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MASTER THESIS

Equation of State Modelling of Field Development Plan and Economic Analysis of Gas Condensate Reservoir of Ahdi Field in Pakistan

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ABSTRACT

Gas condensate systems have been widely produced for the production of valuable liquid condensate along with gas, generating a greater revenue than conventional gas reservoirs. This project focuses on the development of an accurate equation of state model to monitor the behavior of a gas condensate system and utilizing the said fluid model for history matching and field development. The field development plan is the first step to model an efficient gas condensate system and is generally different from conventional methods of field development due to the liquid dropouts involved during production. Therefore, it requires the equation of state model which is used for compositional reservoir simulation. This type of fluid model is necessary to create a simulation model of a reservoir, which at times, is inaccurate due to unavailability of data and low-grade lab equipment. Most of the uncertainties arise due to wrong sampling of the fluid.

The fluid model is generated using the IPM Suite's PVTP software. The major problem in modelling the equation of state is associated with the use of pseudo components. These components constitute a sensitive parameter of the equation and their improper estimation results in an inaccurate fluid model.

The next phase of the project involves history matching which finally allows the formulation of a field development plan for the gas condensate system. The simulation is performed using Schlumberger's Eclipse reservoir simulator. It is aimed to produce the reservoir in such a manner that the rate of pressure drop is kept low for maximum gas recovery above dew point pressure, and to minimize the liquid dropouts in the reservoir when the pressure falls below the dew point.

Various case scenarios such as varying the number of wells and application of fractures were modelled and the best case was selected for development of the field based on factors including maximum production, recovery factor and economics involved in the project.

XÜLASƏ

Adi qaz laylarından daha çox gəlir əldə olunan qaz -kondensat sistemləri qazla birlikdə əhəmiyyətli maye kondensat hasilatı üçün geniş istehsal olunur.

Bu tezis layihəsinin əsas məqsədi qaz kondensat sisteminin hərəkətinə nəzarət etmək üçün dəqiq hal tənliyinin modelinin yaradılması və bu qeyd olunan flüid modelini yataqların tarixi müqayisəsində və işlənməsində istifadə etməkdir.

Yataqların işlənmə planı effektiv qaz-kondensat sisteminin modelləşdirilməsində birinci addımdır və uyğun olaraq, hasilat zamanı mayenin axması səbəbindən yataqların işlənməsinin ənənəvi üsullarından fərqlənir. Uyğun olaraq, kollektor laylarının tərkib modelləşdirilməsi üçün hal tənliyi modeli tələb olunur.

Flüidin bu tip modeli layların tükənmə modeliinin yaradılması üçün vacibdir, hansı ki, məlumatların əldə edilməsinin mümkünsüzlüyü və laboratoriya avadanlıqlarınım aşağı keyfiyyətdə olması səbəbindən bəzən qeyri-dəqiq olurlar. Daha çox qeyri-müəyyənliklər maye nümunəsinin götürülməsi zamanı yaranır.

PVTP Suite IPM proqram təminatının istifadəsi ilə Flüid modeli yaradılır. Hal tənliyinin modelləşdirilməsi zamanı əsas problem psevdokomponentlərin istifadəsi ilə əlaqədardır. Bu komponentlər tənliklərin həyəcan parametrlərindən və flüidin qeyri-dəqiq modelinin qiymətləndirilməsində onların qeyri- dəqiq nəticələrindən təşkil olunmuşdur.

Layihənin növbəti mərhələsi tarixi müqayisədən təşkil olunmuşdur ki, o da son nəticədə qaz-kondensat sistemi yataqlarının işlənməsi planının hazırlanmasına imkan verir. Simulyasiya Schlumberger Eclipse simulator proqramının istifadəsi ilə həyata keçirilmişdir. Onun əsas vəzifəsi laylarda hasilatı o səviyyədə saxlamaqdır ki, təzyiqin düşmə sürəti yüksək təzyiq nöqtəsində maksimal neftvermə əmsalı üçün aşağı olsun və layda flüid axını minimum olsun, harda kı, təzyiq pik nöqtəsindən aşağı düşür.

Layihədə daxil edilən müxtəlif senarilər kimi, quyuların sayının dəyişdirilməsi və çatlılıq modelləşdirilmiş və daha yaxşı hal kimi maksimal hasilat, neftçıxarma əmsalı və iqtisadi faktorlarıın əsasında yataqların işlənməsi seçilmişdir.

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NOTATIONS

Bbl	Barrel of oil
Bo FVF	Formation volume factor bbl/stb
BOE	Barrels of Oil Equivalent MMBOE
Bg	Formation volume factor for gas scf/cubic feet
CAPEX	Capital expenditure
CCE	Constant composition expansion
CVD	Constant volume depletion
DVA	Differential vaporization analysis
FGPT	Total gas production
FGPR	Gas production rate
FOPR	Oil production rate
FOPT	Total field oil production
GIIP	Initial gas in place SCF
Gp	Cumulative gas produced at pressure p SCF
GPM	Gallons of liquid per thousand standard cubic feet in gal/Mscf
Kro	Relative permeability of oil
Krg	Relative permeability of gas

Mi	Molecular weight of component i
No	Moles of oil
Ng	Moles of gas
Nt	Total number of moles
Ni	Initial number of moles of gas = m/Ma
Np	Moles of gas produced
NPV	Net Present Value
OPEX	Operational expenditure
Psc	Standard pressure Psia
Pd	Dew-point pressure Psia
Pcow	Oil-Water Capillary Pressure
PDE	Partial differential equation
Pc	Critical pressure
Rs	(GOR) Dissolved gas oil ratio scf/stb
Rv	Dissolved oil gas ratio stb/scf
R	Gas constant 10.73
Stb	Stock tank barrel
Sw	Water saturation
So	Oil saturation
Sg	Gas saturation
T	Temperature, °R
Tc	Critical temperature
Tsc	Standard temperature, °R
Vo	Volume of oil
Vg	Volume of gas
Vt	Total volume
Vrel	Relative volume at pressure P
Vi	Initial gas volume (ft3)
(Vgp)sc	Volume of gas produced measured at standard conditions (SCF)
(Vrel)1	Relative volume at pressure P1
WBHP	Well bottom hole pressure
Yi	Mole fraction of component i in the gas phase

INTRODUCTION

The one of the most productive but at the same time difficult reservoir for production and field development planning is the gas condensate reservoir. The gas condensate reservoir is the reservoir with has rich condensate along with gas. Moreover, these field as pressure go below dew point condensate start to accumulate in the lower part of the well due to condensate drop out liquid hold is created and production rate per day of gas is reduced drastically.

Now a days, as the technology is advancing and more and more cost effective and productive methods come in to existence its becoming easy to productive these kind of challenging field. One and only technique to produce these field by overcoming the economic constraints in the project is to use Reservoir simulation software because by using it you can analysis a lot before investing the real money in the project.

In our case we have taken the core laboratory Data of the gas condensate reservoir from Ahdi field of Khewra formation. Khewra formation is basically a biggest salt range in Sothern Punjab plain of Pakistan. As per structure it is marked by a widespread, thin conglomerate developed at the base of the Kussak Formation **[14]**. As shown in Fig

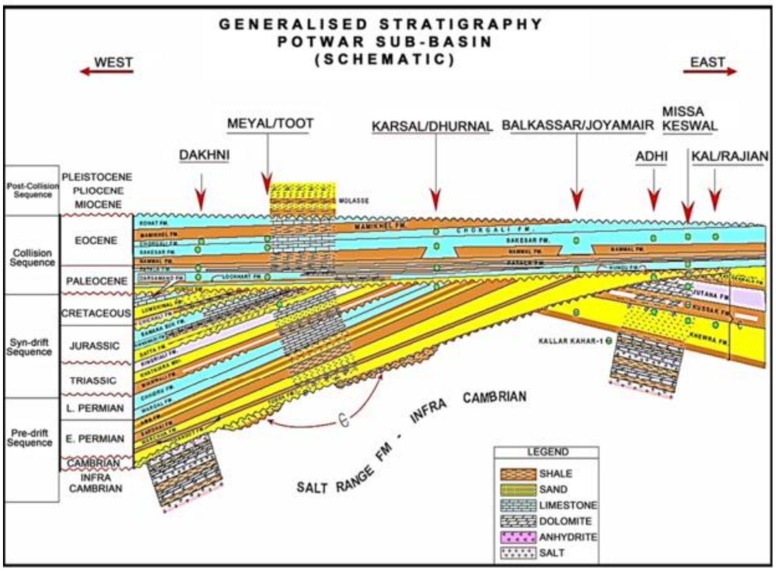


Fig The Early Cambrian Khewra Sandstone, Salt Range, Pakistan **[11]**.

In field development project I have first of all create an Equation of State Model by using IPM suite PVTP software. The reason for modelling EOS model is to analyze the potential of the field as by depicting the perfect model by using the core data of the Texas USA Lab. Furthermore, most important part of the project is synchronizing the data of core into our EOS model for finding the liquid dropout rate and Dew point pressure of the field as these parameter are going to play a key role in the field development planning.

Once the desired EOS Model is created the next phase of my project was to do the history matching of previous production data of the Ahdi field with our EOS model so that we an predict the performance and potential of the field in the future of basis of the EOS model.

Third phase of my project is planning a field development plan of the Ahdi field reservoir. Therefore, for planning multiple case with different parameters and properties are run and analyzed by using the Eclipse Schlumberger E300 Compositional modelling software.

In the last part of the project the Economic analysis with respect to OPEX, CAPEX, NPV and so on have been shown for all possible cases project economics and have given a detail Economic analysis on the best case scenario from 2010 to 2098 years.

SCOPE

In this thesis I have explain the process and tools such as IMP suite PVTP software and Schlumberger eclipse needed to do a gas condensate reservoir case study on any types. However, as in other reservoir case may be data will be different but modelling steps and hierarchy will be somehow similar. In addition I have also present a case study by using the EOS model so that reliability of the EOS modelling with eclipse can be proved.

CHAPTER 1. LITERATURE REVIEW

1.1. Gas Condensate Reservoirs

Reservoirs in which the hydrocarbons vaporized in the gas phase are recoverable as liquids at the surface, are termed as gas-condensate, and the produced liquids are referred to as condensates or distillates. Generally such reservoirs are at a temperature between the critical and the cricondentherm and the reservoir pressure is above dewpoint pressure (except retrograde condensates) at all times.

On a more specific basis Gas condensate reservoirs may be approximately defined as those that produce light colored or colorless stock tank liquids with gravities above 45° API, gas-oil ratios in the range of 5000 to 100,000 SCF/bbl.

The general characteristics of gas condensate reservoir fluid can be summarized as follows **[1]**:

1. Initial Fluid Molecular Weight: 23 – 40 lb/lbmol

2. Stock-Tank Oil Color: Clear to Orange

3. Stock Tank Oil Gravity: 45 – 60 API

4. C7-plus Mole Fraction: 0.01 – 0.12

5. Typical Reservoir Temperature: 150 – 300 F

6. Typical Reservoir Pressure: 1500 – 9000 psia

7. Volatilized Oil-Gas Ratio: 50 – 300 STB/MMSCF

8. Primary Recovery of Original Gas In Place: 70% – 85%

9. Primary Recovery of Original Oil In Place: 30% - 60%

1.1.1. Flow Behaviour in Gas Condensate Field

The typical flow behavior if a gas condensate in a reservoir is depicted by the figure1-1, which shows that during flow there are different regions created throughout the reservoir.

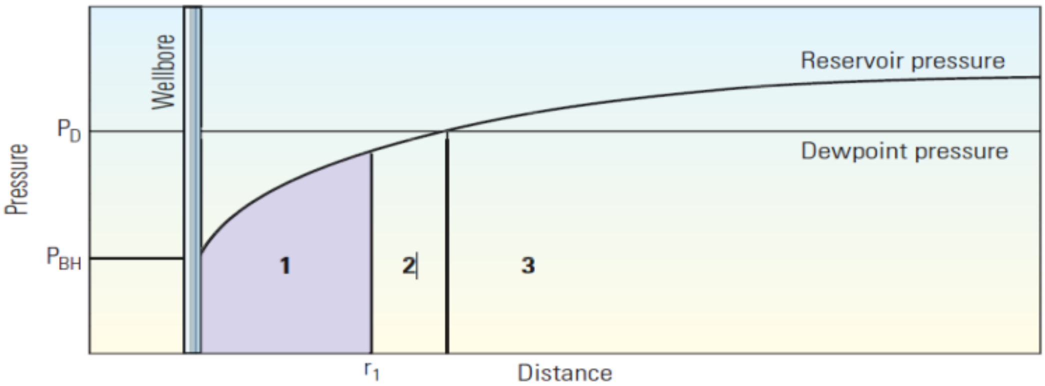


Figure 1-1 Gas condensate regions

The first region is the closest to the wellbore and suffer most of the pressure drop, both gas and oil/condensate phases are mobile in this region. The extent of this region is based on the type of condensate; tens of feet for lean gas condensate and hundreds of feet for rich gas condensate The second region is often termed as condensate buildup region; here as the pressure is below the dew point pressure, liquid dropout takes place and with time and pressure decrement the liquid/condensate saturation increases, the flow or production in this region is mainly due to the gas phase and the dropped out liquid only serves as a hindrance in the gas phase flow until critical saturation is reached otherwise the liquid (condensate) banks**,[2].**

In farthermost region away from the wellbore (third region) the pressure is above dew point and hence the fluid remains in gas phase at every position in the reservoir. The region ranges from the outer most reservoir boundary up till where the reservoir pressure equals the dew point pressure. The inner boundary of this regions increases with decrease in reservoir pressure until the pressure at both the internal and external boundaries of this region is drops below dewpoint pressure at which this region doesn’t exist.

1.1.2. Types of Gas Condensate

Following are the 2 main types of gas condensate reservoirs

- Retrograde Gas Condensate
- Near Critical Gas Condensate

1.1.3. Retrograde gas condensate

At constant temperature a decrease in pressure causes the liquid to convert into gas for a pure substance, this same phenomenon occurs for a mixture of two or more components but the restriction is that the temperature should be below critical temperature. If the temperature is above the critical temperature, the gas cannot be liquefied for a pure substance but for a mixture the temperature is the cricondentherm.

The region between the critical temperature and cricondentherm is called retrograde gas condensation region in which retrograde behavior occurs i.e. with pressure drop the liquid expands and as the pressure continues to decline the liquid re vaporizes.

These reservoirs are initially gas reservoirs and only gas phase exists; as the pressure is above dew point Pd1. If the gas is at temperature between Tc and cricondentherm and pressure P1, then as expansion is made at constant temperature, the pressure drops and separation occurs between the heavy and light components and the molecular attraction among heavy components increases which causes them to condense to form liquid as pressure reaches to Pd1 (first dew point pressure or retrograde dew point). As pressure further decreases, the concentration of liquid increases and up to pressure P2 25% of the mixture will exist as liquid and only 75% remains as gas. As pressure goes down further from P2, the heavy components that have condensed again convert into vapors as molecular forces tend to be weaker at this low pressure and as pressure is dropped up to second dew point Pd2 all liquid become vapor and at pressure P3 only gas exists. In case of a mixture, the gas that exists between critical point and cricondentherm can be liquefied but not the gas that exists above the cricondentherm,**[4].**

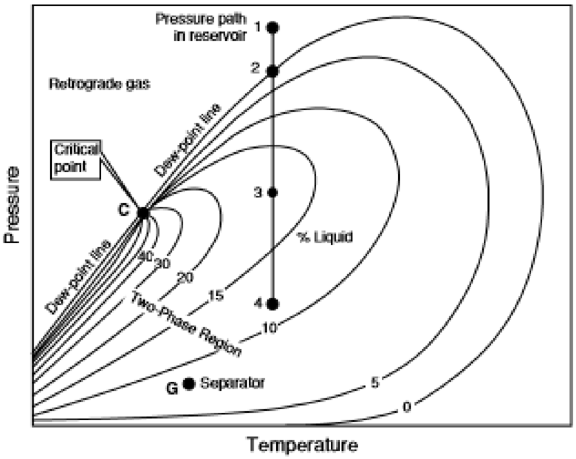


Figure 1-2 gas Condensate Region **[4]**

1.1.4. Near critical gas condensate

If the reservoir temperature is near critical temperature as shown in the figure1-3 the hydrocarbon mixture is classified as near critical gas condensate. The straight line 1-3 in figure1-3 shows the volumetric behavior of this system during isothermal pressure decline where initially at 1 fluid phase is gas but as the pressure decreases below dew point line the system enters two phase region indicating liquid drop out.**[4].**

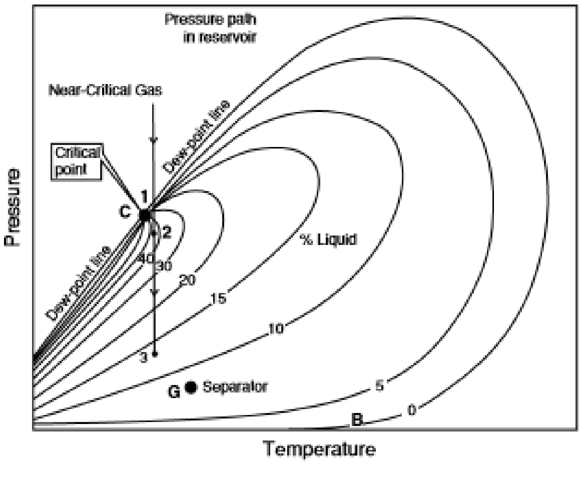


Figure 1-3 Phase diagram of near Critical Gas Condensate Reservoir **[4]**

Condensate reservoir can also further be classified as:

Lean Gas Condensate Reservoirs

Lean gas-condensates are characterized by having a lower content of Heptane plus (heavier ends) therefore they yield lesser condensate (liquid). More over at reservoir conditions the lean gas condensates are at temperatures far from the critical temperature and nearer to the cricondentherm.

Rich Gas Condensate Reservoirs

Rich gas -condensates are characterized by having a higher content of Heptane plus (heavier ends) therefore they result in more condensate (liquid) dropout. The reservoir temperature of the lean gas condensates is relatively closer to critical temperature.

1.1.5. Complications in the Production of Gas condensate

As the pressure declines below dew point pressure in the gas condensate reservoir valuable condensate drops out and accumulates between pores. When condensate liquid first forms in a gas reservoir, it is immobile because of capillary forces acting on the fluids. That is, a microscopic liquid droplet, once formed, will tend to be trapped in small pores or pore throats. Even for rich gas condensate with substantial liquid dropout, condensate mobility, which is the ratio of relative permeability to viscosity, remains insignificant away from wellbores. As a consequence, the condensate that forms in most of the reservoir is lost to production unless the depletion plan includes gas cycling. The effect of this dropout on gas mobility is typically negligible.

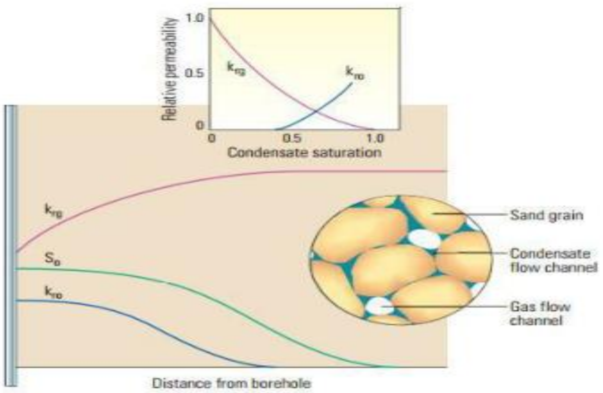


Figure 1-4 Permeability variation with distance (Oilfield Review Winter 2005/2006)

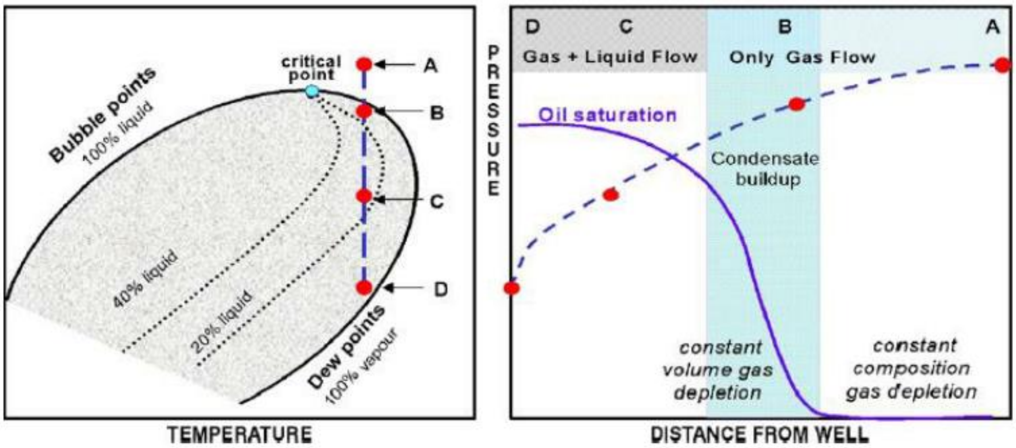


Figure 1-5 Pressure–temperature phase diagram for a constant composition, and pressure–flow regimes as a function of the distance from the well

Near a producing well, the situation is different. Once bottom hole pressure drops below the dew point, a near well pressure sink forms around the well. As gas is drawn into the pressure sink, liquid drops out. After a brief transient period, enough liquid accumulates that its mobility becomes significant. The gas and liquid compete for flow paths, as described by the formation's relative permeability relationship. Condensate blockage is a result of the decrease gas mobility around a producing well below the dew point.

This phenomena, called condensate blockage or condensate banking, results from a combination of factors including fluid phase properties, formation flow characteristics and pressure in the formation and in the wellbore. If these factors are not understood at the beginning of field development, sooner or later production performance can suffer.

1.1.6. Optimizing production from gas condensate

Historically, condensate liquids have been significantly more valuable than the gas, and this is still true in a few places far from a gas market or transport system. The price differential made gas cycling a common practice. Injecting dry gas into a formation to keep reservoir pressure above the dew point slowly displaces valuable heavy ends that are still in solution in the reservoir gas. Eventually, the reservoir is blown down; that is, the dry or lean gas is produced at low bottom hole pressure.

The price of gas has risen to a value that makes reinjection a less attractive strategy, unless the fluid is very rich in heavy ends. Gas injection is now more commonly used as a temporary activity, until a pipeline or other transport facility is built, or as a seasonal activity during period of low gas demands.

Operators also work to overcome condensate blockage. Some techniques are the same in a gas condensate fluid as they are in a dry-gas field. Hydraulic fracturing is the most common mitigating technology in silicate reservoirs, and acidizing is used in carbonate reservoirs. Both techniques increase the effective contact are with a formation. Production can be improved with less drawdown in the formation. For some gas condensate fields, a lower drawdown means single phase production above the dew point pressure can be extended for a longer time.

However, hydraulic fracturing does not generate a conduit past a condensate saturation buildup area, at least not for long. Once the pressure at the sand face drops below the dew point, saturation will increase around the fracture, just as it did around the wellbore.

Horizontal or inclined well are also being used to increase contact area within formations. The condensate still builds up around these longer wells, but it takes a longer time. The productivity of the wells remains high longer, but the benefit must be weighed against the increased well cost.

Some operators have tried shutting in wells to allow time for the gas and condensate to recombine, but fluid phase behavior generally does not favor this approach. Separation of a fluid into a gas and liquid phase in the two phase region of the phase diagram happens quickly, and after this the phases tend to segregate, either within a pore or on a longer scale. This phase separation dramatically slows the reverse process of recombining gas and liquid phases.

Another method, cyclic injection and production from one well, sometimes called huff and puff injections, uses dry gas to vaporize condensate around a well and then produce it. This can have short term benefit for increased productivity, but the blockage returns when production begins again and the formation drops below the dew point pressure of the current gas mixture.

Treatment methods have been suggested for removing condensate blockage through injection of surfactants mixed with solvents to alter wetting preferences in the reservoir.

1.1.7. Sampling of Gas Condensate Reservoir Fluid

Fluid compositions can be determined by taking reservoir samples through surface sampling and subsurface sampling. Surface sampling is relatively easy in which liquid and gas samples are taken from test production separator. Samples are recombined to make the sample representative of the reservoir conditions. However, the result can be unrepresentative of the reservoir conditions, particularly when sampling of gas condensate reservoir. A few examples of potential problems include:

- Recombining gas and liquid samples at an incorrect ratio
- Change in production conditions prior to the sampling
- A small loss of the condensate samples in production tubular or separators.

Another way to collect samples is through sub surface sampling from wellbore fluids in gas condensate reservoirs. This is practical and desirable when reservoir pressure is greater than the dew point pressure as fluid is single phase. However it is not desirable when pressure is below dew point pressure anywhere in the tubing string as liquid drops and there is two phase flow. Any liquid forming in the tubing drops down to the bottom of the tubing and the samples taken are unrepresentative with too much of heavier components.

1.2. PVT Experiments

1.2.1. PVT Analysis

PVT Analysis is done to know how the fluids behave within the reservoir, within the wells, at surface conditions, in the network and at the refinery. The fluid properties need to be known over a wide range of temperatures and pressures. When gas is injected into the reservoir, we also need to know how the properties of the original reservoir fluid will change as the composition changes**.**

We also need PVT fluid properties to predict:

- The composition of well stream as a function of time.
- Completion design, which depends on the properties of the wellbore liquids.
- Whether to inject or re-inject gas.
- The detailed specification of the injected gas - how much C3, 4, 5’s to leave in separator configuration and stage for injection gas.
- Miscibility effects that may result from the injected gas.
- The amounts and composition of liquids left behind and their properties: density, surface tension, viscosity.
- Separator/NGL Plant Specifications.
- H_2S and N_2 concentration in produced gas.
- Product values vs. time.

The standard PVT properties (B_o, B_g, R_s & R_v) are needed for many reservoir engineering calculations. The final set of properties is usually not provided by commercial laboratories but must be computed by the engineer.

The computational effort to obtain a final set ranges from minor to significant, depending on the reservoir fluid and the data supplied by the laboratory. For instance, only minor adjustments are generally needed to generate a final set of PVT properties for black oils.

Much more effort is needed for gas condensate and volatile oils.

A standard fluid property appraisal involves one or more of the following tests:

- Differential vaporization analysis (DVA)
- Constant volume depletion (CVD)

- Constant composition expansion (CCE)
- Flash separation test

Test selection depends mainly on the fluid classification.

- DVA is usually performed on black oils.
- CVD is performed on gas condensates and volatile oils.
- CCE on all fluids.
- Flash separation tests are invariably performed on black oils but also may be extended to other fluids, including wet gases.

1.2.2. Differential Vaporization Analysis (DVA)

The purpose of this test is to measure a preliminary set of PVT properties (Bo, Bg & Rs) for black oils.**[4]**

The experimental procedure of DVA is as follows:

- Charge a windowed PVT cell with a sample of the reservoir fluid at the initial reservoir pressure or at the fluid's bubble point pressure and temperature.
- Decrease the pressure approximately 200 to 500 psi and allow the fluid to equilibrate.
- Remove the entire gas-phase volume if a gas phase appears.
- Return to step 2 and repeat the process.

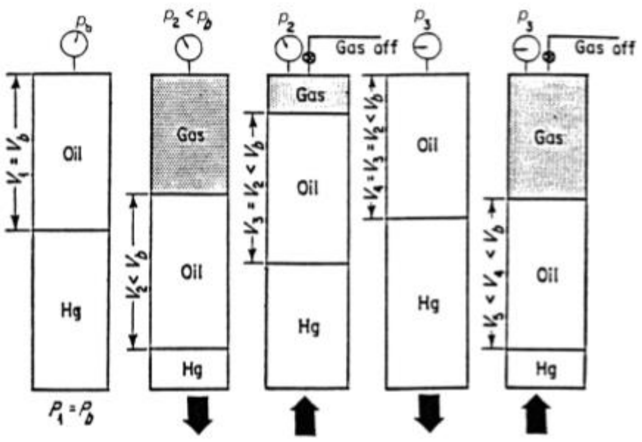


Figure 1-6 Schematic showing the determent during DVT **[4]**

The following measurements are recorded:

- Oil-phase volume at each pressure
- Gas-phase volume (before gas is removed) at each pressure
- Volume of displaced gas at standard conditions at each pressure
- Oil-phase volume remaining at standard conditions.

From the measurements, a preliminary set of PVT properties (Bo, Bg & Rs) is derived.

