Master Thesis

Sawan Gas Well De-Liquification

In

Cooperation

With

OMV Pakistan GmbH

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Danksagung / Acknowledgement

In the name of God who is the most and ever merciful

I, hereby, pay my gratitude’s to all those who have helped and guided me in writing this Thesis. Their directions and supervision were enormous. These gentlemen specially include my Mentor, Mr. Forberich, Christian, my supervisors working in OMV, Pakistan, Mr. Michael and no doubt my university supervisors, Prof. Dr. Herbert Hofstätter. Patrick Eisner in the Montanuniverstiät Leoben, Austria.

I dedicate this Thesis to my parents who are a source of constant moral support for me.

Kurzfassung

OMV Pakistan ist der Betreiber des Sawan Feldes, im Bezirk Sukkur der Provinz Sindh in Pakistan. Das Feld ist ein dry-gas Reservoir, das im Jahr 2003 mittels der Explorations-Bohrung Sawan-1 entdeckt wurde, die auf die kohlenwasserstoffführende „Goru C Sand" Schicht stieß. Sawan ist ein depletion drive Gas-Reservoir mit einem Initialdruck von ~ 5350 psi, einer Bottom-hole Temperatur von 350°F und hat bisher etwa 1,43 TCF Gas produziert.

Das Sawan Gasfeld wird seit Juni 2003 produziert, seit Februar 2010 mit Frontend-Compression (FEC). Bis heute wurden 16 Bohrungen (15 vertikale & 1 horizontal) abgeteuft von denen derzeit 14 Bohrungen 115 mmscfd Gas und 5322 bbl / d Wasser produzieren, während die Bohrung SNH-1 aufgrund von Flow-Assurance Problemen gefrackt wurde.

Das Sawan Feld gliedert sich in zwei Teile, Sawan North und Sawan South, die durch eine in Nord-West - Süd-Ost Richtung verlaufende Blattverschiebung getrennt sind. Sawan North ist ein Sandstein Reservoir guter Qualität mit hoher Permeabilität und einer Netto-Mächtigkeit der gasführenden Schicht von mehr als 100 Metern. Um hohe Gasraten zu erzielen, wurden die Bohrungen in Sawan North (Sawan-2 ST, 3, 7, 8, 9) während Entwicklungsphase mit großen Durchmessern komplettiert.

Das Reservoir Sawan South weist aufgrund von schlechten Fazies in diesem Teil des Feldes eine geringe Permeabilität auf. Bisher wurden 4 Bohrungen (Sawan-4, 5, 6 und 12) in Sawan South abgeteuft, mit 4-1 / 2" komplettiert und hydraulisch gefrackt, große Wassermengen nach dem Fracking von Sawan-6 und 12 produziert und die obertägigen Anlagen von Sawan-12 wurden bei der Bohrung Sawan-6 weiterverwendet.

Der Reservoir Druck in Sawan North ist mittlerweile auf etwa 600psi abgesunken, was zu einem erhöhtem WGR Wert (kondensiert) geführt hat. Dies könnte zu hydraulischen Problemen am Bohrloch oder zu einem frühen natürlichen Abandonment aufgrund eines zu großen Rückdrucks der obertägigen Anlagen führen. In ähnlicher Weise kann es in Sawan South durch die hohe Wasserproduktion nach dem Fracking ebenfalls zu hydraulischen Problemen am Bohrloch kommen.

Diese Arbeit evaluiert das derzeitige und zukünftige Potential der Sonden um die Lebensdauer so wie den endgültigen Gewinnungsfaktor, basierend auf technischen sowie wirtschaftlichen Betrachtungen und unter Berücksichtigung zahlreicher geeigneter Förderstrategien, zu erhöhen.

Abstract

OMV (Pakistan) is the Operator of the Sawan Field, located in district Sukkur, Sindh. The field is a dry gas reservoir, discovered in 2003 by an exploration well, Sawan-1, which encountered the hydrocarbon bearing Lower Goru C sand. Sawan is a depletion drive gas reservoir with an initial reservoir pressure of ~5350 psi, a bottom-hole temperature of 350°F and has produced ~1.43 tcf.

The Sawan Gas Field has been producing for more than 13 years and since February 2010 the field is producing by the application of front end compression (FEC). Up to date 16 wells (15 vertical & 1 horizontal) have been drilled and currently 14 wells are producing 115 MMscfd of gas and 5322 bbl./d of water.

The 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 good quality sandstone reservoir of high permeability, with a 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 large completion diameters during field development phase.

Sawan South, however, is a low permeability reservoir. So far 4 wells (Sawan-4, 5, 6 and 12) have been drilled and completed in Sawan South with a 4-1/2" completion followed by hydraulically fracturing; a huge amount of water was produced after having fractured Sawan-6 and Sawan-12

Currently Sawan has declined to ~600 psi reservoir pressure in Sawan North area which resulted in increased water gas ratio value (condensed) that may cause wellbore hydraulics issues in near future; similarly Sawan South wells may observe wellbore hydraulics issues due to high post-fracture water production.

This thesis evaluates the current and future potential of the well in order to increase the well life and ultimate recovery based on technical and economic considerations by considering different artificial lift strategies.

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Abbreviations

Abdn.	Abandonment
An.	Annular
AOF	Absolute Open Flow
bbl.	Barrels
BHFP	Bottom Hole Flowing Pressure
BHP	Bottom Hole Pressure
CAPEX	Capital expenditure
CIT	Completion integrity test
Cr	Chrome
CRA	Chrome Resistant Alloy
DD	Driller's depth
Di	Initial decline
DST	Drill Stem Test
ESP	Electrical Submersible Pump
FEC	Front End Compression
FOI	Fold of increase
GLR	Gas liquid ratio
GP	Gravel Pack
HP	High Pressure
HT	High Temperature
I.D	inner diameter
in.	Inch
IPR	Inflow Performance
KOP	Kick off Point
lb.(m)	Pounds (mass)
LD	Logger's depth
Ldng.	Loading
MD	Measured Depth
mRT	meters Rotary Table
mSS	Meters-mean subsea level
O.D	outer diameter
OPEX	Operational expenditure
PBTD	Plug back total depth
PCP	Progressive cavity pump
Ppf	pounds per feet
Psi	pounds per square inch.
Res	Reservoir
TOF	Top of fish
Tub	Tubular
TVD	True vertical depth
USD	United State Dollar
V.S	Velocity String
VLP	Vertical Lift Performance
WBC	Wellbore clean out job
WGR	Water gas ratio
WHP	Well head Pressure
WHT	Well Head Temperature

Symbols

A	Area
B	Arp's decline constant
Bcf	10^9 scf
C	Centigrade
C_d	Drag coefficient
C_{wb}	Wellbore storage constant
D	Non Darcy , Day
D	Diameter
F	Friction
F	Fahrenheit
Φ	Porosity
G	Gravity
γ	Specific Gravity
g_c	gravitational constant
H	Hold up
H	Height
K	Permeability
λ	non slip hold up
M	meters
μ	Viscosity
m(p)	pseudo pressure
Md	10^{-3} Darcy
MMscf	10^6 scf
New	Weber number
°	Degree
P	pressure
Q	Flow Rate
R	Radius
ρ	density
Re	Reynold's Number
S	Skin
S	Sawan
σ	surface tension
T	Temperature
T	Time
Tcf	10^{12} scf
V,v	Velocity
V_{wb}	Volume of wellbore
x_f	half length
Z	compressibility factor
A	gas holdup
Θ	angle

Subscripts

abs.	absolute
C	critical
D	droplet
D	Drag
E	external
eff.	effective
F	flowing, fracture
G,g	gas
H	head
I	inner, initial
L,l	liquid
M	mixture
N	normal
O	oil
S	slip, storage
SC	Surface condition
T	turner, tubing
TP	Two phase
W	wellbore
WE	Weber Number

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1. Introduction

De-liquification, by terminology, stands for the removal of liquids from the wellbore. This terminology is particularly associated with gas wells. De-liquification scope-wise covers the techniques that can be deployed to remove the liquids efficiently from the wellbore ensuring smooth gas flow. Usually, at an early stage of the reservoir, the pressure is sufficient to lift all liquids that get produced with gas. but as the reservoir pressure declines over time, the flow rate is reduced, which causes the gas velocities to decrease as well. The produced liquid will accumulate in the well, therefore, creating extra hydrostatic pressure against formation pressure. In order to avoid liquid accumulation in wellbore, loading problems should be diagnosed and dealt in time before liquid accumulation starts to develop a backpressure against the formation. The exertion of a back pressure on the reservoir is not only a liquid loading phenomenon, but downstream plant pressure can also affect the performance of a gas well. In case of the plant back pressure, stand-alone techniques like wellhead compression can increase the life of a well. The purpose of de-liquification is to increase the lifetime of a well -, as long as it is economically feasible.

Liquid loading can occur for both high and low permeable wells. The differences depend on the tubing string size, the surface pressure, and the amount and density of liquids produced along with the gas. Therefore, it is important to recognize liquid loading symptoms in time -, and design proper solutions for the gas wells in order to minimize the negative effects of liquids filling up the wellbore.

OMV Pakistan-Sawan gas field is a dry gas reservoir, discovered in 2003. Sawan is a depletion drive gas reservoir with the initial reservoir pressure of ~5350 psi, a bottom-hole temperature of 350°F. Currently Sawan has produced a total of approximately 1.43 trillion cubic feet. The reservoir pressure has declined to 600 psi in the North of the field which has resulted in the increased Water gas ratio value. The increase of the WGR is due to a high content of condensed water that is being produced together with the gas. This condensed water can cause severe wellbore hydraulics problems; similarly some wells located in the Southern part of the Sawan field are already observing wellbore hydraulics problems due to high post-fracture water production. Sawan South wells are producing formation water together with condensed-water meaning that there is an increased chance for potential hydraulic problems in the near future. . Currently, all Sawan wells are under central compression located at processing plant; yet it is expected that the plant pressure might also create enough back pressure to restrict the well flow resulting in early abandonment.

The objective of this research is to analyze the current and future performances of the gas wells in the Sawan field in order to suggest the optimum strategy based on the technical, economic and risk point of view. The target is to increase the well life and ultimate recovery. Different techniques have been evaluated with both advantages and disadvantages. Recommendations have been made based on a combination of technical, economical and risk analysis.

2. Fundamentals

Gas well liquid loading, by definition, is the inability of a gas well to remove liquids that are produced from the reservoir. The produced liquid will accumulate in the well creating a static column of liquid, therefore creating a back pressure against formation pressure and reducing production until the well ceases to flow. The production rate decreases in proportion to the increased back pressure. The resulting back pressure on the formation may reach a critical pressure where liquid flow from the formation exceeds the rate at which it can be carried out, and the well dies [17].

2.1 Multiphase flow in a Gas Well

To understand the phenomenon of liquid loading in a gas well, the first approach is to familiarize with the concept of different flow regime when in multiphase flowing conditions are present. Types of multiphase flow regime present in a gas well are shown in Figure 2.1. A flow regime is mainly dependent on the velocity of the moving phases. As velocity is proportional to flow rate so flow regimes are often described in terms of flow rate. Flow regimes shown in figure 2.1 are defined below.

2.1.1 Bubble Flow

The tubing is almost completely filled with liquid. Free gas is present as small bubbles, rising in the liquid. Liquid contacts the wall surface and the bubbles serve only to reduce the density.

2.1.2 Slug Flow

Gas bubbles expand as they rise and coalesce into larger bubbles, then slugs. Liquid phase is still the continuous phase. The liquid film around the slugs may fall downward. Both gas and liquid significantly affect the fluid flowing pressure gradient.

2.1.3 Slug-Annular

The flow changes from continuous liquid to continuous gas phase. Some liquid may be entrained as droplets in the gas. Gas dominates the fluid flowing pressure gradient, but liquid is still significant.

2.1.4 Annular Mist Flow

The gas phase is continuous and most of the liquid is entrained in the gas as a mist. The pipe wall is coated with a thin film of liquid, but fluid flowing pressure gradient is determined predominately from the gas flow.

2.2 Gas Well Producing Life Trend

Figure 2.2 shows the progression of a typical gas well from initial production stage to the end life. In this illustration, it is assumed that the tubing end does not extend to the top perforations so that there is a section of casing between the tubing end and the top perforations. The well may initially have a high gas rate so that the flow regime is in mist flow in the tubing but may not be in mist flow regime below the tubing end till mid-perforations

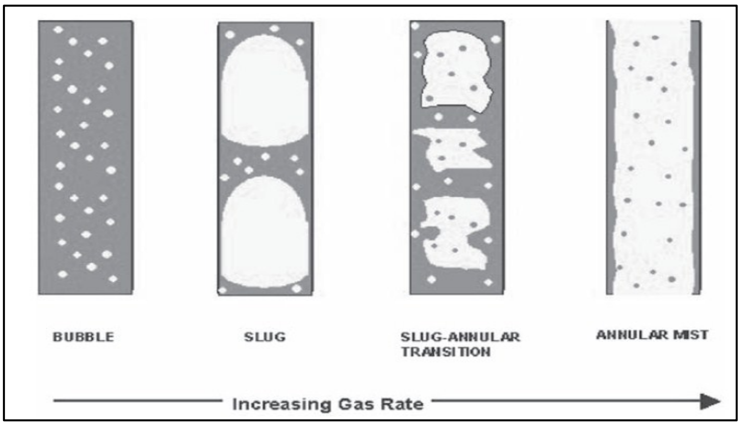

Figure 2-1: Flow regimes in Vertical Multiphase Flow [17, p. 2]

As production declines, the flow regime in tubing as well as below tubing till mid-perforations will change to other flow regimes with the decrease in gas velocity. Flow at the surface will remain in mist flow until the flow conditions in entire well changes reasonably to force the flow regime into slug regime. At this point, the well production becomes erratic and is often accompanied by a marked increase in the decline rate. Eventually, the unstable slug flow at the surface will transition to a stable, fairly steady production rate again as the gas rate declines still further. This occurs when the gas rate is too low to carry liquids to the surface and simply bubbles up through a stagnant liquid column. If corrective action is not taken, the well will continue to decline and eventually load. It is, also, possible for the well to continue to flow for a long period in a loaded condition, producing gas up through the liquids with no liquids coming to the surface.

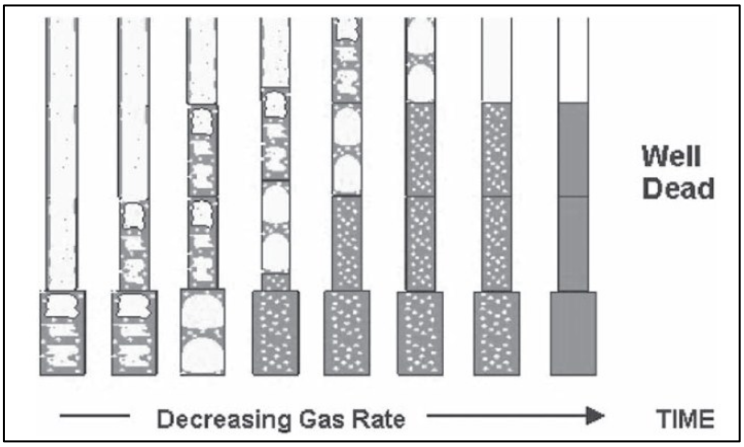

Figure 2-2: Life History of a Gas well [17, p. 3]

Liquid production may also increase as the gas production declines but it depends on Reservoir type, i.e. volumetric, aquifer support etc. Liquids can accumulate in a well in a variety of mechanisms. Often gas wells produce liquids directly into the wellbore. In some cases, both hydrocarbons and water condense from the gas stream as temperature and pressure change while travelling to the surface. Moreover, fluids can flow into the wellbore due to coning water from an underlying zone. The type of reservoir and the pressure-volume-temperature (PVT) behaviour of the reservoir fluids require different methods of analysis in order to predict well operation and allow estimates of, when the gas velocity in the tubing begins to drop below a value too low to bring liquids to the surface. A remedial method must consider the source of the liquid loading in order to be successful.

2.3 Problems in Liquid Loading

Liquid Loading can cause multiple issues not only within well but also affects reservoir performance. The accumulation of liquid within well exerts back pressure on formation resulting in low formation deliverability. The accumulated liquid increases near wellbore liquid permeability restricting gas flow rate from reservoir. Accumulated liquid is a potential cause of tubular corrosion. High water production results higher lifting costs. High water production also requires produced water management system like transportation and water disposal.

2.4 Water of Condensation

Since nearly every reservoir contains free formation water, natural gas may be saturated if the conditions are suitable for water to dissolve in natural gas. In this case, water will enter the well as vapour dissolved in natural gas. The water will start condensing if pressure and temperature drop below the dew point. If the amount of condensed water is high in the well, it will create a high hydrostatic pressure in the string. Eventually, the condensed water will accumulate at the bottom of the well. Condensed water can easily be identified as it has negligible salt contents.

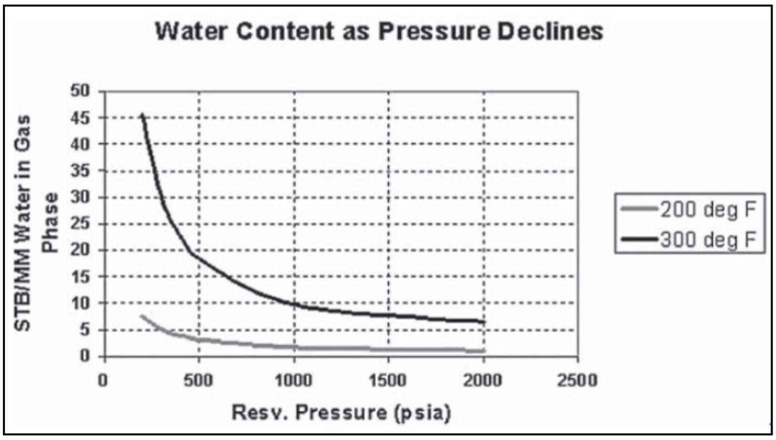

Figure 2-3: Water Solubility in Natural Gas [17, p. 10]

2.5 Critical flow concept

A simple approach to predict “safe” or "minimum" flow rates to avoid liquid loading in the tubing is based on the fact that the gas velocity must be high enough to transport liquid droplets to the surface. When the gas velocity exceeds a threshold[1] velocity, droplets are carried up by the gas and will not accumulate in the well otherwise droplets will accumulate

[1] Threshold velocity is the minimum velocity required by gas to carry water droplets. This velocity is also known as critical velocity.

and becomes source of liquid loading causing a decrease in gas production rate. Various flow models to determine critical velocity and rates have been proposed and can be found in the bibliography of this document. An introduction of some major models is being presented in this section. The two most widely used models for determining critical velocity are Turner et al. and Coleman et al. [17, 23]

2.5.1 Turner Flow Model

Turner et al [1] developed a correlation to predict the threshold velocity in a gas well. The developed model is also known as "Droplet Model". According to this model, liquid droplet weight acts downward and the drag force from the gas acts upward (Figure 2.4). When the drag is equal to the weight, the gas velocity is known as "critical velocity". Theoretically, at critical velocity the liquid droplet should remain stationary in a gas stream, moving neither upward nor downward. Below critical velocity, the droplet falls and liquids accumulate in wellbore. This analysis generated a critical velocity criterion which was compared to available wells data. Predicted critical velocities were compared to the gas velocity of producing wells at wellhead temperature and pressures. The derivation of Turner's equation is presented in the appendix B. The critical velocity equation proposed by turner is present in eq. 2.1.

$$V_t = 1.593 \left(\frac{\rho_L - \rho_G}{\rho_G^{\,2}} \sigma\right)^{\frac{1}{4}} \frac{ft}{s} \qquad (2.1)$$

Where,

$$\sigma = \text{surface tension}, \left(\frac{\text{dynes}}{\text{cm}}\right) \text{and } \rho = \text{density}, \frac{\text{lbm}}{\text{ft}^3}$$

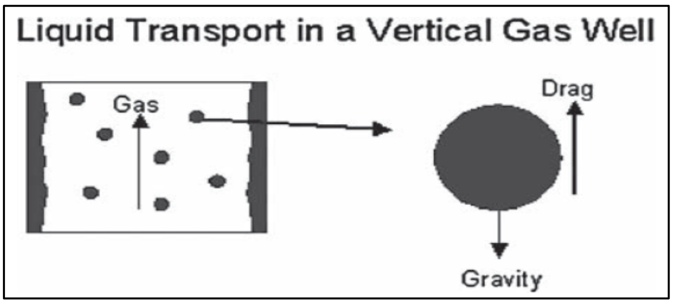

Figure 2-4: Illustration of Critical Velocity Concept [17, p. 32]

Eq. 2.1 is generic and requires surface tension (σ), gas density (ρ) at a particular pressure including use of correct compressibility factor Z and gas gravity. Turner simplified critical velocity eq. 2.1 for gas & condensate and gas & water scenario. Simplified form of eq. 2.1 for the case of gas water scenario is presented in eq. 2.2.

$$V_{t,water} = 5.321 \left(\frac{67 - .0031P}{(.0031P)^2}\right)^{\frac{1}{4}} \frac{ft}{s} \qquad (2.2)$$

2.5.2 Coleman Model

Coleman model is an extension of the original model of Turner [17]. Coleman worked on a data set mostly consisting of wells with low well head pressure. Coleman concluded that for lower reservoir and wellhead flowing pressures, all below approximately 500 psi, a better prediction could be achieved with Turner Model if the constant 4.434 is used instead of 5.321[2]. Coleman equation for gas & water scenario is presented in eq. 2.3.

$$V_{t,water} = 4.434 \left(\frac{67-.0031P}{(.0031P)^2}\right)^{\frac{1}{4}} \frac{ft}{s} \qquad (2.3)$$

2.5.3 Nossier Model

Nosseir et al. [23] focused on the impact of flow regimes and changes in flow conditions on gas well loading. They followed the path of Turner Droplet Model but they considered the impact of different flow regimes on the drag coefficient "C_d"[3]. Turner model assume 0.44 for "C_d" to be .44 under laminar, transition and turbulent flow regimes, which in turn determine the expression of the drag force and hence the critical velocity. By comparing, Nossier observed that values of the Turner model were not matching with the real data for highly turbulent flow. Therefore Nossier suggested 0.2 instead of 0.44 for "C_d" coefficient for turbulent flow. The equation proposed by Nossier is presented as eq. 2.4.

$$V_c = \frac{14.6\sigma^{0.35}(\rho_l-\rho_g)^{0.21}}{\mu_g^{0.134}\rho_g^{0.426}} \frac{ft}{s} \qquad (2.4)$$

2.5.4 LI's Model

Li, Li and Sun postulated that Turner and Coleman's did not consider the deformation of the free falling liquid droplet in a gas medium. [23] They argued that as a liquid droplet is entrained in a high- velocity gas stream, a pressure difference exists between the "fore" and "aft" portions of the droplet. The droplet is deformed under the applied force and its shape changes from spherical to a convex bean with unequal sides as shown in Figure 2.5.

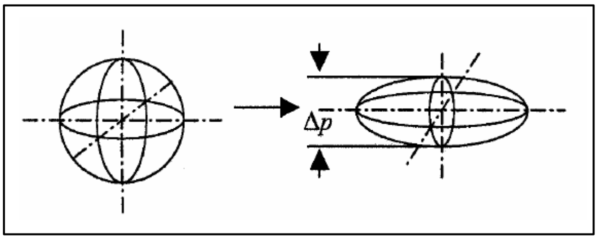

Figure 2-5: Droplet shape modification [21, p. 3]

Spherical liquid droplets have a smaller efficient area and need a higher terminal velocity[4] and critical rate to lift them to the surface. However, flat-shaped droplets have a more efficient area and are easier to be carried to the wellhead. The proposed equation 2.5 is similar to Turner's equation 2.1.

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[2] Constant value of 5.321 supposed by Turner in equation 2.2 is based on adjustment made by turner on original value of 4.434 to fit his model with the available field data. Coleman reworked with low WHP field data and found original model with constant of 4.434 worked better.

[3] Drag coefficient is friction coefficient. "C_d" depends on turbulence nature of fluid flow.

[4] Terminal velocity is the velocity when the net force acting on droplet is zero i.e. drag = gravitational force and droplet becomes stationary.

$$V_c = \frac{2.5\sigma^{0.25}(\rho_l - \rho_g)^{0.25}}{\rho_g^{0.5}} \frac{ft}{s} \qquad 2.5$$

2.6 Critical Velocity Models Comparison

Section 2.5 describes some of the model proposed for calculating critical velocity. However, it is worthwhile to know the most feasible and practical model fit for analysis. Figure 2.6 presents the critical values calculated by different models for same data [21]. Turner's model produces the most conservative critical velocity value. Therefore, Turner critical velocity criteria can be taken as reference for calculating critical velocity.

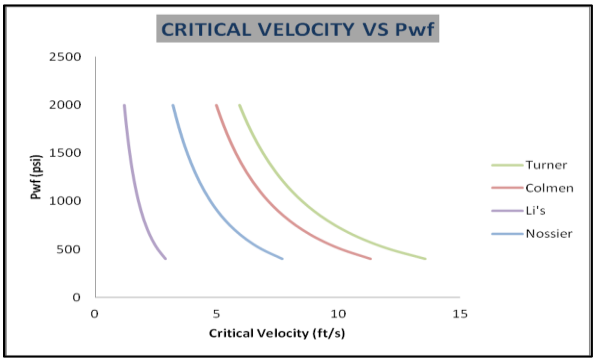

Figure 2-6: Velocity Models comparison [23, p. 5]

2.7 Tubing Performance Curve (TPC)

The vertical lift performance or tubing performance curve (VLP/TPC) shows the relationship between the total tubing pressure-drop with the fluid flow rate. The three principal components that determine the pressure drop in a tubing string consists of Elevation, Friction and Acceleration component. The elevation component for vertical or inclined flow is by far the most important of all three components. It is the principal component that causes wells to load up and die. The frictional pressure loss results from the fluid flow in well. For very high flow rates there can be an additional "acceleration term" to add to the pressure drop but the acceleration term is usually negligible compared to the friction and hydrostatic components. A typical tubing performance curve is depicted in figure 2.7. The TPC passes through a minimum. To the right of the minimum, the total tubing pressure loss increases due to increased friction losses at high flow rates. The flow to the right of the minimum is usually in the mist flow regime that effectively transports small droplets of liquids to the surface. At the far left of the TPC the flow rate is low and the total pressure loss is dominated by the hydrostatic pressure of the fluid column brought about by the liquid accumulation. The flow regime exhibited is typically bubble flow. Slightly to the left of the minimum in the TPC, the flow is often in the slug flow regime. In this regime liquid is transported to the surface periodically in the form of large slugs. Fluid transport remains inefficient in this unstable regime as portions of the slugs "fall-back" as they rise and must be lifted again by the next slug. Fall back and re-lifting the liquids result in higher producing bottomhole pressure.

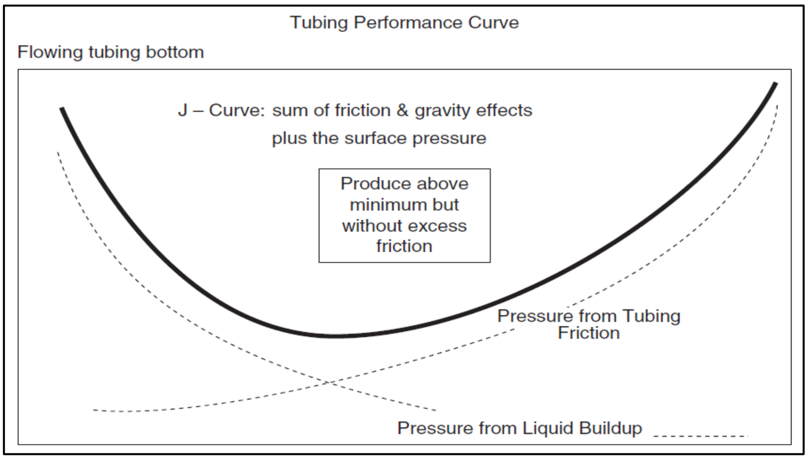

Figure 2-7: Typical tubing performance curve [17, p. 49]

2.8 Tubing Correlations

There are numerous correlations used for vertical lift performances. They are categorized in different classes based on their applicability. They vary in terms of relationships used for pressure gradient calculations. Some correlations are empirical whereas some are mechanics-based models. If, by comparison to field well data, any of these correlations reasonably predict loading conditions, the analyst can plan appropriate measures such as smaller tubing installations or other lift methods to assist production. Figure 2.8 presents some of the widely used gas and gas condensate correlation. Gray model turns out to be the best method for modelling vertical lift performance in gas wells.

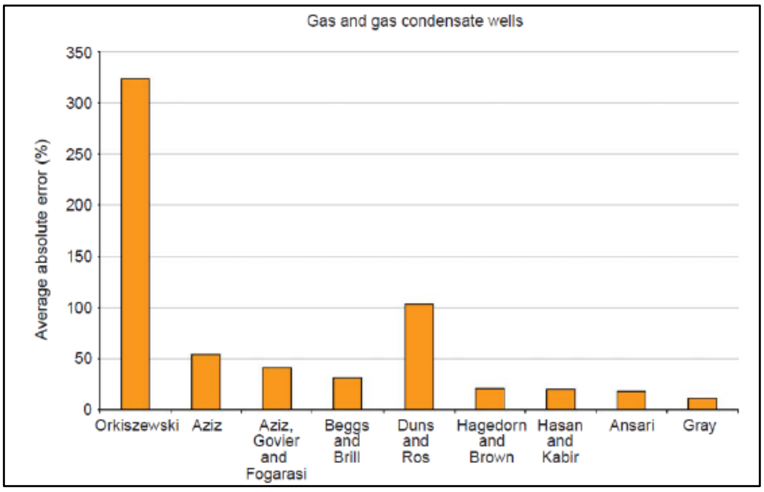

Figure 2-8: Commonly used Gas well correlations [6]

3. Gas Wells Deliquification Techniques

The optimum deliquifying method is defined as that which is most economic for the longest period of operation. Methods successfully implemented in similar offset fields, vendor equipment availability, reliability of equipment, manpower required to operate the equipment, etc. are all important considerations that are involved in selecting the optimum method. Various methods that can be used are presented in this chapter. Chapter starts with liquid loading symptoms followed by introduction to various artificial lift strategies. In end, a comparison of artificial lift strategies is presented.

3.1 Symptoms Techniques

Liquid Loading problem exists for all type of gas wells. Therefore it is important to recognize liquid loading symptoms at early stages, and to design proper solution in order to minimize the negative effects of liquids filling up the wellbore. Symptoms that indicate a well for liquid loading are [11]:

- The onset of liquid slugs at the surface of the well
- Erratic production and increase in decline rate
- Orifice pressure spikes
- Sharp changes (heavier) in fluid pressure gradient on a flowing pressure survey
- Liquid production ceases (extreme conditions)

Figure 3.1 is a simple diagnostic tool to detect liquid loading in gas wells. The onset of liquid loading shows unstable flow in the trend. Liquid Loading problems should be diagnosed in time and dealt properly and efficiently. It is important to analyze gas well liquid loading tendencies at locations in the wellbore where the production velocities are lowest. In practice, it is recommended that liquid loading calculations should be performed at all sections of the tubing where diameter changes occur. In general for a constant diameter string, if the critical velocity is acceptable at the bottom of the string, then it will be acceptable everywhere in the tubing string.

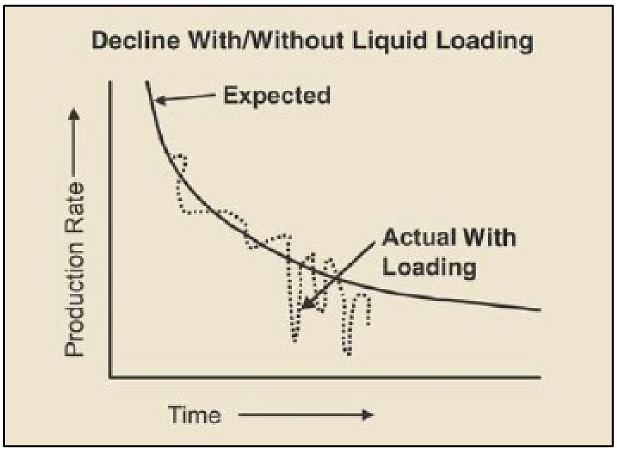

Figure 3-1: Decline curve showing onset of liquid loading [11]

3.2 Measures to decrease critical velocity

The equation for critical flow rate is presented in equation 3.1 [29]. Following parameters play a major role in reducing critical velocity:

- Tubing Diameter Reduction
- Increase/conserve well flowing temperature
- Decrease in liquid density
- Reduction of well head pressure
- Reduction of surface tension

$$Q_c = (1.593) \times 2.4 \times D^2 \times \left[\frac{(\rho_l \times Z \times T - 2.699 \times \gamma_g \times p)}{(2.699 \times \gamma_g)^2} \frac{p^2 \sigma}{T^3 Z^3}\right]^{\frac{1}{4}} \qquad 3.1$$

3.3 Deliquification Techniques

3.3.1 Electrical Submersible Pump (ESP)

The electrical submersible pump, typically called an ESP, is an efficient and reliable lifting method for moderate to high volumes of liquid from wellbores. ESP's main components include multistage centrifugal pump, three-phase induction motor, seal-chamber section, power cable, and surface controls. The components are normally tubing hung from the wellhead. ESP's typically are reserved for applications where the produced flow is primarily liquid. High volumes of gas inside an electrical pump can cause gas interference or severe damage if the ESP installation is not designed properly.

3.3.2 Progressive Cavity Pump (PCP)

The principle of production for such pumps is based on the progressive movement of fluid from one cavity to the other. PC pumps can produce a significant amount of free gas but there is a trade off with pump performance and life expectancy. If gas is the major producing phase then it can result in more friction and higher temperatures. If not corrected, the pump internal temperature may exceed the elastomer temperature limit. Under conventional design and pump sizing practices, a PC pump will typically have a catastrophic failure in less than 30 minutes if operated with no liquid. So, for lubrication of the seals, liquid is must for such pumps.

3.3.3 Gas Lift

Gas lift is an artificial lift method whereby external gas is injected into the produced flow stream at some depth in the wellbore. The additional gas supplements the formation gas and reduces the flowing bottom-hole pressure, thereby increasing the inflow of produced fluids. For dewatering gas wells, the volume of injected gas is designed so that the combined formation and injected gas should be above the critical rate for the wellbore. Gas lift is particularly applicable for lifting fluids in wells that have a significant amount of gas produced with the crude.

3.3.4 Sucker Rod

Beam pumping, or the sucker-rod lift method, is the oldest and most widely used type of artificial lift. A sucker-rod pumping system is made up of several components, some of which operate above ground and other parts operate underground, down in the well. The surface-pumping unit, which drives the underground pump, consists of a prime mover (usually an electric motor) and, normally, a beam fixed to a pivotal post. Sucker Rod pumping system is mostly used for low pressure wells with oil as major producing phase.

3.3.5 Jet/Hydraulic Pumps

Jet pump uses Bernoulli principle to convert high fluid pressure into velocity and again fluid velocity into pressure. The high velocity and low pressure causes the well fluid to enter and mix with the injected fluid in the pump and thereby accelerate itself after extracting energy from the injected fluid. Excessive gas causes erosion and cavitation of pump. Hydraulic pumps are downhole pump and works with the help of external fluids. The principle of operation is same as sucker rod pumps..

3.3.6 Plunger lift

Plunger uses the natural energy of reservoir and travels from downhole to surface thus removing water from the wellbore. Plunger lift is low cost environmental friendly solution for dewatering gas wells. Plunger lift efficiency is directly related to tubing diameter and is not recommended for sizes greater than 2.375”.

3.3.7 Velocity String

Small diameter tubing string (velocity string) is installed inside the production tubing. The smaller cross-sectional flow area increases the gas velocity in the tubing. The higher gas velocity at the bottom of the tubing provides more transport energy to lift liquid up out of the well and liquid no longer accumulates at the bottom of the well resulting in production sustainability. However, tubing too small for the production rate can cause excess friction and require a larger flowing bottom-hole pressure. This causes low rates at surface. The same volume of fluid that may be negligible in larger tubing can be significant in small tubing. The biggest limitation factor of velocity string compared to other options is that it limits the tool size for well intervention job. It is important to evaluate the performance of the existing production tubing to justify velocity string instalment. If the well has already started to load up, it is required to install an appropriate velocity string before the well kills itself. If multiple strings design can prevent the well from loading up, the optimum choice is typically a trade-off between current production (a higher flow rate) and sustained production (a lower bottomhole pressure).

3.3.7.1 Velocity String selection

When selecting velocity strings, considerations, same as conventional production tubing must be accounted. Velocity string selection typically considers the following:

- Size
- Metallurgy
- Bottom-hole Temperature
- String Thickness
- Producing Media
- Partial Pressures of H_2S and CO_2
- Yield Strength of Material

3.3.8 Compression

Compression is vital to deliquification, lowering wellhead pressure and increasing gas velocity. It is usually the first tool used in the life of a gas well. Compression is sometimes the only mean of artificial lift for increasing producing life for the case of dry gas wells that gets early abandonment without liquid loading due to back pressure from system (Processing plant pressure). It can also be used to increase the effectiveness of other deliquification methods. Reducing wellhead pressures can result in significant production increase especially for high-permeability formations. The combination of higher rates and a significant increase in ultimate recovery from high permeability reservoir will likely support the economics of making changes to reach low wellhead pressures. On the other hand, wells within tight gas reservoirs may not be good candidates for nominal reductions in wellhead pressure considering the expense involved. Calculations would have to indicate whether the small rate increase would correspond to a significant percentage of total recoverable production. Figure 3.2 illustrate the effect of various suction pressures on well performance in one instance of time. It is evident from figure that lowering wellhead pressure lowers the flowing bottom-hole pressure causing well to deliver more rates.

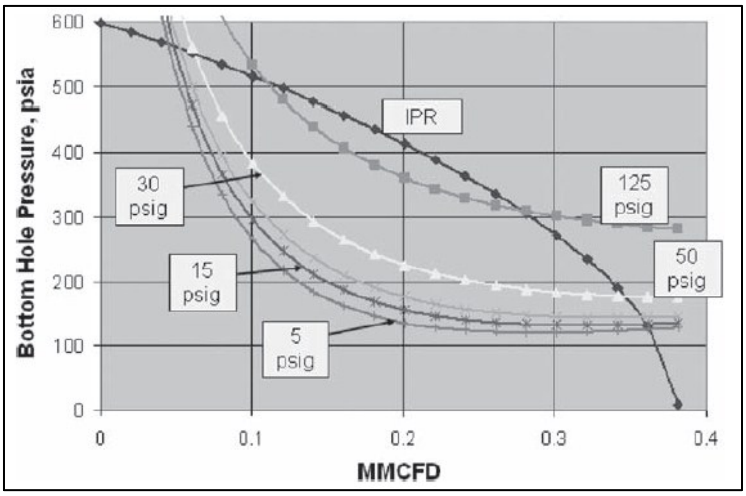

Figure 3-2: Effects of various compression suction pressure [17, p. 103]

3.3.8.1 Compressor selection

Different wells will give different responses to compression therefore, it is crucial that the compressor type, size and properties are selected properly and optimized for maximum efficiency. The process of selecting compression and the proper equipment to achieve the desired pressures and rates is important in optimizing results. There are many different types of compressors, each of them have their own operating range, efficiency, strength, and weakness. The major parameters in compressor selection involved are:

- Producing media
- Pressures Required
- Throughput (Rates)
- Local Experience
- Commercial availability of compressor models
- Power level
- Serviceability of compressor type
- Service Conditions Affecting Compressor Type Selection
- Environmental Issues
- Cost and Delivery Schedule

Compressor can be installed at plants (Centralized compression), at junctions (nodal compressors) and at wellhead (wellhead compressors).

3.3.9 Foam Assisted Lift

Foam is a particular type of gas and liquid emulsion in which gas bubbles are separated from each other by a liquid film. Surface-active agents (surfactants) are generally employed to reduce the surface tension of the liquid to enable more gas-liquid dispersion. The liquid film between bubbles has two surfactant layers back-to-back, with a liquid contained in-between. This method of tying the liquid and gas together is effective in removing liquid from low-volume gas wells. The application of foam to unload low-rate gas wells is generally governed by two operating limitations. These limitations are economics and the success of foam surfactants in reducing bottom-hole pressure. Foam quality appears to vary with the amount and type of liquids present. The economic limitation parameter is a function of chemical costs and equipment costs. Chemical costs are proportional to the liquid production rate. At some level of water production, chemical costs will approach and exceed the cost of pumping. The producing pressure and velocity gradients expected with foam surfactants are ultimately controlled by well conditions and by the performance of specific surfactants in the well.

The two core parameters for analysing foam are surface tension and density. As the bulk concentration of foam in liquid solution increases, the surface tension reduces until the critical micelle[5] concentration (CMC). Beyond CMC[6], surface tension and foam density

[5] The liquid detergent molecules arrange themselves into tiny clusters whenever concentration of detergent increases certain threshold. These tiny clusters are known as micelles

remains almost constant. At the CMC, surfactants in the bulk self-assemble into aggregates known as micelles. Micelles are 3D structures and are arranged such that their hydrophilic heads face the water, shielding the hydrophobic tails from being exposed to water. The reduction of liquid surface tension is a function of property of the type of surfactant, type of liquid solution, surfactant concentration, pressure and temperature.

3.3.9.1 Turner's aspect of Foam injection

Turner's criterion has been used widely for determining the minimum critical velocity that lifts a liquid droplet in the well. [33]

$$V_c = k\frac{\sigma^{\frac{1}{4}}(\rho_l - \rho_g)^{\frac{1}{4}}}{\rho_g^{\frac{1}{2}}} \qquad 3.2$$

$$\text{Where, } k = \sqrt[4]{\frac{4mg_c gN_{we}}{3C_d}} \qquad 3.3$$

Parameter $(\rho_l - \rho_g)^{\frac{1}{4}}$ can also be represented in the form of $(p_f)^{\frac{1}{4}}$ – Eq. 3.4

$$V_c = k\frac{\sigma^{\frac{1}{4}}(p_f)^{\frac{1}{4}}}{\rho_g^{\frac{1}{2}}} \qquad 3.4$$

Equation parameters are presented in bibliography of this document.

