Implementation of the Capillary String Technology in RAG Gas Fields to Improve Production from Liquid Loaded Wells

Thesis

by

Daniel Eichhober

Submitted to the Montan Universität Leoben, Austria,
in partial fulfilment of the requirements for the master's degree
in Petroleum Engineering.

Schwarzmoos, Austria, August 2007

Bestätigung

MINING METALLURGY MATERIALS

WWW.UNILEOBEN.AC.AT

MONTANUNIVERSITÄT LEOBEN

Department MINERAL RESOURCES & PETROLEUM ENGINEERING
Chair of **Petroleum Production and Processing**

Head: **Univ.Prof. Bergrat h.c. Dipl.-Ing.Dr.mont G. Ruthammer**

Franz-Josef-Straße 18
8700 Leoben
Austria

Tel.: +43 (0)3842 402-3030
Fax: +43 (0)3842 46436

e-mail: Gerhard.Ruthammer @mu-leoben.at

UID: ATU 57480504

Rohöl-Aufsuchungs-AG
Herr Dipl.-Ing.Dr. Herbert Hofstätter
Schwarzmoos 28
4851 Gampern

Leoben, am 27.03.2007

Diplomarbeit: "Einsatz von Capillary Strings in Gasfeldern der RAG"

Sehr geehrter Herr Dr. Hofstätter, lieber Herbert!

Für die Bereitstellung einer Diplomarbeit mit obigem Thema möchte ich mich herzlich bedanken.

Ich unterstütze dieses Vorhaben und bin gerne bereit, diese Diplomarbeit universitär mitzubetreuen.

Mit der Übertragung der Ausarbeitung an Herrn Daniel Eichhober bin ich einverstanden.

Mit freundlichen Grüßen und
Glück auf!

MONTANUNIVERSITÄT LEOBEN
Chair of
Petroleum Production
and Processing

Univ.Prof. Bergrat h.c. Dipl.-Ing.Dr.mont Gerhard Ruthammer

Declaration

I declare in the lieu of oath
that I wrote this thesis in hand by myself
using only literature cited at the end of the volume

Daniel Eichhober

Leoben, August 2007

Dedication

An meine Eltern **Erwin** und **Roswitha**, ohne ihre Geduld und Unterstützung wäre mein Studium in Leoben und in Golden nicht möglich gewesen.

Acknowledgements

I would like to express my appreciation to **Univ.-Prof. Bergrat h.c. Dr.mont. Dipl.-Ing. Gerhard Ruthammer** for his support during my thesis and for giving me the opportunity to write this thesis at Rohöl-Aufsuchungs AG.

I would like to thank my advisor **Dipl.-Ing. Markus Seywald** for the extensive amount of time and help he provided during the work on this thesis. Further my thanks are extended to **Dipl.-Ing. Gerald Sam**.

I would also like to thank **Dipl.-Ing. Manfred Kass** for the advice in writing this thesis.

I would like to thank **Rohöl- Aufsuchungs** AG for their financial support during this thesis and additionally I would like to thank **Mr. Karl- Heinz Lederer and his team** representatively for all employees at Rohöl- Aufsuchungs AG for their support in this work.

Abstract

In today's gas fields more and more gas wells suffer from liquid loading. This effect comes along with decreasing reservoir pressure and increasing liquid production. At some point a gas well is no longer able to transport the produced liquids up to the surface which results in an accumulation of liquids in the wellbore. The gas well continuous to produce until the backpressure of the liquid column equals the reservoir pressure and production completely stops.

The reason of the well's inability to transport the liquids up to the surface is because the actual gas rate has fallen below the well's critical rate which is the minimum gas rate required to transport liquid droplets to the surface.

In order to accomplish this problem several methods to unload gas wells are available. Dependent on the method used different sources to solve the liquid loading problem are addressed. Some methods increase the gas rate where others decrease the liquid production. Again some just directly remove the liquids out of the wellbore.

One specific method utilizes a capillary string to inject surfactant into the wellbore at a desired depth. The capillary string technology consists of a chemical injection valve that is attached to the lower end of the capillary string which is hung of at the wellhead. The capillary string is installed under life-well conditions through the wellhead and the tubing. The surface end is attached to an injection unit which includes a surfactant tank, a pump, and a filter. The surfactant is pumped from the surfactant tank through the filter, down the capillary string and enters the wellbore through the chemical injection valve.

The surfactant, a wetting agent that lowers the surface tension of a liquid, causes the formation of foam. A foam has a lower hydrostatic and therefore can be removed more easily from the wellbore. Now the gas well is able to remove the liquids out of the wellbore again by its own.

In order to become the application of foamer a success a suitable candidate well has to be selected. Certain criteria have to be met during the evaluation process.

Kurzfassung

In den heutigen Gasfeldern sind immer mehr Gas-Sonden mit dem Problem des Liquid Loading konfrontiert. Dieses Problem resultiert aus dem sinkendem Lagerstättendruck und der steigenden Produktion von Formationsflüssigkeiten. Zu einem bestimmten Zeitpunkt ist dann die Gas-Sonde nicht länger in der Lage die anfallenden Formationsflüssigkeiten an die Oberfläche zu bringen. Bei erreichen eines entsprechendem Gegendruckes der steigenden Flüssigkeitssäule endet dann schließlich die Gasproduktion. Der Grund für die Unfähigkeit des Flüssigkeitstransportes der Sonde liegt darin, dass die aktuelle Gasrate unter die der kritischen Gasrate, welche für den Flüssigkeitstransport mindestens notwendig wäre, gesunken ist.

Um diesem Problem entgegen zu wirken sind verschiedenste Methoden verfügbar. Je nach Methode werden unterschiedliche Punkte zur Lösung des Problems adressiert. Einige Methoden steigern die aktuelle Gasrate, andere reduzieren die produzierte Flüssigkeitsmenge. Wiederum andere befördern die Flüssigkeit direkt an die Oberfläche.

Eine spezielle Methodik ist die Injizierung von Schäumern durch einen Capillary String. Diese Technik besteht aus einem Injektionsventil, das am unterem Ende des Capillary Strings, welcher am Eruptions-Kreuz abgehängt ist, befestigt ist. Der Capillary String wird unter produzierenden Bedingungen durch den Produktionsstrang eingebaut. Das andere Ende an der Oberfläche ist mit der Injektionseinheit verbunden. Diese besteht aus einem Tank, einer Pumpe und einem Filter. Der Schäumer wird schließlich vom Tank, durch den Filter abwärts durch den Capillary String gepumpt und tritt in das Bohrloch durch das Injektionsventil.

Der Schäumer, ein Benetzungsmittel, welches die Oberflächenspannung der Flüssigkeit reduziert, fördert die Schaumbildung im Bohrloch. Der Schaum hat eine geringere Dichte und kann von der Sonde selbst an die Oberfläche befördert werden.

Für die erfolgreiche Anwendung von Schäumern ist es notwendig eine geeignete Sonde zu finden. Dabei sind bestimmte Kriterien bei der Auswahl zu beachten.

Table of Contents

List of Figures

List of Figures in the Appendix

List of Tables

List of Tables in the Appendix

List of Abbreviations

BOP	Blow Out Preventer	
LGR	Liquid to Gas Ratio	m^3/Nm^3
LL	Liquid Loading	
MLT	Mini-Logging-Tool	
PLT	Production Logging Tool	
RAG	Rohöl Aufsuchungs AG	
SCSSV	Surface Controlled Subsurface Safety Valve	
SSSV	Subsurface Safety Valve	

A_d	Projected Cross-section of Liquid Droplet	ft^2
A_i	Internal Tubing Cross-section	ft^2
C	Turner Constant	1
C_D	Drag Coefficient	1
C_{opt}	Optimum Foamer Concentration	%
d	Droplet Diameter	ft
D_h	Inside Diameter of Production String	in
F_D	Drag Force	lbf
F_G	Gravity Force	lbf
g	Gravitational Constant, 32.17	ft/sec^2
g_C	32.17	$lbm\text{-}ft/lbf\text{-}s^2$
H_0	Initial Foam Height	mm
H_G	Gas Holdup	1
H_t	Foam Height after Time t	mm
H_L	Liquid Holdup	1
h	Injection Valve Setting Depth	m
P	Pressure	psia

p_{op}	Operating Pressure of Injection Valve	Pa
p_{bh}	Bottomhole Flowing Pressure	Pa
p_{hyd}	Hydrostatic Pressure	Pa
p_{inj}	Surface Injection Pressure	Pa
P_{hf}	Wellhead Flowing Pressure	psia
Q_g	(Critical) Gas Rate	Mscf/day
Q_{Gm}	Minimum Gas Rate to transport the Liquids	Mscf/day
Q_{inj}	Foamer Injection Rate	Liters/day
Q_o	Produced Oil or Condensate Rate	bbl/day
Q_s	Produced Solid Rate	ft^3/day
Q_w	Produced Water Rate	bbl/day
q_w	Produced Water Rate	m^3/day
S_g	Gas Gravity (also γ_G)	1
S_o	Condensate or Oil Gravity	1
S_s	Gravity of Solids (fresh water = 1)	1
S_w	Water Gravity	1
T	Temperature	°R
T_{av}	Average Temperature in Wellbore	°R
t	time	minutes
V	Volume of Liquid Droplet	ft^3
V_C	Critical Gas Velocity	ft/sec
$V_{C,foam}$	Critical Velocity achieved with Foamer	ft/sec
V_D	Liquid Droplet Velocity	ft/sec
V_G	Gas Velocity	ft/sec
V_L	Volume of Liquid in the Pipe Segment	m^3
V_T	Volume of Pipe Segment	m^3
v	Velocity of Foam Decay	mm/sec
Z	Real-Factor	1

γ_G	Gas Gravity	1
μ	Gas Viscosity	cp
ρ_f	Foam Density	lbm/ft^3
ρ_{foam}	Foam Density	kg/m^3
ρ_G	Gas Density	lbm/ft^3
ρ_L	Density Liquid	lbm/ft^3
σ	Surface Tension	dynes/cm

1 Introduction

Today most of the gas fields are between 20 to 40 years old. Besides the giant gas fields that soon will achieve their peak production, many small gas fields are already on decline. Due to that operators will have to deal with more and more stripper gas wells which are producing on the edge of their profitability. There are not just low gas production rates that make operators worry about but there are also increasing problems which come along with those low productivity gas wells. One major problem that arises is the accumulation of liquids in the wellbore. Both decreasing gas rates and increasing water production are the cause for the so called problem of “Liquid Loading”. As the number of gas wells that experience such a problem increases methods to solve that problem gain more importance. One of these methods is the Capillary String Technology. It allows the precise injection of foaming agent into the wellbore and with it the removal of liquids out of the wellbore. It is one of the very cheap deliquification methods and therefore it can be economic even in wells where the gas rate is low. This is one of the reasons why RAG is going to consider it for deliquification in their gas fields. The thesis will deal with the problem of liquid loading and further will discuss more precisely the capillary string technology and how a suitable candidate gas well is selected for that particular technology.

To start with liquid loading as the problem and the reason why a technology such as the capillary string is needed is discussed in the first chapter. This chapter addresses additional points such as the recognition of the problem and possible water sources as well. In a chapter following this one the critical velocity is discussed. It is important to know about this parameter because it is responsible for the removal of the liquids out of the wellbore and further it is affected by many deliquification methods, especially by the injection of foaming agents.

A rough overview is given about the available deliquification methods and further the methods related to foamer are discussed in more detail. The author does not emphasis on a detailed discussion of different deliquification methods because another thesis has already presented those and further good literature is available that summarizes these methodologies.

One major part of this thesis and therefore presented in a separate chapter is the capillary string technology itself and its components. In this chapter all the necessary components are discussed in detail and different ways of a capillary installation are presented. This chapter also includes a detailed discussion about the effects of a foamer, how an appropriate foamer is selected, and how the optimum foamer injection rate is found.

Before a capillary string is installed and foamer is injected, a suitable gas well has to be found. This thesis presents a way of finding an appropriate candidate well to maximise the success of such a technology. Points such as common problems, safety considerations, pros and cons, maintenance, and other applications are addressed in a separate chapter called operational considerations.

Finally in the last chapter the elaborated criteria of Chapter 6 are applied on RAG gas wells in order to find the first candidate well for installing the capillary string technology to inject foamer. It does also include an economic evaluation of this project.

All in all this thesis should give the reader detailed information about the capillary string technology and should be a guide for selecting the proper candidate well for a successful application.

2 Liquid Loading

“Liquid Loading of a gas well is the inability of the produced gas to remove the produced liquids from the wellbore”, Lea J.[1]. As a consequence liquid will accumulate in the wellbore and gas production is reduced until the well completely stops producing.

In today’s gas fields more and more gas wells experience liquid loading as a result of decreasing reservoir pressure and increasing liquid rates therefore this problem gains more importance. Basically the main factor in removing liquids out of the wellbore is the gas velocity in the production string. If the gas velocity is sufficient high enough it will drag the liquid droplets out of the wellbore. As long as this velocity is above a critical value (see Chapter 3, Calculation of Critical Velocity) no liquids will accumulate in the wellbore and the well will not load. Once the actual velocity drops below that critical velocity liquids can no longer be carried to the surface and as a result start to fall back and accumulate at the bottom.[1]

Due to the presence of two phases – gas and liquids – a multiphase flow exists in a gas well. For a better understanding of the interaction between liquids and gas in the well the four main flow regimes that a gas well can experience during its life are discussed.[1] Figure 2-1 shows those flow regimes which are dependent on gas- and liquid- phase velocity and the relative amounts of gas and liquids in the production string.

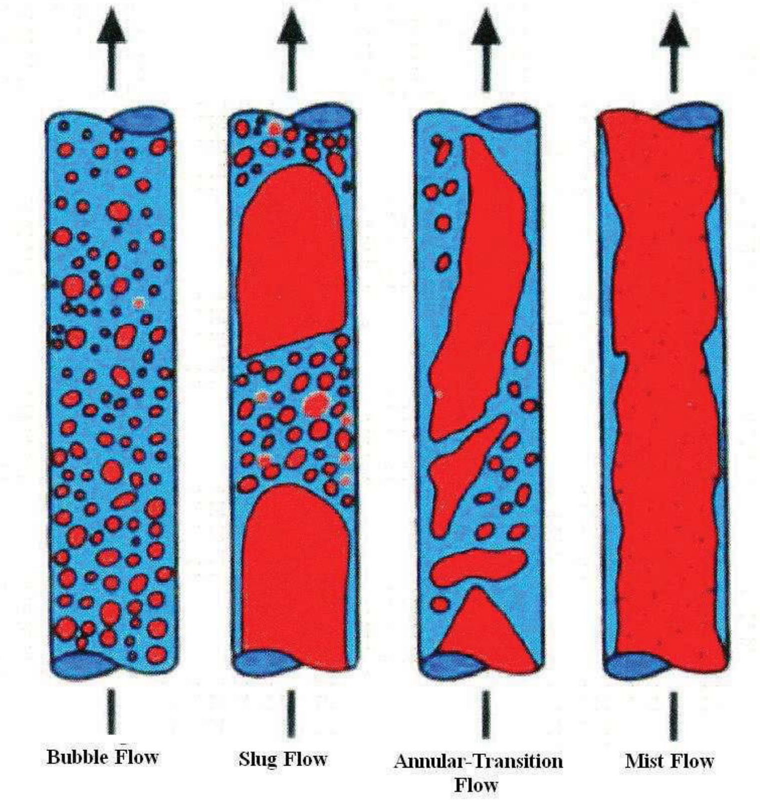


Figure 2-1 The Basic Flow Regimes in a Gas Well[2]

In case of **Bubble Flow** liquid is accumulated in the production string and gas bubbles through that column. The gas bubbles only reduce the density of the multi-phase fluid (Pseudo Density, see Chapter 12.1 in Appendix). This flow regime is the last one a gas well experiences before it stops producing.

In the **Slug Flow** stage more gas is present but liquid is still the continuous phase. Gas bubbles expand when they move upward the tubing and coalesce into large bubbles and further into slugs. A smaller pseudo density as in the bubble flow stage is observed.

When the continuous liquid phase changes into a continuous gas phase the **Slug-Annular Transition Flow** develops. Some liquid droplets are already entrained in the gas phase. The gradient is still significantly influenced by the liquid.

Finally in the **Annular Mist Flow** gas is the dominant phase. Liquid droplets are entrained in the gas phase as a mist. Part of the liquid can be found on the pipe wall. The pseudo density is mainly dominated by the gas flow. This flow regime is the first one a gas well experiences and allows the continuous removal of liquids.

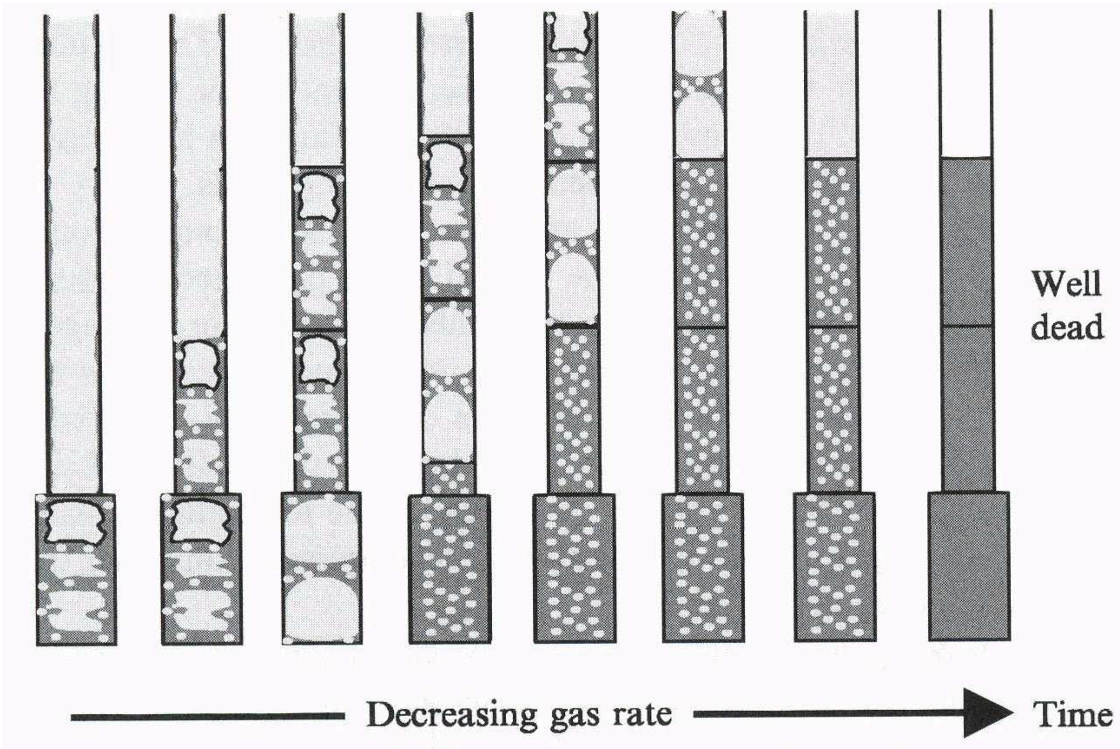


Figure 2-2 Transition of Flow Regimes in a Gas Well[1]

Despite of the main flow regimes transition zones between those exists. Figure 2-2 above shows the life history of a gas well it can go through. This cartoon considers a tubing that is set above the perforation interval and therefore in the larger diameter region in the casing a different flow regime may arise. At the beginning of a well's life the gas rate is high and the flow regime is in the mist flow. Due to a larger diameter below the tubing (lower velocity) a different flow regime can exist. As time passes and the production rate declines flow regimes change. Also an increase in liquid rate is observed in some case when gas rate declines. An increase in the liquid rate also effects the flowing conditions of a wellbore. Initially no changes in the flow regime are recognized at the surface as long as the conditions allow an annular mist flow. Once the slug-annular transition flow reaches the surface production becomes erratic. As the rate further declines the gas rate at the surface becomes steady again. In this stage the flow regime has changed to bubble flow where gas bubbles through a static liquid column and no liquids are transported to the surface. If the backpressure created by the liquid column is high enough the gas rate goes to zero.[1]

In the early stage of a wells life when the flow regime is in mist flow the liquid amount in the production string is low. This results in a low backpressure on the formation. As gas rate declines and flow regime changes the amount of liquid in the wellbore increases which causes an increase in the gravity component of the flowing fluid. The resulting higher backpressure further reduces the actual gas rate. To sum up there are two factors that cause a decrease in gas rate. One is the natural decline in reservoir pressure due to gas production which causes liquid loading to start. Second, once liquid loading in a well has started the increasing backpressure due to a higher amount of water additionally decreases the rate.
Optimizing or reducing liquid loading in wells that are already producing at its economic limit can keep the well online and prevent shutting in of the well. However, liquid loading does not only occur in low rate wells. Also in high gas rate wells problems due to liquid loading can arise. This is because such wells often have larger tubing sizes, to keep the frictional pressure drop low, and/or high wellhead pressures. This fact can result in a velocity that is too low to lift the liquid out of the wellbore.[1] This brings additional problems with it which are discussed in the following chapter.

2.1 Problems associated with Liquid Loading

An increased amount of liquid in the wellbore causes a higher backpressure on to the formation as previously mentioned. Therefore liquid loading reduces the production rate of a gas well. The well is no longer producing at its possible potential. Further an increased backpressure limits the minimum bottom-hole pressure which results in a lower reservoir pressure drawdown. As a consequence a lower recovery factor is achieved. To conclude liquid loading reduces the wells possible rate and decreases the recovery factor.[1]
Another problem associated with is an unstable, erratic gas rate when the flow regime has changed to slug-annular transition flow. Intermittently liquid slugs are produced from the wellbore. However, a smooth and stable gas rate is desired. Erratic production rate is one indication of a liquid loading problem.[1]
Liquid loading causes additional costs. This is because some of the low rate wells load with liquids and soon stop producing. In such a case the liquids being accumulated in the wellbore have to be lifted in order to bring the well back to

production. This well intervention costs money. Different methods of kicking of wells are possible and mentioned in the following chapters.[4]

So far liquid loading has been identified to be a major problem in wells producing liquids but it has not yet been stated where the liquid comes from. Therefore the following chapter presents several sources where the liquids may come from.

2.2 Possible Liquid Sources

When a gas well produces liquids it does not mean that it just produces formation water. If the reservoir pressure has decreased below the dew point condensate drops out and is produced with the gas as a liquid. As long as the reservoir pressure stays above the dew point the condensate is produced with the gas as vapor and condenses in the tubing or either in the separator. In the following the sources of produced liquid are listed:[1]

- **Free Formation Water**
  It is possible that the water comes already through the perforations into the wellbore from the formation due to an initial in situ water saturation.
- **Aquifer Water**
  If the reservoir is supported by an aquifer, water from that source can reach at some point the wellbore and causes liquid loading.
- **Water Coning**
  Due to a significant pressure drop in the near wellbore region water from a lower water zone can be entrained and reach the wellbore. This is possible even though the well is not perforated in the water zone.
- **Produced Water from a Different Zone**
  In case of several perforation intervals that are shot one of the formations could produce the water into the wellbore. This effect can be advantageous if the producing zone is the lowest one then water from a gas zone above can be injected into the lower one by pumps or gravity.
- **Water from Condensation**
  Water can enter the wellbore as a saturated or partially saturated vapor and can condense further up in the tubing when pressure and temperature decrease. If then the actual rate is below the critical one water will accumulate at the bottom of the wellbore. Condensed water can be identified due to a small or even no salt content.
- **Hydrocarbon Condensates**
  Hydrocarbons can be also part of the liquids in a wellbore. They can enter the wellbore in the vapor stage and similar to the formation water they can drop out in the tubing.

As mentioned hydrocarbons can accumulate in the wellbore as well and cause a stop in gas production. However, in the following parts of the thesis it is mainly talked about formation water, even though the term liquid is used.

2.3 Recognition of Liquid Loading

It is likely that during the life of a gas well at some point the liquid production increases and the gas rate drops. Such a situation usually results in an accumulation of liquids in the wellbore which further reduces the gas rate and causes an erratic behavior of the rate.

The earlier liquid loading of a well is recognized the lower can be the loss in production. Additionally accumulating limits across perforations can cause damage to the sand face. Therefore different symptoms are discussed that allow an early detection of liquid loading to prevent further problems.

Several symptoms can be used that indicate possible liquid loading and are listed below.[1, 3]

- Pressure Spikes on a Circular Chart
- Erratic Production Behavior and Increased Decline Rate
- Increasing Difference between Tubing and Casing Pressure
- Gradient Curves Showing a Strong Change in Pressure
- Stop in Liquid Production

These points are addressed in more detail in the following.

2.3.1 Circular Charts

Most of the mature and low gas rate wells are equipped with a pen recorder. This tool usually records wellhead pressure, gas rate, and in some case gas temperature. In case of a rate measurement an orifice in the production line is installed and the differential pressure (the difference between the pressure before and after the orifice) is measured. The rate in Nm^3/day is then calculated from that difference considering temperature, pressure, orifice diameter, and pipe diameter. In case the well produces in a mist flow regime the small liquid droplets in the gas stream have less effect on the pressure drop across the orifice. However, as soon as a liquid slug approaches, the higher density causes a much higher pressure drop across the orifice and a spike on the circular chart is recorded. The Figure 2-3 below shows two cartoons of circular chart readings representing two different flow regimes.

Once spikes on the circular chart occur the well has changed to slug flow which is already a flow regime where liquids start to accumulate in the wellbore. At this point wellhead pressure starts to decline and the gas rate decreases significantly faster as in case of a normal decline. This is a significant sign of liquid loading occurring in the wellbore.[1, 3]

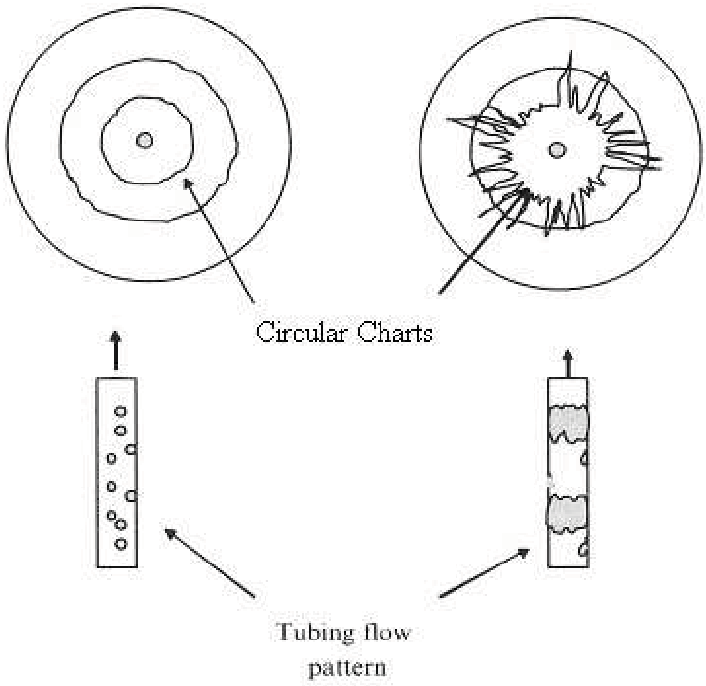


Figure 2-3 Schematic Comparison of Circular Charts Showing Different Flow Regimes[1]

2.3.2 Erratic Production Behavior and Increased Decline Rate

Another important indicator for liquid loading is the shape of the decline curve. When looking at the decline, changes in the overall trends should be recognized. Figure 2-4 shows a typical decline curve. At a certain point the rate significantly deviates from the proposed decline trend. This is the onset of liquid loading. The earlier this point is recognized the sooner relevant well interventions can be planned and the loss in production can be kept a minimum.

This sudden change in rate is due to the liquid accumulations in the well and the resulting increasing backpressure on the formation. A higher bottomhole flowing pressure means a lower gas production rate and this again increases the velocity at which liquids accumulate in the wellbore.[1, 3]

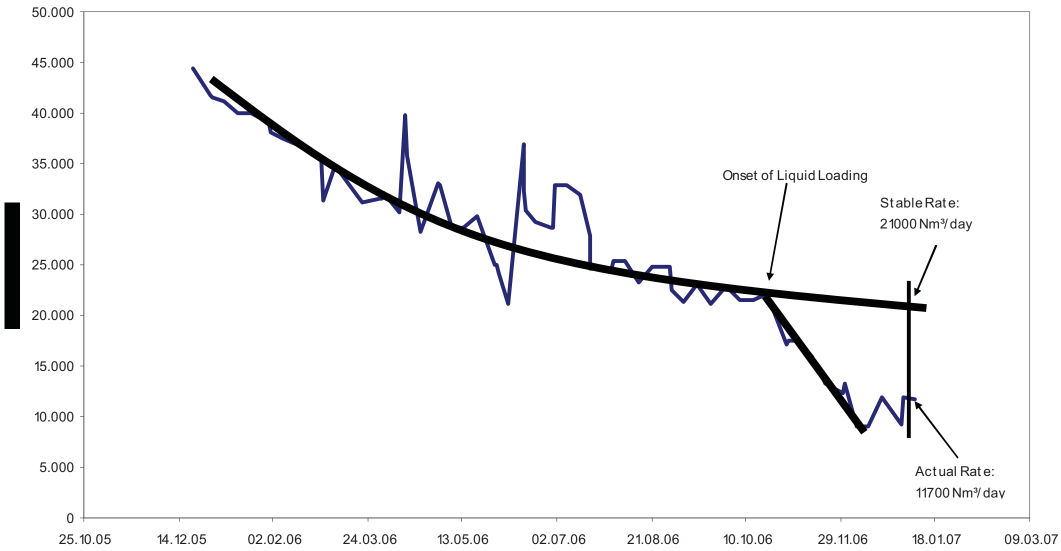


Figure 2-4 Decline Curve Showing a Drop in Rate due to Liquid Loading

2.3.3 Increasing Difference between Tubing and Casing Pressure

There are two reasons that can decrease the tubing head pressure. On the one hand side liquid accumulation at the bottom of the wellbore and on the other hand side an increased liquid production. A higher amount of liquid carried by the gas stream causes a higher backpressure. This results in a higher bottomhole pressure at a lower production rate. In case no packer is present gas can percolate into the tubing-casing annulus. As this gas is exposed to a higher pressure – increased bottomhole pressure - it will cause a higher pressure in the tubing-casing annulus and further a higher surface casing pressure. To sum up liquid loading causes a decrease in tubing pressure and at the same time an increase in surface casing pressure as long no packer is installed. A difference between casing and tubing pressure of greater than 200 psi is excessive.[5] Figure 2-5 shows those two pressures whereas the increase and decrease of the pressures has not to be linear. However in practice this chart is often difficult to achieve because the casing pressure is indeed checked on a regular basis but most of the time not recorded accurately enough especially in wells where no packer is installed.[1, 3]

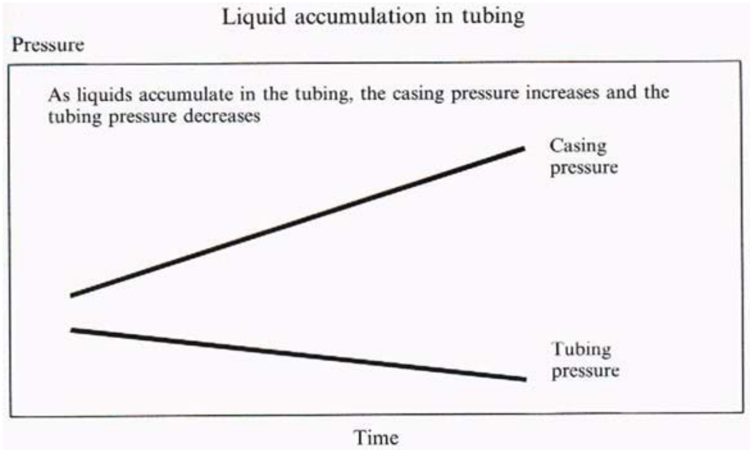


Figure 2-5 Comparison of Wellhead - and Surface Casing - Pressure[1]

2.3.4 Gradient Curves Showing a Strong Change in Pressure

One of the most accurate methods to determine the liquid level in the wellbore is a gradient survey. Measuring the pressure as a function of the depth shows whether a well is loading with liquids or not.[1] A significant increase in the gradient is good sign for determining the liquid level. This effect is much stronger in case the measurement has been conducted under static conditions. Measuring the gradient under flowing conditions no sudden change in the gradient can be observed but a more graduate change is recognized.[3] Figure 2-6 shows a gradient survey conducted under flowing conditions. It definitely shows a larger content of liquid in the lower portion of the wellbore. In the upper part only a small gradient is measured which indicates mainly gas and less liquids in the form of bubbles. Different gradients are observed which let conclude that different flow regimes are present. The measurement in Figure 2-6 definitely shows that the well is liquid loaded.

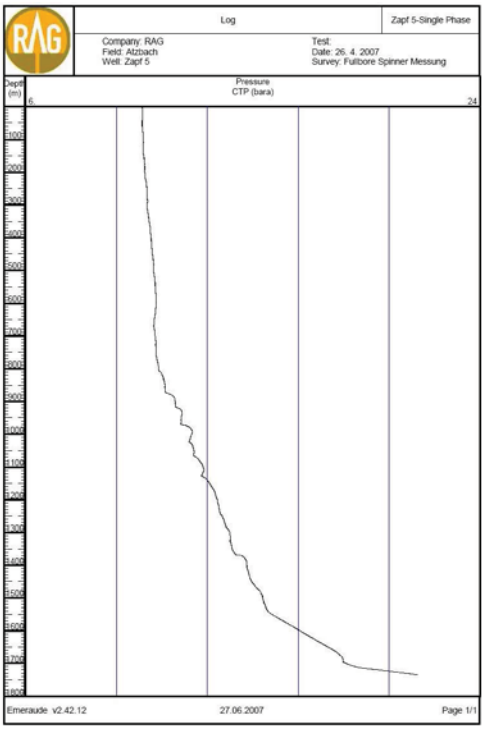


Figure 2-6 Example of a Measured Gradient Curve (from RAG MLT Tool)

2.3.5 Stop in Liquid Production

At some point the gas production rate has been declined to a point where no more liquid is produced to the surface. At this stage only gas is bubbling through a static liquid column in the wellbore. Depending on the liquid accumulation in the wellbore the well could even stop producing gas. In this case liquid loading has caused a complete stop in production. This is a very late sign for liquid loading and the previously mentioned points indicate a loading of the well in a much earlier stage. At least at that point when liquid production stops a well intervention has to be carried out to bring the well back to production.[1]

2.4 Other Problems associated with Liquid Loading

One major problem that comes with liquid loading besides the above mentioned problems is corrosion. Tubulars exposed to a liquid column of formation water experience higher corrosion rates. Another effect that enhances corrosion is the condensation of liquids in the wellbore. Together with CO_2 or H_2S increasing corrosion rates are observed. Also a flow regime in the slug stage is favorable for corrosion. Consequently by unloading the well with a foamer the condensed aqueous phase can be eliminated and the liquid level in the wellbore is reduced, which results in less surface area of pipe exposed to water.[5] Therefore injecting foamer can reduce the corrosion rate by changing the flow regime from slug flow to a pseudo one-phase flow or to annular mist flow.[20] In order to further decrease the corrosion rate corrosion inhibitors can be injected together with the foamer (see Chapter 7.6).

2.5 Prevention of Liquid Loading

In the previous chapters signs of liquid loading have been discussed. However, at this point liquid loading has already started in the wellbore. A much better way would be to prevent liquid loading and avoid loading of the well. One possible way is to predict the onset of liquid loading. This is done by calculating the well's critical rate. Further considering the actual decline of the rate would then enable the design engineer to determine the point when the actual rate of the well falls below the critical rate. However the gained results have to be evaluated carefully because this method assumes two major parameters. One is that the water production from the reservoir remains the same and no increase is observed which hardly is the case (constant LGR). Second to calculate the critical velocity the surface tension of the produced water (see Chapter 5.2.2.1) has to be assumed.

How to determine the wellbore's critical velocity and further to identify wells which suffer from liquid loading is discussed in the following chapter.

3 Calculation of Critical Velocity

In the beginning of the thesis liquid loading has been defined as the inability of the wellbore to bring the liquids up to the surface resulting in an accumulation of liquids at the bottom (see Chapter 2). Now in this chapter the main parameter that influences the liquid removal process is discussed. The velocity inside the production string and the flow regime are responsible for the upward movement of the liquids to the surface. A certain velocity is required to move the liquids upward mainly against the gravity. This certain velocity is the Critical Velocity. There are many different equations available that enable the calculation of the critical velocity at different wellbore conditions. These equations or models would allow identifying wells which suffer from liquid loading and further liquid loading could then be prevented. Many authors have presented different solutions which range from simple ones to very complex solutions. Basically the different possibilities to determine the critical velocity can be distinguished based on the background they are derived from. Some people established critical velocities just based on empirical data, others established models which again were fitted to data. In turn some based their developments on energy models. In the following the different approaches are discussed in separate chapters beginning with the simplest solutions. In all the chapters it is talked about the critical velocity but in terms of gas production it is more convenient to talk about rates. Therefore any critical velocity can be transformed in a critical gas rate by the following equation.[1]

$$Q_g = \frac{3067 P V_C A_i}{TZ} \quad Mscf / Day$$

This makes the critical rate specific for a certain wellbore.

3.1 Critical Velocity Based on Empirical Data

In the 1960s Duggan and Turner, Hubbard, and Duckler investigated the critical velocity in gas wells. Duggan reported a critical velocity that is based on field experience gained from wells producing condensate.[6] He reported that a critical velocity of 1.53 m/sec can unload some of the wells. Smith, who also investigates a wide range of data, came up with a critical velocity in the range of 3.05 to 6.1 m/sec.[6, 7]

Those were the first estimates of a critical velocity based on empirical data. However, as this is only accurate in the area where the data come from, these velocities can not predict a critical velocity in a field with different conditions.
At the same time Turner invested the critical velocity as well but established a physical model to find a solution for predicting the critical velocity in a wellbore.

3.2 Critical Velocity Based on Models

Turner et al.[8] were the first ones to derive an equation for the critical velocity based on a physical model. In 1969 Turner et al. investigated two models. One has been the continuous film model and the second one the entrained droplet model. By comparing those two models they proved that the entrained droplet model is more adequate in the high velocity gas stream. They used this model to evaluate the liquid loading effect in gas wells.[8]
Several modifications due to empirical data were done by different authors but all of them base on the same physical model. Different modifications are discussed as follows.

3.2.1 Turner's Critical Velocity

In the following the critical velocity is derived based on the droplet model.[8] A spherical droplet in a continuous gas stream is assumed. Figure 3-1 illustrates the situation and shows the forces acting on the droplet.

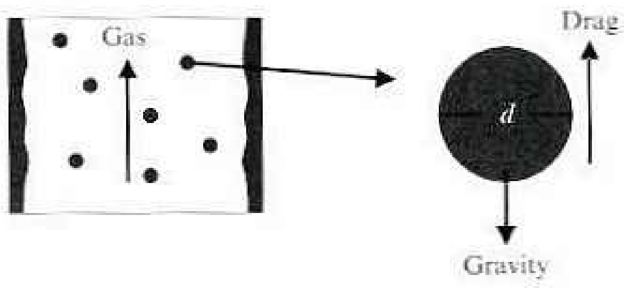


Figure 3-1 Forces Acting on a Liquid Droplet in a Gas Stream[1]

In order to float a droplet the drag force has to equal the gravity force and thus to lift up the droplet the drag force has to be even higher.
The Drag Force is defined as follows:

$$F_D = \frac{1}{2g_C}\rho_G C_D A_d \left(V_G - V_d\right)^2 \qquad (1)$$

The Gravity Force is:

$$F_G = \frac{g}{g_C}(\rho_L - \rho_G)\cdot\frac{\pi d^3}{6} \quad \text{(2)}$$

Setting the two Forces equal:

$$F_D = F_G$$

$$\frac{1}{2gc}\rho_G C_D A_d (V_G - V_d)^2 = \frac{g}{g_C}(\rho_L - \rho_G)\cdot\frac{\pi d^3}{6} \quad \text{(3)}$$

Further substituting $A_d = \frac{\pi d^2}{4}$ into the expression above and solving for V_C results in:

$$V_C = \sqrt{\frac{4g(\rho_L - \rho_G)d}{3\rho_G C_D}} \quad \text{(4)}$$

This equation requires the droplet diameter to be known. However, in reality it is dependent on the gas velocity. For droplets being entrained in a gas stream the dependency can be described by the dimensionless Weber number:[9]

$$N_{WE} = \frac{V_C^2 \rho_G d}{\sigma g_C} = 30 \quad \text{(5)}$$

Rearranging for d:

$$d = 30\frac{\sigma g_C}{\rho_G V_C^2} \quad \text{(6)}$$

Inserting this equation in (4) results in:

$$V_C = \sqrt{\frac{4}{3}\frac{(\rho_L - \rho_G)}{\rho_G}\frac{g}{C_D}30\frac{\sigma g_C}{\rho_G V_C^2}} \quad \text{(7)}$$

or

$$V_C = \left(\frac{40 g g_C}{C_D}\right)^{1/4}\left(\frac{\rho_L - \rho_G}{\rho_G^2}\sigma\right)^{1/4} \quad \text{(8)}$$

Turner et al.[8] assumed a fully turbulent flow regime throughout the whole tubing that is always in the range between $10^4 < N_{Re} < 2x10^5$. This results in a drag coefficient of 0.44.[8] They Inserting this number and values for g and g_C in (8) following equation arises:

$$V_C = 17.514\left(\frac{\rho_L - \rho_G}{\rho_G^2}\sigma\right)^{1/4} \quad \text{.......... (9)}$$

It is more common to use dynes/cm as a unit for surface tension. Using the conversion mentioned below equation (10) arises.

$$1\,{}^{lbf}\!/_{ft} = 0.00006852\,{}^{dynes}\!/_{cm}$$

$$V_C = 1.593\left(\frac{\rho_L - \rho_G}{\rho_G^2}\sigma\right)^{1/4} \quad {}^{ft}\!/_{\sec} \quad \text{.......... (10)}$$

As the gas density is significantly pressure and temperature dependent it is calculated from the real gas law as follows.

$$\rho_G = 2.715\gamma_G \frac{P}{TZ}$$

Inserting this equation in (10) results in:

$$V_C = 1.593\left(\frac{\rho_L - 2.715\gamma_G \,{}^{P}\!/_{TZ}}{\left(2.715\gamma_G \,{}^{P}\!/_{TZ}\right)^2}\sigma\right)^{1/4} \quad \text{.......... (11)}$$

This is the original Turner solution!

Turner et al. figured out that for their field data a 20 % upward correction was necessary to match the data. In this data set wellhead pressures were above 1000psi. Consequently the equation below is valid for wells having such high wellhead pressures.

$$V_C = 1.593 \cdot 1.2 \cdot \left(\frac{\rho_L - 2.715\gamma_G \,{}^{P}\!/_{TZ}}{\left(2.715\gamma_G \,{}^{P}\!/_{TZ}\right)^2}\sigma\right)^{1/4} = 1.912\left(\frac{\rho_L - 2.715\gamma_G \,{}^{P}\!/_{TZ}}{\left(2.715\gamma_G \,{}^{P}\!/_{TZ}\right)^2}\sigma\right)^{1/4} \quad \text{....... (12)}$$

This equation can be simplified if typical values for T, Z, gas gravity and surface tension are used:

$$\gamma_G = 0.6$$
$$T = 580°R$$
$$Z = 0.9$$
$$\sigma = 60 \; dynes/cm \;\; for \; water$$

The simplified equation for the critical velocity for water would then be

$$V_C = 5.321 \frac{(\rho_L - 0.0031P)^{1/4}}{(0.0031P)^{1/2}} \quad ft/\sec \qquad (13)$$

Equation (12) includes two assumptions. First the liquid droplets have a spherical shape and the gas stream is highly turbulent (drag coefficient) where the Reynolds-Number is in between 10^4 and $2x10^5$. Turner et al. suggest that in most of the cases wellhead conditions determine the onset of liquid loading and further they say that LGRs between 5.6E-6 m³/Nm³ and 7.3E-4 m³/Nm³ do not effect the critical velocity.[8] Finally this equation is adapted to wells having wellhead pressures more than 1000 psi.

3.2.2 Coleman's Critical Velocity

Coleman et al.[10] figured out that equation (11) fits their data more precisely. This is the one without a 20% adjustment. This is because most of Coleman's data is from wells having wellhead pressures below a pressure of 1000 psi.[10] Therefore for lower pressures the following equation is valid (the same as equation (11)).

$$V_C = 1.593 \left(\frac{\rho_L - 2.715\gamma_G \, P/TZ}{\left(2.715\gamma_G \, P/TZ\right)^2} \sigma \right)^{1/4} \qquad (14)$$

The simplified version would then be

$$V_C = 4.434 \frac{(\rho_L - 0.0031P)^{1/4}}{(0.0031P)^{1/2}} \quad ft/\sec \qquad (15)$$

Coleman et al. also concluded that the critical flow rate is unaffected by a LGR below of 11.2E-5 m³/Nm³.[10]

Basically for the Coleman equations the same assumptions as for the Turner equations apply. The only difference is that they are more precise for wells having a wellhead pressure below 1000 psi.

3.2.3 Nosseir's Critical Velocity

Turner et al. developed an analytical model which was then adjusted to the data. Therefore Turner's corrected solution is just a semi-analytical one. Nosseir et al.[11] made a new approach and converted this semi-analytical equation into a generalized analytical approach. Nosseir calculated the Reynolds-Number for the data Turner used. He figured out that most of the data has a Reynolds-Number larger then $2x10^5$ which Turner assumed for his drag coefficient (C_D=0.44 for a range between 10^4 and $2x10^5$). However, at Reynolds-Numbers higher then $2x10^5$ a different drag coefficient is valid, namely 0.2. This explains why Turner et al. had to adjust their equation to match the data.

Due to the wide range of pressures, temperatures, and flow rates encountered in gas wells different flow regimes arise. Consequently Nosseir developed two equations one for the transition zone and one for the highly turbulent region. Both equations are derived from the same physical droplet model.[11]

In case of low gas rate wells a transition flow regime is possible. Nosseir derived this equation starting with Allen's equation. That is because Allen derived an equation that is valid for a N_{Re} in the range of 1 to 1000 where turbulence is developing gradually.

Allen's equation:

$$V_G = 0.2\left[\frac{g(\rho_L - \rho_G)}{\rho_G}\right]^{0.72} \frac{d^{1.18}}{\left(\mu / \rho_G\right)^{0.45}} \quad \text{.......} (16)$$

The Hinze equation is applied to determine the largest droplet size.

$$d = \frac{30 g_C}{V_G^2 \rho_G} \quad \text{.......} (17)$$

Inserting the equation above into (16) results in the following equation for a transition flow regime.

$$V_C = 14.6\sigma^{1/4} \frac{(\rho_L - \rho_G)^{0.21}}{\mu^{0.134} \rho_G^{0.426}} \quad \text{.......} (18)$$

In case of a highly turbulent flow regime Nosseir used a drag coefficient of 0.2 for a Reynolds-Number higher than 2E5. Inserting this number into equation (8) will result in the one that follows.

$$V_C = 21.3\left(\frac{\rho_L - \rho_G}{\rho_G^2}\sigma\right)^{1/4} \quad \text{.......} (19)$$

Nosseir improved the semi-analytical solution from Turner and derived an analytical solution that enables the calculation of the critical velocity at Reynolds-Numbers higher then $2x10^5$. For a transitional flow regime a separate equation has been presented by Nosseir.

3.2.4 Min's Critical Velocity

Min et al.[12] observed that there are many gas wells that are producing below the critical velocity and do not load as Turner's equation would estimate. They figured out that the assumption of a spherical shaped liquid droplet is not valid in a high rate well. Due to the pressure difference between before and behind a droplet it tends to deform. The surface tension would then act against this force. This will result in a droplet having a much greater cross section (see Figure 3-2) resulting in a more favorable uplift condition.

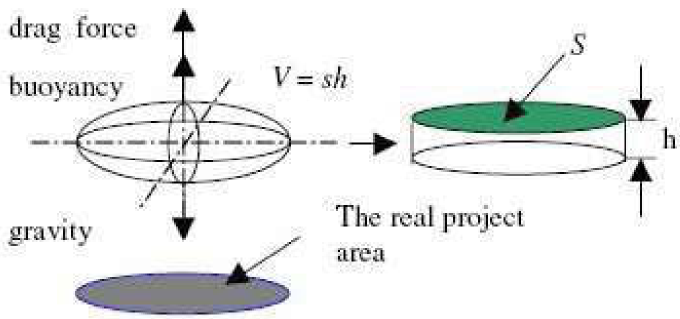


Figure 3-2 Supposed Shape of a Droplet in a High Rate Well[12]

Nosseir developed the following equation for the project area s from the Bernoulli Law and the force balance between surface tension and the pressure difference.

$$s = \frac{\rho_G V_C^2 V}{2\sigma} \quad (20)$$

Inserting the project area s into the equation for the balance of forces between gravitational force and drag force the following equation results.

$$V_C = \sqrt[4]{\frac{4(\rho_L - \rho_G) g \sigma}{\rho_G^2 C_D}} \quad (21)$$

Due to the flat shape of the droplet the efficient area held by gas is 100%. Therefore a drag coefficient of 1 is assumed. Inserting this values and a value for g in the equation (21) leads to the following final equation for the critical velocity.

$$V_C = 0.727 \left(\frac{(\rho_L - \rho_G)}{\rho_G^2} \sigma \right)^{1/4} \; ft/\sec \quad (22)$$

This equation supposes a flat shape of a liquid droplet in gas wells having high rates and assumes a drag coefficient of 1.

3.3 Critical Velocity Based on the Energy Model

Guo B et al.[13] developed a new approach of calculating the critical velocity for liquid removal. They based their solution on the minimum energy that is necessary to move the liquid upward in a flowing gas well.

This new method is based on the minimum kinetic energy criterion and a four-phase mist-flow model in gas wells. The minimum kinetic energy criterion requires that the gas kinetic energy exceeds a minimum value to transport the liquids upwards. The four phase model is necessary to accurately predict the pressure and thus the fluid density which is used in the kinetic energy criterion.

The minimum kinetic energy per volume of gas is calculated as follows.

$$E_k = \frac{\rho_G V_G^2}{2 g_C} \qquad (23)$$

Combining equation (23) with the Turner droplet model (equation (8)) results in the minimum kinetic energy to keep liquid droplets floating (**minimum kinetic energy for floating E_{ksl}**).

$$E_{ksl} = 0.026 \sqrt{\frac{\sigma(\rho_L - \rho_G)}{C_D}} \qquad (24)$$

Taking the drag coefficient from Turner and assuming that the gas density has no effect the following simplified equation comes up.

$$E_{ksl} = 0.04 \sqrt{\sigma \rho_L} \qquad (25)$$

The minimum gas velocity V_{gm} for moving the droplets upwards is equal the sum of the minimum gas velocity to keep the droplets floating V_{sl} plus the transport velocity V_{tr} of the droplets.

$$V_{gm} = V_{sl} + V_{tr} \qquad (26)$$

Transport velocity would be a function of gas production rate, geometry of conduit, and liquid volume fraction. Therefore instead of formulating an expression the transport velocity is taken to be 20 % of the floating velocity based on the work of Turner[8]. This results in the following equation.

$$V_{gm} \approx 1.2 \cdot V_{sl} \qquad (27)$$

Inserting equation (27) and (8) into equation (23) the following equation for the minimum kinetic energy to transport a droplet arises (**minimum kinetic transport energy, E_{km}**).

$$E_{km} = 0.0576\sqrt{\sigma\rho_L} \quad (28)$$

In order to calculate the kinetic energy of gas (equation 23) values for the gas density and gas velocity are needed. The gas density can be calculated from the real gas law and the gas velocity can be calculated from the gas rate throught the following equations.

$$\rho_G = \frac{2.7 S_g P}{T} \quad (29)$$

$$V_G = 4.71\times10^{-2}\frac{TQ_G}{A_i P} \quad (30)$$

Inserting both equations into equation (3) leads to the following

$$E_k = 9.3\times10^{-5}\frac{S_g T Q_G^2}{A_i^2 P} \quad (31)$$

This equation indicates that the kinetic energy decreases with increasing pressure. Therefore bottomhole conditions are the controlling factor which is in contradiction with Turner's results where the wellhead conditions are the most controlling ones.

So far the kinetic energies have been discussed. In the following the four phase model is introduced in order to accurately predict the bottomhole pressure.

Guo B. et al. developed a four phase model where the pressure P at depth L can be calculated from following formula:

$$144b\left(P-P_{hf}\right)+\frac{1-2bm}{2}\ln\left|\frac{\left(144P+m\right)^2+n}{\left(144P_{hf}+m\right)^2+n}\right|-\frac{m+\frac{b}{c}n-bm^2}{\sqrt{n}}\left[\tan^{-1}\left(\frac{144P+m}{\sqrt{n}}\right)-\tan^{-1}\left(\frac{144P_{hf}+m}{\sqrt{n}}\right)\right]= \quad (32)$$

$$=\alpha\left(1+d^2e\right)L$$

where

$$a=\frac{15.33S_sQ_s+86.07S_wQ_w+86.07S_oQ_o+18.79S_gQ_G}{10^3T_{av}Q_G}\cos(\theta) \quad (33)$$

$$b = \frac{0.2456Q_s + 1.379Q_w + 1.379Q_o}{10^3 T_{av} Q_G} \quad \text{......} (34)$$

$$c = \frac{6.785 \times 10^{-6} T_{av} Q_G}{A_i} \quad \text{......} (35)$$

$$d = \frac{Q_s + 5.615(Q_w + Q_o)}{600 A_i} \quad \text{......} (36)$$

$$e = \frac{6f}{gD_h \cos(\theta)} \quad \text{......} (37)$$

$$f = \left[\frac{1}{1.74 - 2\log\left(\frac{2\varepsilon'}{D_h}\right)} \right]^2 \quad \text{......} (38)$$

$$m = \frac{cde}{1 + d^2 e} \quad \text{......} (39)$$

$$n = \frac{c^2 e}{(1 + d^2 e)^2} \quad \text{......} (40)$$

The minimum unloading condition requires that the kinetic energy is at least as high as the minimum kinetic energy to transport a liquid droplet up the tubing string. Consequently equation (31) becomes the following one:

$$E_{km} = 9.3 \times 10^{-5} \frac{S_g T Q_{Gm}^2}{A_i^2 P} \quad \text{......} (41)$$

Calculating the pressure from equation (41) results in

$$P = 9.3 \times 10^{-5} \frac{S_g T Q_{Gm}^2}{A_i^2 E_{km}} \quad \text{......} (42)$$

Inserting equation (42) into (32) the following equation comes up:

$$144b\alpha_1 + \frac{1 - 2bm}{2} \ln(\alpha_2) - \frac{m + \frac{b}{c} n - bm^2}{\sqrt{n}} \left[\tan^{-1} \beta_1 - \tan^{-1} \beta_2\right] = a(1 + d^2 e)L \quad \text{......} (43)$$

where

$$\alpha_1 = 9.3\times10^{-5}\frac{S_g T Q_{gm}^2}{A_i^2 E_{km}} - P_{hf} \quad (44)$$

$$\alpha_2 = \frac{\left(1.34\times10^{-2}\frac{S_g T Q_{gm}^2}{A_i^2 E_{km}} + m\right)^2 + n}{\left(144 P_{hf} + m\right)^2 + n} \quad (45)$$

$$\beta_1 = \frac{1.34\times10^{-2}\frac{S_g T Q_{gm}^2}{A_i^2 E_{km}} + m}{\sqrt{n}} \quad (46)$$

$$\beta_2 = \frac{144 P_{hf} + m}{\sqrt{n}} \quad (47)$$

Equation (43) cannot be solved explicitly. However, numerical methods can be applied. For example using MS Excel the implemented tool Goal Seek Function can be used to solve this equation. Usually a value for the minimum gas rate **Q_{gm}** is assumed and then both sides of the equation are calculated. Q_{gm} is varied until both sides are equal. The author implemented this equation in his critical rate calculations in Chapter 6.2.1. In that chapter the Excel-spreadsheet is explained in more detail.