1.2.3. Constant Volume Depletion (CVD)

Data from CVD are used to compute the standard PVT properties of volatile oils and gas condensates. This test does not compute the PVT properties directly. Earlier it is referred as differential vaporization with constant cell volume. Sometimes this study is called a depletion study.**[4]**

The experimental procedure is as follows:

- Charge a windowed PVT cell with a sample of the reservoir fluid at reservoir temperature and at a pressure equal to or greater than fluid’s saturation pressure.
- Decrease the pressure approx. 10% or 300 psi and allow the fluid to equilibrate.
- Remove a portion of the gas phase so that the cell volume is equal to the original cell volume.
- Decrease the pressure and repeat the process until a pressure of 500 to 1200 psia is reached.

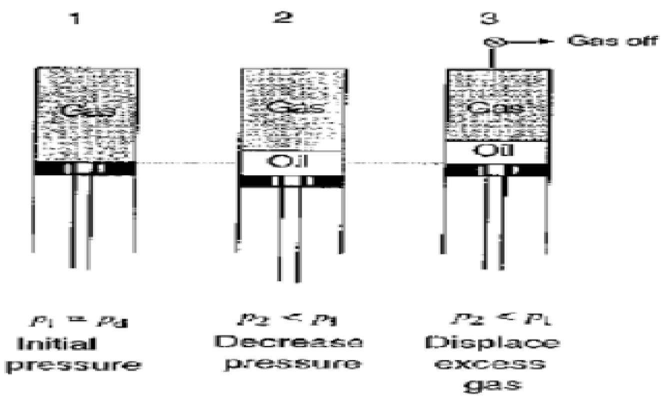


Figure 1-7 One pressure decrement in a CVD (Walsh & Lake, 2003)

Figure illustrates one pressure decrement during a CVD. The portion of the gas that is removed at each decrement is the excess gas. The following quantities are measured:

- Volume of oil and gas phases (before excess gas removed) at each pressure.
- Gas composition including C7+ molecular weight at each pressure.
- Weight and volume of excess gas at each pressure.
- Volume-fraction liquid (computed from phase-volume measurements) at each pressure.

Most PVT laboratories extend the CVD one step further. They liken the CVD to reservoir depletion and compute idealized oil and gas recoveries. The recoveries are computed from the stock tank oil and separator gas recovered from the produce (i.e. excess) gas. This treatment likens the CVD to a reservoir where the liquid phase is immobile and only free gas is produced. For most gas condensate reservoirs, this is reasonable assumption. Usually the recoveries are computed by using flash calculations and assuming the produced gas passes through a hypothetical set of separators. The flash calculations use the equilibrium gas compositions that are measured from CVD.

From the preceding data, the standard PVT properties can be computed using different procedures.

The two phase z-factor, incidentally, is defined as

$$Z2 = \frac{Zo\ no + Zg\ ng}{nT}$$

Where $Zo\ and\ Zg$ and are the oil and gas single phase z factors, $no\ and\ ng$ and are the moles of oil and gas, and nT is the total number of moles $nT = no = ng$. Using these definitions, the real gas law becomes, $PVt = Z2nTRT$

Where VT is the total volume and $VT = V\ o + V\ g$, where $V\ o$ and $V\ g$ are the oil and gas phase volumes. Whereas Zo and Zg are proportional to their individual phase molar $(V_O/n_o \text{and} V_g/n_g), Z_2$ volumes 2 is proportional to the overall molar volume VT/nT.

1.2.4. Constant Composition Expansion (CCE)

This test is performed on all reservoir hydrocarbons. The data from this test are used to compute single phase FVF's above the saturation pressure and two phase FVF's below the saturation pressure. This test can also be used to check the accuracy of the standard .PVT properties computed from either a DVA or CVD. A CCE is also sometimes referred to as flash vaporization or a flash liberation.**[4]**

The experimental procedure is as follows:

- Charge a reservoir fluid sample to a windowed PVT cell at the reservoir pressure.
- Raise the cell pressure to the desired pressure and allow the fluid to come to equilibrium.
- Measure the total cell volume.
- Measure the individual phase volumes.
- Decrease the cell pressure 100 to 500 psia and allow the cell to come to equilibrium.
- Return to step 3 and continue the procedure until the minimum desired pressure is reached.

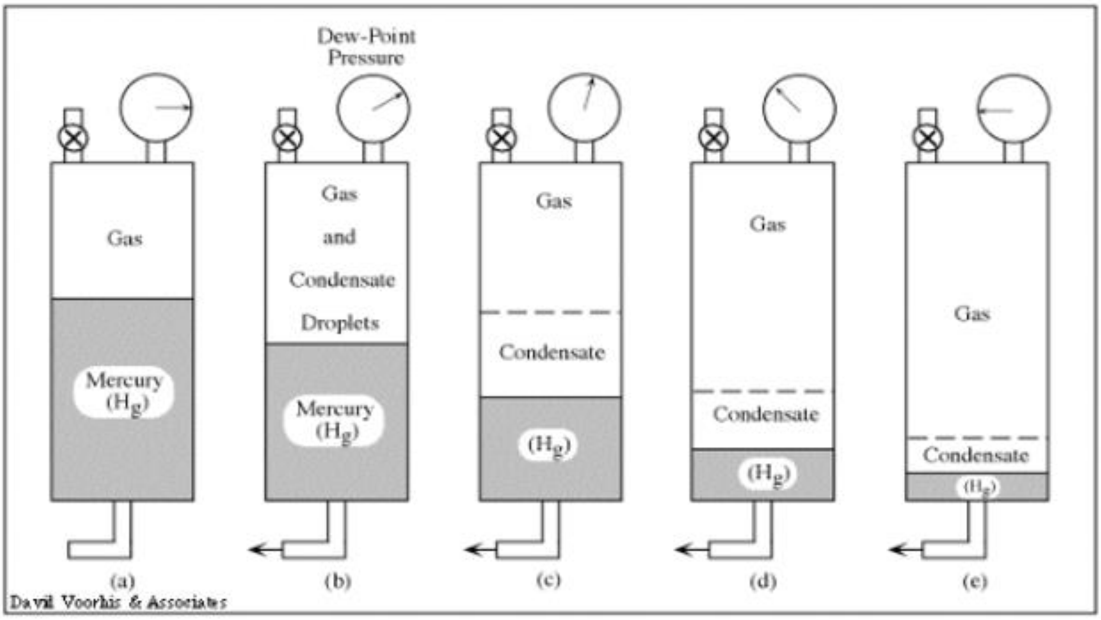


Figure 1-8 Schematic showing on pressure decrement during CCE **[4]**

Note all CCE's measure the individual phase volumes; some just measure the total volume.

1.2.5. Flash Separation Tests

The standard PVT properties depend on the lease separator conditions. The purpose of flash separation tests is to:

- Determine the optimum primary separator pressure
- Measure the stock tank oil and separator gas yields from the separators and the stock tank oil density and separator gas gravity
- Provide data so that the uncorrected standard P VT properties can be corrected for the effects of lease separators.

Flash separator tests mimic lease separators. They are usually limited to only two stage units and to black oils**.[4]**

The system consists of a separator and stock tank. The separator is operated at an elevated pressure while the stock tank approaches ambient conditions. For black oils, the optimum separator pressure is usually between 50 and 300 psi. The well stream enters the separator, oil and gas separate and leave the separator, the gas is metered, and the liquid is fed to the stock tank. The separator liquid separates in the stock tank, gas leaves the stock tank and is metered, and the oil remains in the stock tank. Multistage separation characteristically increases the stock tank oil yield and decreases the separator gas yield, these changes cause Bo and Rs to decrease from those values computed in the DVA.

The flash separation test consists of a series of individual separation tests, each at a different separator pressure. Generally, three to five pressures within the expected range are tested. Each test measures the following data:

- The overall stock tank oil yield in terms of the stock tank oil volume recovered per unit feed volume, STB/RB.

- The total separator gas yield in terms of the volume of gas at standard conditions per unit volume of stock tank oil, scf/STB.
- The liquid shrinkage factor in the separator in terms of liquid effluent volume per unit feed volume, bbls/RB.
- The liquid shrinkage of stock tank oil expressed in terms of liquid feed volume per stock tank oil volume, bbls/STB.
- The stock tank oil density.
- The specific gravity of separator and stock tank gases.

The optimum separator pressure corresponds to the pressure that yields the greatest overall stock tank oil volume. In other words, optimum separator pressure is one which provides;

- Less GOR.
- Less Bo.
- High API gravity.

The data from this test are used to correct the standard PVT properties from the DVA for the effects of separator.

1.3. Equation of State

An Equation of state is an analytical expression that relates the pressure to the temperature and volume of a substance. It is basically the defining factor that predicts the nature or behavior of any substance (pure substance or a mixture) at any given temperature pressure condition. Equation of state is the means of modeling the nature of any particular fluid in order to analyze its phase behavior. With the help of an EOS it is easier to comprehend the type of fluid that a reservoir engineer is dealing with so that future planning can be done accordingly. Understanding the fluid type present in the reservoir is of utmost importance because it can lead to the successful long term production life of a reservoir. A proper description of this PVT relationship for real Hydro Carbon fluids is essential in determining the volumetric and phase behavior of petroleum reservoir fluids and predicting the performance of surface facilities.

There are numerous number of Equations of State that have been developed to date alongside their improved or corrected versions. Following is a list of Equations of State that are most commonly used;

- Ideal Gas Equation
- Van der Waal Equation of State
- Redlich Kwong Equation of State
- Soave Redlich Kwong Equation of State
- Peng Robinson Equation of State

1.3.1. Ideal Gas Equation

An ideal Gas equation is the simplest form of expression to relate the Pressure Temperature Volume of a real gas in order to predict the properties and behavior of the gas. Although this equation has very limited practical value since no gas behaves as an ideal gas; however the equation does describe the behavior of real gas at low pressures. Also the equation served as the basis for future development of Equation of State which describe more adequately and precisely the gas behaviors at elevated temperature pressure conditions **[3].**

$PV = nRT$

Where

P = system pressure, psia

T = system temperature, ^{0}R

R = gas constant 10.732 psi-ft3/lb-mol ^{0}R

n = no of moles

1.3.2. Van der Waal Equation of State

The Van der Waal Equation of State was formulated to correct for the assumptions considered while making the general gas equation. Van der Waal introduced two parameters “a” and “b” in the Ideal Gas EOS. The parameter “a” was related to the intermolecular attraction and the parameter “b” denoted the volume of molecules **[3].**

$$P = \frac{RT}{V - b} - \frac{a}{V^2}$$

$$a = \Omega a \frac{R^2 Tc^2}{Pc}$$

$$b = \Omega b \frac{RTc}{Pc}$$

Where

P = system pressure, psia

Pc= critical pressure, psia

T = system temperature, ^{0}R

Tc=critical temperature, ^{0}R

R = gas constant 10.732 psi-ft3/lb-mol ^{0}R

V = Volume, ft3/ mol

Ωa = 0.421875

Ωb = 0.125

The contributions of Van der Waal EOS can be summarized as follows:

- It radically improved predictive capability over ideal gas EOS.
- It was the first to predict continuity of matter between gas and liquid.
- It formulated the Principle of Corresponding States (PCS).
- It laid foundations for modern cubic EOS.

1.3.3. Redlich Kwong Equation of State

The Redlich Kwong EOS was an improvement to the Van der Waal EOS, the major alterations provided by the EOS was that Redlich and Kwong replaced the term a/V2 with a general temperature dependent term to improve the prediction of volumetric and physical properties of the vapor phase **[3].**

$$P = \frac{RT}{V-b} - \frac{a}{V(V+b)T^{0.5}}$$

$$\mathrm{a} = \Omega \mathrm{a} \frac{\mathrm{R}^2 Tc^{2.5}}{Pc}$$

$$b = \Omega b \frac{RTc}{Pc}$$

[8] Where

P = system pressure, psia

Pc = critical pressure, psia

T = system temperature, ^{0}R

Tc = critical temperature, ^{0}R

R = gas constant 10.732 psi-ft3/lb-mol ^{0}R

V = Volume, ft3/ mol

Ωa = 0.42747

Ωb = 0.08664

The Redlich-Kwong equation of state could be used to reliably calculate the vapour - liquid critical properties of binary mixtures as demonstrated by Spear et al. (1969). Chueh and Prausnitz (1967a, b) also showed that the Redlich-Kwong equation can be adapted to predict both vapour and liquid properties. Deiters and Schneider (1976) and Baker and Luks (1980) have successfully applied the Redlich-Kwong equation to the high pressure phase equilibria of binary mixtures. Many other acknowledgements for more accurate vapor phase prediction by the Redlich Kwong equation are found.

1.3.4. Soave Redlich Kwong Equation of State

In 1972 Soave introduced a most significant modification to the Redlich Kwong EOS which was in the evaluation of the parameter “a”. Soave replaced the term a/T0.5 with a general temperature dependent term aα. It was the first time that “a” was expressed not only as a function of temperature, but also as a function of the shape (sphericity) of the molecules (through ω, Pitzer’s acentric factor).

$$P = \frac{RT}{V-b} - \frac{a\alpha}{V(V+b)}$$

$$\alpha = \left(1 + m\left(1 - Tr^{0.5}\right)\right)^2$$

$$m = 0.480 + 1.574\omega - 0.176\omega^2$$

$$a = \Omega a \frac{R^2 Tc^2}{Pc}$$

$$b = \Omega b \frac{RTc}{Pc}$$

Where

P = system pressure, psia

Pc = critical pressure, psia

T = system temperature, ^{0}R

Tc = critical temperature, ^{0}R

Tr = reduced temperature; T/Tc

R = gas constant 10.732 psi-ft3/lb-mol ^{0}R

V = Volume, ft3/ mol

Ωa = 0.42747

b = 0.08664

ω = acentric factor

In contrast to the original Redlich-Kwong equation, Soave's modification fitted the experimental (vapour-liquid) curve well and it was able to predict the phase behavior of mixtures in the critical region. Although further modification and improvements were made to the SRK EOS such as the introduction of fugacity in the equation it still is one of the most used equations when it comes to prediction accuracies.

1.3.5. Peng Robinson Equation of State

The most popular equation of state for gas, condensate systems is the Peng Robinson EoS. Peng and Robinson were interested in the SRK equation of state for predicting the behavior of naturally occurring hydrocarbons and proposed that an improvement is necessary in the equation in order for it to predict liquid densities and other fluid properties in the vicinity of the critical region. Peng and Robinson conserved the temperature dependency of the attractive term and the acentric factor introduced by Soave. However, they presented different fitting parameters to describe this dependency [**3**].

$$P = \frac{RT}{V-b} - \frac{a\alpha}{V(V+b)+b(V-b)}$$

$$\alpha = \left(1 + m\left(1 - Tr^{0.5}\right)\right)^2$$

$$m = 0.3746 + 1.5423\omega - 0.2699\omega^2$$

$$\mathrm{a} = \Omega\mathrm{a}\frac{\mathrm{R}^2 Tc^2}{Pc}$$

$$b = \Omega b\frac{RTc}{Pc}$$

Where

P = system pressure, psia

Pc = critical pressure, psia

T = system temperature, ^0R

Tc = critical temperature, ^0R

Tr = reduced temperature; T/Tc

R = gas constant 10.732 psi-ft3/lb-mol ^0R

V = Volume, ft3/ mol

a = 0.45724

Ωb = 0.07780

ω = acentric factor

The Peng-Robinson and Soave-Redlich-Kwong equations are widely used in industry (Sadus, 1994). The advantages of these equations are they are easy to use and that they often accurately represent the relation between temperature, pressure, and phase compositions in binary and multicomponent systems. These equations only require the critical properties and acentric factor for the generalized parameters. Little computer resources are required and those lead to good phase equilibrium correlation. However, the success of these modifications is restricted to the estimation of phase equilibria pressure. The calculated saturated liquid volumes are not improved and they are invariably higher than the measured data.

All of the above mentioned equations are applicable to pure substances as well as for mixtures; using the mixing rule available for each equation respectively.

1.4. Procedure for Development of Equation of State

The foremost step in the course of this project was to design and fine tune an Equation of State that could accurately model the behavior of the Gas Condensate. For this purpose the Equation of State was modelled using the IPM Suite PVTP package. The basic procedure which was followed is enlisted below

- Selection of Equation of State
- Initialization of components
- Field and Lab Data input
- Use of Binary Interaction Coefficients
- Splitting of Pseudo Component/s
- Applying Regression
- Tuning of Critical Properties
- Exporting the EOS

1.5. Reservoir Simulation

Reservoir simulation combines physics, mathematics, reservoir engineering, and computer programming to develop a tool for predicting hydrocarbon reservoir performance under various operating conditions.

The need for reservoir simulation stems from the requirement for petroleum engineers to obtain accurate performance predictions for a hydrocarbon reservoir under different operating conditions. This need arises from the fact that in a hydrocarbon recovery project (which may involve a capital investment of hundreds of millions of dollars), the risk associated with the selected development plan must be assessed and minimized. Factors contributing to this risk include the complexity of the reservoir because of heterogeneous and anisotropic rock properties; regional variations of fluid properties and relative permeability characteristics; the complexity of hydrocarbon recovery mechanisms; and the applicability of other predictive methods with limitations that may make them inappropriate. The first three factors are beyond the engineers control; they are taken into consideration in reservoir simulation through the generality of input data built into reservoir simulation models and the availability if simulators for various enhanced oil recovery techniques. The fourth factor can be controlled through proper use of sound engineering practices and judicious use of reservoir simulation.

The use of reservoir simulation as a predictive tool is becoming standard in petroleum industry. It’s widely accepted all because of advances in computational facilities, advances in numerical techniques, as we know that simulators just solve the partial differential equations and predicts the future performance of the reservoir depending on the present performance of the reservoir. These equations incorporate the most important physical processes taking place in the reservoir system, including, among other things, the flow of fluid partitioned into as many as three phases (oil, water, gas), and mass transfer between these phases. The effect of viscosity, capillary, and gravity forces on fluid flow are taken into consideration by use of generalized form of Darcy’s law.

Typical application of reservoir simulation is to predict future performance of the reservoirs so that intelligent decisions can be made to optimize the economic recovery of hydrocarbons from the reservoir.

There are two different approaches to analyse the general case of three-dimensional three phase flow of fluid reservoir through pored rock, the compositional and the black oil models. Generally, Crude oil contains some amount of dissolved gas and invariably occurs in conjunction with water. In many cases, it is acceptable to assume that the oil and gas compositions are fixed and the solubility of the gas in the oil depends on pressure only. And consequently, it is possible to consider a single oil "pseudo-component" and a single gas "pseudo-component." However, if oil and gas equilibrium compositions vary strongly as a function of space and time, a compositional formulation is needed that includes a larger number of components and appropriate equations of state.

1.5.1. Black oil Simulation

Black Oil models assume that the hydrocarbons may be described as two components, oil and gas, and that hydrocarbon fluid composition remain constant during the simulation. All fluid properties are assumed to be determined by oil pressure and bubble point pressure only. All mass transfer between the two components is normally described by the solution gas-oil ratio term, Rso (although an oil-in-gas term to handle condensate may easily be included in the Black Oil formulation).**[5]**

The black-oil model is a simplified compositional model describing multiphase flow with mass interchange between phases in a porous medium. It consist three phases (gas, oil and water), can predict the compressibility and mass transfer effects, and can be used for a low-volatility system, consisting mainly of methane and heavy components, using data from a conventional differential vaporization test on reservoir oil samples. In this model it is assumed that no mass transfer between the water phase and the other two phases (gas and oil). In the hydrocarbon (gas-oil) system, only two components are considered: the oil component; and the gas component. The oil components (also called stock-tank oil) is the residual liquid at atmospheric pressure left after a differential vaporization, while the gas component is the remaining fluid in a porous medium.

1.5.2. Compositional Simulation

It may be taken into account that there are n-hydrocarbon components present in the reservoir fluid in the form of oil or gas phases and a water component that can be found in the form of liquid (water) or vapour (gas) phase. Therefore, there may be n-component in oil phases and (n + l)-component in gas phases and 1-component in water phase. When there is components transfer between phases, a fully compositional model should be used to analyse the reservoir fluid through the pored rock**.[5]**

In reservoirs containing light oil, the hydrocarbon composition as well as pressures affect fluid properties. Equilibrium flash calculations using K values or and equation of state (EOS) must be used to determine hydrocarbon phase compositions. In a compositional model, we in principle make mass balances for each hydrocarbon component, such as methane, ethane, propane, etc. In practice, we limit the number of components included, and group components into pseudo-components **[10].** Then the developed PVT model is matched with the test data. This model is then exported to eclipse.

Many EOR processes, including miscible gas injection, are specifically designed to take advantage of the phase behaviour of multi-component fluid systems. Compositional modelling is also required in modelling depletion and/or cycling of retrograde reservoirs and reservoirs with highly volatile oils. In these cases, the phase compositions are away from the critical point, which simplifies the behavior of the fluid system.

1.6. History Matching Overview

History matching is the process of adjusting the reservoir geological model to match the model from field production data. Reservoir production performance greatly determines the economic feasibility of oil and gas recovery and also the future sustenance of production operations. Thus, for efficient reservoir management, a thorough analysis of past, present and future reservoir performance is required, and history matching is a very handy tool for this.

1.6.1. Objectives of History Matching

History matching aids in updating the current reservoir model, matching it with past production, and optimized future prediction. The main reason for history matching is not just to match historical data, but to enable the prediction of future performance of the reservoir and thus production optimization with regards to economy and oil and gas recovery by improved or enhanced methods.

The actual geometry of a reservoir is largely unknown, thus productivity forecasts made with such a model would be laden with errors. For this reason the model has to be adjusted by history matching to obtain the suitable model with which prediction of future reservoir performance can be competently carried out.

1.6.2. Benefits of History Matching

Aside from giving a good match and providing a model for future predictions, history matching process provides some other benefits. Some other benefits of history matching include:

- Model calibration, which helps to improve and validate reservoir description;
- Prediction of future performance with higher degree of confidence;
- Enhancing the understanding of the reservoir;
- Detecting operational issues during the process of reservoir management.

History matching improves the quality of the simulation model, helps to locate weakness in available data and provides in-depth understanding of the processes taking place in the reservoir.

1.6.3. Methods of History Matching

Many methods of history matching have been developed over the years with many researchers trying to find new ways of faster, efficient, accurate and less time-consuming methods. Earliest history matches were performed by trial and error with the hope that manually adjusting the value of some parameters might help give the desired match. The quality of such history matching would largely depend on the engineer’s experience and the budget allocated for the process. This is due to the fact that petroleum reservoirs are usually very complex and heterogeneous having hundreds of thousands (and in very large reservoirs, millions) of grid blocks in the simulation model required for high resolution evaluation of reservoir parameters. Due to these afore mentioned complexities and the fact that many uncertainties abound in determination of the absolute values and effects of reservoir parameters, manual history matching is not readily considered and is not reliable when the project period is long. For this reason computerized (or automatic) history matching methods have been developed and utilized by many researchers.

However, if the field or segment under consideration is small, accurately delineated, and the reservoir parameters and characteristics well defined as in the case of this study, then manual history matching can be applied with some degree of comfort. Manual history matching basically involves manual perturbation of pre-selected parameters based on sensitivity studies carried out to pre-determine which parameters affect production the most. The Monte Carlo random selection method has been used in many manual history matching projects for parameter selection and combination **[12].**

Automatic history matching is based on algorithms written to specifically calculate an objective function and with several iterations to obtain a perfect or a near-perfect match. Basically, it involves the building of a working mathematical model, setting up of an objective function, and applying a minimization algorithm to the defined objective function. The mathematical model required for the estimation of unknown parameters in history matching consists of two components namely:

- A reservoir simulator to model the flow through porous media, and
- A rock physics model to enable computation of seismic responses.

The objective function is a function of the difference between the observed reservoir performance and the response calculated by the simulation model using the available parameters and can contain many terms representing various constraints.

1.7. Project Economics

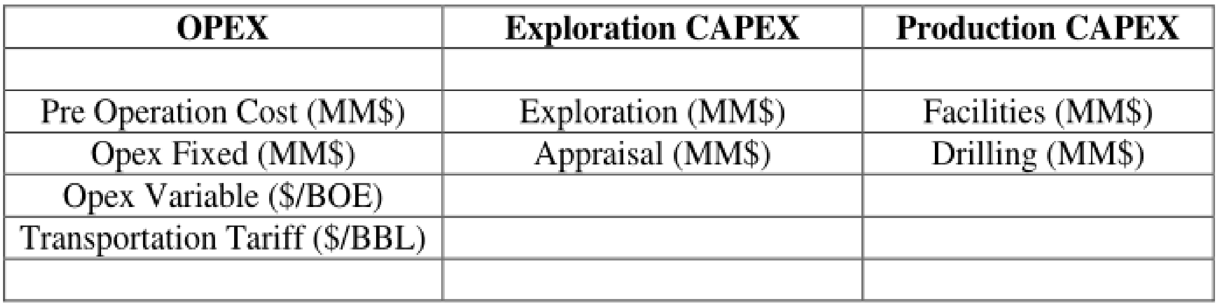
Project costs represent how much is going to be spent during the construction and the implementation phase of the project. The project results depend very strongly on the magnitude of the costs. If the costs are higher than estimated, the project's profit will be less than expected. In some cases higher costs can lead to a big loss, especially when the profit is low or in case the project's revenue is very dependent on the amount of the costs.

Therefore decision-making should take into account the risks and the uncertainties of the costs since we would never know exactly what the costs would be, e.g., we would never know if the facilities cost more or if more wells are going to be drilled. A range of possible costs values should be defined and analyzed **[9].**

Costs are split up into two categories:

- OPEX (operation cost) which is divided into fixed and variable costs,
- CAPEX (capital cost) which is split up into exploration and production costs.

The OPEX and the CAPEX again are divided into several components



OPEX	Exploration CAPEX	Production CAPEX
Pre Operation Cost (MM$)	Exploration (MM$)	Facilities (MM$)
Opex Fixed (MM$)	Appraisal (MM$)	Drilling (MM$)
Opex Variable ($/BOE)		
Transportation Tariff ($/BBL)		

Table 1-1Types of Cost

The units in the table are defined as:

- MM$ = million dollar
- $/BOE = dollar per barrels of oil equivalent
- $/BBL = dollar per barrel

1.7.1. Costs and Expenses

1.7.1.1. CAPEX (Capital expenditures)

- All of costs related to drilling a new wells, repairing wells, purchasing pumps and re- completion etc
- The costs related with maintaining the current capacity or repairing should be absorbed immediately
- The costs of increasing the production should be written off over the usage-years (Ex: drilling costs, Pumps etc)

(Capitalized in purchasing year, Depreciated every year)

1.7.1.2. OPEX (Operation Expenses)

- All of costs related to operating an oil company, such as a salaries (service contracts), performance compensation, field maintenance fee etc. in an oil production site

- Necessary to forecast the cost function and ascertain the fixed or the variable from total costs tracing historical data.

1.7.2. Cash Flows and Profits

Royalty

Royalty is the payment made by a producer of minerals, oil, or natural gas to the owner of the site (government) or of the mineral rights over it.

Cash Flow

It is the net inflow (revenue) or outflow (expenditure) of cash.

Undiscounted Cash Flow

It is a cash flow where time value of money has not been considered.

Discount rate

The interest rate charged on the monetary sum by the banks. In other words it is a factor by which future value of money reduces as you approach the present day.

Discounted Cash Flow

It is a cash flow where expenditure or revenue expected in the future has been discounted for using interest rates, and brought to its present value.

Gross Profit

It is the total revenue less the royalty (on the total revenue), OPEX, CAPEX and well drilling and completion costs.

Net Profit

It is calculated by subtracting tax from gross profit.

Net Present Value (NPV)

It is the present value of all future cash flows. Value of money decreases with time. The value of a certain sum of money earned today will be more than the same amount of money earned a year later because of devaluation. Considering a 5% interest rate per annum, \$100 today will be worth \$105 next year. In other words \$105 earned next year will be worth on \$100 today. Therefore all future cash flows need to be converted into their respective present values so that the NPV's from different simulations can be compared effectively.

$$NPV = [\, Future\ value * \left(\frac{1}{1+i}\right)^{N} - I]$$

i - Discount rate per annum,

N - number of years,

I - total initial investment

1.7.3. Significance of Economic analysis

Before any major operation is put into action, the reservoir engineers spend adequate time working on simulations in order to choose an optimum quantity and quality of the various parameters that will affect the profitability of the operation. For the development of the condensate field considered in this project, several factors were considered in different simulations that were run. Some of them are listed below

- Number of wells
- Type of well
- Location of wells
- Production flow rate

These are the factors that have a pivotal effect on field recovery and hence the profits, the reason being that making a change in any of the above parameters in a simulation will be conducive to different costs being incurred in that scenario and at the same time also yield different volumes of Hydrocarbon being produced and ultimately different profits for each.