3.3.9.2 Surfactant Types

Surfactant molecules have a water-soluble (hydrophilic) end and a non-water-soluble (hydrophobic) end that cause the molecule to concentrate at the interface between the water and non-water phases. When the concentration of the surfactant is such that the interface surface area is completely covered with a maximum number of surfactant molecules, the solute is said to be at its critical concentration. Surfactants are classified as non-ionic, anion, cationic and amphoteric. Surfactant types are tabulated in tables 3.1 to 3.4.

Figure 3-3: Surfactant arrangement at gas liquid interface [26, p. 35]

Table 3-1: Nonionic Surfactant

Low to medium foaming performance
Solubility reduces at higher temperatures
Solubility reduces at higher salt content
Often applied in foam sticks
In general environmentally acceptable

[6] The critical micelle concentration (CMC) is defined as the concentration of surfactants above which micelles form and all additional surfactants added to the system go to micelles

Table 3-2: Anionic Surfactant

High foaming performance
Foaming performances reduces at higher salt content
Not stable at high temperature
May act as an emulsifier (if condensate is present)
Often applied in high water cut / low temperature wells
In general toxic, especially the long hydrophobic chain versions

Table 3-3: Cationic Surfactant

Moderate foaming performance
High temperature stability
Might act also as corrosion inhibitor
Often applied in low condensate wells
Toxic for organisms (bacteria)

Table 3-4: Amphoteric Surfactant

High foaming performance
Good foaming performance at high salt content
Good foaming performance at medium condensate content
Excellent temperature stability
Often corrosive due to presence of chloride as by-product

3.3.9.3 Foam Terminologies

- **Foam Stability**

Foams begin to deteriorate as soon as they are formed. Excess liquid between surfactant layers drains from the bubble film (figure 3.3-Blue part) and results in thinning and weakening of the bubble wall. Liquids in the bubbles below are constantly replenished by the drainage from bubbles above. Also, the bubbles grow as the trapped gas expands until the liquid film becomes thin from liquid drainage and bubble expansion. This thin film eventually breaks the foam. Foam stability can be increased by reducing the liquid drainage rate and by increasing the resiliency of the surfactant layers. Laboratory tests indicate that many surfactants have an optimum effectiveness from about 0.1 to 0.6% concentration in the water phase [4].

- **Foaming Ability**

The foaming ability is typically evaluated in terms of foam build-up time and also the foam breakdown time. Different foamers will show different results in terms of foam build-up and breakdown times (foam half-life).

- **Foam quality**

The percentage of gas in the foam mixture at operating pressure and temperature is termed foam quality. Foam that is 80% gas is called 80-quality foam. Generally for producing stable foam, qualities should be greater than 50% [4].

3.3.9.4 Practical Aspect in Foam selection

Experience has demonstrated that finalized selection of a foaming agent cannot be completed in a lab under all circumstances. Field testing and selection of foaming agents is necessary to obtain accurate results. It is very important that the testing represents downhole conditions in the well that is being considered for foam. This means that the sample of fluids used as well as the testing conditions must be representative of what is downhole. Steps that are followed from lab to field are:

- Well fluid analysis with different surfactants in lab to find appropriate surfactant type.
- Determination of optimum concentration of selected surfactant.
- Field test with selected foam in order to further optimize foam dosage rate.

3.3.9.5 Foam models

Unfortunately, there is no well-established correlation to calculate the pressure drop in well under foam flow conditions. Conventional pressure drop prediction models are unable to correctly predict the pressure drop under foam flow conditions. The major limitation is that these models are only verified on limited data and models applicability is not assured for every well application. Models include [18]

I. Foam Homogenous
II. Foam Slippage
III. Foam Drift Flux
IV. Foam Modified Drift Flux

Current industry Production modelling software can model foam lift but unable to predict the optimized rate of injection. With current technology, calculation of optimized rate is possible only after field testing.

3.3.10 Vacuum Jacket tubing

Vacuum jacket or insulated tubing are special tubing used to conserve temperature within wellbore. These tubing have low heat transfer coefficient. Comparing to conservative steel tubing where heat loss occurs as a result of fluid movement from reservoir to surface, jacketed tubing holds heat within fluid and reduces the chance of water vapours that are being carried by gas to condense inside wellbore.

3.4 Comparison Study

Some of the key factors that affect the selection of artificial lifting techniques include:

- **Liquid production rate:** The anticipated liquid production rate is a controlling factor in selecting a lift method
- **Water cut:** High water cuts require a lift method that can unload a large volumes of fluid
- **Gas-liquid ratio:** A high GLR generally lowers the efficiency of pump-assisted lifting methods.
- **Fluid contaminants**: Sand, paraffin, or scale can cause plugging and/or abrasion. Presence of H_2S, CO_2 or high salt water can cause corrosion.
- **Well depth:** The well depth dictates how much surface energy is needed to move fluids to surface, and may place limits on sucker rods and other equipment.
- **Wellbore deviation:** Highly deviated wells may limit applications of beam pumping or PCP systems because of drag, compressive forces and potential for rod and tubing wear.
- **Power sources:** The availability of electricity or natural gas governs the type of artificial lift selected.
- **Climate and Physical environment:** Affect the performance of surface equipment.
- **Personal efficiency:** Availability of operating and service personnel and support services together with familiarity with equipment must be taken into account.

Item	Adaptability Condition	Sucker Rod Pump	Screw Pump	Electric Submersible Pump	Hydraulic Piston Pump	Hydraulic Jet Pump	Gas Lift	Plunger Lift
Basic conditions of system	Degree of complexity	Simple	Simple	Complex bottomhole	Complex surface	Complex surface	Complex surface	Complex surface
	One investment	Low	Low	High	High	High	Highest	Highest
	Operation cost	Low	Low	High	Low; High in high water cut period	Low	Low; High for small oil field	Low; High for small oil field
Discharge capacity m^3/d	Normal range	1~100	10~200	80~700	300~600	10~500	30~3180	20~32
	Maximum	410	(1000)	1400 (3170)	(1293)	1590 (4769)	(7945)	63
Pump depth m	Normal range	3000	1500	2000	4000	2000	3000	3000
	Maximum	4421	3000	3084	5486	3500	3658	3658
Downhole conditions	Slim hole	Appropriate	Appropriate	Inappropriate	Appropriate	Appropriate	Appropriate	Appropriate
	Separate-zone production	Inappropriate	Inappropriate	Appropriate	Appropriate	Inappropriate	Appropriate	Appropriate
	Directional well	General wear	Serious wear	Appropriate	Appropriate	Appropriate	Appropriate	Appropriate
	Degree of cavitation	Strong	Strong	Strong	Strong	Strong	Strong	Strong
Surface environment	Offshore and city	Inappropriate	Appropriate	Appropriate	Appropriate	Appropriate	Appropriate	Appropriate
	Harsh climate	General	General	Appropriate	Appropriate	Appropriate	Appropriate	Appropriate
Operation problems	High gas-oil ratio	Adaptable	General	Inadaptable	General	Adaptable	Very adaptable	Very adaptable
	Heavy oil and high pour-point oil	Good	Good	Inadaptable	Very good	Very good	Inadaptable	Inadaptable
	Sand production	Good	Adaptable	Inadaptable	General	General	Very adaptable	Very adaptable
	Corrosion	Adaptable	Adaptable	Adaptable	Adaptable	Adaptable	Adaptable	Adaptable
	Scaling	Adaptable	Inadaptable	Inappropriate	Adaptable	Adaptable	General	General
	Working system adjustment	Convenient	Convenient	Lack of flexibility	Lack of flexibility	Convenient	Convenient	Convenient
	Power source	Electricity, natural gas, oil	Electricity, natural gas, oil	Electricity	Electricity, natural gas, oil	Electricity, natural gas, oil	Electricity, natural gas, oil	Electricity, natural gas, oil
	Requirement for power media	None	None	None	Special power fluid	Water power fluid	Avoiding hydrate	Avoiding hydrate
Maintenance and management	Pump inspection	Pulling out tubing for tubing pump	Pulling out tubing	Pulling out tubing	Hydraulic or wire pulling and running	Hydraulic or wire pulling and running	Wire pulling and running	Wire pulling and running
	Mean repair-free period (a)	2	1	1.5	0.5	0.5	3	3
	Auto-control	Appropriate	General	Appropriate	Appropriate	Appropriate	General	General
	Production test	Basically matching	Unmatching	Basically matching	Basically matching	Unmatching	Completely matching	Basically matching

Figure 3-4: General Comparison of different ALS [16]

4. Sawan Gas well Analysis

4.1 Sawan Field

Sawan Field is located in district Sukkur, Sindh, Pakistan. Sawan is a depletion drive dry gas reservoir, discovered in 1998 through exploration well, Sawan-1, which encountered hydrocarbon bearing Cretaceous Lower Goru "C" sand. Sawan virgin/initial reservoir pressure was ~5350 psi with 350^{o}F reservoir temperature. Sawan gas field has been producing since June 2003 and onwards from February 2010 the field is producing through front end compression (FEC). Sawan reservoir has produced a cumulative production volume of 1.434 Tcf till March 2016.

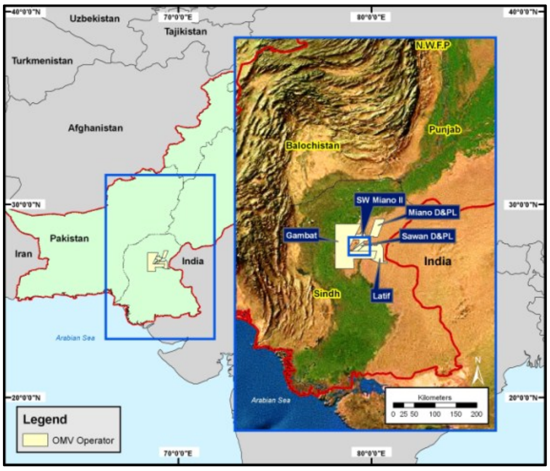

Figure 4-1: Field Location

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 in some parts. Sawan South however consists of low permeability reservoir due to deposition of poor facies in this part of the field.

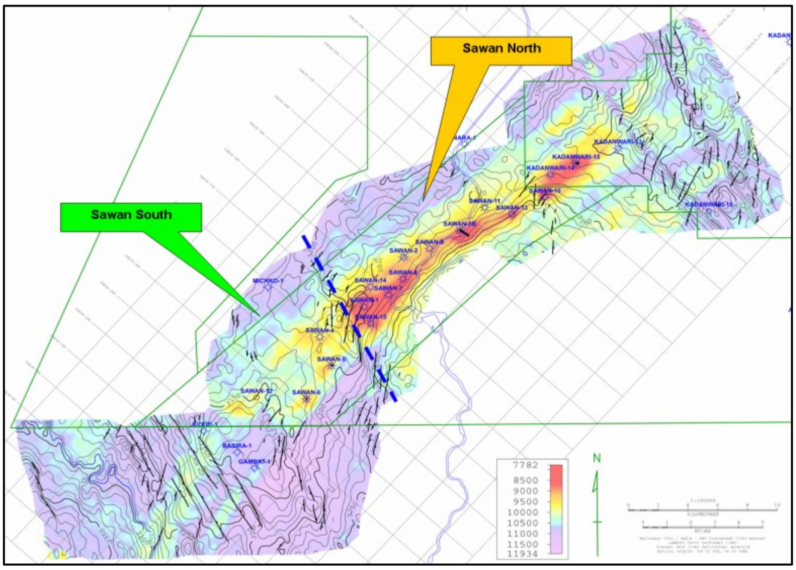

Figure 4-2: North & South Compartment

Currently 14 wells are producing gas. North pool comprises 11 well with all in communication except S-10 which is considered as small separate pool. In other compartment, none of well is under communication. All wells in Sawan south are hydraulically fractured.

Table 4-1: Sawan Field Overview

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

4.2 Sawan Water Production Origin

Sawan field produces gas with water. Analyses of water samples from various well shows that water is condense water. For south wells, condense and formation water is producing with gas.

4.3 Sawan Artificial Lift Strategy

Sawan North is considered as volumetric dry gas reservoir. Sawan south is assume to have a weak formation drive. Overall, the water production from Sawan is accredited as condense water. A miniature program for techniques filtration has been created in MS Excel and as per program suggestion; foam lift turns out to be the most optimum method among conventional methods for Sawan wells. Gas lift can be applied but low liquid production rates rule out Gas lift strategy within created program. Plunger lift seems favourable option for Sawan field but is ruled out because plunger lift is mostly applicable for wells with tubing I.D less than 2.375”. Specific gas well unloading methods like compression and velocity string will be analysed together with foam lift for Sawan field because they were not analysed within program.

4.4 Software Analysis

Delqiuification analysis can be performed in any production analysis software. Since, OMV uses Petroleum Experts “PRSOPER” production software so deliquification analysis has been performed with PROSPER.

Artificial Lift Methods—Miniature Selection Program									Sawan Field								
0=poor, 1=fair, 2=good, 3=excellent																	
	Positive Displacement Pumps								Field Data	Rod Pump	PCP	Hydraulic Piston	ESP	Hydraulic Jet	Gas Lift	Plunger Lift	Foam Lift
Operating Parameters	Rod Pump	PCP	Hydraulic Piston	ESP	Hydraulic Jet	Gas lift	Plunger lift	Foam Lift	Final Selection	✗	✗	✗	✗	✗	✗	✗	✓
Maximum Operating Depth (TVD) ft	16000	6000	17000	15000	15000	15000	20000	22000	10500-11500	✓	✗	✓	✓	✓	✓	✓	✓
Typical Operating volume BFPD	1500	2200	500	30000	4000	10000	5	500	300	✗	✗	✓	✗	✗	✗	✓	✓
Maximum Operating Volume BFPD	6000	4500	4000	40000	15000	30000	200	500	500	✗	✗	✗	✗	✗	✗	✓	✓
Typical Operating temperature F	350	150	250	250	250	250	120	250	350	✓	✗	✗	✗	✗	✗	✗	✗
Maximum Operating temperature	550	250	500	400	500	400	500	400	350	✓	✗	✓	✓	✓	✓	✓	✓
Typical Wellbore Deviation (deg)	20	20	20	20	20	50	20	30	5	✓	✓	✓	✓	✓	✓	✓	✓
Corrosion handling	2	1	2	2	3	2	3	3	2	✓	✗	✓	✓	✓	✓	✓	✓
Gas handling	1	2	1	1	2	3	3	3	3	✗	✗	✗	✗	✗	✓	✓	✓
Solids handling	1	3	0	1	2	2	1	2	0	✓	✓	✓	✓	✓	✓	✓	✓
GLR scf/bbl	3000	3000	3000	3000	3000	40000	3300		10000	✗	✗	✗	✗	✗	✓	✗	✓

Figure 4-3: Miniature Program of Screening Criteria for Sawan Field

4.5 Base cases preparation

Base cases are prepared for all wells based on initial data of well. Field well test reports are used to filter out fluid data (PVT). PVT data is input in PVT section of software. Inflow reservoir performance (IPR) data was based on the field well test data interpretation. For well hydraulics performance (VLP), Well Completion data is inserted in "completion summary" tab in software. VLP model is selected based on the well test validating points.[7] If more than one tubing flow correlation satisfies criteria of matching, correlation selection is made on minimum deviation criteria[8]. Created models were validated with the latest data available to for quality testing. All wellhead chokes in Sawan field are 100% so, well head flowing is considered constant while performing study except for compression.

4.6 Compression Analysis

Field is already producing under centralized compression (FEC). OMV is planning to procure wellhead compressor. The study of compressor selection is still on going with collaboration of subsurface operations and surface departments. Compression analysis has been performed based on the intended compressor specifications (minimum suction pressure: 30 psi and outlet pressure: 200 psi). Compressor rate & pressure charts were not shared so it is difficult to decide compressor price per well.

4.7 Foam lift Analysis

Weatherford has tested "OMNHI FOAM HT" (Weatherford Brand) for Sawan 10. Considering the performance of foam at Sawan 10, relevant performance parameters were used for foam

[7] Well test data validating points consists of pair of flow rate corresponding to bottomhole pressure. This data is taken once per each wellhead choke size.

[8] A minimum deviation criterion is calculated by software in terms of statistical standard deviation from actual test data points.

modelling in Prosper for all wells. The foam model used in analysis is an estimated model as all foam characteristics were not shared by Weatherford. The base correlation used for foam is Modified Drift flux model.

4.8 Velocity string

For selecting optimum velocity string; following steps were carried in order:

I. Analysis of Completion schematics to find minimum restriction in wellbore.
II. Selection of strings applicable for well under consideration.
III. Analysis of loading of base cases with selected strings
IV. Analysis of “tubular+ annular”, “annular”, and tubular flow scenarios.

Table 4-2: Proposed Velocity String-Sawan Field

O.D (inches)	I.D (inches)
3.75”	3.22”
2.875”	2.563”
2.375”	2.025”
1.75”	1.56”
1.5”	1.15”

4.9 Flow Charts

Procedural work flow for the analysis of Sawan is presented in figure 4.4. Figure 4.5 presents the work flow for the preparation of base case in Software. Figure 4.6 presents the workflow for optimizing flow strategy with velocity string.

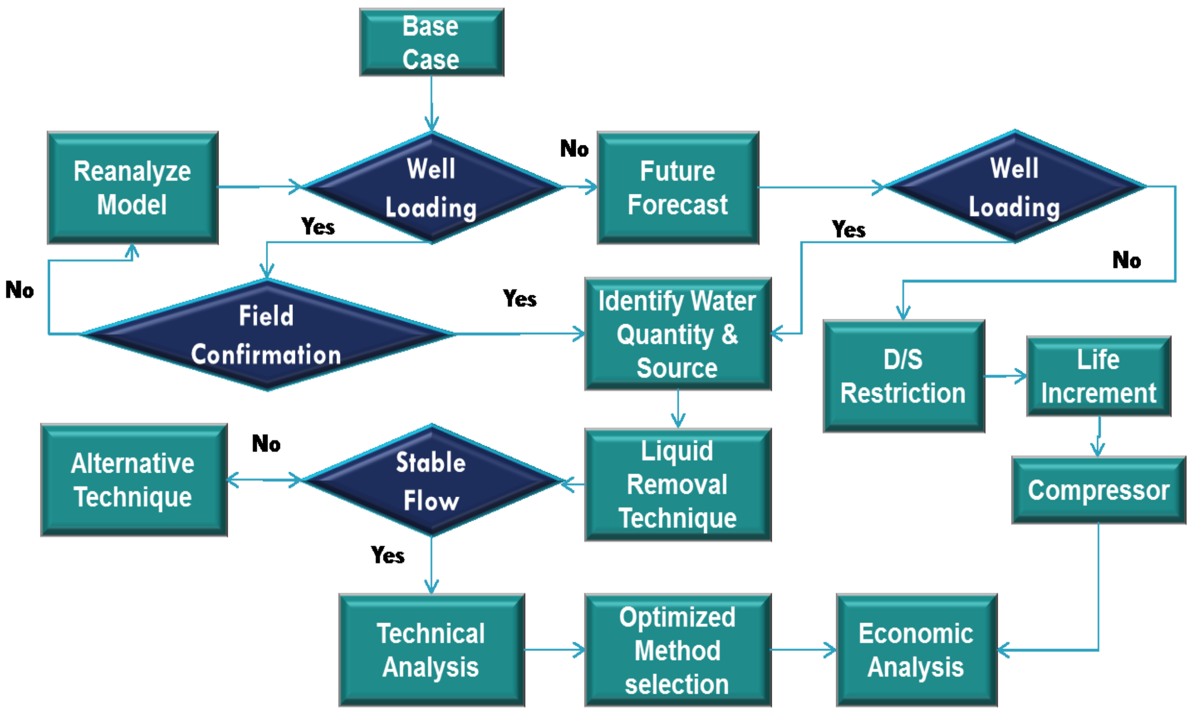

Figure 4-4 : Project Framework

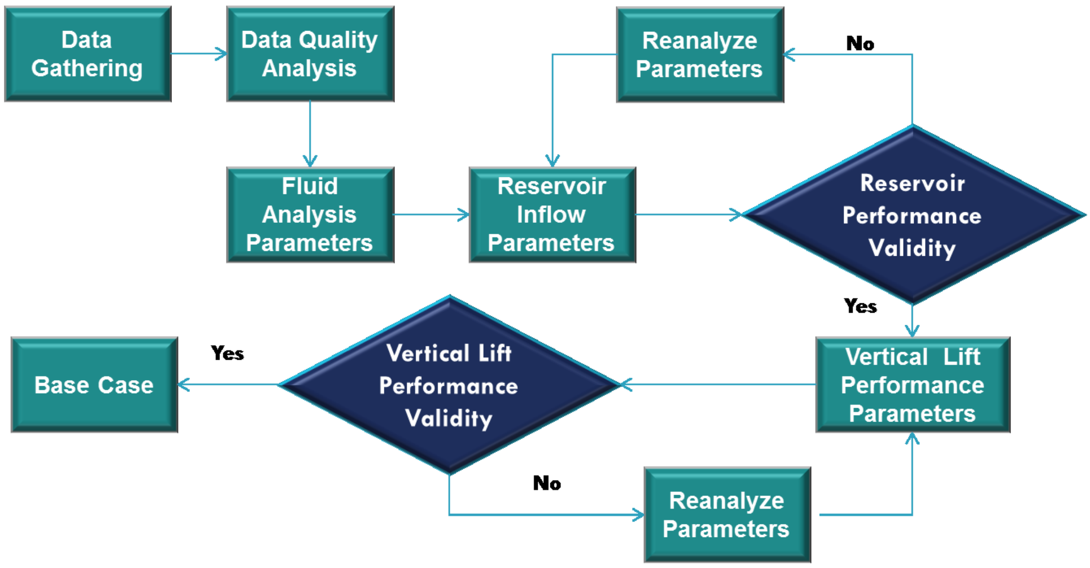

Figure 4-5: Base Case Work flow

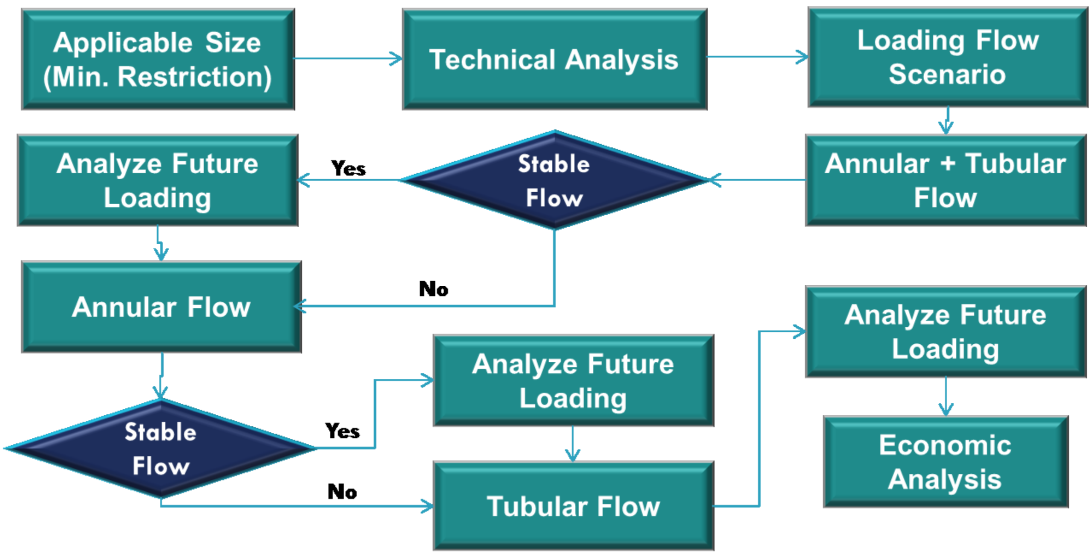

Figure 4-6: Velocity String Application Process

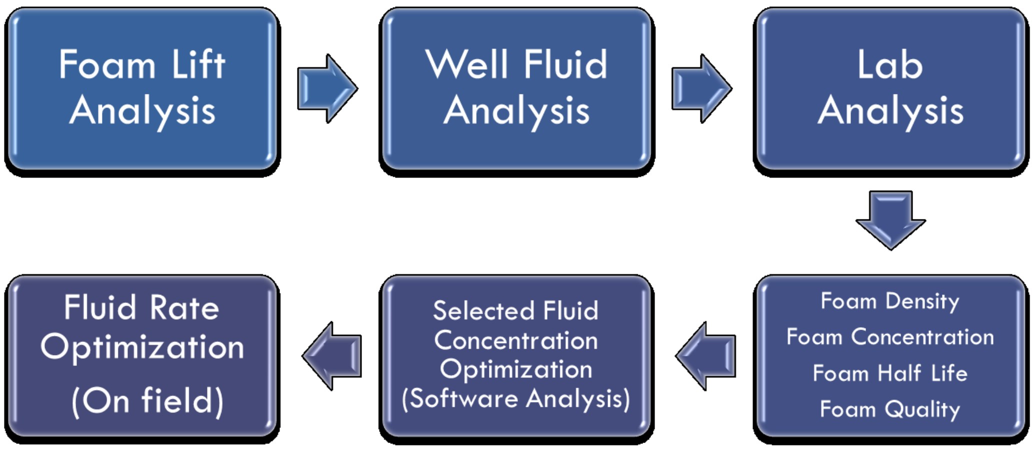

Figure 4-7: Foam Lift Application Process

5. Sawan Wells Technical Analysis

5.1 Sawan 1

Sawan-1 was drilled as exploratory well in Sawan North compartment in 1997 with a target formation of Lower Goru C-Sand. Sawan-1 completed with 7” x 5 ½” x 4 ½” Cr 22 completion. Initial recorded flowing potential of well was 42.05 MMscfd gas rate at 4018 psi WHFP with ~6 bbl/MMscf WGR. Chloride analysis of water sample indicated the production of condense water from reservoir. Well commissioned commercially in July 2003 through Sawan plant. Additional perforations were performed in 2008 to maintain production. Last stimulation job was carried out in 2011 to remove deposited fines near perforations. The well has produced a cumulative of 186.8 Bcf (March 2016).

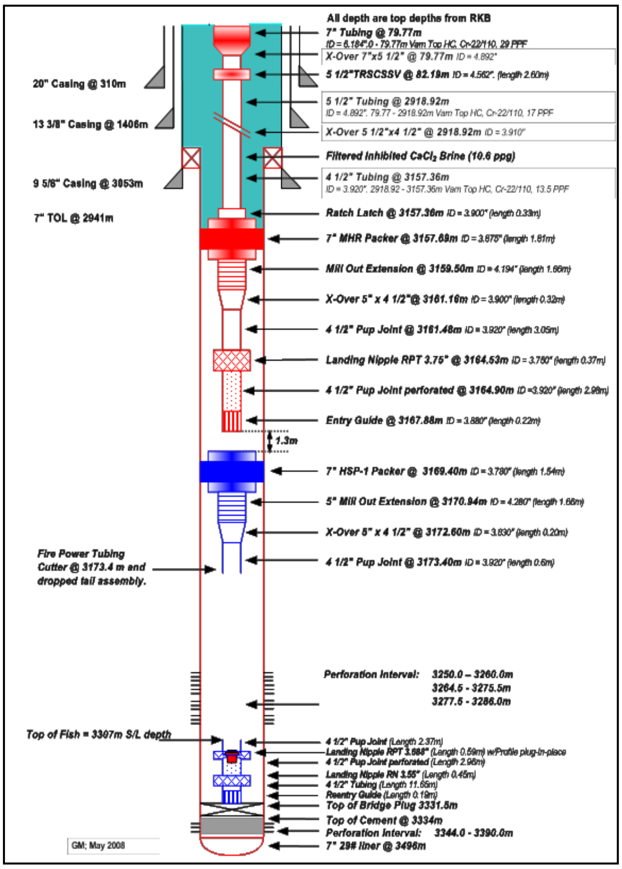

Figure 5-1: Sawan-1 Well completion sketch

5.1.1 Base case

Currently the well is producing 8.79 MMscfd gas. Well is exhibiting stable flow without any loading issue. Key facts are presented in table 5.1. From table 5.1, it can be seen that well permeability is good. Water production is attributed as condense water. Well completion sketch is provided in figure 5.1. Stimulation frequency on this well is extremely low. VLP is matching with Gray correlation. Well current case is summarized in table 5.2. Later life velocity analysis plot (figure 5.3) at 435 psi shows that well will be stable with no hydraulics issue. Water production at base case abandonment will be 250 bbl./day. Well will exhibit natural abandonment at 440 psi. Condense Water plot shown in figure 5.4 will be same for all wells with slight difference in amount of WGR depending on the respective abandonment reservoir pressures.

Table 5-1: Key Facts (Sawan-1)

Well name	**Sawan-1**
Well Type	Exploratory well
Well Location	North
Depth	3334 mRT PBTD
Inline Production	July, 2003
FEC	February 2010
Permeability (mD)	143
Pressure (psi)	491
Current Gas (MMscfd)	8.79
Current Water (BPD)	351.6
Current WGR (bbl/MMscf)	40
Condense WGR (bbl/MMscf)	40
Well Status	Stable

Table 5-2: Base Case (Sawan-1)

Parameters	Base Case		
	Current	Loading	Abandonment
Reservoir P (psi)	491	N/A	440
Rate (MMscfd)	8.79	N/A	5.7
WHP (psi)	208	N/A	208

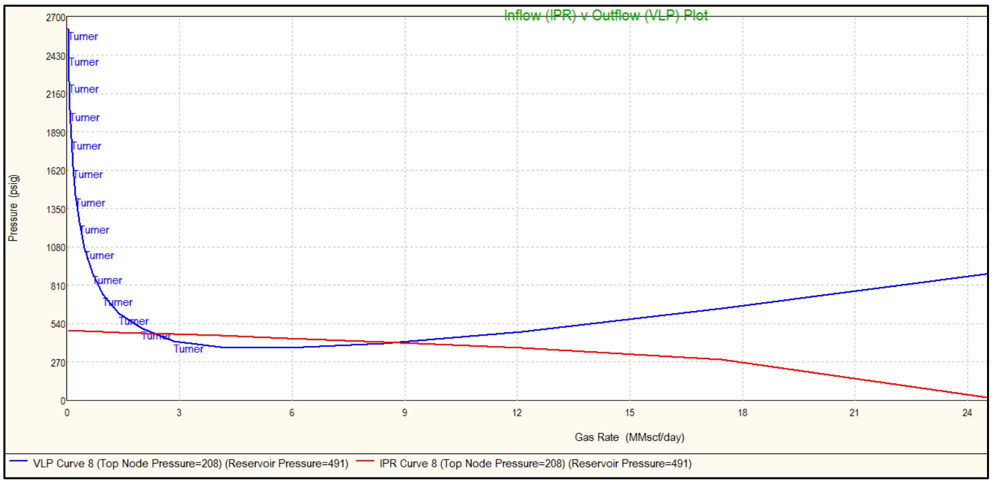

Figure 5-2: Base Model Sawan-1 (Reservoir: 491 psi; WHP: 208 psi)

5.1.2 Compression

Sawan 1 base case analysis suggests well is stable at base abandonment conditions and well life is restricted because of well head pressure (figure 5.6). The only option to increase well life with artificial lift is using compression. Compression is not only extending well life till 215 psi (Life Gain: 230 psi) but also increases production at base abandonment pressure.

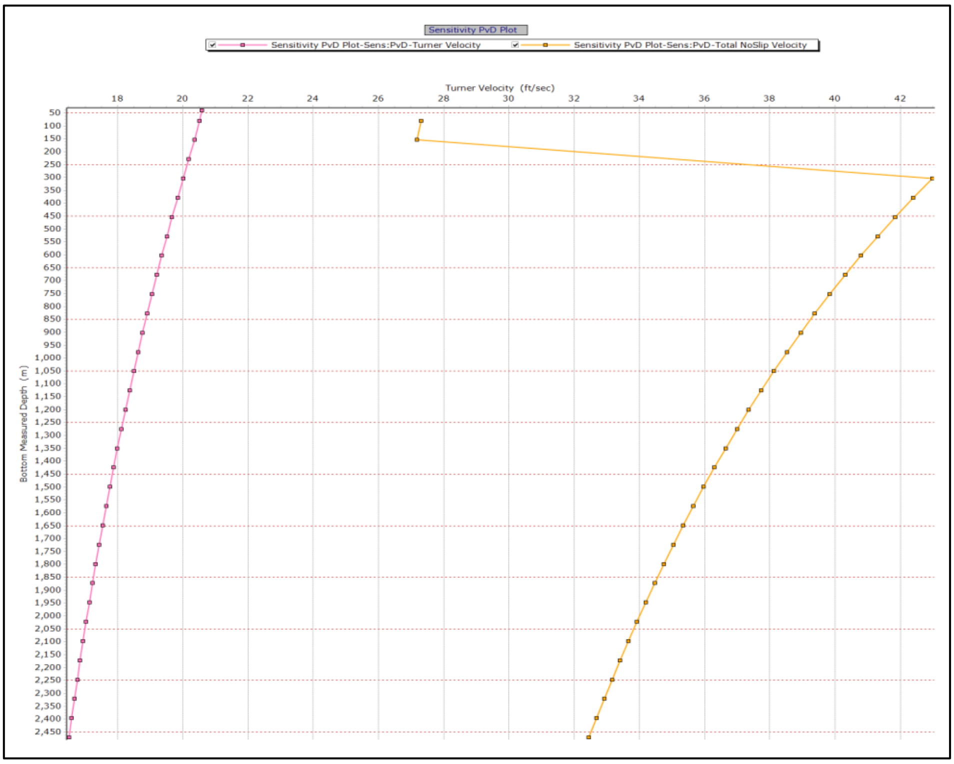

Figure 5-3: Velocity Profile at base abandonment (Res. P: 435 psi; WHP: 185 psi)

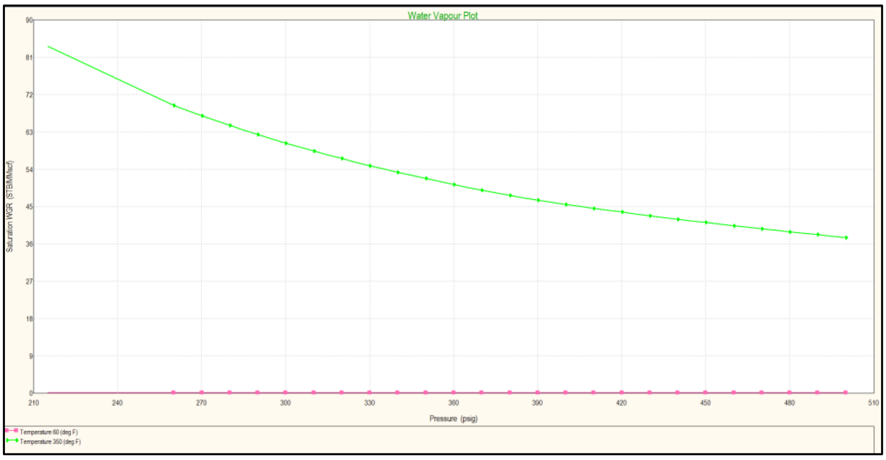

Figure 5-4 : Sawan-1 Condense Water Plot

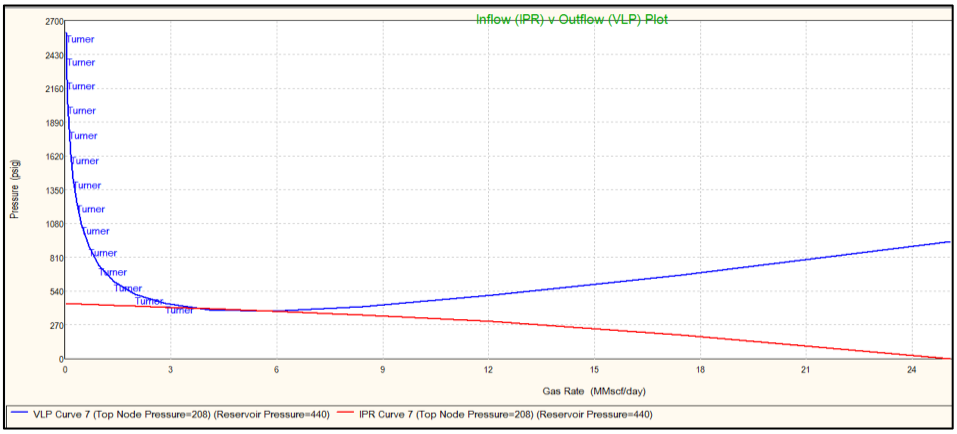

Figure 5-5: Sawan-1 Base abandonment (Res. P: 440 psi)

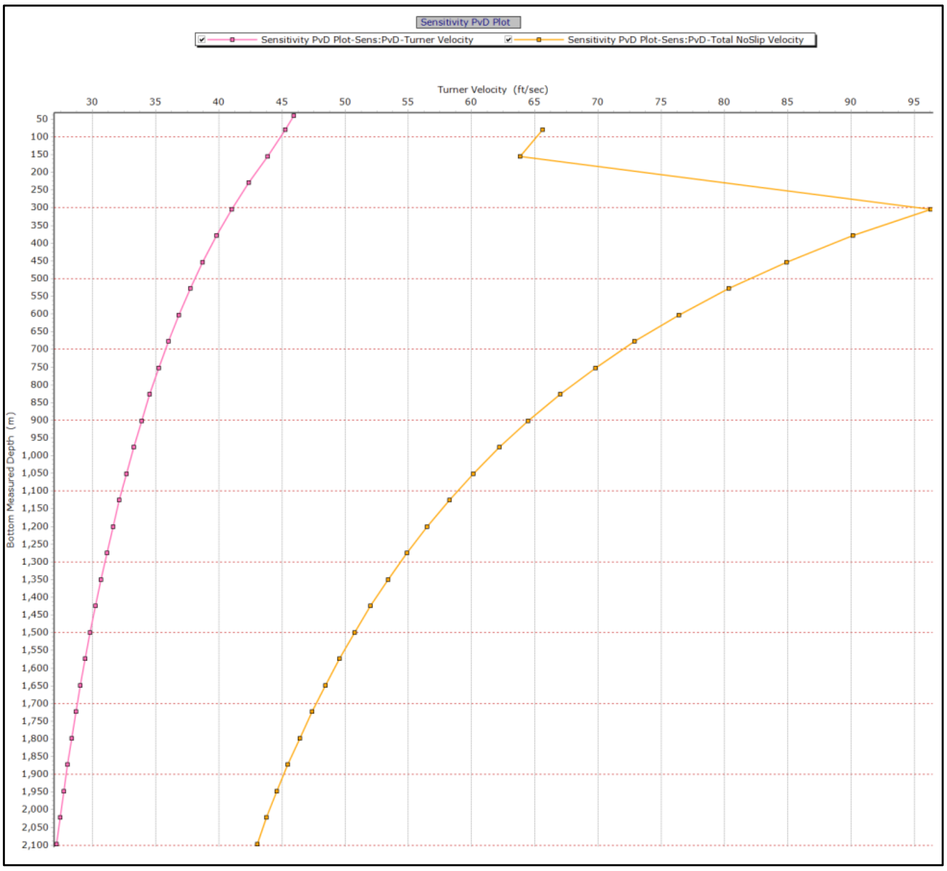

Figure 5-6: Velocity Profile at Compression Abandonment (Res.P: 215 psi; WHP: 30 psi)

Table 5-3: Sawan-1 Compression Case

Parameters	Compression		
	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psig)	440	N/A	215
Rate (MMscfd)	10.54	N/A	3
WHP (psig)	30	N/A	30

5.1.3 Velocity String

The second scenario is based on evaluating option of velocity string. The use of velocity string can't be justified in case of flowing wells without loading because it will add extra friction loss. These friction losses will hinder flow so productivity will be reduced. Higher pressure to overcome friction shall cause low drawdown which in turn will affect the productivity of reservoir. The low productivity causes low rates at surface. Since, this well has no hydraulics issue and is exhibiting natural abandonment because of plant pressure restriction so velocity string has been filtered out for Sawan-1.

5.1.4 Foam lift

Foam lift lower BHFP and causes reservoir to deliver more as well as reduction in density improves hydraulics. Foam lift can't be applied on this well as no hydraulic issues have been observed. This option can't be justified either technically or economically.

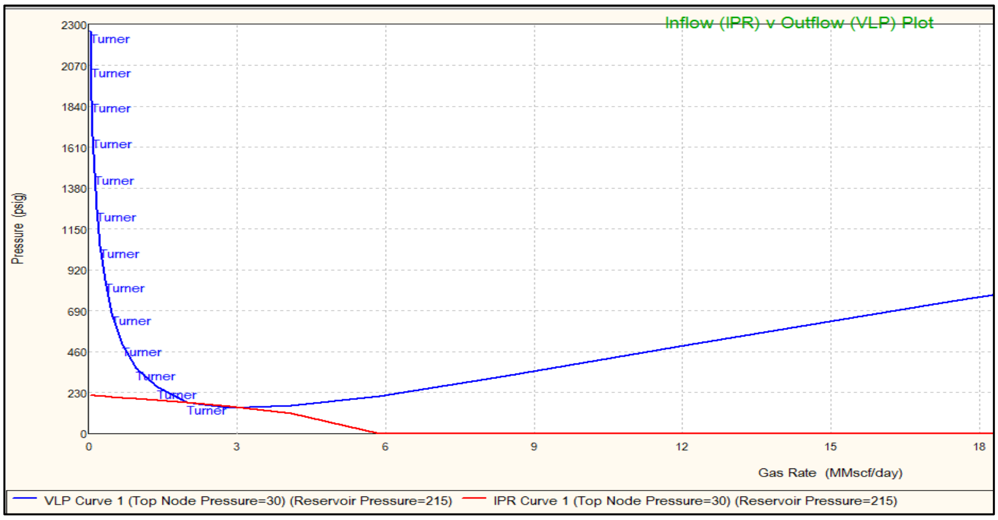

Figure 5-7 Compressor Abandonment Conditions (Res. P: 235 psi; WHP: 30 psi)

5.1.5 Technical Recommendations

Well life extension is possible with compression and it is recommended for this well. No hydraulics issue has been observed. Installing a compressor in this well would be highly commercially attractive. It can be seen from the table 5.3, well rates boosts to 10 MMscfd which is huge gain comparing to base case flow. One biggest advantage of using compression is that later life well intervention is also possible which might be the limiting factor for other scenarios. Economic analysis for this well is provided in chapter 6.

