The People's Democratic Republic of Algeria

Ministry of Higher Education and Scientific Research

N° Série : ………/2024

University of Kasdi Merbah – Ouargla

Faculty of Hydrocarbons, Renewable Energies and Earth Sciences and the Universe

Production of Hydrocarbons department

THESIS

In partial fulfilment of the requirements for

MASTER'S DEGREE

Major Subject: Professional Production

Realized by:

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Title of Master's Thesis:

Design and Installation of Coiled Tubing Velocity String to Overcome Liquid Loading and Optimize Gas Well Production: Case Study in Tiguentourine Field (TG-352)

Submitted on: 06/06/2024

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2023/2024

Dedication:

I dedicate this modest work:

First of all, to my dear parents ;

My dear mother, who taught me to study hard and was my support throughout my academic journey.

To my dear father, who gave me a lot of advice that helped me in the field of academic life and beyond.

My dedications also go to my dear brothers, To all my sisters, and to all members of my family.

Also, I dedicate this work to all my friends, especially my friends in GAZA, Palestine.

Not forgetting all my colleagues in the university.

Guerbouy Mohamed Aiman

Dedication:

To those in whom Allah says:"And your Lord decreed that you should worship only Him and your parents in kindness."

To whom I proudly bear his name, to which God has entrusted with prestige and reverence, my dear father Rachid.

To my angel in life, to the meaning of love and the mystery of existence, to the one who receives me with a smile and bids me farewell by inviting my wonderful mother, Zohra.

I am happy to see you and you are proud and happy with my success thank you for the success of my academic career until my graduation.

To my sister, my soul mate, Iman, my friend, half my smile and half my life.

To my brothers Ali, Zakaria and Ibrahim, may God grant you support for love and safety.

To everyone who provided all the reasons and opportunities to achieve this dream.

To all my family thank you for your giving.

KESSI OUAZNA

Acknowledgment:

First and foremost, we would like to thank Allah, our creator who has enlightened us with the path of knowledge and wisdom and who has given us the strength to accomplish this work.

*We start by first thanking our supervisor, **Mr.BRAHMIA Nabil**, for the time he has dedicated to us, for his help, as well as for the guidance, trust, and patience which have been a considerable contribution without which this work could not have been accomplished.*

*We would also like to extend our thanks to all the workers at **JV GAS** IN AMENAS, especially the workers in the **DEP**, for helping us throughout the duration of the internship.*

Finally, we thank all those who have contributed, near or far, to the realization of this work.

Abstract:

This thesis is dealing with the application of so-called Coiled tubing velocity string in gas wells, A coiled tubing (CT) velocity string is a known method to unload liquids in gas wells it's a production string with a smaller cross-sectional flow area installed inside the production tubing to improve gas velocity, thereby avoiding water column accumulation at the bottom of the well.

Gas and oil wells often experience a decrease in production ability or abandonment due to factors such as depletion natural of reservoir pressure and diminishing production velocity. Additionally, there is an increase in water and condensate accumulation in the perforation area due to condensation in production tubing through temperature and pressure changes. This condensates production can lead to the formation of a liquid column in the wellbore, inhibiting gas production from the reservoir into the production tubing, known as "Liquid Loading", of a gas well.

Th work firstly gives on overview about Tiguentourine field and then it gives all the important background information of the "Liquid Loading" topic itself; we talked in chapter 03 about the methodology of coiled tubing velocity string design and installation and how that the correct choice of CT size and completion design can optimize gas well productivity we finally used the knowledge of the chapter 03 to study our case of Tiguentourine field well TG-352 to mitigate the liquid loading phenomena , we make also discussion about the gain and benefits of CT VS installation .

Keywords: Velocity string, Design, installation, Coiled tubing, Liquid loading , Critical velocity , Critical flow rate , flow regime

الملخص:

تتناول هذه الأطروحة تطبيق ما يسمى الأنابيب الملفوفة عالية السرعة في آبار الغاز وهي طريقة معروفة لتخلص من حمولة السوائل في آبار الغاز، وهو عبارة عن انبوب إنتاج ذو مساحة تدفق عرضية أصغر يتم تركيبه داخل أنبوب الإنتاج لتحسين سرعة الغاز، مما يجنب تراكم عمود الماء في قاع البئر.

غالبًا ما تواجه آبار الغاز والنفط انخفاضًا في القدرة الإنتاجية أو الإغلاق نتيجة لعوامل مثل الاستنزاف الطبيعي لضغط المكمن وانخفاض سرعة الإنتاج. بالإضافة إلى ذلك، هناك زيادة في تراكم الماء والمكثفات في منطقة التثقيب نتيجة التكثف في أنبوب الإنتاج بسبب التغيرات في درجات الحرارة والضغط. يمكن أن يؤدي إنتاج هذه المكثفات إلى تشكيل عمود سائل في تجويف البئر، مما يعيق إنتاج الغاز من المكمن إلى أنبوب الإنتاج، والمعروف باسم "تحميل السائل" في بئر الغاز.

يقدم هذا العمل أولاً نظرة عامة عن حقل تيقنتورين، ثم تقدم جميع المعلومات الأساسية الهامة حول موضوع "تحميل السائل" نفسه. تحدثنا في الفصل الثالث عن منهجية تصميم وتركيب انابيب السرعة باستخدام معدات وحدة الانابيب الملفوفة وكيف يمكن أن يؤدي الاختيار الصحيح لتصميم أنابيب السرعة والإكمال إلى تحسين إنتاجية بئر الغاز. وأخيراً استخدمنا المعرفة المكتسبة من الفصل الثالث لدراسة حالة بئر حقل تيقنتورين TG-352 لتخفيف ظاهرة تحميل السائل، بالإضافة إلى مناقشة المكاسب والفوائد من تركيب ماسورة السرعة باستخدام الأنابيب الملفوفة.

الكلمات المفتاحية:

سلسلة أنابيب السرعة، التصميم، التركيب، الأنابيب الملفوفة، تحميل السائل، السرعة الحرجة، معدل التدفق الحرج، نظام التدفق

Résumé :

Cette thèse traite de l'application de ce que l'on appelle le Coiled tubing velocity string dans les puits de gaz. Un coiled tubing (CT) velocity string est une méthode connue pour décharger les liquides dans les puits de gaz. Il s'agit d'une colonne de production avec une section transversale plus petite installée à l'intérieur du tube de production pour améliorer la vitesse du gaz, évitant ainsi l'accumulation d'une colonne d'eau au fond du puits.

Les puits de gaz et de pétrole voient souvent leur capacité de production diminuer ou sont abandonnés en raison de facteurs tels que l'épuisement naturel de la pression du réservoir et la diminution de la vitesse de production. En outre, l'accumulation d'eau et de condensats dans la zone de perforation augmente en raison de la condensation qui se produit dans les tubes de production à la suite de changements de température et de pression. Cette production de condensats peut conduire à la formation d'une colonne liquide dans le puits de forage, empêchant la production de gaz du réservoir dans les tubes de production, ce que l'on appelle la « charge liquide » d'un puits de gaz.

Ce travail donne tout d'abord une vue d'ensemble du champ de Tiguentourine et donne ensuite toutes les informations de base importantes sur le sujet de la « charge liquide » ; nous avons parlé dans le chapitre 03 de la méthodologie de la conception et de l'installation de la colonne de vitesse du tube spiralé et comment le choix correct de la taille du CT et de la conception de la complétion peut optimiser la productivité du puits de gaz ; nous avons finalement utilisé les connaissances du chapitre 03 pour étudier notre cas du puits TG-352 du champ de Tiguentourine afin d'atténuer les phénomènes de charge liquide et, en outre, , nous aussi discutons des gains et des avantages de l'installation du CT VS.

Mots-clés :

Chaîne de vitesse, Design, installation, coiled tubing , charge de liquide, vitesse critique, débit critique, régime d'écoulement

Contents :

Chapiter04: Case Study

List of Abbreviations:

- ρ_l L iquid density, lbm/ft^3
- ρ_g G as density, lbm/ft^3
- σ **I**nterfacial tension, dynes/cm
- ***P*** **P**ressure, Psi/ Bara
- ***A*** **C** ross-sectional area of conduit, ft^2
- ***T*** **T**emperature, °R
- ***z*** Gas compressibility factor
- S_g Specific gravity of gas
- S_O Specific gravity of produced oil
- S_w Specific gravity of produced water
- P_R Reservoir Pressure
- **PVT** Pressure Volume Temperature
- **IPR** **I**nflow Performance Relationship
- **VLP** Vertical Lift Performance
- **AOF** Absolut Out Flow
- **LH** Liquid Hold UP
- P_{wf} Flowing Bottom Hole Pressure
- V_{cri-T} Critical velocity Turner's model
- V_{cri-C} Critical velocity Coleman's model
- V_{cri-Li} Critical velocity Li's model
- Q_g Gas production rate, Mscf/D
- Q_o Oil production rate, Mscf/D
- **WHP** Wellhead pressure
- **SIWHP** shut in wellhead pressure
- **QTS** Quick Test Sub
- **IH** Injector Head
- **CT** Coiled Tubing
- **VS** Velocity String
- **RIN** Run In Hole
- **POOH** Pull Out Of Hole
- **BOP** Blow out preventer
- **ABOP** Annular BOP

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General Introduction:

Among the fossil fuels, natural gas has seen the fastest growth since the 1970s. It accounts for a fifth of the global energy use. Natural gas is economically appealing, especially for Western countries, and has a low combustion interval that makes it one of the most dependable energy sources available. It ranks second only to oil in terms of energy consumption. The US Department of Energy (EIA) reported that natural gas contributed 22% to the world energy output in 2004 and its demand is expected to increase, as it has an edge over other energy sources. Moreover, technological innovations enhance the effectiveness of extraction, transport and storage methods as well as the energy performance of natural gas-powered equipment. The IN AMENAS site “TIGUENTOURINE” demonstrates the processing and production of natural gas. This site is an important production point for the economy of Algeria.

Problem Definition:

This thesis is written to process and evaluate TG-352 case IN AMENAS Tiguentourine field which suffer from liquid loading problem in Gas wells, this phenomena begin appeared early scince 2017 in the wells because of reservoir shut pressure result of naturel depletion TG-352 was operated by active cycling during production prior installation of VS, a coiled tubing Velocity string has been chosen as solution to mitigate liquid loading and stabilize the production.

Purpose of study and Research Questions:

The purpose of our case study based in simulation with PROSPER software to show the steps of finding the best velocity string design that will return the well to flowing continuously and increase it performance, and its about the coiled tubing velocity installation procedures then evaluation of estimate production and gain with the obtained measured VX Data after VS installation to find recommendation and suggestion for further research.

Research Questions:

- What is the optimum design of coiled tubing velocity string that will solve the problem of liquid loading in TG-352?
- What’s the procedures of CT VS installation?
- How effective are coiled tubing velocity strings in removing liquid from gas wells?
- How much is the gain that will be reached after the installation of VS?

Chapter 01

Description of Tiguentourine Field

I.1 Presentation of the field:

The Tiguentourine field was discovered in 1957 by the first exploration wells. The well TG 2, which was one of the first wells drilled, revealed a large amount of wet gas in the Cambro-Ordovician, followed by several other producing wells belonging to SONATRACH, at the arrival of the association SONATRACH / BP / Statoil in 1998, the latter transformed these wells SONATRACH into monitoring and started the development of the field by drilling and re-completion of new wells. The productivity of the reservoir in this region is characterized by the following petro-physics:

Alpha: zone with a permeability > 1mD and a porosity > 5%

Beta: zone a permeability < 1mD and a porosity > 5%

Hydraulic fracturing came to the rescue of low permeability zones (Beta), it is since the end of the 90s that this alternative has increased the production of this zone from 2 to 25 MM3 / day. Thus, hydraulic fracturing allows to reduce the phenomenon of retrograde condensation in the wells by increasing the bottom pressure.

I.2 Geographical Location:

The Tiguentourine field is located in the southern part of the Illizi basin, about 850 Km south of the city of Hassi Messaoud and 40 Km southwest of the city of In Amenas and 70 km west of the Edjeleh field and 20 km southwest of that of La Reculée. Tiguentourine is partly covered by the Erg Bourarhet. The field is rocky, hence the origin of its name Targui Tiguentourine meaning the torrents , Its location in Lambert coordinates is as follows:

- X = 492500 to 532500 East.
- Y = 3055000 to 3100000 North.

In geographical coordinates:

- To the north by latitude 28°00
- To the south by latitude 27°30
- To the west by longitude 9°00

- To the east by longitude 9°30

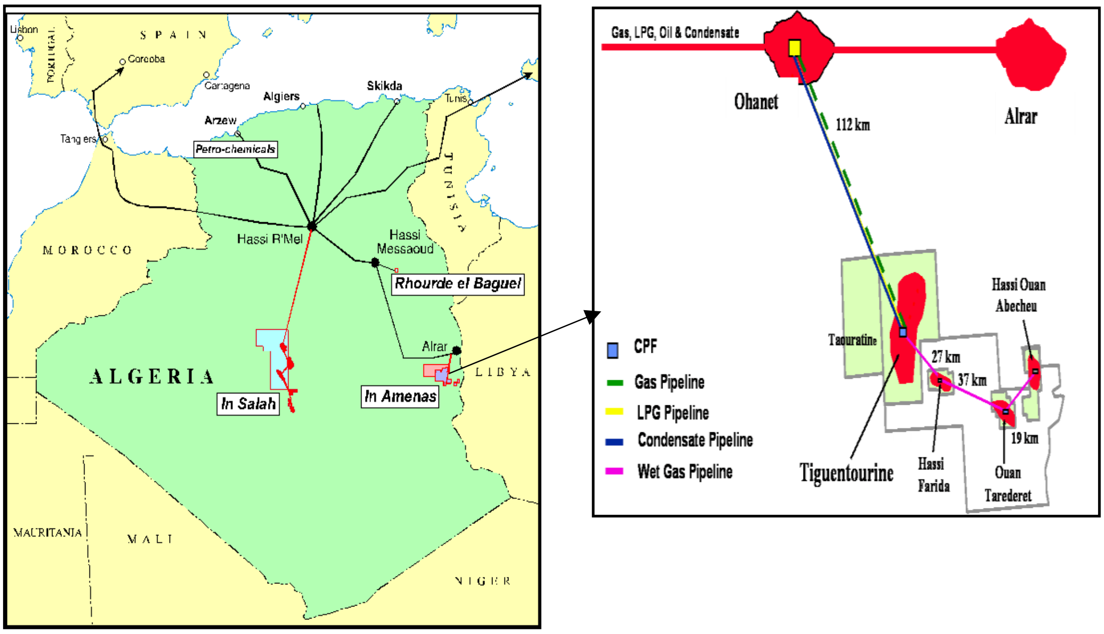

FIGURE 1 : GEOGRAPHIC LOCATION OF THE TIGUENTOURINE FIELD

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I.3 Field History:

The Tiguentourine region consists of two oil reservoirs that are the Carboniferous D2, D4, D6 and the Devonian F2, F4, F6, in the satellite fields (Hassi Farida, Ouan Taredert, and Hassi Onan Abecheu), which are located immediately to the southeast. And a Cambro-Ordovician condensate gas reservoir in the Tiguentourine and La Reculée fields. The condensate gas accumulation of (TG) was discovered in 1957; by drilling the Tiguentourine 2 well (TG-2). The shallow gas horizons have been exploited since 1962. In 1995/1996; six wells were hydraulically fractured, with rates of 2 to 5 MMCF / D. In 1999/2000, five wells were produced for extended flow and accumulate times and a complete fluid sampling program was undertaken. The development drilling started in June 2001. As of March 2003, nine (9) wells were drilled and tested. Consequently, 8 wells were completed for production during the development program, the wells are put into production in 2006. Currently, the number of producing wells in the field has increased to reach 49 wells connected to the CPF through 6 manifolds as follows:

- 31 wells from the north field that are connected to manifolds 1, 2 and 5.
- 8 wells from the southeast field that are connected to manifolds 3 and 4.

- 10 wells from the southwest field connected to manifold 6.

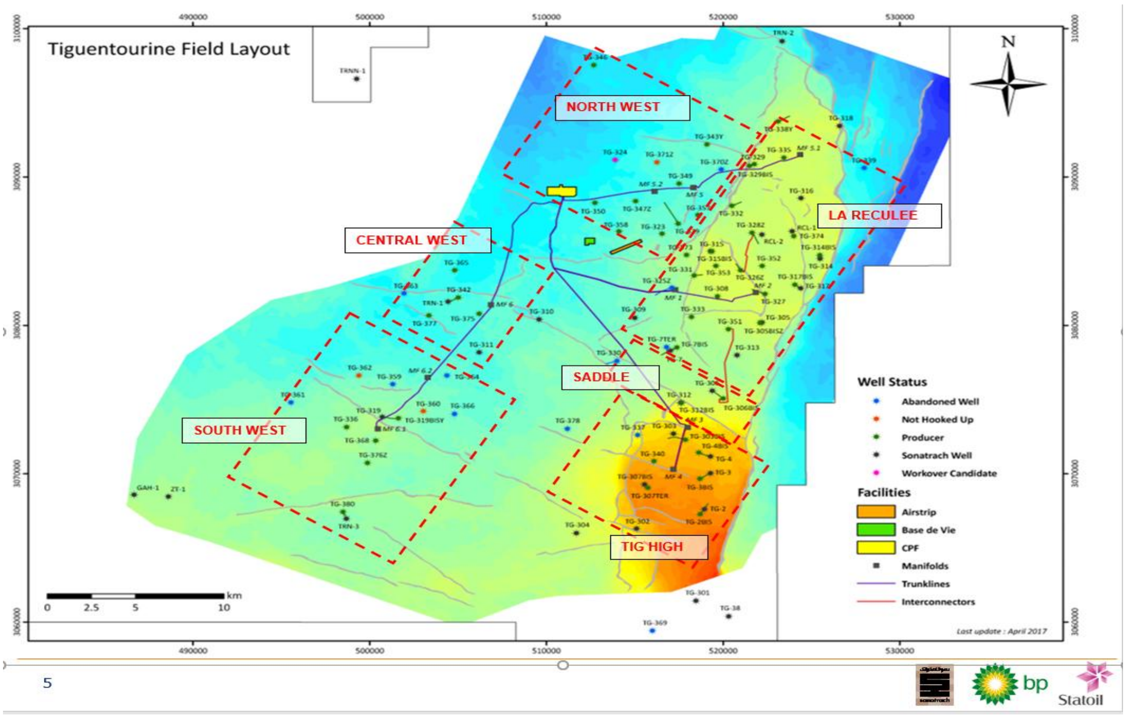

FIGURE 2 THE SITUATION OF THE DIFFERENT WELLS IN THE TG FIELD

I.4 General geology of Tiguentourine field:

The Tiguentourine field is located in the Illizi basin, which is geologically bounded by the Tassilian axes of north-south direction, to the east by the anticlines of the Libyan border, the Tihenbouka and Talagrouna moles. To the west, the anticlines of the west Saméne, the Essaoui méllene horst anticline, to the south by the Hoggar massifs, to the north it is separated from the Ghadamès depression by the Ahrar mole. More precisely, the Tiguentourine structure is located in the northern part of the basin, on the Tiguentourine La Reculée ridge along the Fadnoun trend, consisting of ASSEKAIFAF, LABED-LARACH and the two aforementioned structures, this ridge is located in the regions of the Carboniferous outcrop. The Fadnoun accident extends over 60 km between the Hoggar and the Tiguentourine-La Reculée structure. The Fadnoun trend corresponds to a major structural line in the basement well known on the Hoggar, the structural character will be studied in detail in the structural description. It can also be noted that the Hercynian unconformity appears on the surface between Tiguentourine and La Reculée.

I.4.1 Structural description:

The structure forms an asymmetric anticline with dips of a few degrees on the W flank and more than 10° on the E flank. A fault of a hundred meters of throw, parallel to the anticlinal axis, ensures the closure on the E flank of the structure. Many oblique accidents generally oriented NE-SW create a complex compartmentalization. The north structure of the anticline is about 400 m while to the south, under the dunes, the structure is poorly known.

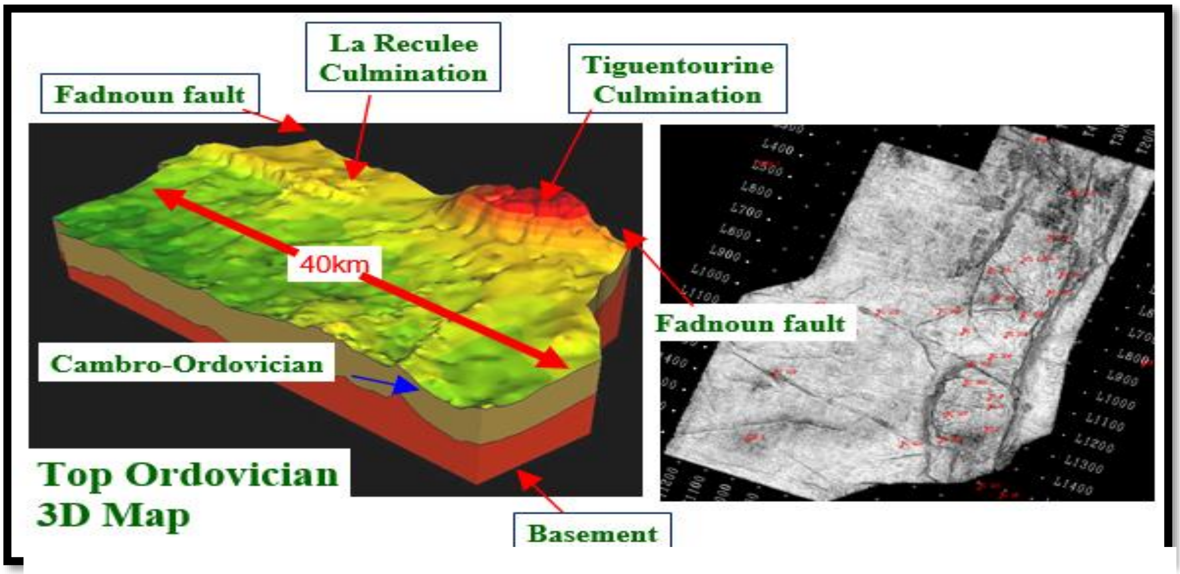

FIGURE 3: PRESENTATION OF THE 3D SEISMIC GEOLOGY (LEFT), AND THE SURFACE (RIGHT) OF THE TG RESERVOIR.

I.5 Stratigraphy of Tiguentourine reservoir:

The Tiguentourine reservoir stratigraphy During the Silurian-Devonian sedimentation, the Caledonian orogenic event affected the entire Sahara platform, reactivating many faults and sharp features. The resulting unconformity marks the boundary between the Silurian and Devonian, and induces a change in the depositional environment. The Devonian fluvial sediments followed by the Silurian marine deposits. In this part of the basin, this surface represents a significant time gap, and almost all of the upper Silurian is missing due to erosion. The whole Illizi basin tilted to the north with the erosion of the Silurian in the south-eastern part.

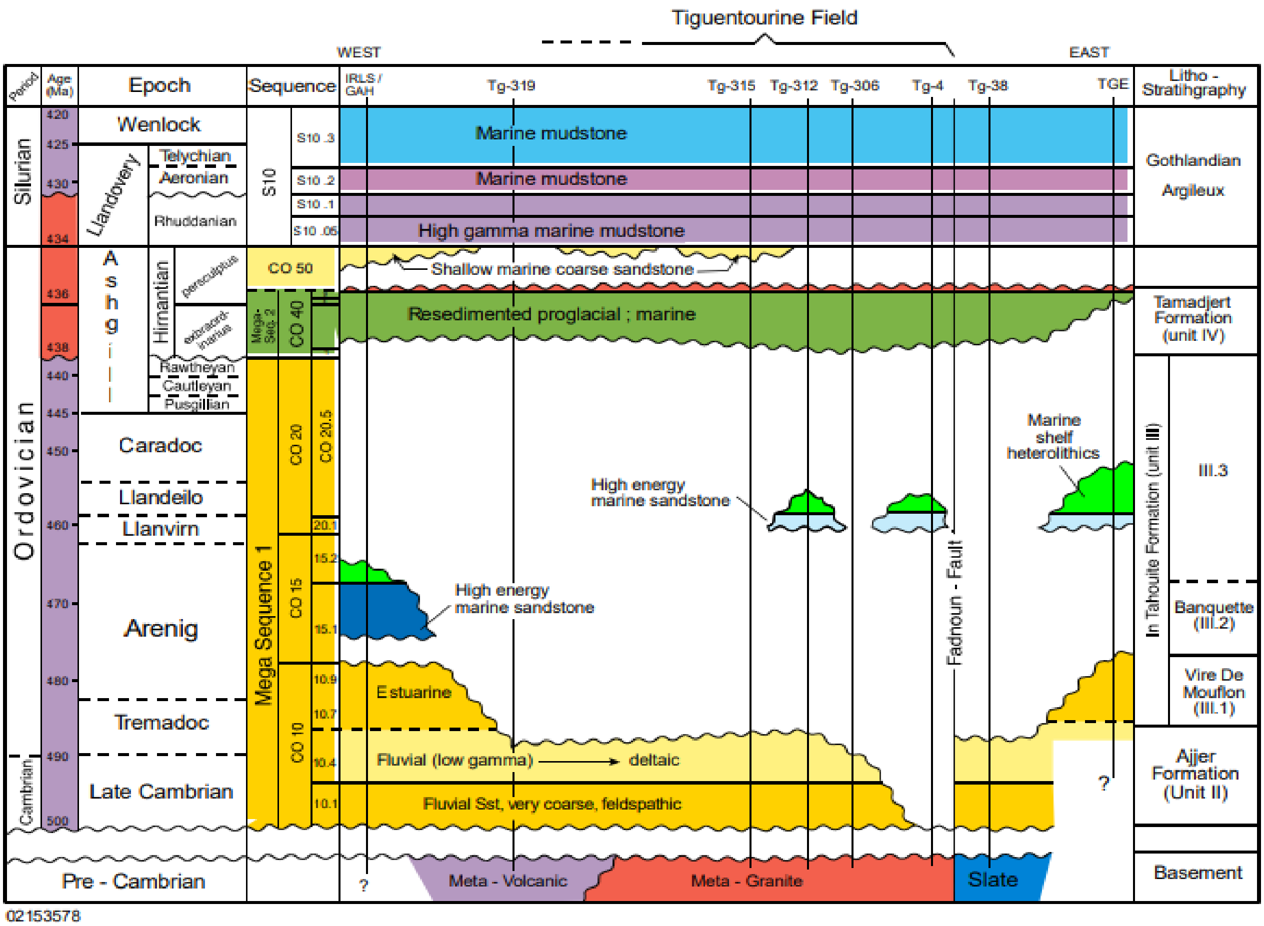

FIGURE 4 : STRATIGRAPHIC SECTION OF THE TIGUENTOURINE FIELD.

I.6 Tiguentourine deposit distribution:

Sampling in the field of Tiguentourine has allowed dividing the reservoir into three main parts: The North, South and Southwest. Each of the three compartments is defined by a reservoir pressure and a composition of separate fluids, also the presence of faults plays a very important role in this area.

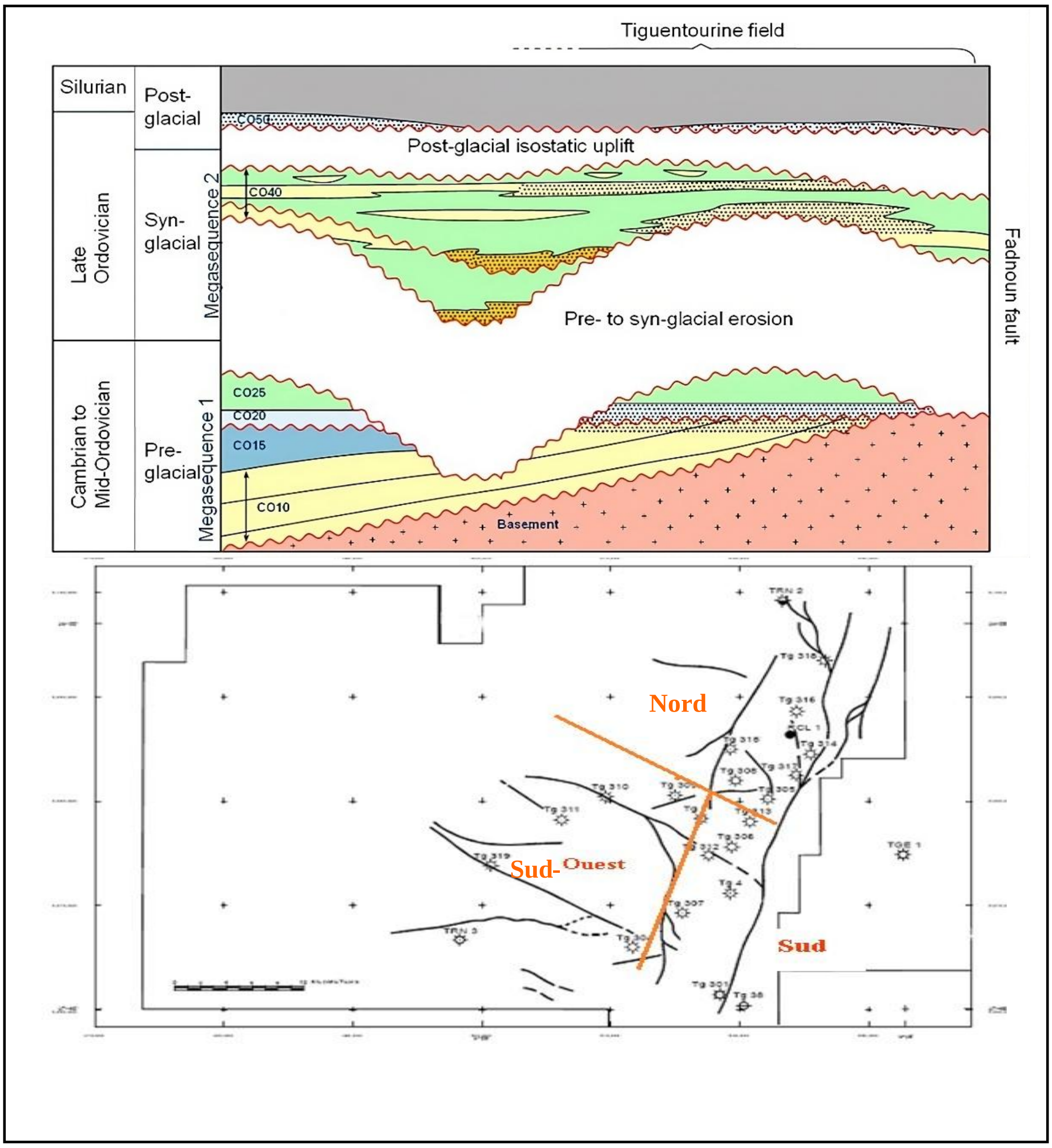

FIGURE 5 : TGN DEPOSIT DISTRIBUTION.

I.7 Reservoir characteristics:

The gas condensate reservoir operated in Tiguentourine region is characterized by Cambro-Ordovician sandstone rock (approximately 500 Million years) with the following characteristics:

- Wells to average depth of about 2200m.
- A shell thickness that varies between 20 - 200m,
- Sediment marine and terrestrial.
- Very heterogeneous.
- No aquifer.
- A significant presence of faults (2 faults).
- A permeability of up to 2 mD.
- The porosity> 5%.
- The temperature varies from 110° C to 125° C.
- An initial deposit is estimated pressure of 3200 psi.
- Compressible rocks.

I.8 Fluid production characteristics:

TABLE 1: CRITERIA OF FLUID OF FORMATION

Proprieties	PVT		
	North	South	South-West
Initial pressure (bar)	233	230	233
Initial CGR (STB/MMscf)	29.2	35.3	42.4
Initial GOR (SCF/STB)	98541.1	78246.6	58400.6
Condensate density (API)	48.4939	49.8406	50.552
Gas Density (API)	0.730129	0.732797	0.760692
Dew point (bar)	182.55	192.62	194.28

The gas gradient is of the order of 0.252 psi/meter for the North and South field, and the temperature varies between 110° C and 125° C with a gradient estimated at about 0.0164 °/meter. The raw gas produced is transported from the well to the manifold, reaching the CPF (Central Processing Facility) which separate gas and liquid products and deliver them to export lines, a pre-refined product can therefore be transported to the final delivery point north (Dry Gas, Condensate and LPG) .