To sum up this approach is based on Turner's droplet model as well and it assumes a spherical shaped droplet. Additionally a drag coefficient of 0.44 is taken and the gas density neglected when calculating the minimum kinetic energy to float a liquid droplet in the wellbore. Further a 20 % increase in velocity is considered to be necessary to finally transport the liquids up. Guo B. et al. found out that bottomhole conditions are the controlling conditions rather then top hole conditions. This is because if a well is not loading at the bottom it will not load at any point up the tubing due to the increasing superficial gas velocity which results in a more favorable flow regime to lift the liquids.

3.4 Sensitivity Study of Critical Velocity

In order to study the effect of different variables on the critical velocity a Monte Carlo Simulation is run. Input variables are summarized in the adjacent Table 3-6.

INPUT		Values		
Variable	Unit	min	max	most common
Liquid Density	[lbm/cf]	62,43	70	64,93
Gas Gravity	[1]	0,6	0,78	0,75
Wellhead Pressure	[psia]	43,5	291	79,8
Surface Temperature	[°R]	510	540	519
Z-Factor	[1]	0,9	0,99	0,98
Pipe ID	[ft]	0,117	0,256	0,166
Surface Tension	[dynes/cm]	60	75	72
"Turner" Constant	[1]	1,593	1,593	1593

Table 3-1 Input Variables and Assumed Values for Monte Carlo Simulation

In a first step the sensitivity of the different variables in Turner's equation are analyzed. This equation is used because it is the most widely one used and many solutions presented in the previous chapters have the same form but just a different Turner's Constant. The equation below is the one used in this analysis.

$$V_C = C \cdot \left(\frac{\rho_L - 2.715\gamma_G \, {}^{P}\!/_{TZ}}{\left(2.715\gamma_G \, {}^{P}\!/_{TZ}\right)^2} \sigma \right)^{1/4}$$

where C is the "Turner's Constant". For all the above mentioned variables triangular distributions where assumed for simplicity. Running the Monte Carlo Simulation the following sensitivity chart comes up.

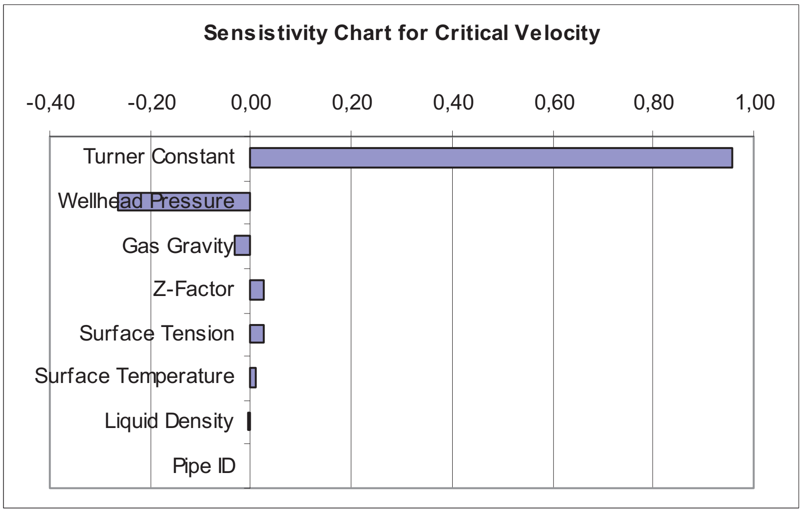


Table 3-2 Sensitivity Chart for the Critical Velocity

The chart above shows that the Turner's Constant has the most influence on the calculated critical velocity. This indicates how important it is to select the right model for the calculation. A second parameter that has a significant influence on the velocity is the wellhead pressure or in other terms the surface wellbore pressure. It shows that with increasing pressure the critical velocity decreases. However, at bottomhole conditions where the pressure is higher the critical velocity would be lower. The way it should be understood here is that an increased pressure in the wellbore increases the gas density and a denser medium can lift the liquid droplets more easily.

In a second study one specific model is selected. This means that the Turner Constant is fixed. In this case the Coleman Model is simulated with a constant of C=1.593. The surface wellbore pressure is also fixed to get a better view on the sensitivities of the other parameters.

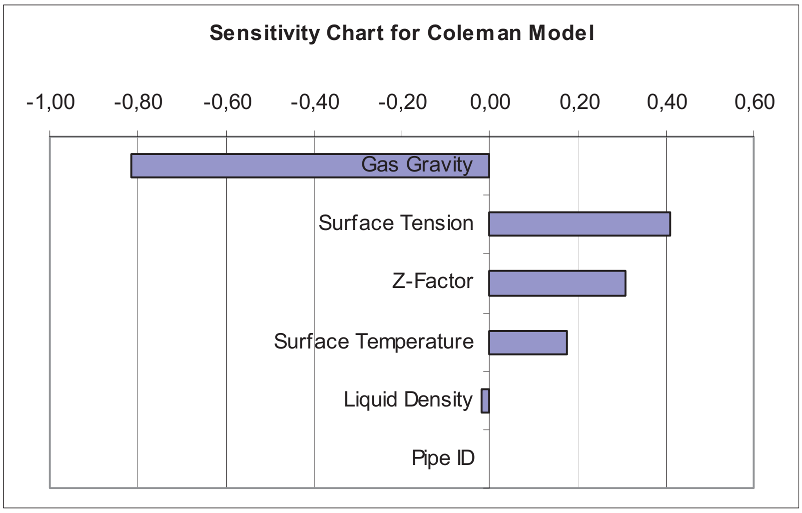


Table 3-3 Sensitivity Chart for Coleman Model (fixed Pressure)

It turns out that gas gravity has a significant effect. The gas gravity is similar to the pressure. A higher gravity means a higher gas density which further is favourable in lifting the liquids. Besides the Turner's Constant and the gas density the surface tension is another very important parameter too. This points out the importance of an accurate value for the surface tension which is in practice often not known and has to be assumed.

The last study calculates the critical **gas rate** according to the following formula:

$$Q_G = \frac{0.4653 P D_h^2 \pi C \sigma^{1/4} \left(\rho_L - 2.715 \gamma_G \frac{P}{TZ} \right)^{1/4}}{\left(TZ \gamma_G P \right)^{1/4}}$$

This equation results from the following two equations.

$$V_C = C \cdot \left(\frac{\rho_L - 2.715\gamma_G \, P/_{TZ}}{\left(2.715\gamma_G \, P/_{TZ}\right)^2} \sigma \right)^{1/4} \quad \text{and} \quad Q_g = \frac{3067 P V_C A_i}{TZ} \quad Mscf / Day$$

Therefore a new sensitivity chart arises considering the pipe ID of the production string.

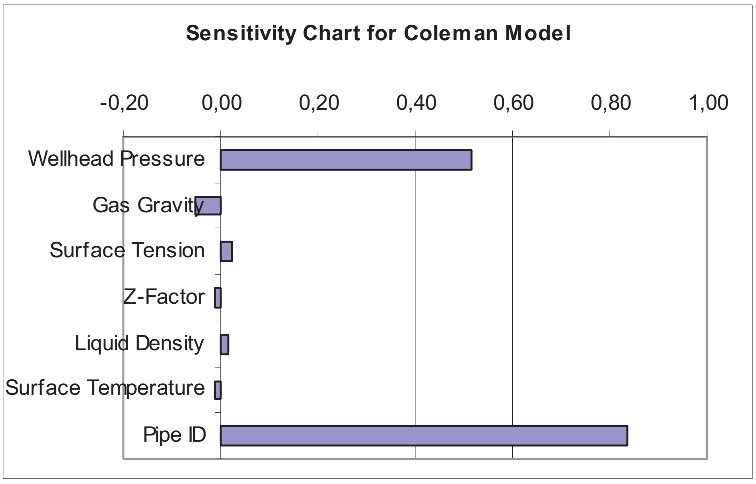


Table 3-4 Coleman Model Sensitivity Chart

This chart shows the pipe ID to be the most important parameter in calculating the critical gas rate. Therefore as a first means to influence the critical rate the tubing size of the current production string should be evaluated. Care should be taken when analysing this chart. Increasing the pipe diameter increases the gas rate as well at a constant gas velocity. On the other hand decreasing the pipe ID and keeping the gas rate constant would cause an increase of the critical velocity which is favourable for liquid removal. To sum up the wellbore's critical gas rate is mainly determined by the pipe ID and the pressure in the wellbore. The smaller the tubing the smaller is the critical gas rate.

3.5 Summary of Critical Velocities

In the following Table 3-5 the different solutions for the calculation of the critical velocity are summarized.

Critical Velocity Solutions			
Reynolds-Number N_{Re}	**1< N_{Re} < 1000 Transition Flow Regime**	**10000 < N_{Re} < 200000 Turbulent Flow Regime**	**N_{Re} > 200000 Highly Turbulent Flow Regime (high Rate Wells)**
Turner Solution			spherical shaped droplet, 20% Adjustment to fit data, semi-analytical solution, P_{WH} > 1000 psi
Coleman Solution		spherical shaped droplet, original Turner Equ., analytical solution, P_{WH} < 1000 psi	
Nosseir Transition Solution	sperical shaped droplet, for low rate wells, analytical solution, transitional flow regime		
Nosseir Highly Turbulent Solution			spherical shaped droplet, analytical solution, drag Coefficient of 0.2
Min's Solution			flat shaped droplet, assumes drag coefficient of 1
Energy Approach		spherical shaped droplet, drag Coefficient of 0.44, considers Liquid Prod., for higher GLRs better	
GLR	between a GLR 5.6E-6 and 7.3E-4 m3/Nm³ the critical velocity is not effected; at higher GLRs the Energy Approach delivers more accurate values		

Table 3-5 Summary of Critical Velocity Solutions

Each equation has certain assumptions it is based on. Consequently to choose the right equation the current wells condition should be as close as possible to these assumptions in order to get accurate results. For example most of the considered RAG gas wells, which are discussed in a later chapter, are in the medium range concerning their flow rates. Further as wellhead pressures are below a 1000 psia there are two equations that predict critical velocities rather accurate. Those are the Coleman solution and the Energy Approach. As a consequence these equations are the basis for the critical velocity calculation in the spreadsheet the author has created and is presenting in Chapter 6.2.1. The author recognized during his evaluation of the critical velocities of RAG gas wells that as long as the LGR is in the requested range Coleman solution and the Energy Approach are very close, with the Energy Approach suggesting a little bit higher values. In case of one well where a higher LGR has been observed the Energy Approach showed a significant higher critical velocity which has been consistent with the critical velocity experienced for this well in the field.

The Table 3-6 below shows a summary for the different equations to calculate the critical velocity.

Critical Velocity Equations			
Reynolds-Number N_{Re}	**$1 < N_{Re} < 1000$ Transition Flow Regime**	**$10000 < N_{Re} < 200000$ Turbulent Flow Regime**	**$N_{Re} > 200000$ Highly Turbulent Flow Regime (high Rate Wells)**
Turner Solution			$V_C = 1.912\left(\frac{\rho_L - 2.715\gamma_G \frac{P}{TZ}}{\left(2.715\gamma_G \frac{P}{TZ}\right)^2}\sigma\right)^{1/4}$
Coleman Solution		$V_C = 1.593\left(\frac{\rho_L - 2.715\gamma_G \frac{P}{TZ}}{\left(2.715\gamma_G \frac{P}{TZ}\right)^2}\sigma\right)^{1/4}$	
Nosseir Transition Solution	$V_C = 14.6\sigma^{1/4}\frac{\left(\rho_L - 2.715\gamma_G \frac{P}{TZ}\right)^{0.21}}{\mu^{0.134}\left(2.715\gamma_G \frac{P}{TZ}\right)^{0.426}}$		
Nosseir Highly Turbulent Solution			$V_C = 21.3\left(\frac{\rho_L - 2.715\gamma_G \frac{P}{TZ}}{\left(2.715\gamma_G \frac{P}{TZ}\right)^2}\sigma\right)^{1/4}$
Min's Solution			$V_C = 0.727\left(\frac{\left(\rho_L - 2.715\gamma_G \frac{P}{TZ}\right)}{\left(2.715\gamma_G \frac{P}{TZ}\right)^2}\sigma\right)^{1/4}$
Energy Approach		see relevant Chapter	
GLR	between a GLR 5.6E-6 and 7.3E-4 m3/Nm³ the critical velocity is not effected; at higher GLRs the Energy Approach delivers more accurate values		

Table 3-6 A Summary of the Equations for Calculating the Critical Velocity

Thus to perform the calculation some data is required. In practice a well can have several flow regimes throughout the whole production string. Therefore dependent on where the calculation is made (at wellhead or bottomhole conditions) different flow regimes may arise. It is recommended that the calculation is made at the wellhead because at this point the gas slippage is highest and with it the gas velocity. This ensures a maximum gas velocity to unload the well.[11] However, the Energy Approach has shown that bottomhole conditions are the more controlling factor. If a well is not loading at bottomhole conditions it will definitely not load in a section further up the tubing. In praxis accurate bottomhole data is rarely available. Analyzing the critical rate at wellhead conditions is accurate enough to do a first estimate of the critical velocity. If the well is already loading at wellhead conditions it is loading at the bottom as well. Despite of this if the well is not loading according to the critical velocity at wellhead conditions it might load at a point further downward in the tubing. In this case bottomhole data is needed to further evaluate the well. For analyzing the critical velocities in this document wellhead conditions as a first approach are considered.

The sensitivity analysis has shown that the type of model to be used has a major impact on the critical velocity. Besides the type of model gas density (affected by pressure, gas gravity, temperature) and surface tension influence the critical velocity significantly. In terms of the critical gas rate the pipe ID comes in. In a smaller production conduit the critical gas rate is lower. At this point the author wants to point out that this sensitivity study is done on the critical velocity and critical gas rate in a wellbore. It does not say anything about the actual gas velocity or gas rate. In Chapter 6.2.1 the critical rate and the wellbores actual rate are compared to figure out whether the well is susceptible to liquid loading or not.

4 Methods to Unload Liquid Loaded Wells

Once liquid loading has been identified as the well's problem and gas production from the wellbore has dropped certain well interventions are necessary to bring the well back to its possible rate. In general there are plenty of methods available where most of them are summarized in the following list starting with the most common ones used in RAG.[14,15,16]

- Change of tubing size (increases tubing velocity)
- Soap Sticks
- Injection of Surfactants
- Venting
- Reduction of the wellhead pressure (e.g. booster, eductor)
- Increase of gas rate (additional perforations, acidizing, reservoir flooding to maintain pressure)
- Debottlenecking of the production system (removal of any restrictions in the tubing and in the surface equipment)
- Reduction of skin effect (e.g. acidizing)
- Production through annulus (if a higher velocity can be achieved)
- Reduction of the water production rate (cement squeeze, gel injection, plug)
- Plunger Lift
- Intermittent Production (well shut-in from time to time)
- Gas Lift
- Downhole Gas- Water Separation
- Velocity or Siphon String
- Pumping (beam-, progressive cavity-, electrical submersible-, hydraulic-pumping)
- Swabbing
- Vortex
- Insulating or heating up the tubing

When looking at the different methods someone recognizes that those treat different sources to solve the liquid loading problem. Basically these methods can be classified into three categories as follows:

- **Increasing the gas rate:** This is one option to solve the problem. Increasing the actual gas rate to a rate higher then the critical rate will cause the liquids being removed from the wellbore.
- **Decreasing the water production**: On the other hand the water source can be treated. For example shutting of the water bearing layers can also solve the problem.
- **Removing the water from the wellbore**: This is the most common way in handling the liquid loading problem. Once the gas rate cannot be increased anymore and water production can not be reduced

these methods remain the last ones before a wellbore has to be shut in.

Part of the above mentioned methods are used to kick-off a wellbore. In case where wells just load from time to time no continuous removal of liquid is necessary.

The method which is best is difficult to predict. That is because there is no clear interface between the different methods. The optimum method is the one that is most economic for the longest period of time.[16] Several factors will influence the selection of a specific solution. Überer W.[17] has discussed several deliquification methods and listed pros and cons for each of them. Additionally Lea J. et al.[16] have also described several methods extensively. Therefore the author refers to these two literatures for more detailed information on different deliquification methods. However, the deliquification methods related to surfactants are discussed in more detail below.

4.1 Deliquification with Surfactants

A foamer is a very popular means in unloading gas wells. It decreases the surface tension and the liquid density (see Chapter 5.2.2). In the form of soap sticks a foamer can be applied very simple and quick. Therefore it is often used as a first attempt to unload gas wells. In general a foamer can be applied to a wellbore either continuously or intermittently.[15]

4.1.1 Intermittent Foamer Application

The volume of surfactant that is needed is determined by the amount of water that is produced by the wellbore which further determines the type of foamer application. In case of a low water production rate resulting in a low loading rate of the wellbore an intermittent application of foamer is sufficient. In practical terms this can be found out by applying the foamer and observing the loading behavior of the well. If one soap stick per week is sufficient to keep the production at the desired level an intermittent application is recommended. However, it has to be evaluated whether a continuous application of foamer would not bring a significantly higher gas production. If an intermittent foamer application turns out to be the most economic solution there are two possibilities someone has.

4.1.1.1 Soap Sticks

Foamer can be applied in the form of a soap stick. These cylindrical shaped sticks are simple to handle by the field people and are inserted in the wellbore through a sticks lubricator mounted on top of the wellhead. The number of sticks being applied is determined by the amount of water in the wellbore and how fast the well will load again. This is one of the most common deliquification methods used within RAG. Very often soap sticks in conjunction with a short well shut-in (1 to 2 hours) are used. This short pressure build up improves the removal of the liquids from the wellbore.

Soap sticks can be lubricated into the well automatically as well, namely by a so called soap stick launcher. This tool is mounted on top of the wellhead and keeps a certain amount of sticks in stock. At specific pre-selected time intervals soap sticks are released and fall into the wellbore. A soap stick launcher has to be ATEX certified in order to be used in an explosion hazard area. Figure Figure 4-1 below shows such a soap stick launcher.

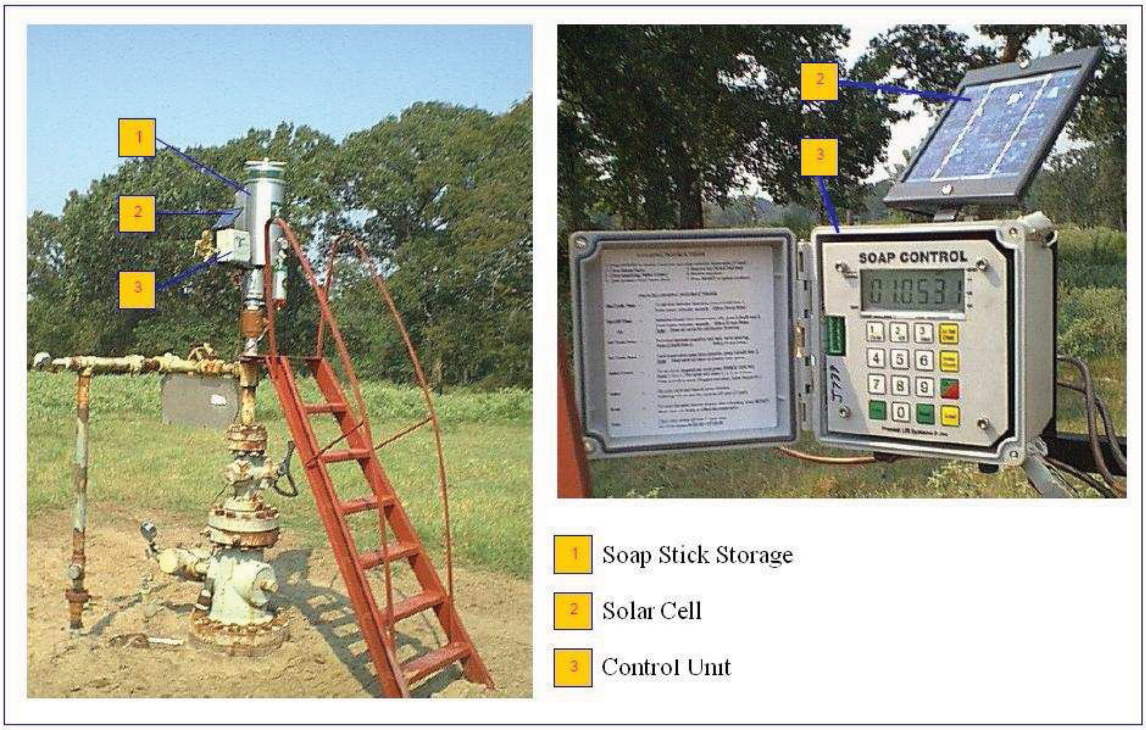


Figure 4-1 Typical Automatic Soap Stick Launcher mounted on Top of a Well in the USA[18]

4.1.1.2 Batch Treatments

Another possibility of intermittent foamer application is the use of liquid foamers instead of soap sticks. In such a case the well has to be shut in to fill a certain amount of foamer into the wellbore. This is done by closing the master– and production– valve. Each time only a limited volume of foamer that fits between the master valve and the top wellhead flange can be added. This is repeated until the desired volume of foamer has been added to the wellbore. After that the well is kept shut-in for a certain period of time because it takes a while till the foamer reaches the bottom of the wellbore. Much more time and work is required by the field people in order to do a batch treatment.

4.1.2 Continuous Foamer Application

In some cases the liquid loading rate is high enough that soap sticks or batch treatments have to be conducted several times a week. This would require even more time and work by the field people and also causes increased costs. Despite of that a higher production rate can be achieved throughout a continuous foamer application. In general a liquid foamer can be applied continuously either through the annulus or through the tubing.

4.1.2.1 Backside Injection

The simplest and cheapest way to inject foamer is through the casing-tubing annulus. An injection unit as described in one of the later chapters is connected to the casing valve. This type of treatment is only possible if there is a connection (no packer or an open SSD) between the annulus and the tubing. Within RAG several such units are operated successfully. They are simple to install and do not require any changes in the existing surface equipment. However, a disadvantage is that foamers are usually injected at low rates and consequently it can take quite a long time till the foamer reaches the bottom where it mixes with the gas and the water. In some cases it takes up to two weeks till a wellbore reacts on any changes of the injection rate, as it is reported by field people.

4.1.2.2 Capillary String

A further possible way to bring the foamer into the wellbore is through a capillary string. This capillary string can be either installed inside the tubing or in the casing-tubing annulus strapped to the tubing. This small in diameter tubing enables the possibility to inject foamer at a controlled rate in a desired depth.

Injecting foamer utilizing a capillary string is the main topic of this thesis and therefore discussed in more detail in the following chapters.

5 Capillary String Technology

The Capillary String Injection System is a technology that utilizes a capillary string to inject surfactants into the wellbore at a desired depth, most likely close at the perforation interval. The capillary string is a conduit having OD's of 0.25, 0.375, and 0.75 in (see also chapter 5.1.3). Usually the capillary string is run into the wellbore through the tubing under life well conditions. On the other hand it is also possible to install the capillary string through the tubing-casing annulus strapped to the tubing, but this requires the co-installation of both tubing and capillary string at the same time. However, this document deals with the capillary string installed through the tubing which has an enormous advantage, namely, as previously mentioned, the installation under life-well conditions. It is not necessary to kill the well in order to run the capillary string into the wellbore.

The capillary string technology is not a new technology. In the United States capillary strings to inject foamers have already been applied successfully for years. Now in Europe this technique gets more and more popular. A few installations can be found in Germany and the Netherlands as well as offshore in the North Sea.

Most of the gas fields are between 20 to 40 years or even older. With declining production rates, operators have to deal with more and more stripper gas wells on the edge of profitability. As a consequence only low cost solutions for production problems at the tail end phase are economic even when the gas price is high.[14] Further with decreasing reservoir pressure the sensitivity of the wellbore to any damage, for example from a workover fluid, increases. Due to that the Capillary Injection System in combination with a suitable foamer is an excellent deliquification method for mature gas wells.[14]

In general the application of foam is limited on the one hand side by the economics and on the other hand side by the success of foam generation which directly influences the bottom-hole flowing pressure. Gas wells having low rates and LGR of 7E-4 to 6E-3 m^3/Nm^3 are better candidates for foam, but there is no upper limit in LGR. Plunger lift may be the better method for higher LGR, but just in case the bottom-hole pressure is high.[19]

Up to now many success stories have been reported in different papers.[23] Just to point out one example Figure 5-1 shows the production of a well prior and after a continuous injection system is installed. Injecting foamer does not only increase the production of a proper selected well (see Chapter 6) but also stabilizes the rate if the well is producing erratically.[20]

How a capillary string is installed, maintained, as well as other operational considerations are discussed separately in Chapter 7.

In the following the whole injection system is subdivided into the necessary hardware (components) and the surfactant that is pumped.

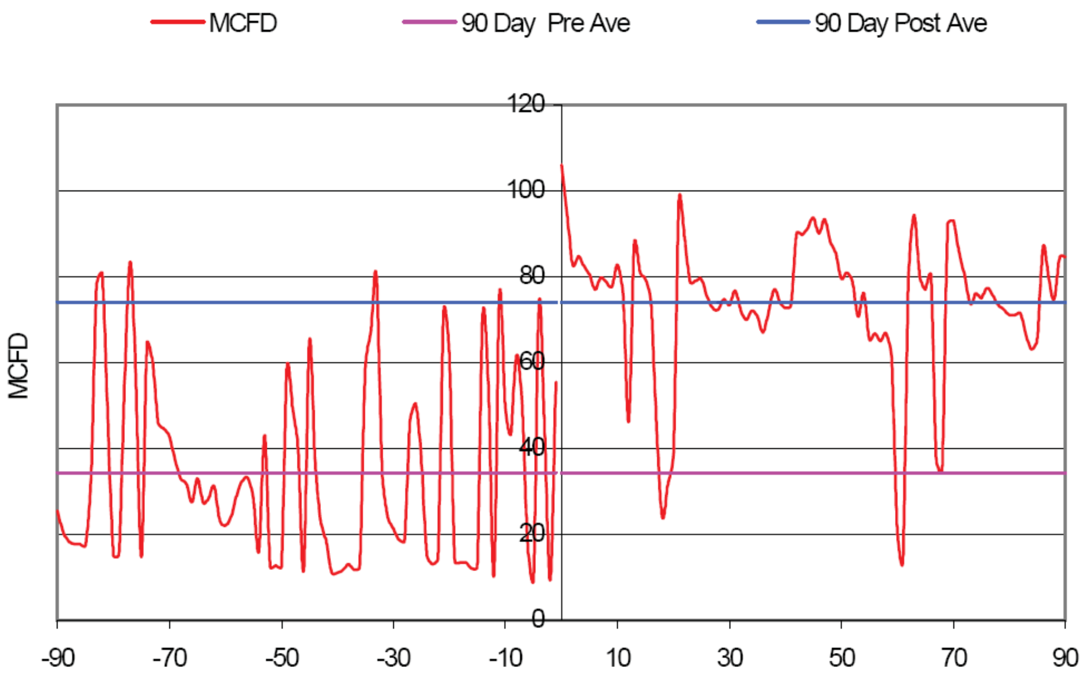


Figure 5-1 90 Day Pre-Installation of Capillary String and 90 Day Post-Installation Production Data[23]

5.1 Components

The whole capillary injection system consists of several components where each of those takes over a specific role. In general the system can be divided between the part that is installed in the wellbore and the part that is mounted on a skid and placed somewhere at the well site. Figure 5-2 shows a general outline of the whole injection system. A pump sucks the surfactant from the tank and pumps it through a filter down the capillary string through the downhole injection valve into the wellbore. In the following chapters each component is discussed in more detail.

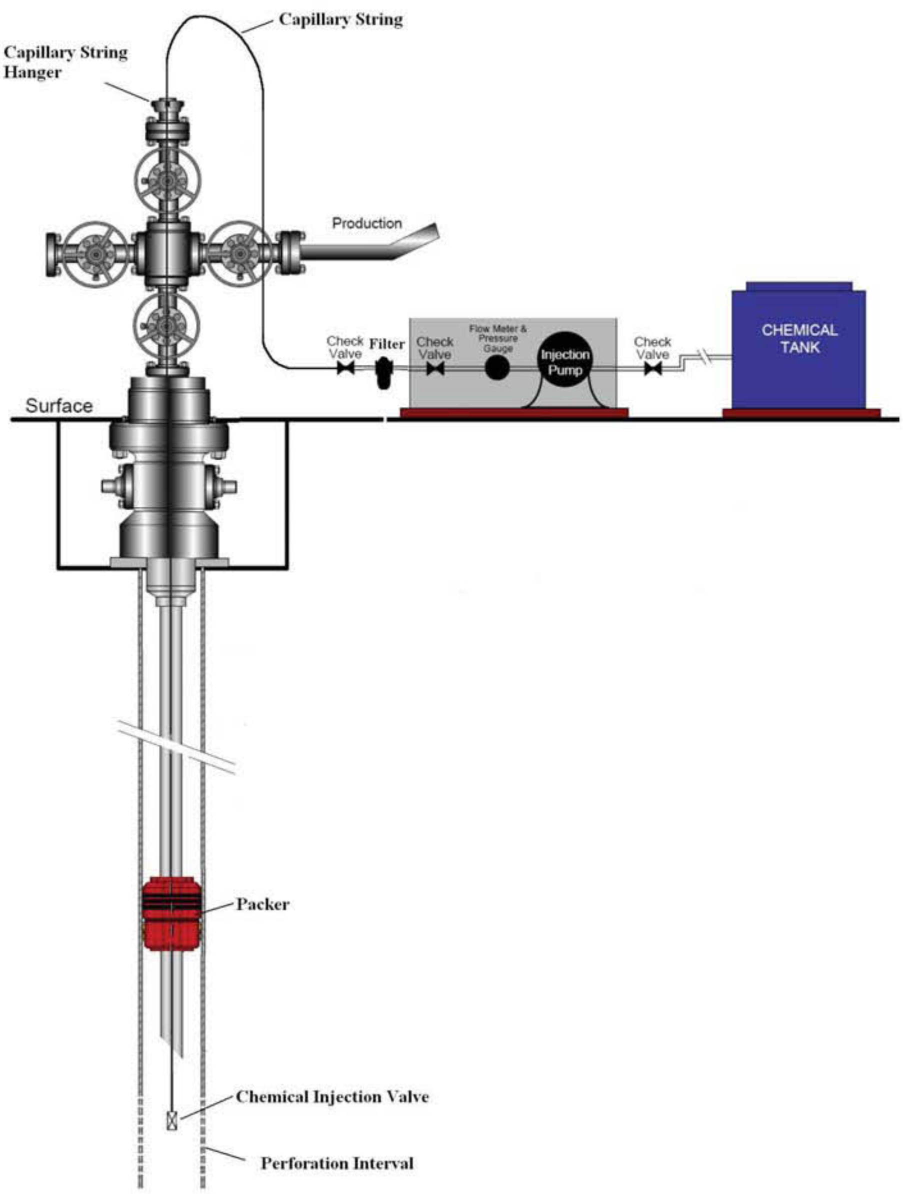


Figure 5-2 Capillary String Injection System Outline [modified from Weatherford]

5.1.1 Downhole Injection Valve

To start with the lowest part of the system is the downhole injection valve (or chemical injection valve) which is connected to the end of the capillary tubing string. It is the point where the foaming agent exits the capillary string and enters the wellbore to mix with the wellbore fluids. The main purpose of the injection valve is to prevent wellbore liquids from entering the capillary string and dependent on the type of injection valve it provides a means of controlled injection. Wellbore fluids such as condensate, formation water, and/or gas may cause plugging of the capillary tubing due to sand, mineral scale, or chemical precipitation (see Chapter 7.3).[24] Further it prevents gas from percolating up the capillary string to the surface tank which would be a significant safety issue. Though an open ended capillary string is not recommended , however, there are some applications, e.g. “siphon applications” where no downhole injection valve is used.

Basically two types of downhole injection valves can be distinguished. On the one hand those that consist of a check valve and on the other hand those that consist of a back pressure valve.

A check valve is made of a ball and a spring where the spring keeps the ball pressed against the ball seat (Figure 5-3). This kind of valve is designed to allow flow only in one direction which enables chemicals in the capillary string to enter the wellbore and prohibits wellbore liquids from entering the capillary tubing. The main disadvantage of an application of such a valve is that it can not hold any backpressure. That is because the valve is usually pre-set only to a certain pressure (roughly 150 psi) on the check allowing the valve to open at a fixed differential pressure. In other words as soon as the wellbore bottom-hole pressure is lower than the hydrostatic head of the liquid column in the capillary string and the opening pressure of the valve (150 psi), the chemical will flow through the valve into the wellbore. It does not allow a controlled injection of surfactants into the wellbore. It is a cheap solution but tends to siphon which should be avoided.[25]

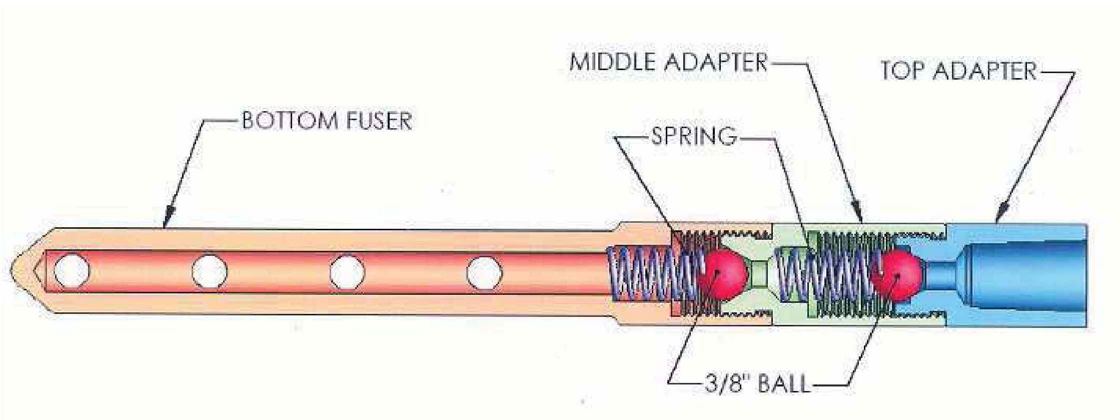


Figure 5-3 A ¾” OD 316L Stainless Steel Check Valve for Capillary Strings[26]

In order to accomplish this problem another type of injection valve, namely a backpressure valve, can be used. The principle components are the same as in case of the check valve but the spring is much stronger and can be adjusted according to the backpressure (hydrostatic column in the capillary string plus the surface injection pressure) that is necessary to hold (Figure 5-4). The activation pressure is determined by bottom-hole pressure, setting depth, and surface pump capability; it can be set up to 8,500 psi. For a valve such as in Figure 5-4 the maximum working pressure (differential pressure) is 5000 psi. It prevents uncontrolled leakage of chemicals in the capillary tubing into the wellbore ("free fall") and enables the design engineer to control the foamer injection rate. An additional pressure at the surface is necessary to overcome the spring tension and force the surfactant into the wellbore. Another advantage of a backpressure valve is that it ensures that the capillary string is filled with surfactants all the time. If there are any gaps in the fluid column the wellbore temperature could bake the chemical and plug up the capillary string.[28] Despite of that the valve has to be set according to a certain setting depth which would require an additional step in the operation sequence.

The downhole injection valves are available in different OD's (5/8", 3/4", or 1") and also with two barriers (two check valves or two backpressure valves) due to different customers needs.[29]

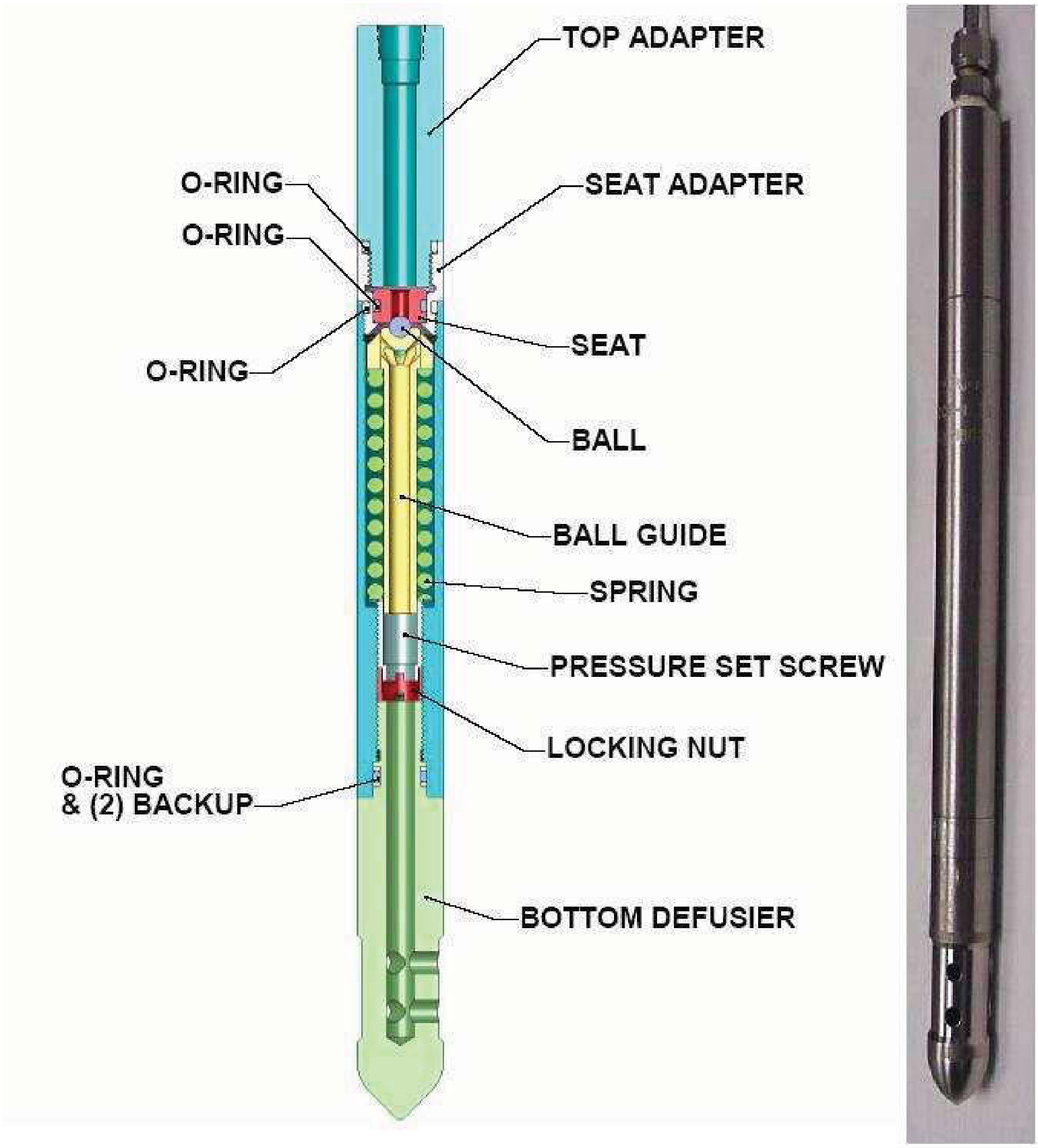


Figure 5-4 Circle "C" Chemical Injection Valve, OD 1", drawing[26] and picture[27]

Common materials for a downhole injection valve body are 316 L stainless steel, Monel© and some other premium materials. The balls and ball seats are either made of 316 L stainless steel in case of check valves or tungsten carbide in case of backpressure valves. Inconel© alloy is used for the high loaded spring in a backpressure valve. In general the valves can be assembled by the manufacturer due to the customer's needs which will depend on setting depth, well temperature, corrosiveness of the wellbore environment, and surfactant properties and injection rate.[30]

As previously mentioned there are some applications where no downhole injection valve is used. Though the above mentioned valves offer a safe and controlled operation of foaming agent injection there might be operators that use a type of barrel at the end of the capillary tubing string that is equipped with nozzles (see Figure 5-5).

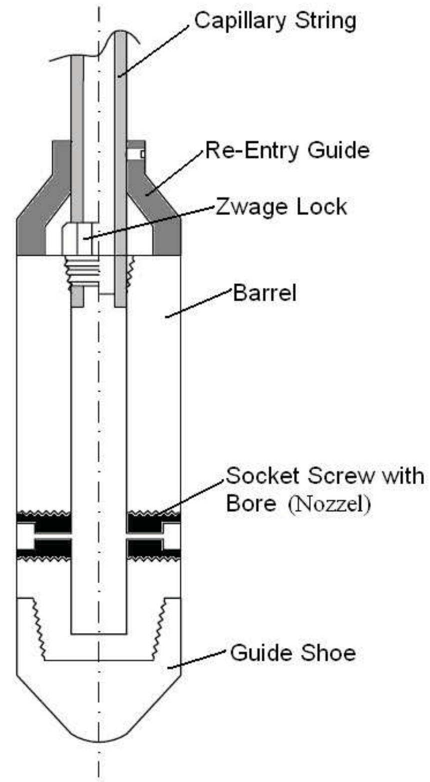


Figure 5-5 Sketch of a Simple Barrel used as a Downhole Injection Tool

This tool consists of the barrel and a guide nose at the lower end of the barrel. The top end of the barrel is connected to the capillary string. A cross hole in the lower part of the tool is the opening where the chemical can enter the wellbore. These openings have a thread that holds a socket screw with a hole inside, the nozzle. The nozzle size can be designed according to the desired injection rate. This is a cheaper solution compared to the above mentioned check valve and backpressure valve but it provides less control over the chemical injection.[31]

In high gas rate wells it is recommended to add a centralizer to the injection valve as well. This will stabilize the valve in the center of the borehole and will prevent bouncing of the valve which can cause the capillary string to fail.

5.1.2 Weight Bar/Sinker Bar

In some cases a weight bar is added to the capillary string to add additional weight to the string which would keep the capillary string in tension and further would ease the installation process. Usually the capillary string is installed without a weight bar but in case it will not run in hole a weight bar is added.[32] Further the downhole injection valve or barrel does have a certain cross-section and in conjunction with a pressure difference between the inside of the tubing and the atmospheric pressure a force in the upward direction will result. This force should be evaluated in the design process but may be negligible dependent on the pressure difference between wellbore and surface.[31]

5.1.3 Capillary Tubing

The capillary string (or macaroni string, cap string, capillary tubing) is a small diameter stainless steel alloy tubing that is hung into the wellbore to inject the foaming agent more efficiently at the desired depth. The upper end of the capillary string is connected either to the tubing or to the wellhead through a capillary string hanger. At the lower end of the string the barrel or chemical injection valve is attached.

Basically the capillary string can be installed through the tubing or the tubing-casing annulus strapped to the production tubing if no packer is installed. In the presence of a packer a control line conduit through the packer would then be required. Nevertheless it is more common to run the capillary string inside the tubing. The reason for this is that a capillary string can be installed under life well conditions and also be removed every time without killing the well. Further if no packer is used (or in case of a packer the SSD has to be open) surfactant can be injected into the casing annulus without a capillary string as well which would be much cheaper but not that effective. Surfactant will tend to hang on the tubing and casing walls which would require diluting the chemical or flushing it down in order to ensure that the chemical reaches the wellbore bottom.[33] On the other hand strapping the capillary tubing to the outside of the production tubing is advantageous in operations where a pump or a plunger is used as well. Additionally other wellbore interventions such as MLT measurements and wireline runs are still possible.

The setting depth of the capillary string should be right above the top perforation or at least in the upper most 1/3 of producing interval.[19] It is necessary to inject at a point where enough agitation ensures a proper mixing of formation fluids (gas and liquids) and foaming agent.[23] Landing the capillary string below the perforations would have no effect due to an absence of gas and further the risk of getting stuck increases if the well is producing some formation fines.[19, 34] In addition foaming agent will have to pass by the upper perforations resulting in a contact with the formation face which again can cause some unwanted plugging of perforations (clay swelling, precipitations) in case of incompatibility.[14, 37]

Usually a capillary tubing has an outer diameter ranging from 0.125 in to 0.375 in where the most common one is 0.25 in. They can be installed up to depths of 24,000 ft (1/4 in OD, 0.035 in wall thickness, duplex 2205 alloy).[34]

Today the majority of capillary strings installed in wells are Duplex Alloy 2205 but the strings are in several other alloys available as well. Those materials are listed in the table below according to increasing corrosion resistance.[24]

Name	Depth Limitation [ft]
300 Series Stainles Steel	14,000
2205 Duplex Alloy	24,000
2507 Duplex Alloy	24,000
INCONEL© Alloy 625	12,000
INCONEL© Alloy 825	7,000

Table 5-1 Capillary String Materials and Depth Limits[24, 34]

Duplex Alloy 2205 got more popular due to its enhanced resistance to corrosion. That was necessary because the previously used 300 Series Stainless Steel was limited to lower temperatures and non corrosive environments. The Duplex Alloy 2205 has excellent mechanical properties but at high bottom-hole temperatures and brines with a high amount of total dissolved solids its corrosion resistance is not predictable. Sullivan et al.[36] reported failures of several 2205 Duplex Alloy capillary strings in environments with 300°F bottom -hole temperature, 3 % CO_2, 3-5 ppm H_2S and chloride saturated water.

Super Duplex Alloy 2507 has a higher corrosion resistance than Duplex Alloy 2205 but still not applicable to highly corrosive environments. In case of the presence of CO_2, H_2S, high bottom-hole temperatures and high chloride brines INCONEL© Alloy 625 is the more proper material for the capillary string. It is a high nickel stainless steel and it provides a good corrosion resistance in such critical environments. Another austenitic alloy is INCONEL© Alloy 825. This type of alloy has similar corrosion resistance but its yield strength is lower and therefore its setting depth is limited to about 7000ft.[34, 37]

In order to select the proper material for the capillary string the following points have to be addressed:[24]

- Partial Pressure of H_2S and CO_2
- Chlorides Concentration, pH-Value
- Bottom-hole Temperature
- Setting Depth

In the following a chart is provided by Schillmoller[38] (Figure 5-6) to choose an alloy based on the partial pressures of CO_2 and H_2S. Further to consider chlorides concentration, pH-value and bottom-hole temperature another chart (Figure 5-7) is applied. These two charts provide a means of selecting the most corrosion resistant alloy for the wells given environment. Finally it has to be determined whether the capillary strings own weight, including the weight of the liquid inside the string, is not exceeding the tensile strength.[24]

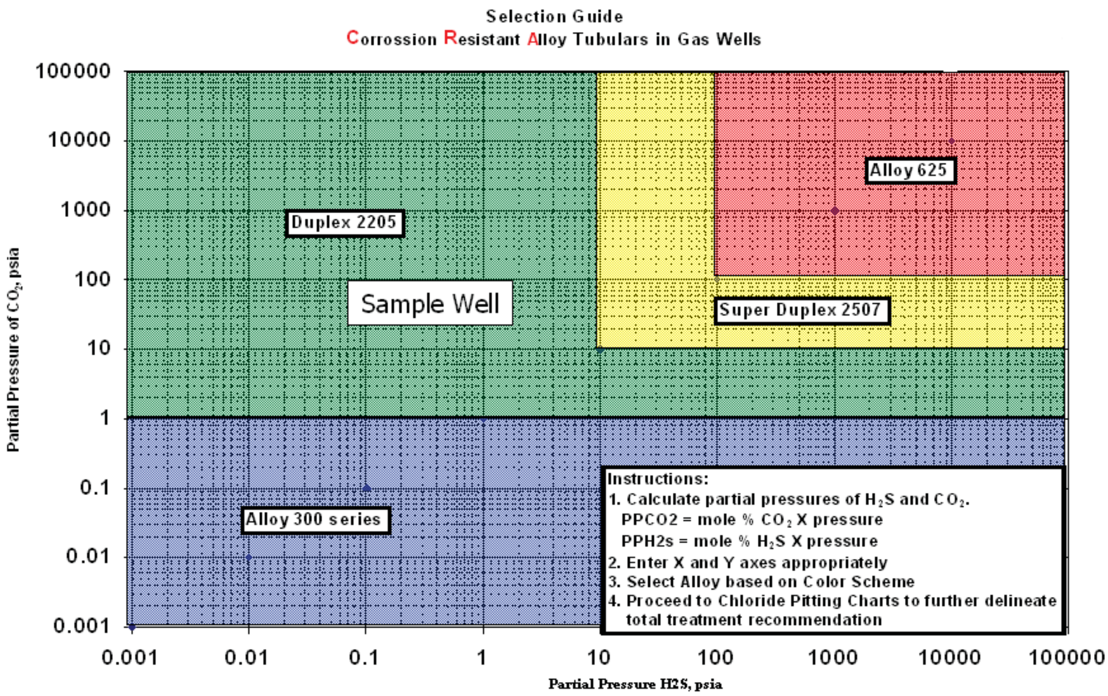


Figure 5-6 Material Selection based on CO_2 and H_2S Partial Pressures[24, 38]

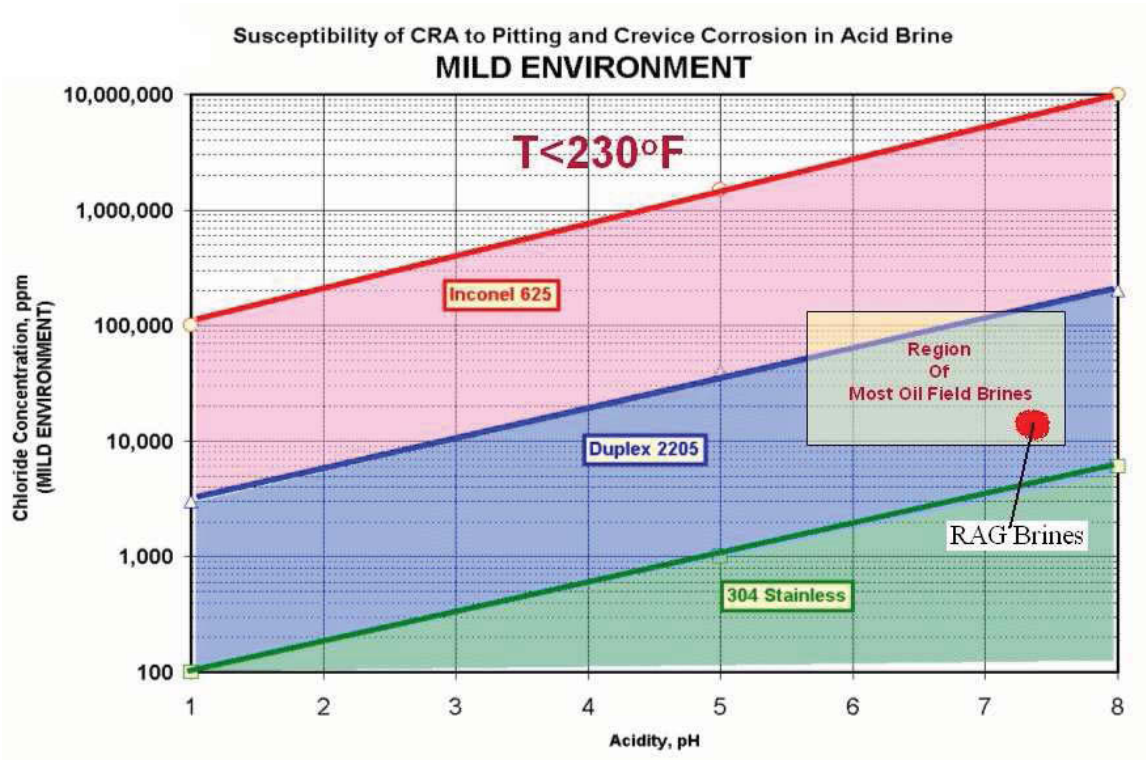


Figure 5-7 Material Selection based on Chloride Concentration and pH-Value[24]

5.1.4 Capillary Tubing Hanger

The capillary tubing hanger is another crucial part of the whole injection system. As a capillary string is just lowered into the well through the tubing it is necessary to somewhere hang of the string close to the surface. There are different types of capillary tubing hangers available but in any case the purpose is the same. A capillary tubing hanger is a means that holds the capillary string mechanically and prevents the string from falling into the borehole. Further a capillary tubing hanger is equipped with a sealing device as well.

Dependent on the wells completion the capillary tubing can be hung of on top of the well head or inside the tubing just below the wellhead. One major criterion whether the capillary string is hung of on top of the wellhead or below inside the tubing is a sub-surface-safety-valve (SSSV). Namely in such a case it is not allowed to run the capillary tubing through the SSSV which then would not close anymore. Therefore several options are available:

Solutions without a SSSV:

- *Wellhead Hanger with Sealing Device*
- *Y-Body Wellhead Adapter*

- *Collar Stop in Combination with a Wellhead Hanger* (a new idea developed during the research together with RAG)

Solutions with a SSSV:

- *InjectSafe™ SCSSV Technology*
- SSSV Solution with Control Line
  - *Shell Patented Solution*
  - *Modified Dummy Solution* (a new idea developed during the research together with RAG)

In the following the different solution methods are described and classified whether a SSSV is installed or not.

5.1.4.1 Solutions for Wells without SSSV

Most of the wells especially onshore have no SSSV installed and this simplifies the installation of a capillary string significantly. In such a case it is not necessary to bypass the SSSV and no special and costly tools are required.

5.1.4.1.1 Wellhead Hanger with Sealing Device

One of the simplest and most common solutions is the capillary tubing hanger that is installed on top of the wellhead (Figure 5-8). They are manufactured in many variations. This type of hanger is either screwed into the top wellhead flange or flanged to the top of the lubricator valve (Figure 5-9). Basically the hanger itself consists of a sealing device (packoff) and slips that secure the string mechanically. Some hangers are equipped with two packoffs (Figure 5-8). The advantage of such a hanger is that an additional packoff provides an additional safety barrier and secondly while the string is run into the wellbore one of the two packoffs can be used as the sealing device. Once the string is installed the second packoff is then used for static sealing.[33] One big disadvantage of such a type of wellhead hanger is that none of the master valves can be closed without cutting the capillary string. It is reported that in any emergency the master valves can be closed and they will seal but the capillary string will be lost.[35] Besides that a more convenient solution would be the following system.

The above mentioned hanger is a special designed hanger system for capillary strings with a sealing and slips to secure the string. Besides that a much more expansive system with a BOP is possible. This system allows an easy installation of a capillary string with a weight bar because of the full diameter of the BOP. As it can be seen in Figure 5-10 a simple capillary string BOP for sealing and a clamp to mechanically secure the capillary injection string can be used. This method has not yet been applied to capillary strings, but can be found where a pressure gauge is hung off on wireline in a wellbore.

