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EFFECTS OF NON-DARCY FLOW ON THE IMPAIRMENT OF GAS CONDENSATE WELLS

By

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CERTIFICATION

This is to certify that the thesis titled "**EFFECTS OF NON-DARCY FLOW On THE IMPAIRMENT OF GAS CONDENSATE WELLS**" submitted to the school of postgraduate studies, African University of Science and Technology (AUST), Abuja,Nigeria for the award of the Master's degree is a record of original research carried out by JONAH Emmanuel Abah in the Department of Petroleum Engineering.

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By

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ABSTRACT

Gas condensate reservoirs are initially discovered as single-phase gas reservoirs. As the reservoir is produced below the fluid dew-point pressure, an increase in condensate saturation in the near wellbore region occur which reduces the relative permeability to gas and in turn causes productivity impairment. It is pertinent to predict condensate banking behavior due to Non-Darcy effects accurately during a field's operational phase to avoid problems with a well's ability to attain production targets. This paper therefore seeks to evaluate the effect of Non-Darcy flow on the impairment of gas condensate wells. This paper seeks to evaluate the effects of Non-Darcy flow on the impairment of gas condensate by varying the degree of Turbulence through adopting various Forchheimer factors. To achieve this, a PVT data for gas condensate reservoir from a field was used to build an input data file using Eclipse 300. A single-layer, radial, 3D reservoir model was used to investigate the effects of Non-Darcy on field gas flow rates and cumulative gas produced over the life span of the well. A fully perforated vertical well was located at the center of the reservoir model. The reservoir model consisted of 30 grid blocks increasing logarithmically with radius away from the well bore.The use of fine-resolution griding near the well bore was to ensure that change in condensate was accurately simulated.

The results showed that When Velocity Dependent Relative Permeability (VELDEP) option was adopted for Forchheimer of 10 there was no significance change in the gas production rate. However, when the factor increases to 100, There exist a significant increase in the gas production rate as well as the cumulative field production. Also productivity of the well decreases by about 22% during the first three years of production due to skin effect arising from increased turbulence around the well-bore region.

Keywords and Phrases: Non-Darcy Coefficient, Velocity Dependent Relative Permeability, Condensate Banking, Gas Condensate Reservoirs, Capillary Number, Interfacial Tension, Viscous force, Gas Relative Permeability, Skin Productivity Index.

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DEDICATION

I dedicate this work to Almighty God who in His infinite wisdom helped me to be where I am today and to achieve all that I have achieved. To you alone be all thanks.

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CHAPTER ONE

1.0 INTRODUCTION

Gas condensate reservoirs are a type of hydrocarbon reservoir that contain a mixture of natural gas and liquid hydrocarbons. These reservoirs are characterised by their unique properties, which differentiate them from conventional gas or oil reservoirs. The presence of both gas and liquid phases in the reservoir fluid makes the production and management of gas condensate reservoir challenging yet highly valuable. Gas condensate reservoirs are typically formed in geological formations with high temperature and pressure conditions. The reservoir fluids consist of a mixture of natural gas, which primarily consists of methane, and heavier hydrocarbon liquids such as ethane, propane and butane. These liquids are in dissolved state within the gas phase under high-presure conditions, but as the reservoir fluids are produced and the pressure decreases, the relatively heavier hydrocarbons undergo a phase change and condense into a liquid phase. The condensation of the liquid hydrocarbons within the reservoir fluid poses unique challenges for reservoir engineers. As the vapour condenses into liquid, they can accumulate and cause liquid dropout or condensate banking, reducing the effective permeability of the reservoir and impeding gas flow. Moreover, the condensate can condense within the wellbore and surface facilities, leading to the flow assurance issues and equipment corrosion. However, gas condensate reservoirs offer significant potential for hydrocarbon production due to the presence of valuable liquid hydrocarbons. The recovery of these liquids, along with the associated natural gas, can result in substantial economic benefits. Various techniques such as pressure maintenance, artificial lift, and gas cycling are employed to optimize production rates and maximise condensate recovery.

In conclusion, gas condensate reservoirs present a unique set of challenges and opportunities for the oil and gas industry. Understanding the behavior and characteristics of these reservoirs is crucial for effective reservoir management and production optimization. As technology and knowledge continue to advance, gas condensate reservoirs will play an increasingly important role in meeting global energy demands.

1.1. PROBLEM STATEMENT

Gas condensate reservoirs have long exhibited production problems when the pressure and temperature along the porous media and well-bore fall below the dew point. In many gas reservoirs that produce from vertical wells, as the gas approaches radially to the well bore, the cross sectional area to flow becomes smaller with reducing distance, and consequently gas flow velocity increases. As a result, turbulent flow might initiate which is directly related with flow velocity and gas condensation might occur. Gas condensate causes a reduction in gas relative permeability, and thus gas production decreases. This mechanism is important for converted underground gas storage reservoirs during their production phases. The impact of the depletion strategy of gas fields on the well productivity, liquid and gas recoveries is a topic of increasing interest. Therefore, there is the need to better understand the factors controlling the drainage and the decline of wells productivity due to condensation and turbulence, and when temperature and pressure fall significantly below the dew point.

1.2 AIM AND OBJECTIVE

The objectives are as follows:

1. To understand the mechanism of condensate dropout and factors that affect it.

2. To quantify the degree of impairment by defining velocity dependent relative permeabilty as a function of condensate banking
3. To build an Eclipse input data file for a gas condensate compositional simulator.

1.3 JUSTIFICATION

The justifications of the research include the following:

- To optimizing the producing strategy for gas-condensate reservoirs.
- To deduce the impact of turbulence on the impairment of gas reservoirs
- To maximize recovery of both gas and condensate

1.4 SCOPE

The scope of the work is to use simulation modeling to investigate the impact of Non-Darcy flow on the impairment of gas condensate wells by measuring variations in the relative permeability as well as optimizing the condensate recovery for gas-condensate systems.

CHAPTER TWO

2.0 LITERATURE REVIEW

2.1. CONDENSATE BANKING-WELL IMPAIRMENT

Condensate banking is a phenomenon associated with retrograde natural gas fluids. During the production of these fluids with the reservoir pressure declining below dew point values and hydrocarbon liquid condensates drop out. The saturation may rapidly build up for high condensate gas ratio(CGR) reservoirs and thus exceeding critical saturation for liquid mobility. The condensate flows towards the producing wells where a “bank of condensates(hydrocarbon liquids)”, is formed around the wells. This condensate bank can grow when both reservoir and well flowing bottom hole pressures decline further and can potentially lead to impairment on the well`s deliverability. Field examples show that the effect of condensate banking could be severe leading to productivity loss factor of between 2 to 6. An example is the Arun Field in North Sumatra, Indonesia, which experienced a decline in productivity by a factor of 2 when the well bottom hole flowing pressure fell below the dew point. (Okporiri *et al.*, 2014).

The generation of a condensate bank around producing wells and the potential impact on The generation of a condensate bank around producing wells and the potential impact on productivity is however dependent on a number of reservoir`s fluid and flow parameters and these parameters will also determine if there will be productivity impairment or not. Therefore in the treatment of condensate banking, there is a need to look at the type of condensate systems as it would be wrong to appropriate the same behaviour of condensate banking on all types of retrograde gas condensate systems due to the dependence on fluid and flow properties. For near-critical fluids, the expected trend will be a similarity between the gas and liquid phases. For rich gas, the large amount of condensates deposited exceeds the critical condensate saturation necessary for mobility and therefore the condensate is mobile. Also the interfacial tension (IFT) between the condensate and gas phases will initially be very small. Under these conditions, the displacement process becomes more "miscible-like" and straight-line relative permeability curves could be used to describe the recovery process. Further depletion below the dew point causes the phases to become more distinct and the IFT becomes larger and immiscible-like and capillary-dominated flow begins to dominate again. Therefore the IFT is a key parameter controlling the flow of gas and condensate for conditions close to the critical point. In general, for natural gas reservoirs viscous forces and flow velocities can become very high. At these high velocities, inertial flow effect are being set up otherwise known as non-darcy conditions which control the productivity of the wells.This is generally referred to in modelling as non-darcy effect. Non-Darcy effect influences relative permeability because of more that usual pressure drop which will increase liquid drop-out. Hence, this work focuses on the effect of non-darcy flow on the impairment of gas condensate wells.

