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Completion Options to Overcome Liquid Loading in the Tail End Production Phase of Gas Wells

Created for

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Abstract

Completion Options to Overcome Liquid Loading in the Tail End Production Phase of Gas Wells

This thesis is dealing with the application of so called "Velocity Strings" in gas wells. A velocity string is a production string with a smaller cross-section, which is implemented into an existing production tubing or casing to increase the velocity of the gas stream and therefore guarantee a continuous water disposal of the wellbore.

A lot of gas and oil wells experience in the course of time a decrease in their production ability or in the end completely abandon their production. Factors that cause this problem are on the one hand the falling reservoir pressure and along with this the diminishing of the production velocity. On the other hand there is to recognize an increase of water accumulation in the area of the perforation. This water is coming from the reservoir and is caused by the condensation in the production tubing through temperature and pressure changes. The growth of this water production can lead to the establishing of a water column in the wellbore, which inhibits the gas production from the reservoir into the production tubing. This phenomenon is known as "Liquid Loading" of a gas well.

This thesis firstly gives all the important background information of the "Liquid Loading" topic itself and summarizes the most common artificial lift methods. Furthermore, the different possibilities for "Hanging Off" a velocity string in the existing completion are listed. This work should also contain the current state of the art for the velocity string installation, therefore individual products and systems from German service companies are specified and described in detail. In the end these different systems are compared and the optimal solution for the Company is found.

Kurzfassung

Komplettierungsoptionen in der Tail End Produktionsphase zur Verbesserung der Wasseraustragsbedingungen von Erdgasbohrungen

Diese Arbeit beschäftigt sich mit dem Einsatz von sogenannten “Velocity Strings”. Ein Velocity Strang ist ein Förderstrang mit geringem Durchmesser, der in einen bestehenden Förderstrang eingebaut wird, um die Geschwindigkeit des Gasstroms im Bohrloch zu erhöhen und damit einen kontinuierlichen Wasseraustrag zu gewährleisten.

Viele Erdgas- und auch Ölbohrungen erfahren im Laufe ihres Lebens eine Abnahme der Produktionsfähigkeit oder stellen letzten Endes ihre Produktion sogar vollständig ein. Faktoren die diese Problematik verursachen sind einerseits der rückläufige Lagerstättendruck und die damit einhergehende Verringerung der Fördergeschwindigkeit. Andererseits kommt es auch zu vermehrter Wasseransammlung im Perforationsbereich durch Lagerstättenwasser und auch Wasser, das durch Kondensation im Förderstrang durch Druck- und Temperaturänderungen entsteht. Die Zunahme dieser Wasserproduktion kann zum Entstehen einer Wassersäule im Bohrloch führen, welche das Gas daran hindert von der Lagerstätte in den Förderstrang zu gelangen. Dieses Phänomen wird als “Liquid Loading” bezeichnet.

Der erste Teil dieser Arbeit befasst sich mit dem Themengebiet von „Liquid Loading“. Zusätzlich werden die gebräuchlichsten „Artificial Lift Methoden“ zusammengefasst. Danach werden die verschiedenen Möglichkeiten, einen Velocity Strang in der vorhanden Bohrlochkomplettierung abzuhängen, besprochen. Diese Arbeit sollte den aktuellen Stand der Technik enthalten, daher werden individuelle Produkte und Systeme aus deutschen Service Unternehmen spezifiziert und im Detail beschrieben. Am Ende werden diese unterschiedlichen Systeme mit einander verglichen um die optimale Lösung für die Firma herauszukristallisieren.

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1 Introduction

1.1 Problem Definition

This thesis is written for the Production District of the RWE Dea Company in Lower Saxony. In their area of responsibility they have gas wells, which suffer from several difficulties that should be observed in this work. Whereby, the main attention is drawn to the problem of liquid loaded gas wells, which are resided in their tail end production phase. Out of this problematic, different options should be analyzed and evaluated. For this purpose the RWE Dea selected two gas wells for which the existing completions should be checked and the respective alternative is described.

1.2 Aims & Objective

The aim of this thesis is to summarize the current technology in terms of velocity string installations from the different German Service Companies. An important question for the planning phase of a velocity string project is the technical realization to implement the velocity string into the existing completion. Thereby there is always the difficulty that the sub surface safety valve, which is installed in a depth of 60 to 80 [m] in the production tubing, has to be fully functional at every point of time. This is a kind of safety installation to guarantee the complete closure of the wellbore in terms of an incident on the surface. Moreover, the possibility for the installation of an auxiliary foaming device into the annular space between the production tubing and velocity string should exist. This is an additional action to guarantee the water discharge of the wellbore and increase the velocity of the gas stream.

2 Background of Liquid Loading

2.1 What is Liquid Loading

"Liquid Loading (LL) of a gas well is the inability of the produced gas to remove the produced liquids from the wellbore. Under this condition, produced liquids will accumulate in the wellbore leading to reduced production and shortening of the time until when the well will no longer produce". [1 S. 1]

If the gas velocity in a well is high enough, the gas is able to flow to surface carrying the produced liquids with it. As a high gas velocity leads to a mist flow pattern (see chapter 2.2) the liquids are finally dispersed in the gas. This leads to a low percentage by volume of liquids distributed in the tubing or production string and in the end results in a low drop in pressure which is created by the gravity components of the flowing fluids. [1 S. 4]

"In the United States of America a stripper gas well is defined by the Interstate Oil and Gas Commission as one that produces 60,000 [cf] (cubic feet), relates to 1,700 [m^3] (cubic meter) or less of gas per day at its maximum flow rate." [2]

This means for low producing gas wells which are already on the edge of their profitability that the optimization and reduction of LL can make the important difference between further production and shutting the well in. The problem of LL in gas wells is not restricted to the low rate producers, also the high rate producers can be affected by this problem. [1 S. 4]

The velocity of the gas decreases with time in the production string and consequently the velocity of the liquids that are carried by the gas drops even faster. As a result, liquid slugs or liquid flow patterns can be generated in or on the wall of the production string. Both of these scenarios can lead to the accumulation of water on the bottom of the well and in the end the percentage of liquids in the string will increase during the well is flowing. As more and more liquid is accumulating during the well is flowing this can result in the reduction of production or even stop the production. [1 S. 4]

At any rate a gas well will always produce liquids directly into the bottom of the well. These liquids are hydrocarbons (condensates) and water and they may condense from the gas stream, due to pressure and temperature changes, during their way up to the surface. In some other cases the liquids come into the bottom of the well because of coning water from an underlying zone or other sources. This subject will be described in greater detail in the paragraph 2.4. [1 S. 4]

2.2 Multiphase Flow in a Gas Well

In the literature there are many types of flow regimes described that characterize the production of a well. If this is limited to two phases, namely liquid and gas, the discussion is simplified very much. If two or more phases stream in a pipe at the same time, the behavior of the flow is much more complicated than for single-phase flow. Due to the differences in the density, the phases show a tendency to separate from each other. When gas and liquid are present in the pipe, they usually do not travel at the same velocity. For an upward flow, the gas with less density and viscosity but more compressibility, flows at a higher velocity than the liquid phase. This phenomenon is called “slippage”. Therefore the gas is able to escape from the wellbore although the formation has not enough energy to get out the liquid from the wellbore. For a downward flow the liquid normally flows faster than the gas. To understand the impact of liquids in a gas well, it is first to understand how the liquid and gas phases interact under flowing conditions. There are four different flow regimes for multiphase flow in a vertical conduit. They are shown in Figure 1 beneath. [1 S. 2] [3 S. 19] [4]

“A flow regime is determined by the velocity of the gas and liquid phases and the relative amounts of gas and liquid at any given point in the flowstream. One or more of these flow regimes will be present at any given time in a well`s history”. [1 S. 2]

During a multiphase flow through a pipe, the existing flow pattern is based on the relative magnitudes of the forces that are acting on the fluids. These forces are: buoyancy, turbulence, inertia and also surface-tension forces. But these forces significantly alternate, with flow rates, pipe diameter, inclination angle and fluid properties of the phases. As a fluid is exposed to large pressure and temperature changes in a pipe, different flow patterns can exist in a given well. Of special importance is the significant change in pressure gradient with different flow patterns. [3 S. 19]

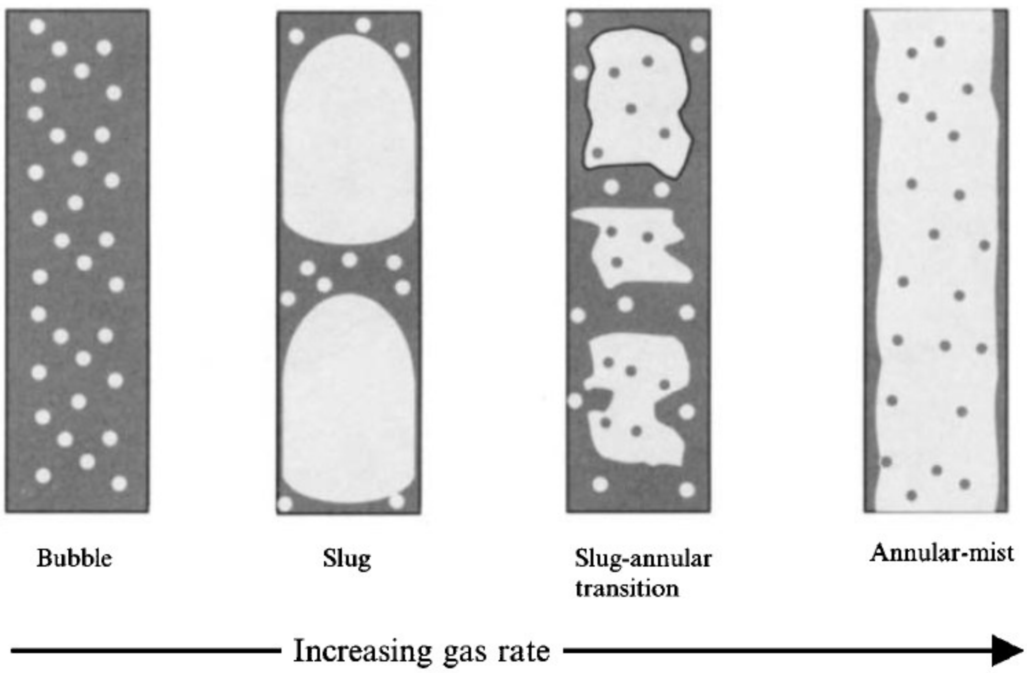

Figure 1: Flow Regimes in Vertical Multiphase Flow [1]

Annular-Mist Flow: If a well has enough "driving force", meaning enough reservoir pressure, it is able to produce the liquids to the surface. Here the gas phase is the continuous phase and most of the liquid is captured in the gas as a mist. The pressure gradient is controlled from the gas flow, although some of the liquid covers the wall of the pipe. [1 S. 3] [5]

Slug-Annular Transition: Decreasing reservoir pressure means a decreasing gas rate. Hereby the gas is still the continuous phase and some of the liquid may be enclosed as small droplets in the gas. The pressure gradient is dominated by the gas but the liquid effects are still present. [1 S. 3] [5]

Slug Flow: With a further decline of the gas rate the slug flow regime is reached. The liquid phase is the continuous phase but gas bubbles expand as they are on their way up and in the end coalesce into larger bubbles and finally to slugs. The liquid film surrounding the slug may fall downward after some times caused by the slip-velocity of the gas. The pressure gradient here is affected by both the gas and the liquid. The slug flow regime is displayed as an erratic production on a production graph. [1 S. 3] [5]

Bubble Flow: In nearly depleted reservoirs the gas rate has reached a point where a well is not able to lift liquids. Hereby the tubing is totally filled with liquid and the free gas is attendant as small bubbles, which are flowing up in the liquid. Here the bubbles serve only for reducing the density and the liquid is able to contact the wall surface. [1 S. 2] [5]

