oil, water/oil and gas/water contacts.
- Predict the reservoir pressure for a given production and /or injection
- Predict the reservoir performance and well production.

The equation is structured to simply keep an inventory of all materials entering, leaving, and accumulating in the reservoir. The concept of the material balance equation was presented by Schilthuis in 1941. In its simplest form, the equation can be written on volumetric basis as:

Initial volume = volume remaining + volume removed ………………………………..2.1

Since oil, gas, and water are present in petroleum reservoirs, the material balance equation can be expressed for the total fluids or for any one of the fluids present.

Treating the reservoir pore as an idealized container as illustrated in Figure 2.2, volumetric balance expressions can be derived to account for all volumetric changes which occur during the natural productive life of the reservoir (Ahmed, 2006).

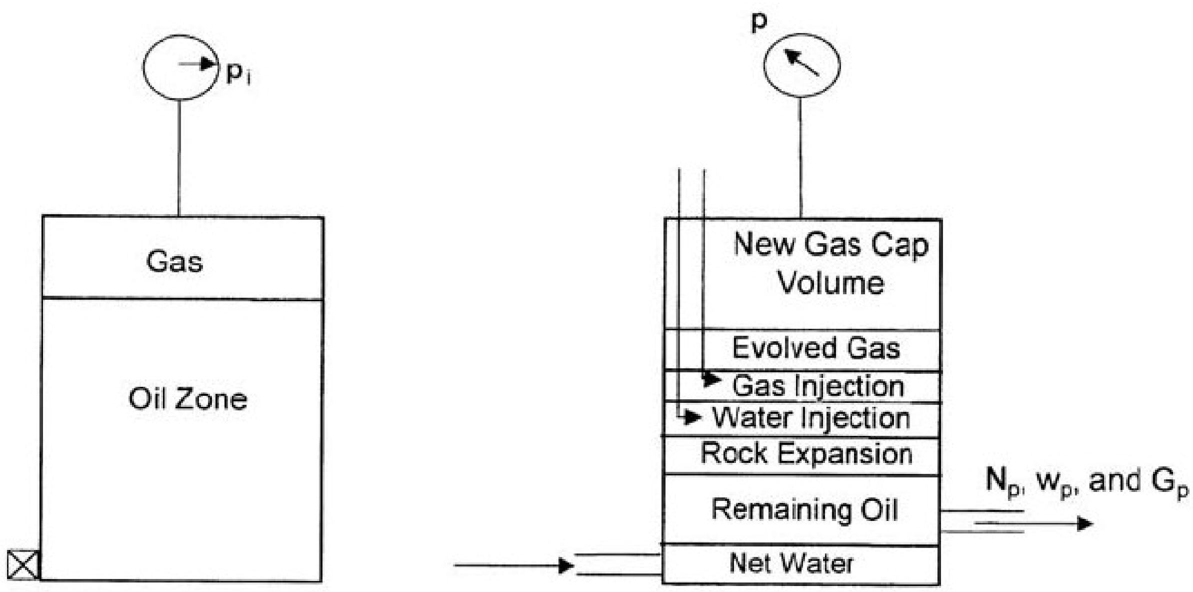


Figure 2.: Tank-model concept. (Ahmed, 2006)

The MBE can be written in a generalized form as follows:

Pore volume occupied by the oil initially in place at p_i + Pore volume occupied by the gas in the gas cap at p_i = Pore volume occupied by the remaining oil at p +

Pore volume occupied by the gas in the gas cap at p +

Pore volume occupied by the evolved solution gas at p +

Pore volume occupied by the net water influx at p +

Change in pore volume due to connate water expansion and pore volume reduction due to rock expansion +

Pore volume occupied by the injected gas at p +

Pore volume occupied by the injected water at p ……………………………….2.2

Combining and rearranging 2.1 above mathematically gives:

$$N = \frac{N_p B_o + (G_p - N_p R_s) B_g - (W_e - W_p B_w) - G_{inj} B_{ginj} - W_{inj} B_w}{(B_o - B_{oi}) + (R_{si} - R_s) B_g + mB_{oi}\left[\frac{B_g}{B_{gi}} - 1\right] + B_{oi}(1+m)\left[\frac{S_{wi} c_w + c_f}{1 - S_{wi}}\right]\Delta p} \quad \text{…. 2.3}$$

(Ahmed, 2006)

The equation can also be written in straight line form

$F = N^*E_t + W_e$ 2.4

Where:

F = Fluid production referred back to reservoir conditions

N = Original Oil in place

E_t = Total expansion of reservoir fluids and the formation

We = Water influx from an aquifer

The total expansion parameter (E_t), is a summation of oil, gas, connate water and pore volume expansion, and when decoupled results to:

Expansion of oil and dissolve gas $E_{o,g}= N[(B_o-B_{oi})+(R_{si}-R_s)B_g]$ +

Expansion of gas cap $E_{gc} = mNB_{oi}[B_g/B_{gi}]$ +

Expansion of connate water $E_{cw}= (1+m)NB_{oi}S_{wc}C_w dP/ (1-S_{wc})$ +

Contraction of pore volume $E_{pv}= (1+m)NB_{oi}C_f dP/(1-S_{wc})$ 2.5

This material balance equation is zero-dimensional, meaning that it does not take into account the geometry of the reservoir, the drainage areas, the position and orientations of wells, etc. (Ahmed, 2006)

2.3 MBAL

Material Balance (MBAL) is a reservoir modeling tool belonging to the Integrated Production Modelling (IPM). It was designed to understand current reservoir behavior and perform predictions while determining its depletion.

The MBAL Package contains the classical reservoir engineering tool, and has redefined the use of Material Balance in modern reservoir engineering. It is also the industry standard for accurate Material Balance modeling. Efficient reservoir developments require a good understanding of reservoir and production systems. It helps the engineer define reservoir drive mechanisms and hydrocarbon volumes more easily (IPM, 2010).

For producing reservoirs, MBAL provides vast matching facilities. More-so, realistic production profiles can be run for reservoirs, with or without history matching. The intuitive program structure enables the reservoir engineer to achieve reliable results quickly. MBAL is commonly used for modeling the dynamic reservoir effects prior to building a numerical simulator model.

Some of its areas of application are:

- History matching reservoir performance to identify hydrocarbon in place and aquifer drive mechanisms.
- Building Multi-Tank reservoir models.
- Generating production profiles.
- Run development Studies.
- Determine gas contract.
- Decline Curve Analysis.

- MBAL's logical and progressive path leads the engineer through history matching a reservoir and generating production profiles.

- It allows the engineer to tune PVT correlations to match with field data. This prevents data error being compounded between modeling steps.

- It's menu system minuses data entry by selecting only data relevant to the calculation option selected and many more. (IPM, 2010).

2.4 WELL WORKOVER

A work-over is any operation done on, within, or through the wellbore after the initial completion. Although proper drilling, cementing, and completion practices minimize the need, virtually every well will need several work-overs during its lifetime to satisfactorily fulfill its purpose.

The majority of work-overs are done because the well is not performing up to expectations. Careful analysis will be done to determine the problem, to investigate if the problem is in the reservoir inflow system, the wellbore outflow system, or both. Inflow problems can be corrected with stimulation procedures such as acidizing, fracturing, scale, or paraffin treatments or by re-perforating or additional perforating, etc., (http://wiki.aapg.org/Workovers).

2.5 ECONOMIC ANALYSIS

Generally, though not always, the objective in reservoir management is economics. Consequently, the economic objective must be clearly defined. After viable operating modes have been identified and the necessary performance predictions made, an economic analysis must be made. (Wiggins and Startzman, 1990).

Economic evaluation always incorporates the impact of oil and gas prices along with the equipment and services, price, cost escalation and operating cost that are reviewed periodically. Other economic factors such as taxes, royalty and depreciation updates are required to reflect current impacts on economic evaluation. (Sawabini and Sawabini, 1997).

The preferred way of evaluating the economic worth of the various operating scenarios is the risk adjusted-incremental approach. This approach assumes that all choices will be compared to the current operating policy and that each choice will involve some risk. The economic analyses will allow for the selection of the mode of operation that will optimize the management objective. (Wiggins and Startzman, 1990).

Some economic analysis tools include:

2.5.1 Net Present Value

The Net Present Value (NPV) is used to determine the most commercial developmental options available. NPV also known as the present value of cash surplus or present worth, is obtained by subtracting the present value of periodic cash outflows from the present value of periodic cash inflows. The present value is calculated using the weighted average cost of capital of the investor, also referred to as the discount rate or minimum acceptable rate of return. (M. A. Mian, 2002)

When NPV of an investment at a certain discount rate is positive, it pays for the cost of financing the investment or the cost of alternative use of funds. Conversely, a negative NPV indicates the investment is not generating earnings equivalent to those expected from alternative use of funds, thus causing opportunity loss. NPV method of evaluating the desirability of investments is mathematically represented by the equation:

....2.6

Where

NCF = Net Cash Flow

i_d = the discount rate. i.e., the required minimum annual rate of return on new investment

t = year (M. A. Mian, 2002)

2.5.2 Internal Rate of return

Another economic analysis tool used is the Internal Rate of Return (IRR). IRR is another important widely reported measure of profitability. It is reported as a percentage rather than a dollar figure such as NPV.

IRR is the discount rate at which the net present value is exactly equal to zero or the present value of cash inflows is equal to the present value of cash outflow. The equation for calculating IRR is:

....2.7

(M. A. Mian, 2002)

2.6 FIELD OVERVIEW

The field is located in OML-35 in the Swamp Area, Niger Delta of Nigeria. The field was discovered in 1988 with the drilling of exploratory well APV-1, which was completed in 1996 and started production in the same year. The well encountered 245 ft Net Hydrocarbon Sand (NHS) in six intervals, between 8600-10700 ftah. This includes 215 ft Net Oil Sand (NOS) and 39 ft Net Gas Sand (NGS) confirmed by log results, Appendix A7. APV-1 is the only well drilled in the field to date and is produced under a Tax/Royalty contract type.

Figure 2. : Map Showing APV Field in the Niger Delta (http://www.rigzone.com/news/image_detail.asp?img_id=139)

A total of six stacked reservoirs (all oil bearing except one with associated gas) were penetrated between 8552 ftss and 10652 ftss by the well. Reservoir blocks A200 and A600 are the largest in the field accounting for 77% of the total field STOIIP. The well was completed (Two String Multiple) on these two levels, with the short string producing from the A200 reservoir, and the long string producing from the deeper A600 reservoir.

The exploratory well APV-1 provides three drainage points in three reservoirs (A200, A300 and A600). As at 31 Marchv2016, production from the short string indicated a net oil rate of 690 bopd, watercut of 81.5% and a cumulative oil production of 13.76 MMstb. The long string on the other hand, had a net production oil rate of 1236 bopd, watercut of 71% and a cumulative oil production of 14.69 MMstb. The Historical field performance plot for the field is shown in Figure 2.4 and Table 2.1 is a summary of the reservoir properties and field data.