2.2 GAS RESERVOIRS

2.2.1 Condensate Gas Reservoirs Flow Behaviour

At discovery, a typical gas-condensate reservoir pressure might be above or close to the critical pressure. At this condition there exists only single-phase gas. However as the production is carried out, there is isothermal pressure decline and as the bottom hole pressure in a flowing well falls below the dew-point of the fluid, a liquid hydrocarbon phase is formed. This retrograde condensate formation results in buildup of a liquid phase around the wellbore leading to a decrease in the effective permeability to gas.. The productivity loss associated with condensate buildup can be substantial. Afidick *et al*. (1994) and Barnum *et al.* (1995) have accounted for several instances in which well productivities have been reported to decline by a factor of two to four as a result of condensate accumulation. The liquid dropout first occurs near the wellbore and propagates radially away from the well if the well is at the center of a circular reservoir. Fevang (1995) and Ali *et al*. (1997) showed that, when reservoir pressure around a well drops below the dew-point pressure, retrograde condensation occurs and three regions are created with different liquid saturations. Away from the well, an outer region has the initial liquid saturation; next, there is an intermediate region with a rapid increase in liquid saturation and a corresponding decrease in gas relative permeability. Liquid in that region is less than the critical condensate saturation and hence is immobile. Closer to the well, an inner region forms where the liquid saturation reaches a critical value, and the effluent travels as two-phase flow with constant composition. The condensate deposited as pressure decreases is equal to that flowing towards the well. According to Economides *et al*. (1987) and Fussel (1973), there may also exist a fourth region in the immediate vicinity of the well where low interfacial tensions (IFT) at high rates yield a decrease of the liquid saturation and an increase of the gas relative permeability.

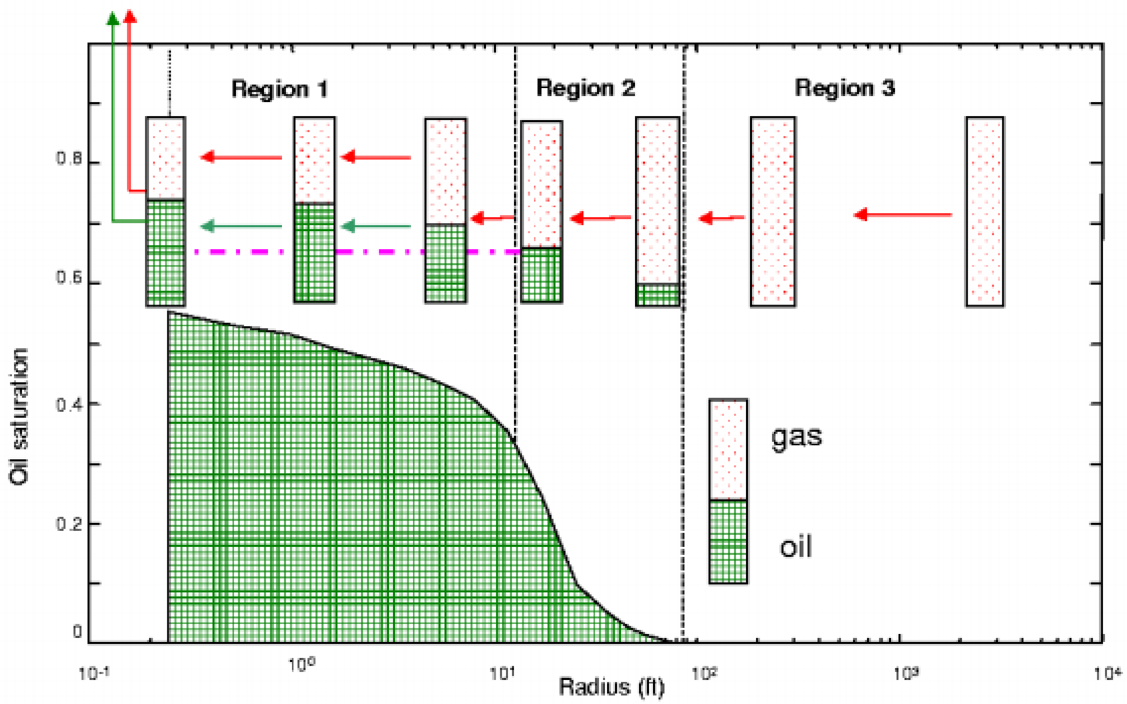

Figure 2.1: Schematic Gas-Condensate Flow Behavior (Roussennac, 2001)

Asar and Handy (1988) investigated the influence of interfacial tension on the relative permeability of gas/oil in a gas condensate system. They postulated that the irreducible gas and liquid saturations approach zero as interfacial tension approaches zero. In addition, they observed that condensate could flow at a low condensate saturation (Scc) of 10%. Finally, it was concluded that liquid could flow at a very low liquid saturation at low interfacial tensions in a condensate reservoir. This is significant as regions with two-phase (gas and liquid) conditions have low interfacial tension.Gravier *et al*. (1983) used the steady-state displacement method with horizontal cores (tight reservoir limestone) with interstitial water saturation from 19.5% to 30%. They determined the critical condensate saturation (Scc) by injecting gas-condensate into the core. The Scc values ranged from 24.5 to 50%, with interfacial tension ranging from 0.5 to 1.5 mN/m.

Danesh *et al*. (1988) investigated retrograde condensation in water-wet pores in their micromodels and a set of sandstone cores. They determined Scc values of 20.5% to 6.8% in the absence and presence of interstitial water, respectively. These various studies suggest the minimum required condensate saturation for the flow of condensate is quite high, yet field experiences suggest otherwise. Allen and Roe (1950) reported on the behavior of a gas reservoir with an average water saturation of 30% and a maximum liquid saturation of 12%. They concluded that condensate flowed from the formation into the wellbore throughout most of the reservoir's productive life.

Nikravesh *et al.* (1996) have accounted for existence of a threshold value or an interval of interfacial tension (0.03-0.05 dyne/cm) in which the shape of the relative permeability curve changes significantly and Scc increases drastically. They also gave account of effect of interstitial water on Scc. Nikravesh et al. (1996) reported that one of the works showed no effect of interstitial water on Scc while another showed negative effect on Scc, and yet another postulated that the liquid saturation (Scc + Swi) is a constant. Unfortunately, even with the limited amount of literature in this area, the conclusions are contradictory and controversial. The contradictions are due to inadequate understanding of chemical and physical processes, especially the adsorption and phase transformation involved in the condensate formation and flow behavior.

Fussell (1973) described the use of a modified version of one-dimensional radial model developed by Roebuck *et al*. (1969) to study the long-term single-well performance. The condensate accumulation in the producing region are much greater than those measured experimentally during constant volume depletion (CVD) process.

Hinchman and Barree (1985) studied the effect of the fluid characteristics on the predicted productivity decline of a gas-condensate well. They demonstrated that the amount of gas-condensate accumulation near the wellbore depends greatly on the richness of the gas-condensate, the relative permeability data and the liquid viscosity. Sognesand (1991) discussed the condensate buildup in vertically fractured gas-condensate wells. He showed that the condensate buildup depends on the relative permeability characteristics and production mode. Increased permeability to gas yields reduced amount of condensate accumulation, and constant pressure production yields the largest near fracture condensate buildup.

Raghavan *et al* (1989) studied theory of the steady-state flow for gas-condensate reservoirs. The relationship between the oil saturation and pressure they presented is the same as that Chopra *et al*. (1986) had given. A no-flow region for condensate liquid was not allowed (only two zones were considered, one where there is only single-phase reservoir fluid and it is mobile and the other near the wellbore that has both gas and condensate present and both phases are mobile) and the condensate saturation values Raghavan et al. (1989) gave are much greater than the critical saturation. In the retrograde condensate region, the interfacial tension between the gas and the condensed phase is very small. Hence, it is expected that the capillary forces, which are the major factor governing multiphase flow behavior in reservoirs, play a less important role relative to both gravity and viscous (shear) forces.

2.3 Gas Reservoir Properties

A reservoir fluid is classified as:

- Dry gas when the reservoir temperature is greater than the cricondentherm and surface/transport conditions are outside the two-phase envelope.