During the life of a well one or all of these flow regimes may occur. Figure 2 illustrates the development of a typical gas well from its beginning of production to its end of life. At the beginning the well has a high gas rate and therefore the flow regime is in a mist flow in the tubing; certainly below the tubing end to the mid-perforations the flow regime can also be in bubble, transition or slug flow. After some years when the production declines the flow regime also changes from the perforations to the surface due to the decreasing gas velocity. Beside of this, the liquid production will also increase as the gas production declines. Higher up in the well the flow will stay in a mist flow regime as far as the conditions change at the surface resulting in a transition flow regime. At this time of production the well changes to a fluctuating production, resulting in a slug flow regime due to the still declining gas rate. Maybe the slug flow at the surface changes to a stable production rate again as the gas rate drops further. This can happen when the gas flow is too low to carry the liquids to the surface and therefore only bubbles up through the liquid column. It is possible that the well is able to flow for a long time and that gas is produced through the liquids with any liquids rising to the surface although it is in a loaded condition. Nevertheless, corrective measurements have to be taken early enough to avoid the further decline of the well and finally prevent the well from death. [1 S. 3-4]

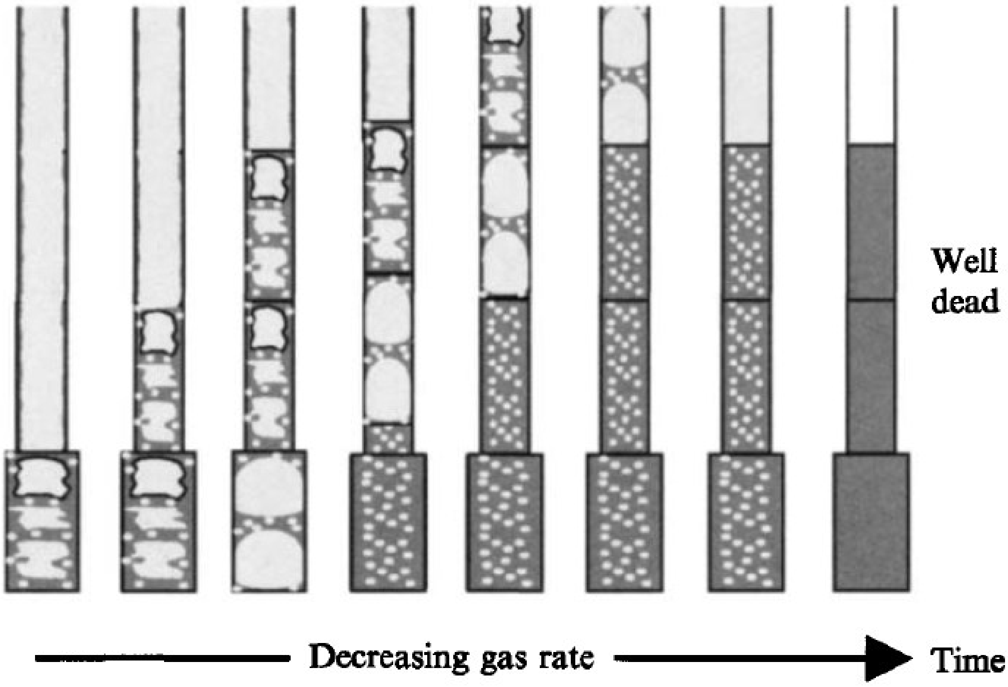

Figure 2: Life History of a Gas Well [1]

2.3 Problems caused by Liquid Loading

Liquid loading can lead to irregular, slugging flow and at least to a minimized production. If the liquids are not removed regularly the well may die or produce at a lower rate than possible. [1 S. 5]

There are two possible cases related to the gas rate. When the gas rate is high enough, the well will be able to produce the gas and most or all of the liquids to surface, while having a stable wellbore formation pressure and production rate. This stable operating condition is predicted previously by the IPR (Inflow Performance Relationship) curve (see Chapter 6.2). When the gas rate is too low, the tubing pressure gradient gets larger and larger due to the liquid accumulation and finally leads to an increased pressure on the formation. Due to this, the backpressure on the formation rises and at the same time the produced rate from the reservoir decreases and even can decline below the "gas critical rate", which is necessary to constantly get the liquid out. In the end the liquid is assembling down in the wellbore while the increasing bottom-hole pressure will diminish the production or even kill the well in the worst case. [1 S. 5]

2.4 Sources of Liquids in a Producing Gas Well

As mentioned above a gas well always produces not only gas but also liquids like condensates and water. There are only a few gas wells in the world that produce only dry gas. If the reservoir pressure declines beneath the dew point, both the condensate and the gas will be produced as a liquid; if the reservoir pressure is above the dew point, the condensate and the gas enter the wellbore in the vapor phase and the condensate will later condense in the tubing string during their way up. [1 S. 8]

There are several possible sources from which the water could come from: [1 S. 8-9]

2.4.1 Water Coning from an Aqueous Zone

An aqueous zone could be situated above or below the producing zone. If the gas rate is high enough the gas is able to drag the water into the production zone, even if the water zone is not perforated at all. For a horizontal well the gradient between the gas region and the underlying water region is greatly reduced, anyway this problem can occur at very high rates and is called “cresting”.

2.4.2 Support from an Aquifer

The reservoir could have the support from an aquifer and therefore the pressurized invading water eventually find its way to the wellbore.

2.4.3 Water Production from another Zone

Water can come from another producing zone (open hole well or a well with several sections perforated), although it is blocked some distance away from the gas zone. The advantage of having a water zone directly below the gas zone is the ability to inject water into the underlying zone, with pumps or gravity, and to push the gas to the surface.

2.4.4 Free Formation Water

It is possible that water and gas gets together into the perforations; the source could be everything. This could be induced by various thin layers of liquids and gas or for some other reasons.

2.4.5 Condensation of Water and/ or Hydrocarbons

Water and/ or hydrocarbons may penetrate the wellbore in the vapor phase with the gas and condense out as a liquid in the tubing string. Here we have to distinguish between the condensation of water and the condensation of hydrocarbons.

- Condensation of water: When saturated or partially saturated gas enters the wellbore, the condensation can occur higher up in the well. This can lead to a high gradient in the flow-string where the condensation takes place. In the end, depending on the velocities, liquids can fall back and accumulate on the bottom of the wellbore. The phenomenon of water condensation in the atmosphere is very similar to the condensation of hydrocarbon gas. The produced gas contains a certain amount of water vapor for a given reservoir temperature and pressure. Figure 3 below demonstrates the water solubility in natural gas in [STB/ MMscf] (Stock Tank Barrel/ Million Standard Cubic Feet). It clearly shows that as the reservoir pressure drops below 500 [psi] (pound-force per square inch) a rapid step up in the water content is noticed. As long as the temperature and pressure conditions do not decrease below the dew point, the water will stay in the vapor phase. But when temperature and water conditions decrease below the dew point, the water vapor will quickly condense to the liquid phase. If this condensation happens in the wellbore and if the gas velocity stays below the critical rate, that is required to carry the liquid water, then liquid loading takes place.

- Condensation of hydrocarbons: It is possible that hydrocarbons together with the gas enter the production interval in the vapor phase. There will be no liquids in the reservoir, when the reservoir temperature is above the cricondentherm, but it is possible that liquids drop out just as water condensation can occur.

Beside all of this, it is to note that if the gas velocity is able to lift the condensed water, corrosion problems may appear at the point in the wellbore where condensation first appears. It is easy to recognize condensed water because it should have a lower or no salt content compared to the reservoir water. Actually pure water is supposed in the vapor phase before condensation. [1 S. 10]

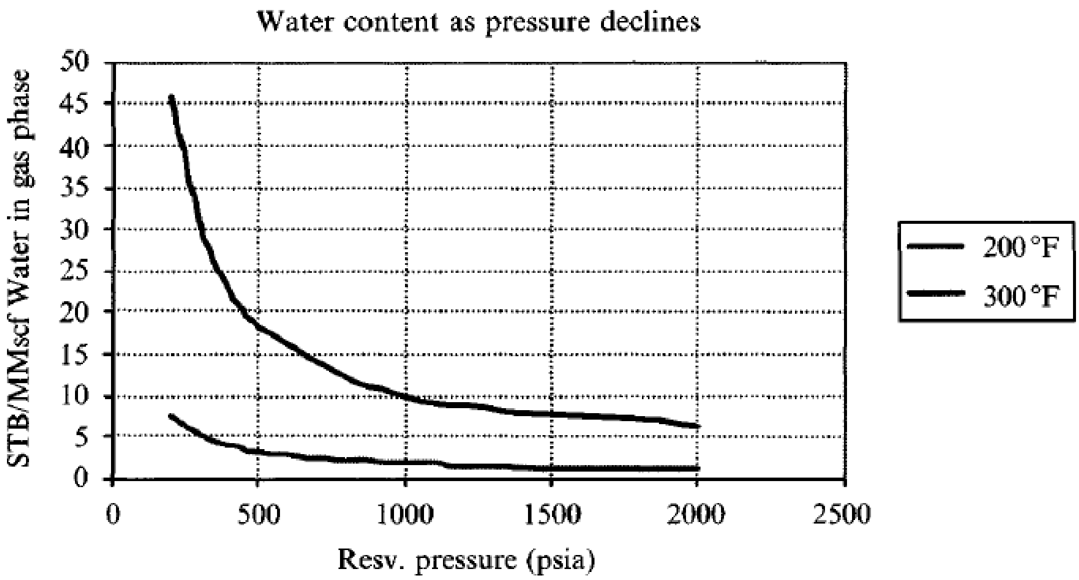

Figure 3: Water Solubility in Natural Gas [1]

2.5 Symptoms of Liquid Loading in a Gas Well

If the problem of liquid loading is recognized early enough, the losses in the gas production can be minimized, by applying one of the method or a combination of it to artificially lift the well. If the problem of liquid loading stays unnoticed, the liquids can penetrate into the wellbore and the adjoining reservoir, causing there severe or not repairable damage. [1 S. 13]

The symptoms for recognizing liquid loading are: [1 S. 13]

1. *"Presence of Orifice Pressure Spikes*
2. *Erratic production and increase in decline rate*
3. *Tubing pressure decreases as casing pressure increases*
4. *Pressure survey shows a sharp, distinct change in pressure gradient*
5. *Liquid production ceases"*

2.5.1 Orifice Pressure Spikes

A well-known and very often used method, for detecting liquid loading problems in the field, is the usage of an automated data collection system or a two pen pressure recorder. These instruments record the production data or to put it another way they record the measurement of the gas flow rate through an orifice over time. If the well produces liquids without any liquid loading problems, the liquids are only present as small droplets in the gas stream (mist flow) and therefore they have little effect on the orifice pressure drop. A pressure spike forms when a liquid slug with a relatively high density flows through the orifice. One pressure spike on a plot of orifice pressure drops displays the accumulation of liquids in the wellbore and/ or in the flow-stream. It also shows that the liquids are unsteady produced to the surface as slugs. Figure 4 gives an example of such a plot. It was made by a two pen recorder. On the left side of the picture there is shown a well that produces normally in mist flow, whereas on the right side a well which is in the early stages of liquid loading problems (slug flow) is pictured. [1 S. 14]

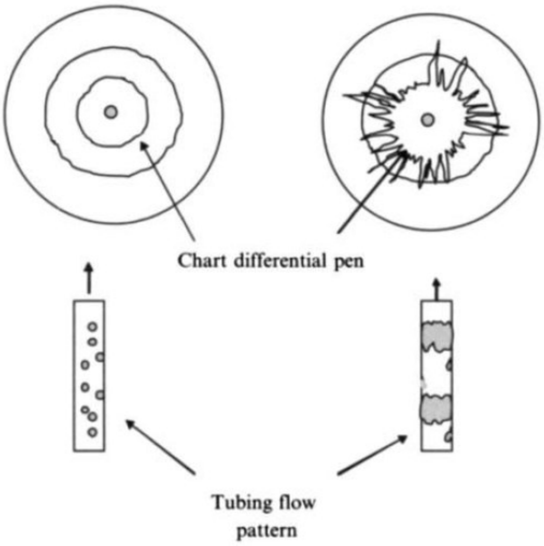

Figure 4: Impact of Flow on Orifice Pressure Drop (Mist Flow left vs. Slug Flow right) [1]

If liquid is assembling on the bottom of the wellbore, the pressure spike gets more frequent on the recorder. Eventually the liquid head restrains the reservoir pressure and therefore the tubing pressure on the surface also starts to decline. Additionally there is to notice a decrease in the gas flow. These three characteristics and the charts of the two pen recorder are reliable indicators for the beginning of liquid loading. To give further examples for severe liquid loading problems and the first stages of liquid loading, two more pictures Figure 5 & 6 are mapped below. [1 S. 14]

These symptoms are only suitable for the inspection in the field. To prevent the loss of production they should be monitored on regular basis.

