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Presented by:

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-THEME-

Solving the water loading problem in In Saleh gas Field

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and our university career and to the entire pedagogical team of the faculty of Hydrocarbons

Dedication

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Chabbi Abdelhamid

Abstract:

Liquid loading, a significant issue in the Tegentour zone of the In Saleh Gas Field, was addressed in this study. Two wells were examined using well production data, well test data, logging, and pressure surveys to identify symptoms of liquid loading. The proposed solutions included implementing a velocity string and conducting a water shut-off installation. The optimal configuration of the velocity string was determined through simulation using Wellflo software. The results of implementing both technologies were thoroughly discussed and analyzed, providing valuable insights into mitigating liquid loading.

Key Words: Liquid Loading; Water Loading; Well Flo software; Symptoms; Water Shut Off; Velocity String

Résumé

Le chargement liquide, un problème significatif dans la zone de Tegentour du champ gazier de In Saleh, a été abordé dans cette étude. Deux puits ont été examinés à l'aide de données de production, de Well tests, Diagraphie, les mesures de pression statique pour identifier les symptômes du chargement liquide. Les solutions proposées comprenaient la mise en place d'un Velocity string et l'installation d'un bouchon d'eau. La configuration optimale du Velocity string a été déterminée par simulation à l'aide du logiciel Wellflo. Les résultats de la mise en œuvre des deux technologies ont été soigneusement discutés et analysés, fournissant des informations précieuses pour atténuer le chargement liquide.

Mots-clés : Chargement liquide ; Chargement d'eau ; Logiciel Wellflo ; Symptômes ; Bouchon D'eau ; Velocity string

تم التعامل في هذه الدراسة مع مشكلة تجمع السائل، وهي مشكلة كبيرة في منطقة تيغنتور في حقل عين صالح. تم فحص بئرين باستخدام بيانات إنتاج البئر، وبيانات الاختبارات، والتسجيلات، واستطلاعات الضغط لتحديد أعراض تجمع السوائل. تشمل الحلول المقترحة تركيب Velocity stringواستعمال حاجز لإيقاف تدفق الماء تسمى:Water shut off تم اختيار التركيب الأمثل لل Velocity String من خلال المحاكاة باستخدام برنامج Wellflo .كما قمنا بمناقشة وتحليل نتائج تنفيذ كلا التقنيتين بشكل كامل ودقيق، مما يوفر نظرة قيمة في تخفيف مشكلة تحميل السوائل في الابار الغازية.

الكلمات الرئيسية:

تجمع السائل، تجمع الماء،Velocity string, Water shut off, Wellflo , حاجز ,أعراض تجمع السوائل.

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GLOSSARY OF TERMS, SYMBOLS AND ACRONYMS

Glossary of Terms, Symbols and acronyms	
GWC	Gas Water Contact (m)
LGC	Liquid Gas contact
LGR	Liquid Gas Ratio
Pr:	Reservoir Pressure (psi)
Tr:	Reservoir Temperature (C°)
P_{wh}	Wellhead Pressure (psi)
P_{wf}	Flowing Bottom Hole Pressure (bar)
WGR	Water Gas Ratio (MMscf/Bbl)
Q_g	Gas Flow Rate (MMscf/d)
Q_{cg}	Critical Gas Rate (Mmscf/d)
Vt	Terminal velocity of the liquid droplet (ft/s)
σ	Interfacial tension is taken as 60 (dynes/cm)
ρl	Liquid-phase density (lbm/ft3)
ρg	Gas-phase density (lbm/ft3)
CNDG	National Center for Gas Distribution,
Vc.condensate:	the critical velocity for condensate (ft/sec**)**
Vc.water	the critical velocity for water (ft/sec**)**
VS	Velocity String
WSO	Water Shut off
TRSV	Tubing Retrievable safty valve
SSSV	Sub Surface Safety Valve
AOF	Absolute open flow potential (Mmscf/d)
VLP	vertical lift performance
IPR	Inflow performance relationship
Δp	Pressure drops (Psi)
TPC	Tubing performance curve
ISG	In Saleh Gas
Kh	Permeability-thickness product
GPLT	Gas loaded net porous thickness

GLOSSARY OF TERMS, SYMBOLS AND ACRONYMS

PBR	Polished Bore Receptacle
XPT	The Pressure Xpress tool
MPLT	Memory Production Logging Tool
mTVDBRT	Metres true vertical depth below rotating
CPF	The central processing facility
GLC	Gas Liquid contact

INRODUCTION

INTRODUCTION

When there is sufficient reservoir energy and gas wells can be produced at medium to high rates, co-production of liquids is seldom a problem, even at high liquid to gas ratio's (LGR). Although the liquid slips through the gas, effectively the gas liquid mixture tends to behave like a single-phase liquid flowing to surface, where the phases can be separated and processed. Those Liquids come from multiple sources, including formation water, condensate, and interstitial water. Formation water invading the wellbore is the most common source. The accumulation of liquids that are co-produced with gas at the bottom of the well during gas production when the transport energy can no longer transport it to the surface is called liquid loading. [1]

The main cause of the liquid loading phenomenon is when the reservoir depletes, the reservoir pressure drops and the produced gas flow rate decreases until the gas reaches a critical condition at which time the liquid loading is initiated, if this condition is allowed to continue, the wellbore will accumulate sufficient fluids to balance the available reservoir energy entirely and cause the well to die and even kills the gas well.

Thesis Problematic:

After more than 10 years of continuous development, part of the wells in the Tegentour gas reservoir located at the IN Saleh gas field have entered the middle–later production stage. With the continuous decline in formation pressure and production rates, some of the gas wells have entered the potential period of liquid loading. due to its high-water production, specific reservoir conditions, and large production 7" ID string is very important and needs to be one of the most essential research projects.

The water loading issue in the Tegntour gas field poses significant challenges and impacts on the production of gas wells. The accumulation of water in the wellbore hinders the flow of gas, resulting in decreased production rates, erratic production behavior, and potential cessation of gas production.

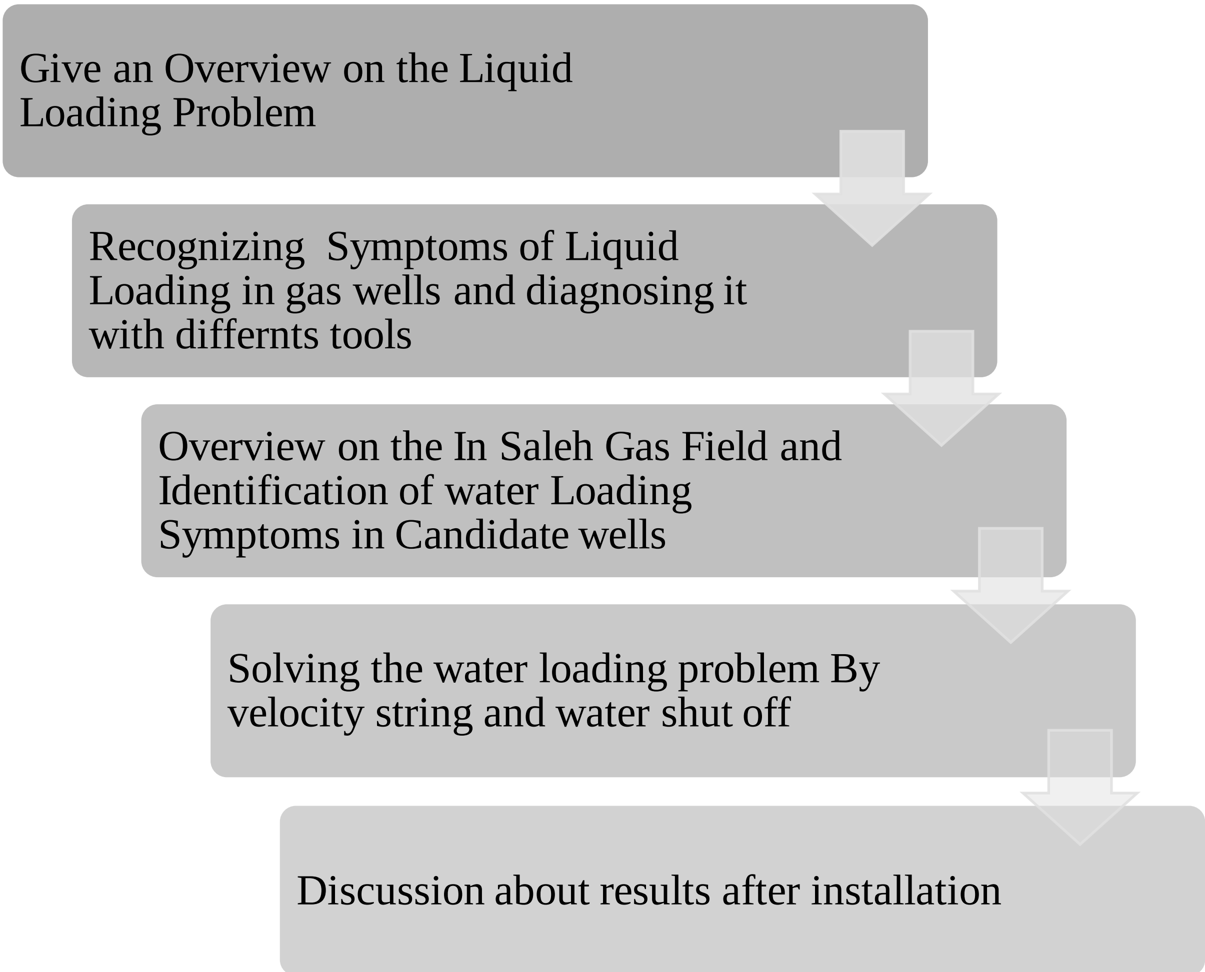
INTRODUCTION

Objectives of the study:

The objectives of this study are as follows:

- ❖ The identification of water loading symptoms in the selected wells for study
- ❖ By simulating the installation process and analyzing its impact on well performance, the efficiency of the Velocity String in mitigating water loading issues was evaluated.
- ❖ Description about the Water shut off method.
- ❖ Discuss the Results after the installation of both methods and evaluating their effectiveness

Methodology :



First chapter

Background Of Liquid Loading Problem

1.1 Notions about liquid loading problem in gas wells:

The concepts of the liquid loading in gas wells based on the understanding of the sources of liquids, the different multiphase flows, and the indicators of the liquid loading.

I.1.1 Preface

Liquid loading is the most common cause of production impairment in gas well and can lead to erratic slug flow and decreased production from the well. The well may eventually die if the liquids are not removed continuously or well may produce at the rate less than the well potential. Hence it is necessary to identify the cause of liquid loading and suitable remedial actions are needed to be taken**.** To understand this problem, we had talk in this chapter the general concepts of liquid loading.

I.1.2 What is liquid loading:

Inability of the well to lift the fluid associated with the gas production to the surface When a gas well is producing, the pressure in the gas reservoir is high and the gas velocity in the tubing is sufficient to lift the liquids that are produced with the gas upwards to the surface. However, after several years, the pressure in the reservoir will become so low that the gas does not meet the critical velocity necessary to transport all produced liquids to the surface, The problem happens because the velocity of the gas in the tubing drops with time, and the velocity of the liquids decline even faster as the production goes on. [1]

Under this condition, the produced liquids will accumulate in the wellbore, imposing additional backpressure (high hydrostatic pressure in the well) against the formation that can significantly affect the production capacity of the well. The overall result of liquid loading is an increase in back-pressure on the reservoir and reduction in gas production, which causes the well to die if no intervention is implemented. [5]

I.1.3 Flow Patterns in a Gas Well:

To understand the effects of liquids in a gas well, it is necessary to understand how the liquid and gas phases interact under flowing conditions. Multiphase flow in a vertical conduit is usually represented by four basic flow regimes as shown in **Figure** I.**1**. At any given time in a well’s history, one or more of these regimes will be present. A flow regime is determined by the velocity of the gas and liquid phases and the relative amounts of gas and liquid at any given point in the flow stream.

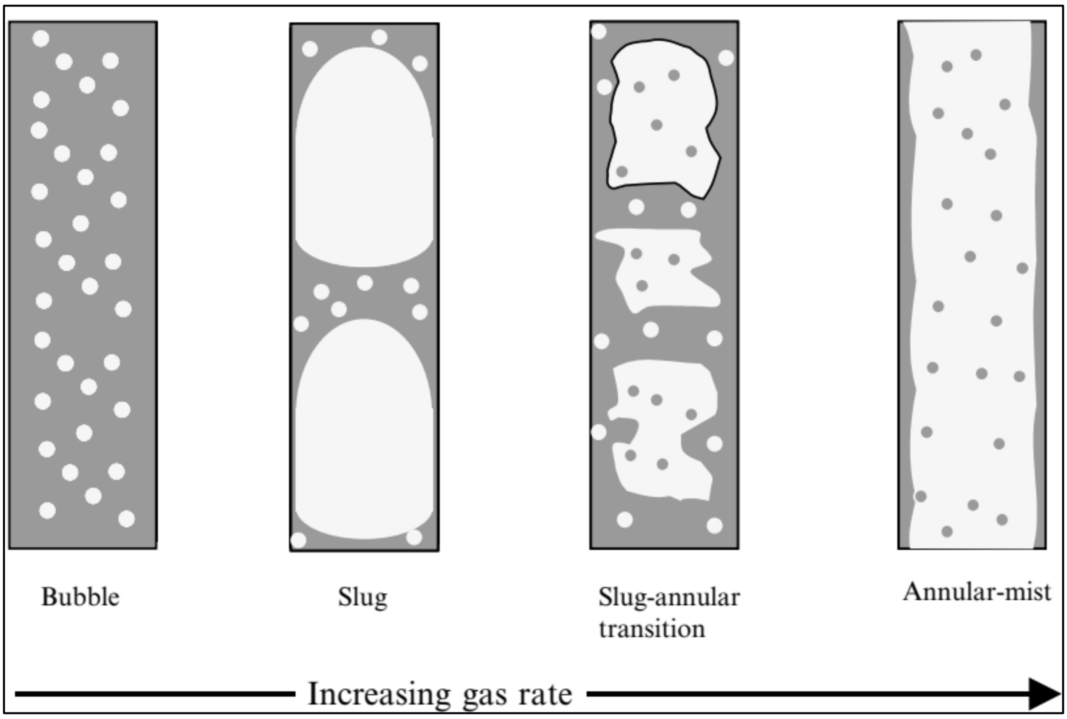
The flow regimes are largely classified with bubble flow, slug flow, slug-annular transition flow and annular mist flow, which are determined by the velocity of the gas and liquid phases and the relative amounts of gas and liquid at any given point in the flow stream. [1]

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

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

Slug-Annular Transition: The flow changes from continuous liquid to continuous gas phase. Some liquid may be entrained as droplets in the gas. Gas dominates the pressure gradient, but liquid is still significant.

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 pressure gradient is determined predominately from the gas flow

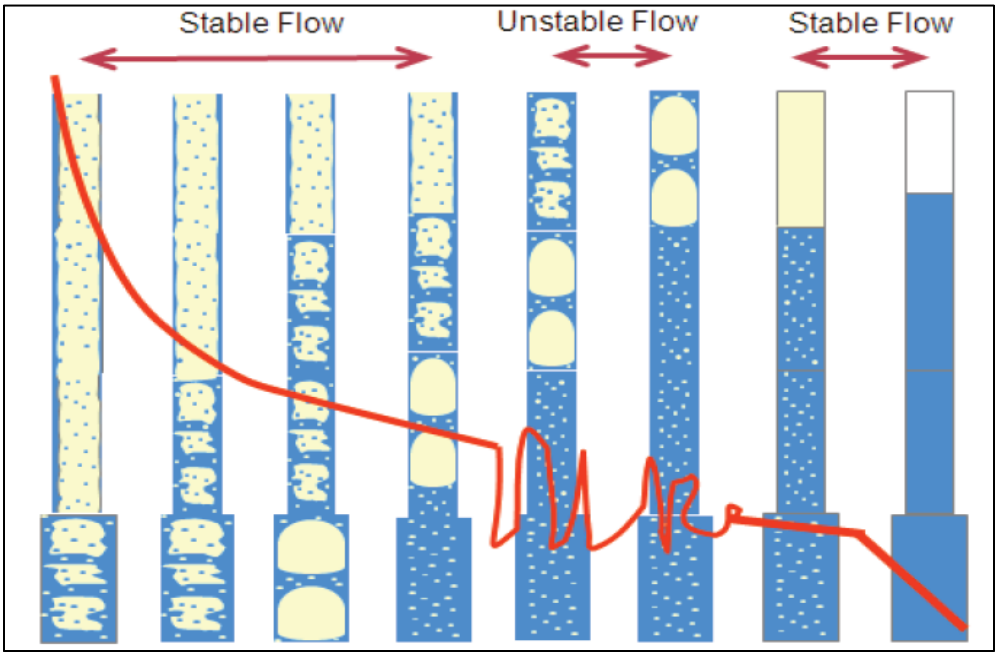


FigureI.1: Flow regimes of a naturally flowing gas **[1]**

I.1.4 Flow regimes in the life of a typical well:

A well may go through several flow regimes including bubble flow, slug flow, slug annular transition flow and annular-mist flow during the course of its life. **Figure** I.**2** shows a well loading Flow regimes in from initial production to end of life.

Initially, the well has a sufficient gas rate, the gas rate is above the critical unloading rate. At this stage, the flow regime in the production tubing is usually mist flow. As time progresses and gas production decreases, typical of normal production decline, the flow pattern progresses from mist flow to bubble flow until a static equilibrium fluid condition is built in the tubing. During the transition from mist to bubble flow the bottom hole backpressure in the wellbore continuously increases, resulting in reduced gas flow rate. The static fluid height in the tubing, associated with the bubble flow regime, will eventually stop or decrease the gas production if no corrective action is taken, resulting in a premature dead well and significant unrecovered gas reserves. [2]



FigureI.2: Life history of a gas well [2]

I.1.5 Source of liquids in gas wells:

Only a small number of gas wells produce completely dry gas. This means that almost every gas well produces liquids along with gas even if the produced amount of liquids is very small. These liquids may be free water, water condensate and/or hydrocarbon condensate. Condensate may be produced as liquid, or vapor depending on the reservoir and wellbore pressure. Produced liquids along with gas may have several sources depending on the conditions and type of the reservoir from which gas is produced. [3]

- There may be an aquifer below the gas zone which may either lead to water coning or water encroachment.
- The source of liquids may be another zone or zones, especially if the completion type of the well is open hole.
- The water produced along with gas may be free water present in the formation.
- Depending on the reservoir, bottomhole and tubing head pressures water and/or hydrocarbon vapor may enter the well and condense while travelling up the production tubing, coming out as liquid.

a. **Water Coning:** Gas wells are often completed in gas zones which are underlain by a water zone (water table). When such a well is put on production, a pressure sink is created around it which may extend all the way to the water zone and cause water to enter the wellbore. This phenomenon is called 'water coning' after the shape of the interface between gas and water. If the gas rate of the well is high enough, this may result in high decline pressure enough to pull water production from the underlying zone, even if the perforations do not extend to the underlying zone. [4]

b. **Aquifer Water:** If the reservoir has a water-drive mechanism, the aquifer giving pressure support to produced gas will eventually reach the perforations and into the wellbore. This phenomenon is also called *water encroachment*. After water reaches wellbore, liquid loading problems will rise, reservoir pressure will start to drop sharper than before as the drive mechanism is depleting with produced gas. [4]

c. **Free Water Formation:** Water can enter the well through the perforations with the produced gas. This can be a result of thin layers of gas and liquid. [4]

d. **Water Production from Another Zone**: Especially in open-hole completions and some cases wells with multiple perforations, it is possible to produce liquids from another zone unintentionally. [4]

e. **Condensed Water**: Since nearly every reservoir contains free formation water, natural gas present in the reservoir may be saturated if the conditions are suitable for water to dissolve in natural gas. In this case, water will enter the well as vapor dissolved in natural gas and there will be no or very little water in liquid phase at the bottom, near the perforations. As the solution flows through the production string the water will start condensing if the temperature and pressure conditions in the well drop below dew point. If the amount of condensed water is high in the well, it will create a high hydrostatic pressure in the string, increasing the pressure, therefore causing water solubility in gas to decrease even more and causing more water to condense. Eventually, condensed water will accumulate at the bottom of the well. [5]

f. **Hydrocarbon Condensates:** Like water, hydrocarbons can also enter the well with the produced gas in the vapor phase. As the gas solution flows to the surface, vapor state hydrocarbons may start condensing when conditions drop below the dew point and eventually start loading up the well just like water. [5]

I.1.6. Factors that Exacerbate Liquid Loading:

Although liquid loading is a natural phenomenon, early and massive liquid production could be caused by a poorly designed well completion or bad production practices such as excessive withdrawal beyond the optimum rate for a particular well, or both. Other important factors that can contribute to liquid loading in gas wells include pressure drops; high drawdown; high wellhead pressure; high condensate/ gas ratio (CGR); leaks; channelling and water coning. In any of these instances, be it a dry or wet gas reservoir, a gas well could be vulnerable to early liquid accumulation in the wellbore. The impact of these factors are briefly discussed below. [6]

- ✓ **Pressure drops with time.** Dropping pressure is inevitable since it is one of the major driving forces causing fluid flow to occur in wells and reservoirs. However, excessive or rapid pressure drop with time, which can occur due to well problems such as damage and inadequate completions, could lead to fast depletion of the reservoir energy, which may not be sufficient enough to lift any liquids that accumulate at the bottom of the wellbore.

- ✓ **High wellhead pressure.** When the reservoir pressure is relatively low and the wellhead pressure is very high and almost equals the bottomhole flowing pressure, the fluid at the bottom of the wellbore may not be able to flow to the surface, thereby allowing the bulk of the fluid to accumulate in the wellbore.

- ✓ **Poorly designed well completions.** Knowledge of the reservoir and fluid characteristics aid optimal well completion design. Inadequate sizing of completion parameters such as tubing size, perforation interval, surface and subsurface restrictions and the flowline could significantly contribute to the problem of liquid loading.