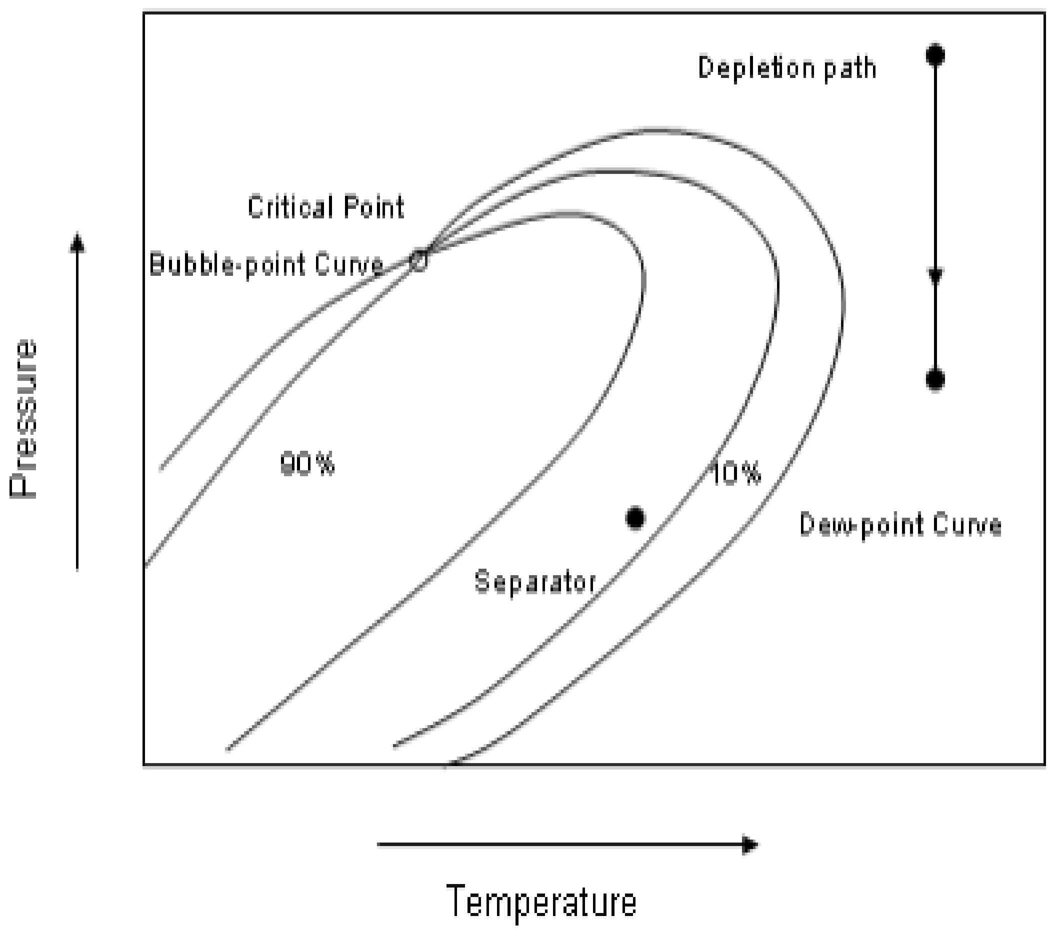

Figure 2.2: Phase Diagram for Dry Gas Reservoir

- Wet gas when the reservoir temperature is less than the cricondentherm and greater than the critical temperature.

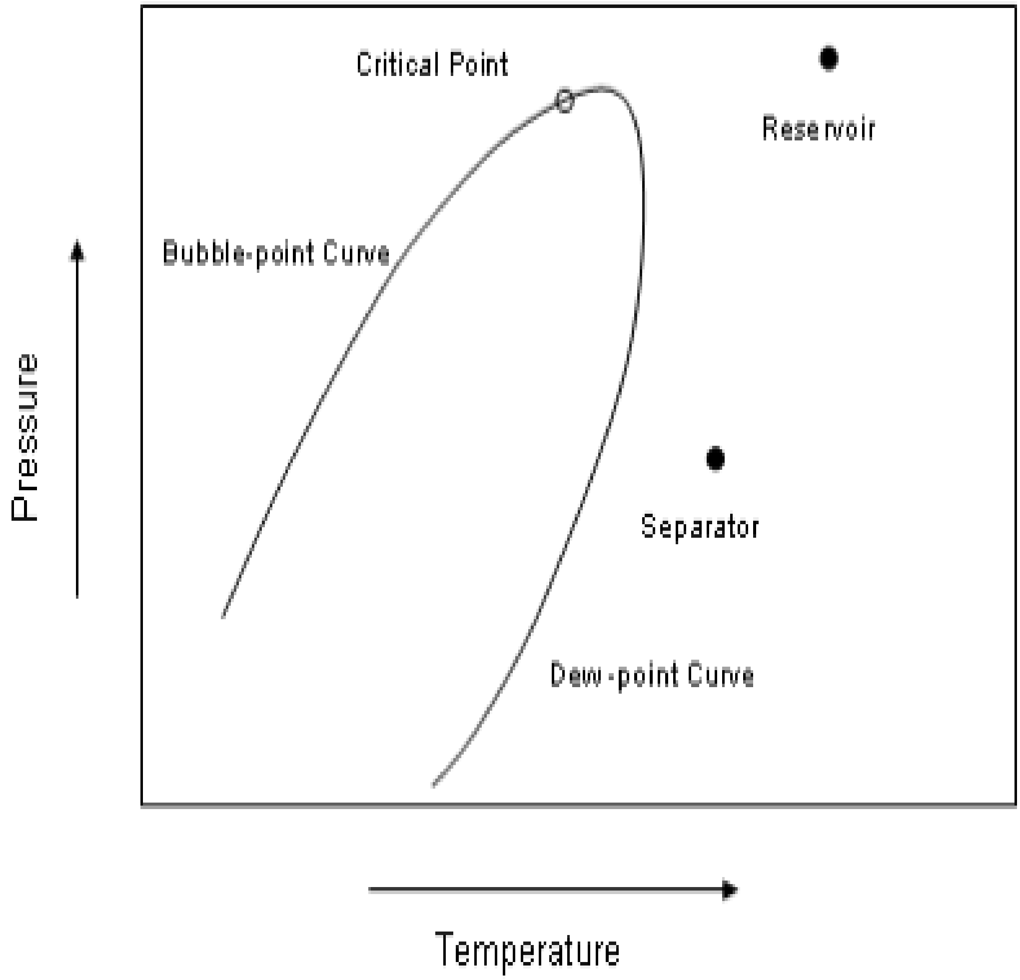

Figure 2.3: Phase Diagram for Wet Gas Reservoir

- **Gas Condensate**

Gas condensate contains a small fraction of heavy component. The presence of the heavy components expands the two-phase envelope of the fluid mixture to the right (Figure 2.4), compared to that of wet gas (Figure 2.3). Hence, the reservoir temperature lies between the critical temperature and the cricondentherm. The liquid will dropout of the gas when the pressure falls below the dew-point pressure in the reservoir. Further liquid.

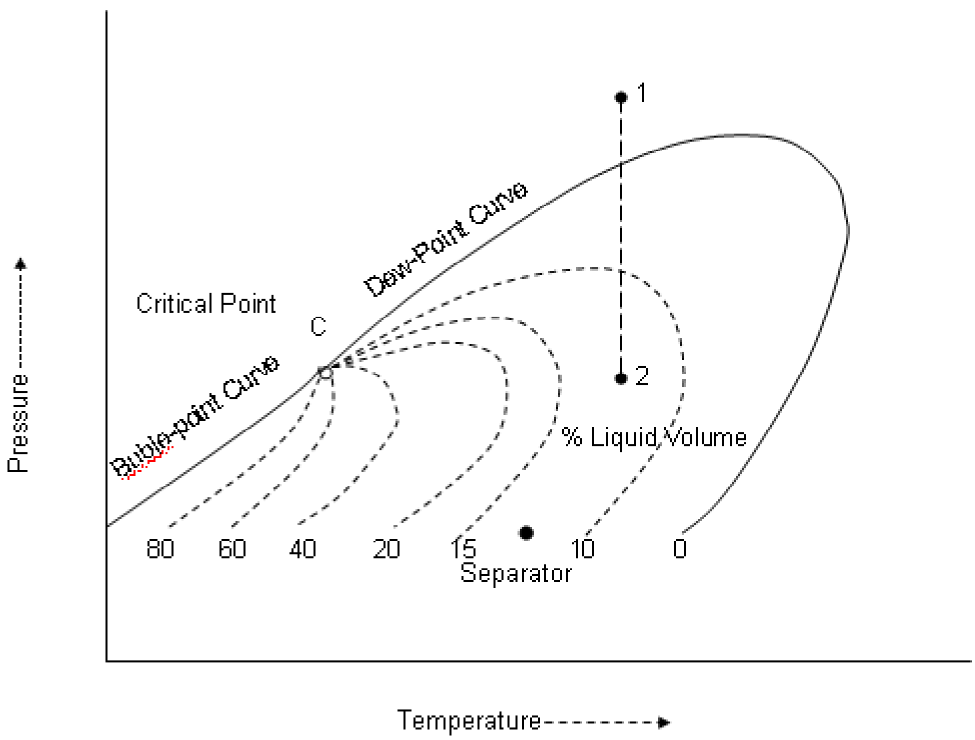

Figure 2. 4: Phase Diagram with a line of Isothermal Reduction of Reservoir Pressure of Gas Condensate.