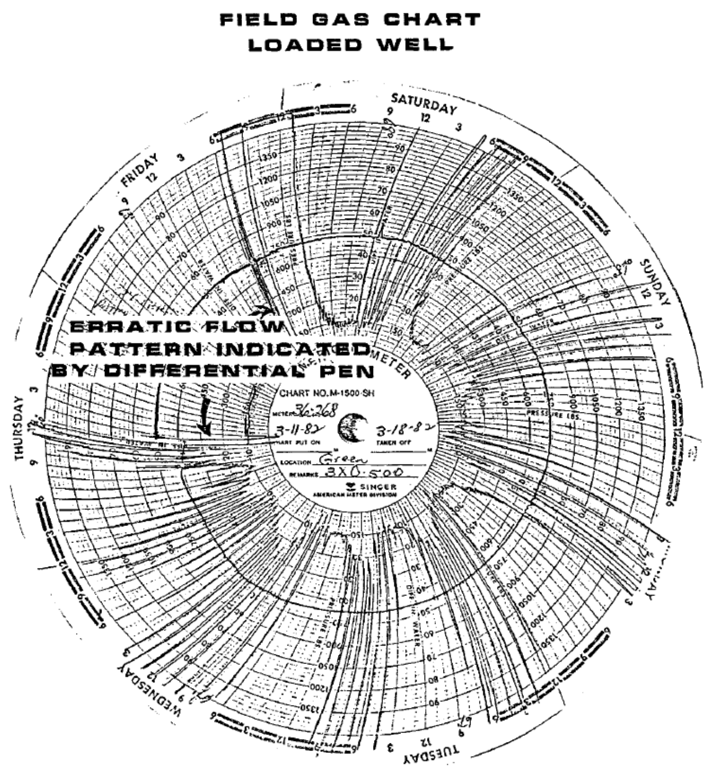

Figure 5: Gas Chart Having Severe Liquid Loading (Indicated Slugs of Liquid) [1]

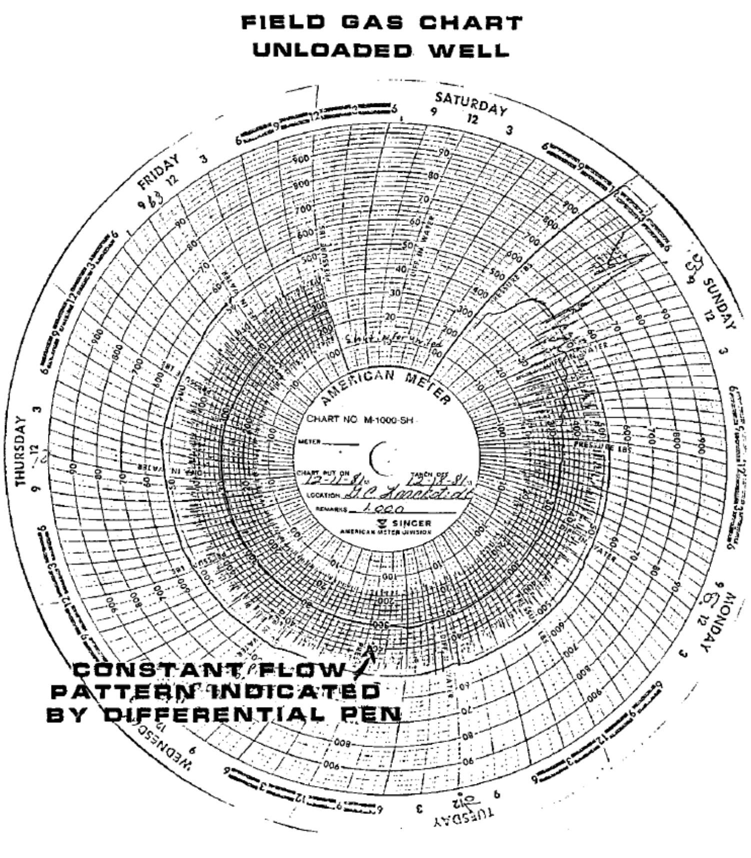

Figure 6: Gas Chart Having Less Indication of Liquid Loading [1]

2.5.2 Decline Rate

The shape of the decline curve is also a very good indicator for liquid loading problems of a well. The curve should be evaluated constantly, searching for changes in the general trend. If the decline curves are observed for a longer period, the wells that are suffering from liquid loading problems will show a deviation from the existing curve to a new one with a steeper slope. For a better understanding two decline curves in Figure 7 are plotted above. The exponential and smooth decline curve is typically for a gas producing well with the aim of reservoir depletion. Whereas the sharply fluctuating decline curve is characteristic for liquid loading and shows in this particular case that the reservoir will deplete earlier than reservoir considerations alone would indicate. [1 S. 14]

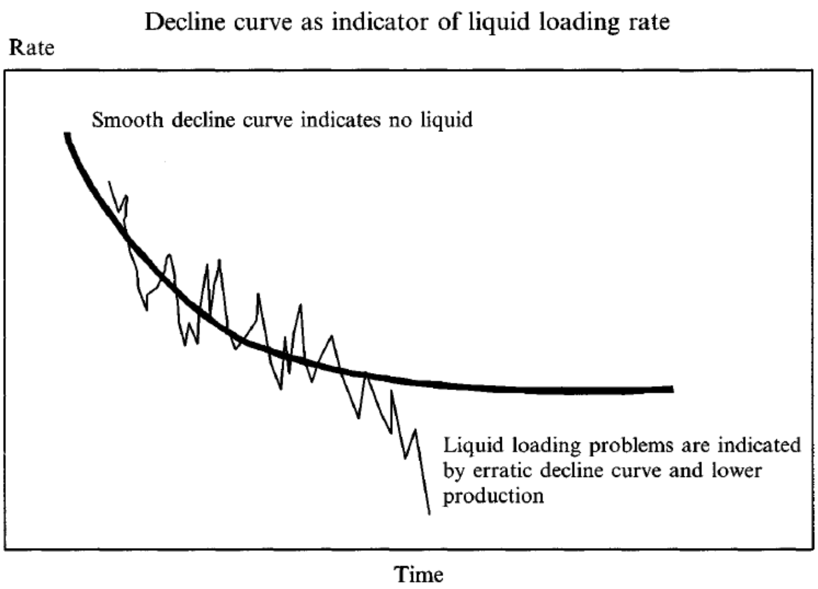

Figure 7: Decline Curve Analysis [1]

2.5.3 Decline in Tubing Pressure and Increase in Casing Pressure

As mentioned before, when liquids accumulate at the bottom of the wellbore there will be an added pressure head on the reservoir and simultaneously decreases the tubing pressure on the surface. After some time the liquid production increase and due to this the gradient in tubing also raises, because of the extra liquid carried by the gas (liquid hold up). Therefore more backpressure against the formation is provided, diminishing again the surface tubing pressure. This phenomenon is especially observed in completions without a packer installed. The gas is produced from the reservoir and afterwards percolates into the tubing casing annulus. There the gas is exposed to the higher reservoir pressure and hence causing a higher surface casing pressure. Accordingly to this, indicators for liquid loading in packerless completions are the decline in tubing pressure and an associated increase in the casing pressure. These effects are presented in Figure 8, but in reality the changes are not to be linear with time. [1 S. 16]

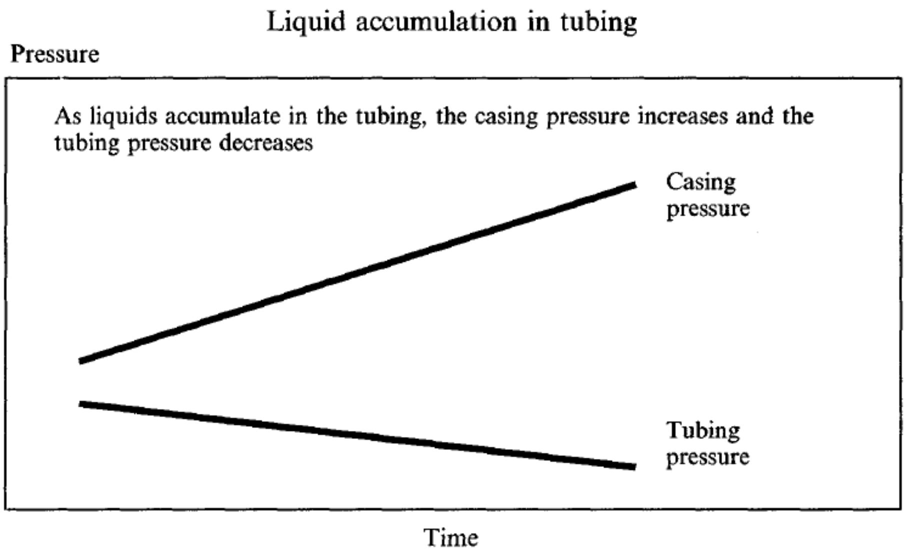

Figure 8: Casing & Tubing Pressure Indicators [1]

2.5.4 Well Pressure Surveys

Well pressure surveys, at flowing or static conditions, are probably the most proper methods to detect the liquid level in a gas well. The pressure surveys collect the pressure with depth in the well. This can be done during flowing well conditions or when the well is shut in. The outcome of the measurement is a pressure gradient which is a function of the density of the fluid and the depth. For example this function should be nearly linear for a single static fluid. [1 S. 18]

In the case of standing liquid in the tubing, the gradient curve will show a sharp change of slope as the density of the gas is much lower than the density of water or condensates. For showing the basic principle of the pressure survey a picture is illustrated in Figure 9. There can be a change in the slopes due to the gas and liquid production rates and accumulations, showing a higher gas gradient because of some liquids dispersed and a lower liquid gradient because of the gas in the liquid. Another method for checking the liquid level in a shut-in gas well is an acoustically one by shooting a liquid level down the tubing. [1 S. 18-19]

Attention should be drawn to the wells that produce in a two phase flow regime because if both, gas and liquids are produced the regime depends on the flow rate and the amount of each constituent phase present. For this reason the flowing pressure data from the survey are not really linear as mentioned before. If the measured pressure gradient that is not linear but indicates a constant increasing pressure with depth, the pressure gradient data from the survey is not enough for determining liquid loading problems. For such cases it is recommendable to repeat the survey at other conditions. [1 S. 19]