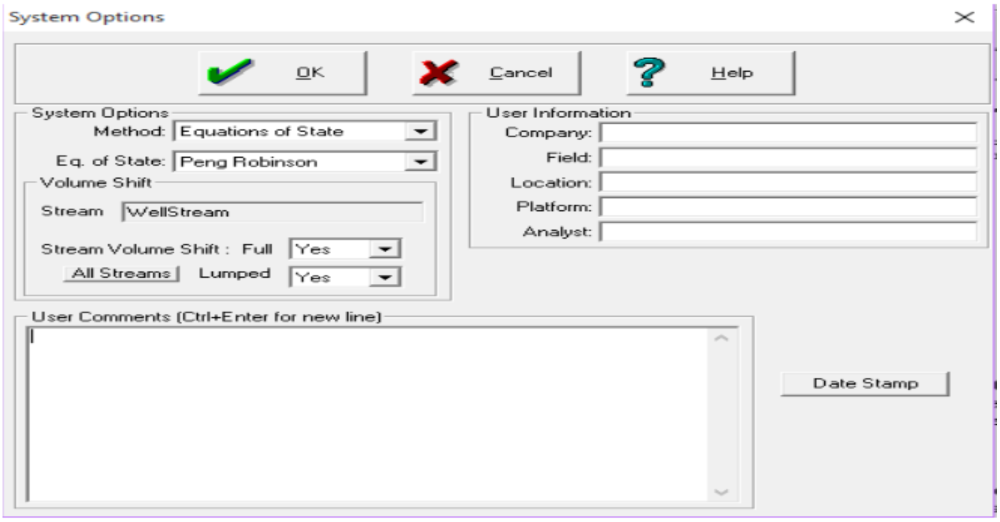
The surface facility has a capacity rating and is designed to deal with a specific volume of reservoir fluid. High flow rates demand for large surface facility like separator, dehydration plant and sweetening plant to handle the large amount of fluids. Moreover higher flow rates demand for higher drawdown that could result in relatively earlier condensate banking and liquid holdup reducing the recovery of oil as well as restricting the gas flow. From an option of dozens of simulation cases, the best plan is chosen by carrying out a detailed economic analysis for each scenario and the result of the cases are compared to determine the optimum drilling and production strategy. Economic analysis is the analytical method that quantifies economic performance or monetary value of a field investment project and provides a meaningful metric for the optimization of field operations.

CHAPTER 2. METHODOLOGY

2.1. Preparing Fluid Properties

2.1.1. Selection of EOS

The PVTP software provides us with two distinct sets of equation for compositional modeling these are the Peng Robinson EOS and the Soave Redlich Kwong popularly known as the SRK EOS. The compositional model was prepared using the Peng Robinson EOS because of the fact that it works best and gives accurate results when working with near critical fluids like Gas Condensates. Although the SRK EOS also performs a better job but the only issue is that it doesn't predict the liquid densities as accurately as the PR EOS.



Method: Equations of State

Eq. of State: Peng Robinson

Stream WellStream

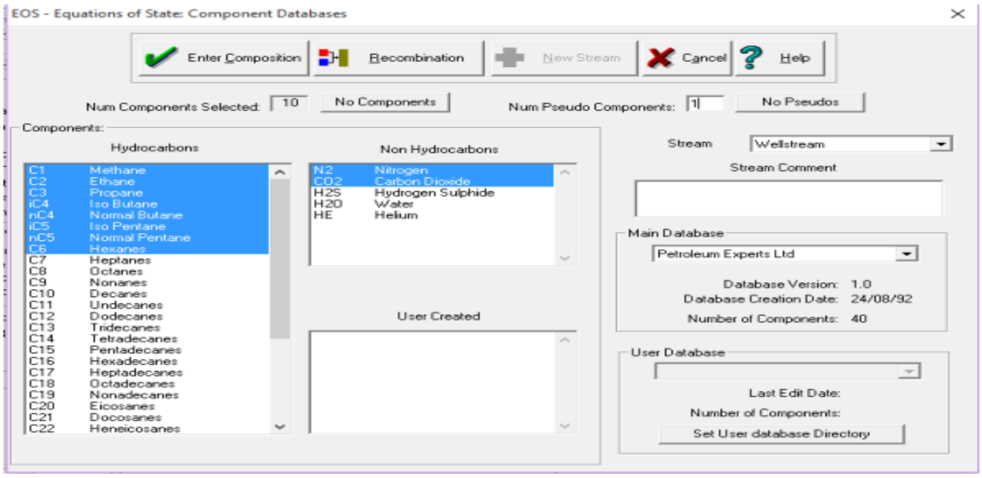
Stream Volume Shift : Full Yes

Lumped Yes

Figure 2-1 Model system and EOS selection window

2.1.2. Components and Composition

The next step was to input the basic and most important data i.e. components of the sample alongside their composition into the simulator as well as define the Pseudo and non-Pseudo Components which were to be further worked upon in order to develop the Equation of State Model



Num Components Selected: 10

Num Pseudo Components: 1

Components:

Hydrocarbons

C1	Methane
C2	Ethane
C3	Propane
iC4	Iso Butane
nC4	Normal Butane
iC5	Iso Pentane
nC5	Normal Pentane
C6	Hexanes
C7	Heptanes
C8	Octanes
C9	Nonanes
C10	Decanes
C11	Undecanes
C12	Dodecanes
C13	Tridecanes
C14	Tetradecanes
C15	Pentadecanes
C16	Hexadecanes
C17	Heptadecanes
C18	Octadecanes
C19	Nonadecanes
C20	Eicosanes
C21	Docosanes
C22	Heneicosanes

Non Hydrocarbons

N2	Nitrogen
CO2	Carbon Dioxide
H2S	Hydrogen Sulphide
H2O	Water
HE	Helium

User Created

Stream: Wellstream

Stream Comment

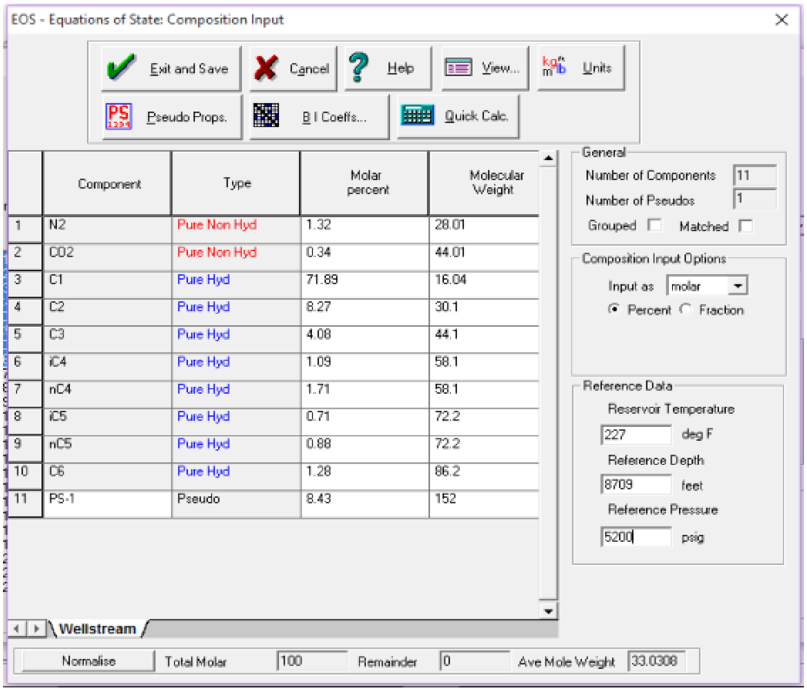
Main Database: Petroleum Experts Ltd

Database Version: 1.0
Database Creation Date: 24/08/92
Number of Components: 40

User Database

Last Edit Date:
Number of Components:

Figure 2-2 Component selection window



	Component	Type	Molar percent	Molecular Weight
1	N2	Pure Non Hyd	1.32	28.01
2	CO2	Pure Non Hyd	0.34	44.01
3	C1	Pure Hyd	71.89	16.04
4	C2	Pure Hyd	8.27	30.1
5	C3	Pure Hyd	4.08	44.1
6	iC4	Pure Hyd	1.09	58.1
7	nC4	Pure Hyd	1.71	58.1
8	iC5	Pure Hyd	0.71	72.2
9	nC5	Pure Hyd	0.88	72.2
10	C6	Pure Hyd	1.28	86.2
11	PS-1	Pseudo	8.43	152

General
Number of Components: 11
Number of Pseudos: 1
Grouped ☐ Matched ☐

Composition Input Options
Input as: molar
● Percent ○ Fraction

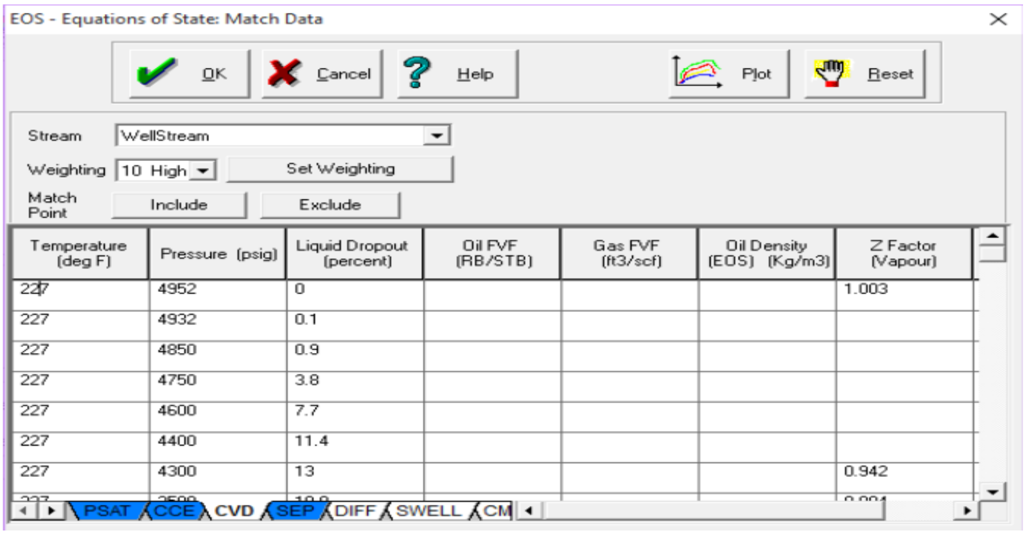
Reference Data
Reservoir Temperature: 227 deg F
Reference Depth: 8709 feet
Reference Pressure: 5200 psig

Total Molar: 100
Remainder: 0
Ave Mole Weight: 33.0308

Figure 2-3 Component composition input

2.1.3. Field and Lab Data

Input In addition to the component and composition the Lab and Field Data is entered into the simulator so that the simulated results could be matched with the available data to ensure that an accurate EOS model is developed which can be used for compositional simulation. Several tabs are available to input various lab results such as that of CVD, CCE, DVA, and Separator Test Results etc.



Stream: WellStream

Weighting: 10 High

Temperature (deg F)	Pressure (psig)	Liquid Dropout (percent)	Oil FVF (RB/STB)	Gas FVF (ft3/scf)	Oil Density (EOS) (Kg/m3)	Z Factor (Vapour)
227	4952	0				1.003
227	4932	0.1				
227	4850	0.9				
227	4750	3.8				
227	4600	7.7				
227	4400	11.4				
227	4300	13				0.942

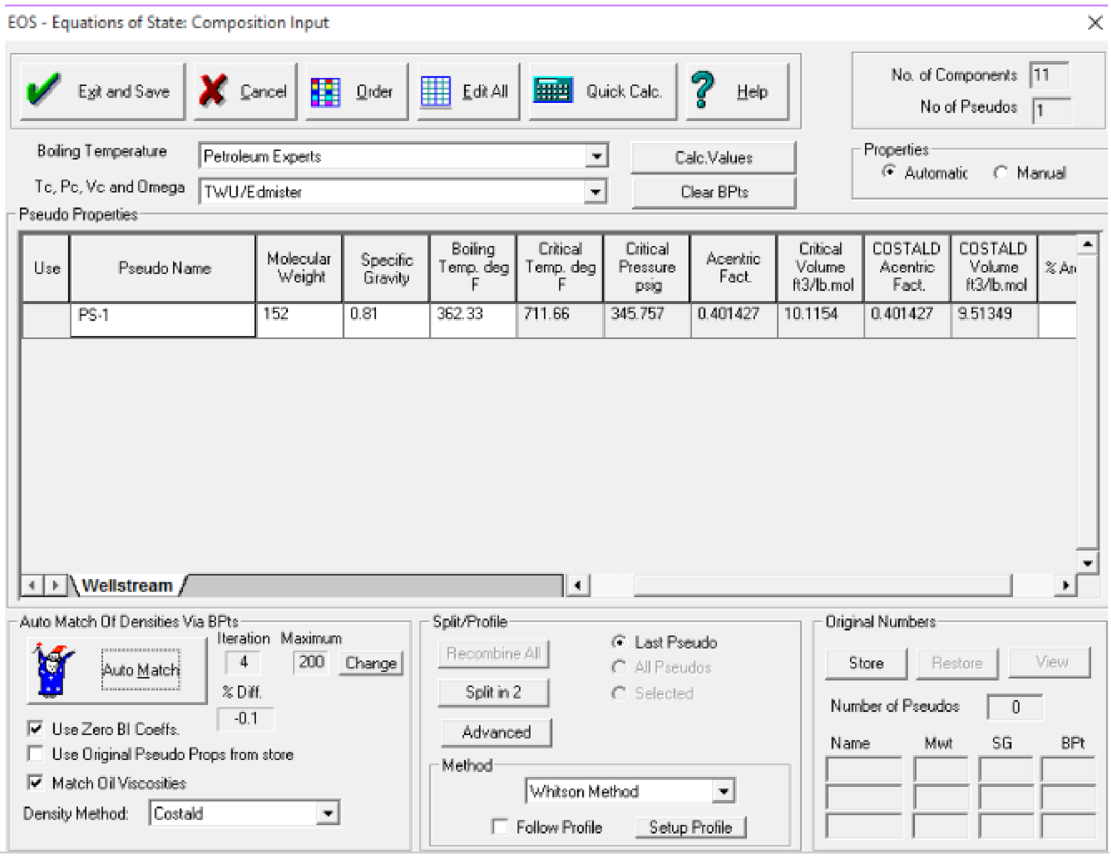
Figure 2-4 Test data input window

2.1.4. Initialization of Pseudo Component

Once the composition of the sample is defined the next step is to initialize the pseudo component as the pseudo component plays the critical role in development of the most appropriate and accurate EOS Model. The pseudo is the greatest unknown within the composition and is always composed of a mixture of many compounds with a wide variety of individual properties. It is therefore, not surprising that the characterization of these compounds is the key area of EOS PVT matching. The pseudo component is initialized by using the specific gravity and molecular weight obtained from the CVD lab report.

The starting values for Tc, Pc, and AF etc. are obtained from correlations. The correlations used are

- Petroleum Experts – Boiling Temperature
- Tc, Pc, Vc and Omega – TWU/Edmister



No. of Components 11
No of Pseudos 1

Boiling Temperature: Petroleum Experts
Tc, Pc, Vc and Omega: TWU/Edmister

Properties: ● Automatic ○ Manual

Pseudo Properties

Use	Pseudo Name	Molecular Weight	Specific Gravity	Boiling Temp. deg F	Critical Temp. deg F	Critical Pressure psig	Acentric Fact.	Critical Volume ft3/lb.mol	COSTALD Acentric Fact.	COSTALD Volume ft3/lb.mol	% Ar
	PS-1	152	0.81	362.33	711.66	345.757	0.401427	10.1154	0.401427	9.51349	

Auto Match Of Densities Via BPts
Iteration 4
Maximum 200
% Diff. -0.1
☑ Use Zero BI Coeffs.
☐ Use Original Pseudo Props from store
☑ Match Oil Viscosities
Density Method: Costald

Split/Profile
● Last Pseudo
○ All Pseudos
○ Selected
Method: Whitson Method
☐ Follow Profile

Original Numbers
Number of Pseudos 0

Name	Mwt	SG	BPt

Figure 2-5 Pseudo component property window

2.1.5. Using Binary Interaction Coefficients

After the Pseudo Component was initialized a phase envelope was simulated to match with the Saturation Pressure obtained from the CVD test. It was observed that the modelled EOS lacked accuracy in predicting the Saturation Pressure and needed some amendments. Hence it was decided to incorporate the Binary Interaction Coefficients to the EOS Model to improve the quality of the Model. Several BICs were checked for and some improvements in the predicting ability of the Model was observed.

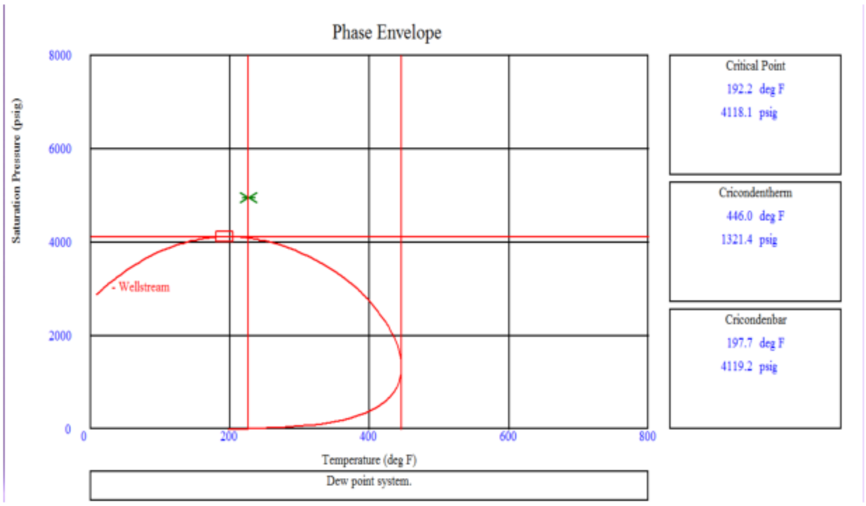
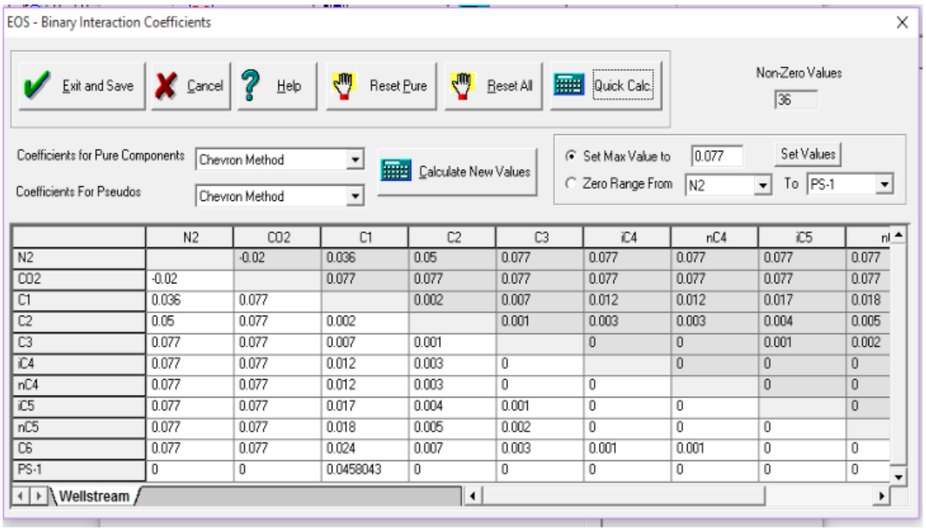


Figure 2-6 Phase envelope before introducing BIC



Non-Zero Values: 36

Coefficients for Pure Components: Chevron Method

Coefficients For Pseudos: Chevron Method

● Set Max Value to 0.077

○ Zero Range From N2 To PS-1

	N2	CO2	C1	C2	C3	iC4	nC4	iC5	n
N2		-0.02	0.036	0.05	0.077	0.077	0.077	0.077	0.077
CO2	-0.02		0.077	0.077	0.077	0.077	0.077	0.077	0.077
C1	0.036	0.077		0.002	0.007	0.012	0.012	0.017	0.018
C2	0.05	0.077	0.002		0.001	0.003	0.003	0.004	0.005
C3	0.077	0.077	0.007	0.001		0	0	0.001	0.002
iC4	0.077	0.077	0.012	0.003	0		0	0	0
nC4	0.077	0.077	0.012	0.003	0	0		0	0
iC5	0.077	0.077	0.017	0.004	0.001	0	0		0
nC5	0.077	0.077	0.018	0.005	0.002	0	0	0	
C6	0.077	0.077	0.024	0.007	0.003	0.001	0.001	0	0
PS-1	0	0	0.0458043	0	0	0	0	0	0

Figure 2-7 Incorporating Binary interaction coefficients

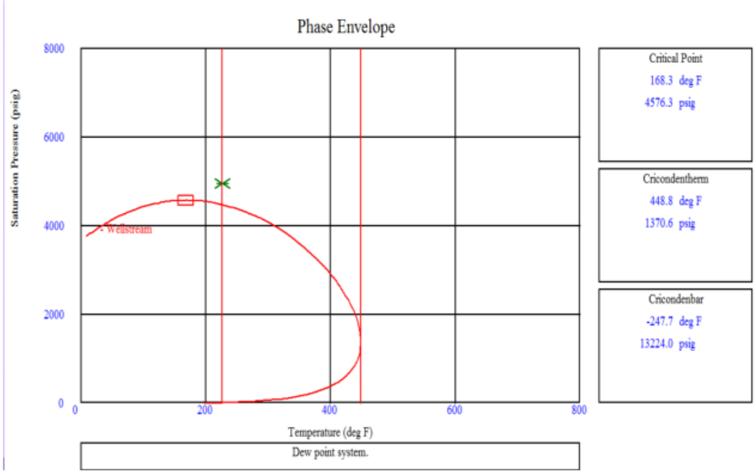
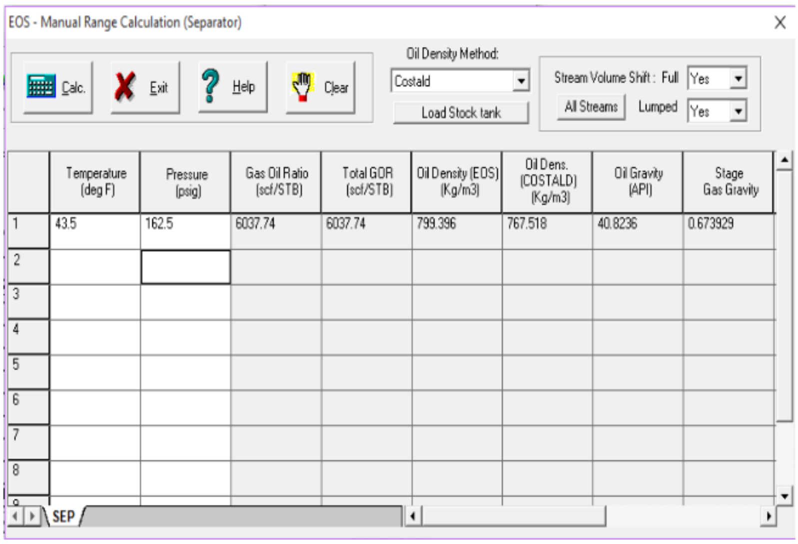


Figure 2-8 Phase envelope after introducing BIC



Oil Density Method: Costald

Load Stock tank

Stream Volume Shift : Full Yes

All Streams Lumped Yes

	Temperature (deg F)	Pressure (psig)	Gas Oil Ratio (scf/STB)	Total GOR (scf/STB)	Oil Density (EOS) (Kg/m3)	Oil Dens. (COSTALD) (Kg/m3)	Oil Gravity (API)	Stage Gas Gravity
1	43.5	162.5	6037.74	6037.74	799.396	767.518	40.8236	0.673929
2								
3								
4								
5								
6								
7								
8								

Figure 2-9 Separator test results after BIC

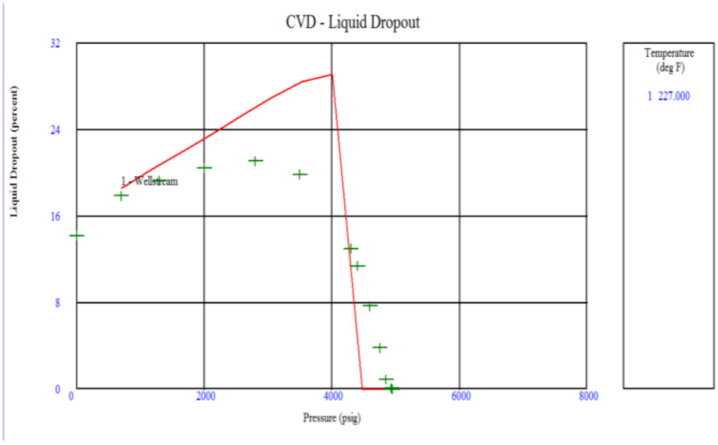
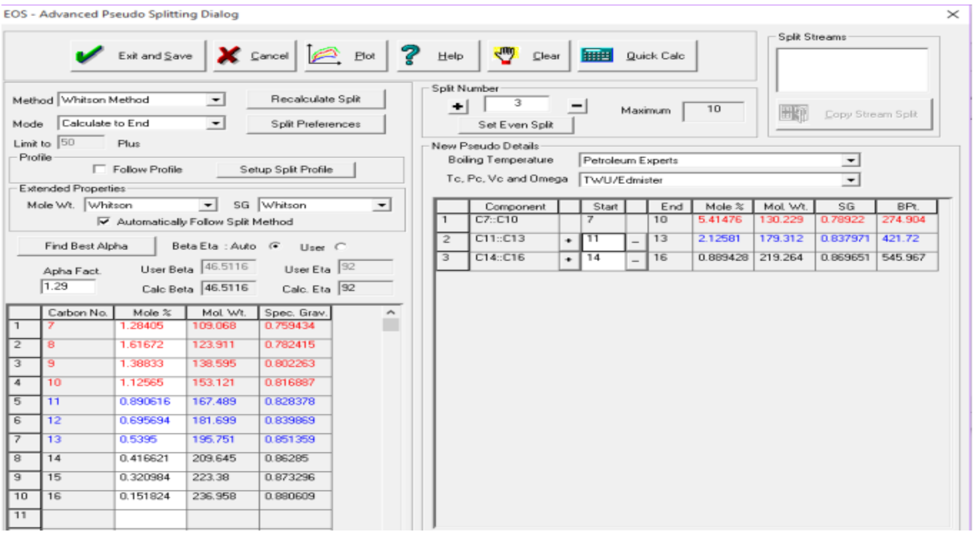


Figure 2-10 CVD liquid drop out after BIC

2.1.6. Pseudo Splitting

The pseudo components were further split into fractions to provide more accuracy in the prediction quality of the EOS. In PVTP there are various methods available for splitting of pseudo components out of which the Whitson Alpha splitting was selected, the pseudo component was split into three pseudo splits using the Whitson Splitting correlation and an Alpha factor of 1.29.