Table 2.1: Physical Properties of Reservoir Fluids(SPE monograph)

Properties						
	Dry Gas	**Wet Gas**	**Gas Condensate**	**Near Critical Oil**	**Volatile Oil**	**Black oil**
M_{C7+}		130	184	219	228	274
γ_{C7+}		0.763	0.816	0.839	0.858	0.920
GOR ,scf/stb	∞	105000	5450	3650	1490	300
OGR, stb/mmscf	0	10	180	275	-	-
γ_{API}		57	49	45	38	24
γ_g		0.61	0.70	0.71	0.70	0.63
$P_{sat,}$ Psia		3430	6560	7015	5420	2810
$B_{sat,}$ bbl/stb		0.0051	0.0039	278	1.73	1.16
$\rho_{sat,}$ lbm/ft^3		9.61	26.7	30.7	38.2	51.4

2.4 FLOW THROUGH POROUS MEDIA

2.4.1 Darcy Law and Non-Darcy Flow

Fluid flow through porous media starts with empirical and unidirectional Darcy's Law. Darcy's law as shown in Eq. 2.1 is a linear relationship between laminar and single phase water (as a Newtonian fluid) flow through an isotropic porous medium, the dynamic viscosity of water and the pressure gradient: Learn to use equation editor and correct symbols

$$u = -\frac{k}{u}\frac{\partial y}{\partial x} \quad ------------------------------------ \quad 2.1$$

Where;

u = superficial velocity (L/T),

K = permeability (L^2),

p = pressure $M/(LT^2)$,

μ = viscosity (M/LT), and

x = dimension in x direction (L).

In Darcy's equation given above the dynamic viscosity has a constant value due to assumed linear relationship where shear stress (as dependent variable) versus shear rates (as independent variable).The deviations from Darcy's conditions have required numerous contributions to Darcy's law. The most significant contributions was made by P. Forcheimer in 1901, when he asserted that there is an additional pressure drop associated with a system at high fluid velocity. Equation 2.2 is known as the Forcheimer equation.

$$\frac{\delta P}{\delta x} = \left(\frac{\mu}{K}\right)u + \beta\rho u^2 \quad -- \quad 2.2$$

where ρ is fluid density (M/L^3), and β is the non-Darcy coefficient (1/L). Here β coefficient has had different names in the literature such as turbulence factor, the coefficient of inertial resistance, the velocity coefficient, the non-Darcy flow coefficient, the Forchheimer coefficient, the beta factor, etc. The deviations from Darcy's law is because of anisotropy in porous media (three dimensional changes in absolute permeability due to tortuosity, layers, fractures, etc.), multi phase flow such as gas, liquid and even sometimes solid flow due to drag forces (non-Newtonian fluid properties, relative permeability, saturation, wettability, gravity segregation, surface tension, interfacial tension, miscibility might become definitive), phase changes due to pressure drop (condensation and vaporization), and high flow rates (turbulence) in different geometries (linear, cylindrical, semispherical, etc). In almost every decade of the last century many empirical and theoretical studies have been published but a clear definition of Non-Darcy flow coefficient covering all affecting parameters has not been developed yet. As a matter of fact, there is no common agreement on the causes of nonlinearity between the pressure gradient and velocity; some scientists attribute it to viscous forces, and some attribute it to inertial forces. It seems that Non -Darcy effect on fluid flow due to viscous forces has not been adequately quantified yet. Especially, gas condensation near well bore regions due to turbulent raises the fluid viscosity which will increase the required pressure drop to flow, and consequently a non-Darcy effect in fluid flow occurs. In the last decades, theoretical, numerical and experimental researches and investigations have proceeded for better understanding of non-Darcy effects in flow through porous media. The survey in literature of non-Darcy flow has been grouped on the basis of non-Darcy flow effects in this part of the dissertation.

The Forchheimer or non-Darcy flow coefficient is usually measured for single-phase flow (in the presence of irreducible water saturation), or inferred from multi-rate well tests. When condensate is deposited in the reservoir, it is necessary to account for the variation of the Forchheimer coefficient with gas saturation. In the Velocity

Dependent Relative Permeability (VDRP) model developed by Heriot-Watt University, this dependence is expressed as:

Note that the value of the Forchheimer coefficient for single-phase flow is given by:

$\beta (S_g)=\beta^{\square} S_g^c (K K_{rg})^d$ ---2.3

$\beta_{sp}=\beta^{\square} (1-S_{w,irr})^c K^d$--2.4

assuming that the end-point relative permeability to gas is equal to unity.

CHAPTER THREE

3.0. METHODOLOGY

Binary-Component Simulation Model

A hypothetical cylindrical reservoir model with radius of 1200 ft and near the well region permeability-thickness of 60 md-ft will be chosen. In the simulation, small radii grid blocks around the wellbore will be chosen to allow accurate pressure drop calculation in the near wellbore region. A proposed simulator E300 (2005a, Eclipse) with fully implicit (FULLIMP) method will be used to simulate the performance under different producing strategies.

The proposed reservoir fluid will be a synthetic gas-condensate system. The simulation will be performed under reservoir temperature of 60^{o}F. The producer in this simulation will be controlled by gas rate and minimum bottom-hole pressure (BHP). The well will be initially produced at the designated gas rate and switched to bottom-hole flowing pressure control if the BHP was below the minimum limit. A single-layer, radial, 3D reservoir model was used to investigate the effect of non-darcy on productivity from gas condensate reservoir with the aid of Eclipse 300 reservoir simulation software. A fully perforated vertical well was located at the center of the reservoir model. The reservoir model consists of 30 grid blocks increasing logarithmically with radius away from the wellbore. The use of high-resolution gridding near the wellbore was undertaken to ensure that changes in condensate saturation are accurately simulated. The reservoir description, properties and reservoir grid distribution of the gas condensate reservoir model are listed in Table 3.1 and Table 3.2 respectively.

Table 3. 1**: Reservoir Grid Dimension and Description**

Grid Dimensions	30 x 1 x1
Datum Depth (ft)	7800
Gas/Water Contact	7801
Initial Pressure at Contact, (psia)	8000
Water Density at Contact (lb/ft^3)	63
Water Compressibility (psi^{-1})	3x10^{-6}
Capillary Pressure at Contacts (psi)	0
Porosity	0.2
Thickness (ft)	60
Kx (md), Kz (md)	60

Table 3.2: Grid size Distribution of the 3D, Radial Reservoir Model Used in the Simulations

Innermost Grid Radius (ft)			0.2917		
Reservoir Grid Cells Size in Radial Direction (ft)	1.71	1.72	1.73	1.74	1.75
	1.76	1.77	1.78	1.79	1.8
	1.9541	2.4544	3.0827	3.8719	4.8631
	6.1081	7.6718	9.6358	12.1026	15.2009
	19.0924	23.9802	30.1192	37.8299	47.5146
	50.55	109.21	235.92	509.68	1101.08

Figures 3.1 shows the 3D view of the reservoir model described in the Tables 3.1 and 3.2.

Model Initialization:

Initialising a compositional model will ensure that lighter component go up and heavy components go down, which results in composition variations with depth effectively estatblishing a hydrostatic equilibrium. There are two possible types of composition gradients; a change of state from gas to oil without a distinct gas oil contact and a change of state from gas to oil with a distinct gas-oil contact. ECLIPSE uses the word EQUIL keyword for initialization. This helps specifies the initial pressure at reference depth, the initial water-oil(WOC), and gas-oil(GOC)contacts.

For our use case, the item 10 of this keyword is set to 1, to request that ECLIPSE use type one initialization for continuous hydrocarbon phase initial state; the WOC equals the GOC, implying that there's no GOC (analogous to a gas-water system). The reservoir top and bottom are 7300 ft. and 7800ft. respectively This is shown is equation 3.1 below:

```
EQUIL
7300 4000 7600 0 7600 0 1 1 0 1 /    --------------------------------------------------------------------------------3.1
```

The default fluid composition with respect to depth, is also set using the ZMFVD keyword, as shown in table 3.3.