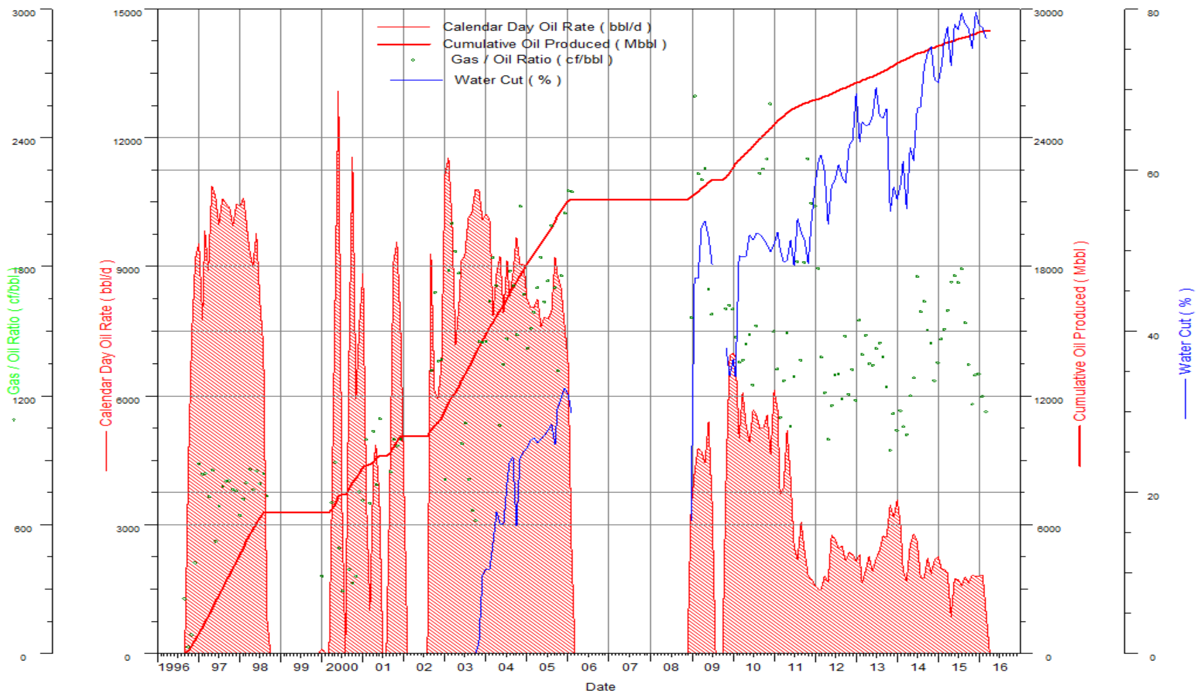


Figure 2. : Historical field production

Table 2. : Summary of the field description and ranges of reservoir parameters

Discovery/ On Stream Date	1988 / 1996	Current Oil Production Rate (29/02/2016)	1.818 Mbopd
Contract Type)	Tax Royalty (JV)	Current Gas Production Rate (29/02/2016)	2.04 MMscf/d
Structure	Rollover Anticline	Cum. Oil Production (29/02/2016)	28.98 MMstb
Connectivity	laterally continuous and vertical connectivity	Cum. Gas Production (29/02/2016)	36.03Bscf
Rock Properties	Good(ϕ= 26 - 31 %, N/G = 80 - 96% and K = 1200 - 2300 mD)	Reservoir water cut	A200: 81%, A600: 71%

Fluid Properties	API (40 – 45 Degrees), Rsi: (1200 – 1838 Scf/bbl), Viscosity: (0.20 –30)	Reservoir Pressure Initial	Psig: (3745 – 4621)
Main Reservoir Energy	Water drive	STOIIP/UR (MMstb) FGIIP/UR (Bscf)	73.4/42.8 MMstb 41.4/30.7Bscf

2.6.1 Volumes Initially-In-Place (Geological Description)

The field has a relatively simple anticlinal structure. A total of six stacked reservoirs were penetrated between 8552 ftss and 10652 ftss by the well. The predominant depositional settings for the field are stacked distributary channel sands and upper shoreface deposits.

The volume of Hydrocarbon initial in-place is shown in Table 2.2, it shows the low, best and high base volume estimate of the initial oil place for the reservoirs.

Table 2. : The Reservoirs Hydrocarbon Initially in-Place

Hydrocarbons Initially In-Place (100%, STOIIP)			
Reservoir	Low Estimate (MMstb)	Best Estimate (MMstb)	High Estimate (MMstb)
A100	4.0	5.0	6.1
A200	20.6	25.7	30.4
A300	3.0	3.8	4.5
A400	1.2	5.1	6.4
A500	1.6	2.0	2.5
A600	25.1	30.7	37.3

2.6.2 Fluid Distribution

Hydrocarbon fluid distribution for the field reservoirs was determined using all available relevant wire line logs and sidewall sample data shown in Figure 2.6. Figure 2.5 is a schematic/pictorial view of the reservoirs.

A100

N=5 MMstb

A200
N=25.7 MMstb
Np=13.5 MMstb

A300
N=3.8 MMstb

A400
N=5.1 MMstb

A500
N=2 MMstb

A600
N=30.7 MMstb
Np=15.0 MMstb

48 ft
10ft
60ft
54 ft
119ft
33 ft
30ft
16 ft
146ft
12ft
80ft
108ft
160ft

Thickness in TVD SS

Figure 2.5: A schematic View of the Field

Figure 2.6: Fluid Distribution Plot

2.6.3 Reservoir drive Mechanisms

The field is being produced under primary recovery techniques. The drive mechanism for the reservoirs is mostly aquifer drive.

CHAPTER THREE

3.0 METHODOLOGY

The methodology employed in this study is as outlined below:

- Data gathering and data Quality Check
- PVT Analysis for reservoirs
- Reservoir Modeling at Tank level and Fractional flow matching
- Production forecasting/predictions
- Work over 3 reservoirs
- Economic Analysis of the developmental plan
- Propose a reservoir development plan based on the analysis.

Below are the details of the methodology:

3.1 DATA GATHERING

All available and accessible Geological data (STOIIP, Reservoir radius, Outer/Inner Radius Ratio and Encroachment Angle), Petrophysical data (Porosity, connate water saturation, Rock compressibility, relative Permeability, Initial Reservoir Pressure and thickness, Water Salinity and Aquifer properties), Reservoir data (Reservoir Temperature, GOR, API gravity and Fluid properties), Well Historical Production Data and Productivity Index (PI) were gathered, quality checked and converted to the necessary/required formats. Details of all data can be found in Appendix A1.

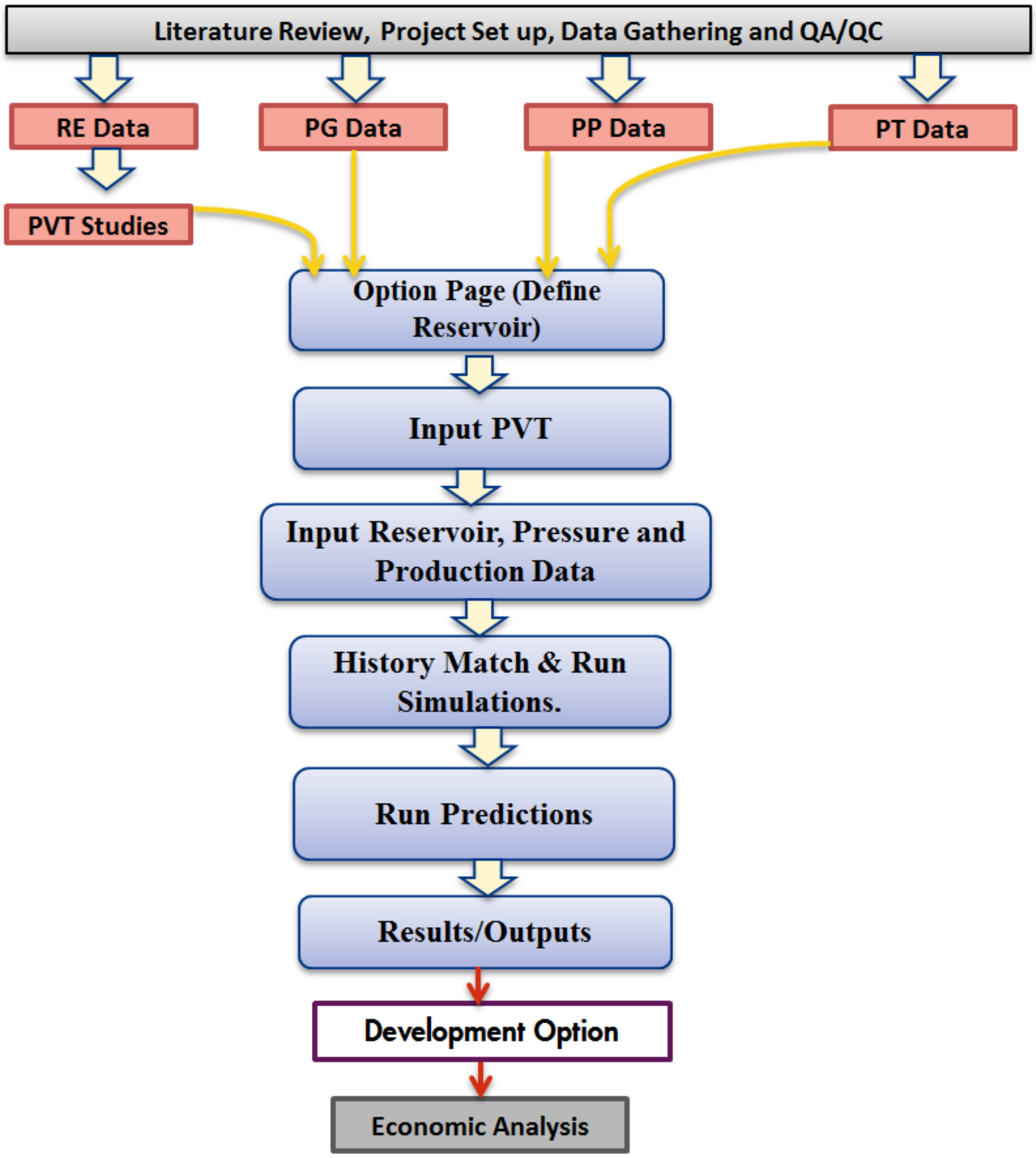


Figure 3.0: Methodology outline

3.2 PVT ANALYSIS FOR FOUR OF THE RESERVOIRs.

Till date, only reservoirs A2 and A6 have a laboratory PVT analysis/report. However, PVT is key in characterizing reservoir fluid, and can be obtained via three (3) basic routes (depending on the type of data available). These routes are as shown in Figure 3.2 below:

PVT Laboratory Reports
Analogue Reservoir PVT
Use of Correlation
Reservoir and Models (MBAL)

Figure 3.1: Basic Routes for Obtaining/Estimating PVT Properties.