- ✓ **High condensate-gas ratio (CGR).** This is peculiar to wet-gas and gas condensate reservoirs. When the liquid-to-gas ratio increases in the well stream, the carrying capacity of the gas reduces, thereby allowing the bulk of the liquids to accumulate at the bottom of the wellbore. This can impose a back pressure on the formation and eventually kill the well if the liquid level rises above the perforation interval open to gas flow in the well. [6]

- ✓ **Leaks, channelling and water coning:** Leaks arise from inherent reservoir and wellbore defects, or from wear and tear. For channelling, water will always look for the path of least resistance (channelling through fractures which connect the aquifer and the reservoir), and flow into the wellbore through the leaks. Since natural gas is soluble in water, dissolved gas can increase the mass of the liquid phase, reducing the carrying capacity of the vapour phase. [6]

I.2. Identification of Liquid Loading in gas wells:

Although wells subject to liquid loading may still produce for a long period of time if properly managed, the occurrence of liquid loading is not always obvious.

Liquid loading will not always lead to non-production. If a well is loaded, it still may produce for a long time. If liquid loading is recognized and reduced, higher producing rates are achieved. This implies that even after the inception of liquid loading, the symptoms may not be conspicuous enough to be detected either by physical means or the use of available predictive models.

I.2.1. Diagnostic Tools

Hence, the use of diagnostic tools to discover its occurrence could be very useful in preventing or delaying it occurrence. Most of these diagnostics require little or no cost to uncover liquid loading. Examples of diagnostic tools that could be deployed include:

a. numerical or analytical models to predict the critical rate
b. monitoring the casing and tubing head pressure with time
c. plots of gas production rate with time
d. making pressure gradient plots

e. use well performance plots

f. use production logging tool (PLT)

I.2.2 Liquid Loading symptoms in gas wells

The first step in preventing liquid loading in gas wells involves the ability to identify the symptoms that are associated with wells that are on the verge of being liquid loaded or are already loaded with liquids. Below is a list of some of the common symptoms of liquid loading, and wells that show two or more of these symptoms have the tendency to produce liquids:

a. Increasing the difference between the tubing and casing pressure:

once liquids begin to accumulate at the bottom of the wellbore, the well will begin to experience a decreasing tubing pressure while the casing pressure will increase. The rise in the casing pressure is due to the percolation of gas from the reservoir in the tubing casing annulus as the tubing is loaded with liquids, whereas the decreasing tubing pressure is due to increase in the liquid holdup in the tubing. This symptom is seen in wells completed without packers where interaction exists between the tubing and the casing. Packers are used for zonal isolation and also to plug-off the annulus between the casing and the tubing to ensure that flow is through the tubing alone. For open-ended completions (without packers), the build-up of liquids at the wellbore will cause the flowing bottom hole pressure to rise thereby causing a back pressure on the formation. [7]

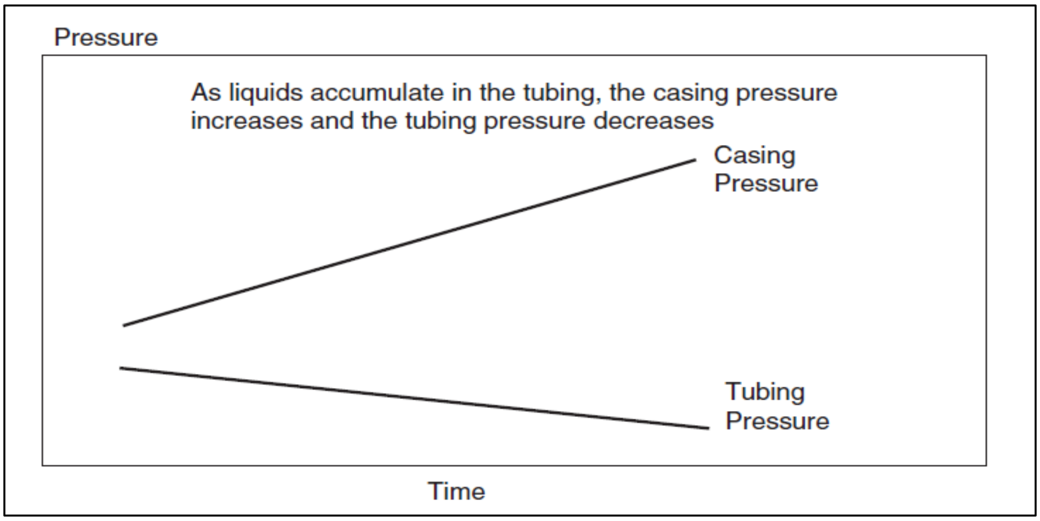


Figure I.3: Casing and Tubing pressure indicator [7]

b. The onset of liquid slugs at the surface of the well:

when a well produces liquids without loading problems, the liquids are produced in the gas stream as small droplets (mist flow) and have little effect on orifice pressure drop. However, when liquid slug passes through orifice the relative high density of liquid slug causes a pressure Spike. A pressure spike on a plot of orifice pressure drop usually indicates that liquids are beginning to accumulate in the wellbore and /or the flow line and are being produced erratically as some of the liquids reach the surface as slugs.

The onset of liquid slugs at the wellhead is one of the ways of detecting liquid loading. When liquids produced from a typical gas well do not arrive at the surface in a steady continuous flow, but instead arrive as slugs of fluid at the surface, this is a clear indication of liquid accumulation in the wellbore. [8]

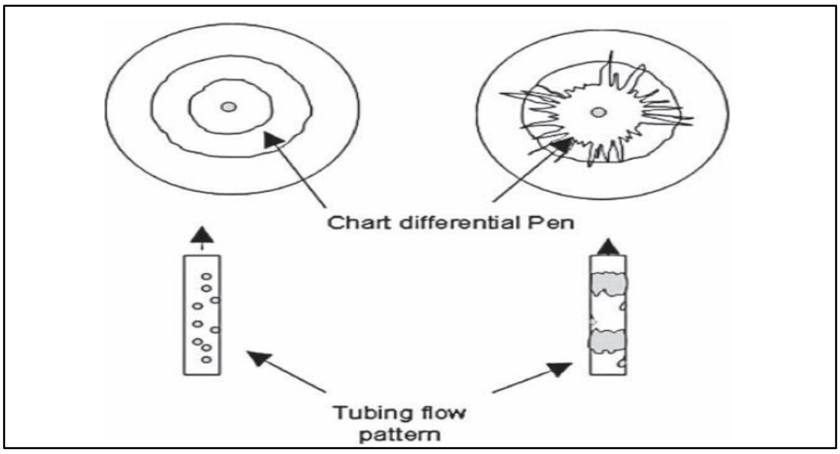


Figure I.4: Effect of flow regime on orifice pressure drop [8]

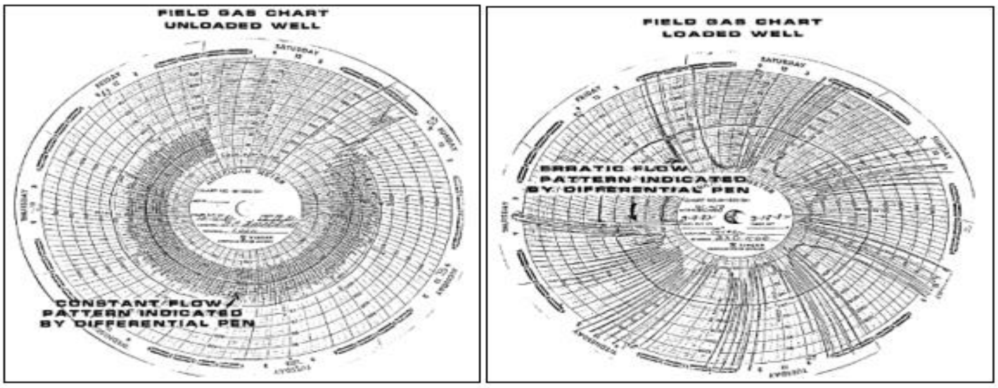


Figure I.5: Gas Chart for loaded and Unloaded Wells.[8]

c. **Erratic production and increase in decline rate**. An important indication of downhole liquid loading problems is the shape of a decline curve. The decline curve should be analysed for long periods and changes in the general trend need to be diagnosed. This is explained by **Figure I.6**. The smooth exponential type decline curve represents a single gas production, while the sharply fluctuating curve is an indicative of liquid loading as it shows a sudden departure from the existing curve to a new steeper slope. Well abandonment will occur far earlier than with the original curve.

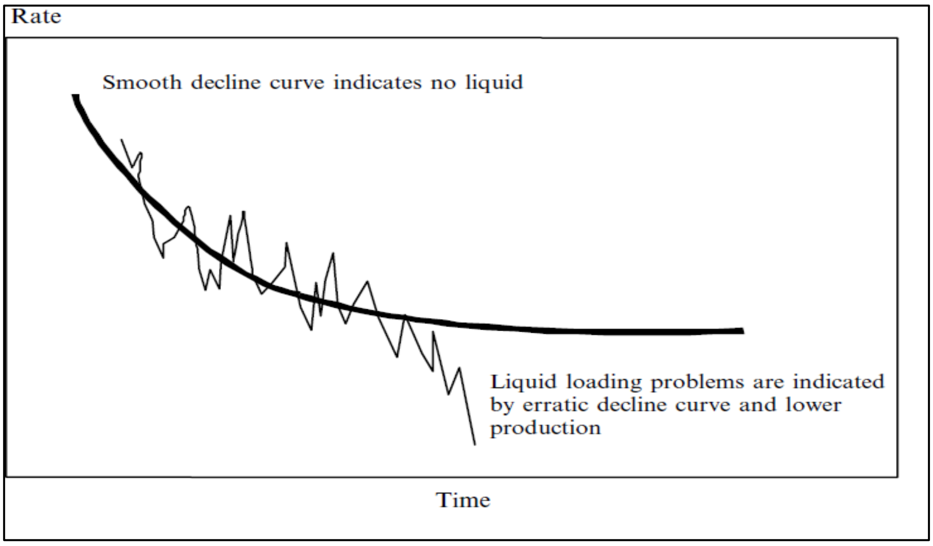


Figure I.6: Decline curve showing onset of liquid loading.[4]

d. **increasing liquid level in a gas well.**

Increasing liquid level in a flowing gas; well, is another indicator of liquid loading. Increasing liquid level can be determined using either pressure surveys or an acoustic liquid level measuring instrument. Pressure surveys (also called pressure gradient surveys) take measurements of pressure with depth when the well is either shut-in or flowing by using a downhole pressure gauge. Two types of pressure survey conducted in gas wells are the flowing and static pressure surveys. A flowing pressure survey is conducted when the well is flowing, while static pressure survey is done when the well is shut-in. The measured pressure gradient is a direct function of the density of fluid and the depth [7]. Figure I.7is a typical gradient plot, showing different pressure gradients above and below the gas-liquid contact (GLC). The pressure is constant across the gas-liquid contact. As can be seen in FigureI.7, the pressure gradient is constant below the GLC, but the increased pressure gradient below the GLC is an indication of the presence of a denser fluid in a standing liquid column within the tubing. [9]

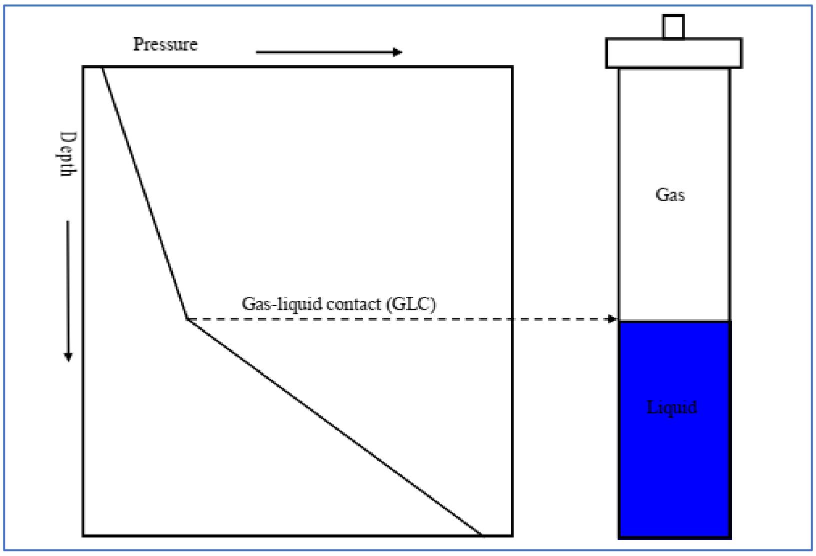


Figure I.7: typical gradient plot, showing different pressure gradients.[9]

e. Acoustic fluid level measurements in gas wells (Echo meter):

The use of an acoustic liquid level instrument is a non-intrusive method that determines the liquid level using an echo sounding technique. Several acoustic shots are made to determine the gas/liquid interface position, which exhibits constant pressure and thus the liquid level in the tubing [4]. This method works best for gas wells that are shut-in for extended periods at the surface to allow for the segregation of the fluids in the system.

f. Liquid production stops altogether:

Continued accumulation of liquids at the bottom of the wellbore can lead to complete stoppage of liquids being lifted to the surface. This happens when the gas production rate has substantially declined to a rate that is unable to transport accumulated liquids to the surface. At this stage, the gas only bubbles through the accumulated liquid and is produced at a reduced production rate at the surface, while the liquid remains at the bottom of the wellbore. [10]

g. Decreasing wellhead temperature:

Like the reservoir temperature, the wellhead temperature is relatively constant, even though there exists a considerable cooling effect as the reservoir fluid flows to the surface. However, a significant drop in the wellhead temperature over time is another indication that liquid loading is taking place [11]

I.3. Predicting liquid loading in gas wells

To mitigate the impact of liquid loading, it is essential to accurately predict the onset of liquid loading and develop effective remediation strategies. In recent years, several models have been developed to predict liquid loading in gas wells.

I.3.1 Critical Rate concepts:

To effectively plan and design the liquid loading problems of gas well it is essential to accurately predict when a particular well might begin to experience excessive liquid loading. The “Critical velocity” method is presented to predict under what conditions the onset of liquid loading occurs. So, in practice, the critical velocity is generally defined as the minimum gas velocity in the production tubing required moving liquid droplets upward. Among the notable and classical correlations in this category still effectively used today is the Turner et al. model. Turner et al. are considered the pioneering investigators of liquid loading phenomena in gas wells and most of the other prediction models developed, even in the other categories, take a cue from this classic model. Turner et al. developed and compared two models:

- The continuous film models.
- The entrained droplet movement model.

They considered each independently even though they recognized that both might contribute to liquid accumulation in gas wells.

I.3.2 Turner et al Entrained Drop Movement Model:

Among the notable and classical correlations in this category still effectively used today is the Turner et al. model. Turner et al. are considered the pioneering investigators of liquid loading phenomena in gas wells and most of the other prediction models developed, even in the other categories, take a cue from this classic model.

The entrained drop model, also called Turner’s droplet model, is currently the most popular empirical correlation for calculating the critical velocity in gas wells in the oil and gas industry. The model was developed based on the force balance on the terminal velocity of a falling droplet. This model proposes that a freely falling liquid droplet in a gas stream will attain a terminal velocity when the drag forces equal the gravitational forces. If the gas were moving at velocity sufficient to hold a droplet in suspension, the gas velocity would be equal to the free fall terminal velocity of the droplet. The studies of Turner et al. state that the existence of liquid drops in the gas stream present a different problem, which is basically determining the minimum gas flow rate that will lift the drops out of the well to the surface (Figure I.8).

According to the study, a free-falling particle reaches a terminal velocity which is the maximum velocity it can attain against gravity. [12]

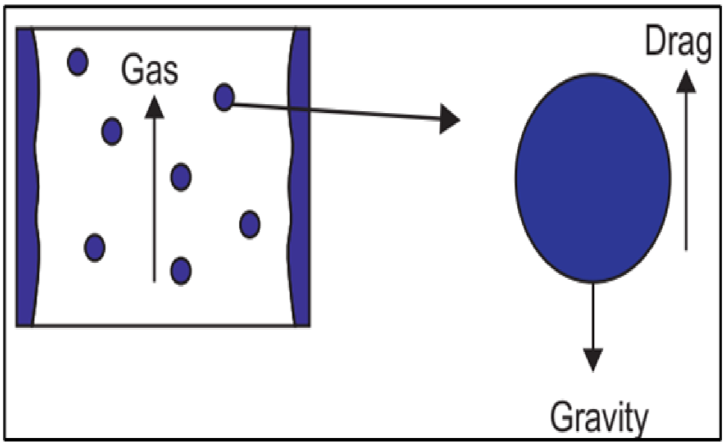


Figure I.8: Liquid Droplets Transport in Vertical Gas Stream [12]

Turner was found to underpredict the critical velocity from the database of well data. To better match the collection of measured field data, Turner adjusted the theoretical equations for the required velocity upward by 20%. After the 20 percent empirical adjustment, the critical velocity for condensate and water were presented as follows:

$$\boldsymbol{V}_{\mathrm{c.condensat}} = \frac{\mathbf{4.02(45-0.0031}\boldsymbol{P})^{\mathbf{1/4}}}{(\mathbf{0.0031}\boldsymbol{P})^{\mathbf{1/2}}} \qquad \boldsymbol{V}_{\boldsymbol{c.water}} = \frac{\mathbf{5.62(67-0.0031}\boldsymbol{P})^{\mathbf{1/4}}}{(\mathbf{0.0031}\boldsymbol{P})^{\mathbf{1/2}}} \qquad [1]$$

The theoretical equation for critical/terminal velocity Vt to lift a liquid drop is given by:

$$V_{\mathrm{t}} = \frac{\mathbf{1.593}\boldsymbol{\sigma}^{\mathbf{1/4}}(\boldsymbol{\rho_l}-\boldsymbol{\rho_g})^{\mathbf{1/4}}}{\boldsymbol{\rho_g}^{\mathbf{1/2}}} \qquad [2]$$

Vt: Terminal velocity of the liquid droplet (ft/s)

Qg : gas rate flow (MMscf/d)

Qcg: Critical gas rate flow (MMscf/d)

σ : interfacial tension (dynes/cm)

ρl : Liquid phase density (lbm/ft3)

ρg: gas phase density (lbm/ft3)

I .3.2.1 Other Notable Critical Velocity Models:

Even though Turner et al. had listed the likely reasons responsible for the underprediction of the critical flow rate across the fields investigated and made possible adjustments to fit the field data; different researchers have reservations and divergent views concerning the adjustment and also discovered several shortcomings associated with it and its application. Some of the contributions from different authors toward enhancing the performance of Turner et al. model is highlighted below. The industry has gained considerable experience in applying the Turner equation in different scenarios and how to modify it to match field observation. As presented in Table (I.1), several investigations have suggested different modified expressions derived from the Turner model. [13]

Table I.1: Review of Turner Equation [13]

Authors	Modifications of Turner Correlation
Turner et al., 1969	Created the widely accepted Turner equation
Coleman et al., 1991	new model for predicting liquid loading for wells with lower reservoir pressures and having wellhead flowing pressures below 500 psi, and also has the +20% adjustment suggested by Turner et al.
Nosseir et al., 2000	Applying the concepts and assumptions of Turner et al., but with the consideration of the impact of gas flow turbulence regimes, Transions regimes.
Zhou and Yuan	presented the model that incorporates the amount of liquid in the gas in the expression estimating the critical gas velocity. They recognized that the amount of liquid in the gas stream also plays a major role in liquid loading.
Li et al.	Involved the droplet's shape also made a useful modification by suggesting that spherical shaped droplets assumed by Turner et al. cannot remain spherical as they fall down the wellbore.
Luan and He	new model considering the influence of deformation and the changes in the gas lift efficiency by introducing a loss factor (S) to account for the energy lost as a result of rollover of the droplets.

The likely reason that Turner's method is so popular is that all the parameters needed in the predictive equation can be readily obtained at the wellhead, which is a great convenience for field operators.

I.3.3 Liquid Film Based Models:

Liquid film-based models are one of the analytical models used to predict the onset of liquid loading in gas wells These models consider the formation of a liquid film on the inside surface of the tubing, which eventually grows and leads to a decrease in the effective diameter of the tubing. As a result, the gas velocity decreases, and liquid begins to accumulate in the wellbore. The liquid film-based models typically use a mass balance equation to calculate the rate of liquid accumulation and a momentum balance equation to determine the pressure gradient in the tubing. These equations are solved simultaneously to predict the onset of liquid loading. Models in this category are developed on the premiss that, instead of entrained droplets, the liquid film on the wall of the pipe is the mechanism through which liquid loading occurs in gas wells. Several reasons which made experts arrive at this conclusion include: [14]

- The liquid droplet sizes used in the derivation of Turner's model are too large and not obtainable from actual wells [15];
- The percentage of liquid flowing as droplets is quite small compared to the percentage of liquid film flowing on the wall of the pipe under an annular flow regime [16];
- The critical gas velocity calculated using Turner's model is too low to predict the onset of liquid loading [17];
- Experimental results seem to consistently match film flow reversal predictions better than that of entrained droplet models [18]

Models in this category explore the effects of liquid film instability on the wall of a pipe and flow regime transition on flow reversal in gas wells. One of the advantages of liquid film-based models is that they can capture the effect of surface tension on liquid film formation, which is particularly important for low surface tension liquids such as hydrocarbons. However, these models have several limitations, including the assumption of a uniform liquid film thickness and neglecting the effect of liquid droplets on the gas flow.

Several variations of liquid film-based models have been developed over the years, including models that consider the effect of non-Newtonian fluids, multi-phase flow, and variable diameter tubing. These models can provide more accurate predictions of liquid loading in gas wells under different operating conditions. This table give us an overview on some models that has developed:

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in gas wells under different operating conditions. This table give us an overview on some models that has developed:

Table I.2: Review of Liquid Film based models

Authors	Model
Barnea	developed analytical models to predict flow regime transitions and thus the critical velocity for gas wells Barnea showed that as the gas velocity decreases, the interfacial shear stress between the gas and the liquid decreases.
Befroid et Al	investigated the impact of well inclinations on liquid loading since Turner's model has no dependency on the angle of inclination.
Veeken et Al	film flow reversal is responsible for the bulk of liquid loading when they performed transient multiphase flow modelling using actual liquid-loaded gas field production data (The gas field data has average rates 40% greater than that predicted by Turner's model)
Westende et al.	investigation on the role of droplets in concurrent annular and churn-annular pipe flow concluded that liquid loading corresponds to film flow reversal.
Pigot et al	used a downhole video footage to also confirm it
Skopich	monitored film flow reversal and pressure drop in vertical pipes to confirm that film flow reversal is mainly responsible for liquid loading.

