ISTANBUL TECHNICAL UNIVERSITY ★ GRADUATE SCHOOL OF SCIENCE ENGINEERING AND TECHNOLOGY

EFFECT OF INTERSECTED WELLS CONFIGURATION ON PRODUCTIVITY

M.Sc. THESIS

Azad Almasov

Department of Petroleum and Natural Gas Engineering

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İSTANBUL TEKNİK ÜNİVERSİTESİ ★ FEN BİLİMLERİ ENSTİTÜSÜ

KESİŞEN KUYULAR KONFİGÜRASYONUNUN VERİMLİLİK ÜZERİNE ETKİSİ

YÜKSEK LİSANS TEZİ

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Petrol ve Doğal Gaz Mühendisliği Anabilim Dalı

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MAYIS 2017

Azad Almasov, an M.Sc. student of İTU Graduate School of Petroleum Engineering student ID 505131502, successfully defended the thesis entitled “EFFECT OF INTERSECTED WELLS CONFIGURATION ON PRODUCTIVITY”, which he prepared after fulfilling the requirements specified in the associated legislations, before the jury whose signatures are below.

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Jury Members:	**Asst. Prof. Dr. İsmail Durgut** Middle East Technical University	....
	Asst. Prof. Dr. E. Didem Korkmaz Başel İstanbul Technical University	....

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To my brother Rustam,

FOREWORD

To Professors I have been working with and Department Stuff
Thanks for all your invaluable suggestions and encouragement.
To British Petroleum Company and JATCAFA nongovernmental organization
Thanks for the financial support you provided.
To my groupmates and friends.
Thanks for all the fun times.
To my mom, dad, sister and brother
Thanks for your continuing support and trust.
Eventually thanks to KAPPA
For providing us with the Rubis-simulator.

May 2017 Azad Almasov
Petroleum and Natural Gas Engineer

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ABBREVIATIONS

API	**:** American Petroleum Institute
BHP	**:** Bottomhole Pressure
CHOPS	**:** Cold Heavy-Oil Production with Sand
DOE	**:** Department Of Energy
EOR	**:** Enhanced Oil Recovery
GOR	**:** Gas-Oil-Ratio
LLF	**:** Late-Linear Flow
PVT	**:** Pressure-Volume-Temperature
RB	**:** Reservoir Barrel
SAGD	**:** Steam-Assisted Gravity Drainage
SCF	**:** Standard Cubic Feet
STB	**:** Stock Tank Barrel
SI	**:** International System of Units
THAI	**:** Toe to Heel Air Injection
VAPEX	**:** Vapor-Assisted Petroleum Extraction

SYMBOLS

A	: Drainage area, ft^2
a_H	: Total width of reservoir perpendicular to the wellbore, ft
B	: Formation volume factor, RB/STB
b_H	: Length in direction parallel to wellbore, ft
C	: Wellbore storage coefficient, RB/psi
c	: Isothermal compressibility coefficient, psi^{-1}
C_H	: Geometric shape factor, dimensionless
c_f	: Isothermal compressibility coefficient of formation, psi^{-1}
c_o	: Isothermal compressibility coefficient of oil, psi^{-1}
c_t	: Total isothermal compressibility coefficient, psi^{-1}
D	: Depth, ft
D_{dyn}	: Depth to the dynamic level of liquid, ft
D_{mp}	: Depth to the middle of the reservoir, ft
D_p	: Depth to the pump, ft
D_{st}	: Depth to the static level of liquid, ft
D_{top}	: Depth to the top of the reservoir, ft
D_x	: Longest distance between horizontal well and x boundary, ft
d_x	: Shortest distance between horizontal well and x boundary, ft
D_y	: Longest distance between tip of horizontal well and y boundary, ft
d_y	: Shortest distance between tip of horizontal well and y boundary, ft
D_z	: Longest distance between horizontal well and z boundary, ft
d_z	: Shortest distance between horizontal well and z boundary, ft
h	: Net formation thickness of the reservoir, ft
IP	: Increase of production, %
J	: Productivity index, STB/D-psi
k	: Permeability, mD
k_h	: Horizontal permeability, mD
k_v	: Vertical permeability, mD
k_x	: Permeability in x-direction, mD
k_y	: Permeability in y-direction, mD
k_z	: Permeability in z-direction, mD
L	: Length of the reservoir, ft
L_w	: Completed length of horizontal well, ft
p	: Pressure, psi
p_i	: Initial reservoir pressure, psi
p_R	: Reservoir pressure, psi
p_{wf}	: Flowing BHP, psi
p_{xy}	: Parameter in horizontal well analysis equations
p_{xyz}	: Parameter in horizontal well analysis equations
p_y	: Parameter in horizontal well analysis equations
Q	: Cumulative production, STB
Q_{ver}	: Cumulative production of vertical well, STB
Q_{int}	: Cumulative production of intersected wells, STB

$\mathbf{q_{sc}}$	**:** Flow rate at standard condition, STB/Day
$\mathbf{q_{v}}$	**:** Flow rate of the vertical well, STB/Day
$\mathbf{q_{int}}$	**:** Flow rate of the intersected wells, STB/Day
r	**:** Radius of investigation of the reservoir pressure, ft
$\mathbf{r_{w}}$	**:** Radius of the wellbore, ft
s	**:** Skin factor, dimensionless
S	**:** Saturation, fraction of pore volume
$\mathbf{s_{d}}$	**:** Skin caused by formation damage, dimensionless
$\mathbf{s_{p}}$	**:** Skin resulting from an incompletely perforated interval, dimensionless
t	**:** Time, days (in the plots), hours (in the equations)
V	**:** Volume, m^3 or Bbl
ΔV	**:** Change in volume, Bbl
X	**:** Horizontal axis of Cartesian coordinate system
Y	**:** Vertical axis of Cartesian coordinate system
Δp	**:** Pressure change since start of transient test, psi
α	**:** Degree of inclination between vertical part and horizontal part of the intersected wells, in degree
γ	**:** Pressure gradient, psi/ft
ρ	**:** Density, lbm/ft^3
μ	**:** Viscosity of the oil, cP
ϕ	**:** Porosity, dimensionless

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EFFECT OF INTERSECTED WELLS CONFIGURATION ON PRODUCTIVITY

SUMMARY

Hydrocarbons are classified as retrograde gases, dry gases, wet gases, volatile oil and black oil depending on their PVT (Pressure Volume Temperature) properties. If only oil is considered, it is categorized based on specific gravity (API gravity) range: light oils (>30^o API), intermediate oil (20^o—30^o API), heavy oil (10^o—20^o API) and the heaviest one- extra heavy oils (<10^o API).

Heavy oils occur in shallow reservoirs where reservoir temperature and pressure is much lower than other type of oils. Therefore, gases existing in oil liberate from oil, and oil becomes dead oil in which there is only one phase. This increases oil viscosity and density. Heavy oil viscosity is higher than 100 cP, even extra heavy oils have more than 100000 cP viscosity.

Having high density and viscosity, heavy oils hardly move in porous media. And if we consider that reservoir pressure is very low, it is impossible for heavy oil to be extracted by its natural energy. Even using conventional ways such as water injection, gas injection, gas-lift etc. it is difficult to recover heavy oils. That is why, if secondary recovery methods are not enough to extract heavy oil, tertiary recovery methods can be used to extract heavy oil. These recovery methods are also called Enhanced Oil Recovery (EOR) methods. There are a variety of heavy oil recovery methods. However, they can be categorized generally into two main groups: thermal and non-thermal recovery methods. Mostly used methods are thermal recovery methods. Nonetheless, non-thermal recovery methods are also useful and beneficial.

In non-thermal recovery methods, using different types of pumps is widely used in the world. The principle of the pumps is the same- to create pressure difference inside the well, even though they have totally different structures. These pumps are mostly used in the vertical wells. However, it could be more beneficial to use pumps in horizontal well structure, because in horizontal well we can have much more area open to flow. The main problem is that it is hard to use pumps in horizontal wells, especially deeper part of horizontal wells. Horizontal wells are drilled with deviation, therefore, pumps cannot work at lower part of horizontal wells due to friction. Due to friction between pump and wellbore, there can be breaking of the pump inside the wellbore. Therefore, it will require a fishing process which is expensive.

In this work, the solution to the problem stated above is proposed. Using intersected wells instead of the horizontal well can be the solution to the problem. Using vertical well intersecting with a horizontal well can give the opportunity to use the pump in vertical well at whatever depth we want. Therefore, we can get the benefit of using the pump as well as the benefit of using horizontal well. In this work, the performance of such a configuration is investigated using a synthetic example. Using the Rubis-simulator, the reservoir and heavy oil are modeled and using this fictional field, different cases are investigated. Single phase, slightly compressible fluid is used since heavy oil is dead oil. Square shaped reservoir with no-flow boundary is used for the cases. The effects of horizontal well length, depth, location, and inclination angle on the performance of the heavy oil field is studied. The reasons for the behavior of reservoir pressure, flow rate and cumulative oil production are also explained using analytical equations. After an investigation, the best case is to use intersected wells having the longest length in the center of the field, in the middle of the reservoir. For the reservoir having higher anisotropy shows higher oil rate for the higher degree of inclination of intersected wells.

KESİŞEN KUYULAR KONFİGÜRASYONUNUN VERİMLİLİK ÜZERİNE ETKİSİ

ÖZET

Hidrokarbonlar, PVT (Basınç Hacim Sıcaklık) özelliklerine bağlı olarak, retrograd gazlar, kuru gazlar, ıslak gazlar, uçucu petrol ve petrol olarak sınıflandırılır. Petroller API gravitesine gore hafif petrol (> 30^o API), orta petrol (20^o-30^o API), ağır petrol (10^o-20^o API) ve ekstra-ağır petrol (<10^o API) olarak isimlendirilir.

Rezervuar sıcaklığı ve basıncının diğer türdeki petrollere göre çok daha düşük olduğu derin olmayan rezervuarlarda ağır petroller oluşur. Bu nedenle, petrol içinde bulunan gazlar petrolü serbest bırakır ve petrol yalnızca bir fazın bulunduğu ağır petrol olur. Bu, petrol viskozitesini ve yoğunluğunu arttırır. Ağır petrollerın viskozitesi 100 cP'den yüksektir, daha ağır petroller ise 100000 cP gibi yüksek bir viskoziteye sahiptir.

Yüksek yoğunluk ve viskoziteye sahip olan ağır petroller, gözenekli ortamda pek hareket edemez. Ve eğer rezervuar basıncının çok düşük olduğunu düşünürsek, ağır petrolün rezervuarın kendi doğal enerjisi ile üretilmesi imkansızdır. Su enjeksiyonu, gaz enjeksiyonu ve gaz-lift gibi geleneksel yolları kullanılsa bile, ağır petrolleri geri kazanmak zordur. Ağır petrolleri geri kazanım yöntemlerinin farklı çeşitleri vardır. Bu yöntemler genellikle iki ana grupta sınıflandırılabilir: termal ve termal-olmayan kurtarma yöntemleri. Çoğunlukla kullanılan yöntemler termal kurtarma yöntemleridir.

Termal olmayan kurtarma yöntemlerinde farklı pompa tiplerini kullanmak daha yaygındır. Pompaların çalışma şekli onların yapılarının tamamen farklı olmasına rağmen aynıdır. Buradaki temel amaç kuyu içinde basınç farkı yaratmaktır. Bu pompalar çoğunlukla dikey kuyularda kullanılır. Bununla birlikte, bu pompaları yatay kuyularda kullanmak daha fazla yarar sağlayabilir, çünkü yatay kuyuların akış alanı daha büyüktür. Fakat yatay kuyularda pompa kullanmak dikey kuyulara göre çok daha zordur. Yatay kuyular yönlü olarak delinir ve bu durum sürtünme ve kırılmalara neden olur. Bu nedenle pompalar yatay kuyuların derin kısımlarında çalışamazlar.

Bu çalışmada, yukarıda belirtilen sorunun çözümü önerilmiştir. Yatay kuyu yerine yatay ve dikey kuyuların kesişdiği bir model yukarıda belirtilen problemin çözümü olarak önerilebilir. Bu modelde pompayı dikey kuyuda kullanmak daha yüksek üretim elde etme fırsatı verebilir. Bu çalışmada sentetik veri kullanılarak yatay ve dikey kuyu kesişim modelinin performansı araştırılmıştır. Rezervuar ve ağır petrol özellikleri Rubis-simülatörü kullanılarak modellenmiştir ve bu model kullanılarak farklı senaryolar incelenmiştir. Ağır petrollerin çoğu gaz fazını içermediğinden, tek fazlı, az-sıkıştırılabilir varsayımı yapılır. Senaryolar için akış olmayan sınıra sahip kare şeklinde rezervuar kullanılmıştır. Ağır petrol sahasının performansı olarak yatay kuyu boyunun, derinliğinin, lokasyonunun ve eğim açısının etkileri incelenmiştir. Rezervuar basıncının, debinin ve kümülatif petrol üretiminin davranış nedenlerinin analitik denklemlerle açıklanması verilmiştir. İnceleme sonrasında rezervuarın ortasında ve

kesişen kuyuların arasındaki mesafenin en büyük olduğu durum en iyi senaryo olarak belirlenmiştir. Eğim derecesinin etkisi rezervuarın anizotropisine bağlı olduğu görülmüştür. Yüksek anizotropiye sahip olan bir rezervuarda kullanılan kesişen kuyu modelinde daha yüksek eğim derecesi kullanmak daha yüksek petrol üretimi sağladığı görülmüş.

Bilindiği gibi ağır petrol konvensiyonel yöntemler kullanılarak üretilemez. Bu nedenle günümüzde çeşitli kurtarma yöntemleri kullanılmaktadır. Ağır petrolün pompa ile yüzeye çıkarılmasında kesişen kuyular kullanmak bu çalışmada önerilen bir yöntemdir.

Sürtünmeden dolayı yatay kuyunun daha derin kısmında pompayı doğrudan kullanma imkanı bulunmadığından yatay kuyu yerine kesişen kuyular kullanılır. Bununla birlikte kesişen kuyuları kullanarak pompa, yatay kuyunun ucu ile kesişen düşey kuyunun en derin kısmına kadar indirilebilir. Aynı zamanda bu modelde yatay kuyu yerine rezervuar parametrelerine dayanarak eğimli kuyu da kullanılabilir. Böylece yatay kuyunun akışa açık alanı arttırarak, üretime vermiş olduğu yararını kullanarak pompa ile düşey kuyunun daha derin kısımlarında ağır petrol üretimi yapılabilir. Böylece hem pompa hem de düşey kuyu kullanımından daha fazla yarar sağlanabilir.

Bu çalışmada çeşitli durumlar araştırılmış, kesişen kuyular için avantajlar ve dezavantajlar tartışılmıştır.

Bu çalışma sırasında aşağıdaki sonuçlara ulaşılmıştır:

1. Rubis simülatörü için kütle-denge doğrulaması yapıldı ve kütle-denge denklemi sonuçları ile rubis simülatöründen alınan sayısal sonuçlar arasında uyum sağlandı.

2. Babu-Odeh denklemi kullanılarak simülatörden gelen sonuçlar için analitik kıyaslama yapıldı. Kıyaslama sonucunda birerbir uyuşma sağlandı.

3. Kesişen kuyularda pompa kullanımı yatay kuyularda pompa kullanımından iki kat daha fazla yarar sağladığı görülmüştür.

4. Farklı yatay kuyu uzunluklarının kullanımının üretime olan etkisi araştırılmıştır. Sonuç olarak en uzun kesişen kuyuda daha fazla üretim gözlenmiş bunun yanı sıra basınç azalımı daha fazla olmuştur. Buradan da anlaşılacağı gibi en uzun kesişen kuyu en iyi durumu ifade etmektedir. Bunun nedeni akışa açık alanın daha uzun yatay kuyularda daha fazla olmasıdır.

5. Farklı derinliklerde kesişen kuyu durumları kullanımının üretime olan etkisi araştırılmıştır. En iyi sonuçlar orta derinlikte kullanılan kesişen kuyularda elde edilmiştir. Sonuç olarak orta derinlikte kullanılan kesişen kuyuda üretim diğer derinliklerde kullanılan kesişen kuyulara göre daha fazladır. Bunun yanı sıra basınç azalımı da daha fazla olmuştur. Bunun nedeni kesişen kuyuların rezervuarın orta derinliğinde olması durumunda yatay kuyunun rezervuarın üst ve alt sınırlarından diğer derinlik durumlarına göre daha uzak olduğu için debinin sınırlardan daha az etkilenmesidir.

6. Farklı lokasyonlarda kesişen kuyu durumlarının üretime olan etkisi incelenmiştir. En iyi sonuçlar rezervuarın merkezinde kullanılan kesişen kuyuda elde edilmiştir. Sonuç olarak rezervuarın ortasından kullanılan kesişen kuyuda üretim oranı diğer lokasyonlarda kullanılan kesişen kuyulara göre daha fazladır. Bunun yanı sıra basınç azalımı da daha fazla olmuştur. Bunun nedeni lokasyonun rezervuarın merkezi olması durumunda kesişen kuyuların diğer lokasyon durumlarına göre rezervuar sınırlarından daha uzak olması ve rezervuar sınırlarından daha az etkilenmesidir.

7. Anizotropik rezervuarda (kv/kh= 0.01) farklı eğim açısına sahip kesişen kuyu durumlarının üretime olan etkisi araştırılmıştır. En iyi sonuçlar daha fazla eğim açısına sahip kesişen kuyularda görülmüştür. Sonuç olarak daha fazla eğim açısına sahip kesişen kuyularda daha fazla üretim olduğu görülmüştür. Bunun yanı sıra basınç azalımı da daha fazla olmuştur. Bunun nedeni anizotropik rezervuarda yatay yöndeki akış debisinin düşey yöndeki akış debisine göre yüz kat daha fazla olmasıdır.

8. Farklı kuyu çaplarına sahip kesişen kuyular incelenmiştir. En iyi sonuçlar daha büyük kuyu çapına sahip kesişen kuyularda görülmüştür. Sonuç olarak daha büyük kuyu çapına sahip olan kesişen kuyular diğerlerine göre daha fazla üretim sağlamaktadır. Bunun yanı sıra daha fazla basınç azalımı görülmüştür. Bunun nedeni daha büyük kuyu çapına sahip kesişen kuyularda diğer durumlara göre akışa açık alanın daha fazla olmasıdır.

9. Farklı kirlenme zonlarına sahip kesişen kuyular incelenmiştir. En iyi sonuçlar kirlenme zonu düşük olan kesişen kuyularda görülmüştür. Sonuç olarak düşük kirlenme zonuna sahip kesişen kuyularun üretim miktarı yüksek kirlenme zonuna sahip kesişen kuyulardan daha fazladır. Bunun nedeni daha büyük kirlenme zonlarındaki geçirgenliğin diğer durumlara göre daha küçük olmasıdır.

1. INTRODUCTION

Four thousand years ago, bitumen from natural leakage was employed in the architecture of the walls and towers of Babylon. The earliest known wells were drilled in China in 347 BC to a depth of 800 feet and were drilled using bits connected to bamboo poles. However, in the Middle East using the petroleum was established by the 8th century in Baghdad to light up the streets. In the 9th century, the first distillation took place in Baku, Azerbaijan, to produce naphtha, which formed the basis igniting *Greek fire* (Cobb, 1995).

In North America, in Oil Springs, Ontario, Canada the first oil well was drilled in 1858 by James Miller Williams. Petroleum is found in the microscopic pores of sedimentary rocks. By sedimentary rocks, it is meant sandstone and limestone which are important by means of relevant reservoir parameters such as necessary permeability to let the oil a path through porous media. Here it is necessary to say that not all pores contain petroleum, but are filled with brine. Nevertheless, discovered oil fields are not always exploited, that is, the oil can be so remote that transport costs would be high (Speight, 2013a).

Petroleum and crude oil are referred to as conventional oil which is available approximately in every part of the world, that is, here *conventional* means that they are such light and of low viscosity that they can be recovered by conventional ways, However, heavy oil is *unconventional* and it cannot be recovered using conventional methods, because it is heavier and has more viscosity (Banerjee, 2012).

The international definition, firstly discussed at the World Petroleum Congress in 1980, and the U.S Department of Energy (DOE) is the following: heavy crude oil is explained as *dead oil* (gas-free oil) when its density is below 21^{o} API and its viscosity is between 100 and 10000 centipoise (cP) at original reservoir temperature. Dead oil is easy to handle by standard techniques to measure the properties. However *live oil* which contains more gas is difficult to obtain and analyze (Banerjee, 2012).

Petroleum is a mixture that consists of hydrocarbon components and other non-hydrocarbon components such as sulfur, nitrogen, and oxygen metals and other elements and is generally in a liquid state and is often called *crude oil* as well. Most heavy oils were before conventional oil, but after having migrated to surface area it was degraded by bacteria as well as weathering, and therefore, lighter hydrocarbons left. Carbon takes more portion of hydrocarbons existing in heavy oils than hydrogen than that of conventional oil. Therefore, heavy oil requires refinery processes to become commercially useful hydrocarbon material (Speight, 2013b).

1.1 Statistics

Today, there are wide sources of heavy oil in Canada, Russia, Venezuela, the United States, and many other countries. Venezuela has 47 to 76 billion barrels of proven reserves, according to the oil industry and U.S. Department of Energy (DOE) estimates. However, Venezuela claims that they have 1.2 trillion barrels of unconventional oil reserves in the heavy oil field stretching from the mouth of the Orinoco River near Trinidad down the east side of the Andes mountains. Furthermore, heavy oil deposits of Venezuela might rival tar sand deposits of Canada (Speight, 2013a).

Oil production and oil consumption for the world by region are plotted, using data given in "BP Statistical Review of World Energy" report, and the comparison of consumption and production of the World is depicted as well (Figure 1.1 to 1.3).

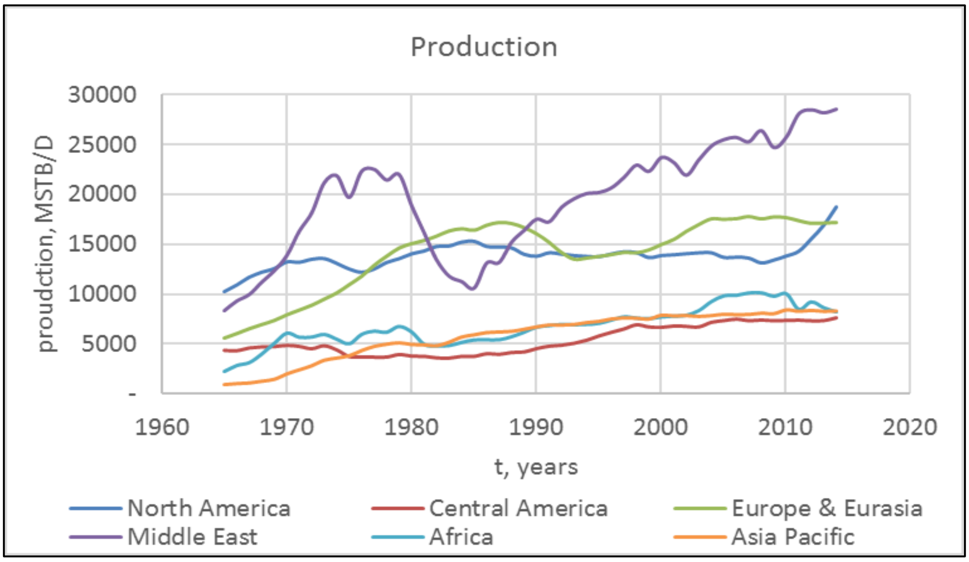


Figure 1.1: Oil production by regions (BP, 2016).