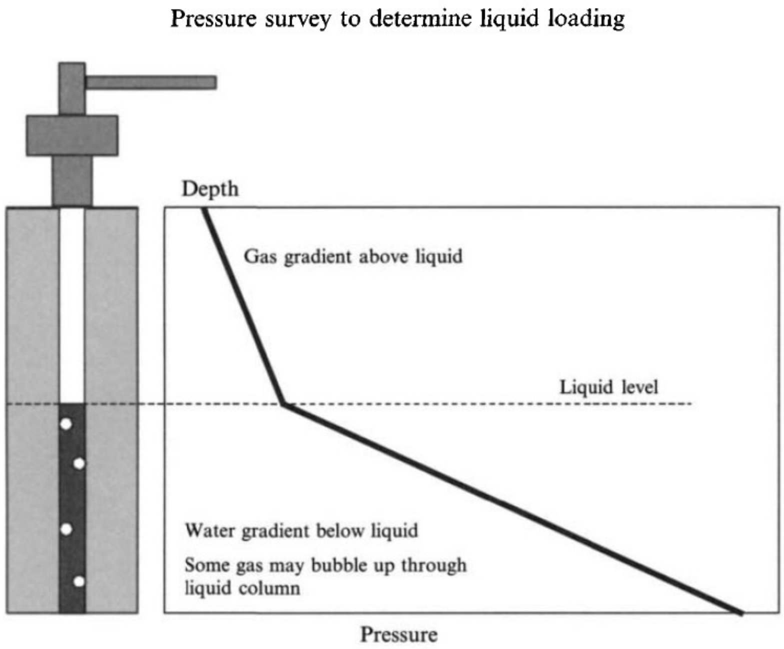

Figure 9: Schematic of a Pressure Survey [1]

2.5.5 Production of Liquids Ceases

There are some high-rate gas wells that produce liquids for a certain time and then decrease to much lower rates. When the gas production falls, the liquid production can also cease. For such cases, the well produces the gas at rates which are below the “critical” rate that transports the liquid to the surface. Hence the liquid accumulates more and more in the wellbore and the gas only bubbles up to the surface through it. Depending on the well pressure and the accumulation of liquids there are only two possibilities for the well, namely the well ceases to flow or the gas bubbles through the liquid to the surface. For both cases the well has dropped its gas rate to a value where liquids are not able to be transported up the tubing. For identifying such low flow response of a well there are two possibilities. The first one is to calculate the minimum critical velocity in the tubing and the second one is to calculate the minimum gas velocity that is required to carry the liquids to the surface. [1 S. 25]

3 Artificial Lift Methods

There are many artificial lift methods described in the literature for removing liquids from a loaded gas well. In Table 1 and 2 there is a basic summary for the main artificial lift and unloading methods for gas wells. As mentioned before there are many articles, papers and textbooks available on the market that give detailed information on this topic. In general it can be said, that these methods are categorized into two main groups, which are based on source energy to provide the required lift. The first is the reservoir supplied energy system group and the second is the external supplied energy system group. [6]

The reservoir supplied energy system group contains methods such as: [6] [5] [7]

- Well Cycling
- Venting
- Chemicals
- Well Swabbing
- Plunger
- Straddle or central delivery point compressor

The external supplied energy system includes methods such as: [6] [5] [7]

- Sucker Rod (Beam) Pump
- Progressing Cavity Pump (PCP)
- Electric Submersible Pump (ESP)
- Hydraulic Powered Pumps
- Jet Pump
- Gas Lift

Today the gas production industry has the possibility to decide among a number of unloading liquid methods. Very often the methods are combined to get the maximum production out of a well. Anyway, there is always the challenge to select the optimum unloading technique for the life of a gas well. These challenges get more and more complex with the complicated dynamic changes in the well and the reservoir characteristics over the life of the gas well. Therefore a number of considerations have to be taken before deciding for an artificial lift method. [6]

These considerations are: *“liquid production rate, gas production rate, wellbore geometry, well depth, desired bottom hole flowing pressure, reservoir temperature, fluid composition, surface system, and operator`s knowledge. Other considerations include economics, availability of power or gas for gas lift, capability to handle solids, onshore or offshore environment, visual impact and space considerations”*. [6]

Table 1: Relative Advantages of Artificial Lift Systems [6]

Rod Pumping	Foam Lift	Hydraulic Piston Pumping	Electric Submersible Pumping	Gas Lift	Hydraulic Jet Pump	Plunger lift	Progressive Cavity Pumps
Relatively simple system design	Least expensive to try initially	Not so depth limited- can lift large volumes from great depths	Can lift extremely high volumes, but now being demonstrated with low rates for gas wells (<100 bpd).	Can handle solids as sand does not pass through valves	Retrievable without pulling tubing.	Retrievable /installable without pulling tubing.	Some types are retrievable with rods
If pump set below perforations (best for gas well) and compression on casing, can take well to depletion. Rate is depth dependent.	Introduce using (1) soap sticks, (2) back side injection, (3) capillary tube injection down tubing, (4) batch treating down tubing	If no solids, pump set below perforations, and compression on casing, can take well to depletion.	Special techniques to set below perforations. If sucessful and compression on casing, can take well to depletion.	If producing low volumes of liquid, then can take well to near depletion. Larger volumes of liquid production may result in higher producing pressures.	Has no moving parts downhole.	Good for low-rate wells. Requires minimum of 400 scf/(bbl-1000') and casing operating pressure to 1 ½ times line pressure.	If set below the perforations and and with CHP, can take well to depletion.
Units easily changed to other wells with minimum cost	Works best with water althougth new products handle hi % consensate but usually with more cost	Crooked holes present minimal problems.	Unobtrusive in urban locations.	Can produce small rates of liquids. Using macaroni strings, can be used in small diameter completions.	No problems in deviated or crooked holes.	Conventional (close for plunger fall) and continuous operation possible	Moderate Cost
Efficient, simple and easy for field people to operate.	Can work in conjunction with other systems such as velocity strings, plunger in some cases, gaslift, other	Unobtrusive in urban locations.	Simple to operate.	Fairly flexible- convertible from continuous to intermittent to chamber or plunger lift as well declines (~150 bpd).	Unobtrusive in urban locations.	Most used in 2 3/8's-2 78's but possible in smaller / larger tubing	Low Profile
Applicable to slim holes and multiple completions.	No downhole moving parts except injection port at bottom of the cap string system.	Power source can be remotely located.	Easy to install downhole pressure sensor for telemetering pressure to surface via cable.	Unobtrusive in urban locations.	Applicable offshore.	Perhaps the most economical method for dewatering when functional.	High electrical efficiency
Flexible-can match displacement rate to well capability as well declines.	Can be used with packer in well (cap string, soap sticks, tubing batch treating).	Analyzable.	Crooked hole present no problem.	Power source can be remotely located.	Can use water as a power source.	Keeps tubing clean of paraffin, scale (smaller amounts).	Can be used with downhole motor (ESPCP). Pump retrievability is possible (ESPCP-TTC)
Analyzable.	Cap strings used to ~15,000' or greater depending on temperature, gasses etc.	Flexible-can usually match displacement to well's capability as well declines.	Applicable offshore.	Easy to obtain downhole pressures and gradients.	Power fluid does not have to be so clean as for hydraulic piston pumping.	Can be used in conjunction with intermittent gas lift.	New systems considered such as hard stator and flex stator and metal-metal PCP for high temperatures. New developments not impacting gas well dewatering so far.
Can use gas or electricity as power source.		Can use gas or electricity as power source.	Corrosion and scale treatment easy to perform.	Lifting gassy wells is no problem.	Corrosion scale emulsion treatment easy to perform.	Best with packer removed- possible depending on well conditions.	Handles solids better than other pumps.
Corrosion and scale treatments easy to perform.		Downhole pumps can be circulated out in free systems.	Availability in different casing applicable sizes.	Sometimes serviceable with wireline unit.	Small jet insertable in 1 ¼ CT can be used in 2 3/8's, 2 7/8's specifically designed for dewatering gas wells.	Possible >~15,000' for lo-rates	Possible to >~ 8000' for low rates.
Applicable to pump off control.		Applicable to multiple completion's.	Lifting cost for high volumes generally very low. Efficiency below about 500 bpd begins to drops.	Crooked holes present no problem.	Possible to ~12,000'.		
Hollow sucker rods have been used for slim hole casing.		Applicable offshore.	Possible >16,000' for low rates but cable losses and discharge pressure must be evaluated for low fluid levels at hi-depths. Usually depth<10000'.	Applicable offshore.			
Special pumps available for solids laden and gassy fluids.		Closed system will combat corrosion.		Possible >10,000' but very deep not that common.			
To 16,000' for low rates?		Easy to pump in cycles by time clock.					
		Adjustable gear box for Triplex offers more flexibility.					
		Possible to ~16,000' for low rates.					

Table 2: Relative Disadvantages of Artificial Lift Systems [6]

Rod Pumping	Foam Lift	Hydraulic Piston Pumping	Electric Submersible Pumping	Gas Lift	Hydraulic Jet Pump	Plunger lift	Progressive Cavity Pumps
Crooked holes present a rod/tubing wear problem but smooth build up can allow use, especially with no-couplings rod such as co-rod. High solids production is troublesome. Gassy wells usually lower volumetric η. Set below perforations, best solution. Is depth limited, primarily due to rod capability. Obtrusive in urban locations. Heavy and bulky so in general not used offshore. Susceptible to paraffin/scale problems. H_2S can cause rods problems (especially high strength rods) Chemical inhibition typically works Use of small diameter pump (often possible for gas wells) leads to very small HP requirements for deep well producing low rates	Can lower pressures in producing wells but most likely will not take well to depletion Requires continuous injection of chemicals so more costly as liquid volumes increase (ie. > ~100 bpd) Can add to corrosion so inhibitors often needed. Concentration need adjustment so foam will break at surface of tubing. Soap sticks may not find their way to bottom of well. Cap string depth limited by strength and chemical concerns so problems if not carefully designed.	Power oil systems are a fire hazard. Large oil inventory required in power oil system which detracts from profitability. Not miniaturized like the jet pump so requires larger casing size. As such not common for gas well dewatering. Solids production is troublesome. Operating costs are sometimes higher if solids not removed from power fluid especially. Must allow gas production vent requiring more strings downhole. Not easy for field personnel to troubleshoot. Difficult to obtain valid well tests in low volume wells. Problems in treating power water where used. Safety problem for high surface pressure power oil. Lost of power oil in surface equipment failure. Hydraulics only small % of total artificial lift use.	Not as efficient for low rates but can be designed for low rates for gas wells regardless. Increased use in gas wells with crooked holes may increase. Only applicable with electric power. High voltages (1,000 V) are necessary. Expensive to change equipment to match declining well capability but VSD helps. POC no desirable. Cable causes problems in handling tubulars. Cables deteriorate in high temperatures. System is depth limited, due to cable cost and inability to install enough power downhole (depends on casing size). Gas and solids production are troublesome. Not easily analyzable unless good engineering know-how. Lack of production rate flexibility. Casing size limitation. Cannot be set below fluid entry without a shroud or other techniques to route fluid by the motor. Shroud also allows corrosion inhibitor to protect outside of motor. More downtime when problems are encountered due to entire unit being downhole.	Lift gas is not always initially available. Producing higher volumes of liquids, with not take well to depletion. Not efficient in lifting small fields or one well leases. Not efficient in general. Gas freezing and hydrate problems. Problems with dirty surface lines. Some difficulty in analyzing properly. Cannot effectively produce deep wells to abandonment. Casing must withstand lift pressure. Safety problem with high pressure gas.	Relatively inefficient lift method. High intake pressures required so will most likely not take well to depletion. Requires intake pressure of perhaps 20-25% of tubing pressure drop with water / 10% with condensates or oil. Design of system is more complex. Pump may cavitate under certain lo-P conditions. Sensitive to any change in back pressure. Producing of free gas through the pump causes reduction in ability to handle liquids. Power oil systems can be fire hazard. High surface power fluid pressures are required (usually safety limited to less than 4000 psi).	May not take well to depletion; hence, eventually requiring another lift method. However reports of 100 psi to 6000'. Requires more supervision to adjust properly or use capable controller . Danger exists in plunger reaching too high a velocity and causing damage. Sand will stick plungers. Brush and special plungers for small amounts of and production. Eventually will cease to function as well depletes. Life extended by use of variations of plunger lift such as (1) casing plunger and (2) progressive plunger lift. Also gas assisted plunger lift in conjunction with gas injection and chamber lift (ie. PECL and some other commercial methods)	Elastomers in stator swell excessively in some well fluids POC is more difficult. Surface rates often used to control. Loose efficiency (back flow increases with depth. Depth limited to ~8000 ft currently for low rates. Rotating rods wear tubing; windup and after-spin of rods increase with depth. Both problems have mitigating solutions. Used when solids excessive for other pumps but still will wear in sand. Low RPM used for sand handling.