For the other reservoirs, the PVT Correlation method is used. Vazquez-Beggs correlation was the best match Pb, Rs and Bo for A1 reservoir while Glaso correlation for A3 andAl-Marhoun for A4 and A5. Beal et al correlation were the match for oil Viscosity for all the reservoirs

3.2.1 PVT Analysis Methodology (Using Correlations)

PVT properties were estimated for the reservoir by testing all available Black Oil Correlations in MBAL. Black oil correlations with the best PVT match was selected, and used for estimating PVT properties for the reservoir.

3.3 THE RESERVOIRS MBAL MODEL

The reservoirs were modeled using MBAL. The workflow for MBAL reservoir modeling is shown below:

Option Page (Define Reservoir)
Input PVT
Input Reservoir, Pressure and Production Data
History Match & Run Simulations.
Run Predictions
Results/Outputs

Figure 3.2: Workflow adopted for modeling the reservoir

3.3.1 Reservoir Modeling (At Tank Level)

The reservoirs will be modeled at Tank level (using a material balance tool MBAL, in the IPM Suite) with the aim of matching production and pressure, running predictions, determining the reservoir drive mechanisms.

3.3.2 Reservoir Modelling Assumptions

The following assumptions were adopted:

- The reservoirs are assumed to be a Tank (Figure 3.3).

➢ The reservoirs are assumed to be homogenous (thus, they have uniform reservoir properties).

➢ The reservoir Pressure and Temperature are uniformly distributed.

3.3.3 Input Data

The key input data for building the MBAL model of the reservoirs include; PVT, production and pressure, average reservoir/petrophysical parameters, and depth versus pore volume from the geological static model. These input data can be found in the appendix.

3.3.4 History Matching

The reservoirs production (oil, water and gas) and pressures were matched (via tank and wells for quality check purpose) by regressing on reservoir parameters with high uncertainty (outer/inner radius, reservoir radius, encroachment angle, aquifer constant). Reservoir Parameters with lower uncertainty such as porosity and thickness were left constant. Figure 3.4 shown the history match for A200 and A600 reservoirs.

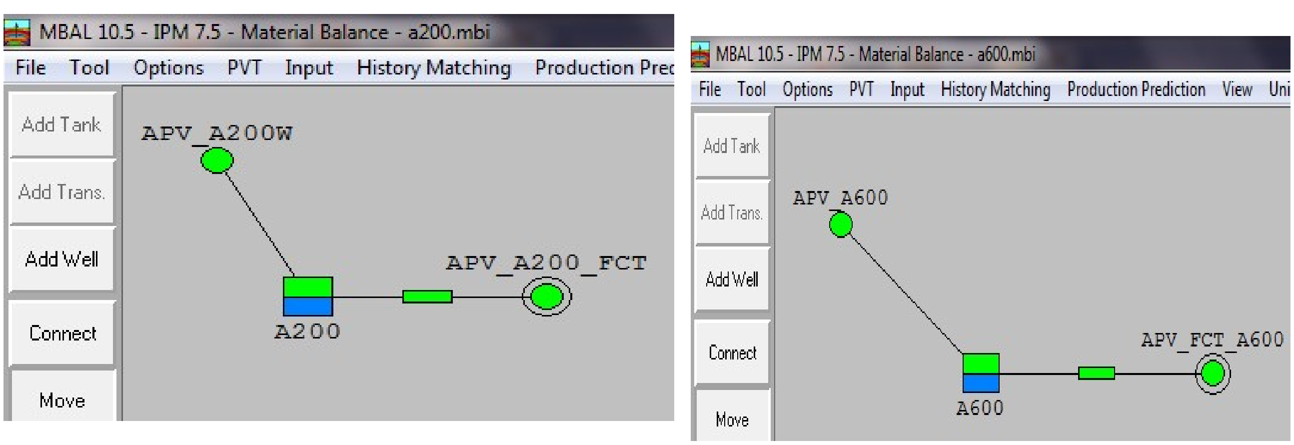


Figure 3.: MBAL Model by Tank and by Wells for Reservoir A200 and A600.

3.3.5 Aquifer Fitting

In the course of the history matching, the Hurst-Van Everdingen-Modified Aquifer model, and a radial system; was fit to the reservoirs. This Aquifer model can be expressed as shown in equation 3.1, while the aquifer response time can be evaluated using equation 3.2. The aquifer permeability was assumed to be the same as that of the reservoir (a usual practice for shallow reservoirs, below 1000ft).

…………………………… (3.1)

Where:

W_e = Water influx from an aquifer

U = Aquifer Strength (aquifer constant)

ΔP = Pressure change

Q_D = Dimensionless influx rate

t_D = Dimensionless time. (Ahmed, 2006)

…………………………………… (3.2)

Where:

K = Aquifer Permeability

t = Aquifer response time

Ø = Aquifer porosity

µ = Aquifer fluid viscosity

ro = Reservoir outer radius (Ahmed, 2006)

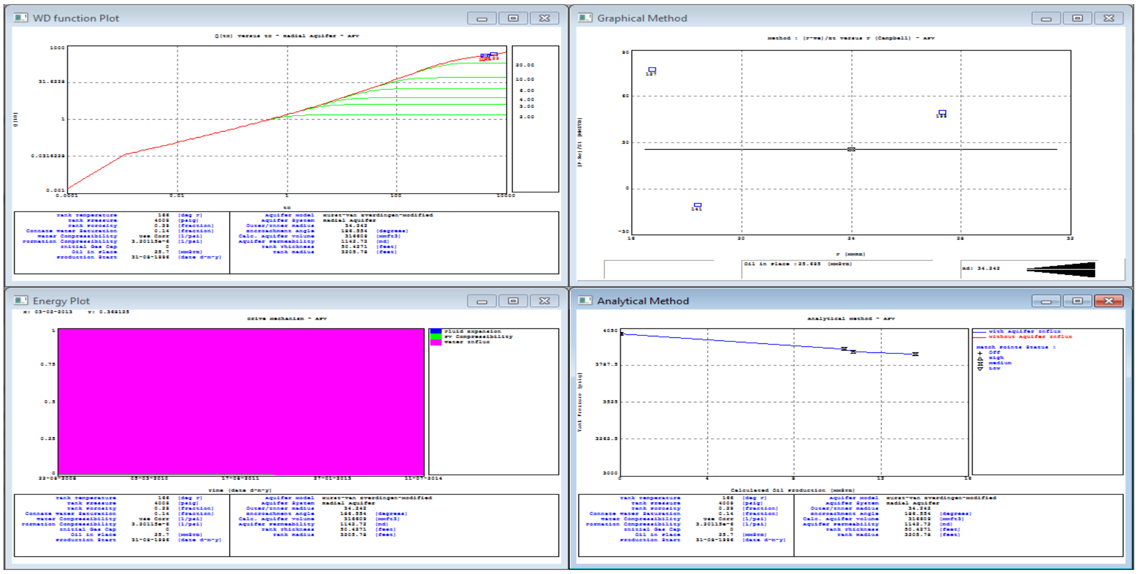


Figure 3.4a: A200 History match.

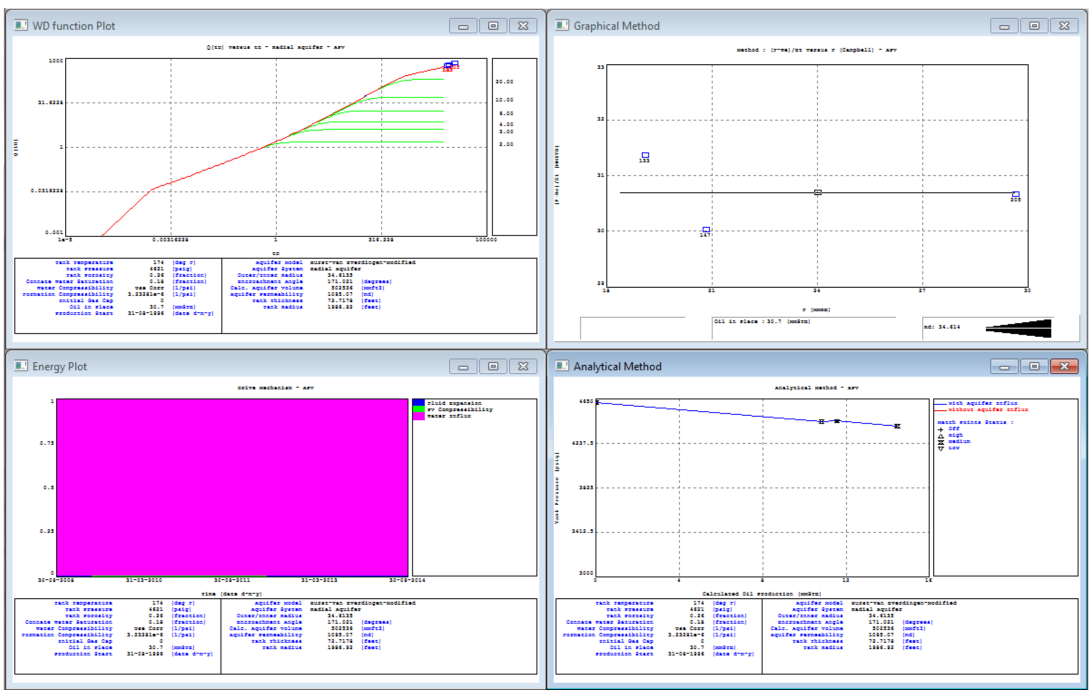


Figure 3.4b: A600 History Match.

3.3.6 Fractional Flow Matching and Pseudo Relative Permeability Generation

Determining a set of relative permeability curves which will result to GOR and Water Cut similar to those observed during the production history is a major requirement for running production predictions. Therefore, after history matching, fractional flow matching was performed, and used in generating Pseudo Relative Permeability via the Corey Function.

The reservoir condition fractional flow was generated using surface productions and PVT as shown in the equations below.

………………………………… (3.3)

Where:

fw, fg, fo = fractional flow of water, gas and oil, respectively

Qx, Qx1 = the flow rate of the fluid phase x and x1, respectively

Bx, Bx1 = the formation volume factor of the phase x and x1, respectively (Ahmed, 2006)

Also using the relative permeabilities, fractional flow can be expressed for the water phase (and for other phases) as shown in equation (3.4)

…………………………… (3.4)

Where:

Kro and Krw = the relative permeability of water and oil.

μo and μw = the viscosity of oil and water.

The ratio Kro/Krw was evaluated (with the MBAL tool), using production history and PVT, and then used in the Corey Function (equation 3.5) to obtain relative permeability, end point saturations and Corey's exponents, via series of regressions.