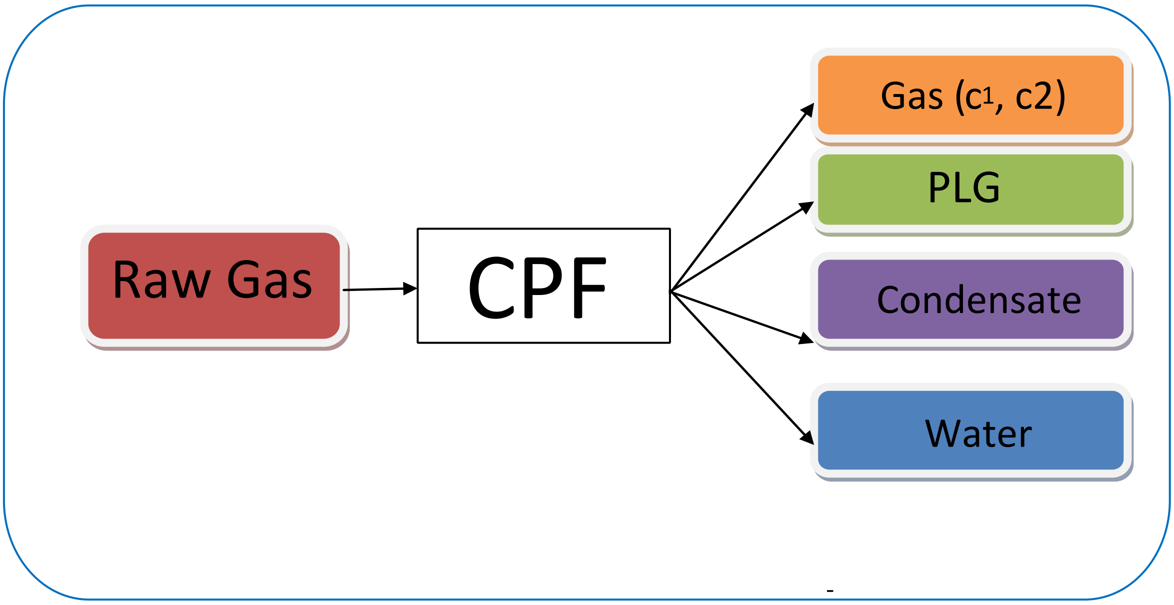

FIGURE 6: SCHEMATIC OF THE DIFFERENT PRE-REFINED PRODUCTS

I.9 The constituents of raw gas:

Due to the heterogeneity, the gas constituents vary from one area to another:

TABLE 2: FLUID CONSTITUENTS OF THE NORTH ZONE

Constituents	Type	Molecular %	Molecular weight
N2	impurity	0,442	28,01
CO2	impurity	4,3047	44,01
C1	Pure	81,1108	16,04
C2	Pure	7,0911	30,1
C3	Pure	3,0237	44,1
nC4	Pure	1,4659	58,1
c5-6	Pseudo	1,1046	77,4
c7-9	Pseudo	0,9307	105,6
c10-14	Pseudo	0,4257	152,2
c15+	Pseudo	0,1008	241,61

TABLE 3:FLUID CONSTITUENTS OF THE SOUTH-WEST ZONE

Constituents	Type	Molecular %	Molecular weight
N2	Pure Non Hyd	0,5459	28,01
CO2	Pure Non Hyd	2,6281	44,01
C1	Pure Hyd	81,1283	16,04
C2	Pure Hyd	7,4901	30,1
C3	Pure Hyd	3,3654	44,1
nC4	Pure Hyd	1,6859	58,1
c5-6	Pseudo	1,3703	77,4
c7-9	Pseudo	1,173	105,6
c10-14	Pseudo	0,5027	152,2
c15+	Pseudo	0,1103	241,61

TABLE 4:FLUID CONSTITUENTS OF THE SOUTH ZONE

Constituents	Type	Molecular %	Molecular weight
N2	Pure Non Hyd	0,4544	28,01
CO2	Pure Non Hyd	3,2594	44,01
C1	Pure Hyd	78,1735	16,04
C2	Pure Hyd	8,4419	30,1
C3	Pure Hyd	3,9286	44,1
nC4	Pure Hyd	1,9612	58,1
c5-6	Pseudo	1,6137	77,4
c7-9	Pseudo	1,3994	105,6
c10-14	Pseudo	0,626	152,2
c15+	Pseudo	0,1419	241,61

I.10 Production History:

The reservoir consists of two layers: MS2 (upper) and MS1 (lower). The 70 wells are drilled by JVGAS and 48 wells are spread over 06 manifolds, called 1.2.3.4.5 and 6.

- The manifolds 01, 02 and 05 are in the North.
- The Manifold 03 and 04 are in the South.

• The manifold 06 is to the southwest. The maximum potential of the field after compression startup is 34 MMsm3/day. Annex: Available production potential.

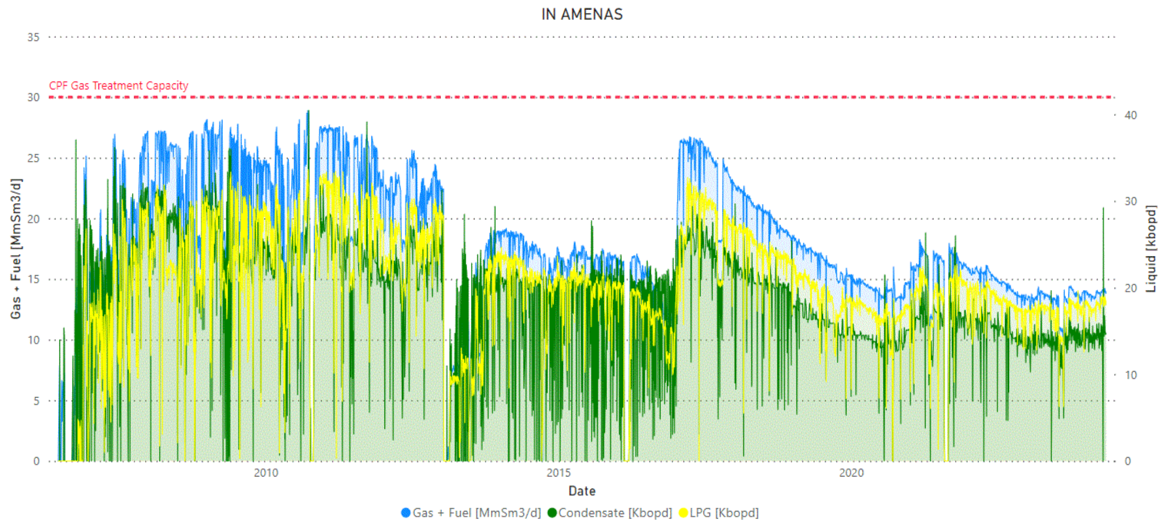

FIGURE 7: PRODUCTION HISTORY OF TG FIELD

Conclusion:

The Tiguentourine field has been under exploration since the late 1950s and holds a large amount of hydrocarbons (Oil/ Condensate). The JV gas company has spent a huge amount of money to extract valuable products from the field , one of the key techniques to improve gas production is to stimulate the liquid loading wells using economical technique called Coiled tubing velocity string, which we will explain in the following chapters.

Chapter 02

Background about Liquid Loading in Gas Wells

Introduction:

The liquids in gas wells can decrease production due to their presence in the flow stream, which affects the flow characteristics and must be carried to the surface by the gas phase to prevent liquid accumulation. This accumulation is due to the lack of transport energy, leading to increased bottomhole flowing pressure and decreased well production. Liquid loading is indicated by sharp drops in the decline curve, onset of liquid slugs at the well's surface, and changes in flowing-pressure surveys.

II.1. Multiphase flow in gas well:

Multiphase flow refers to the simultaneous flow of fluids with distinct physical phases within a conduit. Each phase exhibits unique chemical and physical properties that influence its behaviour within the flow regime. Common examples of multiphase flow in the context of gas wells include the transport of a mixture of natural gas (gaseous phase), condensate (liquid hydrocarbon phase), and formation water (liquid water phase). These phases can coexist due to variations in pressure, temperature, and the inherent immiscibility of certain components within the reservoir fluid.[1]

Gas-liquid two-phase flow:

Gas-liquid mixtures flow in pipes and process equipment, with quality varying significantly over distances. Boiling or condensation can cause significant changes in quality, while the total mass flow rate remains constant.

Different flow regimes and materials require accurate pressure drop calculations in two-phase flow, requiring prediction of flow rates and appropriate calculation procedures.

Flow regimes:

Four basic flow patterns (regimes) usually occur in a vertical production conduit of a gas well with associated liquid are discussed. The flow patterns and their stage in the life of the well are as shown in Fig II.1.

Bubble flow:

Liquid is the dominant phase, with small gas bubbles dispersed within it. Pressure drops are minimal due to the low gas volume.

Slug flow:

Large gas bubbles (Taylor bubbles) separated by liquid slugs dominate the flow. This regime can cause wellbore damage and pressure fluctuations due to the high momentum of liquid slugs.

Churn flow (transitional or semi-annular): Unstable liquid films oscillate within the wellbore due to opposing forces of gravity and shear. This flow only occurs in vertical or near-vertical tubing and creates high pressure drops and flow rate fluctuations.

Annular/Mist flow: Liquid forms a thin film on the tubing wall while gas occupies the center (gas core). Some liquid droplets are entrained in the gas. At high flow rates, most liquid becomes entrained as droplets (mist flow). In some cases, high liquid flow rates lead to "wispy annular flow" with large liquid streaks within the gas core. [2]

II.2. Flow patterns and flow regime maps:

The flow regimes that are obtained in vertical, upward, cocurrent flow at different gas and liquid flow rates are shown in Fig.

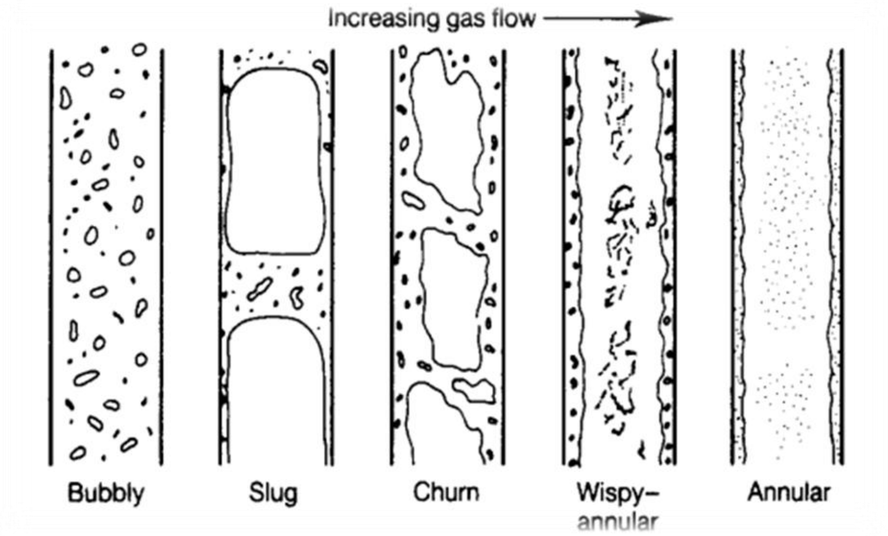

FIGURE 8: FLOW REGIMES IN VERTICAL GAS-LIQUID FLOW

The sequence depicts the process of gas-liquid mixtures, starting with a distribution of bubbles in the liquid, increasing as the gas flow rate increases. The next regime involves gas slugs, which have spherical noses and occupy the entire tube's cross section, separated by a thin liquid film.

most of the cross section there is a churning motion of irregularly shaped portions of gas and liquid. Further increase in the gas flow rate causes a degree of separation of the phases, the liquid flowing mainly on the wall of the tube and the gas in the core. Liquid drops or droplets are carried in the core: it is the competing tendencies for drops to impinge on the liquid film and for droplets to be entrained in the core by break-up of waves on the surface of the film that determine the flow regime. The main differences between the wispy-annular and the annular flow regimes are that in the former the entrained liquid is present as relatively large drops and the liquid film contains gas bubbles, while in the annular flow regime the entrained droplets do not coalesce to form larger drops.

II.3. FUNDAMENTALS OF LIQUID LOADING IN GAS WELLS :

II.3.1. Concept of liquid loading:

Liquid loading occurs in gas wells when gas velocity falls below a critical velocity, hindering its ability to lift co-produced liquids (water and condensate) to the surface. This leads to liquid accumulation at the wellbore bottom, eventually compromising gas production.

At high gas velocities:

- Gas forms a central "gas core", pushing liquid film to the tubing walls.
- Shear forces create liquid droplets within the gas core, enabling transport.
- High gas-liquid ratio leads to lower pressure drop in the tubing.

As reservoir pressure declines, gas velocity decreases:

- Critical velocity is reached at the wellhead, triggering liquid accumulation.
- Increased liquid rate raises hydrostatic pressure, further hindering gas flow.
- Continuous accumulation creates back pressure on the formation, reducing gas production.

Reservoir pressure build-up can intermittently push liquids to the surface (slug flow), but eventually becomes insufficient. This leads to well abandonment if liquid unloading measures are not implemented.

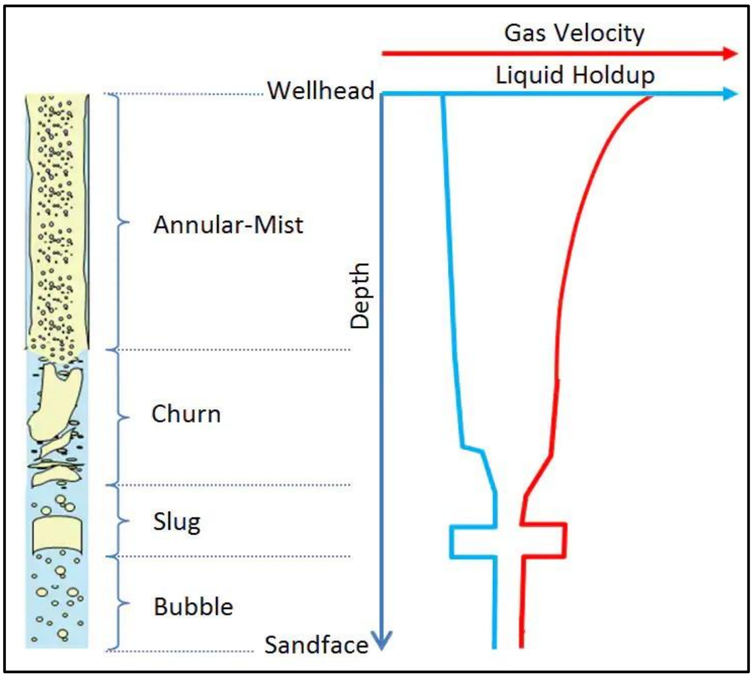

FIGURE 9: MULTIPHASE FLOW REGIMES IN A WELLBORE.

II.3.2. Sources of liquids in the gas wells:

Liquid production is a near-ubiquitous phenomenon in gas wells, occurring at some point throughout their operational lifespan. The source of these liquids within the wellbore is multifaceted and depends on the specific characteristics and state of the reservoir. One prevalent source is formation water, which originates from naturally occurring water trapped within rock pores during sedimentation. As gas production commences, this water can potentially flow alongside the gas towards the wellbore through existing fractures.

Other potential sources of liquids include:

Condensate: This refers to the process of water and hydrocarbons converting to liquid form due to pressure and temperature changes during production.

Water coning: This phenomenon occurs when water from an underlying water zone encroaches upward towards the producing gas zone due to pressure differences.

Water production from a different zone: This situation arises when water from a separate geological zone migrates into the gas zone through communication paths within the formation.

Aquifer water: This refers to the potential for water from nearby aquifers to infiltrate the gas reservoir.

External liquids: These encompass any fluids introduced into the reservoir during various operations, such as drilling fluids, fracturing fluids, or other exploration and development-related fluids.

The presence of one or more of these liquid sources is highly likely within a reservoir. Consequently, efficient well-functioning necessitates the continuous removal of these generated liquids to the surface. [3]

II.3.3. Recognizing symptoms of liquid loading in gas wells:

If liquid loading in the wellbore goes unchecked, the liquids could build up in the wellbore and the nearby reservoir, possibly inflicting temporary or even permanent damage. It is crucial, then, that the effects generated by liquid loading are discovered early to prevent loss of production and subsequent reservoir damage. We will explore methods to recognize the occurrence of liquid loading. Methods can be predictive or can be observations of field symptoms. Although some of them are more visible than others, all lend themselves to the more exacting methods of well analysis.

II.4. Most used systems for unloading:

Today, the most effective liquid-removal devices are the pumping unit and the combination liquid-diverter and gas-lift installation. However, where there is a high risk of formation damage resulting from killing operations, the most economical method of removing liquid may simply be to use a smaller tubing string. These methods of liquid removal are discussed in the following sections.[9]

II.4.1. Plunger lift:

Plunger lift is a system that aids natural flow by reducing the amount of liquid that falls back in the well as it rises. This increases the efficiency of liquid and gas production. Plunger lift is typically applied when gas flow drops to near or below the critical velocity, as liquids are no longer brought to the surface as in mist flow. As slug and bubble flow occurs in the well, accumulated liquids occupy a greater portion of the tubing volume, adding pressure to the formation and reducing gas production. The plunger lift system intermittently carries slugs of liquid to the surface, allowing gas to be produced with less pressure from accumulated liquids.

Most plunger lifts are applied without using external sources of energy; however, in some cases, additional gas can be injected [gas-assisted plunger (GAPL)], and foam can also be applied. In addition, there is a technique of using more than one plunger in one well (progressive plunger), which will be discussed later.

A plunger lift system is relatively simple and requires few components. A typical plunger lift installation, as shown in Fig., would include the following components:

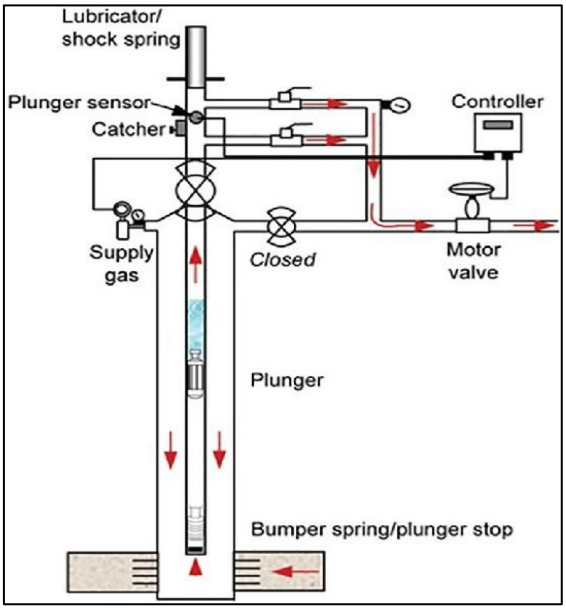

FIGURE 10: PLUNGER WELL.

II.4.2. Gas Lift:

Gas lift is an artificial lift method that injects external gas into the produced flow stream at a depth in the wellbore, augmenting the formation gas and reducing bottom-hole pressure, increasing the inflow of produced fluids. For dewatering gas wells, the volume of injected gas is designed to be above the critical rate for the wellbore, especially for lower liquid-producing wells. This solves the problem of liquid loading in the tubing, allowing the well to produce at higher rates and lower bottom-hole pressures. However, it is crucial to flow gas up the tubing above the critical rate without too much, as friction can slow production. [1]

II.4.2.1 Gas lift system components:

Fig II.4 shows a typical continuous gas lift system that includes:

- A Gas source.
- A surface injection system, including all related piping, compressors, control valves, etc.
- A producing well completed with downhole gas lift equipment (valves and mandrels and packer in this case)
- A surface processing system, including all related piping, separators, control valves, etc.

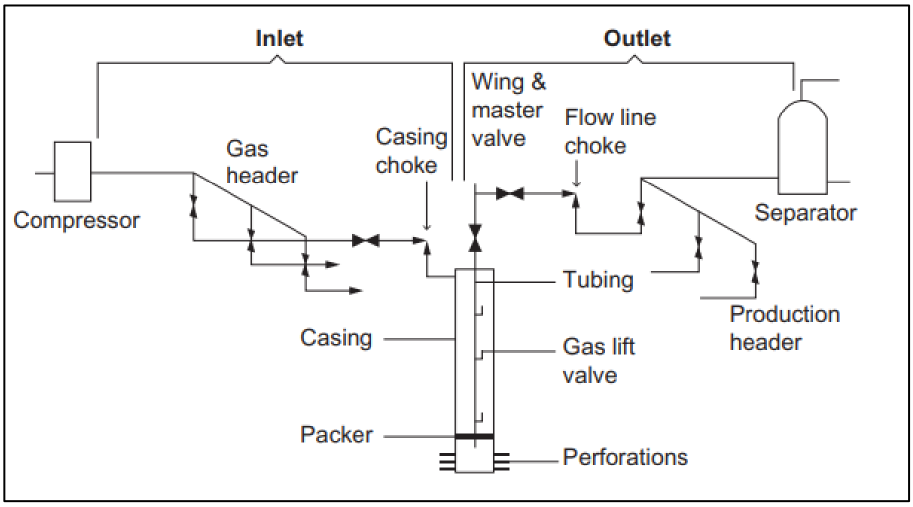

FIGURE 11: CONTINUOUS GAS LIFT SYSTEM.

II.4.3. Surfactants:

The use of surfactants to increase gas production is one of the most important elements in increasing gas production from a mature gas field. Surfactants reduce the cohesive force of molecules to create an elastic tendency to minimize liquid area known as surface tension. Some surfactants create a foam that has a reduced density. Introduction of surfactants in a liquid reduces the gas velocity necessary to keep a central core of gas flowing in the system. When systems in two-phase flow have a central gas core, they operate at lower pressure drops for a given gas liquid flow rate. Surfactants increase entrainment of liquid in gas. Promising candidates for the use of surfactants in gas wells and pipelines experiencing slugging can be identified using relevant computer models. The surfactants can be applied by pumping the fluid down the casing annulus. Surfactants can be used intermittently. In some cases, they can stabilize the flow of wells operating in a metastable condition. Surfactants are found in both liquid and solid forms. They can be used to reduce the need of gas in gas-lifted oil wells. They can be applied using a capillary string. [1]

II.4.3.1 Application of surfactants in field system:

One of the applications of surfactants to alleviate liquid loading in gas wells is to inject a surfactant solution down the casing annulus. As surfactant volumes can be low in these applications, often the surfactant solution is diluted. These allow for better pump regulation assured drainage of the surfactant in these applications.

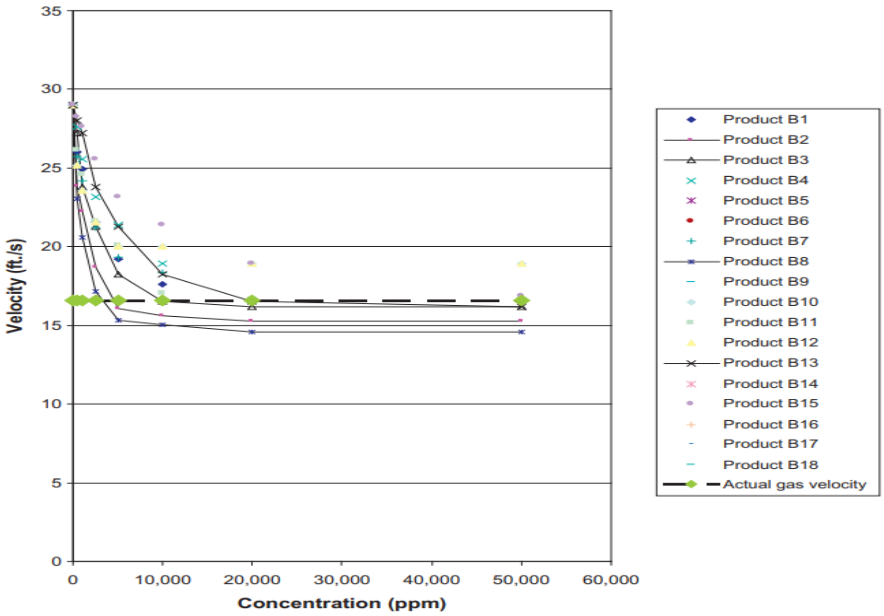

FIGURE 12: EFFECT OF CHEMICAL CONCENTRATION ON THE VELOCITY NEEDED TO UNLOAD THE GAS WELL.

II.4.4. Velocity String:

Velocity strings are a commonly applied remedy to liquid loading in gas wells. By installing a small diameter string inside the tubing, the flow area is reduced which increases the velocity and restores liquid transport to surface. The disadvantage of the velocity string is the increase in frictional pressure drop, constraining production. Hence an optimal velocity string has to be selected such that liquid loading is delayed over a long period with a minimal impact on production. This requires accurate methods to predict pressure drop in the velocity string as well as tubing-velocity string annulus. [5]

Coiled tubing velocity string design and installation its our object and we will talk about it in next chapters.

II.5. Predictive indications of liquid loading:

Predictive indications of loading can be quick and easy. However, there can be a difference in what actually goes on and the predictions made.

II.5.1. Critical velocity:

Critical velocity correlations predict at what rate liquid loading will occur as the well rates decline. It is not a function of liquid production or bbl/mmscf. It is (for some widely used correlations) based on what rate or velocity will carry the liquid droplets up and when they can no longer be foreseen to travel up, then liquid loading is predicted. Turner and Coleman are two widely used methods but there are many other models.

II.5.2. Use of Nodal Analysis to predict if flow is above/below critical:

Nodal Analysis is a model of the well. It usually has a reservoir inflow relationship and an outflow curve plotted. The outflow curve shows what pressure is needed at the bottom of the tubing to overcome the friction in the tubing (or other flow path), weight of gas/liquid in the tubing (gravity effects), and WHP. Some tubing correlations also account for fluid acceleration which is important only at high flow rates.

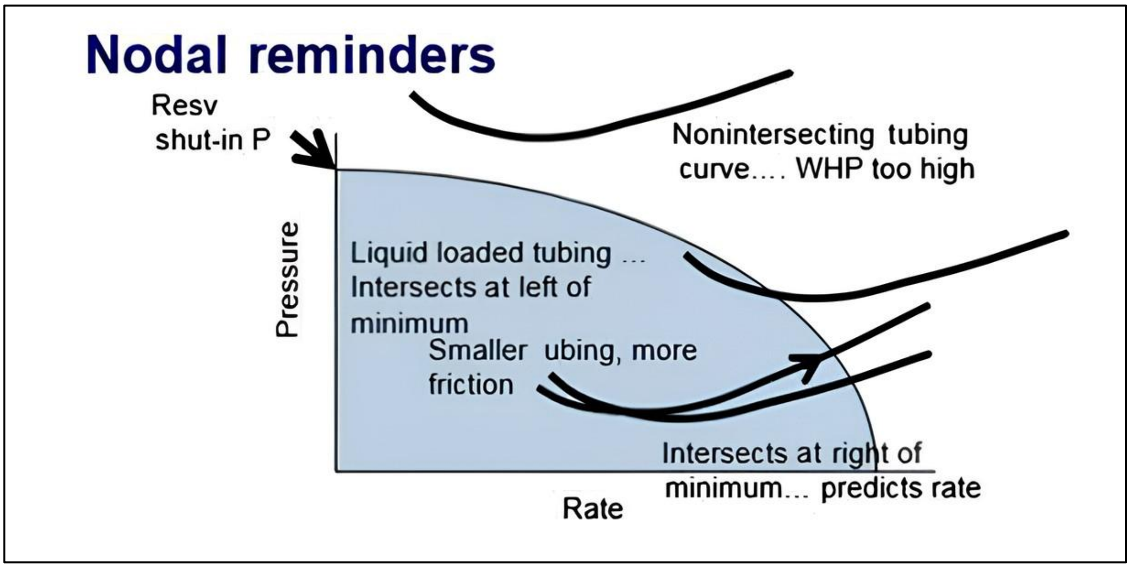

FIGURE 13: NODAL ANLYSE CONCEPTS

Fig13 shows some of the possibilities for the relationship of the tubing performance curve relative to the inflow (reservoir) curve. So, a nodal tubing performance is stable toward the right of the minimum in the tubing curve. If the tubing curve intersects the inflow performance relationship (IPR) curve at the right of the minimum, then a stable rate is predicted at the intersection. Even with no IPR if the tubing curve is slanting up and toward the right, the tubing is stable for that range of flows. [1]

II.5.3. Multiphase flow regimes:

Based on various authors and multiphase pressure drop prediction models, there are a number of flow regime maps available in the literature. One must check the accuracy of the flow regime map with the performance of the well before selecting the map. One such example of the flow regime map is shown in Fig14

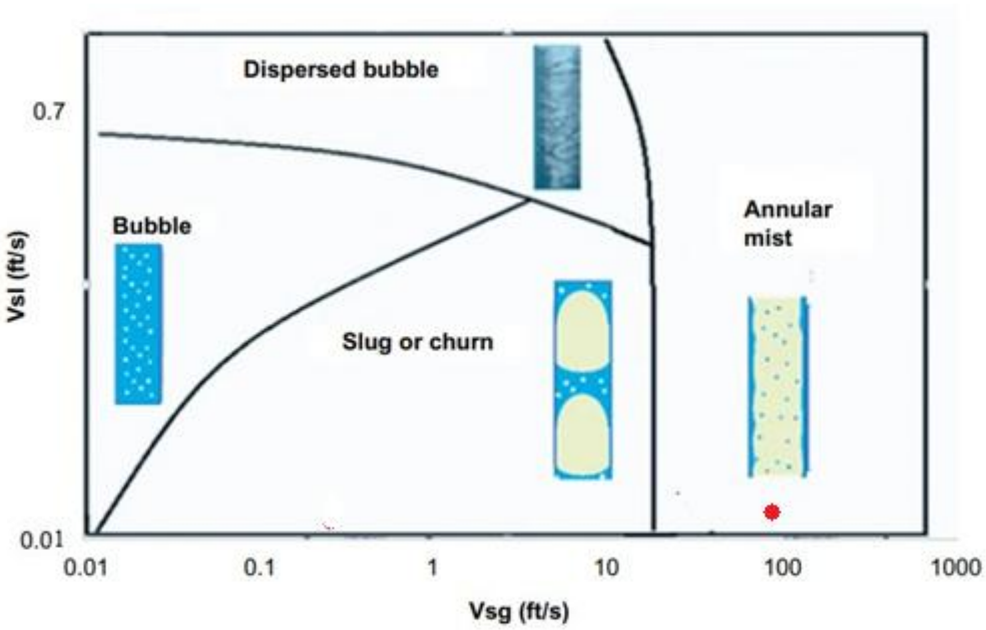

FIGURE 14: ILLUSTRATION OF POSSIBLE FLOW REGIME MAP FOR VERTICAL FLOW.

This map has entries regarding superficial velocity of gas and liquid. The superficial velocities are calculated as if only liquid and only gas are flowing in the conduit. Input data and calculations for flow regime map to generate the round dot in:

TABLE 5:FLOW REGIME MAP CALCULATION INPUT DATA

Input Tbg ID	**6.276**
Input Mscf/D	**1765.735**
Calculated BPD	**36.6821**
Calculated Tbg area ft2	**0.2148**
Reservoir pressure	**661.5 psi**
Input temperature	**240,8 °F**
Input Z factor	**0.89**
Calculated Scf/D	**1765735**
Calculate Vsl	**0.011098 ft/s**
Calculate Vsg	**95.19 ft/s**

where Vsl and Vsg are calculated using the following formulas:

$$Vs_L = \text{BPD*5.615/(86400*}area_{tbg}) \qquad (1)$$

$$Vs_G = \text{ScF/D/(86400*tubing area)} \qquad (2)$$

- The flow regime actual after VX measurement 2022 as result is Annular mist .

II.5.4. Field symptoms of liquid loading:

The shape of a well's decline curve can be an important indication of downhole liquid loading problems. Decline curves should be analysed for long periods looking for changes in the general trend.

Figure II.8 displays a precise objective "goal" that aligns with previous time data. The circular dots represent data from the production process. The production figures at the lower end of the graph are declining below the projected decline curve. The output decrease may indicate that the well is now flowing below critical levels, after formerly flowing above critical levels before the data fell below the goal. If that is the case, it is advisable to explore artificial lift methods to restore production to the desired level. [1]

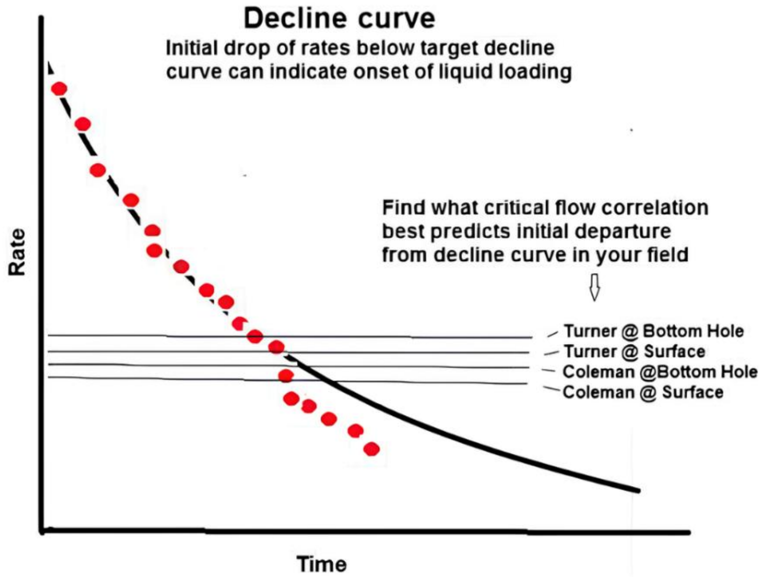

Figure 14: Decline curve analysis.

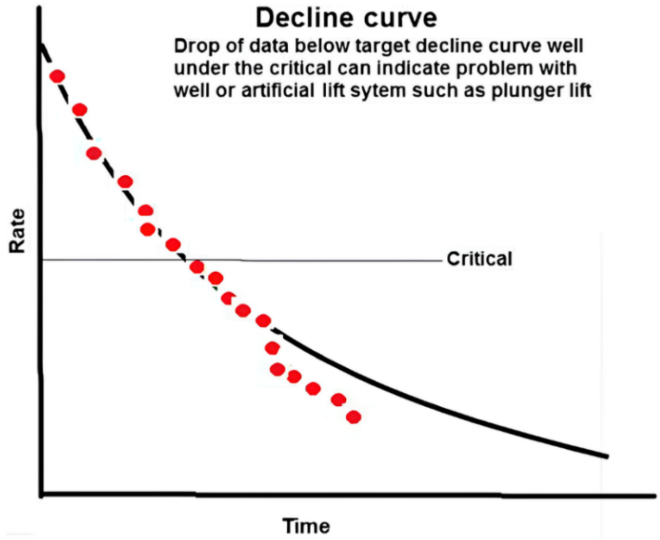

FIGURE 15: DROP OF DATA BELOW THE DECLINE CURVE WELL BELOW LIQUID LOADING.