However, in spite of this credible support for film flow reversal models, the popularity of the Turner's droplet model over the film flow reversal models in the industry remains undisputed; perhaps because the same drag and gravitational forces were applied in its development. [19]

I.3.4 Integrated Wellbore/Reservoir Based Models

Those Models treat liquid loading as being governed by processes influenced by interacting components at the wellbore and reservoir, rather than as a process that is dominated by the wellbore alone as suggested by the film and droplet flow reversal models. These models couple fluid flow from the reservoir to the wellbore and from the wellbore to the surface in order to adequately capture the process of liquid loading. Hence, the entire production system is analysed as a single unit where calculations are carried out to investigate different parameters that could influence the process of liquid loading.

I.3.4.1 Nodal analysis

The system Nodal Analysis has been applied for many years to analyse the performance of systems composed of interacting components. The procedure of Nodal Analysis consists of dividing the system into two subsystems at a certain location called nodal point (node). The nodal point can be located anywhere in the system However, practically, locating nodal point at the bottom hole (at the mid-perforation depth) is very common. [20]

Nodal analysis will be more detailed since normally in a well, gas may have to flow against many restrictions other than liquid itself, such as different tubing sizes, sub surface safety valves, rock matrix of reservoir etc. Nodal analysis divides this system into two subsystems at a certain location called nodal point or simply node.

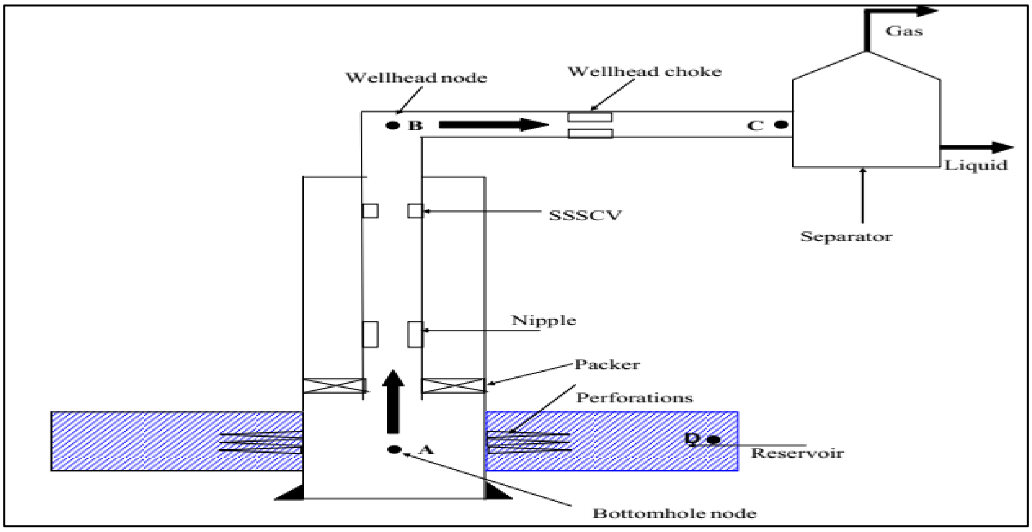


Figure I.9: Typical well configuration showing the positions of nodes in a well

One of these subsystems considers inflow from reservoir to the nodal point selected while the other subsystem considers outflow from the nodal point to the surface. Each subsystem gives a different curve plotted on the same pressure-rate graph (Figure **I.10**). since that way the k inflow curve represents the flow from reservoir into the hole and the outflow curve represents the flow from the bottom hole to the surface.

The curves formed by this relation on the pressure-rate graph are called the inflow curve and the outflow curve, respectively. The point where these two curves intersect denotes the optimum operating point where the following requirements are satisfied:

- Only one pressure can exist at a node
- Flow into the node equals flow out of the node

Once the node is selected, the node pressure is calculated from both directions starting at the fixed pressure:

Inflow to the node: Pnode = Pr – ΔP (upstream components)

Outflow from the node: $P_{node} = P_{sep} + \Delta P$ (downstream components). [19]

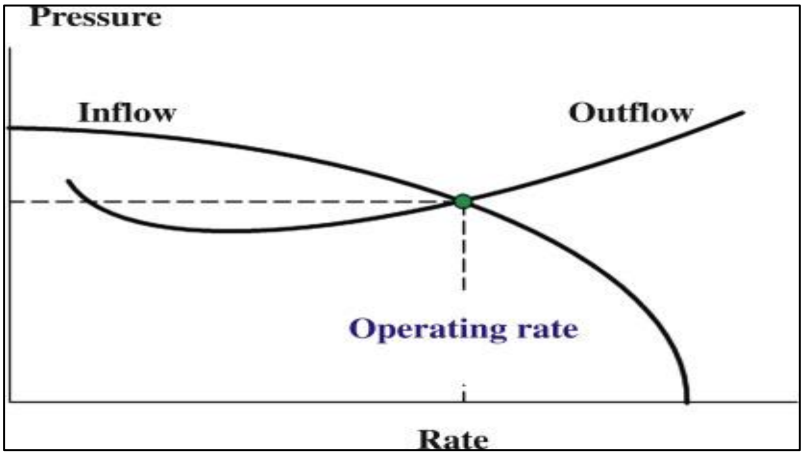


Figure I.10: Typical Nodal Analysis Curves [19]

I.3.4.2 Diagnosing liquid loading with Nodal Analysis:

Liquid load-up can also be determined by nodal analysis. Since critical gas rate equations only give a simple idea for the minimum rates, The nodal analysis can be used with both single and multiphase flow equations; moreover, correlations of different components such as well completion and skin effects and also effects of surface components can be implemented into nodal analysis. The information gathered can be used to determine and evaluate overall well performance for a variety of different conditions that eventually will lead to optimum completion and production practices. It is an important practice not only for analyzing the effects of liquid loading but also for finding possible solutions to the problem. As mentioned, nodal analysis can be used to analyze the effects of different tubing sizes and different flow conditions.

Moreover, it is useful for determining the effects of surface pressure on the system, since excessive surface pressure can cause backpressure on the reservoir. the outflow curve which can also be called the tubing performance curve (TPC) shows the relationship between the pressure drop in the tubing string and surface pressure value. The pressure drops in the tubing string basically consist of the surface pressure value, the hydrostatic pressure of the “loaded liquid” in the string, and the frictional pressure loss due to flow *(***Figure I.11***)*. [21]

It is common practice to use the tubing performance curve alone, in the absence of up-to-date and accurate reservoir performance data, to predict gas well liquid loading problems. The general idea when interpreting the curve is that flow rates to the left of the minimum are unstable and prone to liquid loading problems.

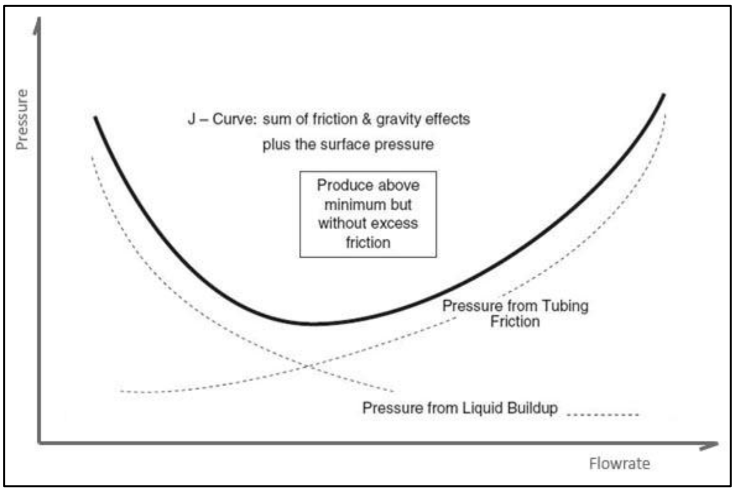


Figure I.11: Tubing Performance Curve [21]

Flow rates to the right of the minimum of the tubing performance curve are considered to be stable and significantly high enough to effectively transport produced to the surface. The intersection point of the tubing outflow curve and the reservoir inflow performance curve allows an accurate determination of the point the well is flowing and what would be the optimum pressure and rate values. Like shown in **The Figure I.12**

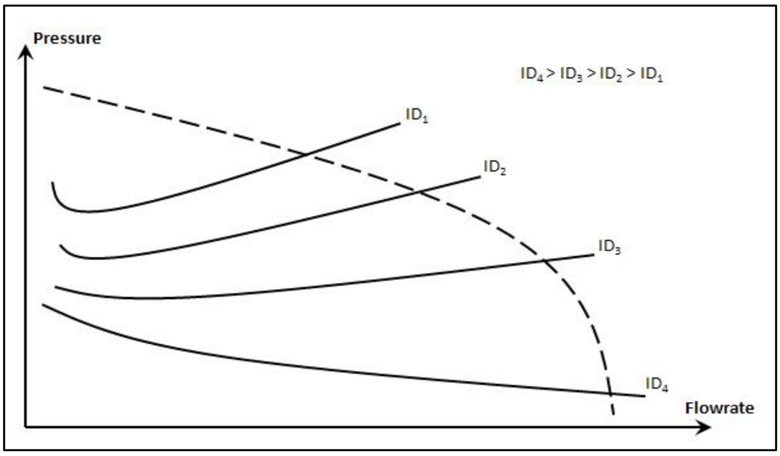


Figure I.12: Nodal Analysis Graph for Different Tubing Sizes [21]

The combination of the IPR and VLP curves gives rise to a system plot as shown in Figures, the combination process is done numerically by solving two equations (the IPR and VLP) simultaneously with two unknowns; the flowrate *q*, and the bottomhole flowing pressure *pwf*. The point of intersections of the IPR and VLP curves (positions D, E, C, F, and G) on Figure II.6 represent different flow rates and bottomhole flowing pressures and are generally called the well operating points at a given time. The well operating point is expected to be the observed flow rate and pressure measured with appropriate gauges. The ability of any correlation to predict the flow rate and pressure accurately in real-time, captures its reliability with regard to predicting well performance. In the example shown in Figure 2, 6there are four IPR curves with two VLP curves; curves AB and CDEFGH. The change in the intersections on the IPR curves (positions D, E, F, G) is an indication of declining reservoir pressure over time. The vertical lift performance curve AB as shown in Figure **I.13** is used to represent a gas well with high production rate that would operate at stable flow condition over time. However, curve CDEFGH exhibits a minimum value (position G) that can be treated as a transition point from a stable to unstable flow as the reservoir pressure declines.

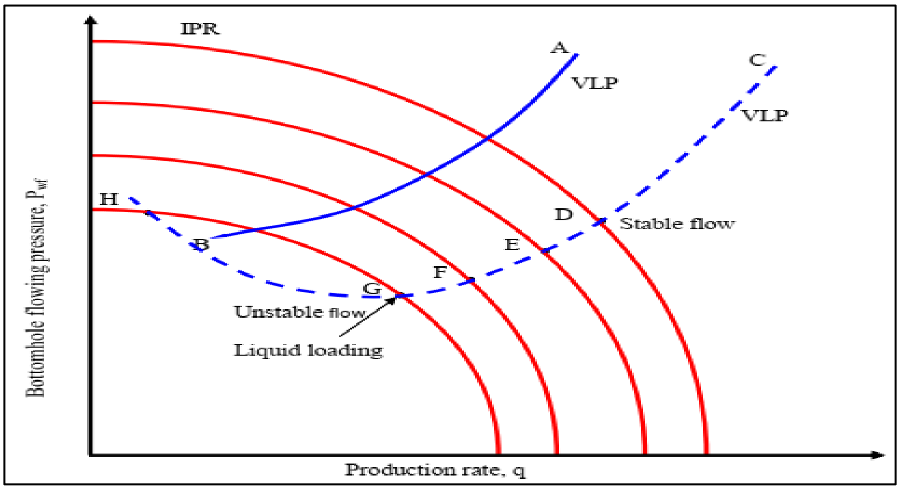


Figure I.13: Different well operating points as the bottom-hole pressure decreases during flow [22]

When there is no intersection between the IPR and VLP curves, there is no solution and thus no production. This implies that the well is not flowing, or is unable to flow with its natural energy. [22] If this occurs, then the well should be abandoned if there are no economic reserves available or subjected to artificial lift mechanism to induce flow. In the example shown in Figure I.13, there are four IPR curves with two VLP curves; curves AB and CDEFGH. The change in the intersections on the IPR curves (positions D, E, F, G) is an indication of declining reservoir pressure over time. The vertical lift performance curve AB as shown in Figure I.13is used to represent a gas well with high production rate that would operate at stable flow condition over time. However, curve CDEFGH exhibits a minimum value (position G) that can be treated as a transition point from a stable to unstable flow as the reservoir pressure declines.

However, when the point of intersection moves to the left of the minimum (position H), such that the VLP make double intersection with the IPR curve, the well will produce under unstable flow conditions caused by liquid loading. [11]

Conclusion:

In conclusion, the chapter focused on the prediction of liquid loading using nodal analysis and critical rate. The study explored the significance of accurately identifying and mitigating liquid loading issues in gas wells, which can lead to decreased production rate.

Chapter Two

Water Loading Problem in In Saleh Gas Field

II.1. Preface

In this chapter, we will explore the In Salah gas field, situated in the Sahara Desert of southern Algeria. This gas field is renowned for its substantial reserves and the difficult conditions it presents for operations. Discovered in 1997 by a consortium comprising BP, Sonatrach (Algeria's state oil company), and Equinor (formerly Statoil), the In Salah gas field has played a vital role in fulfilling Algeria's domestic energy requirements and supporting its gas export industry.

We will focus on the geological and petrophysical aspects of the Tegentour fields, beside that we will identify the symptoms of water loading in the candidates wells and the water sources that caused that problem.

II.2. Introduction

The In Salah Gas project it was a joint venture between Sonatrach (35%), BP (33.15%), and Statoil (31.85%) and now its between Sonatrach (35%), Eni (33.15%), and Equinor (31.85%). Three gas fields, namely Krechba, Teguentour, and Reg, have been developed during the first phase of the ISG project. Phase one achieved its first production in July 2004 and is currently producing at the rate of nine billion cubic meters per year. [23]

The In Salah Southern Fields (ISSF) project forms the second phase of the ISG project which involves the development of the four remaining gas fields including Garet, EL Befinat, Hassi Moumene, In Salah, and Gour Mahmoud. The project will help in the production holding at plateau levels when production from the three existing fields decreases. The ISSF project started in February 2011 and the start-up of the four fields remains began in February 2016. The project is expected to generate 14.1 million cubic meters per day. [23]

The ISG project is the third-largest gas development in the country

III.3. Presentation of ISG field

The name of the In Salah Gas project is derived from the name of the city of In Salah which is located 1230 km south of Algiers. It has some of the richest mineral resources in the country.

The In Salah Gaz project is currently developing the seven gas fields proven:

- Krechba,
- Teguentour,
- Reg,
- Hassi-Moumene,
- Garet-El-Befinat,
- In Salah

- Gour Mahmoud.

The development is carried out in two phases: the fields of Krechba, Teguentour and Reg are developed first with the first gas deliveries starting in 2004. The gas produced is transported to Hassi R'Mel by pipeline and then transported to the growing markets in southern Europe. The four remaining fields (Hassi-Moumene, Garet-El-Befinat, In Salah and Gour Mahmoud) are developed to ensure a regular level of supply and sales throughout the development. Production will be nine billion SMC/year during the first phase of production, which will be exported through the means of Sonatrach. [24]

An efficient operation will depend on staff being able to fulfil the criteria established in terms of HSE (Leader of HSE in Algeria) of production efficiency and annual costs. Our performance in terms of industrial safety and rigorous management environment is recognized. This was sanctioned by a certification international "ISO 14001 Certificate". Minimal industrial emissions and low Waste/landfill volumes are common practice at the In Salah project. [24]
The fundamental distinctive values of In Salah Gas compared to other projects are integrity, innovation, trust and mutual respect. It is on this solid basis that we are currently building an organization each of us can be proud of:

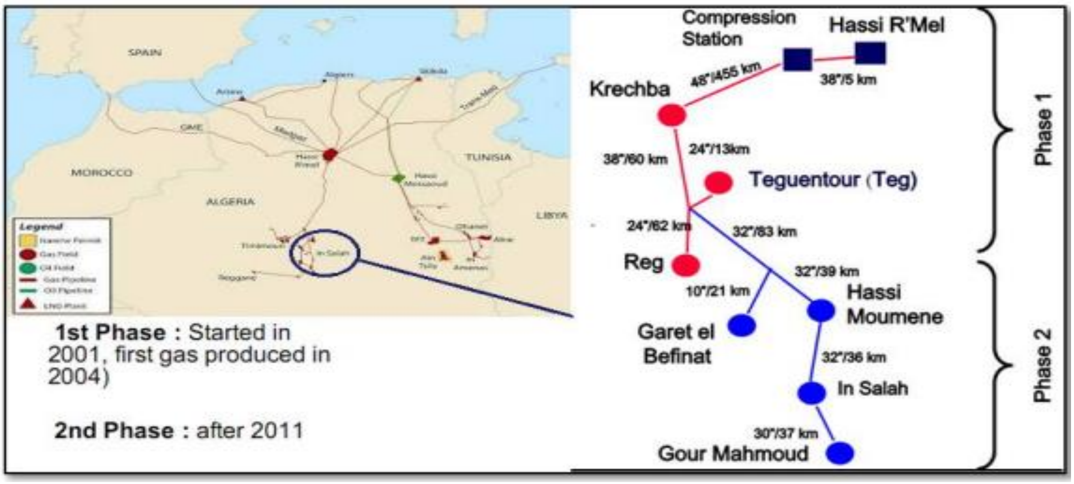


Figure II.1. Geographical location of ISG region. [23]

According to the development plan for the first phase, the dehydrated gas from TEG and REG is sent to the Krechba Central Processing Facilities (CPF) at through the 38" gas pipeline.

After separation, cooling, dehydration and conditioning, the gas from the field from Krechba is combined with gas from TEG and REG. At the Krechba CPF the mixture of gas from the three sites is treated with an Amine solution for the elimination of CO_2 and then the gas is shipped to Hassi R'Mel which is located 456.3 Kms north of Krechba. In Hassi-R"mel the gas is recompressed and exported to the collector of the National Center for Gas Distribution, CNDG. Necessary support processes and utility systems are available in the Krechba CPF.

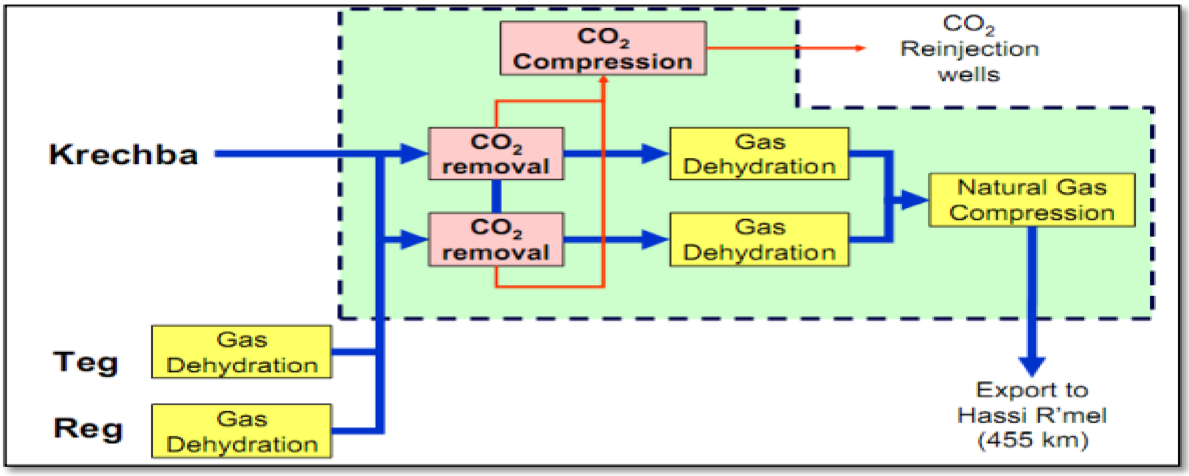


Figure II.2. Plan of the first treatment phase in ISG project. [24]

II.4. Presentation of Tegentour field:

Teguentour (Teg) field is located in Blocks 344 and 345 to the west of District 3 of Algeria, about 75 km south-southeast of Krechba. Most of the production comes from this field (Devonian) which is characterized by very large reserves and high carbon dioxide (CO2).

The Teg field has a total of 23 gas-producing wells, including 7 horizontal wells producing from the D55, 2 multilateral wells producing from the D55 and the D40/D30 and 14 wells vertical or deviated targeting D40/D30 tanks. [25]

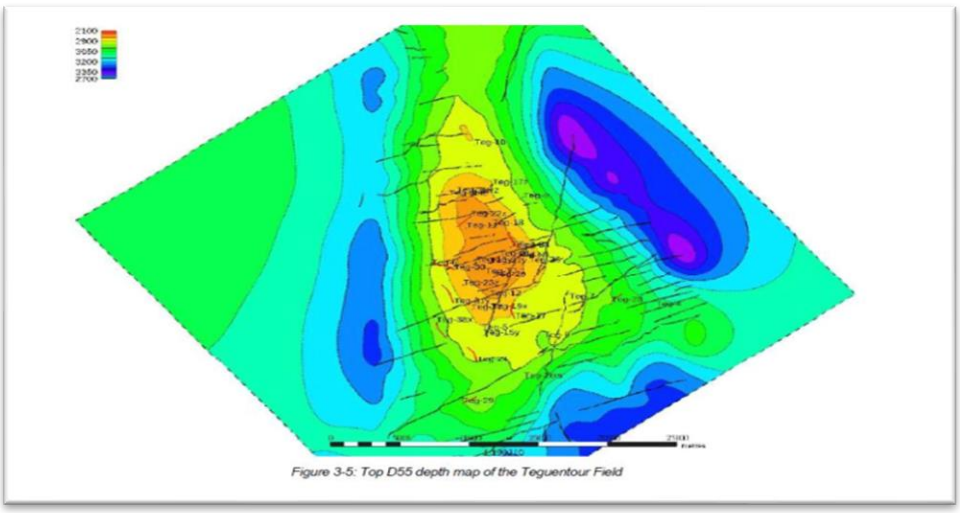


Figure 3-5: Top D55 depth map of the Teguentour Field

Figure II.3 Teg field reservoir D55. [25]

II.4.1. The Geological Structure of Tegentour Gas Field:

The 2D seismic data initially suggested that the Teguentour field consisted of a large anticline with few major faults, but the 3D data obtained in 2006 reveal a more complex fault structure. Four Devonian reservoir sequences are observed, D20, D30, D40 and D55, as well as a Carboniferous reservoir in the C10.2 sequence. The field covers an area ranging from 150 km2 at the D30 level to 500 km2 at the D55 level.