5.2 Sawan 2

Sawan-2 was drilled as an appraisal well in October 1998 to depth of 3489 mRT PBTD with a target formation of Lower Goru Intra C-Sand. Sawan-2 was completed with 7” x 5-1/2” x 7” Cr-22 tapered completion in November 2002. During CIT, Coil tubing fished in well which restricted future well interventions. Well potential during CIT was 74.86 MMscfd at 2741 psi FWHP with 1.6 bbl./MMscf WGR. Sawan-2 was side tracked and recompleted in 2008 with 7” x 5-1/2” x 4-1/2” Cr-22 tapered tubing. Well has cumulative produced 133 Bcf (March 2016). Currently the well is producing 5.8 MMscfd gas. Sawan-2 is exhibiting stable flow without any loading issue. Well key facts are presented in table 5.4. Water production is attributed as condense water.

5.2.1 Technical Recommendations

Sawan 1 and Sawan 2 are quite similar in terms of current reservoir pressure and the base abandonment rate. The difference in rate occurs because of the cleaning job performed in Sawan-2. The completion schematic is same for both wells. The overall analysis behavior turns out to be same for both wells so only the results for Sawan-2 are tabulated. For Sawan-2, water production at base abandonment is estimated to be 160 bbl./day. The only option to increase well life for Sawan-2 is compression. Compression is not only extending well life till 255 psi (Life Gain: 200 psi) but also increases production at base abandonment pressure.

Table 5-4: Key Facts (Sawan-2)

Well name	Sawan-2
Well Type	Appraisal well
Well Location	North
Depth	3458 mRT PBTD
Inline Production	July, 2003
FEC	February 2010
Permeability (mD)	131.5
Pressure (psi)	491
Current Gas (MMscfd)	5.8
Current Water (BPD)	226.2
Current WGR (bbl/MMscf)	39
Condense WGR (bbl/MMscf)	39
Well Status	Stable

Table 5-5: Summarized Results (Sawan-2)

Parameters	Base Case			Compression		
	Current	Loading	Abandonment	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psi)	491	N/A	451	451	N/A	255
Rate (MMscfd)	5.8	N/A	3.82	7.57	N/A	2.1
WHP (psi)	179	N/A	179	30	N/A	30

5.3 Sawan 3

Sawan-3 drilled as development well in Sawan North compartment. During DST, the well was tested at 34 MMscfd gas with FWHP of 1200 psi. The well had severe sand production issue so gravel pack assembly was installed in the well. Sawan-3 was completed in 2002 with 7" x 5-1/2" x 3 ½" Cr-22 gravel pack completion assembly. In 2009, increase in skin and wellbore scaling was observed. The increase in skin suggested plugging of gravel pack so GP was perforated together with scale removal job. To counter scale production, Weatherford "CLEAR WELL"[9] technology was installed to delay the process of scale deposition. The well has cumulative produced 124 Bcf (March 2016). Well completion sketch is provided in figure 5.8.

5.3.1 Base case

Currently well is exhibiting stable flow without any loading issue. Well facts are presented in table 5.6. Water production is attributed as condense water. VLP is matching with Gray

[9] The ClearWELL device is an electronic dipole generator that induces a randomly varying, high frequency electric field throughout the entire piping system. The electric field generated forces homogeneous crystal formation to get in suspension rather than depositing on metal surfaces so that they can b carried away with the gas water mixture.

correlation. Well current case is summarized in table 5.7. Based on the later life velocity analysis plot (figure 5.10) at 480 psi, it seems well will be stable without hydraulics issue.

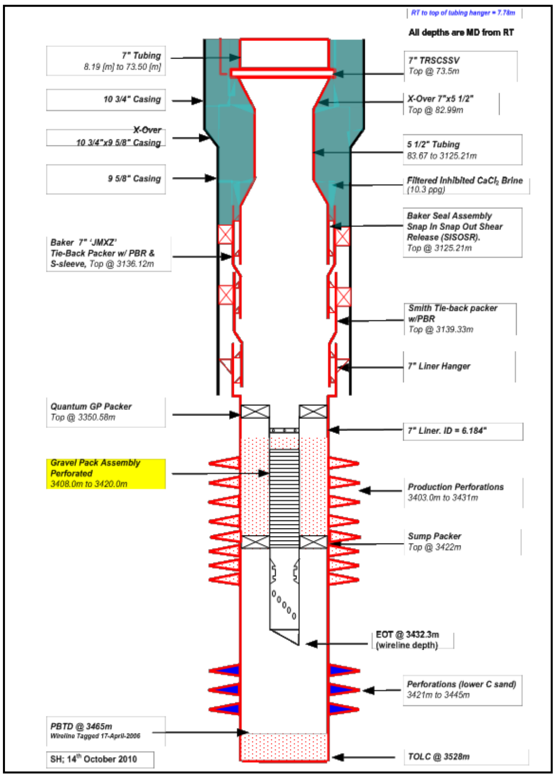

Figure 5-8: Sawan-3 Well completion sketch

Table 5-6: Key Facts (Sawan-3)

Well name	**Sawan-3**
Well Type	Development well
Well Location	North
Depth	3658.3 mMD (3541.5 mTVD)
Inline Production	June 2003
FEC	February 2010
Permeability (mD)	180
Pressure (psi)	561
Current Gas (MMscf)	8.78
Current Water (BPD)	298.52
Current WGR (bbl/MMscf)	34
Condense WGR (bbl/MMscf)	34
Well Status	Stable

Table 5-7: Base Case (Sawan-3)

Parameter	Base Case		
	Current	Loading	Abandonment
Reservoir P (psi)	561	N/A	480
Rate (MMscfd)	8.78	N/A	4.12
WHP (psi)	208	N/A	208

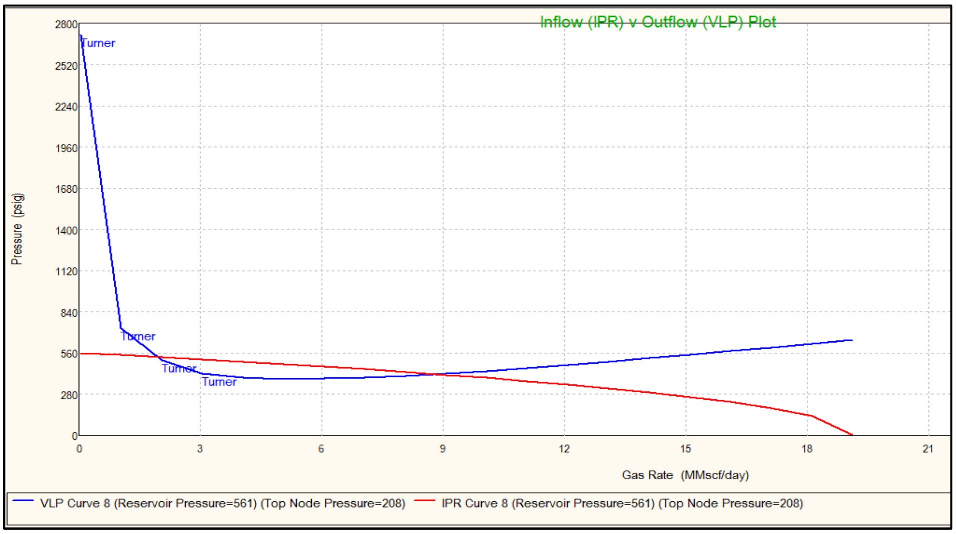

Figure 5-9: Base Model Sawan-3 (Res. P: 561 psi; WHP: 208 psi)

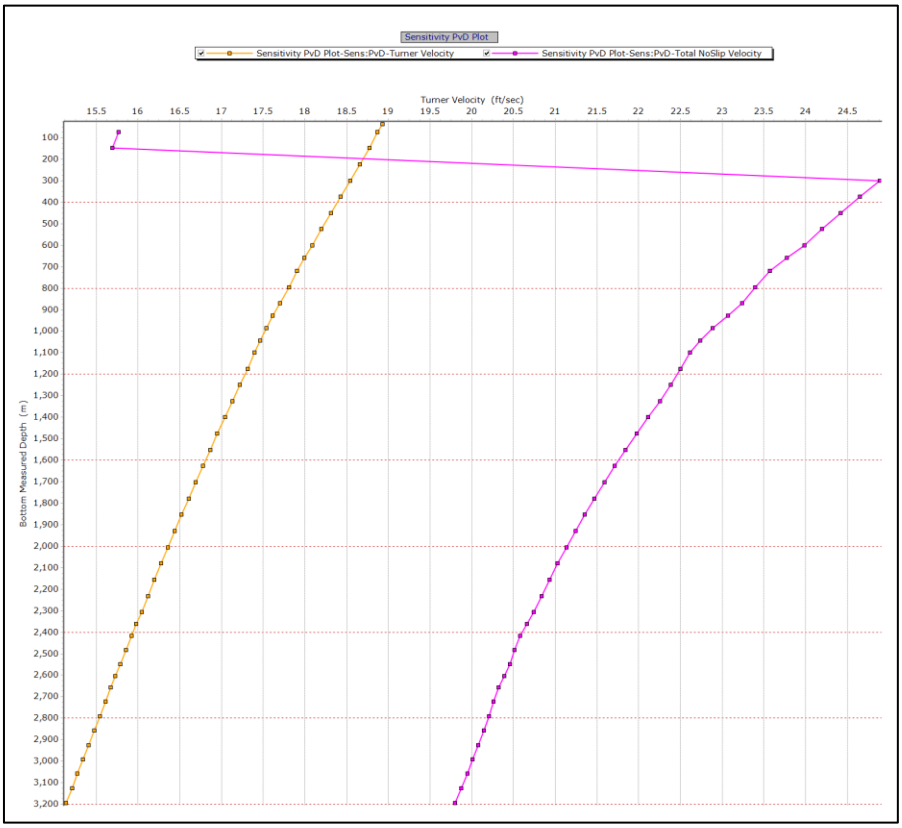

Figure 5-10: Velocity Profile at base abandonment (Res. P: 480 psi; WHP: 208 psi)

5.3.2 Compression

Sawan 3 base case analysis suggests well is stable at base abandonment conditions and well life is restricted because of well head pressure (figure 5.11). The only option to increase well life is using compression. Compression is not only extending well life till 260 psi (Life Gain: 220 psi) but also increases production at base abandonment pressure

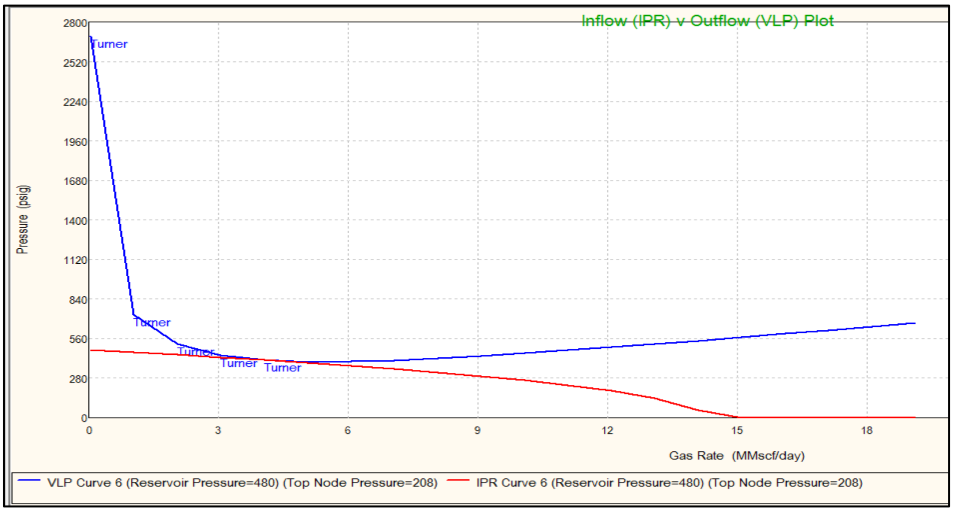

Figure 5-11: Sawan-3 Base case abandonment (Res. P: 480 psi)

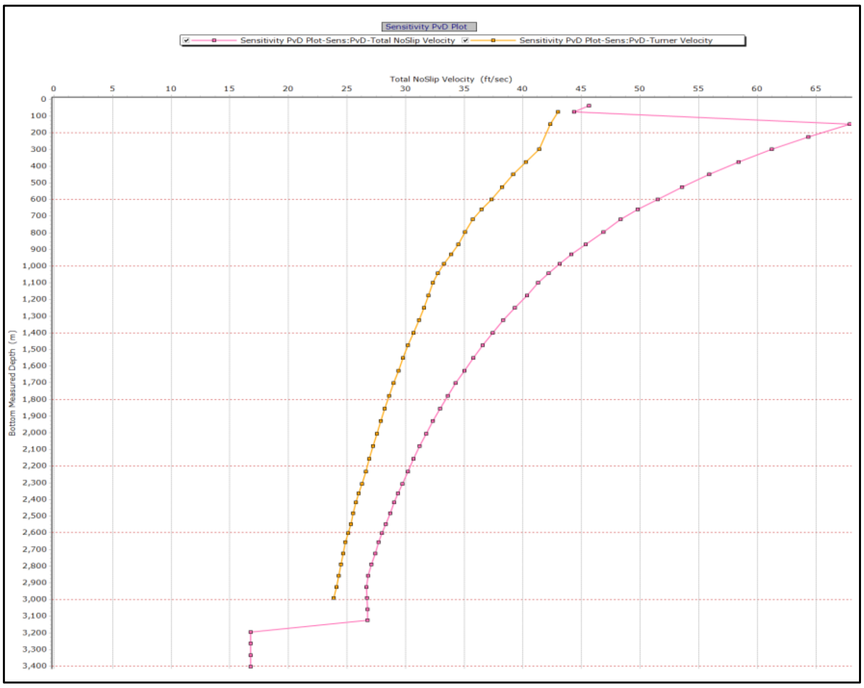

Figure 5-12: Velocity Profile at Compression Abandonment (Res. P: 260 psi; WHP: 30 psi)

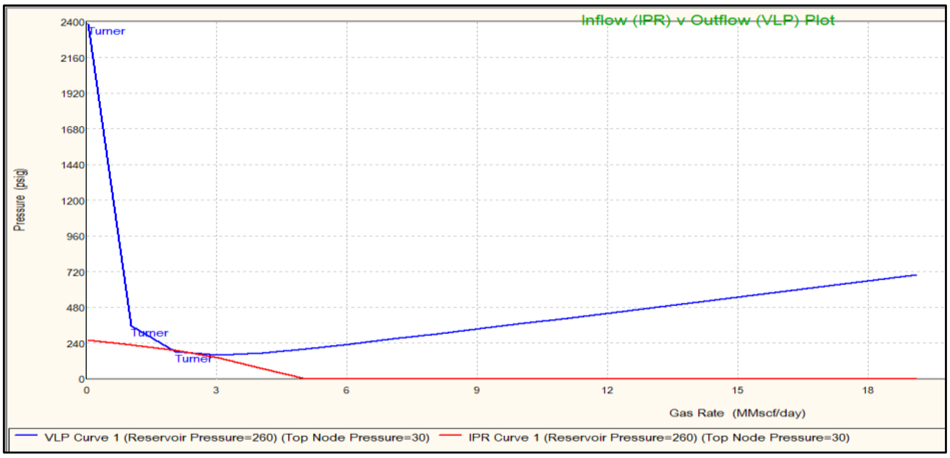

Figure 5-13: Compressor abandonment Conditions (Res. P: 260 psi; WHP: 30 psi)

Table 5-8: Sawan-3 Compression case

Parameter	Compression		
	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psi)	480	N/A	260
Rate (MMscfd)	9.53	N/A	2.39
WHP (psi)	30	N/A	30

5.3.3 Technical Recommendations

Well life extension is possible with compression and it is recommended for this well. No hydraulic issues have been observed. One biggest advantage of using compression is that later life well intervention is possible. Foam Lift and velocity string scenario have been eliminated because well does not exhibit any loading issue on base case as well as compression scenarios.

5.4 Sawan 4

Sawan-4 was drilled as a development well in the Sawan South to target Lower Goru C-Sand in February 2003. The well was completed with 4 ½” Cr-22 tubing. Initial recorded flowing potential of well was 8.34 MMscfd gas flow rate at 1584 psi WHFP with WGR of 6 bbl/MMscf. Initial reservoir pressure was estimated to be 5333.8 psi at datum (3,295mSS). Well was hydraulically fractured to increase production in December 2005. Post fracture recorded parameters were 12.55 MMScfd gas at 1972 WHP and 6 bbl./MMscf WGR. Chloride analysis suggests well produces formation water along with condense water. The well has produced cumulative volume of 21.93 Bcf (March 2016).

5.4.1 Base case

Currently, well is producing 2.21 MMscfd gas and trend is stable. Well key facts are presented in table 5.9. Well completion sketch is provided in figure 5.14. VLP is matching with Petroleum experts 2[10] correlation. Well current case is summarized in table 5.10. Later life velocity analysis plot (figure 5.16 & 5.17) shows that deliquification is necessary. Current water production is 165 bbl./day. Well WGR is expected to vary based on both condense and formation water. Current WGR is taken along with another assumed WGR for future based scenario.

Table 5-9: Key facts (Sawan-4)

Well name	Sawan-4
Well Type	Development well
Well Location	South
Depth	3328 mRT PBTD
Inline Production	November 2003
FEC	February 2010

[10] Petroleum Experts 2 correction is presented in appendix D. This correlation is a combination of various correlations and is a trademark of Petroleum Experts Software Company.

Permeability (mD)	3.95
Pressure (psi)	1397
Current Gas (MMscfd)	2.21
Current Water (BPD)	159.1
Current WGR (bbl/MMscf)	74
Condense WGR (bbl/MMscf)	15
Well Status	Stable

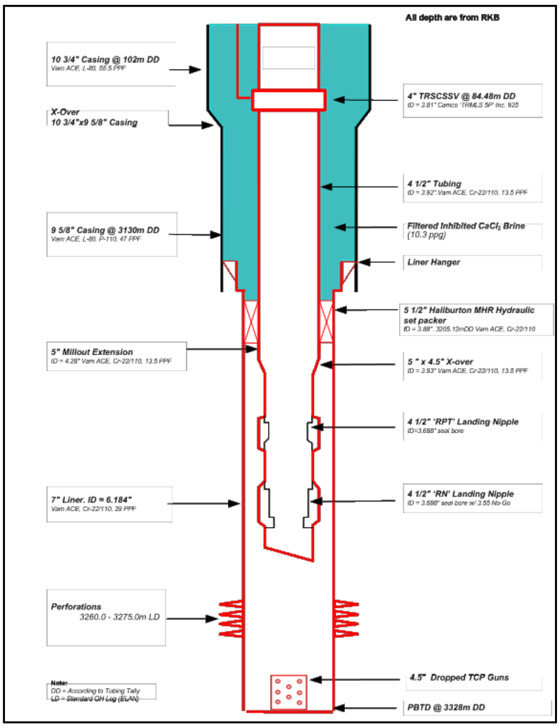

Figure 5-14: Sawan-4 Well Completion Sketch

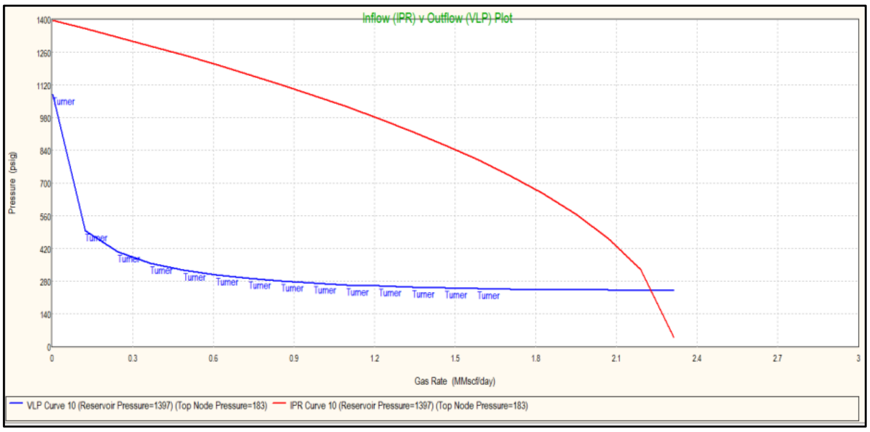

Figure 5-15: Base Model Sawan-4 (Res. P: 1397 psi; WHP: 183; WGR: 74 psi)

Table 5-10: Base case Scenario (Sawan-4)

Parameter	Base Case				
	Current	Loading		Abandonment	
WGR	74	74	100	74	100
Reservoir P (psig)	1397	1235	1255	580	605
Rate (MMSCFD)	2.21	1.76	1.78	0.27	0.28
WHP (psig)	183	183	183	183	183

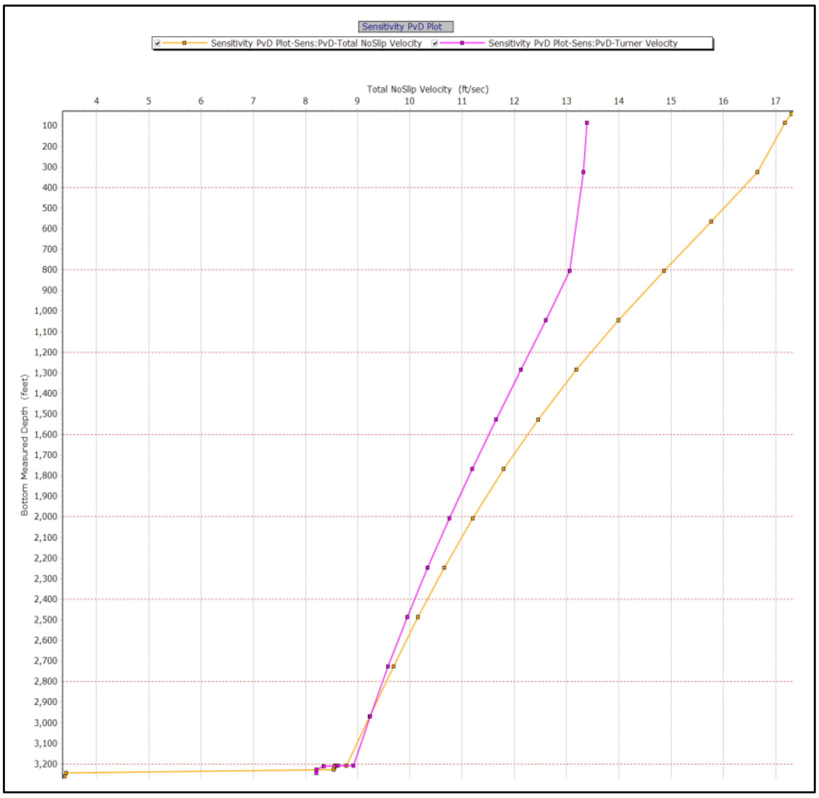

Figure 5-16: Velocity Profile at Base Loading (Res. P: 1255 psi; WHP: 183 psi, WGR: 100)

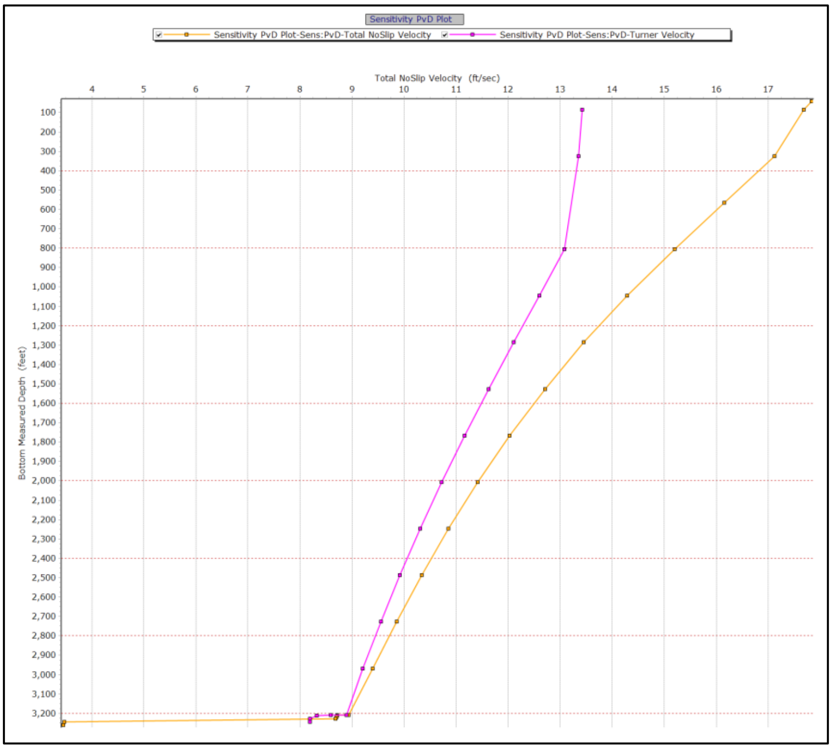

Figure 5-17: Velocity Profile at Base Loading (Res. P: 1235 psi; WHP: 183 psi, WGR: 74)

5.4.2 Compression

Application of compressor on this well (table 5.11) shows a gain of ~355 psi and shifts well to stable flow. Figure 5.18 shows compressor loading conditions for WGR: 74.

Table 5-11: Sawan-4 Compression case

Parameter	Compression					
	Estimated (Base case) Loading		Loading		Abandonment	
WGR	74	100	74	100	74	100
Reservoir P (psi)	1235	1255	880	900	400	430
Rate (MMscfd)	1.87	1.89	0.95	1.09	0.14	0.16
WHP (psi)	30	30	30	30	30	30

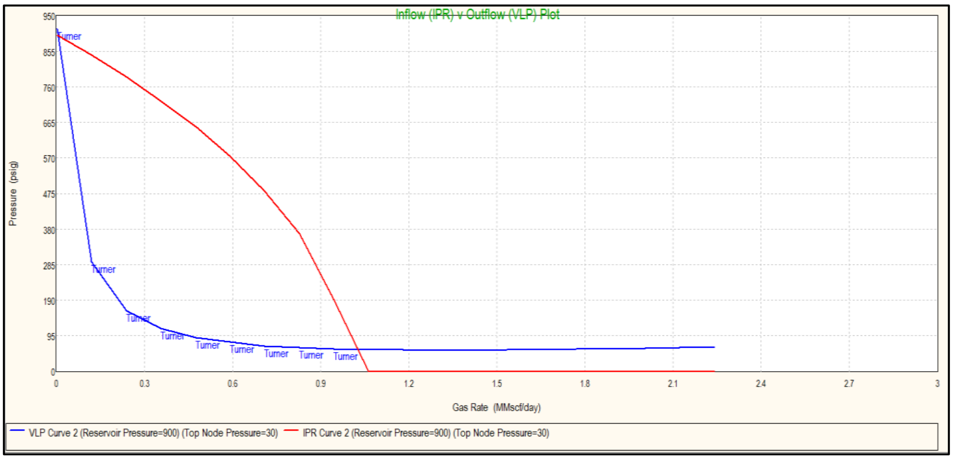

Figure 5-18: Compressor loading (Res. P: 880 psi, WHP: 183, WGR: 74)

5.4.3 Foam Lift

Table 5.12 presents the foam lift feasibility on Sawan-4. It can be seen from predicted results that foam lift is able to lift fluids but in comparison to compression is not technically worthy. It offset loading by ~100 psi and sluggish well trend starts at ~1140 psi. Figure 5.19 present the foam sensitivity. It is visible that foam concentration of 0.4% is optimized for this well. Foam concentration sensitivity like that of figure 5.19 is performed for all foam lift candidate wells.

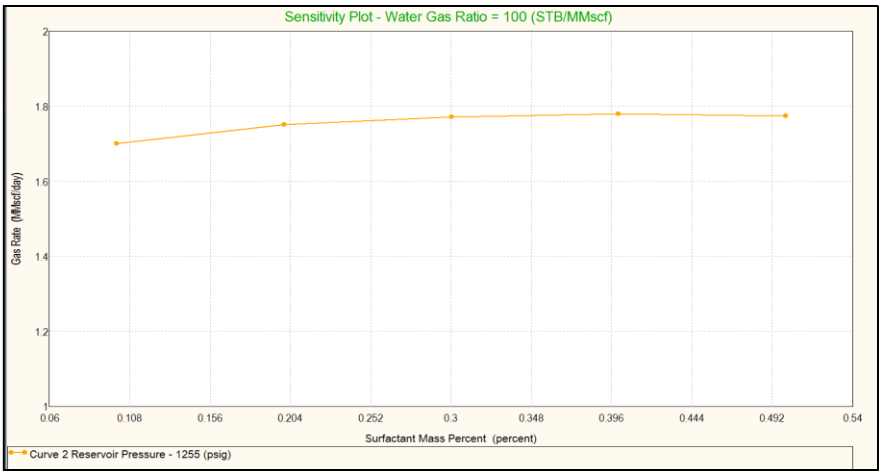

Figure 5-19: Foam concentration sensitivity (Res. P: 1255 psi, WHP: 183- WGR: 100)

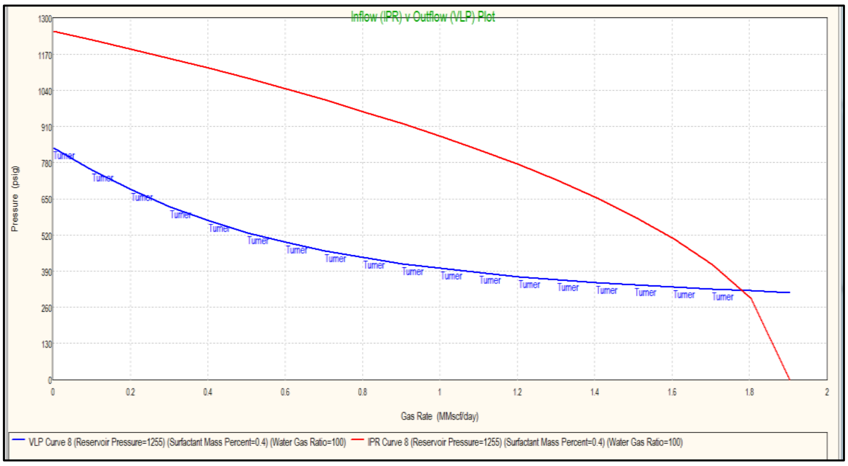

Figure 5-20: Foam lift at base case loading (Res. P: 1255, WHP: 168-WGR: 100)

Table 5-12: Sawan-4 Foam feasibility

Parameter	**Foam Lift**					
	Estimated (Base case) Loading		Loading		Abandonment	
WGR	74	100	74	100	74	100
Reservoir P (psi)	1235	1255	1140	1160	800	835
Rate (MMscfd)	1.77	1.79	1.46	1.47	0.40	0.42
WHP (psi)	183	183	183	183	183	183

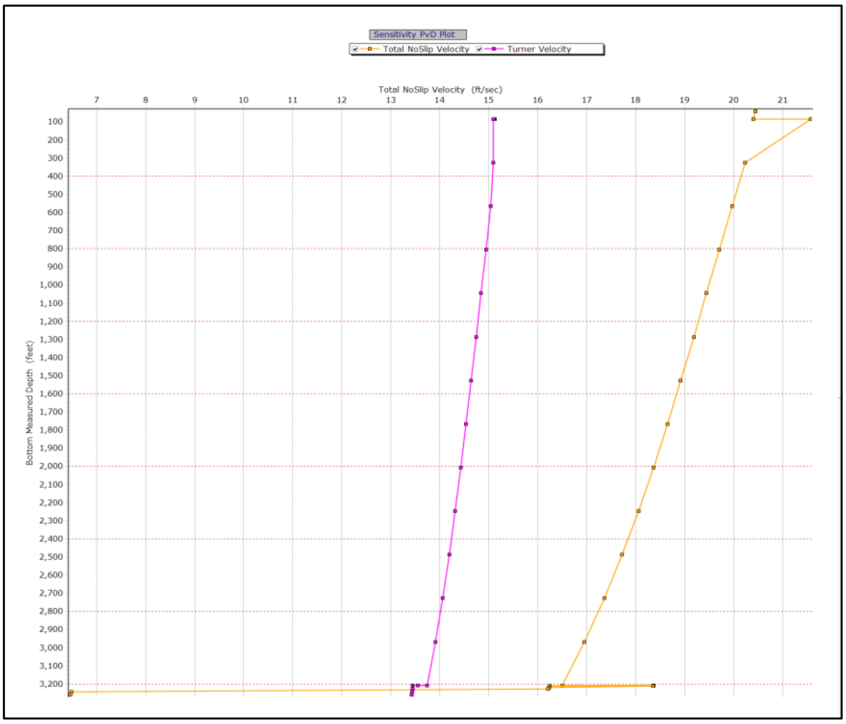

Figure 5-21: Foam Lift velocity Profile at Loading (Res. P: 1235, WHP: 183-WGR: 74)

Figure 5.21 & 5.22 presents foam lift well velocity profile for WGR: 74 bbl./MMscf at base case loading and at foam lift abandonment conditions.

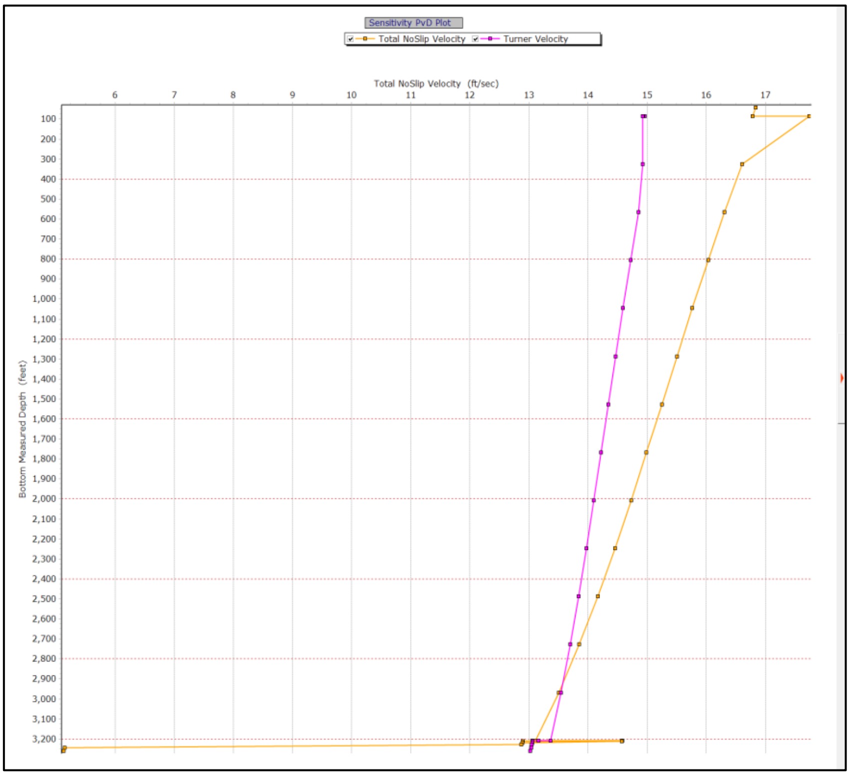

Figure 5-22: Foam Lift velocity Profile at Loading (Res. P: 1140, WHP: 183-WGR: 74)

5.4.4 Velocity String

The third scenario is based on evaluating option of velocity string. Table 5.13 (WGR: 74) and 5.14 (WGR: 100) shows the sensitivity of different tubing string that can be installed in this well considering I.D of well. Both tables are for the case of “annular + tubular” flow scenario succeeded by tubular flow at later stage. The transition from “Annular + tubular flow” to “tubing flow” is considered as soon as loading appears in former case. The case for annular was analyzed but is not presented because after the annular + tubular option, annular option does not provide enough rates to avoid loading. It can be realized that smaller strings are loaded earlier compared to large strings in tubular + annular flow. The reason for this is that well has annular dominant flow in “annular + tubing flow” for small strings which makes loading to appear earlier in small string combination flow. In tubular flow, small string offset liquid loading to much lower reservoir pressures but has disadvantage of low production rates. This needs to be judge with respect to operational expenditure of well to justify installing small or large tubing. Abandonment pressure and rates for strings are not shown as the loading in tubing is quite near to abandonment.

Table 5-13: Sawan-4 Summary of WGR: 74 for different velocity strings

	Status	An. + Tb.		Tubular	
WGR: 74	**Velocity String size (in.)**	**2.875 (2.563)**		**2.875 (2.563)**	
	Condition	**Base**	**Loading**	**Base**	**Loading**
	Reservoir P (psi)	1235	900	900	750
	Rate (MMscfd)	1.737	0.972	0.913	0.67
	WHP (psi)	183	183	183	183

WGR: 74	**Velocity String size (in.)**	**2.375 (2.025)**		**2.375 (2.025)**	
	Condition	**Base**	**Loading**	**Base**	**Loading**
	Reservoir P (psi)	1235	965	965	655
	Rate (MMscfd)	1.749	1.093	1.016	0.52
	WHP (psi)	183	183	183	183
WGR: 74	**Velocity String size (in.)**	**1.75 (1.56)**		**1.75 (1.56)**	
	Condition	**Base**	**Loading**	**Base**	**Loading**
	Reservoir P (psi)	1235	1105	1105	580
	Rate (MMscfd)	1.763	1.224	1.074	0.36
	WHP (psi)	183	183	183	183
WGR: 74	**Velocity String size (in.)**	**1.5 (1.15)**		**1.5 (1.15)**	
	Condition	**Base**	**Loading**	**Base**	**Loading**
	Reservoir P (psi)	1235	1130	1130	535
	Rate (MMscfd)	1.772	1.241	0.753	0.25
	WHP (psi)	183	183	183	183

Table 5-14 Sawan-4 Summary of WGR: 100 for different velocity strings

	Status	An. + Tb.		Tubular	
WGR: 100	**Velocity String size (in.)**	**2.875 (2.563)**		**2.875 (2.563)**	
	Condition	**Base**	**Loading**	**Base**	**Loading**
	Reservoir P (psi)	1255	930	930	820
	Rate (MMscfd)	1.755	0.997	0.950	0.75
	WHP (psi)	183	183	183	183
WGR: 100	**Velocity String size (in.)**	**2.375 (2.025)**		**2.375 (2.025)**	
	Condition	**Base**	**Loading**	**Base**	**Loading**
	Reservoir P (psi)	1255	985	985	700
	Rate (MMscfd)	1.761	1.107	1.01	0.59
	WHP (psi)	183	183	183	183
WGR: 100	**Velocity String size (in.)**	**1.75 (1.56)**		**1.75 (1.56)**	
	Condition	**Base**	**Loading**	**Base**	**Loading**
	Reservoir P (psi)	1255	1120	1120	600
	Rate (MMscfd)	1.782	1.233	1.05	0.37
	WHP (psi)	183	183	183	183
WGR: 100	**Velocity String size (in.)**	**1.5 (1.15)**		**1.5 (1.15)**	
	Condition	**Base**	**Loading**	**Base**	**Loading**
	Reservoir P (psi)	1255	1145	1140	560
	Rate (MMscfd)	1.792	1.251	0.759	0.31
	WHP (psi)	183	183	183	183

5.4.5 Technical Recommendations

The selection case for this scenario is prepared based on loading appearance on well. For this well, the most optimum method turns out to be velocity string. As per the summarized table 5.13 & 5.14 for velocity string, a compromise is made between achievable rates and abandonment pressures. Clearly 1.5" velocity string can offset loading to low pressures but the achievable rate are too low compared to other strings. In combination flow of (An. + Tb.); small string have earlier loading compared to large diameter strings so this factor is taken into account together with the loading rates and pressure in tubular flow case. Table 5.15 presents the selected tubing string. Table 5.16 compares the performance of different methods. Recommendation for this well is velocity string of 2.375" as effective deliquification method. The only limitation is later life intervention on well.

Table 5-15 : Sawan-4 Selected/Optimized velocity String

	Velocity String size (in.)	2.375 (2.025)		2.375 (2.025)			2.375 (2.025)		2.375 (2.025)	
WGR: 74		**An. + Tub.**		**Tub.**		WGR: 100	**An. + Tub.**		**Tub.**	
	Condition	**Base**	**Ldng.**	**Base**	**Ldng.**		**Base**	**Ldng.**	**Base**	**Ldng.**
	Reservoir P (psi)	1235	965	965	655		1255	985	985	700
	Rate (MMscfd)	1.749	1.093	1.016	0.52		1.761	1.107	1.01	0.59
	WHP (psi)	183	183	183	183		183	183	183	183

Table 5-16 : Sawan-4 Comparison of various Scenarios

Parameter	Scenario													
	Base Case		Comp.		Foam Lift		Velocity String				Velocity String			
	Base Loading		Loading		Loading		**Base**	**Ldng.**	**Base**	**Ldng.**	**Base**	**Ldng.**	**Base**	**Ldn g**
							An. + Tbg.		Tbng.		An. + Tbg.		Tubing	
WGR	74	100	74	100	74	100	WGR:74				WGR:100			
Reservoir P (psi)	1235	1255	880	900	1140	1160	1235	965	965	655	1255	985	985	700
Rate (MMscfd)	1.76	1.78	0.95	1.09	1.46	1.47	1.749	1.093	1.016	0.52	1.761	1.107	1.01	0.59
WHP (psi)	183	183	30	30	183	183	183	183	183	183	183	183	183	183

5.5 Sawan 5

Sawan-5 was drilled as a development well in the Sawan South to target Lower Goru C-Sand in September 2004. Well completed with single 4 ½" Cr-25 tubing. Initial recorded flowing potential of well was 31.9 MMscfd gas flow rate at 1249 FWHP with 1.73 bbl./MMscf WGR. Due to relative high declining trend, fracturing was performed in June 2006. Fracturing increased gas rate from 15.6 to 23.3 MMscfd with gain in FWHP from 1970 psi to 3036 psi with 6.0 WGR (bbls/MMscf). Estimated fracture height was 46 feet with 49 feet fracture half-length. The well has cumulative produced 41.3 Bcf (March 2016). Currently well is exhibiting stable flow without any loading issue. Well completion sketch is provided in figure 5.23. Well is producing both condense and formation water. VLP is matching with Petroleum Experts 2 correlation. Well current case is summarized in table 5.18. Later life velocity analysis plot (figure 5.25) shows that deliquification is necessary. Current water production is 145 bbl./day. Well WGR is expected to vary based on both condense and formation water. Current WGR is taken along with another assumed WGR for future based scenario.

