Master Thesis

Analysis of well-known reservoir models and sensitivity of different parameters to estimate deliverability from vertical, horizontal and fracked gas wells.

In

Cooperation

With

OMV Pakistan GmbH

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Affidavit

I declare in lieu of oath, that I wrote this thesis and this has not been submitted previously for any higher degree. All extracts have been distinguished using quoted references and all information sources have been acknowledged.

Date: ____________________________

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Abstract

The real IPR (inflow performance relationship) associated with a well is resulted from a unique well penetrating a reservoir. This IPR of a well is a result of a number of reservoir-well models that are available in literature. These reservoir models are used in industry to estimate deliverability of different well configurations and therefore it is significant to delineate merits and limitations of each reservoir-well model with respect to well configuration. This is essential for production forecasts of wells with no further activities, as well as defining production profiles for exploratory / new development wells.

OMV is operating in Pakistan, producing conventional gas reservoirs from Sawan field with vertical/slanted wells, and tight gas potential (Sawan) that needs to be exploited with multi-fractured horizontal wells. Moreover, OMV Pakistan is operating the field with different well configurations. Significant well and field case histories are available at OMV Pakistan to evaluate which reservoir-well models serves the best deliverability estimate for these gas wells and check the sensitive parameters for optimised production.

In this thesis, different reservoir models are evaluated at different conditions to check which models result in realistic values with respect to the test rates. Furthermore a sensitivity analysis of respective parameters is carried out to quantify its impact on well deliverability. Analysis of these well-known models and the sensitive parameters will serve as a guideline for oil companies in exploration and production business.

Keywords: Inflow Performance, Reservoir Well Models, Deliverability

Zusammenfassung:

Die tatsächliche IPR (inflow performance relationship) einer Sonde stammt von einer einzelnen Sonde in einer Lagerstätte. Diese IPR dieser Sonde ist das Ergebnis unterschiedlicher Lagerstätten- und Fördermodellen, die es in der Literatur gibt. Diese Modelle werden in der industrie verwendet, um die Förderleistung unterschiedlicher Komplettierungskonfigurationen abzuschätzen; daher ist es von Bedeutung, die Vor- und Nachteile all dieser Lagerstätten- und Fördermodelle hinsichtlich unterschieldicher Komplettierungsmethoden zu kennen. Dies ist bedeutsam für Vorhersagen bezüglich der Förderraten, aber auch um Förderprofile für Explorations- und Entwicklungsprojekte zu definieren.

OMV betreibt Gasfelder in Pakistan, die wie im Feld Sawan konventionelles Gas mit vertikalen und abgelenkten Sonden fördert, aber auch Potential für „Tight Gas" zeigen, das mittels mehrfach hydraulisch geklüfteten Horizontalsonden erschlossen werden muss. Ausserdem betreibt OMV Pakistan das Feld mit unterschiedlich konfigurierten Sonden. Es liegen mehrere Fallstudien zu einzelnen Sonden, aber auch dem gesamtem Feld vor, die der Evaluierung dienen, welches Modell die beste Abschätzung der Fördermengen erlaubt, und um den Einfluss unterschiedlicher Parameter festzustellen, um die Förderung zu optimieren.

In dieser Arbeit werden unterschiedliche Lagerstättenmodelle unter unterschiedlichen Bedingungen untersucht. Dabei wird überprüft, welche Modelle realistische Werte für das vorliegende Feld leifern, d.h. solche, die die tatsächlichen Testraten gut annähern. Ausserdem wird eine Analyse durchgeführt, die den Einfluss der Lagerstättenparameter auf die Förderleistung feststellt. Die Analyse dieser Modelle und der sensibelsten Parameter werden als Richtlinie für Firmen auf dem Gebiet der Erdölexploration und -förderung dienen.

Keywords: IPR, Lagerstättenmodell, Förderleistung

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Nomenclature

A = drainage area, acres

a = laminar flow coefficient

a_e = half major axis of drainage ellipse, ft

AOF = Absolute Open Flow (MMscfd)

b = inertial-turbulent flow coefficient

b_e = half minor axis of an ellipse, ft

BHP = Bottomhole pressure

c_f = total compressibility of fracture, psi^{-1}

CIT = Completion Integrity Test

D = inertial or turbulent flow factor

dp/dx = pressure gradient, Psi/ft

F = non-Darcy flow coefficient

FC = fracture conductivity, md ft

FCD/ C_{fD} = dimensionless fracture conductivity

h = reservoir thickness, ft

J = productivity index, Mscf/day/psi

K = permeability, md

K_f = fracture permeability, md

L = length of the horizontal well, ft

m-RKB = length from rotary Kelly bushing

m-SS = length from sub sea level

P = pressure, psi

PI = productivity index, Mscf/day/psi

P_r = reservoir pressure, Psia

P_{wf} = bottom-hole flowing pressure, Psia

Q = flow rate

Q_g = gas flow rate, MMscfd

r_e = drainage radius

$r_w^{/}$ = effective wellbore radius, ft

r_w = wellbore radius, ft

$r^{/}_{wd}$ = dimensionless eff. wellbore radius, ft

S = Skin factor

r_{eh} = horizontal well drainage radius, ft

ψ_{wf} = bottom-hole pseudopressure, , psi^2/cp

s_f = Fracture skin effect

spf = shots per foot

T = Temperature, ^0F

t = time, days

t_{Dxf} = dimensionless time based on x_f

w_f = fracture width, ft

WHIP = Wellhead injection pressure (psia)

x_f = fracture half-length, ft

z = gas compressibility factor

β = turbulence parameter, ft^{-1}

γ_g = gas gravity

η = hydraulic diffusivity

μ_g = gas viscosity, cp

ν = apparent velocity, m/s

ψ_r = avg. reservoir pseudopressure, psi^2/cp

B_g = gas formation volume factor, bbl/scf

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1. Introduction

One of the important tools for computing reservoir ability to produce hydrocarbon is the Inflow performance relationship (IPR). The two important factors to describe the reservoir inflow performance are productivity index (PI) and inflow performance relationship (IPR). These two factors account for relating flow rate to pressure difference resulted from reservoir and bottomhole. Many attempts have been made to improve the PI or IPR solutions appropriate for specific conditions since Darcy proposed the simple and useful Darcy’s law in 1856. As a result various correlations for PI or IPR calculation have been recommended from simple analytical solutions to rough numerical formulations in the literature.

The IPR is well-defined as the fundamental relationship between production rate and the bottomhole flowing pressure. It helps to understand the performance of well flowing pressure and production rate that is an important tool to quantify the reservoir/well behaviour and production rate. The first well analysis using this relationship was proposed by Gilbert in 1954. IPR is generated in pressure ranges between the average reservoir pressure and bottomhole flowing pressure. The flow rate is defined as absolute open flow potential of the well where bottomhole flowing pressure is zero, whereas the flow rate is always zero at the average reservoir pressure bottomhole. The needs for constructing IPR arise for designing completion and artificial lift system, Nodal analysis and production optimisation. Different IPR correlations exist for gas wells in the petroleum industry with the most widely used models as Jones and Back Pressure equation. There are also some more correlations that generally associated with limited applicability. IPR is used as an important tool with outflow performance to predict the production of hydrocarbons from a reservoir. The flow ability in the pipelines and surface equipment from the well bottomhole to surface storage tank is represented by Outflow performance; whereas the reservoir ability which relates well production rate to pressure difference between average reservoir pressure and flowing bottom pressure is reflected by inflow performance. These two performances play a vital role in constructing well deliverability curve that assists in predicting an optimal production rate.

The precise determination of skin effect on the productivity of wells is a key to optimize production in wells as skin effect results in additional pressure drop. The skin effect is resulted in different forms e.g. mechanical skin (resulted from drilling and perforation), well deviation skin, partial penetration skin and non-Darcy or rate dependent skin (due to turbulence). These are the outcomes of different operations in the wellbore such as completion, production, hole geometry effects and sand control operations. The rate dependent Skin is an outcome of producing / flowing the well at a high rate. As the present and future stages of the industry are characterized by production from abundant wells, the turbulence effect on the performance of high rate gas wells can no longer be neglected.

The diffusivity equation helps in deriving an inflow relationship that results in IPR construction. PROSPER (the petroleum expert's software) is used to construct an IPR originating from a semi analytical inflow equation and an experimental or empirical correlation. The simple and cost-effective property of an empirical model makes it more advantageous in the field. However lacking insights is the focal drawback of these models as there are no explanatory analytical formulas that describe the sensitivities of parameters and their effect on the whole phenomenon. In contrast, a well-developed analytical model is beneficial as it provide the insights that are useful for well intervention designer. The limitation of an analytical model is the requisite of expensive detailed input data which is very difficult to be collected precisely from the reservoir and its wells. As described formerly, the cost efficiency of empirical model makes it more flexible to be used in field; while analytical model is more attractive if there is a need to know about potential bases of well productivity decline. As stated earlier, the skin factor 'S' account for the deviations in the field from the ideal computed inflow values resulted from these semi analytical inflow equations. This skin value quantifies the production impairing phenomena which are not accounted for by the formation model.

The PROSPER software includes several analytical formation models for gas wells. These models describe the reservoir in their respective way but all of them use a common skin model. A pseudo-analytical IPR is generated when these models are combined with the skin model available in PROSPER. The widely known Darcy's law deviates from the linear relationship between flow rate and pressure in a porous media with conditions of high velocity flow effects, molecular effects, ionic effects and non-Newtonian fluids phenomena. The term that defines these deviations is non-Darcy flow as explained earlier, mainly attributed to turbulent flow in the reservoirs. The associated effect is termed as rate dependent skin factor that is an outcome of different conditions in petroleum reservoirs including: gas and condensate reservoirs, gravel pack completion, fractured reservoirs (both hydraulic and natural fractured) and near wellbore region.

In order to use PROSPER for analysing vertical and deviated gas wells, it is proposed to use Jones' correlation and the Horizontal well correlation for horizontal wells. Both of the mentioned correlations use a rate dependent skin factor and are resulted from the Darcy inflow equation. In contrast the Petroleum Expert correlation is likely to have similar input as the Jones' equation but it take into consideration the varied liquid saturations near the well bore using the relative permeability curves to tune the permeability values. Vogel 1968 made some experimental observations that outcome an empirical equation known as the Back pressure equation. Similar to Jones-correlations, Back pressure equation used in PROSPER take into account the skin effects in the inflow model. A widely used stimulation technique in both conventional and unconventional oil and gas reservoirs is hydraulic fracturing. Advancements in last two decades have turned vertical and horizontal wells with hydraulic fractures a widely used completion approach in the petroleum industry. These wells need to be modelled also with the respective parameters and PROSPER do it with hydraulically fractured well model that account for the fracture parameters within the IPR model.

The goal of this study is to analyse different reservoir models available in literature for vertical, horizontal and fracked gas wells. These wells are being drilled in Sawan field Pakistan, which are used for the analysis. The study will reveal producing an IPR based on an empirical or analytical inflow correlation with input data available in the historical data base of Sawan field. The investigation will be done on checking which reservoir model serves the best at different well and reservoir conditions. A vertical, horizontal, fracked and gravel packed wells are being selected from the field to analyse the reservoir models for different well configurations. The next step is to carry out sensitivity analysis of various parameters associated with the respective models. This will help in knowing which parameter is most sensitive compared to others. The analysis of these reservoir models and sensitivity of the parameters will serve as a helping tool for different wells of Sawan and surrounding fields.

2. Literature Review

The term deliverability relates to oil or gas production rate obtained from the reservoir at a specified bottom-hole pressure. The well deliverability is mainly affected by this factor. The evaluation of the types of completion and artificial lift methods to be used is carried out by reservoir deliverability. The production engineers must have a thorough knowledge of reservoir productivity. The mathematical modelling of reservoir deliverability is based on the flow regimes i.e. transient flow, steady state flow, and pseudo–steady state flow. For a particular flow regime, an analytical expression between bottom-hole pressure and production rate can be formulated. [1]

There are several factors upon which reservoir deliverability depend e.g.

- Reservoir pressure
- Thickness and permeability of pay zone
- Type of reservoir boundary and distance
- Radius of wellbore
- Properties of reservoir fluid
- Condition of near-wellbore region
- Relative permeability of the reservoir

The former methods of estimating gas well performance consisted of well opening to the atmosphere and then calculating the flow rate. These open flow measurements resulted in waste full of gas, often hazardous to personnel and equipment and probably damaging to the reservoir. The information provided was limited to evaluate production capability under different flowing scenarios. Nevertheless this concept provided the knowledge of absolute open flow (AOF) to the industry. AOF is a basic tool of well productivity and describe the maximum rate of well against a hypothetical atmospheric pressure at the reservoir. [2] The inflow performance (IPR) curve is a graphical representation of the relation between the bottomhole flowing pressure and production rate. In order to measure gas well flow capacity, this relationship between the inflow gas rate and the flowing bottom-hole pressure is required. The appropriate solution of Darcy's equation constructs this inflow performance relationship. This Solution of Darcy's Law rely on the flow conditions or flow regime existing in the reservoir. [1] The flow of fluids through porous and permeable media can be described by mathematical models developed by combining physical relationships associated with mass conservation with an equation of state and an equation of motion. This combination of relationships leads to the diffusivity equations, the tool used in the petroleum industry to define the flow of fluids through porous media. [2]

2.1 Vertical Gas Well Performance

When a well is being shut-in for a period of time, the initial gas flow follow unsteady-state behaviour in the reservoir until the pressure falls at the drainage boundary of the well. Afterwards there is a short transition flow period followed a steady-state or pseudo steady-state condition. The deliverability testing helps to determine gas well productivity and give information that contribute to develop reservoir rate-pressure behaviour for the well and generate an inflow performance curve. [1]

2.1.1 Fluid Flow Equations

The behaviour of fluid flow in reservoir is represented by fluid flow equations that may have different forms subjected to distinct variables combination as described earlier (i.e., flow or fluid types etc.). The required flow equation can be developed when the mass conservation equation is mingled with the transport equation (Darcy's equation) and various equations-of-state. As the flow equations are premeditated to be dependent on Darcy's Law, it is necessary to initially explain this transport relationship.

2.1.2 Darcy's Law

Darcy's law (Henry Darcy in 1856) is the most basic law of fluid flow in porous media. This law in mathematical form express the direct relation of homogeneous fluid velocity in a porous medium to the pressure gradient and inverse proportionality to the fluid viscosity. The applicability of Darcy's Law includes the following conditions:

- Laminar (viscous) flow
- Steady-state flow
- Incompressible fluids
- Homogeneous formation

$$v = \frac{q}{A} = -\frac{K}{\mu}\frac{dP}{dx} \qquad (2\text{-}1)$$

Equation 2-1 expresses the relationship for a horizontal linear system. Where v is apparent velocity (q/A), q is volumetric flow rate, A is total cross-sectional area of the rock, μ is fluid viscosity, dp/dx is pressure gradient and k is proportionality constant (permeability of the rock). The factor A includes both areas of the rock material and pore channels while dp/dx is taken in the same direction as v and q. In equation 2-1, the negative sign indicate negative pressure gradient in the direction of flow as depicted in figure 2.1 while, the pressure gradient is positive for a horizontal-radial system as shown in figure 2.2.

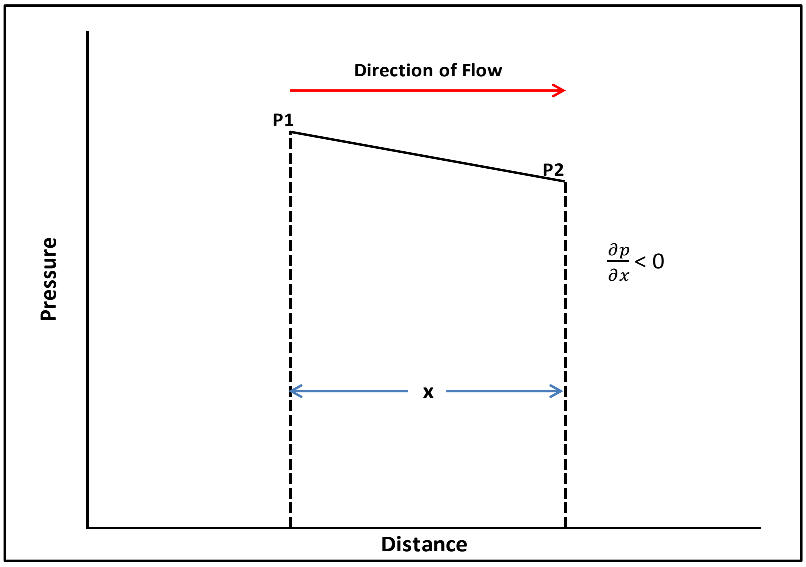


Figure: 2. 1. Pressure vs. distance in a linear flow [1]

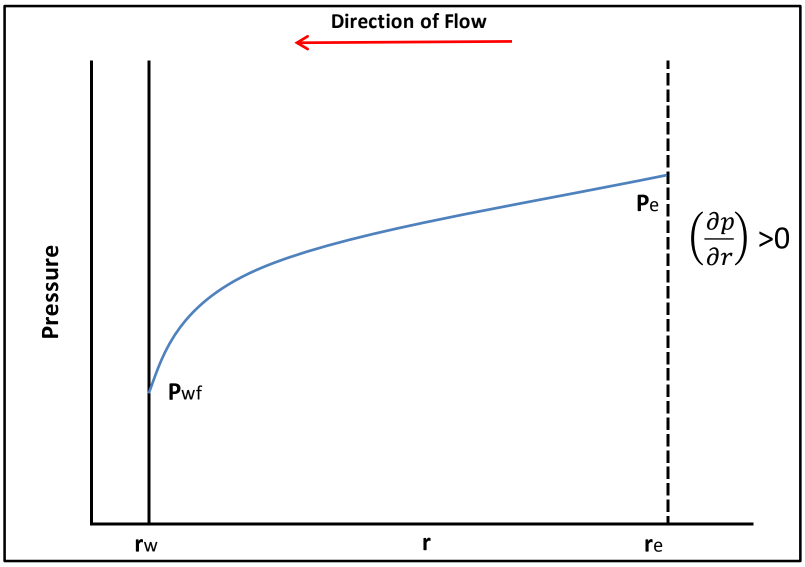


Figure: 2. 2. Pressure gradient in radial flow [1]

$$V = \frac{q_r}{A_r} = \frac{K}{\mu}\left(\frac{\partial p}{\partial r}\right)_r \quad (2\text{-}2)$$

The generalized radial form of Darcy's equation is expressed in equation 2-2. The area A at radius r is the surface area of a cylinder. For a well with a net thickness of h that is fully penetrated, the cross-sectional area A_r is given by:

$$A_r = 2\pi r h \quad (2\text{-}3)$$

At higher velocities turbulent flow occurs and there is a drastic increase in the pressure gradient in contrast to the flow rate and it is necessary to modify the Darcy's equation as Darcy's equation is limited to laminar flow conditions. Some modifications are addressed for turbulent flow in the following equation systems.

2.1.3 Real Gas Potential / Real Gas Pseudopressure

The relation of pressure, viscosity and compressibility factor represented in integral $\left(\int_0^p [2p/\mu_g z]\, dp\right)$ is known as real gas pseudopressure, usually denoted by Ψ or m (p) and expressed in equation 2-4. For compressible fluids under pseudosteady-state flow condition, the precise solution to the Darcy's differential equation is given in equation 2-5.

$$m(p) = \Psi = \int_0^p \frac{2p}{\mu_g z}\, dp \qquad (2\text{-}4)$$

$$Q_g = \frac{Kh[\Psi_r - \Psi_{wf}]}{1422\, T\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]} \qquad (2\text{-}5)$$

Where Q_g is gas flow rate, k is permeability, Ψ_r is avg. reservoir real gas pseudopressure, T is temperature, s is skin factor, h is thickness, re is drainage radius and r_w is wellbore radius. The productivity index J for gas wells in context of pseudopressure can be written as:

$$J = \frac{Q_g}{\psi_r - \psi_{wf}} = \frac{Kh}{1422\, T\left[ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]} \qquad (2\text{-}6)$$

$$Q_g = J(\Psi_r - \Psi_{wf}) \qquad (2\text{-}7)$$

$$(Q_g)_{max} = J\Psi_r \qquad (2\text{-}8)$$

$$\Psi_{wf} = \Psi_r - \left(\frac{1}{J}\right) Q_g \qquad (2\text{-}9)$$

Equation 2-8 shows the absolute open flow potential (AOF, maximum gas flow rate). From equation 2-9, it is clear that a plot of Ψ_{wf} vs. Q_g would result a straight line with a slope of (1/J) and intercept of ψ_r, as shown in Figure 2.3. The slope can be calculated from two different stabilized flow rates extrapolated line to estimate AOF, J, and ψ_r. The integral form of equation 2-5 can be written as;

$$Q_g = \frac{Kh}{1422\, T\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]} \int_{Pwf}^{p} \left(\frac{2p}{\mu_g z}\right) dp \qquad (2\text{-}10)$$

Where ($P/\mu_g z$) is directly proportional to ($1/\mu_g B_g$), B_g being the gas formation volume factor and defined by equation 2-11. Equation 2-10 can then be written in terms of B_g as shown in equation 2-12.

$$B_g = 0.00504 \frac{zT}{p} \tag{2-11}$$

$$Q_g = \left[\frac{7.08(10^{-6})Kh}{\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s}\right] \int_{Pwf}^{p} \left(\frac{1}{\mu_g B_g}\right) dp \tag{2-12}$$

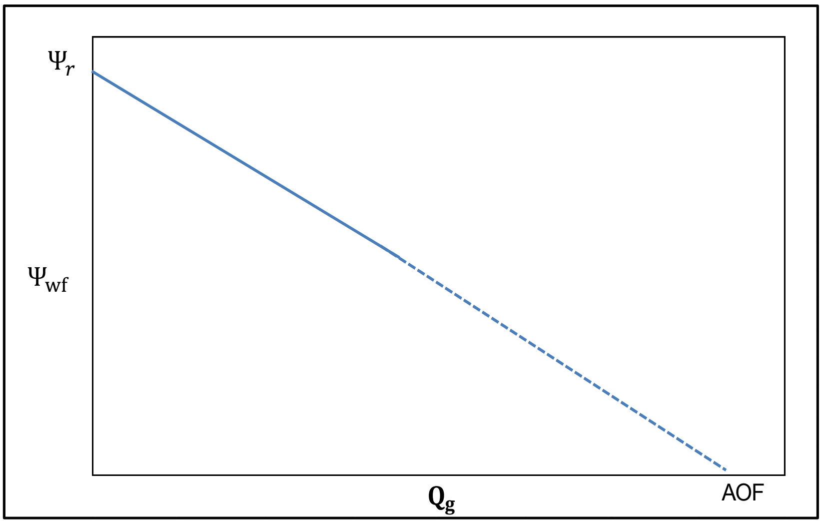


Figure: 2. 3. Steady-state gas well flow [1]

Where B_g is gas formation volume factor, z is gas compressibility factor and μ_g is gas viscosity. The plot of pressure versus the gas pressure functions ($2p/\mu_g z$) and ($1/\mu_g B_g$) is shown in figure 2.4. The integral in Equations 2-10 and 2-12 represents the area under the curve between P_r and Pwf. Figure 2.4 clearly demonstrate that the pressure function shows three distinct regions.

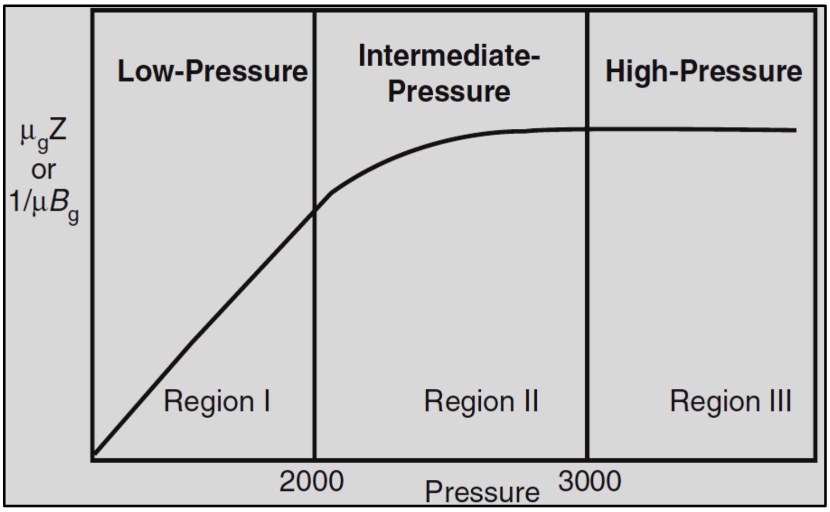


Figure: 2. 4. Pseudopressure VS Pressure, Gas PVT Data [3]

As discussed earlier, all of the mathematical equations expressed above are under the assumption that laminar flow conditions exist during the gas flow. The flow velocity increases as the wellbore is approached during radial flow which causes the development of a turbulent flow around the wellbore. The existence of this turbulent flow accounts for an additional pressure drop analogous to that by mechanical skin effect. Thus for compressible fluids a rate-dependent skin factor DQ_g is introduced to the semisteady-state flow equation to include the additional pressure drop due to the turbulent flow effect. Subsequently the semi/pseudosteady-state equations are expressed in the following three forms:

2.1.4 Region III. High-Pressure Region

The high pressure region is associated with pressures (both P_{wf} and P_r) higher than 3,000 psi where the pressure functions ($2p/\mu_g z$) and ($1/\mu_g B_g$) are nearly constant. In this region the function ($1/\mu_g B_g$) in Equation 2-12 can be fixed as constant and put outside the integral that leads to the following extension of Equation 2-10;

$$Q_g = \frac{7.08(10^{-6})Kh(p_r - p_{wf})}{(\mu_g B_g)_{avg} T \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s + DQ_g\right]} \tag{2-13}$$

Where the gas viscosity (μ_g) and gas formation volume factor (B_g) are calculated at the average pressure P_{avg}. The inertial or turbulent flow factor (D) is given by equation 2-15.

$$p_{avg} = \frac{p_r + p_{wf}}{2} \tag{2-14}$$

$$D = \frac{FKh}{1422\, T} \tag{2-15}$$

$$F = 3.161(10^{-2}) \left[\frac{\beta T \gamma_g}{\mu_g h^2 r_w}\right] \tag{2-16}$$

$$\beta = 1.88 \times 10^{10} k^{-1.47} \emptyset^{-0.53} \tag{2-17}$$

$$\beta = \frac{2.73 \times 10^{10}}{k^{1.1045}} \tag{2-18}$$

Where F is the non-Darcy flow coefficient and is defined in equation 2-16, γ_g is gas gravity, r_w is wellbore radius, h is thickness, $\emptyset$ is Porosity and β is turbulence parameter. When the range of porosity variation in the samples is not too much, the discrepancy of turbulence parameter with porosity can be ignored as compared to the discrepancy of β with the absolute permeability and equation 2-18 can be used. The determination of gas flow rate by equation 2-13 is known as **pressure-approximation method.** Since it is noted that the slope is nearly zero as both Pwf and P_r are above 3,000 psi, the idea of productivity index J cannot be defined in equation 2-13.