The Devonian reservoirs are composed of laterally-extending sandstone units deposited in shallow, marine fluvial environments buried at a depth of 2700 to 3100 m BGL (2100 to 2500 m TVDSS). The Devonian reservoirs have the same open water level at 2410 m TVDSS, and a maximum gas column height of 350 m. Reservoir quality in the main D55, lower D40 and upper D30 sequences is good, with porosities up to 27% and permeability thicknesses of 900 m Dm in one unit. Water saturation in all reservoirs is between 5 and 25%. [25]

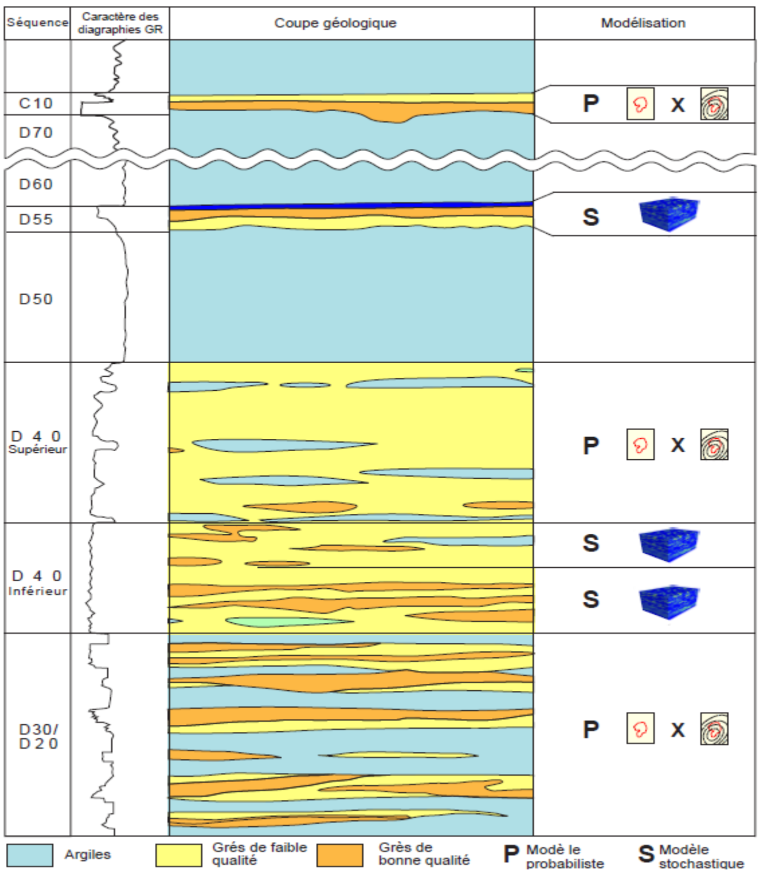


Figure II.4: Geological Model for the Devonian Reservoir. [25]

II.4.2. Petrophysical parameters of Teguentour:

A complete reassessment of the Carboniferous and Devonian reservoirs at Teg was conducted in 2012 for incorporation into the geomodelling. Prior to conducting this reassessment, a new system of zoning system was introduced, resulting in a change in the boundary between the D40 and the D30, as well as the introduction of a more detailed subdivision of reservoirs D40 and D30. [25]

These play changes necessitated the re-evaluation of all wells by updating the petrophysical model. Minor changes were introduced such as the adjustment of the Archie parameters to calculate water saturation from resistivity (increase in calculated gas saturation) and saturation) and deduce a new saturation-height function.

Petrophysical averaging was performed for all wells. A summary of the values of the permeability-thickness product (Kh) and gas loaded net porous thickness (GPLT) is presented in the presented in the following table: [25]

TEG FIELD - PERMEABILITY THICKNESS (K x h) and HYDROCARBON PORE THICKNESS (Gross Thickness x NTG x PHI x (1 - SW))

	Carboniferous C10.2					Emsien D55				
Well	2013 KH mDm	2011 KH mDm	2013 HCPT m	2011 HCPT m	2000 HCPT m	2013 KH mDm	2011 KH mDm	2013 HCPT m	2011 HCPT m	2000 HCPT m
TEG-2BIS	5.14	7.25	0.058	0.076	0.032	8.69	0.68	0.105	0.104	0.173
TEG-3BIS	0.07	0	0	0	0	-	0	-	0	0.32
TEG-4	0.09	0	0	0	0	1.84	2.5	0.222	0.291	0.301
TEG-5	7.61	7.67	0.302	0.292	0.102	21.19	21.17	0.37	0.372	0.45
TEG-6	0.02	0.21	0	0	0	53.8	54.17	0.539	0.574	0.558
TEG-7	88.9	91.4	0.307	0.297	0.318	16.44	16.47	0.198	0.209	0.237
TEG-8	11.3	9.51	0	0	0.005	3.49	3.49	0.215	0.217	0.387
TEG-9	1.87	2.22	0.176	0.177	0	2.86	3	0.178	0.211	0.225
TEG-10	9.6	15.48	0	0	0	1.8	0.38	0.248	0.104	0.006
TEG-11	0.45	0.42	0.138	0.044	0	73.13	87.51	0.585	0.683	0.55
TEG-12	38.6	38.79	0.253	0.259	0.11	38.37	38.22	0.365	0.367	0.5
TEG-14	0.88	1.44	0.296	0.349	0.246	23.29	22.05	0.504	0.525	0.485
SUM			1.53	1.494	0.813			3.529	3.657	4.192
Percentage of 2000 HCPT			188.2	183.8	100.0			84.2	87.2	100.0
TEG-3TERZ	0.07	0	0.028	0		1.15	1.43	0.216	0.247	
TEG-15	0.1	0.08	0.04	0.035		-	-	-	-	
TEG-15Y	-	-	-	0.035		-	-	-	-	
TEG-16Y	118.44	74.12	0.991	0.748		3.88	5.02	0.384	0.411	
TEG-17Z	17.41	20.4	0.213	0.21		0.33	0.52	0.082	0.127	
TEG-18	4.51	-	0.177	-		4.68	14.48	0.322	0.302	
TEG-19X	-	-	-	-		5.82	2.49	0.375	0	
TEG-20	-	-	-	-		7.25	1.7	0.333	0.311	
TEG-21Z	-	-	-	-		9.21	9.22	0.459	0.487	
TEG-22	-	-	-	-		8.36	10.8	0.44	0.455	
TEG-23Z	-	-	-	-		8.73	3.946	0.411	0.355	
TEG-26	1.02	-	0.106	-		0.32	0.273	0.111	0.105	
TEG-30	835.8	777.6	1.335	1.384		-		-		
TEG-37	-		-			1.08		0.326		

	Seigenien D40					Gedinnian D30				
Well	2013 KH mDm	2011 KH mDm	2013 HCPT m	2011 HCPT m	2000 HCPT m	2013 KH mDm	2011 KH mDm	2013 HCPT m	2011 HCPT m	2000 HCPT m
TEG-2BIS	200.31	209.76	0.397	0.323	2.44	33.12	5.25	0	0	0.48
TEG-3BIS	575.42	314.69	1.193	1.192	0.247	71.33	11.2	0.8	0.418	0
TEG-4	-	0	-	0	0	-	0	-	0	0
TEG-5	421.18	422.63	2.332	2.415	3.56	1.99	61.8	0.204	0.785	0.709
TEG-6	684	267.71	1.453	0.604	3.644	0.27	0	0.01	0	0
TEG-7	91.33	56.81	1.342	1.019	2.907	1.76	1.2	0.219	0.174	0.619
TEG-8	3.05	0.93	0.307	0.204	1.377	23.26	8.8	0.871	0	1.174
TEG-9	6.06	6.66	0.553	0.935	0.873	0.43	0	0	0	0
TEG-10	618.82	301.8	3.043	2.109	2.285	35.06	8.1	0.783	0.479	0.865
TEG-11	2002.59	904.7	3.177	2.766	3.618	432.67	315.6	1.395	1.319	1.36
TEG-12	171.9	175.53	1.965	2.048	2.62	115.14	124.2	1.676	1.699	1.48
TEG-14	387.54	384.93	1.288	1.178	1.738	1.907	0.66	0.403	0.174	0.293
SUM			17.05	14.793	25.309			6.361	5.048	6.98
Percentage of 2000 HCPT			67.4	58.4	100.0			91.1	72.3	100.0
TEG-3TERZ	1135.55	0.76	1.092	0.238		61.47	744.7	0.803	2.162	
TEG-15	-	-	-	-		-	-	-	-	
TEG-15Y	153.28	211.51	1.751	2.026		-	-	-	-	
TEG-16Y	0.17	0.25	0.073	0.105		5.07	2.2	0.592	0.338	
TEG-17Z	49.57	20.93	1.289	0.818		-	-	-	0	
TEG-18	146.59	282.33	2.015	2.097		78.72	57.98	0.502	0.374	
TEG-19X	129.46	609.2	1.556	2.181		0.71	0.84	0.131	0.156	
TEG-20	1345.93	2845.592	4.203	4.265		0.57	8.15	0.137	0.36	
TEG-21Z	271.27	770.3	1.869	1.646		5.4	6.12	0.549	0.509	
TEG-22	331.24	554.52	1.838	2.416		8.41	3.55	0.566	0.323	
TEG-23Z	1157.59	1822.96	3.242	3.858		110.77	21.88	0.25	0.056	
TEG-26	368.82	296.79	1.704	1.507		13.2	13.11	0.328	0.317	
TEG-30	-	0	-	0		-	-	-	-	
TEG-37	13.47	-	0.57	-		-	-	-	-	

Figure II.5 The petrophysical values of Teg. [25]

II.4.3. Fluid contacts at Teguentour:

The main gas/water contact of the D55/D40 is estimated at 2410 m TVDSS. However, the lower part of D30 could have a deeper contact at 2440 m TVDSS, this is based on a gas test at the lower D30 gas test at the lower D30 level was performed on the Teg well and on the pressure measurements well Teg-18 where a lower, undrained D30 sandstone was detected at a pressure higher than the initial D55/D40/D30U gradient.

The pressure data obtained in the drilled wells, after the start of production, indicate the presence of vertical barriers/baffles between the D55 and D40/D30U. [25]

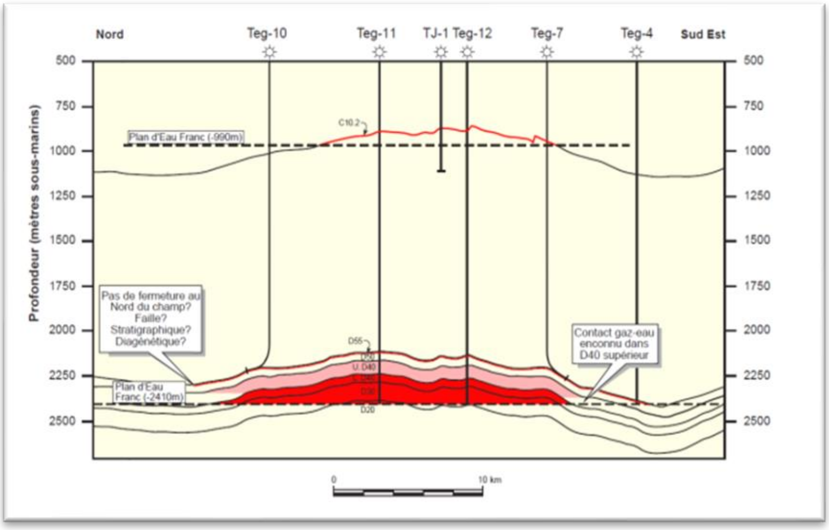


Figure II.6: Cross Section Showing Open Water Level Positions. [25]

II.4.4. Teguentour gas composition:

Teg field production is from the Devonian reservoir (D55, D30 and D40), which produces dry methane-rich natural gas with a high CO2 content. The composition of the Teg field is shown in the table: [25]

Table II.1. Gas composition of Teg. [25]

Gas Composition						
Component	**% mol**	**Critical Temperature (°F)**	**Critical Pressure (psig)**	**Critical Volume (Cubic ft/lb.mol)**	**Acentric Factor**	**Molecular Weight (lb/lb.mol)**
N2	0.76144	-232.51	477.419	1.43842	0.04	28.01
CO2	2.28432	87.89	1054.74	1.50409	0.225	44.01
H2S	0.076144	212.09	1280.96	1.57938	0.1	34.08
C1	91.373	-116.59	661.049	1.58899	0.0115	16.04
C2	2.90794	90.05	702.615	2.37547	0.0908	30.07
C3	1.17239	205.97	608.886	3.25166	0.1454	44.1
C4	0.47332	289.49	528.539	4.21274	0.1868	58.12
C5	0.22004	372.83	492.845	4.08459	0.2251	72.05
C6	0.26722	442.109	449.149	6.41068	0.25352	84
C7	0.16951	483.247	411.018	7.30352	0.27118	94.1122
C8	0.10975	523.677	381.61	8.18188	0.28848	105.063
C9	0.07208	562.42	357.885	9.04576	0.30542	116.5
C10	0.047834	599.311	338.196	9.89516	0.322	128.24
C11-C13	0.04733	660.307	309.294	11.3987	0.35115	149.412
C12-C25	0.017505	792.721	264.277	14.8032	0.4161	202.296
C25-C50	0.000195	1078.59	212.715	22.3047	0.55197	341.472
C50+	0	1575.84	194.354	32.1072	0.69081	630.375

II.5. Identification of water Loading in Candidate wells

II.5.1. Teg 23

Teg-23 was the seventh post-first gas well drilled, to test the lower Devonian reservoirs of the Teg field (D40 and D30). It was planned as the third multilateral on the Teg field and the lateral to primarily target the D55 tank.

The well was blasted with Enafor Rig-41 on January 18, 2010. It was drilled to 1789m TVDbrt where the drill string jammed, cut and a fish was left in the hole. The well was diverted as Teg-23z has 1422 m TVDbrt. The latter was drilled at a final TD of 3028 mDDbrt in the formation (D30) on April 19, 2010**.**

Teg-23 produced in Lo newer Devonian Teg with the following depths:

- D55 from 2820.9 up to 2825.8 mTVDbrt
- D40L / D30U from 2932.7 up to 3028 mTVDbrt

II.5.1.1. Reservoir evaluation:

The properties of the D55 tank are poor. The net interval in the D55 is about 3.5 m. There porosity averages 8.1% and a permeability of 0.84 mD. The water saturation was 7.6%.

In the lower reservoir of the D40, they found a clear interval of 25 m. This interval is good quality, with a porosity of 11.8%, a permeability of 52.1 mD and a water saturation of 11%.

Formation pressures were only obtained in reservoir D55. Pressure measurement planned in D40 and D30 was cancelled due to problems encountered during the first operation.

The pressure measurements were taken with the XPT tool, which made it possible to obtain pressures on fairly tight sands taking only small pre-test volumes. The impoverishment at low pressure was observed in the D55 (400 psi), consistent with expectations from the modeling of the tank D55.

II.5.1.2. Well Completion: [26]

Table II.1 Teg 23 Well completion

Casing	Depth(mDDbrt)
9⅝"	1846.9
7" Liner PBR Top	1699.4
7" Liner Shoe	2806.0
4 ½" Slotted Liner PBR Top	2754.4
4 ½" Slotted Liner Shoe	3027.0

The completion of Teg 23 wells can be observed in Appendix **1**

II.5.1.3. Symptoms of water loading in Teg 23

The presence of water in well Teg-23was observed very early during the petrophysical evaluation of the D55-D30 reservoir, conducted during the drilling phase [26] Knowing that the final flow was estimated at 66 Mmscf/d, for a wellhead pressure of 1039.4 Psi The following figure showing the depletion of production in TEG 23. The onset of water loading in the well was evident from the initial stages and became more pronounced as the reservoir gradually depleted. The presence of water loading significantly impacted the production of the well

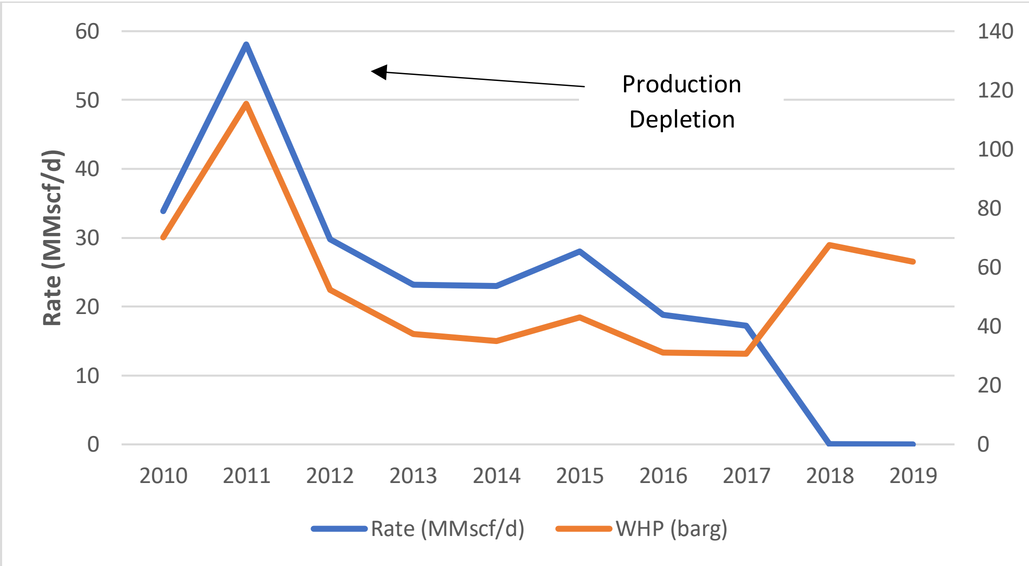


Figure II.7: Teg-23 production rate. [27]

II.5.1.4. Well production history:

The Well TEG23 is a gas well that has encountered significant challenges due to water loading throughout its production history. From the onset of production and even after the Depletion of the reservoir. Water loading has significantly affected the stability and efficiency of gas production in TEG-23. The influx of water into the wellbore has disrupted the natural flow of gas, resulting in unpredictable production patterns. The figure below illustrates the production profile of the well:

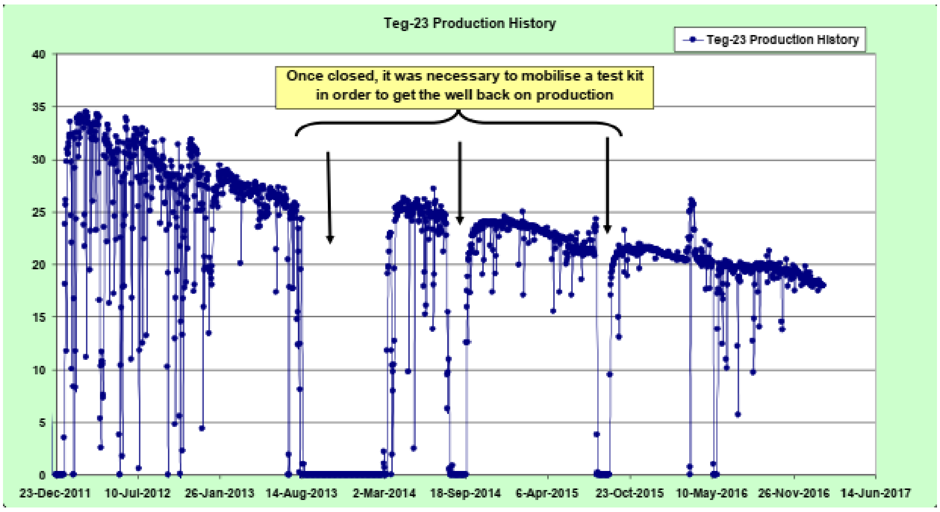


Figure II.8: TEG23 production history. [27]

- Water quantities were observed during the well testing phase while drilling, and this was confirmed by the MPLT results in Oct-2011.

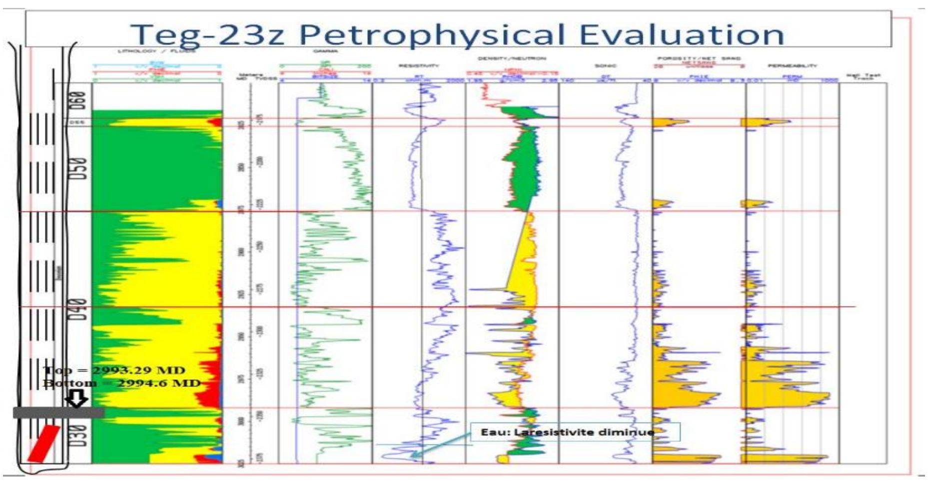


Figure II.9: Petrophysical logging evaluation. [27]

- When the well is shut, D30 formation water crossflow D40L which is the best producing sand. It should be noted that the Devonian formation is water sensitive that requires higher draw down once the water has reached the formation.
- Teg-23 was shut during Aug 2013 for CPF maintenance. Over the 5 months shut down significant amount of water had crossflow into the D40L due to pressure regime difference.