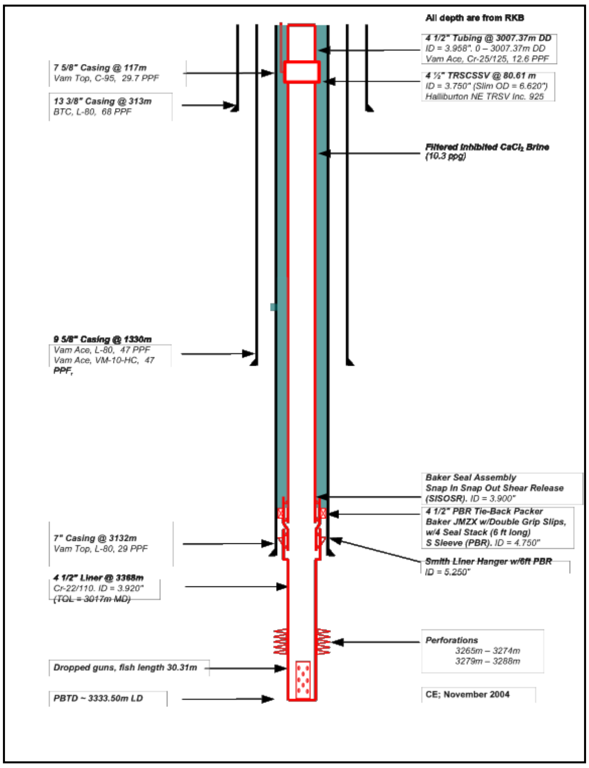

Figure 5-23: Sawan-5 Well Completion Sketch

Table 5-17: Key facts (Sawan-5)

Well name	Sawan-5
Well Type	Development well
Well Location	South
Depth	3333.50 mRT PBTD
Inline Production	Dec-05
FEC	February 2010
Permeability (mD)	8.5
Pressure (psi)	941
Current Gas (MMscfd)	3.3
Current Water (BPD)	145.8
Current WGR (bbl/MMscf)	45
Condense WGR (bbl/MMscf)	19
Well Status	Stable

Table 5-18: Base case Scenario (Sawan-5)

Parameter	Base Case				
	Current	Loading		Abandonment	
WGR	45	45	70	45	70
Reservoir P (psi)	941	735	755	670	670
Rate (MMscfd)	3.3	1.98	2	1.46	1.36
WHP (psi)	168	168	168	168	168

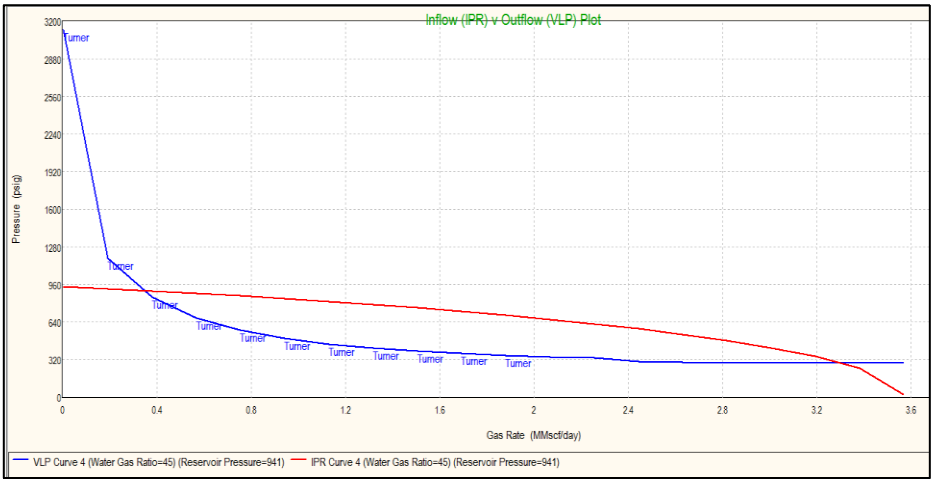

Figure 5-24: Base Model Sawan-5 (Res. P: 941 psi; WHP: 168; WGR: 45 psi)

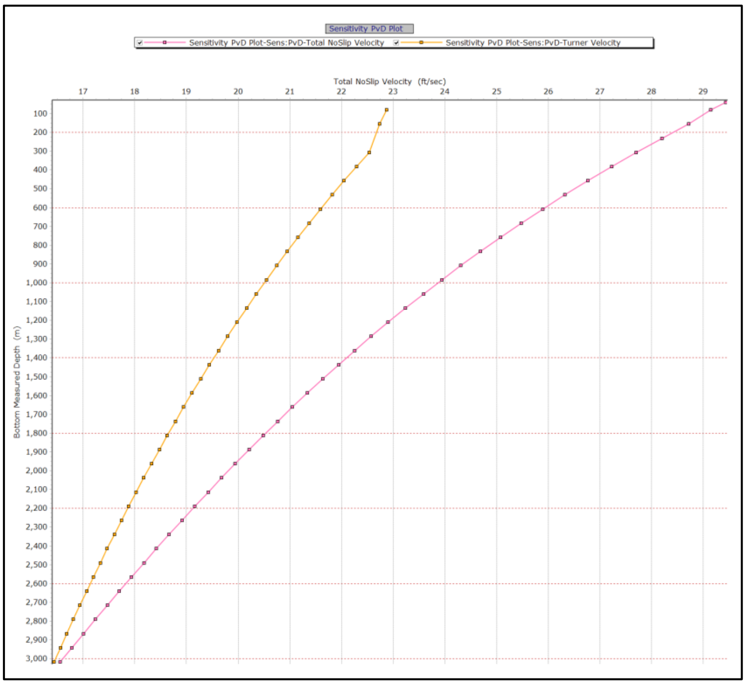

Figure 5-25: Velocity Profile at Base Loading (Res. P: 755 psi; WHP: 168 psi; WGR: 70)

5.5.1 Compression

Sawan 5 base case analysis suggests well is stable till 755 psi (WGR: 70) and 735 (WGR: 45). Application of compressor on this well (table 5.19) shows a gain of ~245 psi and shift well to stable condition till 490 psi (WGR: 45) and 510 (WGR: 70) respectively. Although rate increment is not that noticeable as of north compartment wells but life extension is more obvious than conventional reservoirs.

5.5.2 Foam Lift

Foam lift can be applied as alternative option to compressor or velocity string. Table 5.20 presents the foam lift feasibility on Sawan-5. The loading has been offset with foam lift but achievable pressures don't have much difference with base case. Foam concentration of

0.4% is optimum for this well. Figure 5.27 shows the velocity profile at the abandonment of foam lift injection

Table 5-19: Compression case

Parameter	Compression					
	Estimated (Base case) Loading		Loading		Abandonment	
WGR	45	70	45	70	45	70
Reservoir P (psi)	735	755	490	510	465	490
Rate (MMscfd)	2.37	2.42	1.21	1.25	1.09	1.17
WHP (psi)	30	30	30	30	30	30

Table 5-20: Foam feasibility

Parameter	Foam Lift					
	Base Loading		Foam Loading		Abandonment	
WGR	45	70	45	70	45	70
Reservoir P (psi)	735	755	-	-	675	675
Rate (MMSCFD)	1.98	2.08	-	-	1.40	1.38
WHP (psi)	168	168	168	168	168	168

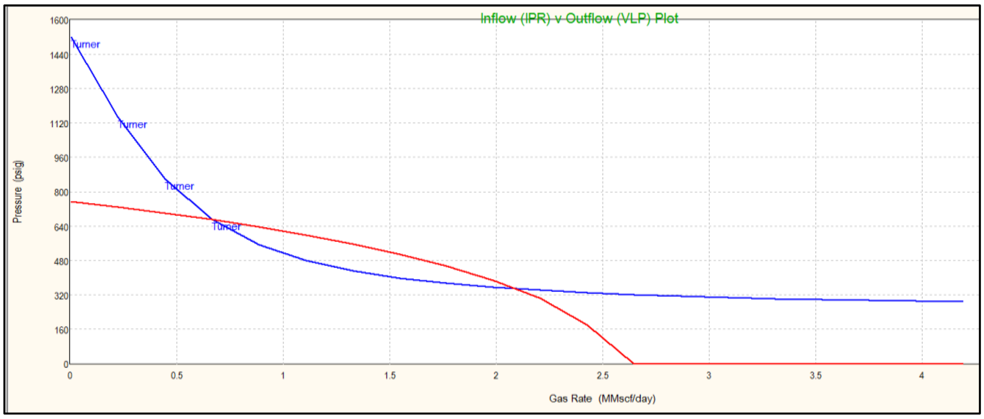

Figure 5-26: Sawan-5 Foam lift at base case loading (Res. P: 755, WHP: 168-WGR: 70)

5.5.3 Velocity String

Table 5.21 to 5.23 shows the sensitivity of different tubing string that can be installed in this well considering well I.D. The tables are prepared with reference to base case loading point. This well is not suitable for flow via “tubing + annular” and “annular” configuration. It is quite evident from table that string of 2.375” (I.D: 2.025) is suitable for this well in case of velocity string “tubing flow” scenario. Well is able to deliver stable rates up to 595 psi (WGR: 70) and 530 psi (WGR: 45).

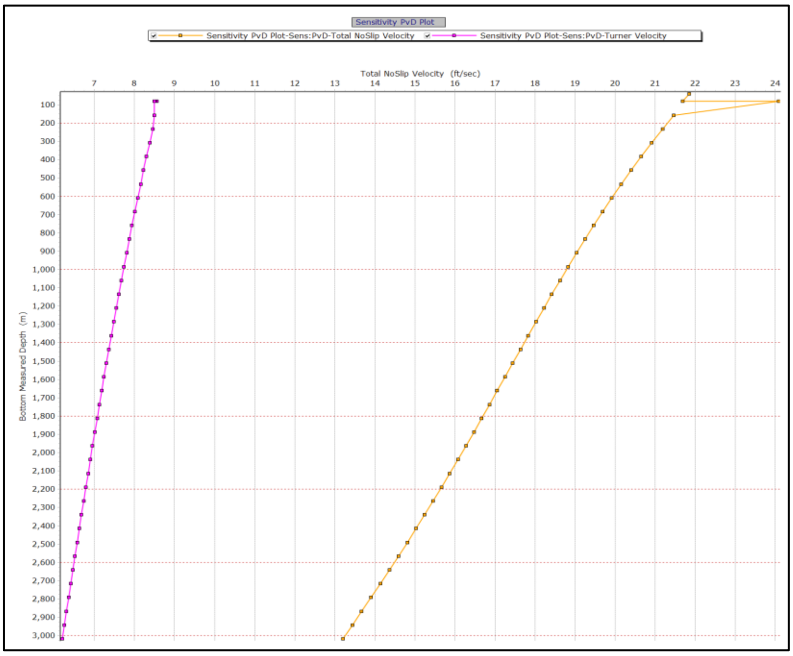

Figure 5-27: Foam Lift velocity Profile at foam abandonment (Res. P: 675, WHP: 168-WGR: 45)

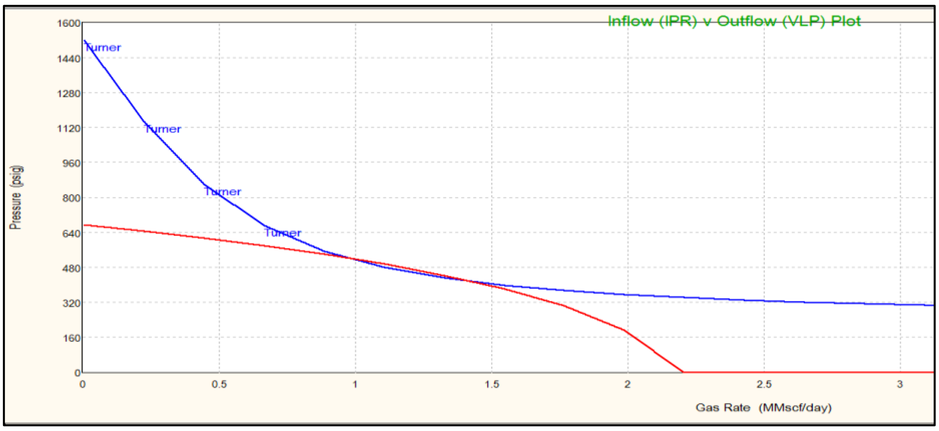

Figure 5-28: Foam injection at foam lift abandonment (Res. P: 675, WHP: 168-WGR: 70)

Table 5-21: Annular + Tubular scenario WGR: 45

Parameters	Velocity String Comparison (A+T) WGR 45							
Velocity String size (in.)	2.875 (2.563)		2.375 (2.025)		1.75 (1.56)		1.5 (1.15)	
Status	Base	Ldng.	Base	Ldng.	Base	Ldng.	Base	Ldng.
Reservoir P (psi)	735	735	735	735	735	735	735	735
Rate (MMscfd)	1.53	1.53	1.61	1.61	1.71	1.71	1.77	1.77
WHP (psi)	168	168	168	168	168	168	168	168

Table 5-22: Tubular Flow scenario WGR: 70

Parameters	Velocity String Comparison Tubing Analysis (WGR: 45)							
Velocity String size (in.)	2.875 (2.563)		2.375 (2.025)		1.75 (1.56)		1.5 (1.15)	
Status	**Base**	**Ldng.**	**Base**	**Abdn.**	**Base**	**Abdn.**	**Base**	**Ldng.**
Reservoir P (psi)	735	585	735	525	735	560	735	-
Rate (MMscfd)	1.36	0.97	1.07	0.49	0.59	0.20	0.24	-
WHP (psi)	168	168	168	168	168	168	168	168

Table 5-23: Tubular Flow scenario WGR: 70

Parameters	Velocity String Comparison Tubing Analysis (WGR:70)							
Velocity String (in.)	2.875 (2.563)		2.375 (2.025)		1.75 (1.56)		1.5 (1.15)	
Status	**Base**	**Ldng.**	**Base**	**Abdn.**	**Base**	**Abdn.**	**Base**	**Ldng.**
Reservoir P (psi)	755	615	755	580	755	630	755	-
Rate (MMscfd)	1.49	0.99	1.09	0.58	0.61	0.31	-	-
WHP (psi)	168	168	168	168	168	168	168	168

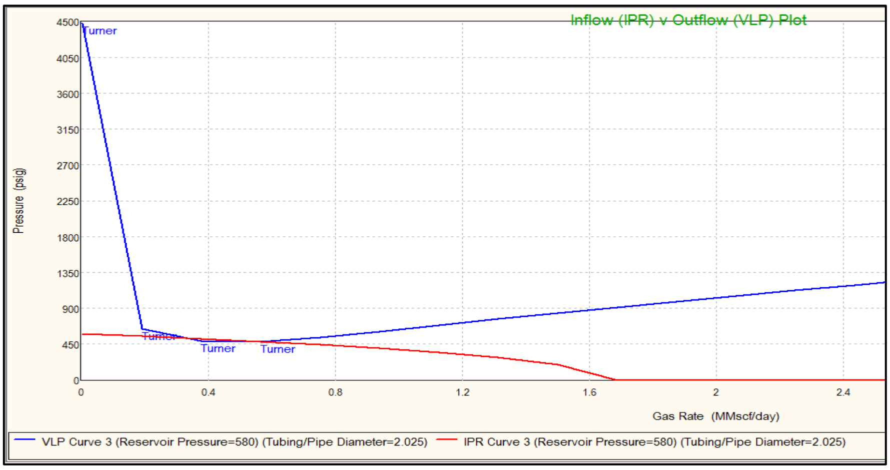

Figure 5-29: Velocity String Abandonment (Res. P: 580 psi, WGR: 70; Velocity String: 2.375")

5.5.4 Technical Recommendations

Table 5-24: Sawan-5 Comparison of various Scenarios

Parameter	Scenario									
	Base Case Loading		**Compression Loading**		**Foam Lift-Abandonment (No loading)**		**Velocity String-2.375"**			
							Base	**Abdn.**	**Base**	**Abdn.**
WGR	45	70	45	70	45	70	45		70	
Reservoir P (psi)	735	755	490	510	675	675	735	525	755	580
Rate (MMscfd)	1.98	2	1.21	1.25	1.4	1.38	1.07	0.49	1.09	0.58
WHP (psi)	168	168	30	30	168	168	168	168	168	168

The selection case for this well is prepared based on loading appearance rate and pressure Foam lift is eliminated as the abandonment pressure is relatively higher than other methods. Comparing to compression and velocity string, compression turns out better based on fact of allowable large I.D intervention jobs. The rates by compression at loading are still higher than other methods. For this well, preferred method is compression and second is velocity string.

5.6 Sawan 6

Sawan-6 was drilled and completed as a development well in Sawan South compartment 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). 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 behavior of reservoir. Well exhibits varying WGR of 60 – 700 bbls/MMscf (extreme sluggish flow). Well has cumulative produced 0.12 Bcf (March 2016).

5.6.1 Base case

The current status of well is intermittent production. From well key facts (table 5.25), it can be seen that permeability is extremely low. The intermittent flow average is 0.28 MMscfd. A rough model is prepared based on average rates of well in one month. Average WGR 350 (bbl/MMscf) is assumed for analysis. "Petroleum Experts 2"[11] VLP correlation has been applied on this well. Well current case is summarized in table 5.26. Figure 5.30 represents base case model.

Table 5-25: Key Facts (Sawan-6)

Well name	Sawan-6
Well Type	Development well
Well Location	South
Depth	3340 mRT PBTD
Inline Production	Oct-07
FEC	February 2010
Permeability (mD)	0.068
Pressure (psi)	3500
Current Gas (MMscfd)	0.28
Current Water (BPD)	105
Current WGR (bbl/MMscf)	350
Condense WGR (bbl/MMscf)	12
Well Status	Unstable

[11] For extreme sluggish behavior, it is recommended by software manufacturer to use Petroleum Experts 2 correlation.

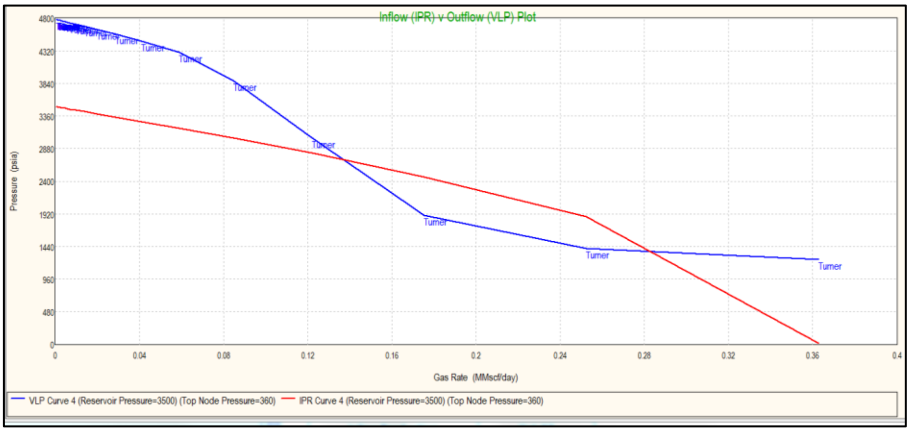

Figure 5-30: Base Model Sawan-6 (Res. P: 3500 psi; WHP: 360)

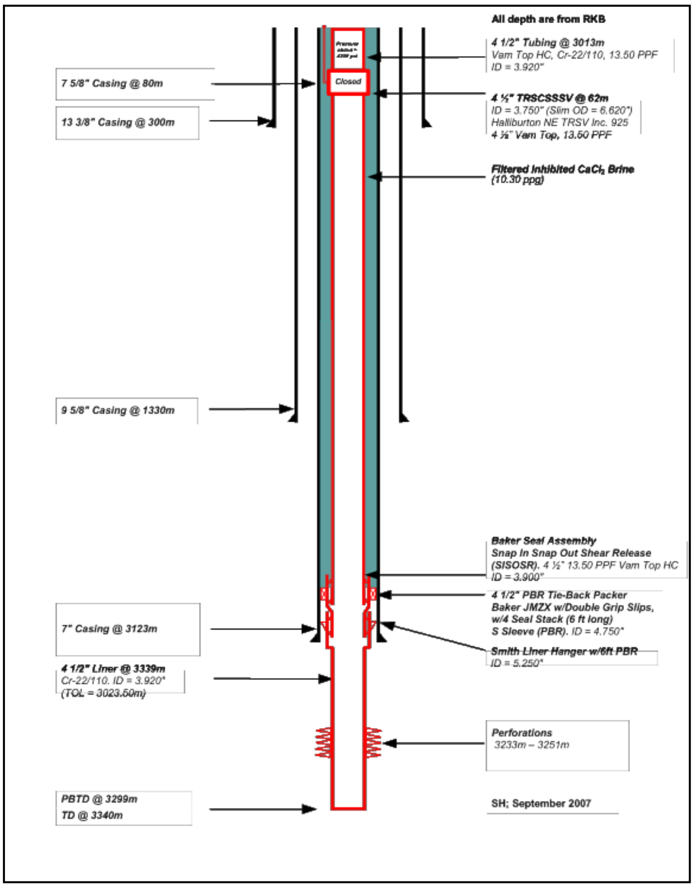

Figure 5-31: Sawan-6 Well Completion Sketch

Table 5-26: Base case Scenario (Sawan-6)

Parameter	Base Case		
	Current	Loading	Abandonment
WGR	350	350	350
Reservoir P (psi)	3500	3500	3150
Rate (MMscfd)	0.28	0.28	0.18
WHP (psi)	360	360	360

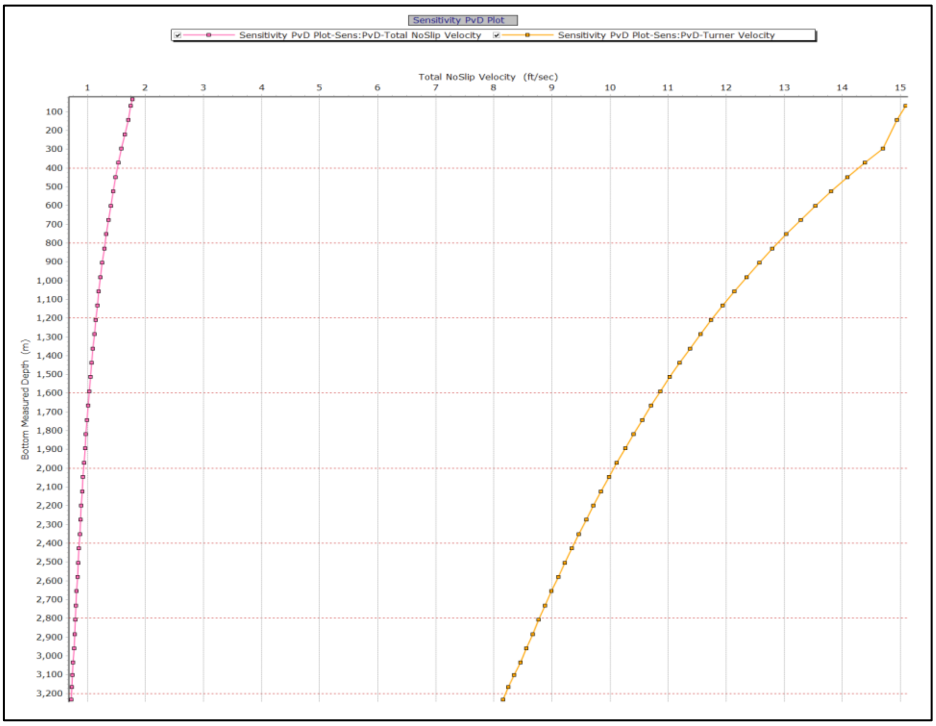

Figure 5-32: Velocity Profile at Base Loading (Res. P: 500 psi; WHP: 360)

5.6.2 Compression

Sawan 6 is being produced intermittently. Application of compressor on this well (table 5.27) shows a gain to 0.33 MMScfd (Increment: 0.05 MMscfd) but this gain is still under critical flow. Velocity plot (Figure 5.32 vs. 5.33) shows improved hydraulics but this hasn't offset loading.

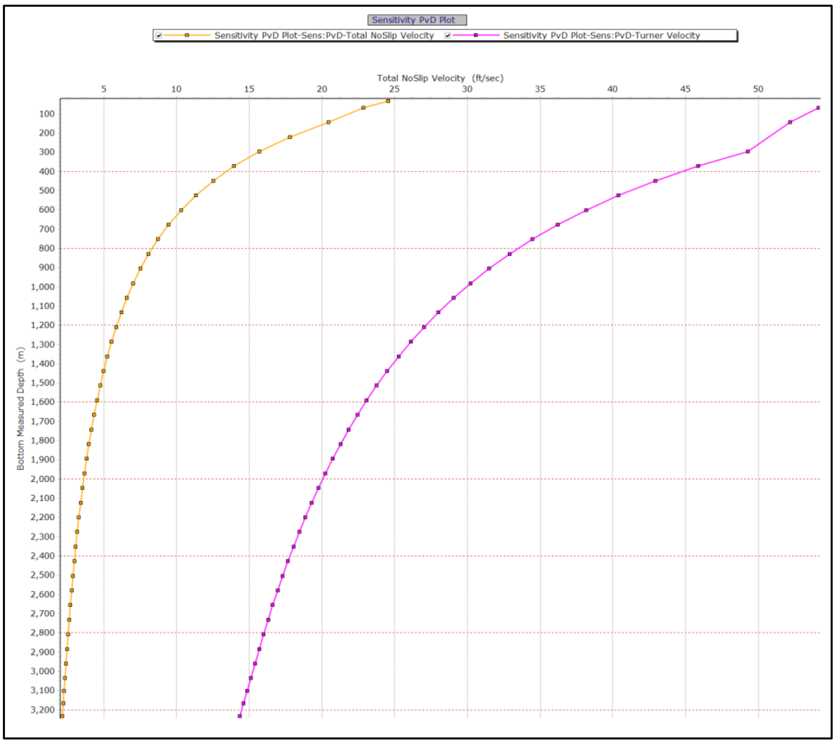

Figure 5-33: Velocity Profile for Compression-Loaded well (Res. P: 3500 psi; WHP: 30)

Table 5-27: Sawan-6 Compression case

Parameter	Compression		
	Estimated (Base case) Loading	Loading	Abandonment
WGR	350	350	350
Reservoir P (psi)	3500	3500	2250
Rate (MMscfd)	0.33	0.33	0.13
WHP (psi)	30	30	30

5.6.3 Foam Lift

Foam lift lowers the turner's critical velocity criteria as it can be seen from velocity plot of base case (figure 5.32) where at wellhead velocity was ~15 ft./sec and foam has reduced it to 5.4 ft./sec (figure 5.34). Loading can't be offset on this well with foam lift as gas velocities are too low to properly even agitate the foam so combination case is required for this well. Sensitivity analysis of foam suggests 0.4% as the optimum foam concentration. Table 5.28 presents the foam lift feasibility on Sawan-06. Well is restricted because of the wellhead pressure.

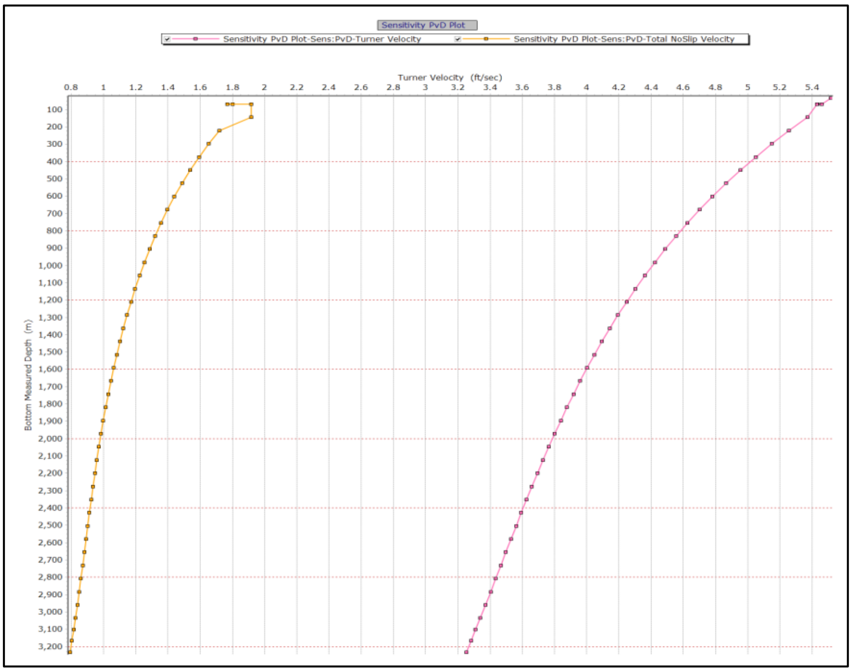

Figure 5-34: Foam Lift velocity Profile- Well Loaded (Res. P: 3500 psi, WHP: 360)

Table 5-28: Sawan-6 Foam feasibility

Parameter	Foam Lift		
	Estimated (Base case) Loading	Loading	Abandonment
WGR	350	350	350
Reservoir P (psi)	3500	3500	2600
Rate (MMscfd)	0.30	0.30	0.021
WHP (psi)	360	360	360

5.6.4 Velocity String

The third scenario is based on evaluating option of velocity string. Table 5.29 shows the comparison of velocity string for current well. String size of 1.5" is recommended for this well in combination with other methods. Table 5.30 present 1.5" string base and abandonment rates in intermittent flowing condition.

Table 5-29: Sawan-6 Velocity String Comparison

Status	Velocity String Comparison			
Velocity String size (in.)	2.875 (2.563)	2.375 (2.025)	1.75 (1.56)	1.5 (1.15)
Reservoir P (psi)	3500	3500	3500	3500
Rate (MMSCFD)	0.29	0.3	0.29	0.27
WHP (psi)	360	360	360	360
Status	Loaded	Loaded	Loaded	Slightly Loaded

Table 5-30: Optimum velocity string

Parameters	1.5" string	simulation
Reservoir P (psi)	3500	1700
Rate (MMscfd)	0.27	0.04
WHP (psi)	360	360

5.6.5 Combination Scenario

Combination cases are special cases that consists of two or more artificial lift system working in parallel. Combination depends on the well type. Analysis of combined three methods (velocity string, compressor and foam lift) can work out in offsetting loading for this well. The simulation results are shown in table 5.31. Well is able to produce stable flow with combination case. Figures 5.35 present loading of combination scenario

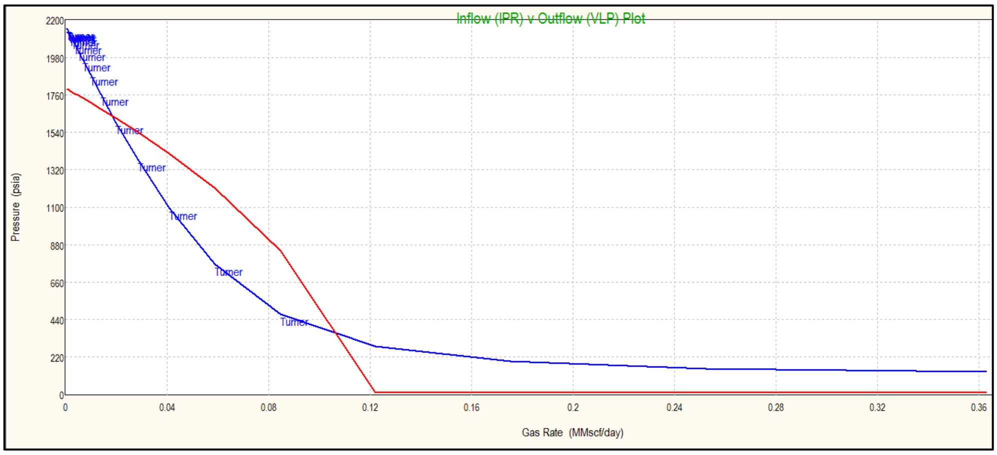

Figure 5-35: Combination Loading: (Res. P: 1800, WHP: 30, Foam Conc. 0.4%, V. S: 1.5")

Table 5-31: Sawan-6 Combination Scenario

Parameter	Combination Scenario		
	Base Loading	Loading	Abandonment
WGR	350	350	350
Reservoir P (psi)	3500	1800	1600
Rate (MMscfd)	0.35	0.10	0.03
WHP (psi)	30	30	30

5.6.6 Technical Recommendations

Combination of three cases has been applied as an experimental study but will not be recommended due to higher costs and low production comparing to OPEX. Velocity string is relative better option than other two cases. This well can't be regarded as candidate for deliquification. Comparison of results is shown in table 5.32.

Table 5-32: Sawan-6 Comparison of Scenarios

Parameter	Base Loading	Compression Loading	Foam Lift	Velocity String	Combination case	
Status	Loaded	Loaded	Loaded	Loaded	Stable	Loading
Reservoir P (psi)	3500	3500	3500	3500	3500	1800
Rate (MMscfd)	0.28	0.33	0.3	0.27	0.35	0.1
WHP (psi)	360	30	360	360	30	30

5.7 Sawan 7

Sawan-7 was drilled in North compartment to depth of 3407.5 m PBTD with a target formation of Lower Goru C-Sand in December, 2002. Sawan-7 was completed with 7" Cr-22 monobore completion. During CIT, well tested at 101.06 MMscfd & 4273 psi FWHP with 2.0 bbl./MMscf WGR. The average reservoir pressure at datum (3295 mSS) was estimated to be 5385 psi. A record production of 140.38 MMscfd was observed in December 2005. The well was put on front end compression in February 2010. Last stimulation job was performed in January 2016. Till March 2016, well has produced a cumulative of 348.1 Bcf.

5.7.1 Base case

Currently flow from well is stable. Well permeability is excellent. Well completion sketch is provided in figure 5.36. Water production from Sawan-7 is attributed as condense water based on chloride analysis of produced water. VLP is matching with Gray correlation. Current case is summarized in table 5.34. Later life velocity analysis plot (figure 5.38) at 390 psi shows no hydraulics issue. Water production at abandonment rate will be 480 bbl./day.

Table 5-33: Key Facts (Sawan-7)

Well name	Sawan-7
Well Type	Development well
Well Location	North
Depth	3407.5 mRT
Inline Production	Jul-03
FEC	February 2010
Permeability (mD)	450
Pressure (psi)	475
Current Gas (MMscfd)	17.7
Current Water (BPD)	699.15
Current WGR (bbl./MMSCF)	39.5
Condense WGR (bbl./MMSCF)	39.5
Well Status	Stable

Table 5-34 : Base Case (Sawan-7)

Parameters	Base Case Summary		
	Current	Loading	Abandonment
Reservoir P (psi)	475	N/A	390
Rate (MMscfd)	17.7	N/A	9.2
WHP (psi)	184	N/A	184

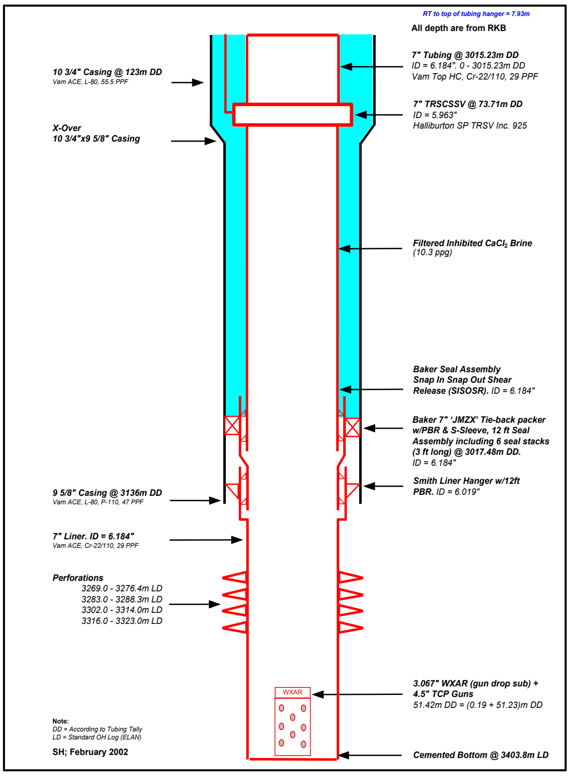

Figure 5-36: Sawan-7 Well completion sketch

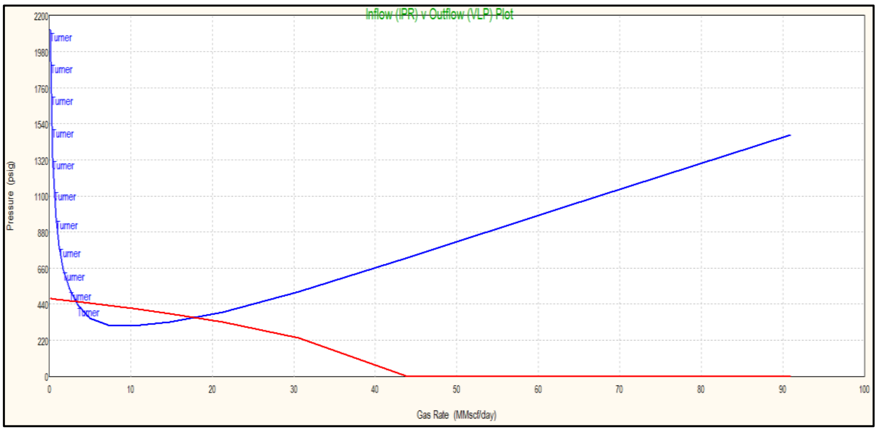

Figure 5-37: Base Model Sawan-7 (Res. P: 475 psi; WHP: 184 psi)

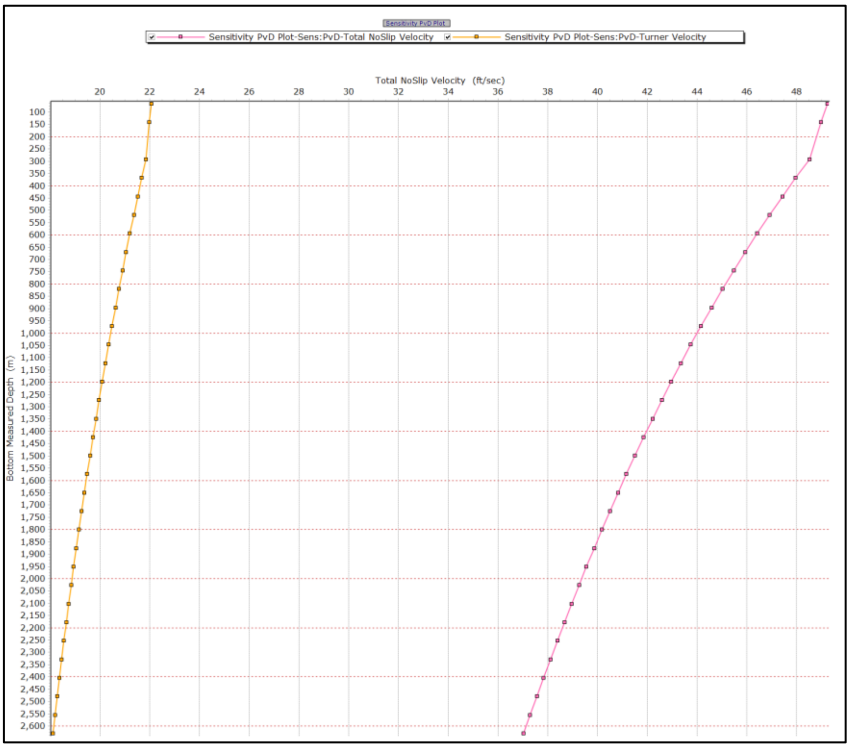

Figure 5-38: Sawan-7 Velocity Profile at base abandonment (Res. P: 390 psi; WHP: 184 psi)

5.7.2 Compression

Sawan 7 base case analysis suggests well is stable at base abandonment conditions and well life is restricted because of well head pressure (figure 5.39). The only option to increase well life is compression. Compression is not only extending well life till 200 psi (Life Gain: 190 psi) but also increases production at base abandonment pressure.

Table 5-35 Sawan-7 Compression Case

Parameters	Compression		
	Base Case Abandonment	Loading	Abandonment
Reservoir P (psig)	390	N/A	200
Rate (MMSCFD)	16.56	N/A	4.73
WHP (psig)	30	N/A	30

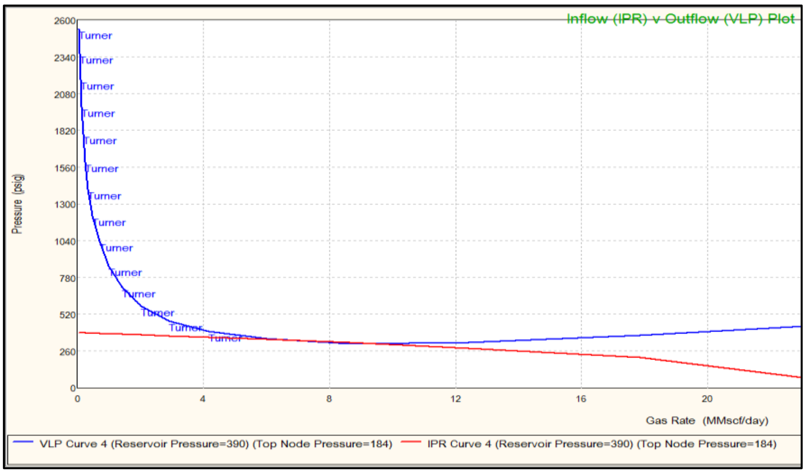

Figure 5-39: Sawan-7 Base case abandonment (Res. P: 390 psi, WHP: 184 psi)

5.7.3 Technical Recommendations

Well life extension is possible with compression and it is recommended for this well. It can be seen from the analysis results (Table 5.35), well rates boosts to 16.56 MMscfd which is huge gain comparing to base case flow. Foam Lift and velocity string scenario have been eliminated because well does not exhibit any loading issue on base case and compression scenarios.