…………………………… (3.5)

Where:

Krx = relative permeability of the phase x

Ex = the end point for the phase x

nx = the Corey Exponent

Srx = the phase residual saturation

Smx = the phase maximum saturation. (Ahmed, 2006)

The relative permeability for the reservoirs is shown in the appendix.

3.3.7 Reservoir Predictions/Forecasting

Production predictions were carried out for twenty (20) years at a rate of 3500 barrels per day for A200 and A600, while the rest 2000 bbl/d. The flow rate was chosen based on the average historical flow rate

3.4 WORK OVER RESERVOIRS

Reservoirs A100, A300, A400, and A500 are modeled using the same method for A200 and A600, and production was forecasted.

Two developmental plans were considered, we can either work over the well with another TSM or use a smart well to commingle the production at the end of the current completion scheme.

3.5 ANALYSIS OF WELL PERFORMANCE AND ECONOMIC ANALYSIS

The Net Present Value (NPV) and the Internal Rate of Return (IRR) economic analysis tools were used to analyze the developmental options.

CHAPTER FOUR

4.0 PRESENTATION OF RESULTS AND DISCUSSION

From the results, the optimal developmental plan in terms of NPV and IRR is obtained. The results also include the volume of oil and gas that can be obtained from each of the plans; details are presented below.

4.1 HISTORY MATCHING

An overall history matching of the reservoirs was carried out; to ensure that the system had the right amount of volumes and energy balance. History matching an MBAL model results to four (4) output charts; that account for the volumes in place, produced volumes, reservoir drive mechanism, and aquifer description. Figure 4.1 is an analytical solution of the model, obtained by doing a non – linear regression through judicious adjustments of some reservoir parameters. The plot (Figure 4.1) reveals a close match between the historical data and aquifer supported production. The slight steepness in slope seen in the reservoir pressure decline can be linked to the presence of an aquifer. The Campbell plot shown in Figure 4.2 for A200 is a means of quality check for the reservoir history match. As can be seen, the data points are distributed all around the straight line that corresponds with oil in place.

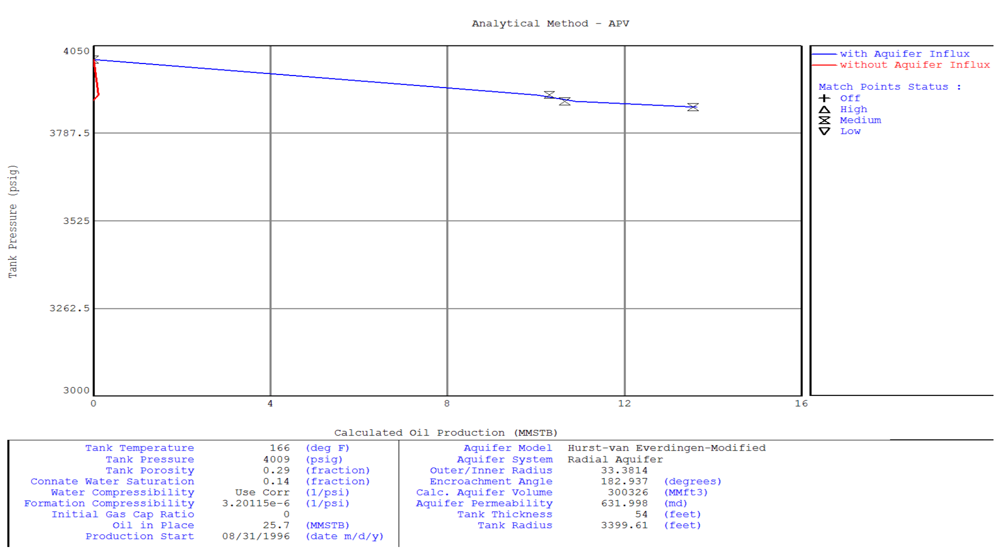


Figure 4.1: Analytical Method

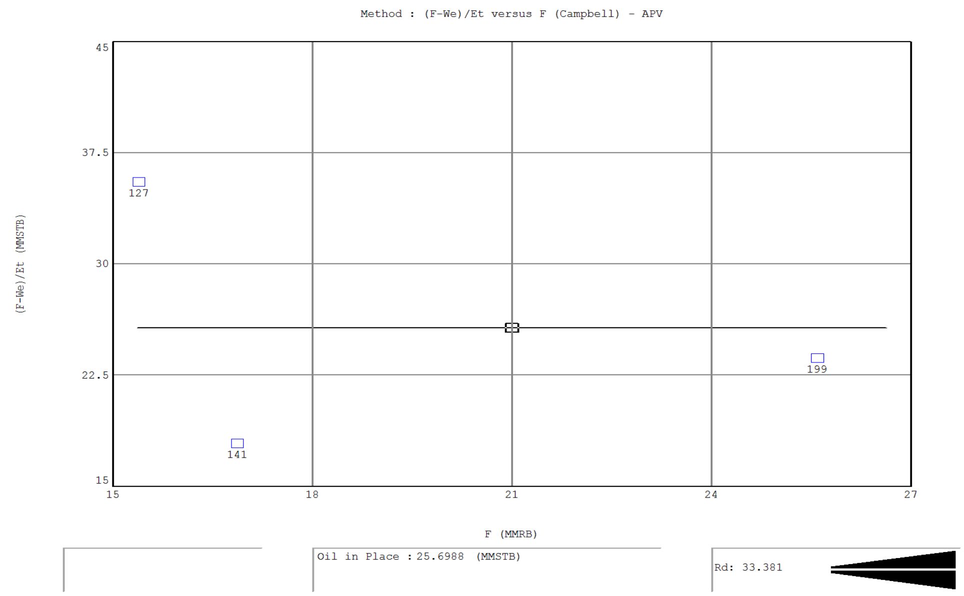
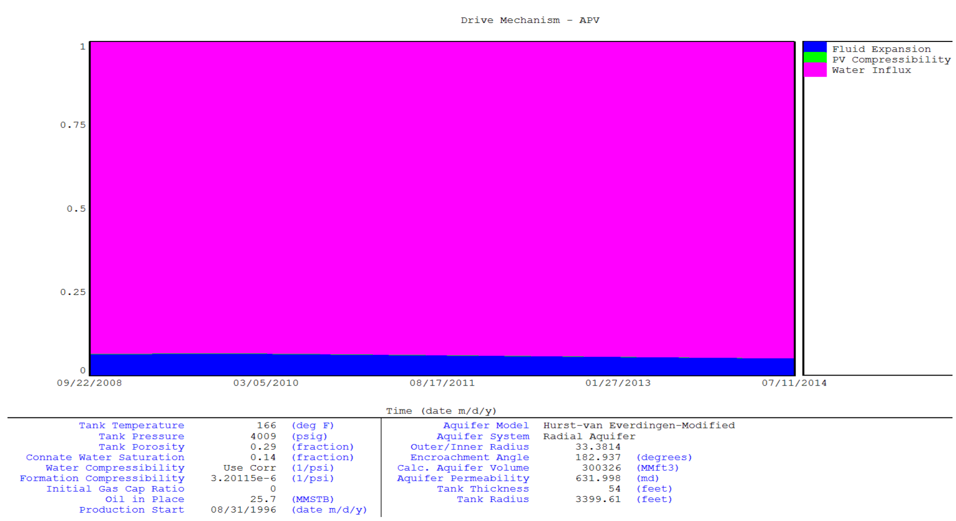


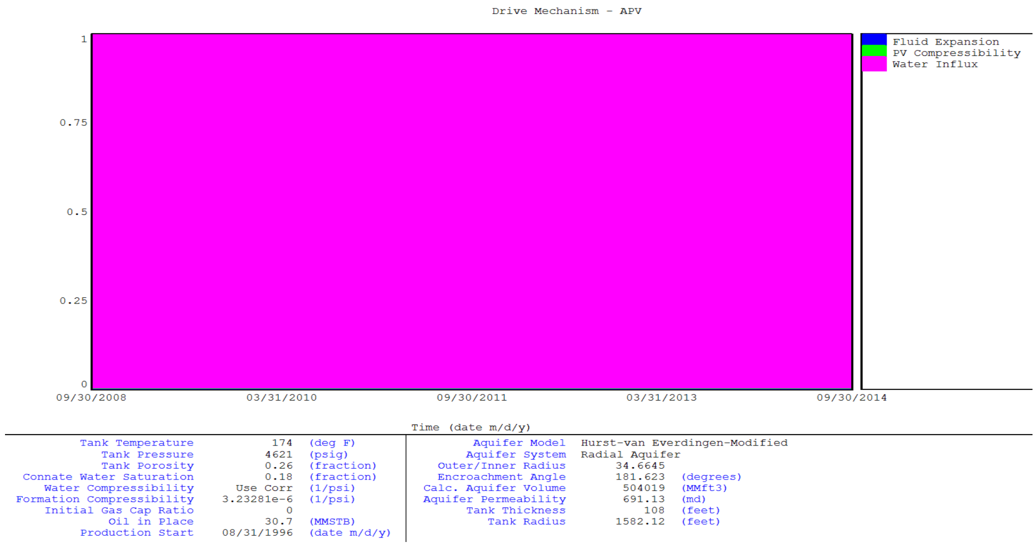
Figure 4.2: Campbell Plot

4.1.1 RESERVOIR DRIVE MECHANISMS

The energy plot for the A200 and A600 reservoirs shown in Figure 4.3 a and b below, reveals that the reservoir A200 has a combination drive mechanism, with about 94% of the reservoir energy attributed to Water Influx and 6% to fluid expansion (the contributions of Fluid Expansion and Pore Volume Compressibility were insignificant). Reservoir A600's energy drive is water influx. In this study no history match was done for the rest of the reservoir because there was no production data.



a.



b.

Figure 4.3: A200 and A600 Reservoirs Drive Mechanism.

4.1.2 FRACTIONAL FLOW MATCHING

Before forward predictions can be carried out, fraction flow matching of GOR and Water cut must be achieved. Results of the fractional flow matching are shown in Figure 4.4 a and b. It shows a fair and acceptable match with historical production. The endpoints and Corey's exponent were used to evaluate relative permeability via Corey's Function.

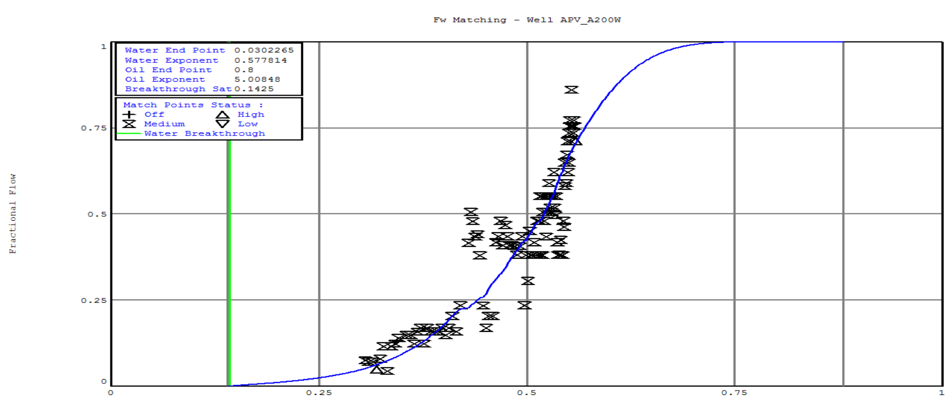


Figure 4.4a: A200 Fractional flow matching.