Fig. II.9 shows a drop below the goal decline curve, indicating an artificial lift is experiencing problems. If a plunger lift is used, the problem could be a worn or sticking plunger or adjusting the cycle for optimal control. If other AL methods are used, troubleshooting techniques must be used.

II.5.5. Increase in difference between surface values of casing and tubing pressures :

Liquids accumulate at the bottom of the wellbore, causing casing pressure to rise to support the additional liquids in the tubing. In packer less completions, the presence of liquids in the tubing increases the surface casing pressure as the fluids bring the reservoir to a lower flow, higher pressure production point. The gas produced from the reservoir percolates into the tubing casing annulus, exposed to higher formation pressure, causing an increase in the surface casing pressure. An increase in the difference between tubing and casing pressures is an indicator of liquid loading. Estimates of the tubing pressure gradient can be made in a flowing well without a packer by measuring the difference in the tubing and casing pressures. The free gas separates from the liquids in the well bore and rises into the annulus. In a flowing well, the difference in the surface casing and tubing pressures indicates pressure loss in the production tubing. Comparing the difference between casing and tubing pressures with a dry gas gradient can give an estimate of the higher tubing gradient due to liquids accumulating or loading in the tubing. This will also allow the comparison to multiphase flow pressure drop correlations to check for accuracy for different correlations (Fig. 16)

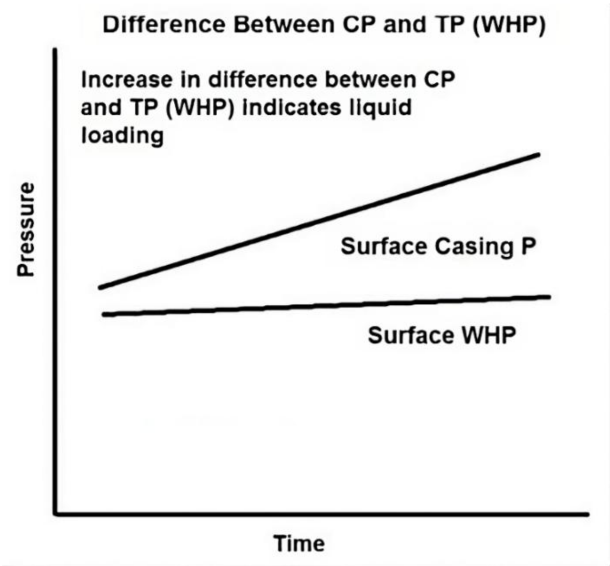

FIGURE 16: CASING AND TUBING PRESSURE INDICATIONS.

II.5.6. Pressure survey showing liquid level:

Flowing or static well pressure surveys are available to determine the liquid level in agas well and thereby whether the well is loading with liquids. Pressure surveys measure the pressure with depth of the well either during shut-in or flowing. The measured pressure gradient is a direct function of the density of the medium and the depth, and the pressure with depth should be nearly linear for a single static fluid.

Since the density of the gas is significantly lower than that of water or condensate, the measured gradient curve will exhibit a sharp change of slope when the tool encounters standing liquid in the tubing. Thus, the pressure survey provides an accurate means of determining the liquid level in the wellbore. If the liquid level is higher than the perforations, liquid loading problems are indicated.

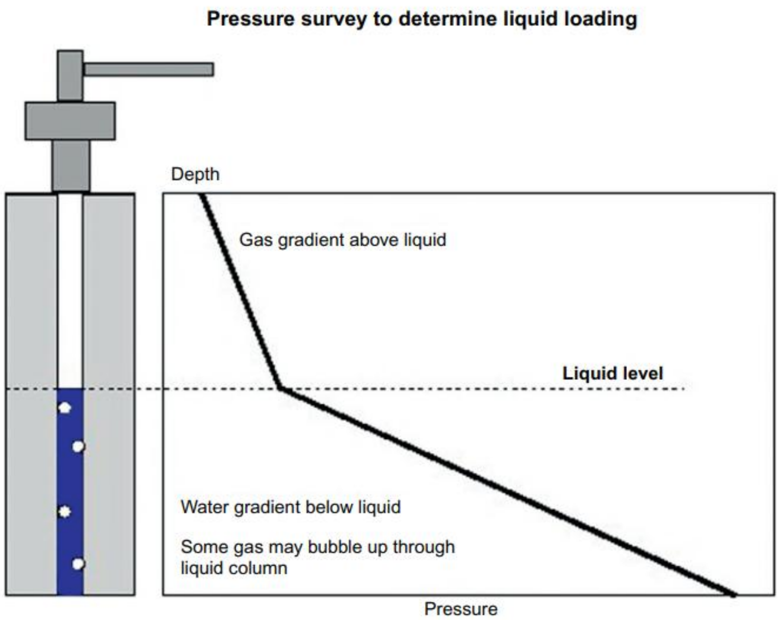

FIGURE 17: PRESSURE SURVEY SCHEMATIC.

Fig17 shows the essential idea linked with the pressure survey. Note that the gas and liquid production rates might affect the slopes measured by the survey giving a larger gas gradient because of certain liquids dispersed and a lower liquid gradient due to the presence of gas in the liquid. Also notice that the liquid level in a shut-in gas well can be measured acoustically by shooting a liquid level down the tubing. Although it was previously done with a wireline pressure survey, a fluid level can be pumped down the tubing with special cautions (echometer technique) to detect a fluid level with no wireline pressure survey.

II.5.7. Appearance of slug flow at surface of well:

Fig18 shows that if you are in the annular-mist regime at first, one can move to the slug flow regime as you move to less gas on the X-axis. In practice, if you are operating a gas well when it is strong, one can see mist flow. But if it liquid loads then you move into the slug flow regime. One indication of liquid loading is that you see slugs of liquid being produced (one can hear them at the well) where there were no slugs of liquid before.

By the time you start seeing the slug flow at the surface, a good portion of the well downhole is most likely already liquid loaded, so this indicator is sort of an after-fact indicator. However, it is still an indicator and if you see slug flow at the surface, the well is liquid loaded (unless well damage dropped the gas flow and put you into the slug flow regime). [6]

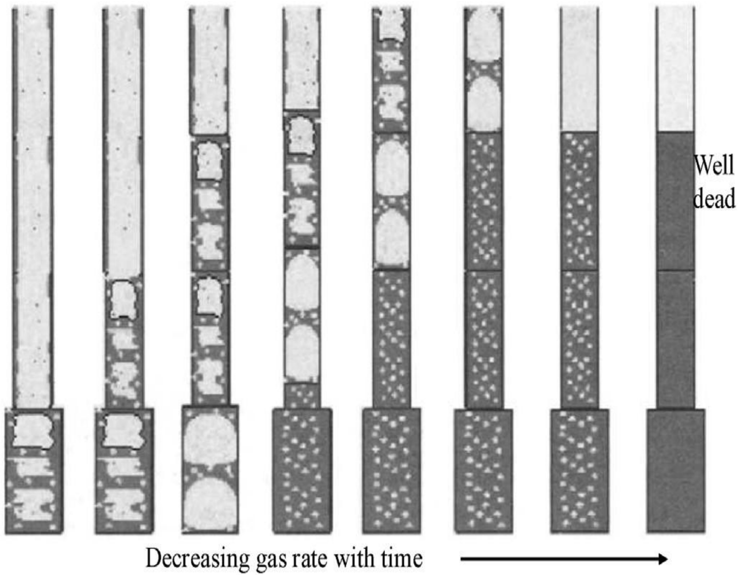

FIGURE 18: LIFE HISTORY AND THE PROCESS OF LIQUID LOADING IN A GAS WELL

II.6. The Critical Velocity:

II.6.1. Critical flow concepts:

For vertical wells, the concept of critical gas velocity can be a valuable tool for identifying liquid loading. The critical gas velocity refers to the minimum gas flow rate required, at any point in the wellbore, to prevent liquid accumulation from initiating. It's important to distinguish between critical gas velocity and critical gas production rate. Critical gas velocity is a downhole property specific to a certain point in the wellbore, while critical gas production rate is the surface gas production rate equivalent to the critical gas velocity, adjusted for standard conditions (pressure and temperature).

When the actual gas flow rate at any point in the wellbore falls below the critical gas velocity for that location, the well cannot effectively lift liquids to the surface. This can lead to liquid hold-up in the wellbore, which may progressively accumulate and eventually restrict gas flow further. Therefore, determining the critical gas velocity profile for a gas well is crucial for assessing the risk of liquid loading and optimizing production strategies. [4]

II.6.2. Critical flow models:

II.6.2.1Turner's model:

Turner et al.'s seminal investigation into liquid loading in gas wells delineated the mechanisms by which liquids are transported within the wellbore. Their research highlighted two primary modes of liquid transport: individual particles being lifted by gas flow and liquid films moving along the tubing wall due to shear stress between the gas and liquid phases. Through extensive experimentation, Turner and colleagues developed and evaluated two correlations, grounded in these transport mechanisms, against a vast dataset. Their findings underscored the efficacy of a droplet model in predicting the movement of liquid droplets within gas flows, contingent upon the gas's velocity. The so-called 'critical velocity' a key concept in their model denotes the gas velocity at which the drag force balances the droplet weight, resulting in the suspension of droplets within the gas stream. Turner et al. proposed a simple yet robust correlation to estimate this critical velocity for near-vertical gas wells, facilitating the prediction of liquid accumulation in the wellbore. Practical applications derived from Turner's work, such as the use of velocity strings and gas lifts, aim to augment gas velocity to surpass the critical threshold, thereby enhancing liquid transport. Turner's correlation, validated against extensive real-well data, has proven instrumental in optimizing gas well production, particularly in wells with surface flowing pressures exceeding 1000 psi, though its applicability may extend to conditions with pressures as low as 5800 psi. [4]

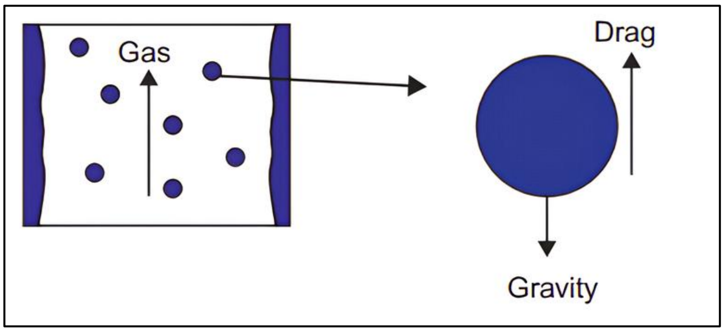

FIGURE 19: ILLUSTRATION OF CONCEPTS (FILM ON WALL AND/OR DROPLET MODEL) INVESTIGATED FOR DEFINING "CRITICAL VELOCITY.

- For the removal of gas well liquids, Turner et al. (1969) proposed two physical models:
    1. **The continuos film model**
    2. **The entrained drop movement model**

The continues film model:

The continuous film model proposed by Turner et al. (1969) emphasizes the inevitable accumulation of a liquid film along the conduit walls during two-phase gas/liquid flow, resulting from liquid drop impingement and vapor condensation. Turner highlighted the necessity of this annular liquid film's upward movement along the walls to prevent gas well loading. Identifying the minimum gas flow rate capable of achieving this movement is deemed crucial for predicting liquid loading. The model's analytical approach focuses on characterizing the upward velocity profile of a liquid film inside a tube. However, its significant limitation lies in the model's inability to distinctly differentiate between adequate and inadequate flow rates when validated against field data.

The entrained drop movement model:

The Entrained Drop Movement Model, introduced by Turner et al. in 1969, conceptualizes the minimum gas flow rate required to elevate liquid droplets from gas wells. This model uses the principle of a freely falling particle within a fluid medium to estimate the necessary gas flow velocity for liquid droplet removal. Initial predictions were adjusted upwards by 20% based on field data discrepancies, highlighting the model's practical application in preventing liquid accumulation in gas wells by accurately determining essential gas velocities. [3]

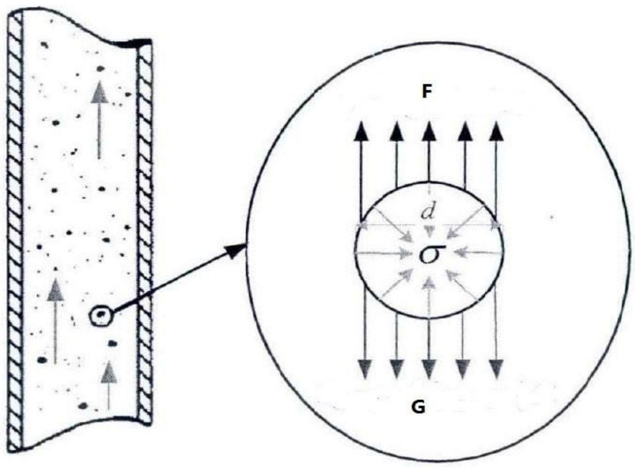

FIGURE 20: FORCE ANALYSIS OF DROPLETS IN TURNER'S MODEL

The minimum gas flow velocity necessary to remove liquid drop is given by the following equation:

$$V_{\text{crit-Tunadjusted}} = 1.539 * \frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{\rho^{1/2}} \quad \ldots\ldots\ldots\ldots (3)$$

The study by Turner et al. (1969) highlighted that the prediction accuracy of the droplet model was significantly lower than expected. To address this, Turner pointed to the underestimated values of the critical Weber number and drag coefficient in the model. He suggested that these parameters were responsible for predicting droplet behaviour, particularly in achieving droplet stability. It was necessary for these values to surpass a certain threshold to ensure that larger droplets could be effectively removed. A revaluation of Turner's data indicated that to better align the model with empirical data, an upward adjustment of approximately 20% was required. A comparison of the revised model with actual test data revealed substantial variances at lower flow rates. Consequently, Turner proposed a modified droplet model, expressed by Equation (3), which accounts for these discrepancies. Furthermore, a new expression for q_crit, denoted by Equation (4), was introduced to further refine the model's predictive capabilities.

$$V_{\text{crit}-\text{T}} = 1.92 * \frac{\sigma^{1/4}(\rho_l-\rho_g)^{1/4}}{\rho^{1/2}} \quad \ldots\ldots\ldots\ldots (3)$$

$$q_{crit-T} = \frac{3000PV_{\text{crit}-\text{T}}*A}{Tz} \quad \ldots\ldots\ (4)\ \ [8]$$

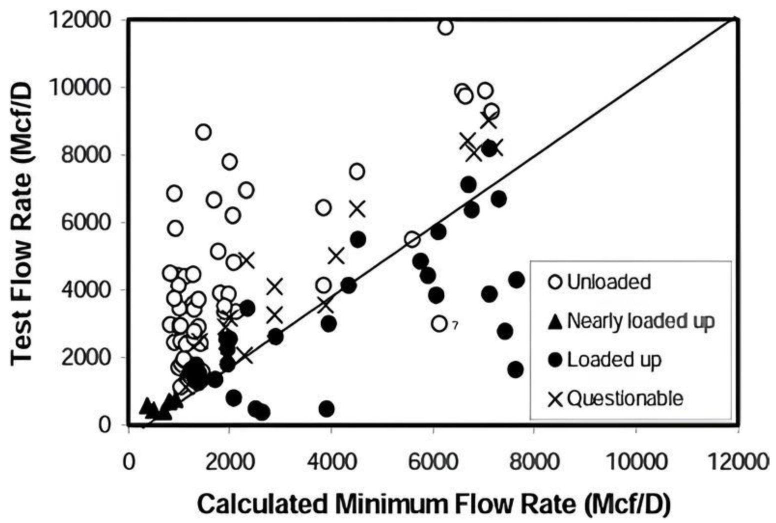

FIGURE 21:TURNER ET AL. MODEL-CALCULATED MINIMUM FLOW RATES MAPPED AGAINST THE TEST FLOW RATES (GUO ET AL. 2006)

II.6.2.2 Coleman model :

Coleman et al. (1991) made use of the Turner model but validated with field data of lower reservoir and wellhead.

flowing pressure all below approximately 500 psia. Coleman et al. (1991) discovered that a better prediction could be achieved without a 20% upward adjustment to fit field data with the following expressions: [5]

$$V_{\text{crit-C}} = 1.593\left[\frac{\sigma(\rho_l-\rho_g)}{\rho_g^2}\right]^{1/4} \quad \ldots\ldots\ldots\ldots (5)$$

$$q_{crit-T} = \frac{3000PV_{\text{crit-C}} * A}{Tz} \quad \ldots\ldots\, (6)\ [10]$$

II.6.2.4. Li's Model:

Li, Sun in their research state that Turner and Coleman's models did not take into account the deformation of the free-falling liquid droplet in a gaseous medium. They argued that when a liquid droplet is entrained in a high-speed gas stream, there is a pressure difference between the front and rear parts of the droplet. The droplet deforms under the applied force and its shape changes from a convex to a convex bean with uneven (flat) sides, as shown in figure II.16. [4]

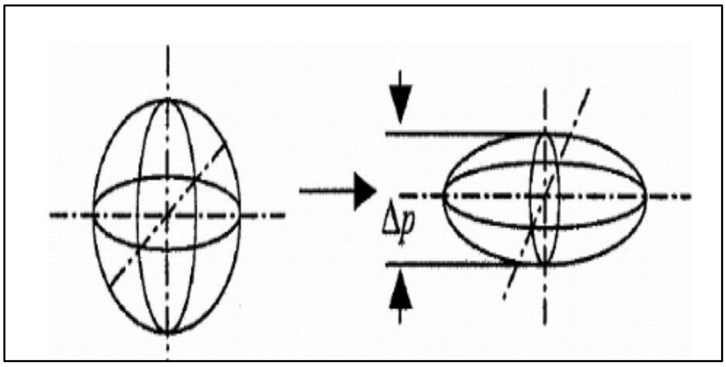

FIGURE 22: FORME PASSE D'UN HARICOT CONVEXE A CONVEXE AVEC DES COTES INEGAUX

Spherical liquid droplets have a smaller zone efficiency and require a higher lifting speed and critical flow rate to lift them to the surface. However, flat droplets have a higher zone efficiency and are easier to transport to the wellhead.

$$v_t = \frac{2.5\sigma^{\frac{1}{4}}(\sigma_l^{\frac{1}{4}}-\sigma_g^{\frac{1}{4}})}{\sqrt{\sigma_g}} \qquad (7)$$

II.7. Nodal analysis and pressure drop in the tubing:

II.7. 1.The importance of nodal analysis:

Nodal analysis is essential in production wells which are equipped to extract oil, gas, or water from a reservoir to the surface, overcoming pressure losses in the production system including tubing and flow lines. The extraction requires energy as fluids move from the reservoir through these conduits, finally flowing into separators.

The production system can range from simple to complex with multiple components where pressure losses occur. It consists of three phases:

- flow through porous media
- flow through vertical or directional conduits
- flow through horizontal pipes

The pressure drop at any point in the system equals the initial fluid pressure minus the final fluid pressure (P_i - P_sep), where P_i is the average reservoir pressure, and P_sep is the separator pressure.

The total pressure drop is the sum of pressure drops across all system components. The pressure drop along any component changes with the production rate, which is controlled by the chosen components. [7]

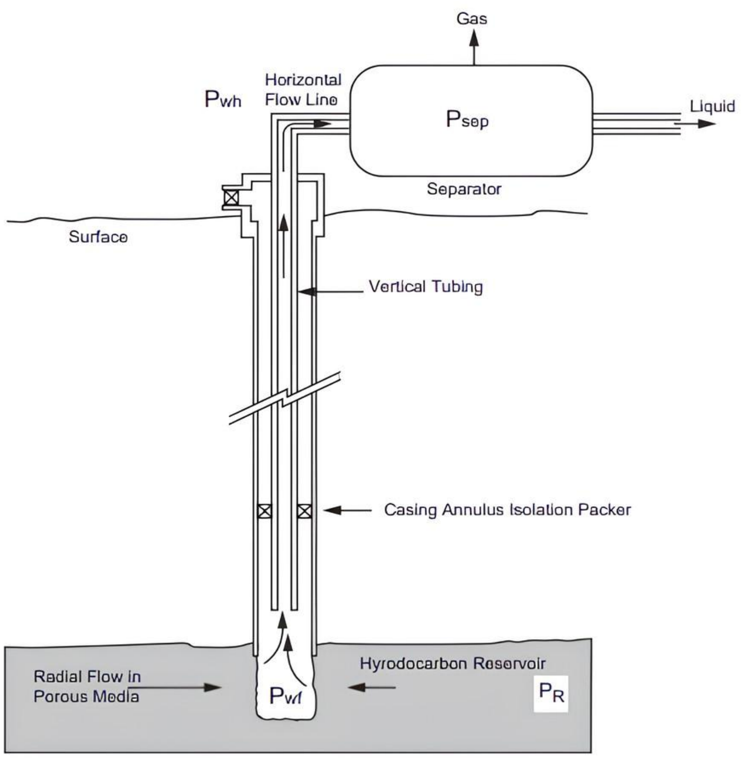

FIGURE 23:SIMPLIFIED HYDROCARBON PRODUCTION SYSTEM

Fig. II.16 shows the various Pressure losses during production that can occur in the system: from reservoir to separator.

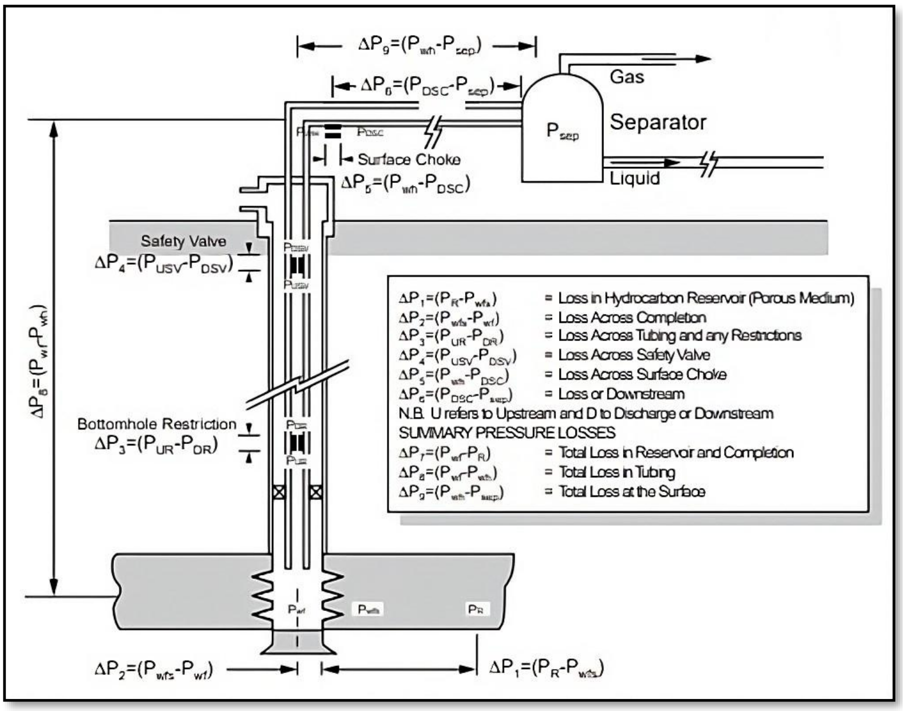

FIGURE 24: PRESSURE LOSSES DURING PRODUCTION

II.7.2. Pressure losses during production system:

The magnitude of these individual pressure losses depends on the reservoir properties and pressures; fluid being produced and the well design. Production Technologists/ Engineers need to understand the interplay of these various factors to design completions which maximise profitability from the oil or gas production. There are no standard "rules of thumb" which can be used. Figure 3 schematically represents the pressure distribution across the production system shown in Figure 2. It identifies the most significant components, flowline, tubing and the reservoir and completion where pressure losses occur.

Table 1 was developed by Duns and Ross ("Vertical flow of gas and liquid mixtures in wells" to illustrate one possible distribution in a conventional land oil field developed with vertical wells. [7]

TABLE 6: PRESSURE LOSS DISTRIBUTION AS A FUNCTION OF WELL PRODUCTIVITY INDEX.

Well Productivity Index (bopd/psi)	Production Rate (bopd)	Pressure Loss Distribution (%): Across Reservoir and Completion (Δ P_r)	Pressure Loss Distribution (%): Across Tubing (ΔP_b)	Pressure Loss Distribution (%): Across Flowline (ΔP_g)
2.5	2700	36	57	7
5.0	3700	25	68	7
10.0	4500	15	78	7
15.0	4800	11	82	7

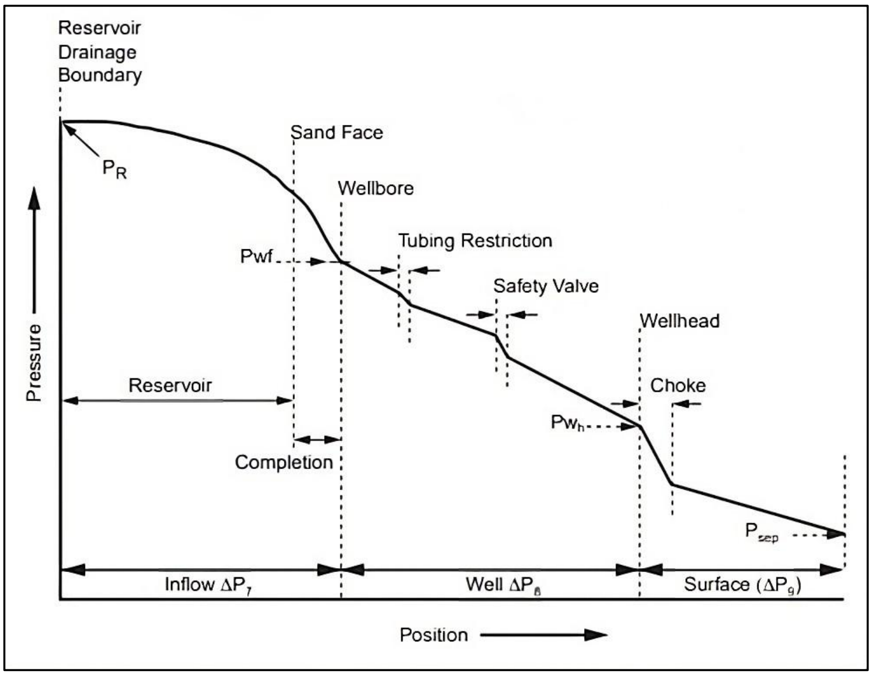

FIGURE 25: PRESSURE ACROSS PRODUCTION SYSTEM.

II.7.3. Systems Analysis of the Production System:

The use of systems analysis to design a hydrocarbon production system was first suggested by Gilbert ("Flowing and Gas Lift Performance", API Drilling and Production Practices, 1954"). Systems analysis, which has been applied to many types of systems of interacting components, consists of selecting a point or node within the producing system (well and surface facilities). Equations for the relationship between flow rate and pressure drop are then developed for the well components both upstream of the node (inflow) and downstream (outflow). The flow rate and pressure at the node can be calculated since:

(i) Flow into the node equals flow out of the node.

(ii) Only one pressure can exist at the node.

Further, at any time, the pressure at the end points of the system {separator (Psep) and reservoir pressure (PR)} are both fixed. Thus:

P_R - (Pressure loss upstream components) = P_{node} (8)

P_{sep} + (Pressure loss downstream components) = P_{node} (9)

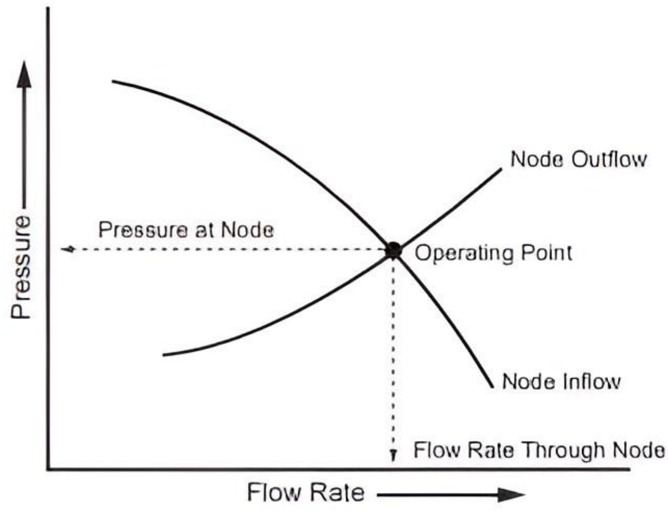

FIGURE 26: NODE FLOW RATE AND PRESSURE.

Typical results of such an analysis is shown in Figure 4 where the pressure-rate relationship has been plotted for both the inflow (Equation 1) and outflow (Equation 2) at the node. The intersection of these two lines is the (normally unique) operating point. This defines the pressure and rate at the node. This approach forms the basis of all hand and computerised flow calculation procedures. It is frequently referred to as "nodal analysis".

The nodal analysis system comprises two parts:

The INFLOW or input is the curve representing all the components between the node and the reservoir boundary.

The OUTFLOW is the curve comprising the components between the node and the separator.

II.8. Hydrocarbon Phase Behaviour:

Reservoir fluids are a complex mixture of hydrocarbon molecules, the composition of which is dependent on the source rock, degree of maturation etc. Phase changes occur when this complex hydrocarbon fluid flows from the (high temperature and pressure) reservoir environment to the (cool, low pressure) separator conditions. Such changes are sketched for an undersaturated oil in Figure 5. Here it can be seen that the fluid:

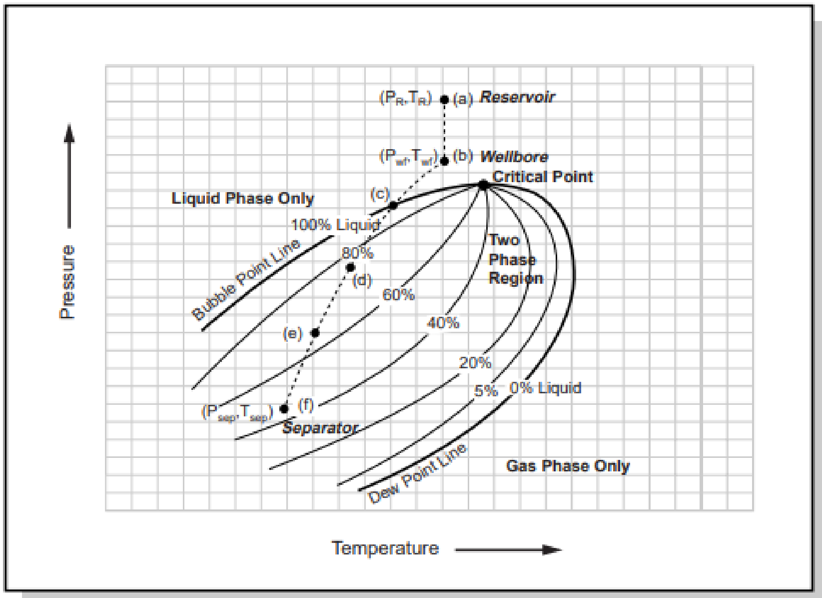

FIGURE 27: SCHEMATIC PHASE DIAGRAM FOR AN UNDERSATURATED OIL

(i) is present as a single phase liquid in the reservoir {point (a)}

(ii) remains a single phase liquid at the wellbore (significant reduction in pressure and small change in temperature during flow in reservoir) {point (b)}

(iii) starts to evolve gas {point (c)} as temperature and pressure are reduced during flow up the tubing

(iv) evolves increasing amounts of gas {points (d) and (e)} until the separator {point (f)} is reached. Some or all of the flow regimes illustrated in figure 6 may occur.

The phase behaviour of the hydrocarbon fluid controls the fluid's gas/liquid ratio as a function of bottom hole pressure. This, in turn, will effect flow rate, i.e. the Inflow Performance Relationship (IPR) discussed in section 1.4 and the outflow tubing performance. [7]

II.8.1 Reservoir Inflow Performance:

The Inflow Performance Relationship (IPR)is routinely measured using bottomhole pressure gauges at regular intervals as part of the field monitoring programme. This relationship between flow rate (q) and wellbore pressure (Pwf) is one of the major building blocks for a nodal-type analysis of well performance.

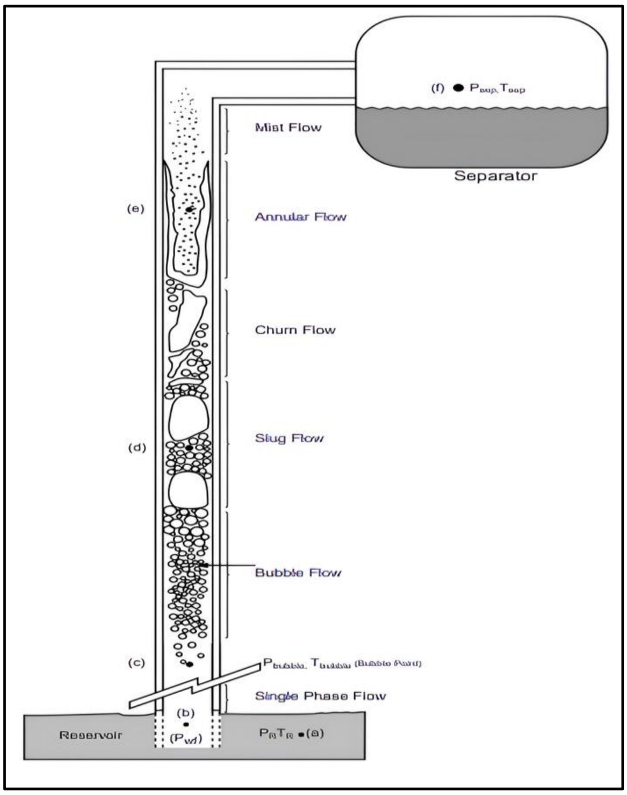

FIGURE 28: SCHEMATIC VIEW OF POSSIBLE PHASE CHANGES IN TUBING.