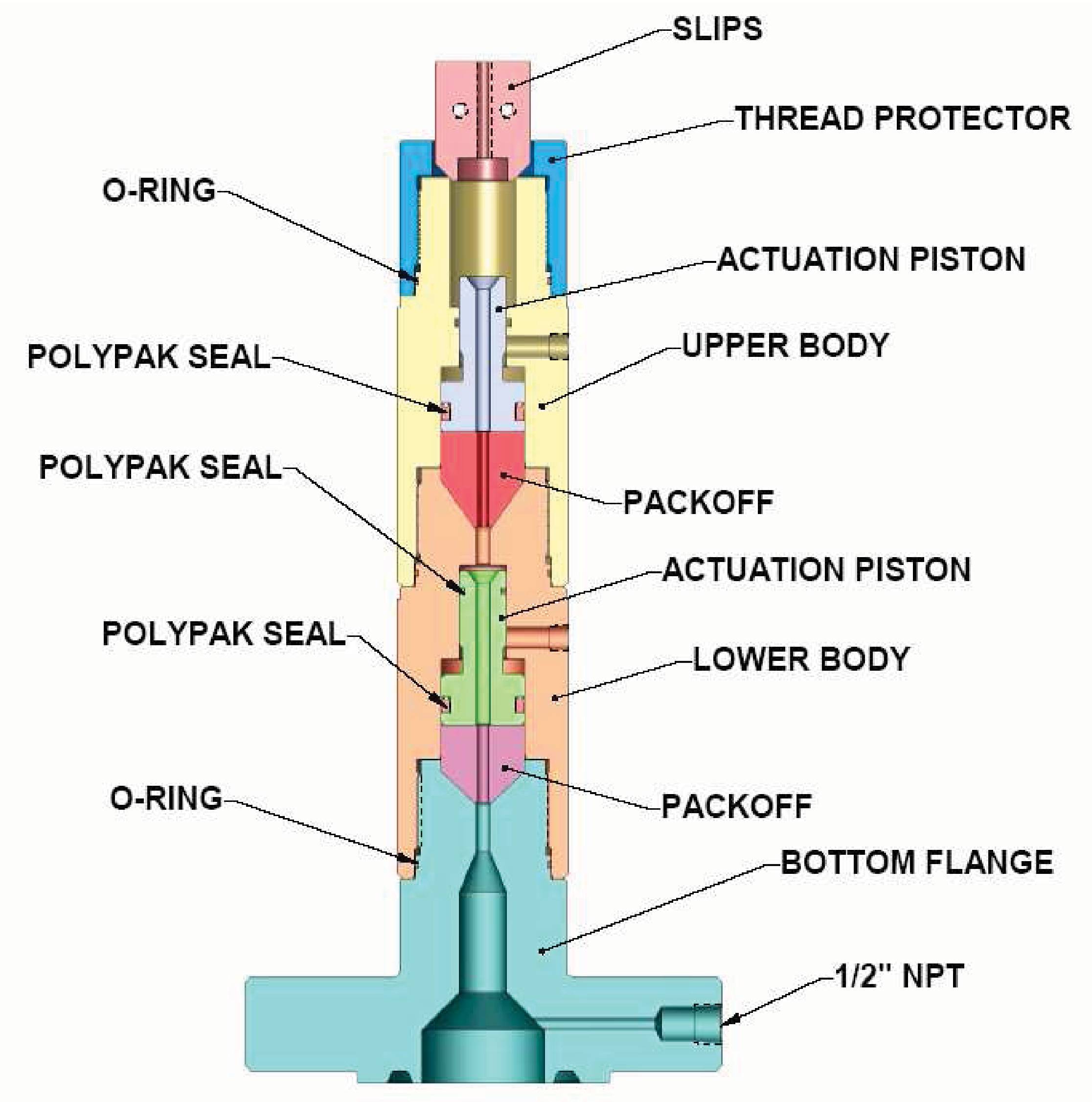


Figure 5-8 Capillary String Hanger with Bottom Flange and two Packoffs[26]

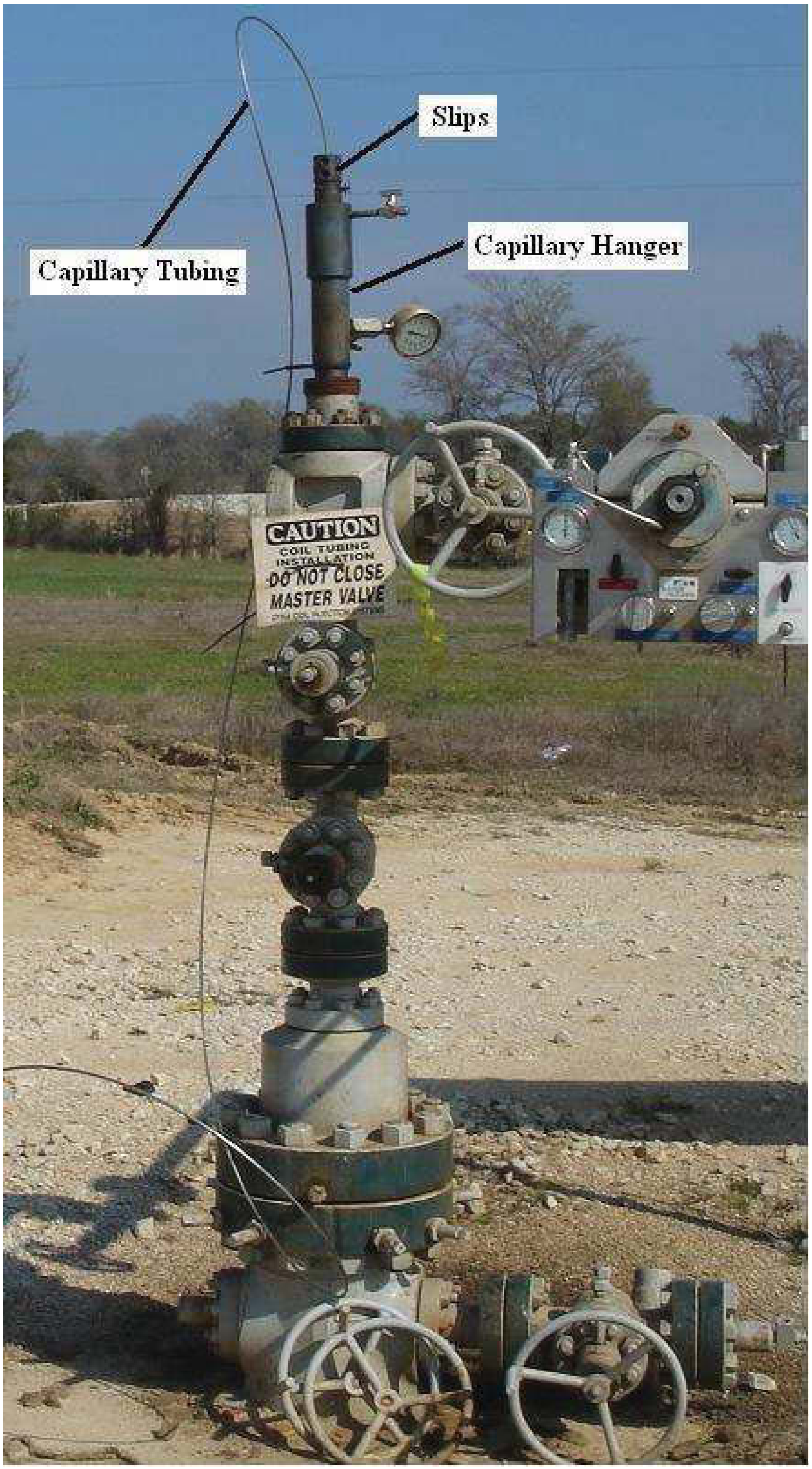


Figure 5-9 Capillary Hanger screwed into the Wellhead Top Flange (a well in the USA)[33]

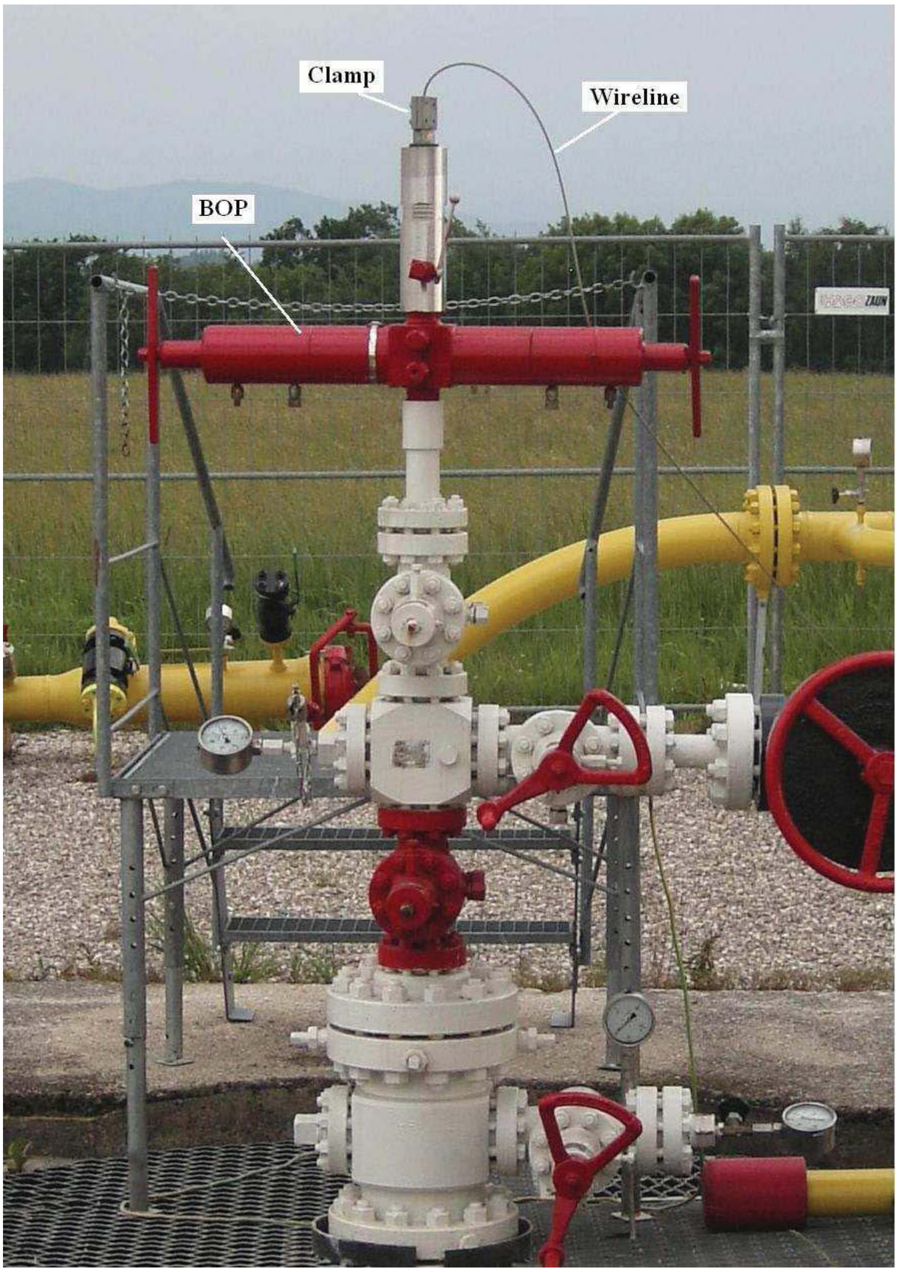


Figure 5-10 RAG Gas Storage Monitoring Well, P 016

5.1.4.1.2 Y-Body Wellhead Adapter

Another wellhead solution is the integrated Y-Body. This tool is installed between the two master valves and allows the capillary tubing to enter the wellbore between the two valves (Figure 5-11 and Figure 5-12). The tool has the shape of a "Y" and that is where the name for this hanger solution comes from. On top of the capillary side a typical hanger as mentioned in the previous paragraph can be installed. Now the capillary string enters the wellbore below the upper master valve but still goes through the lower master valve. The advantage of such a hanger system is that at least the upper master valve can be closed without cutting the capillary tubing.[39] Further as it can be seen from Figure 5-12 the height of the production valve is the same which requires no changes in the production lines. Another theoretical advantage is that it is now possible to enter the wellbore with coiled tubing through the lubricator valve while the capillary string is still installed. For example the capillary tubing gets stuck a coiled tubing can enter the wellbore and could then circulate out any dirt, e.g. sand, salt. It is possible to continue circulating while the capillary string is pulled at the same time. These two actions together would increase the chance to free the stuck capillary tubing. Anyway this hanger solution provides some advantages but on the other hand it also requires a significant wellhead modification and will cost significantly more than the previous mentioned solutions.[33]

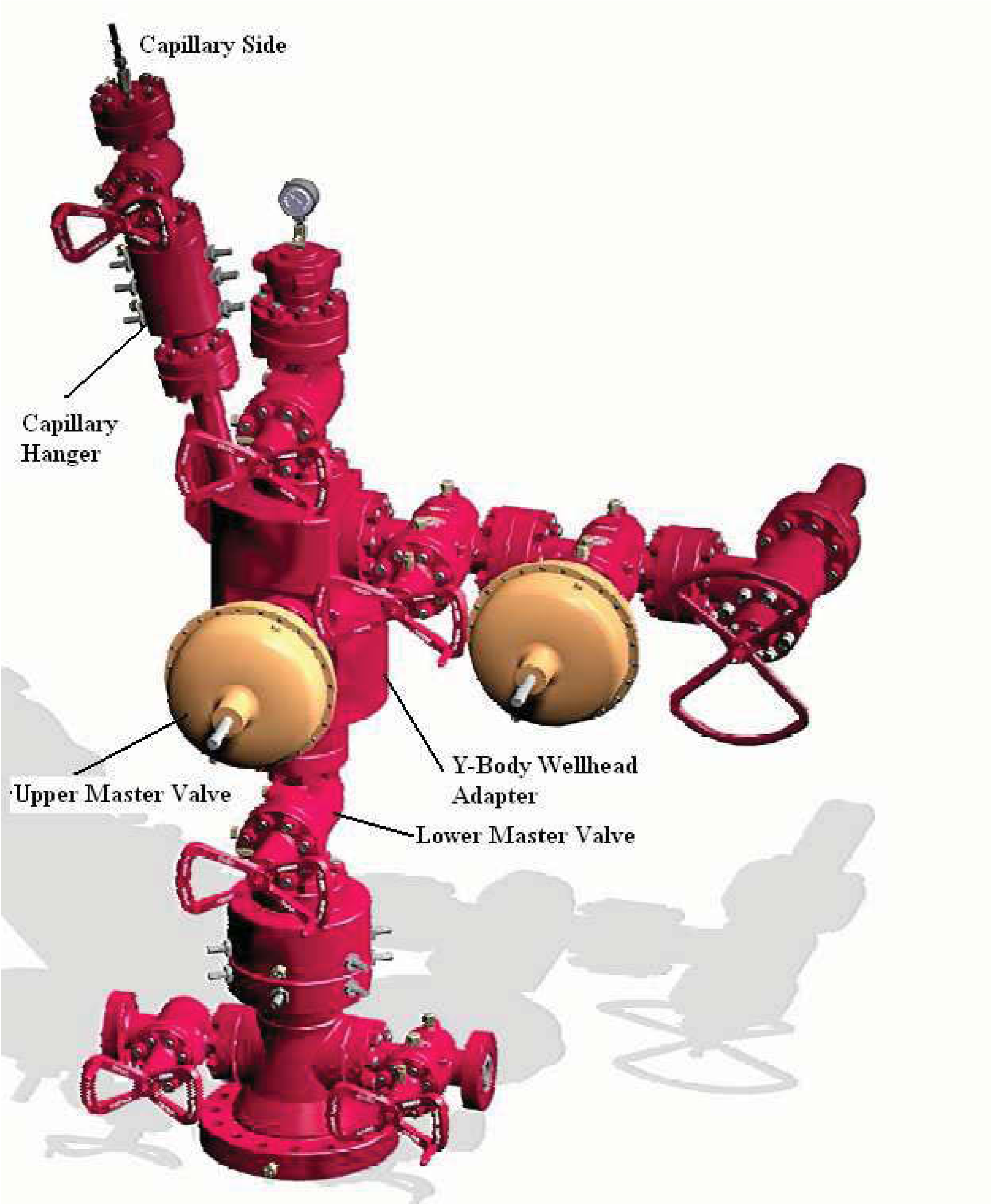


Figure 5-11 Wellhead with Y-Body Wellhead Adapter[39]

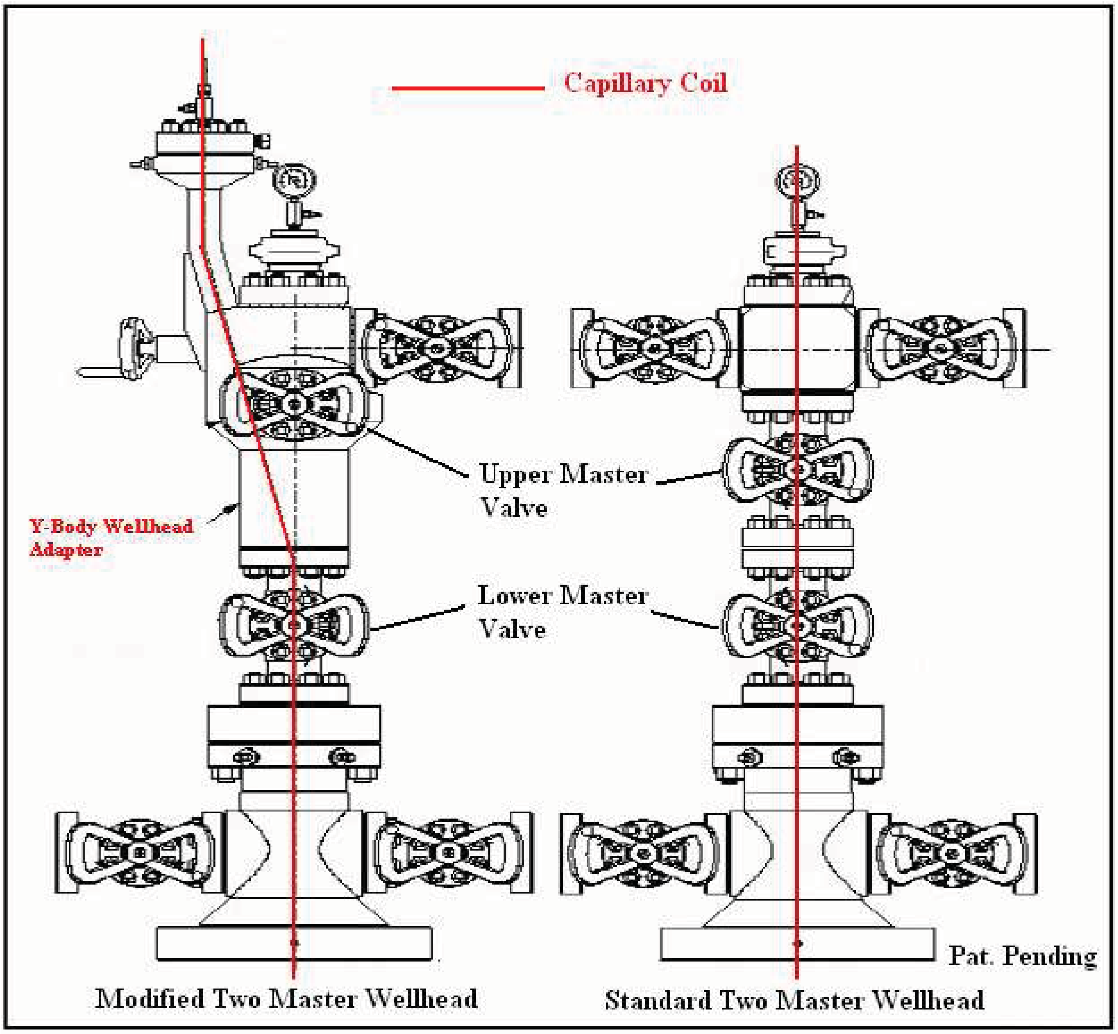


Figure 5-12 Comparison of a Standard Wellhead with One Having a Y- Body Adapter[39]

5.1.4.1.3 <u>Collar Stop in Combination with a Wellhead Hanger</u>

Another idea that utilizes a collar stop would improve the in Chapter 5.1.4.1.1 mentioned wellhead hanger system. This system uses a collar stop in order to hang of the capillary string. The collar stop is installed right below the wellhead at the first tubing connection (collar stops can just be set at points where two tubings are connected) before the capillary string is installed (see Figure 5-13). The capillary string is then run into the wellbore through the collar stop. A clamp on the capillary string transfers the load onto the collar stop which further transfers the load onto the tubing. The capillary string is still one piece and runs through the two master valves. The rest of the equipment is still the same as it is mentioned in the first case. The advantage of this system is that in case a master valve cuts the capillary tubing it will not fall down the wellbore because it is hung of at the collar stop. Now the cut capillary string can be fished somewhere inside the wellhead which significantly simplifies the fishing job. This type of hanger system prevents sever problems in case the capillary string is cut, but on the other hand it complicates the installation of the capillary string. A disadvantage is that in case the capillary string is stuck in the wellbore the collar stop will not allow any well interventions by wireline or coiled tubing. Therefore by using a collar stop the operator is limiting his contingencies. Further in case the capillary tubing is cut a slickline unit has to be rigged up anyway to retrieve the cut capillary string. Therefore there is not much gain in time for retrieving the tubing. Thirdly the installation of the collar stop would require a work-window, which would take some time longer.[40] Anyway as previously mentioned in case of a fishing job it can be faster and increases the chance of a successful job.

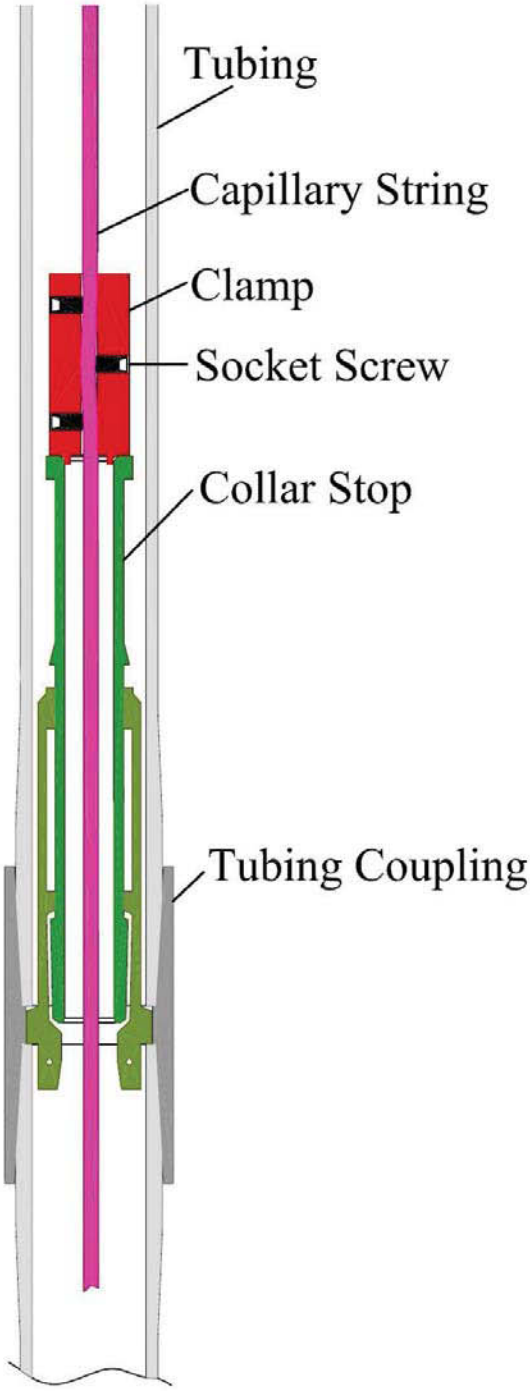


Figure 5-13 A Collar Stop in Conjunction with a Capillary String

5.1.4.2 Solutions for Wells with a SSSV

Many gas wells onshore or offshore are equipped with a SSSV. With the increasing safety concern and drilling activity this number will still rise. In case a SSSV is present, the capillary string can not go through the valve because it then would not close anymore. As a consequence special solutions were invented. In the following two patented solutions are discussed. Basically they can be distinguished in a way that one solution method uses the control-line of the SSSV and the other one a separate injection line.

5.1.4.2.1 InjectSafe™ SCSSV Technology

The InjectSafe SCSSV (**S**urface **C**ontrolled **S**ubsurface **S**afety **V**alve) is run and retrieved with conventional slickline and it works like a conventional WRSCSSV (**w**ireline **r**etrievable **s**urface **c**ontrolled **s**ubsurface **s**afety **v**alve, Figure 5-14) but has a bypass pathway and stinger receptacle. For safety reasons the bypass pathway has a check valve included that prevents any backflow. Further the capillary string consists now of two parts, the long string and the short string. The long string is the part of the capillary string that is installed below the InjectSafe SCSSV with the chemical injection valve attached to the lower end. The length of the long string is equal to the setting depth minus the InjectSafe SCSSV depth. It is ferrel connected to the inject port of the InjectSafe valve. Slips prevent that tensional load is transferred to the compression fitting. Once the long string is connected to the InjectSafe valve the wireline unit suspends the weight of the valve as well as the weight of the capillary string. After the InjectSafe valve together with the long string is lowered into the wellbore the short string is installed. Therefore the stinger (see Figure 5-14) is attached to the short string and is lowered into the wellbore till it stabs into the PBR (polished bore receptacle). It has to be mentioned that the control-line that operates the InjectSafe SCSSV goes up to the surface through the annulus, whereas the capillary string (long string and short string) is located inside the tubing all the time. The surfactant is pumped through the short string and enters the bypass pathway through the stinger; passing the internal check valve the surfactant enters the long string and is pumped downhole to the chemical injection valve. The fluid within the capillary string and the one in the control-line get never in contact with each other. This system allows injecting foamers while a SCSSV still can be operated.[39]

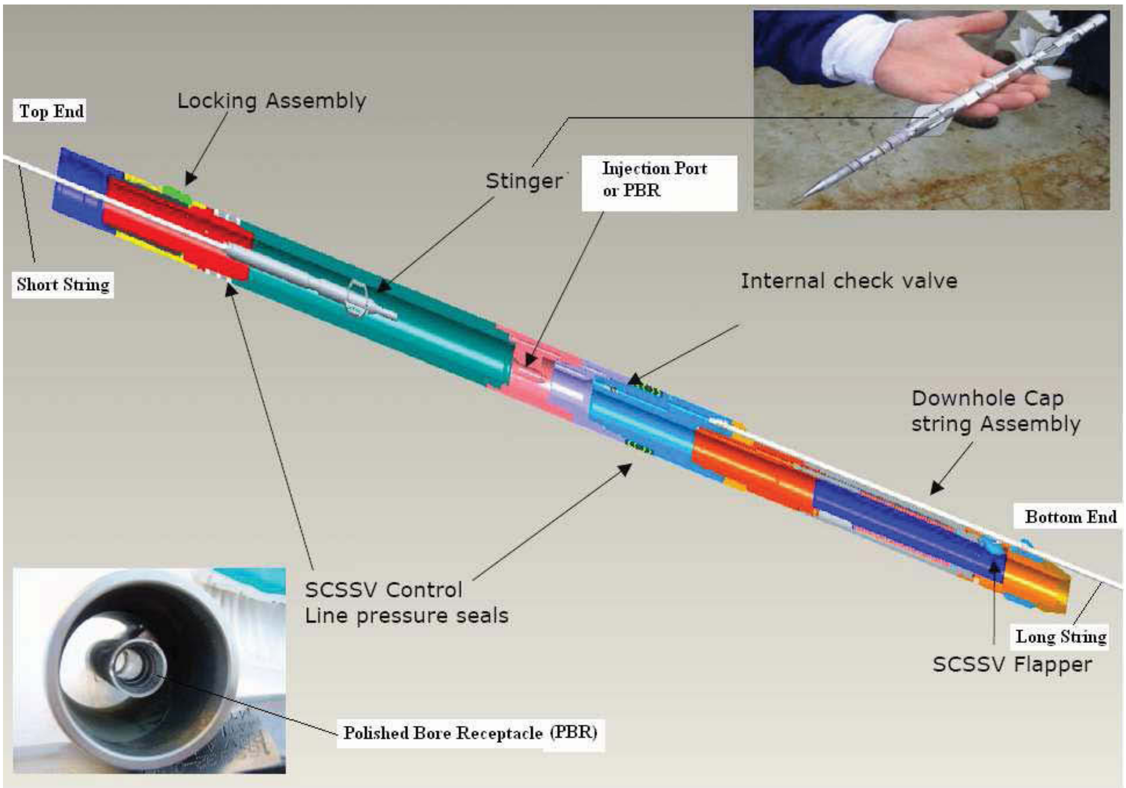
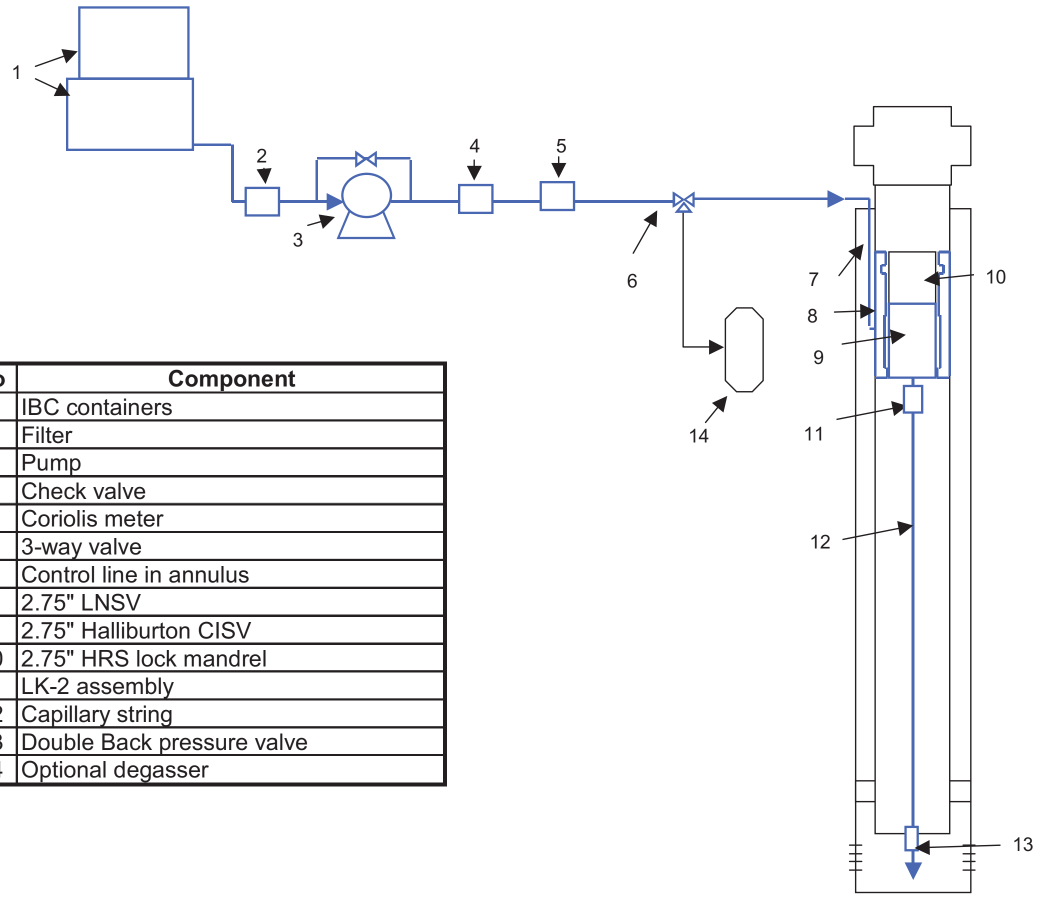


Figure 5-14 WRSCSSV with the Short String and the Stinger[39]

5.1.4.2.2 SHELL Patented Solution

In this system the control-line of the SCSSV is used as a part of the capillary string injection system (Figure 5-15). The ability to deliver the chemical downhole and still operate the SCSSV is achieved by using a modified SCSSV. Figure 5-16 shows such a SCSSV with the flapper valve open and closed. The foam (pink line) is injected down the control-line into the seal bore of the landing nipple and then it enters the valve via a port.[41]



No	Component
1	IBC containers
2	Filter
3	Pump
4	Check valve
5	Coriolis meter
6	3-way valve
7	Control line in annulus
8	2.75" LNSV
9	2.75" Halliburton CISV
10	2.75" HRS lock mandrel
11	LK-2 assembly
12	Capillary string
13	Double Back pressure valve
14	Optional degasser

Figure 5-15 System Layout of a Capillary Injection System utilizing a Modified SCSSV[41]

Once the foamer is in the valve it has two paths it can go which is controlled by pressure. One way is that it can pressure up on the flapper valve as in a normal SCSSV to open the SCSSV and the other possible path goes down the side of the valve into the capillary string for foamer injection after it passes through the so called LK-2 injection valve (see Figure 5-15 component 11). The LK-2 valve controls the injection downhole. It is located right below the flapper valve. In order to operate the flapper valve and the foamer injection at the same time the two valves, flapper valve and LK-2 valve, have different pressure settings. For the SCSSV to open a pressure of 70 bar is necessary, whereas a pressure of 150 bar is required to open the LK-2 valve to inject foamer down the capillary string. This allows the possibility to hold the SCSSV open without injecting any foamer. Any failure of the LK-2 valve or leaks will result in an inability to operate the flapper valve. Previous to the LK-2 valve no valve was used and the pressure setting was dependent on the downhole injection valve. Due to the long distance between the flapper valve and the downhole injection valve pressure maintenance was difficult and from time to time the flapper valve closed.[41]

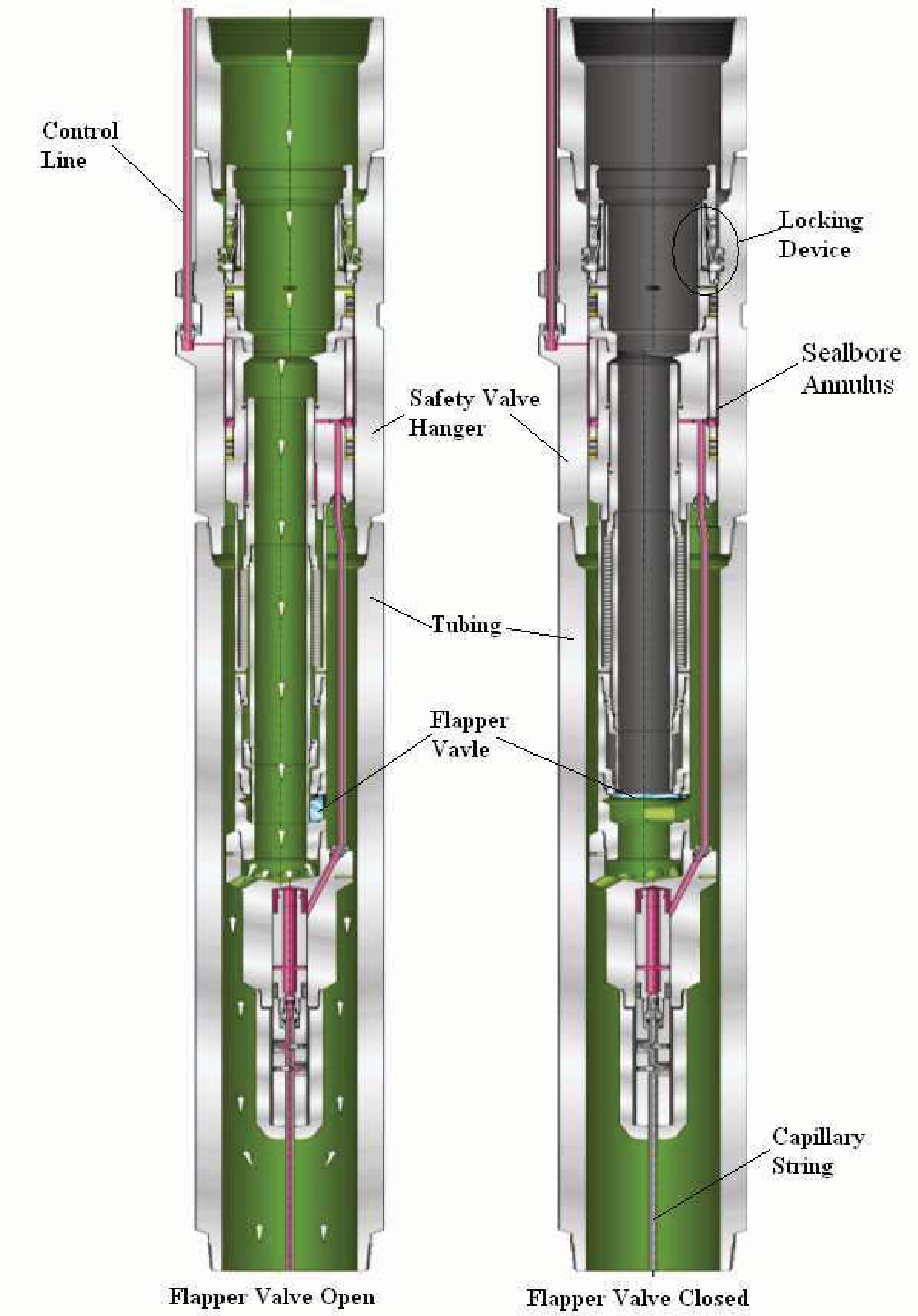


Figure 5-16 Modified SSV with the Flapper Valve open and closed[41]

The main advantage of that capillary hanger system is that the capillary string is not running through the wellhead which allows the masters valves to be closed whenever desired. There is no possibility to cut the capillary string and further to loose the string in the wellbore.

5.1.4.2.3 Modified Dummy Solution

Another new idea, evolved during the research together with RAG, is the one of a capillary hanger system that utilizes the above mentioned modified SSSV hanger system but without the flapper valve. Basically the capillary string is attached to a tool, a so called Modified Dummy which again is connected to a Lock Mandrel. The whole tool is then set in a landing nipple for a SSSV. The foamer is injected through the control line, which is no control line anymore because no valve is installed, and will go through the landing nipple and seal bore annulus into the modified dummy, through a cross-over and further into the capillary string downhole to the chemical injection valve (see Figure 5-17). Such a system can be used in wellbores where a SSSV used to be installed and has been removed due to low production rates. In case a workover is considered it can be evaluated if it makes sense to install a SSSV hanger together with the tubing today in case that in a later stage of the wells life a capillary solution as the one described here can be installed. The advantage of this is that when it is time for a capillary string no workover is required to install the SSSV hanger. Further advantages of such a tool are the same as the ones for a modified SSSV system as mentioned above, namely that no capillary string goes through the wellhead.

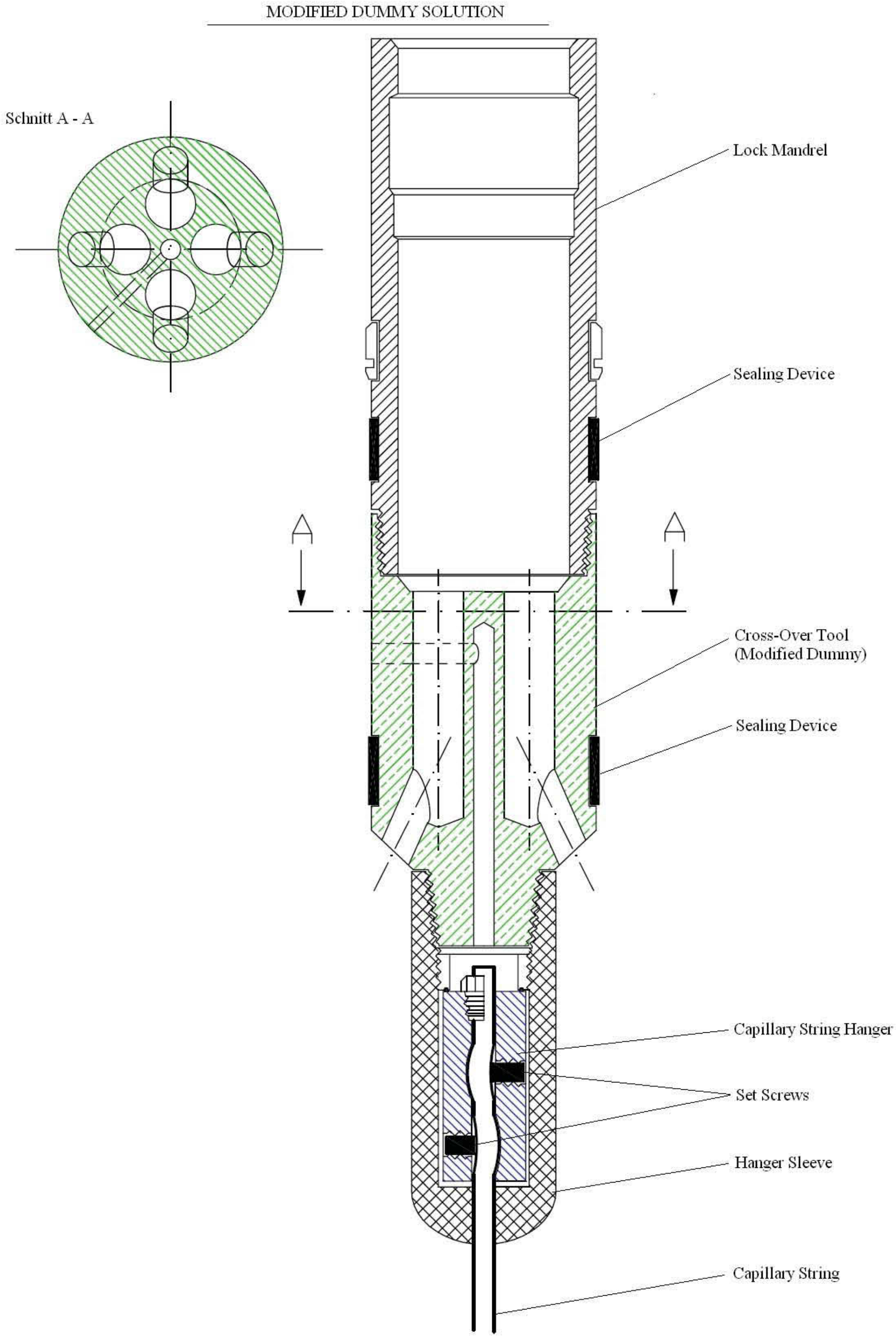


Figure 5-17 Modified Dummy Solution (this Tool is set in a SSSV Landing Nipple)

Finally again a new idea for installing a capillary string is presented. In this case the same modified dummy solution as mentioned above is used. The difference is now that the control-line is not run through the wellhead, which requires a tubing hanger with a conduit, but through one of the casing valves (see Figure 5-18). Behind the casing valve a stuffing box would then provide the sealing. A mechanical securing is not necessary because the short distance (~ 80 m) down to the landing nipple is strapped to the tubing. The advantage of this solution is that no wellhead modifications are necessary which results in much lower costs.

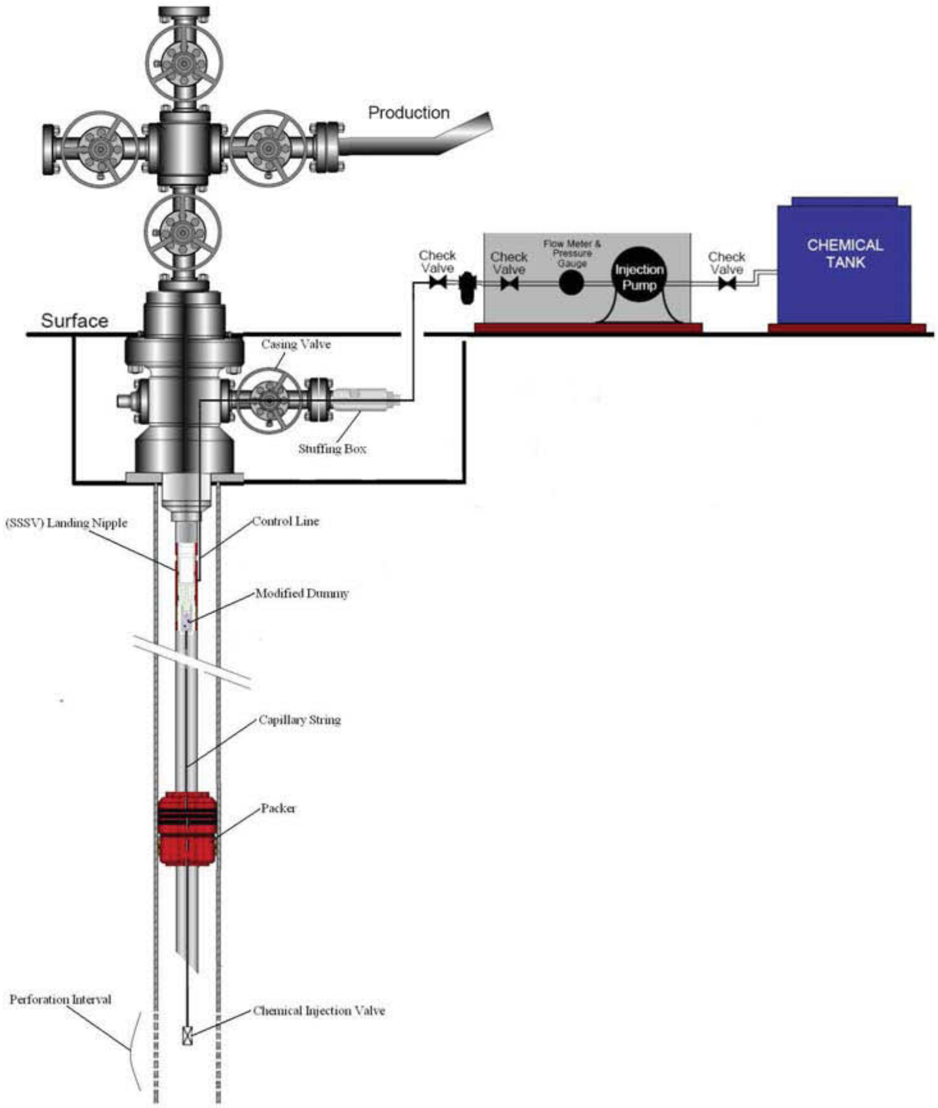


Figure 5-18 Modified Dummy Solution with a Control Line through the Casing Valve [Weatherford[22]]

5.1.5 Surface Manifold or Foam Skid

Besides the above mentioned capillary string, downhole injection valve, and the capillary hanger further equipment is required to complete the whole injection system. A foamer/surfactant tank, a pump, check valves, and filters are additional components that are necessary to complete the whole injection system. Usually all the surface equipment is mounted on a skid with the purpose to have one compact and mobile unit. Different skid designs are available as it can be seen in the Figure 5-19. Most of the foam skids are fully closed which protects the equipment from environmental influences and allows the containers to be heated. Dependent on the foaming agent it may be required to heat the container in order to avoid freezing in of the foamer. Most of the available liquid foamers have freezing points about -20℃ and consequently in most of the cases i n Central Europe it may not necessary to heat the foam skids. Another advantage of the skid mounted surface equipment is the mobility of the units. They can simply be transported to a new well location if needed. In the following the individual components are discussed in more detail.

Figure 5-19 Different Options of Surface Equipment Arrangement[42]

5.1.5.1 Surfactant Tank

The tank for the surfactant/foamer is nothing sophisticated. Usually they are plastic tanks with a volume ranging from 200 Liters up to a few thousands of liters. With increasing LGR the amount of water that has to be foamed increases and therefore the foamer injection rate has to be increased as well. Consequently the size of the tank is selected based on the foamer injection rate and further how often the tank should be refilled. In case of a tank leakage all the tanks are equipped with a containment to prevent any pollution of the environment. A typical tank with containment is shown in Figure 5-19. Additionally the surfactant tank should have a pressure relieve valve in case gas migrates through the capillary system into the tank. This avoids a pressure build up in the tank.[34]

5.1.5.2 Pumps

In general different types of pumps can be used to pump the surfactant. Electrical-, solar-, or gas/compressed air- operated pumps are available. Each pump type has its advantage and disadvantage but the type of pump that is used is more or less determined through the conditions at the well site. For example there are well sites where no electricity or compressed air is available. In this case only a solar powered or a gas operated pump can be taken into consideration. Further the explosion hazard area on the well site influences the type of pump as well. Within this area no electrical or solar powered pump is allowed accept it has an ATEX certification. The advantage of an electrical or solar powered pump is that a desired injection rate can be adjusted more precisely and further it is more suitable to automation, e.g. if the injection rate is automatically adjusted to the water rate.

A very common type of pump used in RAG is the 5100 Series Texsteam Chemical Injector (Figure 5-20), a single acting positive displacement plunger-type pump, powered by a diaphragm motor with spring tension, operated with gas or compressed air. The injection rate is regulated manually by regulating the exhaust gas discharge (speed of the pump; strokes/min) and by adjusting stroke length and plunger size (adjusting volume per stroke). The pump can handle discharge pressures up to 100 bars and a rate of maximum 113 Liters per day. Due to its simple construction and reliability this pump is quite popular.[43]

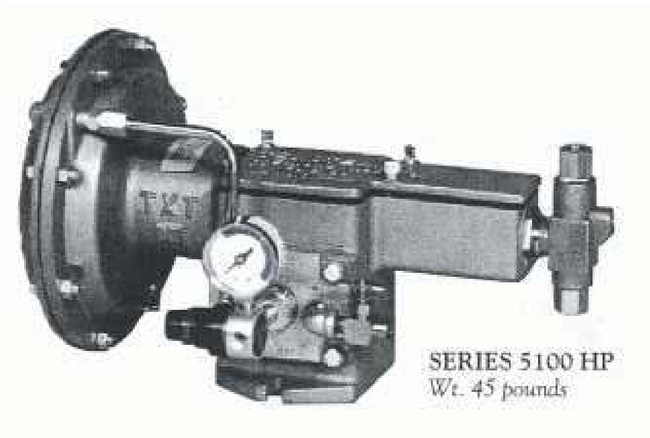


Figure 5-20 5100er Series Chemical Injector Pump[43]

5.1.5.3 Filter, Valves, Manometer

A survey to identify common capillary failures has shown that particle plugging (see Chapter 7.3.1) is the most probable reason why a capillary injection system can fail. Therefore it is recommended to install a filter right behind the pump in order to avoid pumping particles through the capillary string. There are other reasons for plugging as well but the usage of a filter reduces one failure source. Usually filters having a pore size in the range between 5 and 10 microns are sufficient.[34]

Besides that, valves and manometers are additional and smaller parts of the system but they are not less important. A manometer should be placed between the wellhead and the filter. This allows the observation of the injection pressure and further to recognize a plugging or leakage of the capillary string.

An anti siphoning valve should be also installed right behind the filter. This is a special type of valve that prevents siphoning of the surfactant tank in case the downhole injection valve fails. Another check valve would then prevent flow in the other direction and avoid wellbore fluids entering the surfactant tank.[34] Figure 5-21 shows these components.

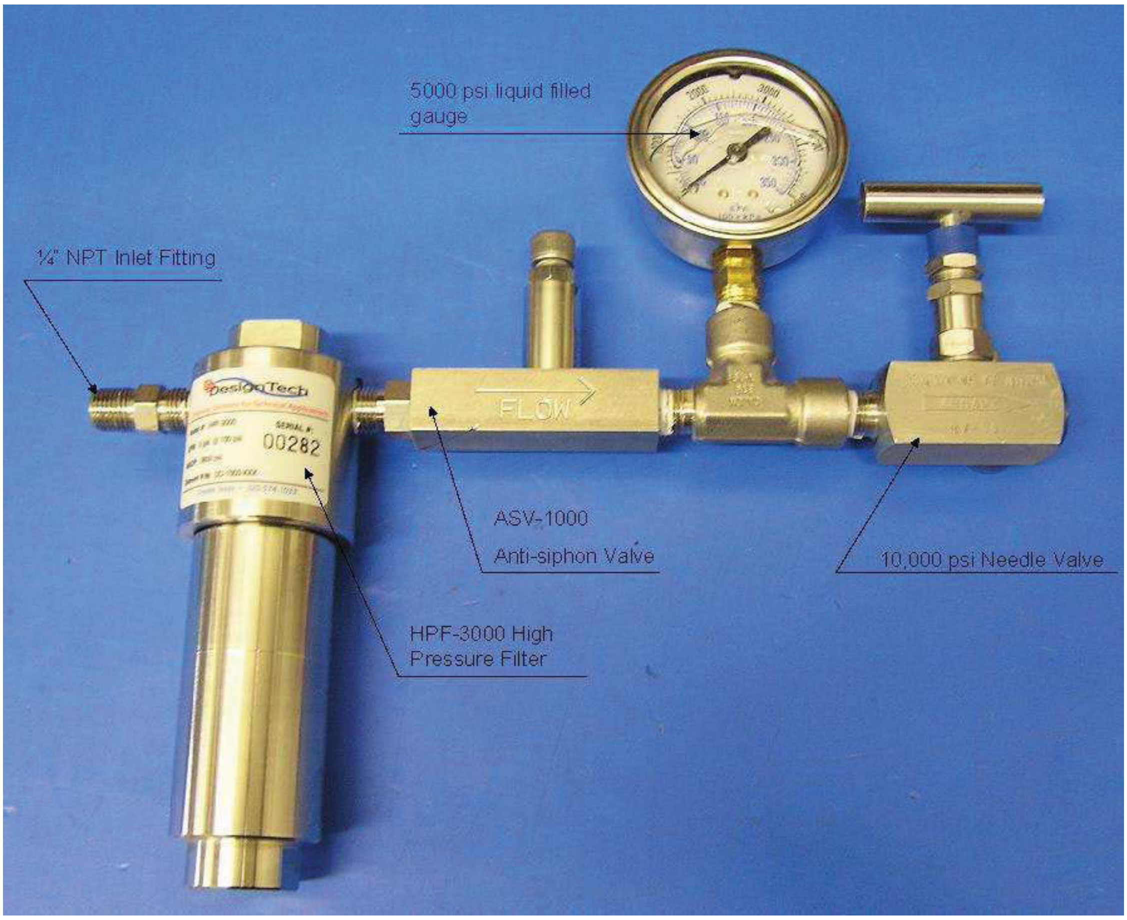


Figure 5-21 Filter, Anit-Siphon- Valve, Manometer, and Backpressure Valve[44]

5.2 Foaming Agent

In the Oil & Gas Industry foam has several areas of application. Foam is used as a drilling fluid, as a hydraulic fracturing fluid, and finally for well cleanouts as it is the case in this thesis.[19] Foam is understood to be a substance that is formed by entrapping gas bubbles in a liquid.[45] In order to successfully remove liquids out of the wellbore it is required to produce useful foam. This is accomplished by a good dispersion of gas and liquid phase (foam generation) and further maintaining the bubble film for a useful time period (foam stability).[19] The following chapters provide some basics about foamers, their influence on the produced liquids and how the right foamer is selected for a specific wellbore.

5.2.1 Foam Lifetime

A surfactant (other terms used in this script are: foaming agent, foamer) is a wetting agent that lowers the surface tension of a liquid. Such an agent is needed to form foam under certain conditions.[20] Surfactant molecules have a hydrophilic (water soluble) and a hydrophobic (non water soluble) part. This attribute let the molecule concentrate at the interface between the water phase (liquid phase) and non water phase (gas phase). If the interfacial surface area is completely covered with the surfactant molecules it is said that the solute has its critical concentration. If further surfactant is added the additional molecules have to go into the water phase. Once the surface area increases, for example through further entrapment of gas bubbles surfactant molecules from the water will move to the new created surface to find their place at the preferred interface. This kind of behavior is described as surface activity of the foamer.[19]

The lifetime of foam is described by three stages which are: formation of lamella (foam generation), thinning of the film (stability), and rupturing of the film (end of foam life).[20]

This section provides the theoretical background to understand the effects a surfactant has on the wellbore liquids.