2.1.5 Region II. Intermediate-Pressure Region

When the pressures lie between 2,000 and 3,000 psi, there is a different curvature depicted by the pressure function. To calculate the gas flow rate while both the reservoir and bottomhole flowing pressures are in range of 2000-3000 psi, the real gas pseudopressure approach as stated in equation 2-5 should be used.

$$Q_g = \frac{Kh[\Psi_r - \Psi_{wf}]}{1422\,T\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s + DQ_g\right]} \quad (2\text{-}19)$$

2.1.6 Region I. Low-Pressure Region

For lower pressures, normally less than 2,000 psi there is a linear relationship of pressure with the pressure functions ($2p/\mu_g z$) and ($1/\mu_g B_g$). In 1986 Golan and Whitson stated that the product ($\mu_g z$) is principally constant where the pressure is lower than 2,000 psi. Introducing this concept to equation 2-10 and integrating results in equation 2-20. The z-factor and gas viscosity can be calculated at average pressure P_{avg} as shown in equation 2-21. To calculate the gas flow rate using equation 2-20 is known as **pressure-squared approximation method.** Equation 2-20 can be modified for the productivity index J that leads to equation 2-22.

$$Q_g = \frac{Kh\left[p_r^2 - p_{wf}^2\right]}{1422\,T(\mu_g z)_{avg}\left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s + DQ_g\right]} \quad (2\text{-}20)$$

$$p_{avg} = \sqrt{\left(\frac{p_r^2 + p_{wf}^2}{2}\right)} \quad (2\text{-}21)$$

$$Q_g = J\left(p_r^2 - p_{wf}^2\right) \quad (2\text{-}22)$$

$$\left(Q_g\right)_{max} = AOF = Jp_r^2 \quad (2\text{-}23)$$

$$J = \frac{kh}{1422\,T(\mu_g z)_{avg}\left[ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right]} \quad (2\text{-}24)$$

The above equations (2-13, 2-19, and 2-20) are fundamental quadratic expressions in Q_g and thus these equations lack representing explicit expressions to determine the gas flow rate. There are two distinct empirical methods taken in account for gas wells to describe the turbulent flow problem. These two treatments with different approximations are directly a result of the above mentioned equations and are known as:

1. Simplified treatment approach
2. Laminar-inertial-turbulent (LIT) treatment

2.2 The Simplified Treatment Approach

Rawlins and Schellhardt (1936) analysed flow data acquired from a many gas wells and proposed the relationship between the gas flow rate and pressure, expressed as:

$$Q_g = C\left(p_r^2 - p_{wf}^2\right)^n \tag{2-25}$$

Where Pr is average reservoir pressure, n is exponent and C is performance coefficient. The power 'n' in equation2-25 represents the extra pressure drop due to high-velocity gas flow rate i.e., turbulence. The exponent value varies from 0.5 for complete turbulent and for fully laminar flow. The term C in Equation 2-25 is the performance coefficient and account for reservoir rock properties, fluid properties and reservoir flow geometry. Equation 2-25 is commonly called the **deliverability** or **back-pressure equation.** As the exponent and coefficient (n and C) are calculated, the flow rate of gas 'Q_g' can be computed at any bottom-hole flow pressure P_{wf} to construct the IPR**.** By taking the logarithm of equation 2-25 on both sides;

$$log\left(Q_g\right) = \log(C) + nlog\left(p_r^2 - p_{wf}^2\right) \tag{2-26}$$

Equation 2-26 shows that, plotting Q_g versus ($P_r^2 - P_{wf}^2$) on log-log scales will result in a straight line with a slope of 'n'. Normally in the natural gas industry; this plot is reversed to have a plot of ($P_r^2 - P_{wf}^2$) versus Q_g on the logarithmic scales to generate a straight line having slope of (1/n). This plot as illustrated in Figure 2.5 is commonly known as the **deliverability graph** or the **back-pressure plot.** In order to determine the exponent 'n', any two points can be selected on the straight line, i.e., (Q_g1, Δp_1^2) and (Q_g2, Δp_2^2), and the flowing equation can be used:

$$n = \frac{\log(Q_{g1}) - \log(Q_{g2})}{\log(\Delta p_1^2) - \log(\Delta p_2^2)} \tag{2-27}$$

As the exponent 'n' is calculated, the coefficient C can be calculated from equation 2-28. The coefficients involved in back-pressure or any other empirical equation are usually calculated from analysis of gas well testing data. The test data can be used in a **multi-rate C**

and n model to determine the coefficients C and n as this model fit the IPR curve according to the test points. These coefficient values are then used in **C and n model** to generate an IPR. If the coefficient C is determined from an analytical equation using different parameters with n being known, the model is cited as **Back Pressure model**.

$$C = \frac{Q_g}{\left(p_r^2 - p_{wf}^2\right)^n} \tag{2-28}$$

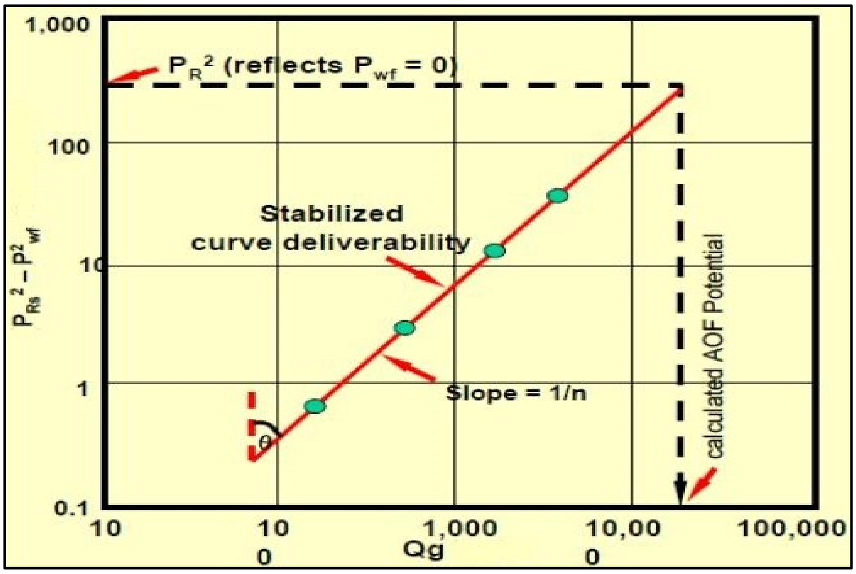


Figure: 2. 5. Rawlins and Schellhardt deliverability graph of pressure-squared approach [4]

The petroleum industry is using the deliverability testing for many years to analyse and describe the flow potential of gas wells. The basic sequence of these tests consists of flowing wells at different rates and gauging the bottom-hole flowing pressure as a function of time. The proper analysis of the recorded data makes it possible to evaluate the gas well flow potential and construct the inflow performance relationships. The deliverability testing has three types:

- Conventional deliverability (back-pressure) test
- Isochronal test
- Modified isochronal test

2.3 The Laminar-Inertial-Turbulent (LIT) Approach

As explained earlier, the three forms of the pseudosteady-state equations (2-13, 2-19, and 2-20) can be organised in quadratic forms to distinguish the laminar and inertial-turbulent coefficients as follows:

2.3.1 Pressure-Squared Quadratic Form

Following equation 2-20, the Pressure-Squared Quadratic equation can be written as shown in equation 2-29, followed by the coefficients 'a' and 'b'.

$$p_r^2 - p_{wf}^2 = aQ_g + bQ_g^2 \tag{2-29}$$

$$a = \left(\frac{1422\, T\mu_g z}{kh}\right)\left[ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right] \tag{2-30}$$

$$b = \left(\frac{1422\, T\mu_g z}{kh}\right) D \tag{2-31}$$

Where 'a' is Darcy (laminar flow) coefficient and b is non-Darcy (turbulent flow) coefficient. To linearized equation 2-32 is obtained by dividing both sides of the equation by Q_g. By plotting $\left(\frac{p_r^2 - p_{wf}^2}{Q_g}\right)$ versus Q_g on a Cartesian scale, the parameters 'a' and 'b' can be calculated as the plot will yield a straight line having slope 'b' and intercept 'a'.

$$\frac{p_r^2 - p_{wf}^2}{Q_g} = a + bQ_g \tag{2-32}$$

$$Q_g = \frac{-a + \sqrt{a^2 + 4b\left(p_r^2 - p_{wf}^2\right)}}{2b} \tag{2-33}$$

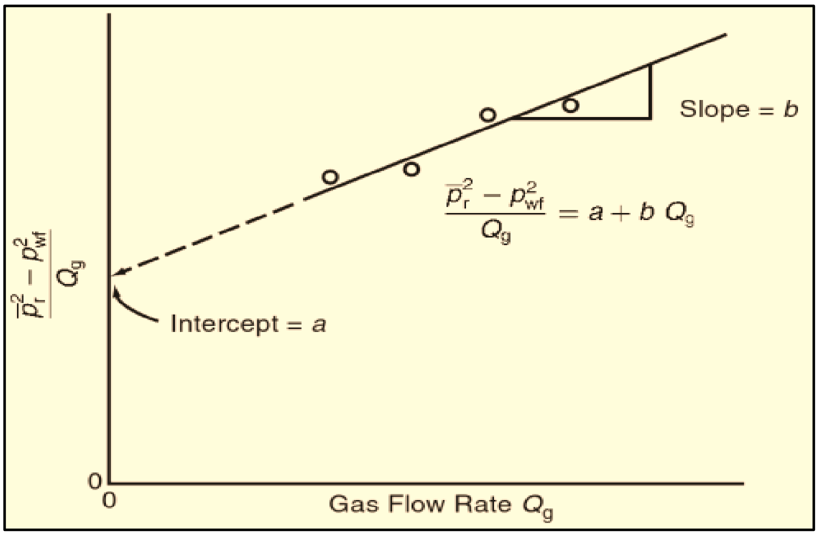


Figure: 2. 6. Graph of the pressure-squared data [3]

Equation 2-29 can be rearranged to equation 2-33 for calculation of Q_g at any P_{wf} once the values of 'a' and 'b' are known. Moreover, considering several values of P_{wf} and computing the corresponding Q_g from Equation 2-33, the gas well IPR can be constructed at the associated reservoir pressure p_r. The assumptions made in developing Equation 2-29 are stated below:

- Reservoir has single phase flow
- Reservoir is homogeneous and isotropic
- Permeability is independent of pressure
- The term (μ_g z) is constant.

Pressure squared method is applicable under pressures of 2,000 psi. The equation of this method can be applied to those stabilized wells that have produced long enough that the pressure transient has a long way into the reservoir.to reach stabilised rates. These equations apply directly to stabilized producing wells; i.e., wells that have produced to long enough so that the pressure transient has reached a long distance into the reservoir. These equations are already improved for non-stabilized wells by using isochronal tests; i.e., equal time duration short flow tests where every flow test is followed by a shut-in period to permit wellbore pressure to increase back to initial reservoir pressure ahead of the next flow test. [5] The equation 2-32 is stated as **Forchheimer's equation**, where only values of 'a' and 'b' are required to generate an IPR with provided reservoir pressure. These coefficients are being calculated from flow after flow test for three to four test points as illustrated in figure 2.6. This method is also called **multi-rate Jones model** where the IPR is adjusted by taking in account the test points and results in 'a' and 'b' values. As the values of 'a' and 'b' are calculated, it can be used in Forchheimer model to construct an IPR. In addition, **Jones model** uses the same equation for generating IPR but calculate the parameters 'a' and 'b' by taking in account the various parameters needed in equations 2-30 and 2-31.

2.3.2 Pressure-Quadratic Form

Following equation 2-13, the Pressure-Squared Quadratic equation can be written in a simple form as shown in equation 2-34. The parameters a_1 and b_1 are the laminar and turbulent flow coefficients and given in below equations.

$$p_{\bar{r}} - p_{wf} = a_1 Q_g + b_1 Q_g^2 \qquad (2\text{-}34)$$

$$a_1 = \frac{141.2(10^{-3})(\mu_g B_g)}{kh}\left[ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right] \qquad (2\text{-}35)$$

$$b_1 = \left[\frac{141.2(10^{-3})(\mu_g B_g)}{kh}\right] D \qquad (2\text{-}36)$$

The term (a_1 Q_g) accounts for the pressure drop due to laminar flow, while the term (b_1 Q^2_g) represents the additional pressure drop due to the turbulent flow condition. Extending equation 2-34 to linear form results in:

$$\frac{p_r - p_{wf}}{Q_g} = a_1 + b_1 Q_g \tag{2-37}$$

$$Q_g = \frac{-a_1 + \sqrt{a_1^2 + 4b_1(p_r - p_{wf})}}{2b_1} \tag{2-38}$$

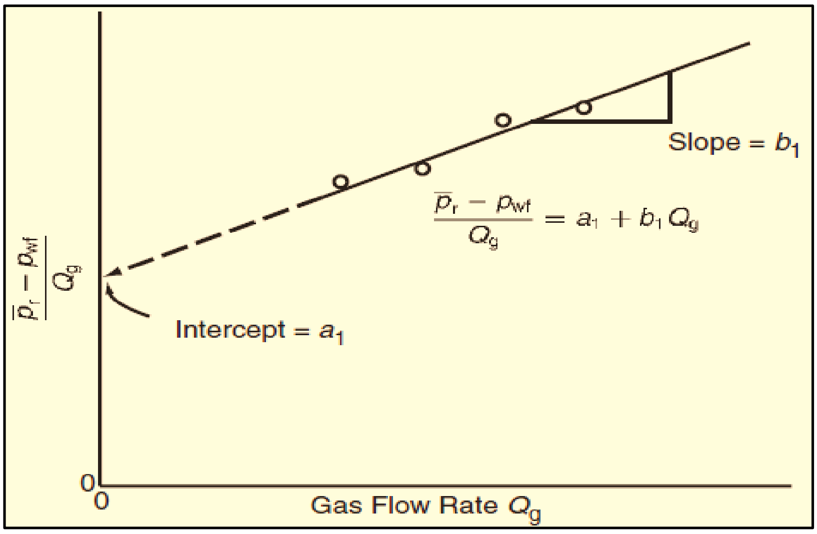


Figure: 2. 7. Graph of the pressure-method data [3]

The above figure (2.7) illustrates a linear plot of the above equation to determine the coefficients a_1 and b_1. At any pressure the flow rate of gas can be calculated from equation 2-38 once the coefficients are known. Similar to the assumptions considered for the pressure-squared approach, the pressure method is also restricted and applicable only at pressures higher than 3,000 psi.

2.3.3 Pseudopressure Quadratic Approach

The pseudopressure equation 2-19 can be extended to a more simplified form to include the laminar and turbulent flow coefficient as:

$$\Psi_r - \Psi_{wf} = a_2 Q_g + b_2 Q_g^2 \tag{2-39}$$

$$a_2 = \frac{1422}{kh}\left[ln\left(\frac{r_e}{r_w}\right) - 0.75 + s\right] \tag{2-40}$$

$$b_2 = \left(\frac{1422}{kh}\right) D \tag{2-41}$$

As described in the above two methods, the term (a_2 Q_g) account for the pseudopressure drop due to laminar flow while the term (b_2 Q_g^2) represents pseudopressure drop due to turbulent flow effects. The linear form of equation 2-39 is given by:

$$\frac{\Psi_r - \Psi_{wf}}{Q_g} = a_2 + b_2 Q_g \tag{2-42}$$

$$Q_g = \frac{-a_2 + \sqrt{a_2^2 + 4b_2(\Psi_r - \Psi_{wf})}}{2b_2} \tag{2-43}$$

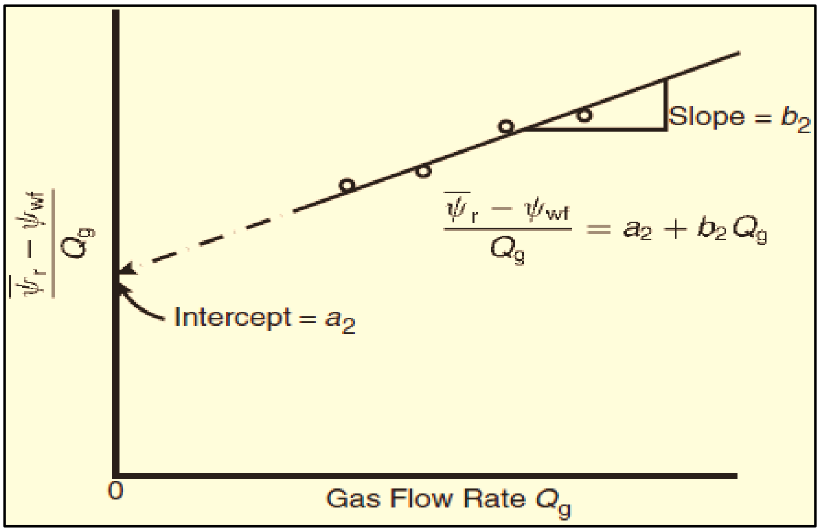


Figure: 2. 8. Graph of the pressure-method data [3]

Equation 2-42 shows that when $\left(\frac{\Psi_r - \Psi_{wf}}{Q_g}\right)$ is plotted versus Q_g on a Cartesian scale; the resultant will be a straight line having slope b_2 and intercept of a_2 as illustrated in figure 2.8. As the values of the coefficients a_2 and b_2 are computed, the flow rate of gas can be calculated at any p_{wf} using equation 2-43.

As the pseudopressure approach is for the intermediate zone (Figure 2.4), it should be noted that this approach is more accurate than either the high pressure zone or low pressure zone approximations and is valid to all ranges of pressure. In PROSPER this equation is being used as **Forchheimer with pseudopressure** that needs just the parameters 'a_2' and 'b_2' to generate an IPR. These parameters are calculated either from flow after flow test points (**multi-rate Forchheimer with pseudopressure)** or calculated using the above equations for the parameters. An exclusive correlation "**Petroleum Experts**" is also included in PROSPER that allows for a change in gas and condensate saturations near the wellbore using a multiphase pseudopressure function. The assumptions include no occurrence of condensate banking and the condensate that drops out is produced. It uses the same equation for constructing IPR but use a modified non-Darcy D factor. Since the Petroleum Experts model calculates flow profile considering transient conditions, the constant 1422 in equation 2-15 is replaced by 1637. [6]

$$D = A_1 \times A_2 \tag{2-44}$$

$$A_1 = \frac{3.161 \times 10^{-12} \beta T_{abs} SG}{\mu_g h_{perf}^2 r_w} \tag{2-45}$$

$$A_2 = \frac{k_{abs} h}{1637 T_{abs}} \tag{2-46}$$

$$k_{eff} = k_{abs}(1 - S_{wc})^2 \tag{2-47}$$

$$\beta = \frac{2.73 \times 10^{10}}{k_{eff}^{1.1045}} \tag{2-48}$$

The time that Petroleum Experts correlation takes into account is the flowing time as the last reservoir pressure equalize up to the analysis time. When the flowing time transcend **Tpsss** (pseudosteady state flow starting time), the deliverability calculation is done by means of **Tpsss** that is correspondent to the pseudo steady state Darcy model. The **Petroleum Experts IPR** allows for the reduction in effective permeability resulting from liquid production in gas and condensate wells as shown in figure 2.9.

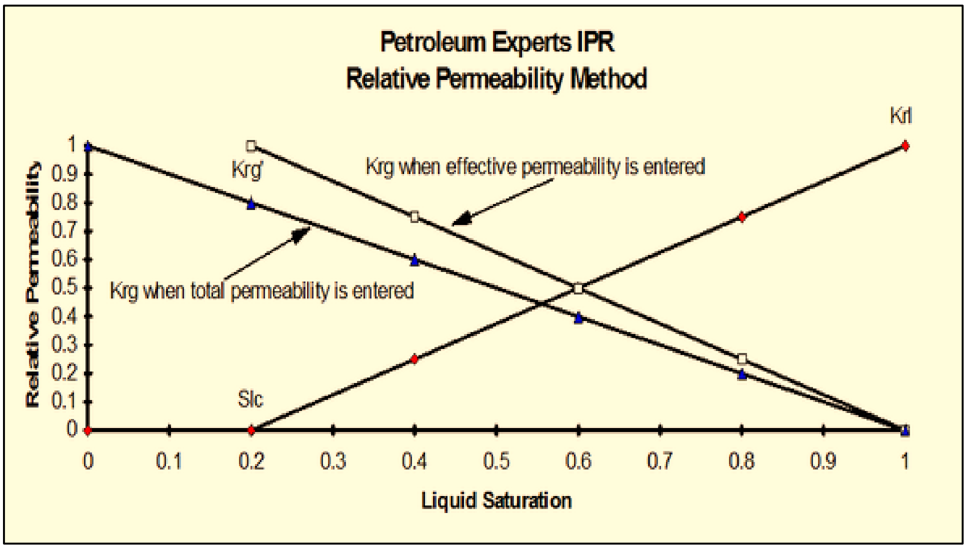


Figure: 2. 9. Relative permeability method

2.3.4 Gravel Pack Completion

The above mentioned models use gravel packed completions as a concentric cylinder that has a specified permeability. The gravel pack is connected to the well bore via perforations that have specific diameter. Performing sensitivity on perforation spacing and diameter, the pressure drop effect due to flow concentration on well performance can be analysed. Similarly the effect of varying gravel length (i.e. thickness of gravel between the OD of the screen and the ID of the original open hole) on skin can be analysed. The pressure drop (dP) across a gravel pack is computed using a summation of a Darcy and a non-Darcy component. This dP is then be transformed into skin to be considered in the IPR models.

$$dP_{GRAVELPACK} = aQ^2 + bQ \qquad (2\text{-}49)$$

Where 'a' is the non-Darcy term, Q is the total liquid rate and 'b' is The Darcy term. Prior computation of the dP_{gravel} value needs intermediate calculations that consider the following variables:

K_g = Gravel Pack Permeability

$\beta = (1.47E^7) / (Kg^{0.55})$

PerfDi = Perforation Diameter

SPF = Shots per ft

PRFINT = Perforation Interval

AOTF = Area Open To Flow = π (PerfDi/24)^{2}SPF*PRFINT

μ_g = Gas Viscosity in cp

B_g = Gas FVF

ρ_g = Gas Density

L = Gravel pack length

a-Term = 9.08E-13* β *B_g^2* ρ_g *L/12/AOTF^2

b-term = μ_g *B_g*L/12/(1.127E^{-3}*K_g*AOTF).

2.4 Horizontal gas well performance

The gas reservoirs having low permeability yield low production rates and are traditionally considered being non-commercial. For acquiring economical flow rates, stimulation either by hydraulic fracturing or acidizing is carried out in tight gas vertical wells. Furthermore to efficiently drain a tight gas reservoir, there should be close spacing between the drilled vertical wells that will result in bulk of vertical wells. The alternative attraction to effectively deplete tight gas reservoirs and attain high flow rates is the horizontal well technology. In 1991 Joshi proposed that both low-permeability and high-permeability reservoirs have applicability for horizontal wells. [1] However there were severe constraints placed on the geometry e.g. the length of well has to be long enough to encounter formation thickness and short enough compared to the dimensions of the drainage area. Additionally it is essential for these equations that the well is in the centre of the drainage volume. [7] In calculating the gas flow rate from a horizontal well, Joshi presented the idea of **effective wellbore radius** r'_w into the gas flow equation. The effective wellbore radius is given by:

$$\acute{r_w} = \frac{r_{eh}(L/2)}{a\left[1+\sqrt{1-(L/2a)^2}(h/2r_w)\right]^{h/L}} \quad (2\text{-}50)$$

$$a = (L/2)\left[0.5 + \sqrt{0.25 + (2r_{eh}/L)^4}\right]^{0.5} \quad (2\text{-}51)$$

$$r_{eh} = \sqrt{\frac{43{,}560\ A}{\pi}} \quad (2\text{-}52)$$

Where L is the length of the horizontal well, h is thickness, r_w is wellbore radius, r_{eh} is horizontal well drainage radius, a_e is half the major axis of drainage ellipse and A is drainage area. It may be assumed that a horizontal well is a number of vertical wells drilled close that have a narrow pay zone thickness. Figure 2.10 depicts the drainage area encountered by horizontal well having length L with a pay zone thickness of h. considering that each end of the horizontal well drain a half-circular area with radius b, with a rectangular drainage shape of the horizontal well, Joshi (1991) pointed out two methods to calculate the drainage area of a horizontal well.