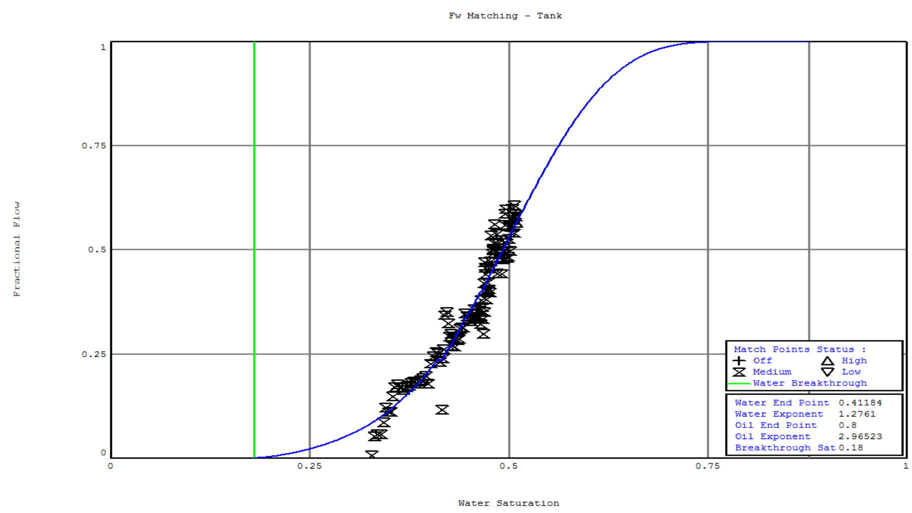


Figure 4.4b: A600 Fractional flow matching.

4.2 RESERVOIR PREDICTIONS

Forward predictions were carried out for the APV Reservoirs at off-take rates of 2000 stb/d for A100, A300, A400, A600 reservoir, and 3500 stb/d for A200 and A600. The results are presented below. A rate of 3500 stb/d was chosen for A200 and A600 reservoirs based on their historical performance, and the 2000 stb/d rate was based on their STOIP.

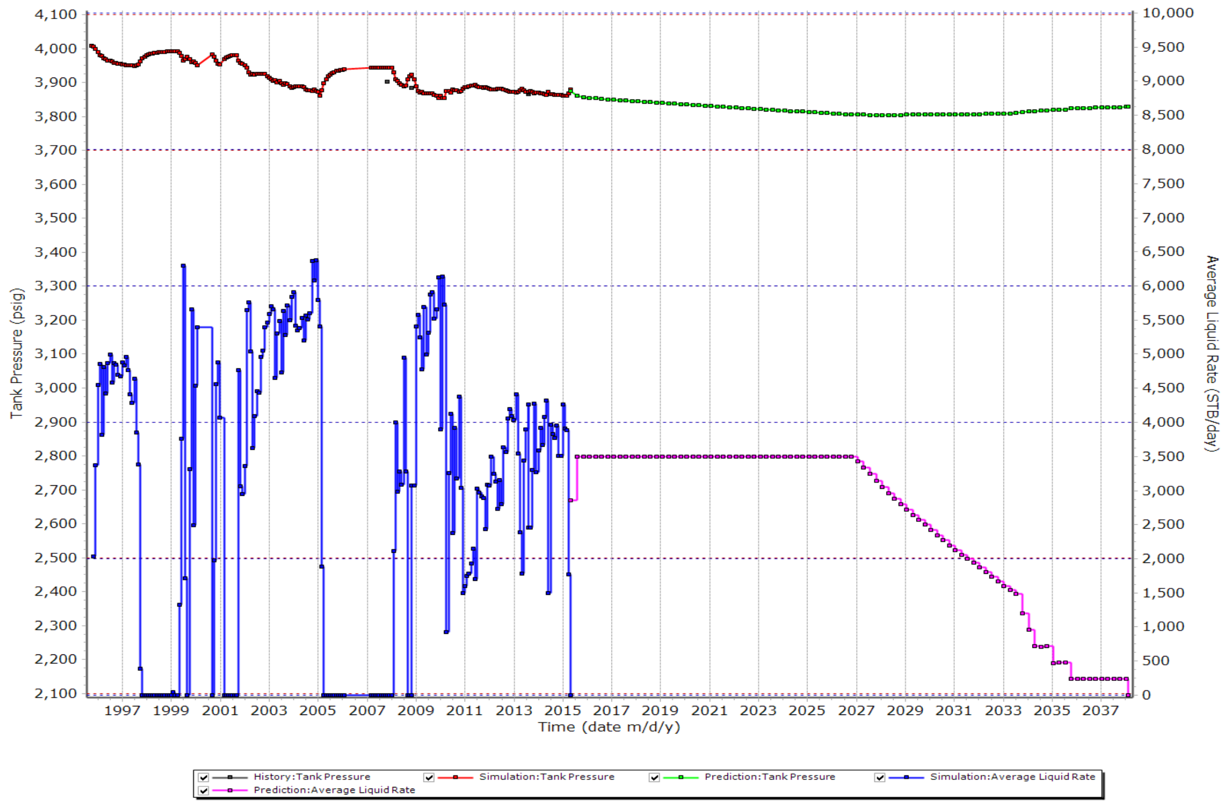


Figure 4.5: A200 Oil rate and Pressure Predictions.

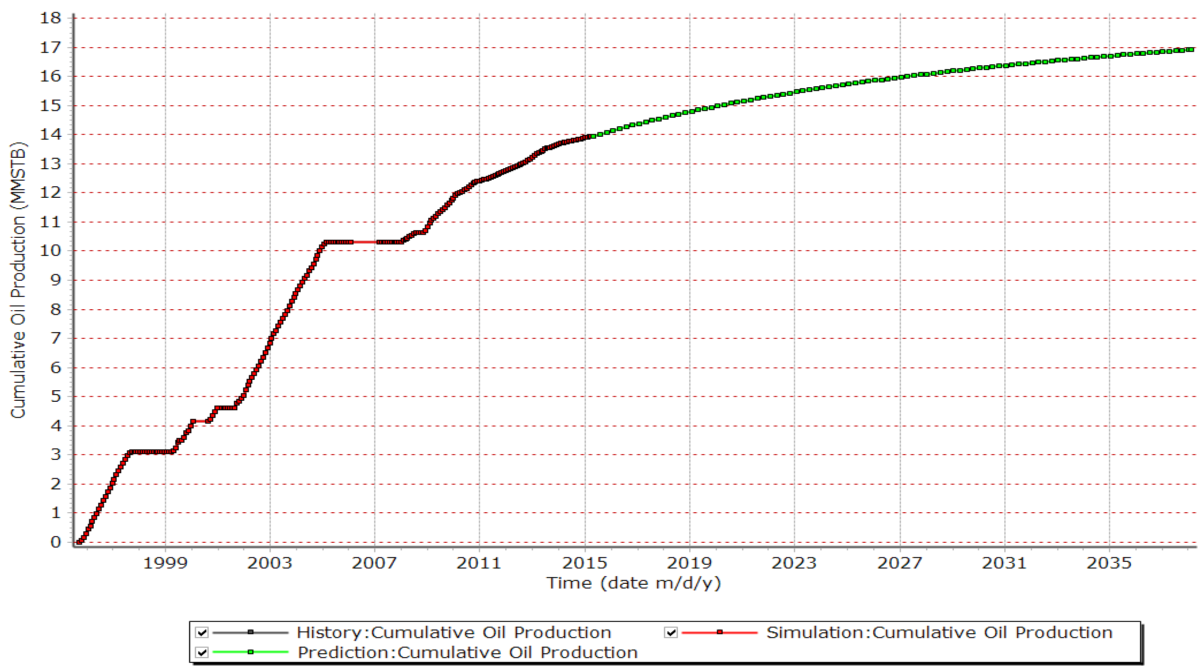


Figure 4.6: A200 Cumulative Oil Production for 20 years Prediction

The graphs for the A6 reservoir can be found in Appendix A4. The summary of the forecast results is presented in Table 4.1 below:

Table 4.1: Prediction Results for Reservoirs

Field Prediction							
	Unit	**F0000X**	**F1000X**	**F1100X**	**F1200 X**	**F1500X**	**F2000 X**
Off take Rate	stb/d	2000	3500	2000	2000	2000	3500
Initial Pressure	Psig	3745	4009	4086	4135	4434	4621
Pressure	Psig	527	3856	3973	3923	4166	4382
Recovery Factor, RF	%	18.59	59.99	52.45	40.44	52.51	61.71
Cumulative Oil Produce, Np	MMbbl	4.037	15.45	1.99	2.062	1.05	18.9441
Cumulative Gas, Gp produced	Bcf	36.37	18.91	2.39	2.578	1.365	26.088
Cumulative Water produced	MMST B	0.0139	10.43	1.561	0.28	1.017	31.59
Water Cut	%	0.363	79.41	86.43	43.22	86.63	93.12

4.2.1 Current Production

Figure 4.6 below shows the prediction profile for the current production system. The well will die by the year 2061 as shown by the profile, after which the company will look for the best production system, either to install another Two String Multiple well or to go for smart well. Another option would be to drill a new well to produce A100, A400, and A500 Reservoirs

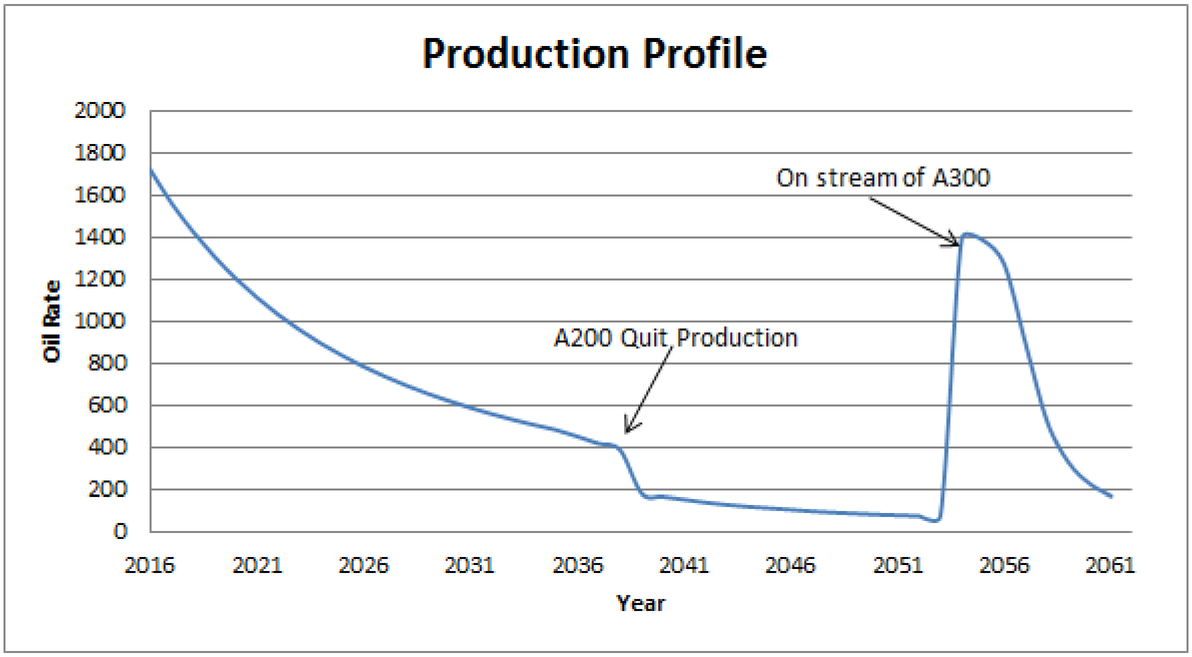


Figure 4.7: Prediction Production profile for the current System

4.3 TWO STRING MULTIPLE (TSM) WELL COMPLETION

At the end of the current production system, completing three reservoirs with a TSM will gives the production profile in Figure 4.7.