II.8.2 Liquid Inflow:

Field measurements have shown that wells producing undersaturated oil (no gas at the wellbore) or water have a straight line IPR (Figure 29).

$$q = PI\ (P_R - P_{wf}) \qquad (10)$$

where q is the flow rate and PI the Productivity Index, i.e. the well inflow rate per unit of well drawdown.

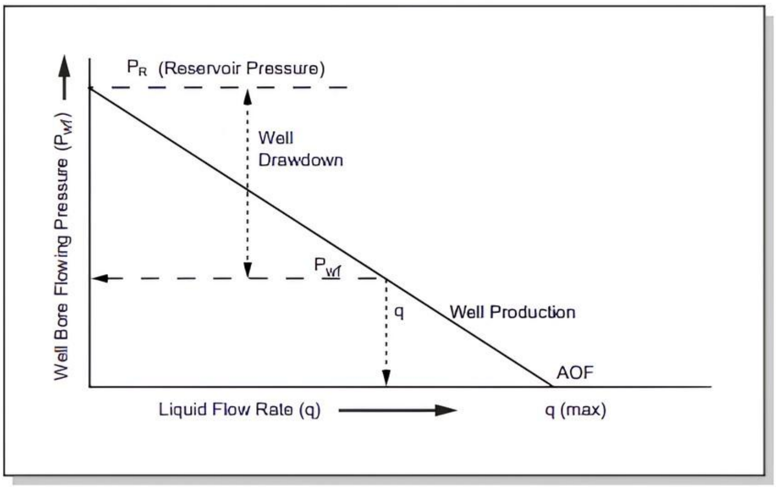

FIGURE 29: STAIGHTLINE IPR (FOR AN INCOMPRESSIBLE LIQUID)

A theoretical basis for the straight line IPR can be derived using Darcy's Law, radial inflow into the well along with other assumptions about rock and fluid properties. PI is a useful tool for comparing wells since it combines all the relevant rock, fluid and geometrical properties into a single value to describe (relative) inflow performance

A straight line IPR can be determined from two field measurements:

(i) the stabilised bottomhole pressure with the well shut in {reservoir pressure of (PR)}

(ii) the flowing, bottom hole, wellbore pressure (Pwf) at one production rate The well's inflow potential can then be calculated at any draw-down (or Pwf)

II.8.3 Gas Inflow:

The compressible nature of gas results in the IPR no longer being a straight line. However, the extension of this steady state relationship derived from Darcy's Law, using an average value for the properties of the gas between the reservoir and wellbore, leads to:

$$Q = C\,(P_R^2 - P_{wf}^2) \qquad (11)$$

* where C is a constant

This relationship is valid at low flow rates but becomes invalid at higher flow rates since non-Darcy (or turbulent) flow effects begin to be observed. This can be accounted for by use of the "Bureau of Mines" equation that was developed from field observations:

$$Q = C\,(P_R^2 - P_{wf}^2)^n \qquad (12)$$

Where: $0.5 < n < 1.0$

Both equations [11] and [12] are illustrated in Figure 8 which shows the >50% reduction in AOF (from 1.4 to 0.9) due to these non-Darcy flow effects

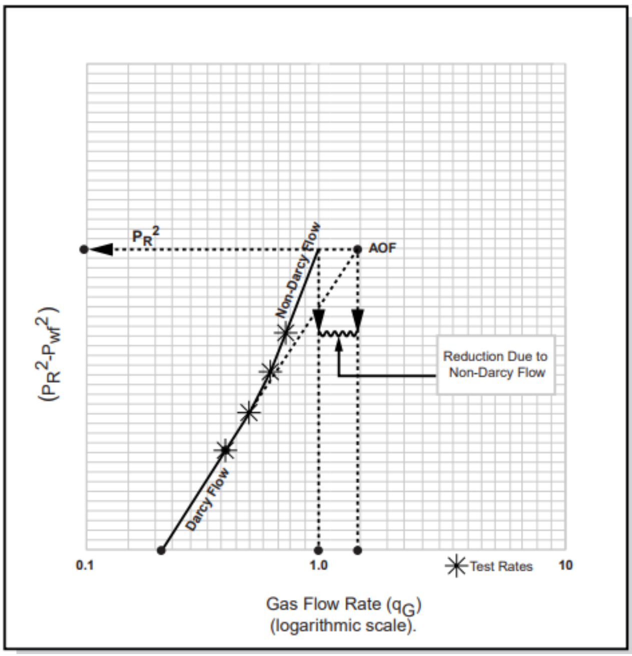

FIGURE 30: GAS WELL DELIVERABILITY REDUCED BY NON-DARCY FLOW PRESSURE LOSSES.

II.8.3 Phase (Gas-Liquid) Inflow:

Straight line IPR are also not applicable to when two phase inflow is taking place, e.g. when saturated oil is being produced. Vogel ("Inflow Performance Relationships in Solution-Gas Drive Wells", J Pet Tech, 1968, 83-92) proposed the following equation based on a large number of well performance simulations:

$$\frac{q}{q_{max}} = 1 - 0.2\left(\frac{P_{wf}}{P_R}\right) - 0.8\left(\frac{P_{wf}}{P_R}\right)^2 \qquad (13)$$

Vogel's key contribution was the introduction of the concept of normalising the production rate to the AOF value (qmax). Rewriting equation [13] in this manner gives:

$$\frac{q}{q_{max}} = \{1 - \left(\frac{P_{wf}}{P_R}\right)^2\}^n \qquad (14)$$

which is virtually equivalent to Vogel's equation when n = 1 (Fetkovitch, "Isochronal testing of oil wells", SPE 4529, Las Vegas, Sept 1973). i.e:

$$\frac{q}{q_{max}} = 1 - \left(\frac{P_{wf}}{P_R}\right)^2 \qquad (15)$$

Figure 31 compares the production rate as a function of drawdown for an undersaturated oil (straight line IPR, line A) and a saturated oil showing the two-phase flow effects discussed above (curve B). The figure also shows the special case (curve C) when the wellbore pressure is below the bubble point while the reservoir pressure is above, i.e. (incompressible) liquid flow is occurring in the bulk of the reservoir.

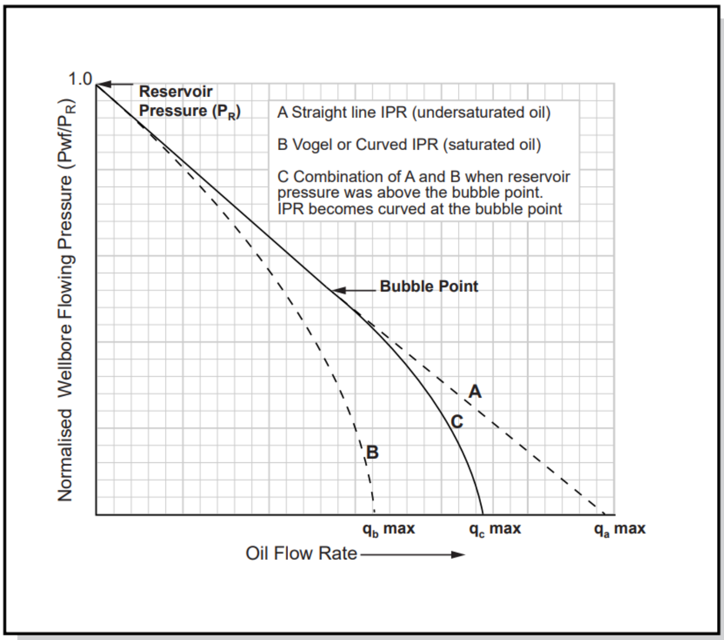

FIGURE 31: INFLOW PERFORMANCE RELATIONSHIPS

Conclusion:

Liquid loading in natural gas wells poses significant challenges to production optimization, the early identification and resolution of liquid loading in gas wells is crucial to overcome liquid accumulation in wellbore of low production critical gas wells.

Chapter 03

Coiled Tubing Velocity String to Mitigate Liquid Loading

Introduction:

Production rate declines with reservoir depletion and eventually falls below the minimal critical velocity. The liquid that is now flowing vertically upward with the gas starts to return to the wellbore. More pressure loss and flow restriction to the surface are caused by liquid collection in the tube. The installation of coiled tubing inside the existing tubing string—also known as the "velocity string" is a straightforward but effective method for overcoming liquid accumulation in the wellbore of low production critical gas wells. This technique is used in the Tiguentourine field and can be carried out without killing the well. A bottom-hole survey of pressure and temperature, either in a static or flowing state, needed to be supplied and matched with a velocity string model. It is necessary to compute the new critical rate evaluation for each wellbore section and the new flow regime following installation. In the field under observation, this applied technology has been shown to boost gas cumulative production and prolong production life. A greater comprehension of thorough well screening is crucial to improving the velocity string installation project's success ratio.

III.1. Overview about Coiled Tubing:

Coiled tubing is being used in an ever-growing number of well intervention projects by the global oil and gas industry. Many operational and financial benefits are provided by coiled tubing, such as the ability to intervene without the need for a rig, the removal of well kill and potentially harmful heavy weight kill fluids, a smaller operational footprint, and the ability to intervene without a well. The largest supplier of coiled tubing well intervention solutions in the industry has developed genuinely functional coiled tubing systems because of these benefits.

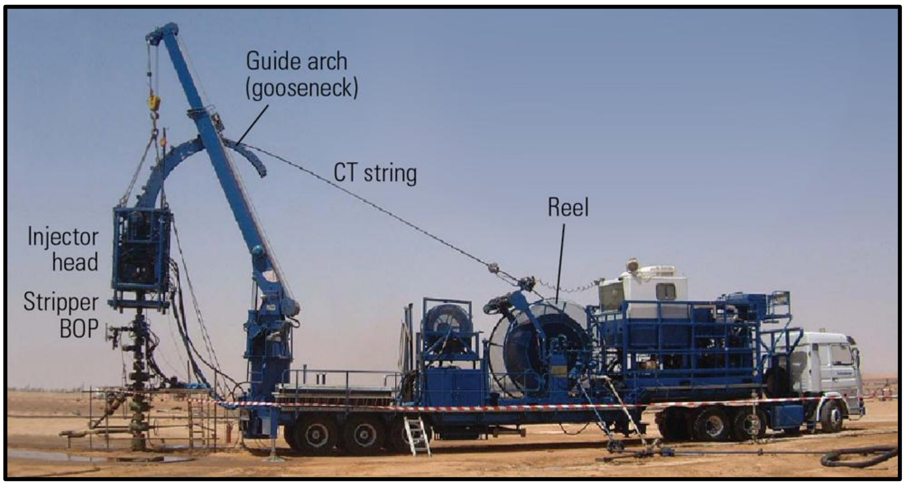

FIGURE 32: COILED TUBING UNIT.

The coiled tubing unit consists of a tube continuous metal approximately ¾” to ½” in diameter (approximately 19 to 38 mm) wound on a coil or drum and which can be raised or lowered in a pressure well. The tube is maneuverer by a injector through a sealing system (BOP). Her implementation requires a specialized team of at least three people.

CT Reel Unit:

The function of this chain-driven device is to uncoil and coil the tubing under constant tension between Reel and Gooseneck; it does not lower or hoist CT in the well. A reel filled with tubing may weigh up to 35,000 lbs.

Injector Head [with Gooseneck]:

transfers the force required to hold, retract, or inject the CT. It is a crucial component that includes a gooseneck and an injector drive.

Power Pack:

provide complete independent power for electric and hydraulic pumps. consists of accumulators for auxiliary and well control devices.

Control Cabin:

gives users a clear view of all necessary equipment and gives them the ability to control and monitor practically everything that goes into running a CT package.

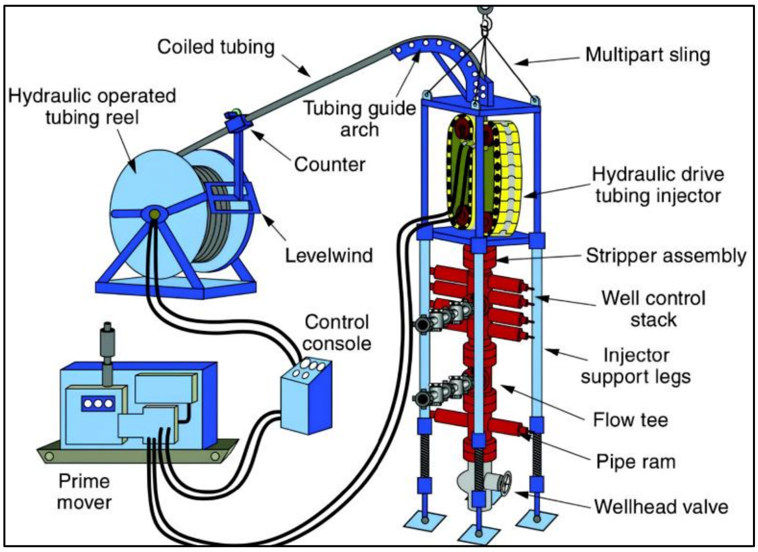

FIGURE 33: CT SURFACE SET UP AND RIG UP SCHEMATIC.

III.1.1. COILED TUBING BARRIER PRINCIPLES:

The parameters of the well and the type of intervention determine the number and type of equipment to be deployed to safely complete the proposed programme.

The safety set during the operation of the CTU consists of a stripper (element with sealants) and BOPs.

STRIPPER

The stripper is a sealing element that is installed under the injection head very close to the grip elements of the injection head chain to prevent the coiled tubing from bursting during manoeuvre.

The stripper constitutes the primary barrier when the coiled tubing is in the well, it ensures perfect waterproofing around the Coiled Tubing as the press suffocates in cable operations.

There are three types of strippers on the walk:

- The conventional stripper
- the stripper side door
- the radial stripper

The principle of operation of all types of strippers is the same, which consists of hydraulically moving a piston to compress a waterproofing fitting directly or indirectly, which in turn makes water proofing around the coiled tubing.

Tandem stripers can be arranged with two stripers of the same type (conventional / conventional) or of different types (conventional / side door)

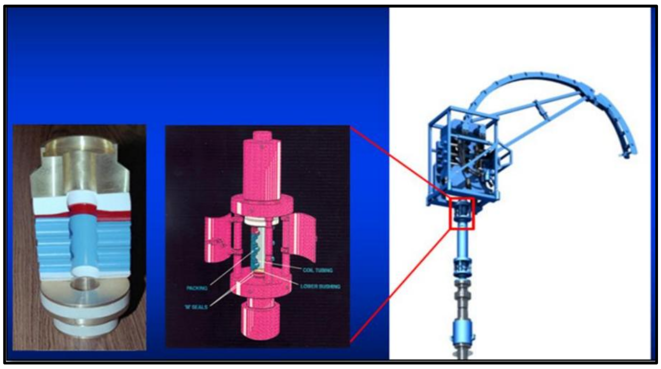

FIGURE 34: THE STRIPER

Bop:

The shutter block consists of 4 floors, from bottom to top:

• Pipe rams (shapes ensuring closure and sealing on the tube).

• Slip rams (angular rams that hold the tube)

• Shear rams (cut blades for cutting the tube)

• Blind rams.

The shutters used in coiled tubing operations are like those used in cable operations.

When the tubing is inside the well, the pipe rams/ring shutter is regarded as a secondary barrier, if the shear/seal rams (safety head) is included in the stack it plays the role of a tertiary barrier.

The most used dimensions of the coiled tubing BOPs are the 3’’ and the 4’’, but in practice you can find larger or smaller dimensions depending on the diameter of the used coiled tube.

Generally, the hydraulic pressure used to operate the coiled tubing BOPs is between 1500 and 3000 psi.

The most common stackers used in coiled tubing intervention operations are:

I. BOP QUAD stacking.
II. BOP CAMBI stacking.

BOPS QUAD:

This type of stacking is the most common BOP used in coiled tubing intervention operations.

It is a solid block consisting of four BOPs with rams arranged from top to bottom as follows:

- BOP Blind Rams
- BOP Shear Rams
- BOP Slip Rams
- BOP Pipe Rams.

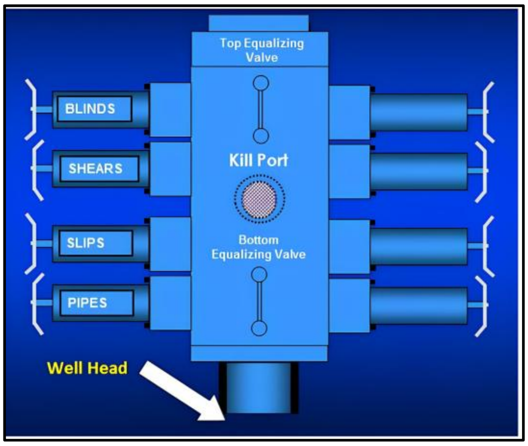

FIGURE 35: QUAD RAMS - CT BOP

III.1.2. Coiled tubing downhole applications:

DRILLING: Coiled tubing has achieved great success performing reentry drilling, where a horizontal lateral is drilled in an existing well with a coiled tubing conveyed mud motor and bit. Coiled tubing reentry drilling can be performed through the existing production casing and in an underbalanced condition. Drilling new wells from the surface with larger 3-1/2" and 4-1/2" coiled tubing has been successful in certain markets, especially shallow gas wells in Canada.

FRACTURING: Coiled tubing has advantages over traditional methods when fracturing relatively shallow wells multiple zone completions. Coiled tubing can convey zonal isolation tools to pinpoint the fracture treatment and then the coiled tubing is used as the conduit for the fracturing fluid. The fracturing proces can be repeated multiple times on a single coiled tubing run

MILLING FRAC PLUGS: The large multistage fracture treatments that are common in horizontal shale gas completions require setting multiple frac plugs for zonal isolation. Coiled tubing, in conjunction with mud motor and bit assembly is then used to mill out the frac plugs and clean the wellbore.

LOGGING/PERFORATING; Wireline cables installed inside coiled tubing allows the deployment of logging or perforating tools in highly deviated wells. Coiled tubing offers several advantages over traditional wireline methods, including enduring greater tensile and compressive forces and the ability to work in live wells.

CLEANOUTS: Coiled tubing can be used to remove scale, produced sand, frac sand and debris from the wellbore. Coiled tubing is run into the wellbore, fluid is pumped down the coiled tubing and returns are circulated through the annulus. Coiled tubing can rig up and get to depth quickly without killing the well or pull the production tubing.

NITROGEN INJECTION: Coiled tubing allows the injection of nitrogen at depth into a dead wellbore to displace the wellbore fluid with nitrogen. This lowers the bottom hole pressure and allows the well to resume flowing.

STIMULATION: Coiled tubing matrix stimulation treatments are designed to restore the natural permeability of the near-wellbore formation by injecting treatment fluids into the formation.

VELOCITY STRINGS: Coiled tubing is run into an existing producing well to reduce the effective flow area to allow the natural reservoir pressure to lift water from the reservoir, allowing natural pressure to sustain production in mature producing wells, and this will be our object. [7]

The Velocity string:

If a well is in its decline phase, it suffers in most cases from liquid loading problems. In this chapter solutions for corrective measurements are discussed. When it is technically not feasible to subject a reservoir with a further treatment, the only remaining possibility, is to change the completion of the well. In this kind of measurement, a smaller diameter coiled tubing string (velocity or siphon string) or a string of jointed pipes is installed inside the production tubing.

III.2. General Function of a Velocity String:

The intention behind the installation of a velocity string with a smaller diameter than the production string minimizes the cross-sectional flow area. When the cross-sectional flow area gets smaller, the gas velocity in the tubing will increase. This means: the higher the gas velocity on the bottom of the well, the more energy for transporting the liquid up to the surface is given. Therefore, the liquid is not able to accumulate on the bottom of the well anymore and the production is guaranteed. Important for the liquid discharge is the velocity of the streaming gas in the production string.

According to the equation of continuity (I) the velocity is defined by:

$$v = \frac{q}{A} = \frac{4*q}{d_i^2*\pi} \qquad \text{III.1}$$

<u>Where:</u>

v: velocity of the gas [m/s]

q: flow rate (volume of the gas per time unit) [m3 /h]

A: cross sectional area of the streamed conduit [m2] di: inner diameter of the streamed conduit [m] Replacing the area by the term A=$\frac{4*q}{d_i^2*\pi}$ then the squared diameter influences the velocity.

According to the equation of real gas (II) the volume is given by:

$$V = \frac{Z*n*R*T}{p} \qquad \textbf{III.2}$$

Where:

V: volume of the gas for the particular section [m3]

z: coefficient of compressibility [1/bar]

n: amount of the gas molecules [mol]

R: general gas constant [m3 bar2 /mol*K]

T: absolute gas temperature [K]

p: pressure of the gas [bar]

The equations **III.1** and **III.2** indicate that, at low pressure, the flow rate increases while the amount of gas remains constant. Hence, the velocity's behaviour on the lower section of the well completion is crucial. Increased velocity at the bottom of the well improves the flow conditions in the upper section of the well. A velocity ranging from 7 to 12 feet per second has been determined to be the optimal value for the lower part of the tubing. It is important to acknowledge that the velocity is entirely dependent on the accompanying liquid holdup.

A key indicator for the liquid discharge by the gas is the so-called **LH (Liquid Holdup)** (III). It is defined as the ratio between the volume of liquid in a pipe element and the volume of the concerned pipe-segment.

$$LH = \frac{V_{free-water}}{V_{pipe\ segment}}$$

If the LH reaches a value of one, there is only liquid present and if the LH reaches a value of zero, there is only gas in the pipe. According to experience the LH should have a value of 0.2 or less.

In Figure 36 shows the relationship between the mixture velocity and the liquid holdup for different tubular configurations is shown. For the lower velocities a rapid variation of liquid holdup is to recognize

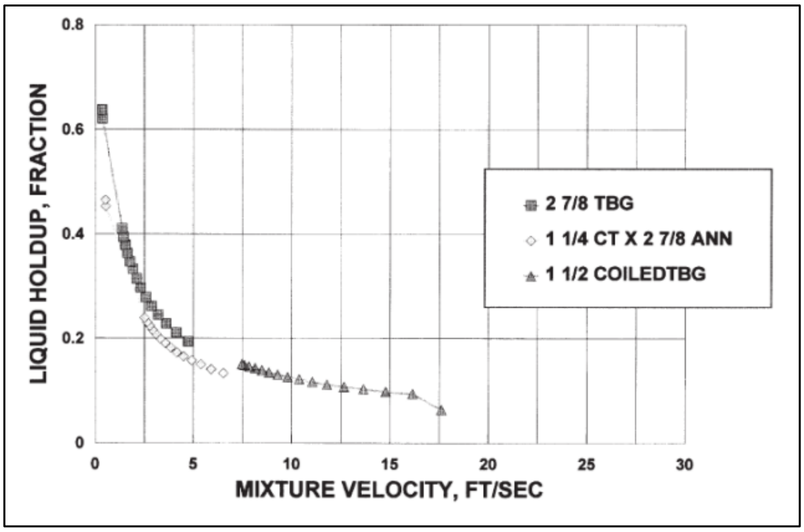

FIGURE 36: VELOCITY VERSUS LIQUID HOLDUP

III.2.1. Velocity string design:

The objective of a velocity string design is to find an optimum coiled tubing size and depth that will restore the well back to flowing production, so that the frictional pressure losses in the tubing are minimal, and production is maximized. The well should also continue producing long enough to offset the cost of installing the velocity string. [..]

Workflow was developed to design coiled tubing velocity string to have expected condition after installation. The workflow includes:

a. Build performance curve and match with measured data.

b. Sensitivity study of coiled tubing size and setting depth.

c. Evaluate design for flow regime alteration and critical rate after installation.

d. post-review after installation: expected well performance and extended application.

Performance curves & Measured Data Matching:

. Builed Inflow Performance Relationship (IPR)

. Builed Tubing Performance Relationship (TPR)

Sensitivity Study :

. Coiled Tubing Size

. Coiled Tubing Setting depth

Design Evaluation :

Calculate the Critical rate after CTVS installation.

Velocity string installation

To design a velocity string that will return the well to flowing production and how long it will sustain production, you compare two curves:

- the reservoir inflow performance relationship (IPR), which describes the performance of gas flowing in from the reservoir.
- the tubing performance characteristic (J-curve), which describes the performance of gas flowing up the tubing.

III.2.1.1 Reservoir Performance:

As we saw in chapter 02 the reservoir inflow performance relationship (IPR) shows the relationship between the flowing bottomhole pressure and the gas flow rate from the reservoir into the well.

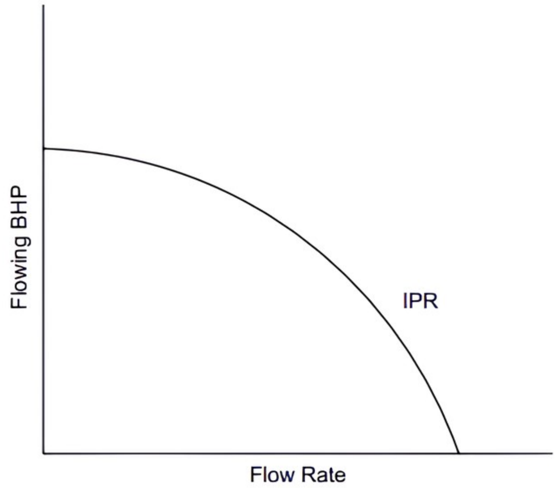

FIGURE 37: RESERVOIR INFLOW PERFORMANCE RELATIONSHIP (IPR) CURVE

There are various methods available in the literature to construct the reservoir IPR for oil and gas wells. Cerberus constructs the reservoir IPR based on Darcy’s equation for oil wells. This can be somewhat of a limitation since many velocity strings are installed in gas wells with high gas-liquid ratios (GLRs)

III.2.1.2 Tubing Performance (J-curve):

The tubing performance curve, often known as the J-curve, provides a comprehensive representation of the performance characteristics of a particular tubing size, depth, and wellhead circumstances. Consequently, the velocity string design varies for each case. This graph illustrates the correlation between the bottomhole pressure and the pace at which gas flows up the well. The term "J-curve" is derived from its distinctive shape.

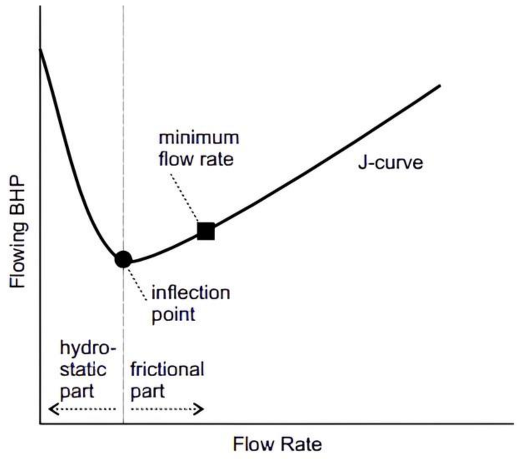

FIGURE 38: TUBING PERFORMANCE CURVE (J-CURVE)

The J-curve is divided into two parts by the inflection (loading) point, where the slope is zero. To the left is the hydrostatic contribution. To the right is the contribution from tubing frictional losses. The minimum flow rate corresponding to the minimum velocity (as determined by the 10 ft/ sec. rule of thumb or the Turner et. al. (1969) correlation) also appears on the J-curve.

There are a variety of multiphase models that can be used to determine the tube performance curve in oil and gas wells. Cerberus employs multiphase models specifically designed for oil wells, and its forecasts are typically accurate, with errors of less than 20%, for GLR values up to around 5000. Each model is applicable only under specific conditions, hence it is important to choose the appropriate model accordingly.

III.2.2. The evaluation of The Design:

A well flows at the flow rate where its IPR and J-curve meet. We will compare this intersection point with the minimum gas flow rate on the J-curve to see which of three situations will occur:

- the well will flow, without loading up.
- the well will flow but will load up and eventually stop producing.
- the well will not flow.

If the intersection point is to the right of the minimum gas flow rate, the well flows faster than the minimum gas flow rate and no liquid loading occur.

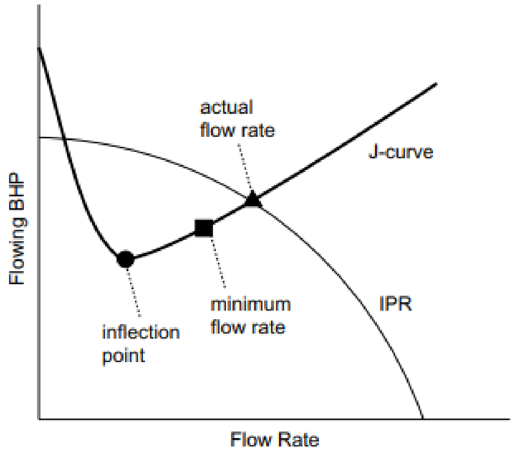

FIGURE 39: INTERSECTION POINT TO THE RIGHT OF THE MINIMUM GAS FLOW RATE

If the intersection point is between the inflection point and the minimum gas flow rate, liquid loading occurs. The well flows but will eventually kill itself.

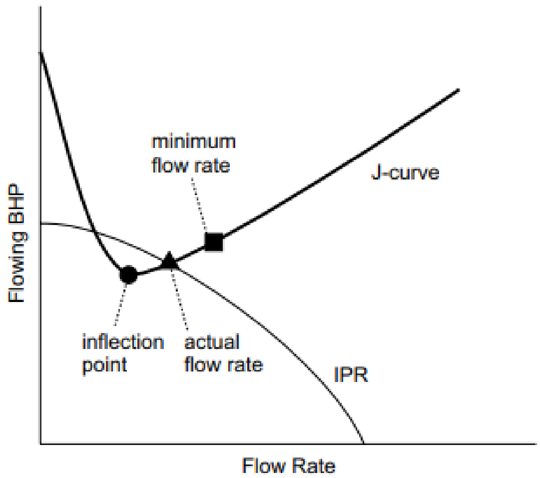

FIGURE 40: INTERSECTION POINT LIES BETWEEN THE INFLECTION POINT AND THE MINIMUM GAS FLOW RATE.

If the IPR and J-curve do not intersect, or if they intersect to the left of the inflection point, the flowing bottomhole pressure is too low for the well to flow for that particular tubing size, depth, and wellhead pressure. Should consider another velocity string design.

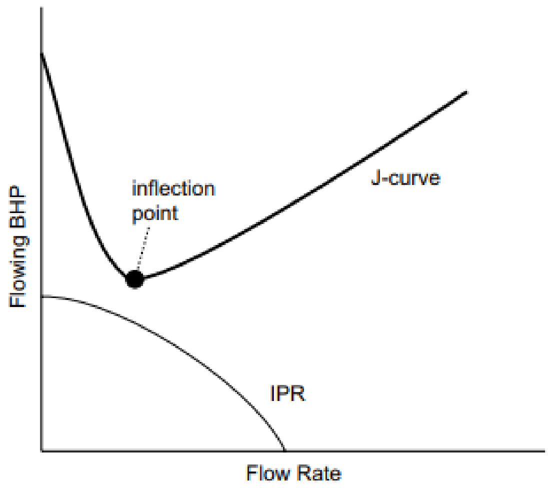

FIGURE 41: NO INTERSECTION POINT OR INTERSECTION POINT TO THE LEFT OF THE INFLECTION POINT

Figure **III.10** shows an example installation where a velocity string is able to provide a reduction in the erruptivity limit, and produce at lower reservoir pressures.

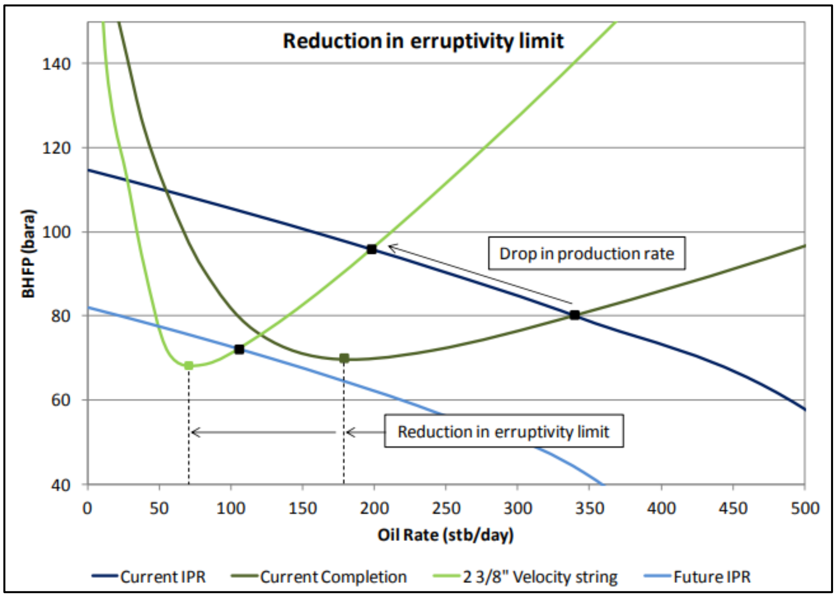

FIGURE 42: A PLOT SHOWING THE REDUCTION IN ERUPTIVITY RATE WHEN A VELOCITY STRING IS INSTALLED

III.2.3. The effects of a velocity string:

Determination of the effects that a velocity string will have on a well is obtained through the nodal analysis simulation (Brown, K.E.). The analysis includes the system from perforations (system intake node) to wellhead outlet (system output node). That will enable to determine:

• The most effective coiled tubing size to install

• Optimum setting depth of coiled tubing

• Incremental production response

Once the well is a potential candidate the relationship between flow rate and bottomhole flowing pressure are developed. The conditions that are considered are coiled tubing size, tubular weights, tubular depths, surface pressure, temperature, gas flow rate, liquid flow rate and liquid makeup. The result is a tubing performance curve. and is generated through the solution of the equation:

$$\frac{dp}{dz} = (\frac{dp}{dz})_{\text{el}} + (\frac{dp}{dz})_{\text{fr}} + (\frac{dp}{dz})_{\text{acc}} \quad \textbf{III.3}$$

Where:

$\frac{dp}{dz}$: pressure drop in coiled tubing, Pa.