Table 3.3: Default fluid sample composition

```
ZMFVD
--  depth       CO2     C1N2    C2      C3      C4      C5C6    C7+     C12+    C22+
    7300.00000  .01210  .01940  .65990  .08690  .05910  .09670  .04745  .01515  .00330
    7600.00000  .01210  .01940  .65990  .08690  .05910  .09670  .04745  .01515  .00330
    7800.00000  .01210  .01940  .65990  .08690  .05910  .09670  .04745  .01515  .00330 /
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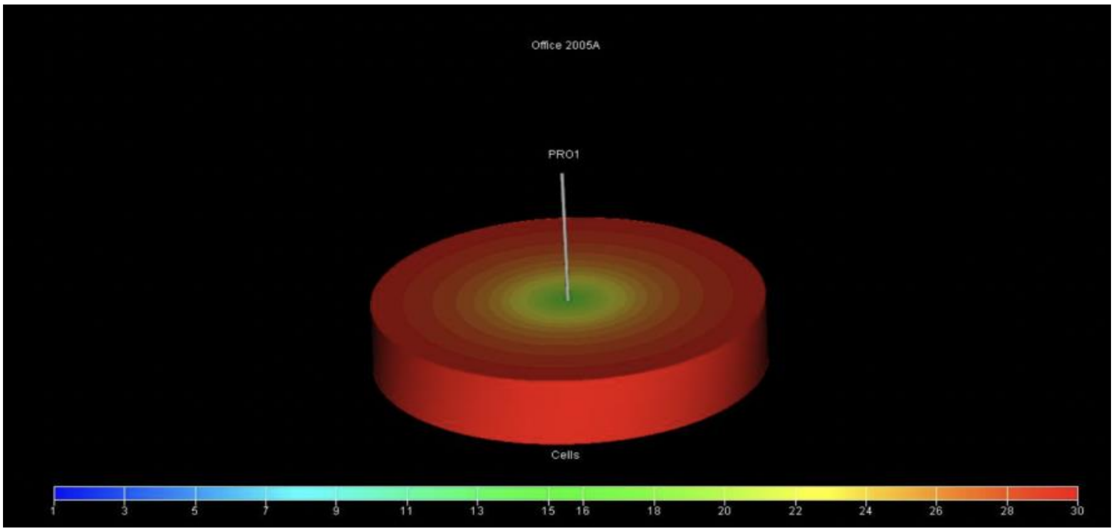

Figure 3.1: 3D view of the radial compositional gas condensate reservoir model used in the simulations

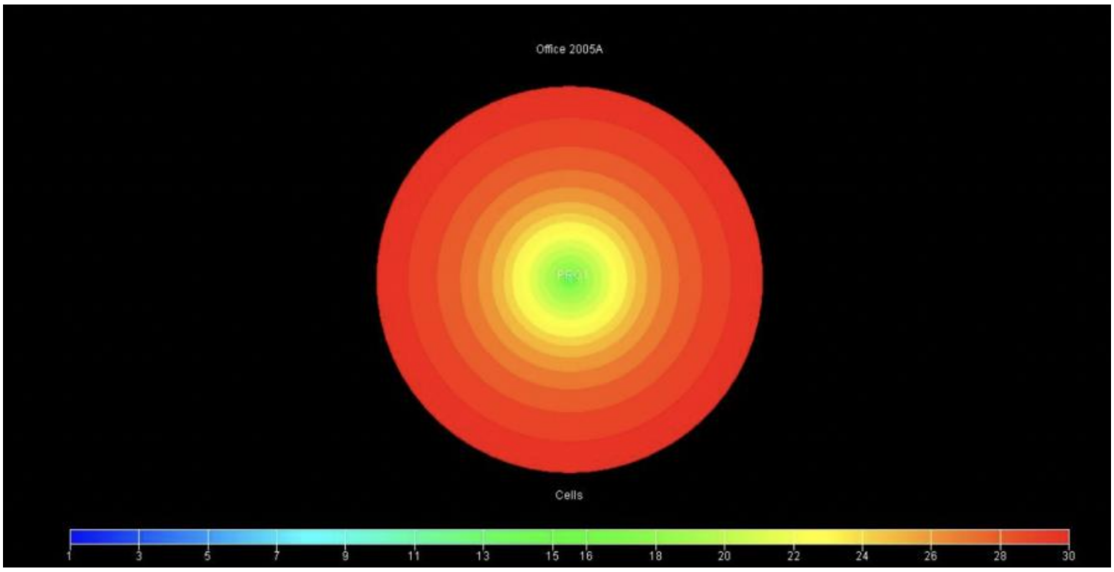

Figure 3.2: Reservoir`s two-dimentional view

CHAPTER FOUR

4.0 RESULTS AND DISCUSSIONS

The impact of non-darcy flow conditions was investigated with the inbuilt key word "VDFLOW" on the eclipse compositional simulator. Two case files were built one with VDFLOW which addresses non-darcy effects and the other, a BASE RADIAL CASE (No VDFLOW) addressing a larminar condition. To evaluate the condensate banking phenomena, a relative permeability plot of the reservoir fluid condition is shown in figure 4.1. This plot gives an insight on how the reservoir exhibits its phase behaviour due to the presence of both gas and liquid condensate phases. The gas relative permeability plot helps characterize the phase behaviour by showing how the relative permeability of the gas phase changes with varying gas saturation. It provides insights into the phase trapping and saturation distribution within the reservoir, aiding in understanding the behaviour of the gas and condensate phases during production of the well. The curve also showed the well is a moderately rich condensate well.

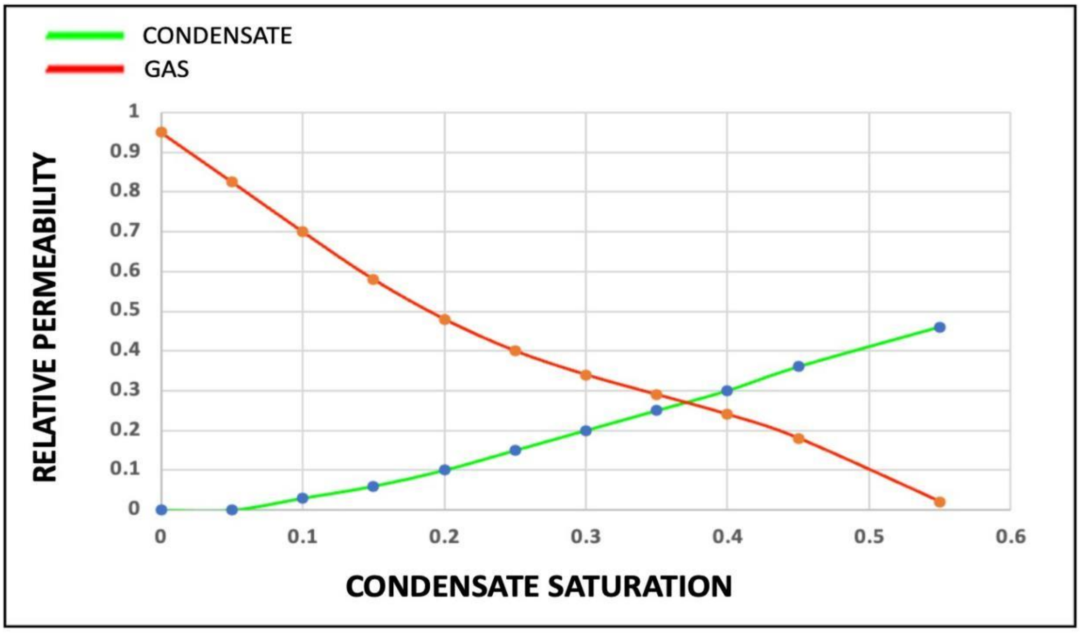

Figure 4.1: Relative permeability plot of the gas condensate well

The **non-Darcy** feature considered **is the Forcheimer correction (F)**, which takes into account inertia effects resulting from high velocity. This may occur around gas producers or in high permeability regions, such as fractures. Denoted by Beta (B), typical values are from 107 - 109. at K = 60mD, gives 9.86F. VDFLOW and VELDEP are ECLIPSE keywords for enabling Non-Darcy flows and Oil/Gas forcheimer respectively. For