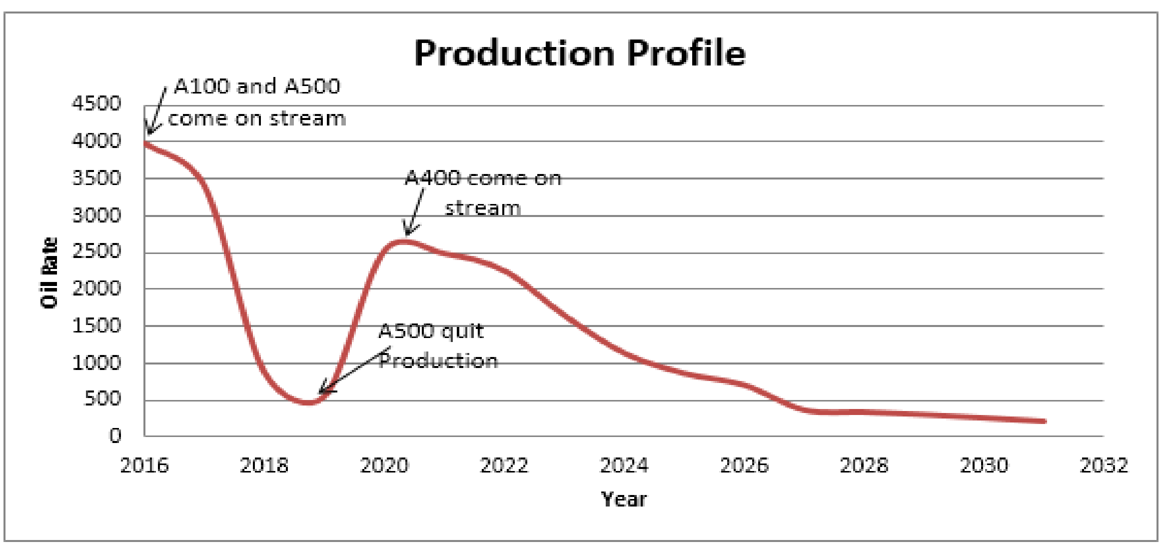


Figure 4.8: Prediction Production profile with TSM

4.4 COMPLETING WITH SMART WELL COMPLETION

With a smart well, the three reservoirs are produced simultaneously from the end of the current production. The profile is presented below:

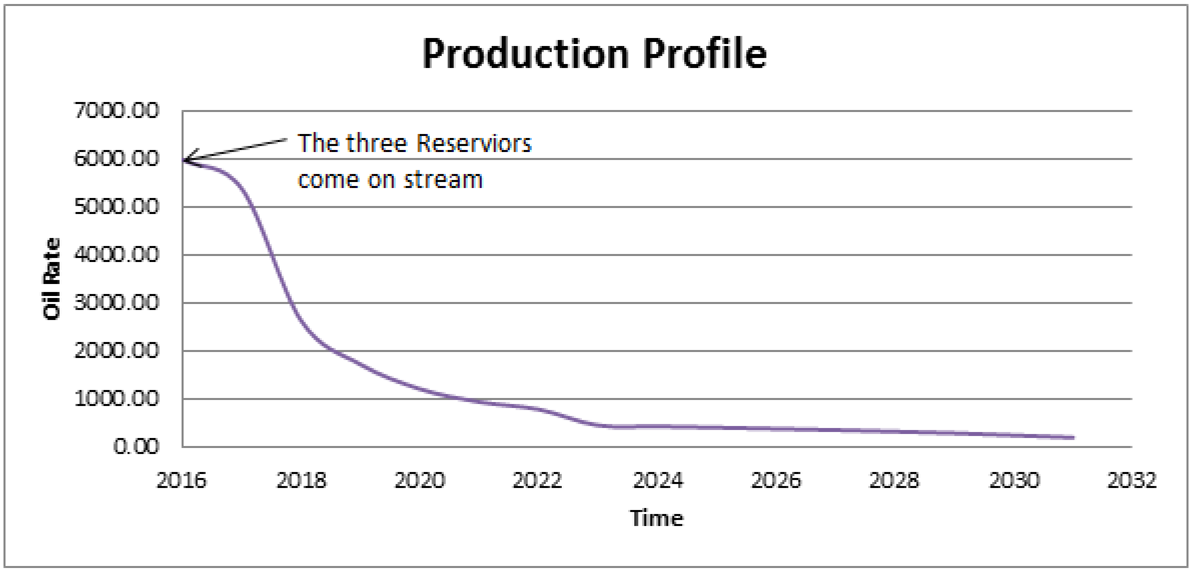


Figure 4.9: Prediction Production profile with a Smart Well

The two development options will produce almost the same volume of oil (7 MMstb) and for the same number of years.

4.5 ECONOMIC ANALYSIS

A production forecast was developed based on the field development plan. A cash flow model was built with the fiscal information given and some profitability indicators (NPV, IRR) were evaluated. Figure 4.9 shows the graphs of Annual Net cash flow and Cumulative Net Cash flow for Two String Multiple and Smart Well.