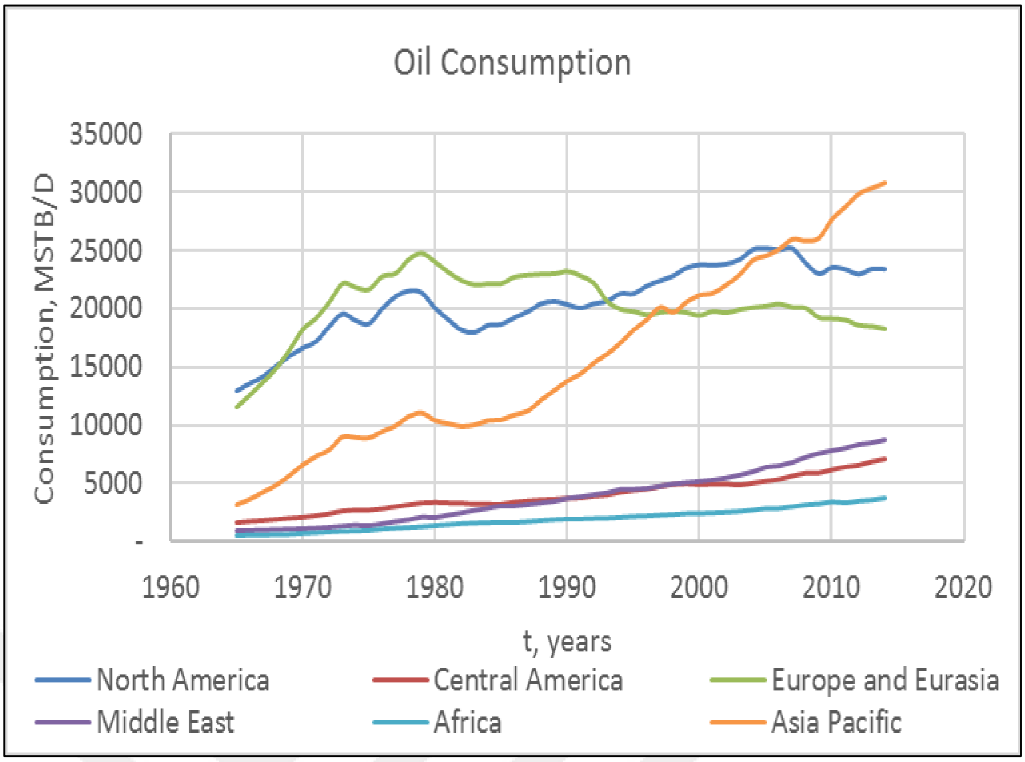


Figure 1.2: Oil consumption by regions (BP, 2016).

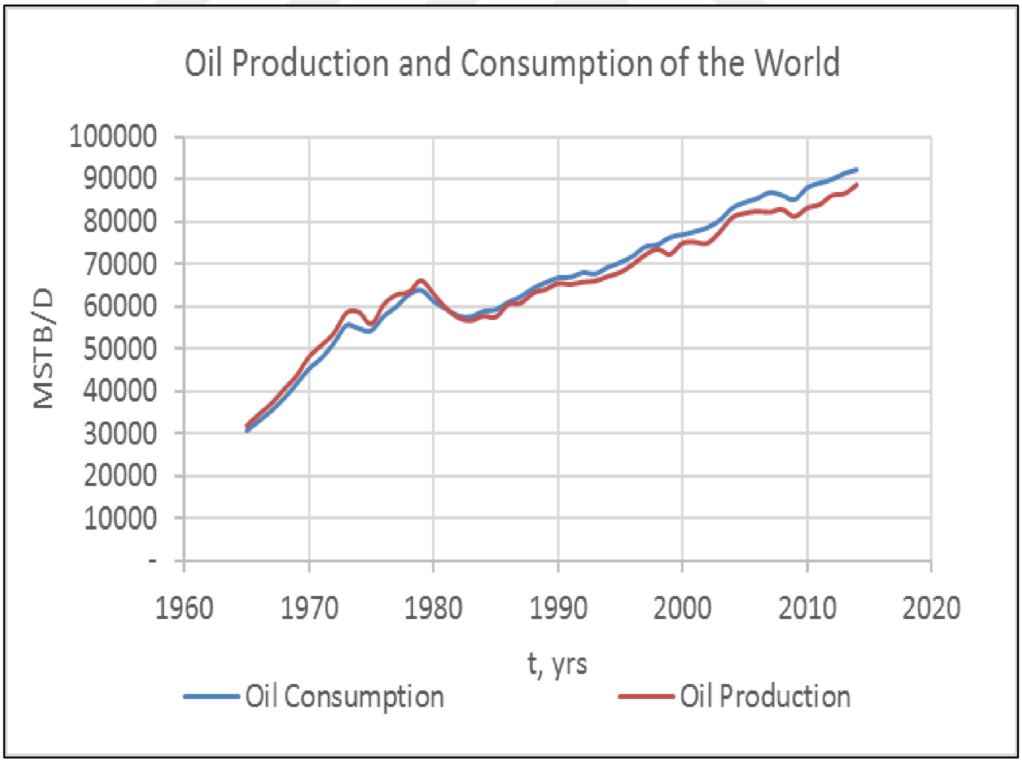


Figure 1.3: Oil consumption and production of the world (BP, 2016).

Oil production and consumption of Azerbaijan are plotted in the same graph (Figure 1.4). After 2003 Azerbaijan started to produce oil much more than previous years. Oil prices by their type are also depicted (Figure 1.5).

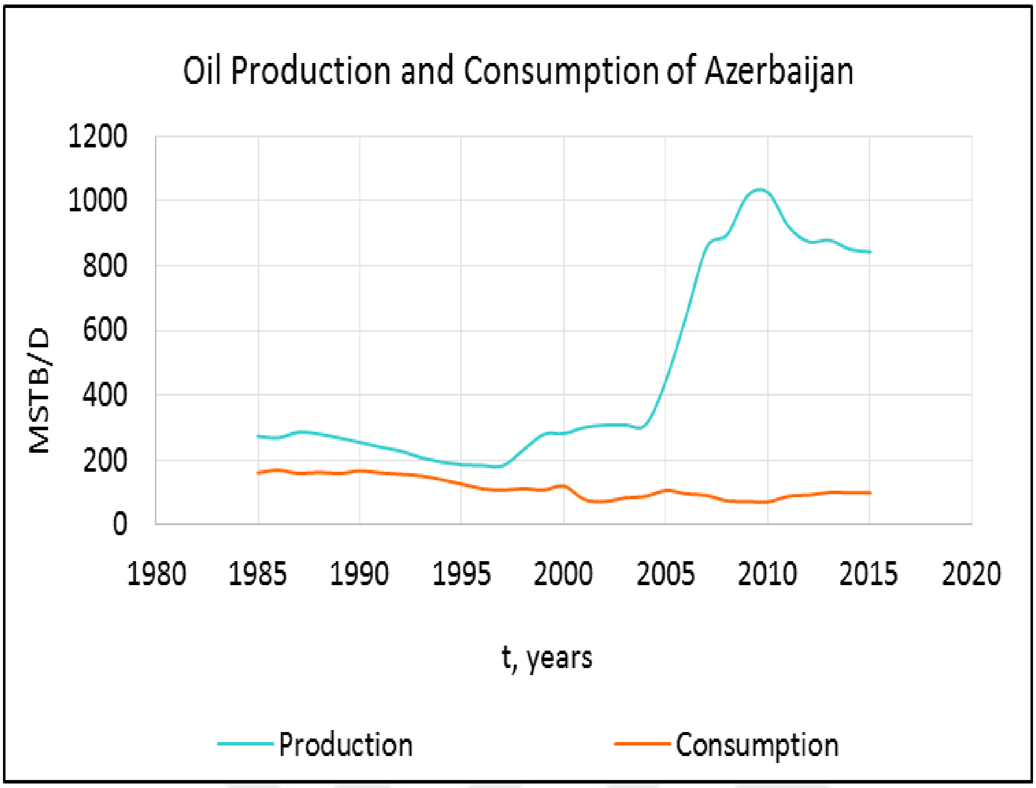


Figure 1.4: Oil consumption and production of Azerbaijan (BP, 2016).

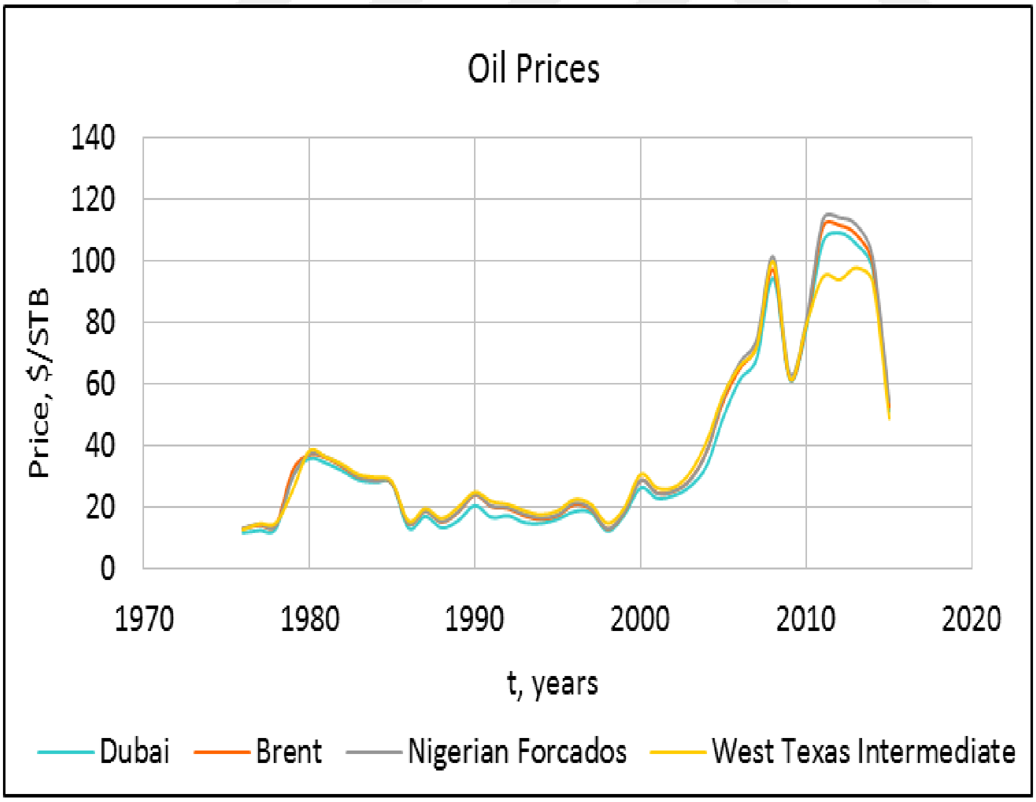


Figure 1.5: Oil prices (BP, 2016).

However, heavy oil production is not as much as conventional oil. Heavy oil production is given in Figure 1.6.

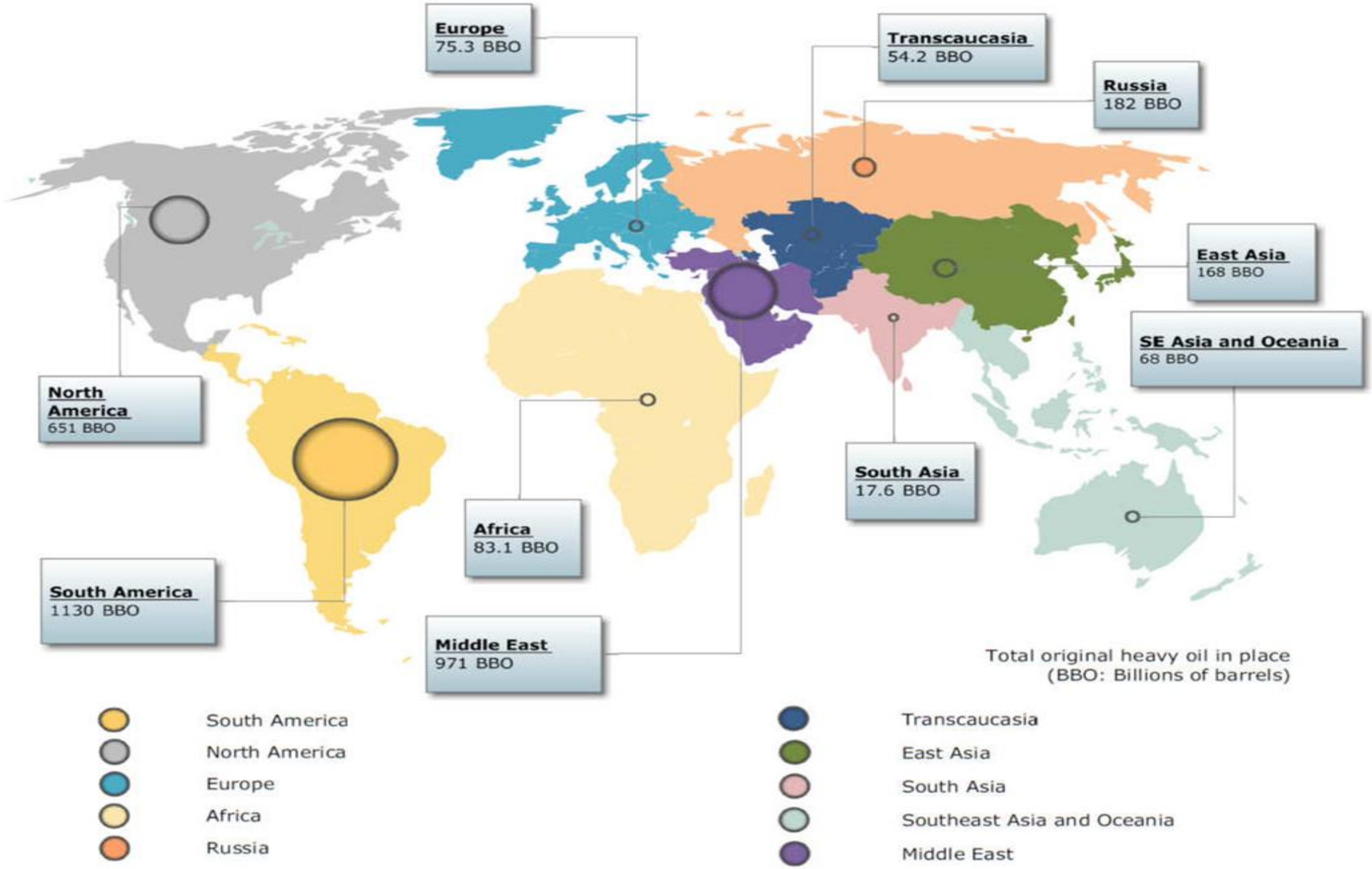


Figure 1.6: Heavy oil resources in the world (Çınar et al., 2011).

1.2 Basic Properties of Heavy Oils

In the reservoir, hydrocarbons can be dry gas; wet gas; retrograde gas; volatile oil; black oil. The oil shrinks when gas in it liberates. Therefore, its gas-oil-ratio (GOR) and formation volume factor (FVF) (*B*) are very low. Actually, it can be seen from the Figure 1.7 that as the molecular weight of hydrocarbon increases, its GOR and FVF decrease significantly. Actually, heavy oil is also one type of black oil, even though it was given separately in Figure 1.7.

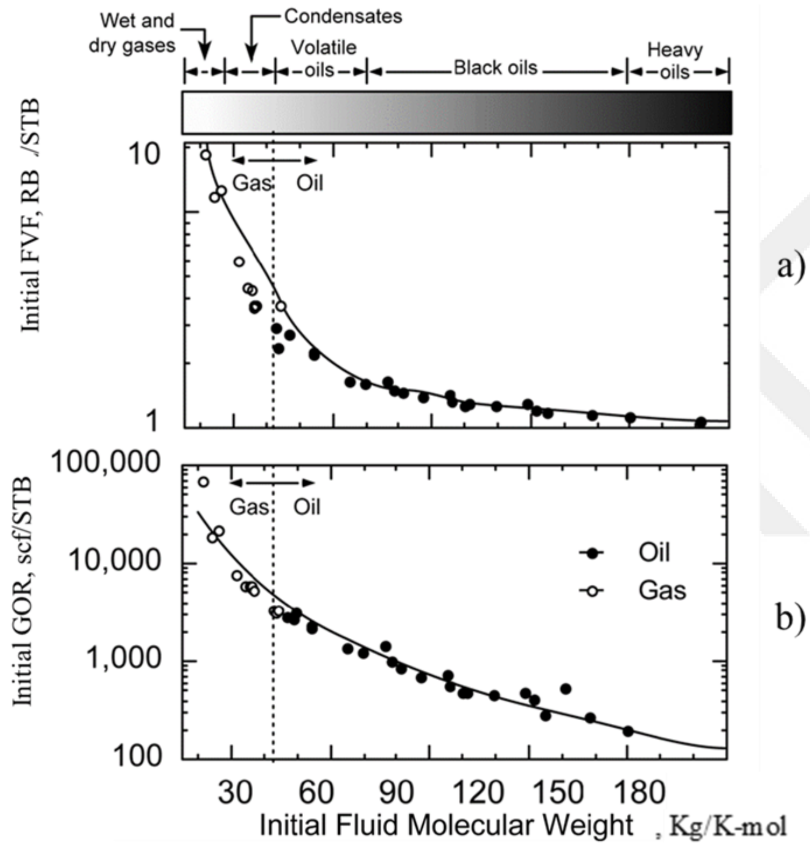


Figure 1.7: (a) Initial formation volume factor (FVF) and (b) initial dissolved GOR as a function of initial fluid molecular weight (Url-1).

Pressure-Volume-Temperature (PVT) properties are the properties that change with temperature and pressure, such as formation volume factor (*B*), compressibility (*c*), GOR etc. As to PVT properties of the reservoir, there are 5 types of reservoirs: dry gas, wet gas, retrograde gas, volatile oil and black oil. Below phase diagrams are plotted for each reservoir type (Figure 1.8, 1.9, 1.10, 1.11 and 1.12). On these graphs the dew point line shows where the first liquid molecule is formed, and the bubble point line is where the first gas bubble is formed. In this envelope, fluid exists in two-phase form.

Each plot has separator point and the line showing pressure path in the reservoir (Figures 1.8-1.12). Separator point shows separator condition, that is, pressure and temperature in the separator. In black oil, volatile oil, retrograde gas and wet gas separator pressure and the temperature are in the envelope, which means at separator condition fluid is in two phase form (Figures 1.8-1.11). However, for dry gas, at separator condition, there is only one phase, gas phase (Figure 112). Pressure path line shows how fluid phase change throughout this path. If we look at the pressure path line of black oil and volatile oil, at point 1 fluid is in the liquid phase. As pressure decreases to the point 2 which is on the bubble point line, the first gas bubble is formed. And finally when pressure further decreases to the point 3, fluid exists in two-phase form (Figures 1.8 and 1.9). However, in retrograde gas, as pressure decreases from point 1 to point 2 it reaches from gas phase to dew point where the first liquid molecule is formed. When the pressure reaches to point 3, the liquid in two phase is formed (Figure 1.10). In wet gas and dry gas, throughout pressure path line in the reservoir fluid is in gas phase always (Figures 1.11 and 1.12). However, as it was stated above, wet gas at separator condition is in two-phase form, while a dry gas is in one-phase form. In volatile oil reservoirs, reservoir temperature and pressure are closer to the critical point than those in black oil reservoirs (Figure 1.8 and 1.9). Therefore, in volatile oil reservoirs, GOR is much higher than that in black oil reservoirs.

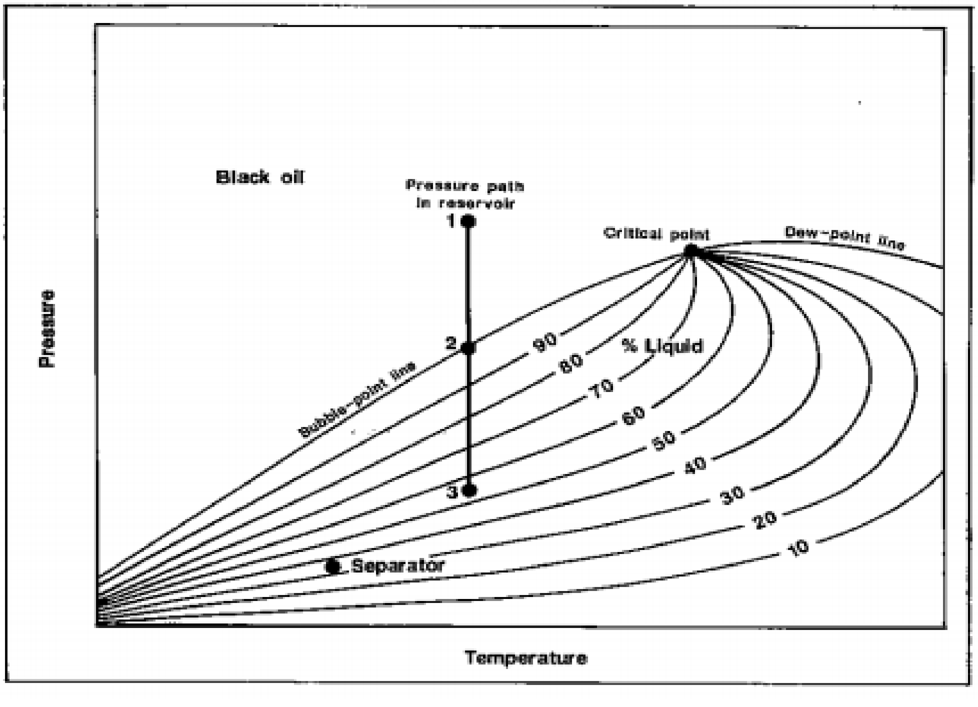


Figure 1.8: Phase diagram of typical black oil (McCain, 1990).

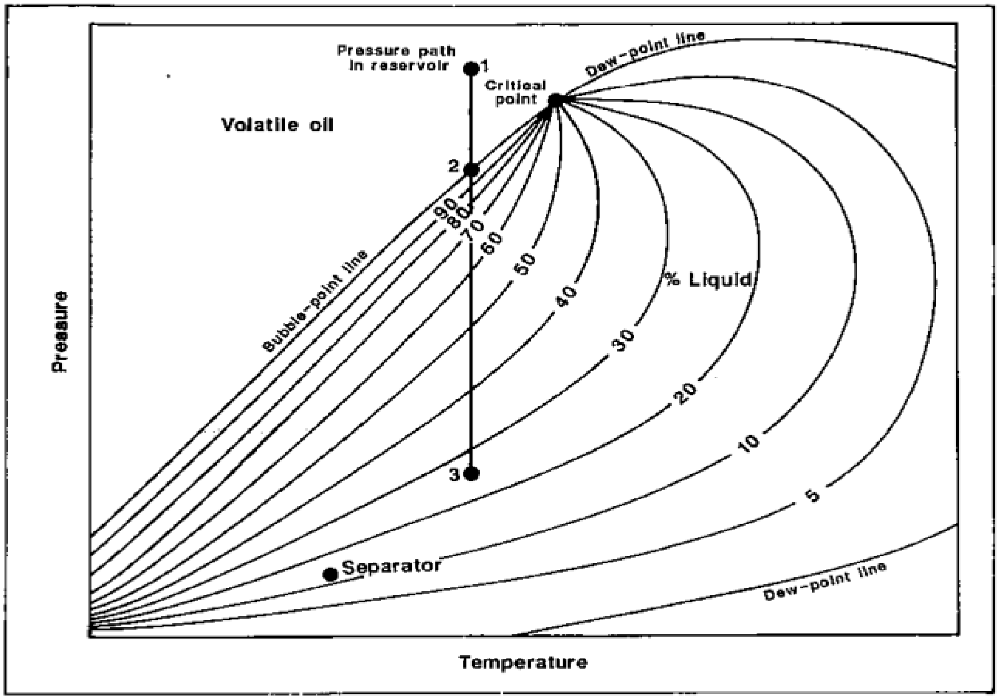


Figure 1.9: Phase diagram of volatile oil (McCain, 1990).