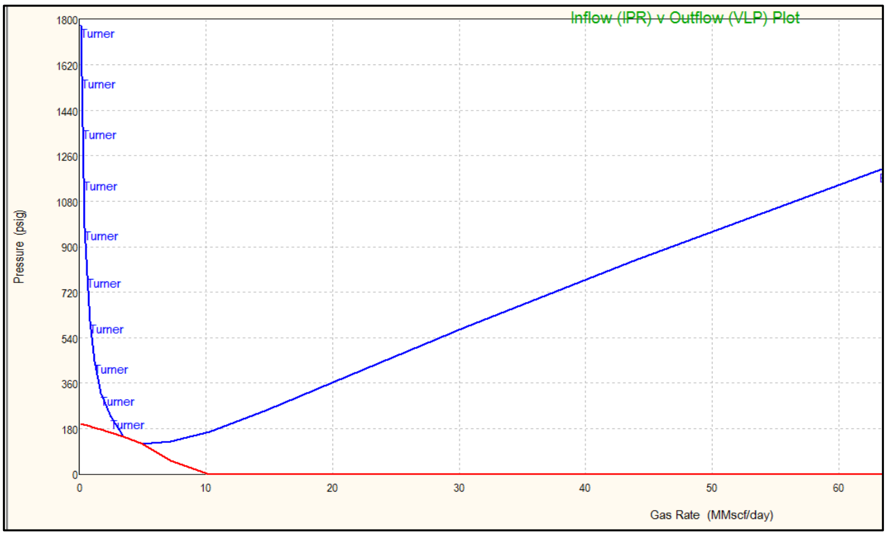

Figure 5-40: Sawan-7 Compressor abandonment (Res. P: 200 psi; WHP: 30 psi)

5.8 Sawan 8

Sawan-8 was drilled as a development well in February 2002 to depth of 3437.5 m PBTD with a primary target of lower Goru C-Sand. The well was completed with 7” x 5-1/2” x 7” Cr-22 tapered tubing. CIT conducted in June 2003 tested well at 103 MMscfd with WGR 2.8 bbls/MMscf at 3988 psi FWHP. The reservoir pressure at datum was estimated to be 5312 psi. The well was tie-in with Sawan Plant on September 15, 2003. In July 2015, additional perforation job was carried out to increase production. Well has cumulative produced a gas volume of 215.8 Bcf.

Well current production is stable. Water production is attributed as condense water. Well completion sketch is provided in figure 5.41. "CLEAR WELL" technology has been applied on this well to reduce scaling effects. Wellbore cleanout jobs have been performed numerous times on this well. Well current and optimized case is summarized in table 5.37.

5.8.1 Technical Recommendations

Sawan 7 and Sawan 8 are quite similar in terms of reservoir pressure and base abandonment parameters. The difference occurs due to permeability. Both wells depict high formation capacity. The overall analysis behavior turns out to be same for both wells so only the results for Sawan-8 are tabulated. The only option to increase well life for Sawan-8 is compression. Compression is not only extending well life till 235 psi (Life Gain: 190 psi) but also increases production at base abandonment pressure.

Table 5-36: Key Facts (Sawan-8)

Well name	Sawan-8
Well Type	Development well
Well Location	North
Depth	3437.5
Inline Production	Sep-03
FEC	February 2010
Permeability (mD)	330
Pressure (psi)	491
Current Gas (MMscfd)	8.91
Current Water (BPD)	338.58
Current WGR (bbl/MMSCF)	38
Condense WGR (bbl/MMSCF)	38
Well Status	Stable

Table 5-37: Summarized Results (Sawan-8)

Parameters	Base Case			Compression		
	Current	Loading	Abandonment	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psi)	491	N/A	425	425	N/A	235
Rate (MMscfd)	8.91	N/A	4.69	9.39	N/A	2.97
WHP (psi)	180	N/A	180	30	N/A	30

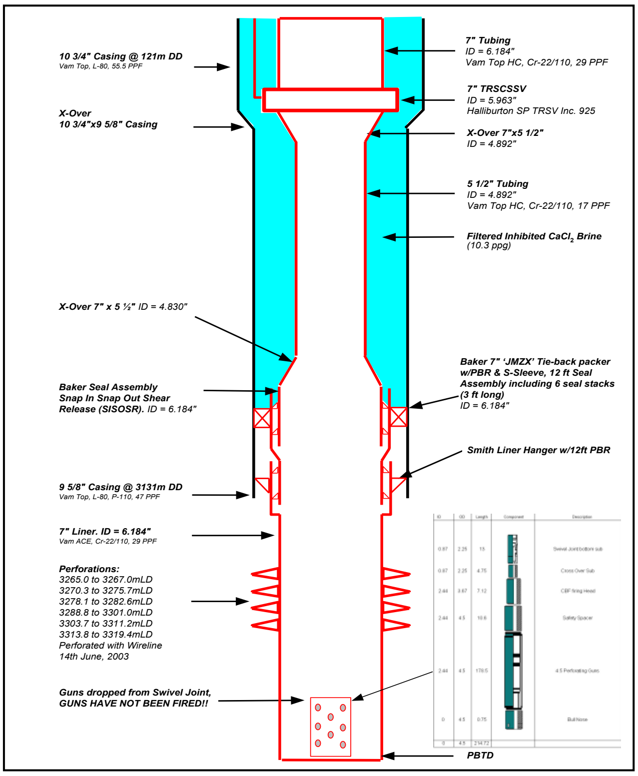

Figure 5-41: Sawan-8 Well completion sketch

5.9 Sawan 9

Sawan-9 was drilled as a development well in Sawan North compartment in April, 2003 to a PBTD of 3450 m with a primary target of Lower Goru C-Sand. Sawan 9 was completed with same completion jewelry as Sawan-8. Initial recorded flowing potential of well was 63.2 MMscfd gas at 4118 psi WHFP with ~2 bbl/MMscf WGR. Well has produced a cumulative of 199.67 Bcf (March 2016). Currently well production is stable. Well key facts are presented in table 5.38. Sawan-9 water production is attributed as condense water.

Table 5-38: Key Facts (Sawan-9)

Well name	Sawan-9
Well Type	Development well
Well Location	North
Depth	3450 mRT PBTD
Inline Production	September, 2003
FEC	February 2010
Permeability (mD)	62
Pressure (psi)	481
Current Gas (MMscfd)	7.36
Current Water (BPD)	279.68
Current WGR (bbl/MMSCF)	38
Condense WGR (bbl/MMSCF)	38
Well Status	Stable

Table 5-39: Summarized Results (Sawan-9)

Parameter	Base Case			Compression		
	Current	Loading	Abandonment	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psi)	481	N/A	435	435	N/A	240
Rate (MMscfd)	7.36	N/A	4.7	9.04	N/A	2.29
WHP (psi)	185	N/A	185	30	N/A	30

5.9.1 Technical Recommendations

Sawan 9 is quite similar in terms of current reservoir pressure and the base abandonment rate to Sawan 7 & 8. The difference in rate occurs because of reservoir permeability. The overall analysis trend turns out to be same for Sawan 7-9, so only the results for Sawan-9 are tabulated. For Sawan-9, water production at base abandonment will be ~200 bbl./day. The only option to increase well life for Sawan-9 is compression.

5.10 Sawan 10

Sawan-10 was drilled as a development well in Sawan South to target Lower Goru C-Sand in 2006. The well was completed with a tapered string format consisting of 7” x 5-1/2” x 7” Cr-22 tubing. Initial recorded flowing potential of well was 32.9 MMscfd gas at 3168 psi WHFP with ~4 bbl/MMscf WGR. Estimated reservoir pressure at datum (3295 mSS) was 4588 psi. Due to high production decline, hydraulic fracturing was performed in February, 2009. Post fracture production resulted in 10.89 MMscfd gas with 47 bbl./MMscf WGR at 1594 psi WHFP. Estimated propped fracture half-length was 40 m with 43 m fracture height. Due to high pressure losses in surface pipeline network, well was put under well head compression in July 2009. Well has produced a cumulative production of 33.455 Bcf (March 2016).

5.10.1 Base case

Sawan-10 is currently producing 1.49 MMscfd gas. Well flow is sluggish. As per figure 5.43 and 5.44, well is liquid loaded and requires immediate attention. Current water chlorides are 15000 ppm which shows production of formation water. Well completion sketch is provided in figure 5.42. Petroleum Experts 2 correlation has been used on this well. Well current case is summarized in table 5.41. Current water production is 225 bbl./day.

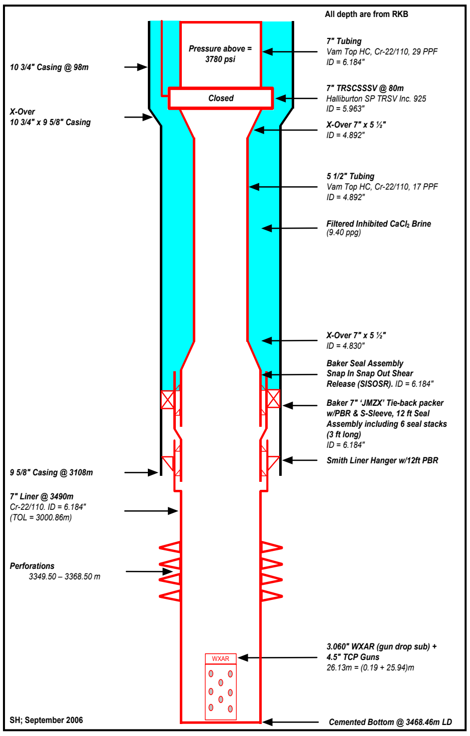

Figure 5-42: Sawan-10 Well completion sketch

Table 5-40: Key Facts (Sawan-10)

Well name	Sawan-10
Well Type	Development well
Well Location	North
Depth	3460 mRT PBTD
Inline Production	Jul-07
FEC	February 2010
Permeability (mD)	35
Pressure (psi)	1000
Current Gas (MMscfd)	1.49
Current Water (BPD)	224.99
Current WGR (bbl/MMscf)	151
Condense WGR (bbl./MMscf)	22
Well Status	Sluggish

Table 5-41: Base Case (Sawan-10)

Parameter	Base Case		
	Current	Loading	Abandonment
WGR	151	151	151
Reservoir P (psi)	1000	1000	985
Rate (MMscfd)	1.49	1.49	1.2
WHP (psi)	134	134	134

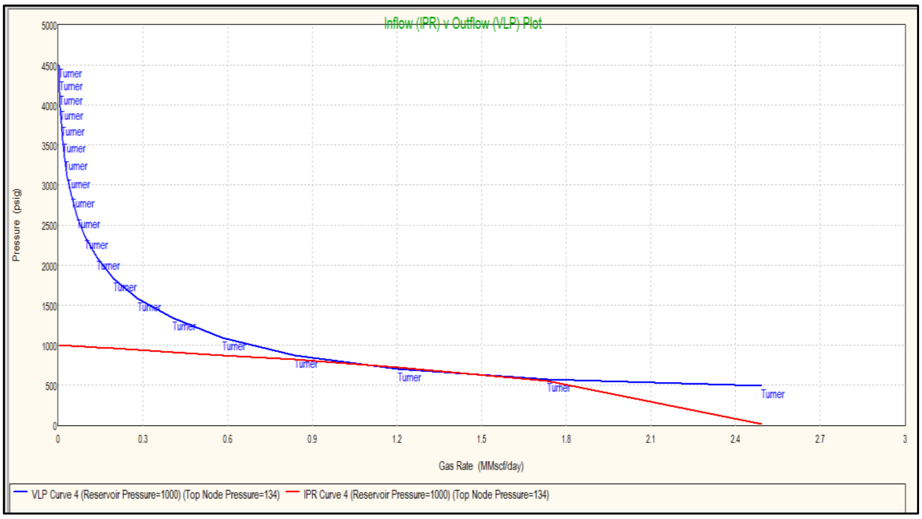

Figure 5-43: Base Model Sawan-10 (Res. P: 1000 psi; WHP: 134)

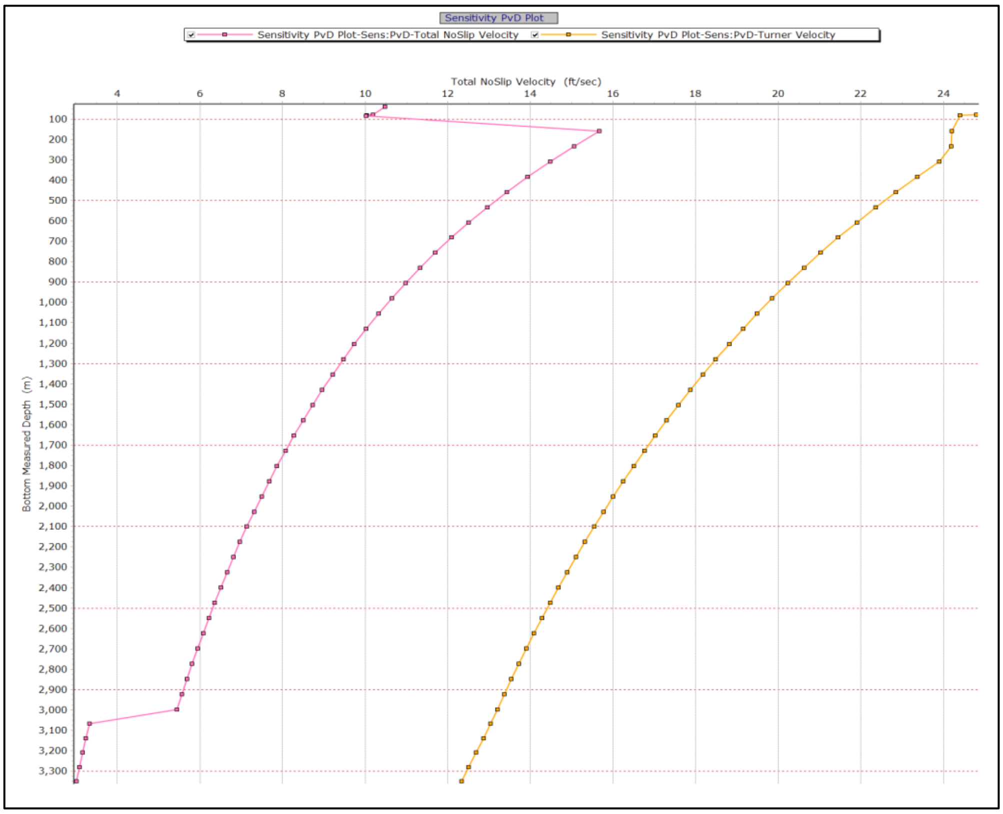

Figure 5-44: Velocity Profile at base loading (Res. P: 1000 psi; WHP: 134)

5.10.2 Compression

Application of compressor on this well (table 5.42) suggests a gain of 0.61 mmscfd but this gain is still under critical flow. Well although exhibits improved hydraulics but this has no effect in offsetting loading. Compressor alone is not enough for this well.

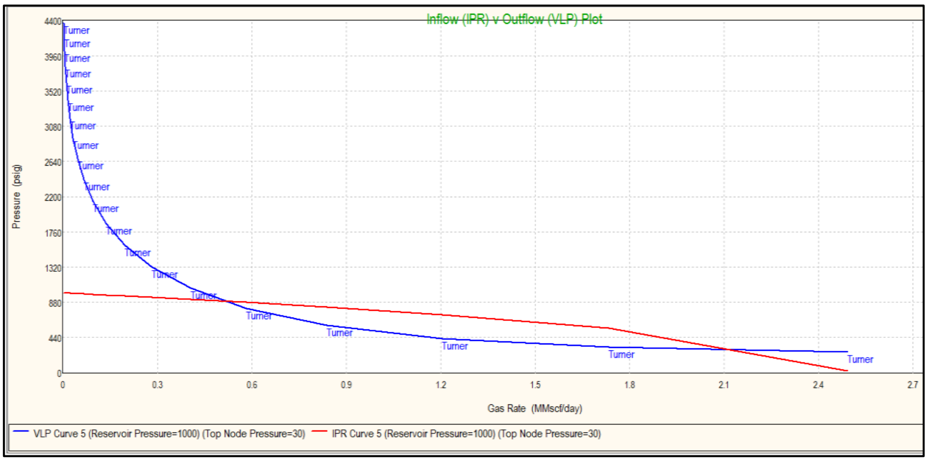

Figure 5-45: Sawan-10 Compression at Base Loading (Res. P: 1000 psi, WHP: 134 psi)

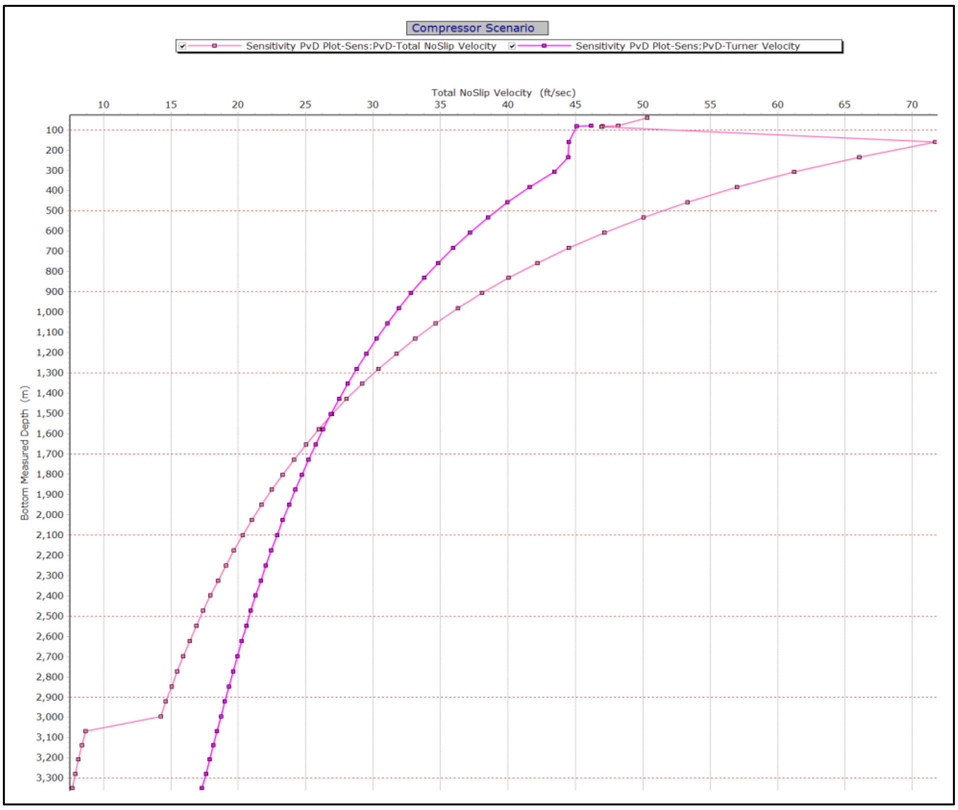

Figure 5-46: Velocity Profile at Compression Loading (Res. P: 1000 psi; WHP: 30 psi)

Table 5-42: Sawan-10 Compression case

Parameter	Compression		
	Base Loading	Loading	Abandonment
WGR	151	151	151
Reservoir P (psi)	1000	1000	820
Rate (MMscfd)	1.49	2.1	1.23
WHP (psi)	134	30	30

5.10.3 Foam Lift

Table 5.43 presents the foam lift feasibility on Sawan-10. Foam concentration of 0.4% is optimized for this well. Foam Lift performance is restricted because of the wellhead pressure. Figure 5.47 shows the velocity profile at the abandonment of foam injection pressure.

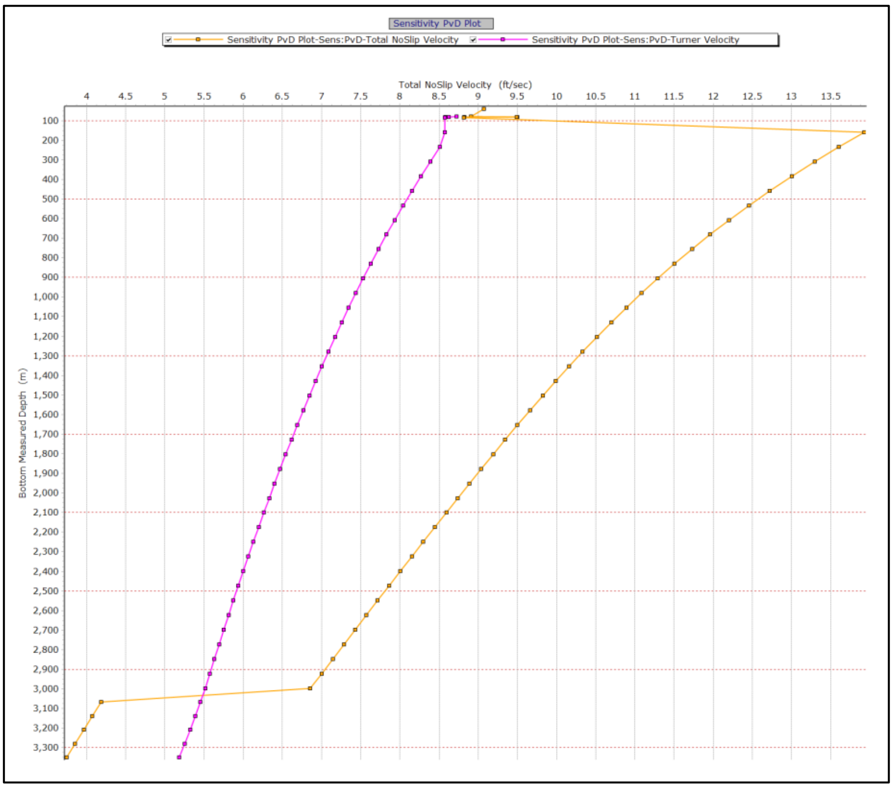

Figure 5-47: Velocity Profile at Foam Lift abandonment (WHP: 134, Res. P: 880 psi)

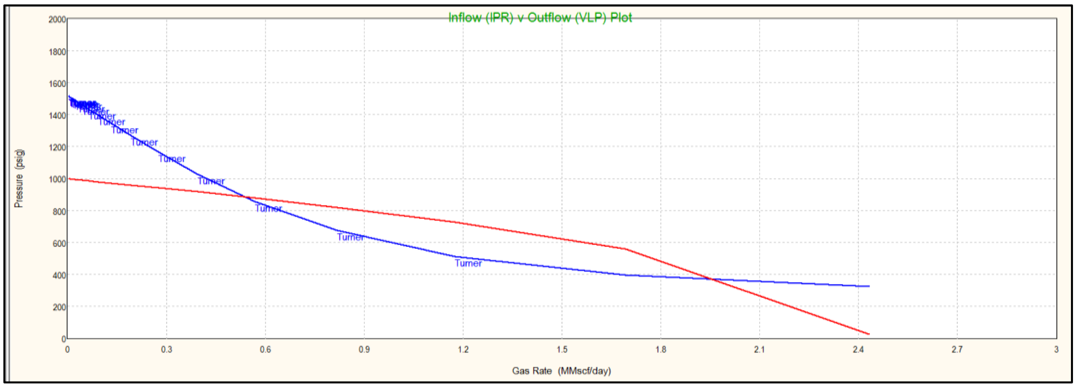

Figure 5-48: Sawan-10 Foam at base case loading (Res. P: 1000 psi, WHP: 134)

5.10.4 Velocity String

The third scenario is based on evaluating option of velocity string. Table 5.44 shows the comparison of velocity string for current well. Figure 5.49 presents the case of comparison of strings. Unfortunately this well is not a good candidate for velocity string comparing to other two methods. Only option of “tubular flow” is analyzed as well production is too low for "annular + tubular" and "annular" criterion. Well is quite near to loading conditions in "tubing flow". It can be observed from figure 5.49 that reducing tubing diameter reduces the critical rate. Optimized velocity string for this well is 2.375".

Table 5-43: Foam feasibility

Parameter	Foam Lift		
	Base Loading	Loading	Abandonment
WGR	151	-	151
Reservoir P (psi)	1000	-	880
Rate (MMscfd)	1.97	-	1.22
WHP (psi)	134	-	134

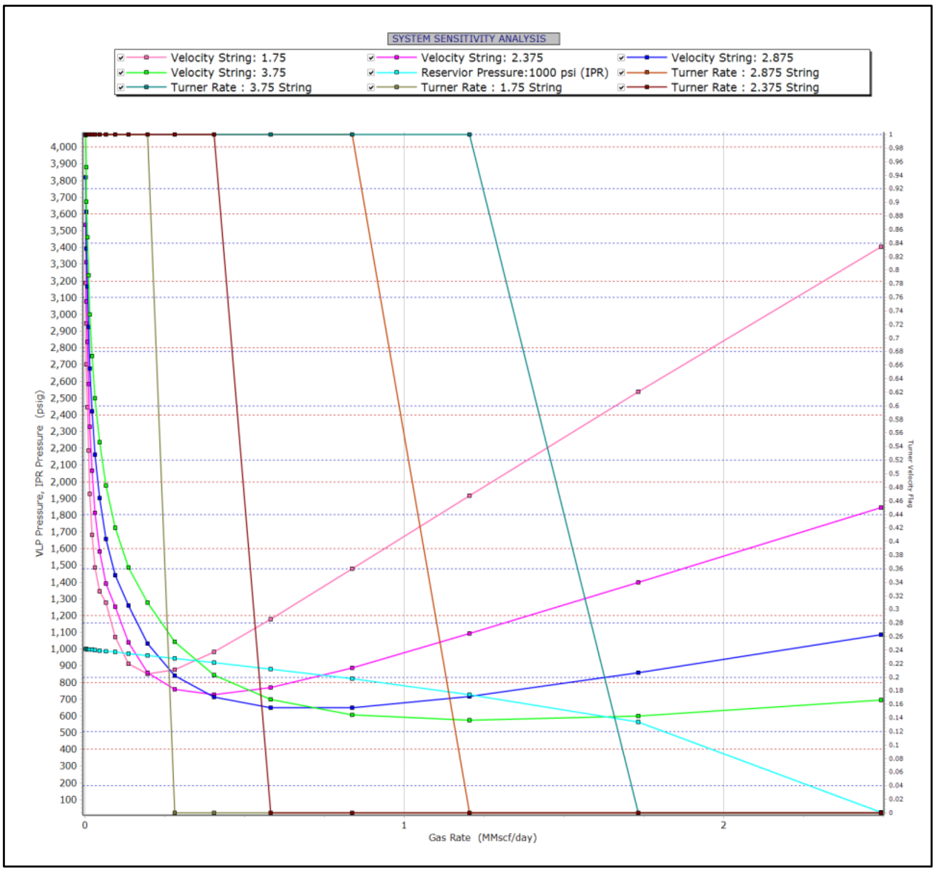

Figure 5-49: Velocity String comparison at base loading case (Res. P: 1000 psi, WHP: 134 psi)

5.10.5 Combination case

Since well productivity is high and well life with either of three presented technique can't be effectively prolonged. Combination of velocity string with foam is suggested for this well. Rates for low suction case (combination of compression + foam + velocity) are also shown in table 5.46. Selected tubing for combination case is 2.375" CT with 0.4% foam concentration.

Table 5-44: Sawan-10 Velocity String Comparison

Parameters	**Velocity String Comparison Tubing Analysis**									
Velocity String size (in.)	**3.75 (3.22)**		**2.875 (2.563)**		**2.375 (2.025)**		**1.75 (1.56)**		**1.5 (1.15)**	
Status	**Base**	**Ldng.**	**Base**	**Ldng.**	**Base**	**Ldng.**	**Base**	**Abdn.**	**Base**	**Ldng.**
Reservoir P (psi)	1000	1000	1000	960	1000	945	1000	970	1000	1000
Rate (MMscfd)	1.51	1.51	1.22	1.11	0.74	0.63	0.36	0.32	-	-
WHP (psi)	183	183	183	183	183	183	183	183	183	183

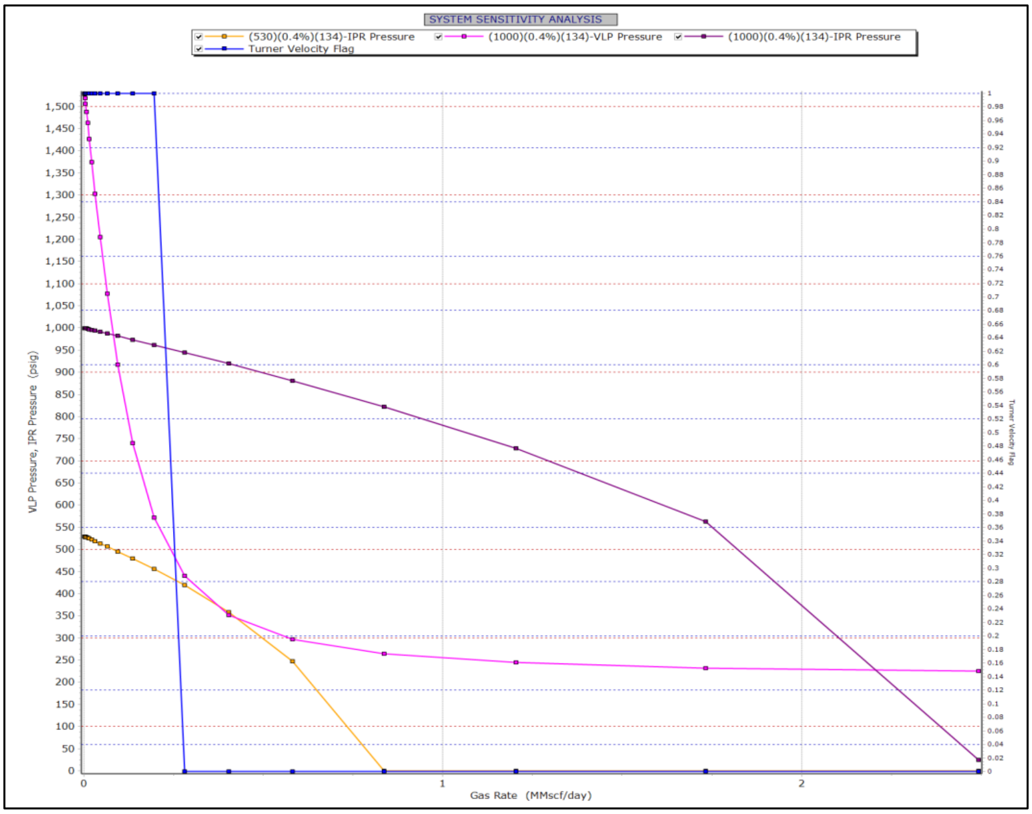

Figure 5-50: Combination case A (WHP: 134; Res P: 1000 & 530; Surfactant: 0.4%)

Table 5-45: Sawan-10 Combination case A

Parameter	Combination (V.S & Foam)		
	Base case (Estimated)	Loading	Abandonment
Reservoir P (psi)	1000	-	530
Rate (MMscfd)	2.29	-	0.42
WHP (psi)	134	134	134

Table 5-46 Sawan-10 Combination case B

Parameter	Combination (V.S, Foam & Compression)		
	Base Case (Estimated)	Loading	Abandonment
Reservoir P (psi)	1000	-	360
Rate (MMscfd)	2.35	-	0.27
WHP (psi)	30	30	30

5.10.6 Technical Recommendation

The well productivity (inflow) can be increased by cleaning job as well depicts high skin value. Summary of presented methods are shown in table 5.47. Foam lift outperforms all cases but the incremental is not enough as well is restricted because of well head pressure. Considering high cost of wellhead compression, it is recommended to install a combination of velocity string and foam lift to improve well life. Combination case B (table 5.46) is just for experimental purpose whereas case A (table 5.45) is taken for comparison purpose.

Table 5-47: Sawan 10 Comparison Summary

Parameter	Base Case	Compression	Foam Lift		Velocity String-“Tubing Flow”		Combination-No Loading	
Status	Loaded	Loaded	Stable	Abdn.	Stable	Loading	Stable	Abdn,
Reservoir P (psi)	1000	1000	1000	880	1000	945	1000	530
Rate (MMscfd)	1.49	2.1	1.97	1.22	0.74	0.63	2.29	0.42
WHP (psi)	134	30	134	134	183	183	134	134

5.11 Sawan 11

Sawan-11 was drilled as a development well in Sawan North in November, 2008 to a PBTD of 3420 mRT. The well was completed with 4-1/2” Cr-22 monobore completion. CIT conducted in December, 2007 produced 19.92 MMscfd gas at 2040 psi FWHP. The reservoir pressure at datum was estimated to be 3331 psi. Frequent wellbore clean out jobs have been performed on this well. Last wellbore clean out job was performed in July 2015. Well was put under FEC in 2010. Well has produced a cumulative gas volume of 28.957 Bcf (March-2016)

5.11.1 Base case

Currently well is exhibiting stable flow without any loading issue. Water production is attributed as condense water. Well completion sketch is provided in figure 5.51. VLP is matching with Petroleum Experts 2 correlation. Base case is summarized in table 5.49. Later life velocity analysis plot (figure 5.53) at 530 psi suggests stable flow without hydraulics issue.

Table 5-48: Key Facts (Sawan-11)

Well name	Sawan-11
Well Type	Development well
Well Location	North
Depth	3420 mRT PBTD
Inline Production	Apr-08
FEC	February 2010
Permeability (mD)	31
Pressure (psi)	551
Current Gas (MMscfd)	2.75
Current Water (BPD)	85.25
Current WGR (bbl/MMscf)	31
Condense WGR (bbl/MMscf)	31
Well Status	Stable

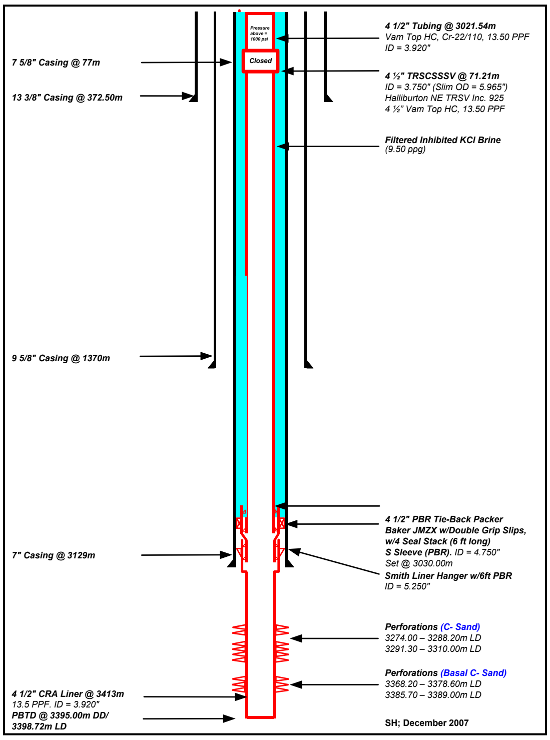

Figure 5-51: Sawan-11 Well Completion Sketch

Table 5-49: Base Case (Sawan-11)

Parameters	Base Case		
	Current	Loading	Abandonment
Reservoir P (psi)	551	N/A	530
Rate (MMscfd)	2.75	N/A	2.13
WHP (psi)	198	N/A	198

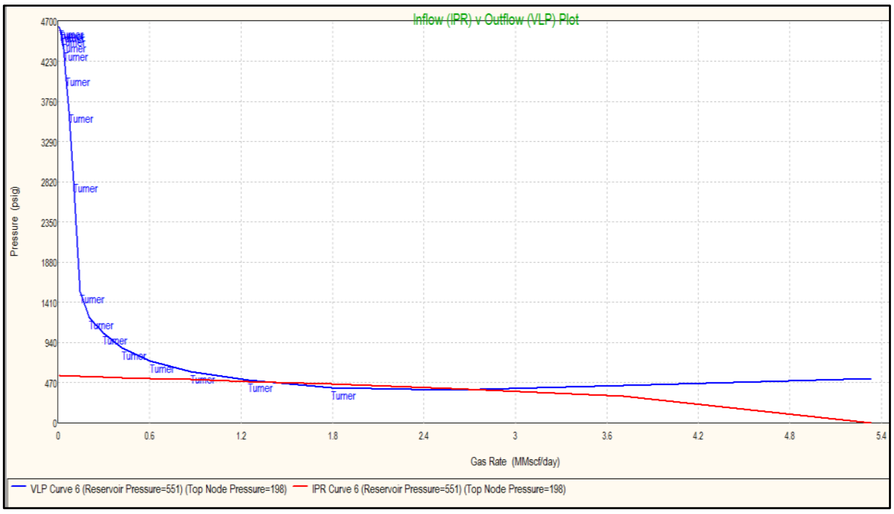

Figure 5-52: Base Model Sawan-11 (Res. P: 551 psi; WHP: 198 psi)

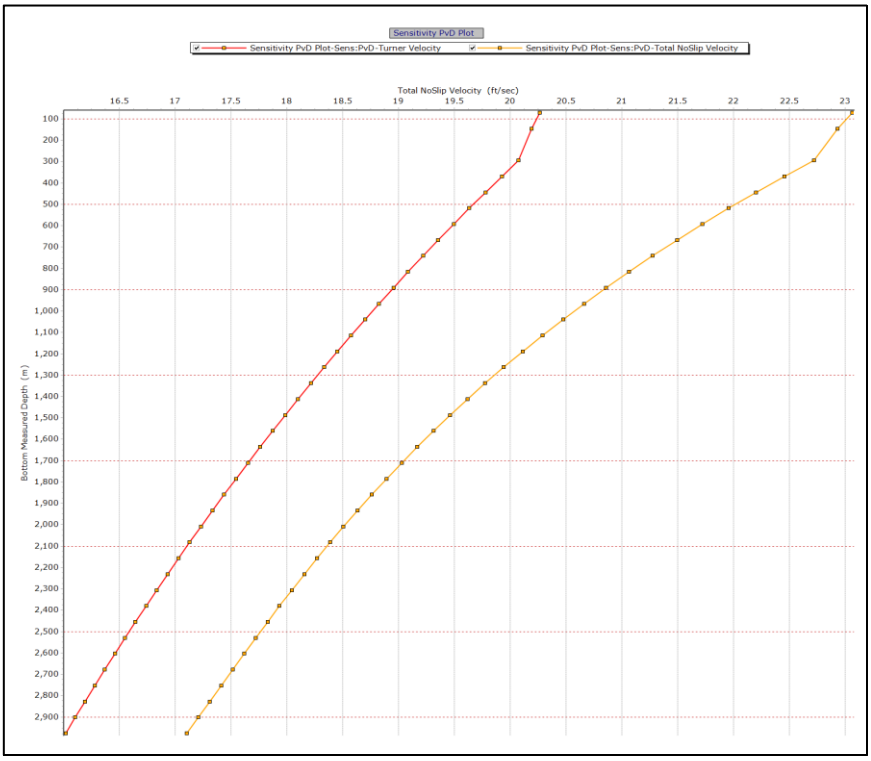

Figure 5-53: Velocity Profile at base abandonment conditions (Res. P: 530 psi; WHP: 198 psi)

5.11.2 Compression

The only option to increase Sawan 11 well life is using compression. Compression is not only extending well life till 315 psi (Life Gain: 215 psi) but also increases production at base abandonment pressure.

Table 5-50: Sawan-11 Compression Case

Parameters	Compression		
	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psi)	530	N/A	315
Rate (MMscfd)	3.69	N/A	1.3
WHP (psi)	30	N/A	30

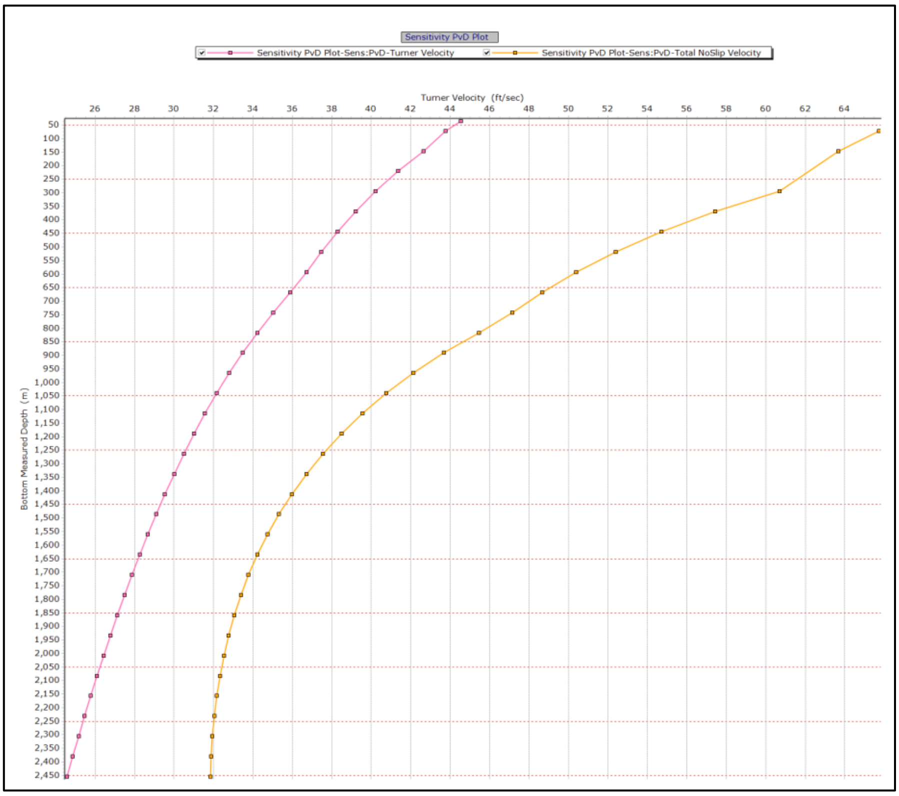

Figure 5-54: Velocity Profile at Compression Abandonment (Res. P: 315 psi; WHP: 30 psi)

5.11.3 Technical Recommendations

Life extension of well is possible with compression and it is recommended for this well. No hydraulics issue has been observed. Foam Lift & velocity string have been eliminated because well does not exhibit any loading issue on base case and compression scenarios

5.12 Sawan 12

Sawan-12 was drilled as development well in the Sawan South to target Lower Goru C-Sand. During CIT, well was tested at a sand free gas rate of 0.11 MMscfd at FWHP of 73 psi. Hydraulic fracturing was performed in November 2013 based on poor rates and extremely low permeability. Estimated fracture half-length was 28.4 m with fracture height of 46m. Post fracture test results 1.30 MMscf (11.8 FOI) which dropped to 0.56 MMscfd. Well liquid sample confirms free water production (chloride contents: 30000 ppm). Well production was sluggish with varying WGR up to 600 STB/MMscf. Well has produced cumulative production of 0.106 Bcf till August, 2015.