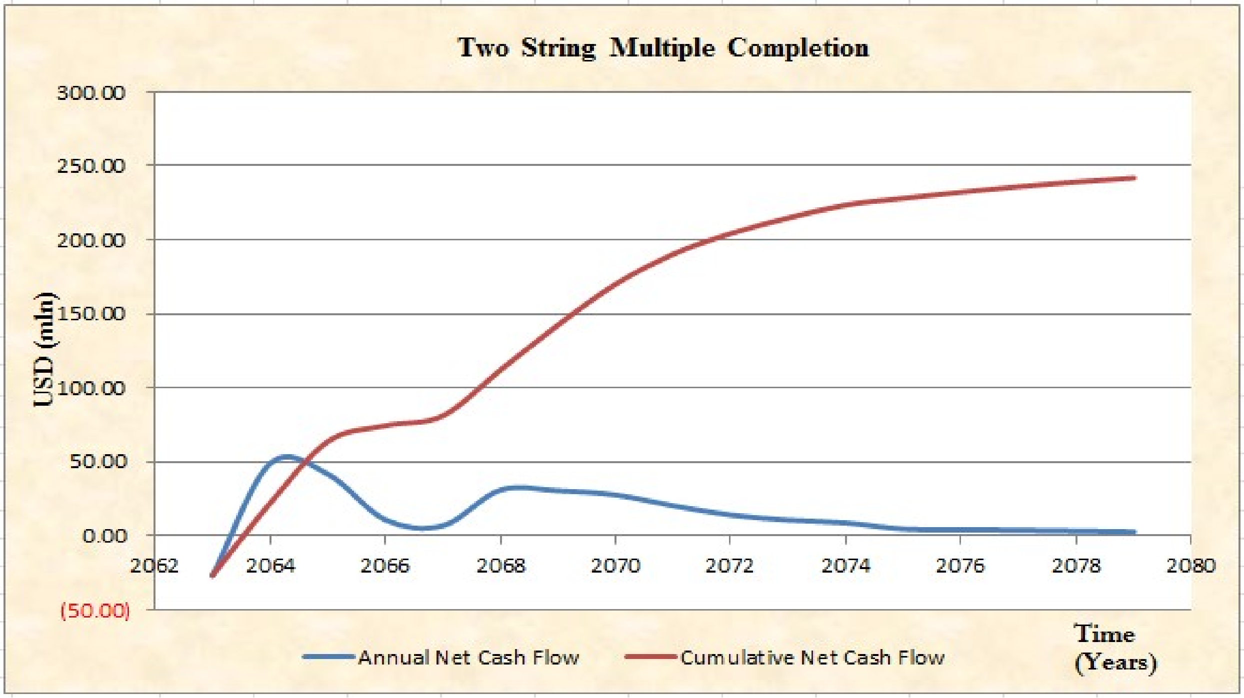


Figure 4.10: Net Cash Flow Profile for TSM Completion

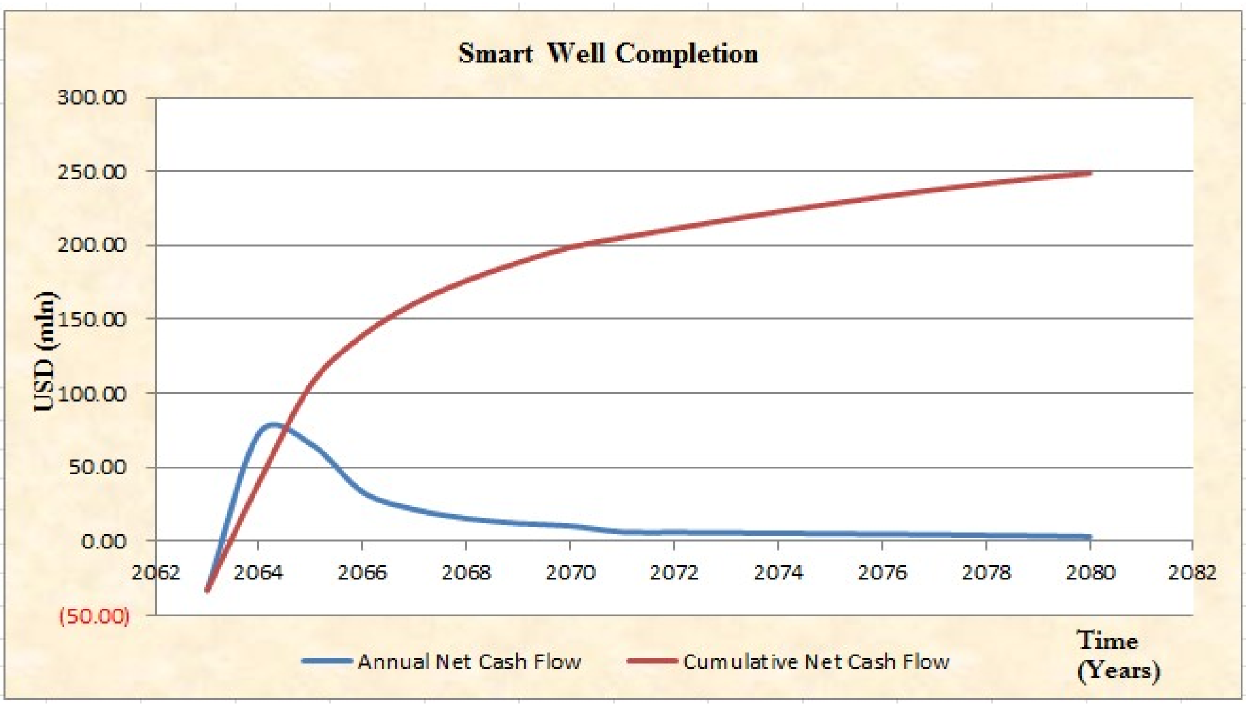


Figure 4.11: Net Cash Flow Profile for Smart Completion

The two development plans show close Net cash Flow (NCF) profiles. To determine the best development option for the well, we calculated the Net present Value and the internal rate of return. The results obtained are shown in Table 4.2, Details of the calculation can be found in Appendix A4 and A5.

Table 4.2: Economics Tools

Economic Tools			
		TSM Completion	Smart Completion
	Unit		
Net Present Value (NPV)	US $ MM	241.90	248.88
Internal Rate of Return (IRR)	%	155	202

From the table, NPV and IRR for the smart completion are higher compared to the TSM completion.

Generally, an investment with a positive NPV will be a profitable and the one with a negative NPV will result in a net loss. Also, the higher a project's internal rate of return (interest rate earned from investment), the more desirable it is to undertake the project.

Smart completions have higher values for both NPV and IRR, hence they are the most profitable option.

CHAPTER FIVE

5.0 CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

The study was aimed at ensuring efficient reservoir development and management, sustaining hydrocarbon production, maximizing the life of the field, complying with both company and government policies and generally optimizing recoveries.

Based on this research, the following conclusions can be drawn:

1. About the same volume of oil will be obtained from the two completion plans.
2. It will take nearly the same number of years to produce the oil with TSM or Smart well completion.
3. Smart well completion gives a higher initial flow rate of 6000bopd compared to 4000bopd for TSM.
4. Smart completion wells cost an average of 26% more than TSM completion wells.
5. Using Smart wells completion will give a higher NPV and IRR.
6. Base on the NPV and IRR value, a Smart Well developmental plan is preferable for execution of the development plan for the APV.

5.2 RECOMMENDATIONS

Based on this research, the following recommendations are suggested:

1. Further detailed study should be carried out in order to determine the technical viability of the proposed developmental plans.
2. Develop 3D Numerical models for the detailed study of the reservoirs with respect to leveraging on the results of MBAL model, in terms of aquifer definition and pressure depletion.

Once the above mentioned recommendations are met, the management can go ahead and implement the reservoir development plan.

NOMENCLATURE

Boi	Initial oil formation volume factor, bbl/STB
Bo	Oil formation volume factor, bbl/STB
Bgi	Initial gas formation volume factor, bbl/scf
Bg	Gas formation volume factor, bbl/scf
Bscf	Billion standard cubic feet
cw	Water compressibility, psi^{-1}
cf	Formation (rock) compressibility, psi^{-1}
E & P	Exploration and Production
FGIIP	Gas initially in place
ft ss	Feet subsea
Gp	Cumulative gas produced, scf
Ginj	Cumulative gas injected, scf
G	Initial gas-cap gas, scf
GOR	Instantaneous gas-oil ratio, scf/STB
JV	Joints Venture
m	Ratio of initial gas-cap-gas reservoir volume to initial reservoir oil volume, bbl/bbl
IPM	Integrated Production Modelling
MM	Million
MMstb	Million Stock tank barrel
MBE	Material balance equation
Mbopd	Thousand barrel of oil per day

MMscf/d	Million standard cubic feet
MBAL	Material Balance
N	Initial (original) oil in place, STB
Np	Cumulative oil produced, STB
NHS	Net Hydrocarbon Sand
NOS	Net Oil Sand
NGS	Net Gas Sand
OML	Oil Mining License
PVT	Pressure Volume and Temperature
pi	Initial reservoir pressure, psi
p	Volumetric average reservoir pressure
Δp	Change in reservoir pressure
pb	Bubble point pressure, psi
PI	Productivity Index
P.V	Pore volume, bbl
Rp	Cumulative gas-oil ratio, scf/STB
Rsi	Initial gas solubility, scf/STB
Rs	Gas solubility, scf/STB
STOIIP	Stock Tank Oil Initially In Place
Scf	standard cubic feet
TSM	Two String Multiple
TVD ss	True vertical depth subsea
UR	Ultimate recovery

We	Cumulative water influx, bbl
Winj	Cumulative water injected, STB
Wp	Cumulative water produced, bbl

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APPENDIX

A1: APV Field Data

APV FIELD DATA

Properties	Unit	A100	A200	A300	A400	A500	A600
STOIIP, N	MMbbl	5	25.7	3.8	5.1	2	30.7
IGIP, G	BCF	40.6	N/A	N/A	N/A	N/A	N/A
Reservoir Radius	ft	3218.83	3421.59	1681.1	3261.25	1642.39	3305.45
Outer/Inner Radius ratio		16	32	25	28	14	31
Encroachment angle	degree	273	310	317	210	230	243
Productivity Index	STB/day/psi	22	22	28	30	31	35
MIN THP	psig	109	107	113	124	123	125
Test water cut	%	80	78	80	80	74	79
Life Curve		Y	Y	Y	Y	Y	Y
Production History		Y	Y	Y	Y	Y	Y
Porosity	%	25.00	29.00	31.00	26.00	28.00	26.00
Sw	%	25.00	14.00	27.00	12.00	34.00	18.00
Initial Reservoir Pressure	Psig	3745	4009	4086	4135	4434	4621
Reservoir Thickness (Net Oil Sand)	ft	10	54	33	16	12	108
water salinity		25000-30000					
Types of Reservoir Fluid		Gas/Oil	Oil	Oil	Oil	Oil	Oil
N/G	%	94.00	80.00	88.00	90.00	96.00	91.00
OWC (ss)	ft ss	8634	9248	9434	9538	10232	10630
GOC (ss)	ft ss	8627	N/A	N/A	N/A	N/A	N/A
Top ss	ft ss	8584	9188	9401	9524	10210	10520
Bottom ss	ft ss	8692	9367	9507	9684	10312	10879
Permeability (Average)	mD	2210	2089	1633	1783	1220	1654
Bubble Point Pressure	Psig	3745	3677	3499	3524	3498	4145
Specific Gravity Oil 60/60		0.81	0.806	0.804	0.805	0.807	0.808
API	API	43.2	44.0	44.5	44.3	43.8	43.7

Viscosity Oil	cp	0.3	0.25	0.28	0.27	0.26	0.2
Boi	bbl/stb	1.524	1.654	1.504	1.521	1.554	1.862
Bgi	rb/scf	0.00072	N/A	N/A	N/A	N/A	N/A
Gas Cap (downhole ratio), m		3.86	N/A	N/A	N/A	N/A	N/A
GOR	Scf/stb	1300	1284	1200	1250	1300	1615
Reservoir Temperature	Deg F	151	166	167	169	172	174
Net Oil Sand	ft	48	54	33	16	12	108
N2	%	0	0	0	0	0	0
Co2	%	0.0092	0.23	0.0034	0.0061	0.0038	0.51
H2S	%	0	0	0	0	0	0

N/A: Not Applicable

A2: RELATIVE PERMEABILITY

Relative permeability				
A100		Residual Saturation	End Point	Exponent
	Krw	0.25	0.482	2.491
	Kro	0.112	0.8	3.687
	Krg	0.05	1	2.159
A200				
	Krw	0.14	0.0422	0.469
	Kro	0.12	0.8	4.709
	Krg	0.05	1	2.159
A300				
	Krw	0.27	0.465	2.795
	Kro	0.129	0.8	3.725
	Krg	0.05	1	2.159
A400				
	Krw	0.12	0.473	2.642
	Kro	0.12	0.8	5.862
	Krg	0.05	1	2.159
A500				
	Krw	0.34	0.46	2.904
	Kro	0.136	0.8	3.737
	Krg	0.05	0.9	2.159

A600				
	Krw	0.18	0.4118	1.2761
	Kro	0.136	0.8	2.965
	Krg	0.05	0.9	2.16

A3: RESERVOIR PVT TABLE

Reservoir A200 and A600 PVT Table

Reservoir A100

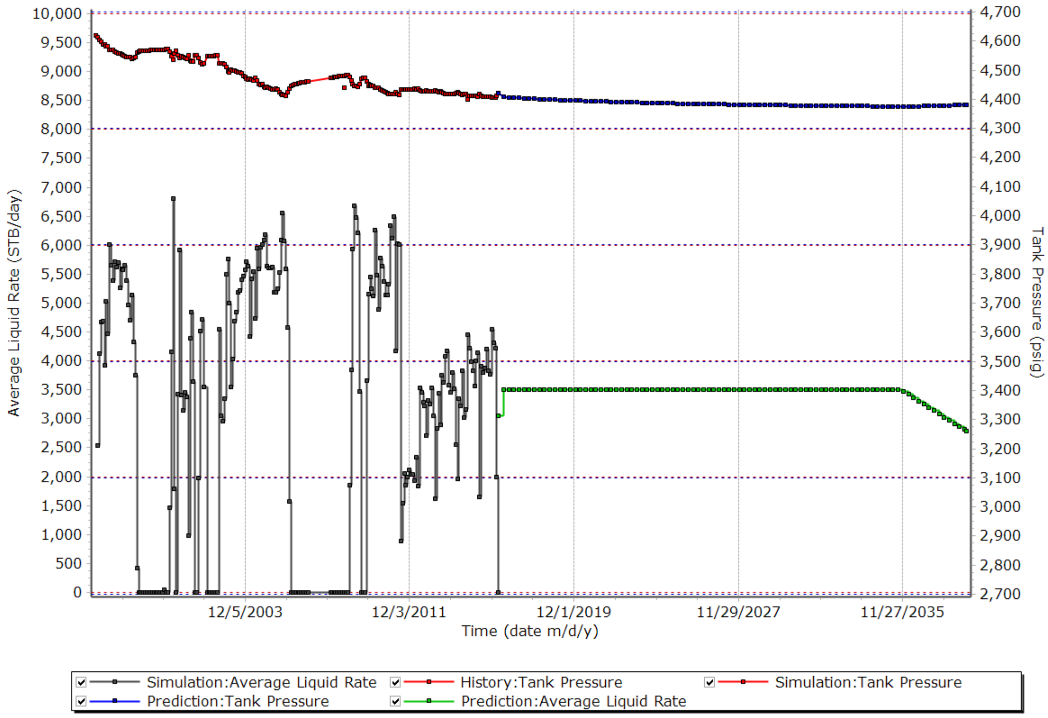
Pressure	GOR	Bo	Oil Viscosity	Bg	Gas Viscosity
3677	1198	1.5980	0.24		
3315	942.35	1.5146	0.26	0.0047	0.0202
2615	699.77	1.3986	0.31	0.006	0.0178
1915	504.76	1.2971	0.38	0.0087	0.0158
1215	338.69	1.2246	0.48	0.014	0.014
515	181.94	1.1602	0.64	0.0343	0.0119
15	0	1.0560	0.87	1.1758	0.0082