VDFLOW values of 10, there was no change in the base Field Gas Production for an extended production period, until the 11th year where the rate declines due to pressure depletion. However, at VDFLOW value of 100 there was a remarkable variations. (Fig. 4.3). The non-Darcy (Forcheimer) model is used to increase pressure drop at high gas velocities. **Turbulent flow** is modeled by **adding a velocity-dependent** term to the pressure drop (this will model high velocities near the well) If we do not consider non-Darcy flow, we overestimate the flow gas production. (Fig. 4.2 and Fig. 4.3). Therefore, it is important to model non-Darcy as a correction factor to accurately predict the production rate. Non-Darcy flow includes additional flow resistance mechanism beyond the linear relationship predicted by Darcy`s law, by incorporating the Forchheimer equation, at a factor of 100(Fig. 4.3), this resistance effect is seen almost immediately.

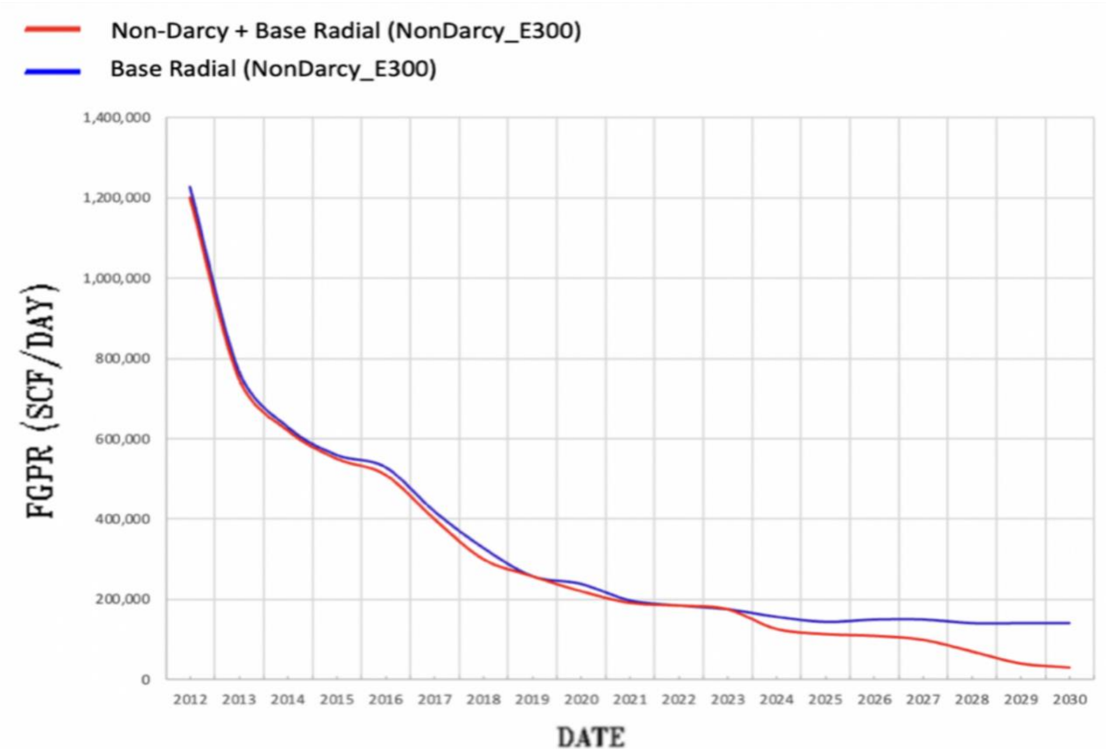

Figure 4.2: Comparing the FGPR for base case and non Darcy at Forchheimer factor of 10

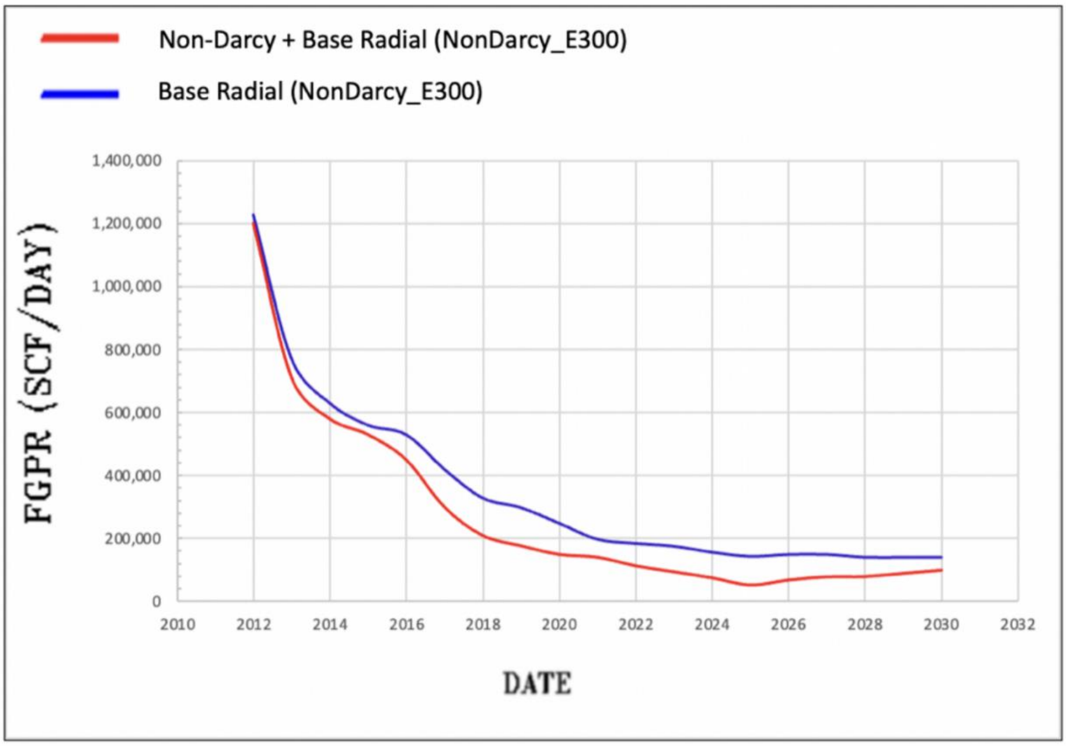

Figure 4.3: Comparing the FGPR for base case and non Darcy at Forchheimer factor of 100

Another Variation was considered by simply adding the velocity dependent relative permeability key word (VELDEP) to the already two existing scenarios. The result however shows no much difference at a low Forchheimer factor of 10. This can be argued that at low inertial effects or low Forchheimer number, the reservoir flow conditions is analogous to the Darcy`s flow behaviour and hence the similarity in the flow production rate curves(Fig 4.4).

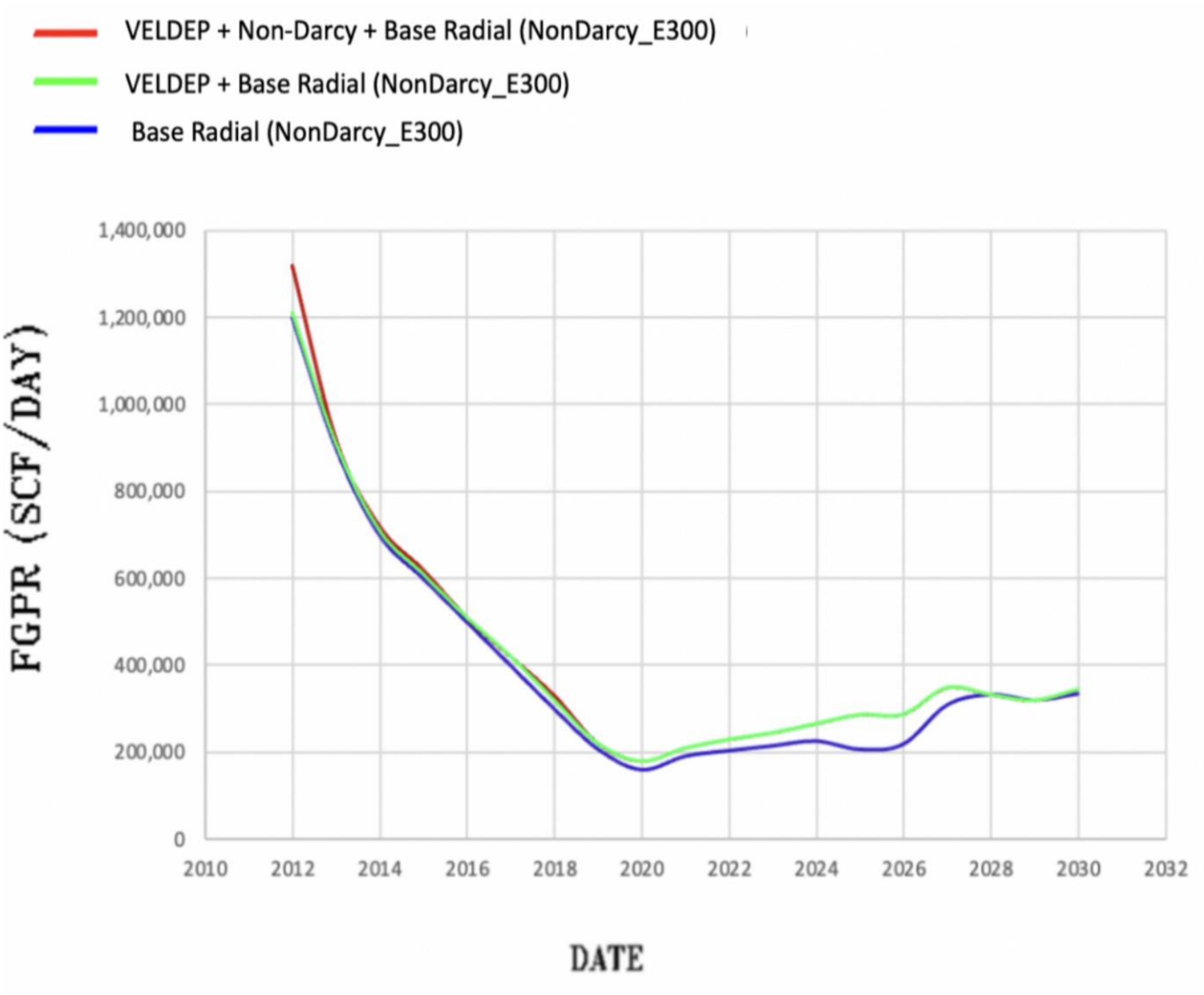

Figure 4.4: Comparing Base Case Radial, Non-Darcy and VELDEP @ 10 Forcheiimer

Figure 4.5 on the other hand shows slight variations as the forchheimer factor changes to 100. The gas produced from 2018, shows a decline to buttress the effect of Non-Darcy flow conditions on the productivity of the well.(J.W Barker,2005). Also,the gas rate shows improvement after enabling the velocity dependent relative permeability key word (VELDEP) as a correction to skin effect.

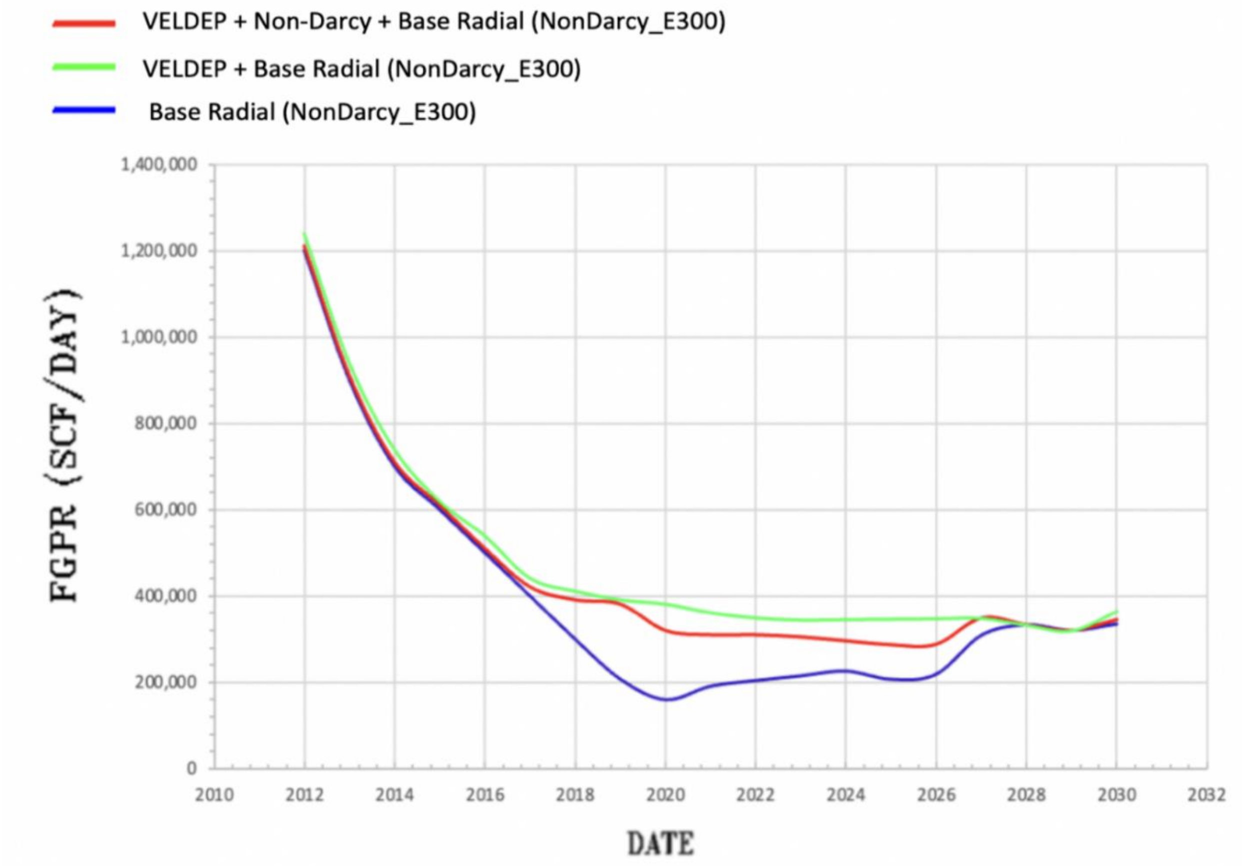

Figure 4.5: Comparing the FGPR for Base Radial, Non-Darcy and VELDEP @ 100 Forchheimer.