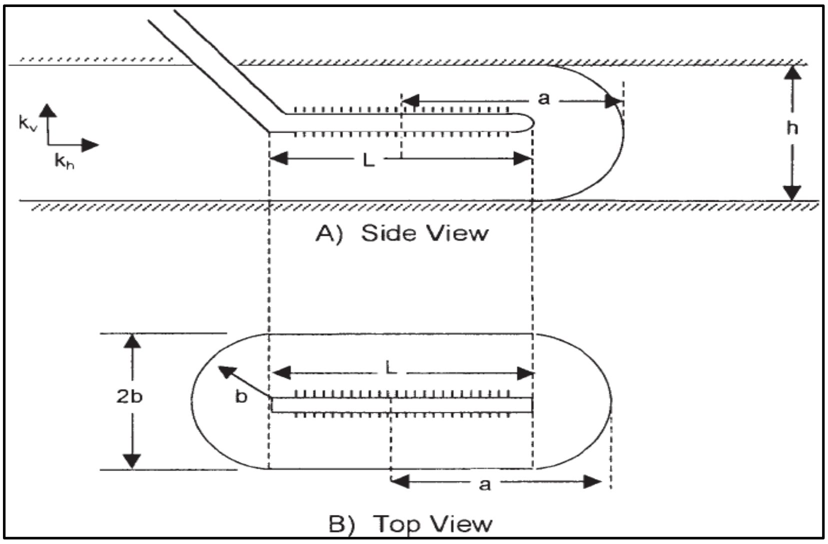


Figure: 2. 10. Horizontal well drainage area [1]

The first method assumes that the drainage area A is represented by two half circles having radius b (equal to radius of vertical well r_{ev}) at every end and a rectangle of magnitude L (2b, b is the half minor axis of ellipse), in the centre. This drainage area calculation is done using equation 2-53. The second method assumes that the horizontal well drainage area is an ellipse and is calculated using equation 2-54.

$$A = \frac{L(2b)+\pi b^2}{43{,}650} \quad (2\text{-}53)$$

$$A = \frac{\pi ab}{43{,}560} \tag{2-54}$$

$$a = \frac{L}{2} + b \tag{2-55}$$

Taking in consideration the pseudosteady-state flow, Joshi presented Darcy's equation for laminar flow in the following two familiar forms:

$$Q_g = \frac{Kh\left[p_r^2 - p_{wf}^2\right]}{1422\, T\left(\mu_g z\right)_{avg}\left[\ln\left(\frac{r_{eh}}{r_w'}\right) - 0.75 + s\right]} \tag{2-56}$$

$$Q_g = \frac{Kh\left[\Psi_r - \Psi_{wf}\right]}{1422\, T\left[\ln\left(\frac{r_{eh}}{r_w}\right) - 0.75 + s\right]} \tag{2-57}$$

2.5 Hydraulically Fractured Gas Well Performance

When the stimulation or good completion for skin removal does not result in an economic flow rate for tight gas well, it is beneficial to use hydraulic fracturing. In a broad cited publication (1961), Prats proposed that hydraulic fractures outcome an effective wellbore radius which leads to correspondent skin effect as the well enters pseudo-radial flow. Alternatively it shows that the flow from reservoir directs to fractured well as if the fracture has an enlarged wellbore. Prats analysis is being illustrated in figure 2.11 that shows a plot of the dimensionless effective wellbore radius r_{wD}' versus the relative capacity parameter a. This parameter a has been expressed as; [8]

$$a = \frac{\pi k x_f}{2 k_f w} \tag{2-58}$$

$$r_{wd}' = \frac{r_w'}{x_f} = \frac{r_w r^{-s_f}}{x_f} \tag{2-59}$$

$$s_f + ln\frac{x_f}{r_w} \tag{2-60}$$

Where x_f is fracture half-length, k_f is fracture permeability and w is fracture width. Equation 2-59 represents the dimensionless effective wellbore radius (r_{wd}'). Considering equation 2-58, if one knows the values of x_f and $k_f w$, then Fig. 2.11 can be used to determine the equivalent skin effect i.e. 's_f'. When the well flows under pseudo-radial conditions, it appears to have the skin of 's_f'. In 1981, Cinco Ley and Samaniego suggested a graphical correlation for s_f by plotting s_f against dimensionless fracture conductivity C_{fD} as shown in figure 2.12. This dimensionless fracture conductivity is defined in equation and related to relative capacity 'a' by equation 2-62. [9]

$$C_{fD} = \frac{k_f w}{k_f x} \quad (2\text{-}61)$$

$$C_{fd} = \frac{\pi}{2a} \quad (2\text{-}62)$$

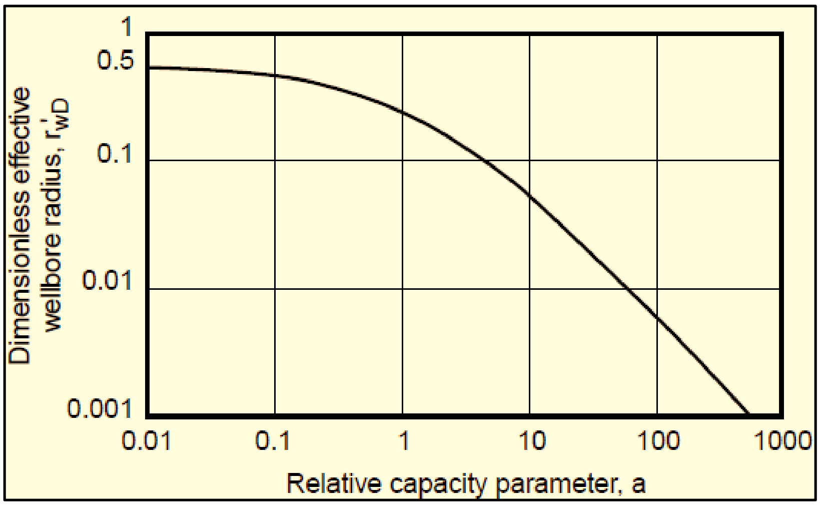


Figure: 2. 11. Dimensionless eff. wellbore radius for hydraulically fractured well [8]

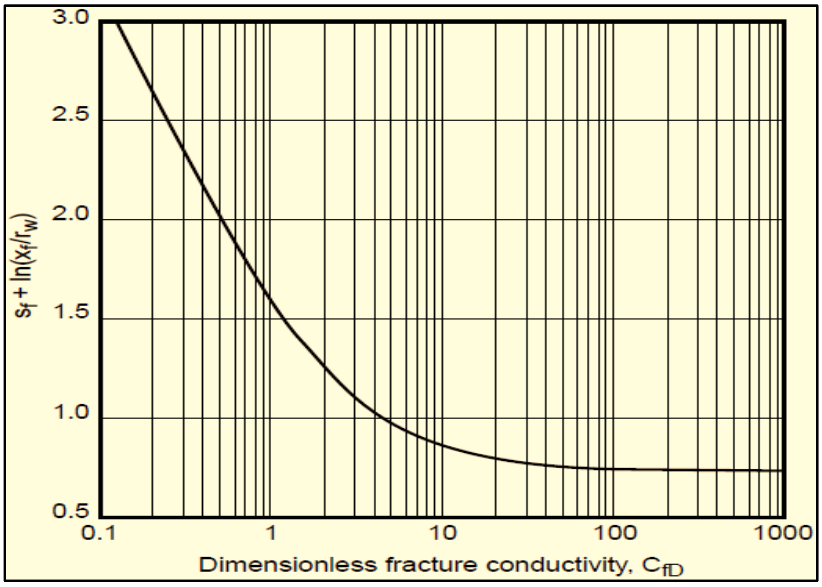


Figure: 2. 12. Equivalent fracture skin effect (Cinco-Ley and Samaniego-V., 1981b) [8]

It is assumed that fracture is a homogeneous, finite, rectangular porous medium of height h, half-length x_f, and width w where fluid entry has rate ***q (x, t)*** per unit fracture length while flow across the edge is negligible as the fracture width is small enough in comparison to fracture length. This last statement considers a linear flow in the fracture and allows simulation of well production by a uniform flux plane source of ***b*** and w, located at the wellbore axis. [10]

Normally the fracture permeability is much higher than formation permeability that influences the pressure response of a well test. So the following dimensionless variables are considered for pressure behaviour solution in a reservoir. [1]

$$\text{Diffusivity group: } \eta_{fd} = \frac{k_f \emptyset c_t}{k \emptyset_f c_{ft}}$$

$$\text{Time group: } t_{Dxf} = \left[\frac{0.0002637k}{\emptyset \mu c_t x_f^2}\right] t = t_D \left(\frac{r_w^2}{x_f^2}\right)$$

$$\text{Conductivity group: } F_{CD} = \frac{k_f w_f}{K x_f} = \frac{F_C}{K x_f}$$

$$\text{Storage group: } C_{Df} = \frac{0.8937\, C}{\emptyset c_t h x_f^2}$$

$$\text{Pressure group: } p_D = \frac{kh\Delta m(p)}{1424 QT}$$

$$\text{Fracture group: } r_{eD} = \frac{r_e}{x_f}$$

All of the above formulations use Dietz shape factor (C_A) of 31.6 (circular boundary). Other values may be considered for different shapes if the proper geometry is known. [1] [11]

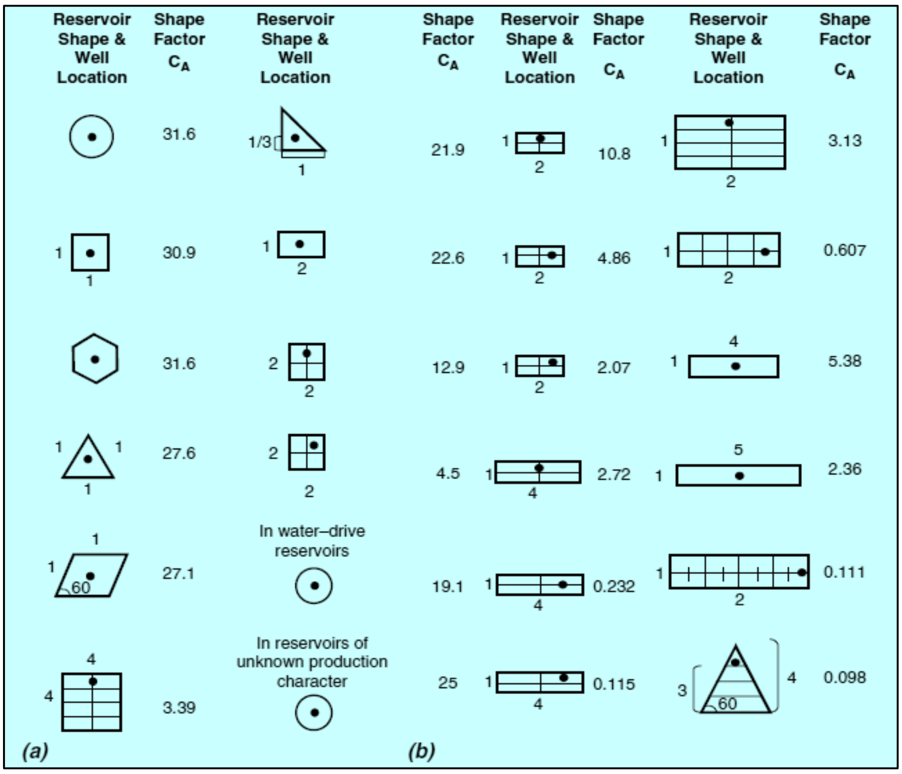
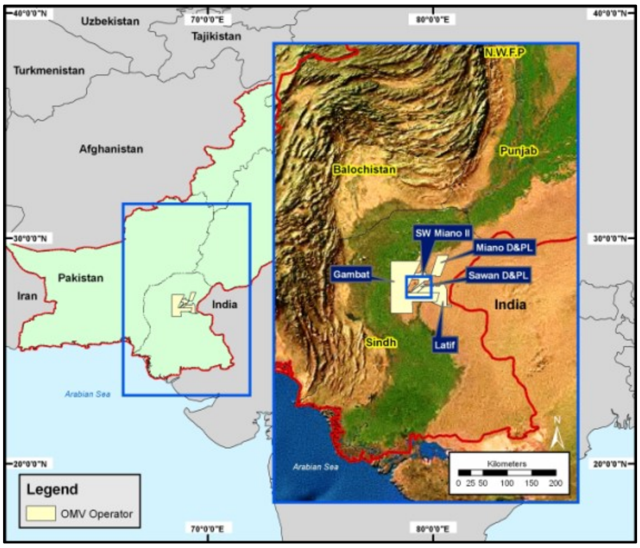


Figure: 2. 13. (a) Shape factors for closed drainage areas with low (a) and high (b) aspect ratios. (Dietz, 1965). [11]

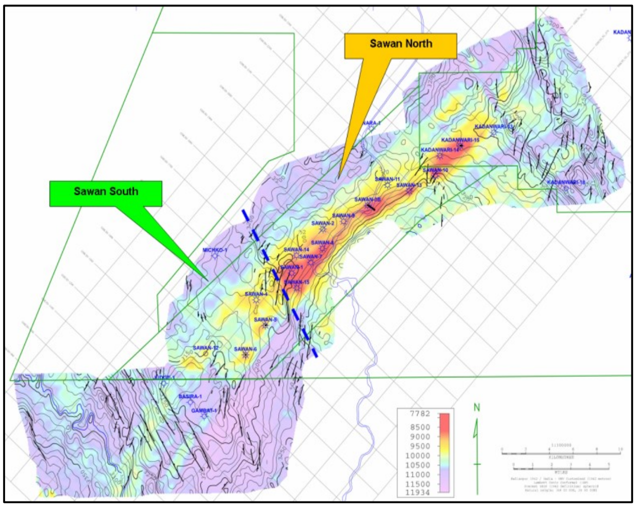
3. Methodology

For the analysis purpose, Sawan field OMV Pakistan was selected. The reservoir well models are being used in different software e.g. Pipesim (Schulmberger), PROSPER (IPM). Different companies use different software based on their requirements. OMV Pakistan is using PROSPER for the well deliverability analysis so the work is carried out with PROSPER.

3.1 Description of the Field under Study



Sawan Field is located in district Sukkur, Sindh and is a dry gas reservoir, discovered in 1998 through exploration well, Sawan-1, which encountered hydrocarbon bearing Lower Goru C-Sand. Sawan is a depletion drive gas reservoir with initial reservoir pressure of ~5350 psi and reservoir temperature of 350°F with cumulative production of 1.4 TCF till October 31, 2015.



Sawan field is divided into two distinct parts, Sawan North and Sawan South, separated by a North West – South East trending strike slip fault. Sawan North is a high permeability good quality sandstone reservoir with maximum net pay in excess of 100 meters. To achieve high gas rates the wells in Sawan North (Sawan-2 ST, 3, 7, 8, 9) were completed with big bore and selectively perforated for sand management. Sawan South however consists of low permeability reservoir due to deposition of poor facies in this part of the field. So far 4 wells (Sawan-4, 5, 6 and 12) have been drilled and completed in this area with 4-1/2” completion followed by fracking.

Sawan gas field has been producing since June 2003 and onwards from February 2010 the field is producing through front end compression (FEC). To date (Dec 2015) 16 wells (15 vertical and 1 horizontal) have been drilled in past and the field had been producing more than

450 MMscfd with record production rate of 140.38 MMscfd in December 2005 from Sawan-7. Currently production has dropped to 114 MMscfd with 14 producing wells.

Table: 3. 1. Details of Sawan Field

Sawan Field		
Section	**Sawan North**	**Sawan South**
Rock Type	Sandstone	Sandstone
Net Pay Thickness (m)	19-89	3.5-30
Average Porosity (%)	12 - 22	12.7-15
Avg. Absolute Permeability (md)	3.35-402	0.06 - 10
Initial Pressure (psi)	5387	5387
Gas Gravity	0.64	0.64
H_2S (%)	0.0021	0.0021
CO_2 (%)	8.6815	8.4733
Total Wells	11	4
Production Wells	11	3
Injection Wells	Nil	Nil
Gas Cumulative Production (Bcf)	1370 (March 2016)	64.36 (March 2016)

3.2 Analysis Strategy

After thorough study of the field, the cases selected for analysis are evaluated on basis of initial CIT details, recent testing operation and current condition w.r.t inflow and outflow relationship. The initial details analysis is carried out for data validation. Recent test operation matching is being carried out as we have uncertainty in initial data. The recent test match helps selecting the right VLP curve for current conditions and reflects the sequence of well deliverability.

3.3 PROSPER Analysis

PROSPER is a well performance, design and optimization program. PROSPER assist in analysing tubing (hydraulics) and reservoir (inflow) performance. PROSPER's sensitivity calculation are used to predict future inflow and outflow performance for each well. The Petroleum Expert software PROSPER allows to generate an IPR starting from both an experimental or empirical correlation and a semi analytical inflow equation (Petroleum Experts, 2012). The first option is more attractive to use in the field for its cost efficiency, the latter option is the most interesting if one wishes to get insight into the possible causes of a decrease in well productivity. Deviations in the field from the theoretically calculated in flow values based on these semi analytical inflow equations are accounted for by a skin factor, S.

This S value quantifies the production impairing phenomena which are not accounted for by the formation model.

3.3.1 Analytical Inflow Models

The available analytical models in PROSPER are;

1. Jones Correlation
2. Back Pressure Correlation
3. Petroleum Experts, A proprietary correlation
4. Hydraulically Fractured Well Correlation
5. Horizontal Well Correlation

Each of these five models, combined with the skin model available in PROSPER, can produce a pseudo-analytical IPR. The Jones and Petroleum Experts correlation uses perforation interval for the inflow calculations that mainly account for the completion skin. This perforation interval is used in the calculation of non-Darcy flow coefficient. Back pressure correlation use the reservoir thickness as a whole for the calculations and doesn't account for the perforation skin while hydraulically fractured well correlation use fracture height for the purpose. All the correlations account for the pressure drop due to sand control (gravel pack). The Petroleum Expert correlation likely (based on input requirements) has a similar form as the Jones' equation. It is developed to account for variations in liquid saturations near the well bore by modifying the permeability values taking into account the relative permeability curves.

3.3.2 Empirical Inflow Models

PROSPER provide many routines to calculate well productivity. These are all related in form to their analytical counter parts as explained above. These productivity approximations should be capable to function within the constraints of the available data. The available analytical models in PROSPER are;

1. Forchheimer correlation
2. Multi-Rate Jones correlation
3. C and n correlation
4. Multi-rate C and n correlation
5. Forchheimer with pseudopressure
6. Multi-Rate Forchheimer with pseudopressure

The coefficients in the Forchheimer relationship are referred to as Darcy / Laminar flow coefficient (a) and non-Darcy / Inertial-turbulent coefficient (b). These coefficients are different for simple Forchheimer and Forchheimer with pseudopressure correlations as already described in Chapter 2. Darcy coefficient is theoretically related to the PI of the well as defined by its rock characteristics. The non-Darcy coefficient incorporates pressure losses related to turbulence in the fluid. Similarly the C and n, express the PI and the “loss” related to turbulence. Ideally we would like to have a productivity indicator (PI) which is independent of pressure and flow rate. In literature it has been described that the C coefficient of the C and n method is not a good indicator because it is a function of the pressure. Theoretically speaking the multi-rate Forchheimer with pseudopressure correlation would be independent off pressure (by use of pseudo pressures) and independent of rate (by use of second order term describing turbulence).

3.4 Analysis Sequence

The analytical models are used for different data available for Sawan wells. The analysis is carried out for different well and reservoir conditions to check which model give realistic results. The data for the analysis is obtained from initial CIT, recent test operation and from simulation model for the current cases.

The empirical models are used by considering test data points available for Sawan wells. The test data points for the analysis are obtained from initial CIT and recent test operation while these are being limited to current conditions as no test data points are available. For the reason, the analytical correlations are used.

After analysing the mentioned correlations for inflow performance, sensitivity has been carried out for various parameters involved in the correlations. This will help in understanding the impacts of these parameters at current conditions (well declined enough).

4. Results and Analysis

From the field (Sawan), five different well configurations are selected to check the respective parameters used in different models. The models for various well types i.e. vertical, horizontal, hydraulically fractured, disposal well and gravel packed wells are analysed and the parameters sensitivity is carried out.

4.1 Case-I: Water Injection Well

4.1.1 Sawan-WDW-1 (Water Disposal Well)

The purpose for the drilling and completion of the Sawan WDW-1 is to allow for the disposal of all produced water from the Sawan CPU (Central Processing Unit) in a cost effective and environmentally friendly manner. The Sawan WDW-1 was considered to be capable of disposing a maximum daily volume of 5000bbl (design) of produced water at injection pressures no greater than 1500psi WHIP. The WDW well is completed open-hole from 1122m to 1208mDD into the Sui Main Limestone (SML) formation. The SML is a non-hydrocarbon bearing reservoir overlain by a thick sequence of shale and clay providing an effective barrier from contamination of potable water aquifers. The WDW is completed with 3 ½" fiberglass injection tubing string to resist corrosion caused by residual CO_2, H_2S and chlorides in the produced water. A water injection test was performed through the 3 ½" fiberglass completion string using 8.8 ppg KCl brine to confirm the reservoir's injectivity. The Results of the water injection test clearly demonstrated the wells ability to handle the volume of water required.

4.1.2 Initial Test Details

The details of the injection test are given below;

Table: 4. 1. Initial test injection data

Injection rate (bbl/min)	Pump Pressure (psia)	Injection Pressure (psia)
0	0	1685
1	110	1795
2	175	1860
3	260	1945
4	370	2055
5	510	2195
6	645	2330

In order to match the injection rates, Darcy's model is used to check whether the injection rates are consistent. The rates are matched at permeability value of 23 md, and the resultant Productivity Index (PI) is 13.5 STB/day/Psi that is used in the PI model. Figure 4.1 shows the IPR plots where the injection rate is increased as we increase the injection pressure. The input details are given in table 4.2 that results an IPR curves for Darcy and PI model with an AOF of 167030 STB/day.

Table: 4. 2. Input values for Darcy model

Parameters	Input Values
Reservoir Pressure (Psia)	1685
Reservoir Temperature (^{0}F)	170
Reservoir Permeability (md)	23
Reservoir Thickness (m)	86
Drainage Area (Acres)	500
Dietz Shape Factor	31.6
Wellbore Radius (in)	4.25
Mechanical Skin	0

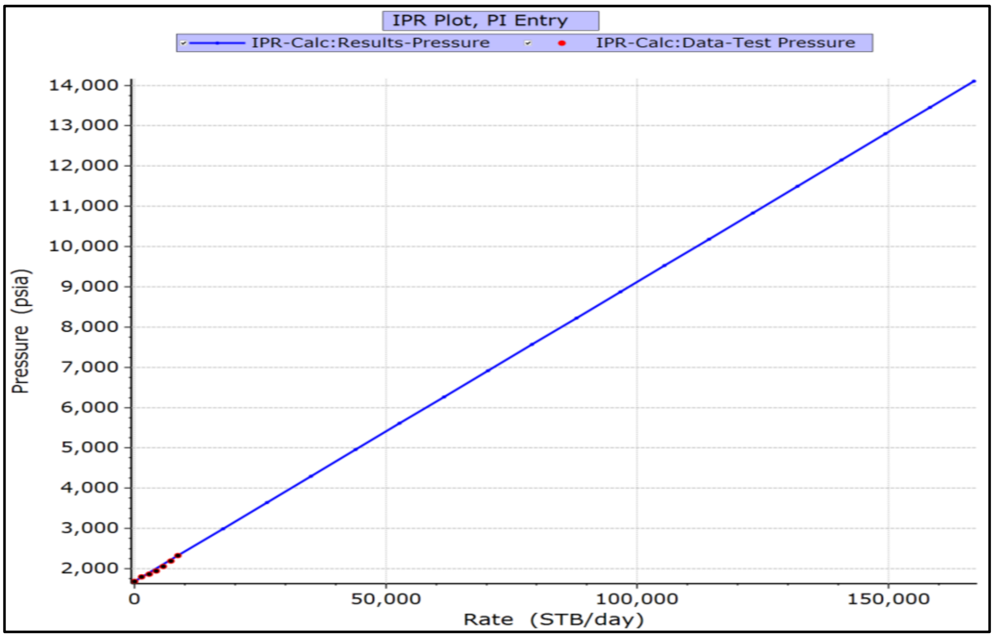


Figure: 4. 1. IPR curve with test injection rates

4.1.3 BHP 2010 Injection Test

An injectivity test in BHP-Survey 2010, with water injection pumps at plant site was carried out at four different rates to find the well's ability to handle the volume of water being injected. Table 4.3 shows the test details. The injection rates are matched with PI model to check whether the results are consistent. It can be noticed that the current results (2010) of water injection test as shown in injectivity plot (Figure 4.2), represent an enhancement in the well's injectivity performance compared to initial results. This may be due to the fracking of the formation where excessive amount of water is injected. As a result the rates are matched with high PI value i.e. 23 rather than 13.5 STB/day/psi. The new IPR generated with PI model is given in figure 4.3.