5.12.1 Base Case

Currently the well is shut in whereas the last recoded production from well was 0.018 MMscfd. Well completion sketch is provided in figure 5.55. A rough model is prepared based on average rates of well in one month. Current water chlorides are 33470 ppm. Average value of WGR (250 bbl/MMscfd) is assumed as per August 2015 analysis. Well depicts low skin value. VLP “Petroleum Experts 2” correlation has been used applied for this well. Well current case is summarized in table 5.52.

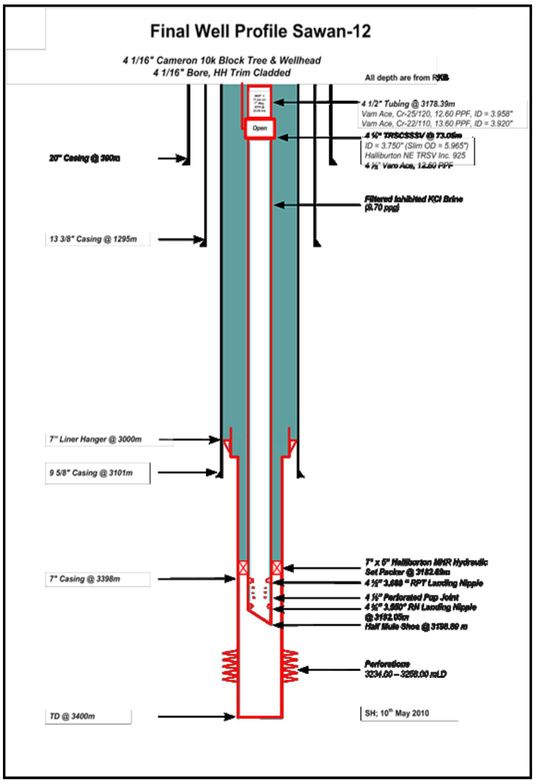

Figure 5-55: Sawan-12 Well completion sketch

Table 5-51: Key facts (Sawan-12)

Well name	Sawan-12
Well Type	Development well
Well Location	South
Depth	3400 mRT PBTD
Inline Production	Dec-12
FEC	February 2010
Permeability (mD)	0.0091
Pressure (psi)	3000
Last recorded Gas (MMscfd)	0.0018
Last recorded Water (BPD)	Sluggish

Last Avg. WGR (bbl/MMscf)	250
Condense WGR (bbl/MMscf)	8
Well Status	Shut in /Sluggish (Last recorded)

Table 5-52: Sawan-12 Base case Scenario

Parameter	Base Case		
	Current	Loading	Abandonment
WGR	250	250	250
Reservoir P (psi)	3000	3000	2970
Rate (MMscfd)	0.018	0.018	0.016
WHP (psi)	362	362	362

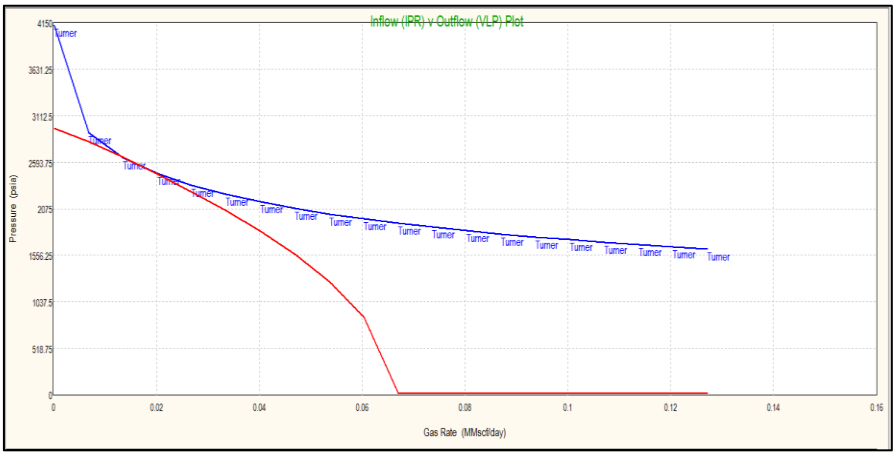

Figure 5-56: Base Model (Res. P: 3000 psi; WHP: 362)

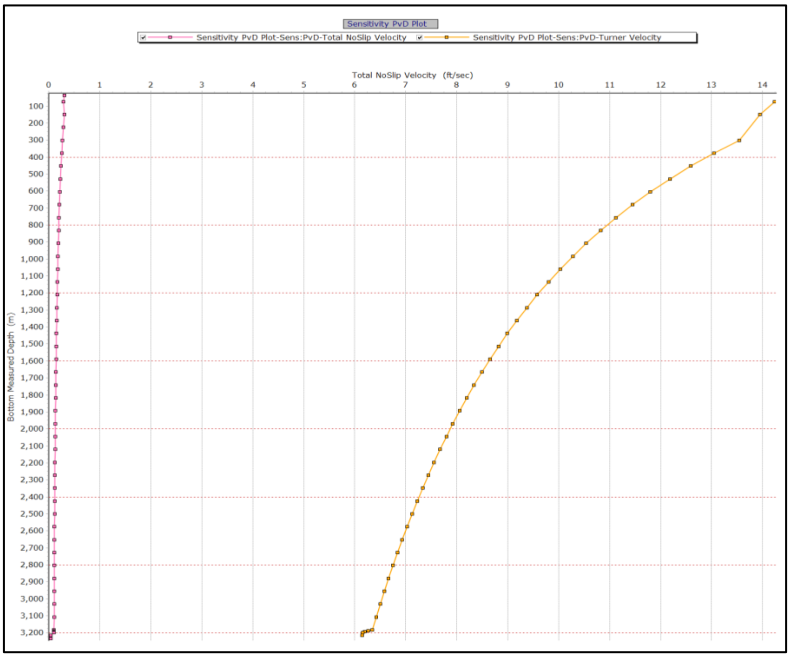

Figure 5-57: Velocity Profile at base loading (Res. P: 3000 psi; WHP: 362)

5.12.2 Compression

Application of compressor on this well (table 5.53) shows a gain of 0.04 MMScfd but this gain is still under critical flow for this well.

Table 5-53: Sawan-12 Compression case

Parameter	Compression		
	Base Case Loading	Loading	Abandonment
WGR	250	250	250
Reservoir P (psi)	3000	3000	2530
Rate (MMscfd)	0.05	0.05	0.019
WHP (psi)	30	30	30

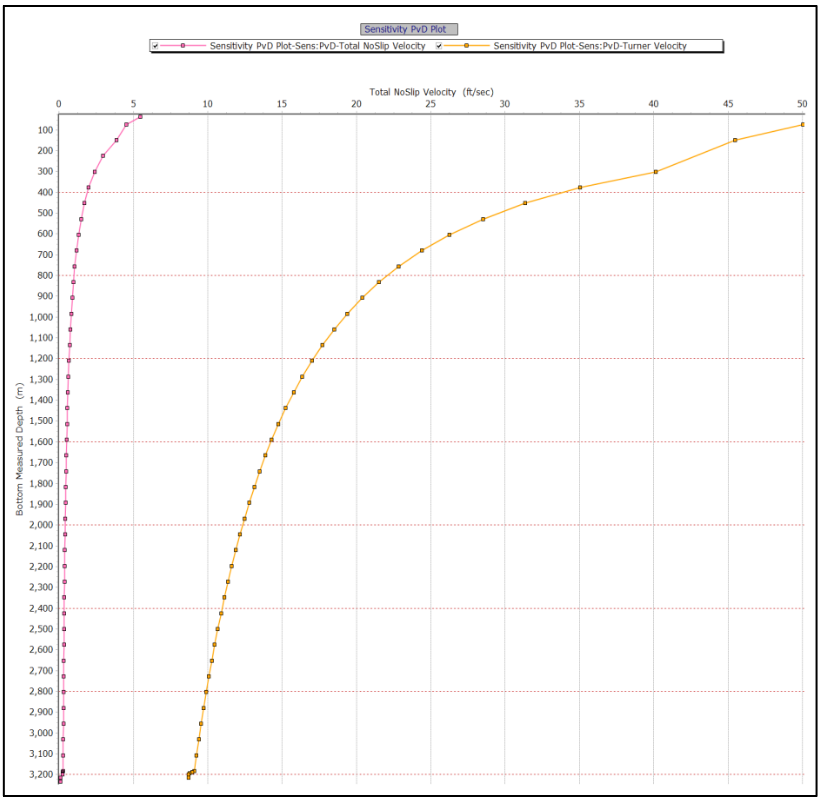

Figure 5-58: Velocity Profile at Compression loading (Res. P: 3000 psi; WHP: 30)

5.12.3 Foam Lift

Foam lift can be applied as alternative option to compressor or velocity string. Table 5.54 presents the foam lift feasibility on Sawan-12. Foam concentration of 0.4% is optimized for this well. Greater concentration makes foam stiff. Figure 5.59 shows the velocity profile at current condition of well. Almost 0.04 MMscfd increment is seen but is of no use.

Table 5-54: Sawan-12 Foam feasibility

Parameter	Foam Lift		
	Base Case Loading	Loading	Abandonment
WGR	250	250	250
Reservoir P (psi)	3000	3000	2700
Rate (MMscfd)	0.05	0.05	0.007
WHP (psi)	362	362	362

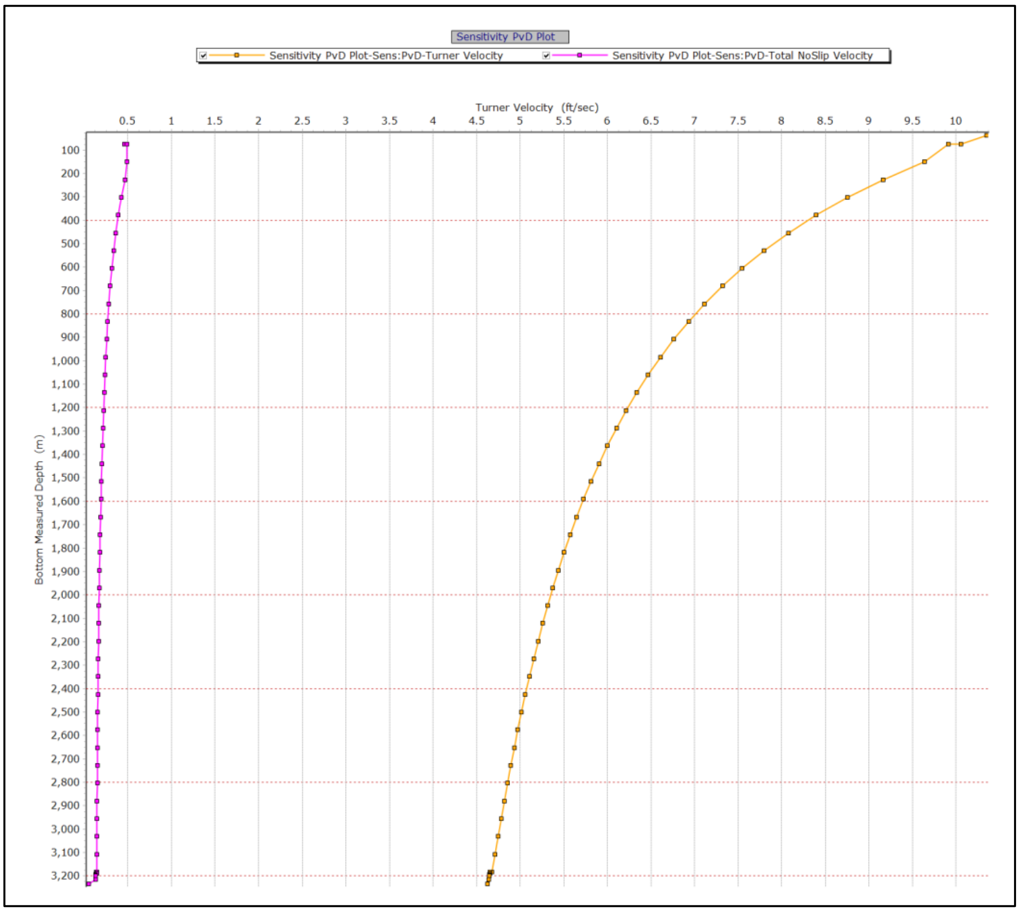

Figure 5-59: Foam Lift Velocity Profile at base loading (Res. P: 3000 psi, WHP: 134 psi)

5.12.4 Velocity String

The third scenario is based on evaluating option of velocity string. Table 5.55 shows the comparison of velocity string for current well. Figure 5.60 represents the case of comparison of strings. Unfortunately this well is not a candidate for velocity string. The reason is that rates are too low for velocity string to boost velocities. All VLP curves are intersecting IPR within gravity dominated region (left side of VLP)[12]. Table 5.56 presents the base and abandonment case for 1.5" velocity string. Figure 5.61 represents the velocity profile in

[12] Left side intersection interpretation details is present in Section 2.7, Chapter 2,

wellbore with 1.5” string. Comparing to base case velocities (<1 ft/s), velocities in this case are ~ 5ft./sec.

Table 5-55: Sawan-12 Velocity String Comparison

Status	**Velocity String Comparison**			
Velocity String size (in.)	**2.875 (2.563)**	**2.375 (2.025)**	**1.75 (1.56)**	**1.5 (1.15)**
Reservoir P (psi)	3000	3000	3000	3000
Rate (MMSCFD)	0.041	0.048	0.051	0.052
WHP (psi)	362	362	362	362
Status	Loaded	Loaded	Loaded	Loaded

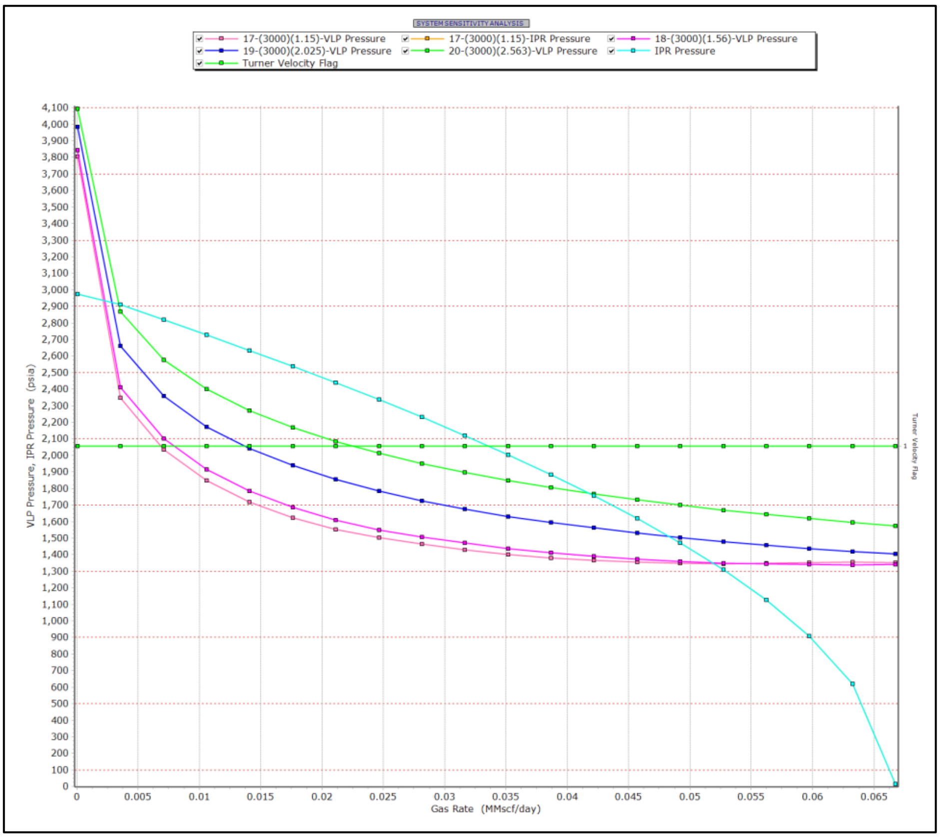

Figure 5-60: Sawan-12 Comparison of string (Res. P: 3500 psi; WHP: 362 psi)

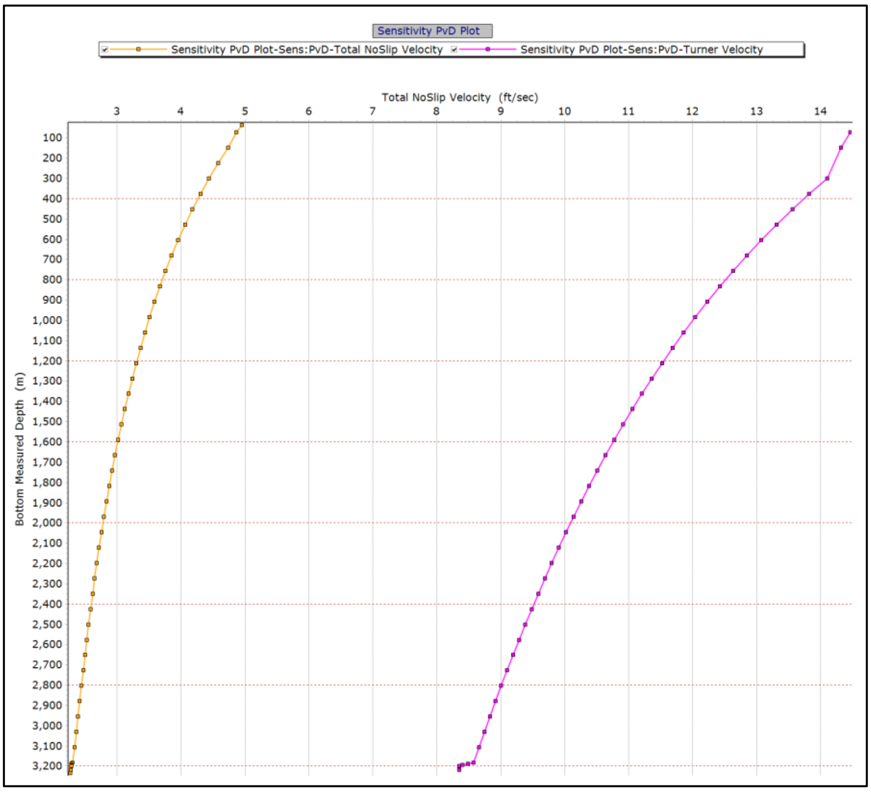

Figure 5-61: V.S 1. 5" Velocity profile at base loading (Res. P: 3500 psi; WHP: 362 psi)

Table 5-56: Velocity String Simulation

Parameters	1.5" String	Simulation
Reservoir P (psi)	3000	2000
Rate (MMscfd)	0.052	0.013
WHP (psi)	362	362

5.12.5 Technical Recommendations

To keep well alive, different deliquification options were evaluated like CSI, VS and compression. Even combination does not work out for this well. Wellbore hydraulics improvement alone can't guarantee the sustainability of well. Parallel to vertical lift performance, well inflow should also be improved. Summary of each case is presented in table 5.62. This well is not a candidate of deliquification.

Table 5-57: Sawan-12 Comparison Summary

Parameter	Base Loading	Compression	Foam Lift	1.5" Velocity String
Status	Loaded	Loaded	Loading	Loading
Reservoir P (psi)	3000	3000	3000	3000
Rate (MMSCFD)	0.018	0.05	0.05	0.052
WHP (psi)	362	362	362	362

5.13 Sawan 13

Sawan-13 was drilled as a development well in Sawan North in January, 2008. CIT conducted in 2008 produced 33.62 MMscfd gas with WGR 7.0 bbls/MMscf at a FWHP of 1855 psi. The reservoir pressure at datum was estimated to be 3056 psi. Last wellbore clean out job was performed in July 2015. Well has produced a cumulative gas production of 38.62 Bcf (March 2016).

5.13.1 Base case

The current status of well is stable flow without any loading issue. Well completion sketch is provided in figure 5.62. VLP is matching with Gray correlation. Well current case is summarized in table 5.59. Based on later life velocity analysis plot (figure 5.64), it seems well will be stable.

Table 5-58: Key Facts (Sawan-13)

Well name	**Sawan-13**
Well Type	Development well
Well Location	North
Depth	3455 mRT PBTD
Inline Production	Sep-08
FEC	February 2010
Permeability (mD)	248
R. Pressure (psi)	571
Current Gas (MMscfd)	4.64
Current Water (BPD)	153.12
Current WGR (bbl/MMscf)	33
Condense WGR (bbl/MMscf)	33
Well Status	Stable

Table 5-59: Base Case (Sawan-13)

Parameter	Base Case		
	Current	Loading	Abandonment
Reservoir P (psi)	571	N/A	510
Rate (MMscfd)	4.66	N/A	2.61
WHP (psi)	228	N/A	228

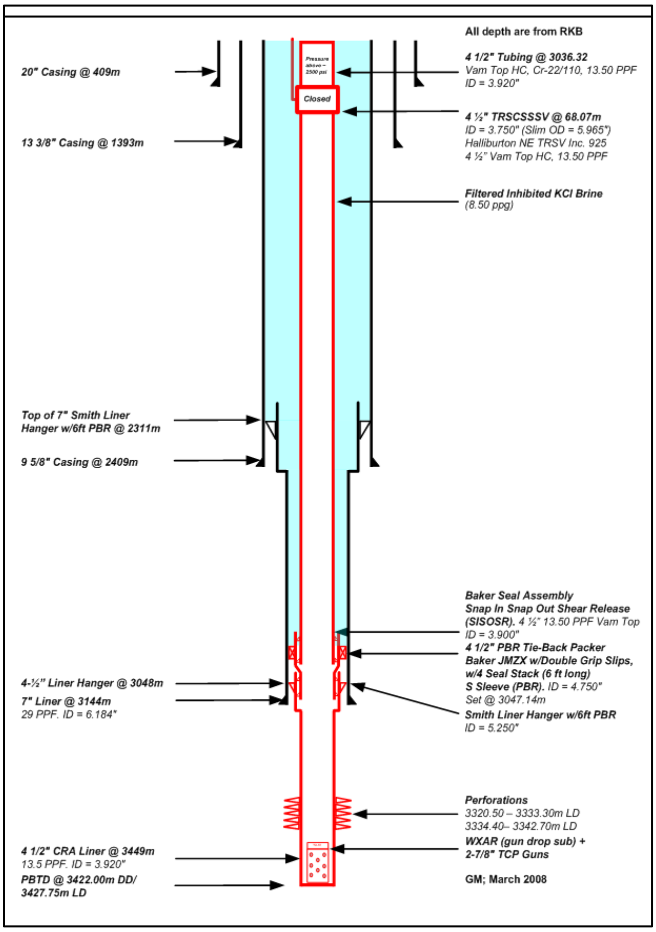

Figure 5-62: Sawan-13 Well completion sketch

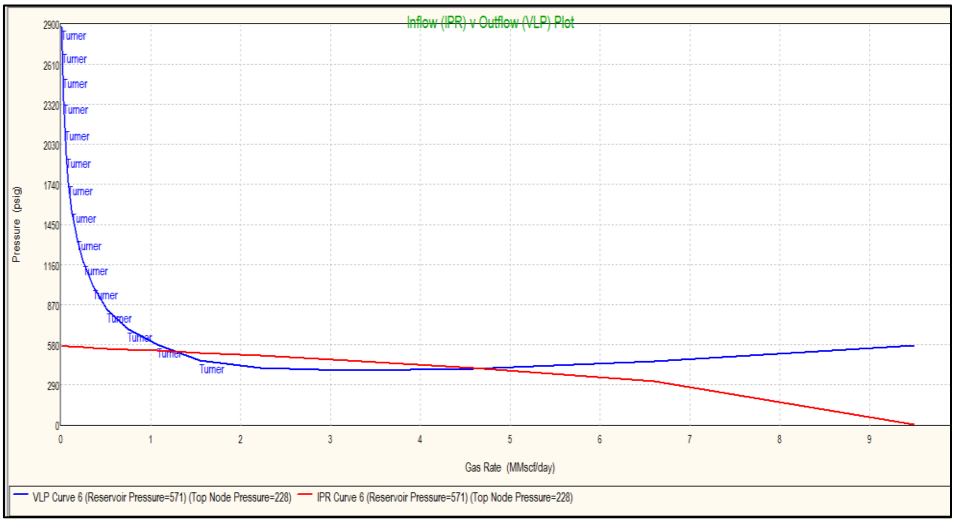

Figure 5-63: Base Model Sawan-13 (Res. P: 571 psi; WHP: 228 psi)

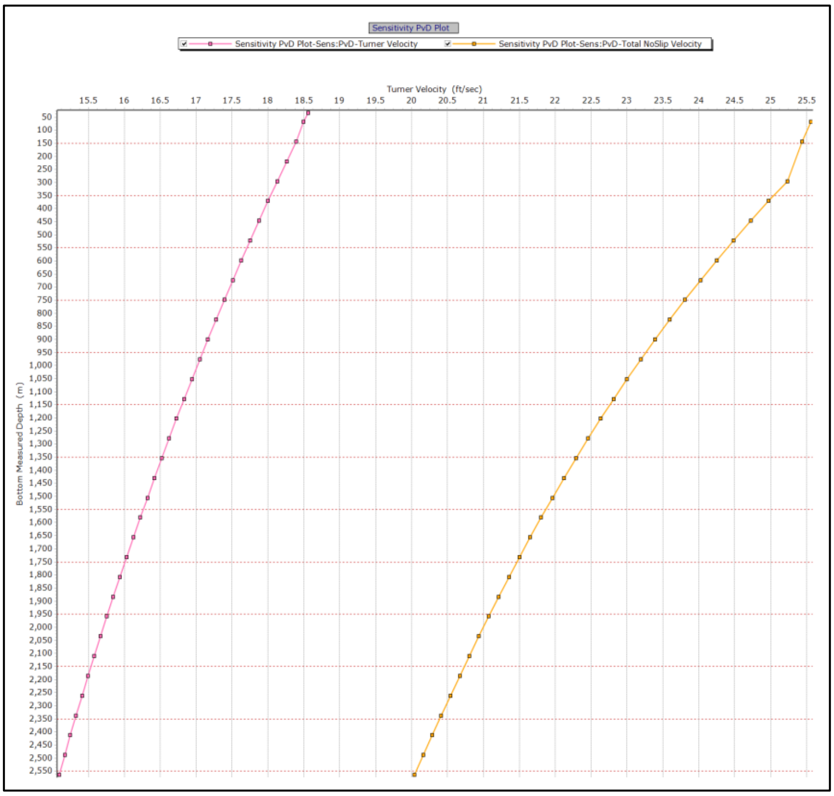

Figure 5-64: Velocity Profile Plot at base abandonment (Res. P: 510 psi; WHP: 228 psi)

5.13.2 Compression

Sawan 13 base case analysis suggests well is stable at base abandonment conditions and well life is restricted because of well head pressure (figure 5.67). The only option to increase well life is compression. Compression is not only extending well life till 270 psi (Life Gain: 250 psi) but also increases production at base abandonment pressure.

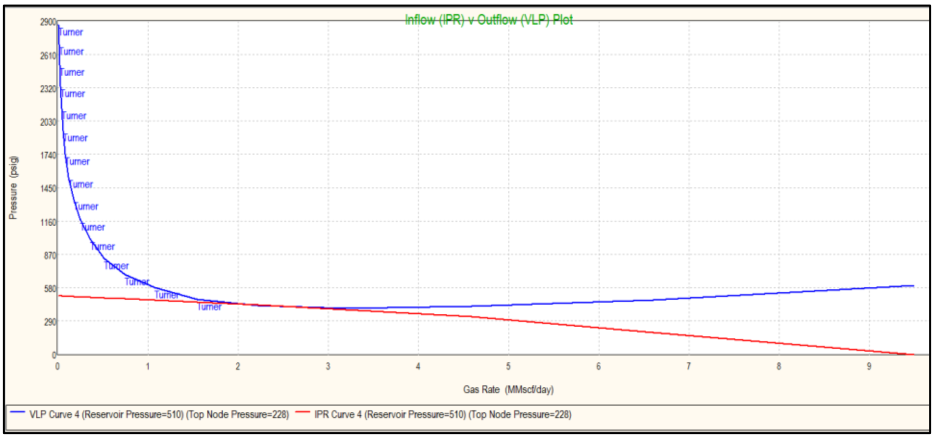

Figure 5-65: Base case abandonment (WHP: 228 psi, Res. P: 510 psi)

Table 5-60: Compression case

Parameter	Compression		
	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psig)	510	N/A	270
Rate (MMSCFD)	5.53	N/A	1.57
WHP (psig)	30	N/A	30

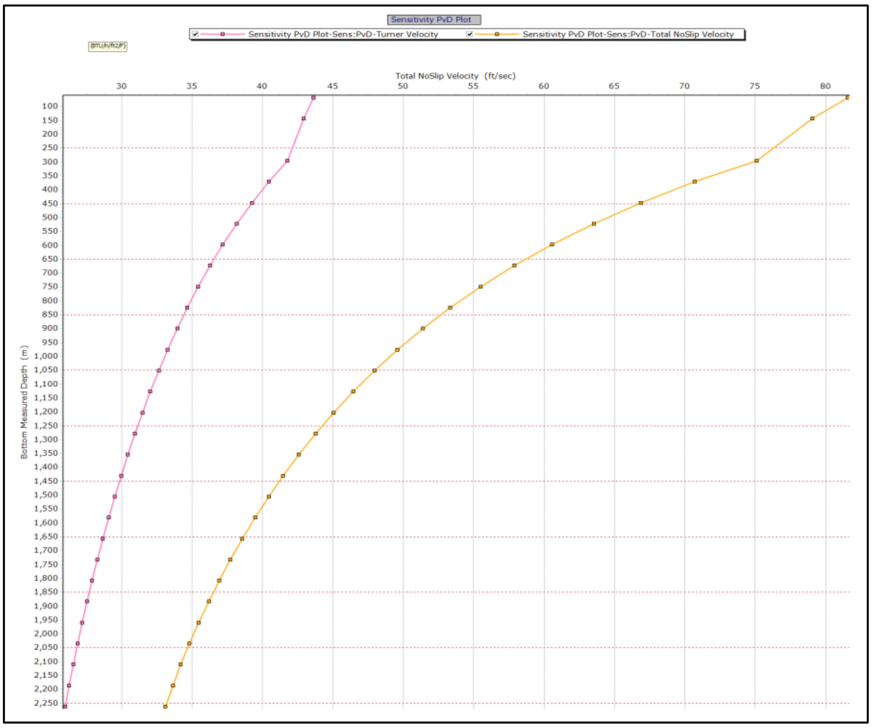

Figure 5-66: Velocity Profile at compression abandonment (Res. P: 260 psi; WHP: 30 psi)

5.13.3 Technical Recommendations

Life extension of well is possible with compression and it is recommended for this well. No hydraulics issue has been observed. Foam Lift and velocity string scenario have been eliminated because well does not exhibit any loading issue on base case and compression scenarios

5.14 Sawan 14

Sawan-14 was drilled as development well in Sawan North compartment. The well was spud in October, 2008 and drilled to a PBTD of 3450 mRT with a target formation of Lower Goru C-Sand. Well completed with 4-1/2” Cr-22 completion. During CIT, the Lower Goru C-Sand produced 27.30 MMscfd at 1459 psi FWHP with 5 bbl./MMscf WGR. Last job carried on well includes stimulation in August 2011. The well has cumulative produced 32.94 Bcf (March 2016).

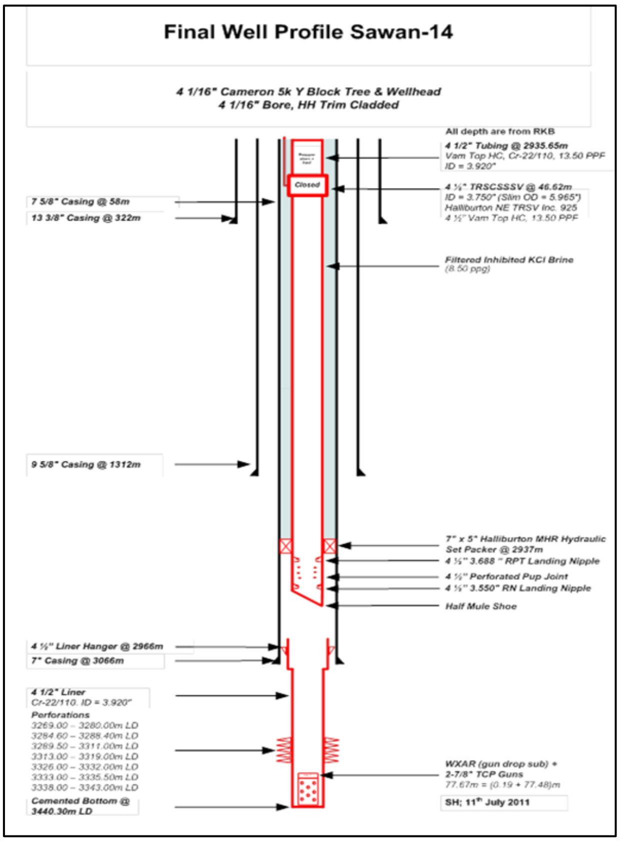

Figure 5-67: Sawan-14 Well Completion Sketch

5.14.1 Base case

Currently the well is producing 3.29 MMscfd. No loading issues have been detected. Well completion sketch is provided in figure 5.67. VLP is matching with Petroleum Experts 2 correlation. Later life velocity analysis plot (figure 5.69) at 400 psi shows us that well will be stable without hydraulics issue.

Table 5-61: Key Facts (Sawan-14)

Well name	Sawan-14
Well Type	Development well
Well Location	North
Depth	3450 mRT PBTD
Inline Production	Mar-09
FEC	February 2010
Permeability (mD)	40
Pressure (psi)	471
Current Gas (MMscfd)	3.29
Current Water (BPD)	111.86
Current WGR (bbl/MMscf)	34
Condense WGR (bbl/MMscf)	34
Well Status	Stable

Table 5-62: Base case (Sawan-14)

Parameter	Base Case		
	Current	Loading	Abandonment
Reservoir P (psi)	471	N/A	415
Rate (MMscfd)	3.29	N/A	2.29
WHP (psi)	170	N/A	170

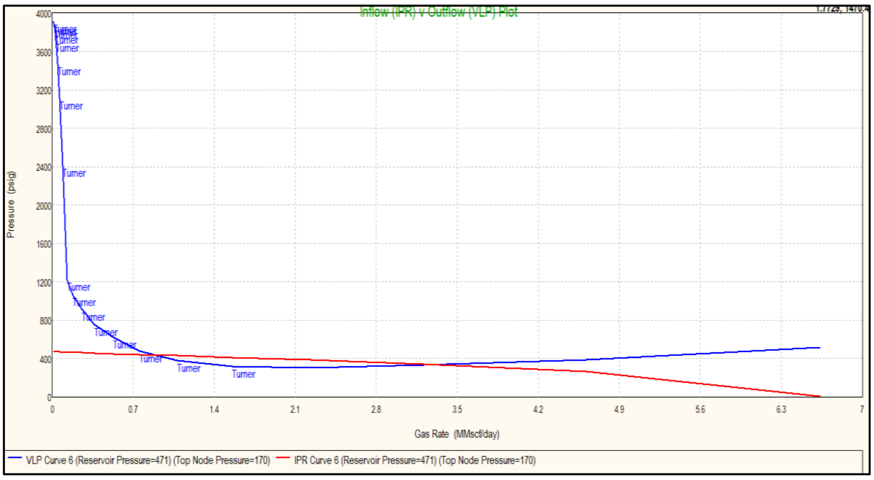

Figure 5-68: Sawan-14 Base Model (Reservoir: 471 psi; WHP: 170 psi)

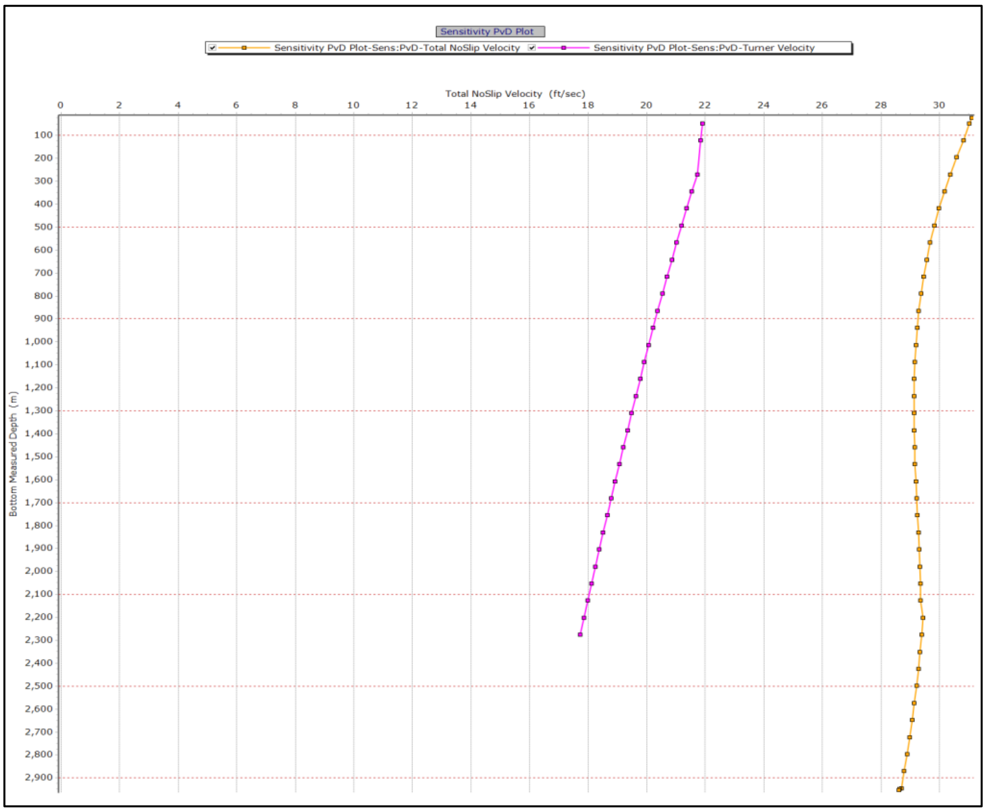

Figure 5-69: Velocity Profile Plot at base abandonment (Res. P: 415 psi; WHP: 170 psi)

5.14.2 Compression

Sawan 14 base case analysis suggests well is stable at base abandonment conditions and well life is restricted because of well head pressure. The only option to increase well life with artificial lift is using compression. Compression is not only extending well life till 240 psi (Life Gain: 175 psi) but also increases production at base abandonment pressure.

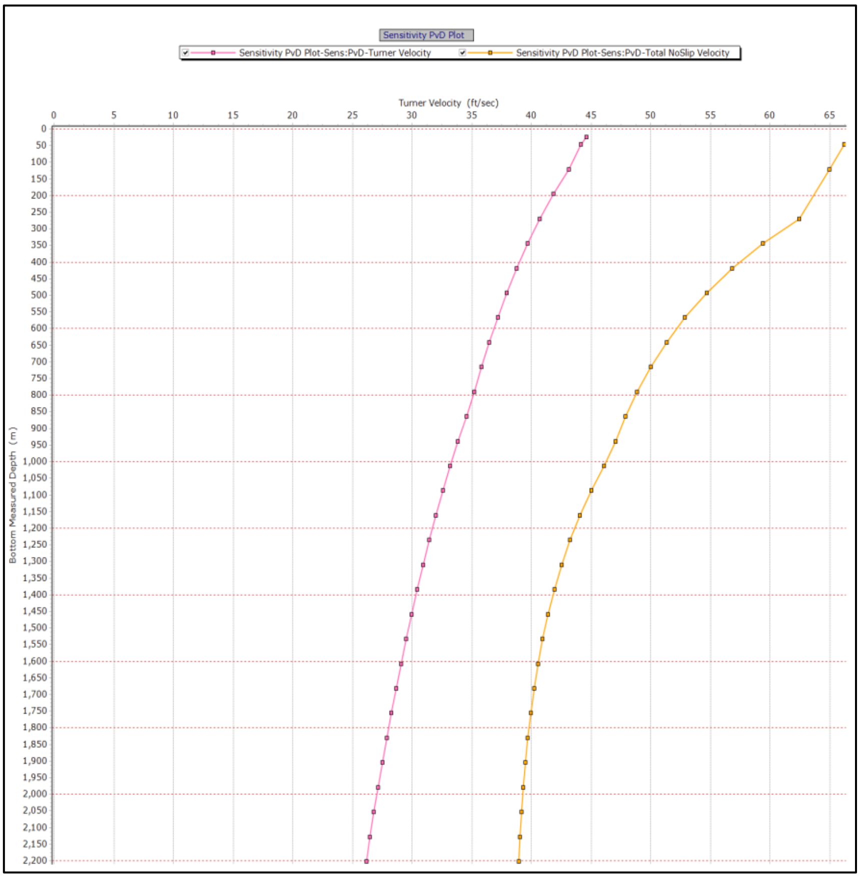

Figure 5-70: Velocity Profile at compression abandonment (Res. P: 240 psi; WHP: 30 psi)

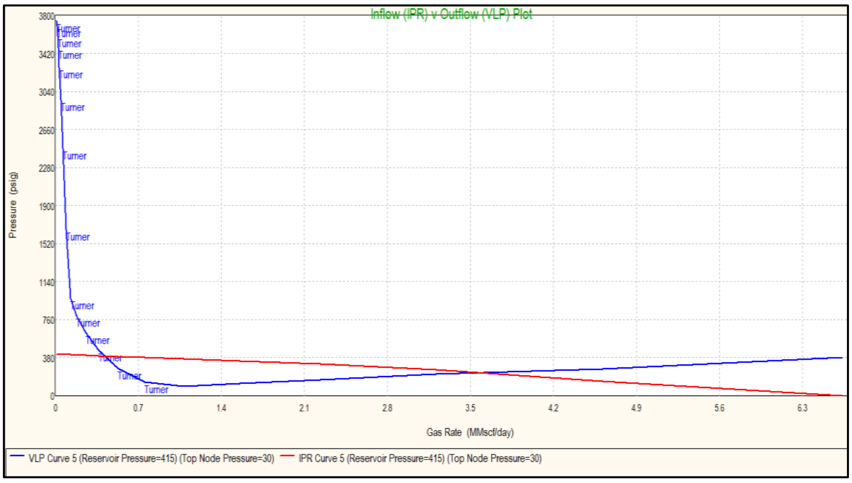

Figure 5-71: Compressor abandonment case (Res. P: 240 psi; WHP: 30 psi)

Table 5-63: Sawan-14 Compression case

Parameter	Compression		
	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psi)	415	N/A	240
Rate (MMscfd)	3.56	N/A	1.19
WHP (psi)	30	N/A	30

5.14.3 Technical Recommendations

Life extension of well is possible with compression and it is recommended for this well. It can be seen from the compression analysis results Table 5.63, well rates boosts to 3.56 MMscfd. One biggest advantage of using compression is that later life well intervention is possible. Foam Lift and velocity string scenario have been eliminated because well does not exhibit any loading issue on base case and compression scenarios.