5.2.1.1 Foam Generation

For the generation of foam several conditions have to be met. First, the foaming agent needs to have a low surface tension and a low vapor pressure. If the vapor pressure of the foaming agent is too high the lamella will evaporate before stable foam is reached. Therefore most of the foaming agents are organic compounds in aqueous solution. Secondly, the solution surface tension must be in a certain range. It has been found out that foaming ability is best if the surface tension is in the order of 50 dynes/cm.[46]

Foam is generated by agitation of the liquid and gaseous phase. This causes the gas to be trapped inside a liquid film (lamella). How easily the gas can disperse depends on the surface tension (see Chapter 12.3 in Appendix) of the liquid. That is the point where the surfactant comes in. A surfactant lowers this surface tension. A usual value for water is 72 dynes/cm which can be reduce by a surfactant to 20 to 35 dynes/cm. Surface tension values for liquid hydrocarbons are in the range between 20 to 30 dynes/cm.[19]

Foaming requires a strongly heterogeneous interface and consequently oils are more difficult to foam. A heterogeneous interface means that the surfactant concentration at the interface is significantly higher than the average concentration of surfactant in the solution.[20]

As for the foam generation liquid and gas is necessary a foamer should not be injected in a liquid column where no gas is present.

5.2.1.2 Foam Stability

The strength of the foam depends on the complex relation between the concentration of surfactant in the solution and the surface activity of the foamer. As soon as foam has been formed it begins to deteriorate. Liquids between the gas bubbles will drain and will constantly fill up the liquid between the bubbles below. This results in thinning of the liquid film between the gas bubbles. Further as the foam move upwards in the tubing gas bubbles expand which weakens the liquid film even more until it will break.[19] A different description of the film thinning has been done by Campbell et al.[20] They described the thinning in terms of critical micelle concentration (CMC). The CMC is the concentration where an addition of surfactant molecules to the solution will form colloidal aggregates. The important factors for film thinning are the surface rheology and the film structure, where the film structure is the more dominant factor.[47] The more micelles are present the easier is the film ordering and consequently the higher the foam stability. A foamer with a lower CMC would have, at the same concentration, more micelles present and would cause the more stable foam.

The foam stability is also influenced by the amount of electrolytes. The higher the salt content the less ordering in the film occurs. The foam stability is reduced and the CMC is changed by the salt as well.[20]

Foam stability can be increased by reducing the liquid drainage rate and increasing the elasticity of the surfactant layer. The viscosity of the surfactant influences foam generation and stability. However high viscosities are not attained in diluted solutions and consequently viscosities are moderate.[19]

Foam stability is one criterion for an effective removal of liquids out of the wellbore. Therefore a stable foam phase has to be maintained from the point of foamer injection up to the wellhead.

5.2.2 Effects of Surfactant on the Liquid Removal

As it is mentioned in Chapter 3.4 surface tension and density have a major influence on the unloading (or critical) velocity of a wellbore. A surfactant as it is discussed in the previous section influences exactly these two parameters. A reduction in surface tension and in density by the foamer decreases the required critical velocity to remove liquids from the wellbore.

5.2.2.1 Surface Tension

Based on the model presented by Campbell et al.[20] (see Chapter3.2.1) the following Figure 5-22 points out the role of surface tension on the predicted unloading velocity. The following well operating data are used in the calculations:

- Flowing Wellhead Pressure 70 psi
- Temperature 100°F
- Production Rate 270 Mscf/day
- Water Density 67 lbm/ft³

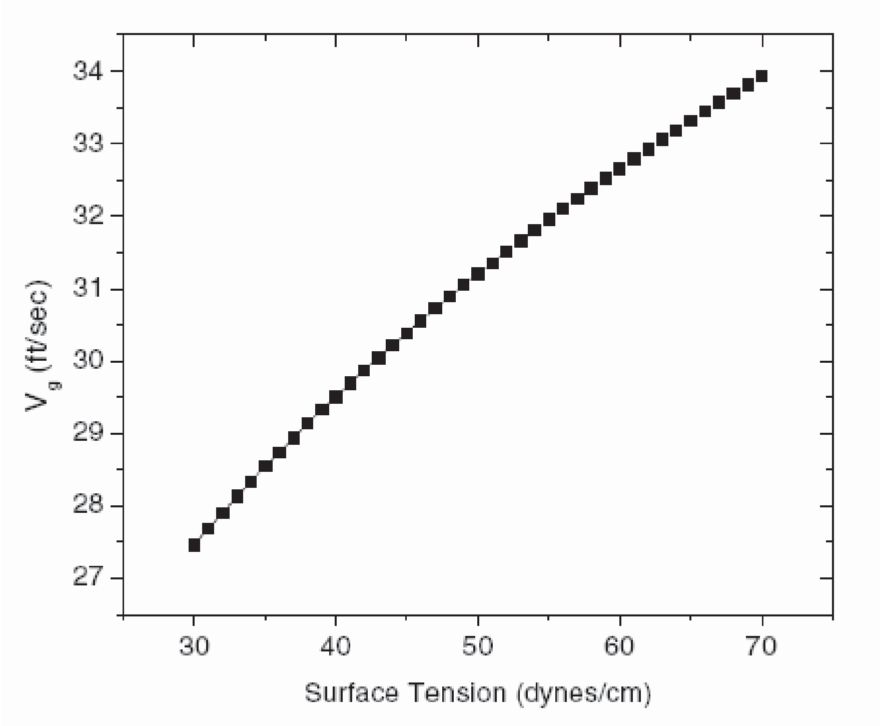


Figure 5-22 The Effect of Surface Tension on the Critical Velocity[20]

The range for surface tension values is between pure brine and the lowest reasonable achievable one with foamer. At a maximum reduction of the surface tension from 72 to 27.5 dynes/cm a reduction of critical velocity of about 19 % is achieved. Using a more typical value for the reduced surface tension of 45 dynes/cm a reduction of only 10 % of the critical velocity can be achieved.[20]

5.2.2.2 Foam Density

In order to study the effect of foam density on the unloading velocity using the same model the surface tension is set constant at a value of 45 dynes/cm. Foam is a two phase fluid and therefore having an apparent density calculated based on laboratory tests (see Chapter 5.2.5 and 12.1 in Appendix). In Figure 5-23 foam density is measured in terms of percent of reduction in liquid density. It shows that foam density is varying between no reduction (0 %) and a reduction of liquid density by 85 %. It can be seen that a reduction of 30 % in critical velocity for typical density values recorded in field production is possible.[20]

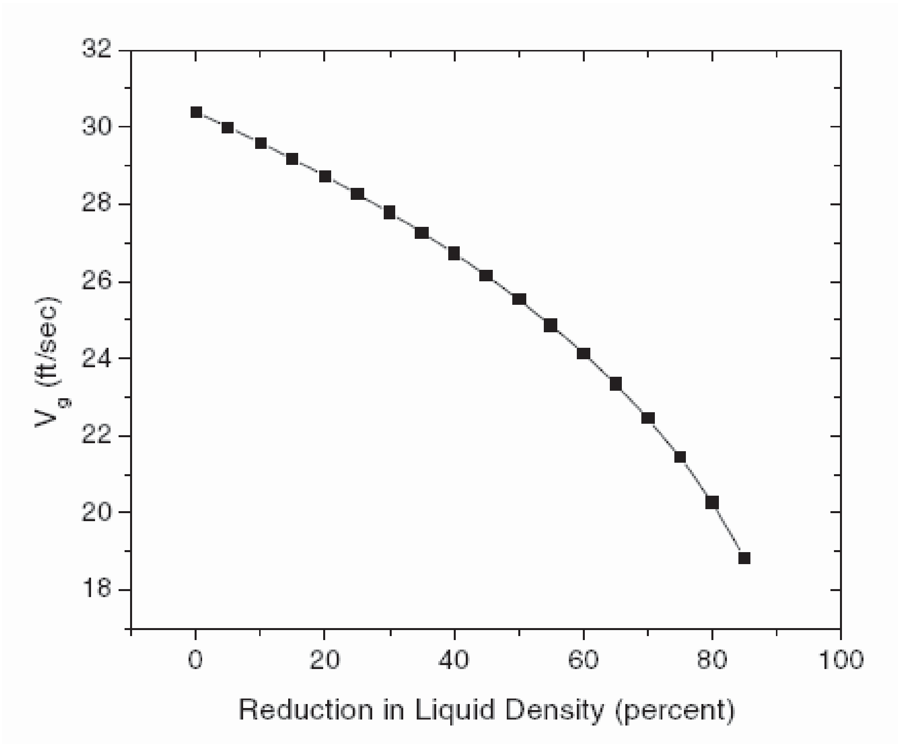


Figure 5-23 The Effect of Density Reduction on the Critical Velocity[20]

This leads to the conclusion that both surface tension and apparent foam density reduce the critical velocity for unloading liquids from the wellbore but with the foam density to be the more significant one.

5.2.3 Surfactant Types

As previously mentioned surfactants have a hydrophilic and hydrophobic end. Based on their ionic characters surfactants can be classified according to non-ionic, anionic, and cationic surfactants.

5.2.3.1 Non-Ionic Surfactants

Typical non-ionic surfactants are those that consist of the polyoxyethylated compounds of phenol or alcohols. In general non-ionic surfactants are more soluble in cool water and in high concentrations of salt their solubility decreases. Due to the homologous series of the polyoxyethylated surfactant they range from oil soluble types to water soluble types. Mostly this type of surfactant is used in wells with unknown brine character because of there non-ionic character they are less affected by activity and chemical nature of the formation brine.[19]

5.2.3.2 Anionic Surfactants

One of the best water foamers are the anionic surfactants. Due to the sulfation process where a sulfate radical (SO_4) is added to the non-ionic molecule the surfactant becomes more polar and anionic in character. As the anionic surfactants are available in a homologous series as well, some of those may be affected adversely by high brine solutions. They are very affective in foaming water but an application in brine solutions is not recommended.[19]

5.2.3.3 Cationic Surfactants

Cationic surfactants are more effective in brines than in fresh water. The low molecular weight agents of these quaternary ammonium compounds are one of the best surfactants for foaming mixtures of hydrocarbons and brines. The higher molecular weight type of this surfactant shows good results in foaming high percentages of liquid hydrocarbons.[19]

Another type of surfactant is an amphoteric one. This kind of surfactant shows an anionic character in basic solutions, a cationic character in acidic solutions, and non-ionic character in neutral solutions. Tests with brines having up to 10 % salt have shown that those surfactants work well at high temperatures (~200℉). At temperature below 70℉ anionic or cationic surfacta nts work better.[19]

5.2.3.4 Surfactants for Hydrocarbons

Foaming hydrocarbons is much more difficult than water, especially when no water is present. Liquids having a hydrocarbon content of 70 to 80 % are foamed more easily than those having a higher content of hydrocarbons. If this is the case expensive fluocarbon foamers have to be used to achieve acceptable results.[19]
The praxis has shown that water- hydrocarbon mixtures show the ability to foam, whereas others do not. In any case only the water phase can build stable foam. Hydrocarbons do not foam well because there are no polar ties with the surfactant. The principle mechanism for foaming hydrocarbons is to place high molecular polymers at the interface to act with many oil molecules in order to build viscosity and/or molecular attraction. Though this develops some film strength but it is still weaker than water foam films. To efficiently foam wells with a high content of

hydrocarbons it is necessary to obtain a strong foam quality in the water phase. New foamers especially for hydrocarbons still have to be developed and tested.[19] Most of the foamers available on the market are designed to foam formation water rather than hydrocarbons. However, experience shows that most of the liquids from gas wells are water or water with a low percentage of hydrocarbons.

5.2.3.5 Effect of Brine

Tests indicate that brines with no oil phase present foam as well as fresh water. However effective foam quality in oil – water mixtures decreases more rapidly when salinity is high. In general two things have to be accounted in the brine reaction behavior: salt tends to reduce the solubility of surfactant in water, and the critical micelle concentration is reduced. As the surfactant concentration in the water increases the surfactant molecules form micelles with the lipophilic ends in the centre. Some of the free hydrocarbon liquid is captured in this centre and this causes more oil to be dispersed in the water phase. Further as the salt concentration increases, it can be noted that the surface tension slightly increases as well.[48] It can be said that the surface tension of formation water at low wellhead flowing pressures is not significantly different from the air and water system.[19] A more critical parameter is the surfactant treatment itself.

5.2.4 Foamer Selection

When it comes to the selection of a foamer somebody soon may recognize that on the market a large variety of foamers is available. If a specific foam supplier is asked for a suitable foamer they want to know the following points in order to make a suggestion.

- Salinity
- Condensate to Water Ratio
- Bottom-hole Temperature

Those three points are the ones a possible foaming agent supplier needs to know to select a proper foamer out of his products.[25, 33] Anyway, many foamers have been tested in the laboratory and at field locations. Those tests have shown that the in the previous section mentioned cationic, anionic, and amphoteric surfactants show the best performance. However, each formation water and liquid hydrocarbon has its own characteristics and therefore different foamers should be tested with the operators own produced liquids.[19]

The ideal way before a field test is conducted different foamers should be tested in the lab. How a foamer is tested and which apparatus is used is described in the following Chapter 5.2.5. Once the first screening has been done in the lab the best one is applied in the field. First the foamer is applied in the form of soap sticks. They are easy to handle and they are cheap.[49] If the well responds well, an increase in production is observed, batches of liquid foamers can be injected into the tubing or through the annulus; if no packer is present (or in case of a packer an open SSD). After such a treatment, having positive results, an injection system can be installed and a foamer can be injected continuously (see Chapter 6).

Basically foamers should be purchased based on the above mentioned parameters from different companies and than tested with the specific wells formation fluids. Due to the fact that wellbore conditions are hard to simulate in the laboratory and the fact that each well reacts differently on a foaming agent, it is essential to test the foamers in the candidate well.

5.2.5 Foamer Testing

There are different tests available to test the foam ability of a product:

- Shaking Tests
- Gas Bubbling Tests

The main purpose to these tests is to determine the foaming characteristics of different foamers at different foamer concentrations, temperatures, water compositions and water/hydrocarbon ratios. To evaluate these characteristics the following parameters are measured during and after the test:

- Foam height and volume versus time: foam stability and foam density
- Remaining liquid versus time: liquid drainage
- Half- life of foam volume: foam decay
- Velocity of foam decay

Half-life of foam decay is the time when the foam volume is decreased to half of its original volume right after agitation. The velocity of foam decay can be calculated according to following formula:[49]

$$v = \frac{H_0 - H_t}{60 \cdot t}$$

The lower the velocity of foam decay the more stable is the foam.[49]

Measuring the foam height (volume) right after a shaking test and the weight of the foam allows the calculation of an apparent foam density. Foam density is often calculated as a function of foamer concentration for different types of foamers as it is presented in Figure 5-24.[20]

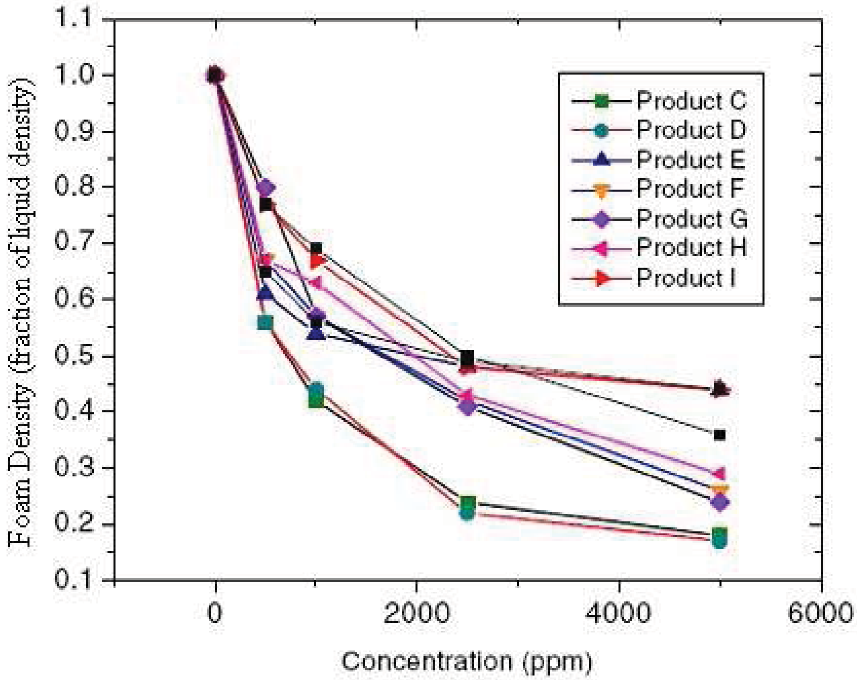


Figure 5-24 Foam Density as a Function of Foamer Concentration[20]

Shaking tests are the simplest form of testing foaming agents. A mixture of formation water and foamer is agitated either manually or with a blender. After shaking is finished the above mentioned parameters are measured. In a gas bubbling type of test a liquid volume with some foamer is blown with a controlled volume of air or nitrogen at different temperatures, liquid types, and water compositions in the presence of foamer. Figure 5-25 shows such a testing apparatus.

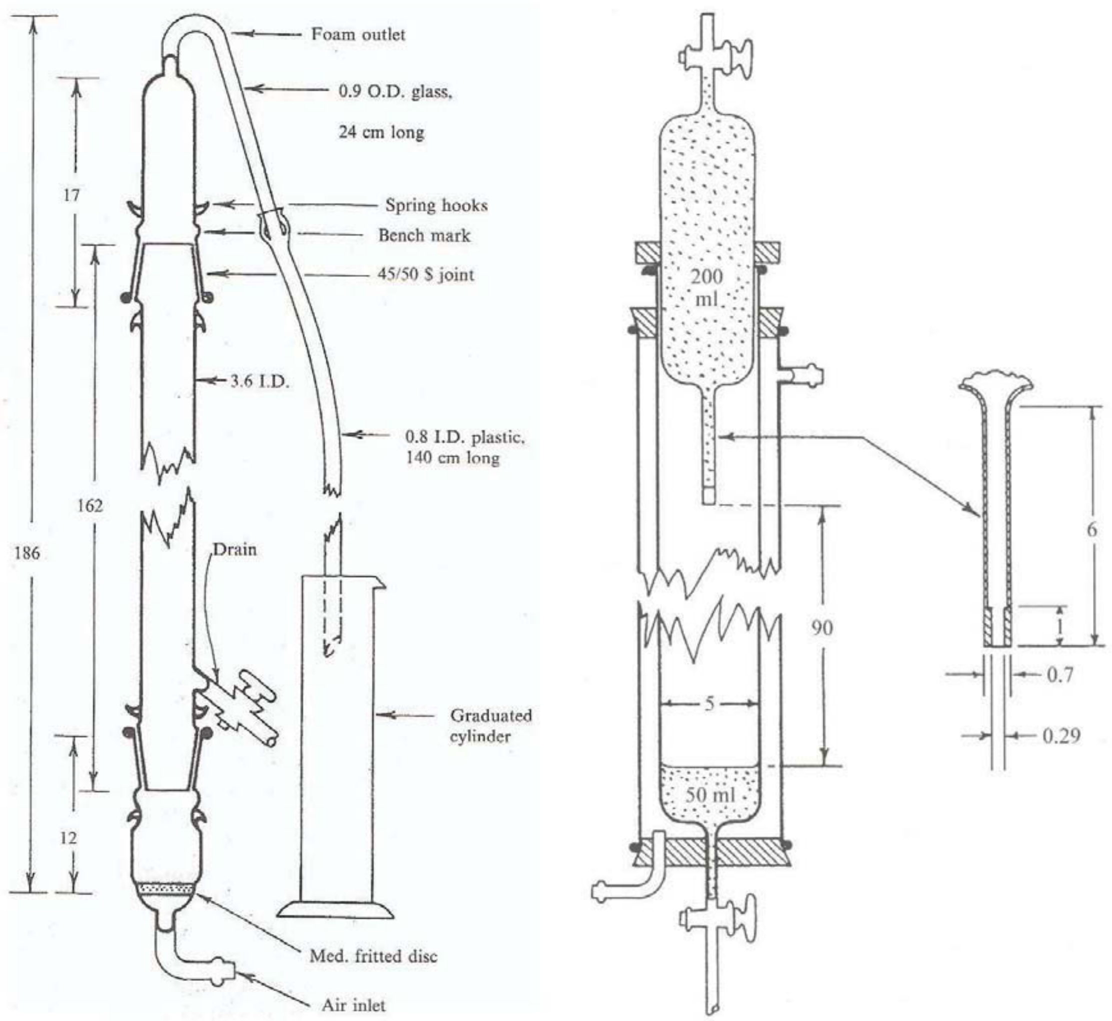


Figure 5-25 Bureau of Mines and Ross- Miles Testing Apparatus[50]

In this case the best foaming agent is the one where the most foam is carried over into the measuring cup. The Bureau of Mines is a simple, quick, and low cost testing procedure. A sample of formation water with a certain amount of foamer is placed in the tube. Gas enters the tube at the bottom and goes through a fretted disk. Liquid that is collected in the beaker is weighed. In a modified version of the Bureau of Mines (Ross- Miles Apparatus) foamer can drop 90 cm and the foam height is measured versus time as the test proceeds. This method is a static testing of foamer. Vosika describes the successful application of the two methods and the use for screening tests.[19, 49]

In order to measure the surface tension Campbell S. et al.[20] used the maximum bubble pressure method.[51, 52] Due to the dependency upon the diffusion rate of the surfactant the surface tension is dependent on the method of measurement. The maximum bubble pressure method has the ability to function in a dynamic system. In this type of technique a small glass capillary (0.25 mm in diameter) is immersed into the fluid of interest. Nitrogen is bubbled into the fluid at a constant flow rate and the pressure for bubble detachment is measured. To correct for the immersion depth another capillary (4 mm in diameter) is also immersed in the solution. It is used as a reference. In order to account for dynamic effects gas rate of nitrogen is varied in the range of 1 bubble/sec and 100 bubbles/sec and precisely measured with a mass flow meter. Results show the dynamic nature of the surface tension (Figure 5-26).[20]

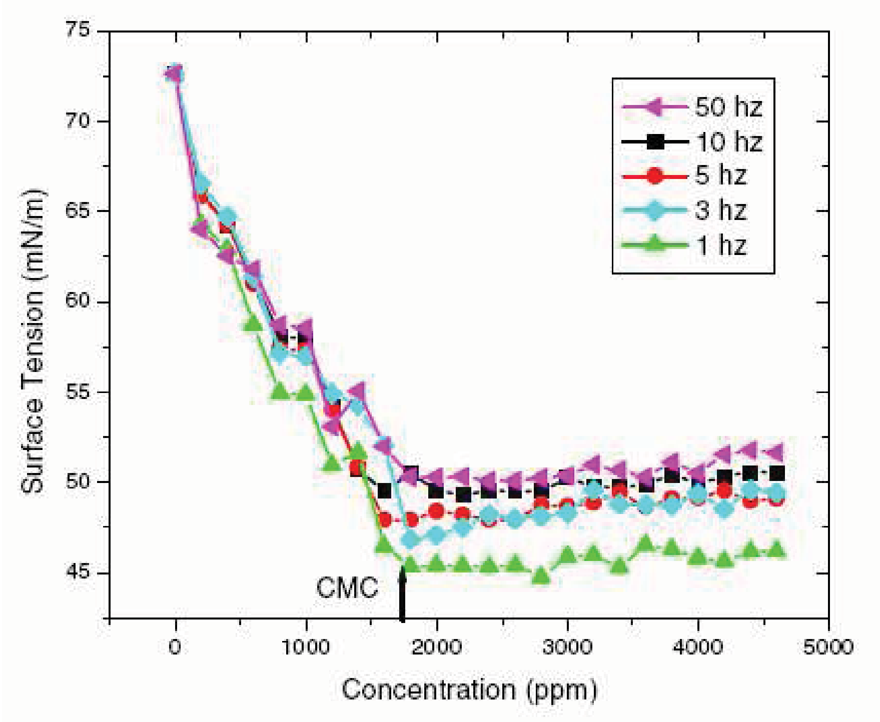


Figure 5-26 Dynamic Surface Tension: as the Bubble Rate Increases the Surface Tension Increases[20]

To predict the effectiveness of a foamer the dynamic nature of the surface tension and the density of the foam have to be considered.

5.2.6 Foamer Injection Rate

Many laboratory tests have been conducted and show that the optimum surfactant concentration is in the range between 0.1 % and 0.2 %. A solution having a too low foamer concentration will not allow any surface effects such as surface tension reduction, film elasticity, and repair of ruptured bubbles. On the other hand if the surfactant concentration is too high a high foam stiffness and high apparent foam viscosity will result. Further increased treating costs of the well are associated with a higher foamer concentration as well.[19] Campbell et al.[20] point out that based on experience a surfactant dosage of 0.1 % to 0.4 % is necessary. Consequently based on laboratory tests and experiences, an optimum surfactant concentration between 0.1 % and 0.4 % arises. Service companies suggest a concentration between 0.27% and 0.3%.[21] Therefore the author recommends assuming an optimum concentration of 0.3 % for calculations.

In order to calculate the injection rate based on the daily water rate the following formula is used:[49]

$$Q_{inj} = 10 \cdot C_{opt} \cdot q_w$$

For example if the well is producing 1 m³/day of water the chemical injection rate would be 3 Liters per day based on an optimum surfactant concentration of 0.3 %. However, due to uncertainties the optimum concentration should be multiplied by a factor of two.[19] Therefore the corrected equation is $Q_{inj} = 20 \cdot C_{opt} \cdot q_w$. This calculated injection rate provides just a starting point for optimizing the foamer injection rate. The optimum injection rate must be found by trial and error on location. Once production has been started and stabilized it is time to optimize the injection rate. Based on Figure 5-27 below the following way describes the optimization of the rate.

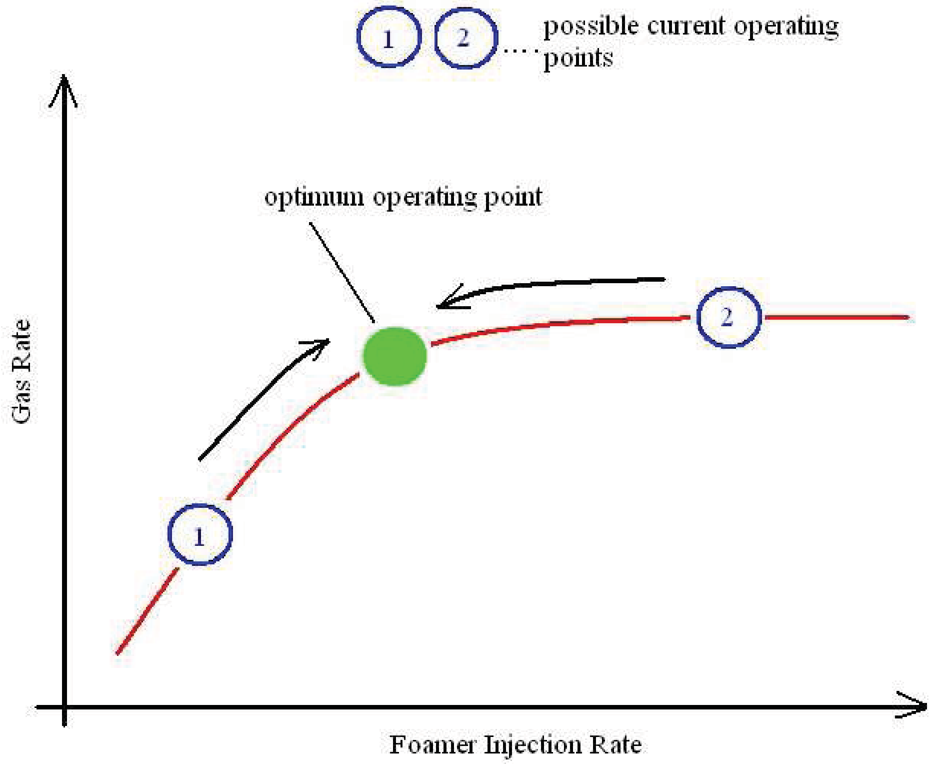


Figure 5-27 Foamer Injection Rate versus Gas Production Rate

The Figure shows two points: point 1 and 2. In the beginning it is not known whether point 1 or point 2 represents the current well condition. Increasing or decreasing the foamer injection rate indicates the corresponding point. If a change in gas rate is recognized then point 1 indicates the current situation. However, if no change in rate is observed point 2 represents the actual situation. Depending on whether point 1 or 2 is the wells current situation the foamer injection rate should be varied till the actual point reaches the optimum point. For example the following Figure 5-28 shows the gas production rate and the corresponding injection rate. This foamer trial leads to maximum production and to minimum well treating costs.[19, 53]

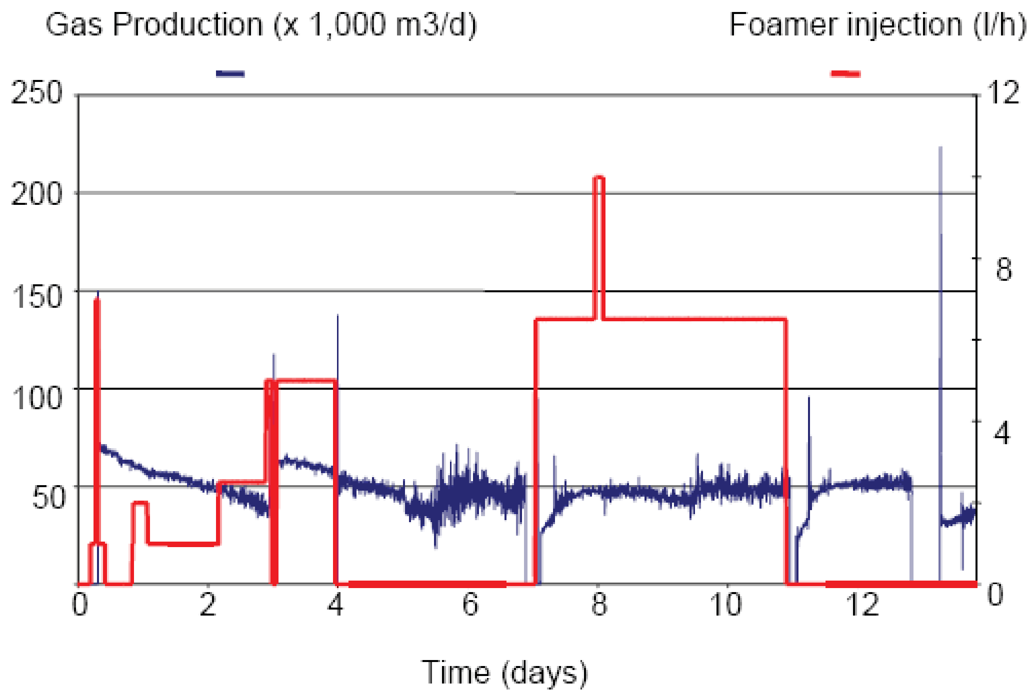


Figure 5-28 Capillary Injection: Foamer Injection Rate Trial[53]

5.2.7 Defoamer

In the previous chapters it has been pointed out how stable foam can be achieved and that a stable foam phase is required for an effective liquid removal from the wellbore. However, now from a production operation stand point of view a complete stable foam phase is not desired.[20] This is because the foam may not deteriorate enough at the surface and can be carried over into the separator and further into the pipeline which is definitely not desired. Functionality of level controllers in a separator are influenced by the foam phase due to a not well defined interface between the gas and water phase. In order to handle this problem a sufficient large separator having more retention time can be used. This would give the foam more time to break. A second possibility is to use de-foamer chemicals that are injected into the flow line right behind the wellhead but still before the separator to allow mixing before the produced liquids enter the separator. Anyway both methods require an additional investment and therefore this is often not conducted by the operator.[19] A more economic way to handle foam carryover is to decrease the surfactant injection rate till no problems with foam at the surface arise. This method may reduce the efficiency of the liquid removal process in the wellbore but does not require further investments. Some recommend to have a look at the produced water. A milky white color, which is often difficult to distinguish from pure formation water, of produced water can indicate that at least the foamer reaches the surface. However, most important is the maximum achievable gas rate to use as an indication for a good foamer treatment.[25, 33]

6 Candidate Evaluation

As mentioned in a previous chapter a large variety of deliquification methods are available. As this document deals with the capillary string technology to inject foamers to remove the liquids out of the wellbore it is important to know which wells are suited best for such an application. Also other deliquification methods should be considered and their performance should be evaluated before a capillary injection system is considered to be the best option.

Selecting the right well for a continuous foamer application is crucial for a successful implementation of such a technology. Though the capillary string solution is the most expensive solution under the surfactant treatment methods, it is still one of the cheapest among the deliquification methods. Due to its high initial investment costs compared to soap sticks and continuous backside injection a certain degree of production increase after installation is expected in order to justify any installation of the technology. Therefore a detailed evaluation of a possible candidate well is necessary.

Once liquid loading is determined as the wells problem (see Chapter 2) the following paragraphs have to be applied and should lead to a good candidate for foamer injection through the capillary string. The following selection guide can be summarized as follows:

- Pre-evaluation and data gathering
- Evaluation of the well's actual and critical velocity
- Evaluation of the critical foam velocity
- Soap trial
- Evaluation of the well's possible potential
- Selecting the best candidate

McWilliams et al.[23] conducted a 10 well pilot project of the capillary string injection system in the San Juan Basin with the objective to find better criteria for selecting candidate wells. The factors that appeared to have significant influences on the post-treatment production increment, starting with the most important one, are:

- Compression Limitations
- Condensate to Water Ratio
- The Well's Potential
- Tubing Shoe Position

Any backpressure on the formation, whether it is liquid or surface restrictions, limits the wells production. Usually there are several factors that limit production and therefore a total system review should identify any restrictions before any artificial lift system is installed.

In a previous section it has been mentioned that it is easier to foam water than condensate. Wells having a condensate to water ratio higher than 50 % foam less well than those having significant more water (see Chapter 5.2.3.4).

Wells having a high uplift potential are among the better candidates. Removing fluids from the wellbore reduces the bottom-hole flowing pressure and consequently an increase in production rate can be achieved. Good candidates are those where a small reduction in the bottom-hole flowing pressure results in a significant production increase.[23]

Al-Jamae'y et al.[54] recommend that a capillary string injection system should not be installed in wells where the tubing is landed below the bottom perforations. There will be not enough agitation to cause proper foaming action. However, a foamer trial should be done also in such wells where the tubing runs across the perforations in order to judge whether there is enough agitation or not and should not be initially excluded from the evaluation process.

This analysis has been done in the San Juan Basin and consequently care should be taken when considering the importance of the individual parameters on the well's post-treatment production. In a different area other parameters can lead this sequence of influencing parameters.

6.1 Pre-Evaluation and Data Gathering

One important factor that has to be considered before any detailed information on the wellbore is collected is the liquid gas ratio (LGR). As this candidate selection procedure is looking for a foamer candidate, only wells having a moderate to low LGR should be considered. As the foamer injection rate is a function of the liquid production high costs can arise if the LGR is high. However, as a first rule the LGR should be not higher than 6E-3 m^3/Nm^3.[24] Another reason is, as in a previous chapter already stated, that the calculated critical gas rates are not effected by LGR's significantly lower then the one mentioned above. Therefore previously presented models for estimating the critical gas rate can be used. The lower the

LGR the lower would be the foamer injection rate and the corresponding treatment costs. Another point is the amount of condensate produced by the wellbore. In general it should be as low as possible but at as a maximum half the amount of the produced water. Condensate is difficult to foam and expansive, specialized foamers are required to achieve adequate results. These two factors can be used as a first cut off for the selection of candidates.

In order to do an analysis a certain amount of data is required. Collecting reliable data is one crucial thing in order to deliver useful results. Table 6-1 presents a data matrix where most of it is used for evaluating the wellbore's critical velocities and part of it as input data for a system analysis program (e.g. PROSPER). Further reservoir data are needed when the wells uplift potential is evaluated by using a system analysis program.

The well data section in Table 6-1 includes the inclination of the borehole. This is zero degrees in case of a vertical borehole and in case of an inclined hole, an average inclination is inserted. Well data are rather precise and therefore not a big problem. More critical is the production. The gas rate has to be stable and accurate. Water production and the corresponding LGR is important but unfortunately very often only estimated and not of good quality. Condensate production is not that important for the calculation but of more importance is the condensate to water ratio for candidate selection. If no condensate or solids are produced zero has to be entered. Gas specific gravity and the Z-factor are sufficient for the calculation. Surface tension values for water range from 60 dynes/cm up to 75 dynes/cm for brines. Drag Coefficients are calculated from surface tension and Turner Coefficient which can be varied if someone wants to. Varying the surface tension helps to study the effect on critical rates (see also Chapter 5.2.2.1). Surface tension of foam is in the range of 20 to 35 dynes/cm and foam density is at least 6 lbm/ft³. Solid density is usually 2.7g/cm³.

When all the data is collected someone can estimate with the following procedure whether the well is able to unload liquids or not.

Based on Coleman	RAG A	For Pressures < 70ba
	RAG Units	

Well Data		
Depth		m
Inclination		°deg
Casing ID		in
Tubing Setting Depth		m
Tubing OD		in
Tubing ID		in
Tubing Wall roughness		mm
Top Perforation Depth		m
Bottom Perforation Depth		m
Surface Temperature		℃
Bottom Temperature		℃

Production Data		
Gas Rate		Nm³/day
Water Rate		m³/day
Condensate Rate		m³/day
Solid Rate		m³/day
Flowing Surface Pressure		bar

Flowing Wellhead Pressure Range		
Minimum	1	bar
Maximum	10	bar

Packer	N	Y/N
Trough Tubing/Annulus	Tub	Tub or Ann.

Gas Properties		
Gas Density		lb/cf
Gas SG		
Z-Factor		

Water Properties		
Water Density		kg/m³
Water SG		
Surface Tension		dynes/cm
Drag Coefficient (Turner)	0,000	(>1000psi)
Drag Coefficient (Colem.)	0,000	(<1000psi)
Turner Constant	1,593	

Condensate/Oil Properties		
Condensate SG		
Surface Tension		dynes/cm
Drag Coefficient (<1000psi)	0,000	
Drag Coefficient (>1000psi)	0,000	

Solids Data	
Solid SG	

Foam Properties		
Foam Density		kg/m³
Surface Tension Foam		dynes/cm
Drag Coefficient Foam	0,000	<1000psi

Table 6-1 Input Data Sheet for Critical Rate Calculation

6.2 Foamer Candidate

As in the introduction of this chapter already mentioned before any soap stick is applied, it should be calculated whether a foamed liquid is even able to unload the wellbore. To accomplish this, different velocities should be compared. Those are the actual velocity, the critical velocity, and the critical velocity of foam. Basically a good foamer candidate is a well whose actual velocity is between the critical foam velocity and the critical velocity for unloading liquids. In this case a foaming agent generates the desired effect (see Figure 6-1). This means the well would be able to unload itself because the actual velocity is higher than the critical foam velocity. Further this implies that a foamer has to be injected continuously to keep the critical velocity for foam at its level.

6.2.1 Evaluation of Actual-, Critical-, and Critical Foam- Velocities

The actual velocity is calculated from the production rate that is currently observed at the well. Mostly this is difficult because rates vary and especially when the well is already in a loading stage this rate is not correct anymore. Figure 6-3 shows a typical production plot when a well is loading. As it can be seen from the Figure the actual rate that is observed is not a stable rate and consequently not the correct actual one. Therefore care should be taken when a certain value is taken and only stabilized production data are useful.

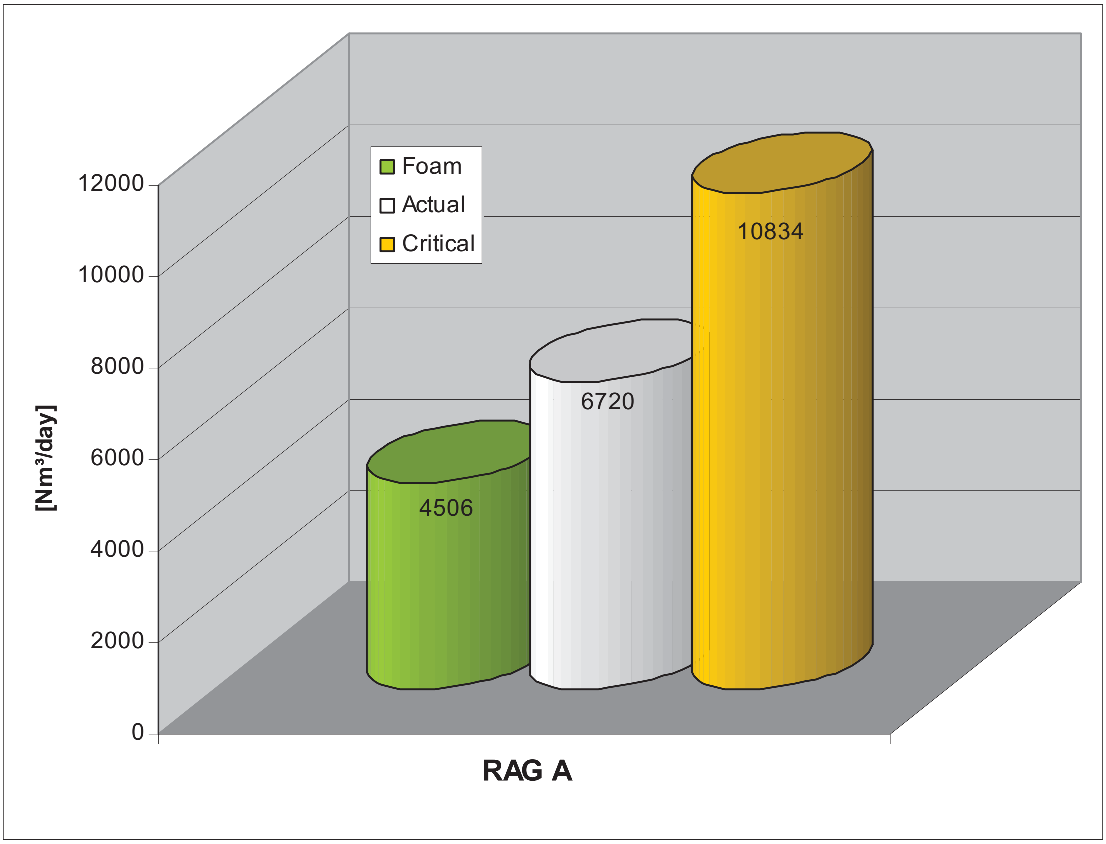


Figure 6-1 A Comparison of Critical Foam-, Actual-, and Critical- Production Rate

Usually gas rates are measured in standard cubic meters per day (Nm³/day) and are converted into a velocity by the following equation:[55]

$$V_G = \frac{Q_G ZT}{3067 P A_i} \quad (1)$$

The critical velocity (or rate) is the one required to remove liquid droplets (Turner Model, see Chapter 3.2.1) out of the wellbore on a continuous basis. In general different models have been presented in Chapter 3.2 but for wellhead pressures below 1000 psi the Coleman solution is the most appropriate one. However, this method does not account for different water production rates of the well. On the other hand so does the energy approach. Therefore it is recommended to use both methods to confine the critical velocity. In practical terms the Coleman model is easier to apply because less data is required. The approximated critical velocity by Coleman (see Chapter 3.2.2) can be calculated using the following formula:

$$V_{C,water}(P)=\frac{4.434\cdot(\rho_L-0.0031\cdot P)^{1/4}}{(0.0031\cdot P)^{1/2}} \quad \text{.......... (2)}$$

Though the critical velocity is the controlling factor it is more common to think in terms of gas rate (Nm³/day). Combining equation (1) and (2) leads to the equation below.

$$Q_{C,water}(P)=\frac{(0.0742\cdot P\cdot D_h^2)\cdot(\rho_L-0.0031\cdot P)^{1/4}}{T\cdot Z\cdot(0.0031\cdot P)^{1/2}} \quad \text{.......... (3)}$$

A more complex equation is the one that calculates the critical rate for liquid removal based on the gas kinetic energy needed to transport a liquid droplet up the tubing. The responding equation is the following (see also Chapter 3.3):

$$144b\alpha_1+\frac{1-2bm}{2}\ln(\alpha_2)-\frac{m+\frac{b}{c}n-bm^2}{\sqrt{n}}\left[\tan^{-1}\beta_1-\tan^{-1}\beta_2\right]=a\left(1+d^2e\right)L \quad \text{......... (4)}$$

This equation can be solved with a numerical method such as the Newton-Raphson iteration technique. There are also software packages available like the Goal Seek function built in Excel. This method takes the liquid production rate into account. As the liquid production increases the critical gas rate increases as well. A higher liquid production (or in other words a high LGR) means that there is more liquid inside the tubing distributed over the whole depth. This again means that more energy is necessary to lift the liquid upwards. The difference between the two models, Coleman and the energy approach, becomes severe if the water production rates are high. At low rates the energy approach delivers slightly higher critical rates (see Figure 6-2).

The critical foam rate is calculated based on the same model as the critical rate, namely the Coleman model. As in Chapter 5.2.2 already described a foaming agent changes the surface tension of the liquid and further generates a foam with a significantly lower density than pure liquid. In praxis it is difficult to predict how far the surface tension is reduced and what foam density is achieved. Laboratory tests and praxis have shown that a surface tension lower than 20 dynes/cm and a foam density lower than 6 lbm/ft³ cannot be achieved.[19, 23, 20] Using these values will give the maximum reduction of critical velocity that is possible under optimum conditions. Consequently the following approximated equation for the critical foam velocity arises:

$$V_{C,foam}(P) = \frac{3.369 \cdot (\rho_f - 0.0031 \cdot P)^{\frac{1}{4}}}{(0.0031 \cdot P)^{1/2}} \quad \text{..........} \quad (5)$$

In terms of gas rate the equation changes to the following one:

$$Q_{C,foam}(P) = \frac{(0.0563 \cdot P \cdot D_h^2) \cdot (\rho_f - 0.0031 \cdot P)^{1/4}}{T \cdot Z \cdot (0.0031 \cdot P)^{1/2}} \quad \text{..........} \quad (6)$$

In order to simplify the process of evaluating the different velocities an EXCEL spread sheet has been created by the author. In the data gathering section the input data sheet is shown (Table 6-1) including all the data required to perform the calculation. Basically this sheet delivers the following two charts. Figure 6-2 shows critical and critical foam rate as a function of the wellhead flowing pressure. They are calculated based on the above mentioned equations. If the wells operating point (actual rate and wellhead pressure) is in the area between the two lines (green area) then the well would be a candidate. This chart helps the design engineer to figure out whether a change in wellhead pressure or rate can shift the wells operating point into the area where a foamer unloads the well or into the area where even no foamer is required. The second chart (Figure 6-1) compares the actual, critical, and critcal foam rate at a specific operating point. Again, if the actual velocity is between the one of foam and critical rate the well is a foamer candidate.

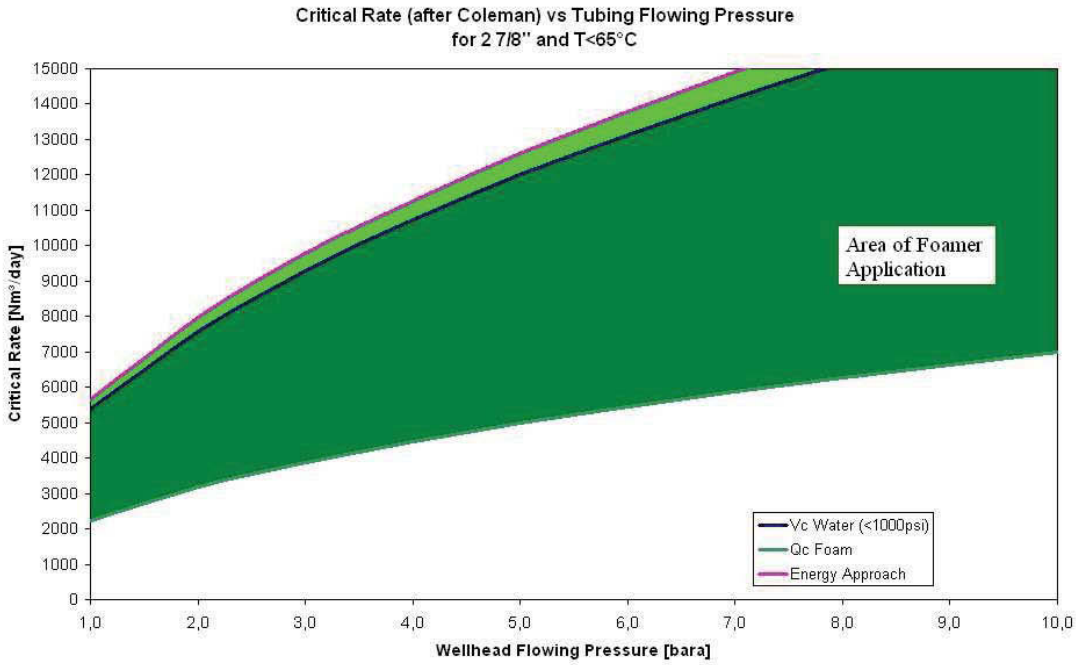


Figure 6-2 Critical Foam Rate and Critical Rate as a Function of the Wellhead Flowing Pressure

Care should be taken when analyzing these charts for two reasons. First the calculated critical foam rate is based upon the assumption of an optimum foam generation. This means if the actual velocity is close to the critical foam rate but still above, an unloading of the well can be still not possible. Second when the actual rate is in between the critical foam rate and the critical rate without foamer it should be considered whether the actual rate is closer to the critical foam rate or to the critical rate. The author recommends that a good candidate well is located right in the middle or even closer to the critical rate. That is because the critical rate is the better predictable one. Additionally if good production data is available the onset of liquid loading can be seen on a production history plot such as shown in Figure 6-3. The rate corresponding to the onset of liquid loading is the critical rate for this specific well. On the other hand if the actual rate is close to the critical rate there is a better chance that the rate stays above the critical foam rate for a longer period of time.

Once the well has been identified to be theoretically a good foaming candidate the next step is to test a foamer in that well. The above mentioned analysis of the critical rates does not replace a soap trial. Before a continuous injection system is installed it has to be tested how a possible candidate reacts on a foamer.

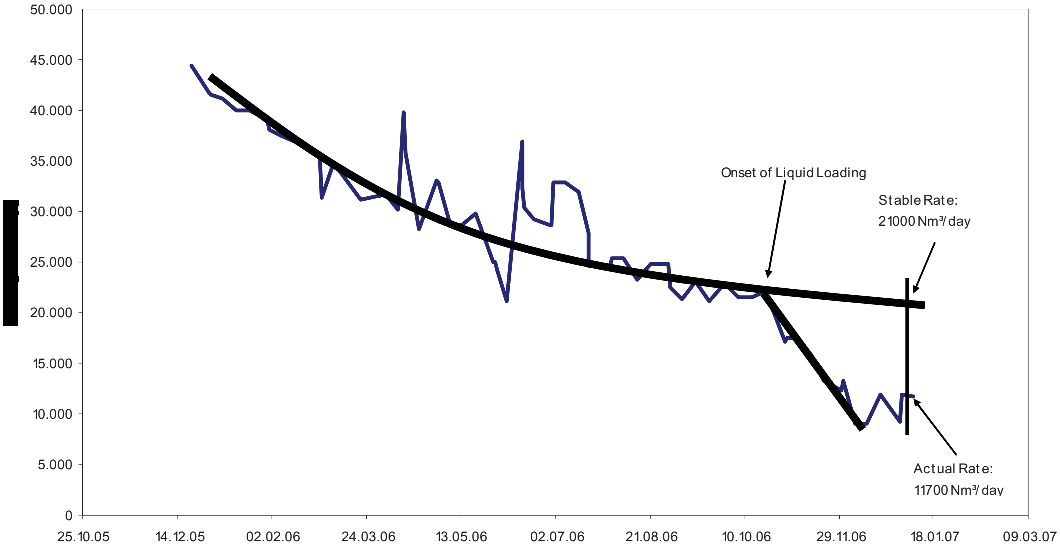


Figure 6-3 Production Data shows Onset of Liquid Loading

6.3 Soap Trial

The big unknown variable in this evaluation procedure is the complex system of foam generation. It can not be predicted how good a certain foamer reacts in a specific wellbore. Each well is unique. Therefore a foamer trial is essential and further it delivers information about the wells reaction behavior and it gives an estimate of possible production increase. Once a foaming agent has been selected (see Chapter 5.2.4) there are two methods how a foamer can be tested in a specific wellbore:

- Soap Sticks
- Liquid Batches through tubing or annulus

Applying soap sticks to a wellbore is a cheap and simple method conducted by the field people. Many wells are treated with soap sticks either once a week or even every second day depending on the amount of produced water. Figure 6-4 shows a typical circular chart of a wellbore treated once a week. Wells showing a significant increase in production right after a soap stick is applied such as shown in Figure 6-4 are among the wells that react well on the surfactant.

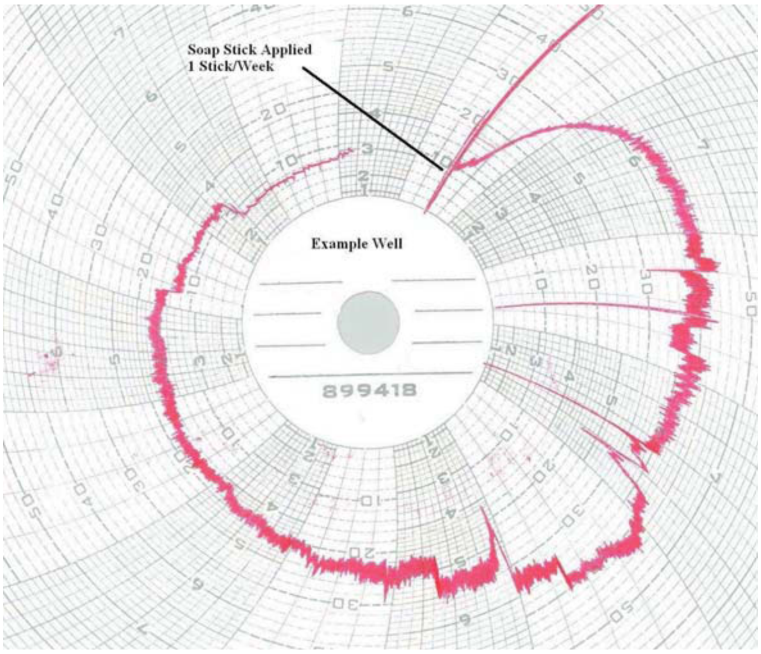


Figure 6-4 Circular Chart of a Wellbore which is Soap Treated once a Week

Further the decline after the production increase is a second parameter that should be considered. Wells showing a slow decline indicate a low loading rate due to a low water production. On the other hand wells that indicate a sharp decline have a higher water production and require more surfactant in case of a continuous injection. Figure 6-5 compares two circular charts from different wellbores where the left one shows a good reaction on soap sticks and the right one a minor reaction.