3.1 Reservoir Supplied Energy Systems

3.1.1 Well Cycling

If a well should undergo cycling the exact monitoring of a well`s fundamental data, like production rate, wellhead temperature, wellhead pressure and also downhole data, is required. The intention behind cycling is to shut the well in at a suitable time, so that the well is able to build up pressure and then open it up again. When the well is shut in, two changes happen to the well: firstly, the hydrostatic liquid column is pushed back into the reservoir, this can be recognized by the increasing wellhead pressure and secondly, the well establishes pressure near the wellbore region. When now opening the well, this accumulated pressure should lift some of the liquids to the surface. Normally this process lasts a short period of time until a liquid column of a sufficient height has built up again to inhibit the well from gas production. A number of trials are needed to find the optimum balance of shut in time and the period of flow and shut in time. If the perfect timing is found, cycling can be a very effective method to activate gas production again. In any case the changes in the gas production have to be controlled from time to time to react upon different shut in and production times. [5]

Above all of this, cycling can be tested in all wells without any regard to the completion or any environmental aspects. The only limitations are wells that are heavily impaired by liquid loading, so called dead wells. Here other methods have to be used before trying to bring them back to life with cycling. In every well a point will be reached, where cycling will not have any positive impact. [5]

3.1.2 Venting

In the past it was often tried to get a maximum pressure drawdown by opening the well up to the atmosphere. Nowadays this is not allowed anymore because it is an environmentally unacceptable option. The main achievement that is gained from venting is the withdrawal of any backpressure on the wellheads. This extra pressure drop can bring a well back to flow. Venting is on the one hand applicable in all types of wells, independent from the type of completion and well location, but on the other hand it is not really an option, because of the environmental consequences. Above all of this, wells decline, due to their nature and a point will be reached where venting will not bring a well back to life and therefore other artificial lift methods have to be taken into considerations. [5]

3.1.3 Chemical Injection

The only chemical used artificial lift method is surfactant injection, also named as soap injection. Here the added surfactant lowers the surface tension of the liquid in the gas well and therefore the gas and the liquid are bounded together. The liquid is exposed to more surface area because it is held as a bubble film. This leads to a fewer slippage of the gas and lowers the density of the mixture and in the end it is lifted easier to the surface by the own energy of the well. To put it another way the liquid is pushed to the surface in the form of foam, where the foam has to break down and in the end releases the liquid; this can be done by a so called defoamer. It is very important that the concentration of the surfactant is suitable for each application type. If the concentration is too low, there is no beneficial effect for unloading the well and if the concentration is too high this can lead to foam blocking of the well. [5]

The surfactant injection can be divided into three different applications:

- Liquid batch injection: For this type of application the well has to be shut-in during the appliance of the surfactant and remain shut-in until the surfactant has reached the liquid level in the well. When the well is re-opened afterwards some gas from the reservoir bubbles through the liquid, containing the surfactant, and so activates the foaming action. Sometimes it happens that the reduction of the liquid column has an additional effect, which is called knock on effect. This means, with the removal of the liquid, there is a limitation of the hydrostatic backpressure on the wellbore and therefore more drawdown might be achieved and in the end this leads to higher rates in gas production. These higher rates in turn can bring a well back above the "critical rate" and some of the liquid can be produced naturally. The knock on effect is not a must have because also the removal of some liquid with the use of foam reduces the liquid column and leads to an extended time period for the well to load up again. There is no limitation for the liquid batch injection but is should be kept in mind that the injected surfactant adds additional hydrostatic backpressure on the liquid column. If this volume is not displaced it can be pushed back into the formation and lead to a condition where the well can not be re-started anymore. [5]

- Liquid continuous injection: The aim of the continuous liquid surfactant injection is to keep wells free from liquid permanently. The surfactant is either injected through a related injection line or filled through the casing-tubing annulus in a packerless completion. In the past the injection line was limited to wells that had no SSSV (Subsurface Safety Valve) installed. But as the technology has improved over the last years the injection line can also be used in wells with a SSSV installed. However such wells need some modifications or for example the displacement of the conventional SSSV. [5]

- Drop of soapsticks: Pre-packed soapsticks are one of the simplest methods used to add surfactant to a gas well, because the sticks are put into the well through the wellhead and sink to the bottom of the well by its own weight. When they reach the liquid level, they disperse in the liquid and provide for some time a constant surfactant release to the well. The soapsticks are unfortunately limited to deviated wells, because it may happen that the stick do not reach the wellbore and therefore has no effect on the deliquification. [5]

3.1.4 Well Swabing

It is possible to minimize the backpressure on the formation, caused by the fluid, by using a mechanical method. For such a method a so called “swab cup” is fixed to a wireline. After this, the swab cup is lowered into the borehole until it reaches a certain depth in the liquid column; attention has to be taken on the wireline, because it should not exceed the tensile strength. The exact knowledge of the fluid level is essential for this procedure. When the swap cup reaches the depth of desire it is pulled out of the wellbore and should take most of the liquids that are situated above of it. In theory the swap cup should expand in the wellbore and form a seal. In practice, there is always a certain amount of liquids that fall back into the borehole because the seal is not completely tight and therefore the operation has to be repeated several times. Special care should be taken on the fact, that the well starts to flow when enough liquids are removed. At the moment this application is not common but with some modifications it has a lot of potential. Such modifications include for example the adaption in non-uniform tubing diameter wells. [5]

3.1.5 Plunger Lift

Another deliquifying method is the usage of plunger lift system for a gas well with uniform tubing diameter and no SSSV. Plungers can be described as a mechanical interface between the liquids that are produced and the gas that uses the energy of the own well. This can be achieved by the movement of a plunger going from the lower side of the tubing to the surface. The operation is better described when looking at the picture below in Figure 10. A plunger is a piston that is actuated by the own power of the well. This facility is able to lift out liquids of a well while intermittent production is going on. At the schematic 1 the well is closed in and therefore the pressure in the tubing-annulus can built up. When the pressure is high enough, the well is opened up (see schematic 2) and the plunger pushes the fluid that has accumulated above it to the surface. There is only little fallback of liquids as the gas turbulence in the clearance area between the tubing and plunger is going on. As mentioned before the plunger is lifted by the own energy of the well, that has established during shut in time. When the plunger comes to the surface (see schematic 3) it is held in a lubricator. The gas can be produced from the well (see schematic 4) as far as the liquid is accumulating. At this time the well is shut in again (see schematic 5) and the plunger is pushed down to the bottom of the well bypassing the liquid. If enough pressure has built up the cycle starts ahead. One of the major advantages of plunger lift systems is the low cost of installation. There are a number of disadvantages of plunger lift design too. For example, plunger wear, problems with low BHP (Bottom Hole Pressure), time consuming plunger cycle optimization, clean and uniform tubing to avoid plunger hold-up and the need of using the wells drive energy. Although this technology is one of the most successful, there are limitations to it, such as wellbore deviation, non-uniform tubing sizes and SSSV requirements. The engineers steadily work on improvements for example to set a plunger below the SSSV and look if the liquid is also lifted between the section from the depth of the SSSV and the wellhead. [5] [8]

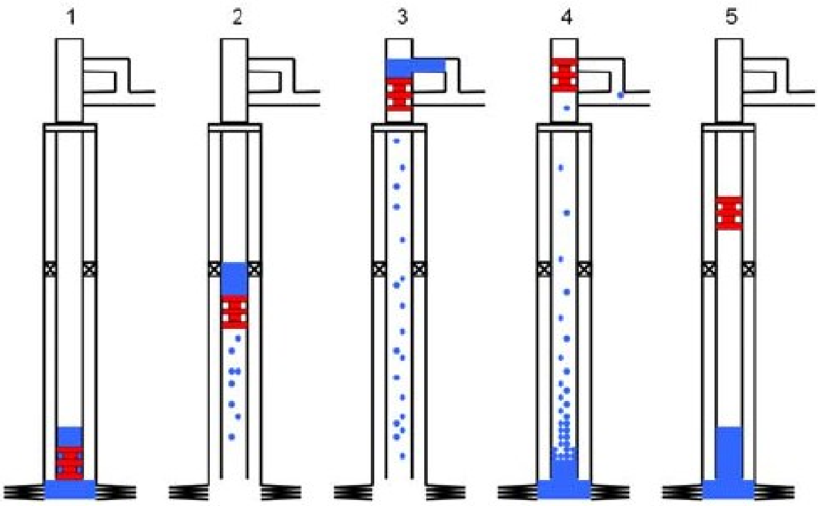

Figure 10: Schematic of a Plunger Lift Operation [5]

3.1.6 Use of Compressors

The use of compression is also very wide spread in the petroleum industry. The function of a compressor is suction on the “inlet” and discharge at a higher pressure at the “outlet”. The compression lowers the wellhead pressure and enables gas to move in the wellbore. By decreasing the wellhead pressure, the bottom hole flowing pressure is also decreased and finally leads to an increased drawdown. Figure 11 shows a diagram which illustrates the beneficial effect of wellhead pressure reduction. The IPR (see chapter 7) stays fixed, only the VLP (Vertical Lift Performance) “falls down” with declining WHP (Well-Head Pressure) and so the intersection shows higher production rates. [5]

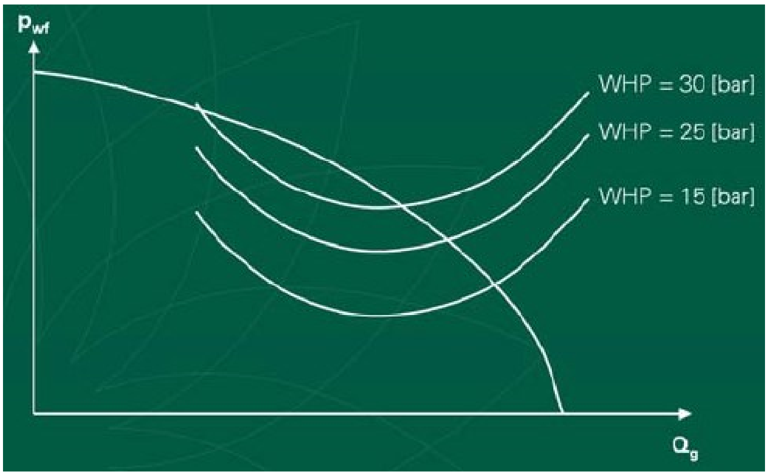

Figure 11: Effect of Compression [5]

3.2 External Supplied Energy Systems

3.2.1 Sucker Rod (Beam) Pumps

The sucker rod pumping systems are one of the oldest and one of the most popular systems for artificial lift. In particular when the well is fully depleted and there is no pressure left in the well. They are very qualified for liquid loading problems because they pump the liquids up the tubing and allow the gas production to flow up the casing. The sucker rod pumps gained a lot of popularity on the market due to their ease application and their fast availability. So they can be used for a wide range of applications; normally when the well has become so weak, that other non-pumping methods cannot be supported. The sucker rod pumps, also called beam pumps, unfortunately carry high costs in comparison to other artificial lift systems, such as foaming, plunger lift or velocity strings. The high costs result from the regularly required maintenance and from the electric motors which are used to power the prime movers. Before the installation of beam pumps, alternative systems for deliquifying gas wells should be taken into consideration. A big problem of rod pumps is gas-locking of the pump. As the pumps are very sensitive to this issue, it is very important that the intake of the pump is situated beneath the lowest point (below the perforation) of gas entry in the well. [1 S. 191] [8] [9]