Method: Whitson Method
Mode: Calculate to End
Limit to: 50 Plus
Profile: ☐ Follow Profile
Extended Properties: Mole Wt.: Whitson SG: Whitson
☑ Automatically Follow Split Method
Beta Eta : Auto ● User ○
Apha Fact.: 1.29
User Beta: 46.5116
Calc Beta: 46.5116
User Eta: 92
Calc. Eta: 92

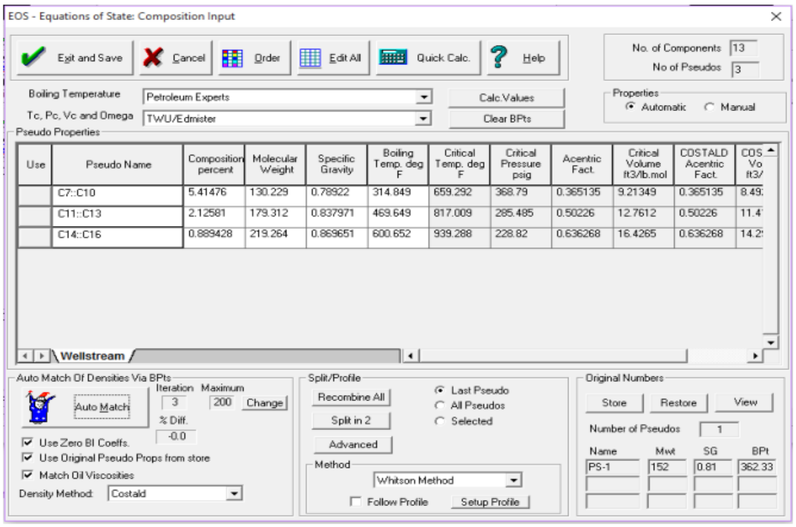
	Carbon No.	Mole %	Mol. Wt.	Spec. Grav.
1	7	1.28405	109.068	0.759434
2	8	1.61672	123.911	0.782415
3	9	1.38833	138.595	0.802263
4	10	1.12565	153.121	0.816887
5	11	0.890616	167.489	0.828378
6	12	0.695694	181.699	0.839869
7	13	0.5395	195.751	0.851359
8	14	0.416621	209.645	0.86285
9	15	0.320984	223.38	0.873296
10	16	0.151824	236.958	0.880609
11				

Split Number: 3 Maximum: 10
New Pseudo Details
Boiling Temperature: Petroleum Experts
Tc, Pc, Vc and Omega: TWU/Edmister

	Component		Start		End	Mole %	Mol. Wt.	SG	BPt.
1	C7::C10		7		10	5.41476	130.229	0.78922	274.904
2	C11::C13	+	11	–	13	2.12581	179.312	0.837971	421.72
3	C14::C16	+	14	–	16	0.889428	219.264	0.869651	545.967

Figure 2-11 Pseudo component splitting window

The properties of the pseudo splits are shown in the figure below; splitting was performed on basis of components having relatively similar mole %



No. of Components: 13
No of Pseudos: 3
Boiling Temperature: Petroleum Experts
Tc, Pc, Vc and Omega: TWU/Edmister
Properties: ● Automatic ○ Manual
Pseudo Properties

Use	Pseudo Name	Composition percent	Molecular Weight	Specific Gravity	Boiling Temp. deg F	Critical Temp. deg F	Critical Pressure psig	Acentric Fact.	Critical Volume ft3/lb.mol	COSTALD Acentric Fact.	COS Vo ft3/
	C7::C10	5.41476	130.229	0.78922	314.849	659.292	368.79	0.365135	9.21349	0.365135	8.49
	C11::C13	2.12581	179.312	0.837971	469.649	817.009	285.485	0.50226	12.7612	0.50226	11.4
	C14::C16	0.889428	219.264	0.869651	600.652	939.288	228.82	0.636268	16.4265	0.636268	14.2

Auto Match Of Densities Via BPts
Iteration: 3 Maximum: 200
% Diff.: -0.0
☑ Use Zero BI Coeffs.
☑ Use Original Pseudo Props from store
☑ Match Oil Viscosities
Density Method: Costald

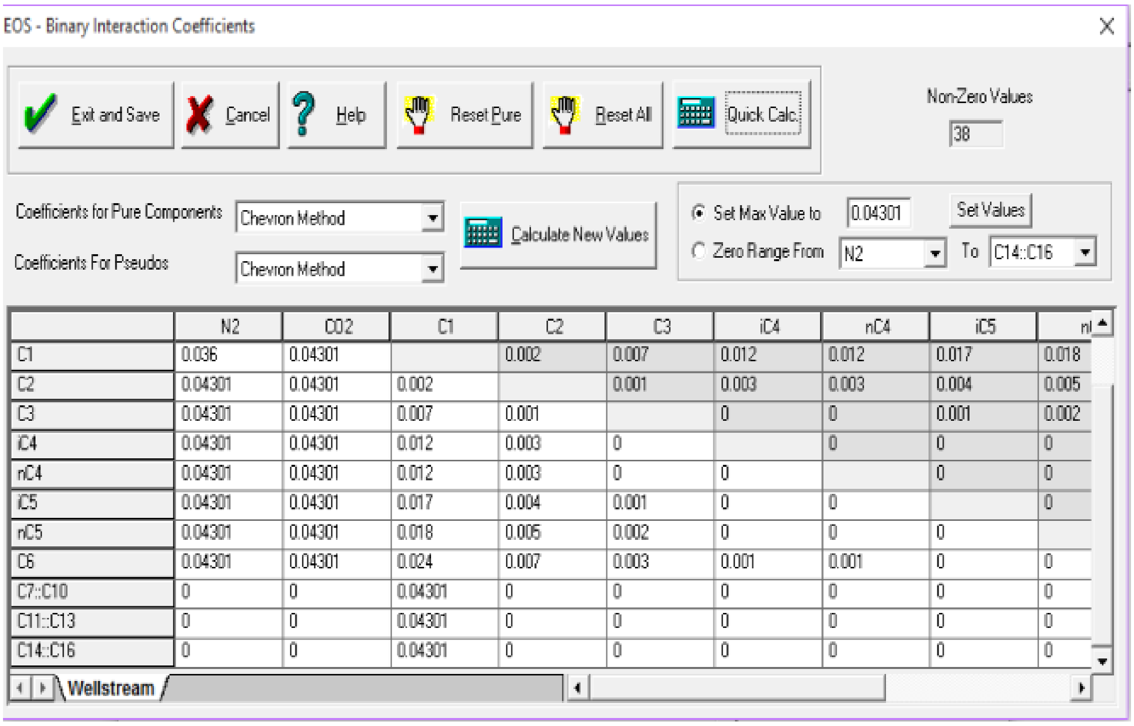
Split/Profile
● Last Pseudo
○ All Pseudos
○ Selected
Method: Whitson Method
☐ Follow Profile

Original Numbers
Number of Pseudos: 1

Name	Mwt	SG	BPt
PS-1	152	0.81	362.33

Figure 2-12 Pseudo Split Initialization

After the pseudo component was split into further components the newly formed splits were also initialized and later the Binary Interaction Coefficients were again introduced in order to improve the matching capability of the EOS model.



Non-Zero Values: 38

Coefficients for Pure Components: Chevron Method

Coefficients For Pseudos: Chevron Method

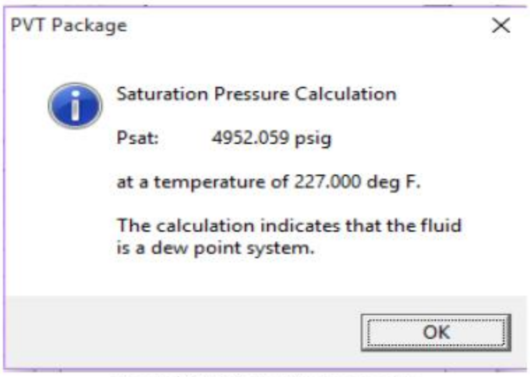
● Set Max Value to 0.04301

○ Zero Range From N2 To C14::C16

	N2	CO2	C1	C2	C3	iC4	nC4	iC5	n
C1	0.036	0.04301		0.002	0.007	0.012	0.012	0.017	0.018
C2	0.04301	0.04301	0.002		0.001	0.003	0.003	0.004	0.005
C3	0.04301	0.04301	0.007	0.001		0	0	0.001	0.002
iC4	0.04301	0.04301	0.012	0.003	0		0	0	0
nC4	0.04301	0.04301	0.012	0.003	0	0		0	0
iC5	0.04301	0.04301	0.017	0.004	0.001	0	0		0
nC5	0.04301	0.04301	0.018	0.005	0.002	0	0	0	
C6	0.04301	0.04301	0.024	0.007	0.003	0.001	0.001	0	0
C7::C10	0	0	0.04301	0	0	0	0	0	0
C11::C13	0	0	0.04301	0	0	0	0	0	0
C14::C16	0	0	0.04301	0	0	0	0	0	0

Figure 2-13 BIC after pseudo splitting

Upon the introduction of BIC it was observed that the Saturation Pressure, API gravity , Density were in a close match with the given set of lab data but the GOR was not completely matching, moreover the CVD Liquid Dropout was still unmatched and hence further improvement were required in the EOS



Saturation Pressure Calculation

Psat: 4952.059 psig

at a temperature of 227.000 deg F.

The calculation indicates that the fluid is a dew point system.

Figure 2-14 Saturation pressure

Figure 2-14 Saturation pressure

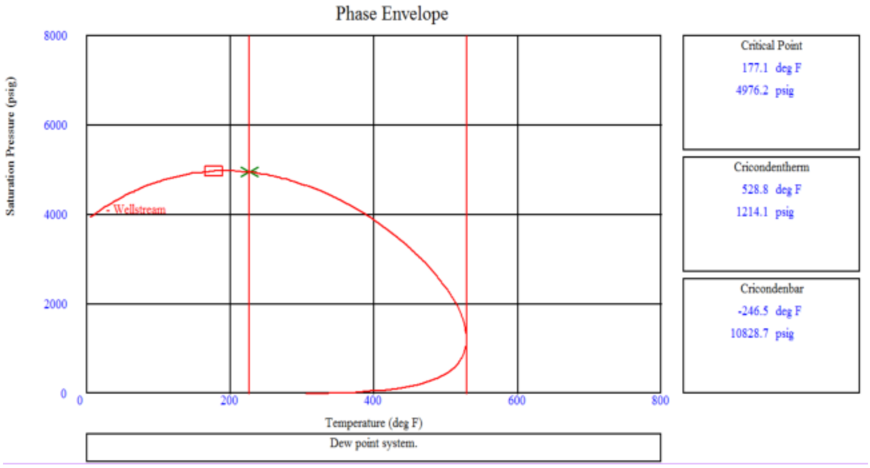
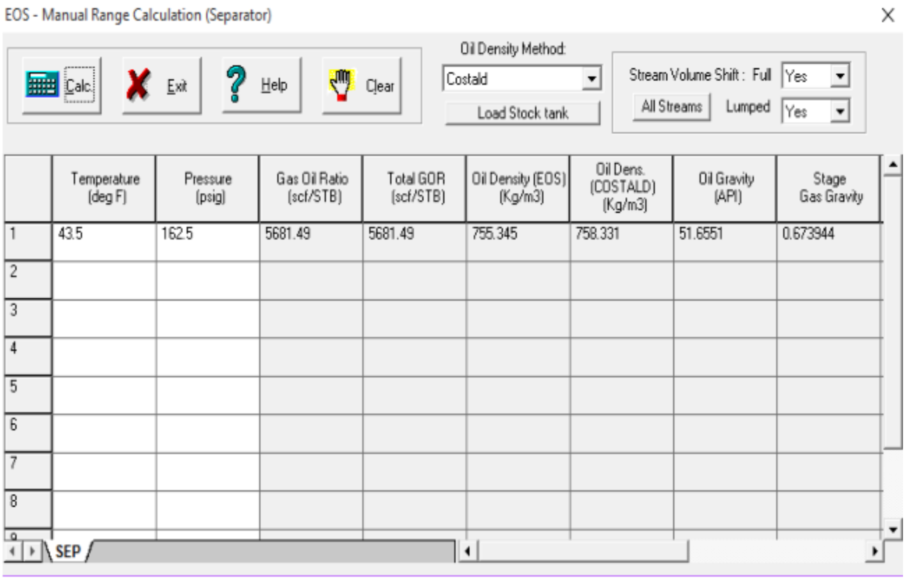


Figure 2-15 Phase envelope after pseudo splitting and BIC



Oil Density Method: Costald

Stream Volume Shift : Full Yes

Lumped Yes

	Temperature (deg F)	Pressure (psig)	Gas Oil Ratio (scf/STB)	Total GOR (scf/STB)	Oil Density (EOS) (Kg/m3)	Oil Dens. (COSTALD) (Kg/m3)	Oil Gravity (API)	Stage Gas Gravity
1	43.5	162.5	5681.49	5681.49	755.345	758.331	51.6551	0.673944
2								
3								
4								
5								
6								
7								
8								

Figure 2-16 Separator test results after pseudo splitting and BIC

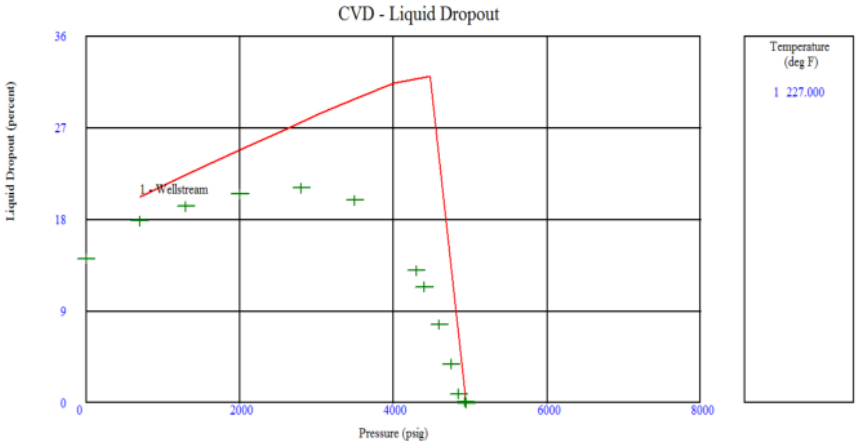
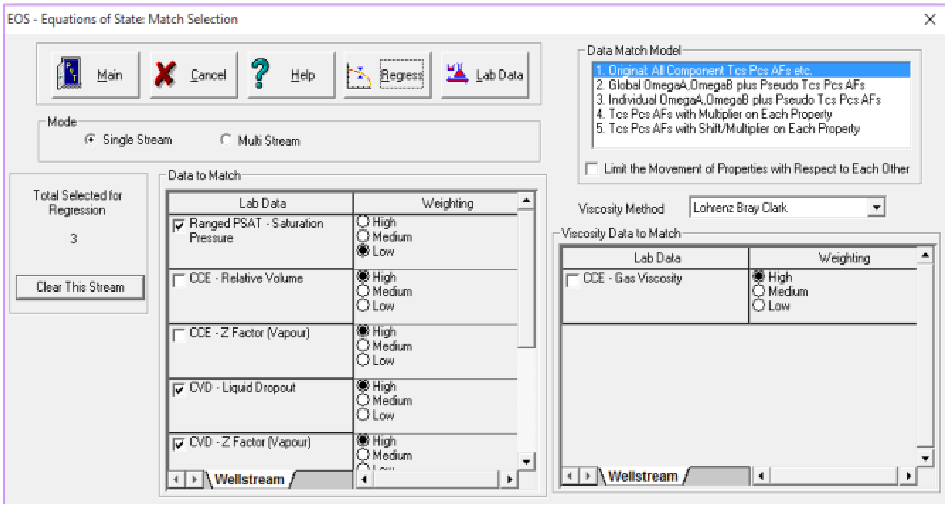


Figure 2-17 Liquid dropout match after pseudo splitting and BIC

2.1.7. Regression

It was noticed that although a good match on the Saturation Pressure, GOR, Oil density was obtained there was a fairly distinct variation in the computed and the actual (lab data) CVD Liquid Drop out results and hence it was decided that regression should be applied. The parameters that were regressed upon were the critical properties (Tc, Pc) of the pseudo components.


EOS - Equations of State: Match Selection

Mode: ● Single Stream ○ Multi Stream

Total Selected for Regression: 3

Data to Match

Lab Data	Weighting
☑ Ranged PSAT - Saturation Pressure	○ High ○ Medium ● Low
☐ CCE - Relative Volume	● High ○ Medium ○ Low
☐ CCE - Z Factor (Vapour)	● High ○ Medium ○ Low
☑ CVD - Liquid Dropout	● High ○ Medium ○ Low
☑ CVD - Z Factor (Vapour)	● High ○ Medium

Data Match Model
1. Original: All Component Tcs Pcs AFs etc.
2. Global OmegaA,OmegaB plus Pseudo Tcs Pcs AFs
3. Individual OmegaA,OmegaB plus Pseudo Tcs Pcs AFs
4. Tcs Pcs AFs with Multiplier on Each Property
5. Tcs Pcs AFs with Shift/Multiplier on Each Property

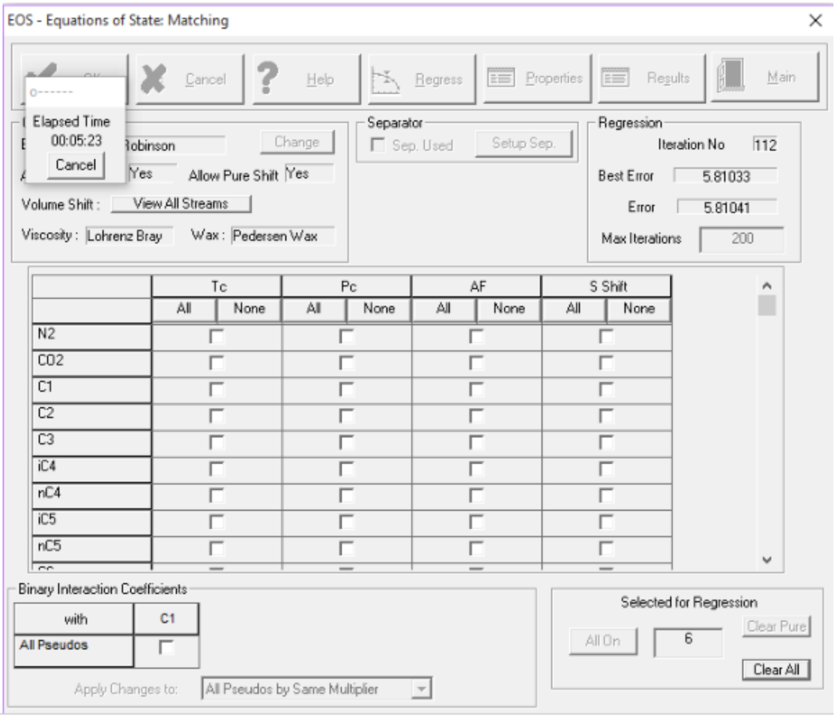
☐ Limit the Movement of Properties with Respect to Each Other

Viscosity Method: Lohrenz Bray Clark

Viscosity Data to Match

Lab Data	Weighting
☐ CCE - Gas Viscosity	● High ○ Medium ○ Low

Figure 2-18 Regression (parameter selection)


EOS - Equations of State: Matching

Elapsed Time 00:05:23

Robinson

Yes Allow Pure Shift: Yes

Volume Shift : View All Streams

Viscosity : Lohrenz Bray Wax : Pedersen Wax

Separator: ☐ Sep. Used

Regression
Iteration No 112
Best Error 5.81033
Error 5.81041
Max Iterations 200

	Tc		Pc		AF		S Shift	
	All	None	All	None	All	None	All	None
N2	☐		☐		☐		☐	
CO2	☐		☐		☐		☐	
C1	☐		☐		☐		☐	
C2	☐		☐		☐		☐	
C3	☐		☐		☐		☐	
iC4	☐		☐		☐		☐	
nC4	☐		☐		☐		☐	
iC5	☐		☐		☐		☐	
nC5	☐		☐		☐		☐	

Binary Interaction Coefficients

with	C1
All Pseudos	☐

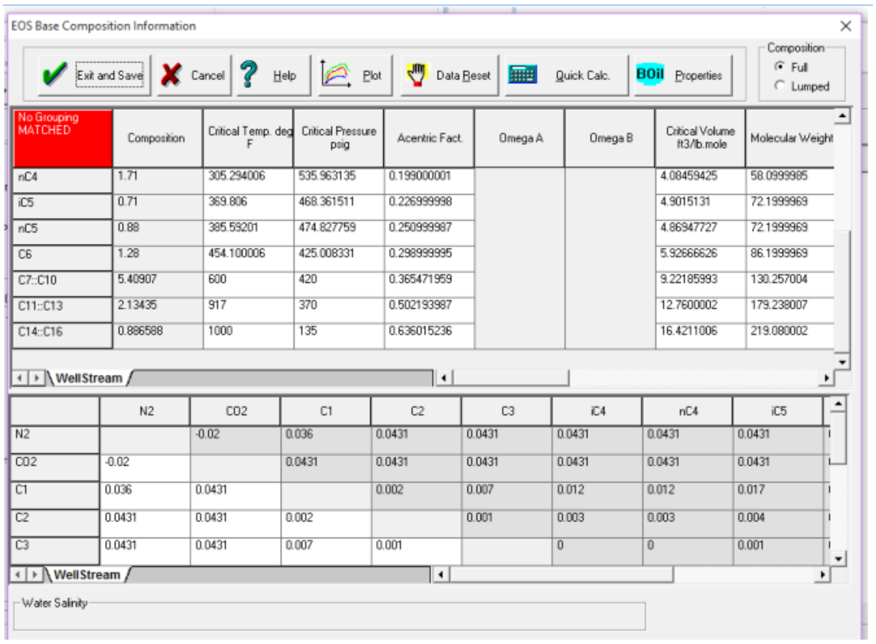
Apply Changes to: All Pseudos by Same Multiplier

Selected for Regression: 6

Figure 2-19 Regression

2.1.8. Tuning of Critical Properties

After the regression was performed it was observed that the critical properties (Tc Pc) of the pseudo components did not follow the natural trend i.e. decreasing pressure and increasing temperature so the critical properties (Tc, Pc) were fine tuned.



No Grouping MATCHED	Composition	Critical Temp. deg F	Critical Pressure psig	Acentric Fact.	Omega A	Omega B	Critical Volume ft3/lb.mole	Molecular Weight
nC4	1.71	305.294006	535.963135	0.199000001			4.08459425	58.0999985
iC5	0.71	369.806	468.361511	0.226999998			4.9015131	72.1999969
nC5	0.88	385.59201	474.827759	0.250999987			4.86947727	72.1999969
C6	1.28	454.100006	425.008331	0.298999995			5.92666626	86.1999969
C7::C10	5.40907	600	420	0.365471959			9.22185993	130.257004
C11::C13	2.13435	917	370	0.502193987			12.7600002	179.238007
C14::C16	0.886588	1000	135	0.636015236			16.4211006	219.080002

	N2	CO2	C1	C2	C3	iC4	nC4	iC5
N2		-0.02	0.036	0.0431	0.0431	0.0431	0.0431	0.0431
CO2	-0.02		0.0431	0.0431	0.0431	0.0431	0.0431	0.0431
C1	0.036	0.0431		0.002	0.007	0.012	0.012	0.017
C2	0.0431	0.0431	0.002		0.001	0.003	0.003	0.004
C3	0.0431	0.0431	0.007	0.001		0	0	0.001

Figure 2-20 Component critical properties

2.1.9. Results

After all the above procedures were applied the following results were obtained which show that the equation of state models the phase behavior accurately to a great extent and can be utilized for compositional simulation; history matching and field development procedures.

2.1.10. CVD Liquid Dropout

Finally after performing regression the CVD Liquid Dropout predicted by the EOS and one obtained from the CVD Report is matched with a minimal error of 3-5%

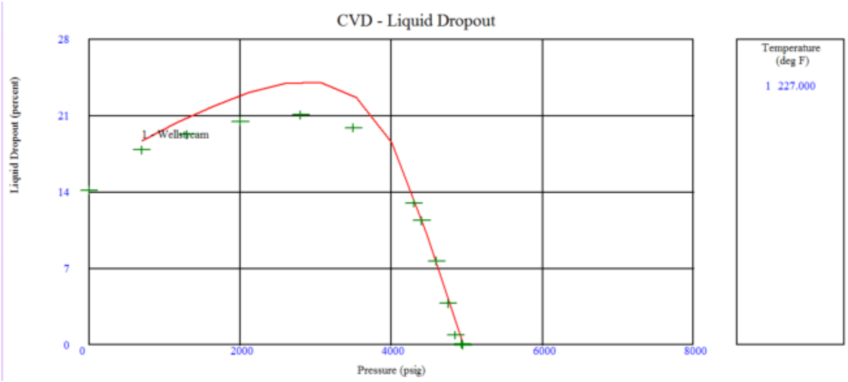


Figure 2-21 CVD liquid dropout

2.1.11. Z Factor (Vapor Phase)

By applying the aforementioned techniques the Z factor obtained from CVD test report and the one predicted by the EoS model are accurately matched

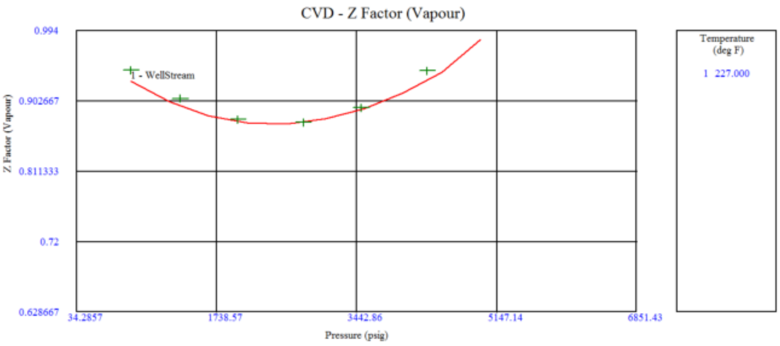


Figure 2-22 CVD Z-factor

2.1.12. Phase Diagram

The phase envelope as predicted by the EOS is shown below

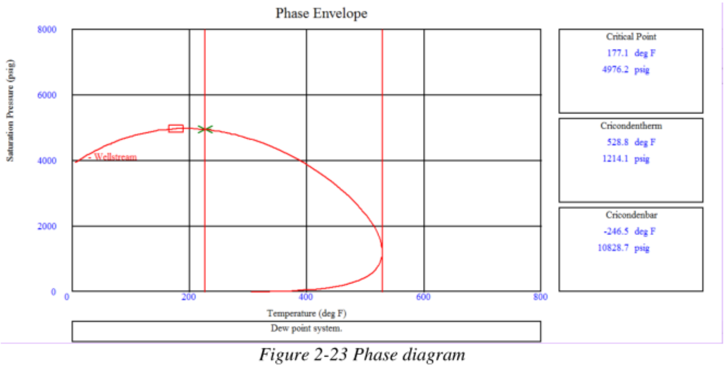
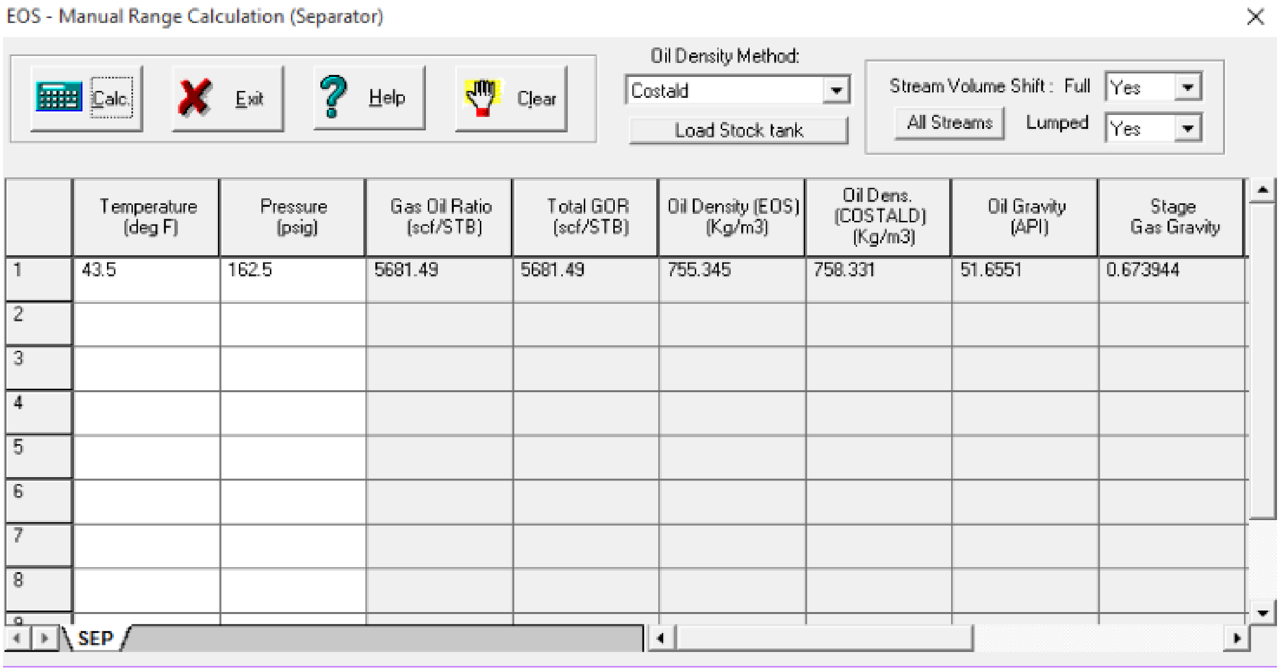


Figure 2-23 Phase diagram

2.1.13. Separator Results



Oil Density Method: Costald

Stream Volume Shift : Full Yes

Lumped Yes

	Temperature (deg F)	Pressure (psig)	Gas Oil Ratio (scf/STB)	Total GOR (scf/STB)	Oil Density (EOS) (Kg/m3)	Oil Dens. (COSTALD) (Kg/m3)	Oil Gravity (API)	Stage Gas Gravity
1	43.5	162.5	5681.49	5681.49	755.345	758.331	51.6551	0.673944
2								
3								
4								
5								
6								
7								
8								

Figure 2-24 Separator result

Once a satisfactory Fluid Model was generated the next step was to perform Compositional Simulation which was done with the following Sector Model.