Table: 4. 3. Injection test data, 2010

Injection rate (bbl/min)	Pump Pressure (psia)	Injection Pressure (psia)
1	121	1806
2	145	1830
3	182	1867
4	234	1919

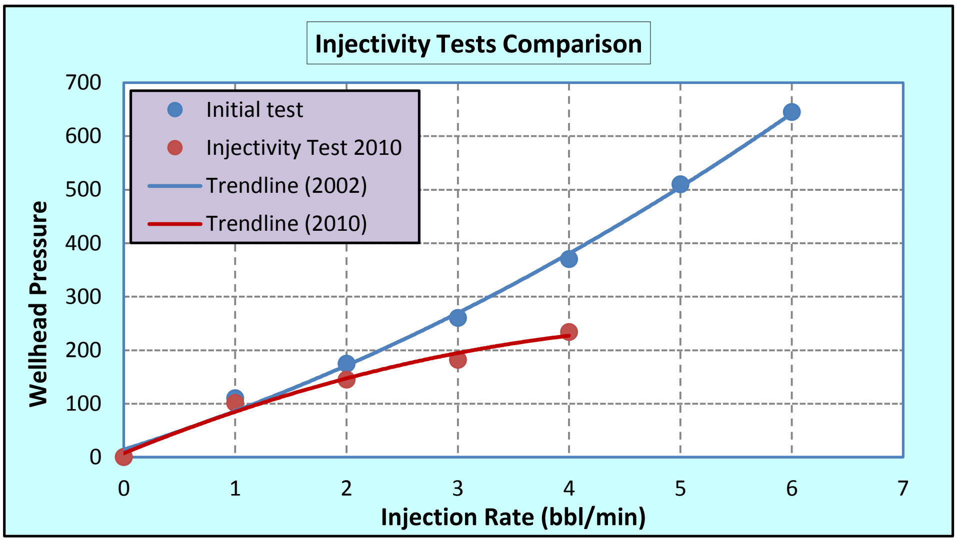


Figure: 4. 2. Injectivity test comparison, initial with 2010 injection rates

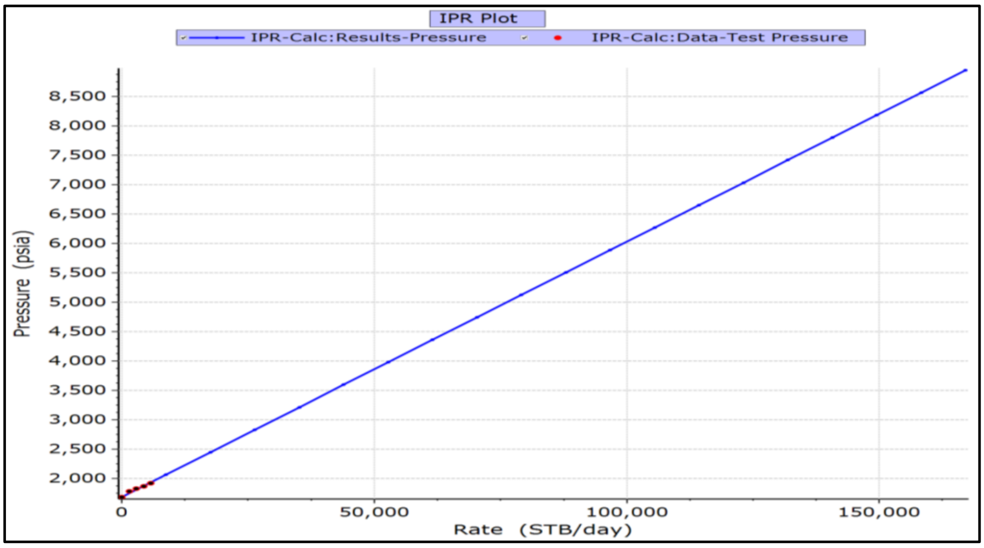


Figure: 4. 3. IPR plot with test injection rates of 2010

4.1.4 Current Conditions

Currently the injection rate is 6.65bbl/min that corresponds to 9576 bbl/day at wellhead pressure of 373 Psia (Pwf = 2058 Psia). To match the injection rates, Darcy and PI models are used. The results for both PI and Darcy's model shows an AOF of 167030 STB/day with injection rate of 9576 STB/day at wellhead pressure of 373 Psia.

Table: 4. 4. Input values for Darcy model

Parameters	Input Values
Reservoir Pressure (Psia)	1685
Reservoir Temperature (^{0}F)	170
Productivity Index (PI) (STB/Day/Psi)	25.5
Reservoir Permeability (mD)	23
Reservoir Thickness (m)	86
Drainage Area (Acres)	500
Dietz Shape Factor	31.6
Wellbore Radius (in)	4.25
Mechanical Skin	-3.9

In order to match the daily injection rate from reports, the parameters are tuned. In PI model the tuned parameter is the productivity index, while in Darcy's model skin factor is being changed for a match. Several attempts were made to match injection rate of 9576 bbl/day and the productivity index value for the match is noticed to be 25.5-bbl/day/psi. For Darcy's model, the matched rate resulted in skin factor of -3.9. This high negative value of skin is being attributed to the fact that the formation is fracked with the excessive amount of water being injected. The productivity index is increased from 13.5 to 25.5 STB/day/psi, so for an injection well in the same formation the PI values is known at initials conditions that can be used to check injectivity of well. The subsequent increase in PI value helps to understand how much water can be injected in a well at different conditions.

4.1.5 Sensitivity Analysis

The next step is to analyse the sensitivity of different parameters e.g. productivity index, reservoir thickness (Open-hole section) and wellbore Radius. The sensitivity of parameters will help to identify which has more impact on the injection rates. All the cases are checked with high, base and low values to quantify the impact of the parameters. Based on the results, a tornado chart has been illustrated in figure 4.4. This chart illustrates that decreasing the productivity index by a value of 15 has more impact than increasing it that may be because of the formation injection ability as it cannot accept more than its ability. The reservoir thickness has the same impact while the wellbore radius has somehow equal effect of increasing or decreasing.

Table: 4. 5. Sensitivity analysis parameters and their output

Sensitivity Analysis			
Parameters	**Low**	**Base case**	**High**
Productivity Index (STB/day/psi)	10.5	25.5	40.5
Reservoir Thickness (m)	52	86	120
Wellbore Radius (in)	3.5	4.25	4.8

Table: 4. 6. High and low output values

Parameters	Low Output	High Output
Productivity Index (STB/day/psi)	5782	11214
Reservoir Thickness (m)	6873	11346
Wellbore Radius (in)	9448	9658

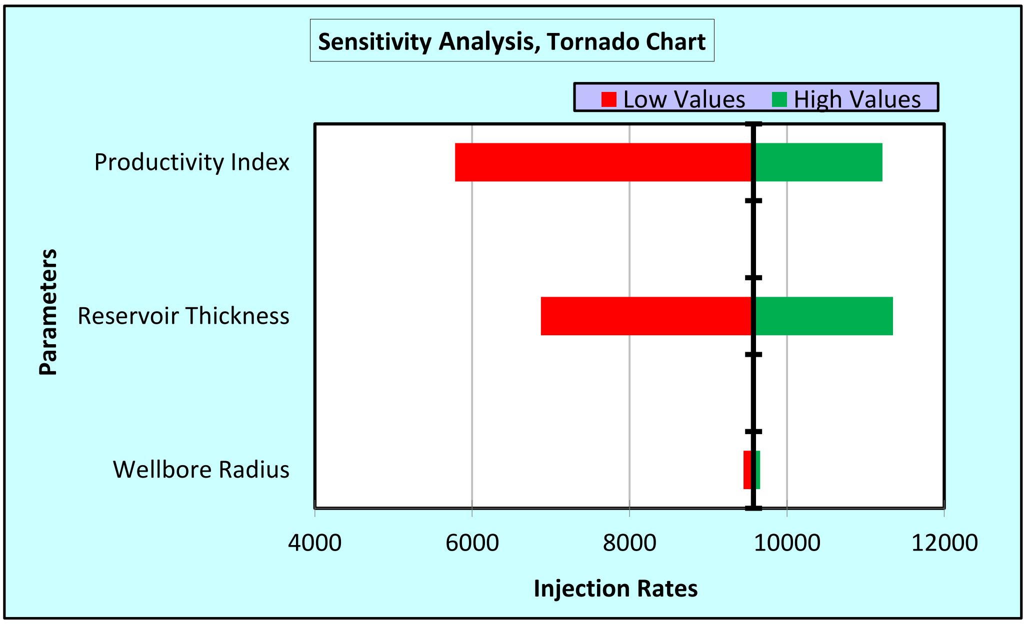


Figure: 4. 4. Tornado chart for the sensitivity analysis

4.2 CASE II: Vertical Well

4.2.1 Sawan Well 7

Sawan-7 was drilled as a development well in North compartment. The well was spud on December 07, 2002 and drilled to a TD of 3407.5 m with a target formation of Lower Goru C-Sand. The well was completed with 7" Cr-22 mono-bore completion. During CIT the interval (3269.0 – 3276.4 m = 7.4 m, 3283.0 – 3288.3 m = 5.3 m; 3302.0 – 3314.0 m = 12 m and 3316.0 – 3323.0 m = 9.0 m; Total = 33.7 m) was selectively perforated. During CIT the well was tested at 101.06 MMscfd and FWHP of 4273 psi with WGR 2.0 bbls/MMscf. The well was tie-in with Sawan plant on July 13, 2003 and had produced a cumulative of 232.7 Bcf at an average gas rate of 100 MMscfd till November 2008 (with record production of 140.38 MMscfd on December 08, 2005) when steep production decline was started to be observed. The well was put on front end compression in February 2010. In August 2010, RST was carried out to determine the depletion across the perforation interval on the basis of which additional / re-perforation in the interval (3279 – 3289 m = 10 m; 3294 – 3300 m = 6 m and 3302 – 3314 m = 12 m; Total = 28 m) were carried out to cater steep production decline. Sawan-7 was flowing at an average rate of 52.64 MMscfd with FWHP of 348 psi in May 2012 where PROSPER sensitivity analysis matched the production with true Darcy skin of 37; consequently matrix stimulation was carried out in November 2012 to increase the well productivity. As a result of matrix stimulation the gas production increased from 45.88 to 60.26 MMscfd.

Currently the well is flowing at 18.46 MMscfd at FWHP of 189 psi has produced a cumulative of 343.4 Bcf till October 13, 2015. For Sawan well 7, all the reservoir models are being checked at each stage to analyse which model provide the best outcome. This will help in analysing other vertical wells, as we will have an idea which model to use for realistic outcome. Figure 4.5 represents the production data for the well until end of April 2016 while figure 4.6 illustrates the well schematics before and after additional perforations.

4.2.2 Initial Details (Completion Integrity Test)

After drilling and completing well Sawan-7, a completion integrity test was conducted. This test consisted of a clean-up period followed by a first build-up and a 4 rate flow-after-flow test followed by a final build-up. The maximum measured rate achieved was 101.06 MMscfd at a FWHP of 4273 psi. It was found that the reservoir shows a permeability of around 450 md. A reservoir pressure of 5,371 psi at a perforation top depth of 3269 m was evaluated. This value corresponds to a reservoir pressure of 5,385 psi at the most likely GWC of 3295m SS.

Mechanical skin factor of 1 and a rate-dependent factor D of 9.1884e-5 1/Mscf/day has been analysed. On site gas sample analysis give a gas gravity of 0.648 and CO_2 content of 8 to 9%. H_2S values ranged from 25 to 35 ppm. In order to check the well deliverability and match initials details, analysis was carried out with various reservoir models. The required reservoir and other details are mentioned below;

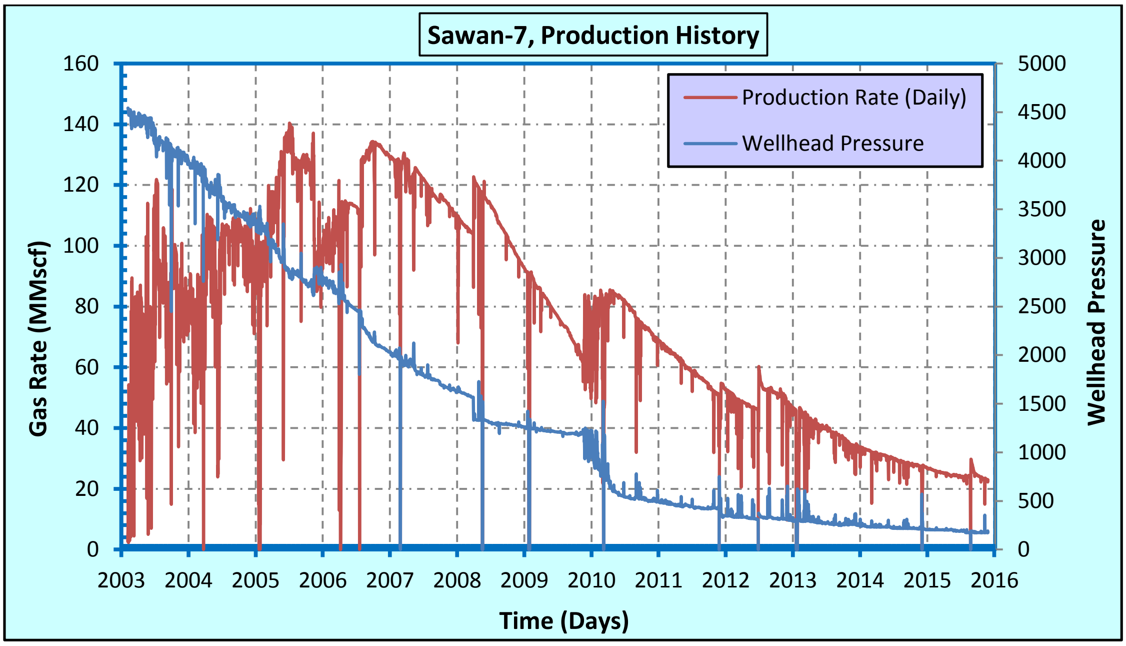


Figure: 4. 5. Production history for Sawan well 7

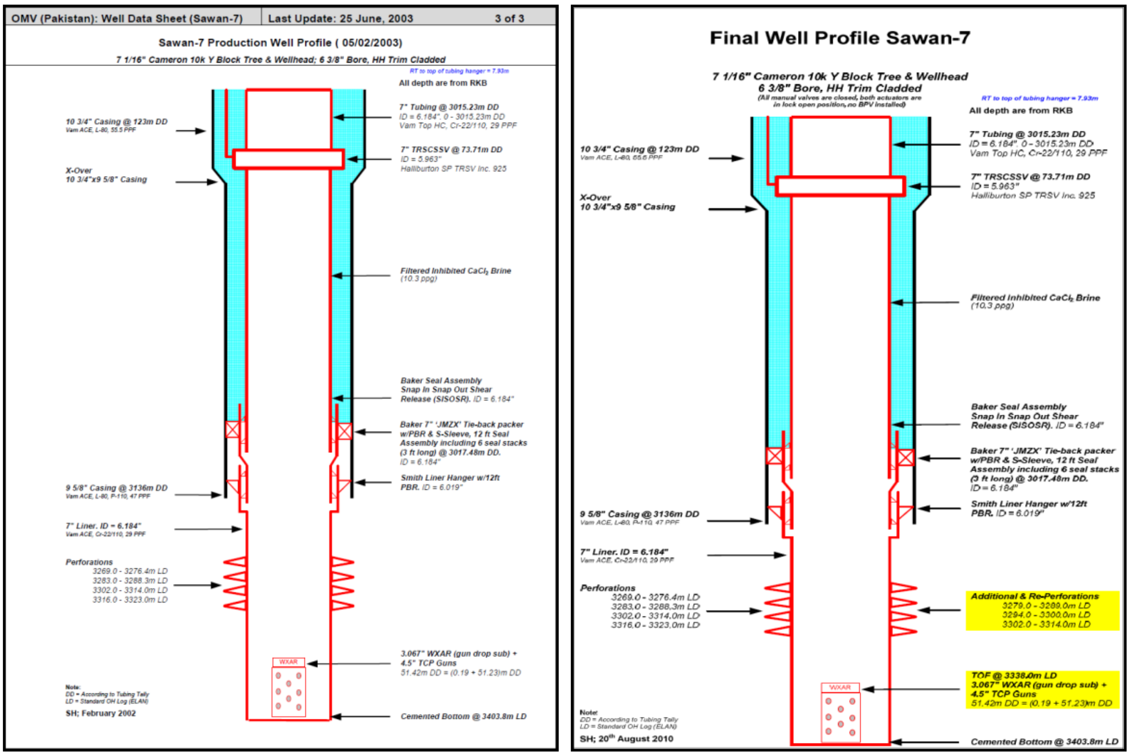


Figure: 4. 6. Initial and final well schematics for Sawan well 7

Table 4.7 represents the parameters and its values for various models. Some parameters are required for all models that are mentioned as general parameters. The results of the models are given in table 4.8 with AOF values and maximum flow rate value at wellhead pressure of 4273 Psia. The maximum measured rate was 101.06 MMscfd at the mentioned FWHP. It can be seen that Forchheimer with PP result in a value that is near to the measured values. C and n and Petroleum Experts model also have near values but both result in quite high and low AOF value.

Table: 4. 7. Input data derived from initial details

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	5371
	Reservoir Temperature (F)	350
	Water Gas Ratio (STB/MMscf)	2
	Condensate Gas Ratio (STB/MMscf)	0
Jones + Petroleum Expert	Reservoir Permeability (md)	450
	Reservoir Thickness (m)	54
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	3.5
	Perforation Interval (m)	31.7
	Mechanical Skin	1
Petroleum Expert	Connate Water Saturation (Fraction)	0.25
	Reservoir Porosity (%)	17.9
Forchheimer Model with Pseudo Pressure	Non-Darcy Coefficient (psi2/cp/(Mscf/day)2	5.57E-04
	Darcy Coefficient (psi2/cp/(Mscf/day)	248.403
C and n Model	C (Mscf/day/Psi^2)	0.33873
	n	0.92838

Table: 4. 8. Results obtained from different models

Results of different Models		
WHP (Psia)		4273
Reservoir Models	AOF (MMscf/day)	Maximum Gas Rate (MMscf/day)
Jones	1722	108
C and n	2856	102
Forchheimer with PP	1346	101.7
Petroleum Experts	959	103

Table 4.9 shows the gauge and wellhead details during CIT. For matching, the pressures are being converted to perforation top depth (3269 m) using gas gradient of 0.073 Psi/ft. Initial WGR is being analysed to be 2 (bbl/MMscf).

Table: 4. 9. Guage and wellhead data obtained during CIT

Bottom hole	Well Head			
Gauge Pwf (Psia)	WHP (Psia)	WHT (F)	Gas Rate (MMscfd)	WGR (bbl/MMscf)
5348	4513	235	35.62	0
5333	4476	264	55.52	2.1
5311	4388	284	85.6	2.2
5303	4273	290	101.06	2

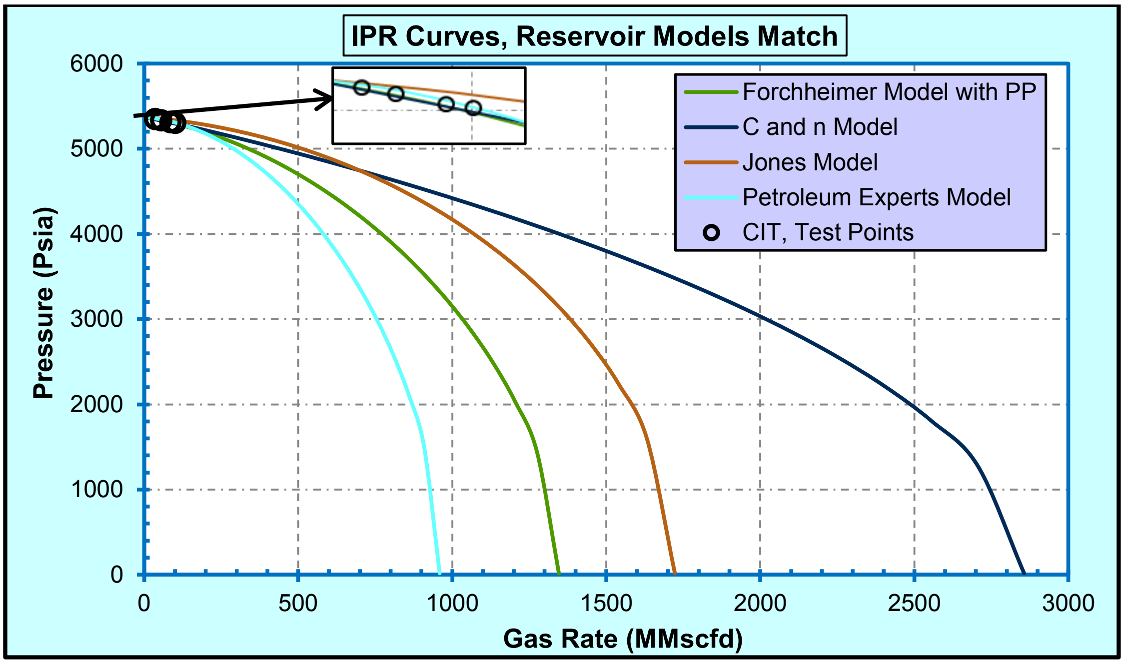
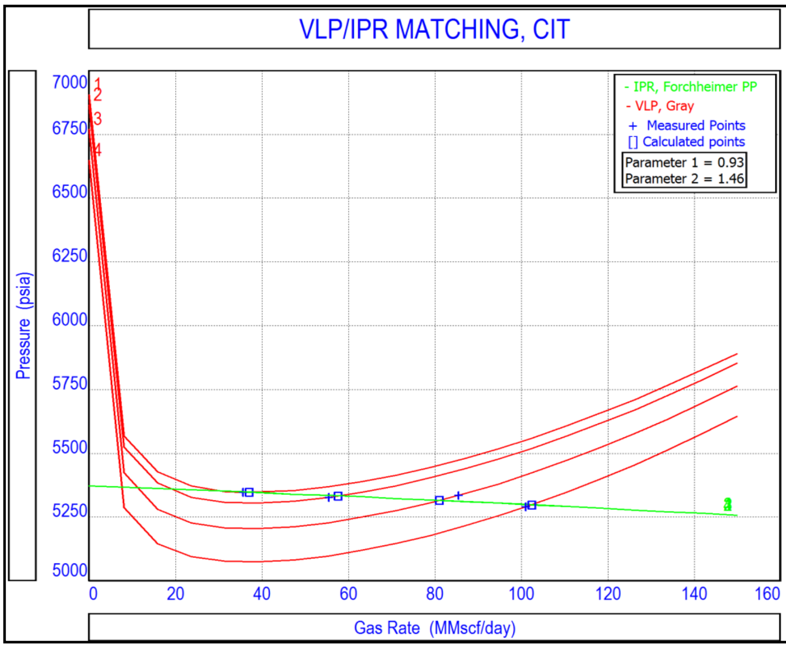


Figure: 4. 7. IPR curves of the reservoir models

It can be seen that the IPR curves result in different AOF values depending upon various model requirements. Since Forchheimer model with pseudo pressure accounts for all pressure ranges, this IPR curve can be considered as the one reflecting real values. For the VLP match, Gray correlation fits the parameter range (∓ 10%) for the gravity term. This VLP correlation is used to match the test rates. The IPR model of Forchheimer with pseudo pressure is used for the VLP/IPR match.

The initial match is carried out for data validation but the initial data is not enough reliable. In order to carry out sensitivity on current conditions, we need to match the recent BHP-Survey (test data) in order to have a VLP profile that suits the well configuration. For

Sawan Well 7, the last BHP-Survey was carried out in 2009 so the matching has been done by considering the details obtained from BHP-Survey 2009.



GAS RATE (MMscf/day)	Measured	Calculated	% Difference
1	35.620	37.088	4.12
2	55.520	57.772	4.06
3	85.600	81.095	-5.26
4	101.060	102.411	1.34

BOTTOM HOLE PRESSURE (psia)	Measured	Calculated	% Difference
1	5346.12	5346.97	0.015844
2	5325.98	5331.99	0.11324
3	5334.05	5314.13	-0.37456
4	5288.68	5296.88	0.15547

Figure: 4. 8. VLP/IPR match for CIT details

4.2.3 BHP-Survey 2009

The build-up pressure was analysed using a radial homogeneous infinite acting model. When the data is plotted in log-log plot it shows an upward turn in the end showing virtual fault like behaviour. The estimated drainage area pressure is 2168 psi at perforation top which is calculated by extrapolating the radial flow regime portion of Horner plot. Mechanical skin factor of 1 and a rate-dependent factor D of 4.5e-5 1/Mscf/day have been analysed. Table 4.10 represents the parameter values for the modelling purpose and their output has been shown in table 4.11.

The maximum measured rate was 92.3 MMscfd at FWHP of 1283. Table 4.11 shows that most of the models match the maximum flow rate at the specific wellhead pressure as the pressure range is applicable to all models. However the AOF values are different for each model as there are several coefficients and parameters involved in each correlation. The associated IPR curves are shown in figure 4.9. The gauge and wellhead details during BHP survey are shown in table 4.12.