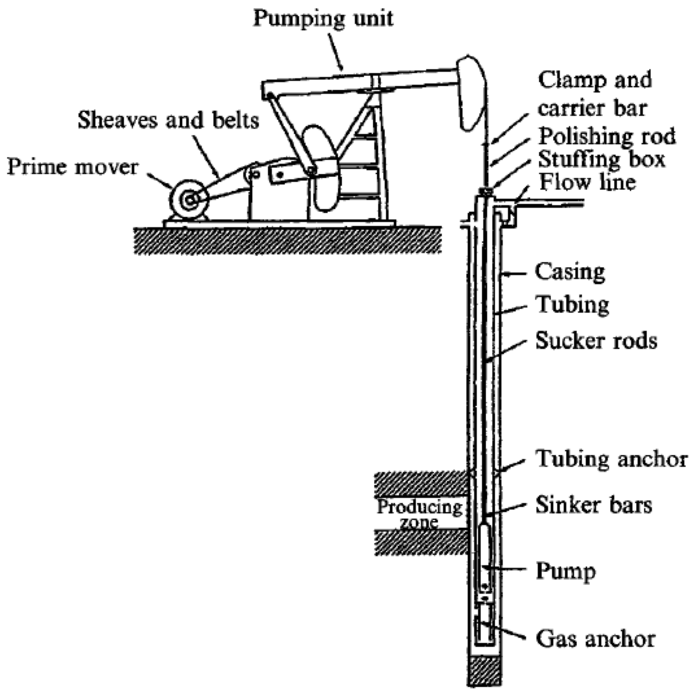

Figure 12: Beam Pump [1 S. 192]

3.2.2 Progressing Cavity Pumps

The PCP (Progressive Cavity Pump) appeared on the market in the year 1936. It has a very simple design and it is able to handle solids and viscous fluids, which is very important for many applications. [7 S. 251]

“The pump consists of a helical rotor which rotates inside an internal helical stator. The rotor is machined from high strength steel; the stator is molded of resilient elastomer. Therefore an interference seal can be obtained. When the rotor is inserted in the stator, chaines of lenticular, spiral cavities are formed. As the rotor turns within the stator, the sealed cavities spiral up the pump without changing size or shape and carry the pumped product to the surface”. [10]

In Figure 13 there is a simple display of such a pump.

Some of the PCPs were tested in onshore applications for deliquifying gas wells. But the test showed that there are problems with the elastomer of the stator and too much free gas in the pump. Now, industry studies what exactly causes the failure to the elastomer and how it can be avoided in the future. [5]

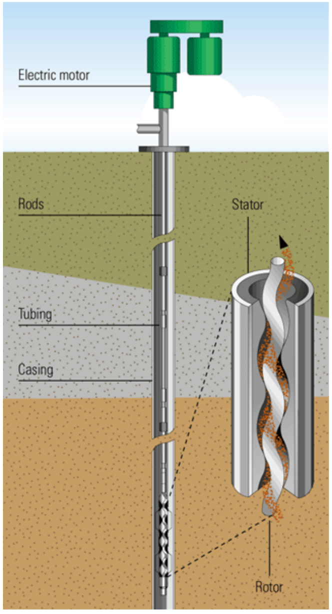

Figure 13: Progressive Cavity Pump [11]

3.2.3 Electric Submersible Pumps

ESPs (Electrical Submersible Pumps) are usually used for applications where the produced flow consists mainly of liquid. The ESP is a multi-stage centrifugal pump which is powered by an electric motor. Both the wellbore fluids and gas are drawn past the motor bringing a kind of cooling action into the pump. The cooling of the motor is very important to increase the life of the ESP. The operation mode of such a pump is simply explained: Impellors give kinetic energy to the fluid and diffusers direct the flow into the next impellor where the kinetic energy is formed into potential energy. This is also called the “head” of the ESP and the number of stages evaluates how much head is produced. The head and the flowrate are directly connected to each other. The power that is needed to drive such a pump is connected to the density of the fluid. If there is a high amount of free gas in the pump this lead to excessive problems. A conventional pump can only handle up to 30 [%] of free gas. Today there are also options for directing the liquid to the ESP intake, whereas the gas is routed through a bypass around the well. PSPs are not the first choice for dewatering a gas well but they can work very well in areas where excessive water production exists. In Figure 14 there is a sketch mapped from an ESP. [5]

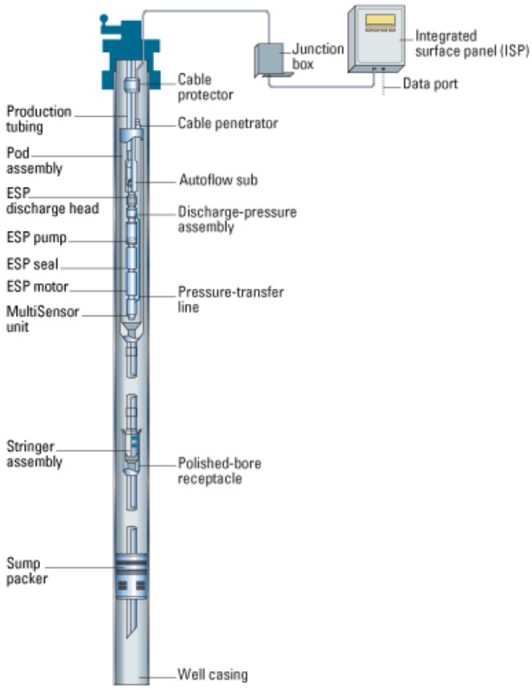

Figure 14: Electrical Submersible Pump [11]

3.2.4 Hydraulic Powered Pumps

Hydraulic pumps use the principle of Pascal to activate a well by generating a power fluid on the surface and transmitting it to the bottom of the well. This power fluid should activate: [10]

- *"An engine with a reciprocating piston driven by a power fluid connected by a short shaft to a piston in the pump end.*
- *A jet pump equipped with a nozzle that leads into a venture, in order to carry the fluid from the pay zone by means of the working fluid.*
- *A turbine pump where a turbine drives a centrifugal pump."*

3.2.5 Jet Pumps

A jet pump uses the principle of Bernoulli. A power fluid provided by a surface pump (triplex pump) is pumped down the wellbore at a very high pressure (low velocity) and down there it is converted to a low pressure (high velocity) jet by the nozzle. When the power fluid leaves the nozzle, a low pressure region is generated which draws the wellbore fluid into this area.

When the power fluid and suction fluid is mixed in the throat it is slowed down by the diffuser. Due to this the velocity is reduced and the pressure is increased leading to a value that is sufficient enough to pump the fluid to the surface. For different requirements, such as power fluid rate and pressure, a full range of nozzle and throat sizes are available on the market. In Figure 15 there is a sketch of a jet pump. The blue arrows stands for the power fluid and the red arrows stand for the wellbore fluid. If well conditions change it can lead to the necessity to change out the nozzles for different sizes. Due to the simplicity of jet pumps the internal parts can be removed for servicing without pulling the whole completion. Moreover, there are no internal moving parts; therefore the pumps have no problems with the attendance of solids in the fluid. Although the jet pumps have many advantages, they have one limitation. This limitation is that the kinetic energy or potential energy conversion efficiency through the device is normally lower than 25 [%]. This means a significant restrain for large volume pumping operations. [10] [5] [8]

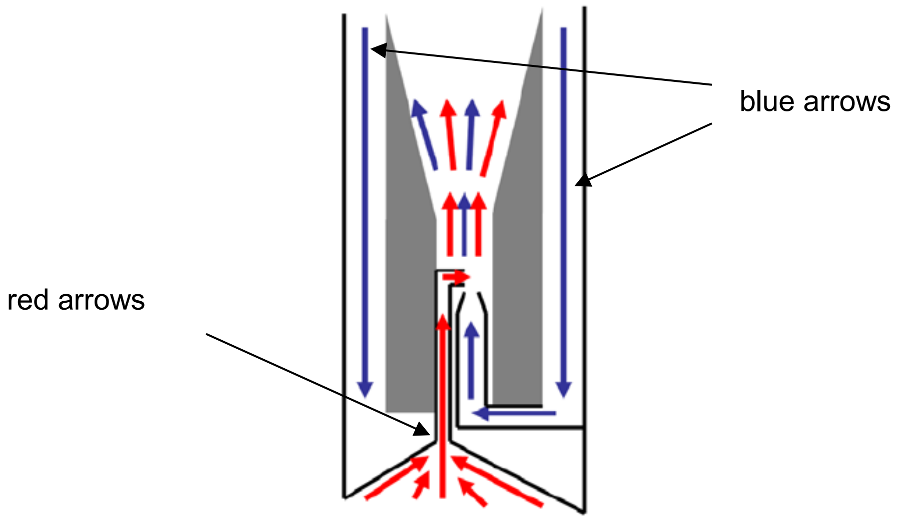

Figure 15: Jet Pump [5]

3.2.6 Gas Lift

Gas lift is a method which uses high pressured external gas to be injected into the producing flowstream at a certain depth in the wellbore. To be most effective, the point of injection should be as deep as possible. The additional gas mixes with the formation gas and reduces the flowing bottomhole pressure and thus increases the inflow of produced liquids. To put it another way it is tried to get the liquid out of the bottom of well by keeping the velocity in the tubing above the "critical velocity" that is crucial for liquid loading (see chapter 7). Gas lift can be divided into different groups of applications: [5]

- "Conventional" gas lift: Through a downhole valve a stream of relatively high pressure gas is injected continuously into the produced fluid column. Thereby the injected gas mixes with the formation gas to lift the fluid to the surface.

- Gas Lift for kick-off: Often after well interventions gas lift for kick-off is used by coiled tubing. The intention behind the process is that the liquid loaded gas wells need a kind of kick to lift on again.
- Continuous gas circulation: Here a continuous gas stream is added to the bottom of the pay zone to keep the tubing velocities above the critical rate at all times. The circulation rate can be adapted on the conditions of the well.
- Intermittent gas circulation: For deliquifying a gas well intermittent gas lift has the same effect as continuous gas lift. At an accordingly time a certain amount of gas is injected under the liquid column, raising the liquid as a slug to the surface. The injection can be done manually or by an intermitter. [5] [9]

The problem with gas lift is that the maximum drawdown cannot really be obtained because the gas has to be injected near the wellbore region and the injection pressure has to be higher than the naturally occurring pressure at that point. This can become very expensive if the high pressure gas supply is not already available. Another problem, are so called “flowloops”, in which flow regimes have been observed, where the gas and the liquid dissociate from each other and the gas on the one hand rises up the tubing and the liquid falls pack on the lower side of the tubing. Of course the biggest advantage of gas lift is the cost, if for example a high pressure source of gas is already available. Furthermore, other advantages are: the need of less maintenance, the simplicity of the operation in the field, the ability of sand handling and finally the creation of low flowing bottom-hole pressure. [5] [9]

4 Geological & Technical Conditions

This chapter gives short background information of the gas production in Northern Germany. Some geological conditions of the reservoir and their important parameters are summed up.