$(\frac{dp}{dz})_{\text{el}}$: pressure drop due to elevation change, Pa.

$(\frac{dp}{dz})_{\text{fr}}$: pressure drop due to friction, Pa.

$(\frac{dp}{dz})_{\text{acc}}$: pressure drop due to acceleration, Pa.

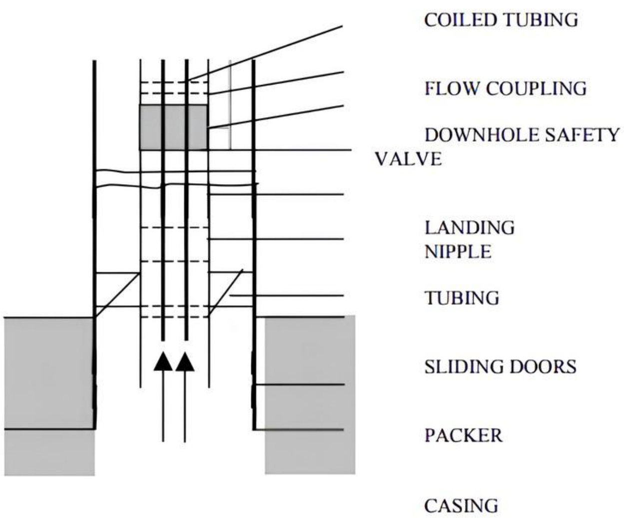

FIGURE 43: COILED TUBING AS A VELOCITY STRING.

To get a realistic tubing performance curve it is important to ensure that the input variables are as realistic as possible. The second half of the system is the reservoir. To describe the hydraulic performance of the reservoir the most common is the back pressure equation (Adams, L.S., 1993.):

$$q = C.(p_r^2 - p_{wf}^2)^n \qquad \textbf{III.4}$$

Where:

q: production rate, m3/day

p_r: average reservoir pressure, Pa

p_{wf} : well flowing pressure, Pa

C: performance coefficient from well data

n: exponent obtained from well tests.

(C) and (n) can be calculated from a log-log plot of (q) versus (pr 2 – pwf2), through a four-point back pressure test, and in equation form as:

$$\log q = \log C + n.\log.\left(p_r^2 - p_{wf}^2\right) \qquad \textbf{III.5}$$

The figure 44 illustrates the dilemma for velocity string design. Introduction of the velocity string moves the intersection with the current IPR curve to the left, i.e., the produced rate is reduced. However, when, due to depletion the IPR curve changes, the tubing IPC curve would no longer intersect, i.e., the well cannot produce, whereas with the velocity string the well still produces. The choice is between a higher production rate over a shorter period and a lower production rate over a considerably longer period (and higher ultimate recovery). This period can even be lengthened by flowing up the velocity string initially, until flow becomes unstable in this string as well and switching to flowing up the annulus between the velocity string and the original tubing in the final stages of production.

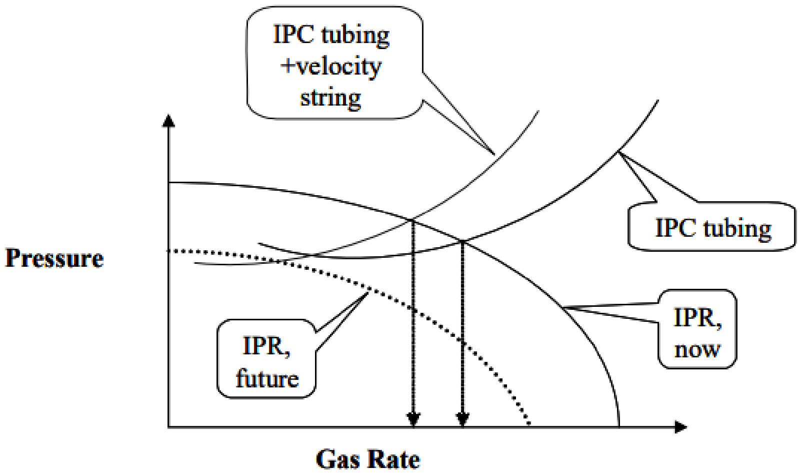

FIGURE 44: J-CURVE COMPARED WITH THE FUTURE RESERVOIR PRESSURE.

III.2.4. Options of a Velocity String:

The installation of a velocity string is a cost-effective solution to liquid loading in a gas well and may be carried out under pressure which means there is no need to kill the well. The installation process, as well as the subsequent maintenance and care, will be significantly reduced.

Moreover, the utilization of stable rates enables the prolongation of well production, surpassing the limitations of conventional tubing or casing. When creating a velocity string, it is important to take the following factors into account:

Production Life: Velocity string size should account for future reservoir pressure decline.

Flow Path: Production can occur through the string, annulus, or a combination of both.

Deployment Depth: Surface, Sub-Surface Safety Valve (SSSV) landing nipple, or below the SSSV.

Corrosion Resistance: Chrome material can be used for wells with CO2 or H2S to mitigate corrosion.

The length of the velocity string: normally the velocity string is placed near the perforation area. If it is placed too close to the perforation, problems with corrosion can appear to the string and if it is placed too high in the well, insufficient gas flow velocities can occur.

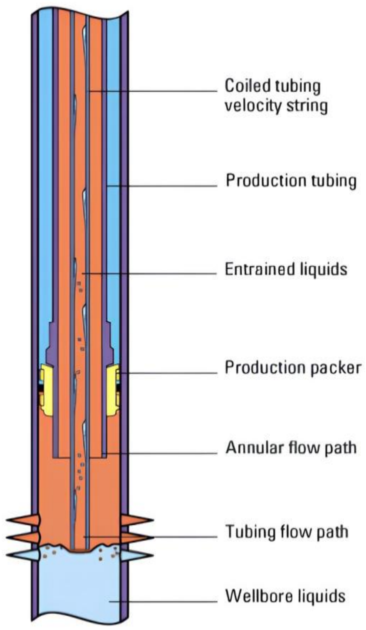

FIGURE 45: SCHEMATIC OF A VELOCITY STRING

Figure 45 sketches a velocity string which clearly shows the casing, the production tubing, the production-packer and the area of the perforation. The entrained liquids are depositing on the wall of the velocity string but in the end they are captured by the passing gas and carried to the surface.

III.2.5 Coiled tubing velocity string:

Coiled tubing hang-offs are commonly used to extend the life of gas wells. However, not all wells react the same way to the same hang-off installation. Coiled tubing can be easily run and hung-off into existing completions, bypassing mechanical restrictions, and eliminating the need for a packer for sealing off. The coiled tubing unit is self-contained and can snub against well pressure, eliminating the need for a work-over rig. After installation, a work-over can be performed. The flow out of the well can be selected, with flow up the coiled tubing being combined with or substituted with flow up the coiled tubing/production tubing annulus. Dual completions can be achieved with a tubing and packer configuration for flow up the tubing/casing annulus separately from the coiled tubing or coiled tubing/production tubing annulus.

III.2.5.1. Coiled Tubing Velocity String completion designs:

Coiled Tubing Velocity String Hanging at the Spool:

Before rigging a coiled tubing unit to a well, well production equipment should be prepared. The pump-off plug (aluminum) is crucial for the hang-off, preventing gas from entering the well. This allows for easy cutting without special safety valves. Depending on reservoir pressure, a single or dual pump-off plug can be used. A pressure differential with nitrogen is applied to shear off the plug. A pump-off nozzle can be used instead of the plug, allowing for easy pumping through bridges or stoppages. The tail end of the CT velocity string has a conical shape to avoid rising on existing profiles.

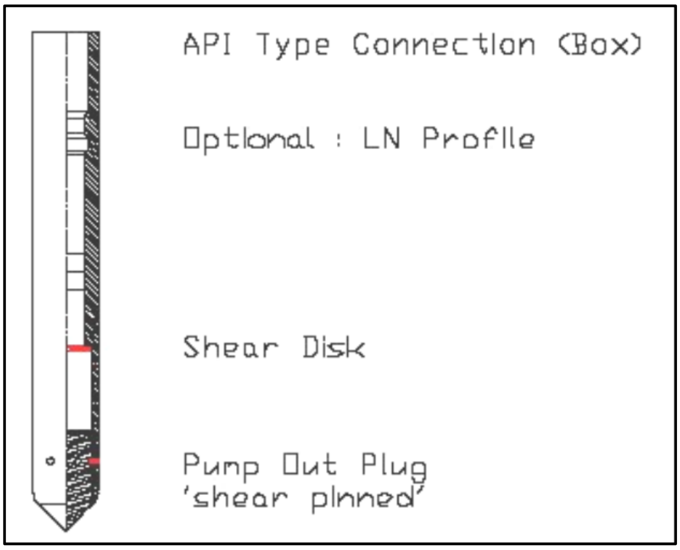

FIGURE 46: BOTTOM ELEMENTS OF A VELOCITY STRING.

Coiled Tubing Hanging Below the SCSSV:

A packer hanger is a widely used method for installing a velocity string in coiled tubing below the SCSSV. This method allows the string to be hanged off the tubing, ensuring it remains functional even below the SSSV. The packer is used to carry the entire weight of the string and itself on the production tubing wall, ensuring the string's functionality.[6]

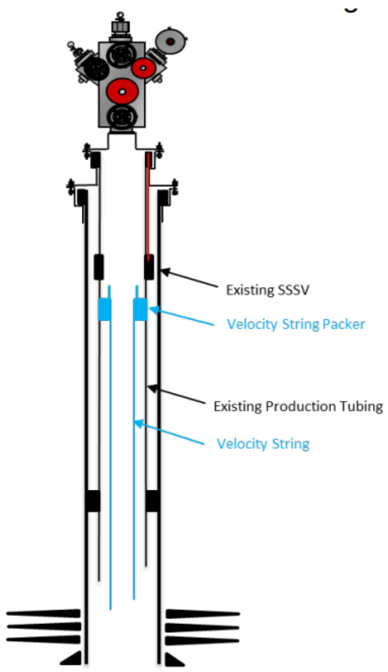

FIGURE 47: COILED TUBING VELOCITY STRING HANGING BELOW THE SCSSV

Combination of CT and SCSSV:

The American Petroleum Institute (API) proposes a surface controlled subsurface safety valve (SCSSSV) called concentric safety valve (CSV) which is inserted into the velocity string. The CSV can be operated and controlled by the existing hydraulic control line from the surface and can simultaneously shut annular and concentric flow paths. The CSV is typically opened when hydraulic pressure is applied on the surface, but when hydraulic pressure is decreased, it can be closed. The CSV is installed with the CT into the production tubing, delivering pressure to the anti-preset mechanism screws. This method provides both production and injection through the CT and annulus. However, the installation is expensive and technically risky, making it a rare use.

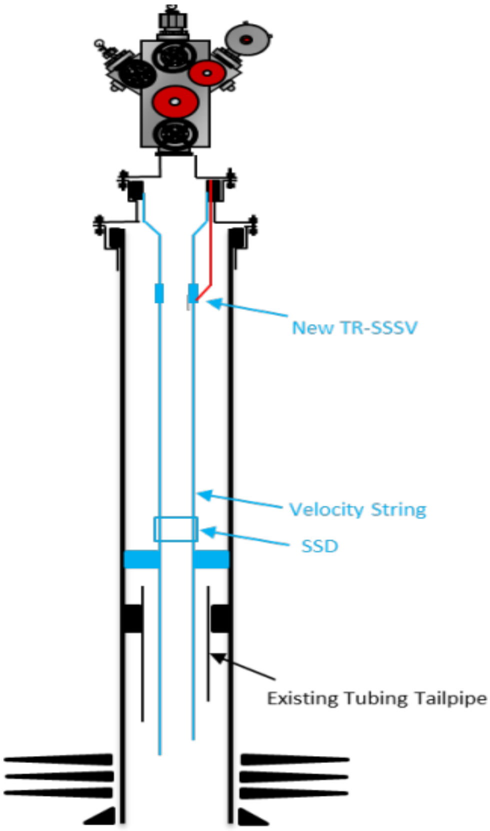

FIGURE 48: INSERT SAFETY VALVE

The advantages and disadvantages of the above-described methods are summarized and Shown in the Table .

TABLE 7: ADVANTAGES & DISADVANTAGES OF THE DIFFERENT HANG-OFF SYSTEMS .

Hang-off Systems	Avantages	Disadvantages
CT velocity string hanging at the Spool	• Simple installation and operation • Good water discharge due to the constant cross section up to the surface • Allows later well treatments. • Production through only the velocity string or through the annulus or a combination of both is possible	• In case of emergency no possibility to shut-in the well (no SSSV)
CT hanging below the SSSV	• Usage of the existing SSSV • Low cost of maintenance	• The section above the velocity string has a higher cross section • The production tubing carries the whole • weight of the velocity string • Bad accessibility of the hanger • Continuous well treatments are not possible
Combination of CT and SSSV	• CT can be hung-off at the wellhead • Production through only the velocity string or through the annulus or a combination of both is possible • In case of emergency the well can be shut-in	• Seldom realized until now • High costs for the CSV • Long delivery periods

III.3. Coiled tubing selection:

The size and length of coiled tubing may be dictated by previous pipe installation. Optimal can be externally tapered coiled tubing because of flexibility for optimizing flow. The following design parameters of coiled tubing string should be reviewed:

• Minimum and maximum tensile load, burst and collapse pressure allowed.

• Desired over pull above string weight of each segment before yield load is obtained.

• Based on wellbore trajectory sinusoidal or helical buckling, pickup, and slack-off loading evaluation.

• Metallurgy that can ensure suitable material for desired time exposure in the well's downhole environment.

A procedure of typical coiled tubing velocity string hang off implements:

• Removal of paraffin or other obstruction if needed

• The way of liquid removal

• Christmas Tree preparation: closing of lower master valve, bleeding of pressure above lower master valve, removing Christmas tree above lower master valve

• Installation of coiled tubing hanger, installation of packoff assembly in hanger and locking

• Riging up the coiled tubing unit, installation of window and blowout preventers

• Installing pump out plug in coiled tubing, opening master valve and running in hole to desired depth

• Landing coiled tubing, installing slips and packoff, cutting tubing in window; re-cutting after rigging down coiled tubing unit

• Installation of Christmas tree on coiled tubing hanger, pumping out plug to enable production [2]

Conclusion:

The methodology of coiled tubing design and installation demonstrates that it plays a pivotal role in enhancing the efficiency of production and the safety of gas well.

Chapter 04

Case Study

Introduction:

In order to improve the well's capacity to unload liquids (such as water and condensate), the velocity sting reduces the cross-sectional flow area up the wellbore, keeps liquids from building up in the wellbore and near-wellbore reservoir, and eventually raises the average gas rate and recovery from the well.

The pilot project to install this kind of equipment in well at In Amanas includes the installation of a velocity string in Tg-352. If velocity strings are installed and operated successfully, more wells at Amanas may be able to use them, reducing the chance that wells will fail too soon from liquid loading.

IV.1. Well History:

Tg-352 is a vertical well completed in 2010 in the southern area. The well was completed with a 7" cemented liner and equipped with a 7" production tubing with permanent downhole gauge. This well history plot presents production data gathered . The data will be used to assess the well's performance over this timeframe and identify potential indicators of liquid loading issues. We'll analyse various parameters like wellhead pressure, downhole pressure, choke position, flow rates (gas, water, oil), and temperatures (flowing and choke) to diagnose any signs of liquid accumulation hindering gas production.

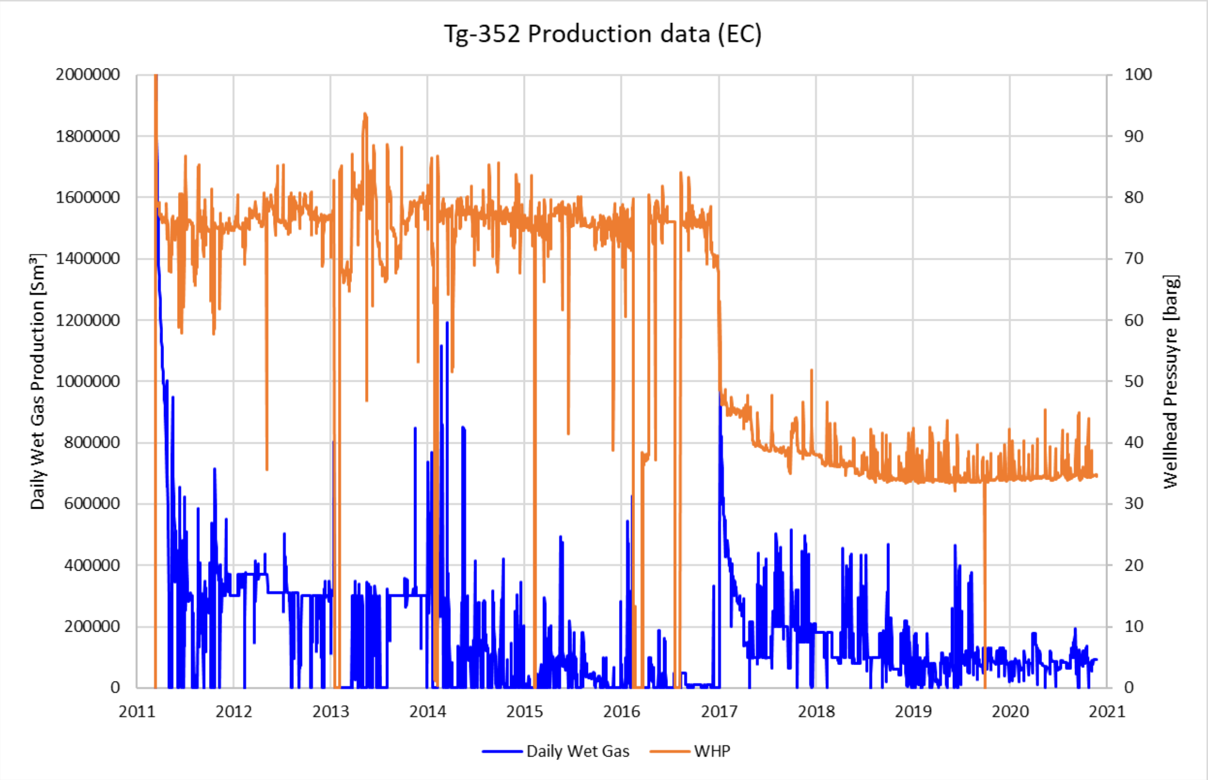

FIGURE 49: TG-352 PRODUCTION HISTORY

After the drilling phase was completed, the well was put into production in 2011. Initially, the well produced at a high rate due to the strong reservoir energy. However, over time, reservoir pressure declined, and liquid loading issues emerged, leading to a decrease in production until 2018. During this period, the well was treated using the cycling operation, which is a common method for well unloading. The coiled tubing velocity string method was employed for this purpose.

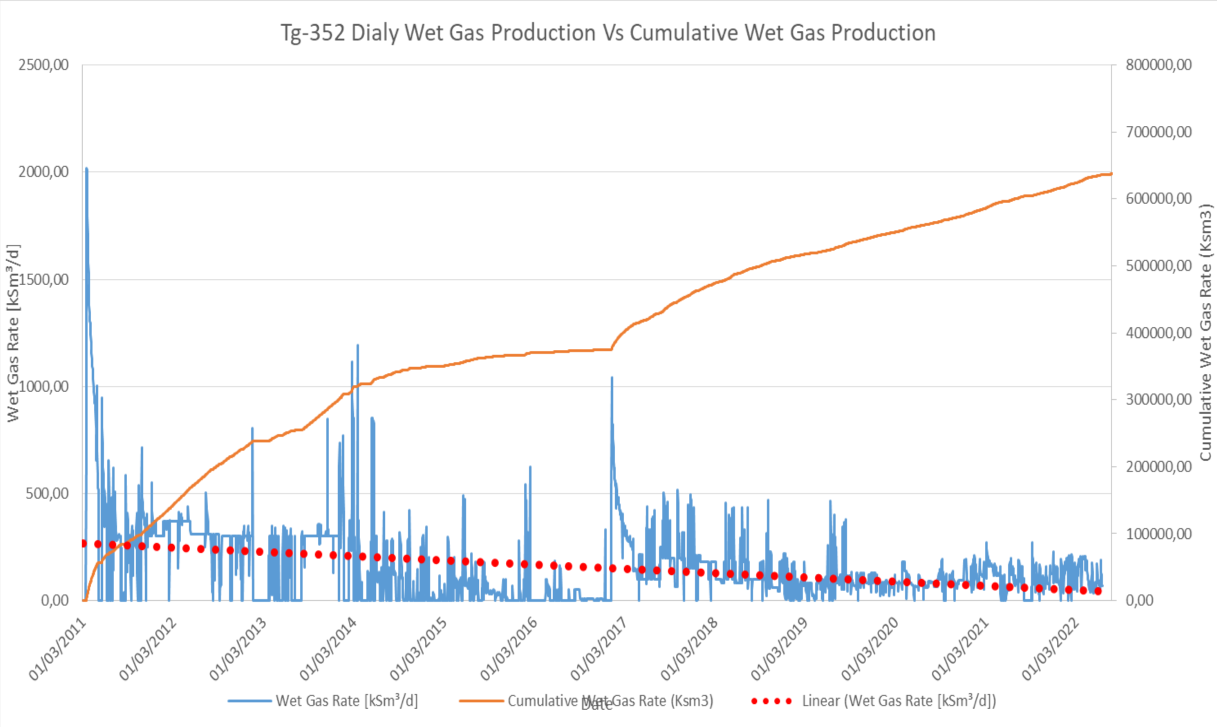

FIGURE 50:TG-352 WET GAS PRODUCTION VS CUMULATIVE WET GAS PRODUCTION .

IV.2. Well data:

Vertical, hydr, fractured, 7 tubing.

Production with current compleyion (7 tbg).

Temperature data indication no-flow since March 2020.

Has been operated by cycling.

Average June daily wet gas allocate rate 84KSm3/d.

Liquid loading occurring since March 2017.

Will not flow at reduced wellhead pressure WHP25bar

TABLE 8: TG-352 WELL INFORMATION

Generic Info	
Well Name	TG-352
Operating Environment	Land, Rigless, Dessert
Field Name	Tigentourine
Well Type (Gas / Oil / Condensate)	Gas Producer
Current well fluid	Gas
Dog Leg Severity	0
Well History Available? (Y/N)	Y
Last Drift	SLK drift need to be performed prior operation with 5.5'' drift to TD & 6.025'' to SSV No-Go profile
Completion Info	
Well Deviation Type	Vertical
Max Deviation / DLS	0
RKB – TH	7.65m
Total Depth (MD)	**2282m**
True Vertical Depth (TVD)	2282m
Casing (OD, Grade, #, MD)	**9-5/8" 26 lb/ft, L80, 2092 m**
Top of Liner	**1987 m**
Liner (OD, Grade, #, MD)	**7" 29 lb/ft, L80 from 1987 to 2282m**
Production Tubing (OD, Grade, #, MD)	**7" 26lb/ft, L80- 13 Cr 1989m**
Min. ID restriction	**5.983"'' TRSSV @ 72.5m** **5.875'' RPT Nipple @ 1936m** **5.75'' RPT Nipple @ 1974m**
Wellhead connection	7-1/16
WH pressure rating	5k psi
Fish in well (Y/N)	N
Reservoir Info	
Reservoir Pressure	661.5 psi
Perforation interval	2135-2146m 2236-2248m
BH Flowing pressure	435 psi
Formation fluid gradient	0.1
SIWHP	558.6psi (CAT1)
Reservoir Temperature	116 degC
H2S Content	5ppm
CO2 content	5%
Frac Pressure	Unknown
Production Info	
Gas Rate	205 ksm3/day
Water cut	46%
GOR	17459

IV.3. Composition of the flui (PVT data):

TABLE 9: TG-352 PVT DATA

Name	Mole Percent	Critical Temp.	Critical Pressure	Critical Volume	Molecular Weight	Volume Shift
N2	0.44209	-147.28	33.9237	0.0898	28.01	-0.19266
CO2	4.30553	30.94	73.9776	0.0939	44.01	-0.08177
C1	81.1265	-82.51	46.407	0.0992	16.04	-0.12108
C2	7.09247	32.11	48.8388	0.1483	30.1	-0.11335
C3	3.02428	30.94	73.9776	0.0939	44.1	0
NC4	1.44687	151.83	37.9666	0.255	58.1	-0.073096
C5-6	1.10481	196.44	33.7515	0.304	77.4	0
C7-9	0.93088	266.83	27.368	0.432	105.6	0
C10-14	0.42578	366.67	19.4443	0.66	152.2	0.034271
C15+	0.10082	461.67	13.1014	1	241.61	0.057149

IV.4. Liquide unloading:

The well experienced a significant decline in productivity until 2018. This decline is attributed to reservoir pressure depletion and the large tubing diameter, which promotes fluid accumulation at the wellbore. This accumulation creates backpressure, hindering fluid flow and further reducing production. As a permanent solution, engineers implemented the cycling.

That involve periodically opening and closing the well to induce pressure fluctuations, which can help dislodge accumulated fluids and improve production method from 2018 to 2020. Since this method proved ineffective, a velocity string was installed in 2022. This string incorporates smaller diameter tubing to increase production column pressure. To determine the optimal and the required coiled tubing diameter, sensitivity tests that evaluate the impact of varying parameters, such as reservoir pressure and tubing diameter, on well performance. And simulations using Prosper software will be conducted.

IV.4.1. Liquide loading symptoms:

The most effective method used to detect liquid loading in the well was the static pressure gradient survey.

IV.4.1.1 Static gradient servery SGS:

Gradient surveys have been performed at various occasions at shut-in conditions. The two latest gradient surveys, performed in September and October 2020, are shown in plots attached. These show water column up into the lower perforation interval and a mixed phase (gas/condensate) up into the top perforation interval. The gradient surveys do not confirm liquid loading at dynamic conditions since there are no liquids detected above top perforation interval (liquids have already segregated into formation at time of survey).

Liquid loading is indicated, however, from the pressure difference between the downhole gauge and wellhead (see plots attached), combined with temperature data.

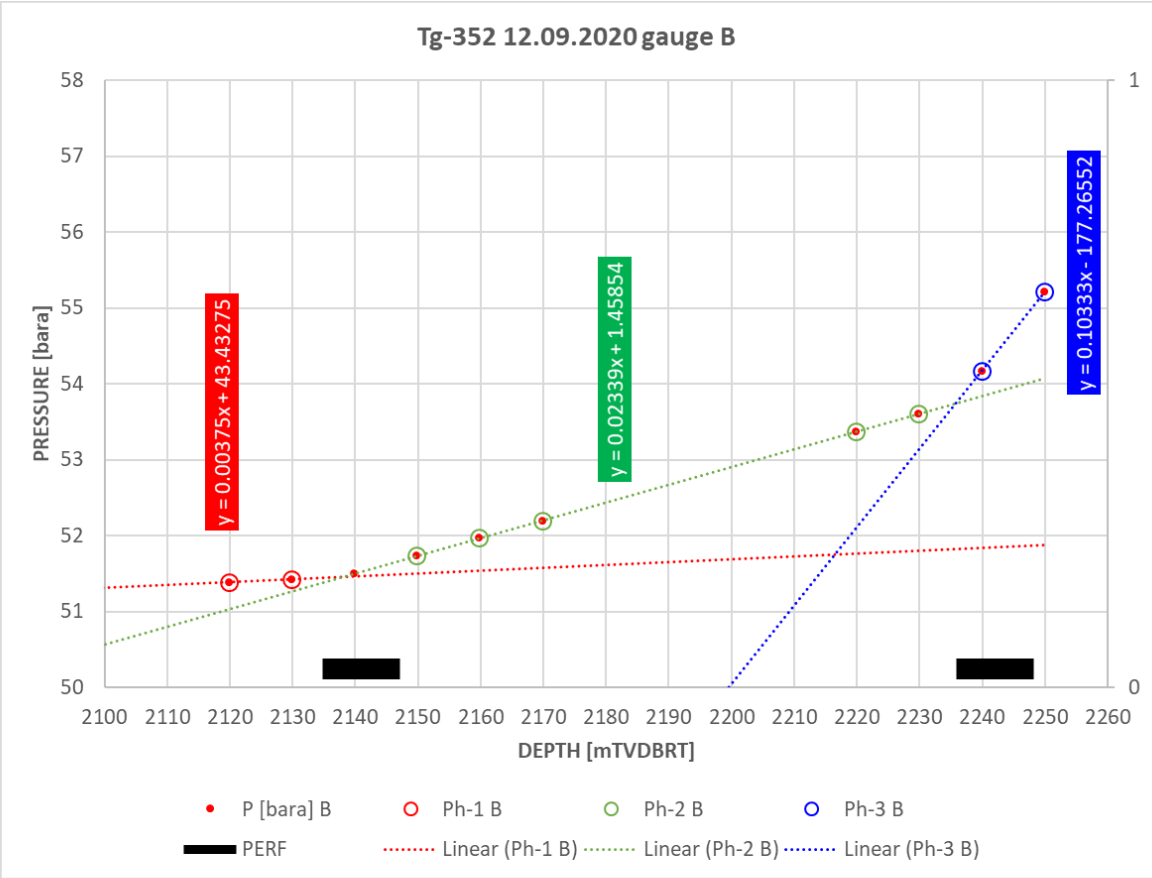

FIGURE 51: GAUGE B SGS TG- 352 12.09.2020

This figure represents Downhole gauge Pressure graph data 12.09.2020 of TG -352

Ph-1 B: A very low gradient suggests minimal liquid presence and hight presence of gas phase indicating minimal change in pressure with depth.

Ph-2 B: A moderate gradient indicating a more noticeable change in pressure with depth.

Ph-3 B: A steep gradient indicating a significant change in pressure with depth.

The significant increase in the pressure gradient from Ph-1 B to Ph-3 B suggests an increasing presence of liquid. A steeper gradient typically indicates higher fluid density, likely due to liquid loading.

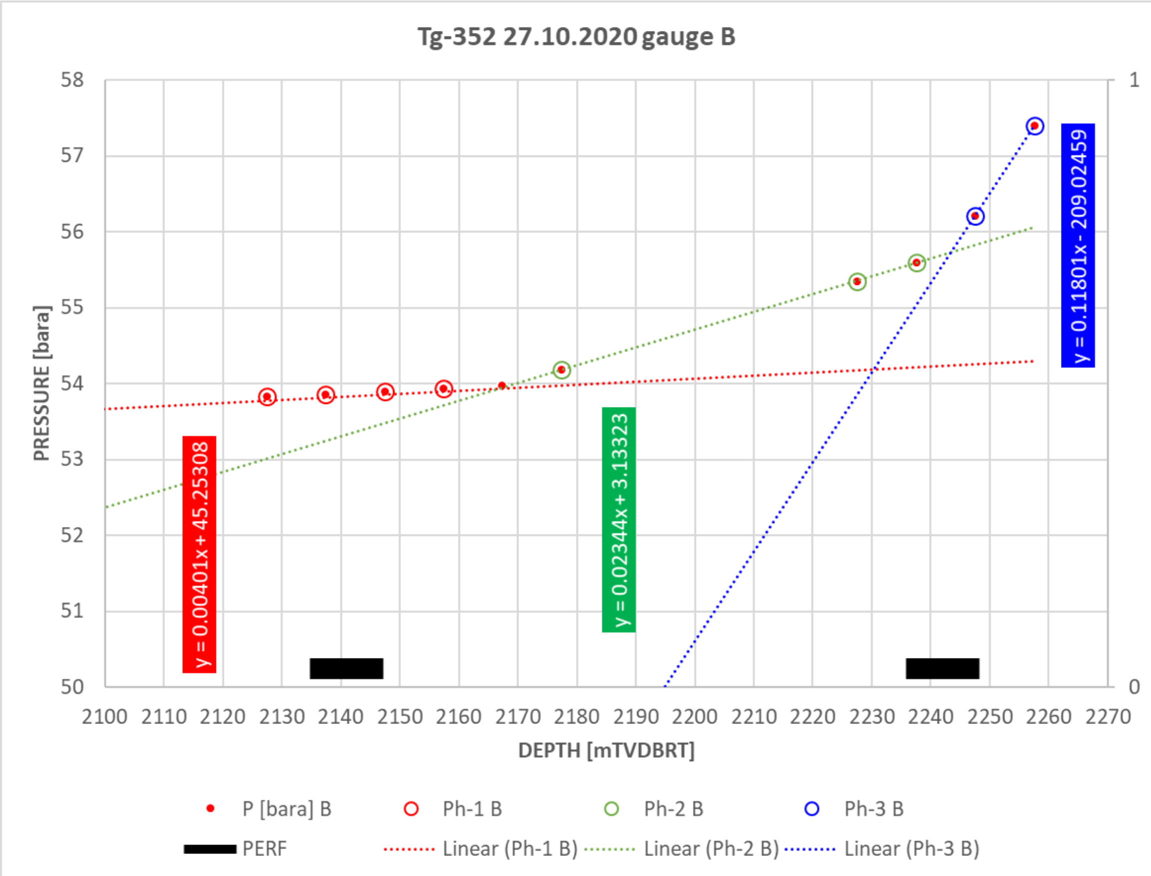

FIGURE 52:GAUGE B SGS TG- 352 27.10.2020

Tg-352 27.10.2020 gauge pressure survey shows that the gauge pressure increases in each gauge phase comparted with the last month that's indicates that the liquid loading level has risen even higher in TG- 352 well.