2.2. Model Description

The model consists of 840 cells, 12 in x direction, 7 in y direction and 10 in z direction with each cell having dimension of 1600ft in x, 1600ft in y and 3.281ft in z axis. The total Area of the model is 4936.64 Acre with 16.747134 MMSTB of OOIP and 125.310142 BSCF of OGIP.

Reservoir fluid included total of eight components, seven hydrocarbons plus water. Top layer of the model was at 7000ft depth, other properties like porosity was set to 0.1, permeability to 6md in x and y direction and 0.3 in z direction. Saturation tables were exported from PROSPER (IPM). Other reservoir model properties are given below:

Reservoir pressure	5200 psi
Water compressibility	3×10^{-6} psi^{-1}
Rock compressibility	4×10^{-6} psi^{-1}
Oil density at surface	37.457 lb/ft^3
Water density at surface	63 lb/ft^3

Table 2.1 Sector Model Properties

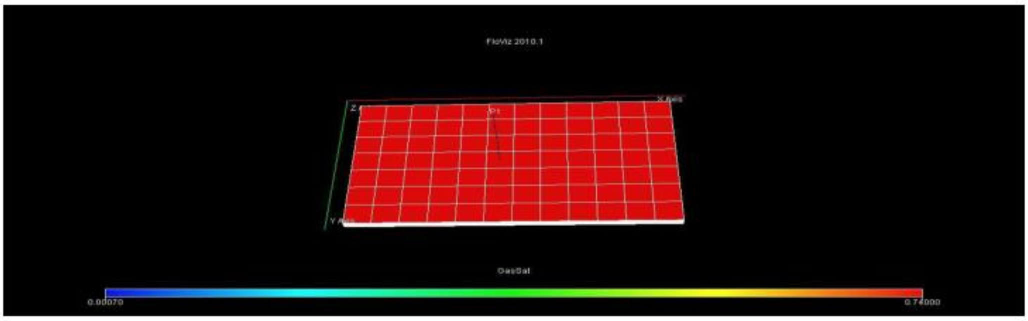


Figure 2-25 Reservoir (Sector) model

Production is taken from a single well which is placed almost at the center of the model and is connected at all the layers of the well. Three stage separation was used 1st separator at 950 psia, 2nd at 450 psia and the stock tank at 14.7 psia.

The provided production history for the well was entered in the schedule section, from March 1990 to December 2009 with average production for each month.

2.3. History Matching

History matching was the main concern in the course of the project. The exported Equation of State from IPM (PVTP) was utilized to simulate the gas condensate reservoir model and predict the production behavior.

The main parameters that were selected for history matching purpose are,

- Oil Production
- Gas Production

- Gas Oil Ratio

After simulation was performed it was observed that by keeping the control mode as Oil Rate (ORAT) the simulated gas production rate matched with the production history, similarly the simulated Gas Oil Ratio BHP matched with the historical data.

The results are shown below

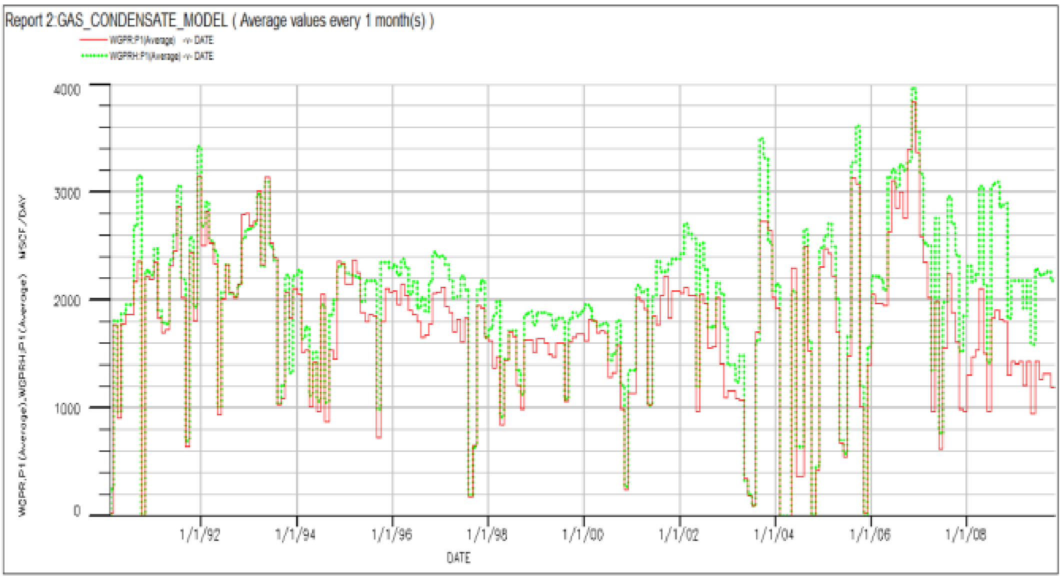


Figure 2-26 Gas Production Rate

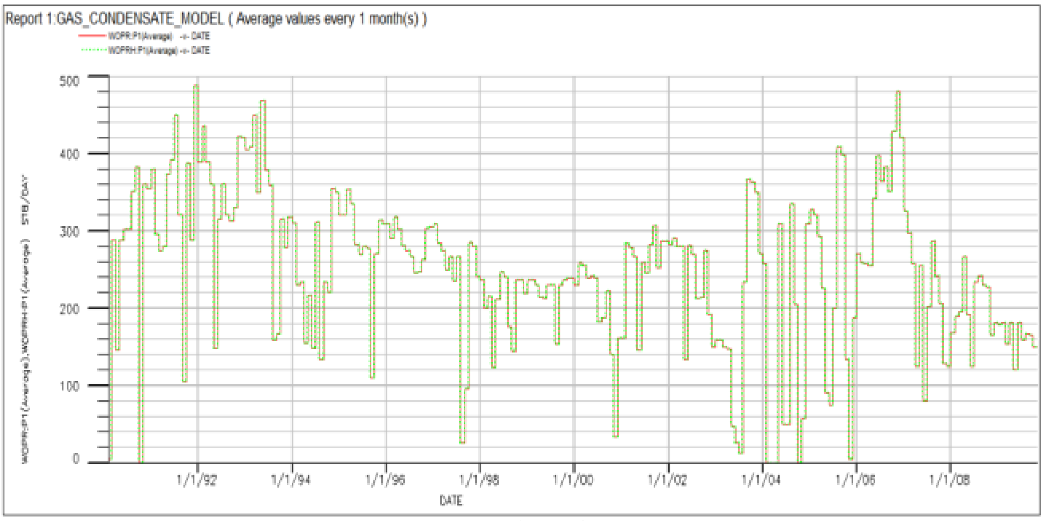


Figure 2-27 Oil Production Rate

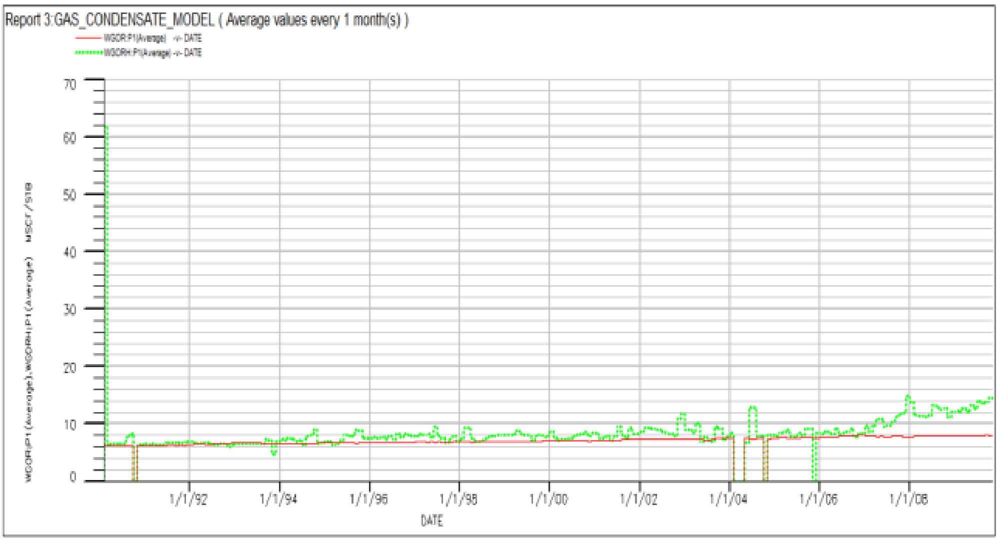


Figure 2-28 Gas Oil Ratio (GOR)

CHAPTER 3. ANALYSIS

3.1. Production Forecasting

After the history matching process was completed the next task was to forecast the production; plateau or life of the field at an optimum oil rate. For this purpose various Gas flowrates were checked for and their impact on the Gas and Oil production was observed. The simulation was performed for the next 84 years from the end of year 2009 and it was decided to abandon the well at 0.1 MMBOE

The results are tabulated below

FGPR MSCF/D	FOPR STB/D	GAS PROD MSCF	OIL PROD STB	R.F	Decline Start	Plateau period (from 2009 onwards)	Abandonment year	NPV MM$
(6723 AOFP)	157.2945	70164320	5635935	0.5599	JAN 2011	No plateau	2052	102.443
6000	156.8114	70466192	5648542	0.5623	MAY 2015	5 yrs 5 mths	2053	103.232
5000	156.5871548	70146576	5649754	0.5597	JAN 2023	14 years	2054	90.297
4000	157.1137	70156864	5666634	0.5598	MAR 2033	23 yrs 2 mth	2058	77.656
3500	157.60194	70387904	5685819.5	0.5617	NOV 2039	29 yrs 11 mth	2062	68.7721
3000	156.8075464	70276320	5695845.5	0.5608	JUL 2048	38 yrs 7 mth	2067	59.2499

Table 3-1 Table for Optimum Gas Rate Selection

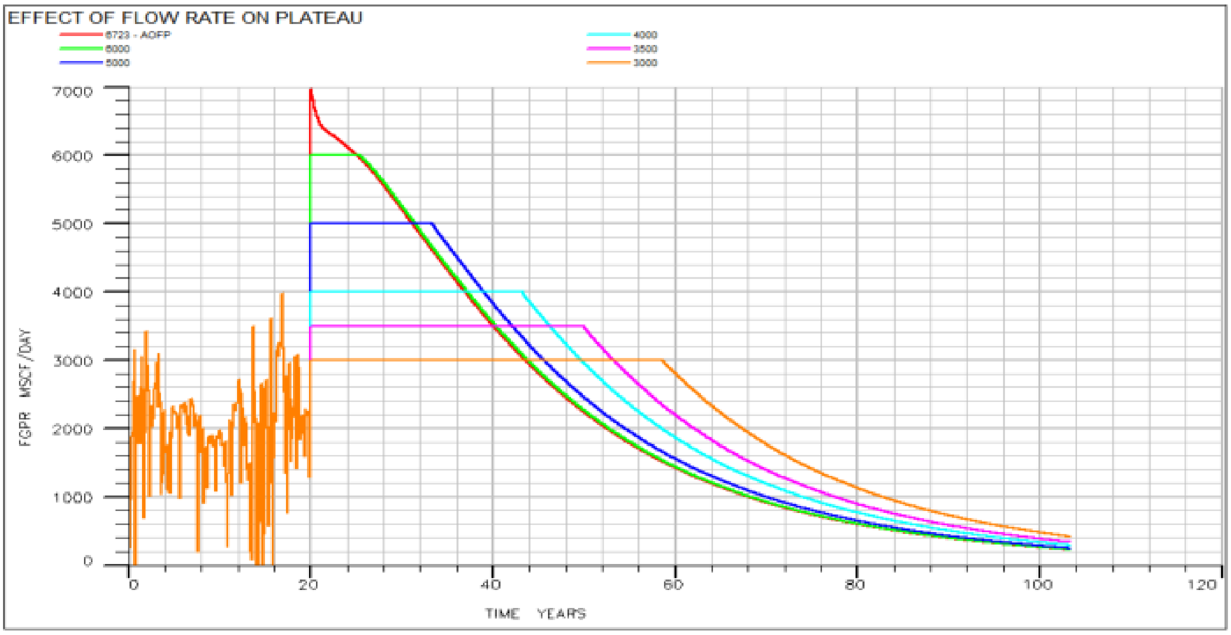


Figure 3-1 Effect of Flow rate on Plateau

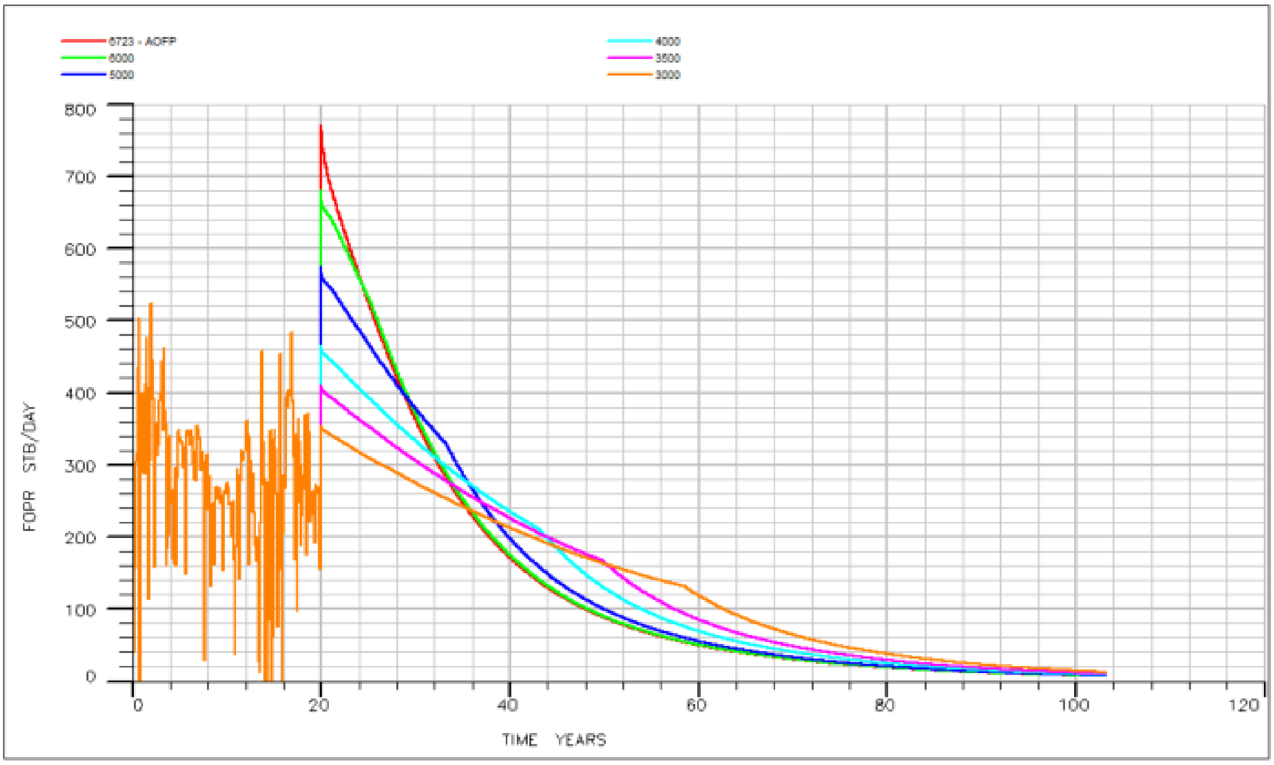


Figure 3-2 Corresponding Oil rates

From the simulated results we can say that with a decrease in the gas flow rate there is an increase in the plateau period however we can also see that the NPV value is decreasing but the Recovery Factor (R.F) is increasing, since with the increase in gas rate the oil production is also affected. Though when field development plan is considered the main thing is the economics alongside the Gas Rate quota allotted by the Government (which in turn means there should be a suitable plateau period present) therefore keeping in mind the NPV value, Recovery Factor (R.F), and Plateau Period; 5000 Mscf/d is selected as the optimum rate for field development.

3.2. Field Development Cases

Before deciding the case to be run in my project I have analyses the khuff gas condensate reservoir field development, **[13]** and finally come up with the following field development cases

3.2.1. Multiple Well Completion

Once the optimum flowrate was selected i.e 5000 Mscf/day it was decided to include more wells to the model and observe their impacts on the production life of the field as well as other parameters. The results are tabulated below as well as seen from the figures below

Single Well

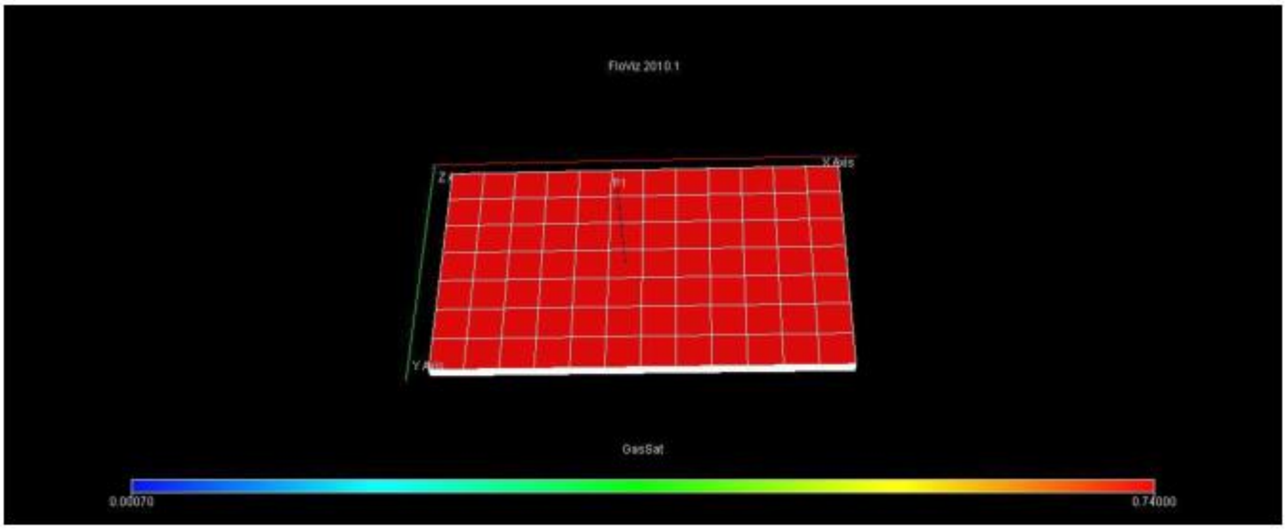


Figure 3-3 Single Well Model Pre Simulation

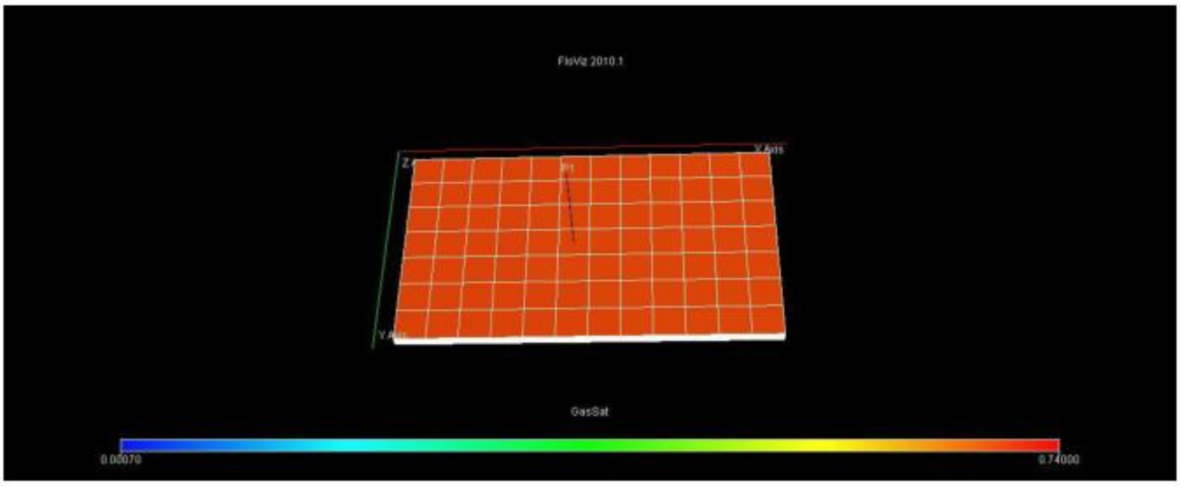


Figure 3-4 Single Well Model Post Simulation

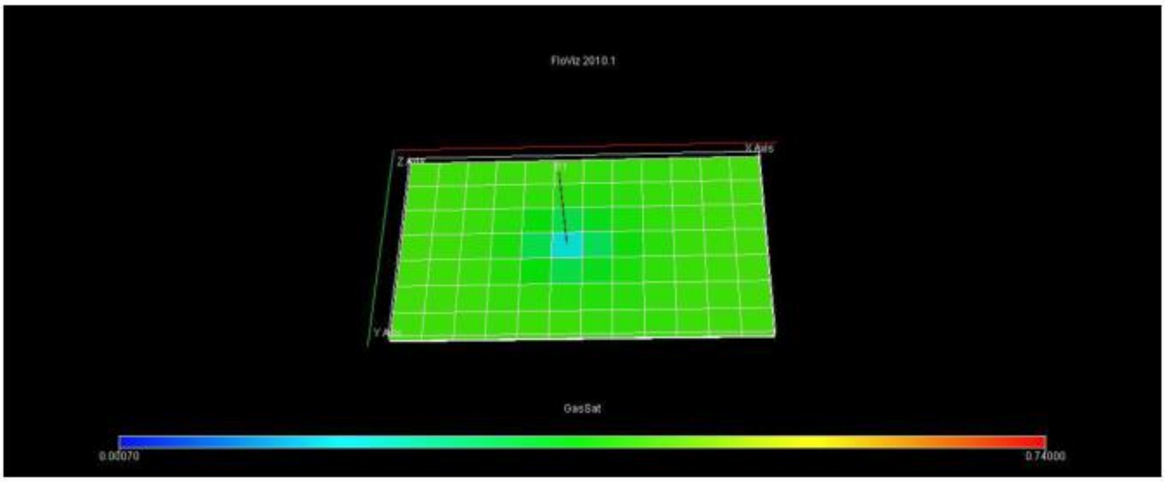


Figure 3-5 Single Well Model - Final 9th Layer

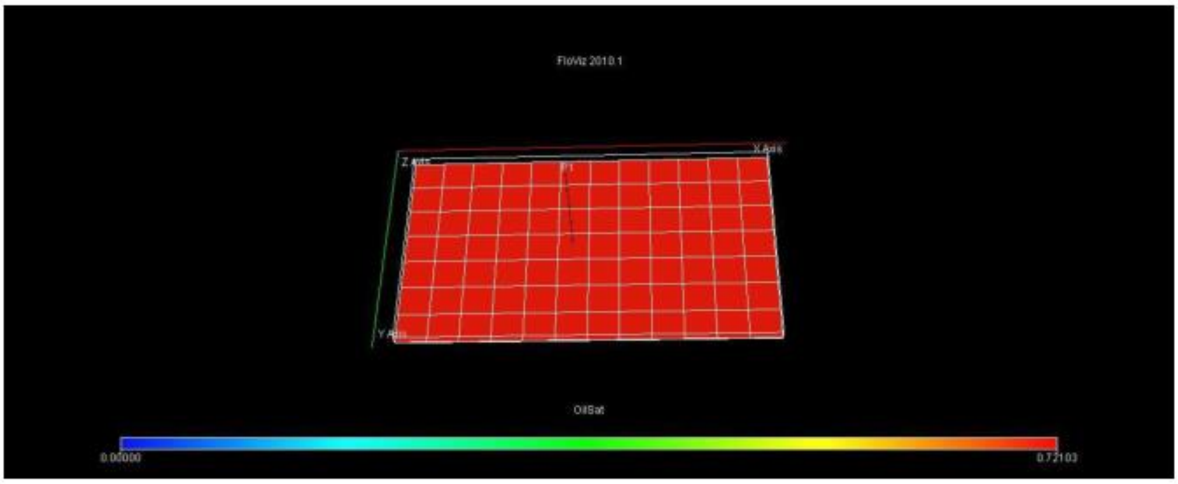
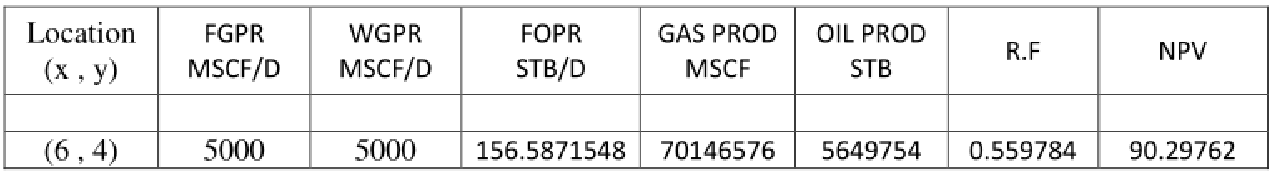


Figure 3-6 Single Well Model - Final 10th Layer

Result



Location (x , y)	FGPR MSCF/D	WGPR MSCF/D	FOPR STB/D	GAS PROD MSCF	OIL PROD STB	R.F	NPV
(6 , 4)	5000	5000	156.5871548	70146576	5649754	0.559784	90.29762