Static pressure surveys showed that a column of water has been building up to the top of D40L or higher. As shown in the figure below:

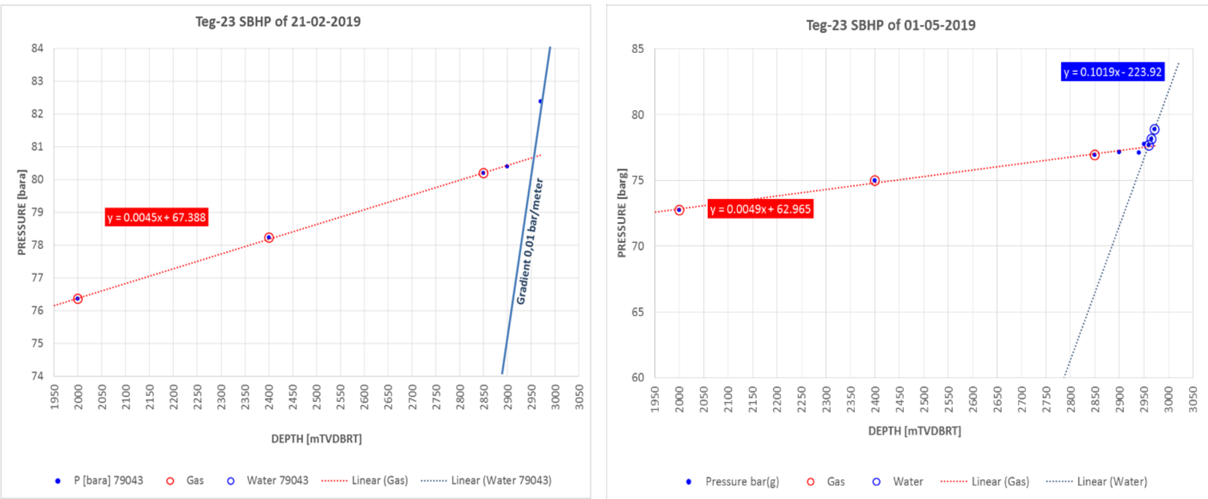


Figure II.10: Static pressure surveys for TEG 23. [27]

Attempts to produce the well through our facility were all unsuccessful. The use of the existing flare line was not considered a feasible option. A decision was made to mobilize standalone test equipment along with Coiled tubing unit in order to unload the well. A mixture of gas and water was reported at the test separator. In other words, the well was unloading water.

- The salinity of the water was in the range of **250 ppm** which is typical to D30 **formation water.**
- Further unloading attempts using test separators and standalone choke manifolds have been carried out in March 2014 and June 2015. These attempts were successful so far, however, due to the depletion the well ‘unloading solution seems reach its limitations and it is uncertain if we can get back the well after a long shut-in period.
- Due to the depletion of the reservoir in 2019, the well test operations conducted on the TEG23 well proved ineffective in facilitating the well's restart. The last Well test operation couldn’t restart the well it was decided to stop the operation due to several issues related with coiled tubing, Nitrogen supply and operation cost. The graphs in the **Appendix 2** showed the amount of continuous water obtained at the surface with the fluctuation in the upper choke temperature and in pressure mentioned meaning that the well trying to start and disgorge this water but without sufficient energy to successful.
- In the case of the TEG23 well, the production has ceased primarily due to the depletion of the reservoir and the accumulation of water in the bottom hole.

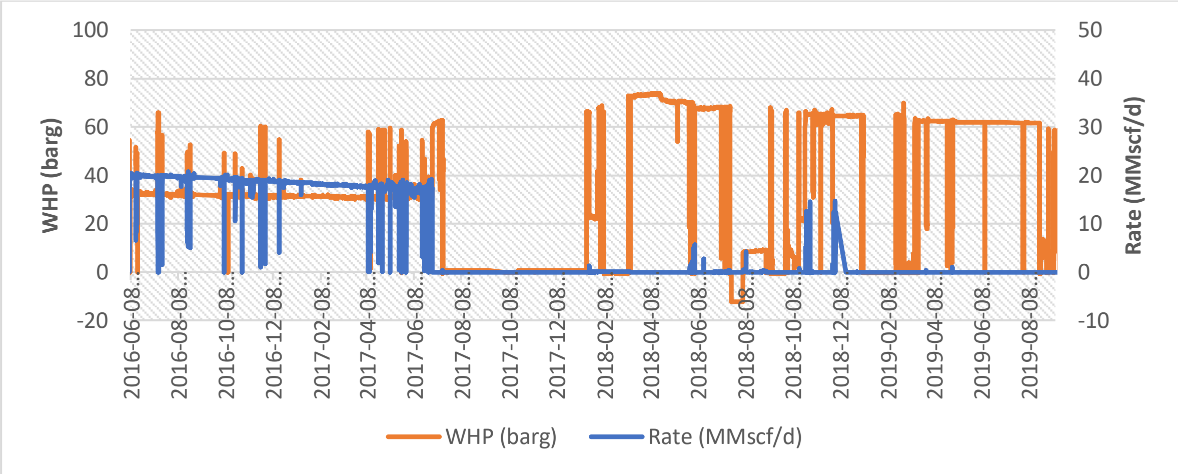


Figure II.11: Production history of TEG23 from 2016 to 2019 [27]

II.5.2. TEG-26:

The Teg-26 well was the sixth gas well drilled to test the Lower Devonian reservoirs of the Teg field. The well was projected with Enafor Rig -19 on November 4, 2009 and was drilled vertically until reaching the depth of 3023m TD in the D30 reservoir formation, reached on December 24, 2009.

Teg-26 occurs in the Lower Devonian of Teg at the following depths:

- D55 from 2811.4 up to 2833 mTVDbrt
- D40L/D30U from 2936.6 up to 3023 mTVDbrt

II.5.2.1. Well completion:

Table II.2 Well completion Teg 26

Casing	Depth(mDDbrt)
9⅝"	1893.0
7" Liner PBR Top	1742.0
7" Liner Shoe	2805.0
4 ½" Slotted Liner PBR Top	2749.0
4 ½" Slotted Liner Shoe	3022.0

The completion of Teg 26 well can be observed in Appendix **3.**

II.5.2.2. Symptoms of water loading in teg 26:

Initially, the well's production was normal during his initial phase. However, as years passed, the pressure began to decline, leading to the accumulation of specific liquids at the bottom of the well. The figure bellow showing the depletion of production:

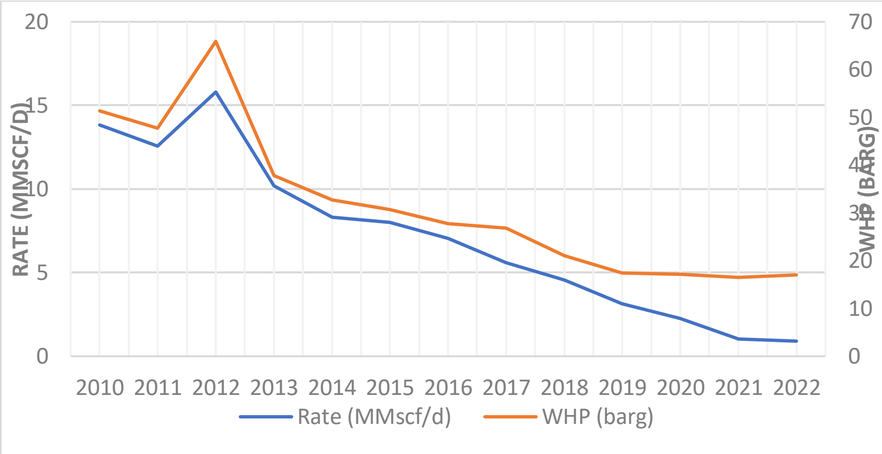


Figure II.12: Teg-26 production rate. [27]

II.5.2.3. Well production history:

The figure below shown the production history of teg 26

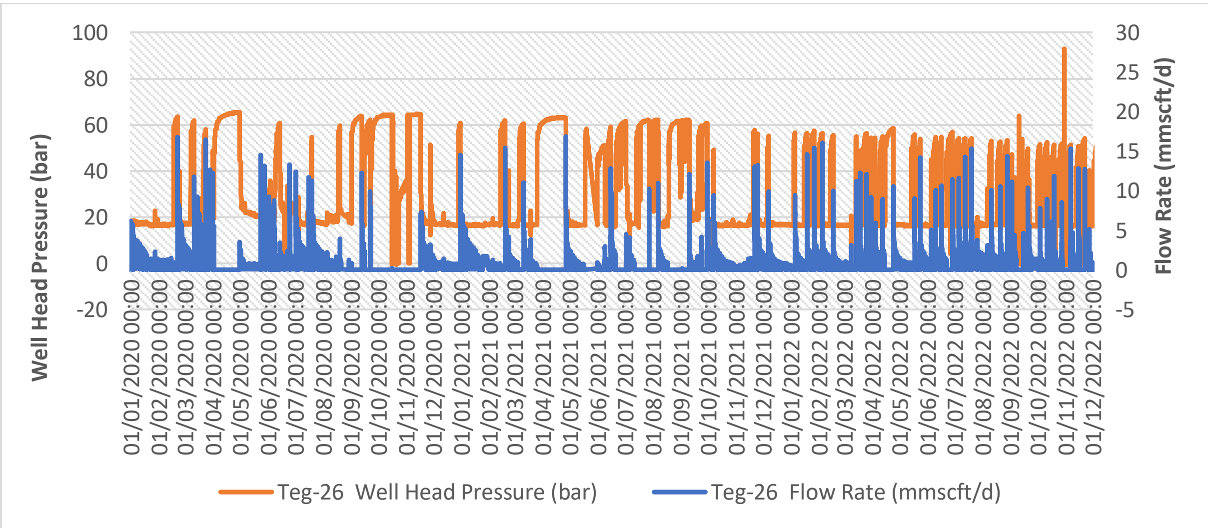


Figure II.12: Teg 26 production history from 2020 to 2022. [27]

- Flow peaks are observed each time the well is put back into production from 2020 to 2022, this indicates that the well is metastable, certain liquids collect at the bottom and are discharged in the form of water slugs on the surface which is represented by peaks of flow.

- The well is on cycling mode because of the accumulation of water in the well
- Even if the production flow has restarted and the head pressure has stabilized, as soon as the well is closed, the reservoir pressure is not always able to discharge the column of liquid that forms after each closure of the well.
- Well test intervention is needed after each closure of the well.

For Teg 26 there is many gradients of pressure static pressure were carried out to monitor the condition of the well since the first indicator of water loading in Sep 2022, we will choose 2 pressure surveys to indicate the liquid level.

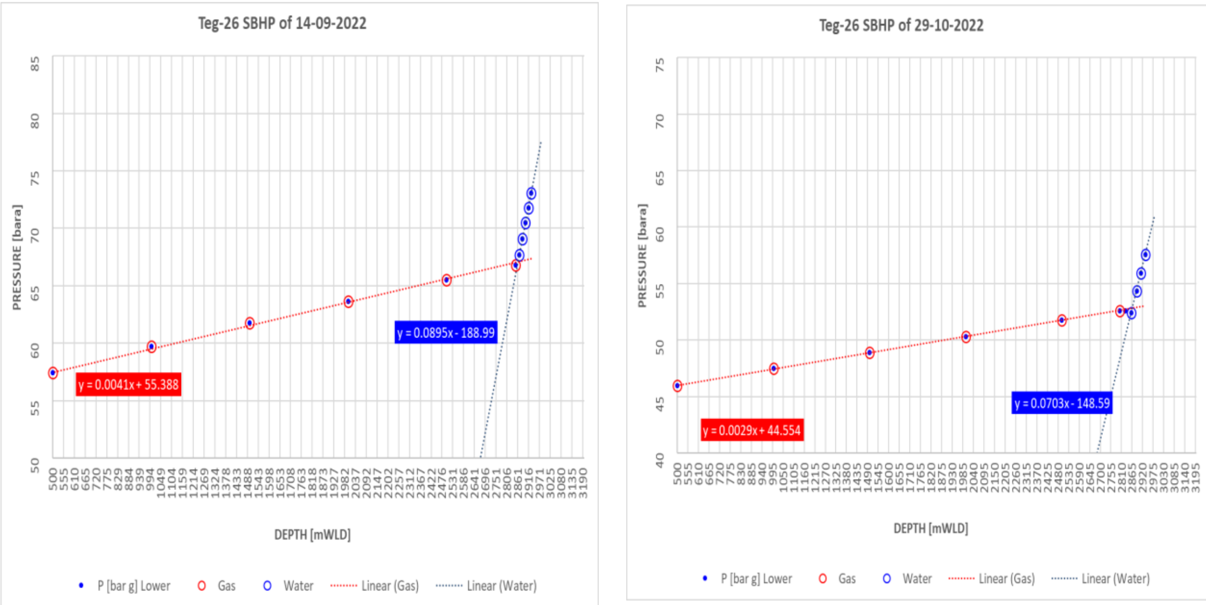
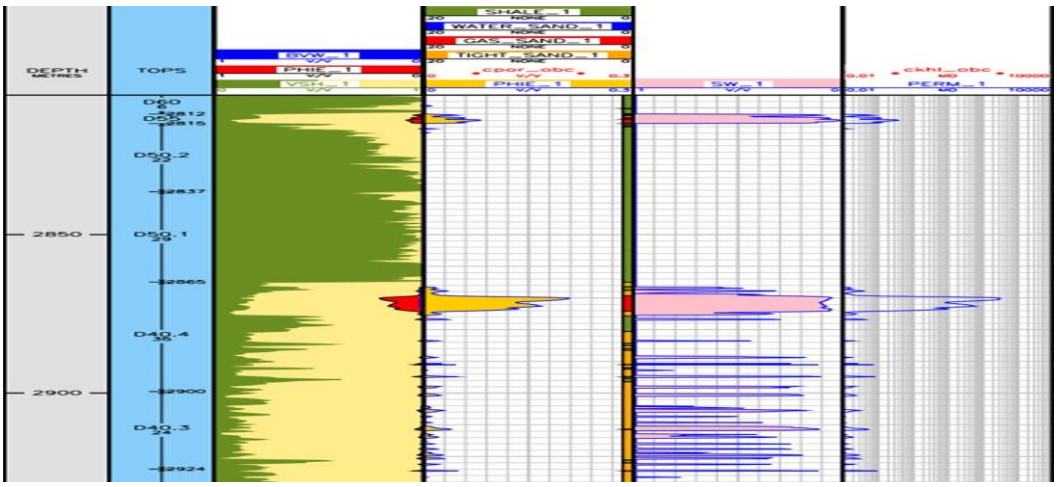


Figure II.14: Static pressure survey of teg 26. [27]



- **Figure II.15:** Logging of teg 26. [27]

- Based on the pressure gradients and logging performed during the production of the Teg-26 well, water quantities were observed in 2022.
- We have seen the water gas contact from 2870m on September 2022.
- Based on the well test conducted in August 2022, the current findings indicate that the water salinity is 0ppm, suggesting that the water type is indicative of condensed water.

II.6. Conclusion:

Due to their high flow rates, the TEG wells are considered to be among the best wells in Salah Gas. As a result, the closure of a well significantly affects the production of the field.
The Teg-23 and Teg-26 wells have an important production potential especially Teg-23. Therefore, we have undertaken an analysis of liquid loading in these wells.
The subsequent identification of water loading symptoms in the candidate wells shed light on the specific indicators that signify the presence of this problem. By recognizing symptoms such as erratic production rates, declining tubing head pressure, and other associated factors, appropriate measures can be implemented to mitigate the adverse effects of water loading.

Chapter Three

Solving water Loading Problem in In Saleh Gas field

Preface:

This chapter depicts the theoretical background of the different methods, curative and preventive, of handling water loading in gas wells. In the second part of the chapter, two of the methods discussed in the first part are applied to studied wells, Velocity string for the TEG 26 and installing a water shut off plug in the TEG 23. The simulation is conducted using Wellflo software, to simulate the installation of the velocity string, which allows for the analysis of well performance under various conditions.

Subsequently, this chapter discusses the outcomes and findings resulting from the implementation of these methods on the candidate wells.

III..1: Deliquification Techniques:

There is no one size fits all solution for wells with liquid loading. However, there are various circumstances that need to be considered when planning to install artificial lift technology in gas wells.

The main factors influencing the successful application of gas well deliquification technologies are the accurate knowledge or estimation of the gas and liquid production rates and the composition of the produced liquid. As some artificial lift technologies have a narrow operating range, it is crucial to overcome the problem of information on liquid rates so that de-liquification technologies can be designed properly. Other crucial factors in the design of artificial lift technology are:

- Well configuration (information about casing and tubing, inclination, depth, ability to work over the well, knowledge if annular flow is possible, subsurface safety valve requirement)
- Flowing well conditions (flowing and static bottom hole pressure, flowing and static bottom hole temperature, surface pressure, gas gravity, presence of CO2 and H2S, flowing gradient and critical rates)
- Infrastructure (onshore or offshore well, power availability and high-pressure gas availability)
- In general, all existing deliquification technologies can be put into one of the following four categories:
- Methods of sustaining natural flow (Well energy)
- Methods of Artificial Lift (External energy)
- Chemical

- Methods to isolate the water source
- Water /gas separation

III.1.1 Methods of Sustaining Natural Flow (Well Energy)

The main operations use the own well energy for solving liquid loading are as follows:

III.1.1.1Cycling:

Cycling a well requires the exact monitoring of well's fundamental data (production rate, wellhead temperature, wellhead pressure). This method involves the shutting in of a gas well that suffers from liquid loading on an appropriate time, to let it build up pressure and then producing the well to a low-pressure system. During the shut-in time the well builds up pressure (gas accumulation) in the near-wellbore region being charged from the reservoir. When opening up the well, this increased pressure might lift some of the liquids that obstruct gas production for a short time and hence gain the well some time until a liquid column of sufficient height has built up again to impact gas production, at which time the well should be shut-in already**.** [28]

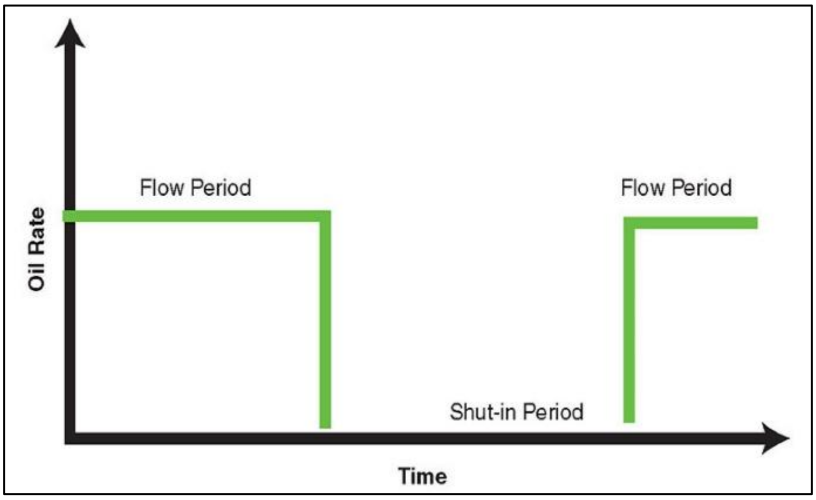


Figure III.1: Cycling wells. [28]

III.1.1.2 Venting:

In order to try to bring dead gas wells back to life, one option is to achieve maximum pressure drawdown by opening a well up to atmosphere. The main effect that is achieved by venting is the removal of any backpressure on wellheads. This "extra" pressure drop might lead to success in bringing a gas well back to life, however on a regular basis it is environmentally not acceptable. [29]

III.1.1.3 Swab Cup:

We can also try to mechanically remove fluid that causes backpressure on the formation. The intervention tool used for this type of operation is a “swab cup”, which is attached to a wire line, Once the swab cup has reached the desired depth it is pulled out of the wellbore again and in theory should remove most of the liquids that are located above it due to the fact that it should expand and form a seal. In practice, there is always a certain degree of fallback due to the fact that the seal cannot be completely tight. The operation might have to be repeated several times. [30]

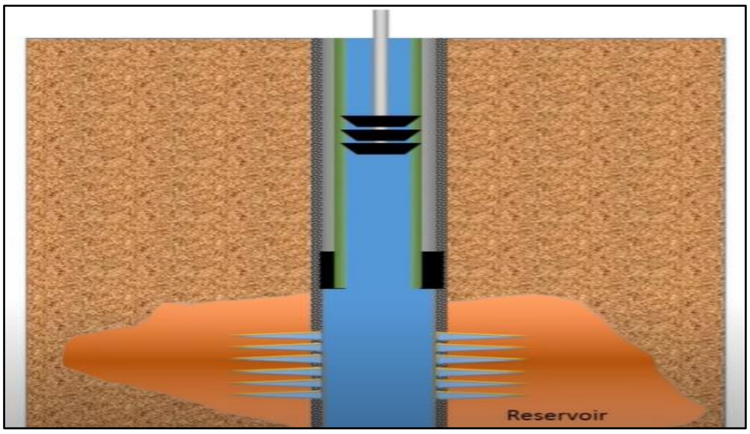


Figure III.2: Swabing operation.