- The Static liquid level consarned was at depth of **1811 m MD**

IV.5 PROSPER simulation:

Definition: Prosper is an industry-standard software program used for production and well performance analysis. Developed by Petroleum Experts (PE Ltd), it allows engineers to:

Model and simulate different scenarios related to oil and gas well production.

Optimize well performance by identifying and addressing factors that limit production, such as frictional pressure losses.

Perform nodal analysis to assess the flow of fluids throughout the wellbore.

Design and optimize artificial lift systems such as gas lift, which are used to bring oil and gas to the surface when natural pressure is insufficient.

Prosper is known for its:

Powerful modelling capabilities.

Sensitivity analysis.

Wide range of inflow performance relationship (IPR) models.

IV.5.1. Scenario for Prosper Wellbore Simulation and Modelling:

In our case there are two scenarios to determinate the diameter of the coiled tubing velocity string required with the exact reservoir pressure to improve the predictive of the well the scenarios are :

Scenario 1: Varying Reservoir Pressure

Objective: Investigate the impact of different reservoir pressures on well production and how it affects predictability.

Modelling: Simulate wellbore flow with various reservoir pressures in Prosper.

Analysis: Observe how changes in reservoir pressure affect the influx of oil and gas into the wellbore. Ideally, choose a reservoir pressure that allows for optimal well production while remaining within safe operating limits.

Scenario2: Varying Coiled Tubing Velocity String Diameter

Objective: Analyse how different coiled tubing diameters impact wellbore friction and overall production efficiency.

Modelling: Simulate wellbore flow with different tubing diameters in Prosper.

Analysis: Compare the pressure drop across the tubing for each diameter. Identify the diameter that minimizes friction and allows for the highest possible flow rate from the reservoir.

IV.5.2. PROSPER SUMILATION STEPS:

Step 01: options summary

1-define the fluid description that continue the nature of the fluid in the reservoir and the calculation method

2 define the well information such as the flow type and the well type

3- Define calculation type

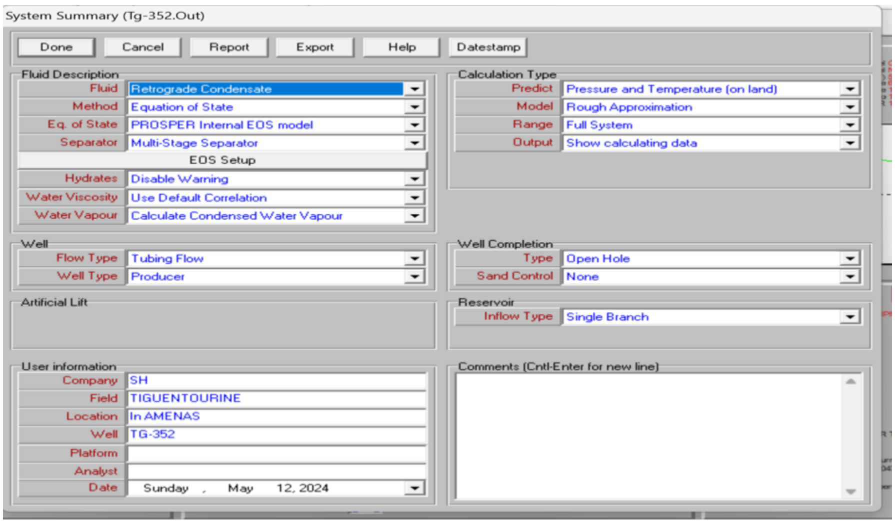

FIGURE 53: PROSPER SOFTWARE WELL INFORMATION INPUT

Step 02: PVT data

1. Define the PVT data of the fluid
2. calculate the critical point of the composition.

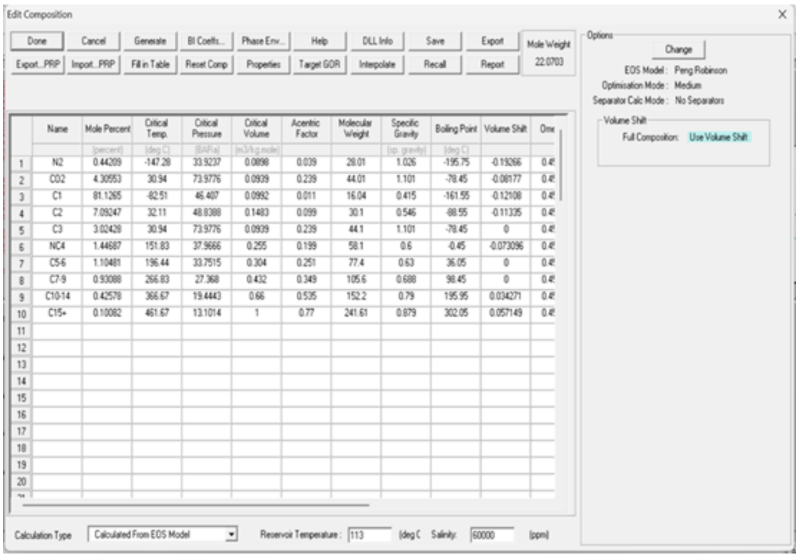

FIGURE 54: PVT INPUT

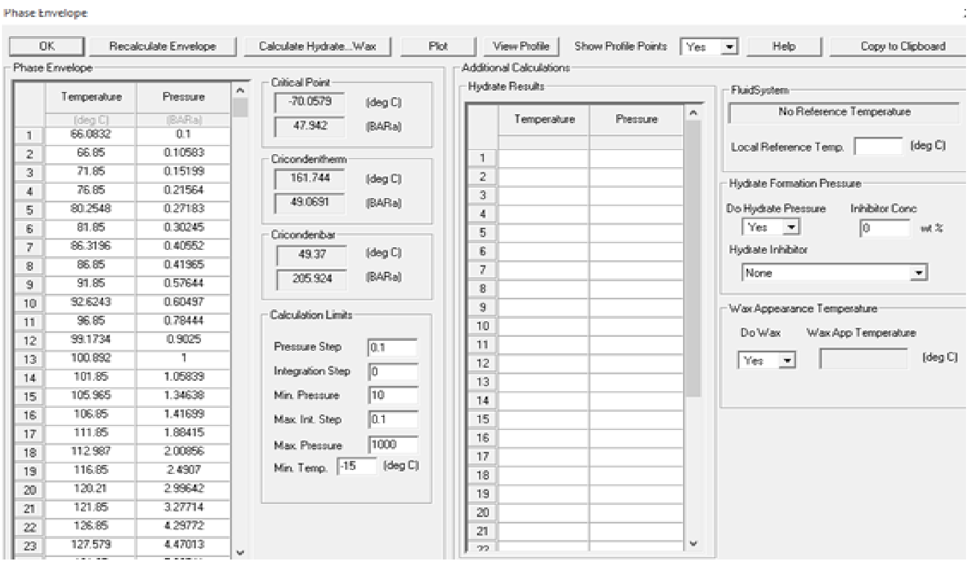

FIGURE 55: THE CALCULATION OF THE PHASE ENVELOPE

3. Plot the phase envelope curve:

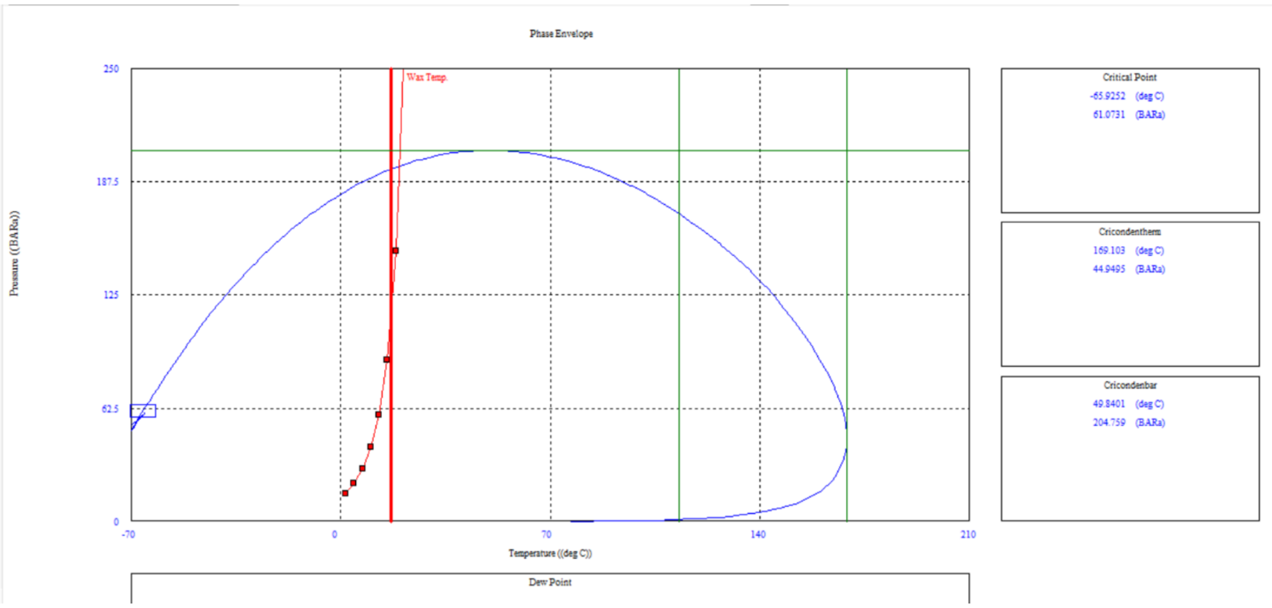

FIGURE 56:THE PHASE ENVELOPE CURVE .

For the retrograde fluid in this case the critical point is:

Critical pressure: 61.0731 BARa.

Critical temperature: -65.9252 deg c°.

Step03: Inflow Performance Relationship (IPR) Curve

1- Define Reservoir Conditions:

Enter the reservoir pressure, temperature, and permeability.

Choose an appropriate Inflow Performance Relationship (IPR) model and provide the required parameters.

The used equation : Backpressure C & n

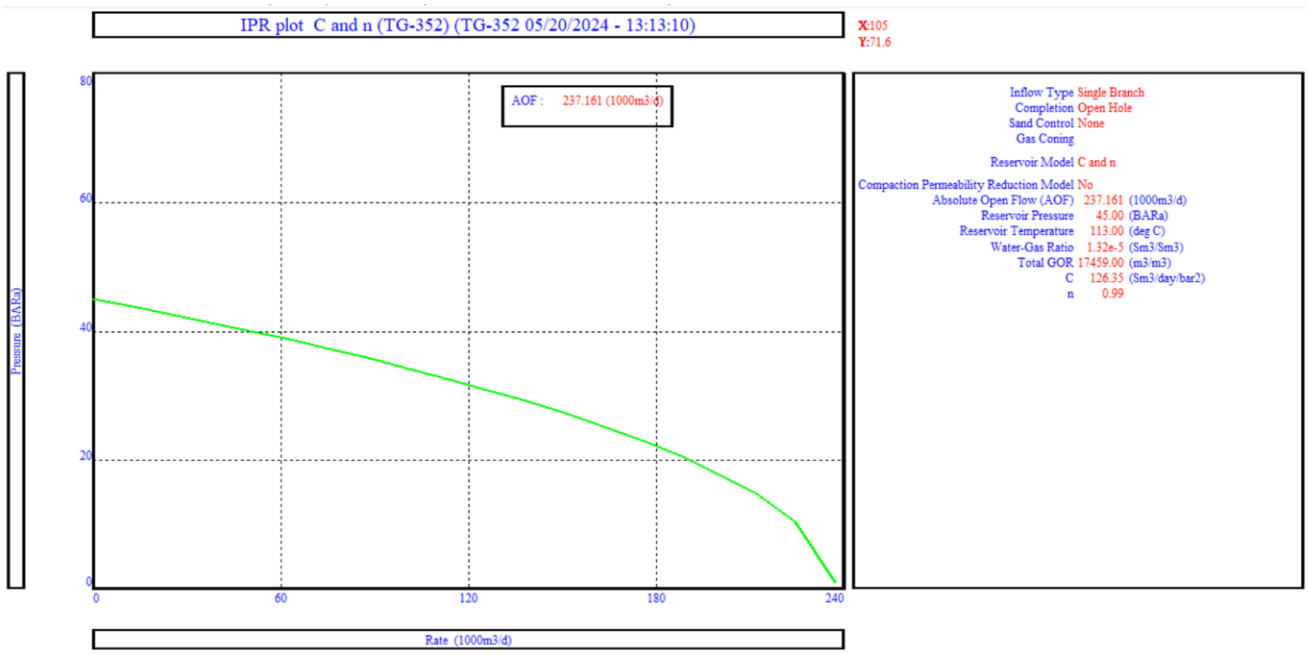

FIGURE 57: IPR CURVE TG-352

The IPR curve shows how much pressure drop (inflow) is needed across the reservoir to achieve a specific flow rate of gas entering the wellbore. This pressure drop is ultimately driven by the pressure of the gas within the reservoir itself pressure here is 45 bar .

Step 04: Well Outflow Performance Relationship (VLP) curve.

1-Define Wellbore & Reservoir Properties:

Wellbore: Enter wellbore geometry details like casing sizes, tubing size, and depth references for each section.

Fluids: Define fluid properties like oil API gravity, gas-oil ratio (GOR), water cut, and viscosity for each fluid phase.

Reservoir: Specify reservoir pressure, temperature.

2-VLP Correlations Setup:

This step involves defining the pressure drop correlations used by Prosper to calculate pressure losses within the wellbore. Prosper offers various built-in correlations or allows user-defined options.

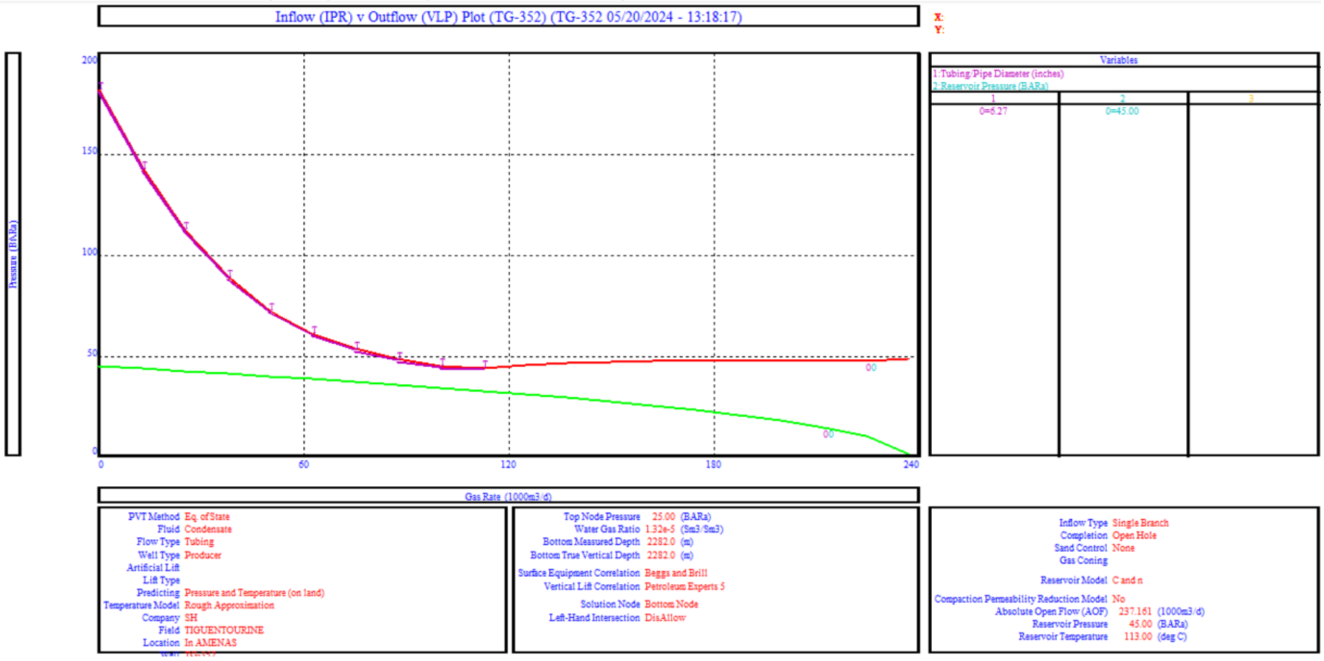

FIGURE 58: INFLOW (IPR) VS OUTFLOW (VLP) PLOT

- In this case the plot indicates that the well not flowing at this reservoir pressure 45 bara with current completion, there is no operating point between IPR & VLP
- The Gas velocity it's below the critical velocity

Sensitivities test:

Scenario 01: Varying Reservoir Pressure

This scenario explores how changes in reservoir pressure impact a well's production. Here's a breakdown of the steps involved in analysing this scenario:

Define Baseline Conditions:

Use the existing pressure vs. inflow graph IPR .

Identify the key parameters on the graph, such as reservoir pressure, wellhead pressure, and flow rate.

2. Modify Reservoir Pressure:

adjust the reservoir pressure value to represent a higher or lower pressure compared to the baseline.

3. Generate New IPR Curves:

Since reservoir pressure directly affects the inflow performance of the well, recalculate the IPR curve for each new reservoir pressure scenario.

The IPR curve will show how the flow rate of fluids entering the wellbore changes with varying reservoir pressure.

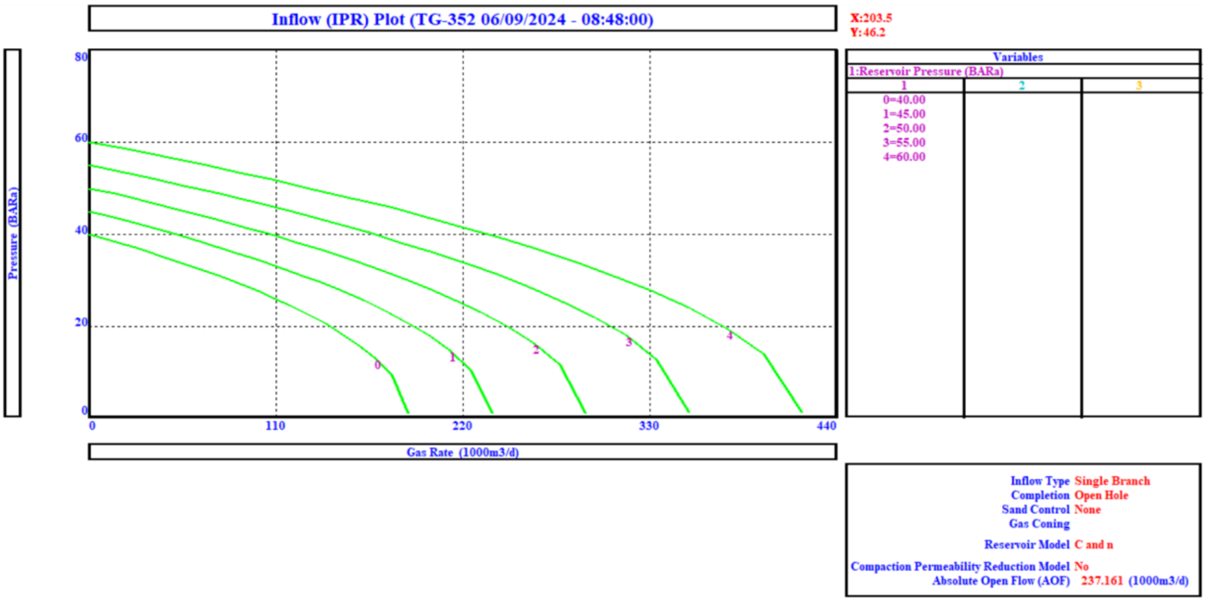

FIGURE 59: SENSITIVITY OF TG-352 INFLOW PERFORMANCE (IPR) TO RESERVOIR PRESSURE CHANGES.

Scenario 02: Varying Coiled Tubing Velocity String Diameter:

We do the same scenario in the Varying Reservoir Pressure but we determined step to complete the stimulation of the Varying Coiled Tubing Velocity String Diameter scenario:

1. Define Baseline Conditions

2. Modify CT VS inner diameters

3. Recalculate VLP Curves sensitivities :

Since coiled tubing VS diameter affects the flow path and pressure losses within the wellbore, recalculate the VLP curve for each new CT VS diameter scenario.

4. Maintain IPR Curves:

The Inflow Performance Relationship (IPR) curve typically represents the reservoir's inflow behaviour and remains relatively constant unless the reservoir properties themselves change.

5. Analyse Intersection Points

Plot the original IPR curve on the same graph with the new VLP curves for different CT diameters.

The intersection points between the IPR curve and each VLP curve represents the operating point of the well for that specific CT VS diameter. This point indicates the flow rate and wellhead pressure the well will achieve under those conditions.

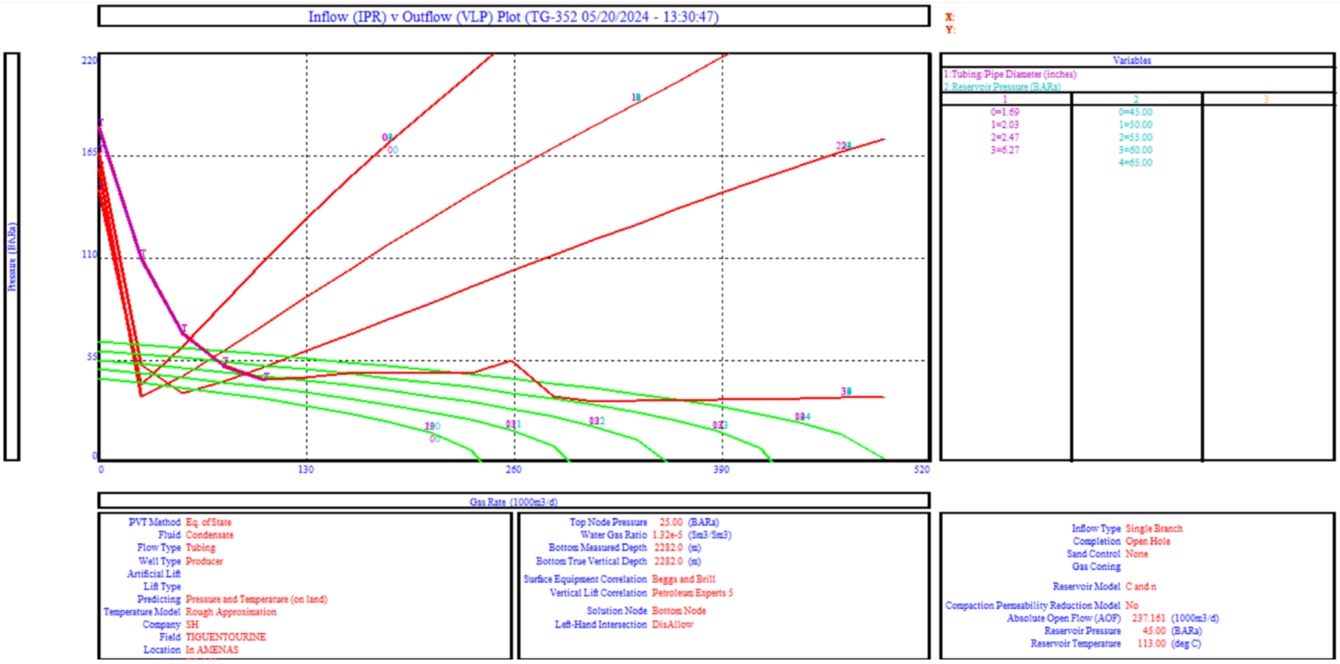

FIGURE 60: SENSITIVITIES OF IPR VS VLP

Solution details:

TABLE 10: THE SOLUTION DETAILS

Well Tg-352	**Prod.tbg / velocity str.ID (in)**			
WHP= 25 BARS , Pressure : 45 Bara	6.27	2.469	2.025	1.688
Solution rate (sm3/D)	-	60135	40872	27467
Critical rate (tumer C=3.5)(sm3/d)	190000	30000	20000	12500
IPR ref.C,N equation	C=126.35sm3/D/bar2		N=0.99	

<u>Interpretation:</u>

The plot shows multiple IPR and VLP curves for different tubing diameters and reservoir pressures. The tubing diameters are represented by different labels

CT velocity string diameters:

0=1.69 inches,

1=2.03 inches

2=2.47

Current Tubing completion:

3=6.27 inches

For each diameter, we note the gas rate (horizontal axis) at the intersection points.

Higher gas rates indicate better performance in mitigating liquid loading.

For pressure of reservoir equal to 45 Bara in our case 2”7/8 OD 2.47 ID diameter of velocity string shows the highest gas rate at the intersection, indicating it can handle the highest inflow rate and is most effective in mitigating liquid loading.

The results of the sensitivity analysis and the selection of a 2 7/8-inch coiled tubing (CT) velocity string with a reservoir pressure of 45 bars demonstrate a well-informed decision. This configuration effectively steers clear of the critical flow rate, a crucial factor in wellbore performance.

IV.6. Discussion and results:

Results:

- The well is flowing continuously following after the installations of V.S.
- Allocated production data filtered based on flowline temperature indicates the following results:

TABLE 11:POST V.S. INSTALLATION PRODUCTION EVALUATED FROM 2 & 6 WEEKS AFTER PRODUCTION RE-START ONWARD

Well	Pre V.S inst. 2 - month average daily gas prod. (Sm3/d)	Post V.S inst. 2 - month average daily gas prod. (Sm3/d)	Post V.S inst. 6 - month average daily gas prod. (Sm3/d)
Tg-352	30,259	62,023	45,474

IV.6.1.The impact of Velocity String Installation on Well TG-352 Production Stability :

Tg-352 was operated by active cycling due to liquid loading during production prior installation of VS ,Velocity string was installed July 2022 and the well restarted

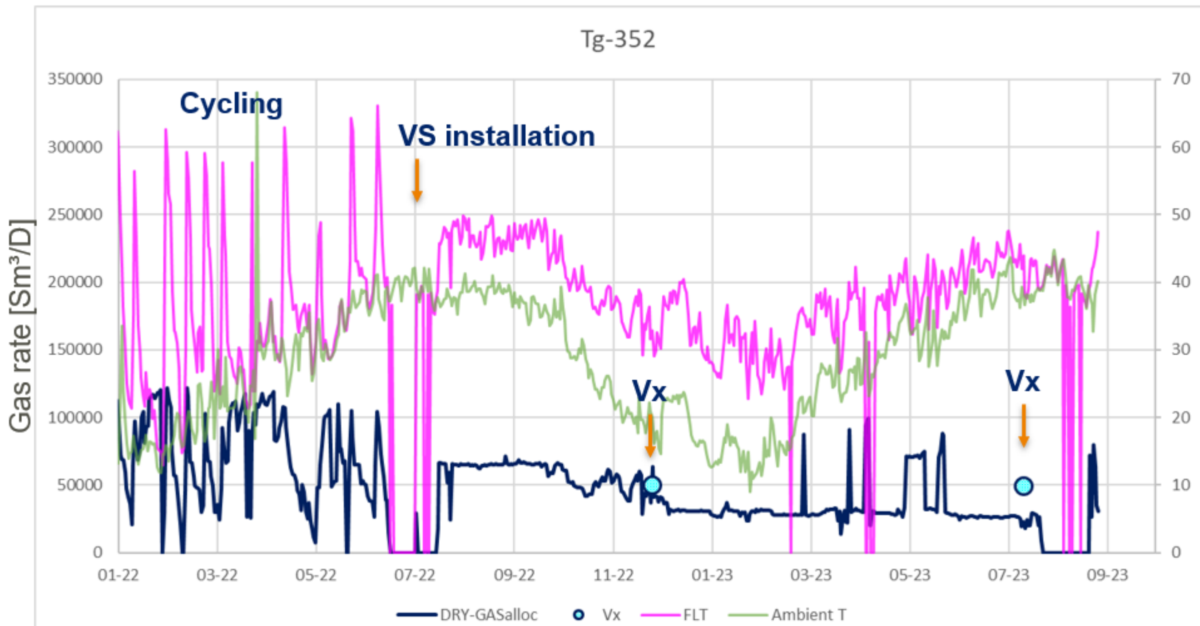

FIGURE 61: PRODUCTION BY CYCLING & AFTER VS INSTALLATION TG352

FIGURE 62: PRODUCTION OF TG-362 BEFORE AND AFTER VC INSTALLATION

The installation of the velocity string (VS) in well TG-352 at the In Amenas – Tiguentourine field significantly improved production stability. Prior to the installation (January 2022 – June 2022), the well exhibited considerable fluctuations in both allocated gas volume and wet gas rate, indicative of liquid loading and associated operational challenges (Figure 74). The average gas production was inconsistent, reflecting the difficulties in maintaining steady flow rates.

Post-installation (June 2022 – September 2022), the production rates stabilized within the range of 0.1 – 0.12 MMSm³/d. This stabilization suggests that the VS effectively mitigated liquid loading, thereby enhancing gas flow continuity. Additionally, the consistent flow line pressures and average tubing head pressures post-installation underscore the VS's role in maintaining favorable downhole conditions for stable production.