Table 3-2 Results for Single Well Model

Two Wells

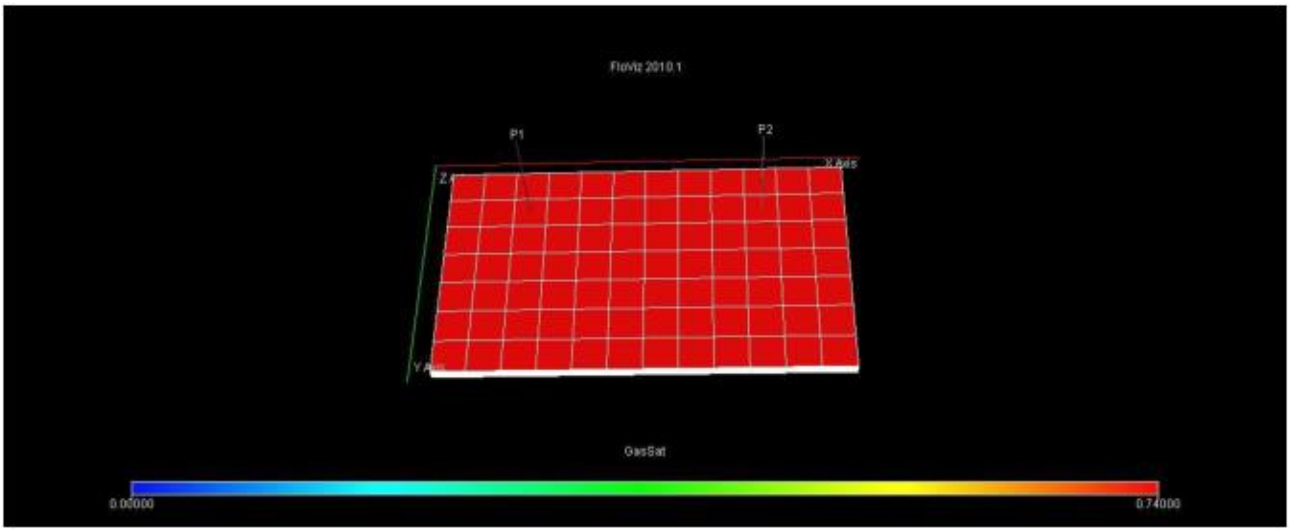


Figure 3-7 Two Wells Model Pre Simulation

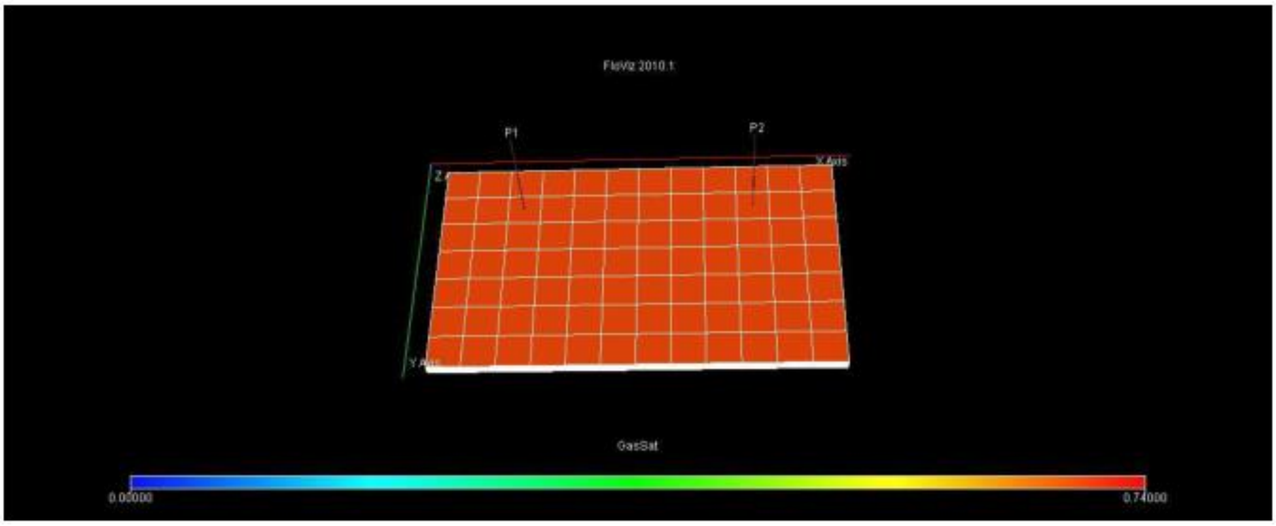


Figure 3-8 Two Wells Model Post Simulation

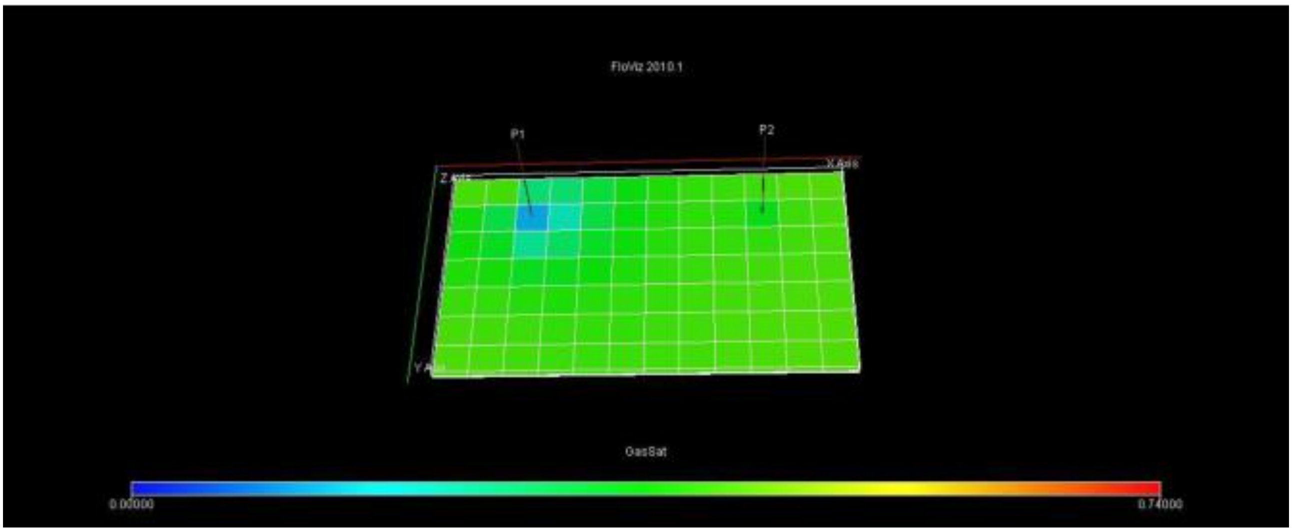


Figure 3-9 Two Wells Model - Final 9th Layer

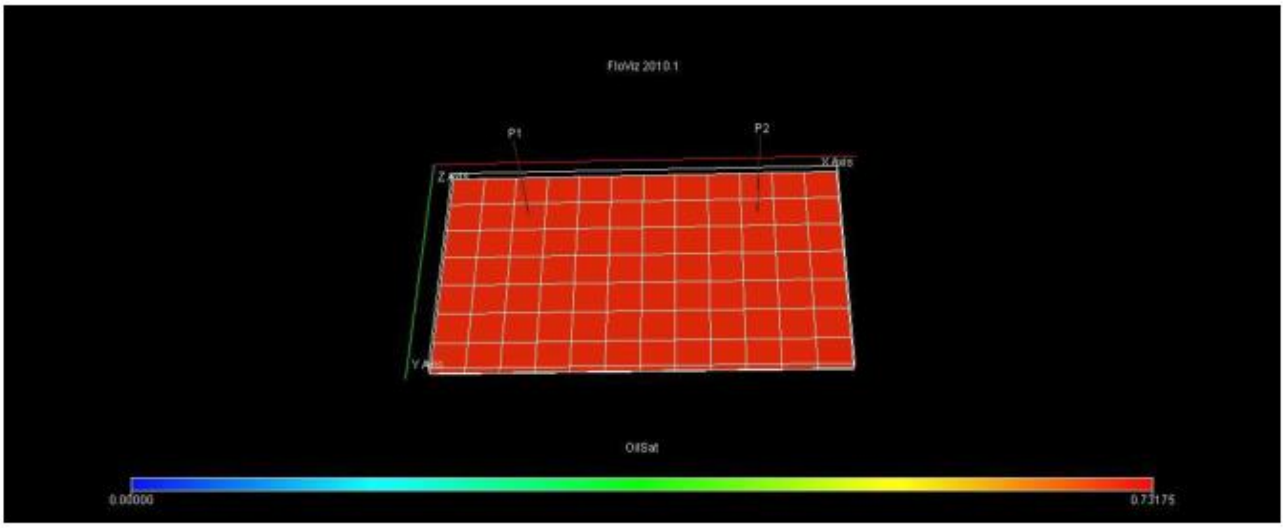


Figure 3-10 Two Wells Model - Final 10th Layer

Results

Well	Location (x , y)	FGPR MSCF/D	WGPR MSCF/D	FOPR STB/D	GAS PROD MSCF	OIL PROD STB	R.F	NPV
1	(3 , 2)	5000	2500	153.7192	75206768	5649683.5	0.600166	88.83038
2	(10,2)		2500					

Table 3-3 Results for 2 Well Model

Three Wells

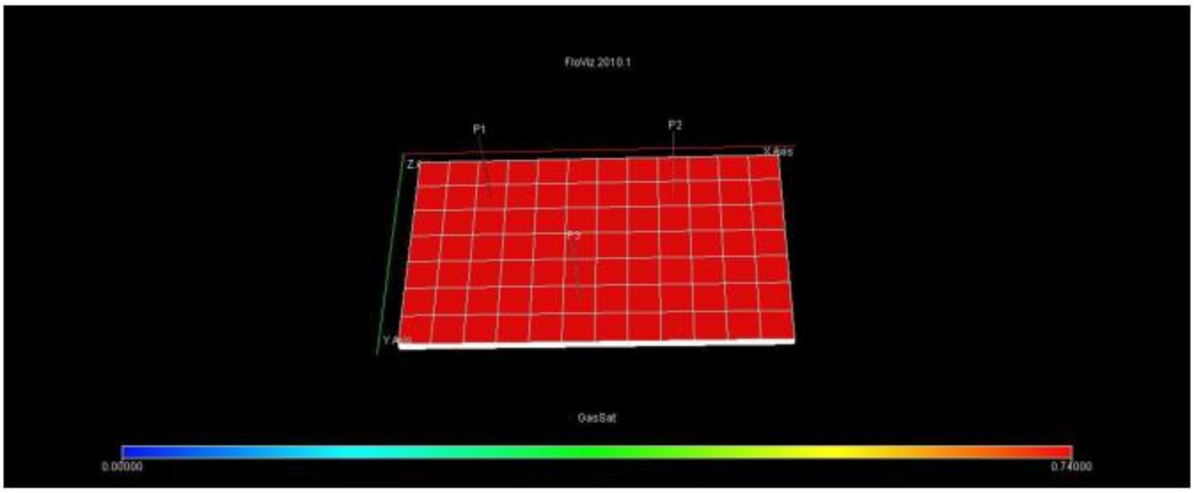


Figure 3-11 Three Wells Model Pre Simulation

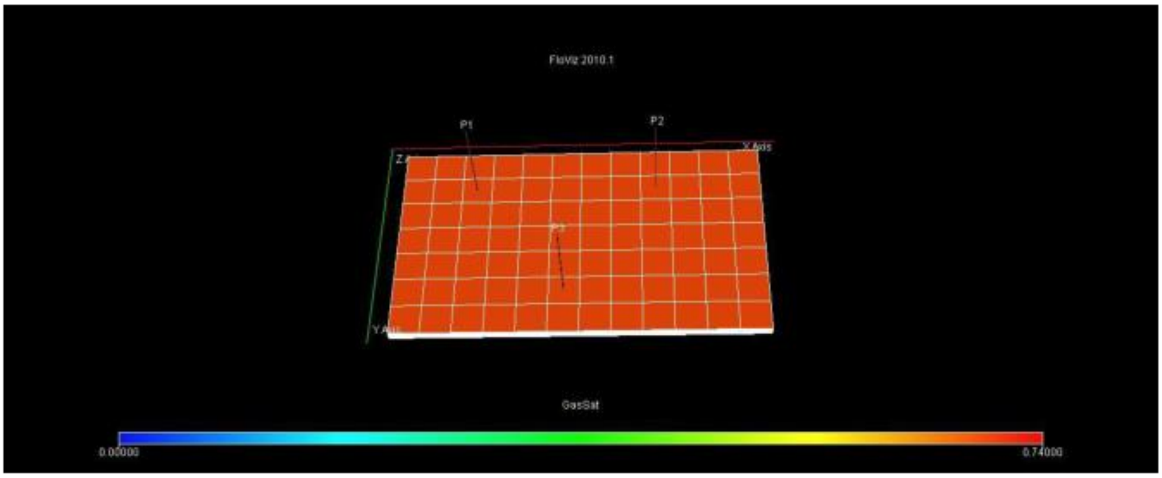


Figure 3-12 Three Well Model Post Simulation

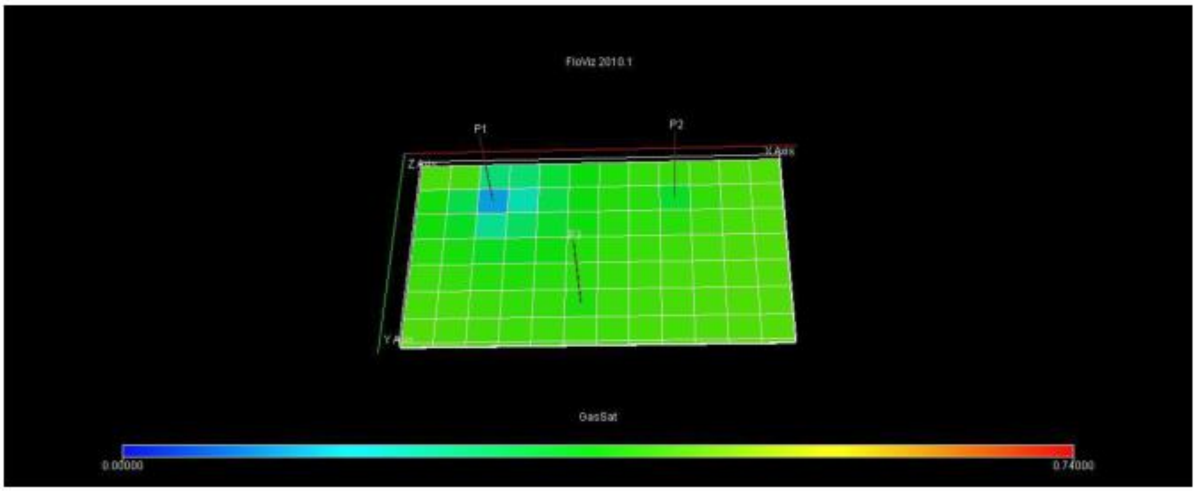


Figure 3-13 Three Wells Model Layer 9

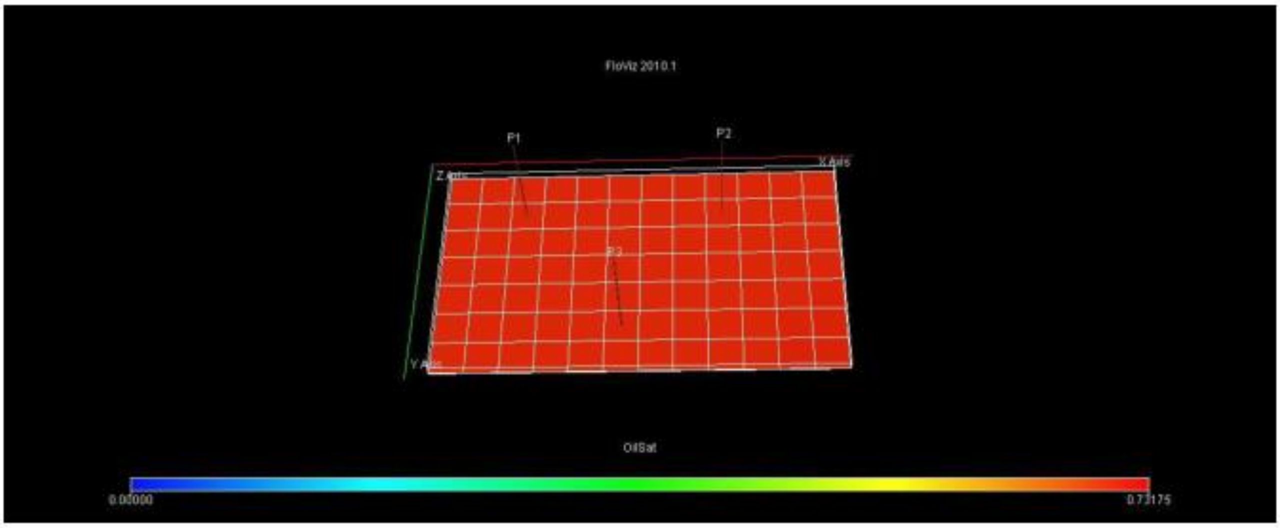


Figure 3-14 Three Wells Model Layer 10

Results

Well	Location (x , y)	FGPR MSCF/D	WGPR MSCF/D	FOPR STB/D	GAS PROD MSCF	OIL PROD STB	R.F	NPV
1	(3 , 2)	5000	1667	153.755	76946592	5702484.5	0.61405	88.7463
2	(9 , 2)		1667					
3	(6 , 6)		1666					

Table 3-4 Results for 3 Well Model

Four Wells

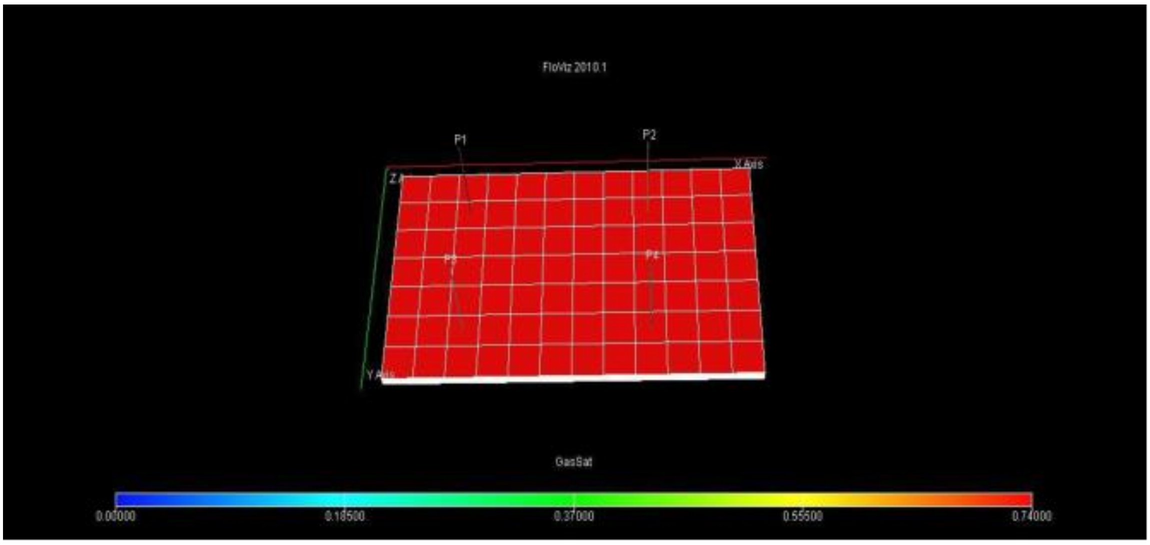


Figure 3-15 Four Well Model Pre Simulation

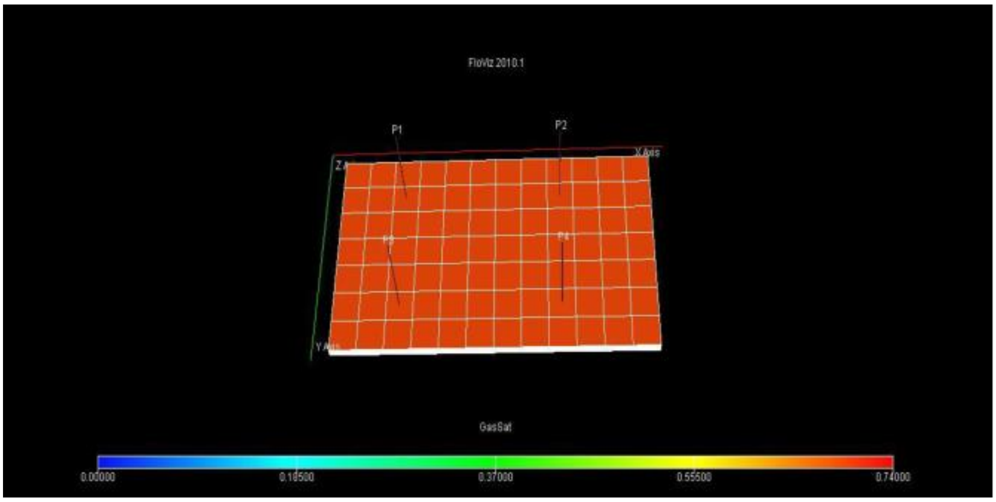


Figure 3-16 Four Well Model Post Simulation

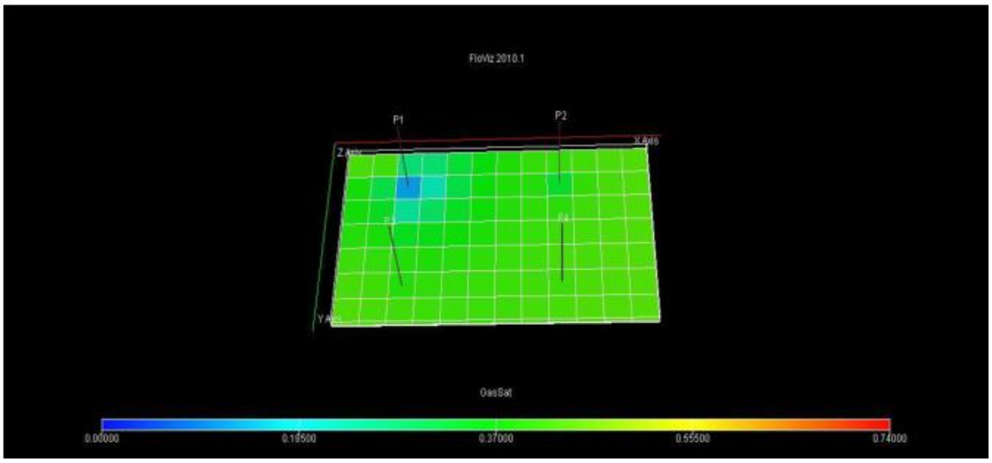


Figure 3-17 Four Well Model Layer 9

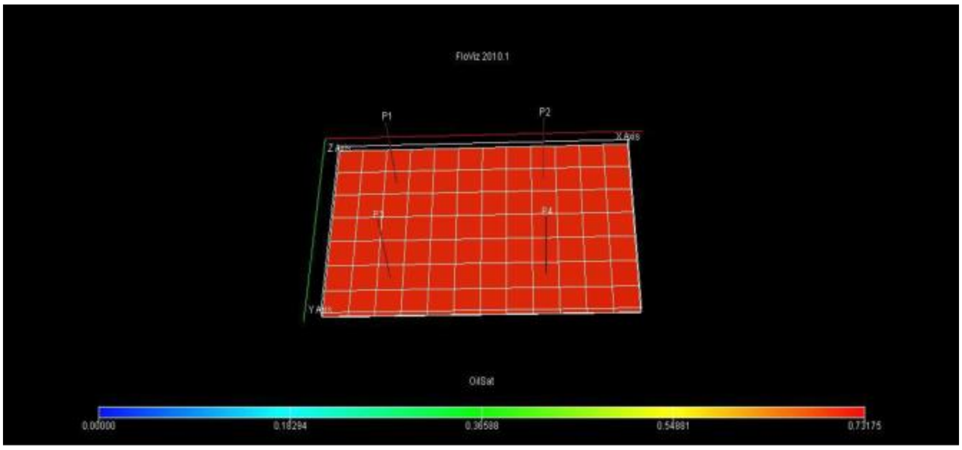


Figure 3-18 Four Well Model Layer 10

Results

Well	Location (x , y)	FGPR MSCF/D	WGPR MSCF/D	FOPR STB/D	GAS PROD MSCF	OIL PROD STB	R.F	NPV
1	(3 , 2)	5000	1250	153.6372	78313224	5741324.5	0.624956	89.83074
2	(9 , 2)		1250					
3	(3 , 6)		1250					
4	(9 , 6)		1250					

Table 3-5 Results for 4 Well Model

Effect of increasing number of wells on Plateau and Oil Flow rate:

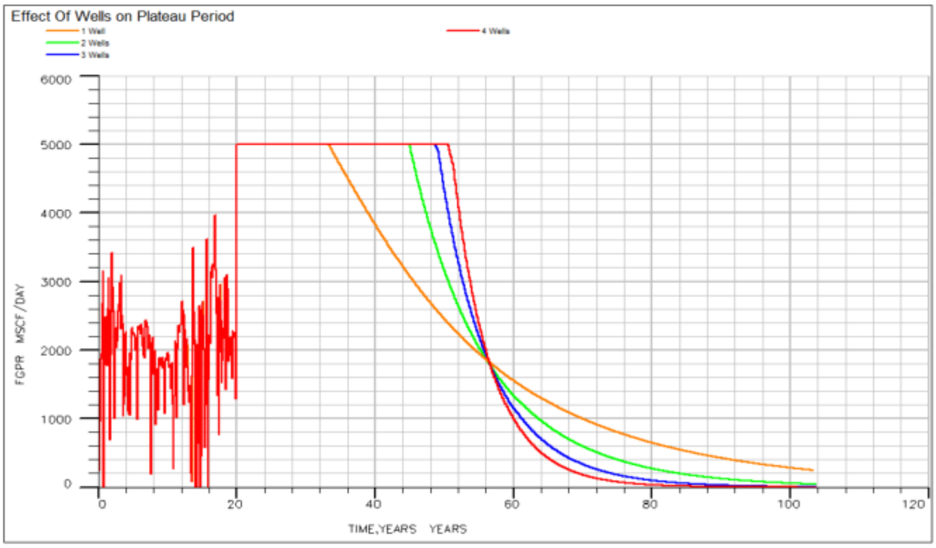


Figure 3-19 Effect of Wells on Gas Rate

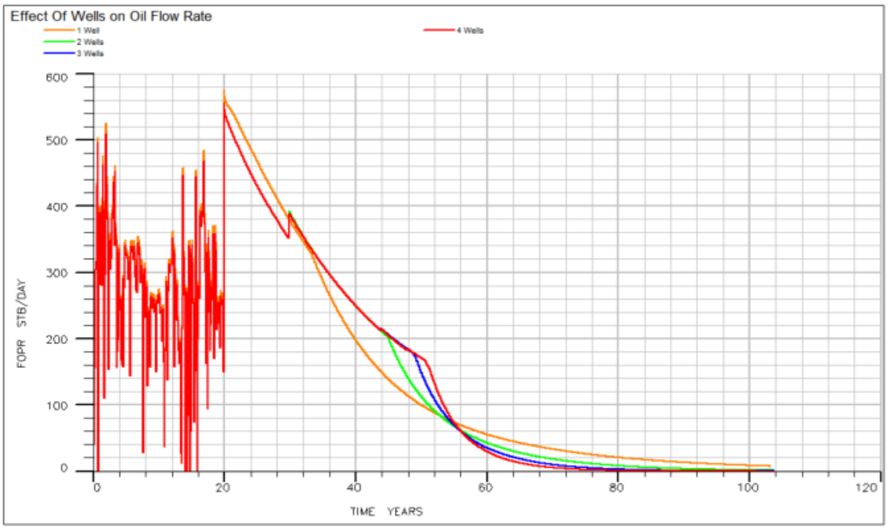


Figure 3-20 Effect of Wells on Oil Rate

3.2.2. Horizontal well

Previously we observed the effect of vertical well on our reservoir model when placed on production. The results depicted that after dew point pressure liquid drop occurred. Liquid started accumulating to the down layers of the reservoir due to the gravity segregation which is the basic phenomena of gas condensates. Oil saturation significantly increased downwards and the vertical well was not able to produce the oil from the grids far away from the wellbore. So, case of horizontal well was established in which horizontal well completion was laid in the 10th layer of the reservoir model where oil saturation was high. The figure below shows the model with a single horizontal well.

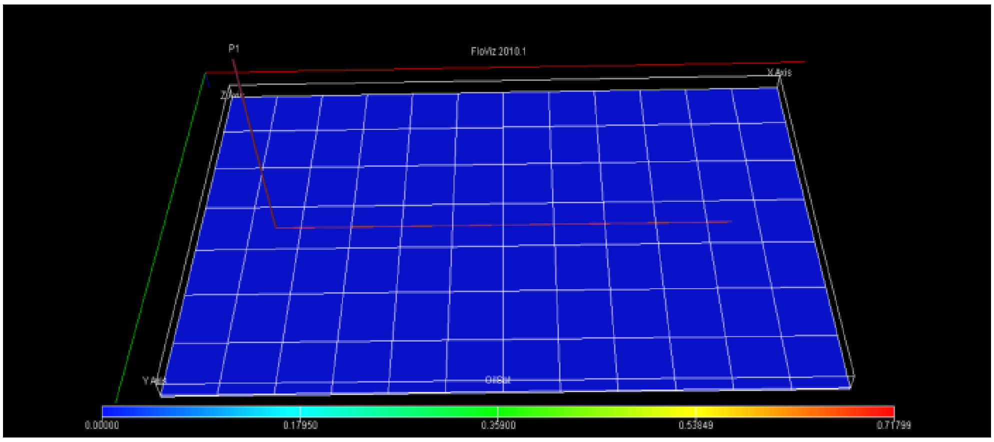


Figure 3-21 Horizontal Well Model (initial)

The well was placed on production on 5000 MSCF/D and simulation results were analyzed.