III.1.1.4 Downsizing of production string ID (velocity string):

The velocity at which gas flows through pipe determines the capacity to lift liquids. When the gas flow velocity in a well is not sufficient to move reservoir fluids, the liquids will build up in the well tubing and eventually block gas flow from the reservoir. One option to overcome liquid loading is to install smaller diameter production tubing or ‘velocity string’. The cross-sectional area of the conduit through which gas is produced determines the velocity of flow and can be critical for controlling liquid loading. A velocity string reduces the cross-sectional area of flow and increases the flow velocity, achieving liquid removal while limiting blow downs to the atmosphere. [31]

and increases the flow velocity, achieving liquid removal while limiting blow downs to the atmosphere. [31]

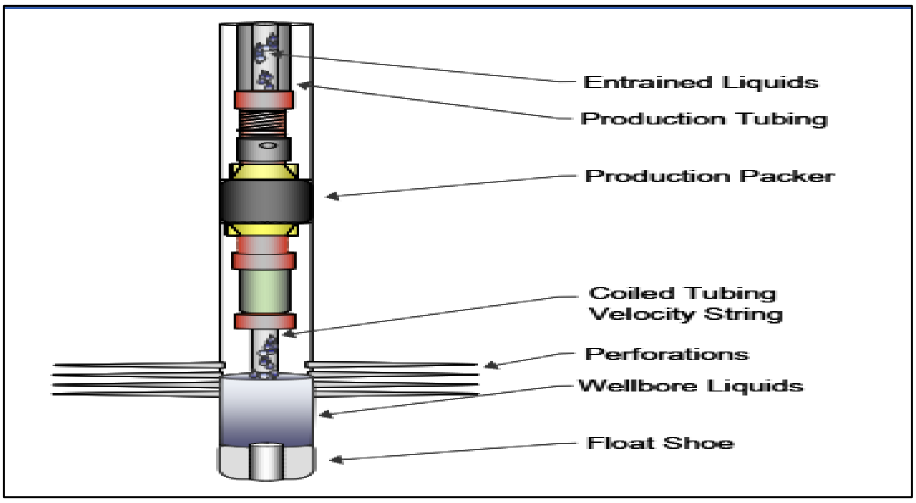


Figure III.3: Velocity String. [31]

III.1.1.5 Plunger Lift:

Plunger lift is a premier method of operating a gas well with liquids. It uses a free traveling plunger/piston to assist the gas in carrying liquid upward without an excessive liquid fallback. Periods of flow and no-flow for pressure build up are required. Plunger lift can operate using the wells' natural energy. [32]

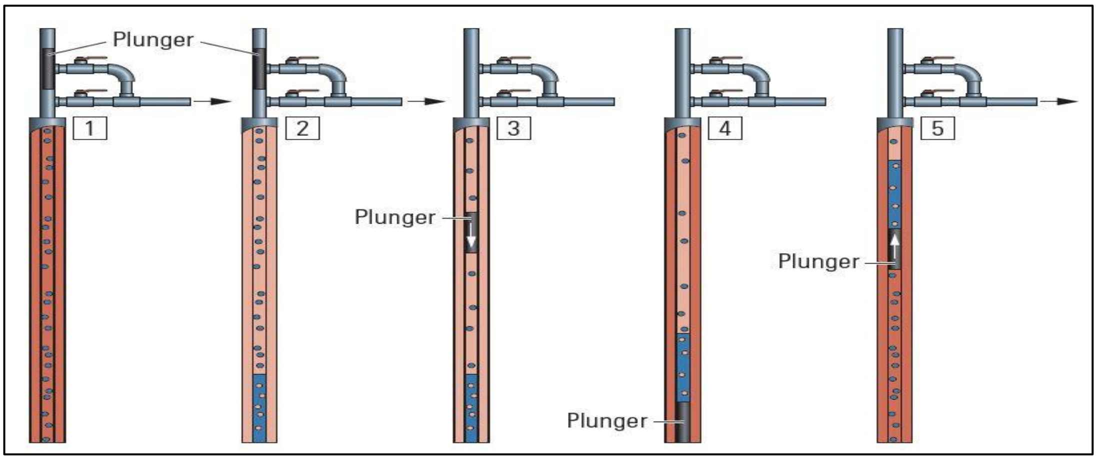


Figure III.4: PLUNGER lift Operation. [32]

III.1.1.6 Compression:

Compression is vital to deliquification as it results in lowering of wellhead pressure and increased gas velocity. Compression lowers wellhead pressure, which in turn leads to a lower bottom hole flowing pressure and increased drawdown. Lowering of bottom hole producing pressure and wellhead pressures, with compression, can result in substantial production and reserves increase. [33]

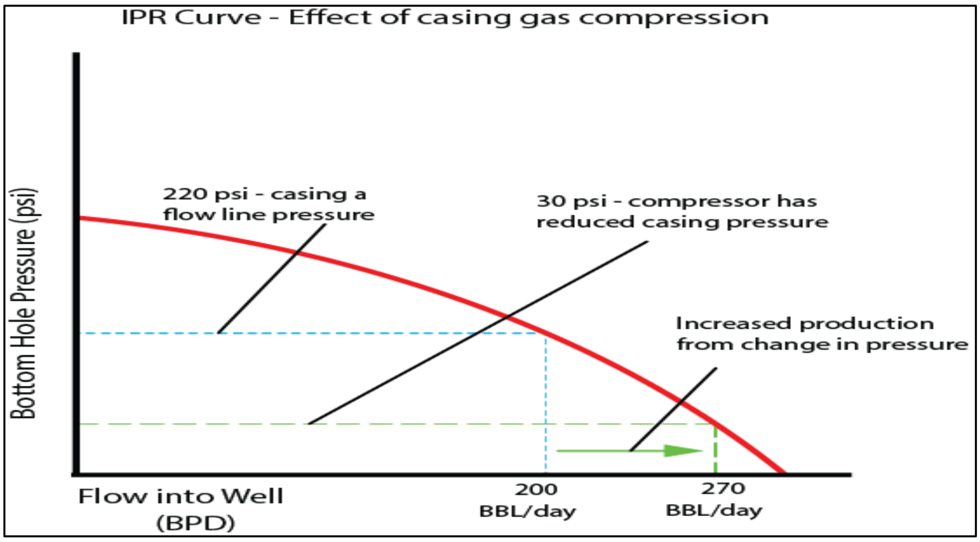


Figure III.5: Compression effect. [33]

III.1.2. Methods of Artificial Lift

III.1.2.1 Pumps:

There are different types of pumps for example ESP (Electrical Submersible Pumps), Rod Pumps, and Hydraulic Pumps, cavity pump the mechanism is pumping liquid out of the well and through coiled or slim tubing to the surface unit. using pumps can be an effective method for unloading liquid-loaded gas wells. The pumps can be used to remove the accumulated liquids from the wellbore, which can help restore gas flow and increase production rates. [34]

While pumps can be effective for unloading gas wells, they can also be costly and require maintenance. In addition, the use of pumps can increase the risk of equipment failure and downtime. Therefore, it is important to carefully evaluate the well conditions and the potential benefits and costs before deciding to use pumps for unloading liquid-loaded gas wells. Other methods for unloading, such as gas lift or plunger lift, should also be considered depending on the specific well conditions.

III.1.2.2 Gas Lift:

Gas lift is a means of injecting high-pressure external gas into the tubing production as deep as a possible injection point. Typically, in gas wells, the additional gas augments the formation gas to lighten the flowing gradient in the tubing 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 will be higher than the critical liquid lift rate. [37]

Gas lift for kick-off can be deployed temporarily by use of a coiled tubing unit and if often used to lift liquid loaded gas wells on (especially after well interventions. [31]

III.1.3 Chemical:

To reduce the density of the liquids, several chemical agents (surfactants/foamers) are available (e.g., liquid foamers, soap sticks). In principle, these agents lead to a reduction in interfacial tension, hence cause foaming with the help of gas flow. Bubbles formed within the liquid decreases liquid density and reduces the head pressure of the liquid column. [35]

The use of foam produced by surfactants can be effective for gas wells that accumulate liquid at low rates, Foam reduces the density and surface tension of the fluid column, which reduces the critical gas velocity needed to lift fluids to surface and aids liquid removal from the well. Compared to other artificial lift methods, foaming agents are one of the least costly applications for unloading gas wells. Foaming agents work best if the fluid in the well is at least 50 percent water. [36]

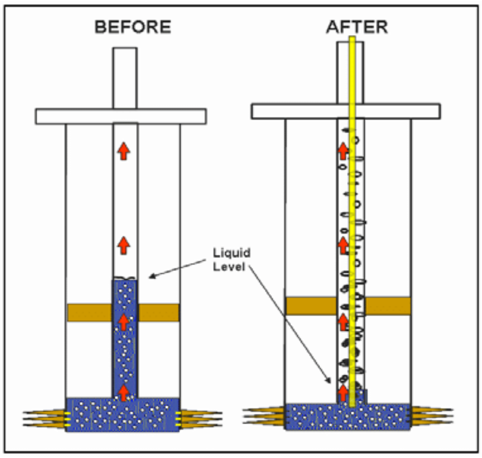


Figure III.6: Liquid Foaming Agent. [36]

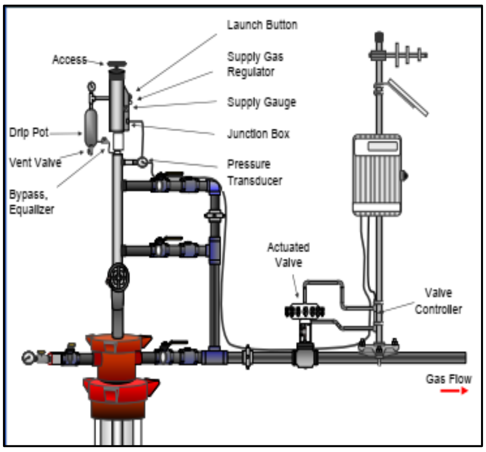


Figure III.7: Soap Stick. [36]

III.1.4 Methods to isolate the water source:

III.1.4.1 Water shut-Off:

Water shut-off in gas wells refers to the process of reducing or completely stopping the production of water from a gas well. Excessive water production can lead to liquid loading, which can significantly reduce gas production and ultimately result in well shut-in.

To shut off water production in gas wells, various techniques are used, including chemical treatments, mechanical interventions, and wellbore isolation. [38]

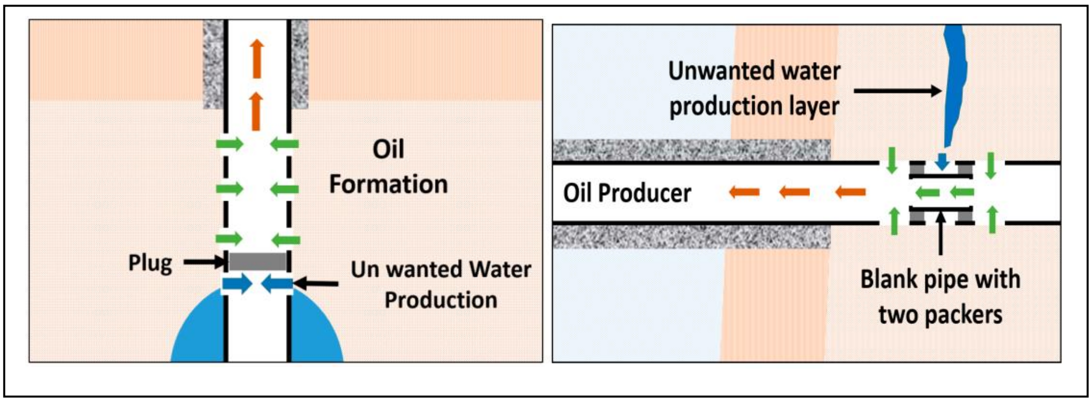


Figure III.8: Examples Water Shut-Off Methods. [38]

III.1.4.1.2 Water / Gas Separation:

- **DGWS (Downhole Gas/Water Separation) technology:**

DGWS technologies can be classified into two main categories: gravity separation and hydro cyclone separation. The majority of downhole gas-water separation was achieved by allowing gas and water to naturally separate in the tubing-casing annulus. [40]

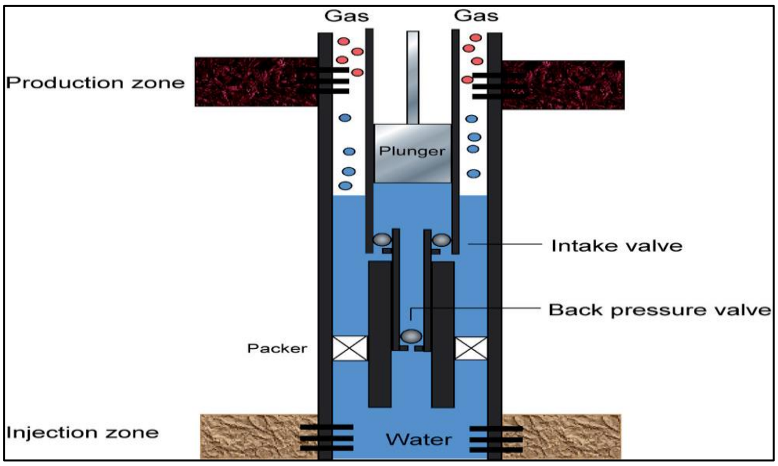


Figure III.9: DGWS with modified plunger pump

- **Down Hole Water Sink:**

Downhole Water Sink (DWS) This is one of the solutions developed to reduce the phenomenon of water coning and water production in vertical wells. vertical wells. This technique requires a double completion in the water and gas zones. The perforation intervals of the gas and water zones are isolated by a packer. [41]

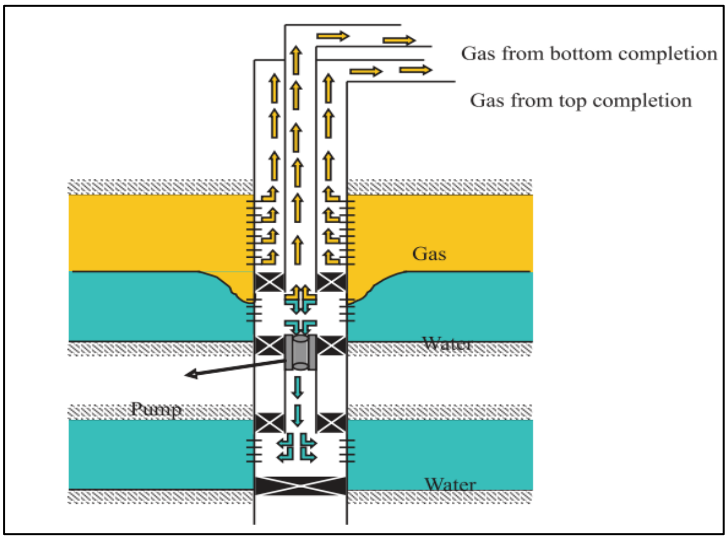


Figure III.10: DWS configuration for gas wells

III.2. Solving water loading problem in Teg23 and Teg 26:

III.2.1 Case study of Teg23:

III.2.1.1. Decision for Water shut off for Teg 23:

The water shut off solution seems to be more optimal for the Teg-23, because the well was drilled in an open hole and completed with a slotted liner, this solution involves placing a plug between the slotted liner and the formation that produces the unwanted water. Based on the well logs and production logs that have been completed on Teg-23 Figure **II.8**, it has been confirmed that the water comes from the D30.

In order to remediate the issue, water shut off options were assessed like chemical treatment and conventional plug-in slotted liner but none of this solution seems efficient and without a risk. New technology is therefore required to resolve the issue.

III.2.1.2. Plug location

Based on the well logs and production logs that were performed on Teg-23 it has been confirmed that the water is coming from below the D40L. Due to a fish being stuck at the bottom of the well and unless fishing attempts are feasible. The plug is to be set at the top of the fish between 2994 and 3000 WLbrt.

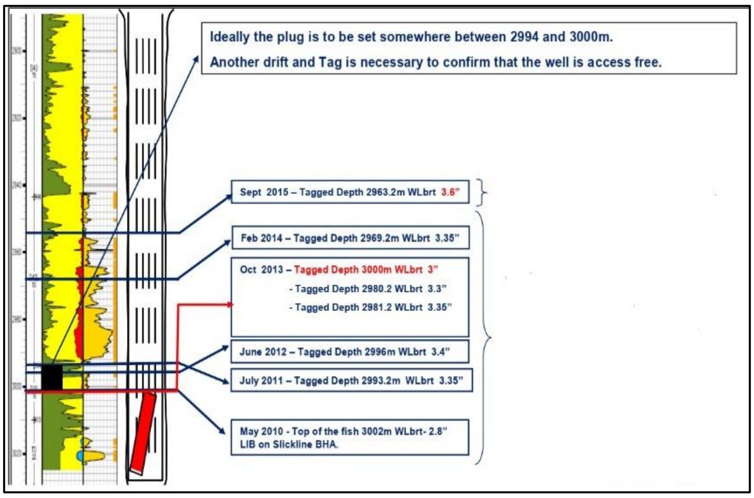


Figure III.12: Plug location

III.2.1.3. The Wel-lok™ WSO:

The Wel-lok™ WSO (Water Shut Off) has been specifically developed to reduce unwanted water production from wells with sand screen and open hole completions. Unlike any other solution on the market, the Wel-lok™ WSO tool seals the annulus and the wellbore in one operation without the need to perforate the sandscreen or squeeze the alloy into the open hole annulus. The melted alloy fills inside the completion and in the annulus to form a metal-to-metal sealing solution that is seamless, significantly reducing unwanted water production.

III.2.1.4. WEL-LOK™ -Deployment Method:

The Wel-lok™ technology consists of utilising a modified thermite chemical reaction heater to melt bismuth-based alloys downhole. The melted alloys have a viscosity similar to water, and a specific gravity 10 times that of water, allowing them to flow into the smallest areas of a wellbore without the need of any surface pumping equipment. As the alloys cool and solidify, they expand to provide a seamless gas tight seal that is noncorrosive and not affected by H_2S or CO_2

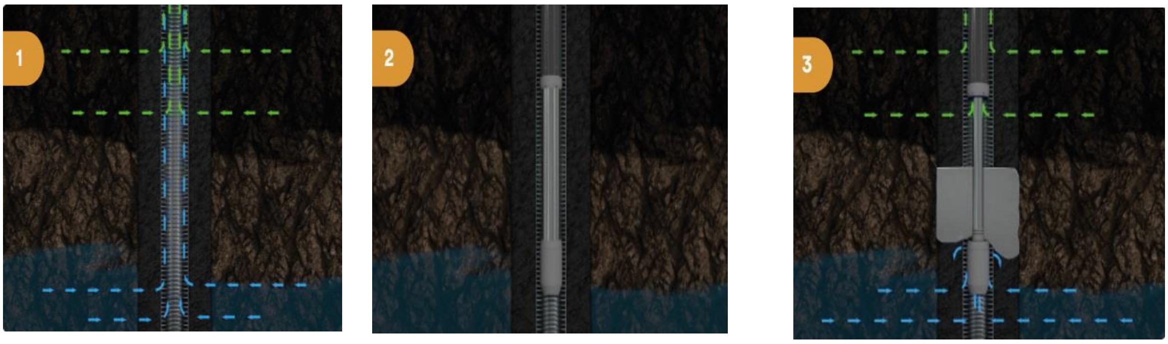


Figure III.13: WEL-LOK™ Plug installation method

III.2.1.5 Results after WEL-LOK™ Plug installation:

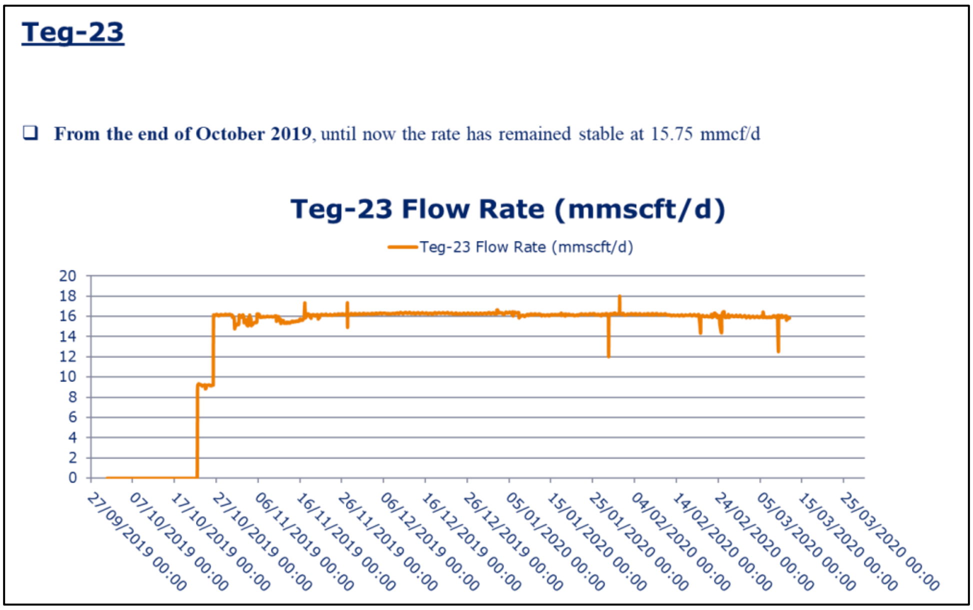


Figure III.14: Flow Rate after the WEL-LOK™ Plug installation

- **Discussion:**

After the installation of WEL-LOK™ Plug in TEG 23 and starting the well the flow rate has remained stable at 15.75mmcf.

As a result of this intervention, the flow rate of the TEG 23 well has stabilized. This stabilization indicates a significant improvement in operational performance, as it ensures a consistent gas flow rate

So, the installation WEL-LOK™ Plug of a as a water shut-off method in TEG 23 has resulted in the stabilization of the well's flow rate. By effectively isolating the D30 zone and preventing water ingress, the plug has addressed the issue of water loading and its associated challenges.

III.2.2. Case Study TEG 26;

III.2.2.1 Decision for Velocity string for TEG 26:

Most of Teg wells completed with a 7-inch tubing are currently producing close to gas critical rate. Managing these wells by running velocity strings will allow to increase field production potential. The velocity string is a method of installing a smaller tubing using VS packer, inside existing production tubing using traditional intervention techniques, making it a cost-effective option that does not require a rig or workover. The velocity string will help increase the velocity of the producing fluid which will eliminate the liquid loading issue. It is relatively cheap option, operationally less complicated to carry out. All operations are though tubing and does not need to kill the Well which will eliminate formation damage impact/issue. It can be installed below the safety valve and Well paths are fully isolated. Teg-26 is producing in cycling mode under the current pressure operating conditions. The existing 7-inch completion does not provide enough velocity to lift water vapour condensing at the bottom of the well.

III.2.2.2 Velocity String Simulation Well TEG- 26:

- **Overview of the Software WELLFLO:**

WELLFLO is an advanced window based well analysis software, which has been used by the international oil and gas industry for almost 30 years. Beside well design and well analysis of multiphase and single-phase oil and gas wells WELLFLO also incorporates many of the capabilities of other fluid property and PVT behaviour program. The software works with naturally flowing well applications, gas and condensate wells, pipeline and surface equipment. It provides modeling, design and analysis for electric submersible pumps (ESP) and gas lift, inflow and outflow performance modelling and other applications. The software was specifically designed to aid petroleum engineers with five basic well completion and production engineering functions: configuration, tuning, analysis, design and output.