VX data mesure :

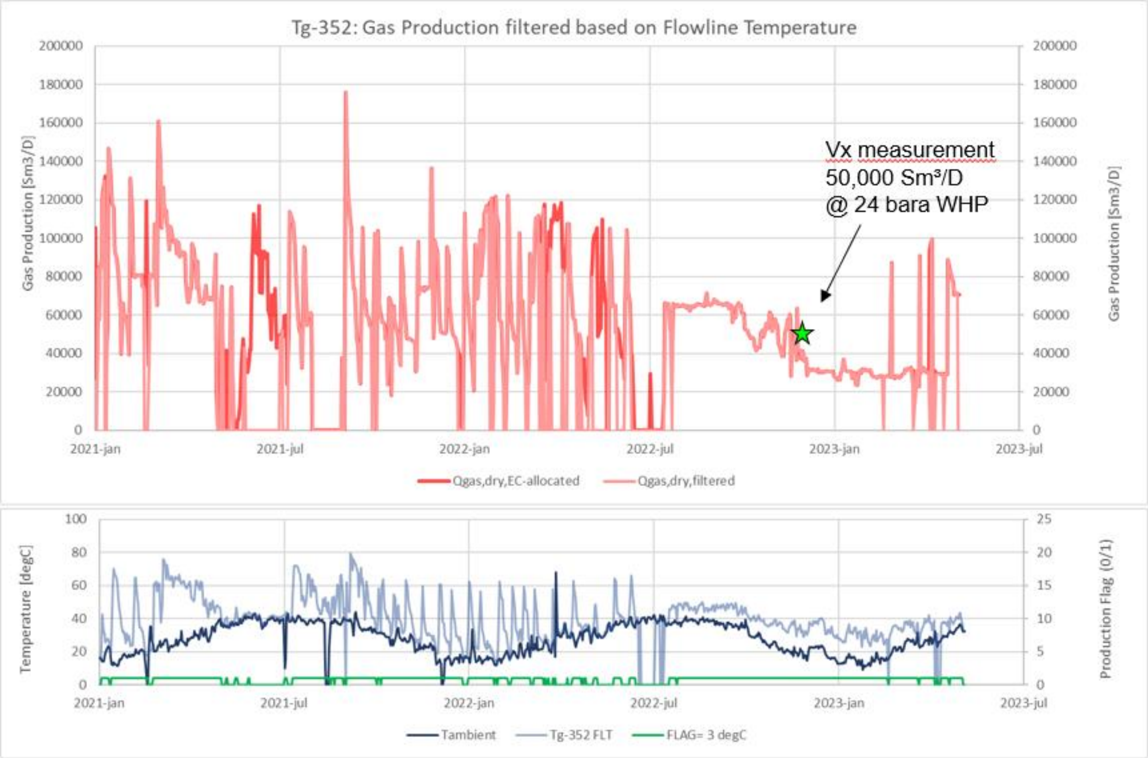

FIGURE 63: VX MESURMENT

Since the Vcone rate meters are unreliable, Vx testing was performed in Nov-2022 and in Jul-2023 to assist rate assessments, indicating flowrate approx 50,000 Sm³/D at both occasions The well has flowed continuously since installation of VS

Recent halt in flow was related to changing pressure conditions during a IGC-15 maintenance

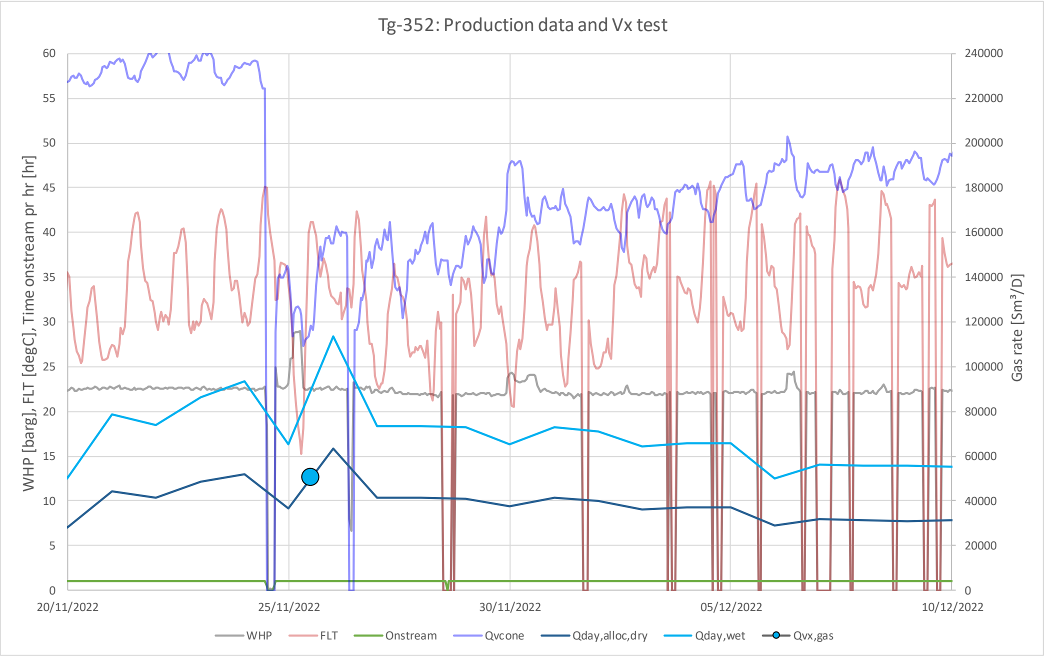

FIGURE 64: VX MEASUREMENT DATA TG-352

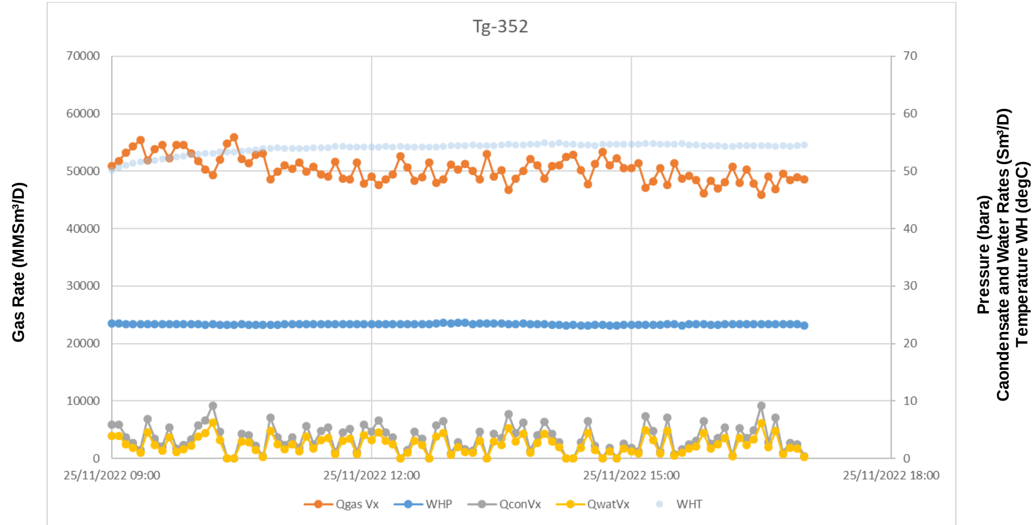

FIGURE 65: VX AND PRODUCTION DATA TG-352 DECEMBRE 2023

IV.6.2. Design evaluation:

The 2”7/8 velocity string shows enhancement in TG 352 production rate

With 7” tubing : no production

With 2”7/8 tubing : producing

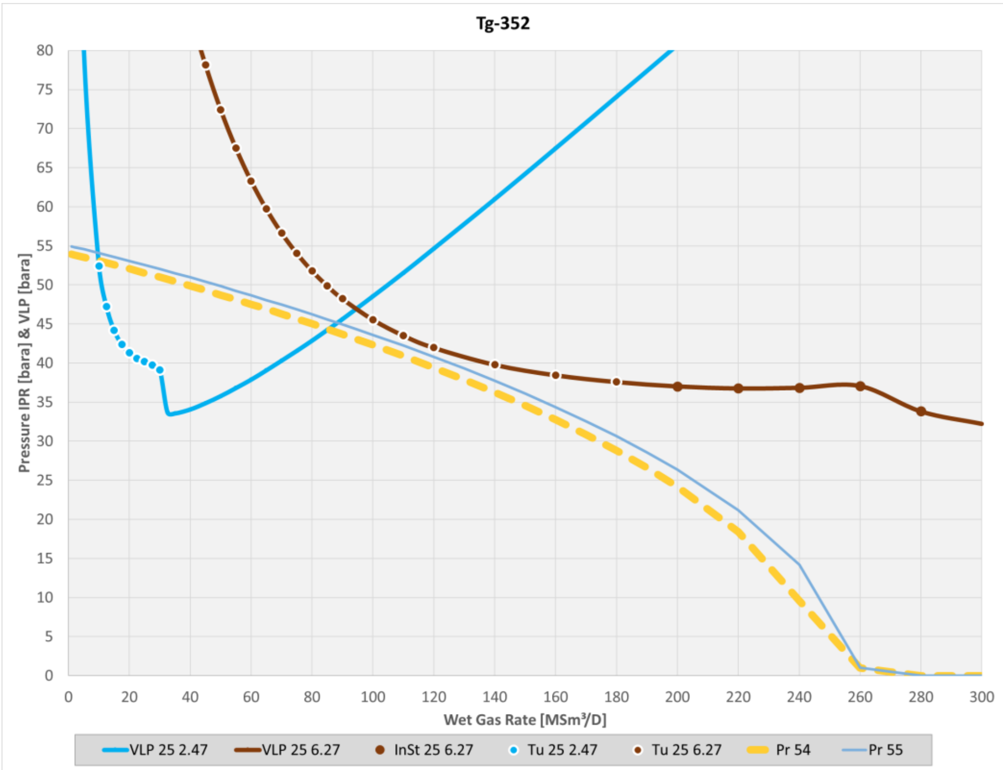

FIGURE 66: IPR WITH 7” TUBING AND WITH 2”7/8 FOR TG-352

IV.6.3. TG-352 Velocity strings Economic Evaluation Summary:

The economic analysis of the velocity string installation in well TG-352 over a three-year period (2022-2025) demonstrates significant financial and operational benefits. The data reveals a substantial increase in cumulative gas production, with the velocity string boosting output from 21.108 $MMSm^3$ to 44.638 $MMSm^3$. This additional production of 23.530 $MMSm^3$ of 3years translates to an increased revenue of 9.412 million USD, assuming a gas price of 0.40 USD per Sm^3.

The cost of installing the velocity string, at 1.805 million USD, is significantly outweighed by the economic gains, resulting in a net value of 7.607 million USD. The return on investment (ROI) of 4.2 further highlights the financial attractiveness of this intervention, indicating that every dollar invested yields a return of 4.2 dollars.

These findings underscore the economic viability of velocity strings in enhancing gas production and mitigating liquid loading issues. The high ROI and substantial net value provide a strong justification for further investments in this technology. Additionally, the improved production stability post-installation aligns with strategic objectives to optimize field performance and extend the economic life of wells.

TABLE 12: COST OF VELOCITY STRING INSTALLATION IN TG-352

No	Item	Cost (usd)
1	Services (Personal + CT Equipment)	894,804.78
2	2-7/8" Coiled Tubing	416,749.00
3	Velocity String Accessories	494,009.64
TOTAL COST		1,805,563.42

TABLE 13 RESERVES AND VALUE OF VELOCITY STRINGS IN TG-352:
(ACCUMULATED PRODUCTION FROM 1ST JUNE 2021 TILL 1ST FEBRUARY 2024)

Well	Compl. Dim.	Vel.str.	Initial rate	Added reserves	Prod. Value	Cost	Net Value
			Sm^3/D	$MMSm^3$	mill USD	mill USD	mill USD
Tg-352	7"	2"7/8	73,116	56	16.965	1.248	15.618

TABLE 14: SUMMRY OF ECONOMY BENEFITS OF VS INSTALLATION IN TG-352

ITEM	UNIT	TG-352
Predicted Cum. 3 year production w/velocity string 2022 - 2025	MMSm³	44.638
Predicted Cum. 3 year production wo/velocity string, 2022-2025	MMSm³	21.108
Production gain over 3 years from velocity string installation	**MMSm³**	**23.530**
Production value from installation, assuming gas price 0,40 USD pr Sm³	MM USD	9.412
Installation cost of Velocity string	MM USD	1.805
Net Value of Velocity string installation	**MM USD**	**7.607**
Return on investment, ROI	-	4.2

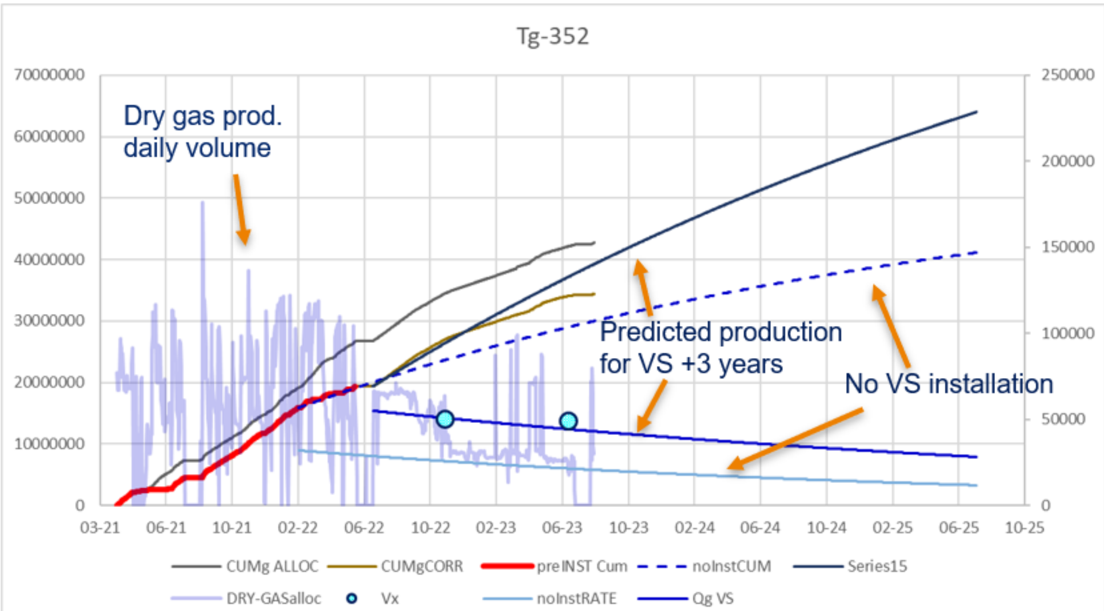

FIGURE 67: TG- 352 PRODUCTION PREDICTION VS VX MESURES

The estimated production gain of the velocity string installation in Tg-352 is **23.5 MM Sm³** during 3 years of productionEqv. Value **9,4 MM USD** assuming gas price 0.40 USD pr Sm³

IV.7. The Installation procedures of CT VS:

The Objectives:

The main objective of this operation is to run 2-7/8’’ Coiled Tubing Velocity string enabled with Safety valve to:

Enhance liquid unloading capabilities of the well

Reduce the cross-sectional flow area up the wellbore

Increase the average gas rate and recovery from the reservoir

IV.7.1. Well completion:

Before the installation of VS string

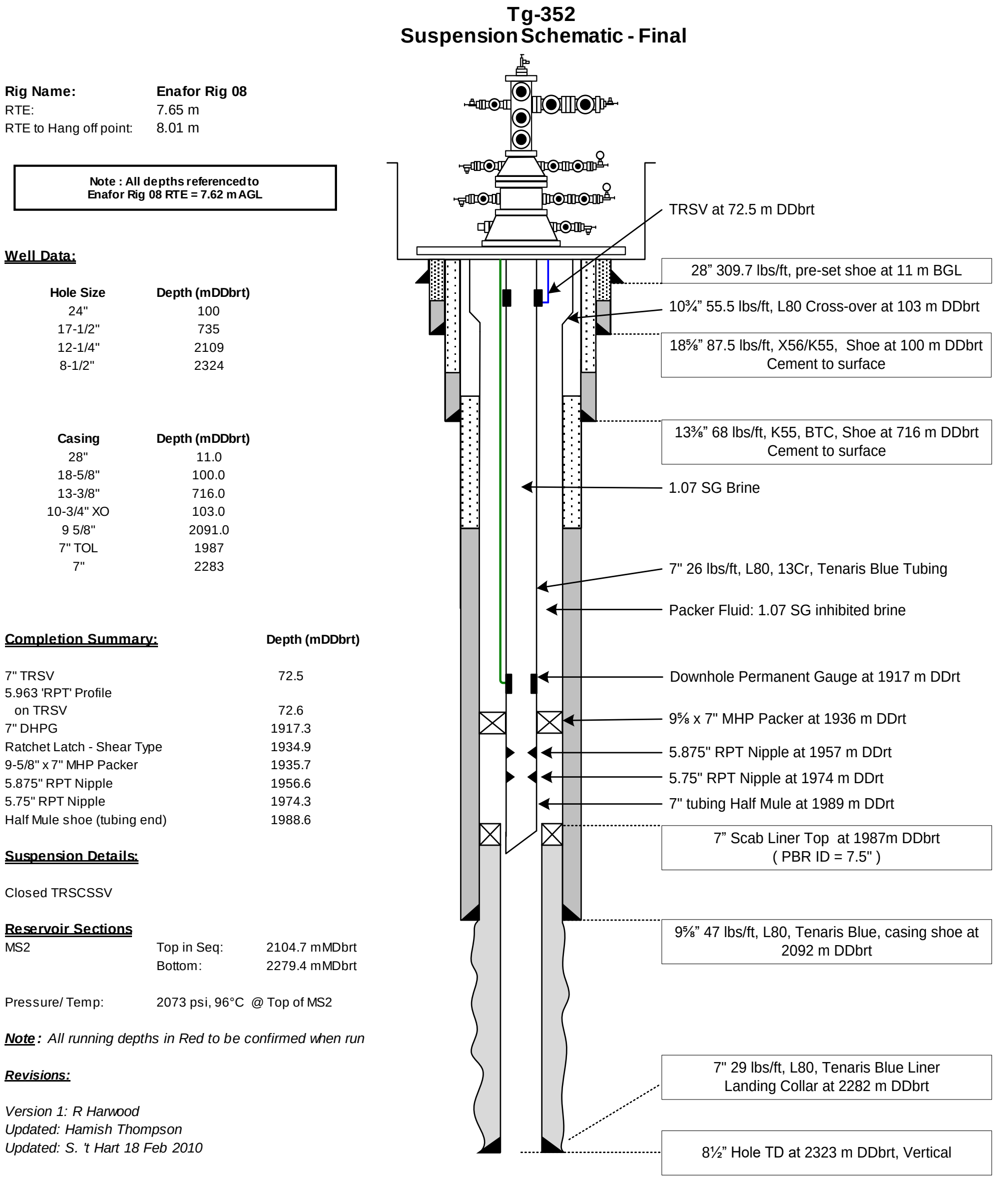

FIGURE 68: TG-352 WELL COMPLETION

After the installation :

The chosen completion after Tg-352 has VS from surface to production zone as shown in the below figure :

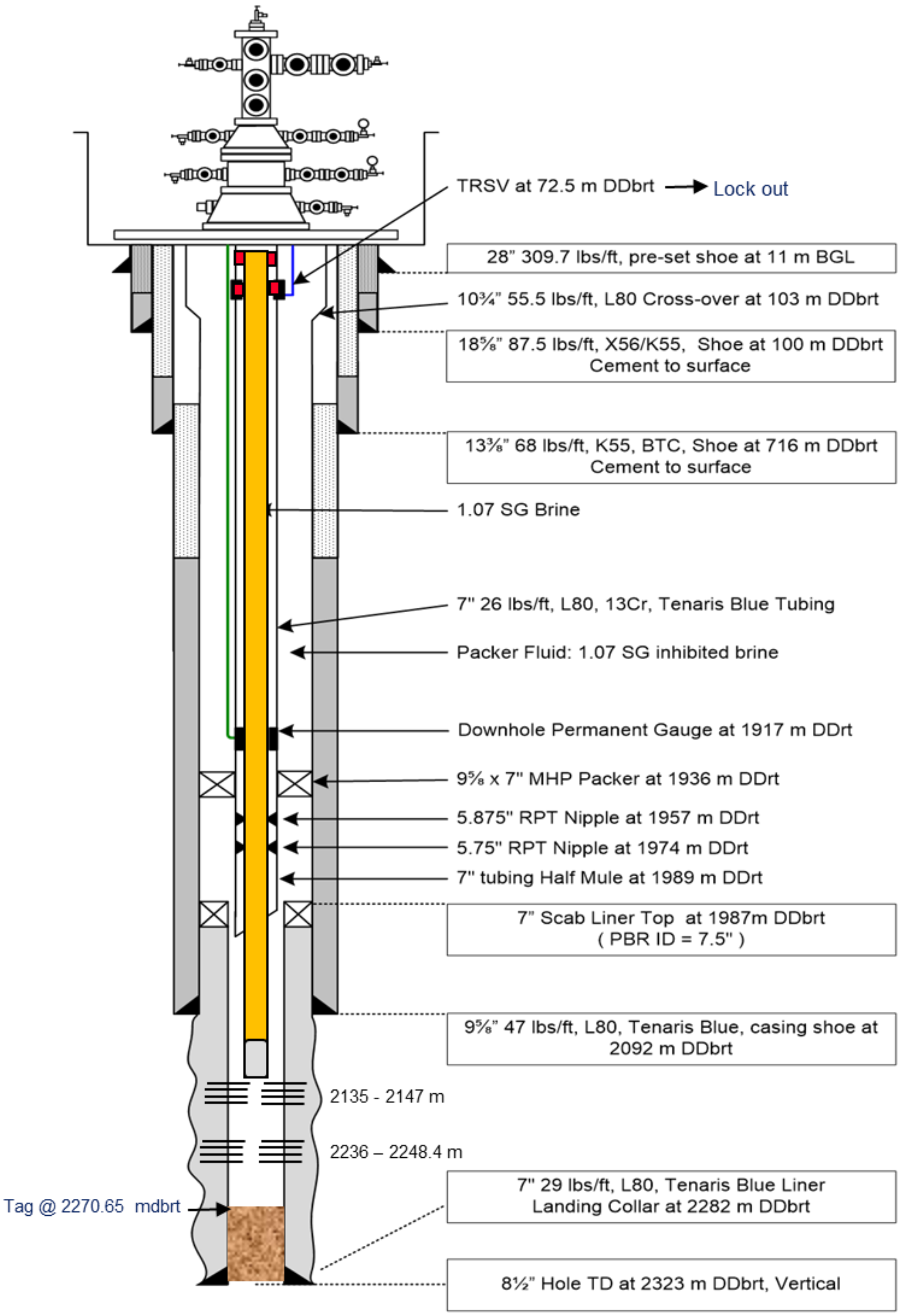

FIGURE 69: TG-352 VELOCITY STRING COMPLETION.

IV.7.2 Pre installation requirement:

1-Coiled Tubing Run: Clean Out Run (If required)

This run will be performed (if required) to ensure the well is clean to the target depth ahead of Velocity String installation considering the low reservoir pressure.

2-Slickline Run: Gauge Cutter and Scraper BHA:

This run will be performed a Slickline company. The aim of this operation is to ensure that Velocity String BHAs will reach the target depth.

IV.7.3 TRSSV Lock Out:

1-Lock out TRSV as per manufacturers procedures

2-Run communication tool and establish communication

3-Flush control line and lock in at surface

IV.7.4. Rig Up equipment:

1.Ensure the well is shut, two (2) barriers are required

2.Confirm with the client representative that the production line is bled off from any pressure

3.Spot the equipment, in accordance with the Equipment.

IV.7.5 Rig Up the tower and PCE (Pressure Control equipment):

To support the well control stack, to increase the level of security of coiled tubing operations and to avoid having the Injector Head just held high in the air with a crane, the coiled tubing tower is deemed as a safe alternative. It is a fit for purpose tool for this type of rig-less operations.

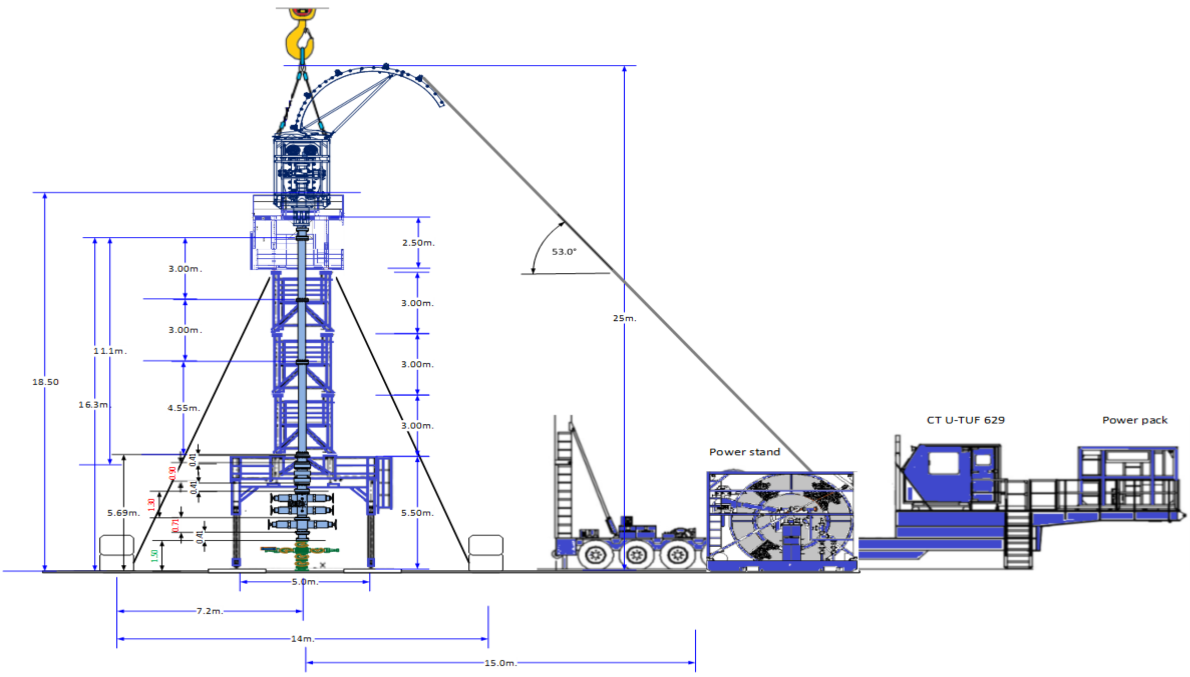

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FIGURE 70: TOWER WITH PCE

IV.7.6. PCE Pressure test & installation:

Pressure test BOPs:

BOPs pressure test will be performed offline (on the ground) using pressure test skid

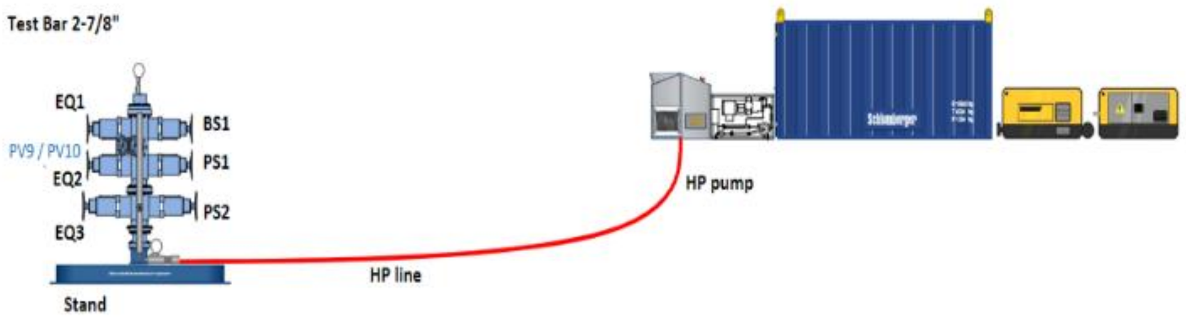

FIGURE 71:BOP TEST

IV.7.7. Rig Up BOPs:

First ensure the wellhead pressure gauge reads 0 psi and remove the top cap. then clean and inspect the connection and gasket areas and install BOP .

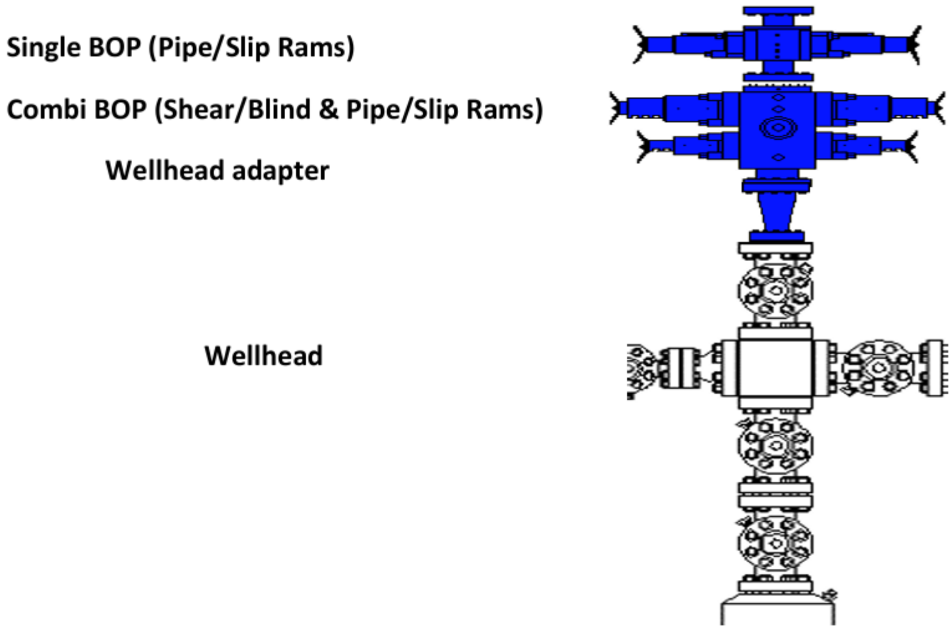

FIGURE 72: RIG UP COMBI & SINGLE BOP ON THE WELLHEAD

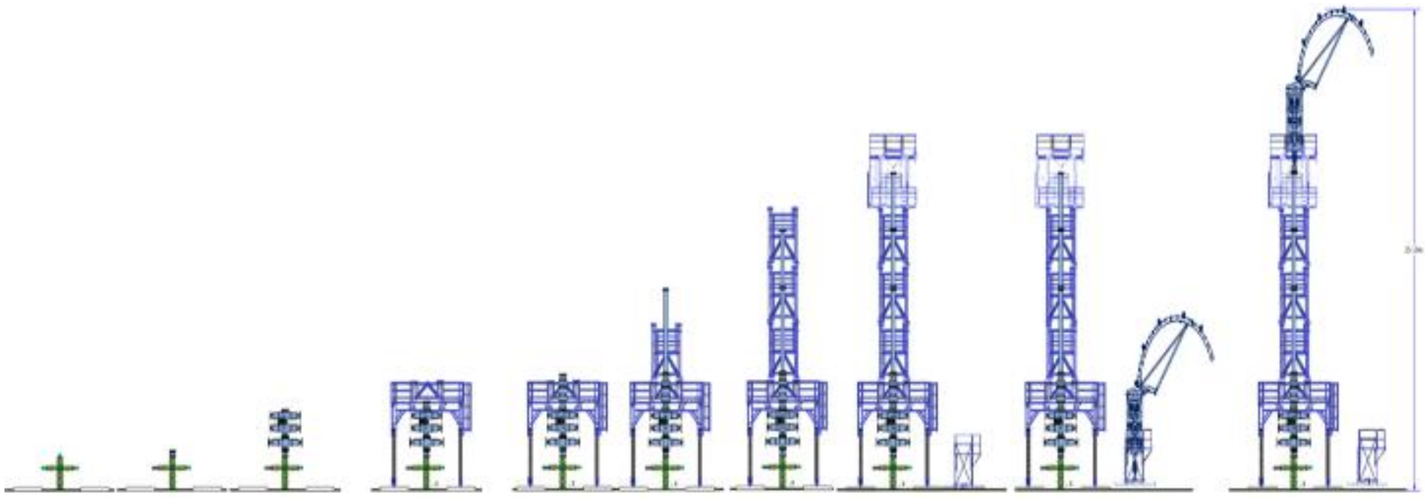

FIGURE 73: TOWER AND PCE RIG UP

IV.7.8 Operating Procedure:

IV.7.8.1 Run#1: Coiled Tubing Run: Installation of Velocity String Hanger

The installation of the Velocity String begins with the Lower Section. The Yo-Yo valve has been tested, and all pressures have been recorded and can be accessed on request. Close the well master valve, open the swab valve and align the flow back to the pit

Installation of lower Section:

1. Displace the water inside 2-7/8’’ CT with Nitrogen, align N2 pump to CT reel and open Swab valve with master valve closed. Align the valves from the kill wing valve to the pit

2. Ensure the pressure inside the CT and the wellhead stack is 0psi before disconnecting the wellhead stack from the QTS level

3.Lift up the Tower Jacking frame

4.RIH CT till the ground level,

5.Align the pumping line to the bottom end of the coil

6.Pump 1m3 (6.3bbl) of 2% KCl treated water, to fill 301m inside 2-7/8’’ CT with around 433psi hydrostatic pressure

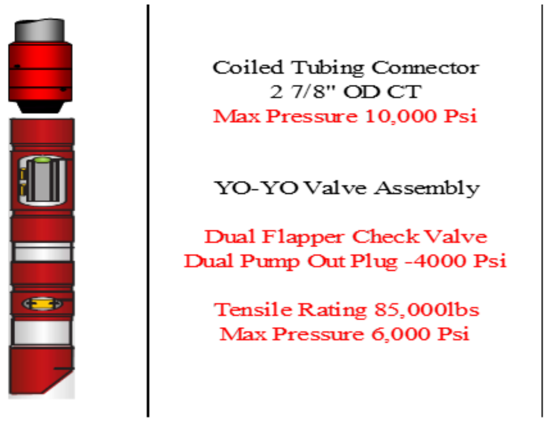

FIGURE 74: LOWER BHA SCHEMATIC

7.RIH CT to **2130m**, confirm target depth of Velocity string

8.CT cut will be performed at QTS level with working Space around 1m

The calculated value need to be communicated and agreed with client representative

9.Calculate height of working Space: ……………... ft/……………m

Required Cut Depth = Total Depth – Current SV Profile Depth – Work widow height

10.Make sure that there is no pressure inside the wellhead stack and inside the CT before opening the QTS connection

11.Open the QTS connection, ensure the reel brake is OFF

12.Jack up the IH frame and allow access to CT pipe in order to perform the cut using hydraulic cutter

13.Perform CT cut using Hydraulic cutter

14.Observe CT end for 5min and confirm YO-YO valve is holding pressure, in case any pressure is observed refer to contingencies.

15.Redress the CT with manual cutter to provide a good CT Section to make up Coil connector

The next step of the installation of the Velocity String, is the installation of the Middle section. The Velocity Hanger has been assembled and tested. All pressures have been recorded and can be accessed on request.

The installation of the Middle section:

Make up the Wish Hanger hanged BHA as per below schematic.

Torque Thru Quick Connect
Tensile Rating 114,200lbs
Max Pressure 10,000 Psi

Coiled Tubing Connector
2 7/8" OD CT
Tensile Rating 114,720lbs
Max Pressure 10,000 Psi

FIGURE 75: WISH HANGER HANGED BHA SCHEMATIC

16.Make up CT connector at the end of the hanged pipe

17.Perform Pull test connector using Hollow Jak and Clamps to 40,000lbf

18.Connect the Torque Thru Quick Connect to the CT Connector

19. Hang off the BHA

20. RIH CT and make up the GS Running BHA

IV.7.8.2 Run#2_ Slickline Run: OptiMax Wireline Retrievable Safety Valve installation:

Prior to installing the OptiMax Retrievable Safety Valve, the protection sleeve already installed in the WISH Hanger Assembly will need to be removed. The protection sleeve can be retrieved using a slickline BHA in conjunction with a 4” GS pulling tool

The OptiMax Retrievable Safety Valve is being suspended using an OQSV Lock. ALL parts of the BHA have been function tested as per the technical units and all results have been recorded as well is critical measurements such ODs, IDs and seal stack space outs.

Safety Valve Section	OD	ID	Connection
OptiMax Retrievable Safety Valve Series 5	3.813”	2.165”	

The assembly to be run should have been made up as per the appropriate Tech Manual assembly instructions.

IV.7.8.3 Run#3_ Coiled Tubing Run: Widepak Packer installation

The final part of the installation is the Widepak Packer. The Widepak assembly has been tested, and all pressures have been recorded and can be accessed on request. Prior to installation all ODs, IDs checked against the Technical Unit for the given Serial number. With CT connector and MHA already rigged up from the last run (Wish hanger running BHA), Make up the Stinger with Shearable centralizer with no seal as per the below.

a. Stinger Dummy Run:

With CT connector rigged up at the end of CT hanged at IH, Make up the Stinger with Shearable centralizer with no seal as per the below.