However, an increase in production indicates a positive effect of surfactants on the well but a qualitative analysis is not enough. Additionally the increase in production should be evaluated quantitatively as well. This surfactant trial helps to roughly estimate the post treatment production. Dependent on the circular chart writer settings an increase in production on a production plot may look significant but converted into the corresponding gas rate it is not. In Figure 6-6 the circular chart values are converted into a gas rate and it can be seen that the right one showing a smaller increase in production is eventually the one having a higher incremental rate. Consequently a qualitative analysis of the production plots should always be done in conjunction with a quantitatively analysis as well.

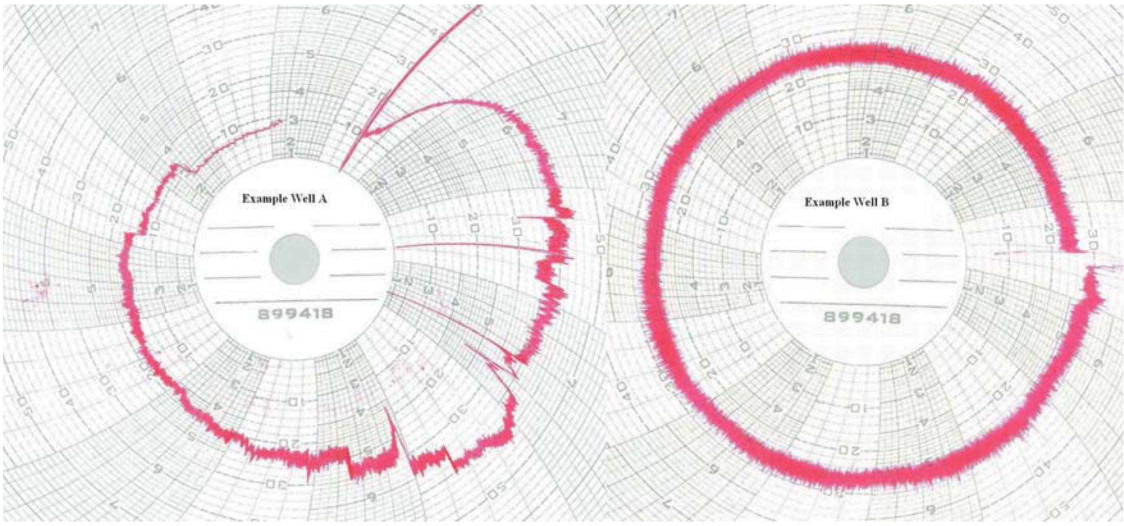


Figure 6-5 Comparison of Soap Stick Response of Two Wells Treated Once a Week

Wells showing a low incremental production rate and a slow decline may not suitable for a continuous injection system. The incremental production would be too less to justify the investment costs for capillary injection system.

Once a soap trial has been conducted and results indicate a possible good candidate the next step would be to model the well performance with a system analysis program.

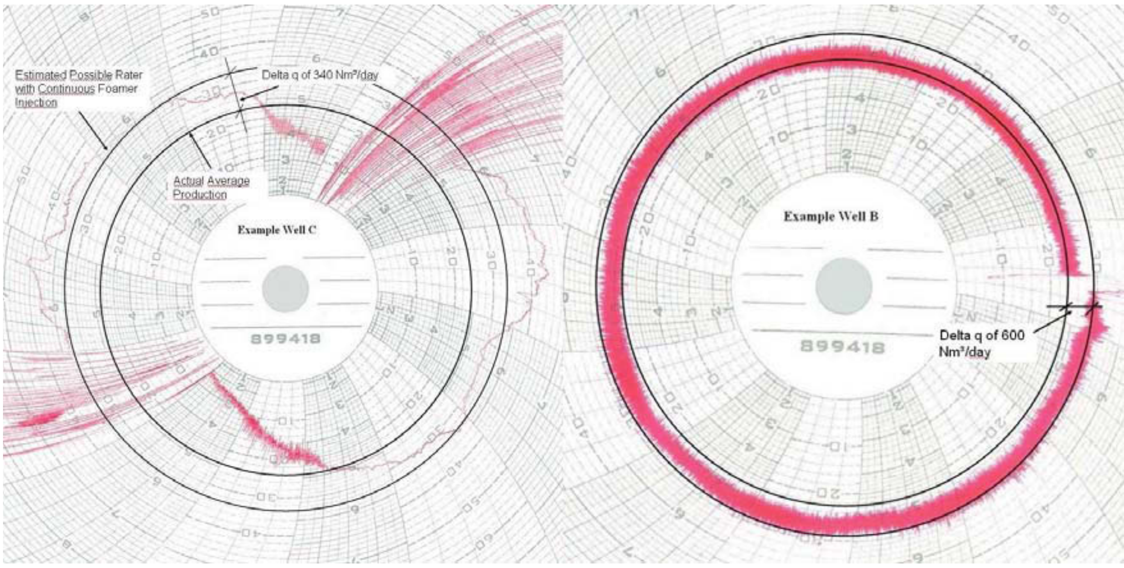


Figure 6-6 A Comparison of Two Different Incremental Rates

6.4 Evaluation of Wells Potential

As a first approach the wells performance can be determined by doing a soap trial as it was mentioned in the section above. This is a more practical way to estimate the post installation production rate. Using a system analysis program to model the wells performance helps on the one hand side to examine the uplift potential and indicate the current operating point and on the other hand to check the influence of different LGRs on the gas rate. Further it allows a comparison of gas rates considering no liquids, a certain LGR and foam, where as the foam rate is difficult to predict because the foam density is difficult to estimate.

At the beginning of the chapter the uplift potential has been mentioned to be one significant parameter for a successful capillary injection candidate. The following Figure 6-7 compares two wellbores having different uplift potentials. A well that can achieve a high incremental gas rate by a small reduction of the bottom-hole flowing pressure indicates a good uplift potential. Due to a continuous surfactant injection liquid is constantly removed from the borehole and therefore reduces the backpressure on the formation. This results in a vertical shift of the tubing performance curve and dependent on the uplift potential a more or less significant increase in production.

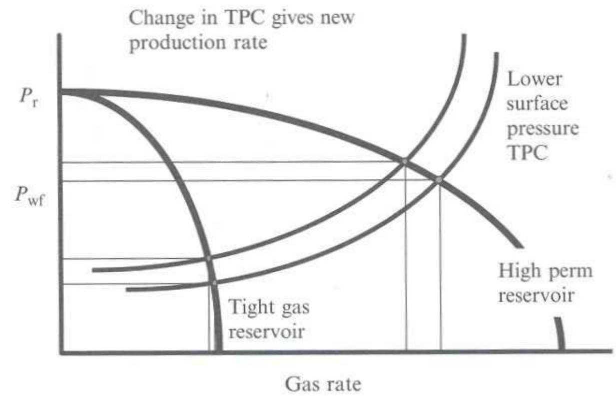


Figure 6-7 Comparison of Two Different Uplift Potentials

Further a system analysis allows the modeling of the loading behavior of the wellbore. Despite of that, the available software package does not have the option to consider the height of the liquid column in the wellbore, but it is possible to simulate an increased backpressure by varying the LGR. A higher LGR means there is more liquid in the wellbore distributed over the whole depth and consequently would cause a higher backpressure. As in Figure 6-8 presented it can be seen that a decline in production after a soap treatment can be modeled by using increasing values for the LGR. However, the most uncertain parameter in this analysis is the LGR which is mostly not known exactly. But using the production data from a soap trial a LGR ratio can be matched to a corresponding production rate. Further these production rates can be compared to a theoretical maximum gas rate considering no liquid production (LGR = 0). The most accurate post installation production rate with foam is the one observed from a soap trial but care should be taken because this rate might be estimated to high. The reason for this is that this rate is observed right after liquids are removed from the wellbore. If a well is loading, the backpressure on the formation increases as well. Therefore loading of the well is similar to a slow shut in of the wellbore till it stops producing. Consequently pressure is build up in the formation and after bringing the well on production again reservoir pressure will decline and with it the production rate. Further due to liquid loading again after unloading the well with a soap stick it is not possible to get a stabilized and accurate production rate. Consequently a slightly lower value has to be assumed. It is advisable to make a decline curve analysis (Figure 6-9) to confine the estimated post-installation rate as well.

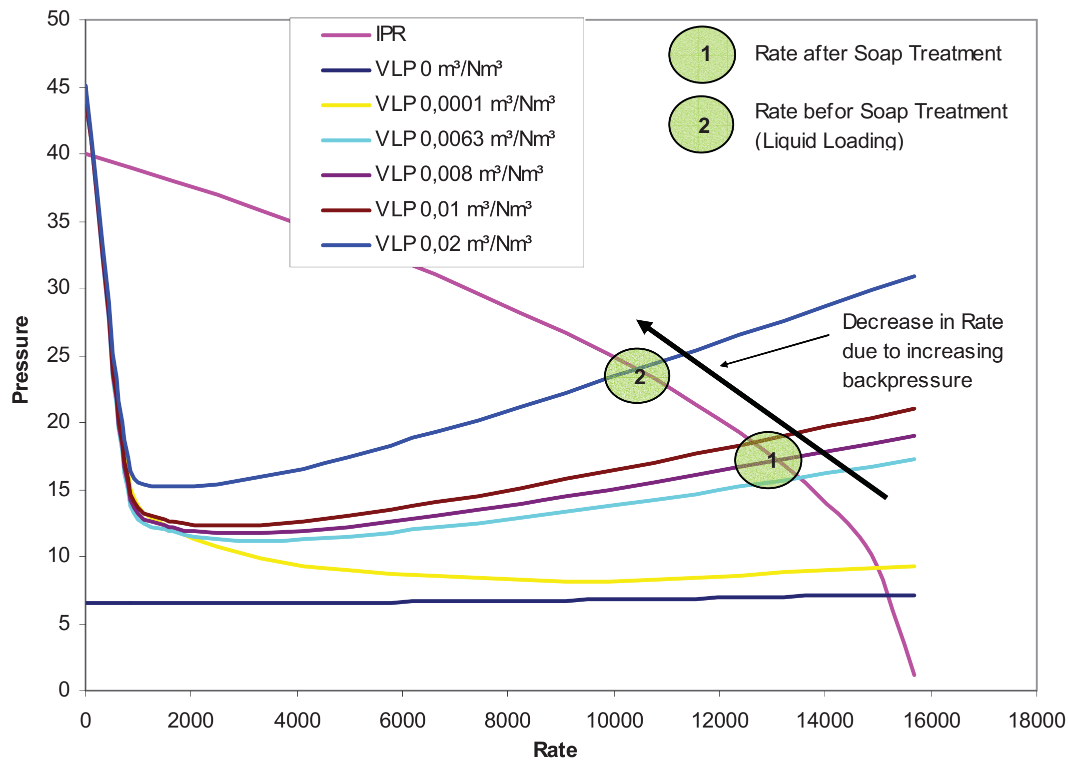


Figure 6-8 IPR and VLP Modeling of Liquid Loading

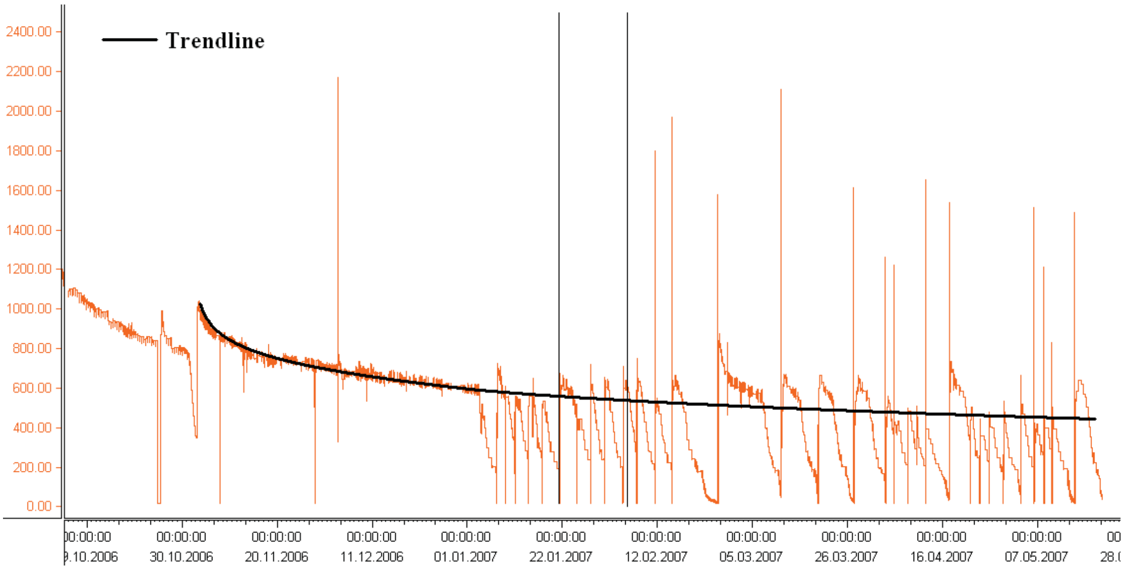


Figure 6-9 Production History with a Decline Curve

Most of the wells are already soap stick or batch treated for a certain period of time. Wells stop producing due to liquid loading and the first action that is done is to throw soap sticks. The well starts producing again but soon the rate declines again. This is done for weeks, months or even for years if only one soap stick has to be thrown per week. This is accepted because due to the law field people have to be at the wellside at least once a week and so it is not a big problem to throw a soap stick at the same time. However, the production increase due to a continuous injection of foamer comes from keeping the production rate at a constant level and prevents falling off of the rate. The average rate of a periodic production behavior is lower then a constant rate with foamer. In Figure 6-10 the incremental production is colored in red.

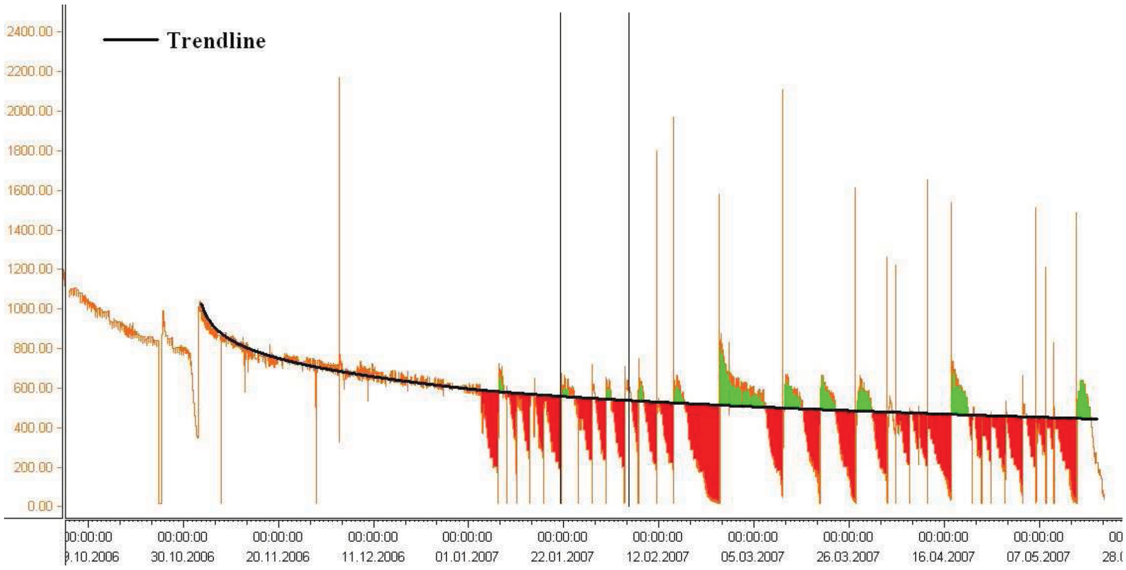


Figure 6-10 Incremental Production (Red) gained by a Constant Rate

Once a possible incremental production rate has been determined the economics of the project can be evaluated. The minimum incremental production that is necessary to justify an installation of the technology is more or less determined by the limits of the economic parameters, e.g. payout time, a company has set individually. Each company sets limits to economic parameters where below those a project is not implemented.

6.5 Best Candidate

To sum up the previous explained selection guide the following criteria have to be fulfilled to identify a well as a good capillary string application candidate.

- First when liquid loading is observed as the well's problem, several other deliquification methods should be investigated as well.
- Once a capillary surfactant treatment seems to be the most economic or only reasonable solution the well has to be analyzed if a surfactant would work and investment is paid back in a reasonable time.
- As a first approach the condensate to water ratio should be below 50 % in order to achieve sufficient foaming of the wellbore liquids.
- Actual production rate should be significantly above the critical velocity to ensure liquid removal from the wellbore for a longer period of time.
- A foamer trial is essential to evaluate the wells reaction on foamer and to determine a post installation production rate.
- Modeling the wellbore in a system analysis program helps to identify the wells uplift potential and to study the effects of liquid loading.
- Finally the economics are evaluated based on the expected incremental production rate.

If all the above mentioned criteria are applied a capillary injection system can be a successful deliquification method and can increase the well's life time. If several wells are examined and more than one well is a potential candidate the one with the highest incremental production and an actual rate close to the critical rate should be a priority candidate for the first installation.

In the Chapter 8 this candidate evaluation procedure is applied on RAG gas wells to identify a well where a capillary string can be successfully installed.

7 Operational Considerations

So far the capillary string technology with all its components has been discussed. Further a procedure has been established that leads to a suitable candidate well for this kind of deliquification method. Besides that other points concerning the injection system have to be addressed. In the following chapters points such as the installation procedure, common problems, maintenance, safety considerations, monitoring, and other possible applications of a capillary string are discussed. Finally, as a summary, advantages and disadvantages of the capillary injection system are pointed out.

7.1 Installation

In general the installation procedure depends on the type of capillary injection system that is installed. As in a previous Chapter 5.1.4 already discussed there are several ways of hanging of a capillary string. Further the type of hanger system to be used is also determined whether a SSSV is present or not. In the following two installation procedures are described; one for a well with a SSSV and one for a well without a SSSV.

In both cases the equipment to be used is the same. A capillary unit consists of the following points:

- Capillary Control Unit
- Slickline Winch
- Capillary Transport Frame
- Capillary Spooler
- Capillary Injection System (pump and surfactant tank)
- Capillary Injector with BOP

The capillary control unit including the power aggregate with the slickline winch is mounted on a skid. This skid can be mounted on a trailer for onshore use or can be transported to a platform for offshore applications. The slickline is used to provide gauge runs before a capillary string is installed in order to figure out whether the wellbore has no restrictions due to scaling or other deposits. This ensures that no problems arise while the capillary string is run in hole down to the desired setting depth. On a second transport frame the capillary spooler and the capillary injection system is mounted. The capillary spooler keeps the capillary coil and spools the coil when running in hole and winds it up when pulling out of hole. The base end of the capillary coil that is attached to the spool is further connected to a chemical injection pump which sucks the surfactants from a tank and pumps it through the whole capillary coil towards the other end of the capillary string. Chemicals have to be provided by the operator. This system allows the injection of surfactant already while the capillary string is installed. Additionally it is needed to adjust the chemical injection valve according to a certain opening pressure. Considering the force balance at the chemical injection valve the following equation arises:

$$p_{op} + p_{bh} = p_{hyd} + p_{inj}$$

The opening pressure of the valve is then calculated based on the equation mentioned below.

$$p_{op} = \left| p_{hyd} + p_{inj} - p_{bh} \right| \quad (1)$$

The opening pressure is the one that is adjusted at the chemical injection valve at the surface before installation and the bottomhole flowing pressure is the one measured at a certain gas production rate. The surface injection pressure can be chosen dependent on the capacity of the surfactant pump at surface. Usually an injection pressure in the range between 10 to 50 bars is sufficient. If the well is brought on production again after shutting in the well, the bottomhole flowing pressure will be higher which will result in a higher injection pressure at the surface.

The capillary injector head is another important part of the capillary unit. This tool is installed right above the wellhead with the BOP in between. It pushes the capillary coil down through the sealing device of the capillary hanger into the wellbore. Figure 7-1 below shows a typical unit for onshore operations. Some companies provide their own crane to move the injector head, where some need a crane from a third party supplier.

The in the latter case described capillary unit is used for all kinds of capillary installations. There is no difference whether a SSSV is installed or not. In the following the installation itself is described in more detail.

Figure 7-1 Two Capillary Units with Injector Head (left: Weatherford[35], right: Coil Services[33])

To start with, a general procedure is described of how a capillary string with a chemical injection valve is installed. In this case a standard wellhead hanger is used where the capillary string is hung of on top of the wellhead. This is the most common type of installing and hanging of a capillary system.

Installation Procedure using a standard capillary wellhead hanger:[32]

I. Once the capillary unit arrives at the wellside it is prepared for operations.

II. As a first step the slickline unit is prepared and a lubricator with a guide roller is installed on top of the wellhead. A gauge run is done down to the desired setting depth.

III. After a successful slickline run the master valve is closed and the lubricator removed again.

IV. Now the capillary injector is positioned right above the wellhead with a crane. The capillary coil is taken from the capillary spooler and is feed in the injector head, further through the stuffing box, and the BOP.

V. Additionally the coil is then feed in the capillary wellhead hanger.

VI. Before the chemical injection valve is connected to the capillary coil it is adjusted according to the pre-calculated opening pressure. Usually this is done with a manually operated high pressure pump.

VII. Once the valve has been adjusted it is connected to the capillary coil after the wellhead hanger has been beaded on the capillary coil.

VIII. As the master valve is still closed the chemical injection valve is now put into the wellhead followed by the wellhead hanger that is screwed into the top wellhead flange.

IX. The BOP together with the injector head is now connected to the capillary wellhead hanger.

X. In case of a double packing capillary hanger one of the packings is set to seal the capillary coil while running in hole. In case only one packing is available the stuffing box between BOP and injector head is used as the sealing device while running the capillary coil.
XI. Finally when the chemical injection valve reaches the desired setting depth the second packing of the capillary hanger is activated.
XII. Now the BOP with the injector head can be disconnected from the wellhead hanger and pulled up a little bit. This causes enough space in between to mount the clamp on the capillary string to secure it mechanically.
XIII. Releasing some coil from the spooler will set the clamp on to the capillary hanger. The capillary string is hung of now.
XIV. Before the coil is cut a certain amount of coil is winded up from the spooler dependent on the operators needs. After cutting the coil the injector head together with the BOP can be removed.
XV. Immediately after that warning signs have to be attached to the master valves so no one can close them and cut the coil unintentionally.
XVI. The surface end of the capillary coil is connected to an injection unit including tank, pump, filter, and anti-siphoning valve.
XVII. The system is now ready to inject foamer.

The above mentioned procedure is a standard installation procedure in case the capillary coil is simply hung of on to of the wellhead. Discrepancies to the above mentioned workflow arise as soon as different wellhead hanger systems are used or a SSSV is installed. In the following a procedure of installing a capillary string in a wellbore having a SSSV is described.

Installation of the SHELL patented modified SSSV (see Chapter 5.1.4.2.2):

As this capillary injection system utilizes the control line of the SSSV no changes at the wellhead are required. Just the modified SSSV together with the capillary coil is run into the wellbore and set in the SSSV hanger.
Step I to VII are the same as in the workflow mentioned above except the use of a wellhead hanger is not required now. Additionally a lubricator is mounted in between the injector head and the capillary BOP. On top of the lubricator additionally a second capillary BOP and a slickline BOP including a stuffing box have to be installed in order to lubricate the modified SSSV into the borehole.

VIII. The chemical injection valve is now put into the lubricator and then the master valve and the lower capillary BOP is opened after the top capillary BOP is closed.

IX. The valve is now run to a depth which is equal to the final setting depth minus the depth of the SSSV hanger. At that point the capillary BOP above the lubricator is activated and a clamp secures the coil from falling downhole.
X. The capillary coil can be cut and the modified SSSV is attached to the coil. A slickline setting tool is attached to the SSSV and suspends now the load of the SSV and the capillary string.
XI. The lower capillary BOP is closed.
XII. The upper capillary BOP is opened again.
XIII. The modified SSSV together with the coil is lowered till the whole valve is in the lubricator.
XIV. The upper slickline BOP can be activated and the lower capillary BOP is opened.
XV. The modified SSSV is run downhole till it is set in the landing nipple. The slickline setting tool is retrieved from the wellbore and the master valve is closed.
XVI. BOPs and lubricator can be dismantled and the well is ready for injecting foamer through the control-line of the SSSV.

This workflow of installing a capillary string is much more complicated compared to the one where no SSSV is present. On the other hand a capillary string solution like this causes fewer problems when operating the well.

There are two additional points that have to be addressed during a capillary string installation. The one is that the capillary coil can be run in hole already filled with foamer. This has two advantages. First the liquid in the capillary string adds additional weight and therefore it would ease the installation procedure. Second it prevents a high loading surface pressure because the liquid column inside the capillary string acts already on the chemical injection valve and consequently it assists in opening the valve.

The second point is that a weight bar attached between the chemical injection valve and the capillary string adds additional weight to the system and helps to run in the coil as it would be the case if the coil is filled with surfactant. Further it stabilizes the injection valve in high gas rate wells. However, talking to experienced service companies they suggest that a weight bar is in most of the cases not necessary. It depends on the gas rate, wellhead pressure and wellbore geometry.

7.2 Safety Considerations (HSE)

As this topic is one of the most important topics within an Oil & Gas Company it is discussed here concerning the capillary string injection system. Considering the terms of safety during the installation of the capillary string the same risks and safety measures apply as for a coiled tubing job. BOP's are used during the installation of the capillary coil as well.

Once the capillary is hung of in the well and normal operation of the foamer injection starts new points in terms of Health, Security, and Environment (HSE) arise. In any emergency where gas can leak from the wellhead, the capillary hanger or the surface part of the capillary coil the wellbore can be closed by the master valve and the capillary string will be cut. This has been tested by Gaz de France in Germany and reported by Coil Services.[56] Further due to the chemical injection valve at the bottom and a check valve in the surface line no gas can percolate up the capillary string through the pump into the tank. No harm to people and the environment can happen.

Foamers provided by Service Companies are treated according to the points mentioned in the safety data sheet. Due to the fact that for the capillary injection the same foamer is used as it is already for the continuous backside injection no new operating instructions apply.

7.3 Common Problems

As any equipment and operating equipment the capillary injection system is also susceptible to failures. A study has been performed by a service company conducting capillary string installations and the result was that basically most of the recognized failures can be categorized into three parts:[24]

- Plugging due to Particles
- Chemical Polymerizations
- Operator Errors

The following Figure 7-2 shows a distribution of the problems. Due to that most of the emphasis should be put on particle plugging and chemical polymerization.

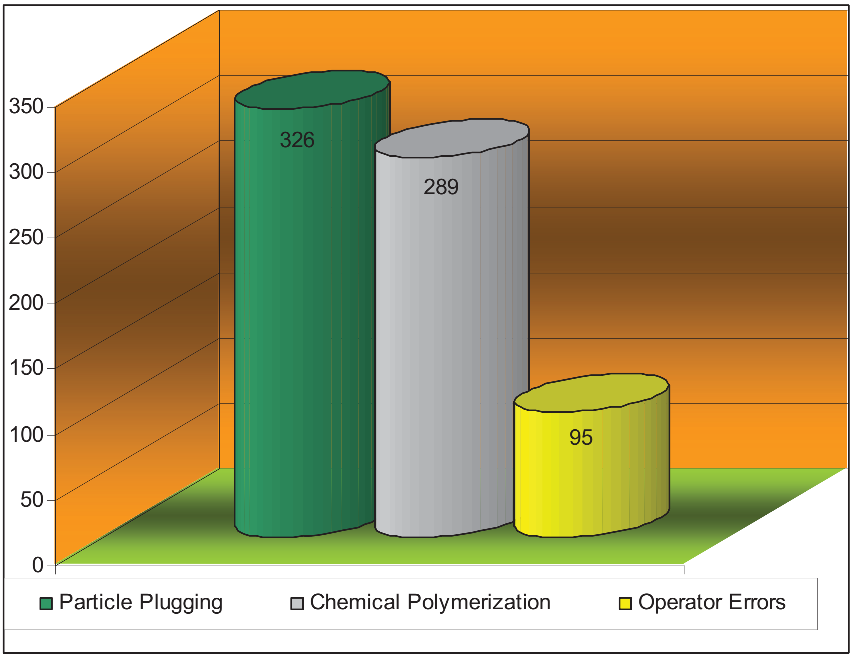


Figure 7-2 Most Common Capillary String Injection System Failures[24]

7.3.1 Particle Plugging

One of the biggest problem in case of capillary string injection system is the plugging of the string itself. Dependent on the capillary coil diameter the string is more or less susceptible to this problem. Particle may get into the capillary coil through the surface or either from subsurface. Dust or impurities from the truck get into the surfactant tank and then are pumped downhole into the capillary string. Another surface source of particles is the use of local water when diluting the surfactant. Chemical reactions between the water and the surfactant can cause precipitates.[24]

In case formation liquids is entering the capillary string from the bottom, formation fines can plug the string and salts can precipitate. Corrosion on the inside of the coil also plugs the string with time or causes the string to fail.

In order to prevent plugging of the string several measures can be done. A first one is installing a filter on top of the tank where it is filled and a second filter should be installed right behind the pump before the surfactant is pumped downhole. Second, selecting the right metallurgy for the coil is crucial to prevent any chemical reactions between the string and the surfactant. Third, a proper setting of the chemical injection valve prevents formations fluids from entering the capillary string.[24]

7.3.2 Chemical Polymerization

A second major point why capillary injection systems can fail is chemical polymerization. Again this categorization can be subdivided into several points as listed below:[24]

- Chemical Incompatibilities
- Carrier Qualities
- Multi-Purpose Chemistries
- Temperature Related
- Inferior Chemistry Feedstock

The following Figure 7-3 shows the occurrence of the different failures relative to each other.

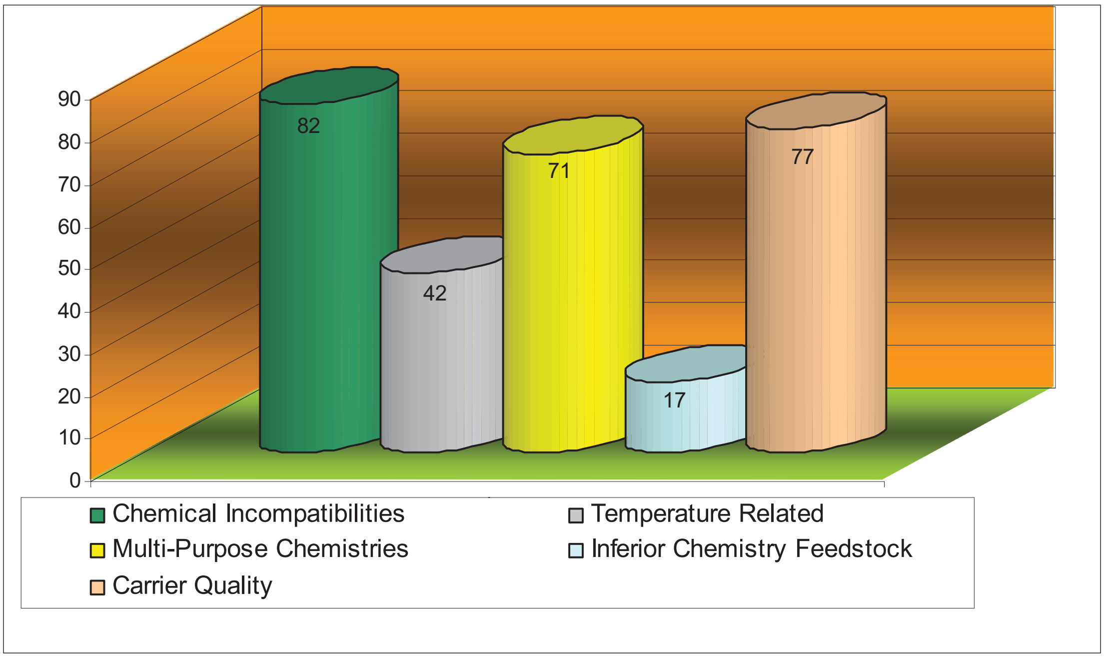


Figure 7-3 Typical Polymerization related Failures and there Frequency[24]

Chemical incompatibilities means that chemical components can be either corrosive, cause scales or react to form organic acids which cause the capillary string to fail.

A clean carrier fluid (distilled water) has to be used for diluting surfactant in order to prevent the formation of any solids; e.g. fluids containing any iron will form rust in the tank which is then pumped downhole.

Using multiple chemistries such as corrosion inhibitor and foamer to handle several problems at once can cause high viscous fluids or even solids in case of incompatibility.
Temperature will cause a breakdown in molecular structure which will result in a greater chance of plugging due to polymerization and/or will form solids.
Finally a pure quality of the feedstock can cause the capillary string to fail.[24]

Despite of that there are several steps that can be done to prevent such errors as mentioned above. Performing a compatibility test of surfactant and capillary coil in the lab to ensure that there are no effects on each other. Additionally the temperature limitations of the chemical should be check whether they are not exceeded in the borehole. An analysis of the carrier fluid is also important in order to avoid any precipitations.

7.3.3 Operator Errors

Part of the common problems can be accredited to the operator as well.[24]

- Insufficient training of the field people: standard operating procedures have to be explained at the well site. Further pinching the capillary string causes a weak point. Wellhead equipment must not mark the coil.
- Selecting the metallurgy: surfactant-, gas-, produced water-properties have to be addressed.
- Candidate well evaluation and setting depth: choosing the right well and injection the foamer at an optimum position increases success rate of installation.
- Splicing two capillary coils: welding procedures have to be reviewed and done by a certified welder.

7.4 Maintenance

As any permanent working system a capillary injection system has to be maintained regularly in order to ensure a problem free operation. Due to the small ID’s it is likely that the string may plug as it was mentioned in the previous chapter. In order to prevent this kind of problem it is recommended to displace the capillary volume with fresh water with a moderate injection rate on a monthly basis. If plugging occurs more frequent this type of treatment should be done in a shorter time interval.

Additionally maintaining a clean system at the well side also increases the lifetime of the capillary injection system. This means that filters should be checked on a regular basis. An increase in injection pressure can be a sign of a plugged filter. Solids found in a filter should be analysed to figure out the possible source and further to prevent this problem. Establishing a maintenance schedule helps to maintain a clean system.[24]

7.5 Monitoring and Automating

After the capillary string has been installed it is necessary to keep track of the production and treatment data. Recording the production data is still the same as before the installation but especially liquid production has to be monitored more accurately. This is because in most of the cases no attention is paid to the liquid rate as long as the well works fine but liquid production becomes important when problems occur. An accurate rate is crucial in order to further optimize the application of foamer. A second important parameter that has to be recorded after the capillary string installation is the foamer injection rate. In conjunction with the monitored gas rate the foamer injection rate can be optimized. The optimum injection rate is the one where it is a minimum and the gas rate a maximum (see Chapter 5.2.6). Additional parameters are wellhead pressure and foamer injection pressure. The wellhead pressure is necessary to analyze any changes in the gas rate and the chemical injection pressure helps to recognize any problems in the capillary string. For example a drop in injection pressure can indicate a leak in the capillary string or a failure of the chemical injection valve. An increase in pressure would than have a plugged capillary string or a plugged filter as a cause. In case no packer is installed casing pressure versus tubing pressure can be recorded as well (see Chapter 2.3.3).[49]

All the above mentioned parameters can be recorded either manually by the field people on a regular basis or continuously through measuring devices at the well site. Recording the data continuously has several advantages besides the disadvantage that it is costly to install them. First the gained data is more accurate and it does not require anybody to get at the well site and read off the values. Second a continuous measurement of data is necessary for automation. For example the chemical injection rate can then be adjusted automatically based on the gas rate. This has the advantage that once the rate decreases or even goes to zero less or no more foamer is injected. For example if the well can be shut down remote controlled the chemical injection pump will still continue pumping foamer into the borehole which would cause even more liquid in the wellbore. Additionally an increase in the water rate and a decrease in the gas rate would be a sign of liquid loading and the chemical injection rate has to be increased.

Implementation of the right software will use all the above mentioned parameters to keep the production rate at its optimum by adjusting the foamer injection rate. Further if any problems occur, for example the injection pressure reaches a maximum or the injection rate drops suddenly to zero, a warning can be sent.

7.6 Other Applications

A capillary string can not just be used as a deliquification method by injecting foamers. Other applications are the use of a capillary string for injecting inhibitors in order to treat corrosion, scaling, salt, paraffin, and hydrates. Additionally all combinations of those liquids are available. Most common is a combination of foamer and corrosion inhibitor. However, as mentioned in the previous chapter compatibilities have to be evaluated in the lab before applied in a wellbore.[5,37]

Another application would be the injection of gas through the coil. This technique can be used to bring wells back on production that suffer from liquid loading and fall of production from time to time. A large in diameter capillary string is more favorable for such an application. For example through an OD ¼” capillary tubing gas can be injected with a rate of 560 Nm³/day ($p_{inj} = 2000 psi \; and \; p_{bh} = 3000 psi$).[33]

Another thought would be the combination of both gas injection and foamer injection through a capillary string. This combination of deliquification methods has not yet been evaluated but the author recommends doing a feasibility study on that.

A capillary string can be also used to measure the static bottomhole or bottomhole flowing pressure. When looking at the formula below it can be seen that all the variables are known and that the bottomhole pressure can be calculated. The hydrostatic pressure is calculated (density of foamer and setting depth is known) and the surface injection pressure is read from the surface pressure gauge installed between the wellhead and the filter. The operating pressure of the valve has been evaluated before it has been installed.

$$p_{op} = \left| p_{hyd} + p_{inj} - p_{bh} \right|$$

A more accurate method is the use of a downhole gauge. It can be installed in conjunction with the capillary string attached right below the chemical injection valve. The next time the string is retrieved from the wellbore the stored data can be uploaded and evaluated on a computer.

7.7 Advantages and Disadvantages

The capillary string technology has been discussed so far in several chapters. One of those was the technology itself and it components. This part describes all the components and their functionality. In a second chapter a candidate evaluation procedure has been established to find a suitable candidate where an implementation of such a technology will be most successful. Finally operational considerations such as the installation procedure have been discussed. When reading through those chapters someone recognizes several advantages but also some disadvantages arise. In the following all the pros and cons of the capillary system are summarized.

To start with one of the major advantages of the capillary system as it is described in the latter chapters is that it can be installed under life well conditions. This means that without killing the well the capillary string is snapped into the wellbore. Due to that no harm to the formation is caused which has an enormous advantage in case of mature gas wells where the reservoir pressure is low and the ability to produce the workover fluid back is weak. Finally no workover unit to install the capillary string is necessary which results in low installation costs. This is of importance because in low gas rate wells expensive deliquification methods may not pay out in a reasonable time frame.

Second using a capillary string has the advantage of injecting foamer at the desired depth. Dependent on the setting depth of the capillary coil foamer is injected at a point where enough agitation of liquid and gas cause a proper foaming of the wellbore fluids. This leads to a better application of foamer and

increases the efficiency of the system. Additionally the chemical injection valve allows a controlled injection of foamer. Foamer can be injected continuously or either from time to time for a certain time period at any desired injection rate. Both depth of injection and controlled injection rate improve the efficiency of foamer applications.
Another advantage besides the more efficient use of foamer is the ability to inject foamer continuously at a desired rate. A continuous injection causes a stabilized production and a constant removal of liquids out of the wellbore. This keeps the production at a constant level and an increase in production compared to an intermittent use of foamer is observed.
Besides the use of foamer the same capillary string can be used to inject inhibitors for corrosion, salt, hydrates, scales, and paraffins. Therefore multi purposes can be treated at once with one capillary string installed. Most common is the combination of foamer and corrosion inhibitor.
Finally another advantage is the re-use of capillary coils. The capillary string can be used in several wellbores. Once a well has reached its end of life the capillary string can be withdrawn and installed in another wellbore just within one day. This of course depends on the condition of the coil but it is a potential for saving money.

The use of a capillary injection system has many advantages but no technology comes along without any disadvantages.
As the capillary coil is installed through the wellhead one major disadvantage is that the master valve can cut the coil and as a result it will fall down the wellbore. As tests have shown when an OD ¼” capillary is cut the master valve will still seal and therefore no safety risks arise. However, the capillary is lost and has to be fished which can work out fine in most cases but can take longer in some cases. To overcome this problem other capillary hanger systems can be used (see Chapter 5.1.4).
Another disadvantage is that in case of a workover the capillary string has to be removed previously. This causes additional costs if the operating company can not withdraw the capillary string on its own and has to contract a service company.

Further as the capillary coil is installed through the tubing no tools can be run in hole anymore. Consequently no more MLT measurements or other slickline jobs are possible unless the capillary string is removed.

All the time a capillary string has to be removed from a wellbore and run in hole again requires a service company. This causes a dependency on those companies and makes well interventions more costly.

All in all it can be said that the capillary injection system is a cheap and effective deliquification method for mature wells that utilizes a foamer to dewater gas wells. It can improve production significantly but it is up to the operator whether he wants to deal with the disadvantages or not.

8 Evaluation of RAG Gas Wells for Capillary Installation

In this section several RAG gas wells in Upper Austria are analyzed to find the best candidates for a capillary injection system. This evaluation considers all gas wells that are surfactant treated whether intermitted (soap sticks) or continuously (backside injection). In general 49 gas wells are evaluated where in 16 wells surfactant is injected continuously. The rest of the wells are soap stick treated once a week or even up to three times a week. A Soap stick in combination with shutting in the well is a popular method within RAG to dewater gas wells having liquid loading problems. They are cheap and simple to handle by the field people. Also foamer is injected continuously in several gas wells but only into the annulus of wells having no packer (or open SSD) installed. Many wells indicate a good response to foamers however some do not. Field people report that soap sticks work well in some wellbores and show no benefit in other wells.

In order to increase the efficiency of soap treatments RAG wants to install the capillary string technology in gas wells to increase cumulative gas production and extend their field life time. Therefore the in the previous section designed candidate selection procedure is applied on the surfactant treated wells.

8.1 Candidate Selection

Due to the large number of wells that had to be analyzed, the sequence of candidate selection as mentioned in the previous chapter is changed. As the foamer trial is one crucial and unavoidable step in finding a candidate only gas wells are considered where surfactants are applied, either through soap sticks or continuously through the annulus. Therefore first the response to foamer and the possible post treatment production rate are analyzed. Out of this a couple of wells are selected for a MLT measurement which gives more accurate data for the evaluation of the critical velocity and the wells uplift potential. Finally a ranking of those wells is done based on post-installation production increase and the comparison of the actual rate to critical rate.

8.1.1 Foamer Trial

As already mentioned all the wells that are considered are treated with foamers. Before their response is evaluated the circular charts of the last 4 weeks of each well are collected. Normally each well's circular chart is changed once a week but the time interval of 4 weeks makes the data more accurate and it eliminates any outlier which would lead to a wrong interpretation. Some wells do not have any circular charts because their rate is already recorded digital and stored in a database which can be accessed.

First the wells response to soap treatment is analyzed and described. Figure 6-5 shows two charts one showing a good response (left one) and the other one showing less response. Always the four charts of a wellbore are considered. In a second step the potential production increase is evaluated as a second parameter. This is done for every week (each chart) for each well. Then an average rate representing all charts of a well is calculated. This gives an average production increase in the last 4 weeks.

Now both response and possible rate increase are considered to classify the wells in four categories:

- RED: primary candidates: wells that show a significant change in production and a high incremental production rate
- GREEN: would be primary candidates as well but other activities are already planned or special well completions make an capillary string installation more difficult
- VIOLET: wells that have to be evaluated in more detail. Based on the circular charts no clear behavior is observed. Some show good response but less increase in production rate.
- BROWN: less or no response to soap sticks is identified. In case of continuous injection the system works fine. No significant improvement of production is expected. A possible increase in rate is too low to justify an installation of a capillary injection system.

This analysis is summarized in an EXCEL spread sheet with a description of the circular chart and a justification for the above mentioned categorization. Table A 12-2 in the Appendix shows this table.

This analysis includes wells that are already continuously treated with surfactants through the casing-tubing annulus. The reason for this is that not all injection systems work well and therefore a capillary string injection system is evaluated to increase the efficiency of a continuous foamer application. Installing a capillary string in a wellbore where foamer is already injected continuously through the annulus makes it possible to find out whether the capillary string technology is significantly better as a continuous backside treatment.

Finally this first step in evaluation comes up with the six most potential candidate wells which are randomly listed below:

- **Atz 001**
- **Atz 005**
- **Atz 016**
- **Zapf 005**
- **Hilp 001**
- **P 026**

In the following each of the above mentioned wells is described in more detail according to their foamer response.

8.1.1.1 Atz 001

This well is continuously backside treated (no packer is installed) with a rate of roughly 1 Liter per day. Despite of this the well is loading twice a week (see Figure 8-1) but is able to unload itself. Average production rate of the last 4 weeks is 6020 Nm³/day. After the well is unloaded the well shows a rate of ~ 7200 Nm³/day. Keeping this rate on a constant level would cause an increase in rate significantly by roughly 1200 Nm³/day.

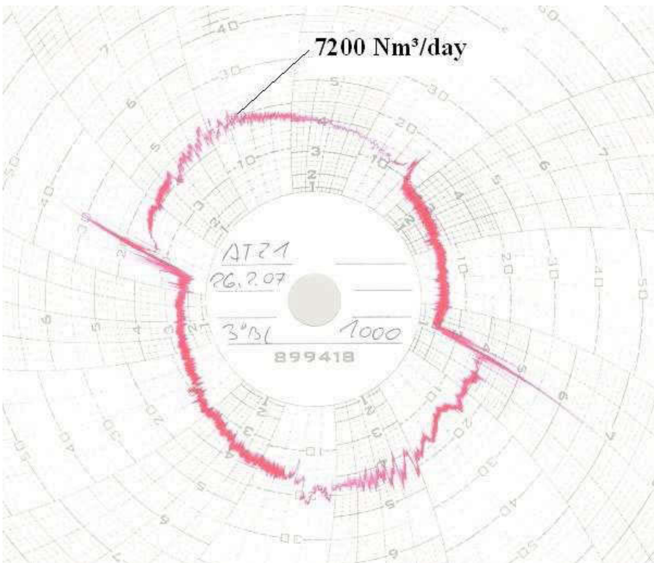


Figure 8-1 Typical Circular Chart of Atz 001

8.1.1.2 Atz 005

This well's average production rate for the last month is 1299 Nm³/day. One soap stick is applied regularly once a week and a good response can be seen in Figure 8-2. Further a graduate decline in rate is observed. First estimation of the possible post soap treatment rate is~1700 Nm³/day which would result in an increase in rate of roughly 400 Nm³/day. Additionally the wellbore diagram shows that the tubing is set below the perforations and a soap stick may fall into the bottom swamp where no gas is present resulting in an inefficient application of the foamer.

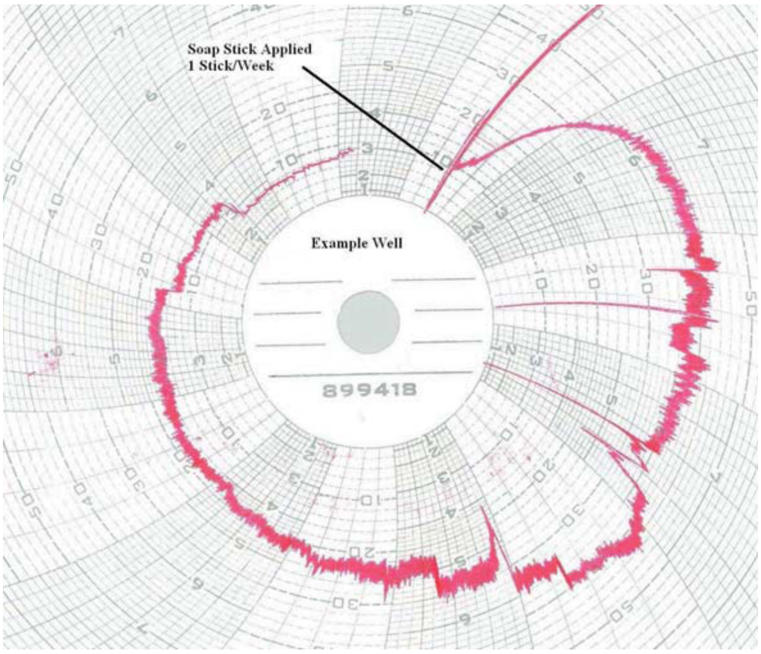


Figure 8-2 Circular Chart of Well Atz 005

8.1.1.3 Atz 016

An average production rate of 6200 Nm³/day is achieved by the well. A continuous injection system is installed and foamer is injected with a rate of ~1 Liter per day through the casing-tubing annulus. Despite of that the circular chart (Figure 8-3) shows still an erratic behaviour. Though the production does not fall off an increasing in efficiency of the system by keeping the production rate more constant would increase production considerably by around 700 Nm³/day to ~6900 Nm³/day. According to the wellbore diagram the tubing is set below the bottom perforations and an installed sliding side door (SSD) is open which can result in a production through that sleeve.

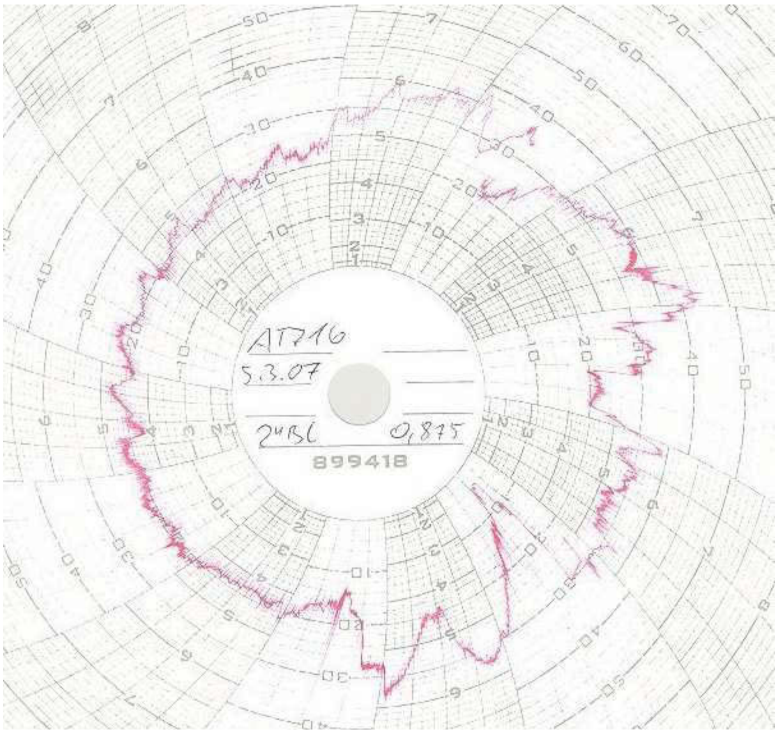


Figure 8-3 Circular Chart Atz 016

8.1.1.4 Zapf 005

This well is producing 4800 Nm³/day on average in the last month. A soap stick is applied regularly once a week. A good response and a graduate decline are observed from Figure 8-4 after each treatment. An increase in rate up to 6000 Nm³/day is recognized resulting in a production increase of roughly 1200 Nm³/day. Due to the wellbore diagram soap sticks fall down below the perforations and foaming might not be efficient as a result.

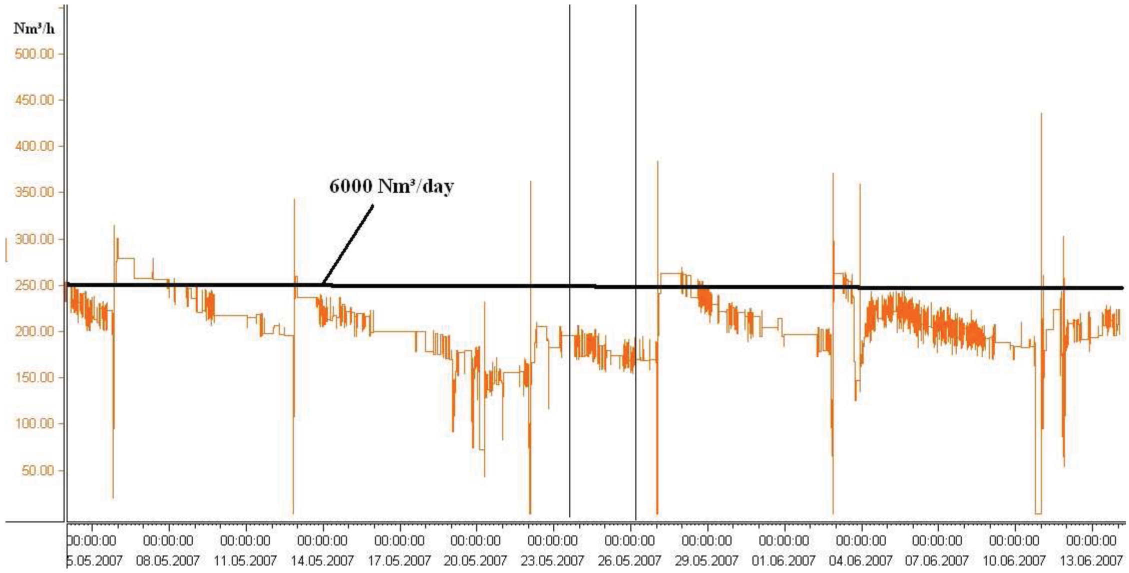


Figure 8-4 Production History of Zapf 005

8.1.1.5 Hilp 001

Average production rate of this well is 7200 Nm³/day. Soap stick treatment varies from one stick per week up to 3 sticks per week. A sharp response and steep decline are identified. Due to a decline curve analysis and soap response a rate of 10550 Nm³/day should be possible. Therefore the increase in rate compared to the average production would be around 3350 Nm³/day. Considering the wellbore diagram soap sticks fall downhole below the perforations and foaming action may not very efficient or on the other hand due to the inclination of the wellbore a soap stick will not get to the desired depth.

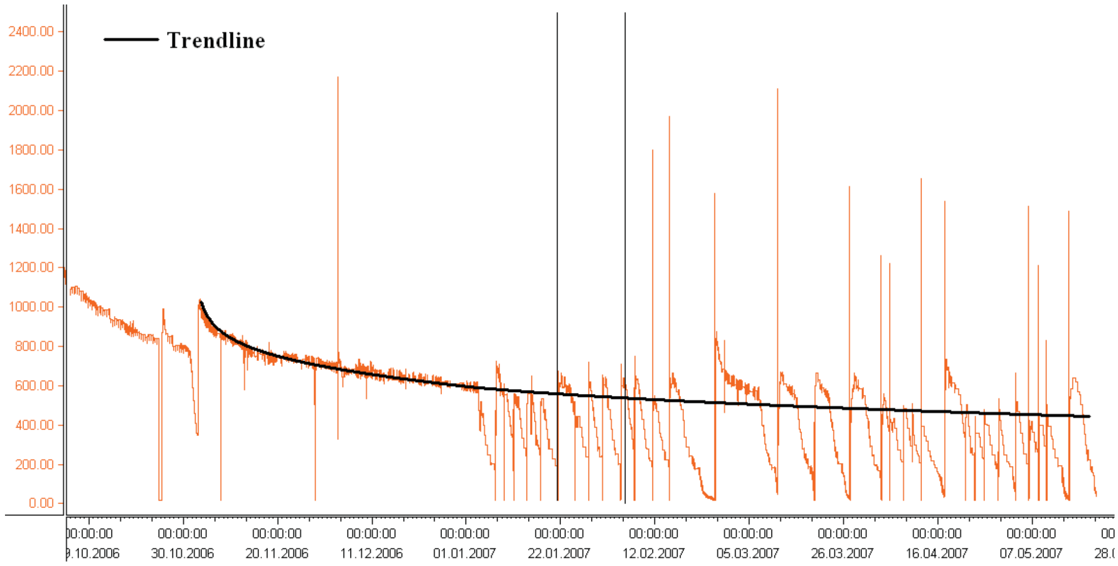


Figure 8-5 Production History of Well Hilp 001

8.1.1.6 P 026

In this case two soap sticks per week are applied (see Figure 8-6). The well shows some response to soap sticks and a very erratic behaviour. Producing an average rate of 2100 Nm³/day and stabilizing the production after a foamer application would cause a possible increase in rate of roughly 600 Nm³/day. A velocity string, set across the uppermost perforation interval, has been already installed as a deliquification method.