5.15 Sawan 15

Sawan-15 was drilled as development well in Sawan North compartment. The well was spud on June 01, 2009 and drilled to a PBTD of 3465.5 m with a target formation of Lower Goru C-Sand. Well was completed with 4-1/2” Cr-22 completion. During CIT, the Lower Goru C-Sand produced 21.68 MMscfd at 1190 psi FWHP with 9.0 bbl./MMscf WGR. The average reservoir pressure at datum (3295 mSS) was estimated to be 2231 psi. The well was tie-in with Sawan plant on October 21, 2009 and from February 2010 onwards with front end compression. The latest job carried on well includes stimulation in January 2016. The well has produced a cumulative gas volume of 28.191 Bcf (March 2016). Currently the well is producing 3.33 MMscfd. The current status of well is stable flow without any loading issue. Well completion sketch is same as Sawan-14.

Table 5-64: Key Facts (Sawan-15)

Well name	Sawan-15
Well Type	Development well
Well Location	North
Depth	3465.5 mRT PBTD
Inline Production	Oct-09
FEC	February 2010
Permeability (mD)	39
Pressure (psi)	471
Current Gas (MMscfd)	3.33
Current Water (BPD)	129.87
Current WGR (bbl/MMscf)	39
Condense WGR (bbl/MMscf)	39
Well Status	Stable

Table 5-65: Summarized Results (Sawan-15)

Parameters	Base Case			Compression		
	Current	Loading	Abandonment	Estimated (Base case Abandonment)	Loading	Abandonment
Reservoir P (psi)	471	N/A	430	430	N/A	260
Rate (MMscfd)	3.33	N/A	2.43	3.78	N/A	1.28
WHP (psi)	161	N/A	161	30	N/A	30

5.15.1 Technical Recommendations

Sawan 14 and Sawan 15 are quite similar in terms of well properties & completion sketches. The overall analysis behavior turns out to be same for both wells so only the results for Sawan-15 are tabulated. For Sawan-15, water production at base abandonment will be ~107 bbl./day. The only option to increase well life with artificial lift for Sawan-15 is using compression. Compression is not only extending well life till 260 psi (Life Gain: 170 psi) but also increases production at base abandonment pressure.

6. Economical & Risk Analysis

This chapter presents Economics for the recommended method as per technical recommendations. Risk Analysis for the compression, foam lift and velocity string is also presented at the end of this chapter.

6.1 Decline curve Analysis

Decline curves are one of the most extensively used forms of data analysis employed in predicting future production. The decline curve analysis technique is based on the assumption that past production trends and their controlling factors will continue in the future. Arps [21] proposed that the "curvature" in the production-rate-versus-time curve can be expressed mathematically by a member of the hyperbolic family of equations. Arps recognized the following three types of rate-decline behavior:

- Exponential decline
- Harmonic decline
- Hyperbolic decline

Each type of decline curve has a different curvature, as shown in Figure 6.1. This figure depicts the characteristic shape of each type of decline when the flow rate is plotted versus time or versus cumulative production on Cartesian, semi log, and log-log scales. The main characteristics of these decline curves can be used to select the flow-rate decline model that is appropriate for describing the rate–time relationship of the hydrocarbon system.

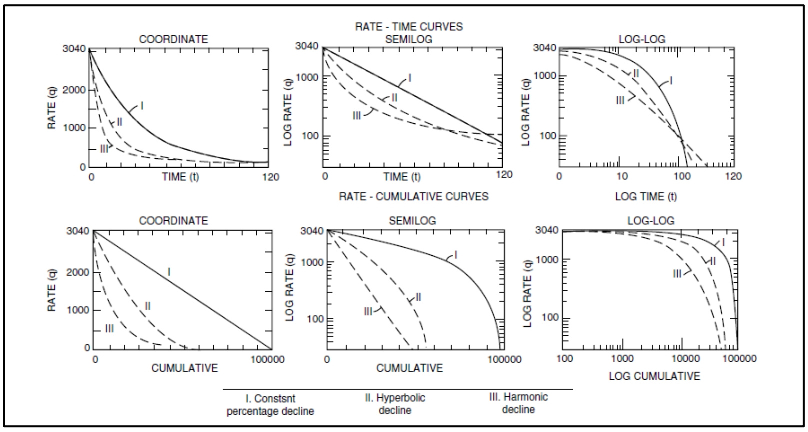

Figure 6-1: Decline Curve Identification Chart [21, p.1236]

Nearly all conventional decline-curve analysis is based on empirical relationships of production rate versus time, given as follows:

$$q_t = \frac{q_i}{(1+bD_it)^{\frac{1}{b}}} \qquad 5.1$$

q_t= gas flow rate at time t, MMscfd

q_i = initial gas flow rate, MMscfd

t= time,days

D_i= initial decline rate, day^{-1}

b= Arp's decline-curve exponent

Case	b	Rate–Time Relationship
Exponential	$b = 0$	$q_t = q_i \exp(-D_i t)$
Hyperbolic	$0 < b < 1$	$q_t = \frac{q_i}{(1 + b D_i t)^{1/b}}$
Harmonic	$b = 1$	$q_t = \frac{q_i}{(1 + D_i t)}$

Figure 6-2: Different regimes in Decline Curve Analysis [21, p.1237]

The data from the field was analyzed using MS Excel and PETEX "Mbal"[13] to analyze production trend. All Sawan wells are found to have exponential decline trend. Therefore exponential equation is used to extrapolate data for future prediction.

6.2 Sawan Economic Analysis

Project might seem plausible via technical analysis but might not be economically sound. Raw Gas[14] production is analyzed to generalize the economic view-point as many aspects like OPEX, compression specification, Raw to feed[15] gas conversion factors etc., all are subjected to differ from well to well basis. The terminology "Raw" refers to the production rate from wellhead flow meters that take into account the production volume per unit time. Amount of shrinkage factor applied on wells is approximate of total daily production from field into plant and varies daily between 0.70-0.80.

6.2.1 Economics Analysis Methodology

The general procedure used for analysis is as follows:

- Gathering of well production history.
- Analysis of well trend either using Rate vs. Time or Rate vs. cumulative Production
- Prediction of future forecast using the recommended technique from technical analysis.
- Analysis of remaining reserves.
- Analyzing the payout time vs. approximate CAPEX

6.2.2 Compression cost

The cost of compressor varies with the amount of gas it can process at the suction of 30 psi. The exact amount per compressor can't be taken because the feasibility of project is still under discussion in OMV Pakistan. However, the average cost per compressor is assumed to be USD $ 3 Million as per OMV Pakistan recommendation.

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[13] PETEX "Mbal" is reservoir analysis software by PETEX. Since, OMV uses this software so it was used in decline curve analysis.

[14] Raw gas is referred to wellhead gas i.e. pretreated gas. The value of raw gas is taken via wellhead flow meters. Raw gas incorporates produced water so it is a rough gas flow rate estimate.

[15] Feed gas refers to gas that is feed into plant for processing. Gas is called as feed gas once slug catcher, separator removes the high contents of water that were incorporated in raw gas.

6.2.3 Velocity String

The cost of velocity string varies with the metallurgy used for string and in Sawan case, high quality string is required based on temperature and acid gas concentrations. The estimated cost for 1.5" string is assumed to be $ 1 Million USD and for large size string i.e. 2.375" is $ 1.5 Million USD.

6.2.4 Foam Lift

The cost of foam lift majorly depends on the type of foam used. The cost in terms of OPEX varies as the amount of water change. So, for economic analysis of Sawan wells, a cost of $ 0.7 Million USD is assumed as per service company recommendation.

6.2.5 Pay Out Calculations

Payout time for compression is calculated via present day gas value of 3200 $/MMscf which roughly equals to 937.5 MMscf of gas production. Payout time of velocity string is calculated via present day gas value of 3200 $/MMscf which roughly equals to 468 MMscf (2.375" V.S) and 312 MMscf (1.5" V.S) of gas production. Payout time for foam lift is calculated via present day gas value of 3200 $/MMscf which roughly equals to 218 MMscf of gas production.

6.3 Sawan-1

Remaining reserves for Sawan-1 are approximate 6.4 Bscf. The compression project extends well life to approximate 5 years from base well life. This will add approximate 14.8 Bscf of reserves. The addition of 14.8 Bscf to estimated remaining reserves of 6.4 makes in total 21.2 bscf. The additional reserves values to 47 Million USD. The estimated payout time of compression project in Sawan-1 is 2.2 months.

Table 6-1: Economic Analysis Sawan-1

Description	Raw	Feed
Cumulative Produced (Bscf)	186.8	139.72
Expected Cumulative Production at Abandonment (Bscf)	193.2	144.51
Expected Cumulative Production till Abandonment with compressor (Bscf)	208	155.58
Economic Analysis		
Remaining Recovery (Base case)	6.4	Bscf
Additional Recovery (Compression)	14.8	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	2.2	Month

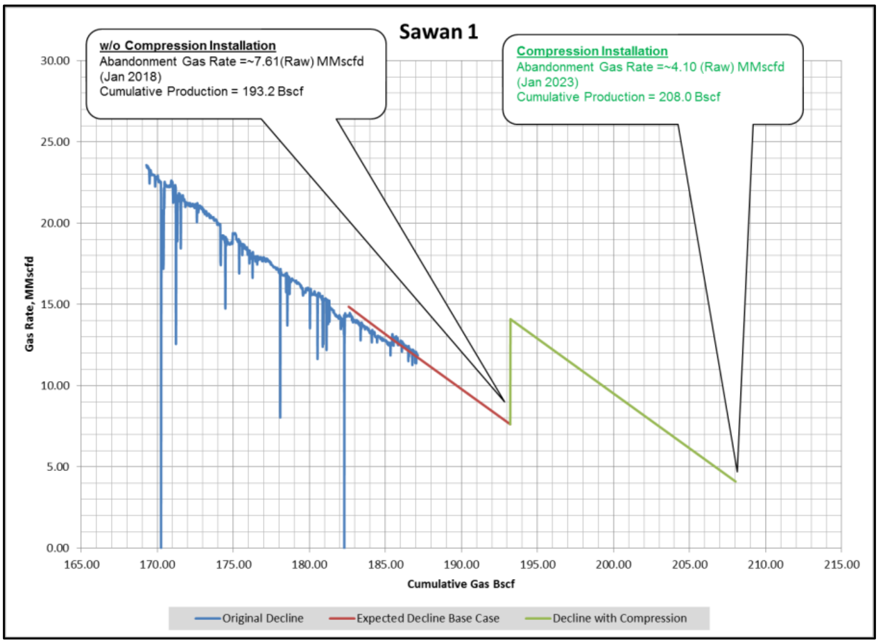

Figure 6-3: Sawan 1 Decline Curve Analysis

6.4 Sawan-2

Remaining reserves for Sawan-2 are approximate 3.9 Bscf. The compression project extends well life to approximate 6 years from base well life. This will add approximate 11.3 Bscf of reserves. The addition of 11.3 Bscf to estimated remaining reserves of 3.9 makes in total 15.2 bscf. The additional reserves values to 36 Million USD. The estimated payout time of compression project in Sawan-2 is 3.2 months.

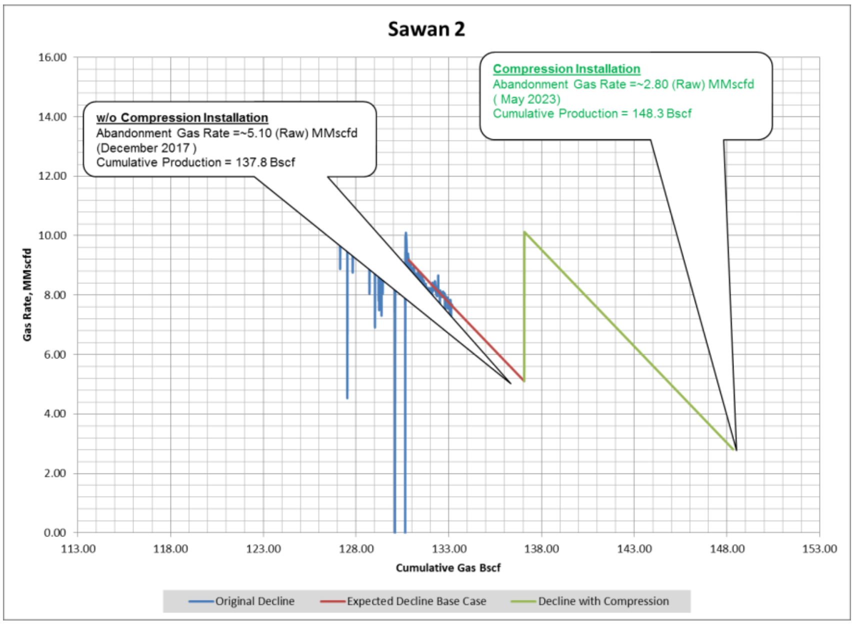

Figure 6-4: Sawan 2 Decline Curve Analysis

Table 6-2: Economic Analysis Sawan 2

Description	Raw	Feed
Cumulative Produced (Bscf)	133.1	99.55
Expected Cumulative Production at Abandonment (Bscf)	137.06	102.52
Expected Cumulative Production till Abandonment with compressor (Bscf)	148.3	110.92
Economic Analysis		
Remaining Recovery (Base case)	3.9	Bscf
Additional Recovery (Compression)	11.3	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	3.2	Month

6.5 Sawan-3

Remaining reserves for Sawan-3 are approximate 8.32 Bscf. The compression project extends well life to approximate 5 years from base well life. This will add approximate 12.48 Bscf of reserves. The addition of 12.48 Bscf to estimated remaining reserves of 8.32 makes in total 20.8 bscf. The additional reserves values to 39 Million USD. The estimated payout time of compression project in Sawan-3 is 2.53 months.

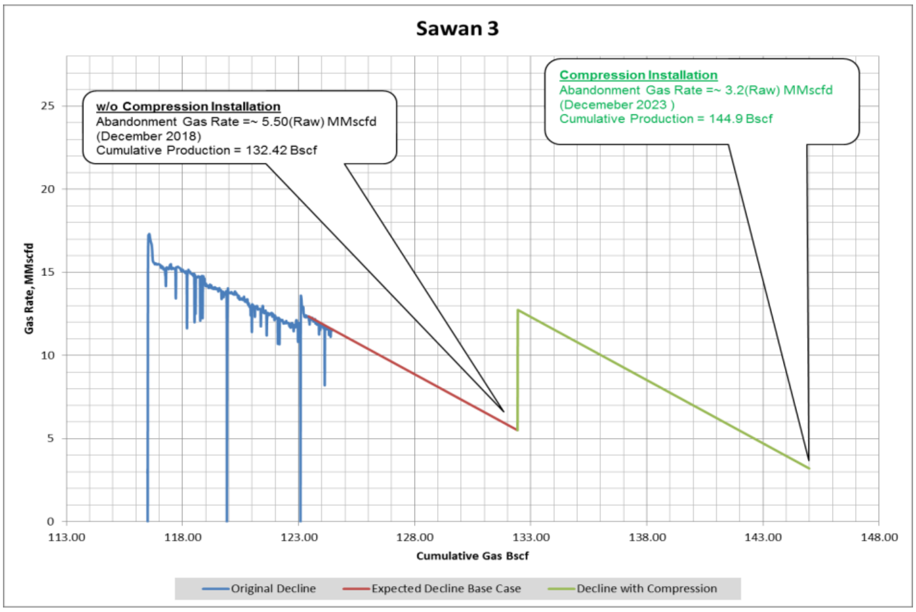

Figure 6-5: Sawan 3 Decline Curve Analysis

Table 6-3: Economic Analysis Sawan 3

Description	Raw	Feed
Cumulative Produced (Bscf)	124.1	92.75
Expected Cumulative Production at Abandonment (Bscf)	132.42	99.05
Expected Cumulative Production till Abandonment with compressor (Bscf)	144.9	108.38
Economic Analysis		

Remaining Recovery (Base case)	8.32	Bscf
Additional Recovery (Compression)	12.48	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	2.53	Month

6.6 Sawan 4

Table 6-4: Economic Analysis Sawan 4

Description	Raw		Feed	
WGR (bbl/MMscf)	**74**	**100**	**74**	**100**
Cumulative Produced (Bscf)	21.93	-	17.52	-
Expected Cumulative Production till Loading (Bscf)	23.22	23.13	18.34	18.27
Expected Cumulative Production till V. String loading	27.37	26.97	21.63	21.30
Economic Analysis				
WGR (bbl/MMscf)	**74**	**100**	**-**	
Remaining Recovery	1.29	1.20	Bscf	
Additional recovery V.S (loading)	4.15	3.84	Bscf	
Approximate CAPEX	1.5	1.5	Million USD	
Estimated Payout time	7.2	7.2	Month	

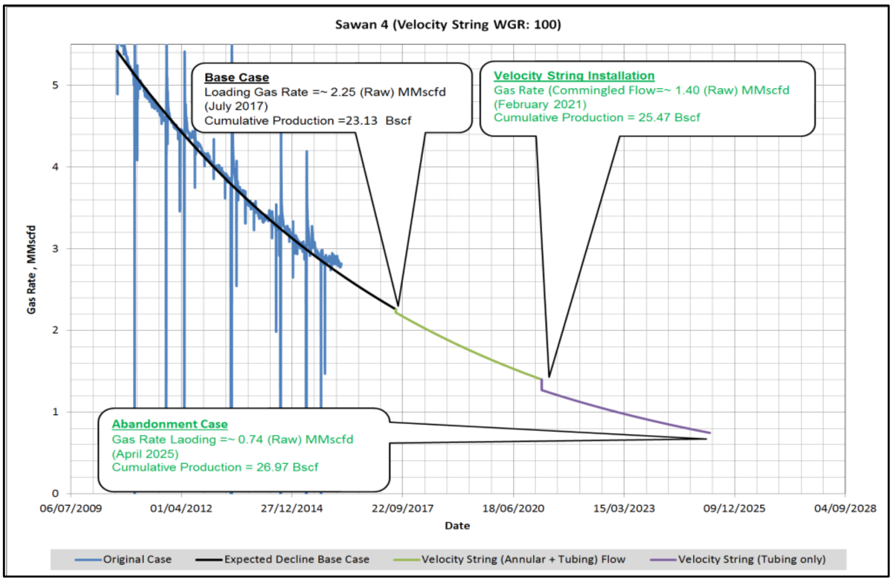

Figure 6-6: Sawan 4 (WGR: 100) Decline Curve Analysis

Well scenario has been distributed as present day WGR (74) and estimated worst case WGR (100). Remaining reserves for Sawan-4 are approximate 1.29 Bcf (WGR: 74) and 1.20 Bcf (WGR: 100). The velocity string project extends well life to approximate 8-9 years with stable flow conditions. The production for first four years in commingled flow and then as tubing flows. This will add approximate 4.15 Bcf (WGR: 74) and 3.84 Bcf (WGR: 100) of reserves. The addition of 4.15 and 3.84 Bscf to estimated remaining reserves of 1.29 and

1.20 makes in total of 5.44 and 5.04 bscf respectively. The additional reserves values to 13 & 12 Million USD. The estimated payout time is 7.2 months.

6.7 Sawan 5

6.7.1 Sawan-5 Option I Economic Evaluation

Well scenario has been distributed as present day WGR (45) and estimated worst case WGR (70). Remaining reserves for Sawan-5 are approximate 3.98 (WGR: 74) and 3.89 (WGR: 100) Bscf. The compression project extends well life to approximate ~5 years with stable flow conditions. This will add approximate 3.95 (WGR: 45) and 3.87 (WGR: 70) Bscf of reserves. These equal to almost same amount of remaining reserves. The addition of 3.95 and 3.87 Bscf to estimated remaining reserves of 3.98 and 3.89 makes in total of 7.93 and 7.76 bscf respectively. The additional reserves values to 12 Million USD. The estimated payout time is 10.3 months.

6.7.2 Sawan-5 Option II Economic Evaluation

The velocity string project extends well life to approximate 6 years (WGR: 45) and 4 years (WGR: 74) with stable flow conditions. The production is only taken via tubing flow. This project add approximate 2.07 (WGR: 45) and 1.67 (WGR: 74) Bscf of reserves. The addition of 2.07 and 1.67 Bscf to estimated remaining reserves of 3.98 and 3.89 makes in total of 6.05 and 5.56 bscf respectively. The additional reserves values to 6.5 & 5.3 Million USD. The estimated payout time is 11.6 months.

Table 6-5: Economic Analysis Sawan 5-Option I (Compression case)

	Raw		Feed	
WGR (bbl/MMscf)	**45**	**70**	**45**	**70**
Cumulative Produced (Bscf)	41.3	-	30.89	-
Expected Cumulative Production till Loading (Bscf)	45.28	45.19	33.86	33.80
Expected Cumulative Production till compressor lndg. (Bscf)	49.23	49.06	36.82	36.69
Expected Cumulative Production till compressor Abdn. (Bscf)	49.35	49. 15	36.91	36.89
Economic Analysis				
WGR (bbl/MMscf)	45	70	Units	
Remaining Recovery	3.98	3.89	Bscf	
Additional recovery- Compression (loading)	3.95	3.87	Bscf	
Additional recovery- Compression (Abandonment)	4.07	3.96	Bscf	
CAPEX	3	3	Million USD	
Estimated Payout time	10.3	10.3	Month	

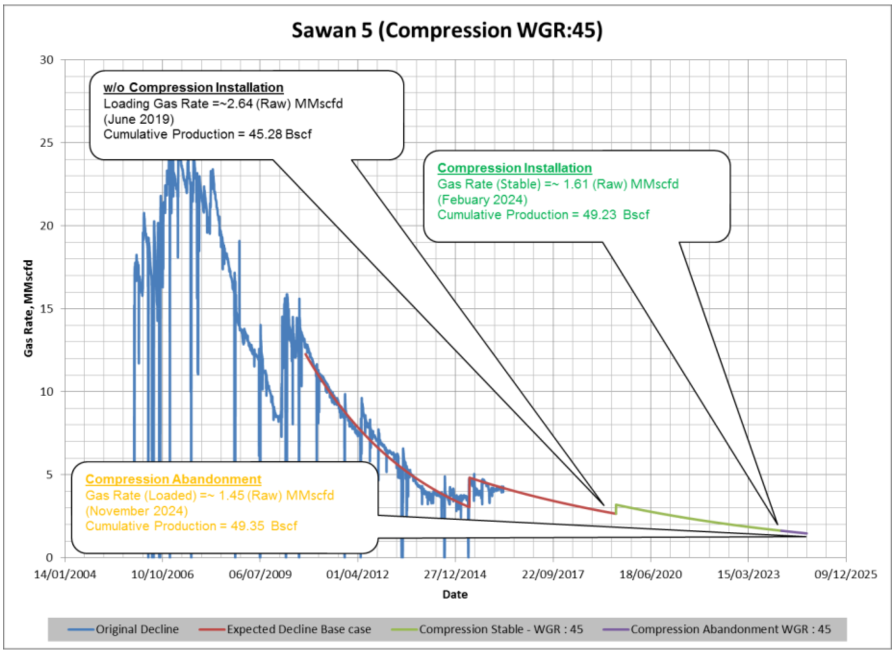

Figure 6-7: Sawan 5 (WGR: 45) Decline Curve Analysis-Compression

Table 6-6: Economic Analysis Sawan 5-Option II (Velocity String case)

Description	Raw		Feed	
WGR (bbl/MMscf)	**45**	**70**	**45**	**70**
Cumulative Produced (Bscf)	41.3	-	30.89	-
Expected Cumulative Production till Loading (Bscf)	45.28	45.19	33.86	33.80
Expected Cumulative Production till V. String loading	47.35	46.86	35.41	35.05
Economic Analysis				
WGR (bbl/MMscf)	**45**	**70**	**-**	
Remaining Recovery	3.98	3.89	Bscf	
Additional recovery V.S (loading)	2.07	1.67	Bscf	
Approximate CAPEX	1.5	1.5	Million USD	
Estimated Payout time	11.6	11.6	Month	

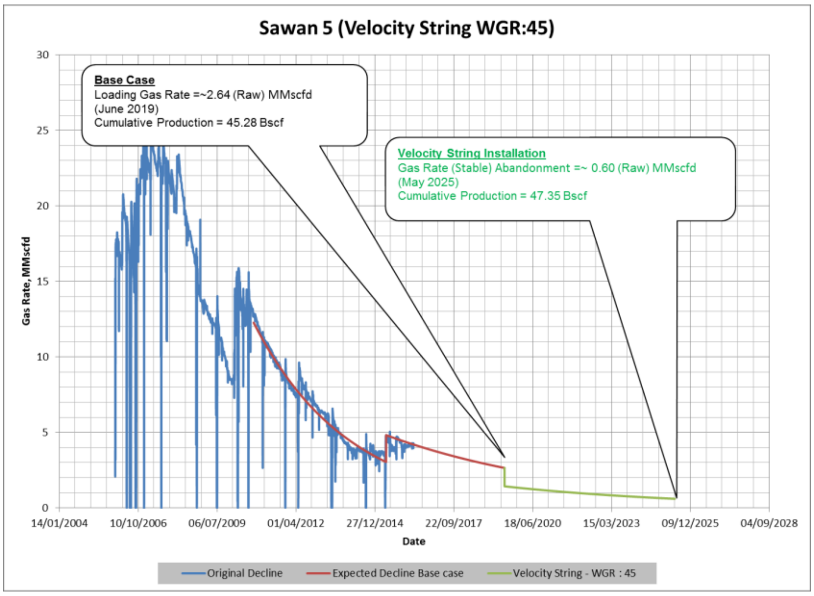

Figure 6-8: Sawan 5 (WGR: 45) Decline Curve Analysis-Velocity String 2.375”

6.8 Sawan 6

Table 6-7: Economic Analysis Sawan 6

	Raw	Feed
Cumulative Produced (Bscf)	0.12	0.12
Expected Cumulative Production till Abandonment (Bscf)	N/A	N/A
Expected Cumulative Production with V.S (Bscf)	0.14	0.14
Economic Analysis		
Remaining Recovery (Base case)	N/A	Bscf
Additional Recovery (Velocity String)	0.020	Bscf
Approximate CAPEX	1	Million USD
Estimated Pay out time	Negative	Month
Combination Case		
Expected Cumulative Production - Stable Flow(Bscf)	0.143	0.143
Expected Cumulative Production till Loading (Bscf)	0.148	0.148
Economic Analysis		
Additional Recovery (Combination Case)	0.028	Bscf
Approximate CAPEX	4.5	Million USD
Estimated Pay out time	Negative	Month

Well scenario has been analyzed with velocity string and combined case. The only benefit from combined case is stable flow section. The additions of reserves by either case are not justifying the CAPEX of the projects. “Raw” and “Feed “are assumed same without shrinkage factor as well is flowing intermittently. Payout time is negative which makes project economically unfeasible.

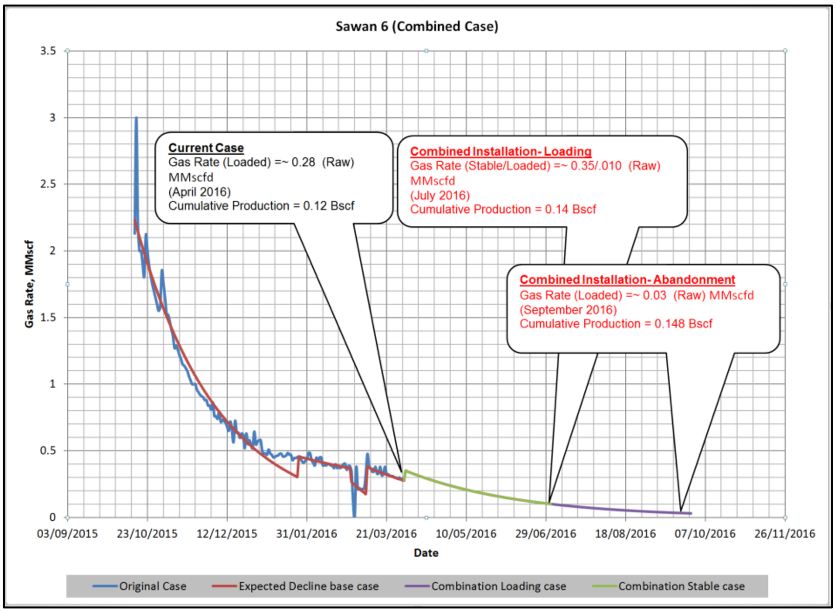

Figure 6-9: Sawan 6 Decline Curve Analysis-Combined case

6.9 Sawan-7

Remaining reserves for Sawan-7 are approximate 10.46 Bscf. The compression project extends well life to approximate 4 years from base well life. This will add approximate 15.74 Bscf of reserves. The addition of 15.74 Bscf to estimated remaining reserves of 10.46 makes in total 26.2 bscf. The additional reserves values to 50 Million USD. The estimated payout time of compression project in Sawn-7 is 1.46 months.

Table 6-8: Economic Analysis Sawan 7

Description	Raw	Feed
Cumulative Produced (Bscf)	348.1	260.37
Expected Cumulative Production at Abandonment (Bscf)	358.56	268.20
Expected Cumulative Production till Abandonment with compressor (Bscf)	374.3	279.97
Economic Analysis		
Remaining Recovery (Base case)	10.46	Bscf
Additional Recovery (Compression)	15.74	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	1.46	Month

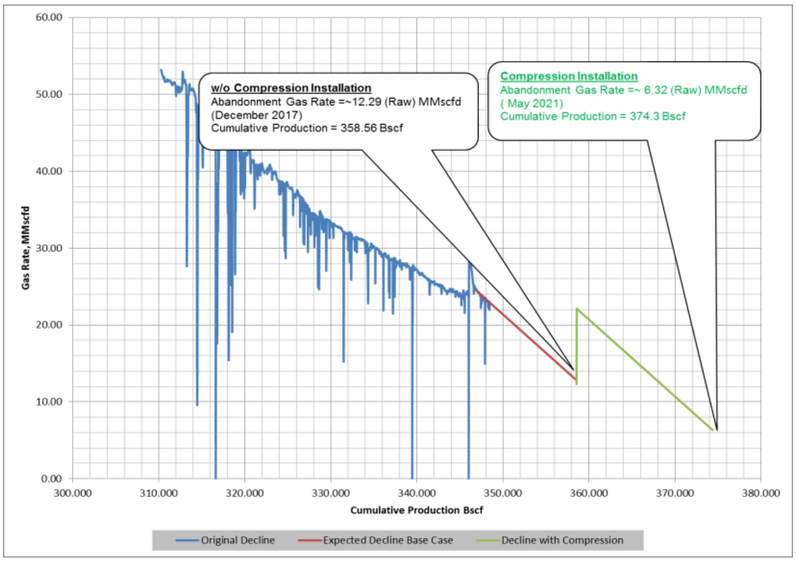

Figure 6-10: Sawan 7 Decline Curve Analysis

6.10 Sawan-8

Remaining reserves for Sawan-8 are approximate 11.38 Bscf. The compression project extends well life to approximate 5 years from base well life. This will add approximate 15.54 Bscf of reserves.

Table 6-9: Economic Analysis Sawan 8

Description	Raw	Feed
Cumulative Produced (Bscf)	215.8	161.41
Expected Cumulative Production at Abandonment (Bscf)	227.18	169.93
Expected Cumulative Production till Abandonment with compressor (Bscf)	242.70	181.53
Economic Analysis		
Remaining Recovery (Base case)	11.38	Bscf
Additional Recovery (Compression)	15.54	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	2.56	Month

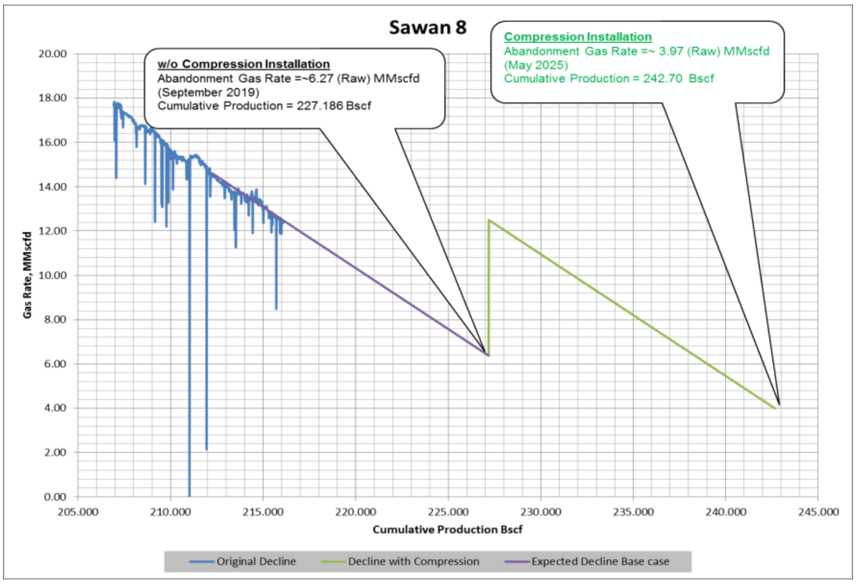

Figure 6-11: Sawan 8 Decline Curve Analysis

The addition of 15.54 Bscf to estimated remaining reserves of 11.38 makes in total 26.92 bscf. The additional reserves values to 49 Million USD. The estimated payout time of compression project in Sawan-8 is 2.56 months.

6.11 Sawan-9

Remaining reserves for Sawan-9 are approximate 5.8 Bscf. The compression project extends well life to approximate 5 years from base well life. This will add approximate 12.04 Bcf of reserves. The addition of 12.04 Bcf to estimated remaining reserves of 5.8 makes in total 17.84 Bcf. The additional reserves values to 38 Million USD. The estimated payout time of compression project in Sawn-9 is 2.73 months.

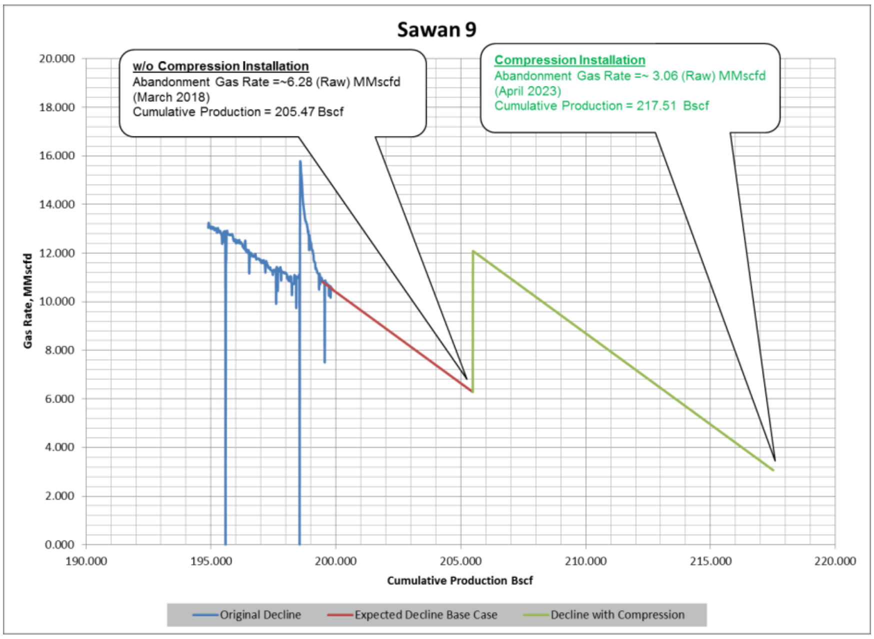

Figure 6-12: Sawan 9 Decline Curve Analysis

Table 6-10: Economic Analysis Sawan 9

Description	Raw	Feed
Cumulative Produced (Bscf)	199.67	149.35
Expected Cumulative Production at Abandonment (Bscf)	205.47	153.69
Expected Cumulative Production till Abandonment with compressor (Bscf)	217.51	162.69
Economic Analysis		
Remaining Recovery (Base case)	5.8	Bscf
Additional Recovery (Compression)	12.04	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	2.73	Month

6.12 Sawan 10

Well scenario has been analyzed with velocity string and foam + velocity string case. Foam lift adds 0.645 bcf additional recovery to current condition of well. The remaining reserves terminology is not applicable as well is already in loaded state. The payout time of 2.96 months justify the installment of foam lift on this well. Additional gross income expected is 2 Million USD. Another strategy is also proposed consisting of foam lift together with velocity string. (V.S: 2.375"). The payout time for this second project is 12.23 months. The expected recovery with gross income is 1.554 Bscf (5 Million USD). Figure 6.13 depicts both cases in one Decline curve.

Table 6-11: Economic Analysis Sawan 10

	Raw	Feed
Cumulative Produced (Bscf)	33.455	25.02
Foam Lift Scenario		
Expected Cumulative Production till Abandonment (Bscf)	34.100	25.50
Economic Analysis		
Remaining Recovery (Base case)	N/A	Bscf
Additional Recovery (Foam Lift)	0.645	Bscf
Approximate CAPEX	0.7	Million USD
Estimated Pay out time	2.96	Month
Foam Lift + Velocity String		
Expected Cumulative Production till Abandonment (Bscf)	35.009	26.186
Economic Analysis		
Remaining Recovery (Base case)	N/A	Bscf
Additional Recovery (Foam Lift + Velocity String)	1.554	Bscf
Approximate CAPEX	2.2	Million USD
Estimated Pay out time	12.23	Month

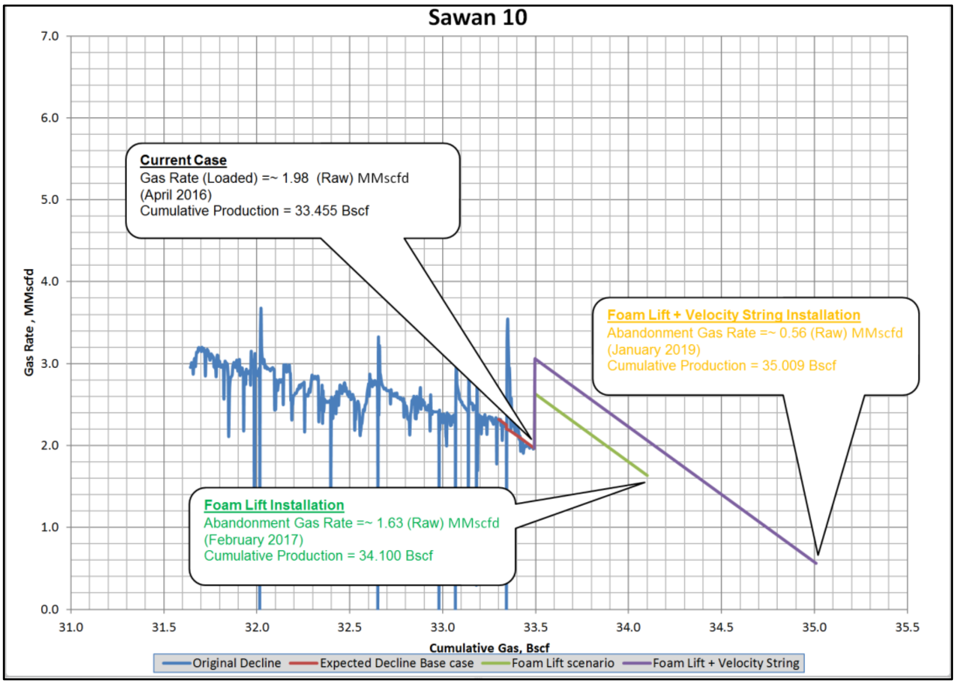

Figure 6-13: Sawan 10 Decline Curve Analysis

6.13 Sawan-11

Remaining reserves for Sawan-11 are approximate 1.33 Bscf. The compression project extends well life to approximate 4 years from base well life. This will add approximate 4.91 Bcf of reserves. The addition of 4.91 Bscf to estimated remaining reserves of 1.33 makes in total 6.24 Bscf. The additional reserves values to 15 Million USD. The estimated payout time of compression project in Sawn-11 is 6.4 months.