Table: 4. 10. Input data from BHP details

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	2168
	Reservoir Temperature (F)	350
	Water Gas Ratio (STB/MMscf)	9.8
	Condensate Gas Ratio (STB/MMscf)	0
Jones + Petroleum Expert	Reservoir Permeability (md)	450
	Reservoir Thickness (m)	54
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	3.5
	Perforation Interval (m)	31.7
	Mechanical Skin	7.3
Petroleum Expert	Connate Water Saturation (Fraction)	0.25
	Reservoir Porosity (%)	17.9
Forchheimer Model with Pseudo Pressure	Non-Darcy Coefficient (psi2/cp/(Mscf/day)2	7.51E-04
	Darcy Coefficient (psi2/cp/(Mscf/day)	178.444
C and n Model	C (Mscf/day/Psi^2)	2.67554
	n	0.80737
Forchheimer	Non-Darcy Coefficient (psi2/(Mscf/day)2	1.34E-05
	Darcy Coefficient (psi2/(Mscf/day)	3.25525

Table: 4. 11. Results obtained from different models

Results of different Models		
WHP (Psia)		1283
Reservoir Models	AOF (MMscf/day)	Maximum Gas Rate (MMscf/day)
Jones	575	92.2
C and n	652	92.3
Forchheimer with PP	491	92.3
Petroleum Experts	499	91.3
Forchheimer	480	92.3

Table: 4. 12. Gauge and wellhead data, 2009

Bottom hole	Well Head			
Pwf (Psia)	WHP (Psia)	WHT (F)	Gas Rate (MMscfd)	WGR (bbl/MMscf)
2108	1553	311	62.7	9.8
2095	1458	312	74.8	9.8
2082	1384	311	83.2	9.8
2070	1283	310	92.3	9.8

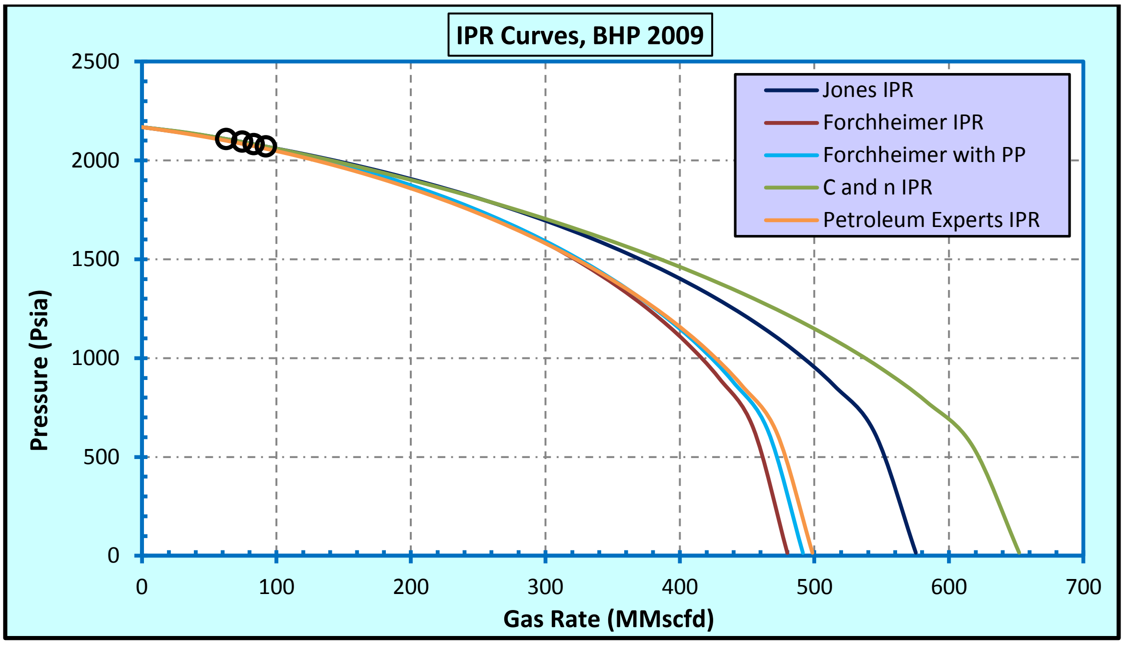


Figure: 4. 9. IPR curves of the models

It can be seen that C and n and Jones model have high AOF that may lead to over estimation. Forchheimer, Petroleum experts and Forchheimer with PP can be considered as having realistic AOF. For matching, the pressures are being converted to perforation top depth (3269 m) using the gas gradient. WGR is being analysed to be 9.8 (bbl/MMscf). For the VLP match, Gray correlation fits the parameter range (∓ 10%) for the gravity term. This VLP correlation is used to match the test rates. The IPR model of Forchheimer with pseudo pressure is used for the VLP/IPR match.

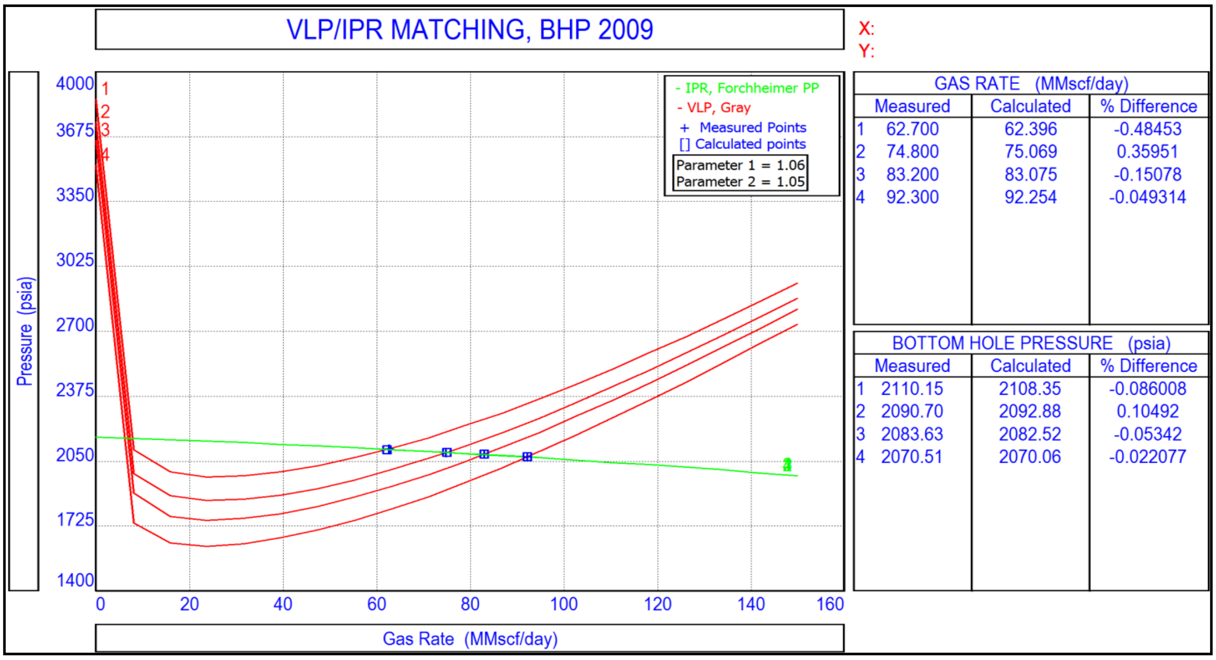


Figure: 4. 10. VLP/IPR match, 2009 test points

The VLP, Gray correlation matched here is used for the recent calculations. The recent reservoir pressure is estimated to be 497 based on prediction of simulation model with WGR value of 40 bbl/MMscf. Mechanical skin value is analysed to be 18 that match the current production rate and is mainly attributed to fines migration causing near wellbore formation damage and plugging perforation.

4.2.4 Current conditions

The recent conditions are being matched with Jones and Petroleum Experts model as the rest (C and n, Forchheimer) need test points for calculating parameters i.e. C, n, A and B. This can be considered as a limitation for the models where test data points are not available. Currently the well is flowing at 18.46 MMscfd at FWHP of 189 psi. The details of varied parameters are given in table 4.13.

Table: 4. 13. Current values for parameters

Varied parameters	
Reservoir Pressure (Psia)	497
WGR (STB/MMscf)	40
Perforation Interval (m)	42.4
Mechanical Skin	18

Table: 4. 14. Results obtained from different models

Results of different Models		
WHP (Psia)		188.7
Reservoir Models	AOF (MMscf/day)	Max. Gas Rate (MMscf/day)
Jones	40	18.46
Petroleum Experts	37	18.05

Referring to the results in table 4.14 and figure 4.11, there is enough difference in AOF value while small difference in gas rate of Jones and Petroleum Experts correlation. It can be noticed that Petroleum Experts correlation use effective permeability based on the connate water saturation to calculate the ß (turbulence)-factor. This factor results in high value for Petroleum Experts model that in return reduce the rate. Since the pressure range is suitable for Jones model, the current condition scenario can be validated/ modelled with Jones model. The VLP correlation used here is Gray correlation as it accounts mainly for gas and gas condensate wells.

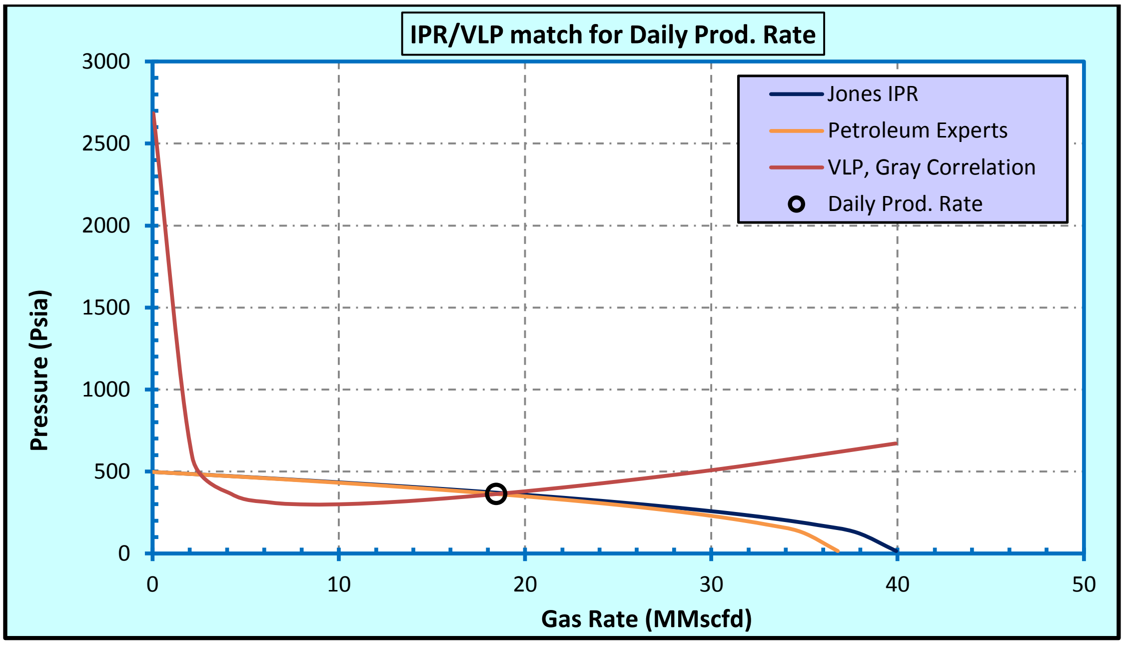


Figure: 4. 11. VLP/IPR curves for current conditions

4.2.5 Sensitivity Analysis

The sensitive parameters in vertical well models are reservoir permeability, skin factor, reservoir thickness, drainage area, Dietz shape factor, wellbore radius, perforation interval, reservoir porosity, specific gravity and temperature. Since most of the parameters are not changed e.g. permeability, thickness, sp. Gravity etc., the sensitivity of those parameters can be neglected. Here the sensitivity is just carried out for skin factor and perforation interval. The results do not highlight a big difference here as the well is declined from a high pressure (5371) to very low pressure (497). These parameters may show high variation for wells flowing with high rates.

Table: 4. 15. Sensitivity analysis parameters

Sensitivity Analysis			
Parameters	**Low**	**Base case**	**High**
Skin Value (Max, Min)	0	18	30
Perforation Interval (m)		42.4	54

Table: 4. 16. High and low output for sensitive parameters

Parameters	Low Output	High Output
Skin Effect	15	25.56
Perforation Interval	18.46	18.52

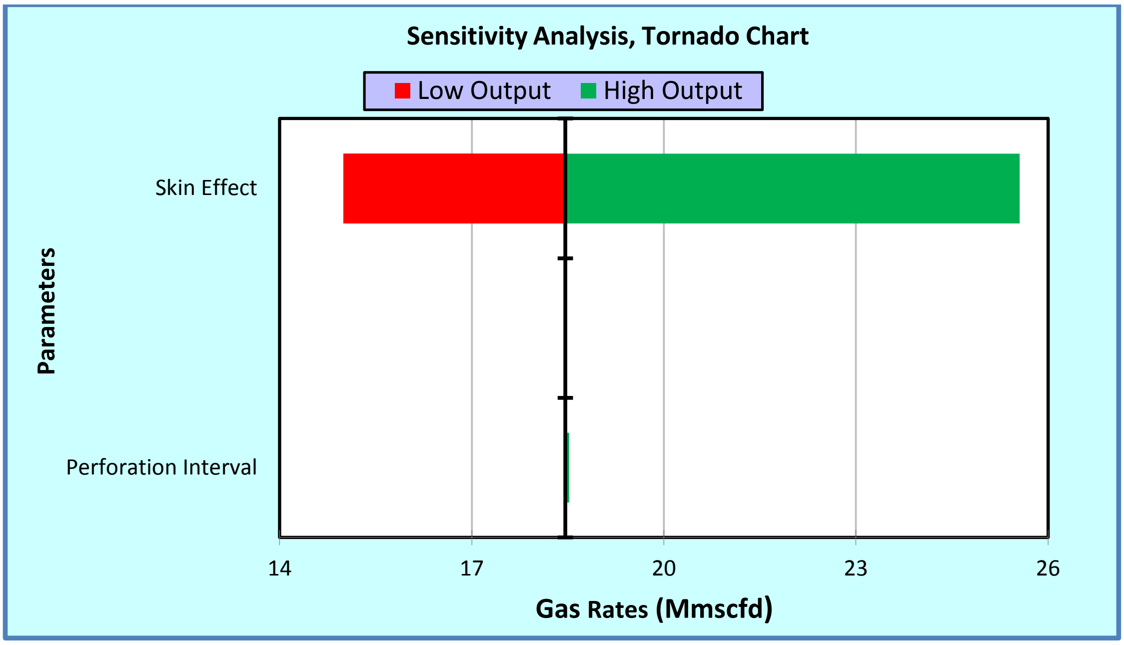


Figure: 4. 12. Tornado chart illustrating sensitivity analysis

4.3 CASE III: Gravel Pack Completion

4.3.1 Sawan Well 3

Sawan-3 was drilled as a development well in Sawan North compartment that mainly consist of friable sands. The well was spud on May 09, 2001, due to drilling problems the well was side-tracked twice (deviated well) and drilled to a TD of 3658.3 mMD (3541.5 mTVD) with a target formation of Lower Goru C-Sand. Based on the core and open-hole wireline log results a cased-hole DST-1a was carried out to test the well productivity, during DST-1a the interval (3403.0 – 3413.0 m = 10 m and 3431.0 – 3445.0 m = 14 m; Total = 24 m) was perforated. The well was tested at 34 MMscfd gas (76 psi drawdown) with FWHP of 1200 psi and 0.01 lb/MMscf of sand. The average reservoir pressure at datum (3295 mSS) was estimated to be 5386 psi while the permeability and true Darcy skin value interpreted to be 400 md and 11 respectively. The analysis of the DST showed that the well can produce without sand production at a drawdown value of 80 psi only which corresponds to 35 MMscfd gas rate, however for more production sand control was required. The well was suspended by placing two cement plugs after DSTs; awaiting completion. A workover to complete the well was conducted on Sawan-3 and the well was completed with 7” x 5-1/2” tapered and 3-1/2” Cr-22 gravel pack assembly in December 2002 to produce sand free gas at rates averaging 60 MMscfd. The well was tie-in with Sawan plant on June 25, 2003 and has been producing at an average rate of ~40 MMscfd till November, 2004 when a steeper production decline was started to be observed; attributed to plugging of the gravel pack due to fines migration. In October

2005 an acid stimulation treatment was undertaken to wash the screen and a remedial rigless workover was planned, which consisted of GP screen wash and re-perforation of lower suspended perforation interval. Suspended interval from 3435.0 – 3445.0 m = 10.0 m was re-perforated and total 17 MMscfd incremental was observed. Additional formation interval of 3421.0 – 3431.0 m = 10.0 m was perforated in May, 2008; an increment of 2 MMscfd was achieved. During BHP-Survey 2009, an increase in skin and scale in wellbore was observed, the increase in skin suggested plugging of gravel pack. The well was put on front end compression (FEC) in February 2010 and GP perforation from 3408.0 – 3420.0 m = 12.0 m and 1st WBC were carried out in May, 2010 resulting ~8 MMscfd increment in total. The well was then producing continuously till August 2014 when again steep production decline was observed and production went down from 12 → 2.9 MMscfd, consequently WBC was successfully carried out in September 2014 and production went up to 17.4 MMscfd.

Currently the well is flowing at 9.19 MMscfd at FWHP of 218 psi and has produced a cumulative of 122.2 Bcf till October 20, 2015. For Sawan well 3, all the reservoir models are being checked at each stage with sand control as gravel pack to analyse which model provide the best outcome. This will help in analysing other wells having sand problems, as we will have an idea which model to use for realistic outcome.

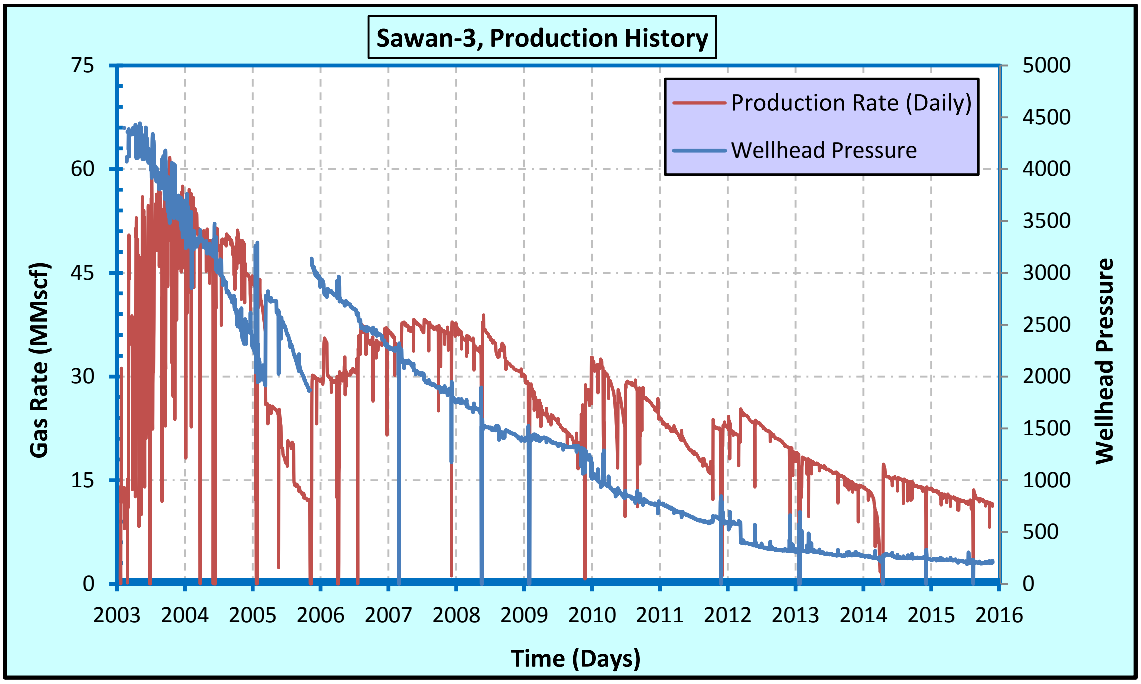


Figure: 4. 13. Sawan well 3 production history

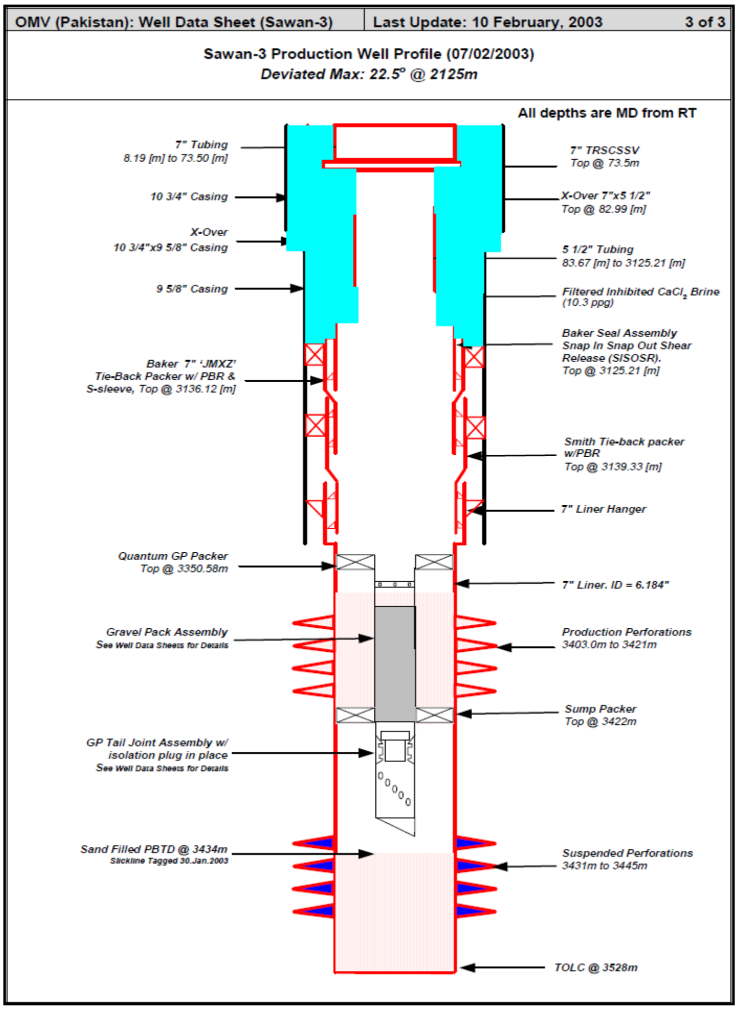


Figure: 4. 14. Well schematics, Sawan well 3

4.3.2 Initial Details (Drill Stem Test 1a)

DST 1a was targeted to test the well productivity over the whole upper sand interval and obtain representative fluid samples by adding perforations into the high porosity sections of the USRS. Test interval DST 1a: 3403-3413 m-RKB and 3431 – 3445 m-RKB. A Reservoir pressure of 5377 psi at a mid-perforation depth of 3424 m MD was evaluated. It correlates to a reservoir pressure of 5386 psi @3295 m SS which is the most likely GWC in the Sawan reservoir. The pressure value was confirmed by evaluation of 4 build-up periods in total. A total skin factor of 35 was seen. This can be split into a Darcy skin factor of 11 and a rate-dependent factor D of 6.3e-4 1/Mscf/day. Responsible for the skin was probably the low shot density (5 spf). For the final completion a higher shot density (12 spf) could improve the skin values and therefore increase the AOF. Well deliverability analysis showed an AOF of 249 MMscfd. A preliminary gas sample analysis shows a gas gravity of 0.642. Sand production was monitored continuously with a surface filter-type sand trap during both tests. A summary of rates, corresponding drawdowns and sand rates is given in the below table:

Table: 4. 17. Initial details from DST 1a

DST 1a			
Choke ["]	Rate [MMscfd]	Δp [psi]	Sand [lb/MMscf]
48/64	28.1	49	0.01
56/64	30.1	56	0.02
64/64	32.1	64	0.03
80/64	34.1	76	0.01

As a rule of thumb an amount of sand up to 1 lb/MMscf sand at producing rates lower than 50 MMscfd can be considered as acceptable. At rates in excess of 50 MMscfd 0.5 lb/MMscf are acceptable. Theory of sand control assumes that a single grain in the sand matrix is stable under low drawdown conditions but gets ruptured off and mobilized as soon as the drawdown exceeds a certain value so the installation of proper sand control from begin on seems to be necessary. In order to check the well deliverability and match DST 1a details, analysis was carried out with various reservoir models. The required reservoir and other details are shown in table 4.18.

Table: 4. 18. Input data from initial details

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	5377
	Reservoir Temperature (F)	350
	Water Gas Ratio (STB/MMscf)	2.6
	Condensate Gas Ratio (STB/MMscf)	0
Jones + Petroleum Expert	Reservoir Permeability (md)	400
	Reservoir Thickness (m)	42
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	3.5
	Perforation Interval (m)	25
	Mechanical Skin	11
Petroleum Expert	Connate Water Saturation (Fraction)	0.25
	Reservoir Porosity (%)	19.8
Forchheimer Model with Pseudo Pressure	Non-Darcy Coefficient (psi2/cp/(Mscf/day)2	2.35E-02
	Darcy Coefficient (psi2/cp/(Mscf/day)	343.76
C and n Model	C (Mscf/day/Psi^2)	8.54801
	n	0.59865

Table: 4. 19. Results obtained from different models

Results of different Models		
WHP (Psia)		1200
Reservoir Models	AOF (MMscf/day)	Maximum Gas Rate (MMscf/day)
C and n	250	34.3
Forchheimer with PP	232	34.3
Petroleum Experts	258	34.3

Table: 4. 20. Gauge and wellhead details

Bottomhole Conditions	Well Head Conditions			
Pwf (Psia)	WHP (Psia)	WHT (F)	Gas Rate (MMscfd)	WGR (bbl/MMscf)
5307	2544	218	28.1	5.5
5300	2296	229	30.1	4.1
5292	1834	231	32.1	3.4
5280	1200	226	34.1	2.6

The results of the models are given in table 4.19 with AOF values and maximum flow rate value at wellhead pressure of 1200 Psia. It can be seen that the drawdown between wellhead and bottomhole flowing pressure is much more that is mainly because of the sand production. Forchheimer with PP, C and n and Petroleum Experts model show the same value for the maximum rate, but result in different AOF values. Table represents the gauge and wellhead details. For matching, the pressures are being converted to perforation top depth (3403 mMD) using the gas gradient. Initial WGR is being analysed to be 2.6 (bbl/MMscf).

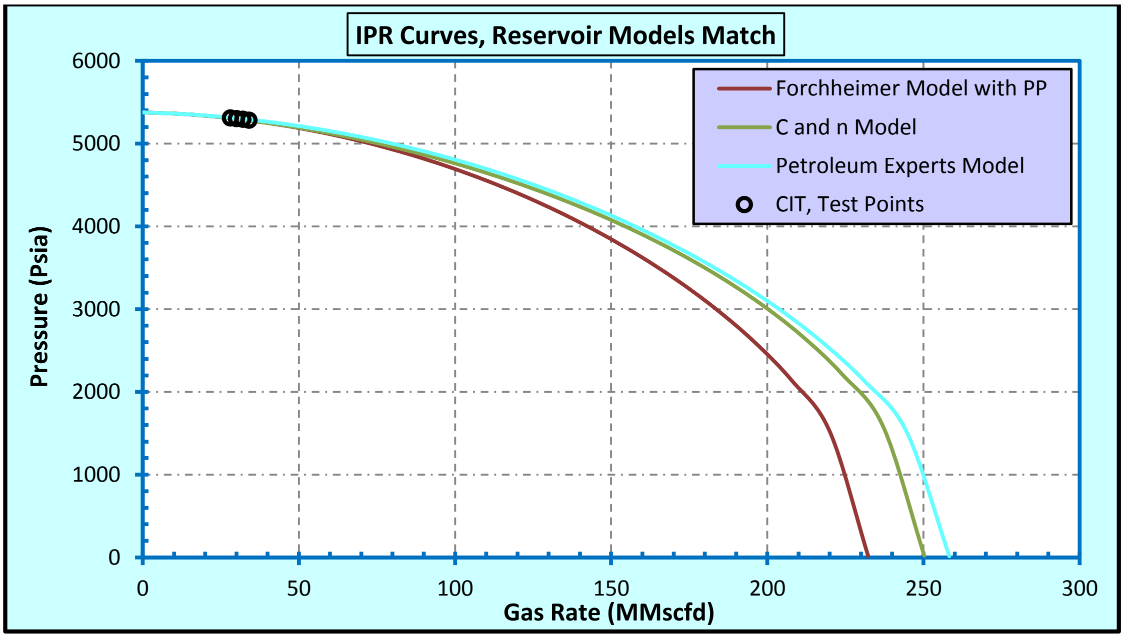


Figure: 4. 15. IPR curves of the models

For the VLP match, Gray correlation is used. Due to the high drawdown and sand production, the VLP match at gravity term multiplier of 0.2. This VLP correlation is used to match the test rates. The DST 1a analysis is being done here to check the rates whether it match the details or there is a mismatch as the DST rates were tested with DST string rather than tubing. Keeping in view the sand bridges, Gravel Pack was installed in 2003 and a CIT was carried out.