Gray's correlation was used for analysis along with fluid PVT properties, reservoir pressure, WHFP and WGR to calculate the production rate associated to these conditions. The results are indicating that for each size of Velocity string, production improvements are attainable and liquid loading issue will be resolved. However, foam lift or other lift energy support will be required to get promising results

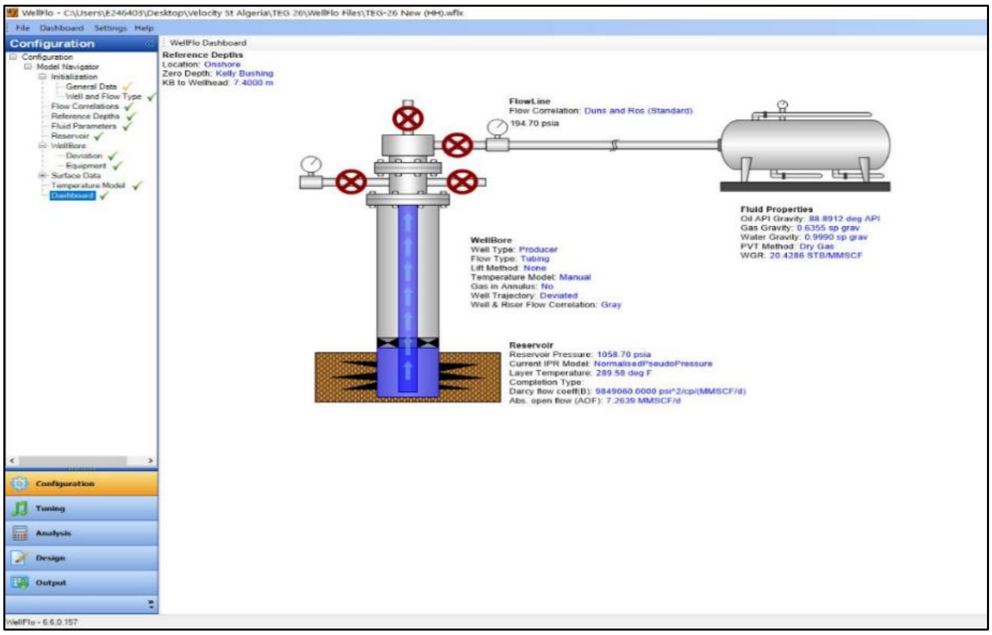


Figure III.15. WellFlo model

- **Input DATA:**

The well schematic, production data, well test data are very important informations to do the simulation of velocity string using the WELLFLO software.

Table III.1 : Input data

INPUT DATA	
Flowing WH Pressure	180 psi
Shut-in WH Pressure	942.2 psi
Shut-in BH pressure	1044 psi
Av. Daily Water Rate	143 bbl/d
Av. Daily Gas Rate	7 mmscf/d
End of Tubing Depth	2751**M**

- **Modelling purposes:**

Table III.2: Modelling purposes for VS installation

VS installation	
Case 01	**2 7/8" X 0.188"** • To Surface • To below Safety valve
Case 02	**2 3/8" X 0.175"** • To Surface • To below Safety valve

- **Conceptual Completions For installing VS:**

Velocity string to surface and to TRSV has been considered for both cases 1 & 2. When considering velocity string to safety valve depth at 66m MD, there will be pressure drop and velocity will decrease due to sudden change in flow area from 2 7/8" or 2 3/8" VS to 7" Completion tubing. There is a potential for liquid drop out above safety valve inside existing production tubing, however this impact seems to be low due to shallow depth of safety valve. The critical unloading velocity curve is shown in the (See**. Figure III .18**), where it can be seen that the in-situ gas velocity is higher than the critical unloading velocity. Hence, no liquid loading is happening in the well. It should be noted that due to flow path suddenly increases at 66m depth (above TRSV) from 2 7/8" VS string to 7" completion tubing, there will be drop in pressure and in Situ gas velocity from 97.65ft/sec to 16.14 ft/sec. However, as the safety valve is at shallow depth of 66m, the impact of pressure and velocity drop seems to be low, so in Teg-26 case we have chosen the surface VS to avoid the pressure drop in top of TRSV Also for the 2 3/8" there will be drop in pressure and in Situ gas velocity.so to avoid the pressure drop in the upper section of the tubing the chosen installation for the well was the installation of velocity string to the surface like shown in **Figure III.17 & Figure III.16**

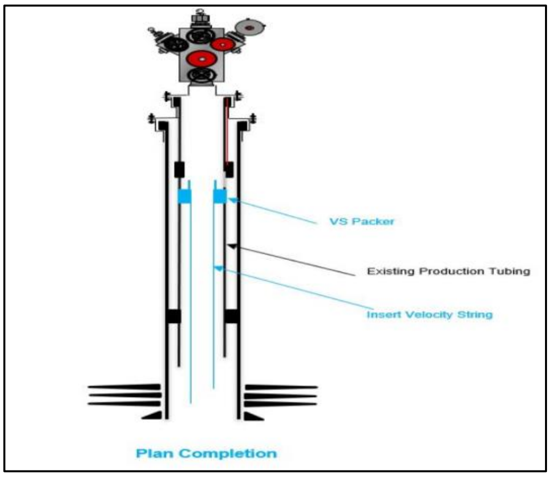


Figure III.16 VS below SSSV

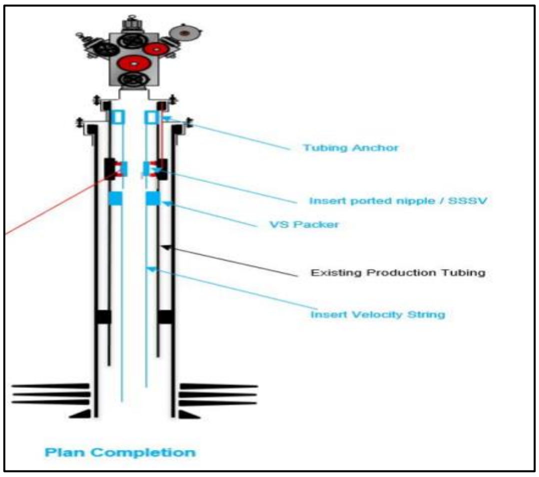


Figure III.17 VS to Surface

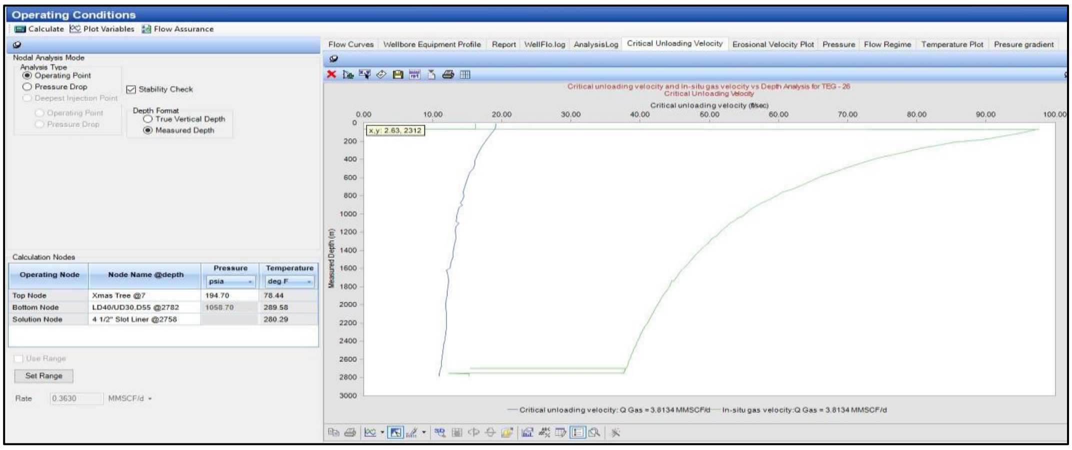


Figure III.18 2 7/8" VS to TRSV- Critical Unloading Velocity Plot

➢ **Tubing size choosing:**

A comparison between 2 7/8" Velocity string and 2 3/8" Velocity string has been evaluated and following are the findings: the results shown in Table 5.16 are based on, after 2 7/8" VS is installed inside existing production completion and model was already fine-tuned with the Well Test data. The flow curve after 2 7/8" VS string installed are shown in the (**Figure III.19**)). Critical unloading velocity plot is shown in (**Figure III.20**).

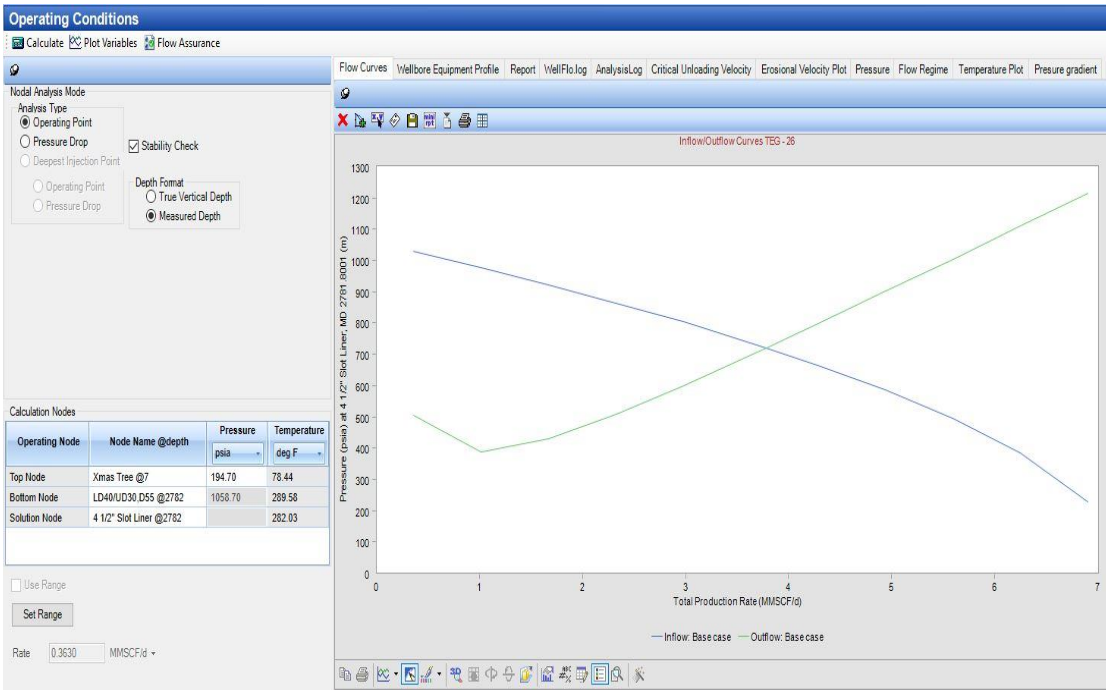


Figure III.19 Flow Curves- 2 7/8" VS Tubing Flow

- **Discussion about comparison results:**

After simulating both 2 7/8" VS & 2 3/8" VS we noticed that in the tubing flow the 2 7/8" VS give us a better result in the gas rate This indicates that the larger tubing size allowed for more efficient fluid flow, reducing the resistance encountered by the gas as it traveled through the wellbore. Consequently, the larger tubing size can potentially enhance production rates by minimizing flow restrictions and optimizing the overall flow efficiency.

Next, we evaluated the critical unloading behavior of the two tubing sizes, It was observed that the 2 3/8" tubing required a higher critical gas velocity to achieve effective unloading compared to the 2 7/8" tubing. This suggests that the larger tubing size provided better fluid lifting capabilities, enabling more efficient unloading and reducing the risk of liquid accumulation and wellbore restrictions.

In conclusion, the comparison of 2 3/8" and 2 7/8" tubing sizes using nodal analysis revealed that the larger tubing size offers potential benefits in terms of improved flow performance and critical unloading behavior.

III.2.3 After installation of 2 7/8" VS:

Sensitivities: To gain a better understanding of the response of Well TEG-26, several sensitivity analyses were conducted on various parameters, including reservoir pressures (Pr), wellhead pressures (WHP), and water gas ratios (WGR). The results of these analyses provide valuable insights into the behavior of the well.

- **Sensitivity run on Reservoir Pressures:**

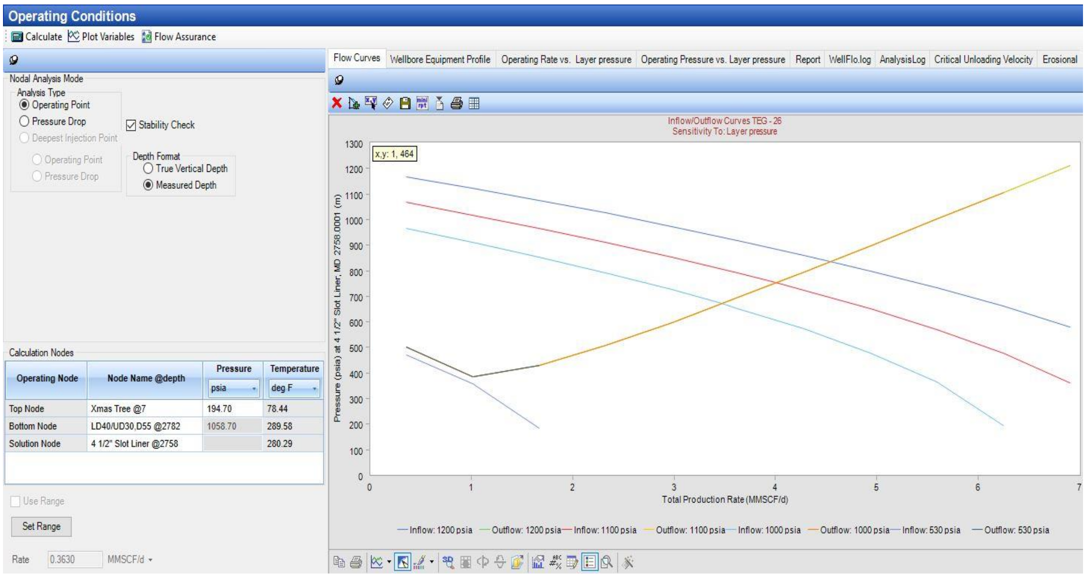


Figure III.23. Well Analysis Summary- Sensitivity on Pr

- **Sensitivity run on WHP :**

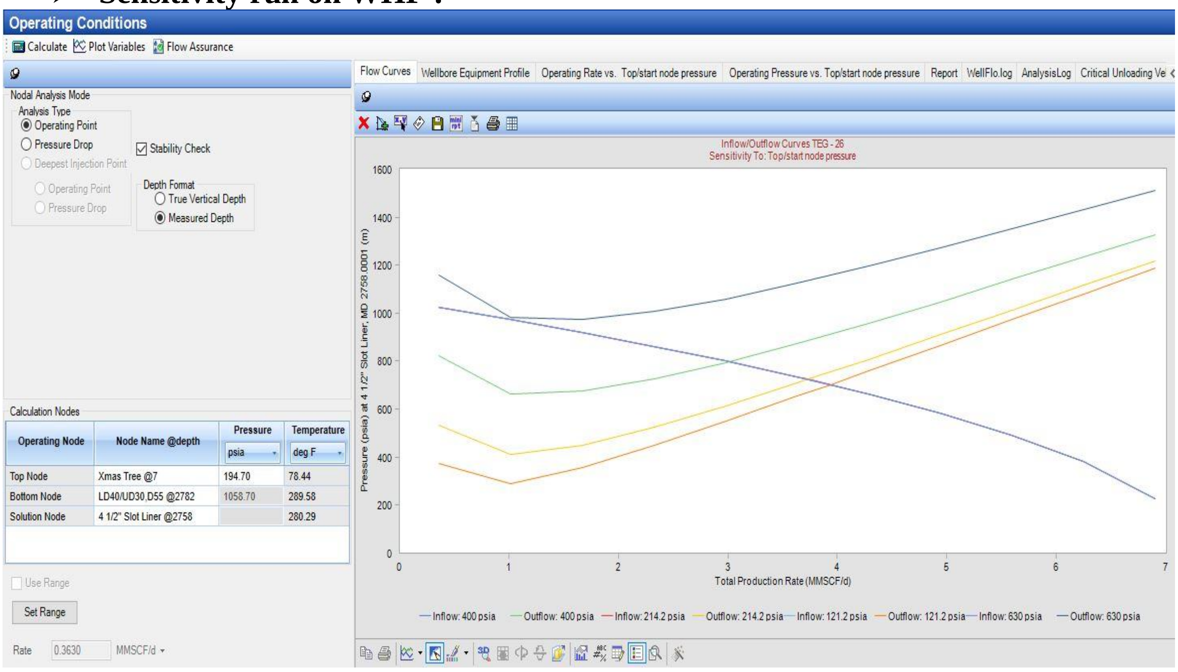


Figure III.24. Well Analysis Summary- Sensitivity on WHP

- **Sensitivity run on WGR :**

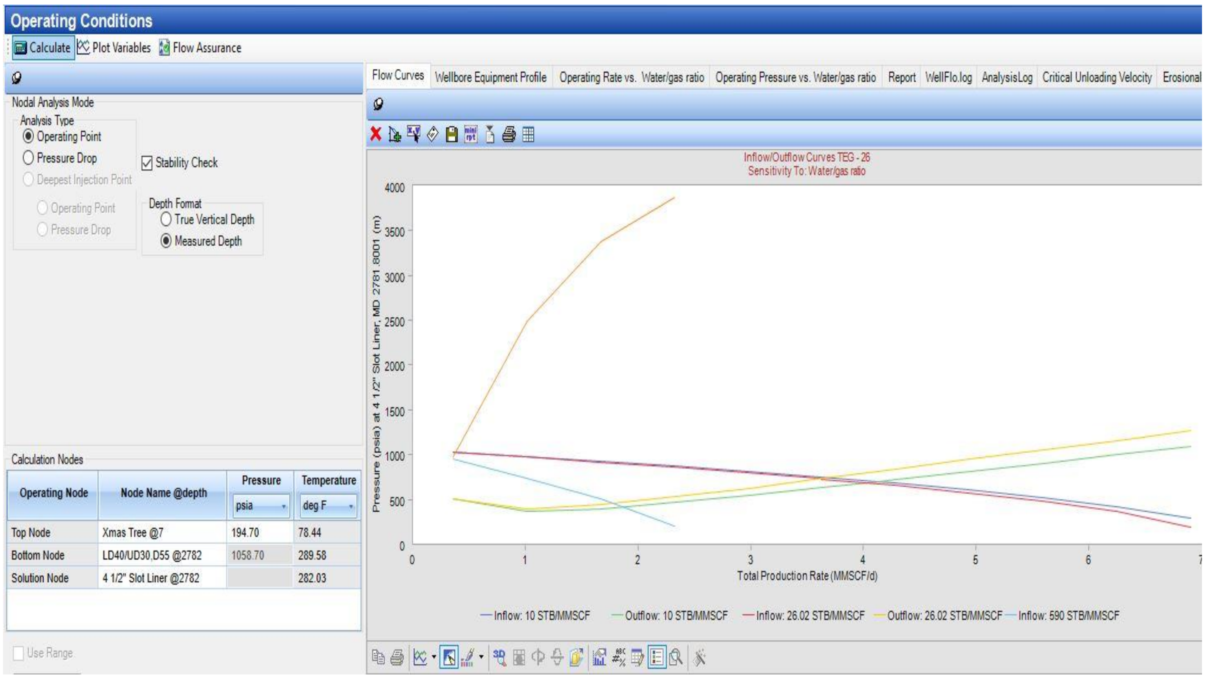


Figure III.25: Well Analysis Summary- Sensitivity on WGR

Table III.7. Well Analysis Summary - Sensitivity Run on WGR

- **Sensitivity run on Reservoir Pressures Vs WHP:**

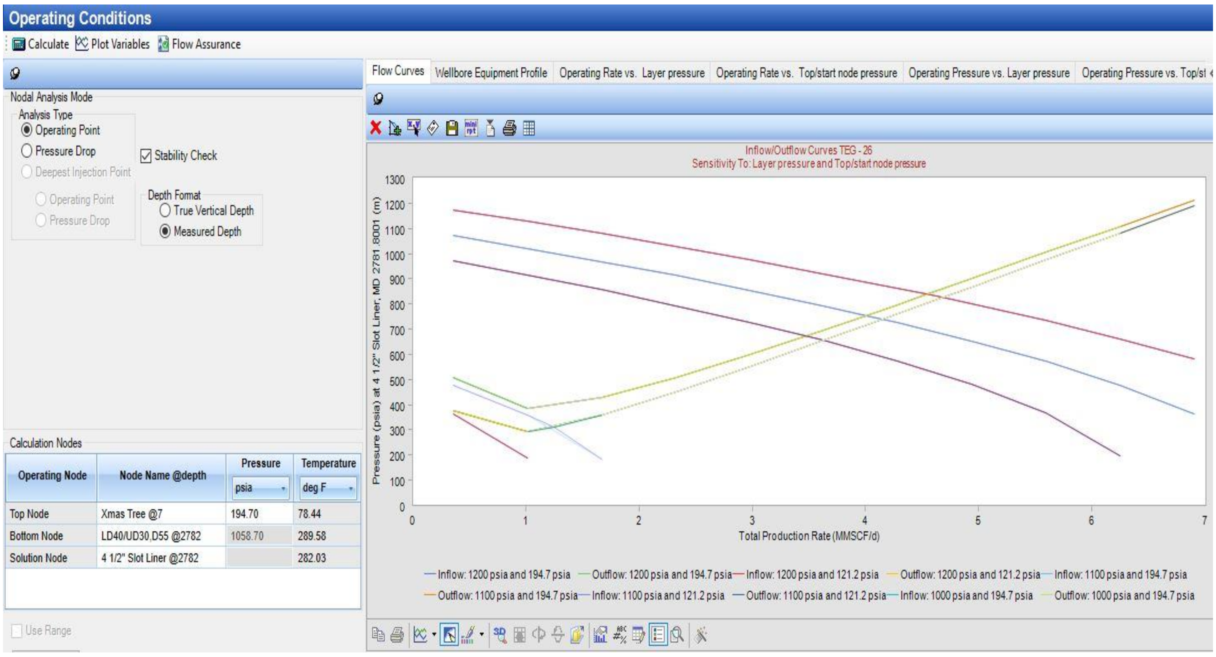


Figure III.26 Well Analysis Summary- Sensitivity on Pr Vs WHP

Table III.8. Well Analysis Summary - Sensitivity Run on Pr Vs WHP

- **Results and discussion :**

Firstly, it was observed that reducing the WHP from 400 psia to 121.20 psia leads to an increase in gas production from 3.01 MMScf/d to 3.94 MMScf/d, without any condensate production. This finding suggests that lowering the wellhead pressure can enhance gas production while maintaining a steady reservoir pressure.

Secondly, as the reservoir pressure declines, an interesting observation was made. At a pressure of 530 psia, the current WHP of 194.70 psia does not have an operating point. However, by reducing the WHP to 121.20 psia, Well TEG-26 can still produce gas at a rate of 1.25 MMScf/d, even at the lower reservoir pressure of 530 psia. This indicates that adjusting the wellhead pressure can enable production under challenging reservoir conditions.

Furthermore, the impact of the water gas ratio (WGR) on gas production was investigated. It was found that increasing the WGR from 10.00 Stb/MMScf to 26.02 Stb/MMScf results in a decrease in gas production rate from 4.14 MMScf/d to 3.62 MMScf/d, as shown in Table III.7 However, it is noteworthy that there is no operating point when the WGR reaches 590 Stb/MMScf. Beyond this threshold, the well experiences an adverse effect on production, and production ceases. This finding emphasizes the detrimental impact of excessive water production on well performance.