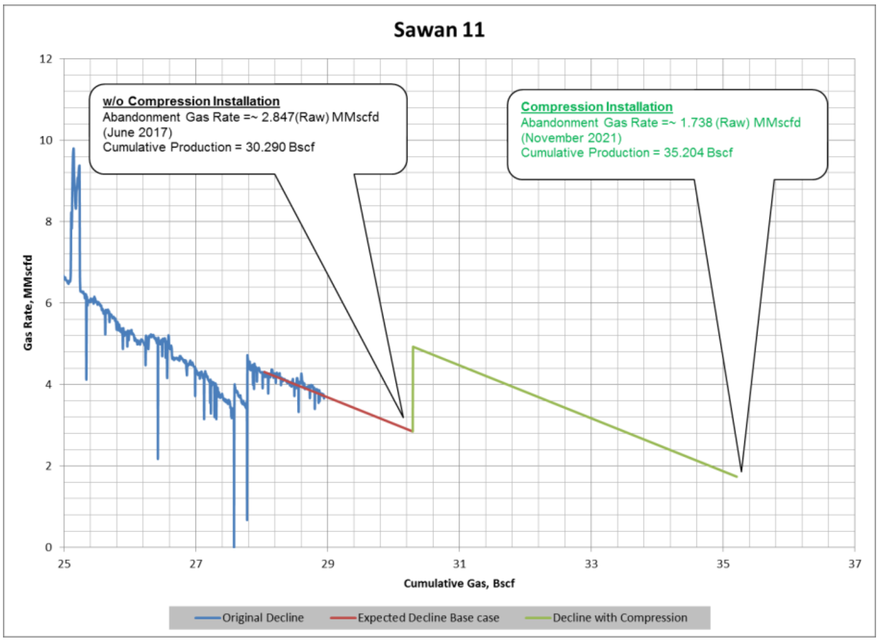

Figure 6-14: Sawan 11 Decline Curve Analysis

Table 6-12: Economic Analysis Sawan 11

Description	Raw	Feed
Cumulative Produced (Bscf)	28.95	21.64
Expected Cumulative Production at Abandonment (Bscf)	30.290	22.65
Expected Cumulative Production till Abandonment with compressor (Bscf)	35.204	47.064
Economic Analysis		
Remaining Recovery (Base case)	1.33	Bscf
Additional Recovery (Compression)	4.914	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	6.4	Month

6.14 Sawan 12

Well scenario has been analyzed with velocity string (1.5”). “Raw” and “Feed “are assumed same without shrinkage factor for this well because of intermittent flow. Reserves can’t be predictable. Rough increment of reserves is present in table 6.13. Payout time is negative which makes project economically unfeasible.

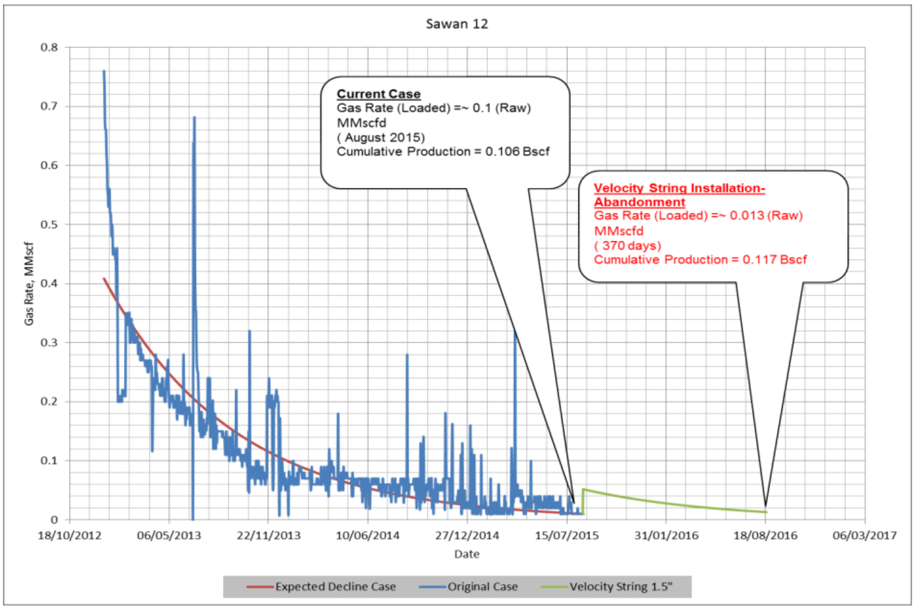

Figure 6-15: Sawan 12 Decline Curve Analysis

Table 6-13: Economic Analysis Sawan 12

	Raw	Feed
Cumulative Produced (Bscf)	0.106	0.106
V.S-Cumulative Production in Loaded Conditions(Bscf)	0.117	0.117
Economic Analysis		
Remaining Recovery (Base case)	N/A	Bscf
Additional Recovery (Velocity String)	0.011	Bscf
Approximate CAPEX	1	Million USD
Estimated Pay out time	Negative	Month

6.15 Sawan-13

Remaining reserves for Sawan-13 are approximate 3.75 Bscf. The compression project extends well life to approximate 5 years from base well life. This will add approximate 7.19 Bscf of reserves. The addition of 7.19 Bscf to estimated remaining reserves of 3.75 makes in total 10.94 Bscf. The additional reserves values to 23 Million USD. The estimated payout time of compression project is 4.3 months.

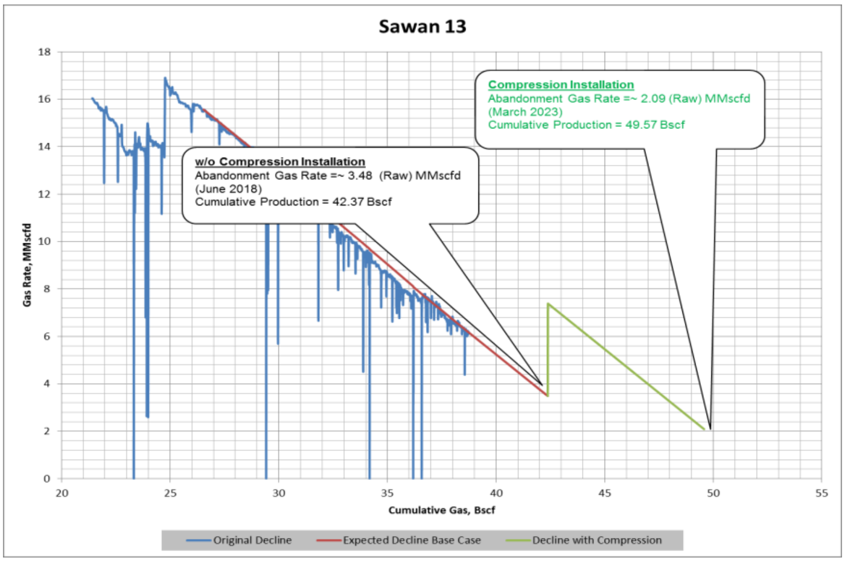

Figure 6-16: Sawan 13 Decline Curve Analysis

Table 6-14: Economic Analysis Sawan 13

Description	Raw	Feed
Cumulative Produced (Bscf)	38.62	28.88
Expected Cumulative Production at Abandonment (Bscf)	42.37	31.69
Expected Cumulative Production till Abandonment with compressor (Bscf)	49.57	37.08
Economic Analysis		
Remaining Recovery (Base case)	3.75	Bscf
Additional Recovery (Compression)	7.19	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	4.3	Month

6.16 Sawan-14

Remaining reserves for Sawan-14 are approximate 1.71 Bscf. The compression project extends well life to approximate 4 years from base well life. This will add approximate 4.35 Bscf of reserves. The addition of 4.35 Bscf to estimated remaining reserves of 1.71 makes in total 6.06 Bscf. The additional reserves values to 13.92 Million USD. The estimated payout time of compression project is 7.63 months.

Table 6-15: Economic Analysis Sawan 14

Description	Raw	Feed
Cumulative Produced (Bscf)	32.94	24.63
Expected Cumulative Production at Abandonment (Bscf)	34.65	25.91
Expected Cumulative Production till Abandonment with compressor (Bscf)	39.01	29.17
Economic Analysis		
Remaining Recovery (Base case)	1.71	Bscf
Additional Recovery (Compression)	4.35	Bscf
Approximate CAPEX	3	Million USD
Estimated Pay out time	7.63	Month

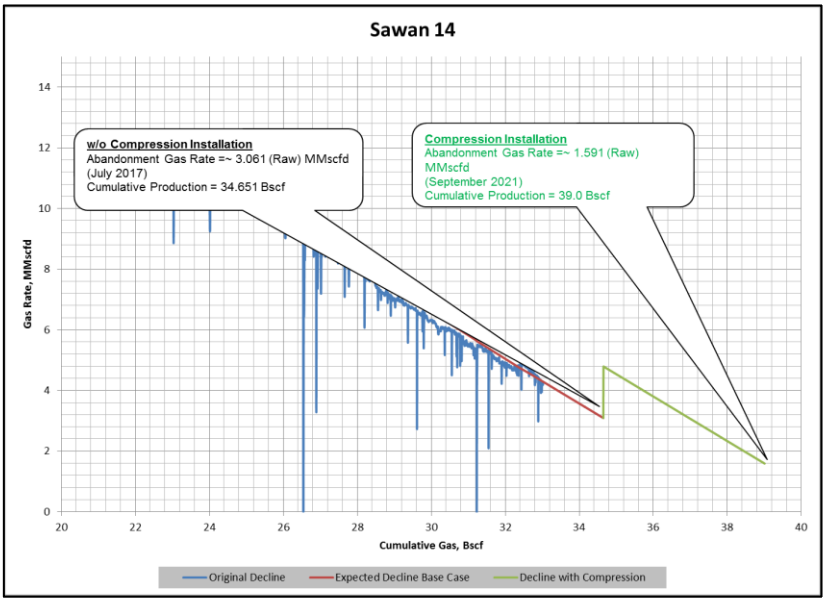

Figure 6-17: Sawan 14 Decline Curve Analysis

6.17 Sawan-15

Remaining reserves for Sawan-15 are approximate 0.62 Bscf. The compression project extends well life to approximate 2 years from base well life. This will add approximate 1.85 Bscf of reserves. The addition of 1.85 Bscf to estimated remaining reserves of 0.62 makes in total 2.47 Bscf. The additional reserves values to 5.92 Million USD. The estimated payout time of compression project is 7.5 months.

Table 6-16: Economic Analysis Sawan 15

Description	Raw	Feed
Cumulative Produced (Bscf)	28.19	21.08
Expected Cumulative Production at Abandonment (Bscf)	28.81	21.55
Expected Cumulative Production till Abandonment with compressor (Bscf)	30.67	22.94
Economic Analysis		
Remaining Recovery (Base case)	0.62	Bscf
Additional Recovery (Compression)	1.85	Bscf

Approximate CAPEX	3	Million USD
Estimated Pay out time	7.5	Month

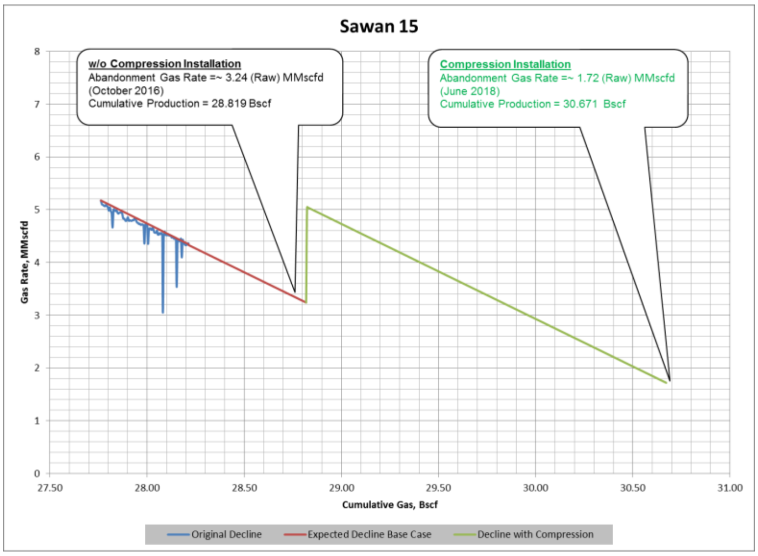

Figure 6-18: Sawan 15 Decline Curve Analysis

6.18 Risk & Safety Analysis

6.18.1 Economic Risk

Foam Lift costs about $ 0.7 Million USD (CAPEX) and $ 300 USD/day (OPEX). The risk of investment is comparatively small. Compression Setup costs about $ 3 Million USD (CAPEX) and $ 1200 USD/day (OPEX). The risk of investment is comparatively high. Velocity string cost about $ 1-1.5 Million USD (CAPEX). The risk of investment is comparatively medium. The cost of Foamer and Deformer is the major OPEX in Foam Lift. Compressor fuel is the major cost for Compression Project. Velocity string does not have any OPEX.

6.18.2 Operational Risk

1. Well Safety:
For Foam Lift, safety is somewhat compromised but it depends on how foam lift is installed in system. For Compression project, all safeties are intact. For Velocity String, safety is a big concern as there is no downhole safety barrier. Most velocity strings have single barrier safety installation.

2. Processing Plant Fluctuations:
Velocity String and Foam Lift are insensitive to plant conditions. Compressor is highly sensitive to upstream and downstream conditions. Fluctuations can possibly trip compressor.

3. Well Downhole Conditions:
Downhole condition highly affects life of velocity and capillary string especially the downhole injection valve for capillary strings. Chance of downhole Injection valve plugging is high in

case of fine production for capillary strings. For velocity strings, a chance of fishing in case of pinhole[16] problem is high. Both capillary and velocity strings are prone to corrosion.

4. Well Interventions:

Downhole intervention requires pulling out of capillary string for foam Lift. For velocity strings, downhole intervention is limited to velocity string inner diameter. For compression, well intervention is no issue.

5. Human Risk:

For Foam Lift, onsite chemical storage is not recommended because of high toxicity of chemicals. Chemicals need to be regularly delivered on site. Chances of hazards are present during chemical transportation and require regular human presence at well site for injection pump maintenance. For velocity string, no human risks are involved. For compressor, human presence is required for inspection.

6. Malfunction Diagnosing:

Downhole malfunctioning for velocity string and capillary string is not easily diagnosable. For compressor, malfunctioning is easy to detect.

7. **Operational Complexity**:

Operation complexity is high in Foam Lift. For Compression, it is medium whereas for velocity string it is low.

6.18.3 Environmental Risk

Foam Lift and Velocity strings have small surface foot prints whereas compressor has large footprints. For Foam Lift, chemicals used are toxic and spillage has negative effect on environment. So is not eco-friendly. Velocity String setup is eco-friendly. Compressor generates sound and air pollution due to fuel exhaust so is comparatively not friendly.

Table 6-17: Risk Summary

Risk Analysis Matrix			
	Foam Lift	**Compression**	**Velocity String**
Economics			
CAPEX			
OPEX			
Operational Risk			
Well Safety			
Plant Fluctuation			
Well Downhole Conditions			
Well Intervention			
Human Risk			
Malfunction Diagnostic			
Operational Complexity			
Environment Risk			
Foot Print			
Ecofriendly			

[16] Pinhole is a small hole that originates because of factors like corrosion

7 Results and discussion

This chapter presents the summarized recommendations for Sawan Gas Wells based on technical, economical and risk analysis.

7.9 Sawan-1

Compression on Sawan-1 is a low risk investment project with valuable gross income. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The rate at base abandonment is around 10 MMscfd. Later life well intervention job is easily possible with compression which will also aid in increasing well life. Compressor installation is satisfactory justified using economic analysis as the payout time is 2.2 months with high increment in recoverable reserves.

Table 7-1: Sawan-1 Recommendation Summary

Current Pressure	491	psi
Current Rate	8.79	MMscfd
Abandonment Base case Pressure	440	psi
Abandonment Base case Rate	5.7	MMscfd
Estimated Rate with Compression at base Abandonment	10.54	MMscfd
Compression Abandonment Pressure	215	psi
Compression Abandonment Rate	3	MMscfd
Remaining Recovery (Base case)	6.4	Bcf
Additional Recovery (Compression)	14.8	Bcf
Cumulative Produced (Bcf)	186.8	Bcf
Expected Ultimate Production	193.2	Bcf
Expected Ultimate Production w/Compression	208	Bcf
Estimated Pay out time	2.2	Month

7.10 Sawan-2

Compression on Sawan-2 is a low risk investment project with valuable gross income. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The difference between current pressure and abandonment pressure is not much. The rate at base abandonment is around 7.5 MMscfd. Later life well intervention job is easily possible with compression which will also aid in increasing well life. Compressor installation is satisfactory justified using economic analysis as the payout time is 3.2 months with high increment in recoverable reserves.

Table 7-2: Sawan -2 Recommendation Summary

Current Pressure	491	psi
Current Rate	5.8	MMscfd
Abandonment Base case Pressure	451	psi
Abandonment Base case Rate	3.82	MMscfd
Estimated Rate with Compression at base Abandonment	7.57	MMscfd
Compression Abandonment Pressure	255	psi
Compression Abandonment Rate	2.1	MMscfd
Remaining Recovery (Base case)	3.9	Bcf
Additional Recovery (Compression)	11.3	Bcf
Cumulative Produced (Bcf)	133.1	Bcf
Expected Ultimate Production	137.06	Bcf
Expected Ultimate Production w/Compression	148.3	Bcf
Estimated Pay out time	3.2	Month

7.11 Sawan-3

Compression on Sawan-3 is a low risk investment project with valuable gross income. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The rate at base abandonment is around 9.53 MMscfd. Compression on this well is not only justified with well life increment considering well head pressure restriction but also later life scale removal jobs or perforation cleaning that seems necessary for this well as per well history. Compressor installation is satisfactory justified using economic analysis as the payout time is 2.53 months with high increment in recoverable reserves.

Table 7-3: Sawan -3 Recommendation Summary

Current Pressure	561	psi
Current Rate	8.78	MMscfd
Abandonment Base case Pressure	480	psi
Abandonment Base case Rate	4.12	MMscfd
Estimated Rate with Compression at base Abandonment	9.53	MMscfd
Compression Abandonment Pressure	260	psi
Compression Abandonment Rate	2.39	MMscfd
Remaining Recovery (Base case)	8.32	Bcf
Additional Recovery (Compression)	12.48	Bcf
Cumulative Produced (Bcf)	124.1	Bcf
Expected Ultimate Production	132.42	Bcf
Expected Ultimate Production w/Compression	144.9	Bcf
Estimated Pay out time	2.53	Month

7.12 Sawan-4

Velocity String on Sawan-4 is a medium risk investment project. Well choke is 100% open. Hydraulics will be issue on this well when reservoir pressure drops to ~1250 psi. Two cases of WGR have been mentioned although difference in recoveries is not that high to impact overall assessment based on WGR view-point. Payout time with velocity string is 7.2 months. The string size of 2.375" has been selected so that later life limited intervention jobs like well cleaning is possible.

Table 7-4: Sawan -4 Recommendation Summary

WGR	74	100	bbl/MMscf
Current Pressure	1397		psi
Current Rate	2.21		MMscfd
Loading Base case Pressure	1235	1255	psi
Loading Base case Rate	1.76	1.78	MMscfd
Estimated Rate with V.S at base Loading	1.74	1.76	MMscfd
V.S Loading Pressure	655	700	psi
V.S Loading Rate	0.52	0.59	MMscfd
Remaining Recovery (Base case)	1.29	1.2	Bcf
Additional Recovery (Velocity String)	4.15	3.84	Bcf
Cumulative Produced (Bcf)	21.93		Bcf
Expected Ultimate Production	23.22	23.13	Bcf
Expected Ultimate Production w/Compression	27.37	26.97	Bcf
Estimated Pay out time	7.2	7.2	Month

7.13 Sawan-5

Table 7-5: Sawan-5 Recommendation Summary

WGR	45	70	bbl/MMscf
Current Pressure	941		psi
Current Rate	3.3		MMscfd
Loading Base case Pressure	735	755	psi
Loading Base case Rate	1.98	2	MMscfd
Estimated Rate with Compression at base Loading	2.37	2.42	MMscfd
Compression Loading Pressure	490	510	psi
Compression Loading Rate	1.21	1.25	MMscfd
Remaining Recovery (Base case)	3.98	3.89	Bcf
Additional Recovery (Compression)	3.95	3.87	Bcf
Cumulative Produced (Bcf)	41.3		Bcf
Expected Ultimate Production	45.28	45.19	Bcf
Expected Ultimate Production w/Compression	49.23	49.06	Bcf
Estimated Pay out time	10.3	10.3	Month

Compression on Sawan-5 is a high risk investment project. Well choke is 100% open. Hydraulics will be issue on this well when reservoir pressure drops to ~750 psi. Two cases have been mentioned with the priority given to compression project. The rate at base loading is around 2.37 MMscfd which is not a remarkable compared to north well cases. Payout time with compression is almost 10.3 months. The option discussed in technical and economical recommendation that consider the installment of 2.375" velocity string has been eliminated in final decision because the payout time for investment was 11.6 months .

7.14 Sawan-6

Sawan 6 might not be regarded as candidate for deliquification project. Stable production can't be guaranteed with any technique. Only combination can shift well to stable flow but combination case couldn't be justified economically. The well seems candidate for reservoir optimization. Performed fractured job on well failed to keep well stable. Currently intermittently flow is observed and incase of installment of velocity string, flow will continue to be intermittent. Payout time is negative which makes project economically unfeasible.

Table 7-6: Sawan-6 Recommendation Summary

Current Pressure (Loaded)	3500	psi
Current Rate (Well Loaded)	0.28	MMScfd
Gas Rate - Loaded (Velocity String-1.5")	0.27	MMScfd
Gas Rate (Velocity String-1.5") at abandonment	0.04	psi
Remaining Recovery (Base case)	N/A	Bscf
Additional Recovery (Velocity String)	0.02	Bscf
Cumulative Produced (Bscf)	0.12	Bscf
Expected Ultimate Production	N/A	Bscf
Expected Ultimate Production w/velocity string	0.14	Bscf
Estimated Pay out time	**Negative**	Month

7.15 Sawan-7

Table 7-7: Sawan -7 Recommendation Summary

Current Pressure	475	psi
Current Rate	17.7	MMscfd
Abandonment Base case Pressure	390	psi
Abandonment Base case Rate	9.2	MMscfd
Estimated Rate with Compression at base Abandonment	16.56	MMscfd
Compression Abandonment Pressure	200	psi
Compression Abandonment Rate	4.73	MMscfd
Remaining Recovery (Base case)	10.46	Bcf
Additional Recovery (Compression)	15.74	Bcf
Cumulative Produced (Bcf)	348.1	Bcf
Expected Ultimate Production	358.56	Bcf
Expected Ultimate Production w/Compression	374.3	Bcf
Estimated Pay out time	1.46	Month

Compression on Sawan-7 is a low risk investment project with valuable gross income. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The rate at base abandonment is around 16.56 MMscfd. Compression on this well is not only justified with well life increment considering well head pressure restriction but also later life perforation cleaning that seems necessary for this well as per well history. Compressor installation is satisfactory justified using economic analysis as the payout time is 1.46 months with high increment in recoverable reserves.

7.16 Sawan-8

Compression on Sawan-8 is a low risk investment project with valuable gross income. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The rate at base abandonment is around 9.39 MMscfd. Compression on this well is not only justified with well life increment considering well head pressure restriction but also later life scale removal jobs or perforation cleaning that seems necessary for this well as per well history. Compressor installation is satisfactory justified using economic analysis as the payout time is 2.56 months with high increment in recoverable reserves.

Table 7-8: Sawan -8 Recommendation Summary

Current Pressure	491	psi
Current Rate	8.91	MMscfd
Abandonment Base case Pressure	425	psi
Abandonment Base case Rate	4.69	MMscfd
Estimated Rate with Compression at base Abandonment	9.39	MMscfd
Compression Abandonment Pressure	235	psi
Compression Abandonment Rate	2.97	MMscfd
Remaining Recovery (Base case)	11.38	Bcf
Additional Recovery (Compression)	15.54	Bcf
Cumulative Produced (Bcf)	215.8	Bcf
Expected Ultimate Production	227.18	Bcf
Expected Ultimate Production w/Compression	242.7	Bcf
Estimated Pay out time	2.56	Month

7.17 Sawan-9

Compression on Sawan-9 is a low risk investment project with valuable gross income. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The rate at base abandonment is around 9.04 MMscfd. Compression on this well is not only justified with well life increment considering well head pressure restriction but also later life interventions. Compressor installation is satisfactory justified using economic analysis as the payout time is 2.73 months with high increment in recoverable reserves.

Table 7-9: Sawan -9 Recommendation Summary

Current Rate	7.36	MMscfd
Abandonment Base case Pressure	435	psi
Abandonment Base case Rate	4.7	MMscfd
Estimated Rate with Compression at base Abandonment	9.04	MMScfd
Compression Abandonment Pressure	240	psi
Compression Abandonment Rate	2.29	MMscfd
Remaining Recovery (Base case)	5.8	Bcf
Additional Recovery (Compression)	12.04	Bcf
Cumulative Produced (Bcf)	199.67	Bcf
Expected Ultimate Production	205.47	Bcf
Expected Ultimate Production w/Compression	217.51	Bcf
Estimated Pay out time	2.73	Month

7.18 Sawan-10

Sawan-10 well is currently producing in sluggish flow regime. Pilot test regarding installment of foam lift has been conducted in past which improved well hydraulics and rates. This well also needs cleaning job as no cleaning job has been conducted on this well in last five years. Sawan-10 can be divided as low risk and high risk cases. Low risk is the priority case based on early payout time. Secondary option has time of about one year. Well is quite stable with foam lift though increment in overall reserves is not much. The disadvantage of installing foam lift is the limited intervention on well. For some jobs, capillary string needs to be pulled out. In high risk case, safety needs to be compromised because of velocity string. The remaining reserves terminology is not applicable on this well. Sawan 10 is quite near to intermittent flow conditions

Table 7-10 Sawan-10 (Priority Case-Low Risk Scenario)

Current Pressure	1000	psi
Current Rate (Sluggish Flow)	1.49	MMscfd
Estimated Rate with Foam Lift (Stable Flow)	1.97	psi
Estimated Pressure at Foam Lift Abandonment	880	psi
Estimated Rate at Foam Lift Abandonment	1.22	MMscfd
Remaining Recovery (Base case)	*N/A	Bcf
Additional Recovery (Foam Lift)	0.645	Bcf
Cumulative Produced (Bcf)	33.455	Bcf
Expected Ultimate Production	*N/A	Bcf
Expected Ultimate Production w/Foam Lift	34.1	Bcf
Estimated Pay out time	2.96	Month

Table 7-11 Sawan-10 (Secondary Case-High Risk Scenario)

Current Pressure	1000	psi

Current Rate (Sluggish Flow)	1.49	MMscfd
Estimated Rate with Foam Lift+ Velocity String (Stable Flow)	2.29	psi
Estimated Rate with Foam Lift+ V.S Abandonment (Stable Flow)	530	psi
Estimated Rate at Foam Lift Abandonment	0.42	MMscfd
Remaining Recovery (Base case)	*N/A	Bcf
Additional Recovery (Foam Lift + V.S)	1.554	Bcf
Cumulative Produced (Bcf)	33.455	Bcf
Expected Ultimate Production	*N/A	Bcf
Expected Ultimate Production w/Foam Lift + V.S	35.009	Bcf
Estimated Pay out time	12.23	Month

7.19 Sawan-11

Compression on Sawan-11 is a medium risk investment project. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The rate at base abandonment is around 3.69 MMscfd. Later life well intervention job is easily possible with compression. Compressor installation is acceptable via economic analysis. The payout time for project is 6.4 months.

Table 7-12: Sawan -11 Recommendation Summary

Current Pressure	551	psi
Current Rate	2.75	MMscfd
Abandonment Base case Pressure	530	psi
Abandonment Base case Rate	2.13	MMscfd
Estimated Rate with Compression at base Abandonment	3.69	MMscfd
Compression Abandonment Pressure	315	psi
Compression Abandonment Rate	1.3	MMscfd
Remaining Recovery (Base case)	1.33	Bcf
Additional Recovery (Compression)	4.914	Bcf
Cumulative Produced (Bcf)	28.95	Bcf
Expected Ultimate Production	30.29	Bcf
Expected Ultimate Production w/Compression	35.204	Bcf
Estimated Pay out time	6.4	Month

7.20 Sawan-12

Sawan 12 may not be regarded as candidate for deliquification project. Stable production is not guaranteed even in combination case. The well seems candidate for inflow optimization. Performed fractured job on well failed to keep well alive. No reserves estimates are possible from well as abandonment and recovery for this well is based on the OPEX. Payout time is negative which makes project economically unfeasible.

Table 7-13: Sawan-12 Recommendation Summary

Last Recorded Pressure	3000	psi
Last Recorded Rate (Well Loaded)	0.018	MMscfd
Gas Rate (Velocity String-1.5")	0.05	MMscfd
Gas Rate (Velocity String-1.5") at abandonment	*[17]0.013	psi
Remaining Recovery (Base case)	N/A	Bcf
Additional Recovery (Velocity String)	*0.011	Bcf
Cumulative Produced (Bcf)	0.106	Bcf
Expected Ultimate Production	*0.013	Bcf
Expected Ultimate Production w/velocity string	*0.117	Bcf
Estimated Pay out time	Negative	Month

7.21 Sawan-13

Compression on Sawan-13 is a low risk investment project. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. Frequent cleaning jobs are required as per well history. The gain at base abandonment is around 5.53 MMscfd. Later life well intervention job is easily possible with compression. Compressor installation is acceptable via economic analysis. The payout time for project is 4.3 months.

Table 7-14: Sawan-13 Recommendation Summary

Current Pressure	571	psi
Current Rate	4.66	MMscfd
Abandonment Base case Pressure	510	psi
Abandonment Base case Rate	2.61	MMscfd
Estimated Rate with Compression at base Abandonment	5.53	MMscfd
Compression Abandonment Pressure	270	psi
Compression Abandonment Rate	1.57	MMscfd
Remaining Recovery (Base case)	3.75	Bcf
Additional Recovery (Compression)	7.19	Bcf
Cumulative Produced (Bcf)	38.62	Bcf
Expected Ultimate Production	42.37	Bcf
Expected Ultimate Production w/Compression	49.57	Bcf
Estimated Pay out time	4.3	Month

7.22 Sawan-14

Compression on Sawan-14 is a medium risk investment project. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The rate at base

[17] *Well last recorded rate is an averaged rate as behavior of well flow was intermittent.

abandonment is around 3.56 MMscfd. Later life well intervention job is easily possible with compression. Compressor installation is acceptable via economic analysis. Payout time is 7.63 months.

Table 7-15: Sawan-14 Recommendation Summary

Current Pressure	471	psi
Current Rate	3.29	MMsfd
Abandonment Base case Pressure	415	psi
Abandonment Base case Rate	2.29	MMsfd
Estimated Rate with Compression at base Abandonment	3.56	MMsfd
Compression Abandonment Pressure	240	psi
Compression Abandonment Rate	1.19	MMsfd
Remaining Recovery (Base case)	1.71	Bcf
Additional Recovery (Compression)	4.35	Bcf
Cumulative Produced (Bcf)	32.94	Bcf
Expected Ultimate Production	34.65	Bcf
Expected Ultimate Production w/Compression	39.01	Bcf
Estimated Pay out time	7.63	Month

7.23 Sawan-15

Compression on Sawan-15 is a medium risk investment project. Well choke is 100% open. As per technical analysis high wellhead pressure is restricting the well flow and indirectly controlling well life. Hydraulics will not be an issue for this well. The rate at base abandonment is around 3.78 MMscfd. Later life well intervention job is easily possible with compression. There are comparatively less reserves left for recovery from this well. Compressor installation is acceptable via economic analysis. Payout time is 7.5 months.

Table 7-16: Sawan-15 Recommendation Summary

Current Pressure	471	psi
Current Rate	3.33	MMscfd
Abandonment Base case Pressure	430	psi
Abandonment Base case Rate	2.43	MMscfd
Estimated Rate with Compression at base Abandonment	3.78	MMscfd
Compression Abandonment Pressure	260	psi
Compression Abandonment Rate	1.28	MMscfd
Remaining Recovery (Base case)	0.62	Bcf
Additional Recovery (Compression)	1.85	Bcf
Cumulative Produced (Bcf)	28.19	Bcf
Expected Ultimate Production	28.81	Bcf
Expected Ultimate Production w/Compression	30.67	Bcf
Estimated Pay out time	7.5	Month

8 Conclusions

The wells of the Sawan North area are still able to recover substantial reserves. North wells have only condensed water production. Almost all Sawan North producing condense water are showing natural abandonment trend because of high surface downstream pressure. The application of a wellhead compressor for wells located in the North of the Sawan field is highly recommended. The payout time for most of these wells is below 5 months. However, the well Sawan-10 requires special treatment. This well is showing hydraulics issues at the base case, meaning that other form of lifts like foam lift should be applied on this well. Otherwise this well may die in the near future. On contrary to the wells located in the North, South wells will show hydraulics issues in later life. For Sawan-6 and Sawan-12 deliquification is not recommended, but they should be considered for reservoir treatment. For Sawan-4, the velocity string is the best option whereas compression is better for Sawan-5. Table 8.1 presents the conclusive recommendations per well basis. The risk analysis is shown with different color codes. Low risks are colored in green based on payout time and possible hazards. A Payout time of less than 5 months is marked in green, 8 months in orange and higher in red.

Table 8-1 : Recommended Decision Matrix

Well	Suggested Method-Technical	Suggested Method-Economical	Suggested Method-Risk Analysis	Final Selection
Sawan 1	Compression	Compression		Compression
Sawan 2	Compression	Compression		Compression
Sawan 3	Compression	Compression		Compression
Sawan 4	Velocity String	Velocity String		Velocity String
Sawan 5	Compression/ Velocity String	Compression		Compression
Sawan 6	Velocity String/Combined*	Not Recommended		Not Recommended
Sawan 7	Compression	Compression		Compression
Sawan 8	Compression	Compression		Compression
Sawan 9	Compression	Compression		Compression
Sawan 10	Foam Lift/ Foam + V.S	Foam Lift		Foam Lift
Sawan 11	Compression	Compression		Compression
Sawan 12	Velocity String	Not Recommended		Not Recommended
Sawan 13	Compression	Compression		Compression
Sawan 14	Compression	Compression		Compression
Sawan 15	Compression	Compression		Compression

The option for vacuum jacket tubing for the individual wellbores has not been considered as wells having hydraulic problems produce more formation water than condensed water. Wells that only produce condensed water are the candidate for compression only due to the back pressure of the plant. Ultimate recovery on a well basis is summarized in table 8.2. Sawan 6 and 12 have been included since incremental reserves from these two wells are not affecting overall field recovery.

Table 8-2: Summary of Reserves Analysis

Well	Location	Produced Reserves (Bcf)	Remaining (Base case Reserves) (Bcf)	Recommended Incremental Reserves (Bcf)	Total (Bcf)
Sawan 1	North	186.8	6.4	14.8	208
Sawan 2	North	133	3.9	11.3	148.2
Sawan 3	North	124	8.32	12.48	144.8
Sawan 4	South	21.93	1.29	4.15	27.37
Sawan 5	South	41.3	3.98	3.95	49.23
Sawan 6	South	0.12	N/A	0.028	0.148
Sawan 7	North	348.1	10.56	15.74	374.4
Sawan 8	North	215.8	11.38	15.54	242.72
Sawan 9	North	199.67	5.8	12.04	217.51
Sawan 10	North	33.455	N/A	0.645	34.1
Sawan 11	North	28.95	1.33	4.91	35.19
Sawan 12	South	0.106	N/A	0.011	0.117
Sawan 13	North	38.62	3.75	7.19	49.56
Sawan 14	North	32.94	1.71	4.35	39
Sawan 15	North	28.191	0.62	1.85	30.661
Total	**-**	**1432.982**	**59.04**	**108.984**	**1601.006**

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Appendices

Appendix A: Condense Water Plots

Calculation is based on the equations of Bukacek [5, 31]. The Bukacek correlation is presented in graphical format in figures in this appendix figures A.1 and A.2.

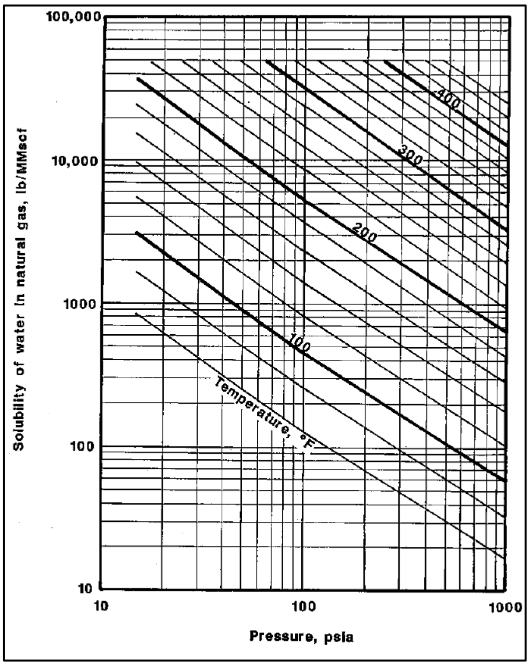

Figure 0-1: Solubility of water in Natural gas at low pressure [5. p.458]

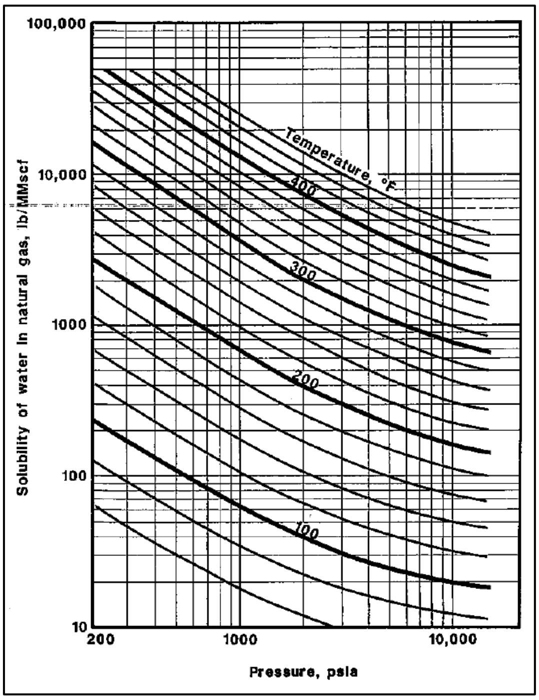

Figure 0-2: Solubility of water in Natural gas at high pressure [5. p.459]

Appendix B: Development of Critical Velocity Equation

This appendix summarizes the development of the Turner equation to calculate the minimum gas velocity to remove liquid droplets from a vertical wellbore. [1, 11] Consider gas flowing in a vertical wellbore and a liquid droplet transported at a uniform velocity in the gas stream. The forces acting on the droplet are gravity, pulling the droplet downward, and the upward drag of the gas as it flows around the droplet. The gravity force is

$$F_G = \frac{g}{g_c}(\rho_L - \rho_G) \times \frac{\pi d^3}{6} \qquad B.1$$

And drag force is

$$F_D = \frac{1}{2g_c}\rho_G C_D A_d (V_G - V_d)^2 \qquad B.2$$

Parameters have already been described in abbreviation section of document. For convenience, some are presented here:

$g = \text{gravitational constant} = 32.17 \frac{ft}{s^2}$

$g_c = 32.17 \frac{lbm - ft}{s^2}$

$d = \text{droplet diameter}$

$\rho_L = \text{liquid density}$

$\rho_L = \text{liquid density}$

$\rho_G = \text{gas density}$

$C_D = \text{drag coefficent}$

$A_d = \text{droplet projected cross} - \text{sectional area}$

$V_G = \text{gas velocity}$

$V_d = \text{droplet velocity}$

The critical gas velocity to remove the liquid droplet from the wellbore is defined as the velocity at which the droplet would be suspended in the gas stream (terminal velocity). A lower gas velocity would allow the droplet to fall, resulting in liquid accumulation in the wellbore. A higher gas velocity would carry the droplet upward to the surface and remove the droplet from the wellbore. At critical velocity the liquid droplet velocity is zero, i.e. the net force on the droplet is zero. The defining equation for the critical gas velocity is then:

$$\frac{g}{g_c}(\rho_L - \rho_G)\frac{\pi d^3}{6} = \frac{1}{2g_c}\rho_G C_D A_d {V_c}^2 \qquad B.3$$

Substituting $A_d = \frac{\pi d^2}{4}$ and solving for critical velocity "V_C" gives

$$V_c = \sqrt{\frac{4g}{3}\frac{d}{C_D}\frac{(\rho_L - \rho_G)}{\rho_G}} \qquad B.4$$

This equation assumes a known liquid droplet diameter. In reality, the droplet diameter is dependent upon the gas velocity. For liquid droplets entrained in a gas stream Turner used dimensionless Weber number concept. The droplet diameter "d" can be replaced in B.4 with the Weber number defined presented in eq. B.5. B.4 simplifies to B.6 after introducing B.5.

$$N_{WE} = \frac{V_c^2 \rho_G d}{\sigma g_c} = 30 \qquad B.5$$

$$V_c = \left(\frac{40 g_c g}{C_D}\right)^{\frac{1}{4}} \left(\frac{\rho_L - \rho_G}{{\rho_G}^2}\sigma\right)^{\frac{1}{4}} \qquad B.6$$

Turner assumed a C_D "drag coefficient" as 0.44. Substituting the turbulent drag coefficient and values for g and g_c gives:

$$V_c = 1.593 \left(\frac{\rho_L - \rho_G}{{\rho_G}^2}\sigma\right)^{\frac{1}{4}} \frac{ft}{s} \qquad B.7$$

$$\rho_G = \text{gas density} \frac{lbm}{ft^3}$$

$$\rho_L = \text{liquid density} \frac{lbm}{ft^3}$$

$$\sigma = \text{surface tension } \frac{dyne}{cm}$$

Equation can be simplified further by applying typical values for the gas and liquid properties. From the real gas law, the gas density is given by

$$\rho_G = 2.715 \gamma_g \frac{P}{(460 + T)Z} \frac{lbm}{ft^3} \qquad B.8$$

$$\text{Water density} = 67 \frac{lbm}{ft^3}$$

$$\text{Condensate density} = 45 \frac{lbm}{ft^3}$$

$$\text{Water surface tension} = 60 \frac{dyne}{cm}$$

$$\text{Condensate surface tension} = 20 \frac{dyne}{cm}$$

$$\gamma_g = 0.6$$

$$T = 120 \text{ F}$$

$$Z = 0.9$$

Putting above values in equation B.8 gives

$$\rho_G = 0.0031P \frac{lbm}{ft^3} \qquad B.9$$

Finalized equation proposed by Turner is B.10

$$V_{c,water} = 5.321 \left(\frac{67 - .0031P}{(.0031P)^2}\right)^{\frac{1}{4}} \frac{ft}{s} \qquad B.10$$