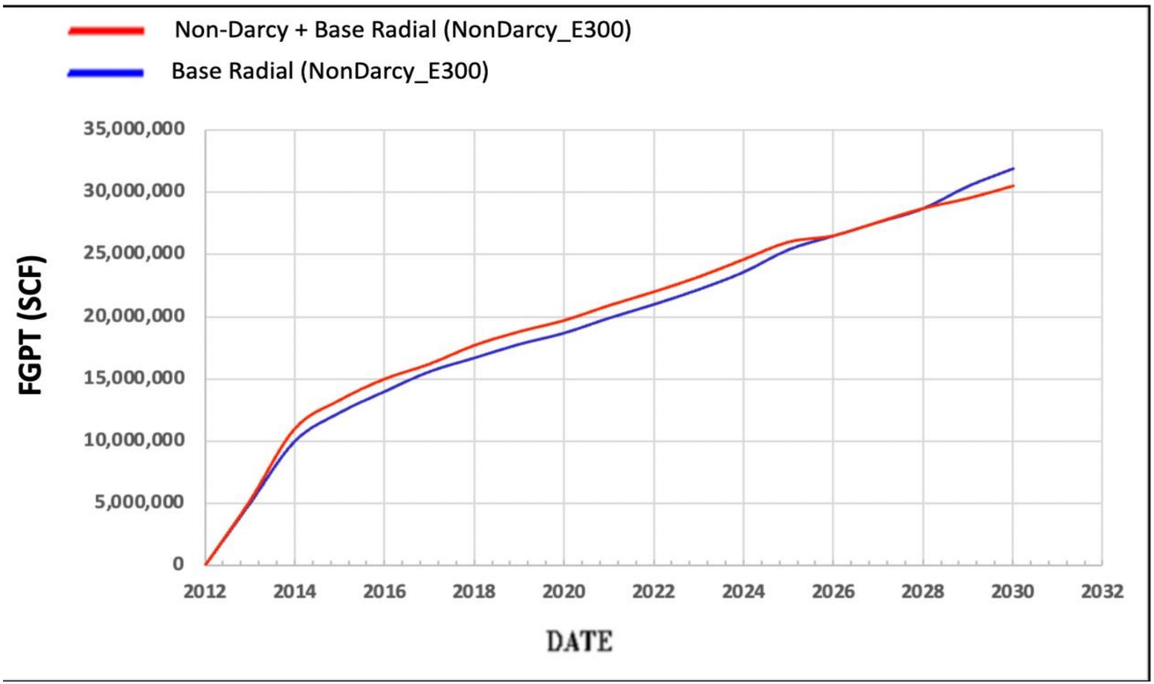

FIgure 4.6:Field cummulative gas production for Base Radial and Non-Darcy

Fig 4.6 above shows a comparison between the the base radial case and the Non-Darcy. Again, the results shows a huge similarity at the initial years of production. After 16years of production and as bottom hole pressure declines further, due to skin impairment in the well productivity as a result of condensate dropout. At this point, (Fig 4.6) inertial forces dictates the productivity of the well.

However, as Forchheimer factor is raised significantly from 10 to 100 respectively(Fig 4.7 and 4.8), while applying the VELDEP keyword, there`s a drastic improvement to the cummulative gas produced throughout the production period agreeing to the work by (J.W Barker, 2005).

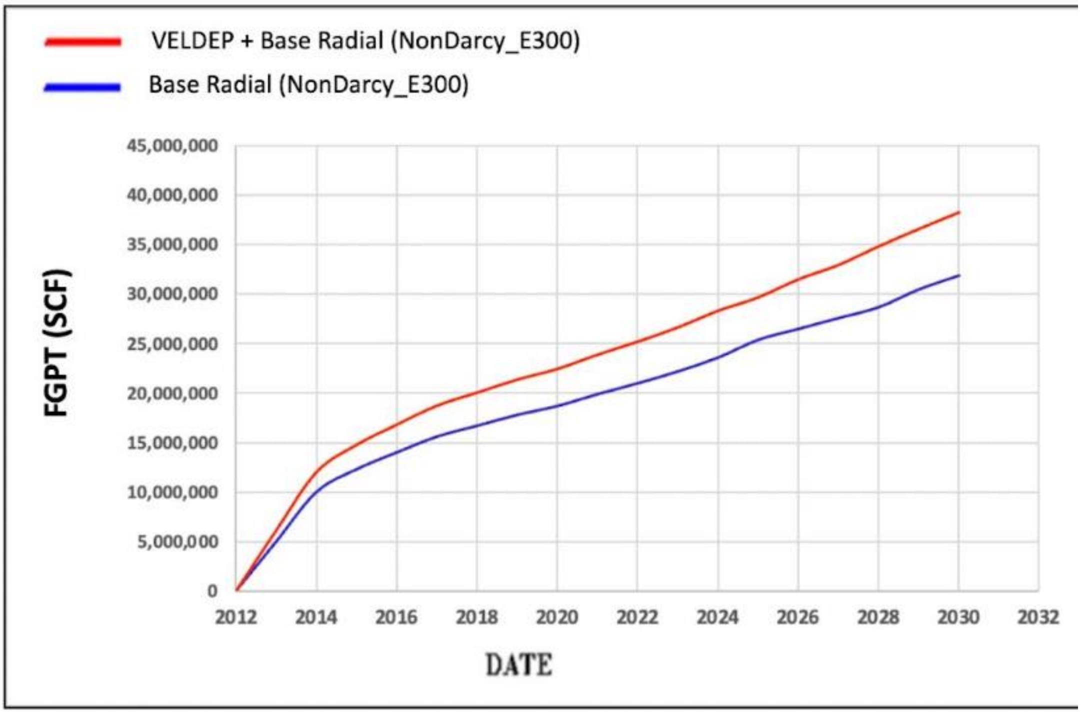

Figure 4.7: Field cummulative production for Base Radial and Non-Darcy with VELDEP @ 10 Forchheimer

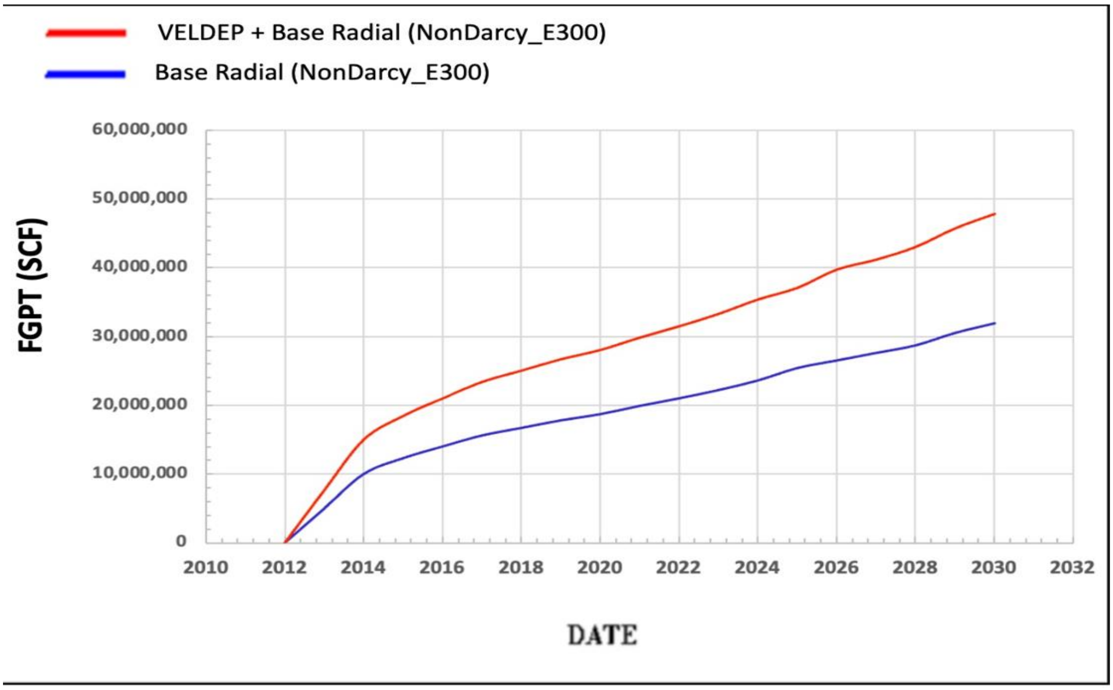

Figure 4.7: Field cummulative production for Base Radial and Non-Darcy with VELDEP @ 100 Forchheimer

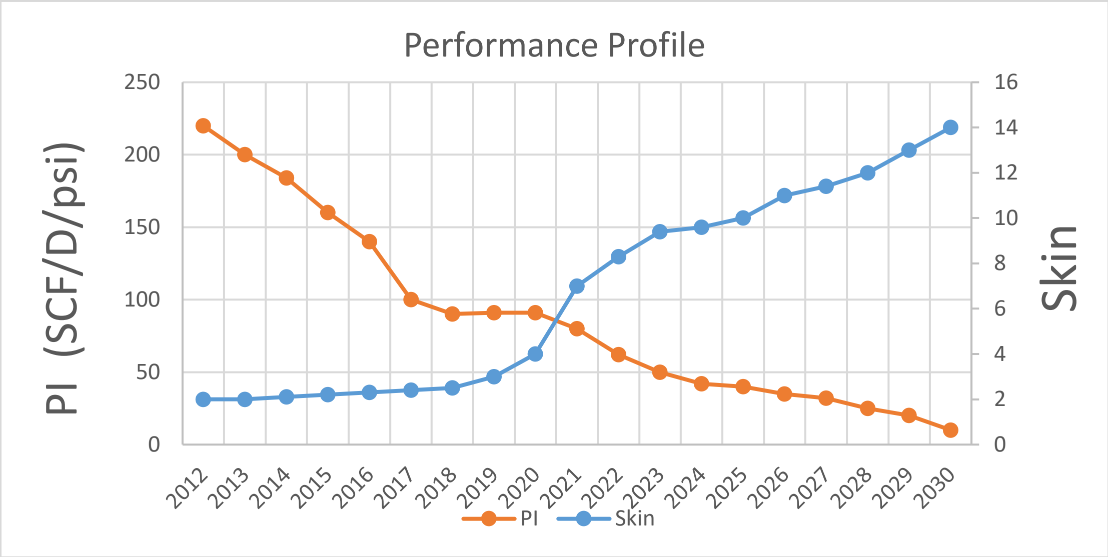

Figure 4.8: Well Performance profile with Non-Darcy flow conditions

Table 5.1 Reservoir flow conditions without Non-Darcy effect

CGR(STB/MSCF)	Permeability (mD)					
	0.001	0.01	0.1	1	10	100
120000	25	34	49	77	81	5
108000	14	24	32	43	38	2
100000	8	17	23	28	14	2
850000	0	4	4	4	3	2

Table 5.2 Reservoir flow conditions with Non-Darcy effect

CGR(STB/MSCF)	Permeability (mD)					
	0.001	0.01	0.1	1	10	100
120000	25	34	**39**	**8**	**5**	**1**
108000	14	24	**14**	**4**	**3**	1
100000	8	17	**8**	**3**	**2**	2
850000	0	4	3	3	1	0

Figure 4.8 typically shows the effect of condensate drop out on the productivity of the well. As seen from the plot, Figure 5.1, as condensate saturation increases, it constitute more skin effect and hence, the effective permeability of the gas also reduces. Consequently, the wells productivity experiences a decline. Table 5.1 and 5.2 further shows the effect of condensate saturation on flow condition of the reservoir. The effective permeability of the reservoir is seen to significantly decline when the VDFLOW(Non-Darcy) keyword is enabled (Table 5.2). This reduction in permeability is a direct consequence of skin due to condensate dropout(Table 5.2).