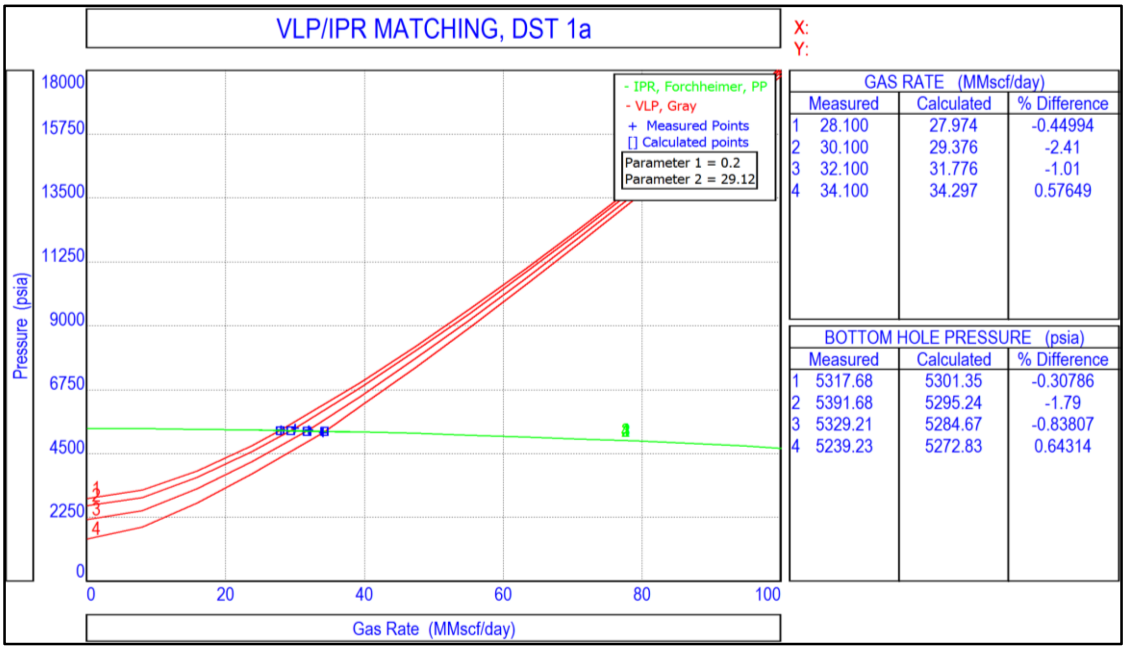


Figure: 4. 16. VLP/IPR match curves

4.3.3 Initial Details (Completion Integrity Test)

During the CIT after gravel pack installations, maximum rates of 55 MMscfd (limited by the erosional velocity inside the gravel pack) can be produced with a total drawdown (reservoir and gravel pack) of approx. 450 psi. The AOF potential is estimated to be 180 MMscfd. The average WGR observed during these flow periods was around 6-bbls/MMscf, attributed to clean-up of completion fluid and production of condensed water. Some sand production was observed during the last flow period (57/64" equivalent choke). As the produced sand does not contain any gravel pack proppant it is concluded that it origins from the earlier lower perforations. Preliminary on-site gas sample analysis of the samples collected during the test from Sawan-3 shows a gas gravity of 0.642, consisting of CO_2 (6.0%) and H_2S (36 ppm). Since no production has been obtained from the reservoir since then it is concluded that the reservoir pressure is 5,374 psi at a mid-perforation depth of 3412 m MD. Similarly, the permeability value determined from the final build-up data of the same DST-1A was 400 md however, for the new perforation interval tested during the recent CIT (3403 – 3421 m MD) the average weighted permeability from the core data is around 320 md.

Table: 4. 21. Input data from CIT details

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	5371
	Reservoir Temperature (F)	350
	Water Gas Ratio (STB/MMscf)	6
	Condensate Gas Ratio (STB/MMscf)	0
Jones + Petroleum Expert	Reservoir Permeability (md)	320
	Reservoir Thickness (m)	42
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	3.5
	Perforation Interval (m)	18
	Mechanical Skin	25
Petroleum Expert	Connate Water Saturation (Fraction)	0.25
	Reservoir Porosity (%)	19.8
C and n Model	C (Mscf/day/Psi^2)	0.24914
	n	0.80275
Gravel Pack details	Gravel Pack Permeability (md)	120000
	Perforation Diameter (in)	0.3
	Shot Density (1/ft)	12
	Gravel Pack Length (in)	2
	Perforation Efficiency (Fraction)	1

Table: 4. 22. Results obtained from different models

Results of different Models		
WHP (Psia)		3881
Reservoir Models	AOF (MMscf/day)	Max. Gas Rate (MMscf/day)
C and n	219	56.53
Petroleum Experts	206	58.52

Table: 4. 23. Gauge and wellhead data

Bottomhole Conditions	Well Head Conditions			
Pwf (Psia)	WHP (Psia)	WHT (F)	Gas Rate (MMscfd)	WGR (bbl/MMscf)
5170	4298	218	22.67	6
5084	4146	229	41.52	6
4991	4055	231	49.06	6
4898	3881	226	56.76	6

The results of the models are given in table 4.22 with AOF values and maximum flow rate value at wellhead pressure of 3881 Psia. For matching, the pressures are being converted to perforation top depth (3403 mMD) using the gas gradient. WGR and skin values are analysed to be 6 (bbl/MMscf) and 25. The high skin value is mainly because of sand particles migration that plugs the gravel pack.

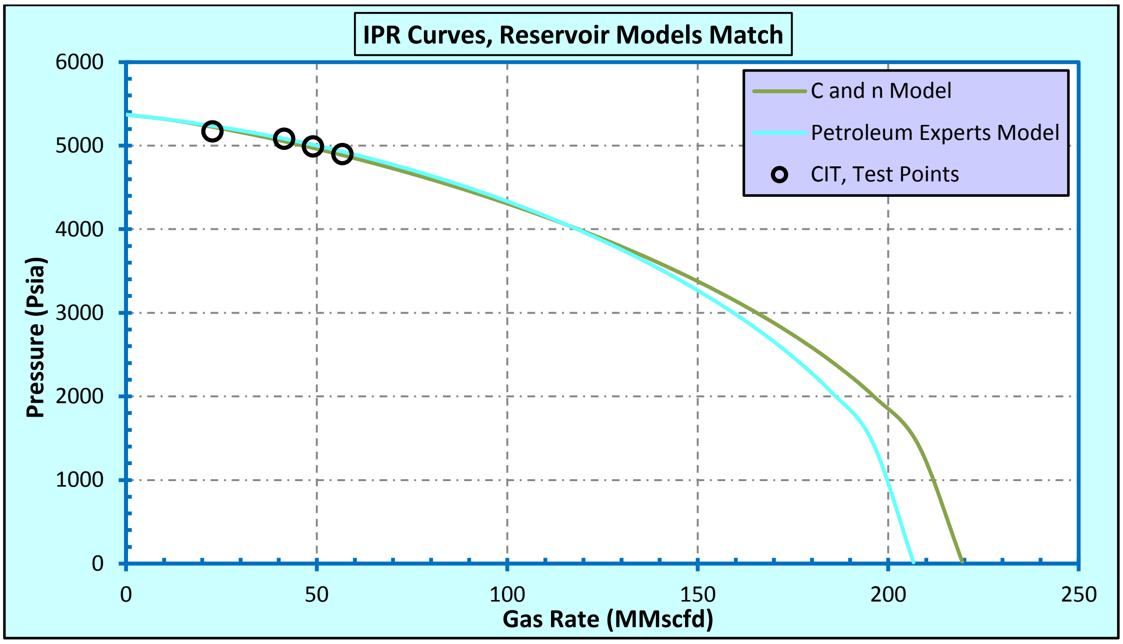


Figure: 4. 17. IPR curves of the models

It can be seen that the IPR curves result in different AOF values depending upon various model requirements. Forchheimer model with pseudo pressure results in negative log parameter so it is not used in the IPR section. For the VLP match, Gray correlation fits the parameter range ($\mp$ 10%) for the gravity term. This VLP correlation is used to match the test rates. The C and n IPR model is used for the VLP/IPR match as it result in a matching rate at wellhead pressure of 3881 (Figure 4.18).

The initial match is carried out for data validation. In order to carry out sensitivity on current conditions, we need to match the recent BHP-Survey in order to have a VLP profile that suits the well configuration. For Sawan Well 3, the last BHP was carried out in 2012 so the matching has been done by considering the details obtained from BHP 2012.

4.3.4 BHP-Survey 2012

The LTR response observed in Log-Log plot may be due to drainage effects of other producing wells in the same compartment. The estimated reservoir pressure is 1259 psi at gauge depth (3455m-RKB). Mechanical skin factor of 4 and a rate-dependent factor D of 1.25e-4

1/Mscf/day have been analysed. The details of the required parameter for modelling are given in table 4.24.

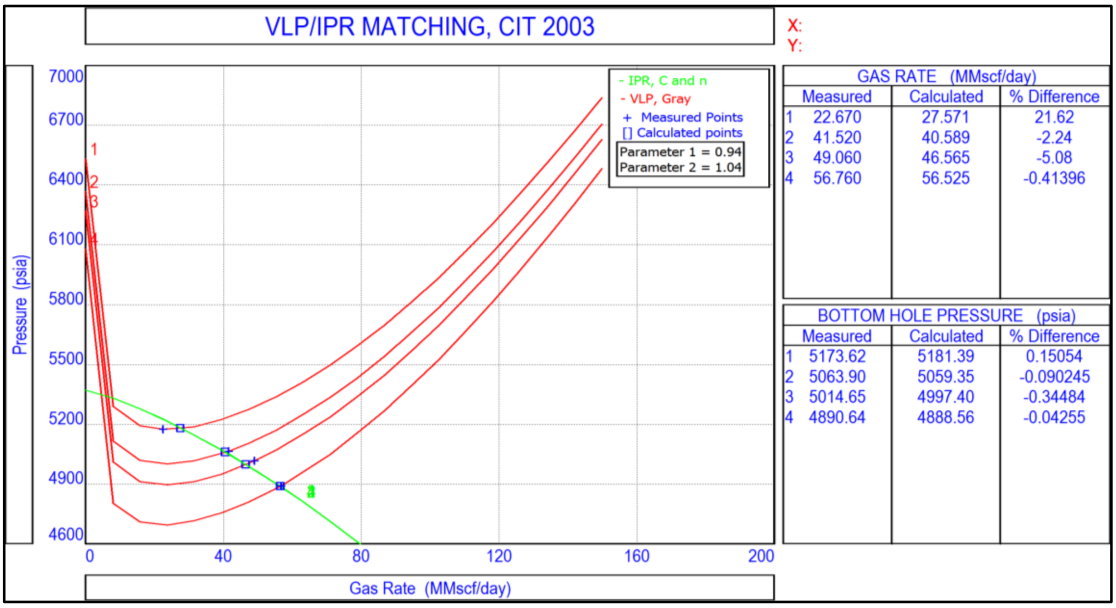


Figure: 4. 18. VLP/IPT match curves

Table: 4. 24. Input data from BHP details

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	1252
	Reservoir Temperature (F)	350
	Water Gas Ratio (STB/MMscf)	15
	Condensate Gas Ratio (STB/MMscf)	0
Jones + Petroleum Expert	Reservoir Permeability (md)	320
	Reservoir Thickness (m)	42
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	3.5
	Perforation Interval (m)	42
	Mechanical Skin	4
Petroleum Expert	Connate Water Saturation (Fraction)	0.25
	Reservoir Porosity (%)	19.8
Forchheimer, PP	Non-Darcy Coefficient (psi2/cp/(Mscf/day)2	0.019908
	Darcy Coefficient (psi2/cp/(Mscf/day)	277.092
Forchheimer	Non-Darcy Coefficient (psi2/(Mscf/day)2	0.00033533
	Darcy Coefficient (psi2/(Mscf/day)	4.71731
C and n Model	C (Mscf/day/Psi^2)	5.35901
	n	0.66588
Gravel Pack and Sand control	Gravel Pack Permeability (md)	120000
	Perforation Diameter (in)	0.3
	Shot Density (1/ft)	12
	Gravel Pack Length (in)	2
	Perforation Efficiency (Fraction)	1

Table: 4. 25. Results obtained from different models

Results of different Models		
WHP (Psia)		694
Reservoir Models	AOF (MMscf/day)	Maximum Gas Rate
Jones	107	20
C and n	69	19.9
Forchheimer with PP	60	19.9
Petroleum Experts	81	20
Forchheimer	60	19.9

Table: 4. 26. Gauge and wellhead data

Bottomhole Conditions	Well Head Conditions			
Pwf (Psia)	WHP (Psia)	WHT (F)	Gas Rate (MMscfd)	WGR (bbl/MMscf)
1219	922	218	10	15
1193	840	229	15	15
1156	694	231	20	15

Table 4.25 shows that most of the models match the maximum flow rate at the specific wellhead pressure as the pressure range is applicable to all models. However the AOF values are different for each model. The IPR curves are as follows;

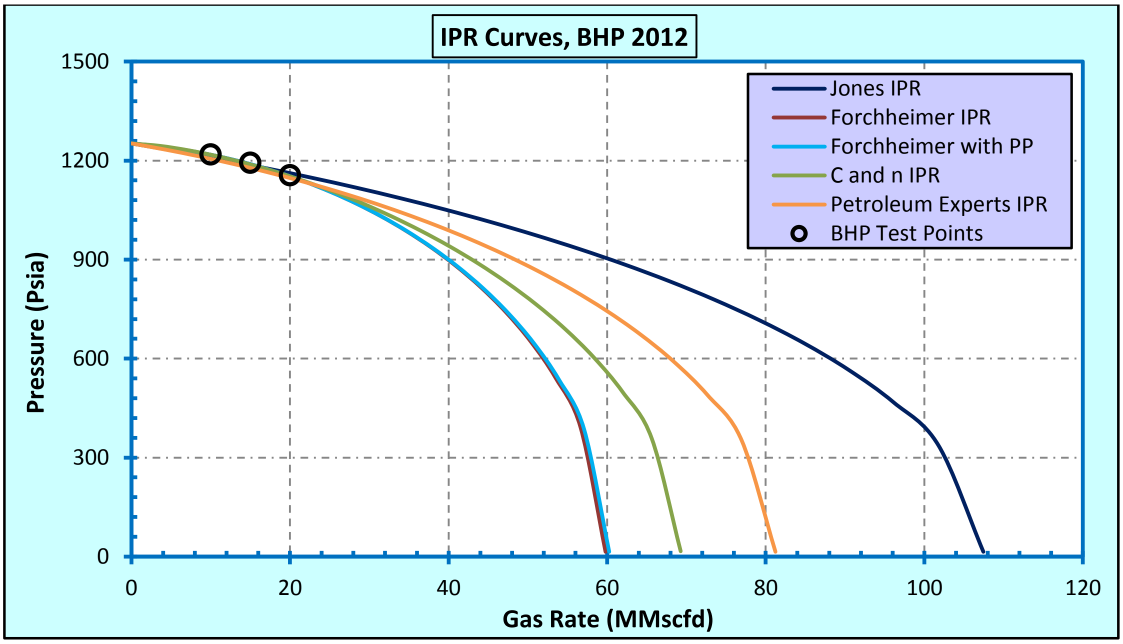


Figure: 4. 19. IPR curves of the models

It can be seen that Petroleum Experts and Jones model have high AOF that may lead to over estimation. Forchheimer, C and n and Forchheimer with PP can be considered as having realistic AOF. For matching, the pressures are being converted to perforation top depth (3403 mMD) using the gas gradient. WGR is being analysed to be 15 (bbl/MMscf). For the VLP match, Gray correlation fits the parameter range (∓ 10%) for the gravity term. This VLP correlation is used to match the test rates. The IPR model of Forchheimer with pseudo pressure is used for the VLP/IPR match. The VLP, Gray correlation matched here is used for the recent calculations. The recent reservoir pressure is estimated to be 561 based on prediction of simulation model with WGR value of 31 bbl/MMscf. Mechanical skin value is analysed to be 6 that match the current production rate and is mainly attributed to fines migration of friable sands.

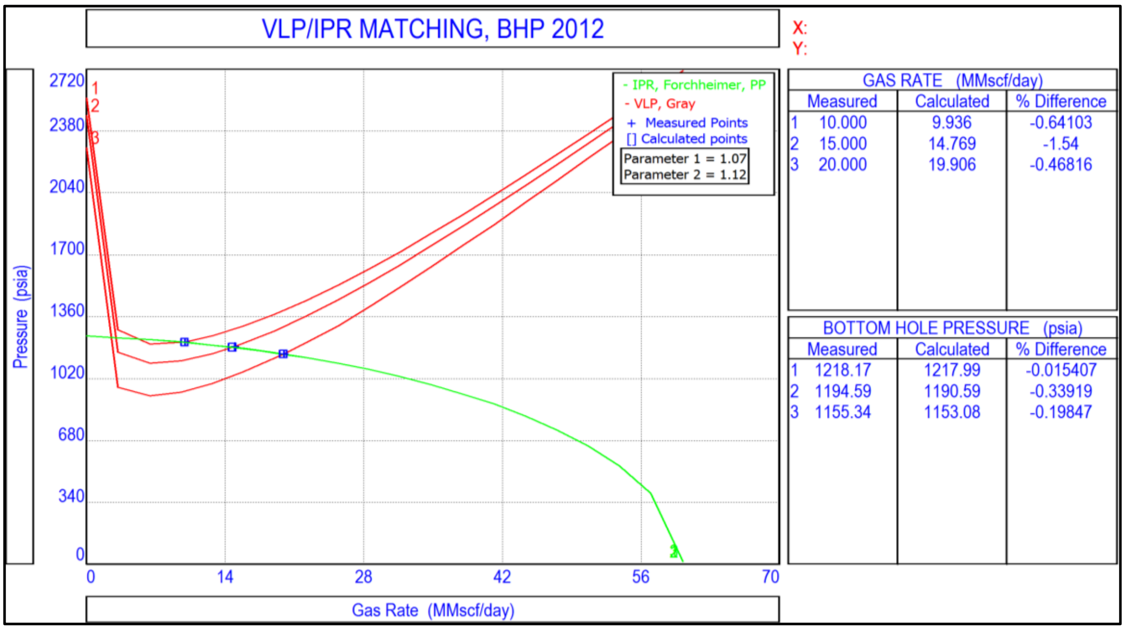


Figure: 4. 20. VLP/IPT match curves

4.3.5 Current conditions

The recent conditions are being matched with Jones and Petroleum Experts model as the rest (C and n, Forchheimer) need test points for calculating parameters i.e. C, n, A and B. Currently the well is flowing at 9.19 MMscfd at FWHP of 218 Psia. The details of varied parameters are given in table below:

Table: 4. 27. Current condition parameter values

Varied parameters	
Reservoir Pressure (Psia)	561
WGR (STB/MMscf)	31
Perforation Interval (m)	42.4
Mechanical Skin	6

Table: 4. 28. Results obtained from different models

Results of different Models		
WHP (Psia)		218
Reservoir Models	AOF	Maximum Gas
Jones	15.7	9.19
Petroleum Experts	15.2	8.9

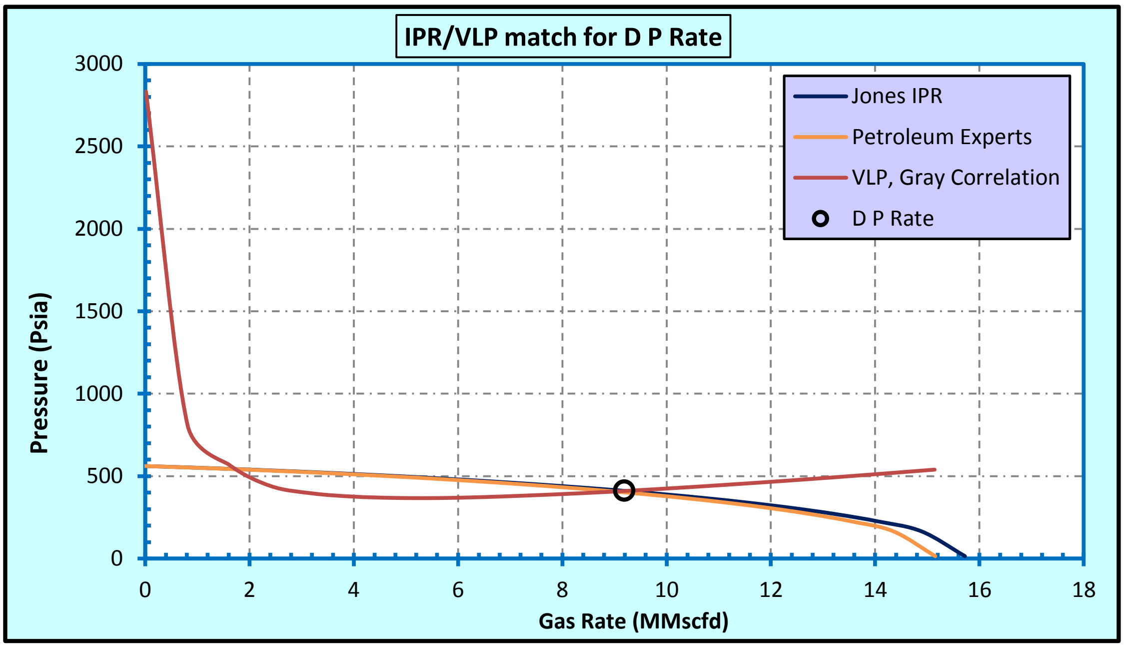


Figure: 4. 21. VLP/IPR curves for current condition

Since the pressure range is suitable for Jones model and Petroleum Experts results in low rate because of ß-factor, the current scenario can be validated with Jones model.

4.3.6 Sensitivity Analysis

The sensitive parameters that can be considered in case of gravel pack are skin, gravel pack permeability, perforation diameter, shot density, gravel pack length, perforation efficiency. The analysis is carried out to check the possible impact of these parameters.

Table: 4. 29. Sensitivity analysis parameters

Sensitivity Analysis			
Parameters	Low	Base case	High
Skin Value (Max, Min)	0	6	12
Gravel Pack Permeability (md)	80000	120000	180000
Perforation Diameter (in)	0.1	0.3	0.5
Shot Density (1/ft)	5	12	17
Gravel Pack Length (in)		2	10
Perforation Efficiency (Fraction)	0.65	0.85	1

Table: 4. 30. Output of the sensitive parameters

Parameters	Low Output	High Output
Skin Effect	8	10.5
Gravel Pack Permeability (md)	8.85	9.49
Perforation Diameter (in)	0	10.68
Shot Density (1/ft)	7.86	9.85
Gravel Pack Length (in)	6.15	
Perforation Efficiency (Fraction)	8.37	9.6

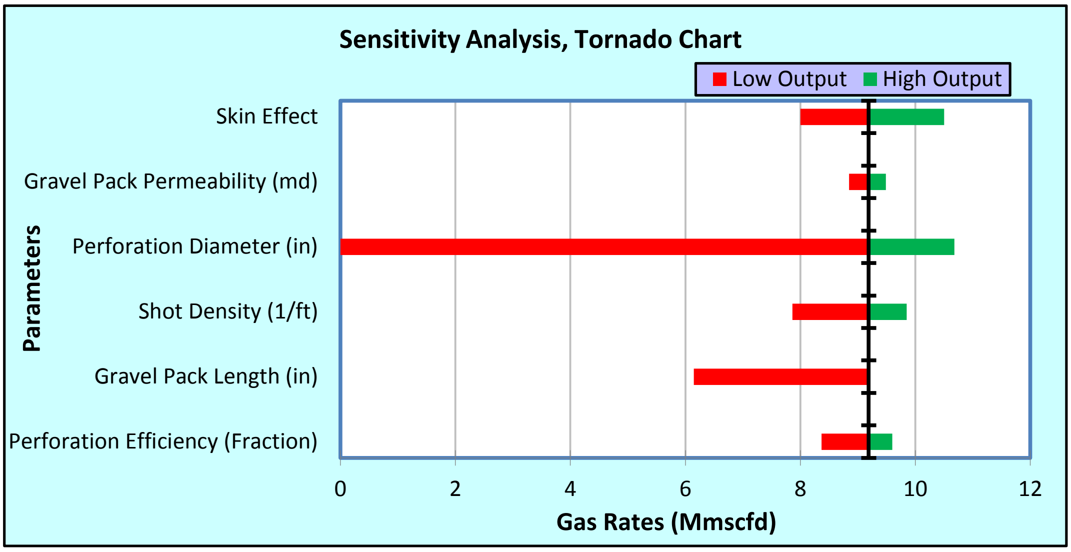


Figure: 4. 22. Tornado chart illustrating the parameters sensitivity

The results indicate that the perforation diameter is most sensitive in case of low value (0.1 in) that takes the gas rates to 0. The shot density value should be the max as low value will result in partial penetration effect, causing more skin effect to decrease the rate. The gravel pack should be as near as possible to the wellbore to avoid extra pressure losses and keep the rate high. Keeping the perforation efficiency high (~1) will result in high rate, so gravel pack should be placed next to all the perforations.