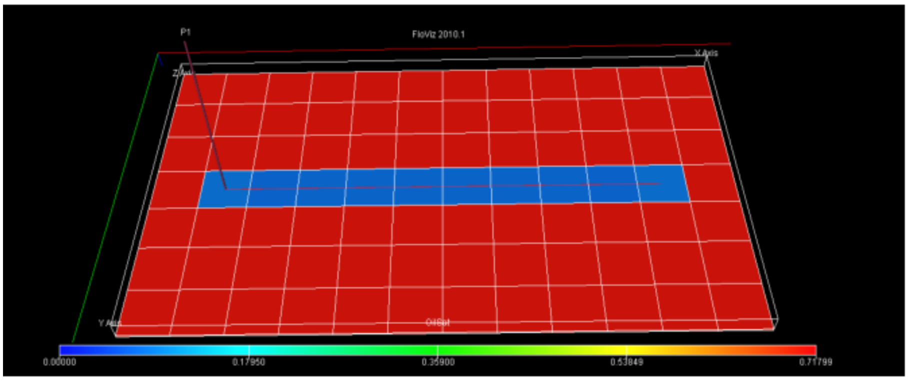


Figure 3-22 Horizontal Well Model (final)

FGPR MSCF/ D	FOPR STB/D	GAS PROD MSCF	OIL PROD STB	R.F	Decline Start	Plateau period (from 2009 onwards)	Abandonment year	Profit (NPV) MM$
6000	187.94	71868304	6843036	0.573	Jan 2011	No Plateau	2051	99.937
5000	187.93	72101984	6850835.5	0.575	June 2026	16 years 6 months	2052	99.159
4000	187.74	72167136	6854125.5	0.575	May 2037	27 years 5 months	2057	82.161
3500	187.525	72132272	6853875.5	0.575	Feb 2044	34 years 2 months	2061	72.399
3000	187.1	72053872	6852498.5	0.575	Nov 2052	42 years 11 months	2067	62.091

Table 3-6 Horizontal Well Model - Results for various Gas Flow rates

The well was simulated to produce on different flow rates, so as to analyze which flow flow rate would be most appropriate. The table above shows some results of analysis. On the basis of highest NPV, plateau period and recovery factor best flow rate seemed 5000 MSCF/d as company’s foremost aim is to obtain maximum profit in short span of time.

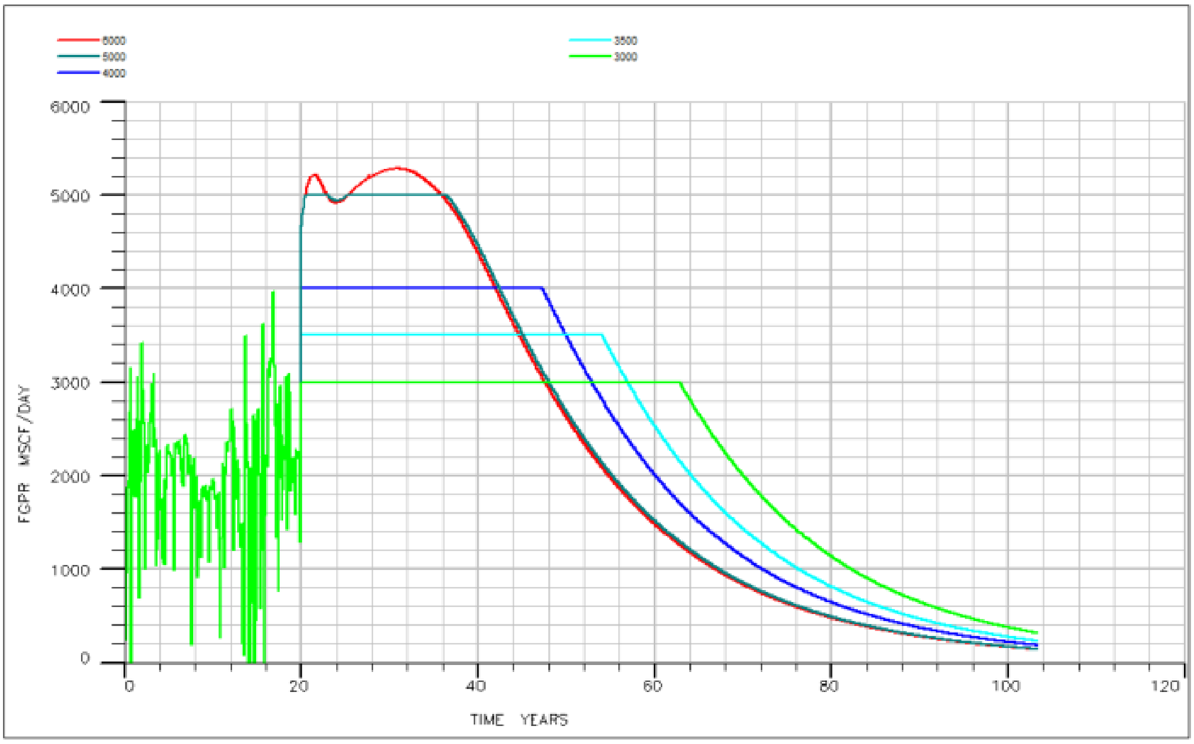


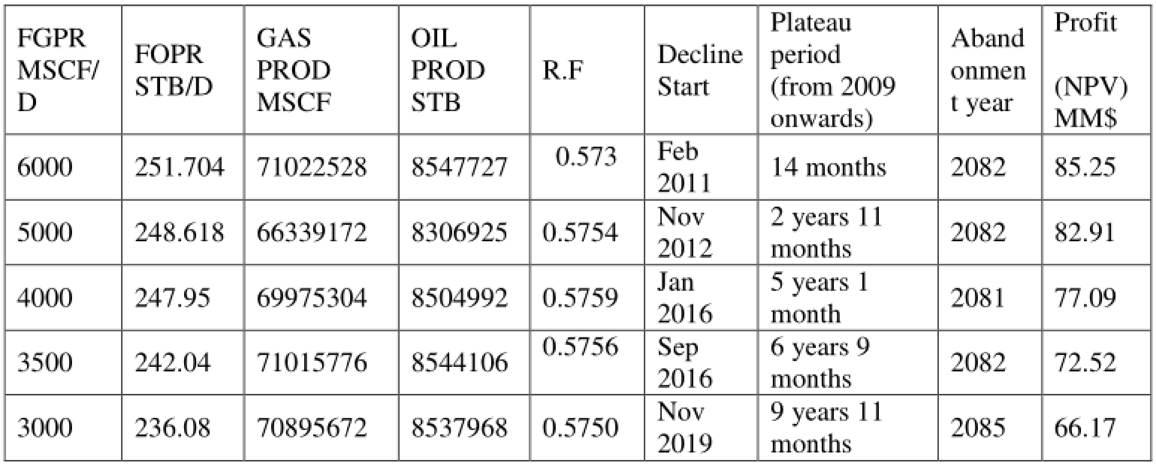
Figure 3-23 Effect of Flow rate on Plateau Period

3.2.3. Fractured well

We observed the effect of vertical and horizontal well on our reservoir model when placed on production. As we know that condensate started to accumulate at the bottom of the reservoir after the dew point so our priority should be produce the maximum amount of condensate for economic reasons. For this purpose, fracturing the reservoir can improve the productivity of the condensate once they have started to accumulate.

As we know that fractures improve the transmissibility of the reservoir and make the reservoir fluid flow easier to the wellbore, so fractures are incorporated by increasing the transmissibility of the layers containing condensate in the schedule section after the date 1st December 2010 using keywords MULTX and MULTY with BOX.

Similar to previous cases the well was simulated to produce on different flow rates, so as to analyze which flowrate would be most appropriate. The table above shows some results of the analysis. On the basis of highest NPV, plateau period and recovery factor best flow rate for this case is also obtained 5000 MSCF/d so as to obtain maximum profit as well as a considerable plateau period. Plateau period for different gas flowrate is shown in Figure 61.



FGPR MSCF/D	FOPR STB/D	GAS PROD MSCF	OIL PROD STB	R.F	Decline Start	Plateau period (from 2009 onwards)	Abandonment year	Profit (NPV) MM$
6000	251.704	71022528	8547727	0.573	Feb 2011	14 months	2082	85.25
5000	248.618	66339172	8306925	0.5754	Nov 2012	2 years 11 months	2082	82.91
4000	247.95	69975304	8504992	0.5759	Jan 2016	5 years 1 month	2081	77.09
3500	242.04	71015776	8544106	0.5756	Sep 2016	6 years 9 months	2082	72.52
3000	236.08	70895672	8537968	0.5750	Nov 2019	9 years 11 months	2085	66.17

Table 3-7 Fractured Model - Result for various Gas Flow rates

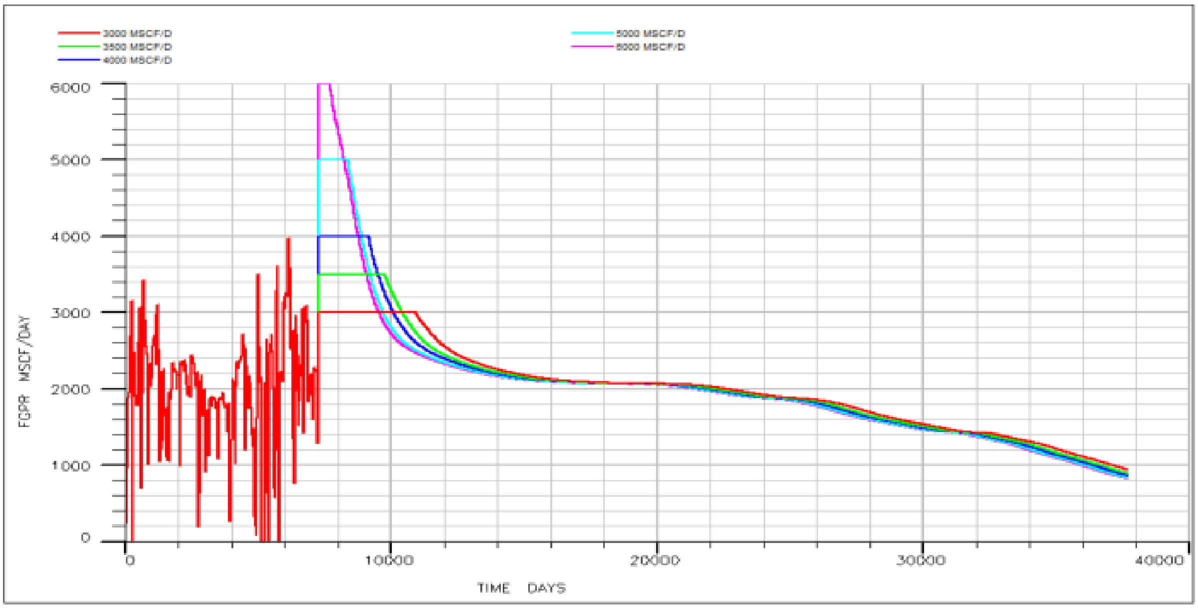
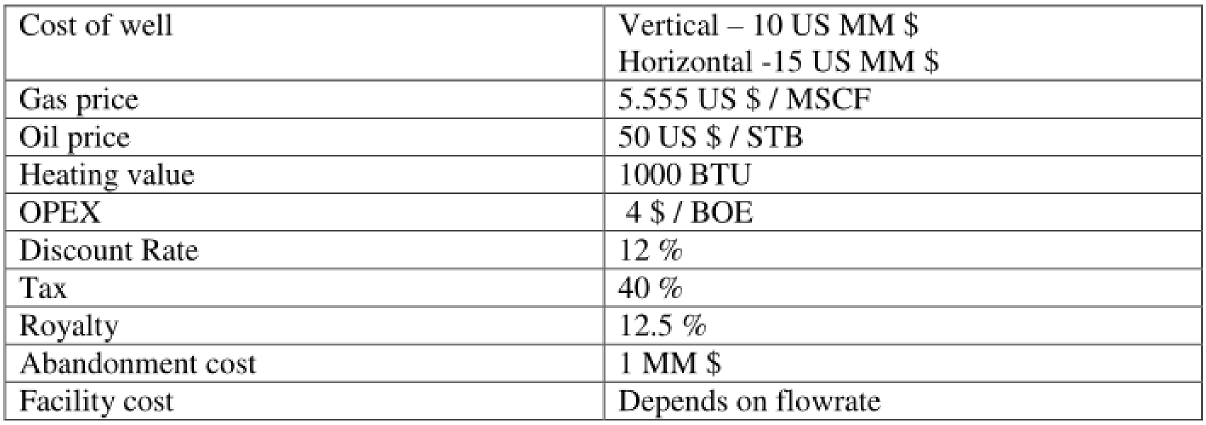


Figure 3-24 Gas flowrate effect on plateau period

CHAPTER 4. PROJECT ECONOMICS

4.1. Economic Analysis

The following data was utilized in performing economic analysis



Cost of well	Vertical – 10 US MM $ Horizontal -15 US MM $
Gas price	5.555 US $ / MSCF
Oil price	50 US $ / STB
Heating value	1000 BTU
OPEX	4 $ / BOE
Discount Rate	12 %
Tax	40 %
Royalty	12.5 %
Abandonment cost	1 MM $
Facility cost	Depends on flowrate

Table 4.1 Cost Analysis

4.1.1. Calculations:

Following calculations are performed for the various case scenarios at each successive time step

1) Facility Cost

Facility cost = Gas rate In MMSCF/day (100/ 60)

= 5 * (100/60)

=8.33 US $MM

2) Conventional Gas produced

Conventional Gas produced = Conventional Gas Rate * No. of Producing Days

= 5000 x 365

= 1825 MMSCF

3) Oil produced in the year

Oil produced in the year = Oil rate * No. of producing days

= 555.07272 x 365

= 202601.54 STB

4) BOE

BOE = (((MMSCF of Cumulative Gas * Heating value)/5.62) +STB of Cumulative Oil) /1000000

= (((1825.00 * 1000)/5.62) + 202601.54) /1000000

= 0.53 MM BOE

5) Gross Revenue:

Gross Revenue = BOE * Oil Price

= 0.53 * 50

= 26.37 US $MM

6) Operating Cost:

Operating Cost = 4$/BOE * BOE

= 4 * 0.53

= 2.11 US $MM 7) Investment

7) Investment

= Cost of well + cost of plant

= 10 + 8.33

= 18.33 US $MM 8) Net Cash Flow

8) Net Cash Flow

= Gross Revenue - OPEX - Investments

=26.37- 2.11- 18.33

= 5.92 US $MM

9) Royalty

Royalty = 12.5 % * Gross Revenue

= .125 * 26.37

= 3.3 US $MM

10) Discounted Cash flow

Discounted Cash flow = Net cash flow/ (1 + interest rate) ^ time

= 5.92 / (1 + 0.12) ^ (2010 -2010)

= 5.92 US $MM

11) Net Profit before tax

= Gross Revenue – Royalty – OPEX – Investments

Net Profit before tax = 26.37 – 3.3 – 2.11 – 18.33

= 2.63 US $MM

12) Tax

Tax = 40% of Net profit before tax

= 0.4 * 2.63

= 1.05128742 US $MM

13) Net Profit after tax

= Net Profit before tax – tax

= 2.63 - 1.05128742

= 1.58 US $MM

14) NPV

NPV = (Net Profit after tax)/ (1+interest rate) ^time

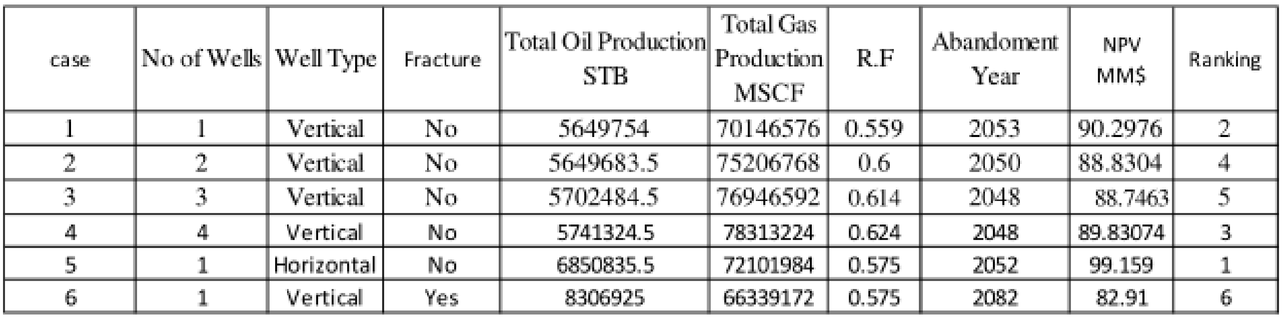
= 1.58/ (1 + 0.12) ^ (2010 – 2010)

= 1.576931137 US $MM

The above calculations are performed for the various scenarios discussed above, an example economic analysis for single well model case is present in the Appendix C

CHAPTER 5. CASES RESULT

The effect of varying the no of wells and changing the type of well from vertical to horizontal also the effect of including a fracture was observed and the results are tabulated below



case	No of Wells	Well Type	Fracture	Total Oil Production STB	Total Gas Production MSCF	R.F	Abandoment Year	NPV MM$	Ranking
1	1	Vertical	No	5649754	70146576	0.559	2053	90.2976	2
2	2	Vertical	No	5649683.5	75206768	0.6	2050	88.8304	4
3	3	Vertical	No	5702484.5	76946592	0.614	2048	88.7463	5
4	4	Vertical	No	5741324.5	78313224	0.624	2048	89.83074	3
5	1	Horizontal	No	6850835.5	72101984	0.575	2052	99.159	1
6	1	Vertical	Yes	8306925	66339172	0.575	2082	82.91	6

Table 4-1 NPV Ranking of Cases

Ranking was done on the basis of NPV, the abandonment year for all the cases is approximately same therefore it was not considered as the basis of ranking. Recovery Factor is an important consideration but here we see that although there is an increase in Recovery Factor from Case 1 to Case 4 but the NPV is decreasing therefore Recovery Factor was also not considered for the ranking of the cases.

In all the cases the wells are flowing at a field Gas Flowrate of 5000 MSCF/D was abandoned when the total MMBOE decreased below the value of 0.1 MMBOE. Hence the best case scenario is Case 5: Single Horizontal Well producing at a rate of 5000 MSCF/D, because the NPV is calculated based on MMBOE and so in this case max oil recovery was obtained at a considerably moderate abandonment time.

CONCLUSION

In conclusion, first of all, compositional model of Equation of state was created by using the PVTP Software of IPM suite. In the second phase of the project reservoir model with the total Area of 4936.64 Acre with 16.747134 MMSTB of OOIP and 125.310142 BSCF of OGIP was formed. In the third phase of the project manual history matching takes place. In addition, forecasting has been done for 84 years and 0.1 MMBOE for well abandonment was selected.

Furthermore, main part of the case study was field development planning of the gas condensate reservoir. In this regard different scenario were tested. Firstly, field was produced by increasing number of well from 1 to 4. With a constant flow rate of 5000 MSCF. Moreover, in the second cases one horizontal well was selected for production with multiple flow rate. In both cases well was abandon at 0.1 MMBEO. However, in horizontal well case, which is the 5 case in the Table 4.1 is the best case with highest NPV along with a steady plateau period. Additionally, best flow rate for horizontal case was 5000 MSCF/d.

FUTURE RESEARCH

In this regard I want to address that in future focus can be done by using more complex system of reservoir in which we can increase the hydrocarbon and non-hydrocarbon component and so on. Even though we can also add NNC (Non Neighbor Connection) in our reservoir by making the fracture by interesting by creating the complex dual porosity model and then analyze the further application of the Schlumberger Eclipse Software

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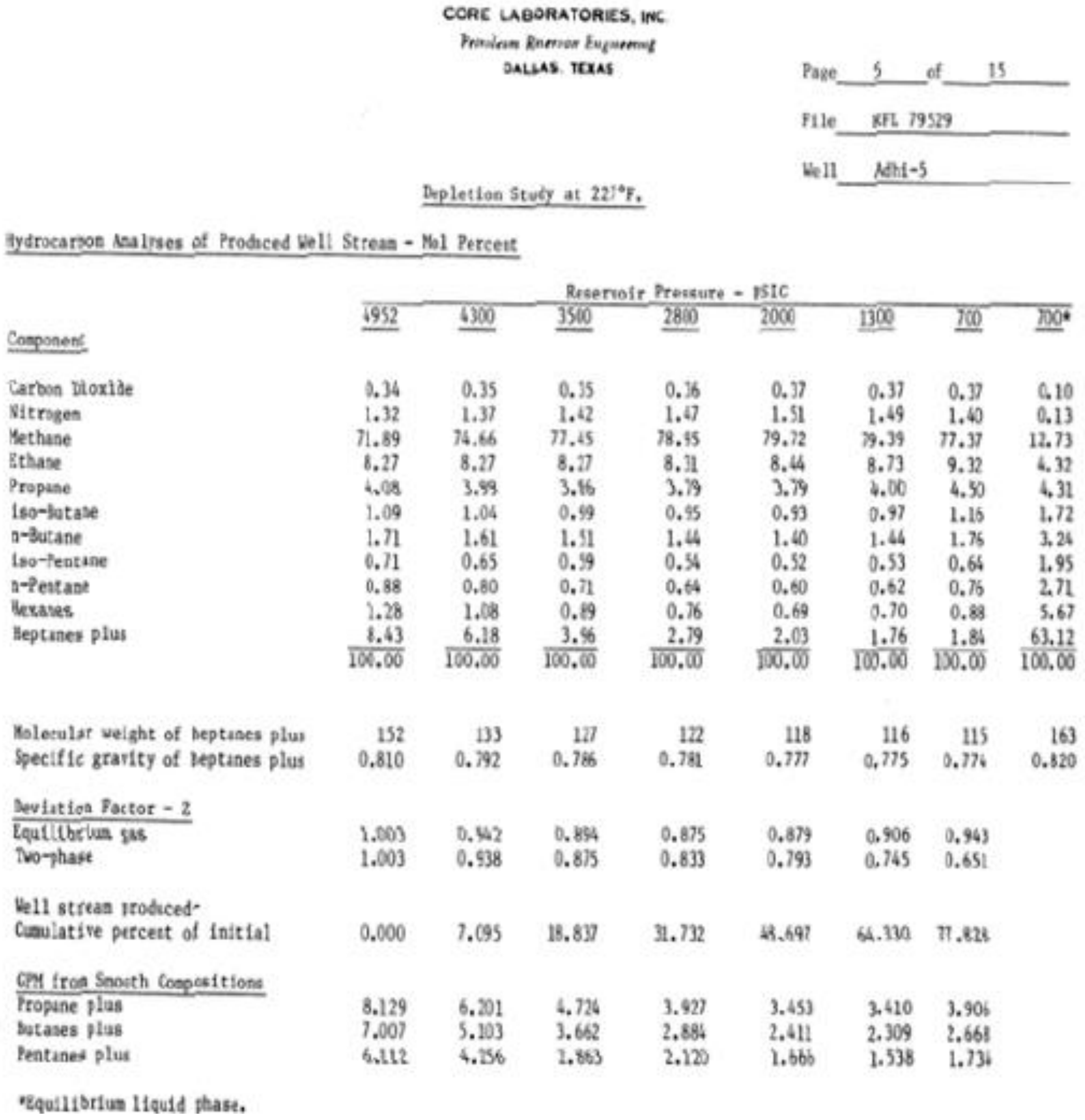
APPENDIX A

Constant Volume Depletion (CVD) Report



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File KFL 79529

Well Adhi-5

Depletion Study at 227°F.

Hydrocarbon Analyses of Produced Well Stream - Mol Percent

	Reservoir Pressure - PSIG							
Component	4952	4300	3500	2800	2000	1300	700	700*
Carbon Dioxide	0.34	0.35	0.35	0.36	0.37	0.37	0.37	0.10
Nitrogen	1.32	1.37	1.42	1.47	1.51	1.49	1.40	0.13
Methane	71.89	74.66	77.45	78.95	79.72	79.39	77.37	12.73
Ethane	8.27	8.27	8.27	8.31	8.44	8.73	9.32	4.32
Propane	4.08	3.99	3.86	3.79	3.79	4.00	4.50	4.31
Iso-Butane	1.09	1.04	0.99	0.95	0.93	0.97	1.16	1.72
n-Butane	1.71	1.61	1.51	1.44	1.40	1.44	1.76	3.24
Iso-Pentane	0.71	0.65	0.59	0.54	0.52	0.53	0.64	1.95
n-Pentane	0.88	0.80	0.71	0.64	0.60	0.62	0.76	2.71
Hexanes	1.28	1.08	0.89	0.76	0.69	0.70	0.88	5.67
Heptanes plus	8.43	6.18	3.96	2.79	2.03	1.76	1.84	63.12
	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molecular weight of heptanes plus	152	133	127	122	118	116	115	163
Specific gravity of heptanes plus	0.810	0.792	0.786	0.781	0.777	0.775	0.774	0.820
Deviation Factor - Z								
Equilibrium gas	1.003	0.942	0.894	0.875	0.879	0.906	0.943	
Two-phase	1.003	0.938	0.875	0.833	0.793	0.745	0.651	
Well stream produced- Cumulative percent of initial	0.000	7.095	18.837	31.732	48.697	64.330	77.828	
GPM from Smooth Compositions								
Propane plus	8.129	6.201	4.724	3.927	3.453	3.410	3.906	
Butanes plus	7.007	5.103	3.662	2.884	2.411	2.309	2.668	
Pentanes plus	6.112	4.256	1.863	2.120	1.666	1.538	1.734	

*Equilibrium liquid phase.