FIGURE 76:STINGER BHA SCHEMATIC

2. Perform Inflow test for 15min and confirm the annulus Tubing/2-7/8’’ CT is isolated and YOYO valve is still holding, ensure WHP= 0 prior RIH

3.RIH until to 60m (10m above the Wish Hanger)

4.Reduce RIH speed and perform weight checks

5.Continue RIH to land-off Seal Stinger fully

6.POOH CT

7.At surface, perform Before Close Wellhead

8.Close wellhead valves, bleed off the wellhead stack pressure from kill wing valve to chock manifold

9. Break QTS connection and inspect the BHA.

b.Widepak Packer Run:

1. Slowly run upper BHA through the X-tree till the CT packer hanger is at ± 20-ft below the setting depth.

2. Pick up to reference depth = packer element depth,

3. Set down weight to set the packer.

4. Pressure test packer from above through the annulus CT string and Production Tubing.

5. Pump through the 3.632” OD Hydraulic disconnect to release from the packer.

6. POOH to the surface and rig down.

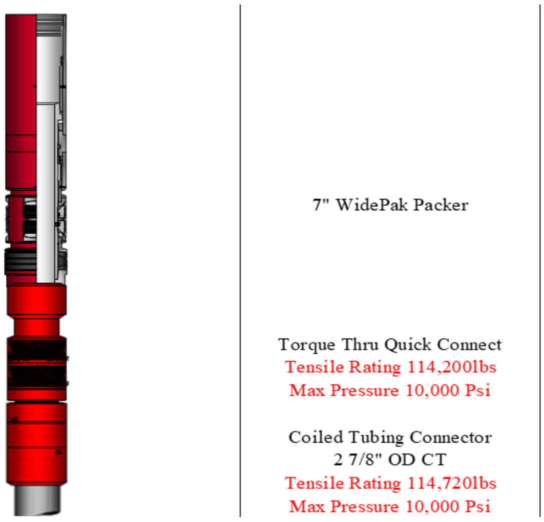

FIGURE 77: WIDEPACK HANGED BHA SCHEMATIC

The details for the packer setting as illustrated in Figure 71 are presented below:

A. Begin RIH CT with Velocity String packer.

B. Prepare to set packer.

C. Setting Velocity String packer at reference depth.

D. Slack off 5,000 lbf below neutral weight to test packer.

E. Pick up to neutral weight.

F. Start pumping through CT-Tubing annulus to pressure test packer @ 5000 psi for 10 minutes.

G. Pressure up CT Velocity String against the 3⁄4” ball and shear set screws on disconnect above packer. H. Begin POOH to surface.

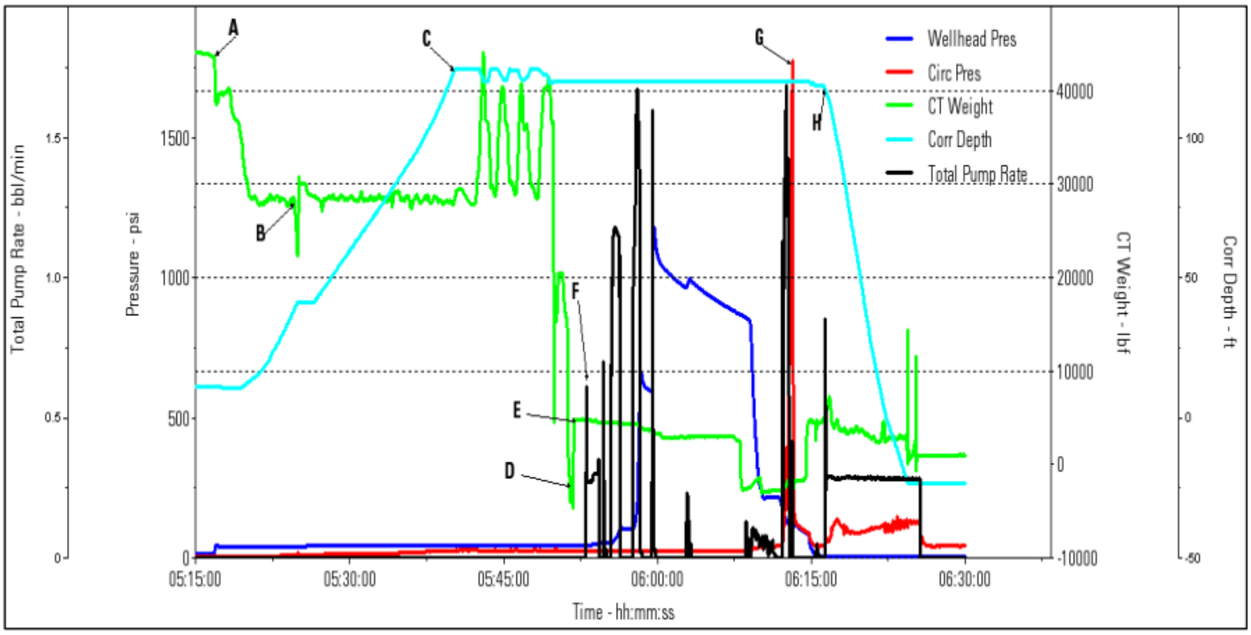

FIGURE 78: VELOCITY STRING PACKER INSTALLATION

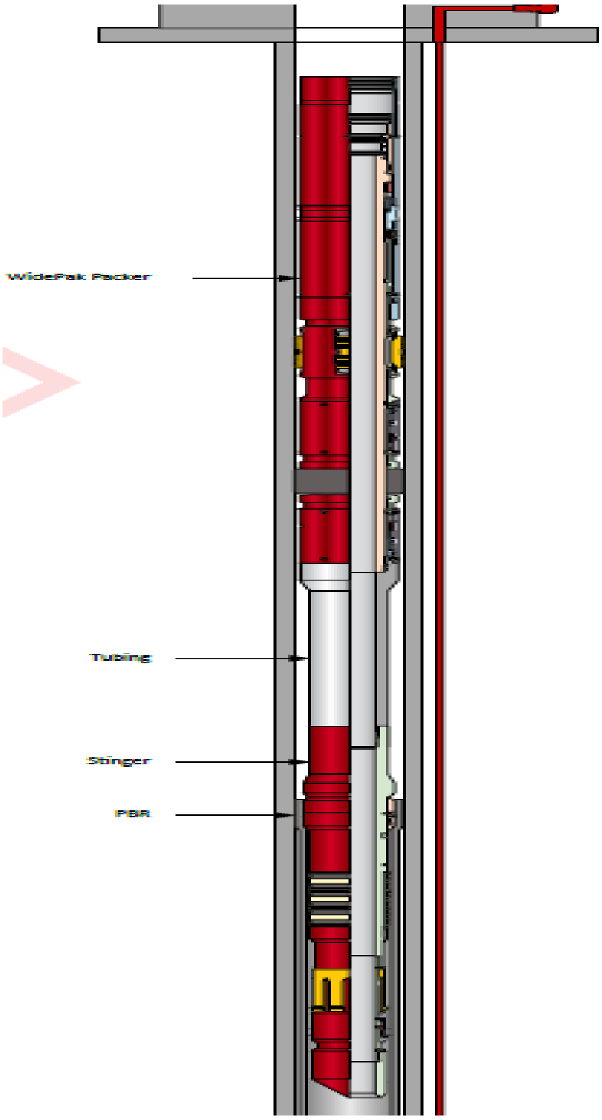

FIGURE 79: VELOCITY STRING INSTALLATION

Final steps:

1. POOH to surface
2. At surface, perform Before Close Wellhead CT
3. Close carefully the WH valve, count the numbers of the turns to confirm it's free from the Velocity string
4. Break QTS connection and inspect the BHA, RIH CT and check the Running BHA free from VS
5. Rig down all the PCE and CT tower from the wellhead

IV.7.8.4 Run#4 Kick off & Flowback the well (if required):

Shearoff YO-YO valve and after commissioning, Flowback the well observe the well for natural flow If the well cannot sustain the flow by itself Run 1-1/4'' CT in order to perform Nitrogen Kick off.

Summary:

Purpose of the Study: To evaluate the effectiveness of coiled tubing velocity strings in mitigating liquid loading in gas wells.

Research Questions:

- What is the optimum design of coiled tubing velocity string that will solve the problem of liquid loading in TG- 352?
- What's the procedures of CT VS installation ?
- How effective are coiled tubing velocity strings in removing liquid from gas wells?
- How much is the gain that will be reached after installation of VS?

Methodology: Employed a mixed-method approach, including field experiments, simulation modeling , to gather comprehensive data

Findings: The study found that the installation of 2''7/8 diameter coiled tubing velocity strings in TG 352 is significantly improved liquid removal efficiency. Optimal performance was achieved with specific diameter and length configurations, tailored to individual well conditions.

Conclusion:

The Study of TG-352 case in Tiguentourine field after dedication of the liquid loading problem while cycling and after CT VS installations shows how essential is the employment of simulation in designing the optimal velocity string, such as those Treated by PROSPER software, it helps in identifying the best configuration to mitigate liquid loading and extend the productive life of the well.

Based on our study of the problem of liquid loading in TG-352 before and after installation of CT VS and the results of the nodal analysis and curves:

- The analysis of the well performance while cycling operating method indicate that its ineffective over the time and giving instable production.
- The installation of 2”7/8 in TG-352 has proven to be highly effective in addressing liquid loading in, it enables continuous gas production, thereby mitigating the effects of liquid accumulation.
- Calculating the critical flow and future declination of the reservoir pressure determines whether to use a velocity string to mitigate liquid loading.
- Liquid loading of gas wells should be identified and resolved as early as possible.
- The analysis of remaining reserves should be considered to ensure the cost-benefit ratio for implementing such solutions.
- Velocity strings can be a cost-effective means to delay liquid loading in gas wells, extend the well life and increase ultimate recovery.
- Finding the best installation completion play essential role in future well interventions and also in production loses.

Recommendations:

- Use of the ROI should focus in the deployment of coiled tubing velocity string in wells facing similar challenges. This can optimize overall field productivity and extend the economic life of mature wells.
- replace cycling method and focusing in the employment VS , this can yield more profitable production .
- Evaluate the performance and select the future candidates wells for velocity string installation as soon possible.
- Do the design simulation and gain estimation of velocity string early for each candidate well.
- Completion should be improved by adding nipples in the lower part of the VS

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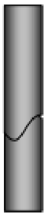
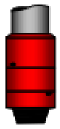
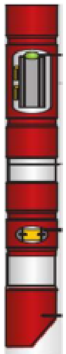
Appendices:

Appendix 01: BHA Schematic

1. Lower Section BHA_ WISH Lower Assembly

Weatherford

Client:	SCHLUMBERGER - JV GAS	Lease:	SONATRACH
Address:	TIGUENTOURINE - IN AMENAS	Field	TIGUENTOURINE
	ILLIZI	Parish	SONATRACH
		OCS-G	N/A
Platform:	SLB COILED TUBING	CONTACT	Samir Gritteli
Well Number:	TG-352	Phone	00213 697 348 920
Type of Operation:	WISH SYSTEM BHA#01 _ LOWER COMPLETION _ YO-YO VALVE		

Item	C/T to Surface	Tool Description	Tool O/D	Tool I/D	Length m	Fish Neck	Connection	Asset No.
		**2-7/8" COILED TUBING**	2.875"	TBC	2130m	2.875"		
1		**COILED TUBING CONNECTOR** 2-7/8" OD Coiled Tubing Tensile Rating: 114,720 lbs Pressure Rating: 10,000 Psi	3.875"	2.371"	0.50	3.875"	2 7/8" 6.5# WTS-8 Pin 2300ft-lbs Optimum	2904845
2		**YO-YO VALVE** Tensile Rating: 85,000lbs Pressure Rating: 6,000 Psi Dual Flapper Check Valve: * DFCV Shear Pressure:1800Psi (8 Pins x 225 Psi each) * DFCV Ball Size: 2-1/4" Dual Pump Out Plug: * Upper Plug: 4,010Psi (5 Pins x 802Psi) * Lower Pug: 4,053Psi (7 Pins x 579Psi)	4.625"	2.125"	1.24	4.625"	2 7/8" 6.5# WTS-8 Box 2300ft-lbs Optimum	2909661
	Total Length of B.H.A. :-				1.74	METERS	B.H.A Prepared by	Date
Please note that all O/D's and I/D's are approximate, and are given as a guideline only							ZEGHOUD ELHAOUAS	21-Jun-22

1. WISH Hanger Assembly

Client:	SCHLUMBERGER - JV GAS	Lease:	SONATRACH
Address:	TIGUENTOURINE - IN AMENAS	Field	TIGUENTOURINE
	ILLIZI	Parish	SONATRACH
		OCS-G	N/A
Platform:	SLB COILED TUBING	CONTACT	Samir Gritteli
Well Number:	TG-352	Phone	00213 697 348 920
Type of Operation:	WISH SYSTEM BHA#02 _ MID COMPLETION _ WISH HANGER		

Item	C/T to Surface	Tool Description	Tool O/D	Tool I/D	Length m	Fish Neck	Connection	Asset No.
1		**WISH HANGER** Tensile Rating: 90,000lbs Pressure Rating: 5000psi diff 6" GS Profile Setting Force (Downward): 20,000lbs	6.025	2.371"	6.42	6.025	2 7/8" 6.5# WTS-8 Box 2300ft-lbs Optimum	2913069
2		**COILED TUBING CONNECTOR WITH TORQUE THRU QUICK CONNECT** Tensile Rating: 114,720 lbs Pressure Rating: 10,000 Psi	3.875"	2.371"	0.92	3.875"	2 7/8" 6.5# WTS-8 Pin 2300ft-lbs Optimum	2892493
		2-7/8" COILED TUBING	2.875"	TBC	2130m	2.875"		
	Total Length of B.H.A. :-				7.34	METERS	B.H.A Prepared by	Date
	Please note that all O/D's and I/D's are approximate, and are given as a guideline only						ZEGHOUD ELHAOUAS	21-Jun-22

2. Stinger BHA (with Seals)

Weatherford

Client:	SCHLUMBERGER - JV GAS	Lease:	SONATRACH
Address:	TIGUENTOURINE - IN AMENAS	Field	TIGUENTOURINE
	ILLIZI	Parish	SONATRACH
		OCS-G	N/A
Platform:	SLB COILED TUBING	CONTACT	Samir Gritteli
Well Number:	TG-352	Phone	00213 697 348 920
Type of Operation:	WISH SYSTEM BHA#03 - PART#01 _ UPPER COMPLETION _ STINGER BHA		

Item	C/T to Surface	Tool Description	Tool O/D	Tool I/D	Length m	Fish Neck	Connection	Asset No.
		**2-7/8" COILED TUBING**	2.875"	TBC	TBC	2.875"		
1		**COILED TUBING CONNECTOR** 2-7/8" OD Coiled Tubing Tensile Rating: 114,720 lbs Pressure Rating: 10,000 Psi	3.875"	2.371"	0.50	3.875"	2 7/8" 6.5# WTS-8 Pin 2300ft-lbs Optimum	2904845
		STNIGER Tensile Rating 102,000lbs Shearable Centralizer: Shear Force 6,104lbs 08 Pins x 763lbs each	5.900	2.500"	2.59	Exernal	2 7/8" 6.5# WTS-8 Box 2300ft-lbs Optimum	2913079
	Total Length of B.H.A. :-				3.09	METERS	B.H.A Prepared by	Date
Please note that all O/D's and I/D's are approximate, and are given as a guideline only							ZEGHOUD ELHAOUAS	21-Jun-22

3. WISH Widepak BHA/ Setting Widepak BHA :

Client:	SCHLUMBERGER - JV GAS	Lease:	SONATRACH
Address:	TIGUENTOURINE - IN AMENAS	Field	TIGUENTOURINE
	ILLIZI	Parish	SONATRACH
		OCS-G	N/A
Platform:	SLB COILED TUBING	CONTACT	Samir Gritteli
Well Number:	TG-352	Phone	00213 697 348 920
Type of Operation:	WISH SYSTEM BHA#03 - PART#02 _ UPPER COMPLETION _ WIDEPAK PACKER		

Item	C/T to Surface	Tool Description	Tool O/D	Tool I/D	Length m	Fish Neck	Connection	Asset No.
1		**COILED TUBING CONNECTOR** 2-7/8" OD Coiled Tubing Tensile Rating: 114,720 lbs Pressure Rating: 10,000 Psi	3.875"	2.371"	0.36	3.875"	2 3/8" PAC Pin 2600ft-lbs F/ PAC	2904845
2		**MOTOR HEAD ASSEMBLY (BAKKE)** 7/8" Ball F/Disconnect 3/4" Ball F/ Circulating Sub Circ. Sub W/ 3 x 900 psi Shear Screws Disconnect W/ 3 x 1000 psi Shear Screws 1 X 5K Burst Disc Tensile Rating: 103,000 lbs	2.875"	3/4"	0.84	2.875"	2 3/8" PAC Box X Pin M.U.Torque 2693 ft lbs	274143
3		**CROSSOVER** 2-3/8" PAC Box x 2-7/8" NV Pin	3.150"	1-1/2"	0.25	3.150"	2-3/8" PAC Box x 2-7/8" NV Pin 2390 ft-lbs F/ NV 2600ft-lbs F/ PAC	TT-XO-0157
4		**CROSSOVER** 2-7/8" NV Box x 2-7/8" EUE Pin	3.250"	2-3/8"	0.33	3.250"	2-7/8" NV Box x 2-7/8" EUE Pin 2390 ft-lbs F/ NV 2400 ft-lbs F/ EUE	1442132
5		**HYDRAULIC SETTING TOOL (HST)** 03 Cylinders Ball on seat: 1-3/4" Area per Cylinder: 5.613 in2	4.375"	1-3/4"	1.55	4.375"	2 7/8" EUE Box M.U.Torque 2400 ft lbs F/ EUE	1323643
6		**WIRE LINE ADAPTER KIT** Baker#20 // Total Length: 0.65m Setting Force: 52,200lbs (12 x 4,350lbs each)	5.72"	N/A	Connected to WP & CPST 0.35	5.72"	BAKER#20	783635
7		**WIDEPAK PACKER** Packer size 450 x 300 (Tubing OD: 5-1/2") Temperature rating : 4°C (40°F) to 176°C (350°) Pressure Rating: 5000 Psi ISO 14310 V0 Validation Release force: 8 Pins (1,200lbs each) - 9,600 lbs	5.72"	4.000"	2.52	5.72"	2 7/8" 6.5# WTS-8 Pin 2300ft-lbs Optimum	2922053
8		**COILED TUBING CONNECTOR WITH TORQUE THRU QUICK CONNECT** Tensile Rating: 114,720 lbs Pressure Rating: 10,000 Psi	3.875"	2.371"	0.92	3.875"	2 7/8" 6.5# WTS-8 Pin 2300ft-lbs Optimum	2892493
		2-7/8" COILED TUBING	2.875"		TBC	2.875"		
	Total Length of B.H.A. :-				7.12	METERS	B.H.A Prepared by	Date
	Please note that all O/D's and I/D's are approximate, and are given as a guideline only						ZEGHOUD ELHAOUAS	21-Jun-22

Appendix 02: Wellhead Schematic

WELLHEAD DATA				
	SUPPLIER	TYPE	RATING	TOP CONNECTION
XMAS TREE CAP	Cameron	6.3/8" FLS	5M	9.1/2" OTIS Quick Union
XMAS TREE	Cameron	6.3/8" FLS	5M	7 1/16" API Studded
2 STAGE WELLHEAD	Cameron	SSMC	5M	13 5/8" Flangelock
TUBING HANGER	Cameron	13 5/8"	5M	

Appendix 03 : Well schematic

COMPLETION SCHEMATIC - FINAL	FIELD: TIGUENTOURINE	WELL NUMBER: Tg-352

WELL DATA

Well Type:	7" Producer	**End of string:**	1988.6 m	**Original RTE:**	8.01 m
Original Drilling Rig:	Enafor 08	**Annulus Fluid:**	NaCl Brine	**New RTE:**	N/A
New Drilling Rig:	N/A	**Annulus Fluid Wt:**	1.07	**Minimum string ID:**	5.75 in.
First Completed:	1/28/2010	**Completion Fluid:**	NaCl Brine	**Well TD:**	2324. mDDbrt
Workover Number:	N/A	**Completion Fluid Wt:**	1.07	**Max DLS (°/30m):**	N/A
Workover Date:	N/A				

CASING DATA

Size (in.)	Weight	Grade	Thread	MD (m)	TVD (m)
18-5/8"	87.5 lb/ft	K55	BTC	100.0	100.0
13-3/8"	68 & 72 lb/ft	K55/HC95	BTC	716.0	716.0
10.75 (w / 9-5/8)	55.5 lb/ft	L80	Tenaris Blue	103.0	103.0
9 5/8	47 lb/ft	L80	Tenaris blue	2091.0	2091.0

WELLHEAD DATA

	SUPPLIER	TYPE	RATING	TOP CONNECTION
XMAS TREE CAP	Cameron	6.3/8" FLS	5M	9.1/2" OTIS Quick Union
XMAS TREE	Cameron	6.3/8" FLS	5M	7 1/16" API Studded
2 STAGE WELLHEAD	Cameron	SSMC	5M	13 5/8" Flangelock
TUBING HANGER	Cameron	13 5/8"	5M	

LINER DATA

Size (in.)	TOL (mDD)	Weight	Grade	Thread	MD (mDD)	TVD (m)
7	1987	29	L-80	Tenaris Blue	2283	2283.0

ADDITIONAL COMPLETION INFORMATION

Rig 08 RTE to hang off point (m): **8.01**

PACKER:

Packer mid element (mBRT):	1936.64
Top of packer to mid element (m):	0.99
Nearest 9.5/8" Casing couplings (mBRT):	1940.31
1/2 Mule Shoe inside 7" TOL (m):	1.6
1/2 Mule Shoe inside 7" TOL including stretch (m):	**3.23**
Maximum inclination before bottom nipple	0°
Tubing Stretch taking into account buoyancy, temp. effects & pick up:	1.63
End of string including calculated stretch (m):	**1990.2**

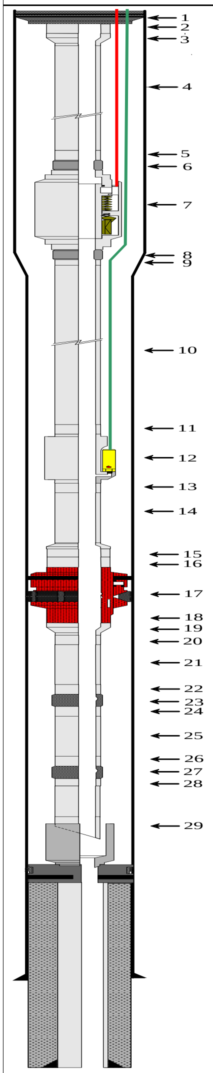
COMMENTS / NOTES:
NOTE: The well was left with gas pressure in the "B" annulus. The final recorded preaaure was 440psi. The wellhead was configured with additional valves to compesate for this pressure. 173 cable clamps to the TRSV. 2 of the special clamps on the TRSV. (above/below). 2 Cannon cast iron special clamps for the flow couplings were used to hold the TRSV control line. Maximum allowable pressure in tubing 5000psi. "A" annulus pressure tested to 3500psi

RESERVOIR ZONES:
MS2 Top in Seq: 2104.7 mMDbrt
Bottom: 2279.4 mMDbrt

Pressure/ Temp: 2073 psi, 96°C @ Top of MS2

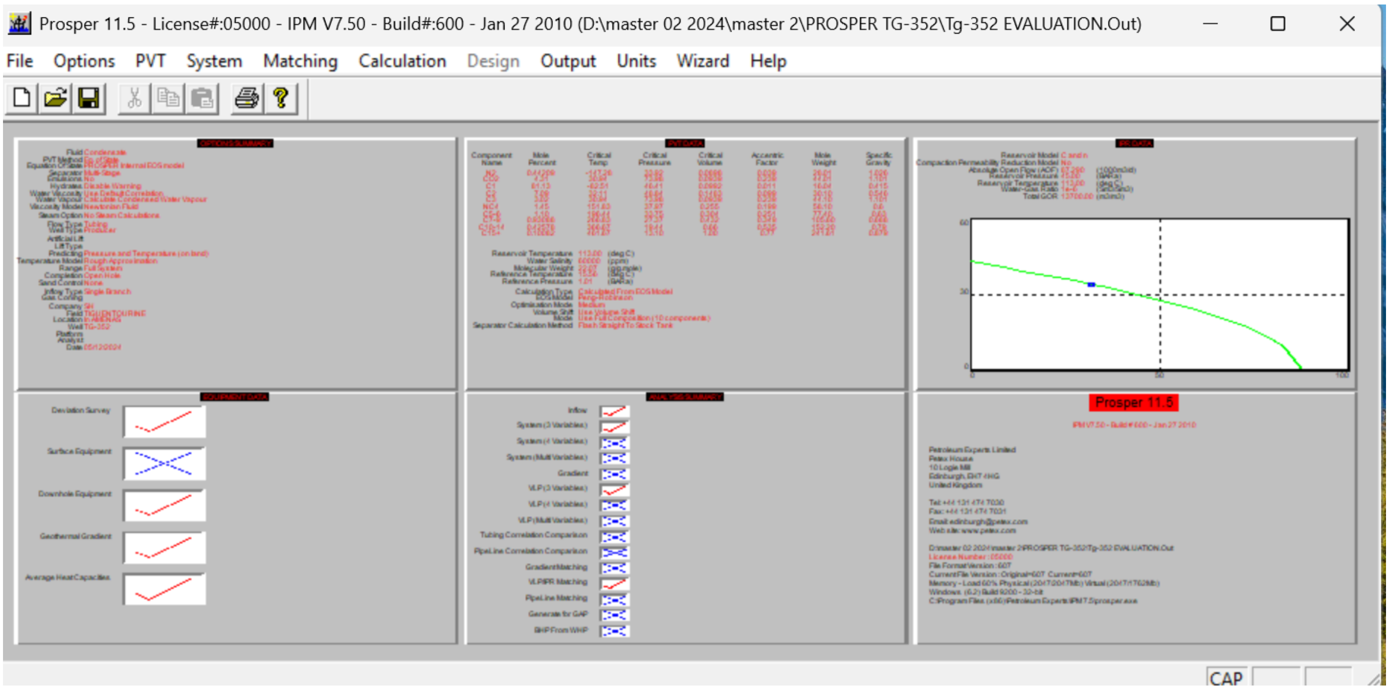
CONTROL LINES:
TRSV: 1/4" Inconel Encapsulated Control line with 1/4" Swadgelok fittings.
TEC Cable,1/4" x .028", c/w Santoprene encapsulation, 0.43" diameter encapsulated.

WELL SCHEMATIC



ITEM NUMBER	DESCRIPTION	LENGTH (m)	TOP ITEM (mBRT)	ID (inches)	OD (inches)	THREAD	MODULE / No. Joints	SUPPLIER	Volume (bbl)
	Correction for RTE (Workover only)								
1	Tubing Hanger below HOP Part number: 2205088-06 Serial number: 111404146-4	0.26	8.0	6.276	13.293	Tenaris Blue B	Cameron	Cameron	0.0
2	7" Pup Joint, 26ppf, 13Cr L80	1.37	8.3	6.276	7.677	Tenaris Blue B x P		Cameron	0.2
3	7" Pup Joint, 26 ppf, 13Cr L80 (for space out)	0.000	9.6	6.276	7.677	Tenaris Blue B x P	1	INA	0.2
4	7" Tubing, 26ppf, 13Cr L80	58.07	9.6	6.276	7.677	Tenaris Blue B x P	4.0	INA	7.5
5	7" Pup Joint, 26ppf, 13Cr L80	0.00	67.7	6.276	7.677	Tenaris Blue B x P		INA	7.5
6	7" Pup Joint, 26ppf, 13Cr L80	3.02	67.7	6.276	7.677	Tenaris Blue B x P		INA	7.9
7	**7" Flow Coupling, 13 CR, L80 26 lb. (long pin)** Part number : 493934 Serial Number: 1993679	1.73	70.7	6.177	7.697	Tenaris Blue B x P		Halliburton	8.1
8	**TRSV, SP Valve, 7", 26 ppf Self Equalizing, 13cr With 5.963" 'RPT' Internal Lock Profile** Part number : 101555558 Serial Number: 2006075-1	3.29	72.5	5.963	9.250	Tenaris Blue B x P	INA -189	Halliburton	8.5
9	**7" Flow Coupling, 13 CR, L80 26 lb.(standard pin)** Part number : 493936 Serial Number: 1993872	1.72	75.7	6.177	7.697	Tenaris Blue B x P		Halliburton	8.7
10	7" Pup Joint, 26ppf, 13Cr L80	1.97	77.5	6.276	7.677	Tenaris Blue B x P		INA	8.9
11	7" Tubing, 26ppf, 13Cr L80	1834.88	79.4	6.276	7.677	Tenaris Blue B x P	161.9	INA	239.2
12	7" Pup Joint, 26ppf, 13Cr L80	2.99	1914.3	6.276	7.677	Tenaris Blue B x P		INA	239.6
13	**Downhole Permanent Gauge, 7", 26 ppf** Part number : 9293-9293 Serial Number: 256138	1.82	1917.3	6.201	8.490	Tenaris Blue B x P	INA-195	Halliburton	239.8
14	7" Pup Joint, 26ppf, 13Cr L80	1.03	1919.1	6.276	7.677	Tenaris Blue B x P		INA	240.0
15	7" Tubing, 26ppf, 13Cr L80	11.76	1920.2	6.276	7.677	Tenaris Blue B x P	1.0	INA	241.4
16	7" Pup Joint, 26ppf, 13Cr L80	3.01	1931.9	6.276	7.677	Tenaris Blue B x P		INA	241.8
17	**Ratchet-Latch Locator 7-7/8" VERSA -LTH LH, 7" 26 ppf (Shearable Releasable Ratchet - Latch)** Part number : 493842 Serial Number: 1943914-6	0.74	1934.9	6.000	7.813	Tenaris Blue B		Halliburton	241.9
18	**Packer, 9-5/8" x 7", 40-47# MHP, 13Cr** Part number : M467024T Serial Number: MY1957461-2	2.09	1935.7	6.000	8.420	7-5/8" 33.7ppf New VAM B	INA-177	Halliburton	242.1
19	**Mill Out Extension** Part number: 101269312 Serial Number: HES1978860	1.55	1937.7	6.765	7.701	7-5/8" 33.7ppf New VAM PxP		Halliburton	242.4
20	**Adaptor Cross Over** Part number: M495478-A Serial Number: 1943912	0.34	1939.3	6.202	8.165	7-5/8" New VAM B x 7" Tenaris BlueP		Halliburton	242.4
21	7" Pup Joint, 26ppf, 13Cr L80	1.97	1939.6	6.276	7.677	Tenaris Blue B x P			242.7
22	7" Tubing, 26ppf, 13Cr L80	12.03	1941.6	6.276	7.677	Tenaris Blue B x P	1.0	INA	244.2
23	7" Pup Joint, 26ppf, 13Cr L80	3.02	1953.6	6.276	7.677	Tenaris Blue B x P		INA	244.6
24	**5.875" 'RPT' Landing Nipple** Part number: 493907-A Serial Number: 1943922	0.63	1956.6	5.875	7.697	Tenaris Blue B x P	INA-	Halliburton	244.6
25	7" Pup Joint, 26ppf, 13Cr L80	2.03	1957.3	6.276	7.677	Tenaris Blue B x P		INA	244.9
26	7" Tubing, 26ppf, 13Cr L80	12.03	1959.3	6.276	7.677	Tenaris Blue B x P	1.0	INA	246.4
27	7" Pup Joint, 26ppf, 13Cr L80	2.99	1971.3	6.276	7.677	Tenaris Blue B x P		INA	246.8
28	**5.750" 'RN' Landing Nipple** Part number: 493908-A Serial Number: 1943909	0.64	1974.3	5.750	7.697	Tenaris Blue B x P	INA-185	Halliburton	246.8
29	7" Pup Joint, 26ppf, 13Cr L80	1.96	1975.0	6.276	7.677	Tenaris Blue B x P		INA	247.1
30	7" Tubing, 26ppf, 13Cr L80 with Half Mule Shoe	11.68	1976.9	6.276	7.677	Tenaris Blue B x P	ISG-225	Halliburton	248.5
	Bottom of String		**1988.6**						

Appendix 04: PROSPER SOFTTWARE SIMULATION FRONT



The Calculations:

Calculation of Vs_L and Vs_G:

$$Vs_L = \text{BPD*5.615/(86400*}area_{tbg})$$

$$Vs_G = \text{ScF/D/(86400*tubing area)}$$

Q_L = 36.6821 BPD

Q_g= 1765735 SCF/D

calculate the cross-sectional area of a circular tubing:

Area=$\pi(\frac{d}{2})^2$

where:

d is the diameter of the tubing.

d=6.275

Radius=3.1375 inches

Calculate the area in square inches:

Area=π(3.1375)2

Area=π×9.847

Area≈3.14159×9.847

Area≈30.929 square inches

Convert the area to square feet:

1 ft^2= 144 in^2

Area in square feet=30.929/144

Area in square feet≈0.2147

So:

Vs_L = 36.6821 *5.615/(86400*0.2147) = 0.011098 ft/s

Vs_G= 1765735/ (86400*tubing area) = 95.19 ft/s