Reservoir A600

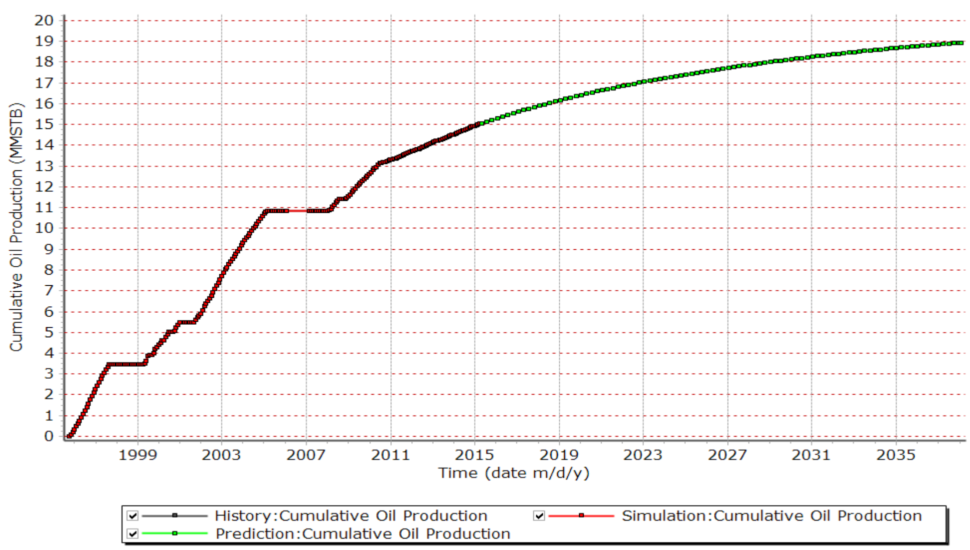
Pressure	GOR	Bo	Oil Viscosity	Bg	Gas Viscosity
4145	1615	1.8620	0.20		
3815	1390.94	1.7510	0.22	0.0038	0.0236
3015	1021.02	1.5747	0.25	0.0049	0.0197
2215	709.97	1.4310	0.28	0.0067	0.0169
1415	479.76	1.3279	0.35	0.0107	0.0146
615	264.4	1.21	0.50	0.026	0.012

	8	78		9	3
15	0	1.06 00	0.81	1.189 1	0.007 5

A4: RESERVOIR FORECAST



A600 Oil rate and Pressure Predictions



A600 Cumulative oil Production for 20 years Prediction

A4: TWO STRING MULTIPLE WELL COMPLETION ECONOMIC ANALYSIS

Facility:	APV
Case:	TSM
Working Interest:	30% SPDC JV

	Prices
Oil price (US$/bbl)	48.16
Gas price (US$/Mscf)	2.07
Flares Penalty (US$/Mscf	0.0503

Start year	2063

Opex Rates	OIL	GAS
Fixed - US $mln/per annum	-	
Variable (US $/bbl) / (US	4.99	0.86
Royalty rate	20%	7%

Cumulative net cash flow positive?	TRUE
Last Year of Proved Reserve	2079
First Year of Reserve Truncation	2080

Discount rate	13%
Mid-year discounting	0.50

	Production & Sales				Capital Cost		Operating Costs		Cashflows					
Year	Oil rate	Gas Production	Gas sales	Own Use gas	Capital Cost - Oil wells	Capital Cost - Oil facilities	Fixed Operating Cost	Variable Operating Cost	Revenue (Net of Royalty)	Development Charge (NDDC)	Annual Net Cash Flow	Cumulative Net Cash Flow	DISCOUNTED TAKE	CUMMLATIVE DISCOUNTED TAKE
	bbls/d	Mscf/d	Mscf/d	Mscf/d	US$ Mln.				US$ Mln.					
2063				0.00	26.00		0.00	0.00	0.00	0.78	(26.78)	(26.78)	-28.40	-26.78
2064	4000.00	8.04		17.00			0.00	7.29	56.29	0.22	48.78	22.00	45.99	22.00
2065	3414.92	12.92		17.00			0.00	6.22	48.06	0.19	41.65	63.65	34.90	63.65
2066	879.84	248.61		17.00			0.00	1.60	12.38	0.05	10.73	74.37	7.99	74.37
2067	553.91	3.86		17.00			0.00	1.01	7.79	0.03	6.76	81.13	4.47	81.13
2068	2535.53	5.99		17.00			0.00	4.62	35.68	0.14	30.92	112.05	18.20	112.05
2069	2496.75	5.65		17.00			0.00	4.55	35.14	0.14	30.45	142.50	15.93	142.50
2070	2264.69	5.10		17.00			0.00	4.13	31.87	0.12	27.62	170.11	12.84	170.11
2071	1659.18	4.12		17.00			0.00	3.02	23.35	0.09	20.23	190.35	8.36	190.35
2072	1144.25	3.27		17.00			0.00	2.09	16.10	0.06	13.95	204.30	5.13	204.30
2073	868.03	2.75		17.00			0.00	1.58	12.22	0.05	10.59	214.89	3.46	214.89
2074	710.62	2.38		17.00			0.00	1.30	10.00	0.04	8.67	223.56	2.52	223.56
2075	372.21	1.80		17.00			0.00	0.68	5.24	0.02	4.54	228.09	1.17	228.09
2076	342.35	1.61		17.00			0.00	0.62	4.82	0.02	4.18	232.27	0.96	232.27
2077	308.66	1.41		17.00			0.00	0.56	4.34	0.02	3.76	236.03	0.77	236.03
2078	264.64	1.19		17.00			0.00	0.48	3.72	0.01	3.23	239.26	0.59	239.26
2079	216.72	0.96		17.00			0.00	0.39	3.05	0.01	2.64	241.90	0.43	241.90
Totals	0	0	0		26	0	0	40	310	2	242		135	
	0													

ECONOMICS ANALYSIS TOO	US $ MM
Net Present Value	241.90
Internal Rate of Return	155%
Cum Fixed Opex at max Cum NCF	0.00
Cum Variable Opex at max Cum NC	40.16
Cum Capex at max Cum NCF	26.00

A5: SMART WELL COMPLETION ECONOMIC ANALYSIS

Facility:	APV
Case:	Smart
Working Interes	30% SPDC JV
	Prices
Oil price (US$/bbl)	48.16
Gas price (US$/Mscf)	2.07
Flares Penalty (US$/Mscf	0.0503

Start year	2063

Opex Rates	OIL	GAS
Fixed - US $mln/per annum	-	
Variable (US $/bbl) / (US $/Mscf)	4.99	0.86
Royalty rate	20%	7%

Cumulative net cash flow positive?	TRUE
Last Year of Proved Reserve	2080
First Year of Reserve Truncation	2081
Discount rate	13%
Mid-year discounting	0.50

	Production & Sales				Capital Cost		Operating Costs		Cashflows					
Year	Oil rate	Gas Production	Gas sales	Own Use gas	Capital Cost - Oil wells	Capital Cost - Oil facilities	Fixed Operating Cost	Variable Operating Cost	Revenue (Net of Royalty)	Development Charge (NDDC)	Annual Net Cash Flow	Cumulative Net Cash Flow	DISCOUNTED TAKE	CUMMLATIVE DISCOUNTED TAKE
	bbls/d	Mscf/d	Mscf/d	Mscf/d	US$ Mln.				US$ Mln.					
2063				0.00	32.00		0.00	0.00	0.00	0.96	(32.96)	(32.96)	-34.96	-32.96
2064	6000.00	9.89		17.00			0.00	10.94	84.43	0.33	73.17	40.21	68.99	40.21
2065	5395.79	16.12		17.00			0.00	9.83	75.93	0.30	65.80	106.01	55.15	106.01
2066	2730.29	8.17		17.00			0.00	4.98	38.42	0.15	33.30	139.31	24.80	139.31
2067	1771.60	6.32		17.00			0.00	3.23	24.93	0.10	21.61	160.91	14.31	160.91
2068	1266.78	5.20		17.00			0.00	2.31	17.83	0.07	15.45	176.36	9.09	176.36
2069	999.33	4.47		17.00			0.00	1.82	14.06	0.05	12.19	188.55	6.38	188.55
2070	850.38	3.94		17.00			0.00	1.55	11.97	0.05	10.37	198.92	4.82	198.92
2071	520.84	3.24		17.00			0.00	0.95	7.33	0.03	6.35	205.27	2.63	205.27
2072	500.73	2.96		17.00			0.00	0.91	7.05	0.03	6.11	211.38	2.24	211.38
2073	478.91	2.70		17.00			0.00	0.87	6.74	0.03	5.84	217.22	1.91	217.22
2074	456.17	2.47		17.00			0.00	0.83	6.42	0.02	5.56	222.78	1.62	222.78
2075	432.38	2.25		17.00			0.00	0.79	6.08	0.02	5.27	228.06	1.36	228.06
2076	406.23	2.04		17.00			0.00	0.74	5.72	0.02	4.95	233.01	1.14	233.01
2077	378.26	1.83		17.00			0.00	0.69	5.32	0.02	4.61	237.62	0.94	237.62
2078	346.59	1.63		17.00			0.00	0.63	4.88	0.02	4.23	241.85	0.77	241.85
2079	311.35	1.43		17.00			0.00	0.57	4.38	0.02	3.80	245.65	0.61	245.65
2080	264.65	1.18		17.00			0.00	0.48	3.72	0.01	3.23	248.88	0.46	248.88
Totals	0	0	0		32	0	0	42	325	2	249		162	
	0													

ECONOMICS ANALYSIS TOO	
	US $ MM
Net Present Value	248.88
Internal Rate of Return	202.25%
Cum Fixed Opex at max Cum NCF	0.00
Cum Variable Opex at max Cum NC	42.12
Cum Capex at max Cum NCF	32.00