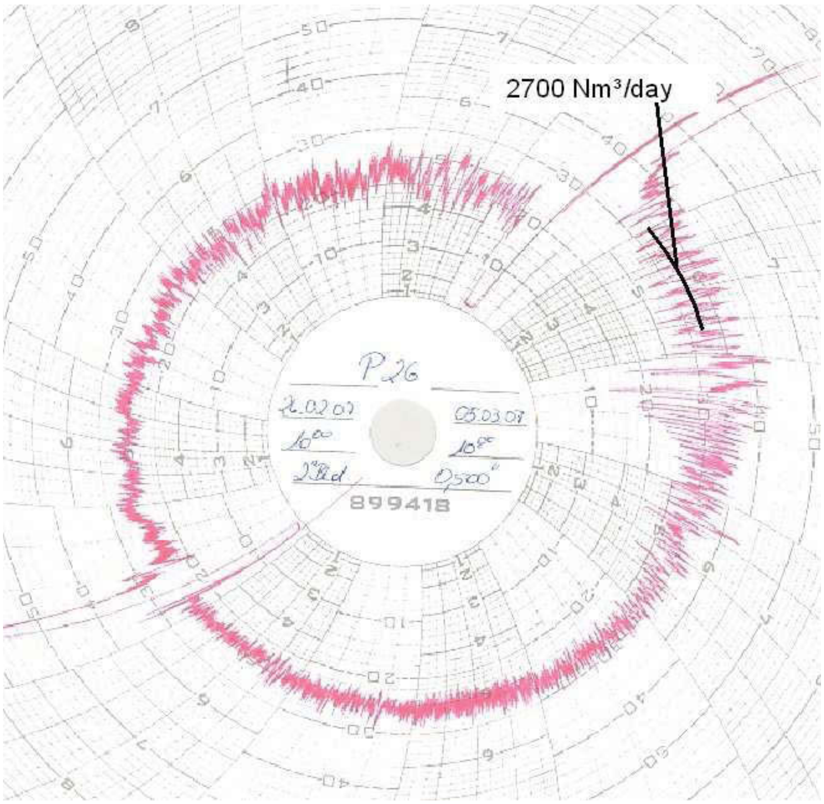


Figure 8-6 Typical Circular Chart of Well P 026

8.1.2 PLT Measurements (with RAG MiniLoggingTool, MLT)

As a second step measurements in the above selected wells are conducted to get more precise data for the evaluation process. All the measurements are done with the RAG's own MLT tool. This tool includes the measurement of pressure, temperature, CCL, and optionally inline- or fullbore- spinner measurements. A production log (PLT) with a fullbore spinner is run in cases where the tubing is set above the perforations. This measurement gives valuable information about the gas entry from the perforations. This information helps to identify a possible setting depth of the chemical injection valve. The inline spinner measurement can be used to determine any inflow into the tubing through leaks or SSD's, helps to identify the liquid level, and helps to identify the flow regime. Further a flowing pressure gradient survey helps to estimate the amount of water that is in the wellbore. Density calculation from pressure over depth (gradient survey) shows the amount of liquid at each depth point. Second this type of measurements gives information about the current bottom-hole flowing pressure. Together with the production rate recorded while the measurement is done, it specifies the actual well operating point. This accurate data is used for modeling the well in a system analysis program. A jump in the temperature gradient in combination with pressure and spinner readings is used as an identification of the liquid level. Measurements should be done under flowing conditions.

The data recorded by the measurement are interpreted with a suitable software program and collected for each well in the Appendix (Figure A 12-7 to Figure A 12-26). In the following these charts are evaluated for each well.

8.1.2.1 Atz 001

An Inline and Fullbore Spinner measurement has been done.

During the measurement no problems can be reported. Both Inline and Fullbore Spinner Measurement showed positive results. Figure A 12-7 to Figure A 12-9 show the interpreted results of the measurement data.

The inline spinner survey was mainly to find out about the flow regime in the tubing. At a depth of 1500 m a decrease in speed can be observed which results from an increased amount of water below that depth. This corresponds with an increased calculated pseudo density.

The fullbore spinner measurement shows that all 3 perforation intervals are producing, whereas the most of the production comes from the middle one. The upper one produces still a relevant amount rather than the lower one, which produces a very little amount of gas.

According to the Fullbore Spinner Measurement, in case a capillary injection system is installed, the injection valve should be set across the uppermost perforation interval at **1625 m**. In this case all the gas and water is available for foam generation and further the area above, up to the tubing shoe can be foamed as well which reduces the backpressure on the formation.

The pressure survey indicates a low water content inside the tubing. A pressure increase of roughly 2 bars from 0 to 1725m (0.0012 bar/m) is observed. Nevertheless more water is present between 1510 m and end of tubing. This is also justified by a decrease in apparent velocity and a slightly stronger increase in the pressure gradient. Through the tubing gas is the dominant phase. Below the tubing shoe water is more dominant and gas may bubble through a static water column. Due to the low water rate and water in the tubing the foamer injection rate can be low. Calculating an apparent density shows regular spikes in the curve which indicate slug flow in the wellbore. This is a typical sign of liquid loading.

8.1.2.2 Atz 005

In this wellbore only an Inline Spinner Measurement has been done. This is due to the fact that the tubing is set below the bottom perforations. Unfortunately the spinner didn't deliver any useful results. The reason might be a too low gas rate to cause rotation of the spinner. Nevertheless in this case a change in spinner speed due to a change in water content would just support any changes in the gradient curve. Additional during the measurement no problems were reported. Figure A 12-11 and Figure A 12-12 in the Appendix show the interpreted data of the measurement.

The pressure survey shows that the water content is still small due to a low increase (but more than a typical gas gradient) in pressure towards the tubing shoe (roughly 2 bara across 1000m; 0.002 bar/m). This is definitely higher as in well Atz 001. The temperature shows no remarkable behaviour whereas the pseudo density indicates no continuous flow regime. This well is in slug flow which is confirmed by the Circular chart and pressure measurement.

As the tubing is set below the perforations as a first well intervention the tubing should be punched from 963 to 968 m before a capillary string is installed. Anyway, the optimum setting depth of a capillary string would then be **965 m**.

8.1.2.3 Atz 016

Due to the fact that the tubing is set below the perforation interval as well, no fullbore spinner measurement has been conducted. However, an inline spinner measurement has been done which delivered some useful information. During running the tool into the borehole and pulling it out of the hole no problems have been observed. Figure A 12-14 and Figure A 12-15 in the Appendix summarizes the interpreted data from the measurement.

The inline spinner survey has shown that all the production comes through the SSD into the tubing. To conclude, in case of a capillary string installation, the cap string should then be set right above the SSD at **1582 m**. As there is no gas coming up from the tubing shoe it makes no sense to inject foamer below the SSD because no gas will be present in order to generate foam.

The pressure and the pseudo density show rough fluctuations which indicate alternating phases of water and gas. The slug sizes in this well are larger then in the previous mentioned wells. The pressure increase down to the tubing shoe at 1610 m is about 2.3 bar (0.0014 bar/m) which means that the water content is still small but significant enough to load the well.

8.1.2.4 Zapf 005

Zapf 005 is a wellbore where the tubing is set above the perforation interval which makes a fullbore spinner survey reasonable. However, the velocity in the tubing might be too low to turn an inline spinner and therefore no inline spinner survey is run. Finally no problems have been reported from the people conducting the measurement. The interpreted data is summarized in Figure A 12-17 to Figure A 12-19.

The well has 4 perforation intervals where the lowest one produces the largest amount of gas (see Figure A 12-17 in Appendix). All other perforation intervals are producing as well but not as much as the lowest one. In this case a recommended setting depth for the capillary string would be right across the second perforation at a depth of **1703m**. This is the deepest point where enough gas is present to cause proper foaming.

Considering the pressure survey someone can observe that between 0 and 900 m the water content is very low and the gradient is close to a gas gradient. From 900 to 1550 m the pressure increase is more significant due to more water present. In the lower portion of the tubing a constant pseudo density can be observed which indicates a more continuous flow regime. In this section water is the main phase (linear increase in pressure) and gas bubbles through that water. This effect is even stronger in the area below the tubing across the perforations. Overall the pressure increases from surface to bottom (1710 m) by 9.3 bar (0.0054 bar/m). In Figure A 12-19 it can be seen that the gas entering the wellbore from the bottom perforation significantly influences the flowing gradient. To summarize in the tubing three flow regimes can be found: annular flow in the first section (0 to ~900 m), slug flow in the section from ~900 to 1550 m, and bubble flow in the lower portion of the tubing. The pseudo density in Figure A 12-18 is a good indicator for that.

8.1.2.5 Hilp 001

In this wellbore a fullbore spinner survey has been done. Unfortunately the measurement has not delivered any reasonable results in order to figure out where most of the gas production comes from. However, as an acceptable approach the gradient curve across the perforation intervals can be considered. Finally, when conducting the measurement a problem has been occurred namely re-entering the tubing was quite an issue. Several attempts were necessary to get back into the tubing. Back at the surface it has been observed that it was not the fullbore spinner which was initially believed to be the problem but it was the point where the cable was connected to the tool. Carvings have been recognized at that point and indicate a sharp edge at the end of tubing (no tubing shoe installed!).

The pressure curve indicates almost no water in the vertical section of the well (Figure A 12-21). Beyond the kick off point of the well the water content increases gradually and below the tubing significantly. From surface to bottom (2165 m) the pressure increases by 23.3 bar significantly (0.011 bar/m) which results in a strong backpressure on to the formation.

Due to the fact that no production-log is available it is not possible to identify a perforation interval that produces most of the gas. However from the pressure survey it can be said that the lowest perforation interval produces gas (Figure A 12-22). Further some gas is also produced from the second perforation interval. As it is not possible to say with reasonable certainty if the uppermost perforation interval produces gas it is recommended to set the capillary string between the first and second interval (**MD: 2165m**). On the one hand side this is in the upper 1/3 of the full perforation interval (general rule of thumb) and on the other hand side it allows to lower the hydrostatic head below the tubing shoe and the first perforation interval (foam density).

8.1.2.6 P 026

This wellbore has a velocity string installed and therefore measuring depth is limited to 1724 m. A pressure, temperature, and inline spinner measurement have been conducted. While running the tool into the wellbore and out again no problems occurred.

The pressure and pseudo density survey (Figure A 12-24) indicate a higher liquid content in the lower portion of the tubing. Nevertheless liquid is present through out the whole tubing. The increase in pressure (~2.9 bar from 0 to 1725m; 0.0017 bar/m) down to the tubing shoe is low due to a low overall liquid content. The calculated pseudo density shows remarkable plateaus but still indicate slug flow through out the whole tubing with changing slug sizes.

The setting depth for a cap string would be right above the velocity string (**1723 m**) because the chemical injection valve would not fit through that piece of tubing (ID 1.4 in).

8.1.3 Modeling of Candidate Well and Evaluation of Critical Velocity

The advantage of the MLT measurement is that it delivers an accurate operating point for the well. In order to establish an Inflow Performance Relation (IPR) of a wellbore reservoir data is required. In the following the reservoir pressure from the most recent measurement together with the reservoir data delivered by the reservoir engineers an IPR is modeled with PROSPER, a system analysis program used in RAG. Further to improve this model the operating point (rate and bottom-hole flowing pressure) which is observed during the recent MLT measurement is used to optimize the IPR and fitted through that point. The most reasonable parameter to change is the reservoir pressure (declining reservoir pressure). As already mentioned the amount of produced water is the most uncertain production variable. Therefore to start with a LGR of zero is assumed. This gives the maximum possible production of this wellbore (theoretical maximum) but due to the fact that this wells have to produce some water the achievable rate will be lower than that one. Then the LGR is slowly increased to fit the Tubing Performance Curve (TPC) through that measured operating point. Figure A 12-10 shows such a system analysis including TPC for different LGR. The red colored point indicates the operating point during the measurement where the blue square indicates different rates of the past view weeks. It is possible to vary the LGR till the TPC intersects the IPR at a rate that corresponds to the considered point. Actually the blue squares indicate the range where the well is operating.

The minimum required foam velocity to remove liquids out of the wellbore and the critical rate is evaluated using the spread sheet introduced in the previous Chapter 6.2.1.

Critical foam rate and critical rate are more or less determined by the operating pressure and wellbore geometry. Additionally assumptions of the surface tension are further influencing factors. More critical is the actual production rate to be entered in the spread sheet. Especially when production rate is not constant and varies each time when soap sticks are applied. Basically the rate that has to be used in this calculation is the stabilized rate the reservoir can deliver under a certain tubing performance curve (TPC).

8.1.3.1 Modeling Atz 001

The following Table 8-1 summarizes the current operating point. Figure A 12-10 in the Appendix shows the relevant inflow/outflow performance of this well. It is remarkable that during the measurement the rate was rather high. This lets conclude that the wellbore has unloaded itself shortly before the MLT measurement. Further due to the circular chart and the high rate during the measurement a maximum stable production of 7300 Nm^3/day can be achieved but definitely not more than 7700 Nm^3/day. Keeping this rate constant would cause an increase in rate of ~1200Nm^3/day compared to the production average of the last 4 weeks, which is a good uplift potential.

Well Atz 001			
Operating Point during MLT Measurement	Rate	7720	Nm^3/day
	pwh	6,10	bara
	pwf	8	bara
Theoretical Maximum		8700	Nm^3/day
Estimated Rate from Circular Chart		7200	Nm^3/day
	Average Rate	6000	Nm^3/day

Table 8-1 Operating Point of Well Atz 001

Considering the critical rates the above estimated stable production rate is inserted into the new designed Excel spreadsheet and the following chart arises.

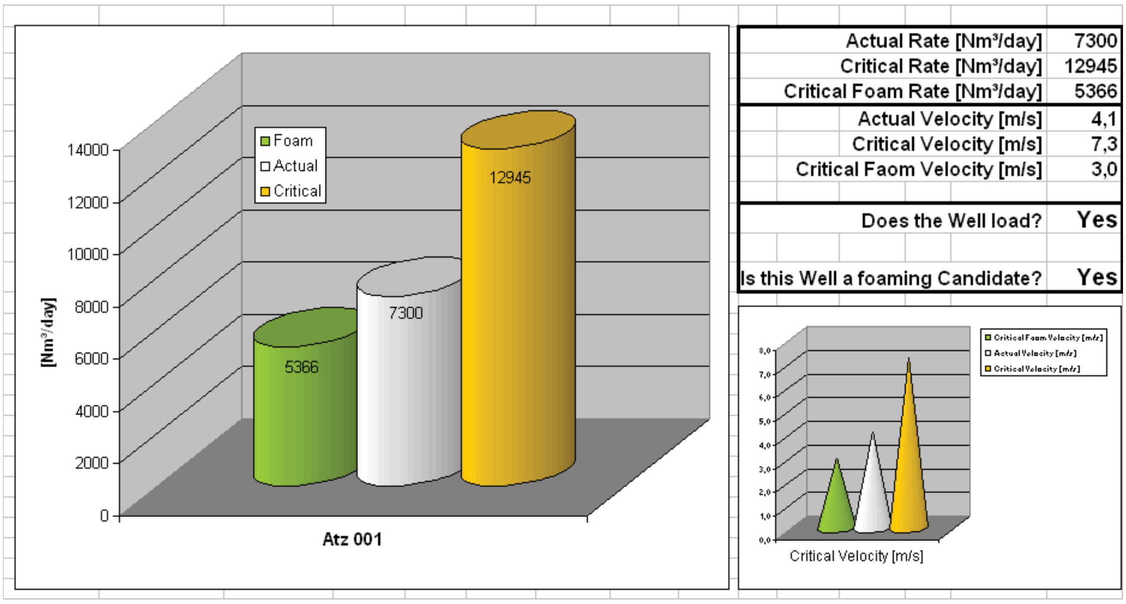


Figure 8-7 Comparison of Critical Rates from Atz 001

Due to the latter chart Atz 001 should show a constant production behavior. Foamer is injected on a continuous bases and the stable rate is above the critical velocity when foamer is applied. However, due to the circular chart (Figure 8-1) shown previously the well is loading twice a week. Therefore the theoretically estimated critical foam rate is too low. The reason could be a too low assumed surface tension, or foam density. As a first approach increasing the surface tension up to 55 dynes/cm would give a critical foamer rate of 6900 Nm³/day. However, as the stable rate can not be increased the surface tension has to be lowered. This can be done by increasing the current injection rate or by improving the efficiency of the foamer injection by installing a capillary string. If the surface tension is lowered a stable production and therefore a higher cumulative rate can be achieved by this wellbore.

8.1.3.2 Modeling Atz 005

All the rates observed until now including the operating point during the measurement are summarized in the following Table 8-1. The operating point is used to fit the IPR curve in order to get a more accurate result. Unfortunately it is not possible to handle any LGR with the pressure correlations offered in the system analysis program. Even a gradient match of different correlations to the measured gradient was not successful. The problem is that those pressure correlations are not suitable for such low pressures and rates in this particular case. However, it was possible to establish a TPC for a LGR of zero which allows the estimation of the theoretical maximum. Figure A 12-10 in the Appendix shows the IPR vs TPC.

Well Atz 005			
Operating Point during MLT Measurement	Rate	1200	Nm³/day
	pwh	4,30	bara
	pwf	5,9	bara
Theoretical Maximum		1535	Nm³/day
Estimated Rate from Circular Chart		1700	Nm³/day
	Average Rate	1299	Nm³/day

Table 8-2 Operating Point of Well Atz 005

The estimated theoretical maximum gas rate (1535 Nm³/day) without any water production is about 200 Nm³/day lower than the rate observed from the circular chart. This may have two reasons. One reason can be that the rate from the circular chart has been estimated too high and the other reason can be that due to liquid loading the reservoir pressure builds up a little bit and therefore for a short period of time a higher rate is observed. However, both estimates show that a stable rate higher than roughly 1500 Nm³/day is not possible for this well. Further as the average production rate is around 1300 Nm³/day. The author estimates a possible stable rate slightly slower than the theoretical maximum which then is about 1450 Nm³/day. This rate encounters a low LGR to unload the well.

Entering this rate together with the wellhead pressure into the pre-designed Excel spread sheet for evaluation of the critical rates will result in the following chart.

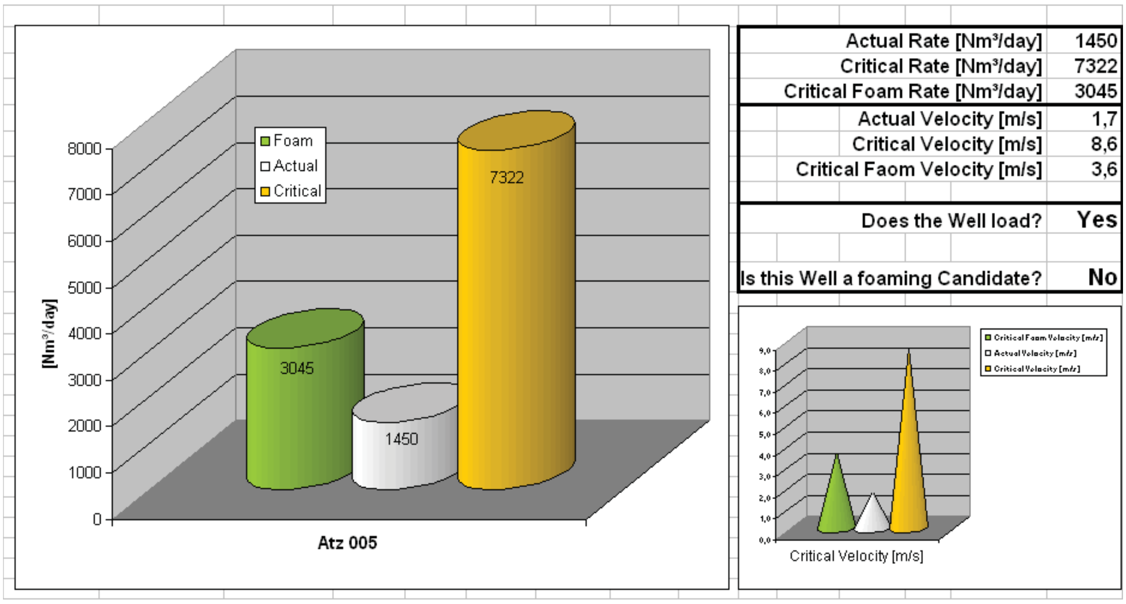


Figure 8-8 Critical Velocity for Well Atz 005

As the above shown diagram indicates the critical rate with foamer for this wellbore is about 3000 Nm³/day. This is still significantly above the rate the wellbore is able to deliver. Further ideal conditions, 20 dynes/cm and 6 lbm/cf foamer density are assumed and considering even more realistic conditions this critical foamer rate will be higher. To conclude a constant production is hardly to achieve even when a foamer is applied continuously. Despite of that a continuous injection system may increase the time interval of loading and therefore increase production. In any case the maximum achievable constant rate can be between 1500 and 1700 Nm³/day. This is an increase of 200 to 400 Nm³/day, which is a low uplift potential for this wellbore.

8.1.3.3 Modeling Atz 016

The operating point of this wellbore during the MLT measurement together with other rates observed during the evaluation procedure are summarized in Table 8-3. The well is modelled in a system analysis program including the operating point in order to improve the results. Figure A 12-16 in the Appendix shows the relation between IPR and TPC.

Well Atz 016			
Operating Point during MLT Measurement	Rate	6720	Nm³/day
	pwh	5,20	bara
	pwf	7,5	bara
Theoretical Maximum		8700	Nm³/day
Estimated Rate from Circular Chart		6900	Nm³/day
	Average Rate	6200	Nm³/day

Table 8-3 Operating Point of Well Atz 016

Analysing the theoretical maximum it comes up with a rate of 8700 Nm³/day. Further considering the minimum possible LGR the system analysis program can handle shows a rate of about 7850 Nm³/day. Additionally it is shown that during the measurement the well was producing at a rate of 6720 Nm³/day which is already at a high level. Considering that a rate higher than the one observed during the MLT measurement has a significantly lower LGR which is too less to unload the well. Therefore a rate higher than the one observed from the circular chart is not possible. Due to the circular chart the well is not loading anyway but production is just erratic. This might come either from fluctuations in wellhead pressure (well is very sensitive to pipeline pressure - reported by field people) or due to an intermittent inflow of foamer from the casing into the tubing (no packer installed). In this case a capillary injection system would cause the expected stabilization of the rate and a rate of roughly 6900 Nm³/day. Evaluating the critical rates for this wellbore (Figure 8-9) it is shown that the circular chart and the theory both indicate a stage where the well is not loading.

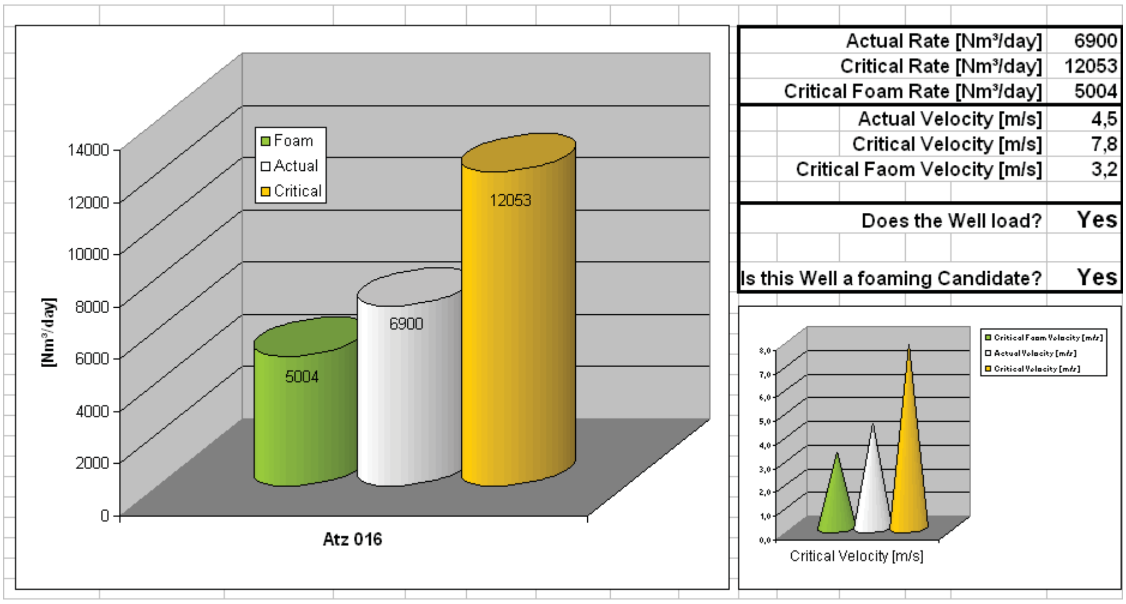


Figure 8-9 Critical Rates for Well Atz 016

The system analysis shows that a possible rate of 6900 Nm³/day can be delivered by the reservoir and keeping this rate constant by an improved application of foamer (capillary injection system) can cause an increase in rate of 700 Nm³/day. This well is therefore a good candidate to proof whether a capillary string can really improve the performance of a backside treatment.

8.1.3.4 Modeling Zapf 005

In Table 8-4 relevant data for the well Zapf 005 that has been observed so far are summarized. Using the operating point during the measurement an IPR is constructed and further a TPC is added. Figure A 12-20 in the Appendix shows the two production points (blue square) where one rate is determined right after soap stick treatment and the second one just before the foamer is applied. Further it can be seen that the operating point of the well during the measurement is in between those two.

Well Zapf 005			
Operating Point during MLT Measurement	Rate	5160	Nm³/day
	pwh	10,60	bara
	pwf	19,9	bara
Theoretical Maximum		7930	Nm³/day
Estimated Rate from Circular Chart		6000	Nm³/day
	Average Rate	4800	Nm³/day

Table 8-4 Operating Point of Well Zapf 005

Considering a LGR of zero the well would be theoretically able to produce 7930 Nm³/day. As already pointed out in a previous section estimating the well's current LGR ratio is difficult. The rate observed right after a soap stick treatment is roughly 6000 Nm³/day and the corresponding LGR is 2.5e-5 m³/Nm³ which is already low. Taking an even lower LGR of 1e-5 m³/Nm³ into consideration would cause a rate of 6800 Nm³/day. To sum up due to the system analysis and the production history the well is able to produce a stable rate of 6000 Nm³/day or even more up to 6800 if the LGR is even lower. Evaluating the critical velocities of the wellbore the following diagram comes up.

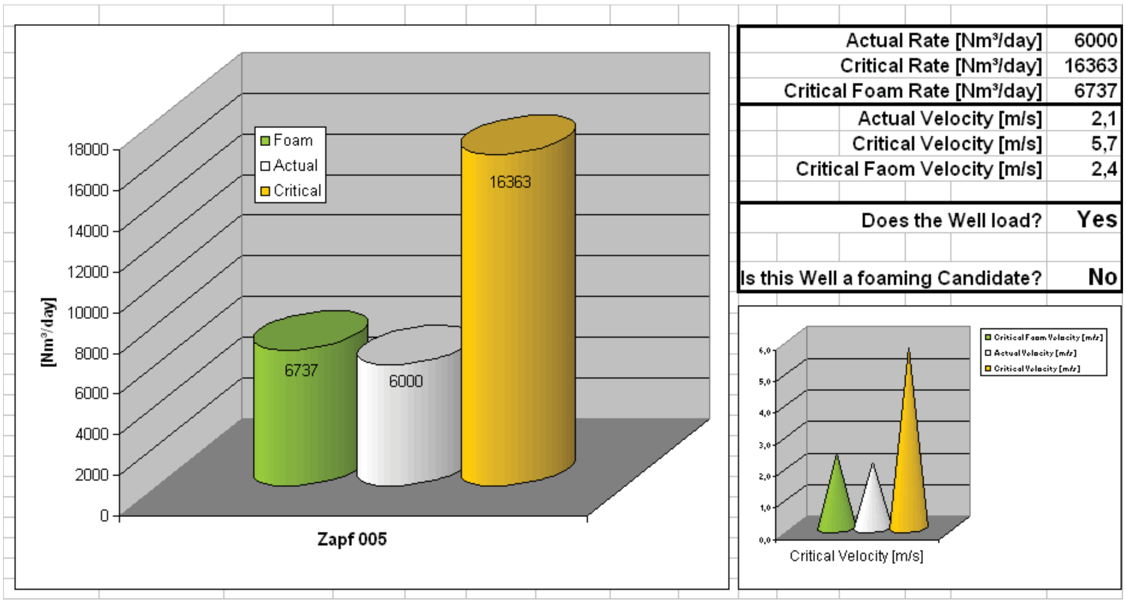


Figure 8-10 Critical Velocities for Well Zapf 005

When comparing the critical rates it can be seen that the estimated stable rate is still lower then the critical foam rate though ideal conditions (20 dynes/cm and 6 lbm/cf) are assumed. Despite of the fact that the critical foam rate is difficult to predict and that a stable rate higher than 6000 Nm³/day can be possible it does not mean that the well is not a foamer candidate. In this case if a foamer is applied the well can still load but the time interval between a complete stop in production can be much longer and therefore incremental production is higher then the one before the continuous treatment. Finally a production increase of 1200 Nm³/day can be achieved if the rate can be kept constant at a level of 6000 Nm³/day.

8.1.3.5 Modeling Hilp 001

Table 8-5 summarizes the data which has been collected from the previous evaluation procedure. Additionally Figure A 12-23 in the Appendix shows a system analysis of well Hilp 001. The actual production data (shown as blue squares) are presented in the plot. They build the range between the well is operating before and after a soap stick is applied. The operating point during the MLT measurement (red dot) is shown as well and it can be seen that it is closer to the left point (lower rate). Considering the bottomhole pressure measured during the measurement lets conclude that a high amount of liquid has already been accumulated in the wellbore. The rates observed after each soap treatment can not be considered to be the one kept constant through a continuous injection. That is because reservoir pressure builds up due to liquid loading and as soon as the liquid is removed from the wellbore significantly higher rates are observed. A more accurate estimation of a stable rate would be the use of a decline curve analysis like it is done in Figure 8-5. This comes up with an expected stable rate of 10550 Nm³/day (440 Nm³/h).

Well Hilp 001			
Operating Point during MLT Measurement	Rate	7920	Nm³/day
	pwh	6,30	bara
	pwf	29,6	bara
Theoretical Maximum		15550	Nm³/day
Estimated Rate from Circular Chart		10550	Nm³/day
	Average Rate	7200	Nm³/day

Table 8-5 Operating Point of Well Hilp 001

In order to figure out whether the well is unloading or still loading at the expected rate the critical velocities are evaluated in the Figure 8-11 below.

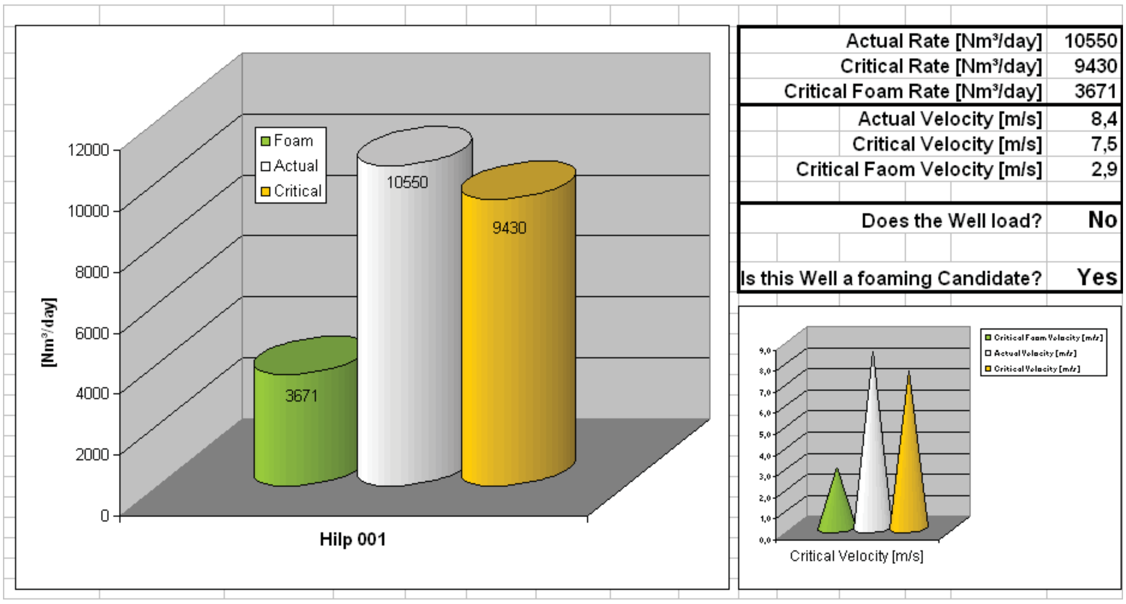


Figure 8-11 Critical Velocities of Well Hilp 001

The above shown analysis indicates that the well Hilp 001 is not loading, even if no foamer is applied. But it is a matter of fact that this well is loading, therefore the estimated critical rate is too low. From production data the onset of liquid loading is recognizable and this indicates a critical rate of roughly 14400 Nm³/day. The reason why the Coleman approach in this case is wrong is that it does not consider any water production rate. Consequently as long as the LGR is very low the Coleman approach is sufficient. However, if the LGR is higher the energy approach delivers a more accurate result (see Figure 8-12 below).

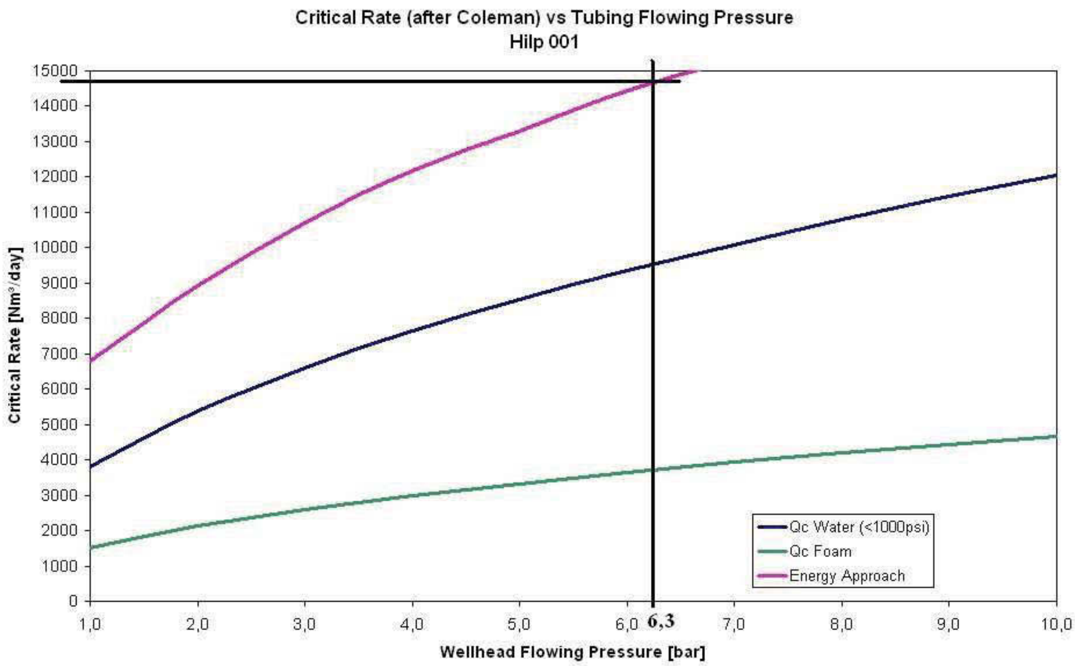


Figure 8-12 Comparison of Coleman- and Energy-Approach for Well Hilp 001

On the other hand the assumed surface tension of 60 dynes/cm for brine is too low. Even an increase up to 75 dynes/cm is not able to model the critical velocity observed from the production plot. Therefore in this particular case the energy-approach is the more accurate one in modelling the critical rate.

To sum up the well Hilp 001 is liquid loading and the expected stable rate of 10550 Nm³/day is far above the critical rate of foam. Consequently a constant production can be achieved and an increase of rate by about 3300 Nm³/day is expected.

8.1.3.6 Modeling P 026

All the relevant rates including the operating point during the MLT measurement are collected in Table 8-6. Additionally the well is modelled and the result is shown in Figure A 12-26. The smallest LGR that can be handled is 1e-5 m³/Nm³. The theoretical maximum has been estimated to be 3100 Nm³/day. It can be seen that during the MLT measurement the well was operating close to the theoretical maximum. Therefore a rate higher than the 2700 Nm³/day can not be achieved with a foamer. As this rate requires a very low amount of gas liquid ratio a more realistic and stable rate would be one lower than the 2700 Nm³/day. Assuming a low LGR of 1e-5 m³/Nm³ a possible stable rate would be 2300 Nm³/day.

Well P 026			
Operating Point during MLT Measurement	Rate	2950	Nm³/day
	pwh	6,60	bara
	pwf	9,5	bara
Theoretical Maximum		3100	Nm³/day
Estimated Rate from Circular Chart		2700	Nm³/day
	Average Rate	2100	Nm³/day

Table 8-6 Operating Point of Well P 026

To evaluate if this rate can constantly remove liquids out of the wellbore the critical rates are calculated (Figure 8-13).

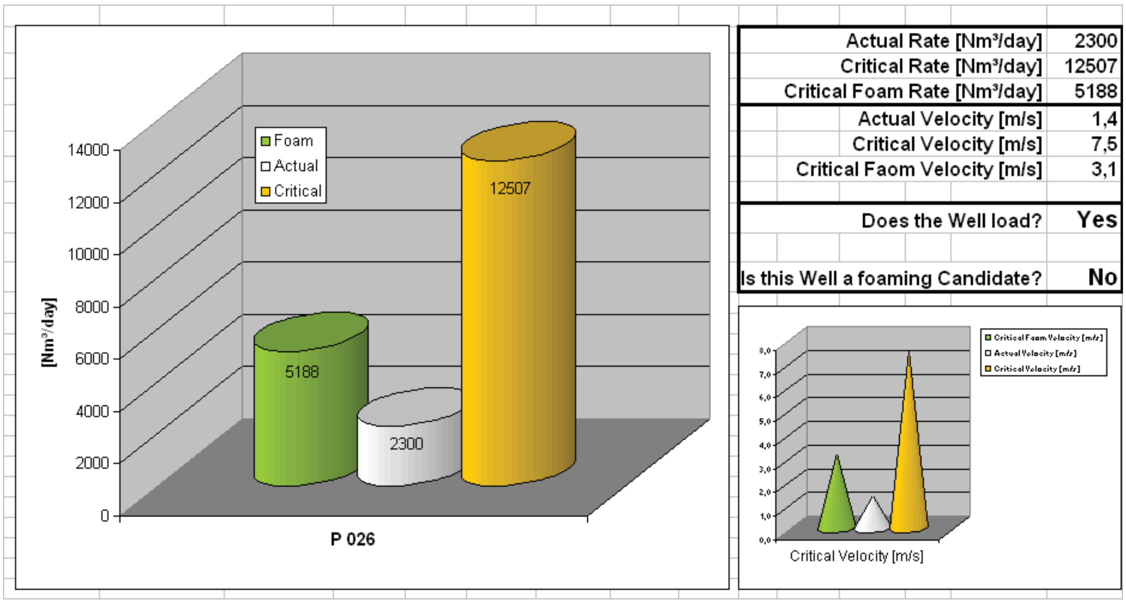


Figure 8-13 Evaluation of Critical Velocities of Well P 026

Analysing the graph shown above indicates that the expected stable rate is far below the optimum critical rate of foam. This leads to the conclusion that a continuous removal or liquids out of the wellbore is not possible. Therefore injecting a foamer continuously will not be sufficient and the well will still load. Despite of that injecting foamer with a capillary string can smooth the production and as a result an increase in rate can be expected. The uplift potential of this well is rather small because the expected rate increase is just about 200 Nm³/day which can be even lower if the rate is not kept constant.

8.2 Summary of Candidate Selection and Ranking

The following Figure 8-14 summarizes the process of evaluating the possible candidates and selecting the right candidate for a capillary string application. In the context below the 6 best candidates are ranked according to soap stick response, expected stable rate, and production increase.

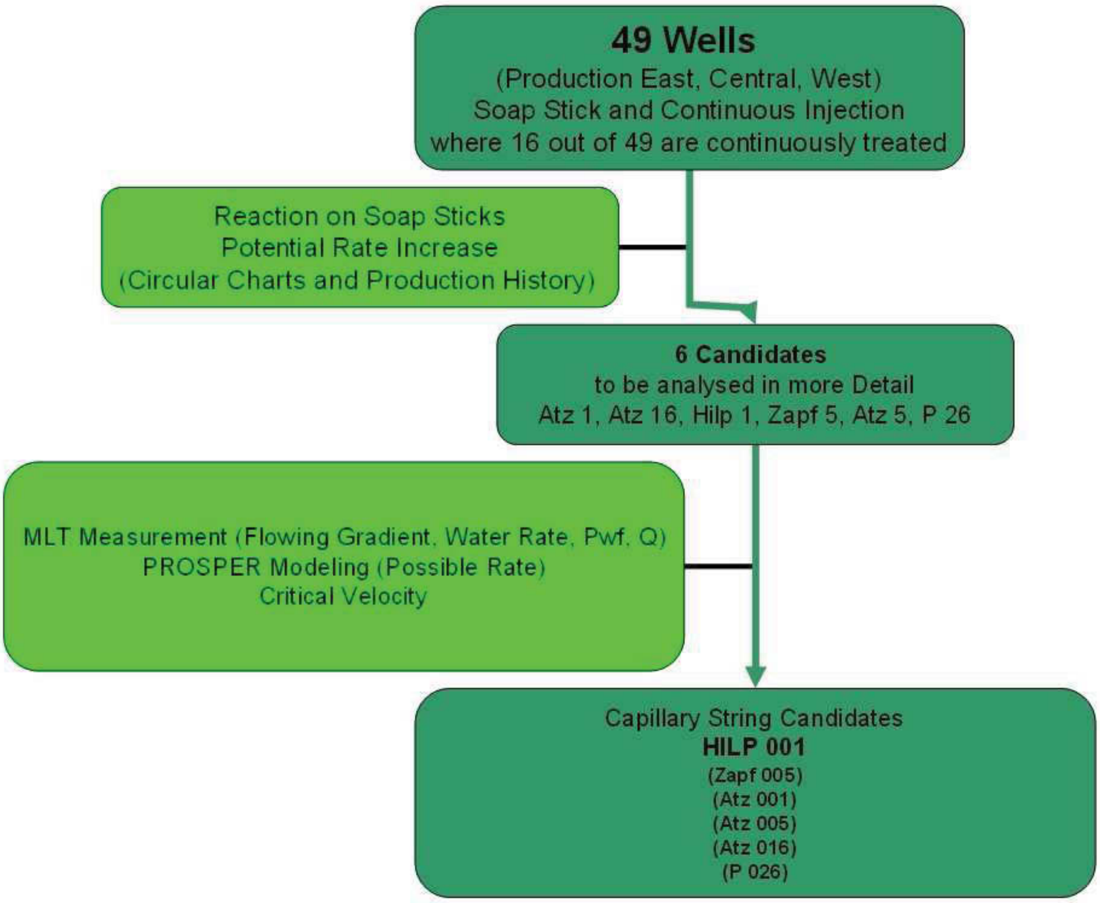


Figure 8-14 Summary Chart of the Candidate Evaluation

8.2.1 Hilp 001

Currently this well is soap stick treated once a week or even up to 3 times a week. The well shows an excellent response to that kind of treatment. A packer completion prevents the possibility to inject foamer through the backside. The existing production of 7200 Nm³/day can be increase up to 10550 Nm³/day. This rate is high enough to ensure a continuous removal of liquids out of the wellbore. The uplift potential is significant, namely about 3300 Nm³/day. Considering the above mentioned points this well turns out to be the best candidate for a capillary string installation.

8.2.2 Zapf 005

Similar to the above mentioned candidate this well has a packer installed. Consequently foamer injection through the tubing-casing annulus is limited. Further one soap stick per week is applied and a good response is recognized. Currently the well is producing an average rate of 4800 Nm³/day where a possible stable rate of 6000 Nm³/day has been determined. This causes an increase in rate of 1200 Nm³/day which is a significant uplift potential. Indeed it has to be taken into account that the stable rate is close to the critical rate of foam which increases the chance of loading though foamer is injected continuously.

8.2.3 Atz 001

As a third candidate well Atz 001 would be the right one. This well is already surfactant treated continuously through the backside but circular charts indicate that this well is loading twice a week but it is able to unload itself. The actual average rate of this well is 6020 Nm³/day. Stabilizing the rate close to a point observed after unloading a rate of roughly 7200 Nm³/day is possible which is still above the critical rate of foam. This leads to a production increase of ~ 1200 Nm³/day. This is the same incremental rate as it has been determined for Zapf 005, but a continuous injection system is already installed and therefore this well is ranked behind Zapf 005. In this particular case it is possible to evaluate how a capillary string injection system improves the continuous injection of foamer through the backside. As a first approach in order to solve the well’s problem the current foamer injection rate should be increased.

8.2.4 Atz 005

This wellbore is treated with one soap stick once a week. The response is good and a stable rate of 1450 Nm³/day is possible. However, this rate is still far below the optimum critical rate of foam and therefore this well would load even when a foamer is applied continuously. In spite of that a continuous injection could increase the time interval between a complete loading of the well and therefore increase production. Even when a stable rate of 1450 Nm³/day can be kept constant the production increase would be just about 200 Nm³/day and would not justify a costly installation of a capillary string.

8.2.5 Atz 016

A continuous injection system has already been installed in this wellbore. The well does not load but production is very erratic. The average production is 6200 Nm³/day whereas a maximum expected rate can be 6900 Nm³/day. This would lead to an increase in rate of 700 Nm³/day. A capillary injection system can stabilize this rate, which is above the critical rate of foam. This well is also a candidate to proof whether a capillary injection system can improve the efficiency of foamer. Further it has to be considered that most of the fluctuations in the circular charts come from variations in the pipeline pressure because of the wells sensitivity to pressure changes.

8.2.6 P 026

This well is soap stick treated twice a week. A velocity string is already installed as a deliquification method. The response to soap sticks is not that significant but when evaluating the post treatment rate from circular charts a relevant potential shows up. The well produces 2100 Nm³/day on average and after soap stick treatment a possible stable rate of 2300 Nm³/day has been estimated which is still significantly below the critical rate for unloading foam. The estimated uplift potential of 200 Nm³/day is rather small.

To sum up, well Hilp 001 fulfils all the criteria to be a good candidate for a capillary string installation as well it shows a significant increase in rate. Well Zapf 005 still shows a good possible incremental production rate but its stable rate is close to the critical rate of foam. Atz 001 is an excellent candidate for figuring out of how a capillary string installation could improve the wells performance compared to a continuous backside treatment. Atz 005 shows a relative low incremental production and the expected rate may not be kept constant. Wells Atz 016 and P 026 are not recommended for capillary installation. Atz 16 has a continuous backside injection system installed which works well and a possible stabilization of rate may not cause a sufficient high incremental rate to justify the investment costs. Finally P 026 shows the lowest incremental rate which leads to a long payout time during that a capillary string system has to work fine all the time.

Before a second candidate for a capillary string installation is selected, the author recommends analysing the results of the first installation in order to figure out if the expected results are met. This helps to further improve the candidate selection for capillary string installation.

8.3 Candidate Well Hilp 001

Well Hilp 001 has been evaluated to be the best candidate for a capillary string installation. Once the relevant well is known further aspects have to be addressed. Points such as setting depth, material of capillary string, opening pressure of injection valve, capillary hanger solution, surface equipment and injection rate have to be considered individually for that certain candidate. This is done in the upcoming chapter and in a separate paragraph the economics for this project are evaluated.

8.3.1 Design of Capillary Injection System

Before the capillary string can be installed in the selected well several points have to be clarified.

First the type of capillary hanger system has to be selected. Due to the fact that no SSSV is installed in this wellbore no modified SSSV is needed. A simpler solution can be used. Therefore a capillary hanger that is mounted on top of the wellhead would be the best option. It is the simplest and cheapest solution. Using a collar stop (see Chapter X) in addition to prevent falling downhole of the capillary string when it is cut is not recommended by the author for the first pilot project. That is because the installation of the system and possible later well interventions are considerable more difficult if a collar stop is in place. Another better option would be the Y-adapter but this requires a wellhead modification which significantly increases the costs. As this is the first installation of a capillary string in RAG gas fields and no experiences of how good a capillary injection system works are made yet, the installation has to be cost effective. To conclude a wellhead hanger with two packoffs and a flanged bottom (see Figure 5-8) is used.

An OD ¼” capillary string is sufficient because only low rates (liters/day) are injected downhole. In case of the material Duplex Stainless Steel 2205 is found to be the best one for those specific wellbore conditions. Wellbore temperature is below 230°F and the pH-value of the water is around 7.5. Further salinity ranges between 10,000 ppm and 15,000 ppm. H_2S content is zero and CO_2 is about 0.2 %. Using the selection charts provided in Chapter 5.1.3 Duplex Stainless Steel 2205 is sufficient.

Concerning the chemical injection valve the operating pressure is calculated based on the equation below. As the well is considered to have a post treatment rate of 10550 Nm³/day the corresponding bottomhole pressure will 23.8 bara (see Figure A 12-23 in the Appendix). However, for the calculation a bottomhole pressure of ~5 bara is assumed. This assumes the lowest possible bottomhole pressure in the wellbore and ensures that the valve is not leaking even when the bottomhole pressure is low. Further an injection pressure of 30 bar is considered and therefore the following operating pressure of the valve is calculated:

$$p_{op} = \left| p_{hyd} + p_{inj} - p_{bh} \right| = \left| \rho_{foam} g h + p_{inj} - 5E5 \right|$$
$$p_{op} = \left| 1040 \cdot 9.81 \cdot 2042.8 + 3E^{6} - 5E5 \right| = 23.33 \cdot 10^{6}\ Pa = 233.3\ bar$$

A pressure of 234 bara is used to adjust the valve at the surface before it is installed. The high injection pressure of 30 bara guarantees that the injection pressure is always positive even when the bottomhole pressure declines to a minimum pressure of 5 bara.

Finally the setting depth of the valve is needed before the string can be installed. According to the MLT measurements a setting depth has already been determined in Chapter 8.1.2.5. The valve has to be set at a depth of MD 2165m. (TVD 2042.8m).

On the surface a standard chemical injection unit as it is already used in RAG is taken. There are units available and therefore no new ones have to be ordered which further keeps the costs low.

The same foamer is used as it has been already applied in the form of soap sticks. This type of foamer has already delivered good results.

The last point that has to be clarified before the system can be started is the necessary injection rate. In order to calculate a rate, which is used as a starting point for optimization an optimum foamer concentration (see Chapter 5.2.6) and a water production rate has to be known. Unfortunately it can not be said what the water rate will be. Therefore as a rough approach the last recorded water rate (or LGR) is considered and corrected for the expected rate. A LGR of 3.24E-5 m³/Nm³ was reported before the well was liquid loading. The optimum foamer concentration is assumed to be 0.3 %. Well Hilp 001 would then have a water rate of 0.342 m³/day at an expected gas rate of 10550 Nm³/day. Using the equation mentioned in Chapter 5.2.6 the foamer injection rate is calculated as follows:

$$Q_{inj} = 20 \cdot C_{opt} \cdot q_w = 20 \cdot 0.3 \cdot 0.342 = 2.05\ Liters / day$$

The author figured out about another way on how to estimate the wells current liquid rate. When considering the gas rates before and after a soap treatment the relevant bottomhole pressures from Figure (see Figure A 12-23) can be estimated. The difference between the two pressures is caused by the liquids accumulated in the meantime. Based on that pressure difference the height in the tubing of the liquid column can be determined. Further considering the capacity of the tubing the amount of liquid produced between two soap treatments can be calculated. Estimating the time between two soap treatments allows then the calculation of the approximated liquid rate per day. In the following the calculation is done for well Hilp 001.

The estimated rates and corresponding bottomhole pressures before and after a soap treatments are:

after: $Q_1 = 14400 Nm^3 / day \quad p_{wf} = 13.7 bara$

before: $Q_2 = 6370 Nm^3 / day \quad p_{wf} = 33.2 bara$

Resulting pressure difference:

$\Delta p = 19.5 bara$

This is caused by a liquid column of

$$h = \frac{p}{\rho g} = \frac{19.5E5}{1040 \cdot 9.81} = 191.1\ m$$

Considering the tubing capacity of 2.02 Liter/m results in a

$volume = 191 \cdot 2.02 = 386\ Liters$.

The time interval between those two soap treatments is 2.9 days (estimated from a production history plot, see Figure 8-5). This again results in a water rate of 0.133

m³/day, which corresponds to the actual rate of 7200 Nm³/day. Correcting the water rate for a possible rate of 10550 Nm³/day results in a liquid production of 0.194m³/day. This value is inserted into the above mentioned equation for calculating the injection rate and a value of 1.16 Liters/day comes up. Due to the two values that resulted for the foamer injection rate the author concludes that once the well is unloaded an injection rate between 1 and 3 Liters/day can be expected.

This rate is used as a starting point for further optimization on location through trial and error. The relevant procedure is described in Chapter 5.2.6.

From a technical stand point of view the candidate Hilp 001 is ready for the capillary installation. In the following the required economic parameters are calculated in order to justify the expenses that are necessary to implement this technology.

8.3.2 Economics

As a last step in evaluating a project the economics are considered. Parameters such as Net Present Value (NPV) or payout time are calculated in order to rate a project. The economic evaluation will show whether a project is worth spending the money or if it is better investing it in a different project.

As a base for the economic evaluation certain parameters have to be assumed. The future performance of the project, prices, and costs are incorporated into the economics. Therefore the author assumes the following scenario where the calculation is based on.

8.3.2.1 Scenario

After the capillary string is installed, the author expects that it would work for a time period of four years. The success of the installation is evaluated with an 80 % chance to generate the expected incremental production rate. A 20 % chance is left that there is no gain in incremental production. Additionally the author assumes a well intervention in the second year for what ever reason which requires the capillary string to be removed and re-installed again after the intervention. In case of the operating costs the expected foamer injection rate is considered. Taking an injection rate of 2 Liters/day and costs of 2.4 €/Liter of foamer results in operating costs of 4.8 €/day. The author does not consider the savings made due to fewer well interventions by the field people. Further unit costs such as system maintenance are considered as well. This results in a very conservative assumption of the operating costs of the project. In case of the gas price three different cases are distinguished. A low, base, and a high case are considered. In the following the assumptions are summarized.

8.3.2.2 Assumptions of Parameters

A number of parameters have to be assumed to be able to perform the calculation. Additionally economic considerations such as royalties, taxes, and depreciation are taken into account. The following Table 8-7 summarizes these assumptions.