CHAPTER FIVE

CONCLUSION

The following conclusions can be deduced from the iterations using the VDFLOW key word (Non_Darcy)

1. Flow resistance Increase: Non-Darcy effects in gas condensate wells lead to an increase in flow resistance compared to the linear Darcy flow. The presence of inertial and turbulent flow effects introduces additional flow resistance in form of skin resulting in higher pressure drops for a given flow rate.

2. Reduced Gas Production Rates: The overall well performance sees a decline when the Non-Darcy key word (VELDEP) is enabled. The increased flow resistance due to Non-Darcy effects can lead to reduced gas production rates in gas condensate wells. The higher pressure drops associated with non-Darcy flow result in lower effective permeabilities for both gas and condensate thereby limitind the overall productivity of the well.

3. Adopting the VELDEP improves the gas rate and field cummulative production of gas condensate wells.

4. Neglecting VDFLOW (Non-Darcy effect) can lead to unrealistic forecasts and inaccurate reservoir management decisions.

RECOMMENDATIONS

1. **Need for Non-Darcy Correlations:** Non-Darcy correlations, such as the Forchheimer equation are required to accurately model the flow behaviour in gas condensate wells. These correlations account for the additional flow resistance and non-linear flow behaviour associated with inertial and turbulent flow effects, ensuring more accurate predictions of pressure drop and gas production rates. Other correlations such as the Ergun equation in comparison to the Forchheimer.

2. **Validated with Field Data:** The Non-Darcy flow model should be validated against field production data. Compare the model`s predictions of pressure drop and flow rates with the observed production history to assess the model`s accuracy and reliability. Adjust the model parameters if necessary to achieve a better match with field data.

3. A wider range of Forcheiimer factor should be used in future work to capture more intricately the flow behaviour of gas condensate wells under different turbulent condition.

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