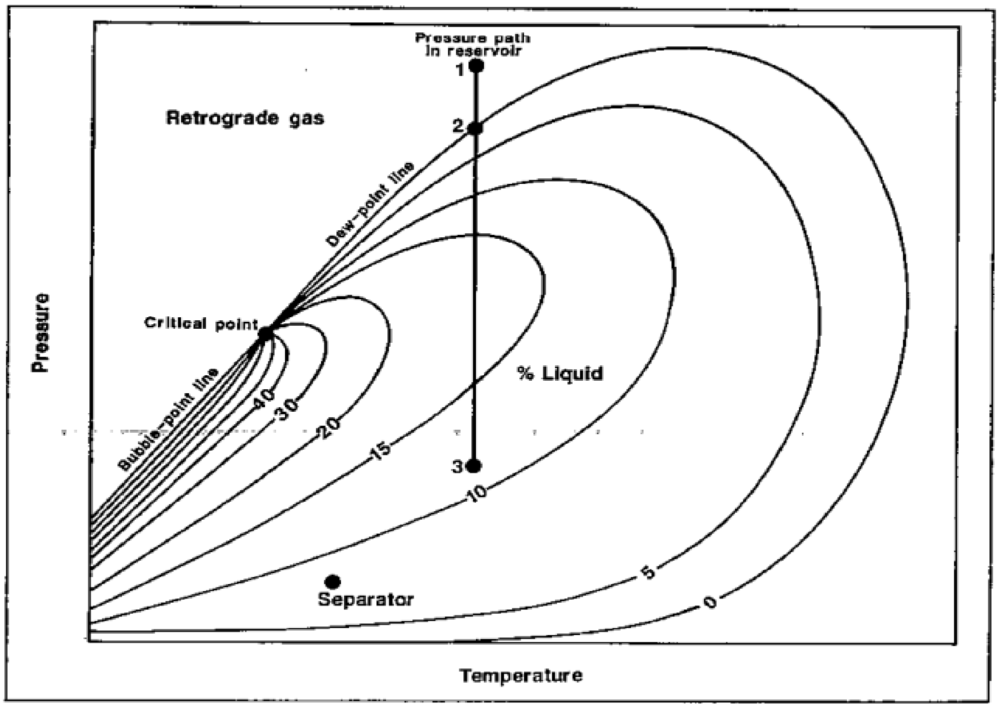


Figure 1.10: Phase diagram of retrograde gas (McCain, 1990).

It can be observed from Figures 1.13-1.16 that the critical point here is bubble point pressure where almost all PVT properties can behave differently before and after it (Figures 1.13, 1.14, 1.15 and 1.16). We can see as well, bubble point pressure in heavy oil reservoirs is much lower than in light oil reservoirs.

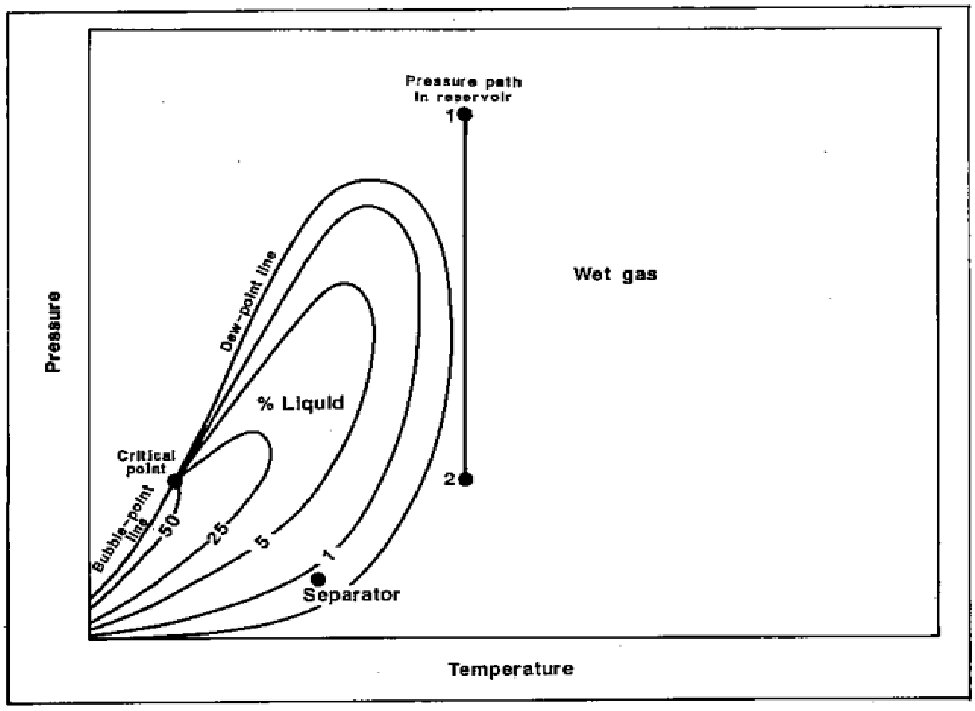


Figure 1.11: Phase diagram of wet gas (McCain, 1990).

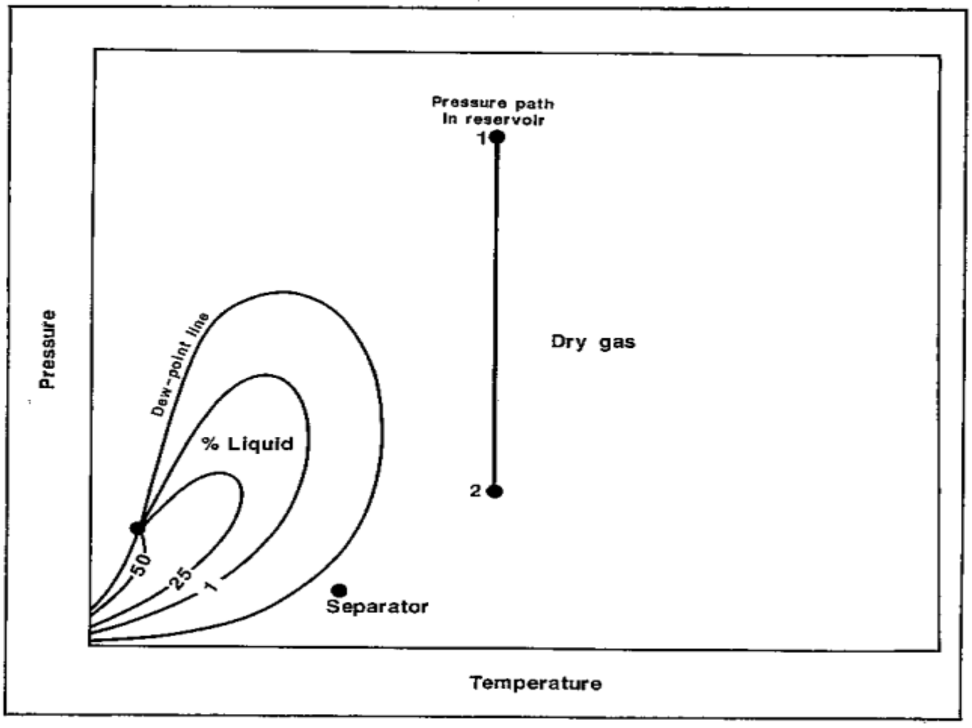


Figure 1.12: Phase diagram of dry gas (McCain, 1990).

If we look at the Figure 1.13 of viscosity vs temperature plot we can see that at high temperatures they are the same. This is because, at high temperatures, gas and some short-chained paraffin liberate light oil and therefore the decrease of viscosity is steady, on the other hand, in heavy oil, viscosity decreases as temperature goes high since the interaction between molecules becomes weaker. As I have mentioned before, because of long chained compounds and metals the density of heavy oil is higher than that of light oil (Figure 1.14). As pressure goes up more gas dissolve in oil, thus, its density decreases. After bubble point pressure, as pressure increases the volume of oil decreases, therefore, its density starts to increase (Figure 1.14). Because heavy oil is found in mostly shallow depths, reservoir temperature and pressure are lower. Therefore, most of the dissolved gas leaves heavy oil. Therefore, its GOR is less than that of light oil reservoirs (Figure 1.15). As pressure increases more gas dissolves in it, and thus, GOR increases. At bubble point pressure it reaches a plateau since there will not be any gas dissolving after that point (Figure 1.15). As dissolved gas is lower in heavy oil reservoirs, FVF is also less than that of light oil reservoirs (Figure 1.16). As pressure increases, the volume of the oil in the reservoir increases because of dissolved gas. After bubble point pressure, further pressure increase causes density to increase, therefore, FVF decreases (Figure 1.16). Compressibility for light oils, since they contain gas phase is different from heavy oil compressibility, that is, compressibility for light oil changes with pressure, thus with time, but for heavy oil compressibility change due to pressure is negligible, so we can assume compressibility of heavy oil as slightly-compressible. Another conclusion obtained from Figures 1.14-1.16 is that one of the main differences between heavy oils and light oils is that heavy oils have a much lower bubble point pressure. This is because they are made up of heavier hydrocarbon molecules. As PVT properties are so different from light oil, recovery methods are different as well.

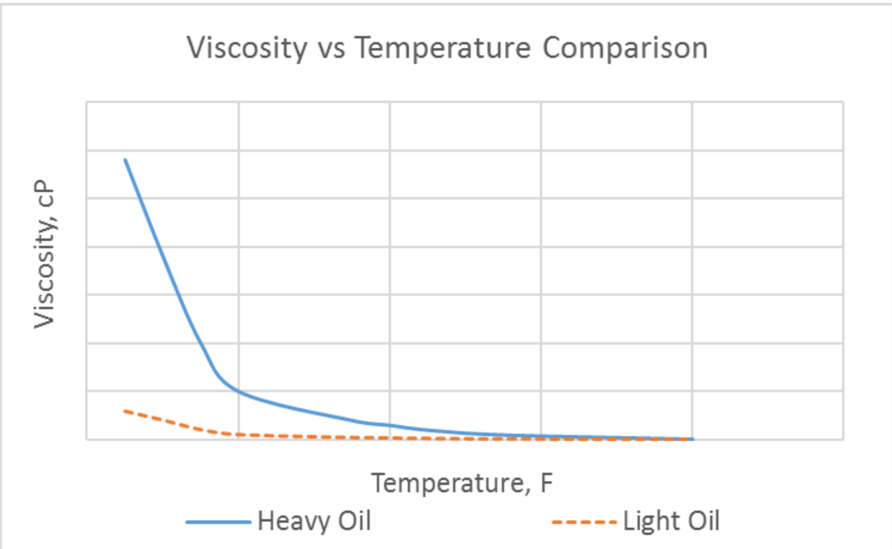


Figure 1.13: Viscosity vs temperature plot for heavy and light oils.

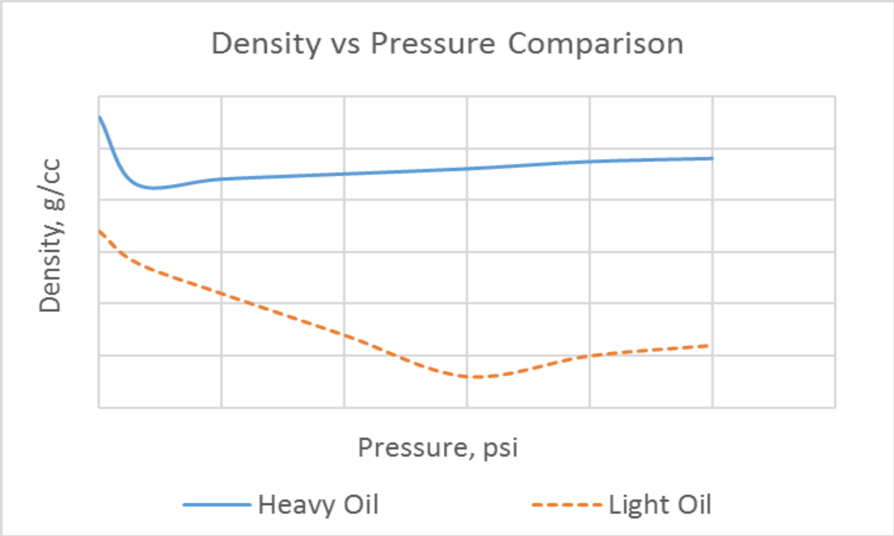


Figure 1.14: Density vs pressure plot for heavy and light oils.

Here it is worth to mention that in Figures 1.14—1.16 are given for the purpose of illustration, to show the behavior qualitatively rather than quantitatively.

Production rate is a function of heavy oil properties such as viscosity, compressibility, formation volume factor etc., and reservoir parameters such as permeability, skin factor etc.

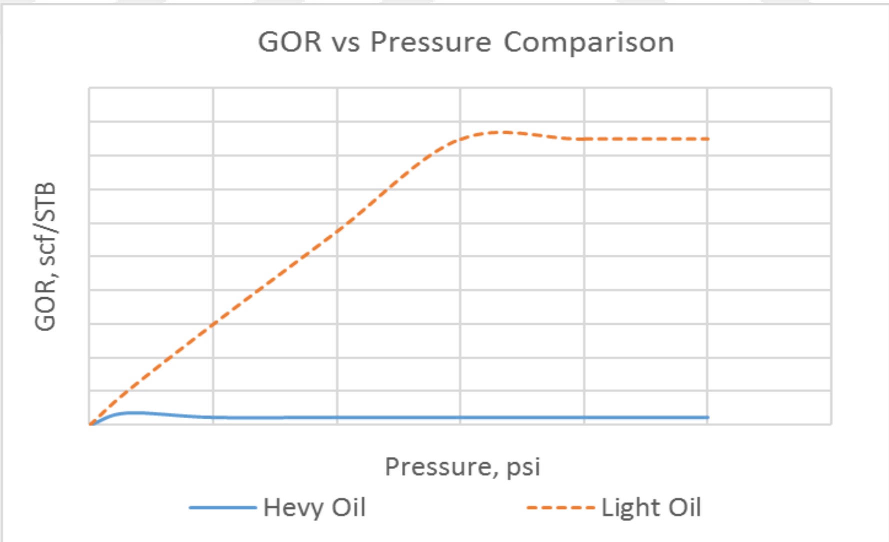


Figure 1.15: GOR vs pressure plot for heavy and light oils.

Production rates can vary due to number of factors like (1) reservoir geometry—primarily formation thickness and reservoir continuity, (2) reservoir pressure, (3) reservoir depth, (4) rock type and permeability, (5) fluid saturations and properties, (6) extent of fracturing, number of wells and their locations, (7) mobility—the ratio of the permeability of the formation to the viscosity of the oil. Production rate can be increased by applying different methods such as fracturing the reservoir to open new channels—to increase the permeability of the formation, injecting gas and water to increase the reservoir pressure, or lowering oil viscosity with heat or chemicals. (Speight, 2013b).

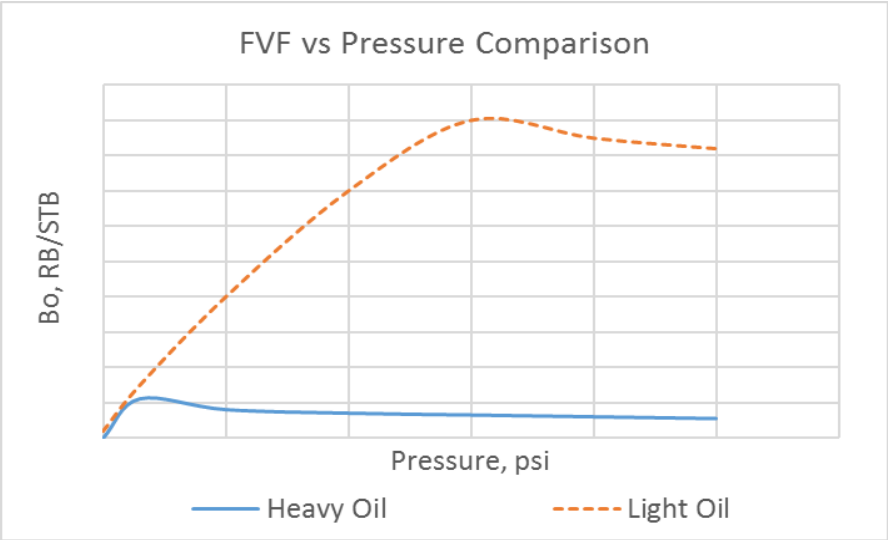


Figure 1.16: FVF vs pressure plot for heavy and light oils.

1.3 Recovery Methods of Heavy Oils

Typical recovery methods are as follow: primary, secondary recovery techniques, and tertiary recovery techniques. *Primary recovery* occurs at the very beginning of production, the petroleum in the reservoir trap is forced up to the surface naturally, by the expansion of the fluid existing in the trap because of realizing the pressure in the reservoir. There can be other reasons for expansion such as dissolved gas or existing aquifer which support the pressure of the reservoir. *Secondary recovery* is the recovery that starts after the time when natural energy is not enough to recover the existing oil in the trap. It tries to maintain reservoir pressure which plays the driving role. There are several techniques for supporting pressure such as injecting gas forcing the oil above it and injecting water to the aquifer. Since it requires some cost to inject natural gas, CO_2 or N_2 are used to inject them to the oil in the method of gas-lift. *Tertiary recovery* is the third period after the secondary recovery not being enough to extract oil in place, which is very expensive compared to secondary recovery. It involves injecting steam, detergents, solvents, even bacteria and bacterial nutrient solutions to change petroleum’s some properties to the relevant level such as wettability, surface tension, density, permeability (Speight, 2013a).

Recovery processes depend not only on the oil characteristics but also reservoir characteristics, that is, reservoir temperature, reservoir pressure and pour point of the oil.

1.3.1 Nonthermal recovery methods

There are various non-thermal recovery methods, and these methods vary from production using reservoir energy to enhanced oil recovery methods where assisted energy is needed to recover oil from the reservoir. These methods vary because of the properties of heavy oil as well as the properties of the reservoir (Selby et al., 1989).

The well-known nonthermal recovery methods are as follows:

1. Alkaline flooding
2. Carbon dioxide flooding
3. Polymer flooding
4. Micellar—polymer flooding
5. Cold production
6. Cold heavy oil production with sand (CHOPS)
7. Microbial enhanced oil recovery
8. Vapor-Assisted Petroleum Extraction (VAPEX)
9. Hydraulic fracturing (Speight, 2013b).

Below, some of the methods given above are discussed briefly. Using these recovery methods, they can be combined with the horizontal well application. In the methods given above: CHOPS, VAPEX and cold production use pumps and horizontal wells.

Cold production is one of the nonthermal recovery methods that uses pumping equipment without applying heat. The basis of the cold production is that the oil production and recovery improve when sand production occurs naturally. Sand production is a function of (1) the absence of clay minerals and cementation materials, (2) the viscosity of the oil, (3) the producing water cut and GOR, and (4) the rate of pressure drawdown (Chugh et al., 2000).

In *VAPEX* method two parallel horizontal wells are drilled with about 15 ft vertical distance (Yazdani and Maini, 2008).

Cold heavy oil production with sand (CHOPS) is used as nonthermal recovery as well in unconsolidated sandstones. It increases permeability near wellbore because it reduces the amount of sand near the wellbore. It also prevents heavier hydrocarbons from plugging the zone near the wellbore (Speight, 2013b).

1.3.2 Thermal methods of recovery

Since the cost of finding new reserves is rising continuously, the oil industry, therefore, needs to focus on improving recovery factors of existing reservoirs. The high viscosities and low API gravity give rise to the major problems of heavy oil recovery (Szazs and Thomas, 1965).

So whatever the solution of the problem is, the main principles are to reduce viscosity and density of heavy oil or to improve reservoir relative permeability of heavy oil to improve the mobility ratio. Thermal recovery methods are applied mostly for only the purpose of reducing viscosity and density of heavy oil.

There are plenty of thermal recovery methods. Heat application can be generalized as either at the surface or in the wellbore or within the rock formation. Surface-generated heat requires transportation of this heated fluid to the reservoir effectively, but there can be a lot of heat loss due to convection and conduction. However, heat application at the surface is easy to control. Circulating of the hot fluid inside wellbore can be used to heat up the reservoir, but the main problem is heat loss during this method in the reservoir, that is, we heat up the strata where we do not need, and thus it affects economically (Szazs and Thomas, 1965).

Thermal enhanced oil recovery methods reduce viscosity and density of heavy oil and thus improve its mobility. However, this type of heavy oil recovery method does more than decreasing viscosity of heavy oil like improving important factors of heavy oil related to chemistry and oil- rock interactions that play a role in a heavy oil recovery (Lake and Walsh, 2004).

There are various thermal heavy oil recovery methods:

1. Hot-fluid injection
2. Steam injection
3. In-situ combustion
4. Toe to Heel Air Injection (THAI)
5. Steam-assisted gravity drainage (SAGD)

It is worth to give some data about use of horizontal wells in heavy oil recovery and application of horizontal well to different fields.

At the early time of heavy oil recovery, methods were focusing on vertical wells employing thermal methods. However, in the recent trends, using horizontal wells and non-thermal recovery methods are becoming as popular as vertical well applications and thermal recoveries (Ganesh, 1997).

Actually, horizontal well technology can be applied in both nonthermal recovery and thermal recovery methods. Horizontal well technology usually is used as a combination of other recovery methods such as SAGD.

For heavy oil reservoirs, as was mentioned before, recovery methods try to change fluid properties, mainly density and viscosity or reservoir and well property so as to achieve more production. And one of the way to achieve this is to enlarge the drainage area that is open to flow, and thus reduce the number of locations to be drilled within the reservoir by using horizontal well instead of vertical wells. This method was applied in Venezuela to one of the fields. The pump was used in horizontal well as well. The oil rate increase has been observed, and positive conclusions are achieved. In the cold production method, the response was 3 to 5 times better than that of a vertical well (Aura and Aquiles, 1996).

As a result of the experiment of horizontal well placement in Colombia, it economically maximized oil recovery. However, there were several challenges such as the high level of geological and well position uncertainty. The experience gained in that field has been used to develop other fields in Colombia (Jaime et al., 2012).

From the experienced application mentioned above, it can be said that horizontal well application on heavy oil recovery method is used widely. It can also be used with a combination of other methods. As a recovery method horizontal wells combined with pumps are used but not much. In the chapter below application of horizontal well with the pump is discussed, and review of the thesis is given.

1.4 Review of Thesis

In the next section, the problem statement is given. Here the problems associated with lowering a pump into the horizontal wells are introduced. A solution is proposed which is intersecting of a vertical well with a horizontal well. In the third chapter, the performance behavior of the intersecting wells configuration is studied by using a synthetic example. In this chapter, the effects of various parameters such as horizontal well length, the position of wells and etc. on the performance of the reservoir are given. Finally, the thesis ends with the conclusions section.

2. PROBLEM STATEMENT

Heavy oil has higher gravity and viscosity. In cases where the pressure of the reservoir is not sufficient to raise the level until the surface, pumps are required. The pump is a device that moves fluids (liquids or gases), or sometimes slurries, by mechanical action.