APPENDIX B

Eclipse Data File (Single Well Completion)

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--RUNSPEC section-----------------------------------------------------------

RUNSPEC

FIELD

WATER

COMPS 13 /

DIMENS 12 7 10 /

TABDIMS 1 1 40 40 /

UNIFOUT

START 1 FEB 1990 /

--Grid section------------------------------------------------------------------------

GRID

DX 840*1600 /

DY 840*1600 /

DZ 840*3.281 /

TOPS 84*7000 /

EQUALS PORO 0.1 / PERMX 6/

64

PERMY 6 / PERMZ 0.3 / / INIT --Properties section----------------------------------------------------------

PROPS NCOMPS       13 / EOS PR /
```

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-- Peng Robinson correction

PRCORR

-- Standard temperature and pressure in Deg F and PSIA

STCOND    60.0206     14.6960 /

-- Component names

CNAMES  N2  CO2  C1  C2  C3  IC4  NC4  IC5  NC5  C6  C7::C10  C11::C13
C14::C16 /

-- Critical temperatures Deg R

TCRIT   2.26565996e+002  5.47362001e+002  3.43152002e+002  5.49467997e+002
6.65675997e+002      7.34364000e+002      7.64964006e+002      8.29476000e+002
8.45262010e+002      9.13770006e+002      1.11236476e+003      1.36481258e+003
1.16440767e+003

65

/

-- Critical pressures PSIA

PCRIT   4.92022080e+002  1.07295491e+003  6.73076798e+002  7.08347184e+002
6.17378983e+002      5.29055985e+002      5.50659135e+002      4.83057511e+002
4.89523759e+002      4.39704331e+002      3.82446824e+002      4.68330552e+002
1.51588960e+002 /

-- Critical volumes FT3/LBMOLE

VCRIT   1.43841791e+000  1.50409186e+000  1.58898735e+000  2.37547183e+000
3.25165749e+000      4.21273851e+000      4.08459425e+000      4.90151310e+000
4.86947727e+000      5.92666626e+000      9.22185993e+000      1.27600002e+001
1.64211006e+001 /

-- Reservoir 3-Parameter EoS Shift Coefficients
```

```
SSHIFT -1.53999999e-001 -1.00199997e-001 -1.53999999e-001 -1.00199997e-001
-8.50099996e-002 -7.93500021e-002 -6.41300008e-002 -4.34999987e-002 -
4.18299995e-002 -1.47799999e-002 5.22767529e-002 1.15136474e-001
1.52510792e-001 /

-- Critical volumes for LBC Viscosities FT3/LBMOLE

VCRITVIS 1.43841791e+000 1.50409186e+000 1.58898735e+000
2.37547183e+000 3.25165749e+000 4.21273851e+000 4.08459425e+000
4.90151310e+000 4.86947727e+000 5.92666626e+000 9.22185993e+000
1.27600002e+001 1.64211006e+001 /

-- Acentric factors

ACF 3.90000008e-002 2.38999993e-001 1.09999999e-002 9.89999995e-002
1.52999997e-001 1.82999998e-001 1.99000001e-001 2.26999998e-001
2.50999987e-001 2.98999995e-001 3.65471959e-001 5.02193987e-001
6.36015236e-001

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/ -- Molecular Weights

MW 2.80100002e+001 4.40099983e+001 1.60400009e+001 3.01000004e+001
4.40999985e+001 5.80999985e+001 5.80999985e+001 7.21999969e+001
7.21999969e+001 8.61999969e+001 1.30257004e+002 1.79238007e+002
2.19080002e+002 /

-- fluid sample composition

ZI 1.31999989e-002 3.39999973e-003 7.18899942e-001 8.26999934e-002
4.07999967e-002 1.08999991e-002 1.70999986e-002 7.09999943e-003
8.79999930e-003 1.27999990e-002 5.40906957e-002 2.13434983e-002
8.86587929e-003

/
```

```
-- Boiling point temperatures Deg R

TBOIL    1.39319994e+002  3.50460001e+002  2.00879991e+002  3.32280001e+002
4.15980001e+002       4.70520000e+002       4.90860001e+002       5.41799997e+002
5.56559999e+002       6.15420000e+002       7.74839006e+002       9.29194994e+002
1.06001198e+003 /

-- Reference temperatures Deg R

TREF     5.19690600e+002  5.19690600e+002  5.19690600e+002  5.19690600e+002
5.19690600e+002       5.19690600e+002       5.19690600e+002       5.19690600e+002
5.19690600e+002       5.19690600e+002       5.19690600e+002       5.19690600e+002
5.19690600e+002 /

-- Reference densities LB/FT3

DREF     2.99663993e+001  2.62205992e+001  1.56075000e+001  2.49720004e+001
3.17144410e+001       3.51480914e+001       3.64591194e+001       3.90187500e+001
3.93933289e+001       4.27645501e+001       4.92726887e+001       5.23088493e+001
5.42828243e+001 /

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-- Parachors (Dynes/cm)

PARACHOR              6.04000015e+001       7.80000000e+001       7.00000000e+001
1.15000000e+002         1.55000000e+002      1.81500000e+002       2.00000000e+002
2.25000000e+002         2.45000000e+002      2.82500000e+002       3.91688629e+002
5.05978455e+002   5.88708374e+002 /


BIC  -- Binary Interaction Coefficients

 -2.00000000e-002        3.60000000e-002     4.31000000e-002          4.31000000e-002
4.31000000e-002       2.00000000e-003          4.31000000e-002       4.31000000e-002
7.00000000e-003       1.00000000e-003          4.31000000e-002       4.31000000e-002
```
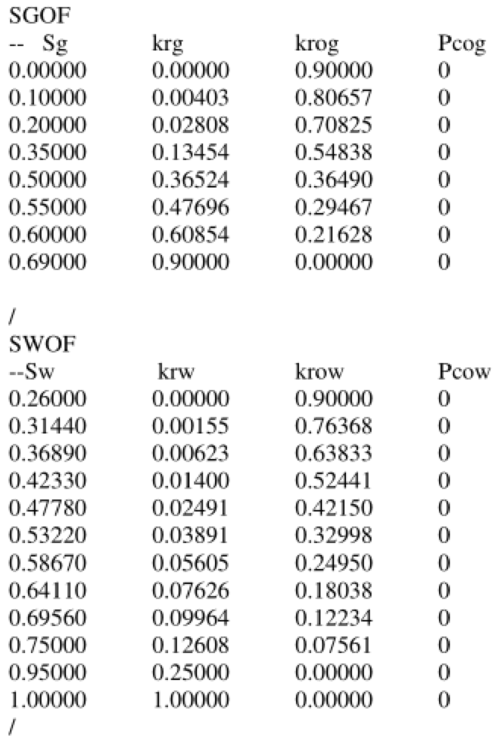

```
1.20000000e-002    3.00000000e-003    0.00000000e+000    4.31000000e-002
4.31000000e-002    1.20000000e-002    3.00000000e-003    0.00000000e+000
0.00000000e+000    4.31000000e-002    4.31000000e-002    1.70000000e-002
4.00000000e-003    1.00000000e-003    0.00000000e+000    0.00000000e+000
4.31000000e-002    4.31000000e-002    1.80000000e-002    5.00000000e-003
2.00000000e-003    0.00000000e+000    0.00000000e+000    0.00000000e+000
4.31000000e-002    4.31000000e-002    2.40000000e-002    7.00000000e-003
3.00000000e-003    1.00000000e-003    1.00000000e-003    0.00000000e+000
0.00000000e+000    0.00000000e+000    0.00000000e+000    4.31000000e-002
0.00000000e+000    0.00000000e+000    0.00000000e+000    0.00000000e+000
0.00000000e+000    0.00000000e+000    0.00000000e+000    0.00000000e+000
0.00000000e+000    4.31000000e-002    0.00000000e+000    0.00000000e+000
0.00000000e+000    0.00000000e+000    0.00000000e+000    0.00000000e+000
0.00000000e+000    0.00000000e+000    0.00000000e+000    0.00000000e+000
4.31000000e-002    0.00000000e+000    0.00000000e+000    0.00000000e+000
0.00000000e+000    0.00000000e+000    0.00000000e+000    0.00000000e+000
0.00000000e+000  0.00000000e+000

-- Reservoir temperature in Deg F

RTEMP  227 /
```



```
SGOF
--  Sg        krg        krog       Pcog
0.00000   0.00000    0.90000    0
0.10000   0.00403    0.80657    0
0.20000   0.02808    0.70825    0
0.35000   0.13454    0.54838    0
0.50000   0.36524    0.36490    0
0.55000   0.47696    0.29467    0
0.60000   0.60854    0.21628    0
0.69000   0.90000    0.00000    0

/
SWOF
--Sw       krw        krow       Pcow
0.26000   0.00000    0.90000    0
0.31440   0.00155    0.76368    0
0.36890   0.00623    0.63833    0
0.42330   0.01400    0.52441    0
0.47780   0.02491    0.42150    0
0.53220   0.03891    0.32998    0
0.58670   0.05605    0.24950    0
0.64110   0.07626    0.18038    0
0.69560   0.09964    0.12234    0
0.75000   0.12608    0.07561    0
0.95000   0.25000    0.00000    0
1.00000   1.00000    0.00000    0
/
```

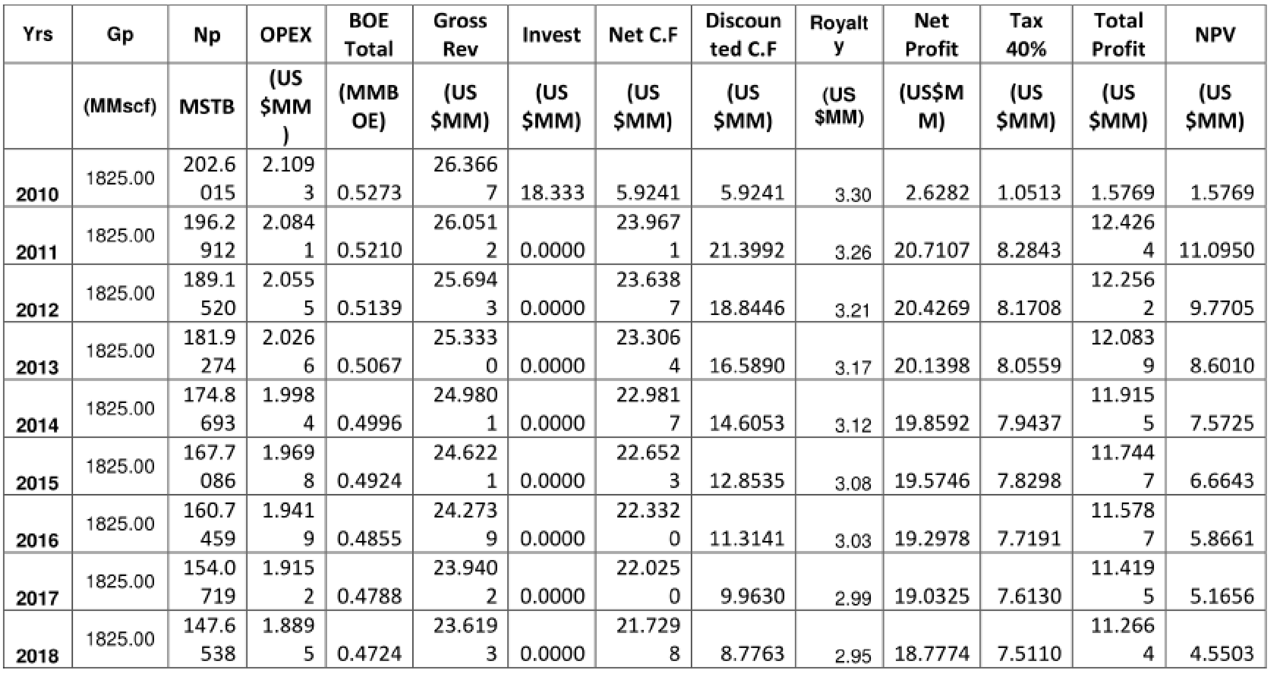
```
--Rock and water pressure data

ROCK 5200 0.000004 /

PVTW 5200 1.0 0.000003 0.31 0.0 /

--Surface density of water

DENSITY 1* 63.0 1* /

--Solution section-----------------------------------------------------

SOLUTION

EQUIL 7200 5200 7200 0 7050 0 1 1 0  /

RPTRST PRESSURE SOIL SGAS SWAT  /

RPTSOL PRESSURE SOIL SGAS SWAT  /

SUMMARY
===========================================================

ALL
```

```
RUNSUM

WBP9 / WBHPH / WGORH / WGPRH / WOPRH /

--Schedule section------------------------------------------------------

SCHEDULE

RPTSCHED PRESSURE SOIL/

INCLUDE Schedule_history.INC * / END
```

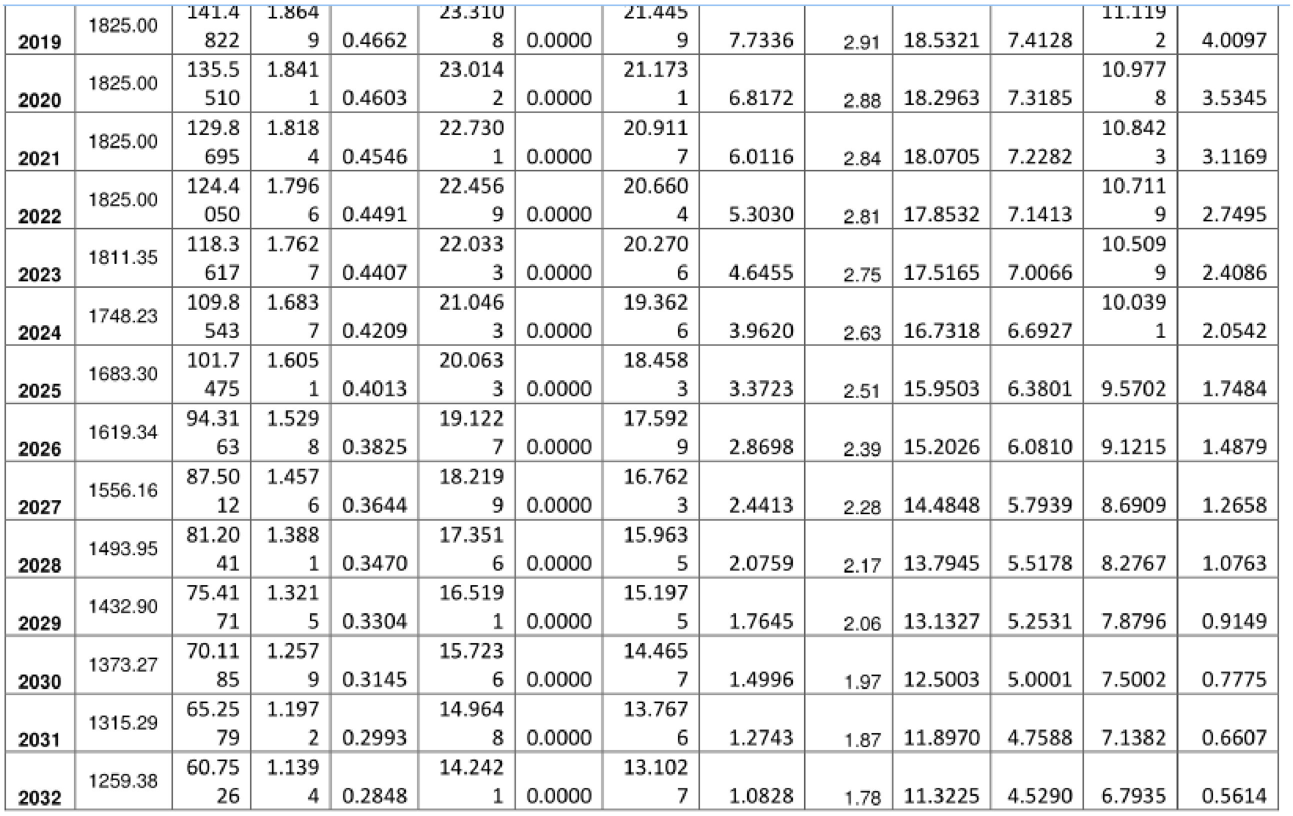
* The schedule section (containing the history data as well as data for further time steps) is not shown for the sake of brevity

APPENDIX C

Economic Analysis (Single well model 5000 MSCF/D)



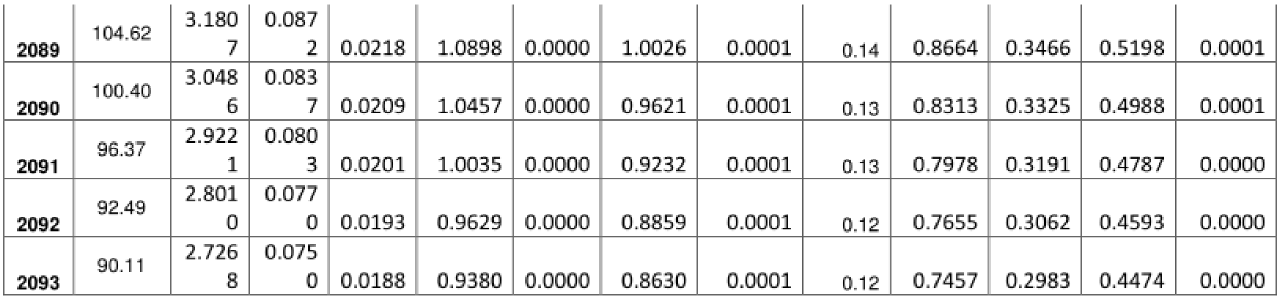
Yrs	Gp	Np	OPEX	BOE Total	Gross Rev	Invest	Net C.F	Discounted C.F	Royalty	Net Profit	Tax 40%	Total Profit	NPV
	(MMscf)	MSTB	(US $MM)	(MMBOE)	(US $MM)	(US $MM)	(US $MM)	(US $MM)	(US $MM)	(US$MM)	(US $MM)	(US $MM)	(US $MM)
2010	1825.00	202.6015	2.1093	0.5273	26.3667	18.333	5.9241	5.9241	3.30	2.6282	1.0513	1.5769	1.5769
2011	1825.00	196.2912	2.0841	0.5210	26.0512	0.0000	23.9671	21.3992	3.26	20.7107	8.2843	12.4264	11.0950
2012	1825.00	189.1520	2.0555	0.5139	25.6943	0.0000	23.6387	18.8446	3.21	20.4269	8.1708	12.2562	9.7705
2013	1825.00	181.9274	2.0266	0.5067	25.3330	0.0000	23.3064	16.5890	3.17	20.1398	8.0559	12.0839	8.6010
2014	1825.00	174.8693	1.9984	0.4996	24.9801	0.0000	22.9817	14.6053	3.12	19.8592	7.9437	11.9155	7.5725
2015	1825.00	167.7086	1.9698	0.4924	24.6221	0.0000	22.6523	12.8535	3.08	19.5746	7.8298	11.7447	6.6643
2016	1825.00	160.7459	1.9419	0.4855	24.2739	0.0000	22.3320	11.3141	3.03	19.2978	7.7191	11.5787	5.8661
2017	1825.00	154.0719	1.9152	0.4788	23.9402	0.0000	22.0250	9.9630	2.99	19.0325	7.6130	11.4195	5.1656
2018	1825.00	147.6538	1.8895	0.4724	23.6193	0.0000	21.7298	8.7763	2.95	18.7774	7.5110	11.2664	4.5503



2019	1825.00	141.4822	1.8649	0.4662	23.3108	0.0000	21.4459	7.7336	2.91	18.5321	7.4128	11.1192	4.0097
2020	1825.00	135.5510	1.8411	0.4603	23.0142	0.0000	21.1731	6.8172	2.88	18.2963	7.3185	10.9778	3.5345
2021	1825.00	129.8695	1.8184	0.4546	22.7301	0.0000	20.9117	6.0116	2.84	18.0705	7.2282	10.8423	3.1169
2022	1825.00	124.4050	1.7966	0.4491	22.4569	0.0000	20.6604	5.3030	2.81	17.8532	7.1413	10.7119	2.7495
2023	1811.35	118.3617	1.7627	0.4407	22.0333	0.0000	20.2706	4.6455	2.75	17.5165	7.0066	10.5099	2.4086
2024	1748.23	109.8543	1.6837	0.4209	21.0463	0.0000	19.3626	3.9620	2.63	16.7318	6.6927	10.0391	2.0542
2025	1683.30	101.7475	1.6051	0.4013	20.0633	0.0000	18.4583	3.3723	2.51	15.9503	6.3801	9.5702	1.7484
2026	1619.34	94.3163	1.5298	0.3825	19.1227	0.0000	17.5929	2.8698	2.39	15.2026	6.0810	9.1215	1.4879
2027	1556.16	87.5012	1.4576	0.3644	18.2199	0.0000	16.7623	2.4413	2.28	14.4848	5.7939	8.6909	1.2658
2028	1493.95	81.2041	1.3881	0.3470	17.3516	0.0000	15.9635	2.0759	2.17	13.7945	5.5178	8.2767	1.0763
2029	1432.90	75.4171	1.3215	0.3304	16.5191	0.0000	15.1975	1.7645	2.06	13.1327	5.2531	7.8796	0.9149
2030	1373.27	70.1185	1.2579	0.3145	15.7236	0.0000	14.4657	1.4996	1.97	12.5003	5.0001	7.5002	0.7775
2031	1315.29	65.2579	1.1972	0.2993	14.9648	0.0000	13.7676	1.2743	1.87	11.8970	4.7588	7.1382	0.6607
2032	1259.38	60.7526	1.1394	0.2848	14.2421	0.0000	13.1027	1.0828	1.78	11.3225	4.5290	6.7935	0.5614

2033	1205.35	56.5774	1.0842	0.2711	13.5526	0.0000	12.4684	0.9200	1.69	10.7744	4.3097	6.4646	0.4770
2034	1152.71	52.7369	1.0314	0.2578	12.8923	0.0000	11.8609	0.7814	1.61	10.2494	4.0997	6.1496	0.4052
2035	1101.99	49.2213	0.9812	0.2453	12.2652	0.0000	11.2840	0.6638	1.53	9.7509	3.9003	5.8505	0.3441
2036	1053.19	45.9903	0.9336	0.2334	11.6695	0.0000	10.7360	0.5639	1.46	9.2773	3.7109	5.5664	0.2923
2037	1006.37	43.0180	0.8884	0.2221	11.1044	0.0000	10.2161	0.4791	1.39	8.8280	3.5312	5.2968	0.2484
2038	961.58	40.2835	0.8455	0.2114	10.5692	0.0000	9.7236	0.4071	1.32	8.4025	3.3610	5.0415	0.2111
2039	918.72	37.7608	0.8049	0.2012	10.0617	0.0000	9.2568	0.3460	1.26	7.9991	3.1996	4.7994	0.1794
2040	877.66	35.4306	0.7664	0.1916	9.5799	0.0000	8.8135	0.2942	1.20	7.6160	3.0464	4.5696	0.1525
2041	838.29	33.2844	0.7298	0.1824	9.1223	0.0000	8.3925	0.2501	1.14	7.2523	2.9009	4.3514	0.1297
2042	800.69	31.3013	0.6951	0.1738	8.6886	0.0000	7.9935	0.2127	1.09	6.9075	2.7630	4.1445	0.1103
2043	764.84	29.4613	0.6622	0.1656	8.2777	0.0000	7.6154	0.1809	1.03	6.5807	2.6323	3.9484	0.0938
2044	730.62	27.7492	0.6310	0.1578	7.8876	0.0000	7.2566	0.1539	0.99	6.2707	2.5083	3.7624	0.0798
2045	697.99	26.1581	0.6014	0.1504	7.5178	0.0000	6.9164	0.1310	0.94	5.9766	2.3907	3.5860	0.0679
2046	666.90	24.6821	0.5734	0.1433	7.1673	0.0000	6.5940	0.1115	0.90	5.6980	2.2792	3.4188	0.0578
2047	637.20	23.3090	0.5468	0.1367	6.8345	0.0000	6.2878	0.0949	0.85	5.4335	2.1734	3.2601	0.0492
2048	608.80	22.0294	0.5214	0.1304	6.5179	0.0000	5.9964	0.0808	0.81	5.1817	2.0727	3.1090	0.0419
2049	581.67	20.8387	0.4974	0.1243	6.2170	0.0000	5.7196	0.0688	0.78	4.9425	1.9770	2.9655	0.0357
2050	555.78	19.7310	0.4745	0.1186	5.9312	0.0000	5.4567	0.0586	0.74	4.7153	1.8861	2.8292	0.0304
2051	531.07	18.6972	0.4528	0.1132	5.6597	0.0000	5.2069	0.0500	0.71	4.4995	1.7998	2.6997	0.0259
2052	507.55	17.7307	0.4322	0.1080	5.4021	0.0000	4.9700	0.0426	0.68	4.2947	1.7179	2.5768	0.0221
2053	485.34	16.8316	0.4128	0.1032	5.1596	1.0000	3.7468	0.0287	0.64	3.1018	1.2407	1.8611	0.0142
2054	465.22	16.0275	0.3952	0.0988	4.9403	0.0000	4.5451	0.0310	0.62	3.9275	1.5710	2.3565	0.0161
2055	445.12	15.2365	0.3778	0.0944	4.7219	0.0000	4.3442	0.0265	0.59	3.7539	1.5016	2.2524	0.0137
2056	425.63	14.4788	0.3609	0.0902	4.5106	0.0000	4.1498	0.0226	0.56	3.5860	1.4344	2.1516	0.0117
2057	407.06	13.7650	0.3448	0.0862	4.3098	0.0000	3.9650	0.0193	0.54	3.4263	1.3705	2.0558	0.0100
2058	389.41	13.0936	0.3295	0.0824	4.1192	0.0000	3.7897	0.0164	0.51	3.2748	1.3099	1.9649	0.0085
2059	372.59	12.4575	0.3150	0.0788	3.9377	0.0000	3.6227	0.0140	0.49	3.1305	1.2522	1.8783	0.0073
2060	356.55	11.8523	0.3012	0.0753	3.7648	0.0000	3.4636	0.0120	0.47	2.9930	1.1972	1.7958	0.0062

2061	341.25	11.2811	0.2880	0.0720	3.6001	0.0000	3.3121	0.0102	0.45	2.8621	1.1448	1.7172	0.0053
2062	326.67	10.7425	0.2755	0.0689	3.4435	0.0000	3.1680	0.0087	0.43	2.7376	1.0950	1.6425	0.0045
2063	312.76	10.2336	0.2635	0.0659	3.2943	0.0000	3.0307	0.0075	0.41	2.6189	1.0476	1.5714	0.0039
2064	299.49	9.7520	0.2522	0.0630	3.1521	0.0000	2.8999	0.0064	0.39	2.5059	1.0024	1.5035	0.0033
2065	286.80	9.2959	0.2413	0.0603	3.0164	0.0000	2.7751	0.0054	0.38	2.3980	0.9592	1.4388	0.0028
2066	274.69	8.8650	0.2310	0.0577	2.8871	0.0000	2.6562	0.0047	0.36	2.2953	0.9181	1.3772	0.0024
2067	263.13	8.4565	0.2211	0.0553	2.7639	0.0000	2.5428	0.0040	0.35	2.1973	0.8789	1.3184	0.0021
2068	252.08	8.0688	0.2117	0.0529	2.6461	0.0000	2.4344	0.0034	0.33	2.1037	0.8415	1.2622	0.0018
2069	241.51	7.7012	0.2027	0.0507	2.5338	0.0000	2.3311	0.0029	0.32	2.0143	0.8057	1.2086	0.0015
2070	231.43	7.3529	0.1941	0.0485	2.4266	0.0000	2.2325	0.0025	0.30	1.9292	0.7717	1.1575	0.0013
2071	221.79	7.0225	0.1859	0.0465	2.3243	0.0000	2.1384	0.0021	0.29	1.8478	0.7391	1.1087	0.0011
2072	212.56	6.7084	0.1781	0.0445	2.2266	0.0000	2.0484	0.0018	0.28	1.7701	0.7080	1.0621	0.0009
2073	203.75	6.4101	0.1707	0.0427	2.1332	0.0000	1.9626	0.0016	0.27	1.6959	0.6784	1.0176	0.0008
2074	195.32	6.1267	0.1635	0.0409	2.0441	0.0000	1.8806	0.0013	0.26	1.6250	0.6500	0.9750	0.0007
2075	187.26	5.8575	0.1567	0.0392	1.9589	0.0000	1.8022	0.0011	0.24	1.5573	0.6229	0.9344	0.0006
2076	179.54	5.6008	0.1502	0.0375	1.8774	0.0000	1.7272	0.0010	0.23	1.4925	0.5970	0.8955	0.0005
2077	172.15	5.3564	0.1440	0.0360	1.7994	0.0000	1.6554	0.0008	0.22	1.4305	0.5722	0.8583	0.0004
2078	165.09	5.1241	0.1380	0.0345	1.7250	0.0000	1.5870	0.0007	0.22	1.3713	0.5485	0.8228	0.0004
2079	158.33	4.9029	0.1323	0.0331	1.6538	0.0000	1.5215	0.0006	0.21	1.3147	0.5259	0.7888	0.0003
2080	151.85	4.6917	0.1268	0.0317	1.5856	0.0000	1.4587	0.0005	0.20	1.2605	0.5042	0.7563	0.0003
2081	145.65	4.4905	0.1216	0.0304	1.5203	0.0000	1.3987	0.0004	0.19	1.2087	0.4835	0.7252	0.0002
2082	139.72	4.2988	0.1166	0.0292	1.4580	0.0000	1.3413	0.0004	0.18	1.1591	0.4636	0.6955	0.0002
2083	134.04	4.1160	0.1119	0.0280	1.3983	0.0000	1.2864	0.0003	0.17	1.1117	0.4447	0.6670	0.0002
2084	128.59	3.9414	0.1073	0.0268	1.3411	0.0000	1.2338	0.0003	0.17	1.0662	0.4265	0.6397	0.0001
2085	123.37	3.7747	0.1029	0.0257	1.2863	0.0000	1.1834	0.0002	0.16	1.0226	0.4091	0.6136	0.0001
2086	118.38	3.6158	0.0987	0.0247	1.2340	0.0000	1.1353	0.0002	0.15	0.9810	0.3924	0.5886	0.0001
2087	113.61	3.4643	0.0947	0.0237	1.1840	0.0000	1.0892	0.0002	0.15	0.9412	0.3765	0.5647	0.0001
2088	109.02	3.3192	0.0909	0.0227	1.1359	0.0000	1.0450	0.0002	0.14	0.9030	0.3612	0.5418	0.0001



2089	104.62	3.1807	0.0872	0.0218	1.0898	0.0000	1.0026	0.0001	0.14	0.8664	0.3466	0.5198	0.0001
2090	100.40	3.0486	0.0837	0.0209	1.0457	0.0000	0.9621	0.0001	0.13	0.8313	0.3325	0.4988	0.0001
2091	96.37	2.9221	0.0803	0.0201	1.0035	0.0000	0.9232	0.0001	0.13	0.7978	0.3191	0.4787	0.0000
2092	92.49	2.8010	0.0770	0.0193	0.9629	0.0000	0.8859	0.0001	0.12	0.7655	0.3062	0.4593	0.0000
2093	90.11	2.7268	0.0750	0.0188	0.9380	0.0000	0.8630	0.0001	0.12	0.7457	0.2983	0.4474	0.0000

The NPV value at abandonment year 2053 is 90.2976 MM