Parameters			
	CASES		
	Low	Base	High
Gas Price [€/Nm³]	0,13	0,183	0,235
Royalties	€167/TJ and 15% of Import Value in €/TJ		
Taxes	25%		
Depreciation	CAPEX distributed over a 4 year period		
CAPEX Initial	40000		
CAPEX Intervention	15000		
OPEX	see Figure below		

Table 8-7 Summary Table of Assumed Parameters

Incremental gas production and the total OPEX are shown in Figure 8-15. The incremental gas production per year is calculated based on the expected daily gas rate starting with 3300 Nm³/day. Moreover a decline in incremental rate of 15 % per year is assumed by the author. In year 2007 the incremental production is much lower than in the following years. This is because the capillary string is installed in July and a full year of production can not be counted. The same corresponds to the operating costs. They include the foamer costs and the unit costs. They do not include the savings due to fewer well interventions.

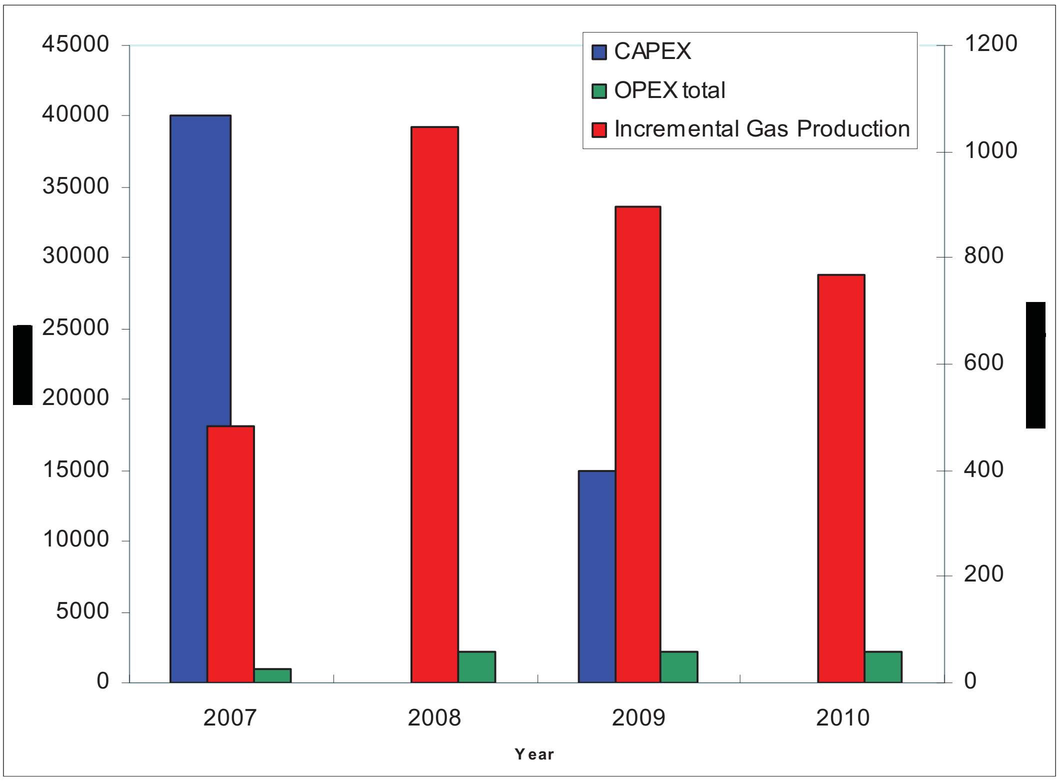


Figure 8-15 Incremental Gas Production and Costs of the next four Years

These assumed parameters can now be entered in an Excel- spreadsheet and the parameters payout-time, NPV at different interest rates, VIR (Value Investment Ratio), and a cumulative cash flow curve versus time are calculated.

8.3.2.3 Economic Results

The adjacent Table 8-8 summarizes the calculated economic parameters. Figure 8-16 presents the cumulative cash flow.

Results				
Cases	**Low**	**Base**	**High**	**Units**
Payout-Time	6,6	4,3	3,3	Months
NPV @ 7%	132	212	292	1000 Euro
NPV @ 15%	115	187	259	1000 Euro
VIR (PVR) @ 7%	2,6	4,2	5,8	€/€
VIR (PVR) @ 15%	2,3	3,8	5,3	€/€

Table 8-8 Economic Parameter Summary

The results show that this project is highly economic even a success rate of 80 % is assumed. In any case the investment is paid back in a couple of months. The payout- time includes royalties, OPEX, depreciation, and tax. Further the investment is paid pack about 4 times within a time period of four years. It has to be considered that this economic evaluation is very conservative: it does not include the savings due too fewer well interventions by the field people, a removal and re-installation of the capillary string within the four years is included, and a 80 % success rate is assumed. Considering that the capillary string is installed in the second half of year 2007 there is only the low case where the installation does not payout this year.

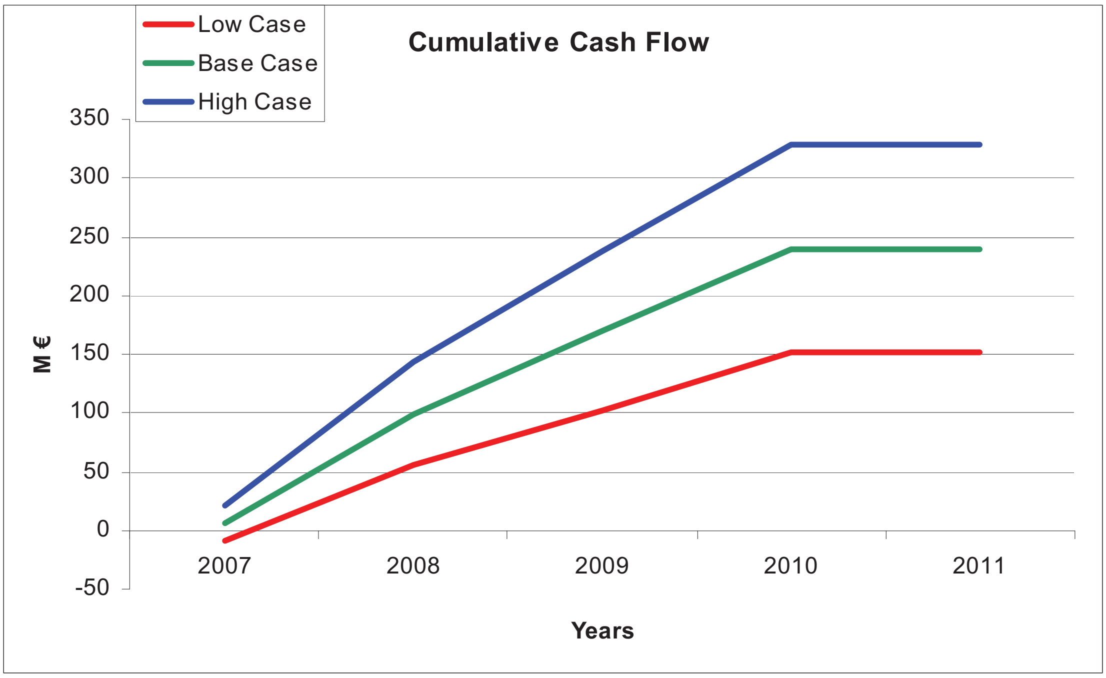


Figure 8-16 Cumulative Cash Flow Curve

9 Conclusion

So far liquid loading has been determined to be a major problem of low gas rate wells and that this problem gets more common due to much more gas wells getting on decline. RAG itself operates gas- and oil- wells where in some gas wells liquid loading has been recognized as the main problem. Especially gas wells where the production rate is low tend to load more easily. However, liquid loading is not a problem that can not be treated. Several deliquification methods have been mentioned and especially the capillary string technology in conjunction with foamer application has been described in detail. Before any well intervention can be conducted liquid loading has to be determined as the well’s problem. Different signs of liquid loading have been presented where the most important ones are an increased decline rate and an erratic production behaviour due to slug flow in the wellbore. Those two are usually the first ones to be recognized by the field operator. As soon as liquid loading is recognized as the wells problem a well intervention has to be planned and conducted. Many methods for dewatering gas wells are available but just a few of them are economic in wells where the gas rate is already low. This is one reason for RAG to decide on the capillary string technology because it is one of those methods that can be implemented in low rate wells due to the low installation costs. Therefore even if the incremental gas rate is low it can be paid back in a reasonable time frame. Further this technology allows a more efficient application of foaming agents. Foamers can be injected at any desired rate in any depth. It also improves the adjustment of foamer injection rate significantly compared to other foamer applications because any changes in the surface injection rate are immediately transferred to the bottom of the wellbore where a chemical injection valve prevents uncontrolled leakage into the wellbore. This is another reason for RAG to implement the capillary string technology because it improves the actual continuous backside injection significantly. As in this thesis presented several possibilities of a capillary string installation are possible. Dependent on the type of hanger system that is used, more or less advantages and disadvantages of a system arise. It has been pointed out that in case of the simplest and therefore cheapest solution where the capillary coil is hung of on top of the wellhead the master valves will cut the capillary string when they are closed in case of an emergency or unintentionally by somebody else. However, more sophisticated hanger solutions have been presented where it is not possible to cut the capillary coil. As these solutions are more complex, they are more expensive and some are even more difficult to install but by the end of the day they are simpler and safer to operate.

One crucial part of a capillary system for foamer injection is the proper selection of the foaming agent. As a first step in foamer selection several foamers offered by different companies have to be tested in the laboratory. After that it has been pointed out that it is unavoidable to test the best foamer in the field, right in a wellbore that can be a candidate. The well's response to a foamer is used as one major criterion in selecting a proper candidate well. A capillary string should never be installed without testing the foaming agent in the candidate well. This significantly reduces the chance of success of a project.

Therefore a foamer trial is one very important part in selecting a proper candidate for a capillary string installation. Other criteria are a comparison of the wells actual-, critical-, and critical foam rate. The author has already pointed out that the wells actual rate has to be estimated carefully. This is because in case of a liquid loaded well the well's current rate might not be the well's actual rate. In order to determine the actual rate foamer trial, decline curve analysis, and a system analysis are considered. An accurate value for the actual rate is crucial in order to gain useful results when comparing this rate with the critical velocity of the wellbore. The critical rate is evaluated based on the Coleman model. In a separate chapter different models have been compared and the Coleman model turns out to be the most suitable one for RAG gas wells. The sensitivity study has shown that it is of great importance to select the proper model to get accurate values. Further gas density and surface tension are two more relevant factors that influence the critical velocity. Surface tension is often not known and has to be assumed in most of the cases. In literature it is reported that values between 60 and 75 dynes/cm can be assumed for brine. The application of foamer reduces this value and consequently the critical velocity of the wellbore is reduced. As a result the actual gas rate can be above this critical value and liquids are removed from the wellbore again. A foamer does not only affect the surface tension but also the liquid density. Foam is a substance that is formed by entrapping gas bubbles in a liquid. The resulting pseudo density is much lower which further decreases the critical velocity. A foamer effects both surface tension and liquid density and a reduction of these values leads to a lower critical velocity but with the density to be the more significant effect.

Once a capillary string is installed it is susceptible to problems as other technologies as well. One of the most common problems is plugging of the capillary string due to particles that get into the small diameter string from the surface or from the bottom in case no chemical injection valve is installed. Other problems reported are those related to chemical polymerization where chemical incompatibilities between capillary coil, foamer, wellbore fluids, and gas are a major reason.

Finally a number of RAG gas wells have been evaluated due to the procedure established in the chapter candidate evaluation. This evaluation turns out the well HILP 001 to be the one where a capillary string installation is most successful. An incremental rate of 3350 Nm^3/day has been estimated. Installation costs are going to be 40000 Euros including some contingency. A conservative scenario has been assumed and three cases concerning the gas price are considered in order to calculate the economic parameters. To conclude this project is very economic and that payout time is less then 6.6 months in case of the worst case. As a result RAG wants to implement this technology in their wellbore.

10 Recommendation

As this thesis has pointed out the author suggests installing a capillary string in well HILP 001. Further details of information such as setting depth, capillary material, hanger system, and foamer injection rate are addressed in the relevant chapter and recommended to be considered for the first implementation of the capillary string in RAG gas wells. Once the capillary injection system is installed it is necessary to record gas production rate, wellhead pressure, water production rate, surface foamer injection pressure, and foamer injection rate continuously. This is required for further evaluation of the capillary string project and it builds a basis for future capillary installations. After stabilized conditions have been achieved the actual gas rate has to be compared to the one expected before the capillary string has been installed. Additionally it should be clarified if the well is producing at a constant level or if the well is still loading. Also the current foamer injection rate should be compared to the one suggested by the author. This is recommended for further improvement of the assumed parameters in the evaluation process with the result of getting more relevant values for parameters for RAG gas fields. The main focus should be on parameters such as surface tension, foamer density, and optimum foamer concentration. Based on the information gained from the first capillary installation another capillary string can be installed in a second wellbore. Basically the candidate that comes in second after the candidate evaluation can be used for the next capillary string. However, if the analysis of the first capillary string shows rough variations between the current values and the ones first proposed, a re-evaluation considering the new information gained from the first project is recommended for the other candidate wells which are listed in the end of the candidate evaluation section.

For future capillary string installations the author further recommends to test several foamers offered by different companies. There is a large variety of foamers on the market. Consequently it is advisable to order samples of foamers that are suitable for RAG's formation water (salinity) and the expected temperature range from different companies. These samples are then tested in the laboratory in order to make a pre-screening before the ones that perform best are tested in the field.

This would be a further step towards improving the performance of foamers in RAG gas wells.

Once one or two capillary strings haven been installed successfully and experiences are made a next step would be the implementation of one of the new hanger systems that have been presented. The author recommends the use of a modified dummy in conjunction with a control-line that is run through the casing valve to the chemical injection unit as it is presented in this thesis. The advantage of this system is significant, namely the master valves can not cut a capillary string anymore and no risk in loosing the capillary string arises. Further due to the fact that the control-line is run through the casing valve no modifications at the wellhead are required. Besides the slightly higher costs that arise compared to the much simpler wellhead hanger solution, a dummy hanger has to be installed as part of the production string. A dummy hanger can be installed during a workover even if no capillary string is considered currently but for the case a capillary string is installed in a later stage of the well’s life.

To sum up the capillary string technology can significantly improve gas production from the candidate well HILP 001 and detailed data collection from the first installation will build a basis for further capillary string installations in RAG gas fields.

11 References

1 Lea J. et al.: "Gas Well Deliquification: Solutions to Gas Well Liquid Loading Problems", Gulf Professional Publishing, Elsevier, p. 1, pp. 10 – 33, 2003.

2 KAPPA Engineering: "Production Log Interpretation", Foundation Course Notes, http://www.kappaeng.com, accessed May 2007.

3 Lea J. and Nickens H. V.: "Solving Gas Well Liquid Loading Problems", paper SPE 72092, Distinguished Author Series, 2004.

4 Reinicke, K.M., Dr. et al., Department of Petroleum Engineering, TU Clausthal: "Optimierung maturer Felder – Aufrechterhalten der Produktion aus verwässerten Erdgasbohrungen", DGMK Forschungsbericht 607, unveröffentlicher Bericht, Juni 2006.

5 Campbel S. et al.: "Corrosion Inhibition and Production Improvement via Chemical Treatment", CORROSION/01, NACE paper no. 1051, 2001.

6 Duggan J.O.: "Estimating Flow Rates Required to keep Gas Wells Unloaded", Net. Gas Eng. pp. 1173 – 1176, December 1961.

7 Smith R.V.: "Practical Natural Gas Engineering", PennWell Publishing Co., Tulsa 205, 1982.

8 Turner R.G. et al.:" Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells", JPT, Trans., AIME, 246, pp. 1475 – 82, 1969.

9 Hinze J.O.: "Fundamentals of the Hydrodynamic Mechanism of Splitting in Dispersion Processes", AICHE Journal, September, 1, no. 3, p. 289, 1955.

10 Coleman S.B. et al.: "A New Look at Predicting Gas-Well Load up", JPT, March, pp. 329-333, 1991.

11 Nosseir M.A. et al.: "A new Approach for Accurate Prediction of Loading in Gas Wells Under Different Flowing Conditions", paper SPE 66540, presented at the SPE Production Operations Symposium held in Oklahoma City, Oklahoma, March 9 – 11, 1997.

12 Min Li. Et al.: “New View on Continuous-removal Liquids from Gas Wells”, paper SPE 70016, presented at the SPE Permian Basin Oil and Gas Recovery Conference held in Midland, Texas, May 15-16, 2001.

13 Guo B. et al.: “A Systematic Approach to Predicting Liquid Loading in Gas Wells”, paper SPE 94081, presented at SPE Production Operations Symposium, Oklahoma City, Oklahoma, April 17-19, 2005.

14 Jelinek W. et al.:”Improved Production from Mature Gas Wells by Introducing surfactants into wells”, paper IPTC 11028, presented at the 2005 International Petroleum Technology Conference held in Doha, Qatar, 21-23 November.

15 Lea J.F.:” Gas Well Deliquification”, Course Notes, Petro Skills, 2006.

16 Lea J. et. al.: “Gas Well Deliquification : Solutions to Gas Well Liquid Loading Problems”, Gulf Professional Publishing, Elsevier, pp. 6 – 7, 2003.

17 Überer W.:”Liquid Unloading in Low Pressure Gas Wells”, Diploma Thesis, October 2001.

18 Pro-Seal Life Systems: www.soaplauncher.com/pictures.htm, accessed June 2007.

19 Lea J. et al.: “Gas Well Deliquification: Solutions to Gas Well Liquid Loading Problems”, Gulf Professional Publishing, Elsevier, pp. 147 - 174, 2003.

20 Campbell S., et al.: “Corrosion Inhibition/Foamer Combination Treatment to Enhance Gas Production”, paper SPE 67325, presented at the Production and Operations Symposium in Oklahoma City, OK, March 24 -27, 2001.

21 Smalt Gus, Region Sales Manager: Email June 5th, 2007.

22 Weatherford Completions, received by email from Gus Smalt, 2007.

23 McWilliams J.P. et al.: “Downhole Capillary Surfactant Injection System Pilot on Low Pressure Gas Wells in the San Juan Basin”, SPE paper 94293, presented at the Production and Operations Symposium in Oklahoma City, OK, 17 – 19 April.

24 Turk S., Horn B., Fuller B.: “Foam Lift”, Presentation prepared by Weatherford, accessed May 2007.

25 Smalt, G., Weatherford Sales Manager Europe: Email from April 26th, 2007.

26 McKee & Associates: Product Catalogue of Capillary Equipment, p. 3-3, accessed May 2007.

27 Weatherford: "Chemical Injection Valve Specification Sheet", accessed May 2007.

28 Mc Kee, J., McKee & Associates: Email from March 12th, 2007

29 Mc Kee J., McKee & Associates: Email from March 13th, 2007.

30 Weatherford Artificial Lift Systems Technical Manual: "Chemical Injection Valve", accessed May 2007

31 Donke W., Operations and Business Development Manager Austria and Eastern Europe, Halliburton: Meeting from March 16th in Gampern at RAG, 2007.

32 Frieling K., Sales Manager Coil Services: Meeting from June 28th, Gampern, 2007.

33 Frieling, K. Sales Manager Coil Services: Meeting from April 20th in Gampern at RAG, 2007.

34 Strickland, N., Baker Petrolite: "Best Practices: Chemical Injection with Capillary Tubing", Baker Hughes Incorporated, October 2004.

35 Samlt Gus, Region Sales Manager Weatherford: Meeting from April 3rd, Gampern, 2007.

36 Sullivan R.B., et al.: "Benefits and Challenges Associated with CRA Injection Tubing in Corrosive Gas Wells", paper SPE 91692, Houston, September, 2004.

37 Awadzi J., et al.: "Downhole Capillary Soap Injection Improves Production", paper SPE 52153, presented at the Mid- Continent Operations Symposium held in Oklahoma, OK, March 28 – 31, 1999.

38 Schillmoller, C. M.: "Selection of Corrosion Resistant Alloy Tubulars for Offshore Applications", OTC 1989 held in Housten, Vol. 3, p. 255, May 1-4.

39 Hartman E. L. and Bolding J.: "Micro String Technology in Conjunction with Sub- Surface Safety Valve", BJ, Dyna Coil, and Chevron Presentation, September 20th, 2006.

40 De Jonge R., BJ Services: "Clarifications to Capillary Tubing Questions", Email from March 27th, 2007.

41 Klompsma D., Shell: Email from March 20th, 2007.

42 De Jonge R., BJ Services: Email from October 26th, 2006.

43 Texsteam Inc., "Product Description of the 5100er Series of Air and Gas Driven Injectors".

44 Frieling K. Sales Manager Coil Service: Email from 4. Juni, 2007

45 Wikipedia: Free Encyclopedia: Definition of Foam

46 Berkmann S. and Egloff G.: "Emulsions and Foams", NY, Reinhold Publishing Corporation, pp. 116 – 151, 1941.

47 Joos P., Uffelen M.: "The Relation between the Surface Elasticity Modulus and the Dynamic Surface Tension", coll. Surf. A.: Phys. Eng. Asp. 75, 273-275, 1993.

48 Jacoby R. H., NGPA Phase Equilibrium Project, API Proceedings Division of Refining, p. 288, 1964.

49 Solesa M., et al.: "Production Optimization Challenges of Gas Wells with Liquid Loading Problem Using Foaming Agents", paper SPE 101276, presented at the Russian Oil and Gas Technical Conference and Exhibition held in Moscow, Russia, October 3-6, 2006.

50 Dunning H. N. et al.: "Using Foaming Agents for Removal of Liquids from Gas Wells", Monograph 11, Bureau of Mines, Am Gas Assoc., New York, NY, 1961.

51 Tamura T., et al.: "Dynamic Surface Tension and Foaming Properties of Aqueous Polyoxyethylene n-Dodecyl Ether Solutions", J. Coll. Int. Sci. 173, 493 – 499, 1995.

52 Dushkin C., et al.: "Dynamic Surface Tension of Micellar Solutions Studied by the Maximum Bubble Pressure Method: 3. Theory of the Solutions Containing Micelles", Colloid. Polym. Sci. 273, 370-378, 1995.

53 Bowman C.W. and Collins J.A.: "Increasing the Production From Marginal Gas Wells", paper SPE 100514, presented at the SPE International Oilfield Corrosion Symposium held in Aberdeen, Scotland, May 30, 2006.

54 Al-Jamae'y M. et al.: "Foam-Assisted Liquid Lifting in Low Pressure Gas Wells", paper SPE 37425, presented at the SPE Production Operations Symposium, Oklahoma City, OK, March 9 – 11, 1997.

55 Lea J. et al.: "Gas Well Deliquification: Solutions to Gas Well Liquid Loading Problems", Gulf Professional Publishing, Elsevier, pp. 30-32, 81; 2003.

56 Koos Frieling, Sales Manager Coil Services: Email from June 15th, 2007.

57 Economides M.J. et al.: "Petroleum Production Systems", Prentice Hall, PTR, 2004.

58 Lea J. et al.: "Gas Well Deliquification", Gulf Professional Publishing, Elsevier (USA), pp. 293, 294, 2003.

59 Wikipedia the free Encyclopedia: "Surface Tension", http://en.wikipedia.org/wiki/Surface_tension, accessed June 2007.

12 Appendix

This Appendix gives additional information on the properties of gas and a definition of the surface tension. Further the installation of the capillary string in the candidate well is summarized. Finally all interpreted data gained from the MLT measurements are added, including the system analysis charts for each well.

12.1 Pseudo Density Calculation of Two Phase Mixture.

The density of a two phase mixture depends at given temperature and pressure conditions on the density of each single phase and the relative amounts of each phase. Therefore to calculate a pseudo density it requires to know the amount of liquid phase present and the amount of gas. In case of a gas well producing liquids this is a function of the flow regime. The amounts of liquid and gas which are present can be expressed by a liquid holdup which is defined as follows:[57]

$$H_L = \frac{V_L}{V_T}$$

thus the holdup of gas is then

$$H_G = 1 - H_L$$

The holdup phenomenon in a typical gas well is in fact because the lighter phase (gas) moves upward faster then the denser (liquid) phase. Therefore the in-situ volume fraction of the liquid will be greater than the input volume fraction of the liquid phase. This causes the liquid phase to be held up in the pipe relative to the lighter phase.[57]

Knowing H_L and the densities of each phase at the specific temperature and pressure conditions, a pseudo two phase density can be calculated as follows: [57]

$$\rho_p = \rho_G \cdot (1 - H_L) + \rho_L \cdot H_L$$

ρ_p ......*Two Phase Pseudo Density*

Another parameter used in describing two-phase flow is the input fraction of each phase, λ, where it is defied as follows: [57]

$$\lambda_L = \frac{q_L}{q_L + q_G} \text{ and } \lambda_G = 1 - \lambda_L$$

q_L and q_G are the volumetric flow rates of the two phases. λ is also referred to as the no-slip holdup. This is because there is no relative movement between the gaseous and liquid phase. In case of no slippage the pseudo- or mixture density is then calculated as follows: [57]

$$\rho_{p,no\ slippage} = \rho_L \cdot \lambda_L + \rho_G \cdot \lambda_G$$

12.2 Dew Point and Phase Diagram

Natural gas is a mixture of different hydrocarbon molecules in varying compositions. Dependent on the type of hydrocarbon molecules and relative amounts, the mixture properties vary. Figure A 12-1 illustrates a typical gas well reservoir phase diagram which gives the mixture properties at a given temperature and pressure. Above the critical temperature the gas can no longer be liquefied by increasing pressure. The critical pressure is the one the gas exerts when in equilibrium with the liquid phase at the critical temperature. Cricondenbar is the highest pressure at which gas can exist and cricondenterm is the highest temperature at which liquid can exist. Above the bubble point line the mixture is 100% liquid and below the dew point line the mixture is 100% gas.[58]

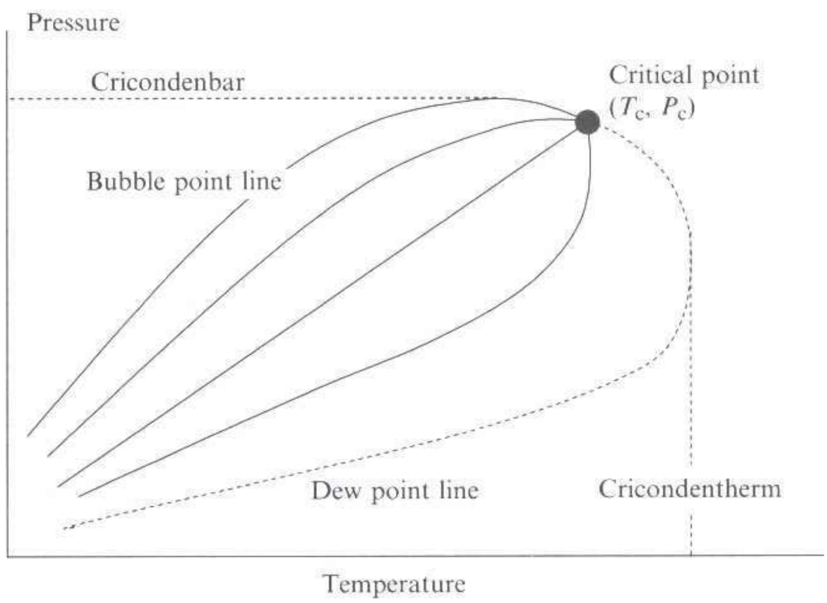


Figure A 12-1 Typical Gas Well Reservoir Phase Diagram[58]

12.3 The Principle of Surface Tension

Surface tension is the effect within a surface layer of a liquid that causes the layer to act as an elastic sheet. This effect is the cause why small objects such as insects or needles and razor blades float on the liquid surface. Further it is the cause of capillary action.

The reason for this effect is the attraction between the molecules of a liquid through various intermolecular forces. In the bulk of the liquid a molecule is pulled equally in all directions. Therefore the resulting net-force is zero. Considering a molecule at the boundary, it is pulled inwards by the molecules deeper inside the liquid and it is not attracted as much by the molecules in the neighbouring medium (see Figure A 12-2). This medium can be vacuum, air or any different liquid. This results in a net force that points inwards and wants to compress the liquid. The only resistance to this force in order to achieve equilibrium is the resistance of the liquid to compression. Thus the liquid squeezes itself together until it achieves the locally lowest possible surface area. The surface will then assume the smoothest flattest shape it can.[59]

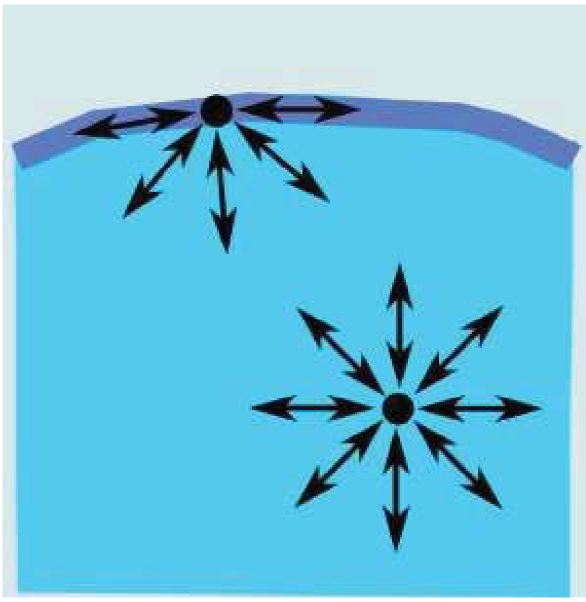


Figure A 12-2 Diagram of the Forces on a Molecule of Liquid[59]

In physics surface tension is represented by symbol $\sigma, \gamma \; or \; T$ and it is defined as the force along a line of unit length where the force is parallel to the surface but perpendicular to the line. Surface tension is measured in N/m where it is more common to use dynes/cm. Figure A 12-3 shows a crossection of a needle floating on the surface of a liquid and the forces acting on that needle.

Soap bubbles have a very large surface area compared to very small masses. For example pure water can not form bubbles because water has a very high surface tension. However, surfactants can be used to decrease the surface tension. They can reduce it more than tenfold which makes it very easy to increase the surface area and thus the bubble size.[59]

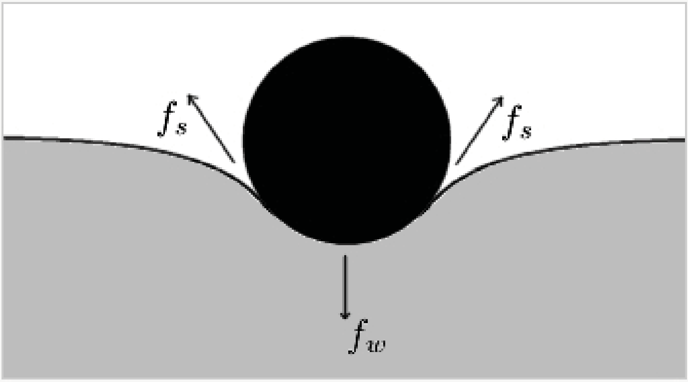


Diagram shows, in crossection, a needle floating on the surface of water. Its weight, f_w, depresses the surface, and is balanced by the surface tension forces on either side, f_s, which are each parallel to the water's surface at the points where it contacts the needle. Notice that the horizontal components of the two f_s arrows point in opposite directions, so they cancel each other, but the vertical components point in the same direction and therefore add up.

Figure A 12-3 Crossection of a Needle on the Surface of a Liquid[59]

12.4 Results of Capillary String Installation in Candidate Well HILP 001

In this thesis the author comes up with HILP 001 as the primary candidate well for the first capillary string installation in RAG's gas fields. This installation is supposed to inject surfactant in that particular well in order to remove liquids on a continuous basis. Until now this well was soap stick treated up to three times a week and production declined after each treatment rapidly.

Right after a promising candidate has been identified a service company was conducted to realize this project as soon as possible. Finally shortly after this thesis has been finished in the middle of July, the RAG and the service company have been ready for the capillary installation.

All in all the installation took a whole day including a gauge run at the beginning and connecting the capillary coil to the injection unit by the end of the day.

The gauge run showed that there were no restrictions in the wellbore down to the tubing shoe. Anyway, no restrictions were expected but just to be sure not to get stuck while the capillary string is installed in the production tubing. Figure A 12-4 shows the equipment during the gauge run. Now the wellbore was ready to install the capillary string.

After preparing the necessary equipment and connecting the capillary hanger with the BOP to the wellhead everything was ready to run in the capillary string (see Figure A 12-4). Before the capillary hanger was connected to the wellhead the pressure setting of the chemical injection valve was checked (see Figure A 12-5).

Figure A 12-4 LEFT: Lubricator and BOP for Gauge Run; RIGHT: Injector-Head and BOP

Figure A 12-5 LEFT: Capillary Hanger; RIGHT: Cap.-Hanger, Pressure Gauge and Injection Valve

The well was shut in (closed production valve) during the gauge run but was on production during the installation of the capillary string. The capillary string was run downhole very slow in order not to cause any buckling of the string. It took almost three hours until the capillary string together with the chemical injection valve was set at the pre-designed setting depth.

Finally the two packoffs of the capillary hanger were activated and the capillary coil was cut. Roughly 50 meters of additional coil at the surface was left and winded up. The surface end of the capillary string was connected to the injection unit. Right after that the injection of surfactant was started.

Table A 12-1 shows data that has been collected so far and Figure A 12-6 shows a production plot considering a certain time interval before the installation and after the installation.

To sum up the installation of the first capillary string worked out very well and also the expected positive results where very satisfying.

HILP 001 Daten nach Cap String Einbau

Bereich Mitte **Jahr: 2007**

Datum	Verbrauch Schäumer	TBG Druck	CAS Druck	Pumpendruck	Menge Nm3/T
17.07.2007	ca 3 l	6,3 bar	29,7 bar	40-44 bar	12090
18.07.2007	ca 3 l	6,1 bar	29,2 bar	38-42 bar	11480
19.07.2007	ca 1,5 l	6,1 bar	29,1 bar	38-41 bar	11060
20.07.2007	ca 2 l	6 bar	29 bar	38-40 bar	10860
23.07.2007	ca 2 l	6 bar	28,4 bar	42-45 bar	10490
25.07.2007	ca 2l	6,1 bar	27,9 bar	39-42 bar	10330
26.07.2007	ca 3,5l	6,3 bar	27,7 bar	50-54 bar	10460
30.07.2007	ca 2l	6,0 bar	27,4 bar	50-52 bar	10150
01.08.2007	ca 2l	5,9 bar	27,1 bar	50-54 bar	9900
06.08.2007	ca 0,5l	5,9 bar	26,9 bar	45-50 bar	9630
07.08.2007	ca 4l	6 bar	26,7 bar	54-58 bar	9770
08.08.2007	ca 6l	5,9 bar	26,7 bar	54-58 bar	10380

Table A 12-1 Collected Data, Post-Installation

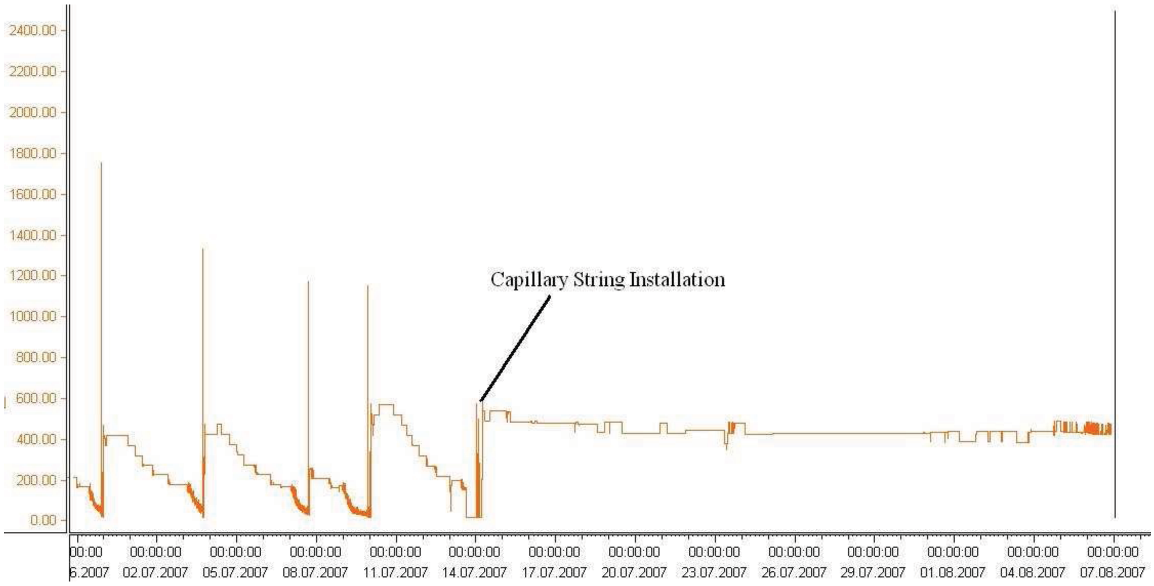


Figure A 12-6 Pre-Job and Post-Job Production History of Well HILP 001

Platzhalter für Tabelle

Table A 12-2 Summary Table of Foamer Response Evaluation

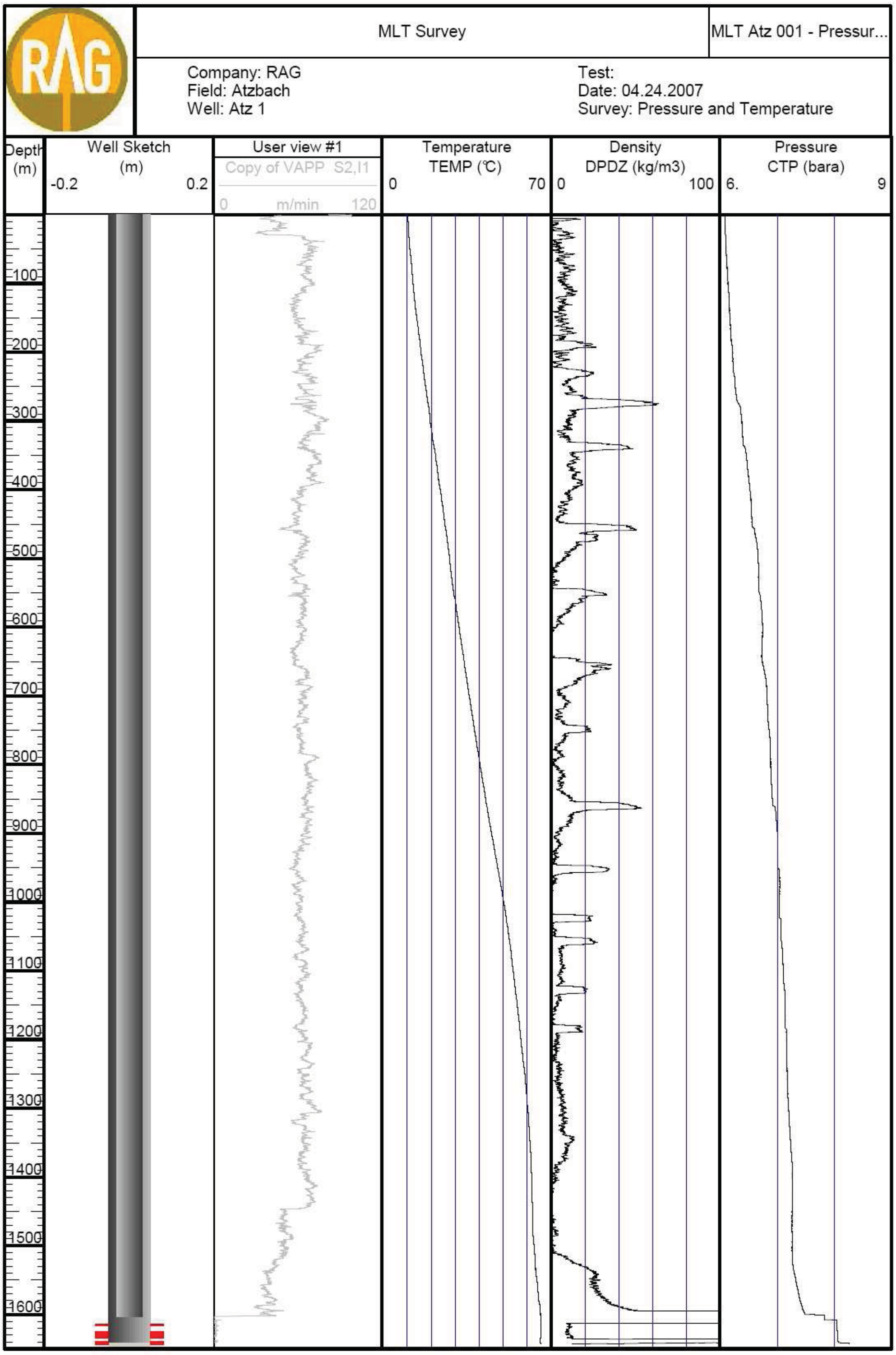


Figure A 12-7 Atz 001 MLT Measurement: Total Depth Interval

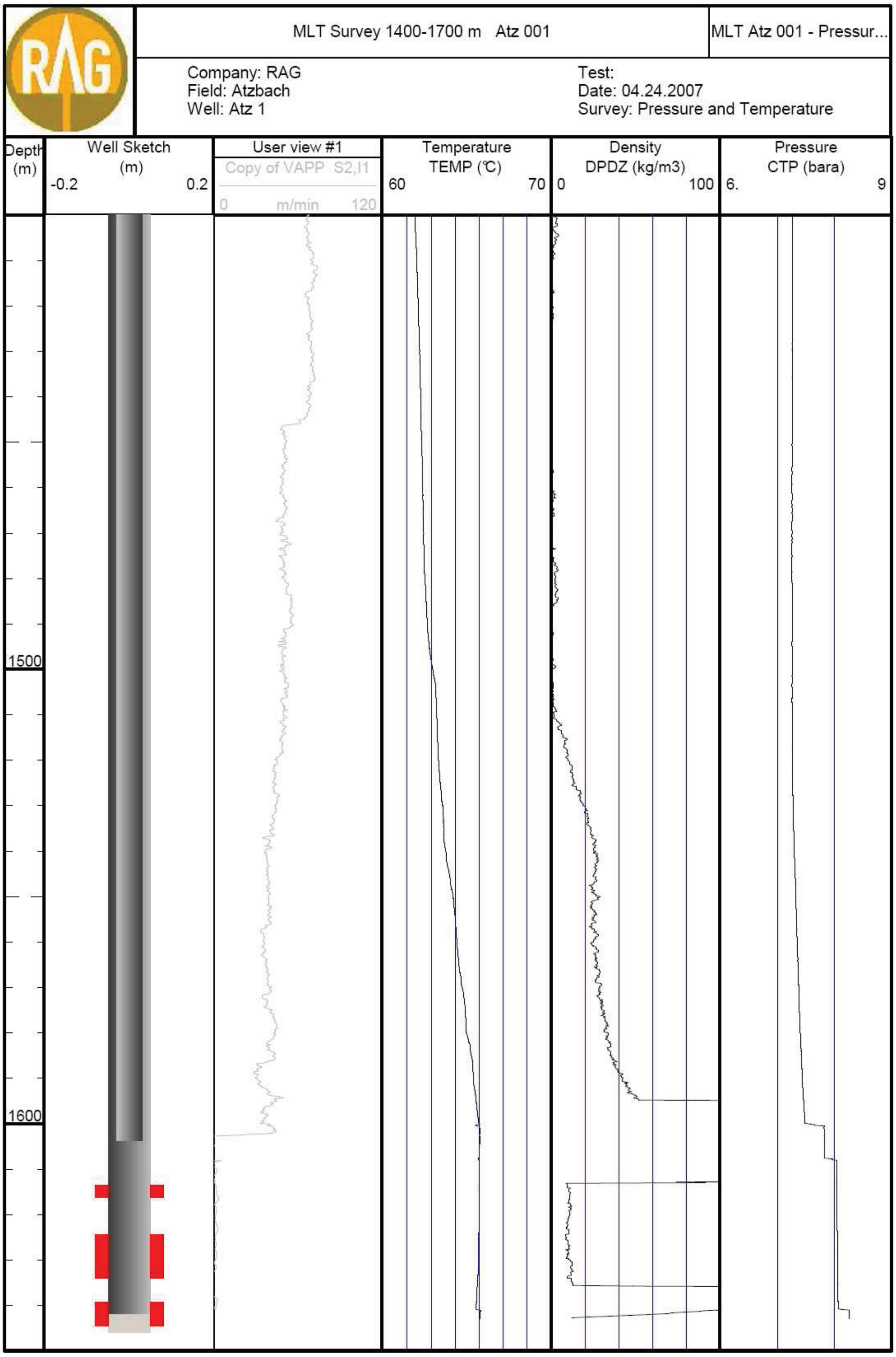


Figure A 12-8 Atz 001 MLT Measurement: Zoom of Lower Part of Wellbore

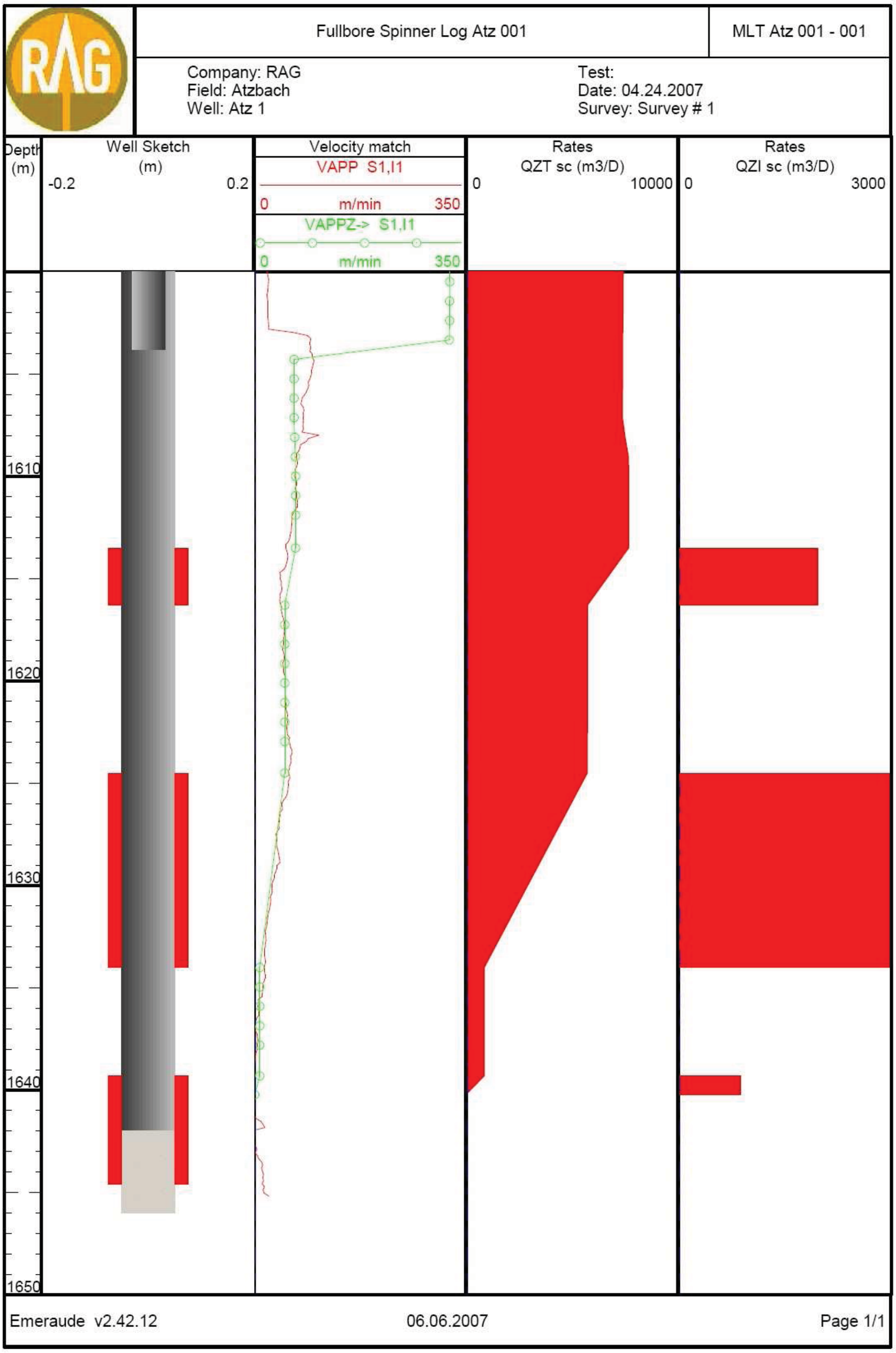


Figure A 12-9 Atz 001 Fullbore Spinner Measurement

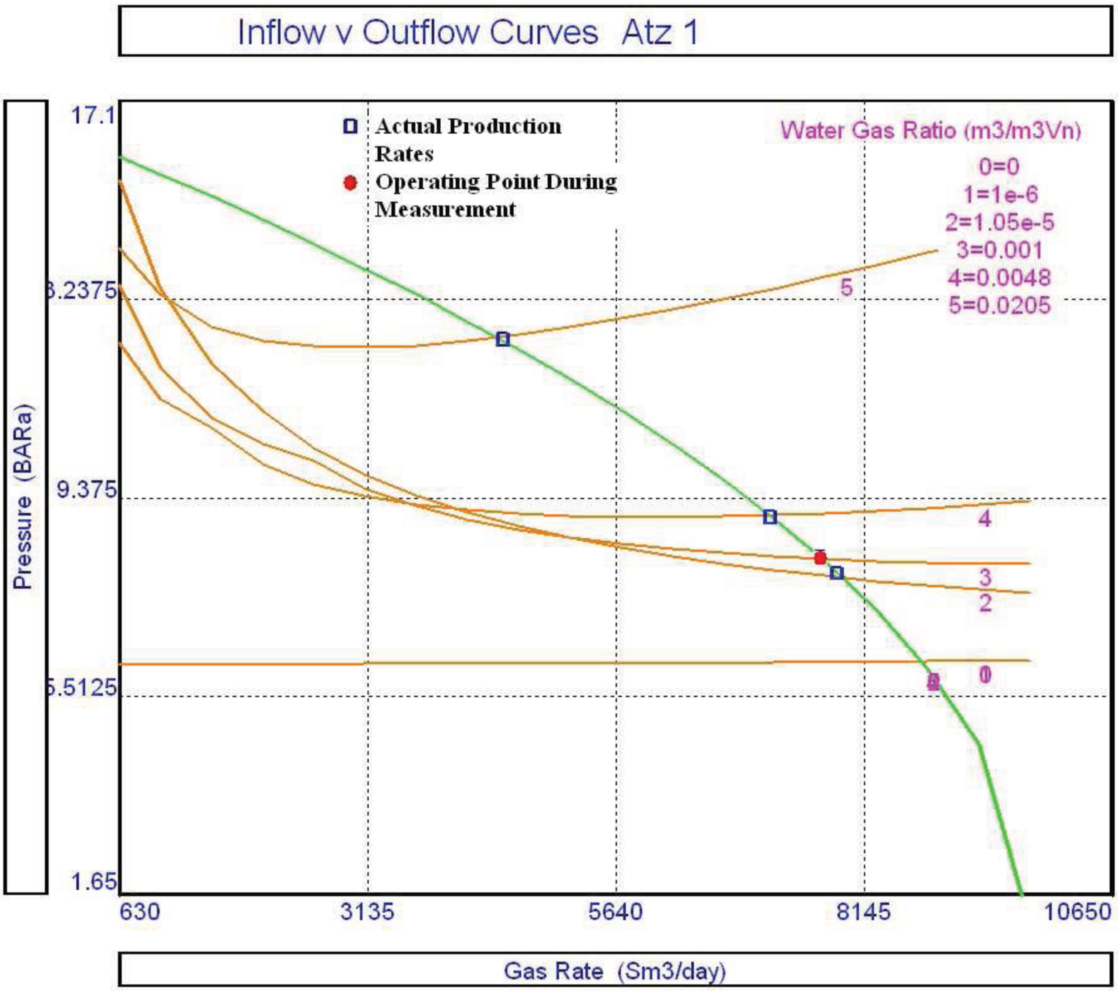


Figure A 12-10 Atz 001 Inflow and Outflow Performance

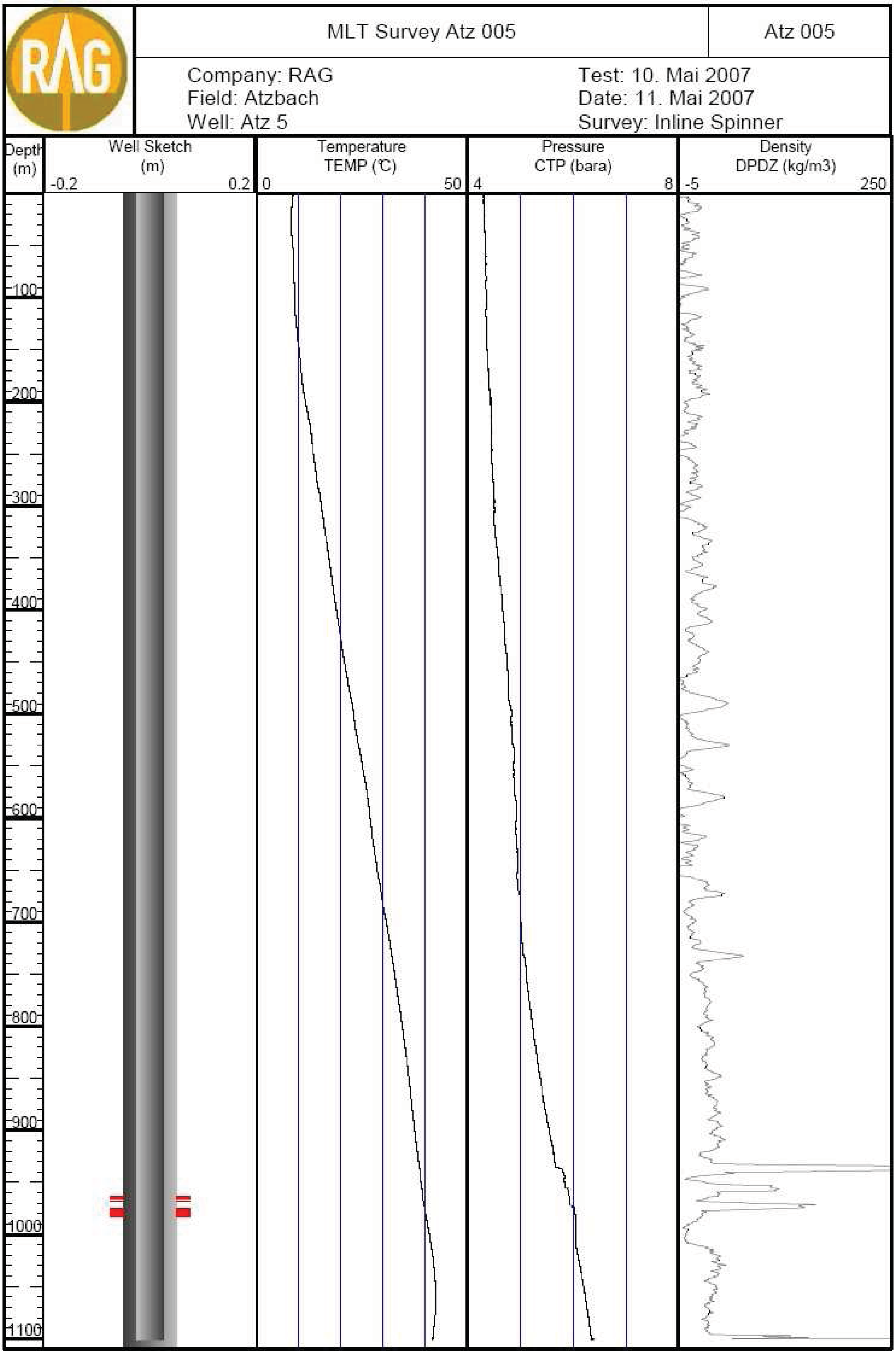


Figure A 12-11 Pressure and Temperature Survey of Well Zapf 005

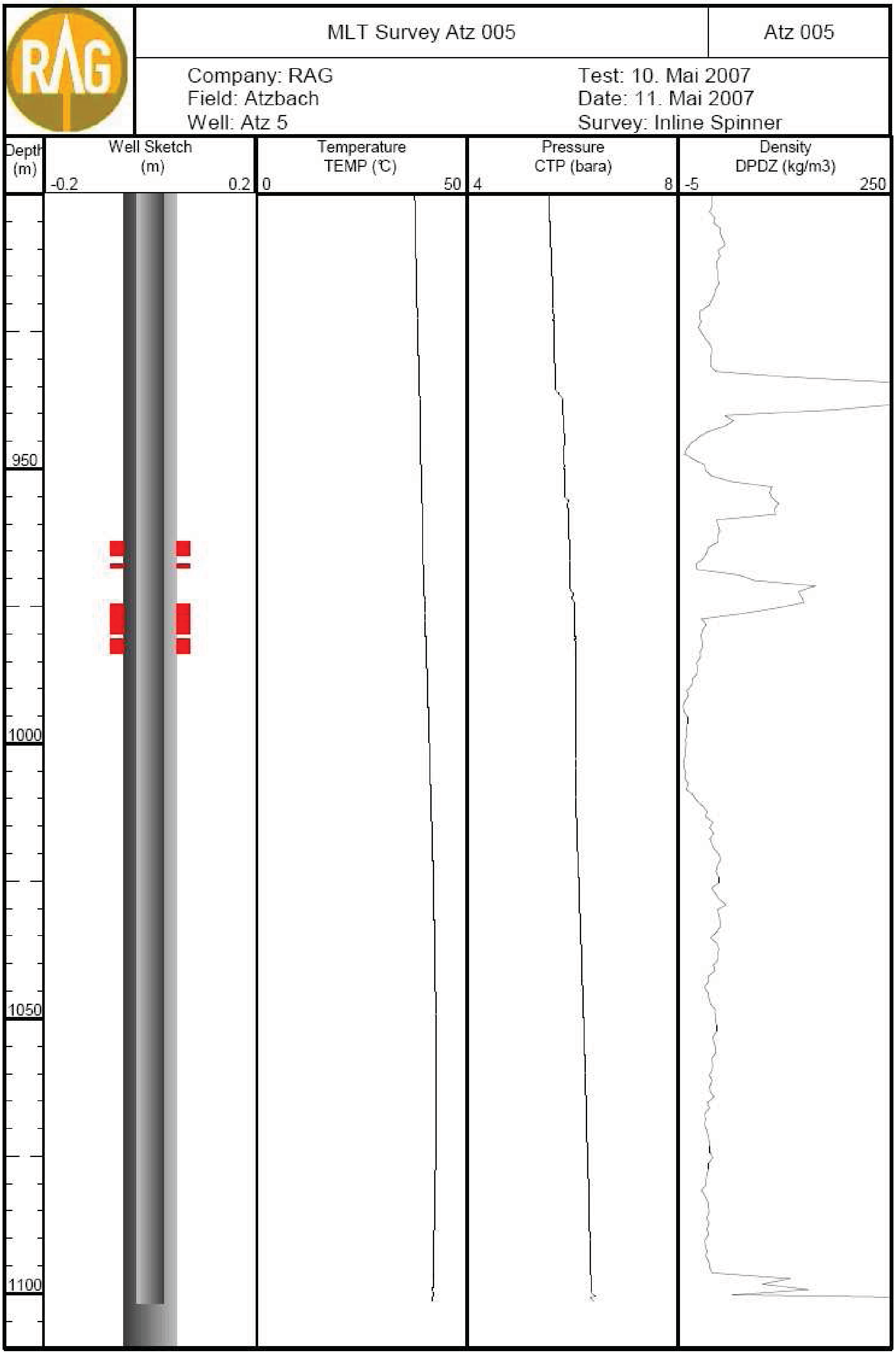


Figure A 12-12 Pressure and Temperature Survey between 900 and 1100 m of Well Atz 005