Even though a variety of pumps exist, their working principle is the same for most of them. Pumps are lowered to the well, and therefore, creating a pressure difference at the bottom, and thus the pressure difference pushes the oil up to the surface. Pumps are dynamic devices inside the well, therefore, it is used in vertical wells mostly. Even if we use pumps in horizontal wells, pumps cannot be lowered to the desired level (Figure 2.1 a).

No matter, what the type of the pump is, it is hard to use pumps in horizontal wells. As it is known, horizontal wells are deviated wells, they are drilled with giving deviation to them. Therefore, pumps inside deviated well cannot act properly because of friction. This friction can be resulted in a break of the pump inside the well. It requires a fishing process which is a very expensive process for removing broken devices or metals left inside the well. On the other hand, because heavy oils have a very high viscosity, the use of horizontal wells are very advantageous since the area open to flow increases significantly compared to vertical wells. However, as stated, pumps cause problems in horizontal wells. In this study, an alternative method is analyzed where we benefit the advantages of a horizontal well while lowering the pump in a vertical well.

Instead of a horizontal well in this case intersected wells can be used with the same principle (Figure 2.1 b). With this kind of an approach, production is achieved through the vertical well only. The horizontal well, in this case, is used only for increasing the area open to flow. Using the pump in vertical well intersecting with the horizontal well has no negative effect on the pump. Since here pump is used in vertical well intersected with horizontal well or deviated well, the benefit of the pump can be reached fully as well as the benefit of the horizontal well. That is why applying intersected wells option can solve this problem. The performance production of a vertical well intersecting a single horizontal well is demonstrated on a synthetic example given in the next chapter. The effects of various parameters are studied. However, a vertical well can be intersected with more than one horizontal well (Figure 2.1 c).

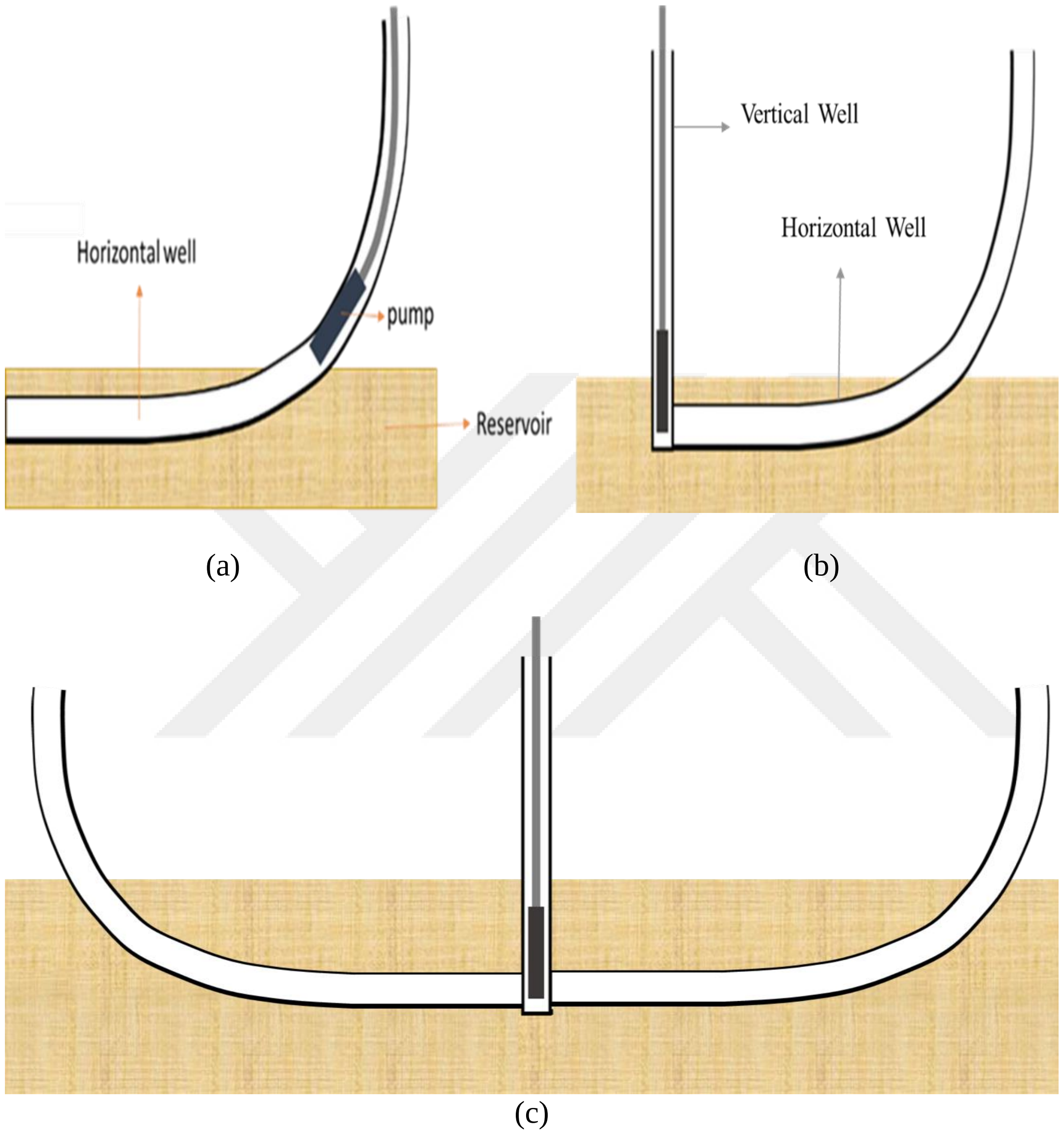


Figure 2.1: Horizontal well (a); Intersected wells (b); Intersected wells with multiple horizontal sections (c).

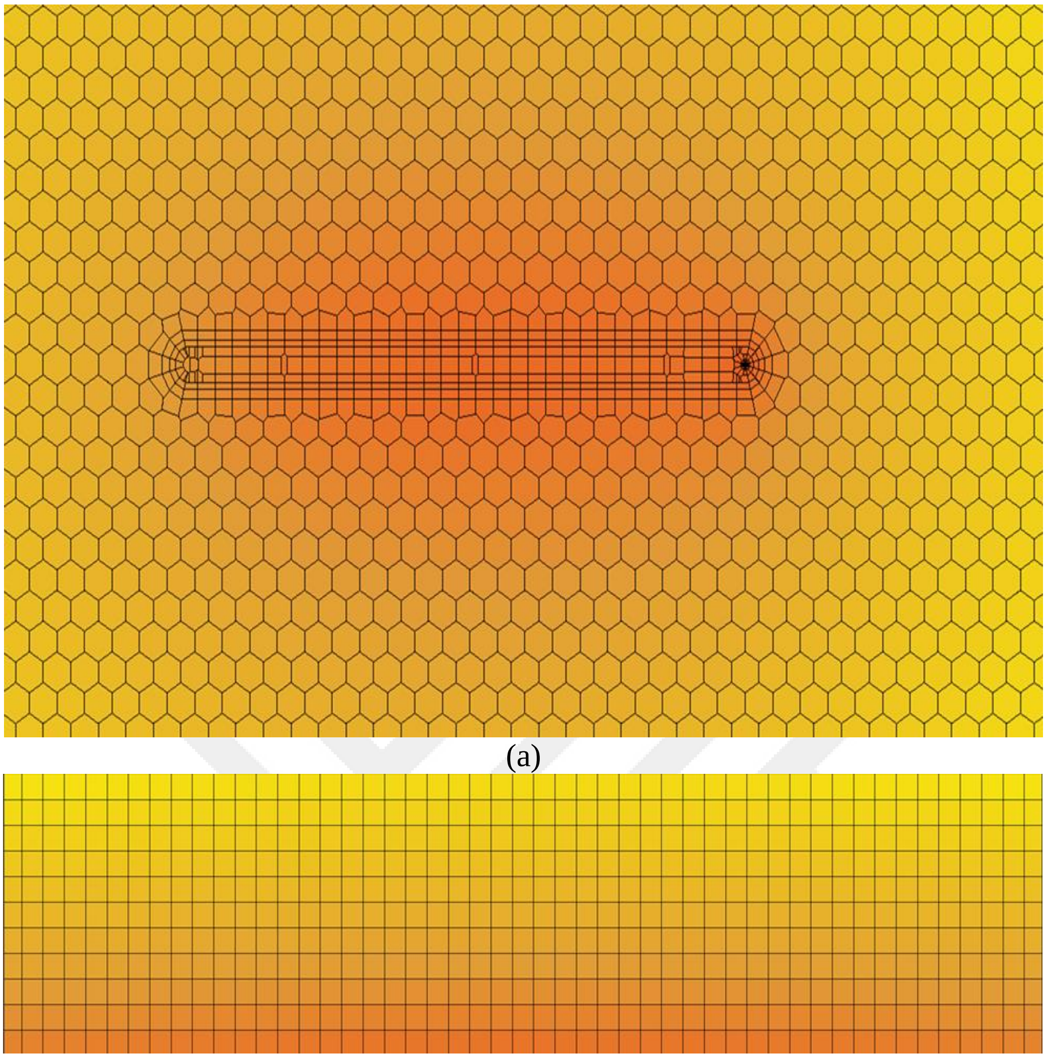
3. MODELING STUDY

It was mentioned in the previous section that the proposed solution to the problem is to use vertical well intersected with horizontal or inclined well (intersected wells). Different cases are investigated to find the best case for the production increase. For the purpose of investigating the different cases, a synthetic reservoir and fluid are modeled in Rubis-simulator. Rubis is a 3D, 3 phase, multipurpose numerical modeler which sits somewhere between single cell material balance and massive full-field simulation models (Kappa-Ecrin v4.3, 2013). In Rubis, structured or unstructured grids can be used. Different types of fluid system can be taken into the consideration as well as their properties such as viscosity (μ), compressibility (c), formation volume factor (B) can be calculated or estimated using different approaches. Different kind of reservoir shapes can be modeled in Rubis. Furthermore, heterogeneity and anisotropy can be taken into consideration.

Hexagonal grids are used to grid fictional Reservoir-A. The height of reservoir is divided by 11 grids (Figure 3.1). In the figure vertical well intersected with horizontal well are shown. Grid refinement around the wellbore in the final simulation grid is applied as well (Figure 3.1).

Fluid properties, well model as well as pressure drop model inside the well are also modeled using Rubis-simulator.

For illustrating intersecting wells model, the wiggy-well option is used, since there is no any option to intersect vertical well with a horizontal well in one grid in Rubis-simulator. It assumes intersecting wells as one well deviated by any degree (here since the horizontal well is used, the degree of inclination is 90 degree). Fluid flow in the well is all trajectory. All trajectory is a wellbore model used to compute the pressure drop along the complete well path. Pressure drop model is one-phase liquid pressure drop model. Pressure drop due to friction is also assumed, and roughness of wellbore is equal to 0.0012 ft. The model also assumes thermal gradient and its effect on the fluid flow.



(a)

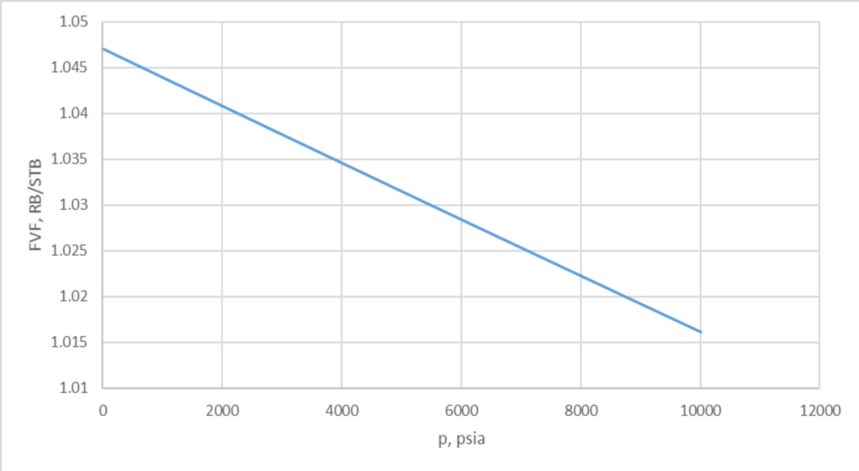
(b)

Figure 3.1: Grid system used in the Rubis-simulator: top view (a); side view (b).

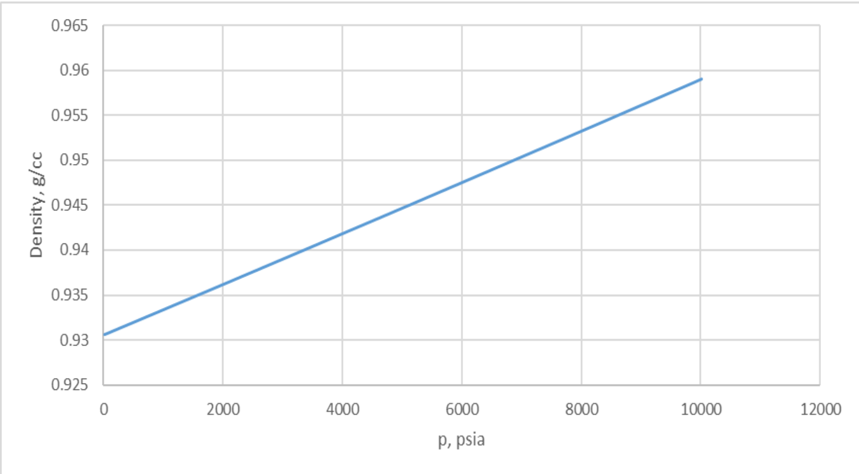
Since GOR of heavy oil is very low, the one-phase liquid model is assumed ignoring existing water and gas. Viscosity and compressibility of heavy oil are chosen as constant with pressure. Even so, since compressibility is constant, and one-phase liquid is used, FVF and density are changing linearly with pressure using standing correlation (Figure 3.2).

Effect of gravity also plays role in reservoir. That is, with depth reservoir pressure is changing by means of the hydrostatic pressure of liquid level. Therefore, the middle of the reservoir is treated as the reference depth to assign the initial reservoir pressure.

There are, as it was mentioned in the statement of the problem, vertical and horizontal wells are drilled and intersected with their tips (Figure 2.1b). Square shaped reservoir with 10000 ft to 10000 ft area and 300 ft height is used. Reference depth is chosen D_{mp}= 3150 ft (middle of the reservoir) (Figure 3.3).



(a)



(b)

Figure 3.2: FVF (a) and density (b) of heavy oil modeled by Rubis-simulator.

At static condition, the depth of oil level was D_{st}= 1000 ft (Figure 3.3). Using pressure gradient given in Table 3.1, the static level of oil and the depth to the middle of the reservoir in equation 3.1, initial reservoir pressure in the middle of the reservoir is equal to p_i= 900 psi.

The pump is lowered to the D_p= 2000 ft. Here, D_p is the depth of the pump. It has to be noted that there is a 100 ft liquid column above pump so as to have good use of a pump at whatever depth it is (Figure 3.3). And when production starts, the pressure at the wellbore decreases and oil level also decreases. At this dynamic state, the depth of oil level lowers to dynamic level- D_{dyn}= 1900 ft. Using pressure gradient, the dynamic level of oil and the depth to the middle of the reservoir in equation 3.2, bottom hole wellbore flowing pressure is equal to p_{wf}= 900 psi.

$$p_i = (D_{mp} - D_{st}) \cdot \gamma \qquad 3.1$$

where,

D_{mp} is the depth to the middle of the reservoir, ft

D_{st} is the depth to the level of the oil at static condition, ft

p_i is the initial pressure in the middle of the reservoir, psi

γ is the pressure gradient, psi/ft.

$$p_{wf} = (D_{mp} - D_{dyn}) \cdot \gamma \qquad 3.2$$

where,

p_{wf} is the flowing bottom hole pressure, psi

D_{dyn} is the depth to the level of the oil at the dynamic condition, ft.

Using this flowing bottom hole pressure constant pressure drawdown for 730 days is taken into consideration to calculate oil production and production increase for each case. Other reservoir properties are given in Table 3.1.

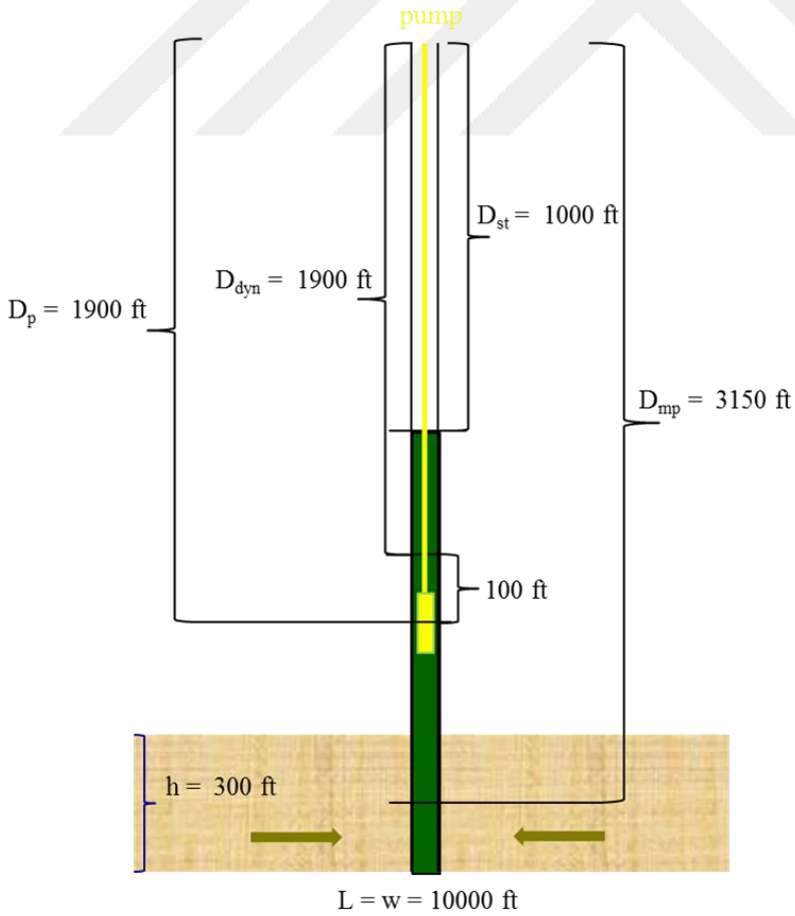


Figure 3.3: The fluid level at the dynamic and static state.

Table 3.1: Reservoir and fluid properties used in the modeling study.

API	15^o	h (ft)	300
ρ (lbm/ft^3)	58.93	w (ft)	10000
c_o (psi^{-1})	$3x10^{-6}$	L (ft)	10000
μ (cp)	100	D_{top} (Top of the reservoir) (ft)	3000
c_f (psi^{-1})	$3x10^{-6}$	p_i (psi) (initial reservoir pressure)	900
ϕ (porosity)	0.15	p_{wf} (psi) (flowing wellbore pressure)	523
r_w (inch)	0.3	k (mD)	100
s (skin factor)	0	t – production time (days)	730
γ (pressure gradient) (psi/ft)	0.418318	C (STB/Day/Psi)	0

Figure 3.4 gives the reservoir pressure during production time depicted using the Rubis-simulator for the base case, where intersected wells are in the middle of the reservoir with 2000 ft length; there is no skin factor, neither wellbore storage; and wellbore radius is equal to 0.3 ft. Figure 3.4 is given for the purpose of illustration of the grids and how the pressure profile changes in the reservoir.

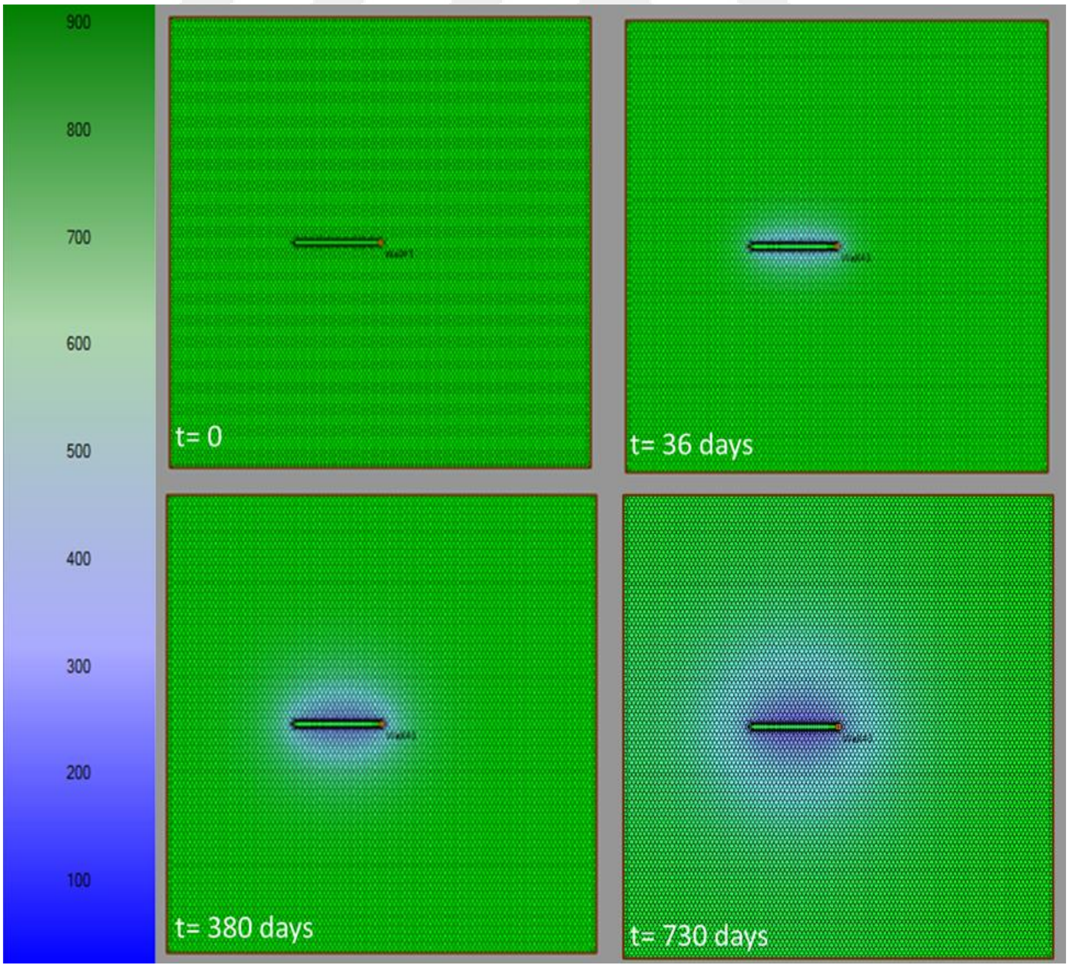


Figure 3.4: Reservoir pressure distribution during the drawdown.

Using this model various cases are investigated. The cases investigated in this thesis are as follows:

1. Effect of the depth of the pump
2. Effects of length of intersected horizontal wells
3. Effects of depth of intersected horizontal wells
4. Effects of location of intersected wells
5. Effects of degree of inclination of intersected wells
6. Effects of the wellbore radius
7. Effects of the skin zone.

In all cases, the production is achieved at a constant bottom hole pressure scheme. This is done as to mimic a pump. The specified bottom hole pressure is obtained so that the liquid level in the well stays 100 ft above the pump during production.

3.1 Verification of Simulation Results

For this purpose, square shaped reservoir intersecting wells with 2000 ft of length drilled at the center of the reservoir is taken. This well is drilled to the bottom of the reservoir. The reservoir is taken as isotropic for simplicity. Gravity effect to pressure is ignored since in Babu-Odeh equation there is no gravity term. Furthermore, pressure loss due to friction is ignored since Babu-Odeh equation does not take friction into account. It has to be mentioned that constant FVF equal to 1.29 RB/STB is taken since Babu-Odeh equation is for constant FVF (Figure 3.5).