For velocity string simulations a depth of 2749 mMD was considered. However, a further deeper depth can be evaluated

In conclusion, the sensitivity analyses provided valuable insights into the behavior of Well TEG-26. Lowering the wellhead pressure can enhance gas production, even under declining reservoir pressure conditions. However, an excessively high-water gas ratio has a negative impact on gas production, with production ceasing beyond a certain threshold. These findings underscore the importance of carefully managing wellhead pressure and water production to optimize gas production from the well.

III.2.2.4 Results after Velocity String installation:

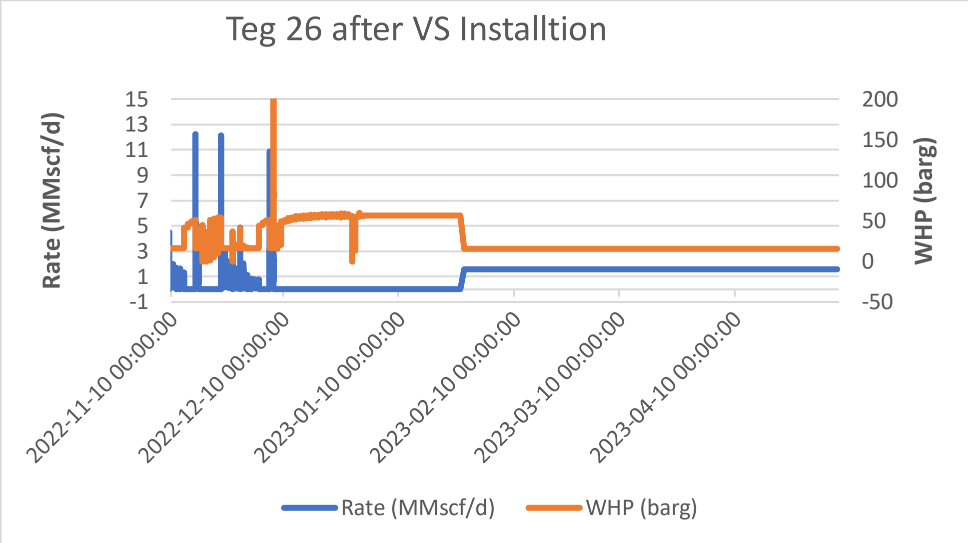


Figure III.27 Production curve after VS installation

- **Results &Discussion:**

After the installation of the velocity string on the TEG 26 well, the well has provided a steady gas flow rate of 1.6 (Mmscf/day) with no water production and a stable wellhead pressure of 227,65 psi.). The installation of the velocity string in the TEG 26 well has led to a remarkable transformation in production outcomes. Previously, the well had been producing at a fluctuating rate of 7 (MMscf), without a stable flow. Additionally, the cessation of water production, coupled with diligent monitoring of the wellhead pressure, further enhances the positive impact of the velocity string installation. But the results of the installation does not match with the simulation results

Table III.9. Well Data after VS installation

Gas rate (Mmscf)	1.6
Water production (Bbl/Day)	0
Wellhead pressure (Psi)	227.65

It is important to acknowledge that the installation of the velocity string in the TEG 26 well represents a new implementation, and as such, a comprehensive evaluation is necessary to fully understand the results. Given the uniqueness of this installation, it would be prudent to conduct a follow-up study to assess the performance and effectiveness of the velocity string in the well.

A subsequent study would enable a more in-depth analysis of various factors, such as production stability, water production, and wellhead pressure, to determine the long-term implications of the velocity string installation. It would also provide an opportunity to compare the actual results with the initial expectations and simulation models.

While the current results of the velocity string installation show positive outcomes, a thorough post-installation study will provide a more comprehensive understanding of the impact and effectiveness of this technology. It is important to gather sufficient evidence and data to make informed judgments and to refine any necessary strategies or adjustments based on the specific conditions of the well.

III.3. Conclusion:

In conclusion, the third chapter focused on theoretical methods to address water loading issues in the Tegentour field and their practical application on candidate wells. Two specific methods were employed: the velocity string technology and water shut off using the M2M Lock Plug.

The results of applying these technologies on the wells were analyzed, although it is important to note that the evaluation of the velocity string technology effectiveness was limited due to its recent implementation. However, the outcomes of the water shut off using the M2M Lock Plug showed promising results in terms of solving water loading and enhancing well productivity

Conclusion

In conclusion, this study aimed to tackle the prevalent issue of water loading in gas fields. The research provided a thorough overview of water loading, encompassing its diagnosis and prediction techniques. The focus was on a specific case study, examining water loading symptoms in two wells located in the Tegntour field. Furthermore, the study delved into the application of the velocity string and water shut off methods as viable solutions to address this problem.

- Most gas wells will have liquid loading occur at some point during the productive life of the well.
- Utilizing critical velocity and nodal analysis to predict the onset of water loading is an effective strategy in managing its occurrence. It is essential to have a comprehensive understanding of the well's behavior through detailed information to make informed decisions when implementing deliquification methods to resolve the issue.
- The Tegentour field commonly experiences water loading, which is indicated by different symptoms
- In order to address water loading issues in the Tegntour field, two distinct methods, velocity string and water shut off, were implemented in the wells. These methods were utilized to tackle the water loading problem.
- The implementation of water shut off operations effectively prevents the ingress of water from the lower zone beneath the reservoir, thereby mitigating the occurrence of water loading.
- Nodal analysis using Wellflo software suggests that implementing a velocity string can stabilize production in TEG 26.
- The installation of the velocity string, although a recent development, has helped to stabilize the gas production. However, its actual performance differed from what was initially expected based on simulation results.
- The use of velocity string works to delay the occurrence of the liquid loading but does not solve it finally; the installation of the velocity string will be a short-term solution.

However, it is important to note that a conclusive judgment regarding the results of the velocity string installation cannot be made at this time. Further evaluation and monitoring are necessary to assess the long-term effectiveness and performance of the installation in stabilizing gas production.

Recommandations

- Gathering additional data, particularly dynamic bottom hole pressure, is crucial to enhance the accuracy of well performance modelling.
- Early diagnosis of water loading and identification of water sources can be highly effective in preventing the losses associated with water loading.
- In future completions, choosing the optimal tubing size can serve as a viable long-term solution for addressing liquid loading challenges.
- While the cycling mode is often used to address water loading, it can exacerbate water accumulation in certain cases like the Teg 23 well. So detailed well behaviour Data is very important.
- The Teg 26 well was selected as a pilot well for the installation of a velocity string. Although the results of this recent installation are still being evaluated, studying the well's behavior and assessing the economic aspects can provide valuable insights for implementing similar measures in other wells experiencing water loading issues in the Tegentour gas field.
- The implementation of water shut off operations on the TEG 23 well has successfully achieved a stabilized gas rate. However, it is important to note that the well still carries the risk of encountering condensation water, potentially leading to another water loading issue with a different water source.
- There are alternative permanent solutions available to address liquid loading, such as the implementation of Plunger Lift and Gas Lift pumps. However, the selection and application of these solutions require careful consideration of economic factors.

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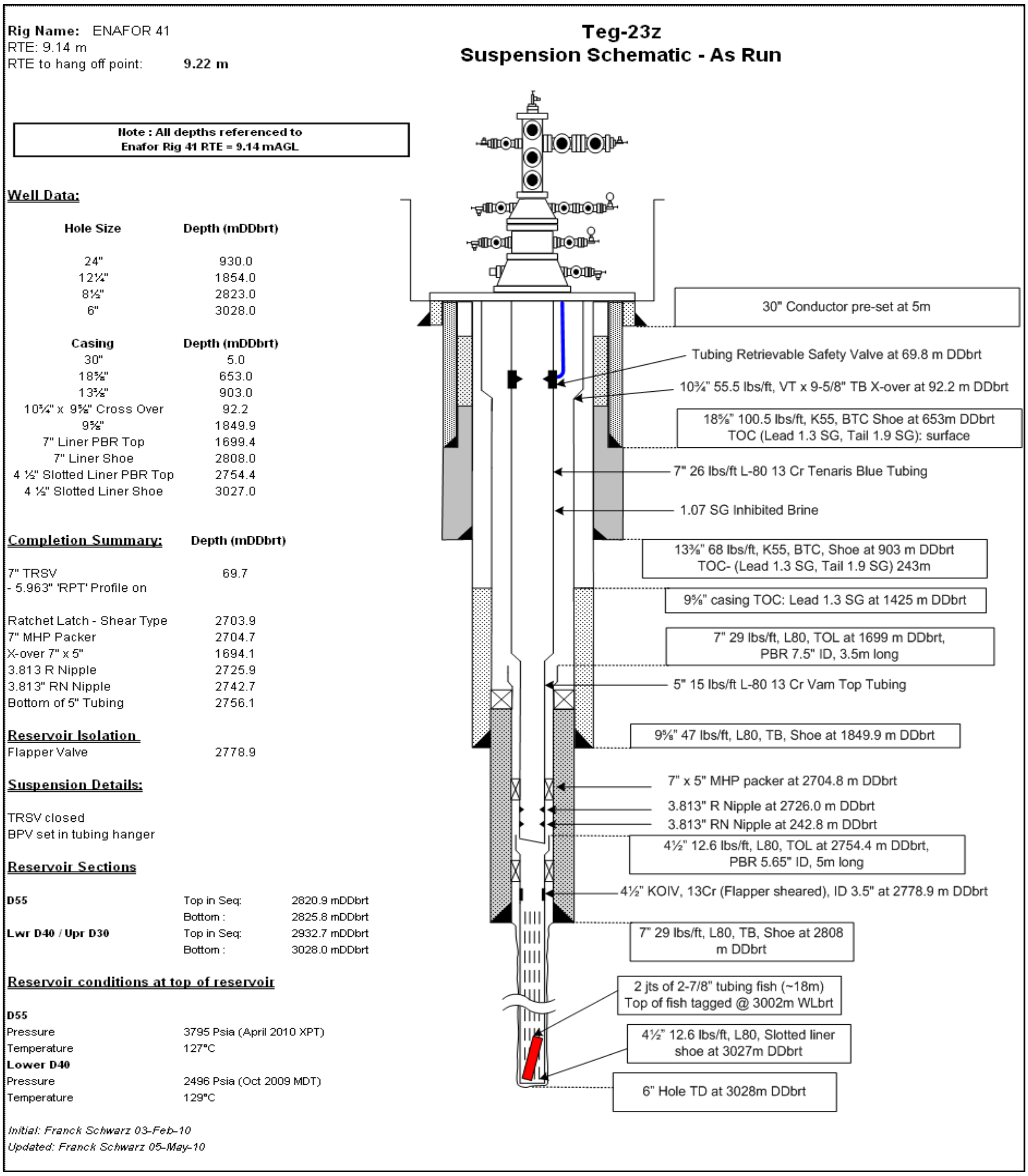
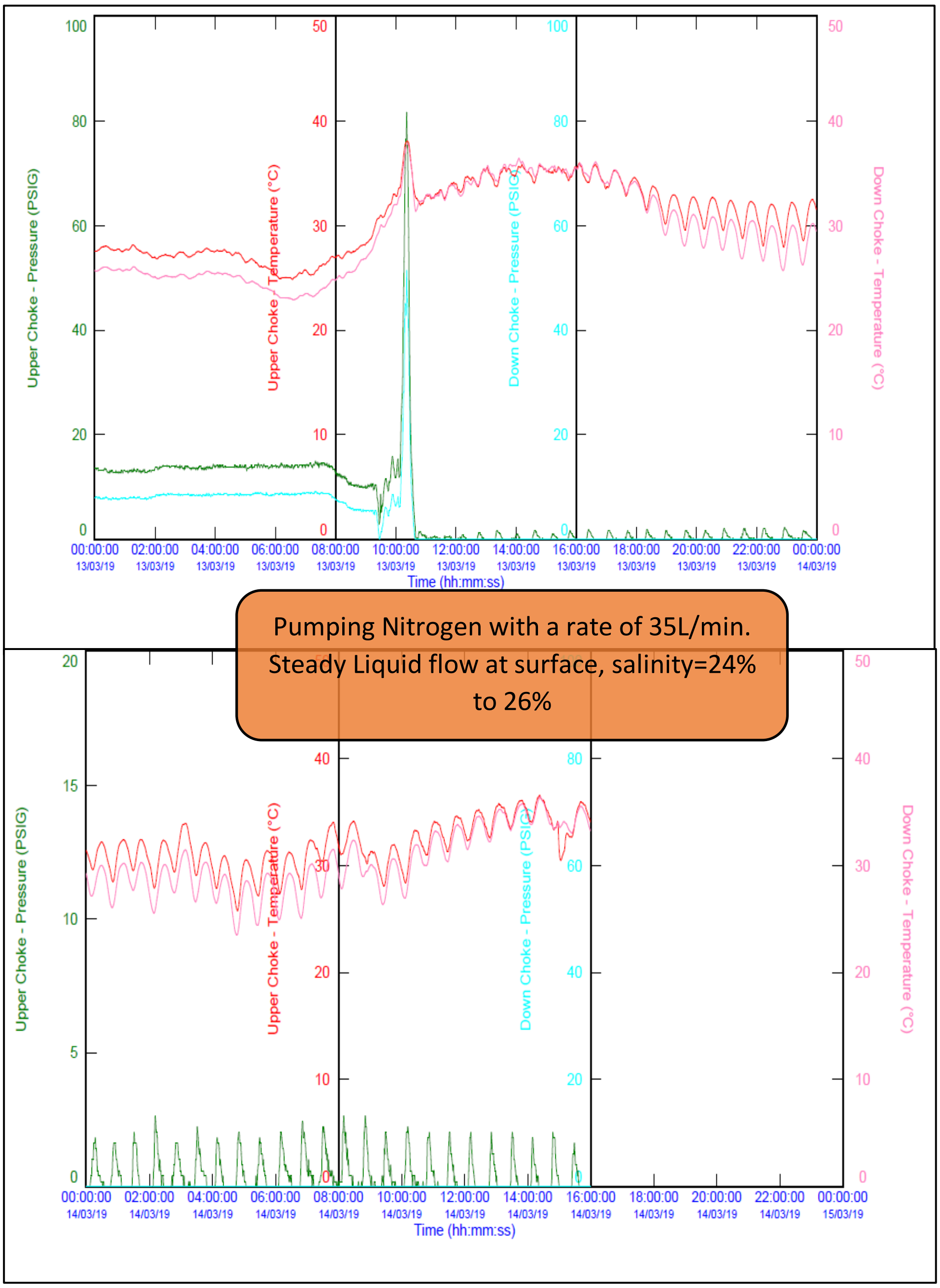
Appendix 1

Teg 23 Completion :



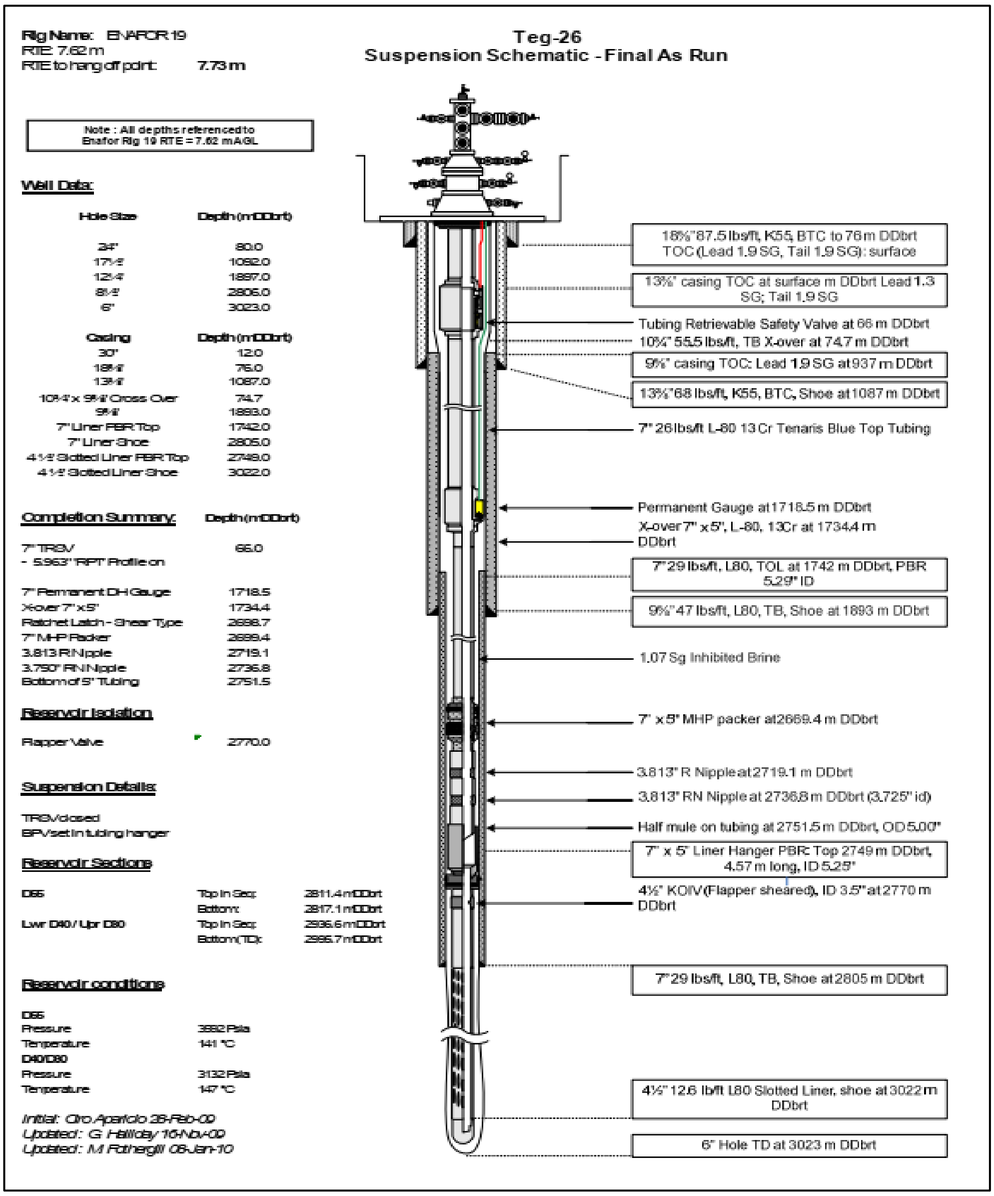
Appendix 2

Rate fluctuations during nitrogen pumping



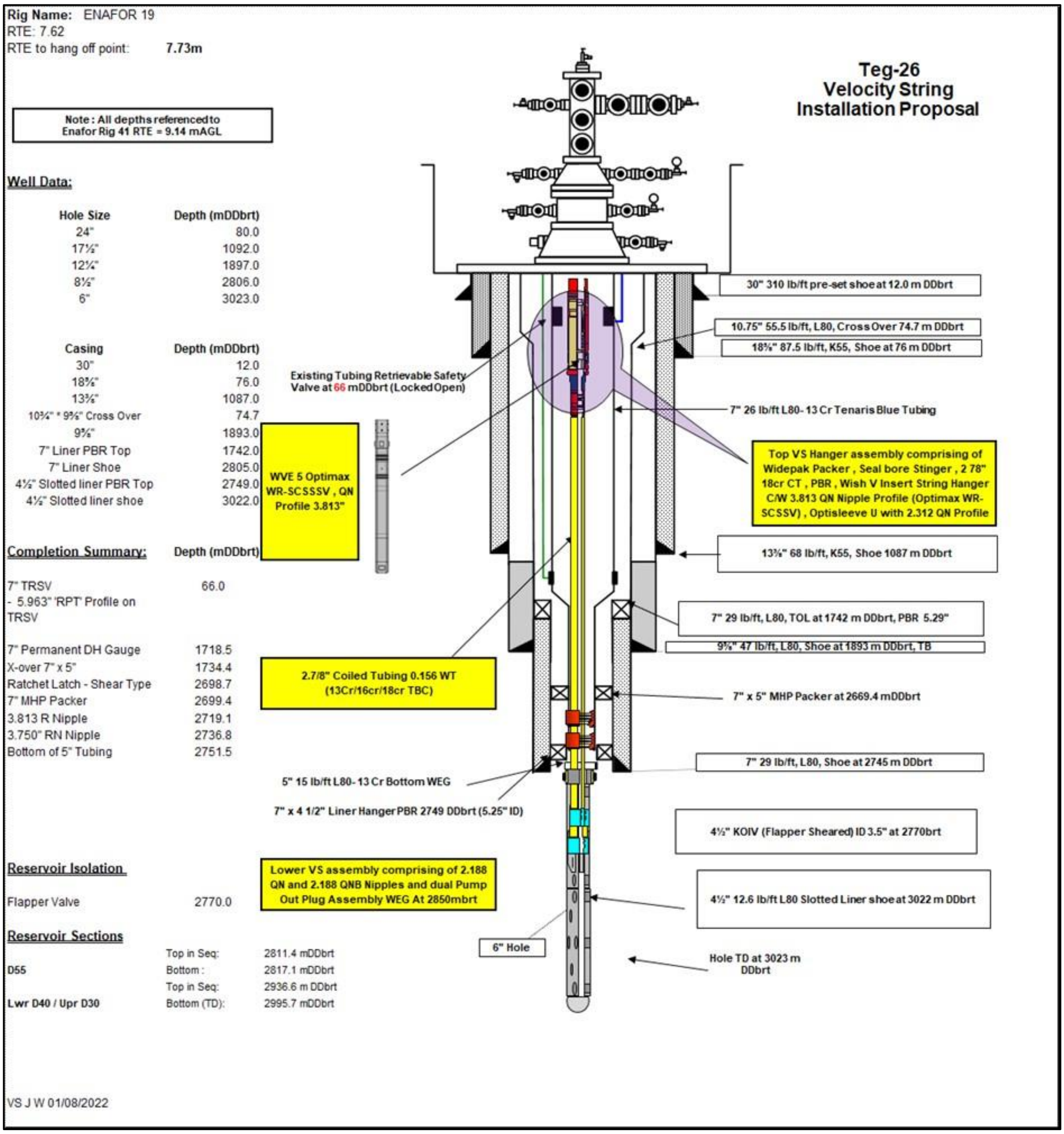
Appendix 3

Teg-26 completion schematic



Appendix 04

Teg 26 after VS installation



APPENDICES