4.4 CASE IV: Hydraulically Fractured Well

4.4.1 Sawan Well 5

Sawan-5 was drilled as a development well in Sawan South compartment. The well was spud on September 19, 2004 and drilled to a TD of 3376 m with a primary target of Lower Goru C-Sand. The well was completed with 4-1/2" completion from Nov 07 –11, 2004 and C-Sand Interval (3265 – 3274 m = 9 m and 3279 – 3288 m = 9.0 m; Total = 18.0 m) was perforated. During CIT the well was tested at 31.9 MMscfd and FWHP of 2212 psi with WGR of 1.73-bbls/MMscf. The well was tie-in with Sawan Plant on December 23, 2005. Well was producing at 15.5 MMscfd @ 1917 psi FWHP in June 2006 when it was fracked. During post frac testing, the well was tested at 23.3 MMscfd and FWHP of 3036 psi with WGR of 6.0-bbls/MMscf. The average reservoir pressure at datum (3295 mSS) was estimated to be 4100 psi while the fracture face skin and X_f value interpreted to be 0 and 88 m respectively.

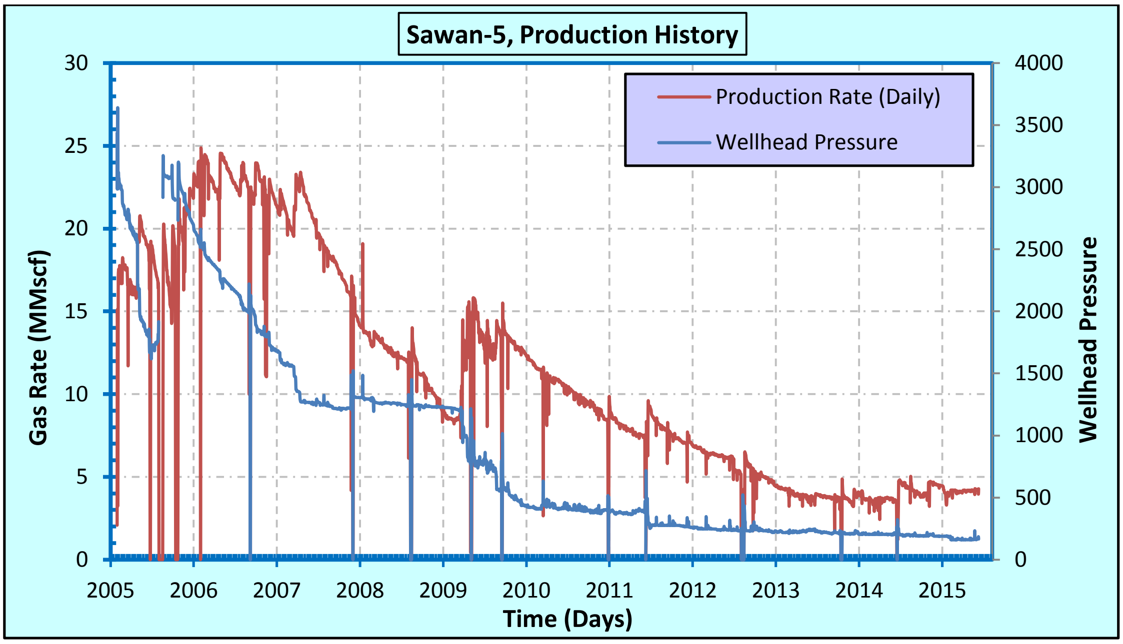


Figure: 4. 23. Production history, Sawan well 5

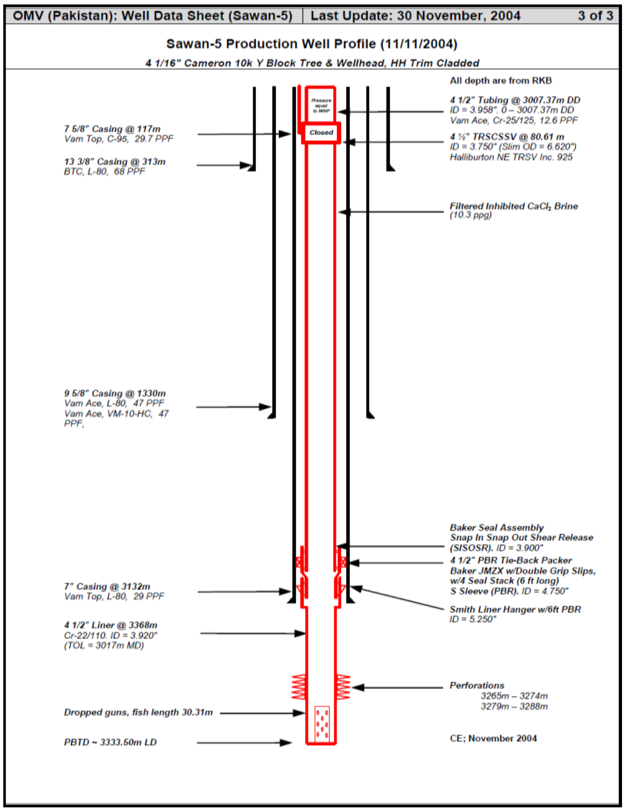


Figure: 4. 24. Well schematics, Sawan well 5

4.4.2 Initial Details (Completion Integrity Test)

After completing the well in perforations at 3,265m - 3,274m and 3279m - 3288m, a completion integrity test was conducted from November 07 to 11, 2004. The test consisted of Initial perforation clean-up and Initial build-up followed by clean-up, a four rate flow-after-flow test and final build-up. The well tested at maximum measured gas flow rate of 31.9 MMscfd at a FWHP of 1249 psi. It was found that the reservoir shows a permeability of around 8.7 md. A total skin factor of 10.9 was seen at maximum rate which was split into a Darcy skin factor of 4.5 and a rate-dependent factor D of 0.0002 (1/Mscfd). The pressure estimated from final build-up, after clean-up and rate test, was 5,281 psi at datum. Well deliverability showed an AOF of 38 MMscfd. Sand production showed a decreasing trend and is solely attributed to perforation clean-up. Final sand production rate was 0.002 lb/MMscfd at maximum rate of 32 MMscfd which is a negligible quantity. The gas and water samples were taken during test and analysis was performed through Core Lab. Analysis give a gas gravity of 0.636 and CO2 content of 8.19%. The results of the models are given in table 4.32 with AOF values and maximum flow rate value at wellhead pressure of 1249 Psia. For matching, the pressures are being converted to perforation top depth (3265 m) using the gas gradient. WGR and skin values are analysed to be 5 (bbl/MMscf) and 3.5.

Table: 4. 31. Input data from initial details

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	5261
	Reservoir Temperature (F)	350
	Water Gas Ratio (STB/MMscf)	5
	Condensate Gas Ratio (STB/MMscf)	0
Jones + Petroleum Expert	Reservoir Permeability (md)	8.7
	Reservoir Thickness (m)	23
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	2.25
	Perforation Interval (m)	18
	Mechanical Skin	3.5
Petroleum Expert	Connate Water Saturation (Fraction)	0.25
	Reservoir Porosity (%)	15
Forchheimer Model with Pseudo Pressure	Non-Darcy Coefficient (psi2/cp/(Mscf/day)2	3.52E-01
	Darcy Coefficient (psi2/cp/(Mscf/day)	20849
C and n Model	C (Mscf/day/Psi^2)	0.0097514
	n	0.88537

Table: 4. 32. Results of different models

Results of different Models		
WHP (Psia)		1249
Reservoir Models	AOF (MMscf/day)	Maximum Gas Rate (MMscf/day)
C and n	37.8	31.8
Forchheimer with PP	38	31.8
Petroleum Experts	37.8	31.8

Table: 4. 33. Gauge and wellhead data

Bottomhole Conditions	Well Head Conditions			
Pwf (Psia)	WHP (Psia)	WHT (F)	Gas Rate (MMscfd)	WGR (bbl/MMscf)
4591	3796	201	10.65	5.58
4061	3304	223	16.82	5.02
2810	1992	244	28.4	2.8
2210	1249	239	31.9	1.73

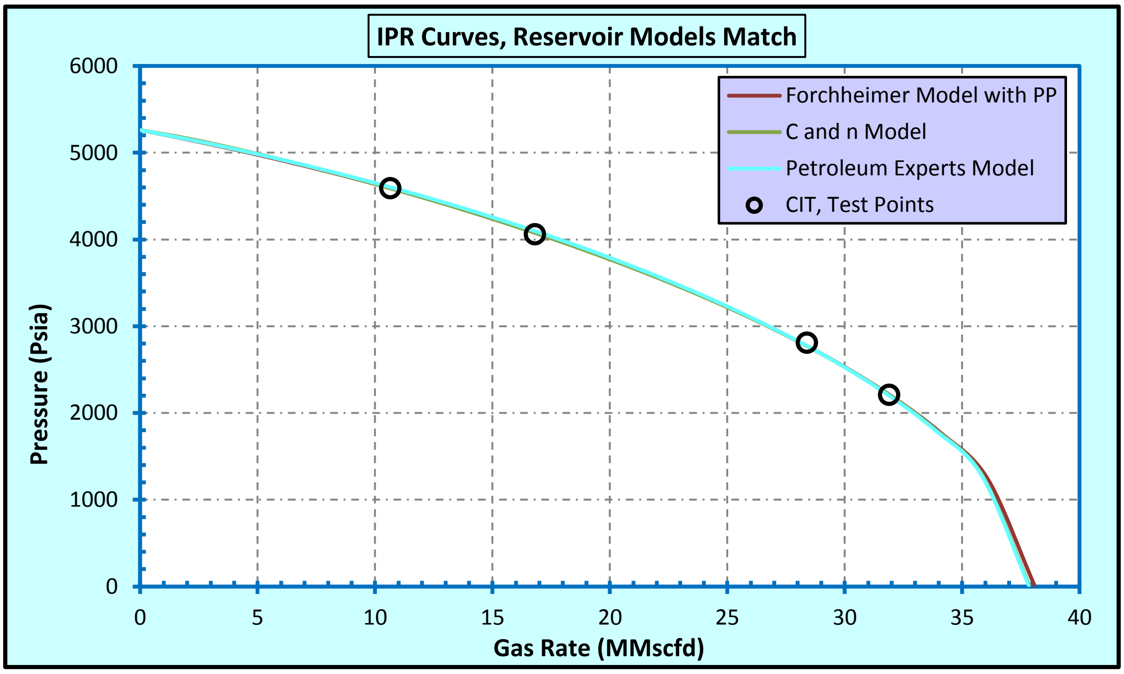


Figure: 4. 25. IPR curves of different models

It can be seen that the IPR curves have almost the same AOF values and all the correlation match the test points. Forchheimer model with pseudo pressure give negative non-Darcy parameter so it is not used in the IPR section. As the AOF of the models also depend on the non-Darcy factor (being more in Petroleum Experts), and is less in these conditions, the values are same here for all models. For the VLP match, Gray correlation fits the parameter range (∓ 10%) for the gravity term. This VLP correlation is used to match the test rates. The Forchheimer with PP IPR model is used for the VLP/IPR match.

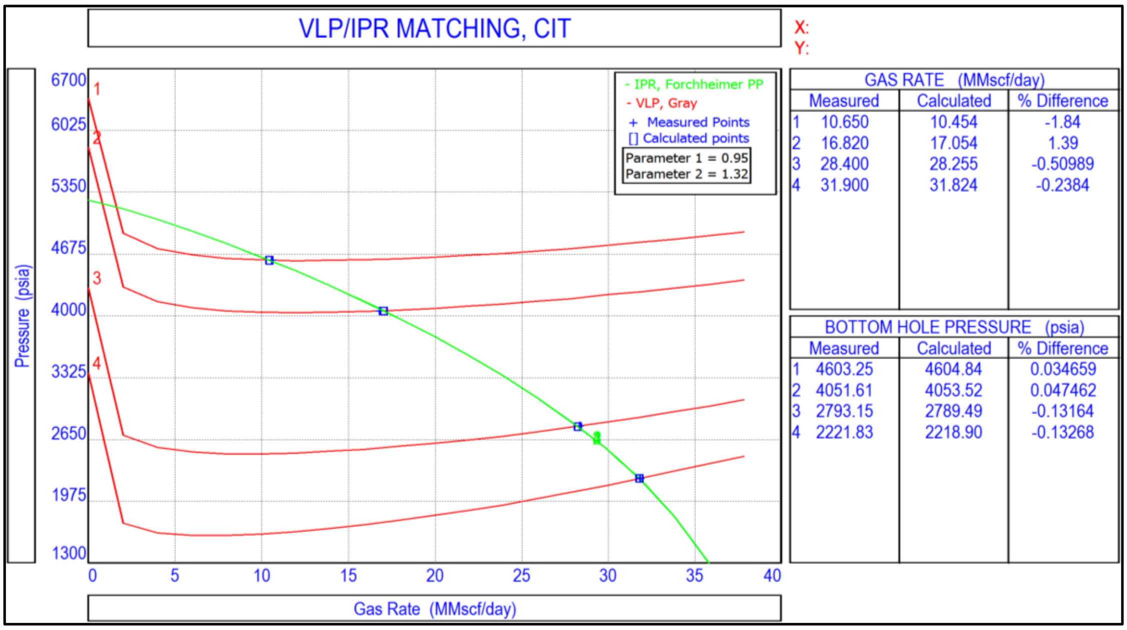


Figure: 4. 26. VLP/IPR match curves

4.4.3 Frac Initial Details

On June 27, 2006, proppant was successfully placed into the Sawan-5 Lower Goru C interval. In the matched fracture profile the fracture half-length is about 88 m, the fracture height is about 33 meters which successfully covers the interval of interest. The average proppant concentration in the fracture is 3.0 lbs/ft^2 and the fracture conductivity is 5,226 mD*ft, indicating that a highly conductive fracture was created. The results of the model from the details interpreted from the mini-frac test (table 4.35) are shown in table 4.34. Table 4.36 shows that the well was tested at maximum rate of 23.2 MMscfd at wellhead pressure of 3036. This value is matched with a mechanical skin value of -1 as the fracture reduces the skin and improves the near wellbore region for high flow. The WGR value was recorded to be 6 bbl/MMscf. For IPR calculations, hydraulically fractured well model is used that show an AOF of 72 MMscfd.

Table: 4. 34. Results of the model used

Results of IPR Model		
WHP (Psia)		3036
Reservoir Model	AOF	Maximum Gas
Hyd. Frac. Model	72	22.7

Table: 4. 35. Input data from post frac details

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	4090
	Reservoir Temperature (F)	350
	Water Gas Ratio (STB/MMscf)	3.6
	Condensate Gas Ratio (STB/MMscf)	0
Hydraulically Fractured Well Model	Reservoir Permeability (md)	8.7
	Reservoir Thickness (m)	23
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	2.25
	Mechanical Skin	-1
	Connate Water Saturation (Fraction)	0.25
	Reservoir Porosity (%)	15
	Fracture Height (m)	33
	Fracture Half Length (m)	88
	Dimensionless Fracture Conductivity	2.09

Table: 4. 36. Gauge and wellhead data

Bottomhole Conditions	Well Head Conditions			
Pwf (Psia)	WHP (Psia)	WHT (F)	Gas Rate (MMscfd)	WGR (bbl/MMscf)
4030	3348	185	6.9	6
3936	3239	216	16.1	6
3897	3187	234	18	6
3812	3036	248	23.2	6

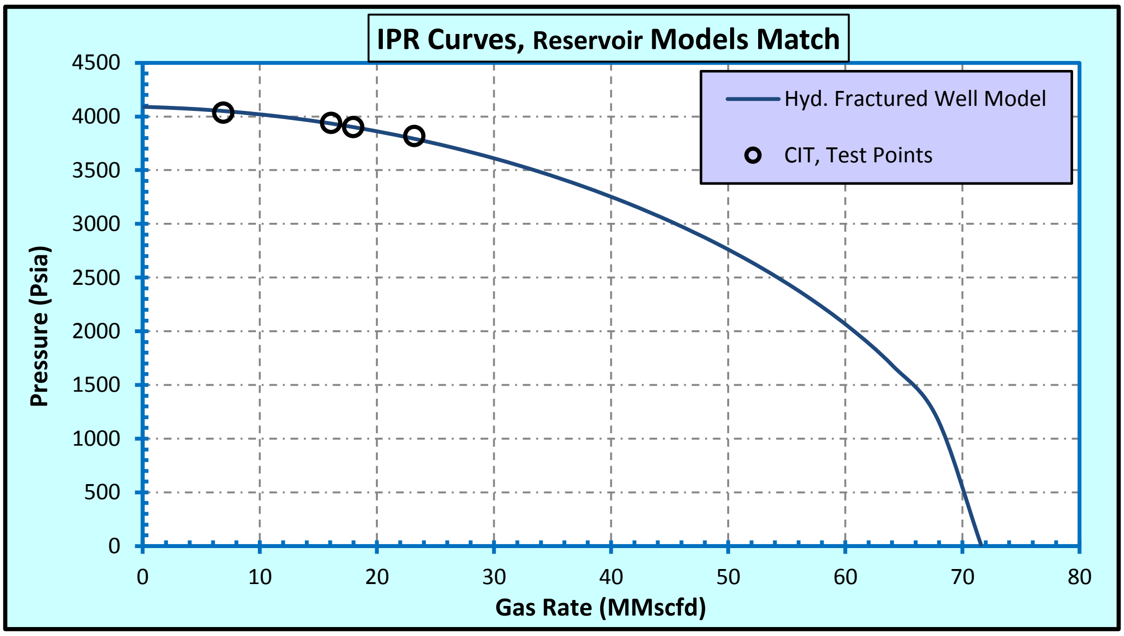


Figure: 4. 27. IPR curve with test points

For matching, the pressures are being converted to perforation top depth (3265 m) using the gas gradient. WGR is being analysed to be 15 (bbl/MMscf). For the VLP match, Gray correlation fits the parameter range (∓ 10%) for the gravity term. This VLP correlation is used to match the test rates.

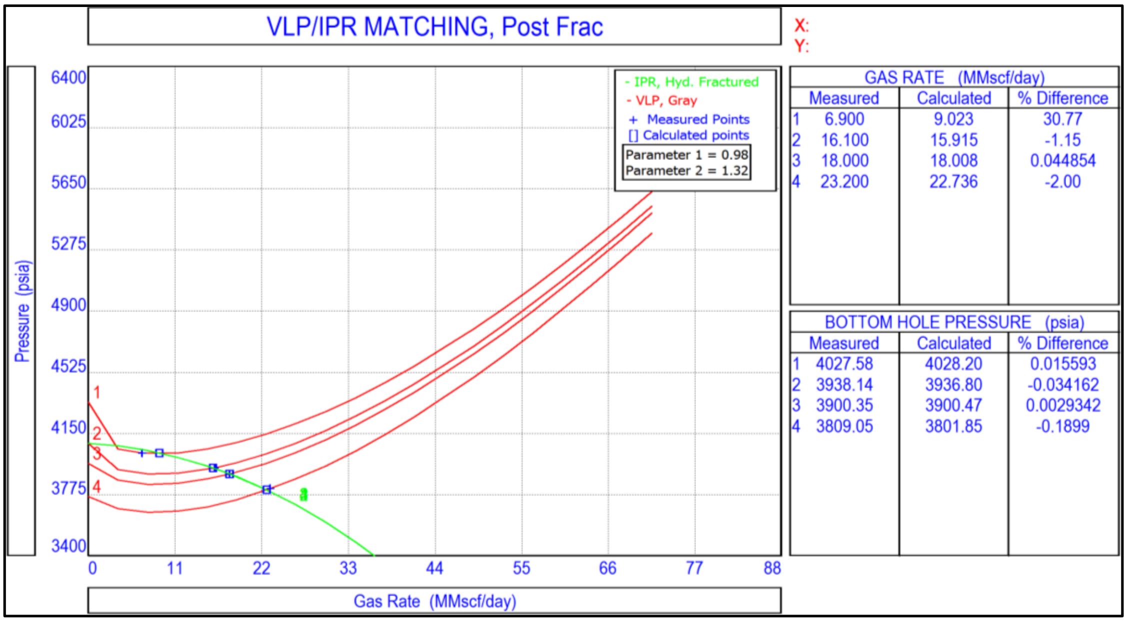


Figure: 4. 28. VLP/IPR match curves

The initial match is carried out for data validation. In order to carry out sensitivity on current conditions, we need to match the recent BHP-Survey in order to have a VLP profile that suits the well configuration. For Sawan Well 5, the details obtained from BHP-Survey 2013 are considered for this purpose.

4.4.4 BHP-Survey 2013

The estimated reservoir pressure is 1292 psi at gauge depth (3296m-RKB). A rate-dependent factor D of 5.17e-7 1/Mscf/day has been analysed. The results of the hydraulically fractured well model are given in table 4.37 and details of the required parameter for modelling are given in table 4.38. Table 4.39 shows that the single rate test has been matched at wellhead pressure of 372 Psia with mechanical skin value of 0. Wellbore cleanouts of the well with time may have reduced the skin. The IPR shows an AOF of 8.4 MMscfd.

Table: 4. 37. Results of the model used

Results of different Models		
WHP (Psia)		372
Reservoir Models	AOF (MMscf/day)	Maximum Gas Rate (MMscf/day)
Hyd. Frac	8.4	4.92

Table: 4. 38. Input data from BHP details

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	952
	Reservoir Temperature (F)	350
	Water Gas Ratio (STB/MMscf)	31
	Condensate Gas Ratio (STB/MMscf)	0
	Reservoir Permeability (md)	8.7
Hydraulically Fractured Well Model	Reservoir Thickness (m)	23
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	2.25
	Mechanical Skin	0
	Connate Water Saturation (Fraction)	0.25
	Reservoir Porosity (%)	15
	Fracture Height (m)	33
	Fracture Half Length (m)	13
	Dimensionless Fracture Conductivity	15.05

Table: 4. 39. Gauge and wellhead details

Bottomhole Conditions	Well Head Conditions			
Pwf (Psia)	WHP (Psia)	WHT (F)	Gas Rate (MMscfd)	WGR (bbl/MMscf)
620	372	300	4.92	31

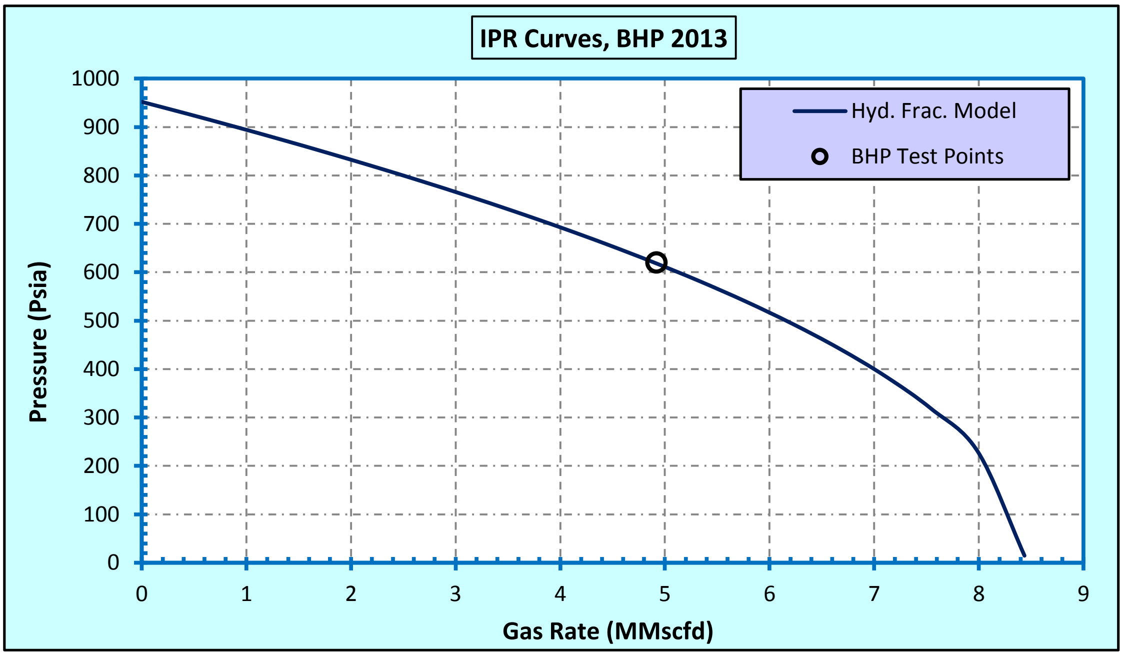


Figure: 4. 29. IPR curve with test data point

For the VLP match, Gray correlation fits the parameter range (∓ 10%) for the gravity term. This VLP correlation is used to match the test rates. The VLP, Gray correlation matched here is used for the recent calculations. The recent reservoir pressure is estimated to be 561 based on prediction of simulation model with WGR value of 40 bbl/MMscf. Mechanical skin value is analysed to be 6 that match the current production rate and is mainly attributed to fines migration of friable sands.