There are several methods for estimating of productivity of horizontal wells. Babu and Odeh obtained a rigorous solution to the diffusivity equation for a well in a box-shaped reservoir. Babu-Odeh equation is a handy approach to find out productivity, but has the following certain limiting assumptions:

- Fluid flows to the well uniformly at all points along the wellbore and the well is completed uniformly.
- The sides of the drainage volume are aligned with the principal permeability direction.
- The wellbore is parallel to the sides of the drainage area and perpendicular to the other two.

- The boundaries of the reservoir are all no-flow boundaries and the well reaches stabilized pseudosteady-state flow.
- The formation damage around the wellbore is uniform at all points along the wellbore (Url-2).

However, the base case does not go beyond these assumptions. So, this method can be used for the analytical check. Since this equation is for constant rate, 77.5 STB/D constant rate drawdown is used instead of constant pressure drawdown. As Babu-Odeh is applied for pseudo steady state flow regime, 10 years of drawdown is considered to see this flow regime.

Figure A.1 (in APPENDIX A) introduces the nomenclature in the Babu and Odeh solution. Details of the Babu-Odeh equation are provided in APPENDIX A. The solution is quite complex but is approximated accurately with an equation written in the same form as the pseudo steady-state flow equation for a vertical oil well producing a single-phase, slightly incompressible liquid.

So, in the base case, a_H= b_H= 10000 ft; d_x= 3000 ft; D_x= 5000 ft; d_y= D_y= 5000 ft; d_z= 290 ft; D_z= 10 ft; h= 300 ft; L_w= 2000 ft. Babu-Odeh equation is the solution of the productivity index- J of the horizontal well for late-linear flow regime, which is the last flow regime. Using the values of the parameters of the Reservoir-A given in our base case in the equation A.13, productivity index of the horizontal well is calculated. It had better be mentioned that k_x= k_y= 100 mD, since the Reservoir-A is isotropic.

In APPENDIX A, equations are used to estimate productivity index- J . All unknown parameters are calculated using equations given in APPENDIX A, and finally, J is calculated using equation A.13, and it is equal to 0.62 STB/Day-psi for this case. Using productivity index value in the equation 3.3, p_{wf} values are analytically calculated.

$$p_{wf} = \left(p_R - \frac{q}{J} \right) \qquad 3.3$$

Reservoir pressure values-p_R are exported from the Rubis-simulator. The wellbore flowing pressures obtained from Rubis and the Babu-Odeh equation are compared in Figure 3.6.

As it can be observed from the plot, at an early time, till about 455 days, the analytical result doesn’t match with numerical result. As it was mentioned above, this because

Babu-Odeh equation is applied for pseudo steady state flow regime. And it seems pseudo steady state flow regime for Reservoir-A to start after 455 days. However, for pseudo steady state time, they match perfectly (Figure 3.6).

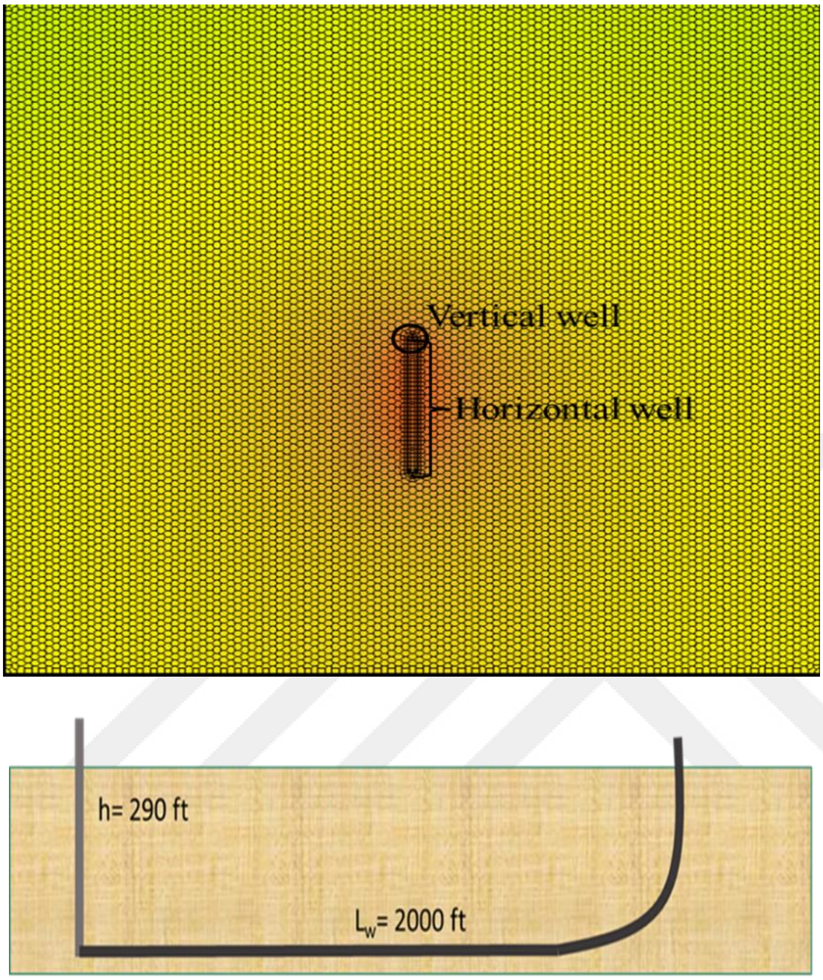


Figure 3.5: The base case for Babu- Odeh analytical check of Rubis-simulator.

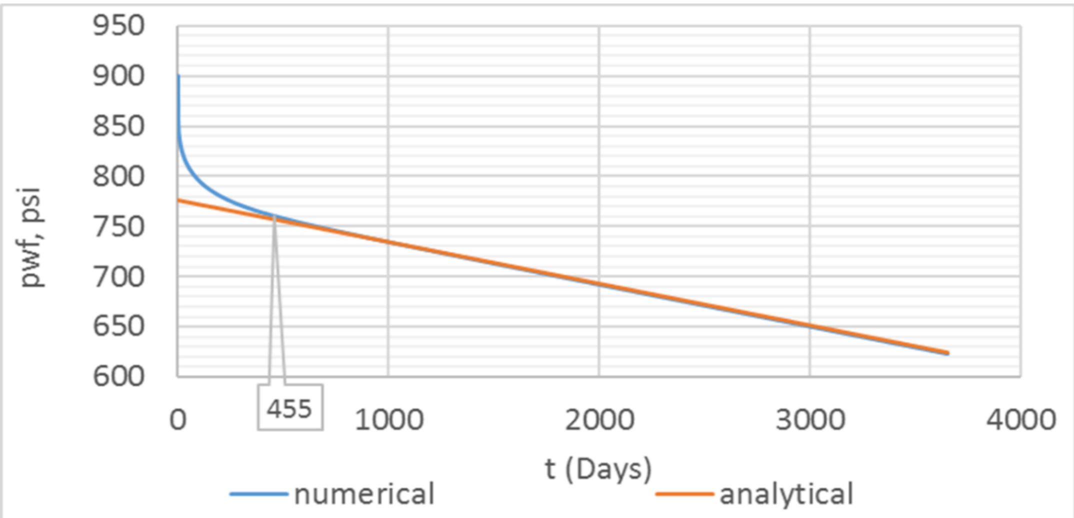


Figure 3.6: Analytical check of numerical results.

After having checked numerical results analytically with Babu-Odeh equation, they can be checked by using material balance check. Material balance equation can be obtained using the compressibility equation of the one-phase liquid (3.4). Equation 3.9 is the material balance equation for the field unit. Using the equations 3.5 and 3.8 in 3.4, we can get the equation 3.9.

Using equation 3.9, p_R values are calculated and checked with those of the Rubis-simulator for the length case where L_w= 2000 ft (Figure 3.7).

$$c = -\frac{1}{V_0}\frac{\Delta V}{\Delta p} \qquad 3.4$$

$$\Delta V = -Q \cdot B_o \qquad 3.5$$

$$V_o = V_p = V_b\phi \qquad 3.6$$

$$c = c_t = c_f + c_o \qquad 3.7$$

$$\Delta p = p_i - p_R \qquad 3.8$$

$$p_R = p_i - 5.615\frac{1}{V_b\phi}\frac{Q}{c_t} \qquad 3.9$$

where,

B_o is the oil formation volume factor (FVF), RB/STB

c is the isothermal compressibility coefficient, psi^{-1}

c_f is the isothermal compressibility coefficient of the formation, psi^{-1}

c_o is the isothermal compressibility coefficient of the oil, psi^{-1}

c_t is the total isothermal compressibility coefficient, psi^{-1}

p_R is the reservoir pressure at any time, psi

p_i is the initial reservoir pressure, psi

Q is the cumulative oil production, STB

V_b is the bulk volume of the reservoir, ft^3

V_o is the initial volume (initial oil in place), ft^3

V_p is the pore volume of the reservoir, ft^3

Δp is the pressure difference, psi

ΔV is the volume change, ft^3

ϕ is the porosity of the reservoir, fraction

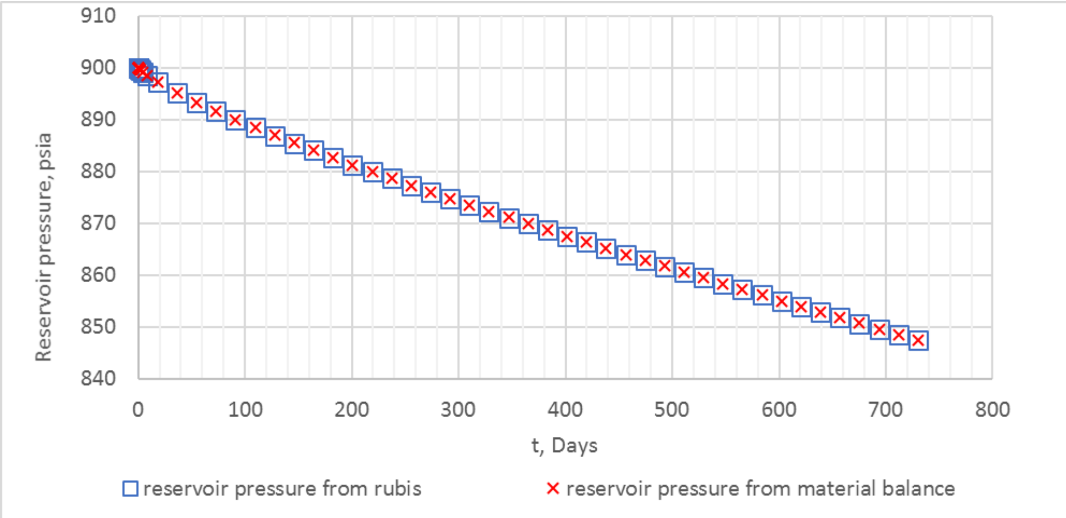


Figure 3.7: Material balance check of the reservoir pressure.

It can be observed from Figure 3.7 that the reservoir pressure from the Rubis-simulator and from the material balance are perfectly matched.

3.2 Pump at Different Depths

It was mentioned above that the main benefit of using intersecting wells configuration is to use pump properly, at desired level. For this purpose, horizontal well drilled into the middle of the reservoir (D= 3150 ft) at the center of the reservoir. Intersected wells are also drilled to the same depth and at the center of the reservoir (Figure 3.8). For horizontal well, since pump can only be used in the vertical part of the horizontal well not deviated part, the maximum depth it can be lowered is chosen to be equal to D_p= 2000 ft, therefore, dynamic level of the liquid will be equal to D_{dyn}= 1900 ft (Figure 3.9). However, for the intersected well, the pump can be used at any depth. Pump depth is chosen to be equal to D_p= 3000 ft, at the top of my reservoir (Figure 3.10). As there is always 100 ft liquid column above the pump, dynamic depth will be D_{dyn}= 2900 ft. Using those dynamic levels in the equation 3.2, bottom hole wellbore flowing pressures are calculated both for the horizontal well case and for intersected wells case:

Horizontal well: $p_{wf} = (D_{mp} - D_{dyn}) \cdot \gamma = (3150 - 1900)\,ft \cdot 0.418318 \frac{psi}{ft} = 523 psi$

Intersected wells: $p_{wf} = (D_{mp} - D_{dyn}) \cdot \gamma = (3150 - 2900)\,ft \cdot 0.418318 \frac{psi}{ft} = 104 psi$

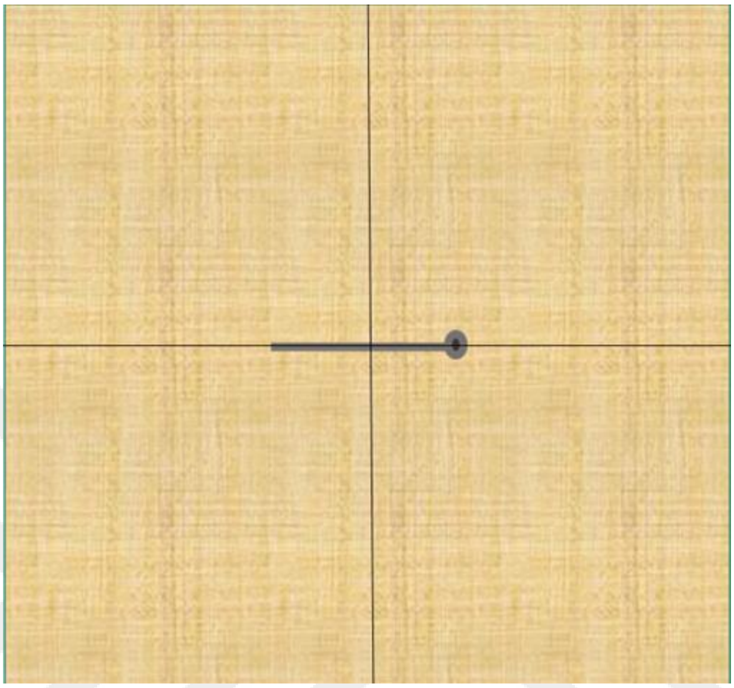


Figure 3.8: Location of the intersected wells and horizontal well configuration (top view)

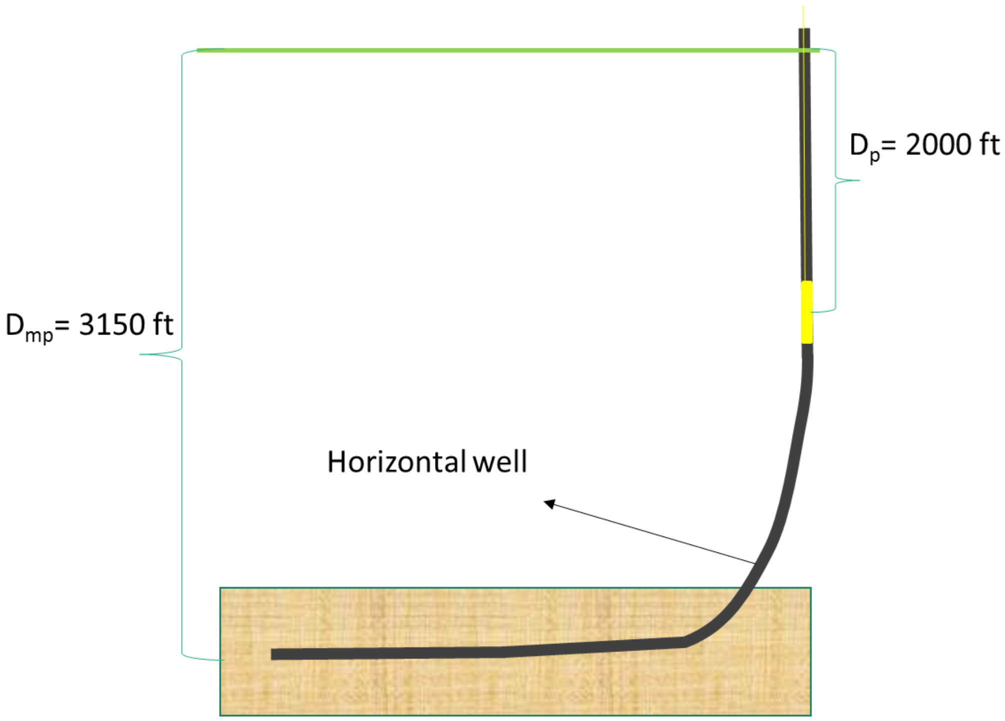


Figure 3.9: Location of the pump in horizontal well configuration.

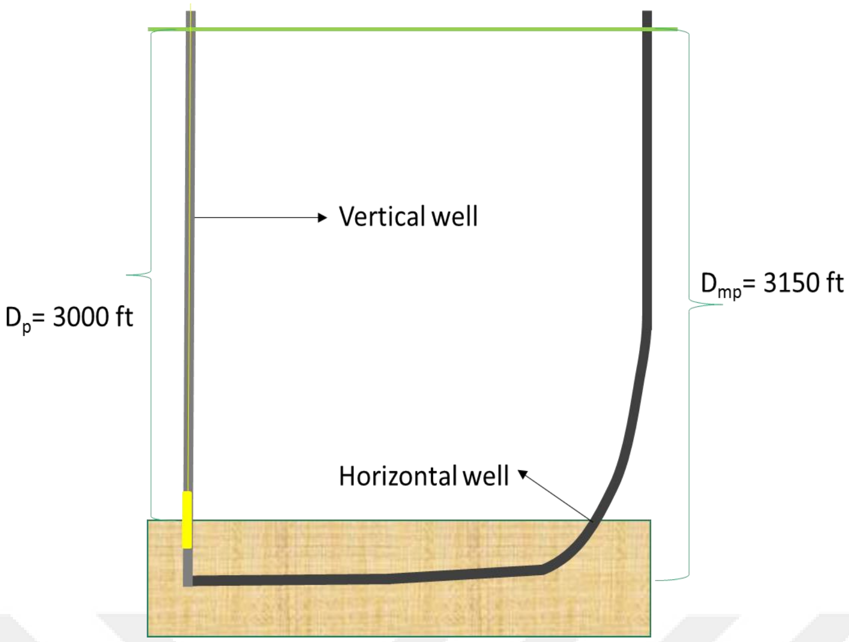


Figure 3.10: Location of the pump in horizontal well configuration.

Using these different flowing wellbore pressure due to different depth of pump in the Rubis-simulator, flow rate, cumulative oil production and reservoir pressure values are plotted vs time (Figures 3.11, 3.12 and 3.13).

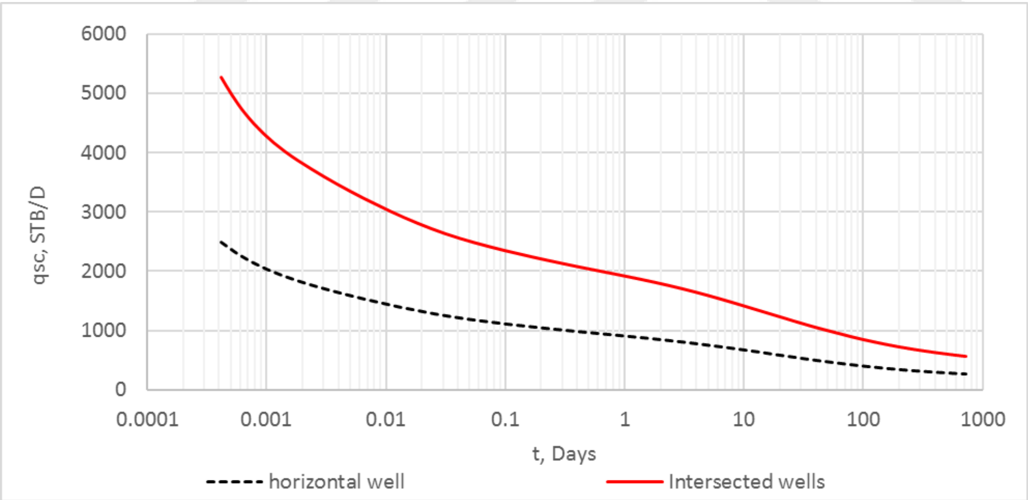


Figure 3.11: Oil flow rate vs time plots for the pump at different depth case.

Final cumulative oil production of those cases are tabulated (Table 3.2). More than two times of production increase is achieved by using intersected wells instead of horizontal well.

As it can be seen flow rate and cumulative oil production plots (Figures 3.11 and 3.12), the best case was using the pump in intersected wells. Therefore, higher reservoir pressure drop was for this case (Figure 3.13).

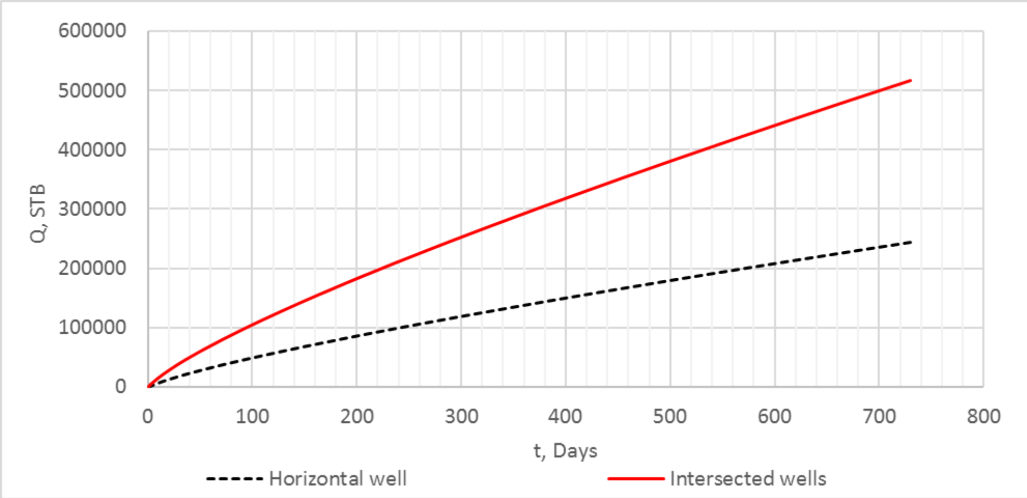


Figure 3.12: Cumulative oil production vs time plots for the pump at different depth case.

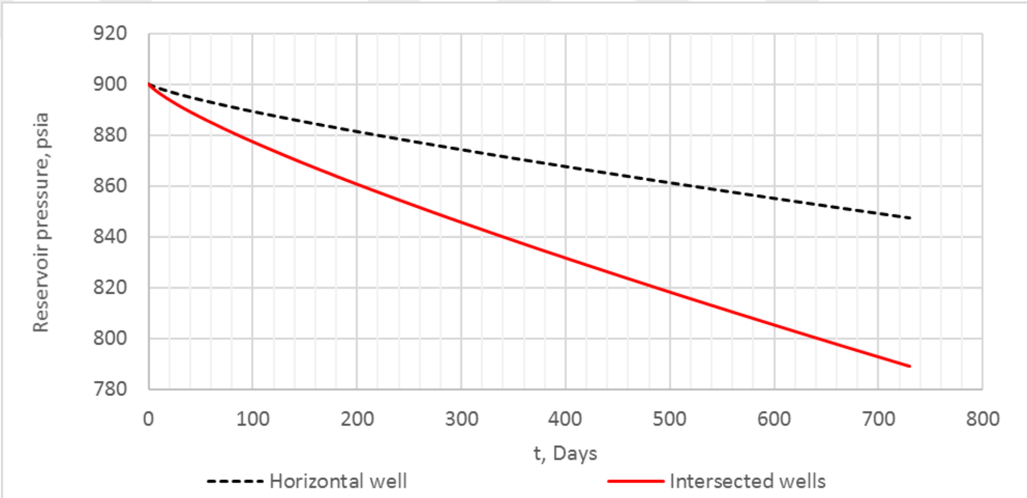


Figure 3.13: Reservoir pressure vs time plots for the pump at different depth case.