4.1 Overview of the Gas Production in the North-German Zone

For Germany the most important delivering countries for gas are Russia 31 [%], Norway 28 [%] and the Netherlands 19 [%]. Around one-fifths of the demand is covered by the German industry – mainly from Northern Germany. More than 94 [%] of the German natural gas is from the production districts in Lower Saxony and Schleswig-Holstein (see Figure 16). Although Germany is deemed to be a mature area, the German Oil & Gas industries see changes in the production of oil and gas from native fields in the future. It depends on developing the available potential and also to use the existing reservoirs with the help of new technology. Figure 17 shows the chronological development of the RWE Dea gas production since 1985. It is known that between the sixties and seventies there was a high growth of the gas production worldwide, but since 1996 the gas production of the RWE Dea wells, for example, has a constant value of approximately 2;5 [Bill. m^3(SSC)] (billion cubic meters) per year. SSC means “Under Standard State Conditions”. [12] [13] [14]

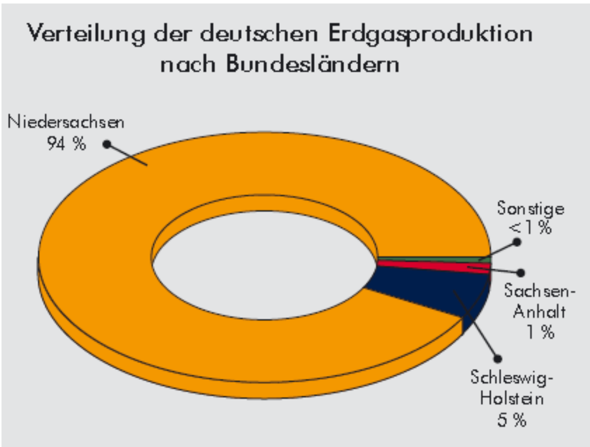

Figure 16: Allocation of the Gas production according to the States [15]

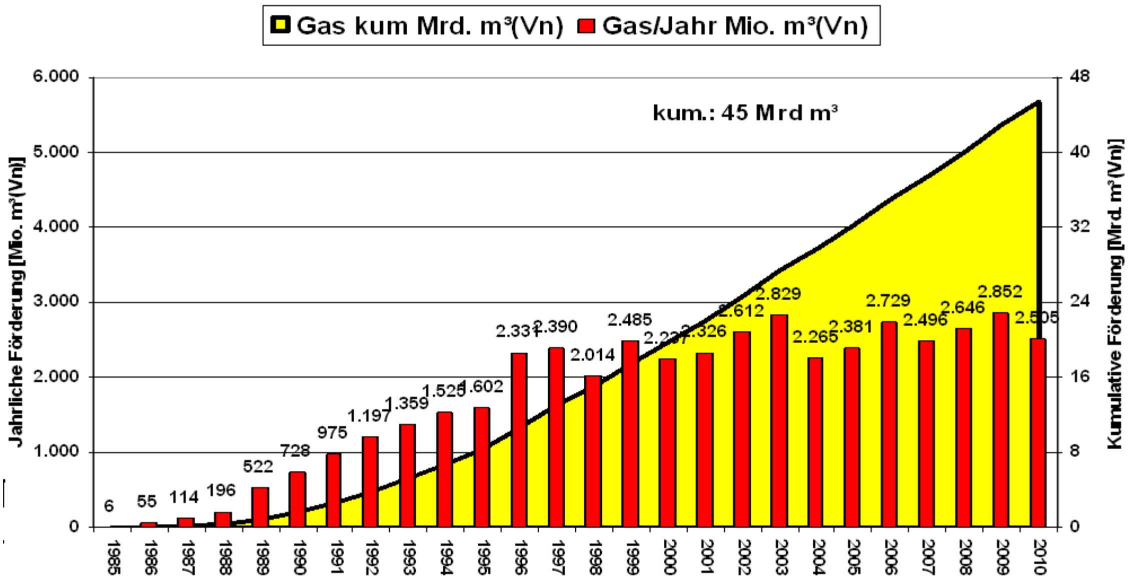

Figure 17: Annual & Cumulative Production of the RWE-Dea Gas Wells [16]

From an economical point of view the gas reserves from Germany are sustained from four major companies, namely the EMPG Exxon Mobil Production GmbH (in former times the BEB & Mobil), Gas de France Production & Exploration GmbH, Wintershall AG and certainly from the RWE Dea AG. The production facility from the RWE Dea AG in Lower Saxony exists since 2002 and is responsible for 31 gas wells and 13 oil wells. Here about 2 [%] of the annual gas consumption of Germany is produced, which equates to 15 [%] of the inner production of Germany. At the moment the production facility in Lower Saxony operates six gas fields: Voelkersen, Voelkersen Nord and Bleckmar with 100 [%], Hemsbuende, Boetersen, Weissenmor and East Hanover in different shares. [16]

4.2 Geological Description of the Reservoir

Geographically the gas reservoirs in North Germany are situated on a strap which is running from the west to the east. To put it another way this strap is going from the Netherlands to West-Lower-Saxony, ending in the west of Saxony-Anhalt (Figure 18). For the gas exploration and production in Germany there are some disadvantageous geological conditions. The biggest problem is the great depths in which the gas is entrapped. The reservoirs for the gas and oil are mainly situated in three principal formations; the Perm, Jura and Carbon. In Germany the Perm is classified into two sections: the Rotliegend and the Zechstein. All over the world the Permian stones are high in Gas and Oil reserves.

In Lower-Saxony one of the biggest gas fields of the RWE Dea, named Field I (name is changed due to corporate policies); the rift structure was built in the age of the carbon at approximately 300 million years. This rift structure is mainly filled with sediments of the Rotliegend. As mentioned above the gas lies in great depths of 4,700 – 5,000 [m] in so called sandstone deposits. These sandstone reservoirs are called the Hannover Wechselfolge and the Havel Sandstone. For the Hannover Wechselfolge the following parameters are estimated: porosity between 9-14 [%], permeability between 1-10 [mD] (Milliy Darcy) and about 4,000 [Mill. m^3(SSC)] OGIP (Original Gas In Place). For the Havel Sandstone on the other hand the parameters are: porosity between 8-13 [%], permeability between 5-50 [mD] and approximately 23,600 [Mill. m^3(SSC)] OGIP. The reservoir of the Rotliegend consists of a source-rock (coal of the carbon), a reservoir-rock (dune-sandstone of the Rotliegend) and is finally covered by a sealing layer (salt of the Zechstein). In the formation of the Rotliegend only sweet gas appears. [16] [17] [18] [19]

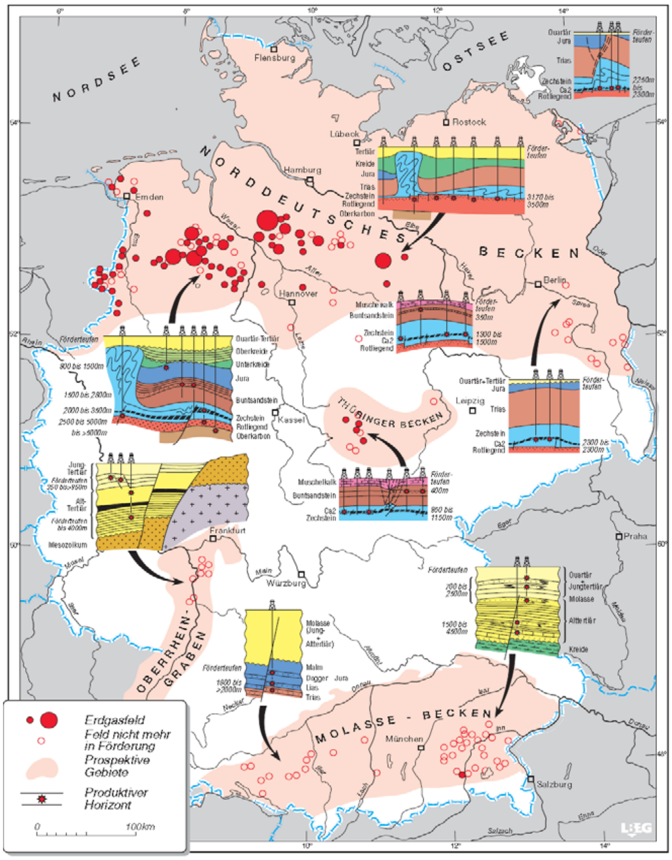

Figure 18: Map of Gas Production in Northern Germany [15]

5 Completion Background & Production History

The Rwe-Dea company in Lower Saxony has two sample wells for which they want to install a velocity string. Due to corporate policies, the names of the wells are changed to, Well I and Well II. As the completion schematics and the production histories of both wells differ in some points they are separately summed up in the chapters below and in Figure 20 and 22 a detailed schematic of each well is given.

5.1 Well I

In 1997 well number one was drilled to an end depth of 4,939 [m] measured depth (MD), which relates to 4,811 [m] true vertical depth (TVD). In doing so the gas bearing formation of the Havel-sand was encountered. A few months later the well was put on production. [20]

The completion of well number one consists in the first instance of an 18 5/8 ["] (inch) casing, a 13 3/8 ["] casing and a 9 5/8 ["] casing, where only the 18 5/8 ["] casing is cemented to the surface. A 7 ["] liner is set into the completion too, going from about 3519 [m] till about 4685 [m]. In the area of the reservoir a 5 ["] liner (perforated in three sections) is installed ending at a final depth of 4,925 [m]. The produced gas from the reservoir is flowing through a 4 ½ ["] tubing production string up to the surface. Some distance above the producing zone, exactly at a depth of 4,552 [m], a production packer is set used to seal off the flow of fluids through the annular space between production string and the production casing (the 7 ["] liner). Further important completion installations arranged from the bottom of the well to the surface are: the centralizer sub, the RN- and X-landing nipple, the flow couplings and the ball-valve-landing-nipple. The last installation in the completion is the SSSV (Sub-Surface-Safety-Valve). In this case, it is a wireline-retrievable-ball-valve. [20]

When the well was put on production it had an initial rate of approximately 20,000 [m^3(SSC)/h] (cubic meters per hour). Certainly a few years later from 1998 to 2000 there was to notice a decline of the pwf (Well Flowing Pressure) from 450 [bar] (bar) to 125 [bar], which resulted in a varying production rate between 16,000 and 18,000 [m^3(SSC)/h]. In the end the well reached a pwf of 100 [bar]. At this point the engineers decided to shut-in the well till 2003. During this time the static surface pressure increased to 330 [bar]. After this the well produced for more than one year with a gas rate of 3,500 [m^3(SSC)/h] and a pwf of 120 [bar] until again a shut-in period was necessary. In November 2005 the RWE Dea executed a hydraulic frac treatment in the formation of the Havel-sand. This measurement resulted in the last years of the well`s production (2009/2010) to an intermittent gas rate of 3,600 [m^3(SSC)/h] with a declining pwf of 165 [bar] to 90 [bar] in the end. For a pressure increase and associated production the well had to be shut-in several times. In Figure 19 the production history of the Well I from 2005 to 2010 is given. It shows the allocated dry gas rate [m^3/hr] (cubic meters/ hour] and the wellhead pressure [bar] versus time [dd.MM.YY]. The red line stands for the daily wellhead pressure in [bar], the blue line is the daily water allocated in [m^3] and the green dots and line on the bottom of the picture represent the daily salinity in [g/l] (gram/ liter) and the black line shows the daily sales/dry gas allocated rate in [m^3/h]. [20]

Due to the low production rate the discharge condition for the liquid in the 4 ½ ["] tubing string is too low so that LL is occurring. To guarantee the production of the well in the future a velocity string is decided to be installed in the well, but this is described in much more detail in Chapter seven. [20]