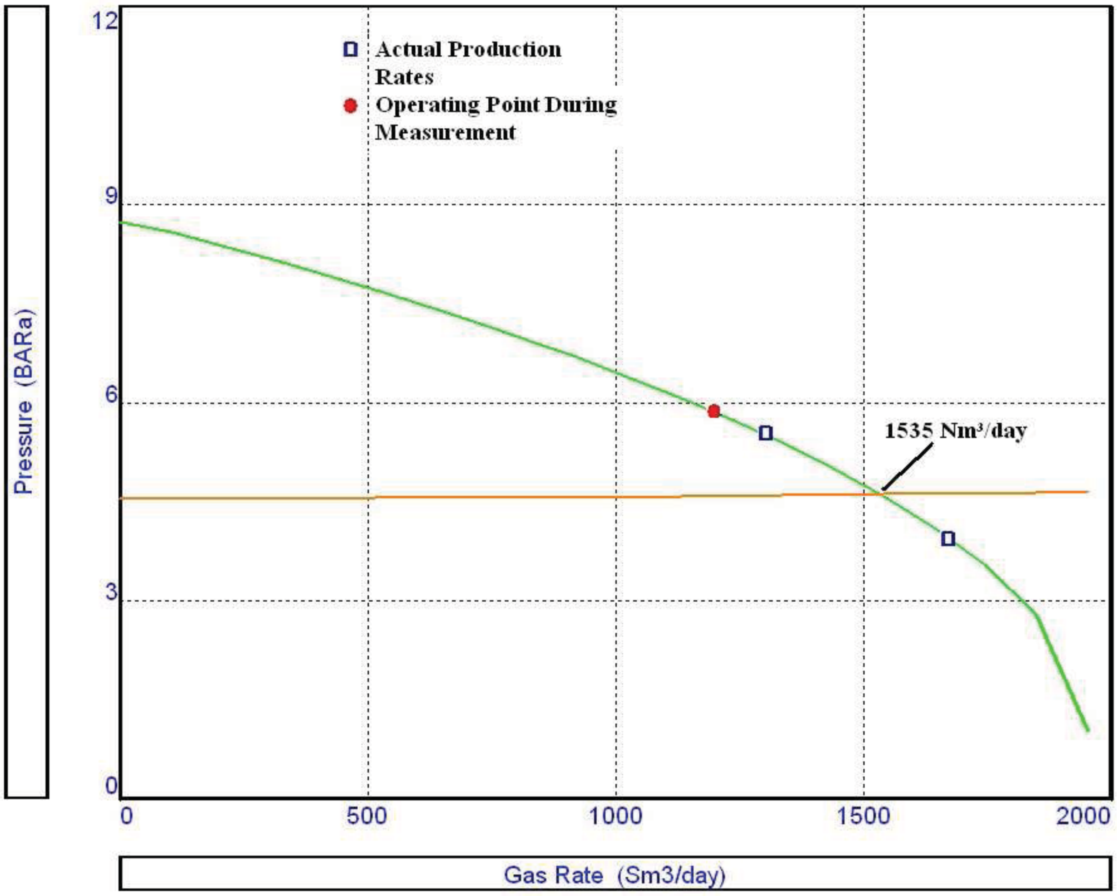


Figure A 12-13 Inflow and Outflow Performance Curve of Well Atz 005

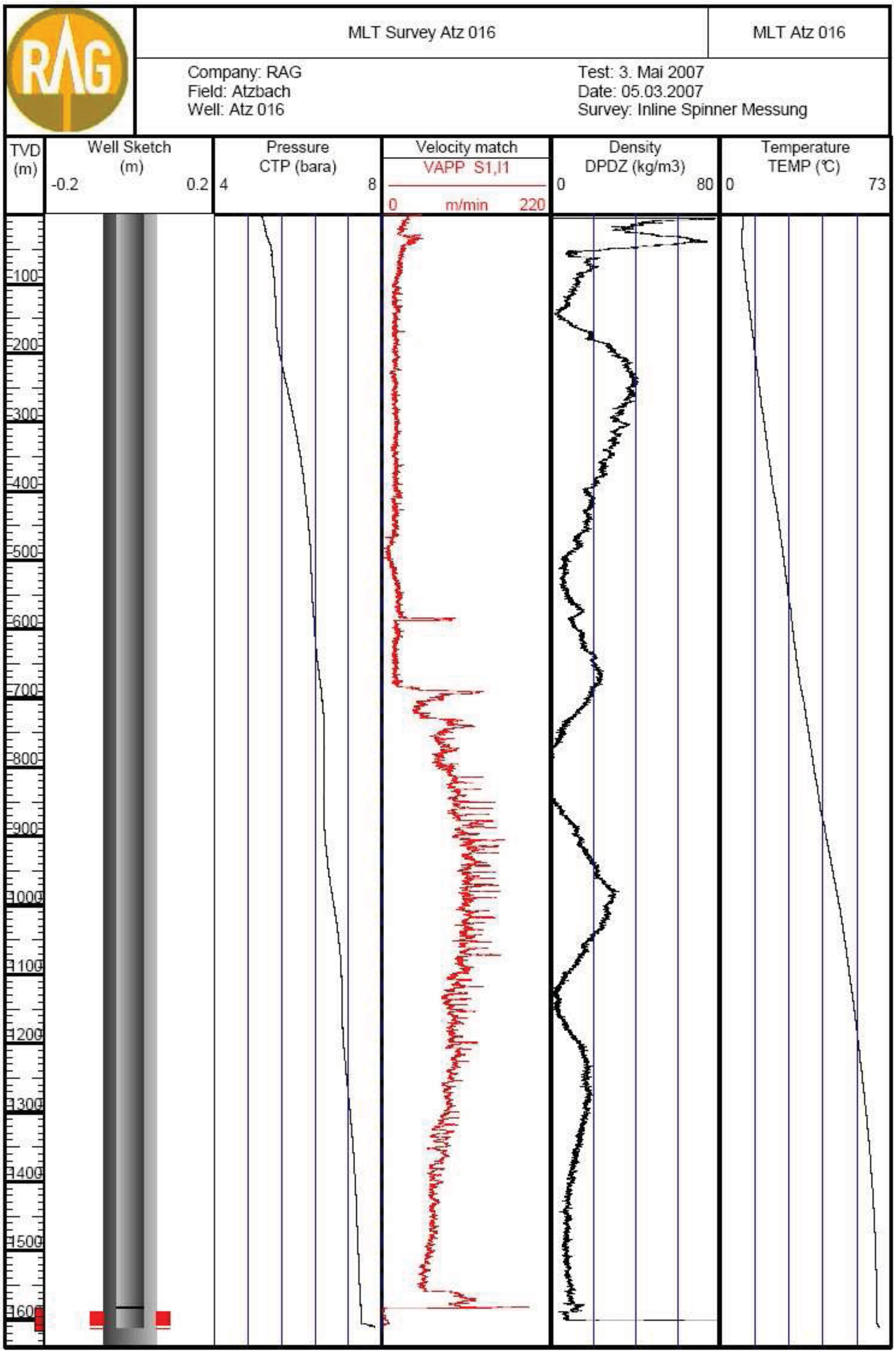


Figure A 12-14 MLT Survey of Well Atz 016

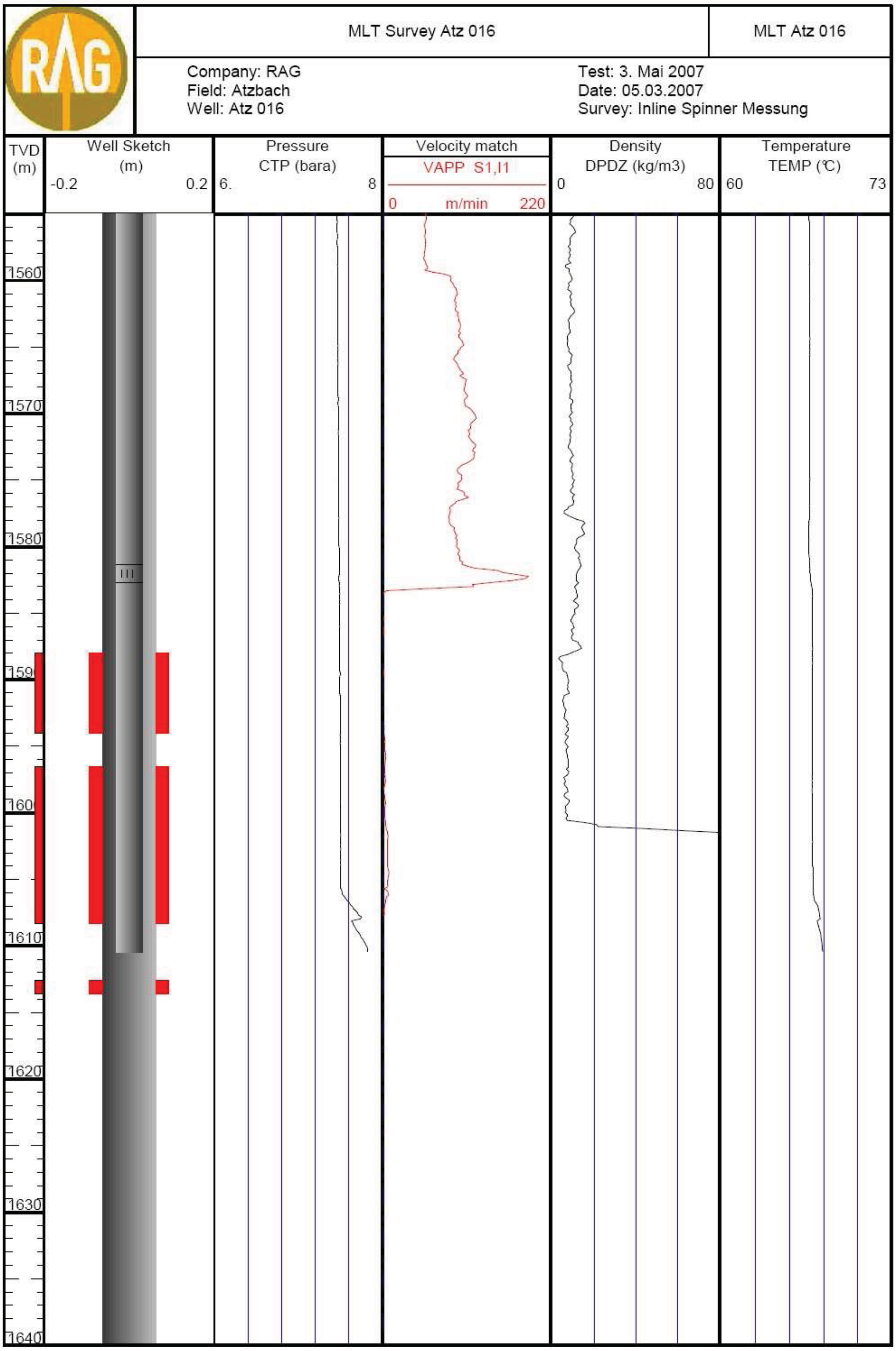


Figure A 12-15 MLT Survey of Well Atz 016 from 1555 to 1640 m

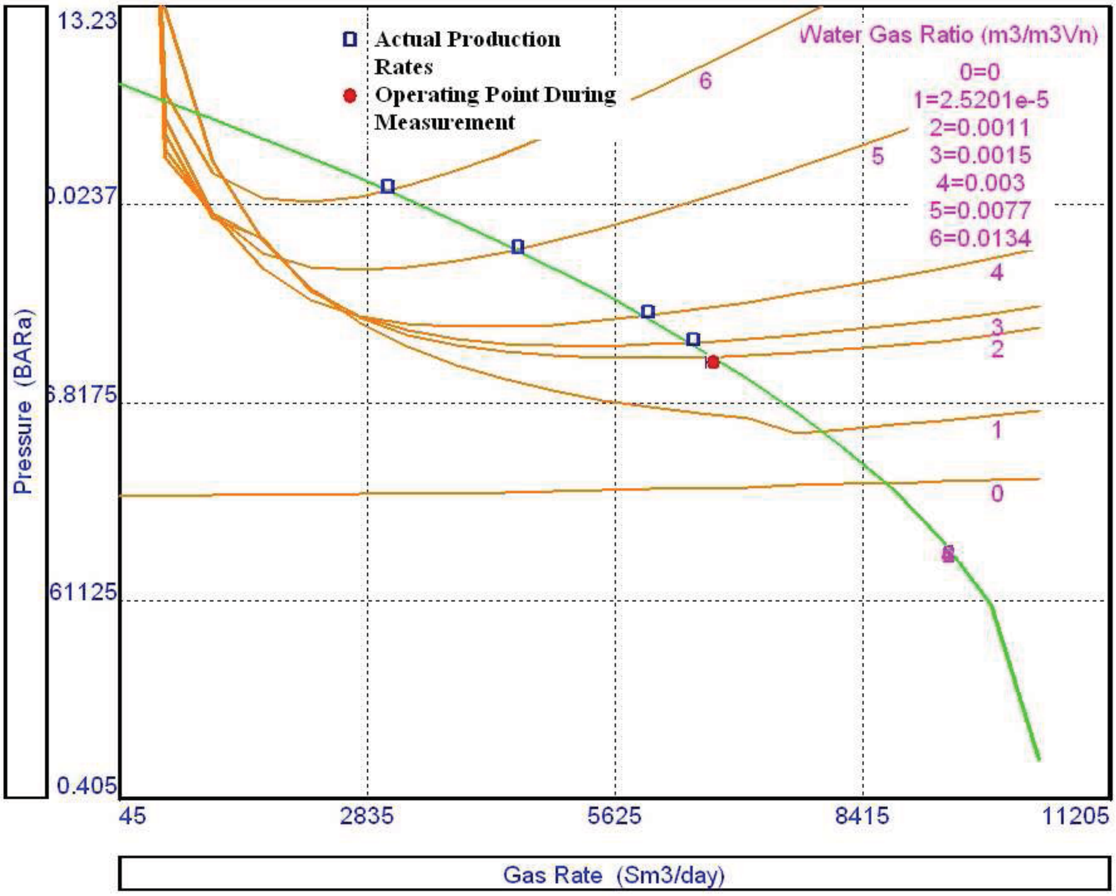


Figure A 12-16 Inflow and Outflow Performance of Well Atz 016

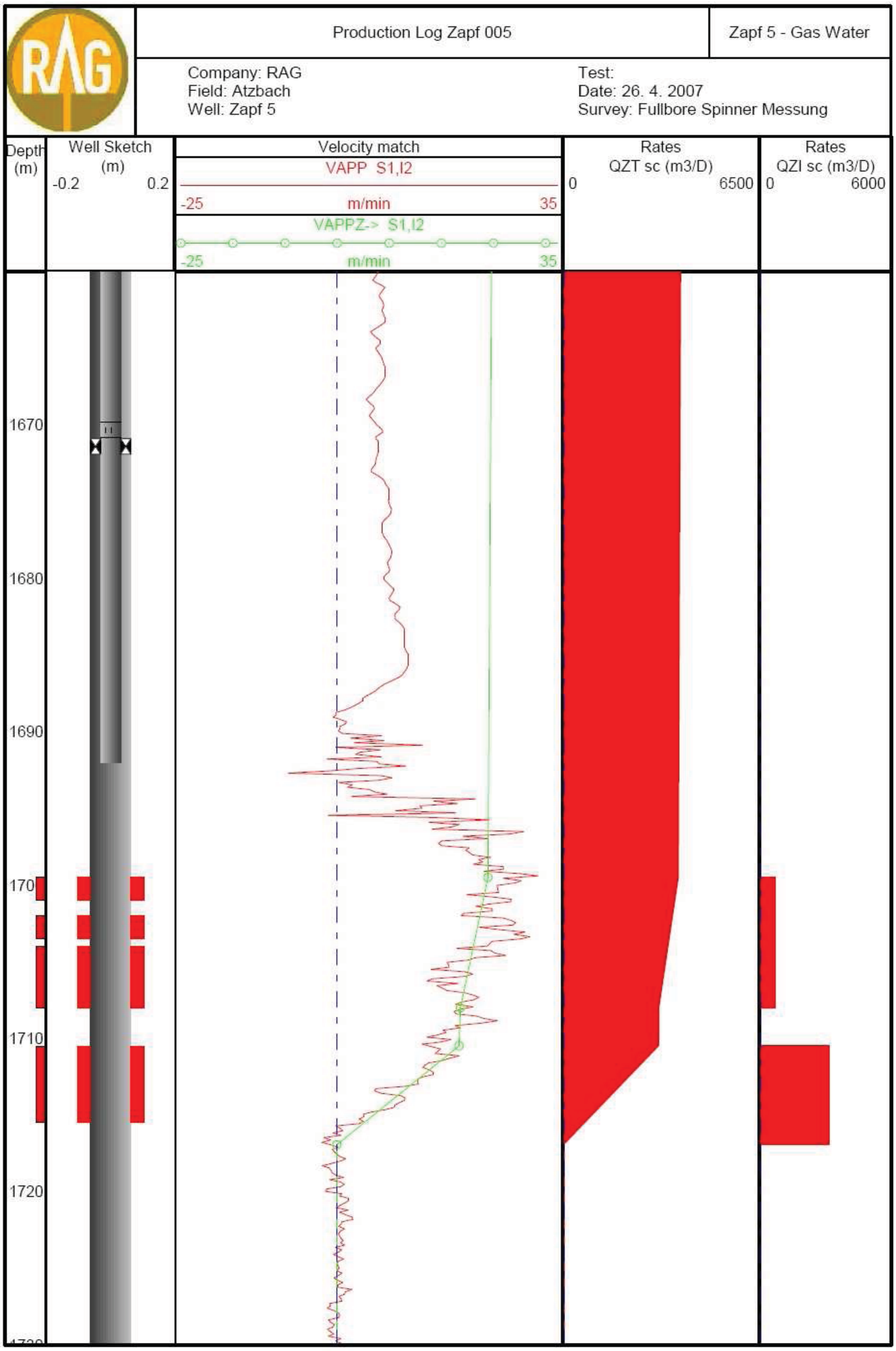


Figure A 12-17 Well Zapf 005 Production Log

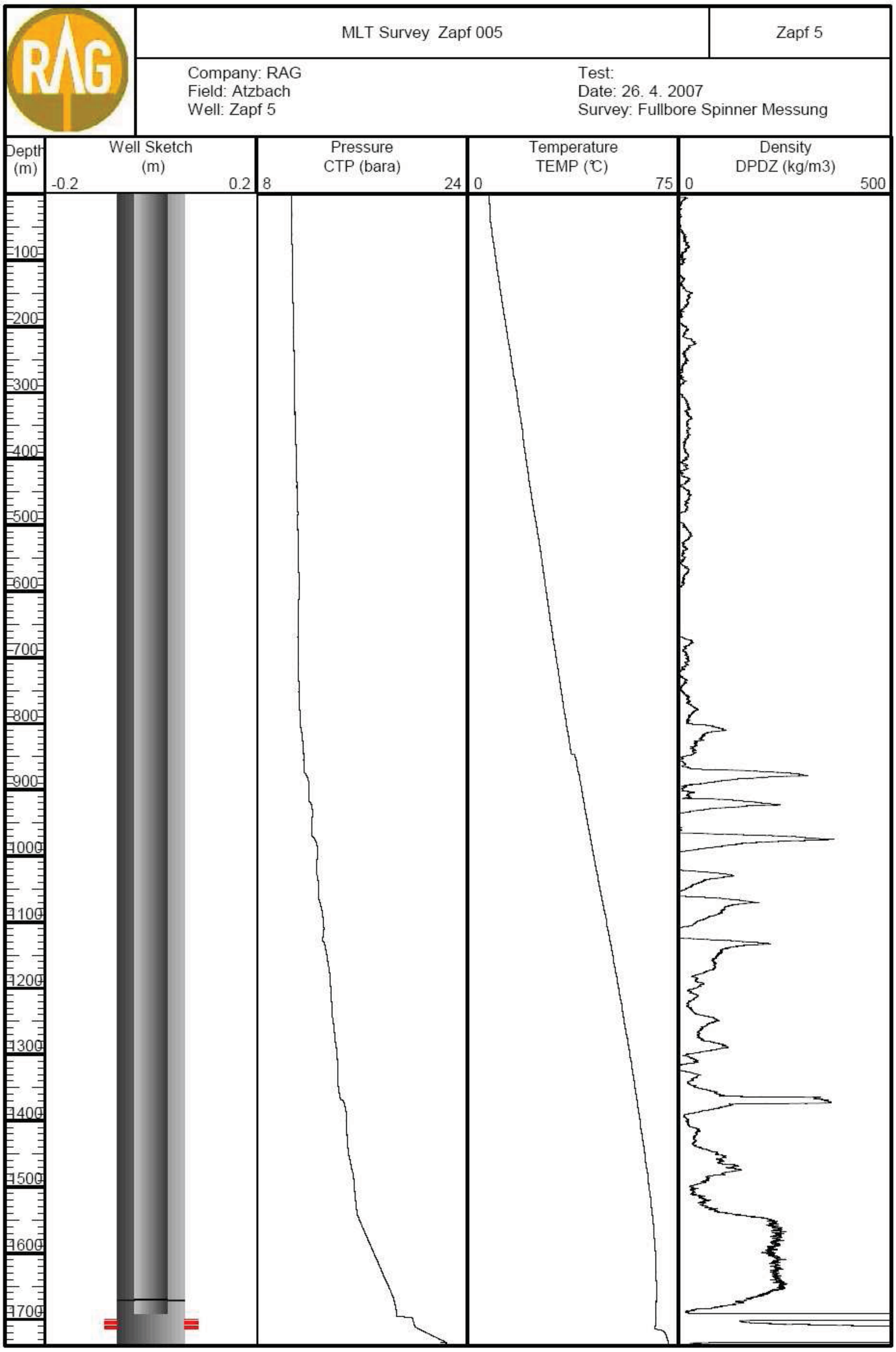


Figure A 12-18 Zapf 005 Pressure and Temperature Survey

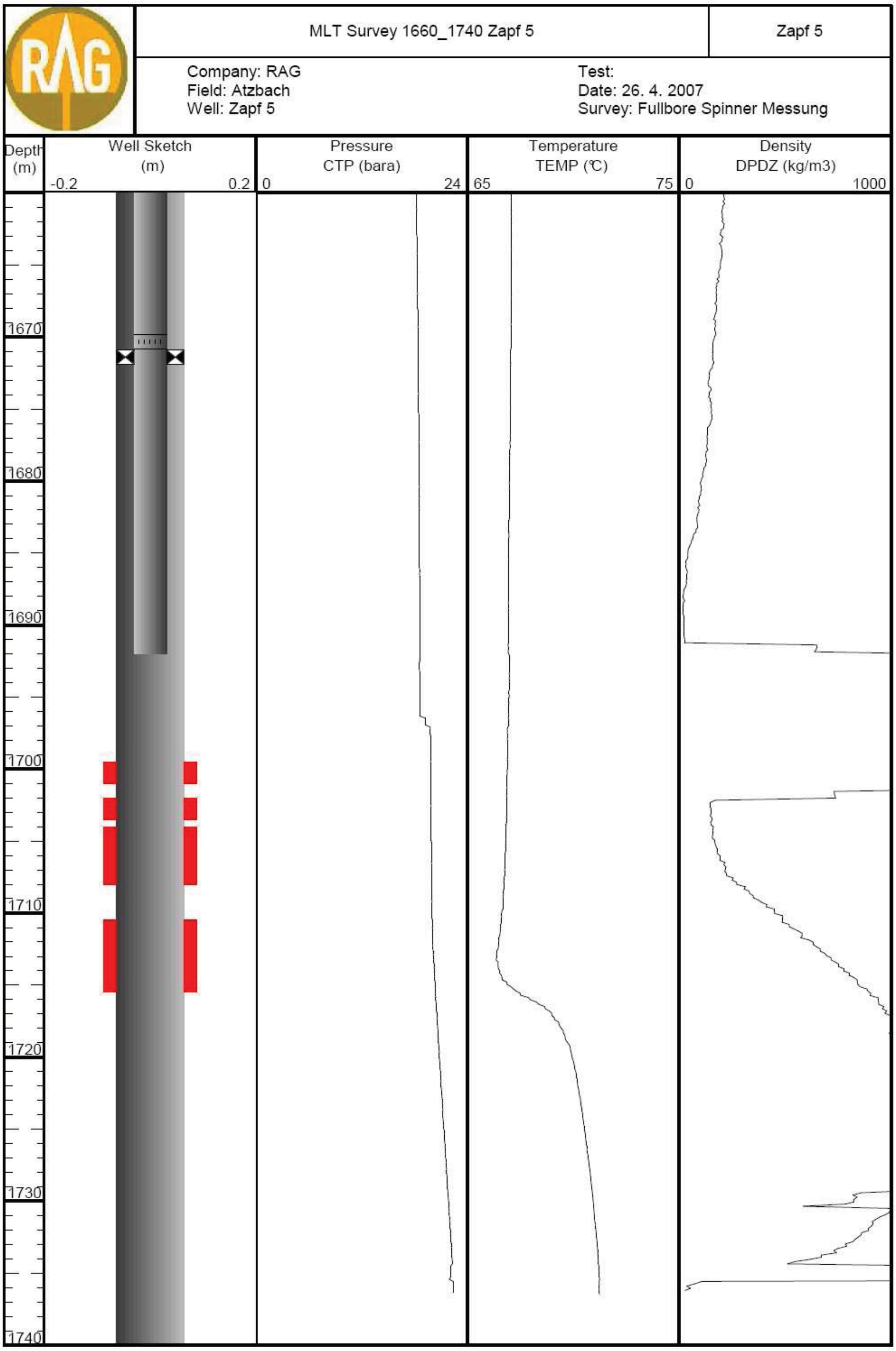


Figure A 12-19 Well Zapf 005; Pressure and Temperature between 1660 m and 1740 m.

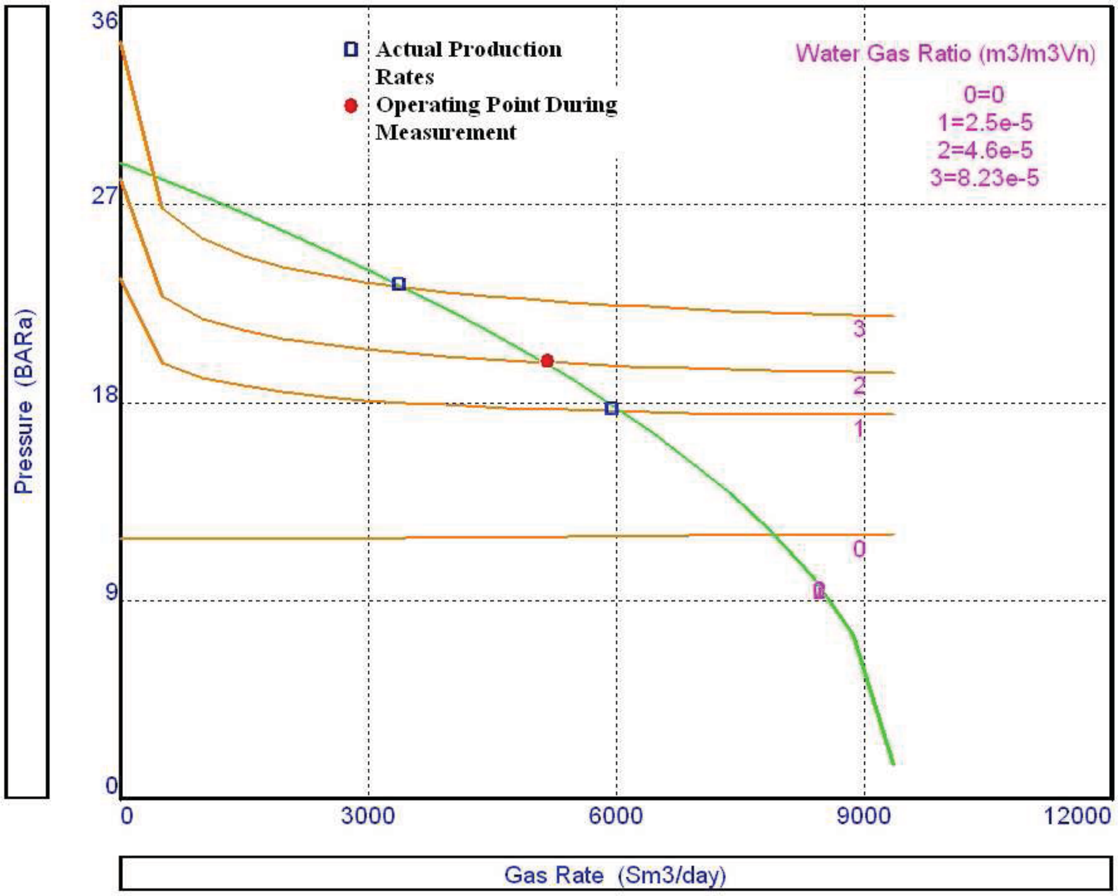


Figure A 12-20 Inflow and Outflow Performance of Well Zapf 005

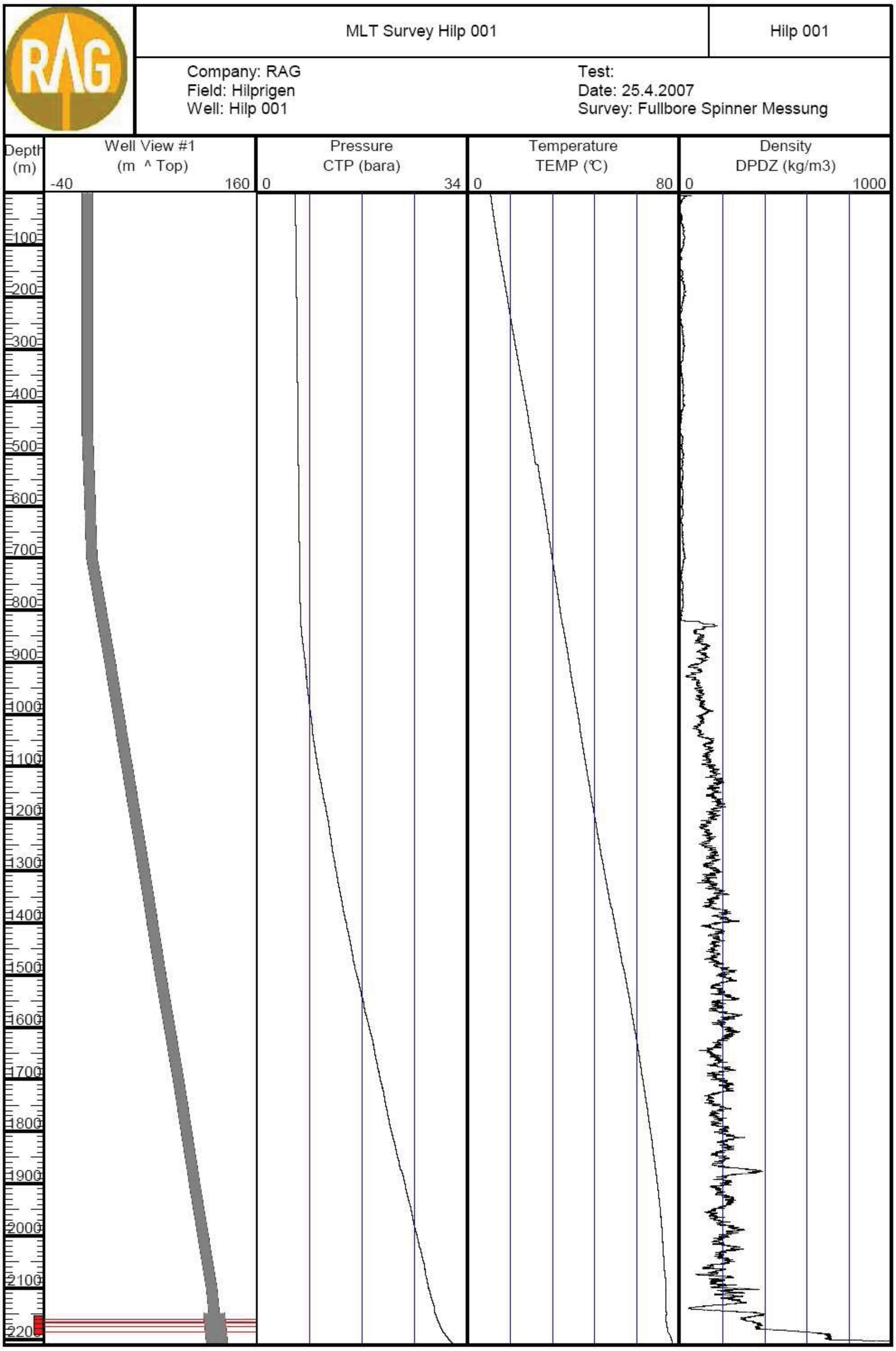


Figure A 12-21 Pressure and Temperature Survey of Well Hilp 001

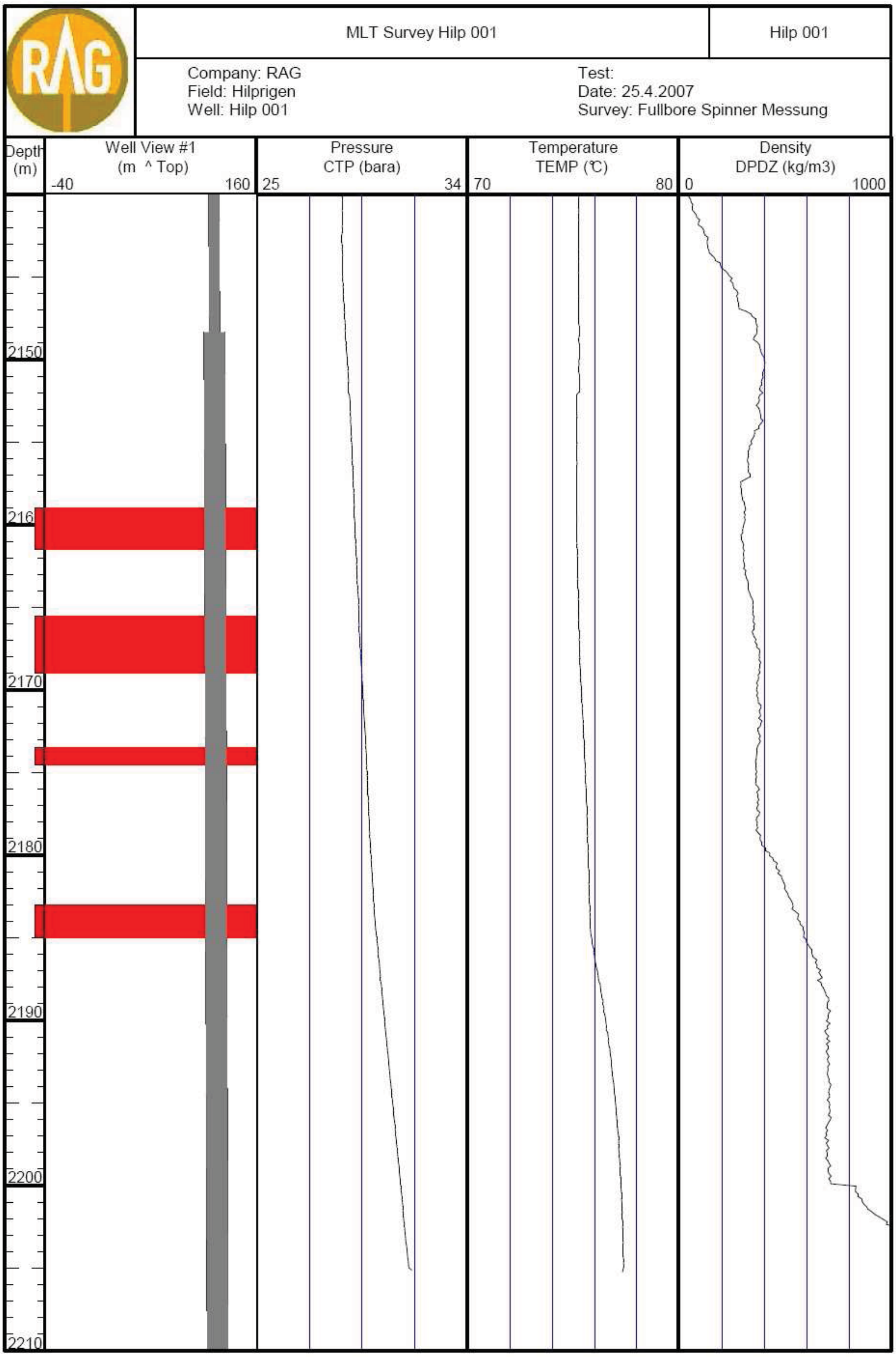


Figure A 12-22 Pressure and Temperature Survey of Well Hilp 001 between 2140 and 2210 m

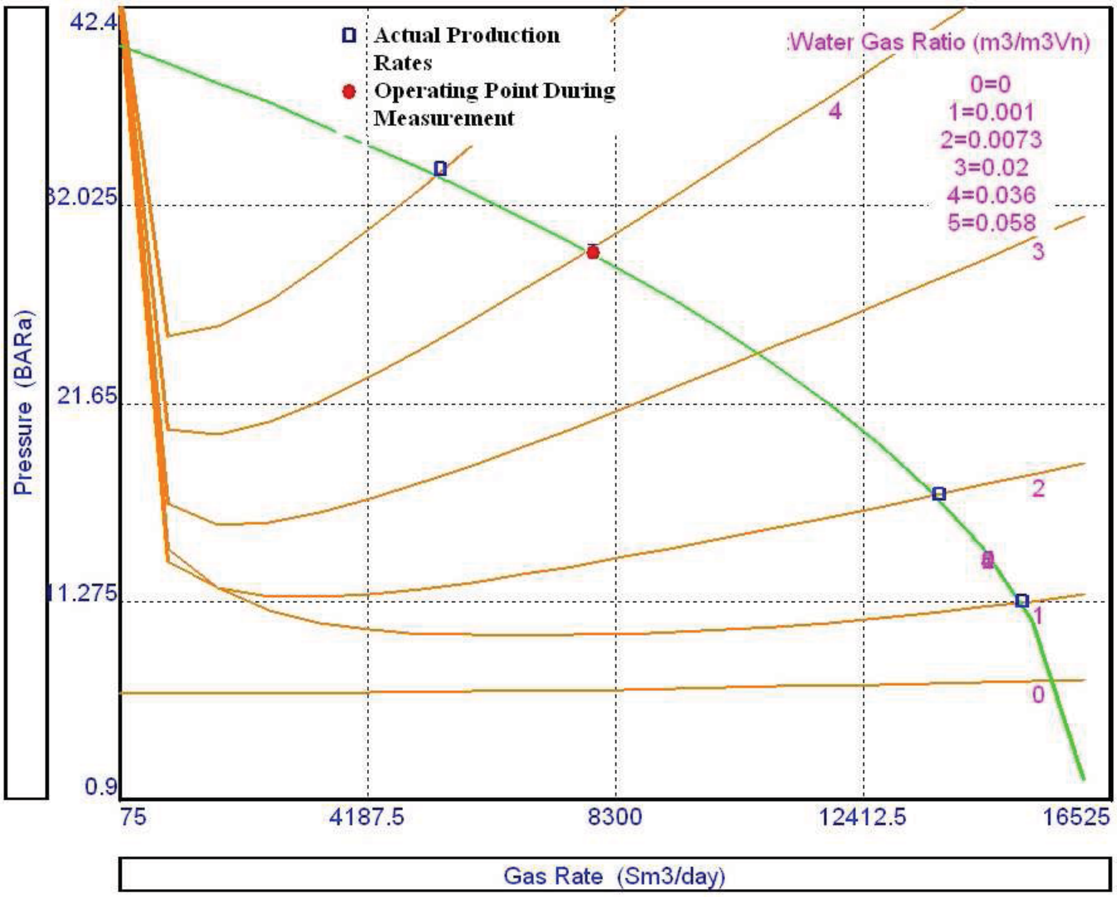


Figure A 12-23 Inflow and Outflow Performance of Well Hilp 001

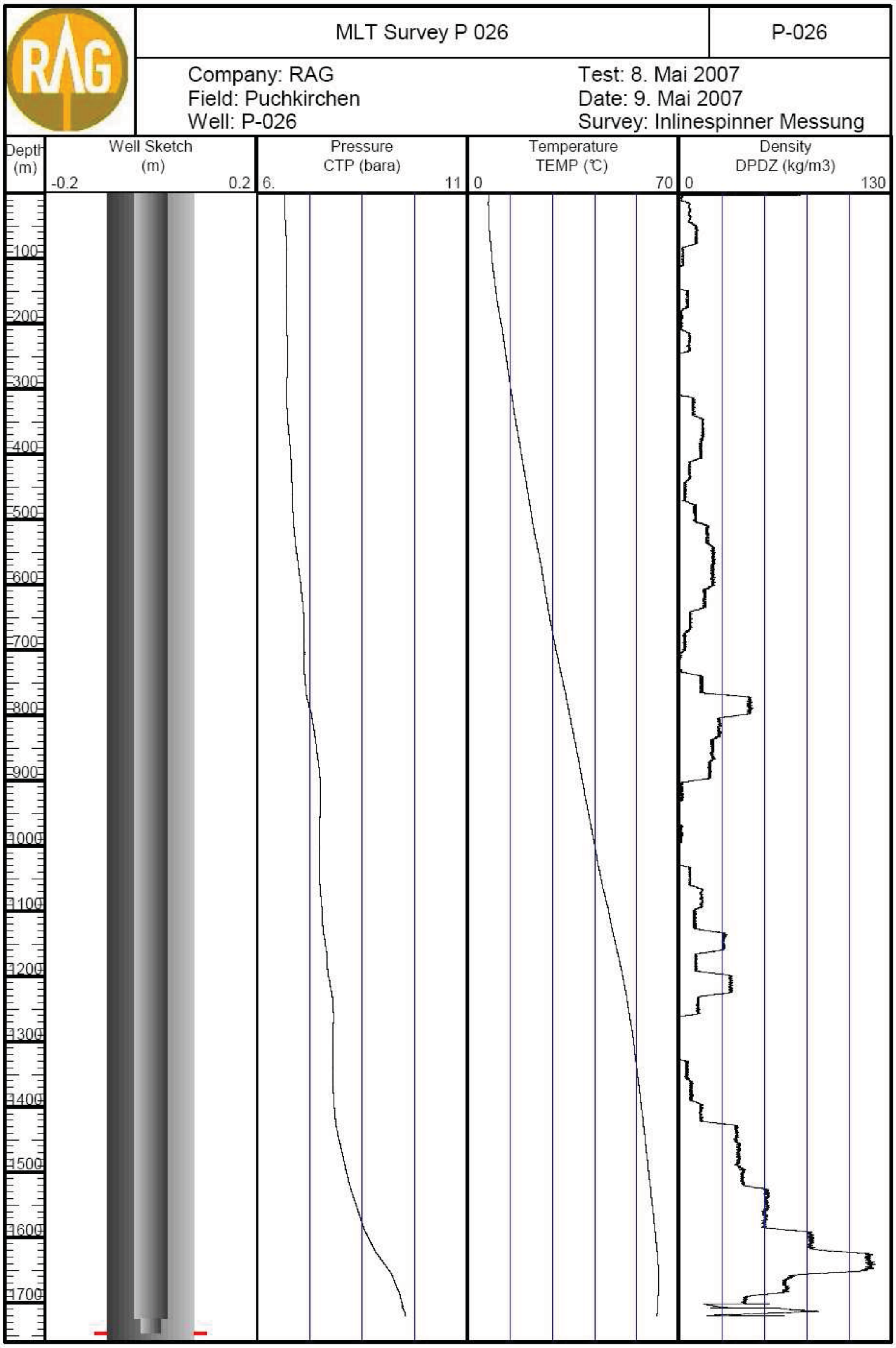


Figure A 12-24 Pressure and Temperature Survey of Well P 026

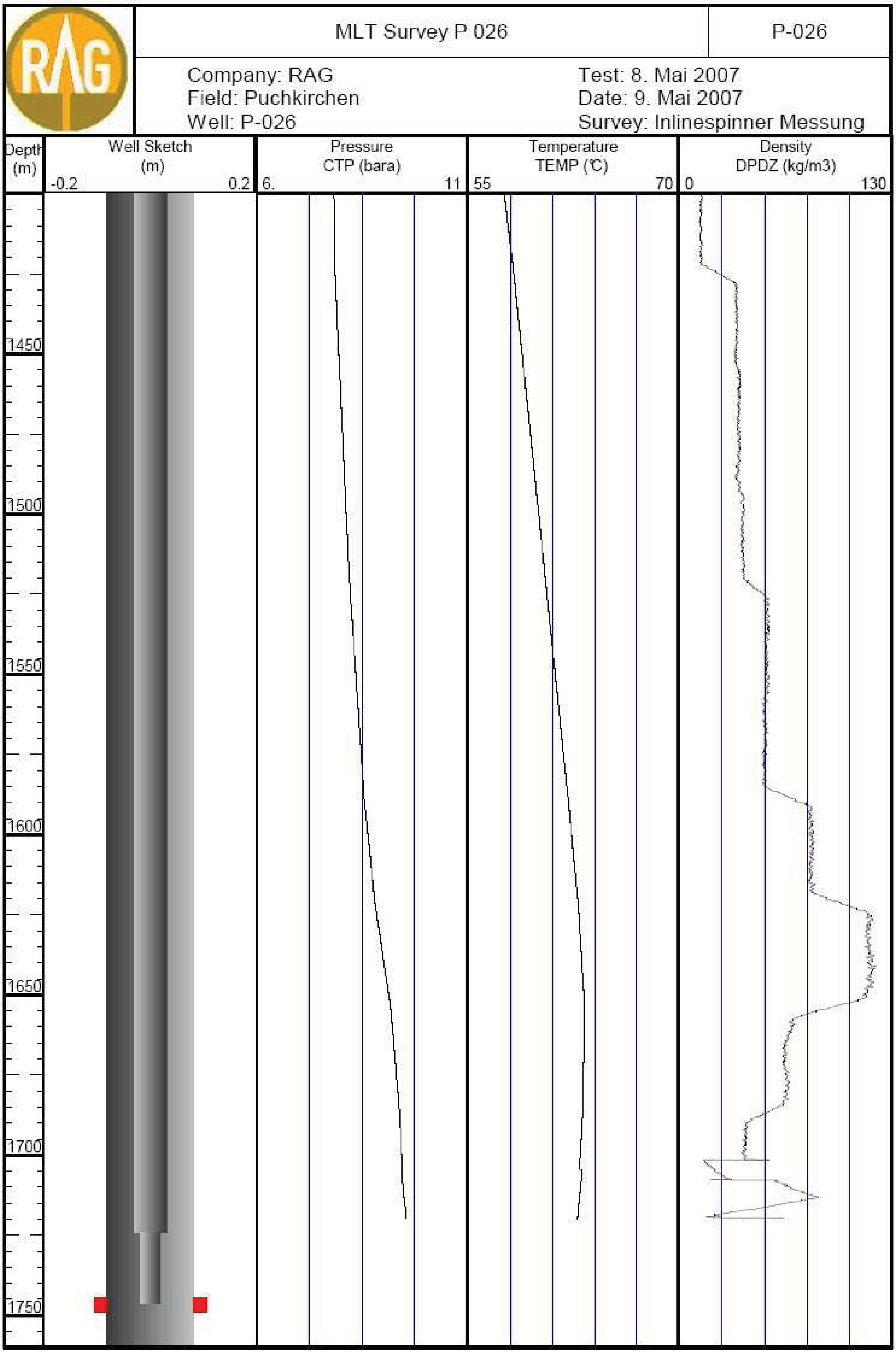


Figure A 12-25 Pressure and Temperature Survey from 1400 to 1750 m of well P 026

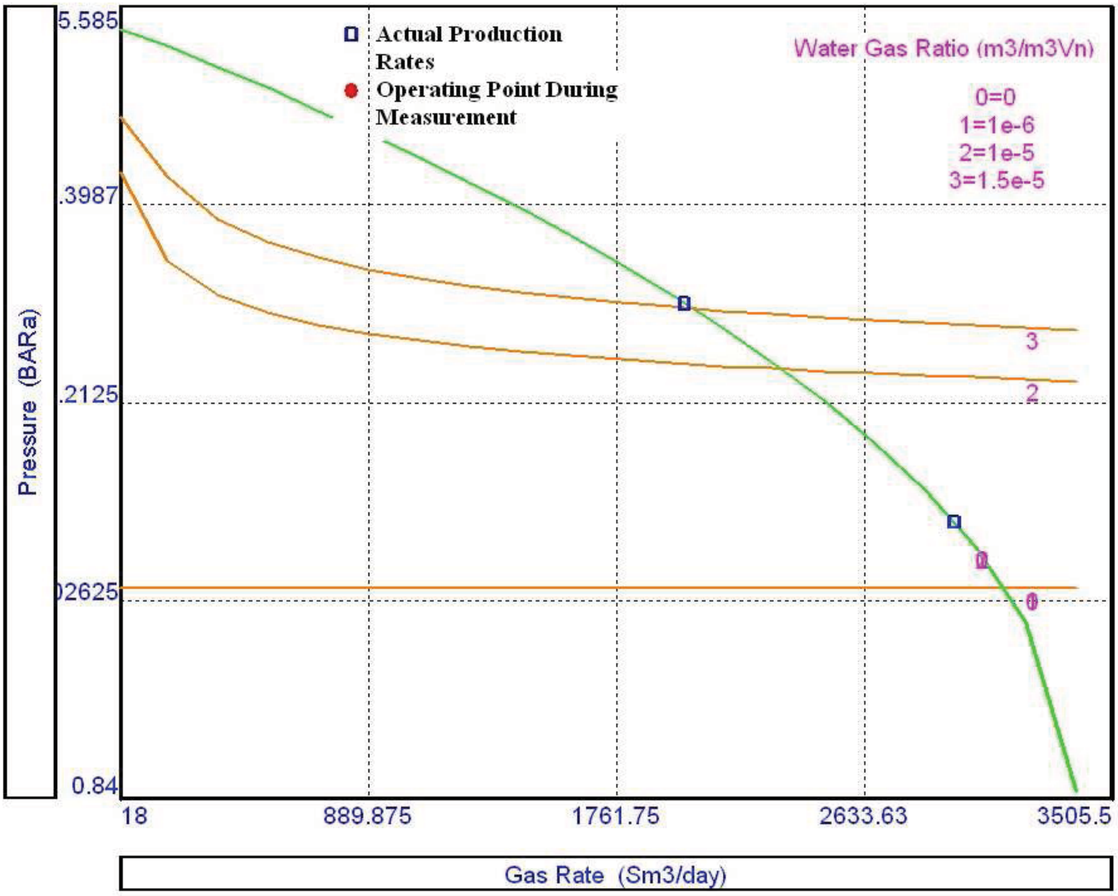


Figure A 12-26 Inflow and Outflow Performance of P 026