Table 3.2: *Q* for the pump at different depth cases.

cases	*Q* (STB)
Horizontal well (D_p= 1900 ft)	243967
Intersected wells (D_p= 2900 ft)	516042

3.3 Effect of the Length of the Intersected Wells

Increasing length of horizontal well intersected with a vertical well drilled into the middle of the reservoir is used as (*D*= 3150 ft) (Figure 3.14). The center of the intersected wells is at the center of the reservoir for each case (*X*= 0; *Y*=0) (Figure 3.15).

where,

D is depth of the intersecting well, *ft*

L_w is length of the intersecting horizontal well, *ft*

X and Y are horizontal axes and the vertical axis of the 2D Cartesian coordinate system (or Rectangular coordinate system) respectively. It indicates the location of the intersected wells as depicted in the Figure 3.15.

q_{sc} (STB/D) vs t (Day) are plotted for those cases compared with vertical well at the same location and perforated to the middle of the reservoir (D= 3150 ft). As it can be expected, the increasing length of intersecting wells shows production rate increase due to an increase of the area open to flow (Figure 3.16). Therefore, cumulative oil rate—Q (STB) is greater for the longer intersected wells (Figure 3.17). Since the longer intersected wells provide more cumulative rate, reservoir pressure decreases with time more rapidly (Figure 3.18).

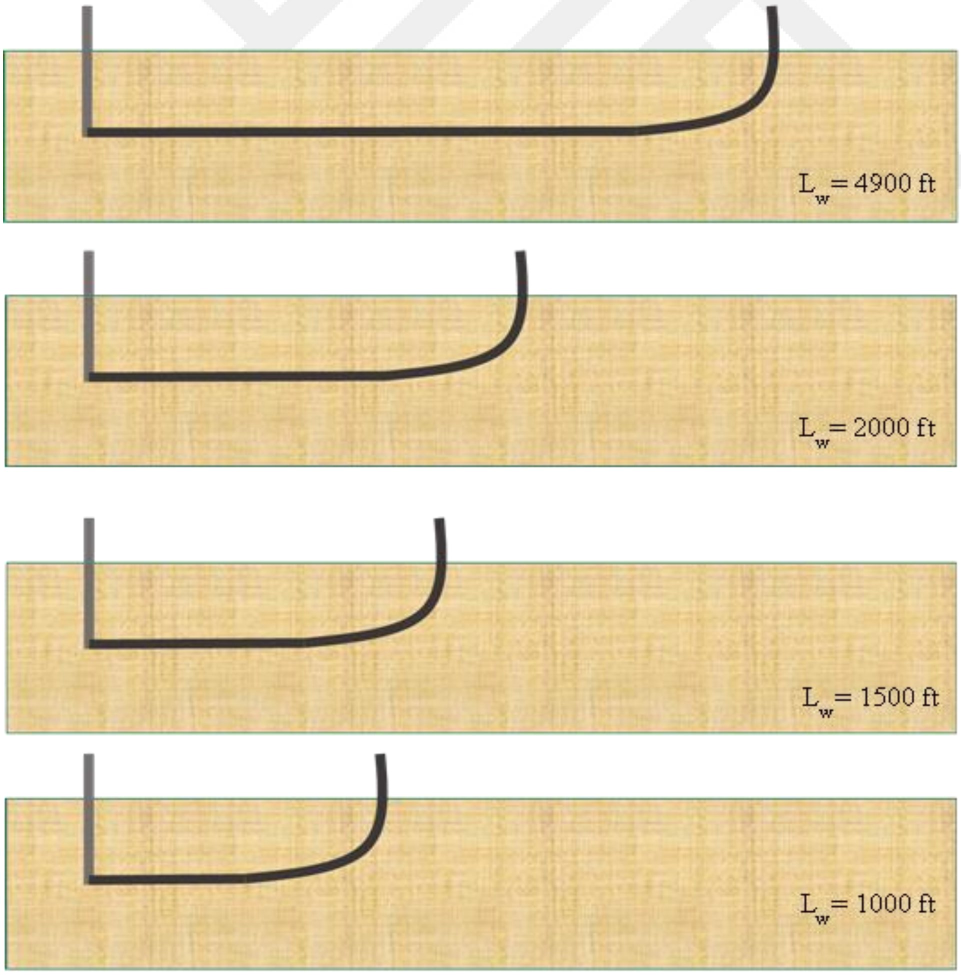


Figure 3.14: Various horizontal well lengths used in intersecting wells.

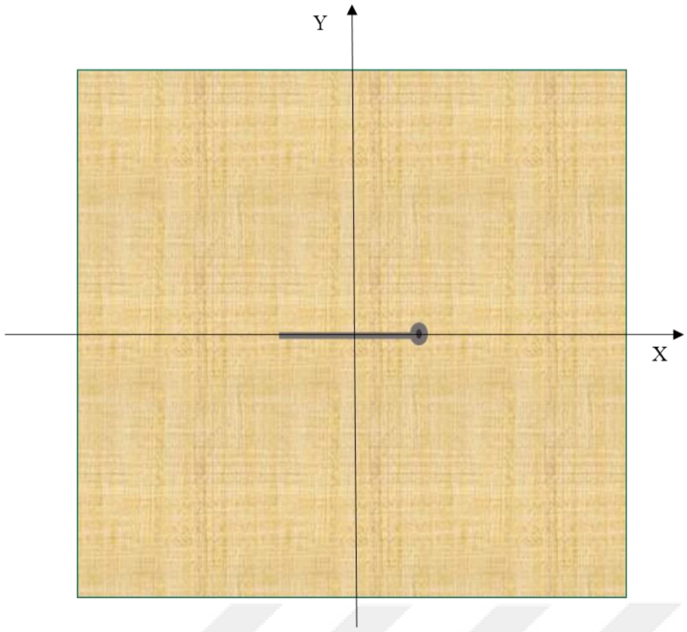


Figure 3.15: Areal location of intersecting wells.

Total cumulative oil (Q) for the vertical only case and intersected wells cases, and the increase of the production (IP) were calculated using the equation 3.10.

$$IP = \frac{Q_{\text{int}} - Q_{ver}}{Q_{ver}} \cdot 100 \qquad 3.10$$

where,

Q_{ver} and Q_{int} is cumulative oil production of vertical well and intersected wells respectively, STB

IP is an increase of production, %.

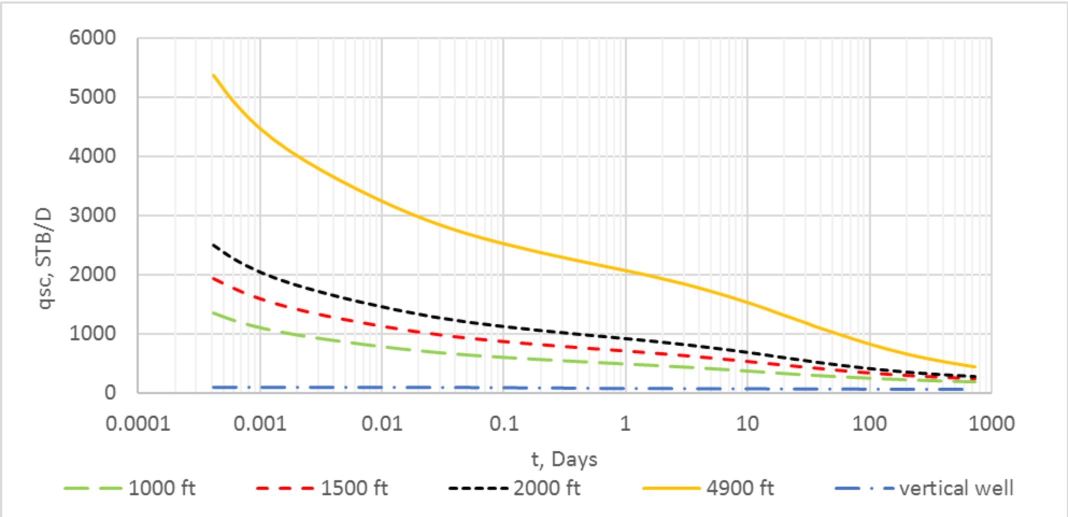


Figure 3.16: Oil flow rate vs time plots for intersected wells-length case.

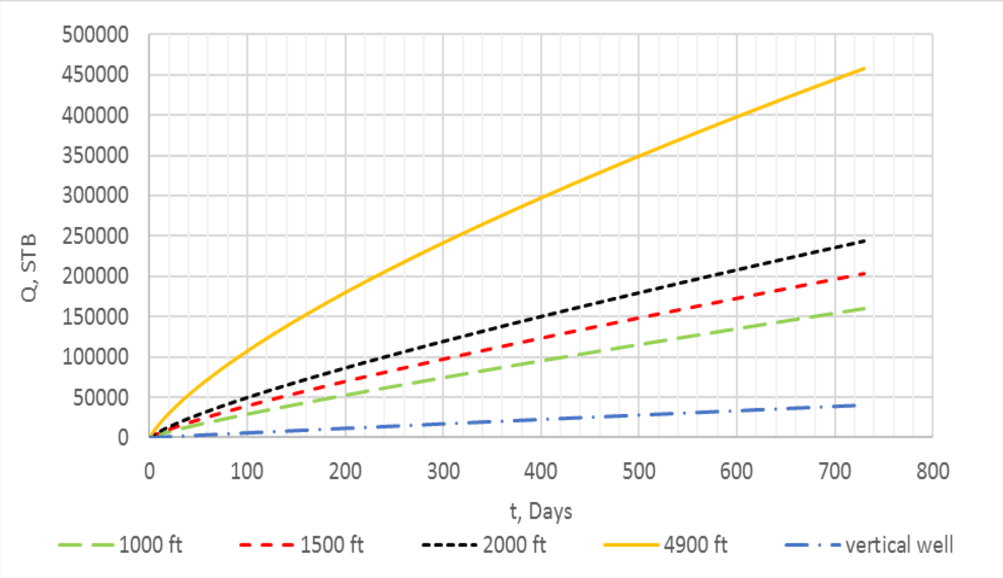


Figure 3.17: Cumulative oil production vs time for intersected wells-length case.

It is important to note that the vertical well is placed at the center of the reservoir. Calculated values are tabulated in Table 3.3 below.

Table 3.3: Cumulative rate and a production increase of intersected wells with different length compared with vertical well at the same condition.

cases	*Q* (STB)	Production increase comparing with vertical well case (%)
Vertical well	33552.252	
L_w= 1000 ft	162089.719	383.096
L_w = 1500 ft	206434.740	515.263
L_w = 2000 ft	246805.807	635.586
L_w = 4900 ft	423541.194	1162.333

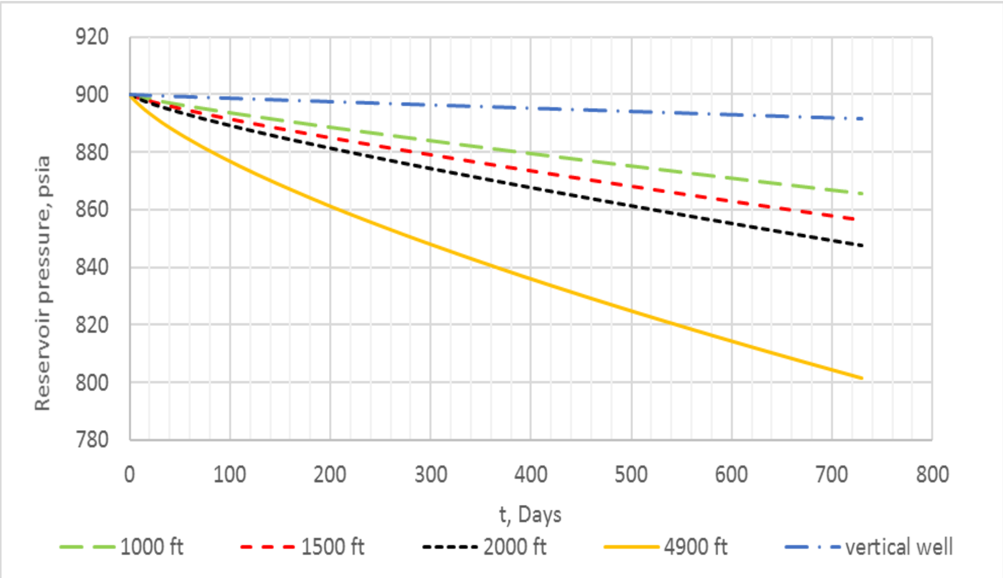


Figure 3.18: Reservoir pressure vs time for intersected wells-length case.

The reason why reservoir pressure declines with increasing cumulative oil production can simply be explained by using material balance. Material balance is given in the section of the analytical check of numerical results. As it can be understood from equation 3.9 as cumulative oil production Q increases, reservoir pressure p_R decreases.

3.4 Effect of the Depth of the Intersected Wells

Here different depth of intersection has been taken: D= 3010 ft, 3150 ft, 3290 ft (Figure 3.19**)**. For this purpose, the base case is taken: intersected wells are in the center of the reservoir (X= Y= 0); L_w= 2000 ft; there is no anisotropy. Furthermore, only horizontal part of the intersected wells is perforated but vertical part is not perforated. Therefore, here, only a comparison of the three cases are given. A comparison with vertical well is not provided. That is why, their increases of the production are not calculated, but only their production behaviors are compared.

q_{sc} (STB/D) vs t (Days) is plotted for each case (Figure 3.20). As it can be understood, intersected wells in the middle of the reservoir gave more cumulative oil production (Figure 3.21), and therefore, its reservoir pressure decline more rapidly (Figure 3.22).

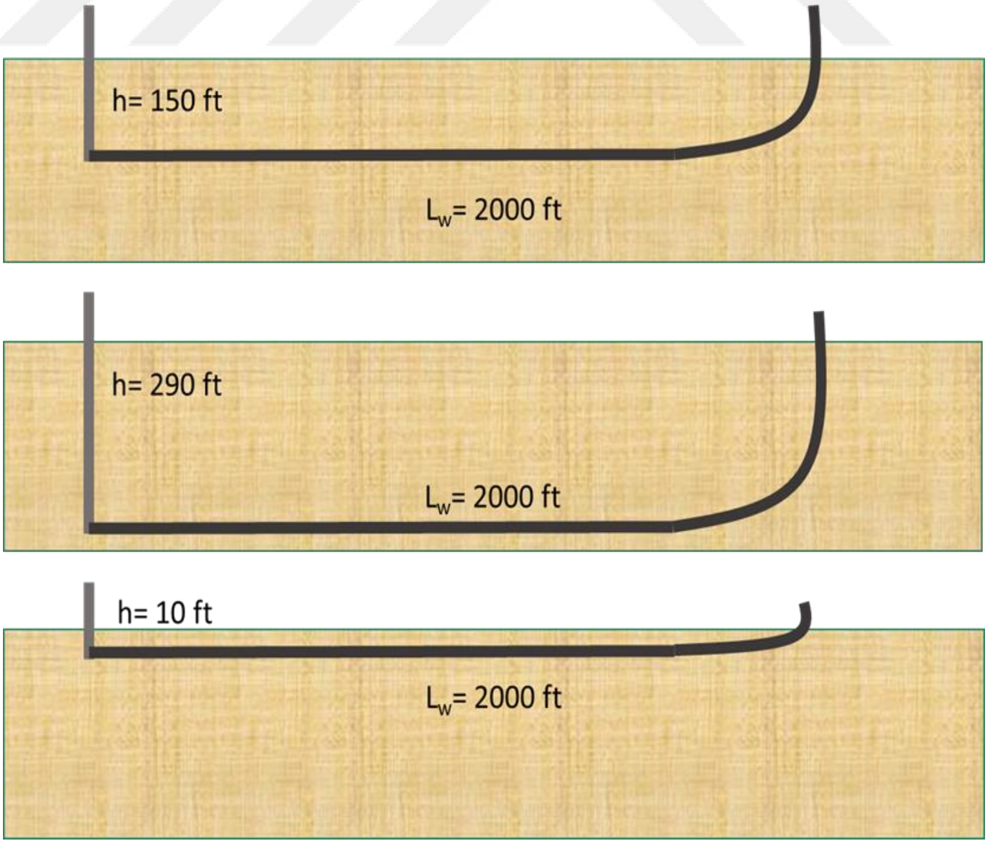


Figure 3.19: Depth cases.

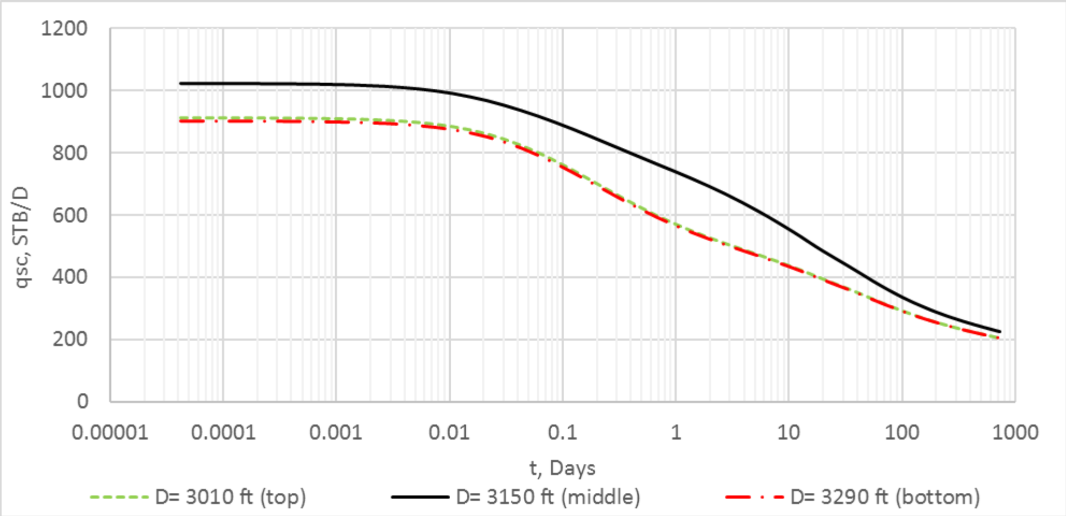


Figure 3.20: Oil flow rate vs time plots for depth cases.

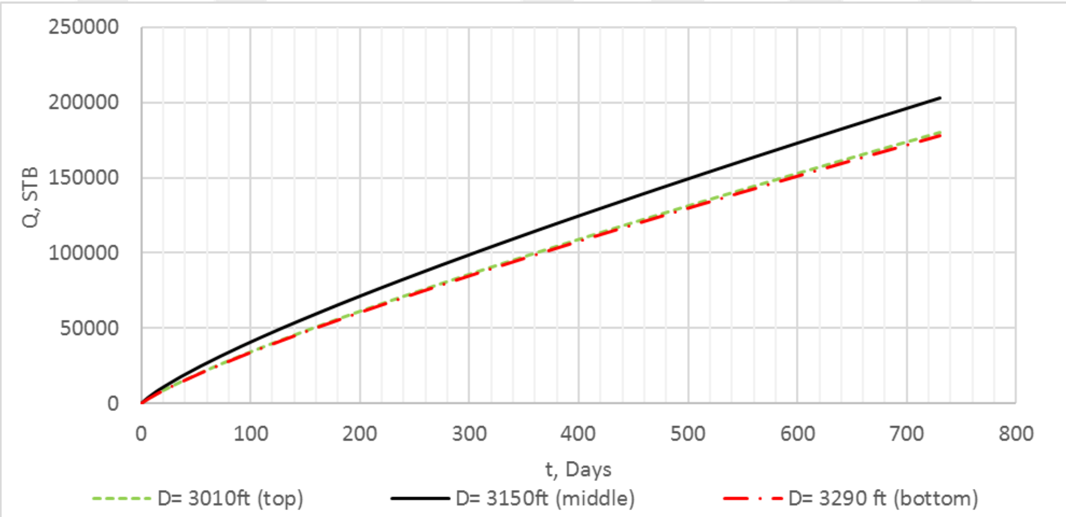


Figure 3.21: Cumulative oil production vs time plots for depth cases.

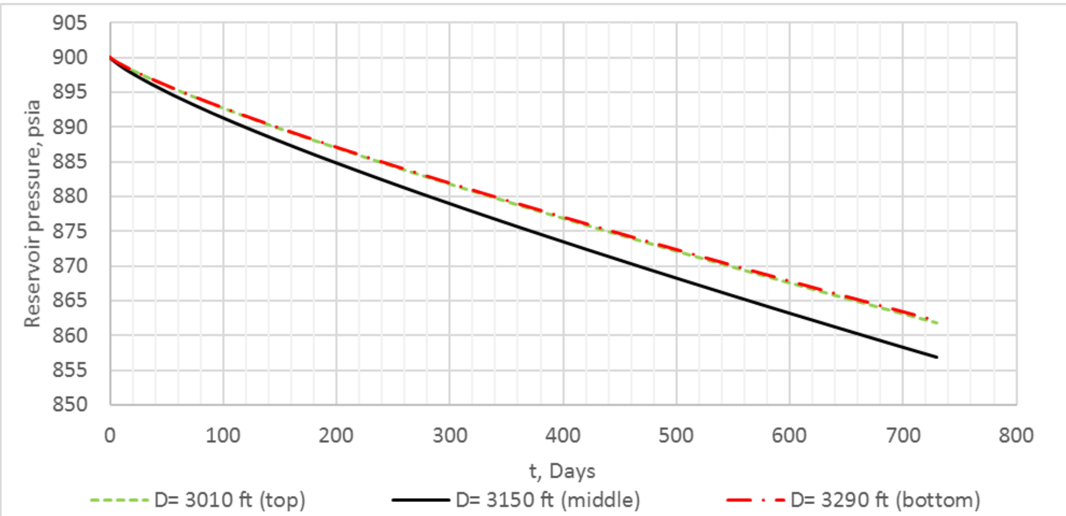


Figure 3.22: Reservoir pressure vs time plots for depth cases.

This is because when the horizontal well is in the middle, boundary effects are felt less than other cases which are close to upper and lower boundary of the reservoir. This is important by means of flow rate because after seeing upper or lower boundary, flow regime changes and it negatively affects flow rate. The reason why at higher cumulative oil production the reservoir pressure is lower is explained at the section- “Effect of the Length of the Intersected Wells” and it can be applied to all cases below.

As it can be seen from Figure 3.20, top and bottom depth cases showed almost the same flow rate during production time. It is reasonable because they both are 10 ft far from the border, and therefore, boundary effect and flow rates of both cases are the same.

However, if we look at the shape of the flow rate vs time plots of the middle depth case and other cases, we could see the difference between them. This is because, the shape of the flow rate vs time plot depends on the flow regimes changing during production time, and thus depends on the boundary effect as well. And, final cumulative oil production values are calculated and tabulated (Table 3.4).