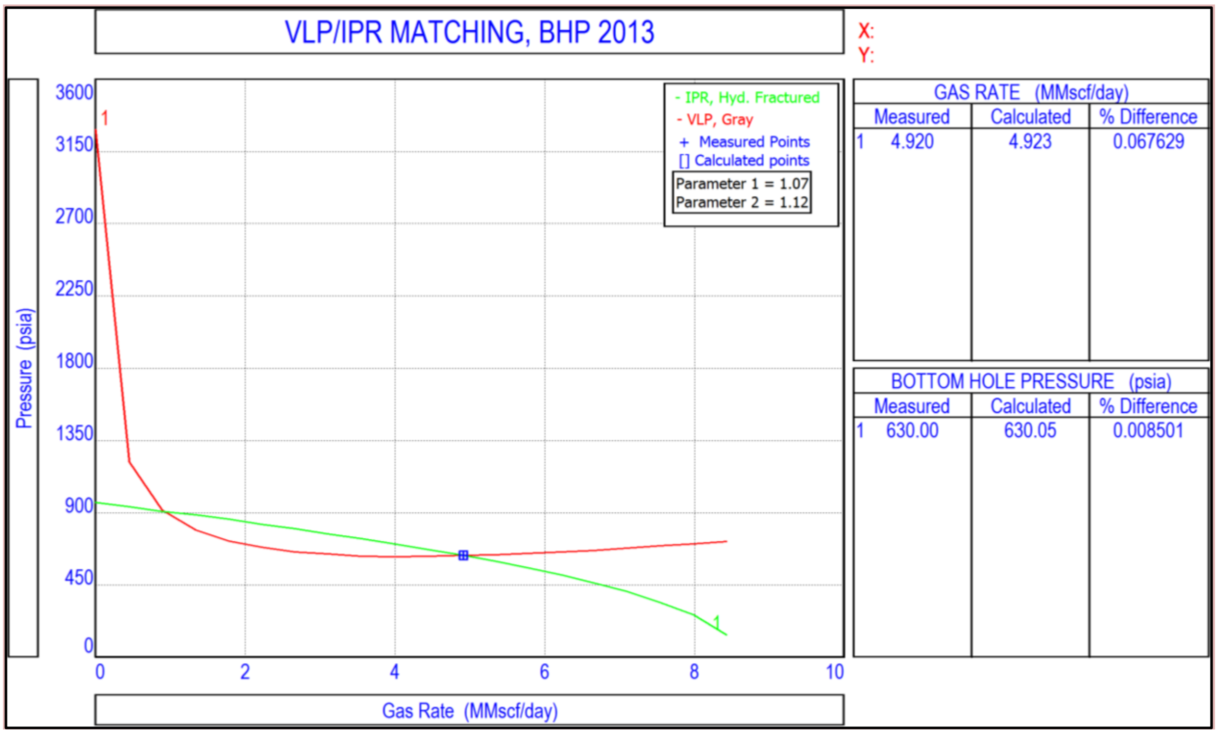


Figure: 4. 30. VLP/IPT match curves

4.4.5 Current conditions

Currently the well is flowing at 3.49 MMscfd at FWHP of 178 Psia. The details of varied parameters are given as;

Table: 4. 40. Current conditions aparmeters values

Varied parameters	
Reservoir Pressure (Psia)	940
Water Gas Ratio (STB/MMscf)	45
Mechanical Skin	8.5

Table: 4. 41. Results of the well model

Results of Model		
WHP (Psia)		178
Reservoir Models	AOF (MMscf/day)	Max. Gas Rate (MMscf/day)
Hyd. Frac	4.13	3.49

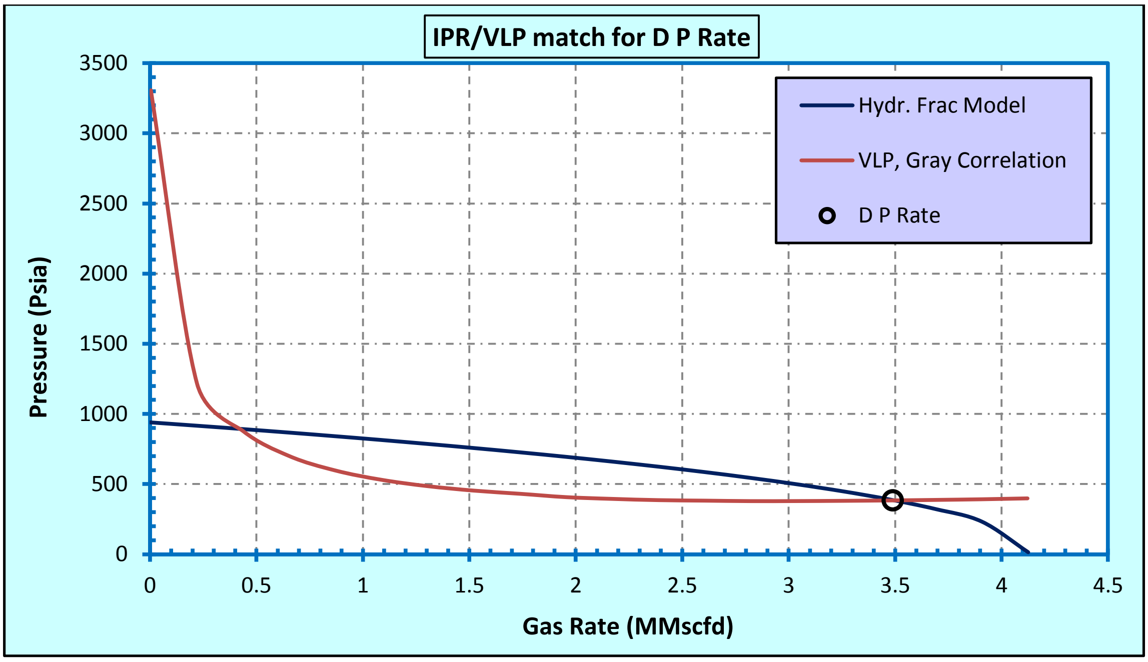


Figure: 4. 31. VLP/IPR curves for current conditions

4.4.6 Sensitivity Analysis

The sensitive parameters in hydraulically fractured well model are skin factor, fracture half-length and dimensionless fracture conductivity (FCD). The sensitivity is carried out for these parameters and the results are shown in the tornado chart.

Table: 4. 42. Sensitivity analysis parameters

Sensitivity Analysis			
Parameters	Low	Base case	High
Skin Value (Max, Min)	0	9	5
Fracture Half Length (m)	4	10	100
Dimensionless Frac. Conductivity	10	65	80

Table: 4. 43. Output of the sensitive parameters

Parameters	Low Output	High Output
Skin Effect	2.38	3.96
Fracture Half Length (m)	3.17	3.95
Dimensionless Frac. Conductivity	3.43	3.50
Best Case		4.1

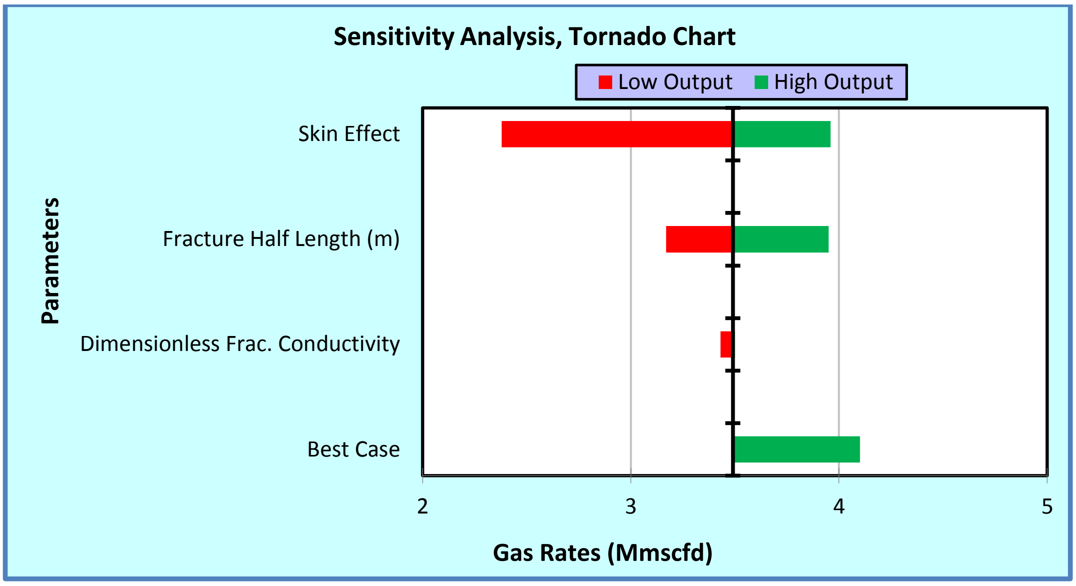


Figure: 4. 32. Tornado chart illustrating sensitivity analysis

In theory, to minimize the pressure drop down the fracture, the value of FCD should be approximately 10 or greater. FCD and Xf are inversely proportional to each other so if we increase the FCD, Xf should be reduced. Here keeping Xf constant and increasing FCD increase the rate because it adjusts the equation by changing other parameters i.e. Wf and Kf. The best case (high rate) is obtained with FCD = 80 and Xf = 100. Below 10 and above 50 values, FCD doesn't show any change. Similarly Xf variation doesn't show any change at value higher than 100 and lower than 4. Increasing fracture height has no impact on the gas rate as the pressure is not high enough to deliver more gas but decreasing the fracture height declines the rate as pressure is sufficient to account for the rate from a narrow fracture.

4.5 Case v: Horizontal Well

4.5.1 Sawan Well 6

Sawan-6 was drilled as a development well in Sawan South compartment. Well was spud on March 15, 2006 and drilled to 3340 mRT PBTD with a target formation of Lower Goru C-Sand. The well was completed with 4-1/2" Cr-22 monobore completion. During CIT, the well was tested at 0.97 MMscfd with 198 FWHP. During CIT, water chlorides analysis confirmed the production of formation water (~25,250 ppm). The average reservoir pressure at datum (3295 mSS) was estimated to be 5396 psi. The water production was although low but sluggish behaviour of well confirmed hydraulics issue in well. Due to very low reservoir inflow potential, the well was fractured in July 2006. Afterwards, well was tested at maximum rate of 6.3 MMscfd (~6.5 FOI) at 2238 psi FWHP with 87 bbl./MMscf WGR. Estimated fracture height was 50 meters with 89 meters fracture length. Well was tie-in with Sawan Plant in

October, 2007 at maximum rate of ~6.0 MMscfd; sharp decline in production observed in first 3 months and gas rate dropped below 1.0 MMscfd confirming tight behaviour of reservoir. Well exhibits varying WGR of 60 – 700 bbls/MMscf (extreme sluggish flow).

4.5.2 Recent vertical Case

The well has hydraulically fractured but the connectivity to volume was not that good and excessive water cut occurred. Currently the well is flowing at 0.4 MMscfd at wellhead pressure of 360 Psia. The details of the well models are shown in table 4.44.

Table: 4. 44. Input data for Sawan 6

Reservoir Model	Parameters	
Required Parameters for all models	Reservoir Pressure (Psia)	3500
	Reservoir Temperature (^{0}F)	350
	Water Gas Ratio (STB/MMscf)	50
	Condensate Gas Ratio (STB/MMscf)	0
Hydraulically Fractured Well Model	Reservoir Permeability (md)	0.213
	Reservoir Thickness (m)	20.26
	Drainage Area (Acres)	40
	Dietz Shape Factor	31.62
	Wellbore Radius (in)	2.25
	Mechanical Skin	0
	Connate Water Saturation (Fraction)	0.40
	Reservoir Porosity (%)	15
	Fracture Height (m)	50.5
	Fracture Half Length (m)	89
	Dimensionless Fracture Conductivity	0.028

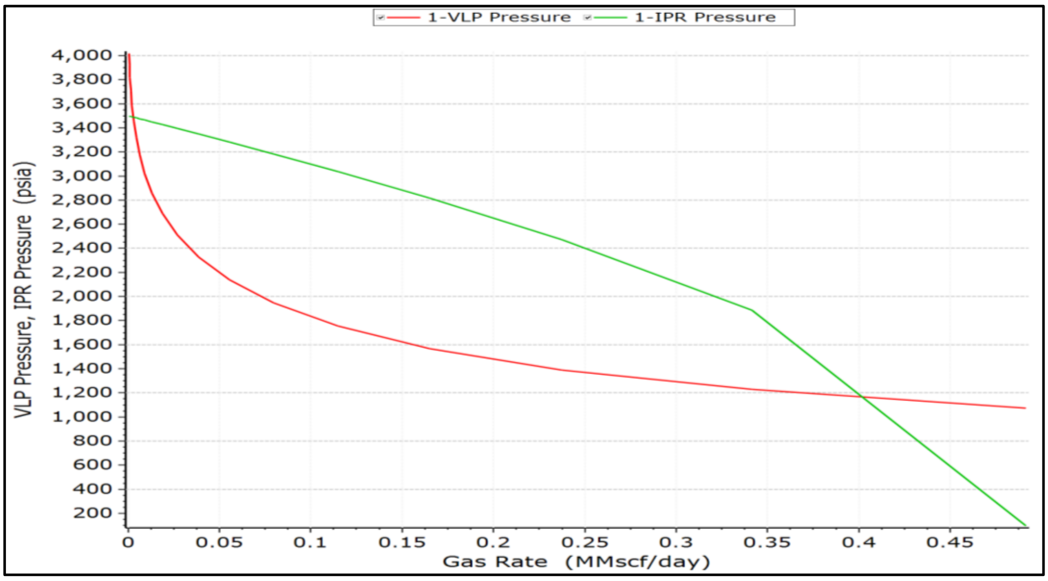


Figure: 4. 33. VLP/IPR curves for Sawan 6, hydraulic fracture case

4.5.3 Horizontal well case

The well is planned to be side tracked (horizontal well) so that to check if the production can be enhanced. When changed to horizontal well with well length (horizontal) of 1000m the rate has been increased to 1.15 MMscfd. The productivity index is evaluated to be 1.21 Mscfd/Psi.

Input Parameter	Values	Units
Reservoir Permeability	0.213	md
Reservoir Thickness	59.0551	ft
Wellbore Radius	0.354	ft
Horizontal Anisotropy	1	fraction
Vertical Anisotropy	0.1	fraction
Length of Well	3280	ft
Reservoir Length	25000	ft
Reservoir Width	20000	ft
Distance from Length Edge to Centre of Well	7000	ft
Distance from Width Edge to Centre of Well	7000	ft
Distance from Bottom to Centre of Well	30	ft
Reservoir Porosity	0.12	fraction
Connate Water Saturation	0.3	fraction
Non-Darcy Flow Factor (Calculated by PROSPER)	4.12E-08	1/(Mscf/day)

Figure: 4. 34. Horizontal well details

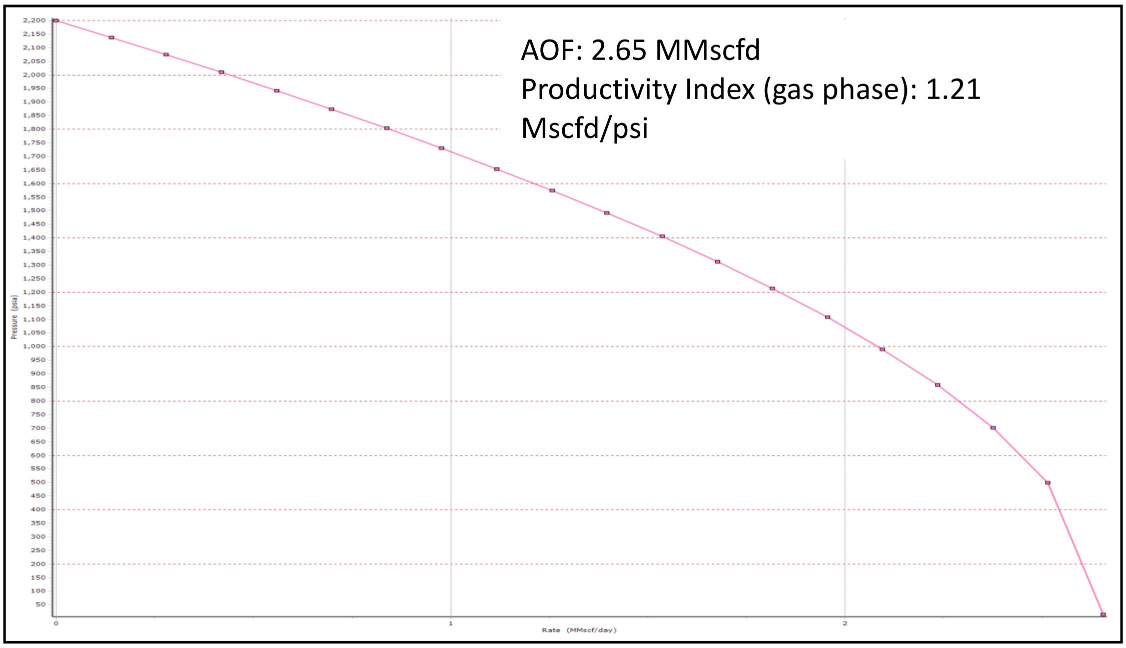


Figure: 4. 35. IPR curve Sawan 6 horizontal

When the same parameters are checked in Eclipse, it resulted in productivity index of 9.2 is obtained which is far more than the realistic behaviour. The simulator's calculation of the productivity index should not be used for a horizontal well because the equation requires that a steady radial flow regime perpendicular to the well bore exists out to the drainage radius. For a horizontal well, this flow regime will rapidly be disrupted by the top and bottom boundaries of the formation and the ultimate flow regime may be linear or pseudo-radial depending on the geometry of the well and its drainage region. For horizontal wells, therefore, you should calculate the productivity index "manually" by using the equation. As PROSPER is the easy way for calculating PI so the value is used from there.

Increasing furthermore the length of the well will increase the rate but due to the fact that Sawan south is tight zone so the rate may not be that high. A realistic high rate of 3.5 MMscfd can be achieved with well length of 4500 m.

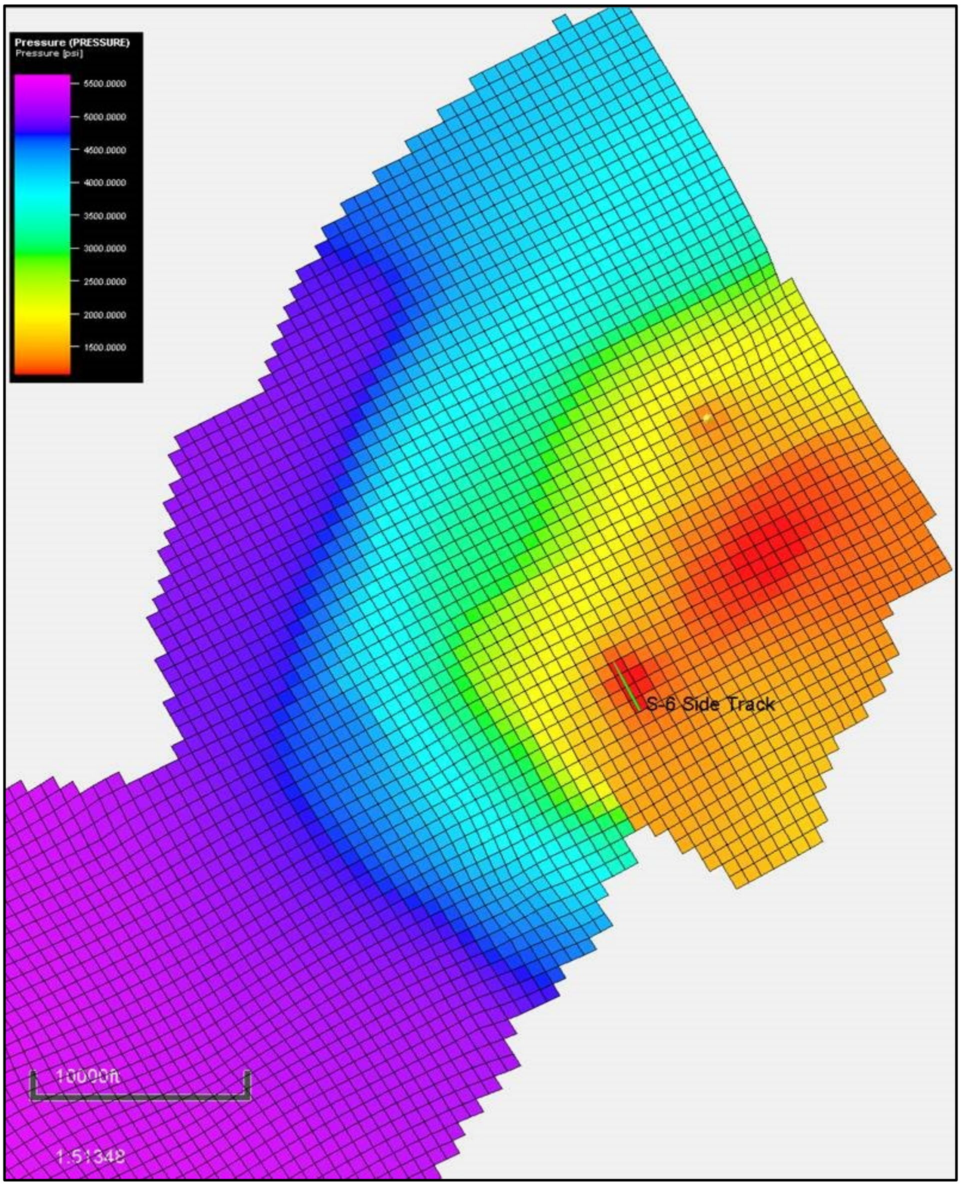


Figure: 4. 36. Pressure profile of Sawan 6 region

5. Conclusions

In the analysis of the above cases, several results are noted and some conclusions are being made. These conclusions are based on the analysis carried out and may be subjected to further research.

In analysing the water disposal well, the initial test data results in low PI value with low liquid injected for high pump pressure. With time, the PI is being increased and slightly more liquid is injected on the respective pump pressure. This phenomenon can occur because of the fact that injecting much more liquid can frack the formation with time that results in high PI value. In planning a disposal well, if we require injecting more liquid with respect to the initial injection, this phenomenon can help to understand that the PI for disposal well increase with time and more liquid can be injected.

The vertical wells with high pressures (initial conditions) results in realistic calculation when modelled with Forchheimer with pseudopressure as pseudopressure model is applicable to all pressure ranges. Petroleum experts can also result in somehow realistic results as it use the effective permeability to calculate the turbulence factor (ß). The resultant turbulence factor is high and it can be justified with the fact that gas wells with high pressure results in more turbulence. The inflow performance modelling of a well should be done by considering initially the pressure range. Using backpressure equation may result in a good match but due to the fact that coefficient C is dependent of pressure; this model cannot be considered as the best for the inflow performance. The multi-rate models that uses the test points to calculate the coefficients ‘C’, ‘n’, ‘a’ and ‘b’. These models use the data from the test rates and count for rate dependent skin but don’t account mechanical skin that may exist in the well. If the perforation interval is equal to the reservoir thickness, the correlations result in enhanced rate as the partial penetration effect is avoided and there is no additional skin encountered. At the conditions of well, where there is sufficient decline, Jones model construct a realistic IPR and avoid too optimistic or pessimistic results. In contrast, Petroleum Experts correlation still calculates high turbulence even at low pressure that lead to pessimistic results. So Jones correlation is preferred here. Table 5.1 shows the comparison and applicability of the inflow correlations for various conditions / parameters.

Table: 5. 1. Comparison of various inflow correlations

Reservoir Inflow Correlations	Jones	Forchheimer	Back Pressure	C and n	Petroleum Experts	Forchheimer with PP
Analytical	☑	☒	☑	☒	☑	☒
Empirical	☒	☑	☒	☑	☒	☑
Pressure > 2500	☒	☒	☑	☑	☑	☑
Pressure < 2500	☑	☑	☑	☑	☑	☑
Mechanical Skin	☑	☒	☑	☒	☑	☒
Perforation Skin	☑	☒	☒	☒	☑	☒
dp (Sand Control) skin	☑	☑	☑	☑	☑	☑
Effective permeability	☒	☒	☒	☒	☑	☒
Test Points	☒	☑	☒	☑	☒	☑

The use of gravel pack for sand control encounters extra dP in the form of skin. This dP is more sensitive to perforation diameter as low diameter results in very low or no flow. Shot per density is also of considerable value as it may result in partial penetration effect, so this value needs to be high enough to cover the reservoir thickness and result in high flow rate. This effect is the same with perforation interval. The above three parameters are used as a square in the calculation of dP so these are more effective parameters. When the gravel pack length is less, the flow rate is high as no extra pressure drops between sandface and gravel pack. With time, the sand may be trapped in the gravel pack screen and thus reduce the perforation efficiency which in turn reduce the rate.

In modelling a hydraulically fractured well, the FCD needs to be correctly calculated as this is responsible for the term $[S_f + \ln (x_f/r_w)]$. If fracture height equals the thickness of reservoir, then the interval of interest is covered and high rates are achieved. It has been noticed that the fracture half-length sufficiently decreases with time. This may be attributed to the fact that the proppants were not sufficient enough to enhance the fracture life. FCD and xf are inversely proportional to each other and increasing both of their values in the model doesn't result in high rates. With high xf, high FCD can result in high flow rate only if the width of the fracture is taken into account.

The conclusions are based on wells of one field; it may vary for other fields but can be considered valid for the nearby fields. The difference in the nearby fields will not be that significant compared to other fields on far locations.

6. Recommendations

Bases on the analysis carried out; there are some recommendations for optimized results.

1. For the initial inflow modelling (P > 2500 Psi), Forchheimer with pseudopressure correlation should be used when there are some test data points available.
2. If the test points are not available, Petroleum Experts correlation should be used for the initial details.
3. For pressures less than 2500, Forchheimer correlation should be used for better results when some test points are available.
4. If test points are not available (current conditions), Jones correlation should be used for realistic results.
5. When gravel pack is used, the gravel pack length should be as less as possible, the perforation diameter should be as high as possible with maximum shot density and the perforation interval should be kept equal to reservoir thickness.
6. The migration of sand to the screen of gravel pack stuck there and decreases the perforation efficiency. The screen should be washed quite often to keep the perforation efficiency equal to 1.
7. Wellbore cleanout should be carried out on these wells because the skin is very high after sometime due to fines migration.
8. During hydraulic fracturing of a well, the fracture height should be kept considered high so that it covers the area of interest (reservoir thickness).
9. Proppants should be used in enough quantity so that to prevent sharp decrease of fracture half-length.
10. Fracture half-length should be increased to some extent because it will decrease the dimensionless fracture conductivity and in practice the dimensionless fracture conductivity should be kept higher than 10 for better flowrates.

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