Table 3.4 : *Q* for depth cases.

cases	*Q* (STB)
D= 3010 ft (top)	179837.5
D= 3150 ft (middle)	202721.81
D= 3290 ft (bottom)	177994.86

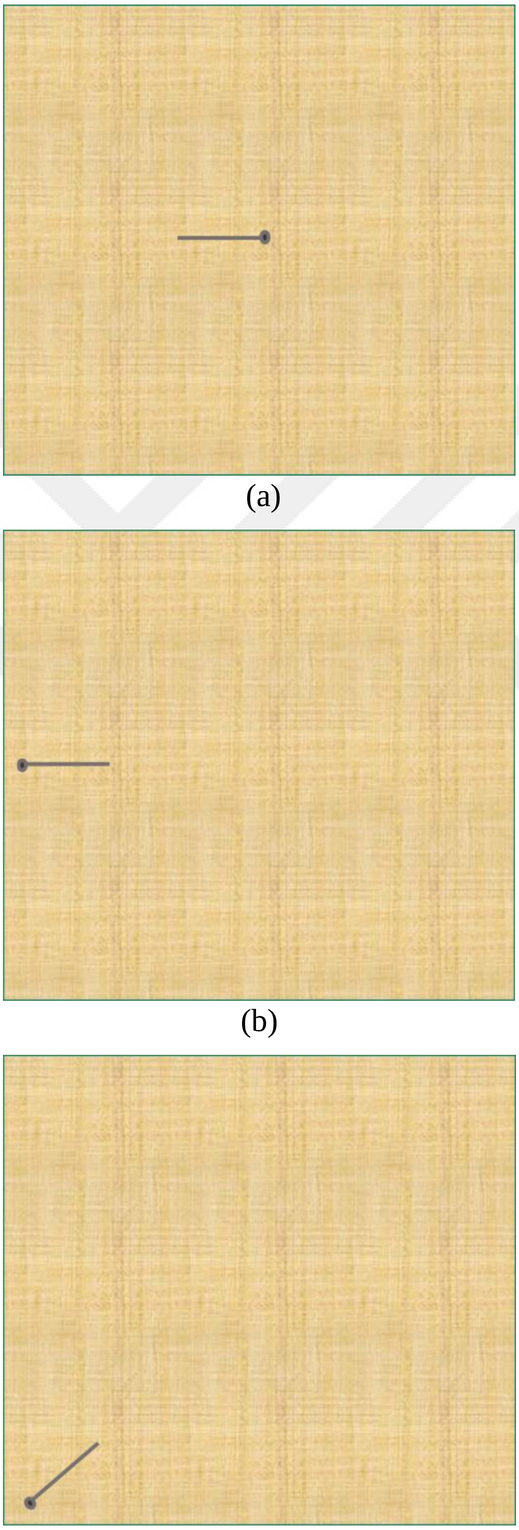
3.5 Location case

The base case has been taken as the intersected wells with the length of 2000 ft in the middle of the reservoir.

Here as a location case, three locations have been taken:

1. At the center of the reservoir (Figure 3.23 a)
2. At the left (West) of the reservoir (100 ft farther from the West border) and intersected wells are directed to the center of the reservoir (Figure 3.23 b)
3. At the corner (South-West) of the reservoir (100 ft farther both from the West and South border) and intersected wells are directed to the center of the reservoir (Figure 3.23 c).

As it is reasonable, the case in the middle gives better results than other cases. Cumulative oil productions are calculated for those cases for both intersected and vertical well cases at those locations and made a comparison with that of a vertical well, and production increases are calculated for all cases and tabulated (Table 3.5).



(a)

(b)

(c)

Figure 3.23: Intersected wells- location cases: center (a); west (b); south-west (c)

Table 3.5 : *Q* and production increase for the location case.

cases	*Q* (STB) vertical well	*Q* (STB) intersected wells	Production increase comparing with vertical well case (%)
Middle	33552.25	246805.807	635.586
West	28687.22	204720.702	613.630
South West	22630.75	148405.247	555.768

q_{sc} vs t for all cases were plotted (Figure 3.24). The results are reasonable because, flow regimes affect flow rate, and for the well to be in the center is the best case. This is because the well in the center see boundaries much later than other cases do. Cumulative oil production and reservoir pressure plots with respect to time are depicted as well (Figures 3.25 and 3.26).

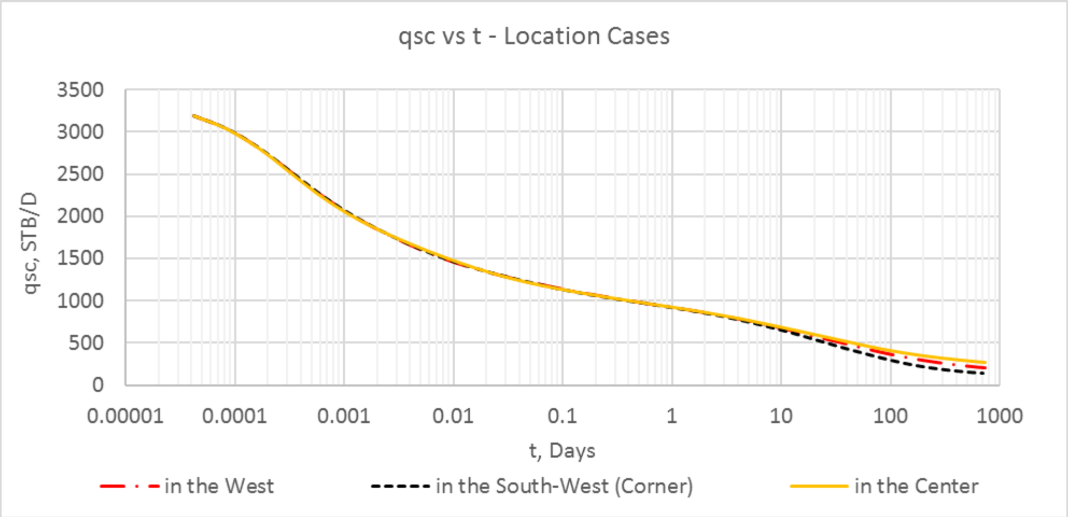


Figure 3.24: Oil flow rate vs time plots for location cases.

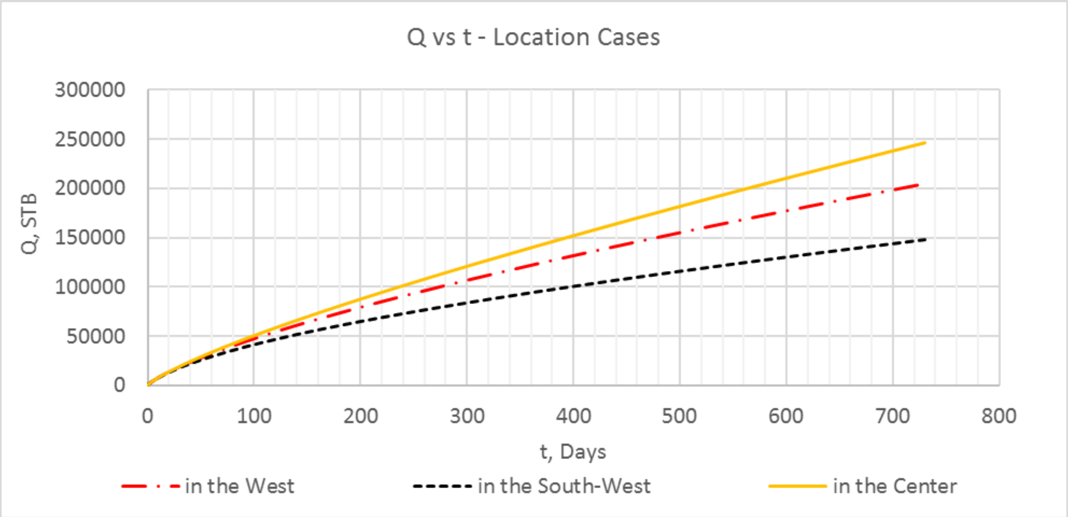


Figure 3.25: Cumulative oil production vs time plots for location cases.

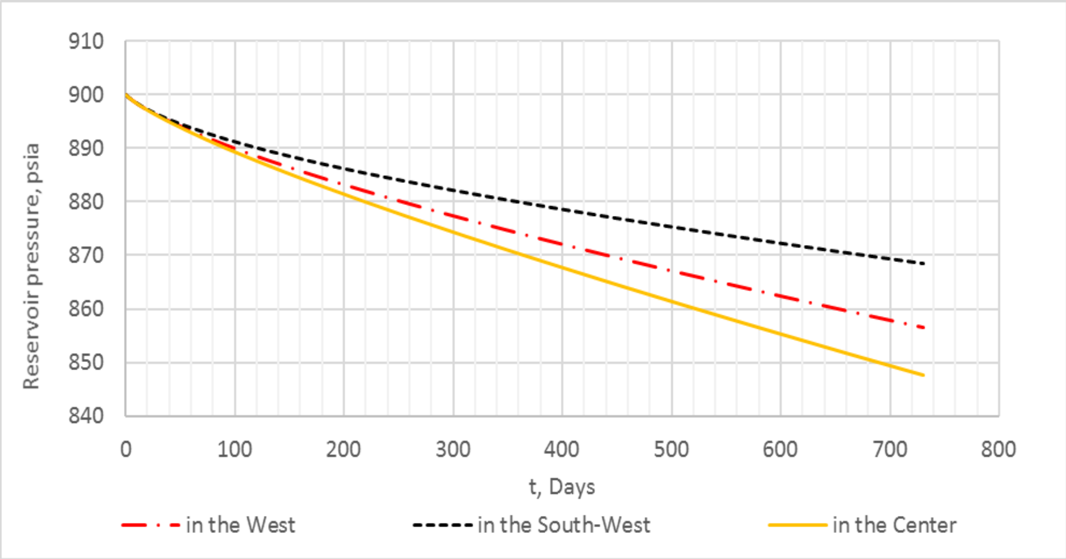


Figure 3.26: Reservoir pressure vs time plots for location cases.

3.6 Inclined Intersected Wells in the Anisotropic case

Inclined intersected wells case has been tested for a reservoir having k_v/k_h= 0.01 anisotropy, where k_h= 100 mD. For this purpose, the intersected inclined wells and intersected horizontal wells are compared with a vertical well. All of them are in the middle of the reservoir, drilled to the depth from D= 3000 to 3295 ft (Figure 3.27**)**.

The degrees between inclined section of intersected wells and X – direction are 0^o (Figure 3.27 a), 8.5^o (Figure 3.27 b) in which inclined section of the intersecting wells goes from D= 3000 ft to D= 3295 ft with length of L_w= 2000 ft, and 5^o (Figure 3.27 c) in which inclined section of the intersecting wells goes from D= 3295 ft to D= 3120 ft.

The production increase is computed by comparing vertical well drilled to that depth (D= 3295 ft), in the reservoir having the horizontal anisotropy that corresponds to the case. Plots showing oil production rate vs time are plotted (Figure 3.28). Cumulative oil production and reservoir pressure plots with respect to time are plotted as well (Figures 3.29 and 3.30).

From comparison of these cases, it can also be concluded that at an early time, for various inclination angles, horizontal intersected wells start with higher oil rate. However, after 247 hrs, oil rate of the intersected wells having a higher degree of inclination increases and gets first place. The results are expected since the inclined wells have a vertical component, and therefore, can make use of the higher horizontal permeability. Thus, in the reservoir having higher horizontal anisotropy using inclined intersected wells is more beneficial than horizontal intersected wells. Final cumulative oil production for intersected wells and vertical well and production increase for each case are tabulated (Table 3.6).

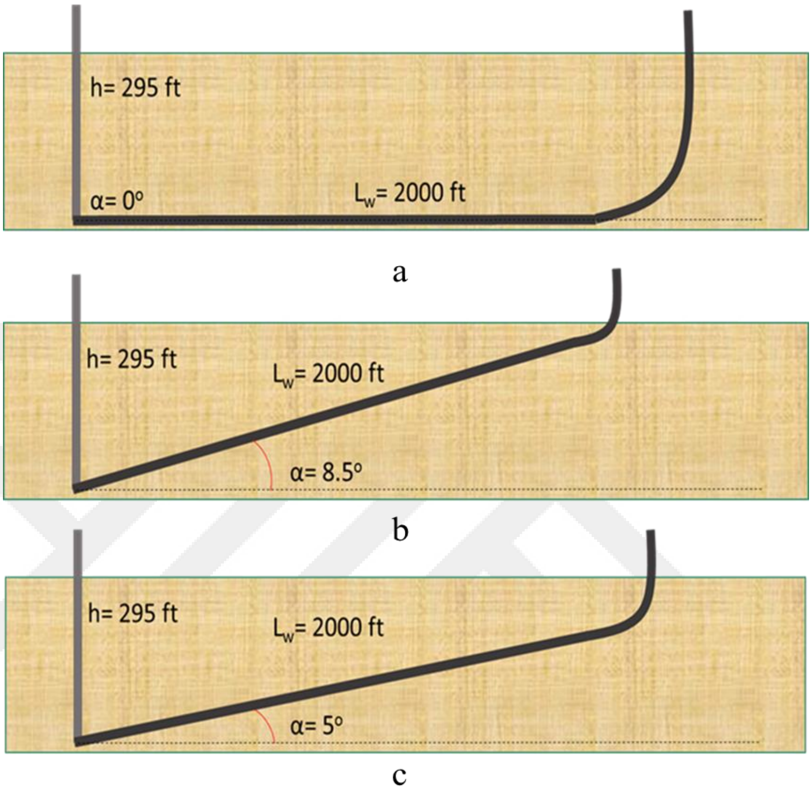


Figure 3.27: Degree of inclination of intersected wells: α=0° (a); α=8.5° (b); α=5° (c).

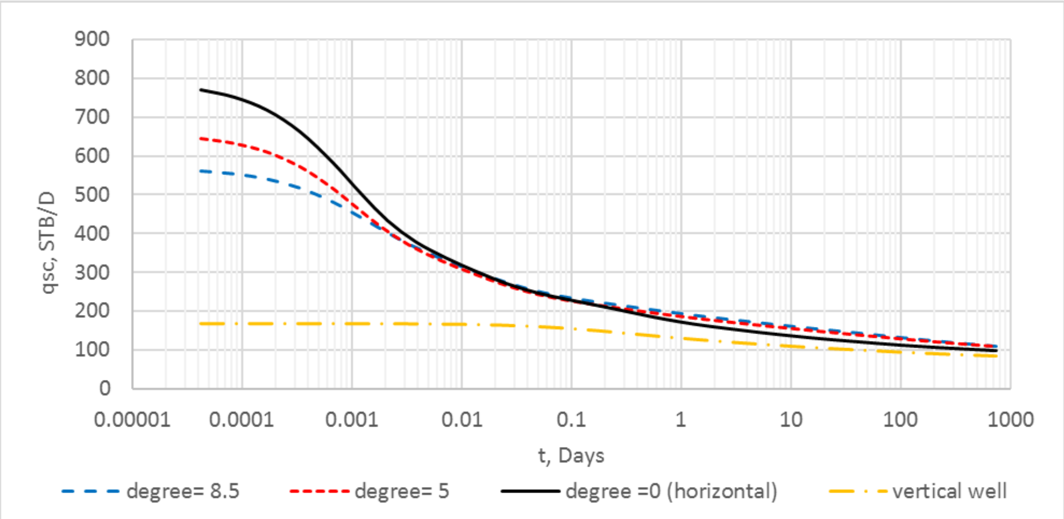


Figure 3.28: Oil flow rate vs time plots for inclined intersected wells at k_v/k_h= 0.01 anisotropy case.

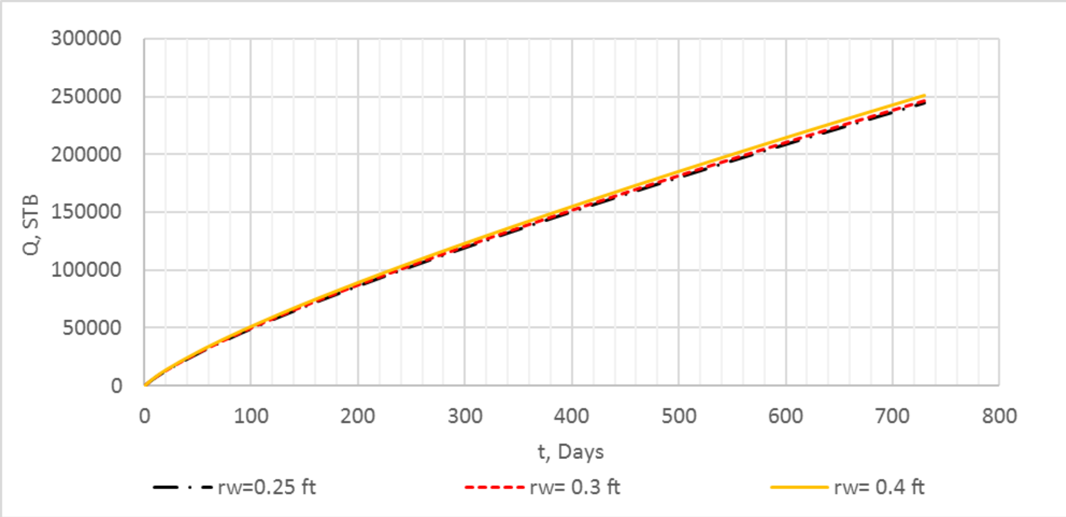


Figure 3.29: Cumulative oil flow rate vs time plots for inclined intersected wells at k_v/k_h= 0.01 anisotropy case.

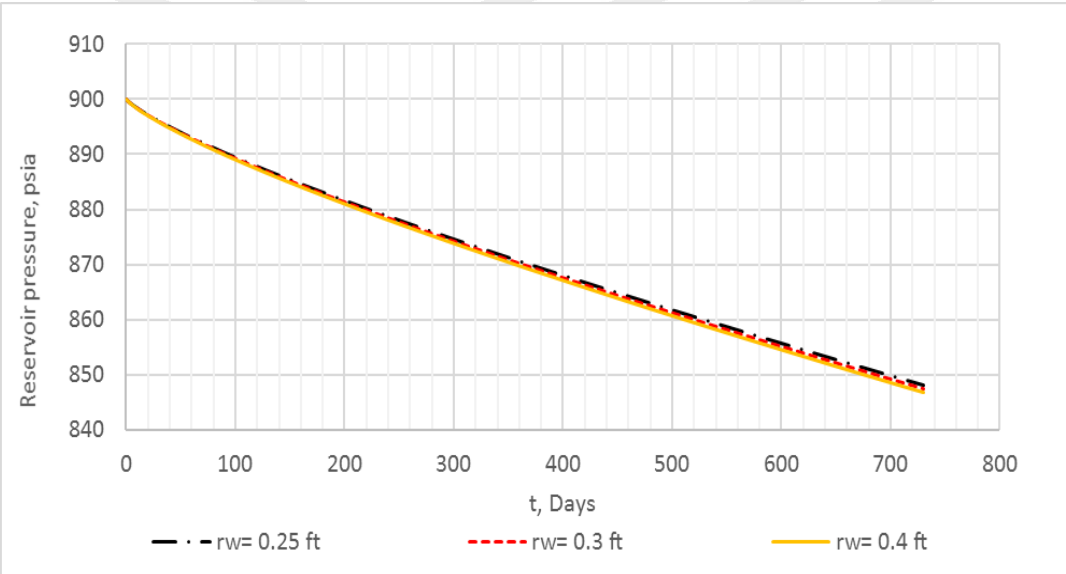


Figure 3.30: Reservoir pressure vs time plots for inclined intersected wells at k_v/k_h= 0.01 anisotropy case.

Table 3.6 : *Q* and production increase for inclined and horizontal intersected wells in horizontal anisotropy case (k_h= 100 mD; k_v/ k_h = 0.01).

cases	*Q* (STB)	Production increase comparing with vertical well case (%)
Inclined Intersected wells (8.5^o)	87196.95	35.64
Inclined Intersected wells (5^o)	86461.29	34.5
Horizontal Intersected wells	77250.12	20.2
Vertical well	64285.46	

3.7 Wellbore Radius of Intersected Wells

To check the effect of the wellbore radius (r_w) of the intersected wells at the base case stated in the above sections, three wellbore radius values are chosen: r_w= 0.25; 0.3; 0.4 ft. Cumulative oil production and a production increase of those cases are calculated and tabulated (Table 3.7). As the wellbore radius increases, oil rate, thus the cumulative oil production increases as well (Figures 3.31 and 3.32). Furthermore, due to cumulative oil production increase in the case of higher wellbore radius, reservoir pressure decrease is higher (Figure 3.33).

Table 3.7: *Q* and production increase for the wellbore radius case.

cases	*Q* (STB) vertical well	*Q* (STB) intersected wells	Production increase comparing with vertical well case (%)
r_w=0.25 ft	32709.52	244211.35	646.6
r_w=0.3 ft	33552.25	246717.52	635.32
r_w=0.4 ft	34967.38	250742.17	617.07

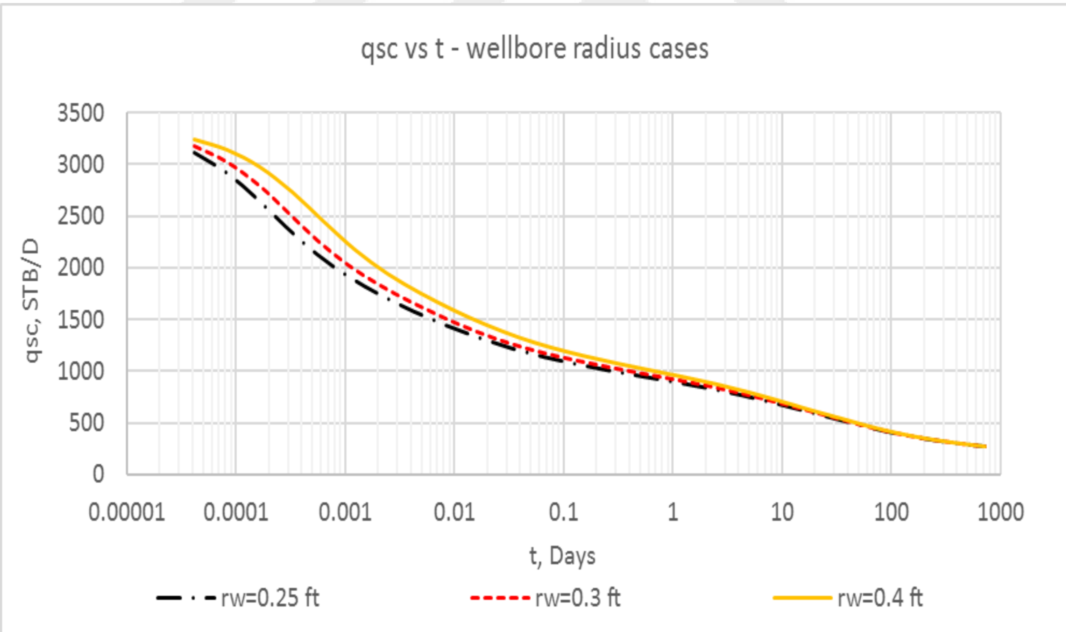


Figure 3.31: Oil flow rate vs time plots for the wellbore radius effect case.

As expected, with an increase in well radius, the cumulative produced amount increases as well.

From Table 3.6 it can be seen that even though cumulative oil production was higher for the intersected wells having higher wellbore radius, the production increase compared with a vertical well of those cases was lower. This is because higher radius affects to vertical well much more than to the intersected wells due to boundary effect. That is, the horizontal part of intersected wells see upper and lower boundary effect much earlier than vertical well see the boundaries.

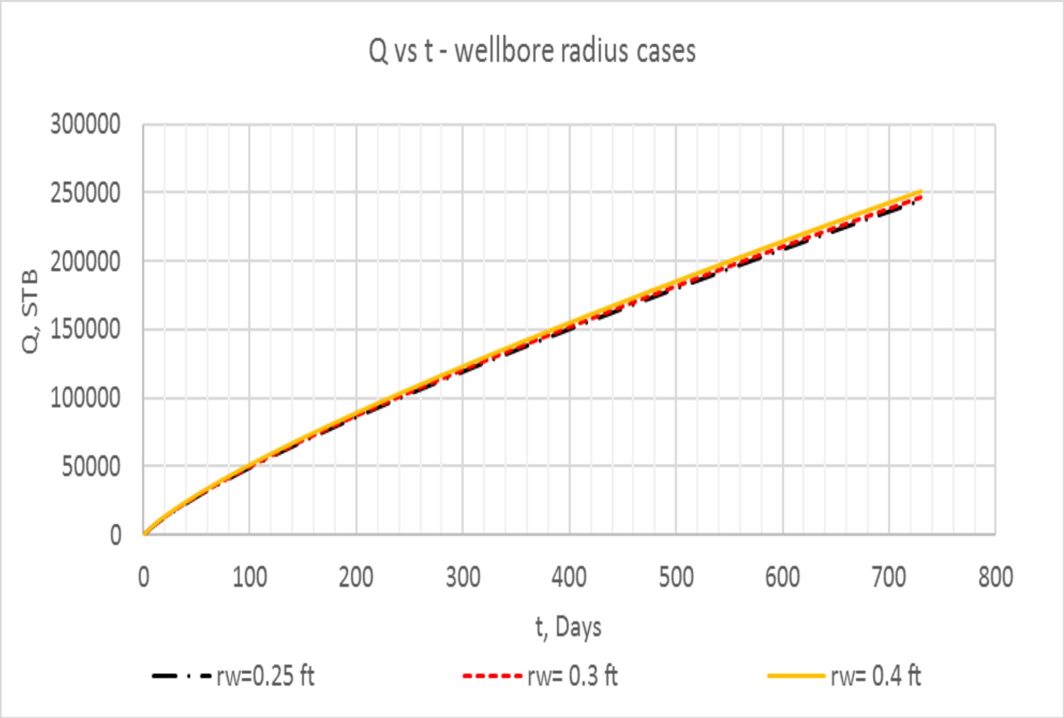


Figure 3.32: Cumulative oil production vs time plots for the wellbore radius effect case.

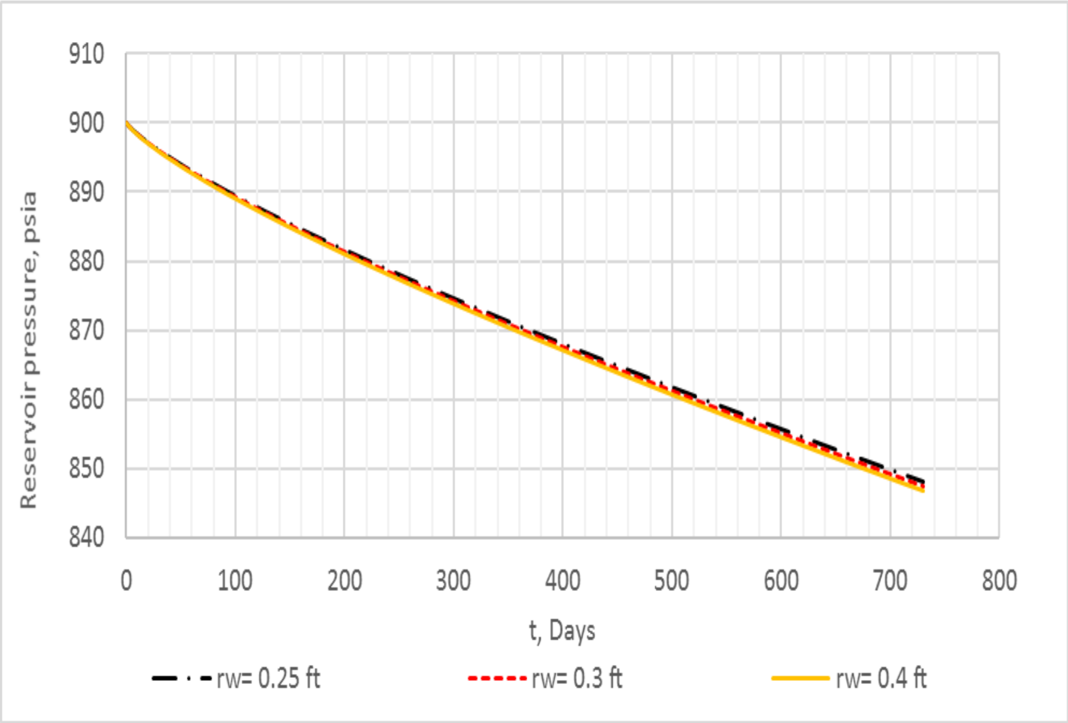


Figure 3.33: Reservoir pressure vs time plots for the wellbore radius effect case.

3.8 Skin Zone Effect on the Intersected Wells

For this purpose different skin factors (s) are taken into the consideration: s= 0; 1; 10; 20. With increasing skin factor, oil rate, cumulative oil production decreased, and thus reservoir pressure decreased less (Figures 3.34, 3.35 and 3.36). Cumulative oil production and production increase compared with vertical well at those cases are calculated (Table 3.8). Skin zone is the zone in the near-wellbore zone, where the permeability of zone is different from the reservoir, that is, either it is lower or higher than the reservoir permeability. Skin factor indicates the degree of skin zone.

The reasons for the skin zone to form are various, the main reason is invasion zone during the drilling process. From Table 3.8, it can be seen that as skin factor increases, both cumulative oil production and an increase of production compared with vertical well at that case gets lower.

Table 3.8: *Q* and production increase for the skin zone case.

cases	*Q* (STB) vertical well	*Q* (STB) intersected wells	Production increase comparing with vertical well case (%)
s=0	33552.25	246804.52	635.6
s=1	31334.21	172571.13	450.74
s=10	19689	46328	135.3
s=20	13945.58	25530.36	83.1

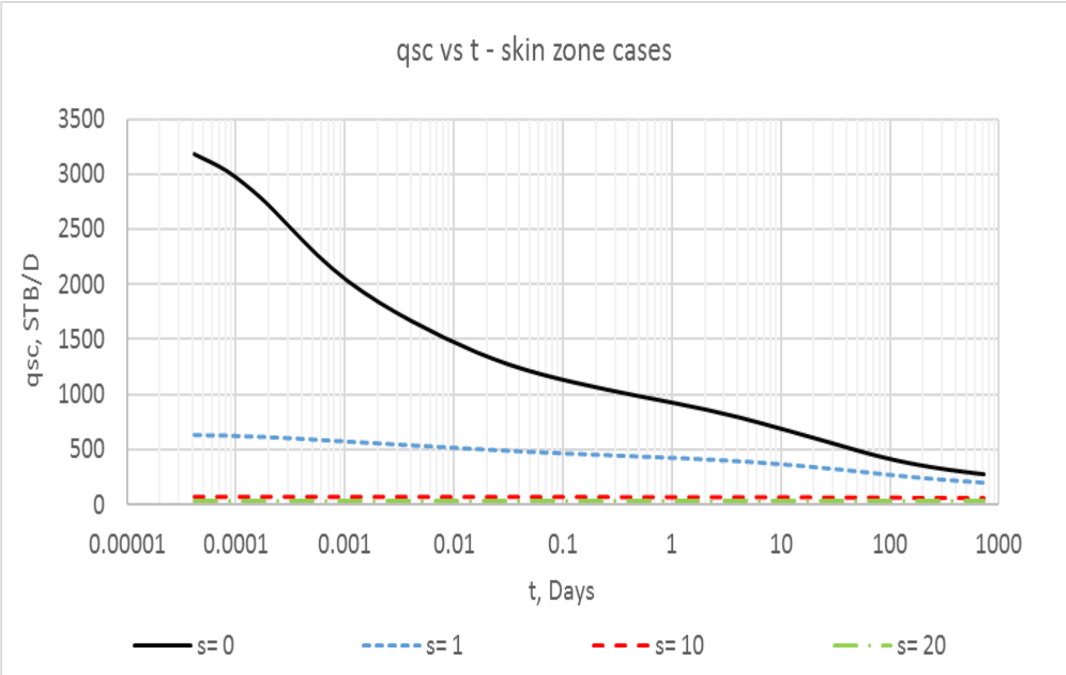


Figure 3.34: Oil flow rate vs time plots for the skin zone case.

The reason for the reservoir pressure to have decreased more in the case of zero skin factor is explained in the chapter about well length effect with material balance equation. This indicates that with increasing, cumulative oil production reservoir pressure decreases and the slope of the cumulative oil production decline is a negative form of the slope of reservoir pressure decline.

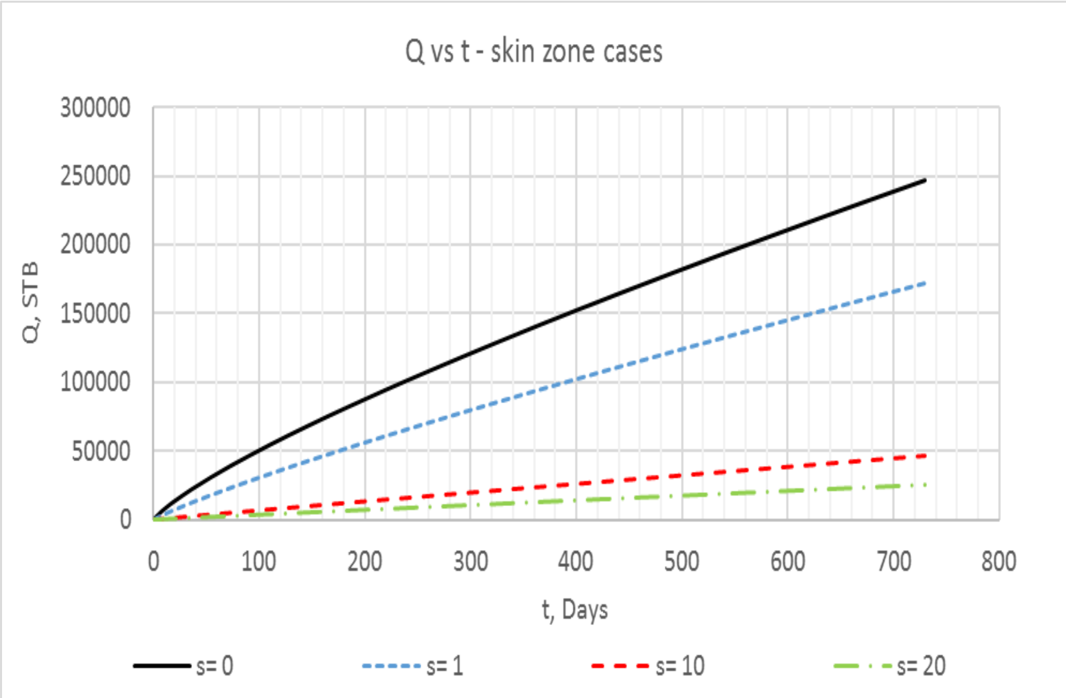


Figure 3.35: Cumulative oil production vs time plots for the skin zone case.

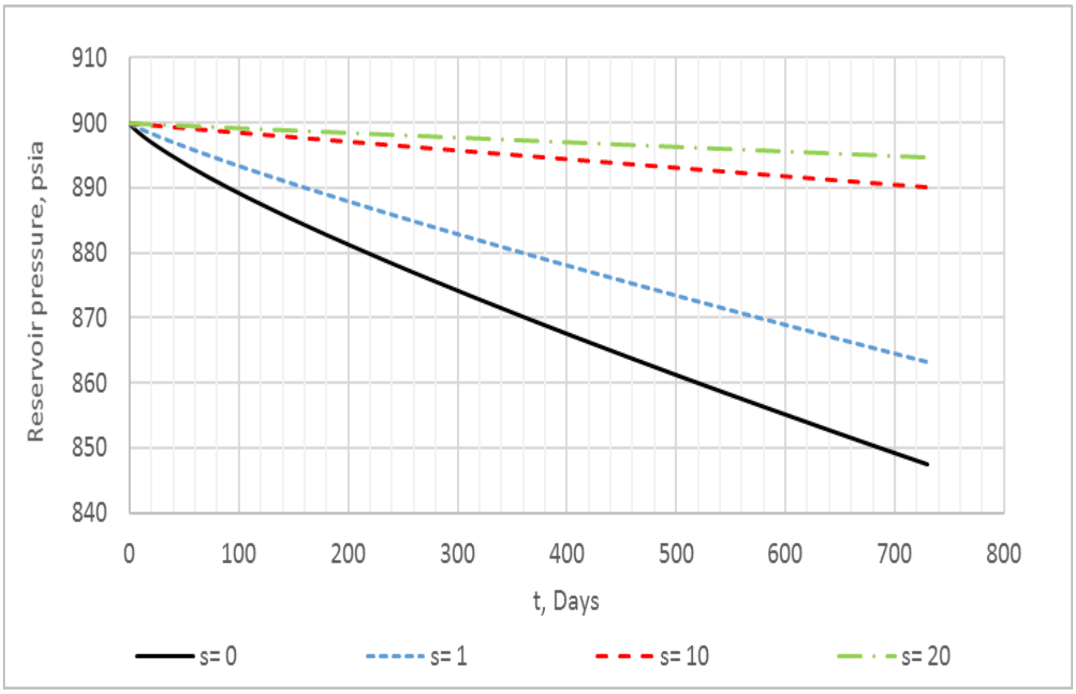


Figure 3.36: Reservoir pressure vs time plots for the skin zone case.

4. CONCLUSIONS

As it is known, heavy oil cannot be produced using conventional methods. Therefore, different types of recovery methods are used nowadays. Using intersected wells to raise heavy oil to the surface with the pump is another method proposed in this study.

Intersected wells are used instead of horizontal well since there is no possibility to directly use the pump in the deeper part of the horizontal well due to friction. However, by using intersected wells, the pump can be lowered to the bottom of the vertical well tip of which is intersected with the tip of horizontal well (or inclined well, depending on cases and reservoir parameters). Thus, using the benefit of a horizontal well, heavy oil can be raised by a pump from the lower part of the vertical well, even bottom of well if needed.

In this study, various cases have been investigated, their advantages and disadvantages have been discussed for intersected wells.

During this study following conclusions have been reached:

1. Material balance check was performed for the Rubis-simulator, and the plots of analytic results and the numerical results from the Rubis-simulator matched.
2. Analytical Babu-Odeh check was performed and there was the absolute match.
3. The benefit of using the pump in intersected wells was more than twice of that at horizontal well.
4. For the length case, the best case was the longer intersected wells. In that case higher cumulative oil production, higher oil rate, but more pressure drop is observed. The reason for this is the area open to flow is larger for the longer length case.
5. For the depth case, the best case was intersected wells in the middle of the reservoir. In that case higher cumulative oil production, higher oil rate, but more pressure drop is observed. The reason for this is that in the middle case well is far from upper and lower boundaries, and, therefore it is less affected by boundary than in other depth cases, and thus it results for the middle-depth case to have more production rate than other depth cases.

6. For the location case, the best case was intersected wells at the center of the reservoir. In that case higher cumulative oil production, higher oil rate, but more pressure drop is observed. The reason for this is that intersected wells in the middle are less affected by the boundaries since it is farther from boundaries than that at the other location cases.
7. For the degree of inclination case in the reservoir having anisotropy (k_v/k_h= 0.01), the best case was the intersected wells with a higher degree of inclination. In that case higher cumulative oil production, higher oil rate, but more pressure drop is observed.
8. For the wellbore radius case, higher cumulative oil production was for the higher wellbore radius of the intersected wells, but the production increase compared with vertical well at that case was lower for the higher wellbore radius. However, if we take an assumption that only horizontal part of intersected wells is perforated, the best case is the higher wellbore radius of the horizontal part of the intersected wells.
9. For the cases of the skin zone, the best case was the lower skin factor value. Production increase showed the great difference between cases, and the higher value was for the lower skin factor. The reason for this is that the skin zone with lower permeability results in less oil rate, and thus less cumulative oil production.

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APPENDICES

APPENDIX A: Babu-Odeh Productivity Model

APPENDIX A

There are several methods for estimating of productivity of horizontal wells. Babu and Odeh obtained a rigorous solution to the diffusivity equation for a well in a box-shaped reservoir. Babu-Odeh equation is a handy approach to find out productivity, but has the following certain limiting assumptions:

- Fluid flows to the well uniformly at all points along the wellbore (uniform flux) and the well is completed uniformly.
- The sides of the drainage volume are aligned with the principal permeability direction.
- The wellbore is parallel to the sides of the drainage area and perpendicular to the other two.
- The boundaries of the reservoir are all no-flow boundaries and the well reaches stabilized pseudosteady-state flow.
- The formation damage around the wellbore is uniform at all points along the wellbore (Url-2).

Figure A.1 introduces the nomenclature in the Babu and Odeh solution. The solution is quite complex but is approximated accurately with an equation written in the same form as the pseudo steady-state flow equation for a vertical oil well producing a single-phase, slightly incompressible liquid (Url-2).

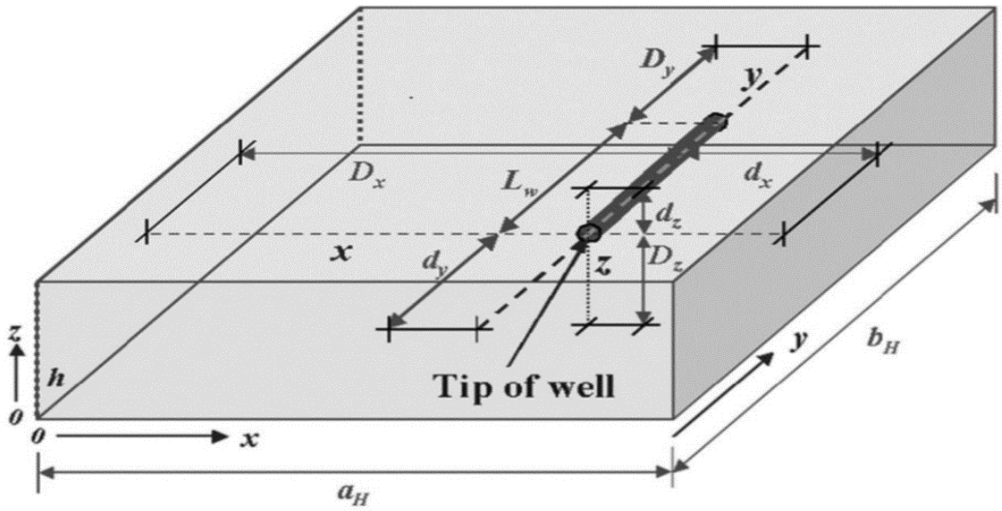

Figure A.1: Well and reservoir geometry and nomenclature for Babu-Odeh solution of the horizontal well productivity (Url-3).

Babu-Odeh equation is for the constant rate, and for uniform flux fluid flow which starts at late-linear flow regime, last flow regime. Babu-Odeh equation does not assume compressibility of fluid (c_o=0), pressure loss due to friction and gravity.

Calculating partial penetration skin-s_p in late-linear flow, geometric shape factor-C_H and productivity equations are given below (equation A.1 to A.12):

$$p_{xyz} = \left(\frac{b_H}{L_w} - 1\right)\left\{\ln\left(\frac{h}{r_w}\right) + 0.25\ln\left(\frac{k_x}{k_y}\right) - \ln\left[\sin\left(\frac{\pi d_z}{h}\right)\right] - 1.838\right\} \quad \text{A.1}$$

$$\text{Case 1, } \frac{a_H}{\sqrt{k_x}} \geq \frac{0.75 b_H}{\sqrt{k_y}} >> \frac{0.75 h}{\sqrt{k_z}} \quad \text{A.2}$$

$$s_p = p_{xyz} + p'_{xy} \quad \text{A.3}$$

$$p'_{xy} = \frac{2{b_H}^2}{L_w h}\sqrt{k_z/k_y}\left\{F\left(\frac{L_w}{2b_H}\right) + 0.5\left[F\left(\frac{4y_m + L_w}{2b_H}\right) - F\left(\frac{4y_m - L_w}{2b_H}\right)\right]\right\} \quad \text{A.4}$$

$$\text{where, } y_m = d_y + \frac{L_w}{2} \quad \text{A.5}$$

$$F(u) = -u\left[0.145 + \ln(u) - 0.137(u)^2\right], u < 1 \quad \text{A.6}$$

$$F(u) = (2-u)\left[0.145 + \ln(2-u) - 0.137(2-u)^2\right], u > 1 \quad \text{A.7}$$

$$\text{Case 2, } \frac{b_H}{\sqrt{k_y}} > \frac{1.33 a_H}{\sqrt{k_x}} >> \frac{0.75 h}{\sqrt{k_z}} \quad \text{A.8}$$

$$s_p = p_{xyz} + p_y + p_{xy} \quad \text{A.9}$$

$$p_y = \frac{6.28{b_H}^2}{a_H h}\frac{\sqrt{k_x k_z}}{k_y}\left[\left(\frac{1}{3} - \frac{y_m}{b_H} + \frac{y_m^2}{b_H^2}\right) + \frac{L_w}{24 b_H}\left(\frac{L_w}{b_H} - 3\right)\right] \quad \text{A.10}$$

$$p_{xy} = \left(\frac{b_H}{L_w} - 1\right)\left(\frac{6.28 a_H}{h}\sqrt{k_z/k_x}\right)\left(\frac{1}{3} - \frac{d_x}{a_H} + \frac{d_x^2}{a_H^2}\right), d_x \geq 0.25 a_H \quad \text{A.11}$$

$$\ln C_H = 6.28\frac{a_H}{h}\sqrt{\frac{k_z}{k_x}}\left[\frac{1}{3} - \frac{d_x}{a_H} + \left(\frac{d_x}{a_H}\right)^2\right] - \ln\left(\sin\frac{\pi d_z}{h}\right) \quad \text{A.12}$$

$$-0.5\ln\left[(a_H/h)\sqrt{k_z/k_x}\right] - 1.088$$

Using geometric shape factor-C_H, skin factors s_p, s_d and other reservoir parameters in the equation A.13, productivity index of the horizontal well can be calculated for late-linear flow regime (uniform flux) (Url-2):

$$J = \frac{q}{p_R - p_{wf}} = \frac{0.00708 b_H \sqrt{k_x k_y}}{B\mu\left[\ln\left(\frac{C_H A^{1/2}}{r_w}\right) - 0.75 + s_p + \left(\frac{b_H}{L_w}\right)s_d\right]} \qquad \text{A.13}$$

where,

A= drainage area of the reservoir, ft^2

a_H= total width of reservoir perpendicular to the wellbore, ft

B= formation volume factor, RB/STB

b_H= length in direction parallel to wellbore, ft

C_H= geometric shape factor, dimensionless

D_x= longest distance between horizontal well and x boundary, ft

d_x= shortest distance between the horizontal well and x boundary, ft

D_y= longest distance between tip of horizontal well and y boundary, ft

d_y= shortest distance between the tip of a horizontal well and y boundary, ft

D_z= longest distance between horizontal well and z boundary, ft

d_z= shortest distance between the horizontal well and z boundary, ft

h= net formation thickness, ft

J= productivity index, STB/D-psi

k_x= permeability in x-direction, md

k_y= permeability in the y-direction, md

k_z= permeability in z-direction, md

L_w= completed length of horizontal well, ft

p_R= reservoir pressure, psi

p_{wf}= flowing BHP, psi

p_{xy}= parameter in horizontal well analysis equations

p_{xyz}= parameter in horizontal well analysis equations

p_y= parameter in horizontal well analysis equations

q= flow rate, STB/Day

r_w= wellbore radius, ft

s_d= skin caused by formation damage, dimensionless

s_p= skin resulting from an incompletely perforated interval, dimensionless

μ= viscosity, cp

ϕ= porosity, dimensionless.

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