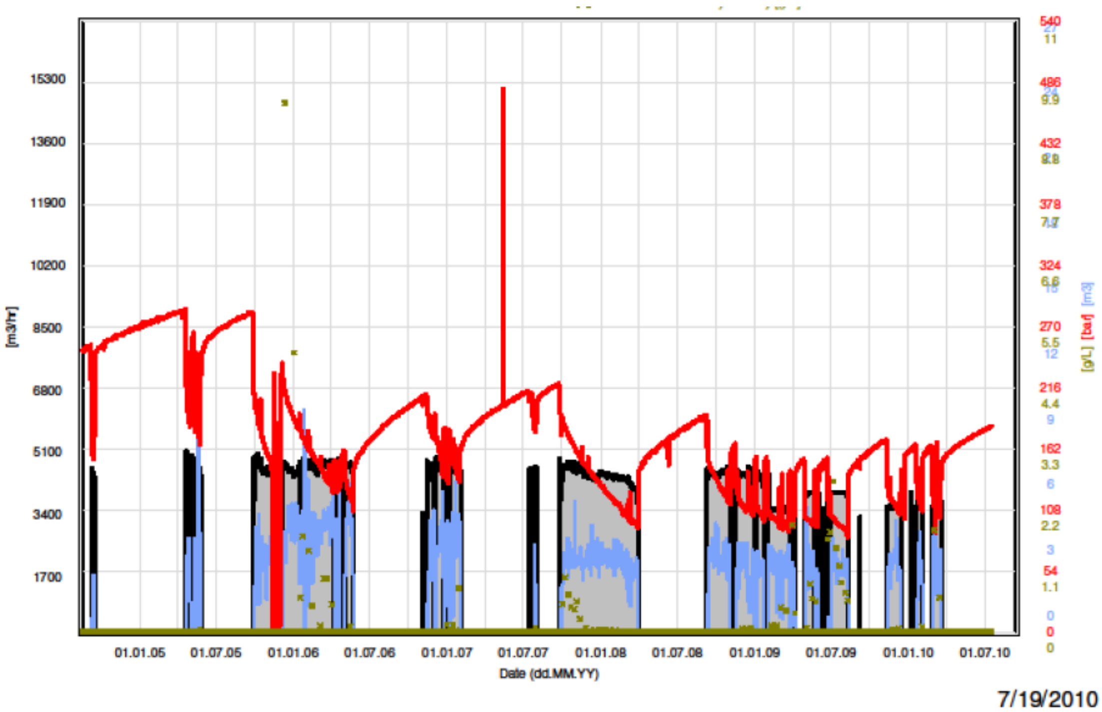

Figure 19: Production History of Well I [20]

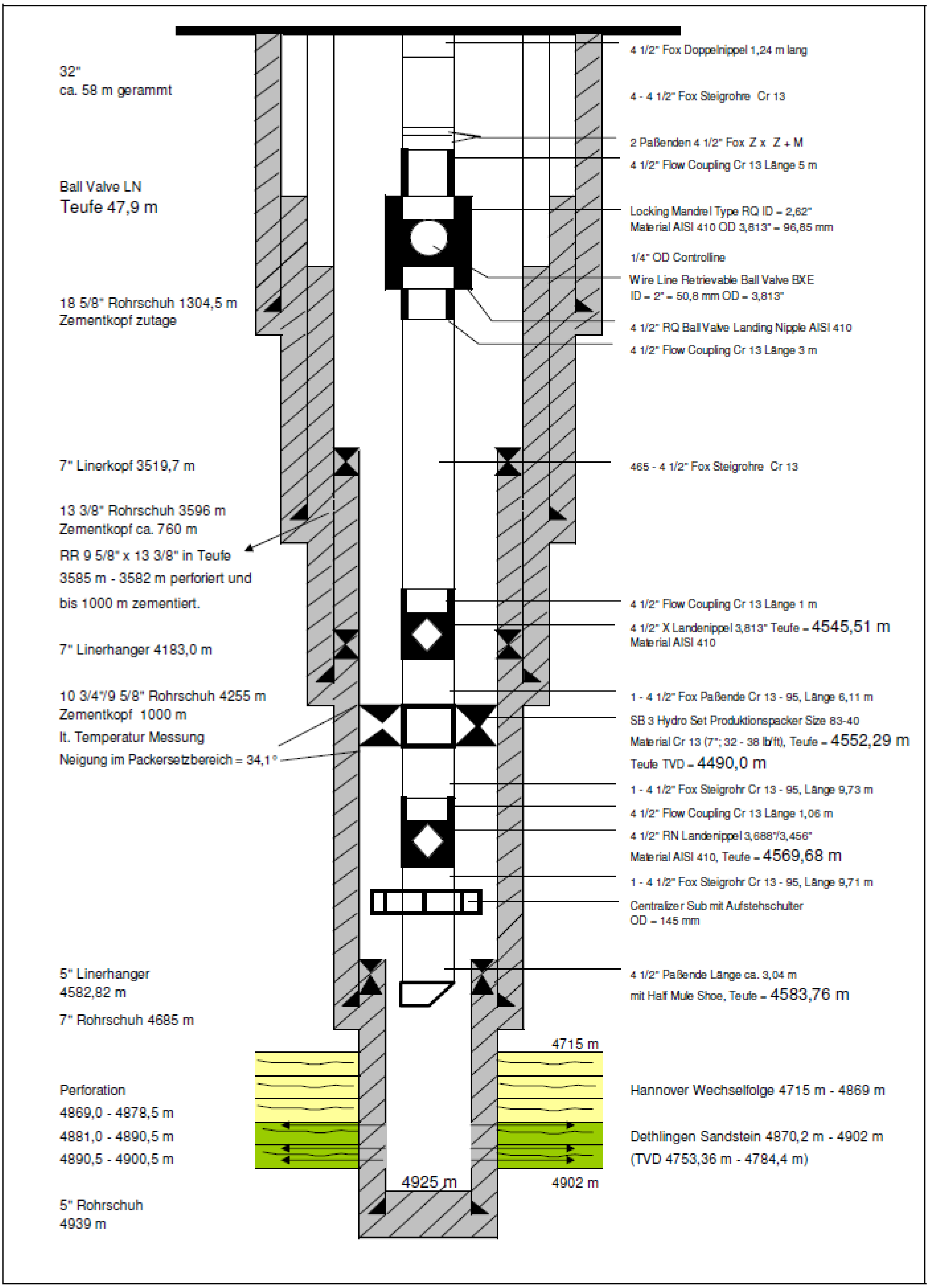

Figure 20: Completion Schematic of Well I [20]

5.2 Well II

The well number two was drilled in the year 2002 to its end depth of 5;648 [m] MD, which relates to 5;460 [m] TVD. Thereby the gas carrying formations of the Heidberg-, Niendorf-, Wustrow-, and Havel-Sand come across. [20]

The composition of the second well is nearly the same as for well number one. It consists predominantly of an 18 5/8 ["] casing, a 13 3/8 ["] casing and a 9 5/8 ["] casing; where again only the 18 5/8 ["] casing is cemented up to the surface. The main difference to well number one is, that in the area of the reservoir (four perforations) a 7 [“] liner is running from 4708 [m] to the depth of 5130 [m]. The gas is produced through a 4 ½ ["] tubing string and at 4780 [m] there is set a retainer production packer again. Additional completion installations listed from the bottom of the well to the surface are: the guiding-piece of the tubing string, the RPT-and X-landingnipple, the flow couplings and in the end there is a ball-valve-landing-nipple for the SSSV installed. Here the SSSV is again a wireline-retrievable-ball-valve. [20]

After the whole completion and the perforation of the Dethlingen (Havel)-Sand in the depth of 5,029 – 5,062 [m] MD, the well was put on production some months later. In August 2003 a frac treatment of the Havel-sand was performed. In the following years, 2005 and 2006, the formations of the Wustrow-, Heidberg- and Niendorf-Sand were reperforated. In March 2010 the production interval of the Havel-Sand from 5,029 – 5,034 was also reperforated. Well II had a cumulative production of 110 [Mill. m^3(SSC)] till the year 2010. Since 2005 the well produces gas rates of 5,000 [m^3(SSC)/h] accomplished by a sharp decline of the pwf. As the completion is equipped with a 7 [“] liner installation and as the produced rates are very low it is impossible to discharge liquids & solids through such a big borehole completion. This condition certainly leads to an increase of the bottom-level with liquids and sand particles. In March 2010 a bottom-level determination was carried out which showed a new bottom-level at a depth of 5,037 [m]. The low pwf and the low gas production rate can be returned on the bad connection to the Havel-Sand. The accumulation of the liquid on the bottom of the well and the thereby involved LL problem decrease the production performances of the well. To avoid a complete breakdown of the well II, it was shut-in several times for building-up a pressure. This enabled in the year 2009 some short periods of production. Figure 21 shows the production history of well II from 2005 to 2010. It represents the allocated dry gas rate [m^3/h] (cubic meters/ hour) and the wellhead pressure [bar] versus time [dd.MM.YY]. The red line stands for the daily wellhead pressure in [bar], the blue line is the daily water allocated in [m^3] and the green dots and line on the bottom of the picture represents the daily salinity in[g/l] (gram/ liter) and the black line shows the daily sales/dry gas allocated rate in [m^3/h]. [20]

With the actual production delivery a continuous production is not possible, therefore a velocity string should be installed into the completion, which is described as well in Chapter 7. But before this installation a CT (Coiled Tubing) wash for the perforated section is planned to guarantee a dynamic connection to the Havel-Sand. [20]

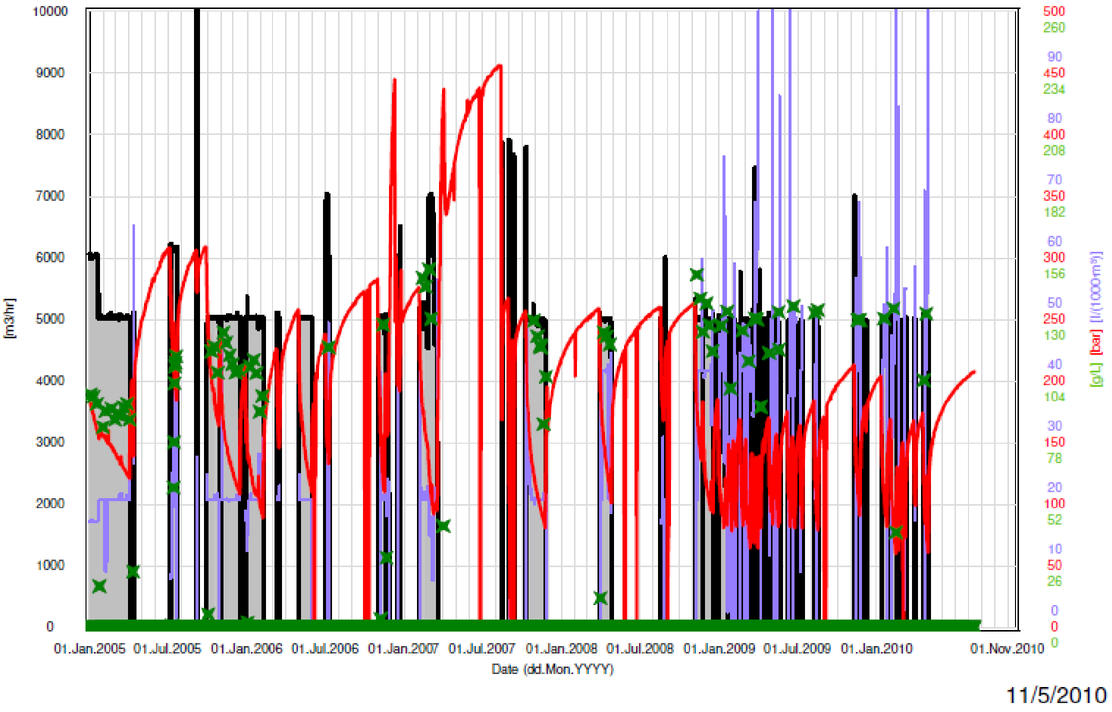

Figure 21: Production History of Well II [20]

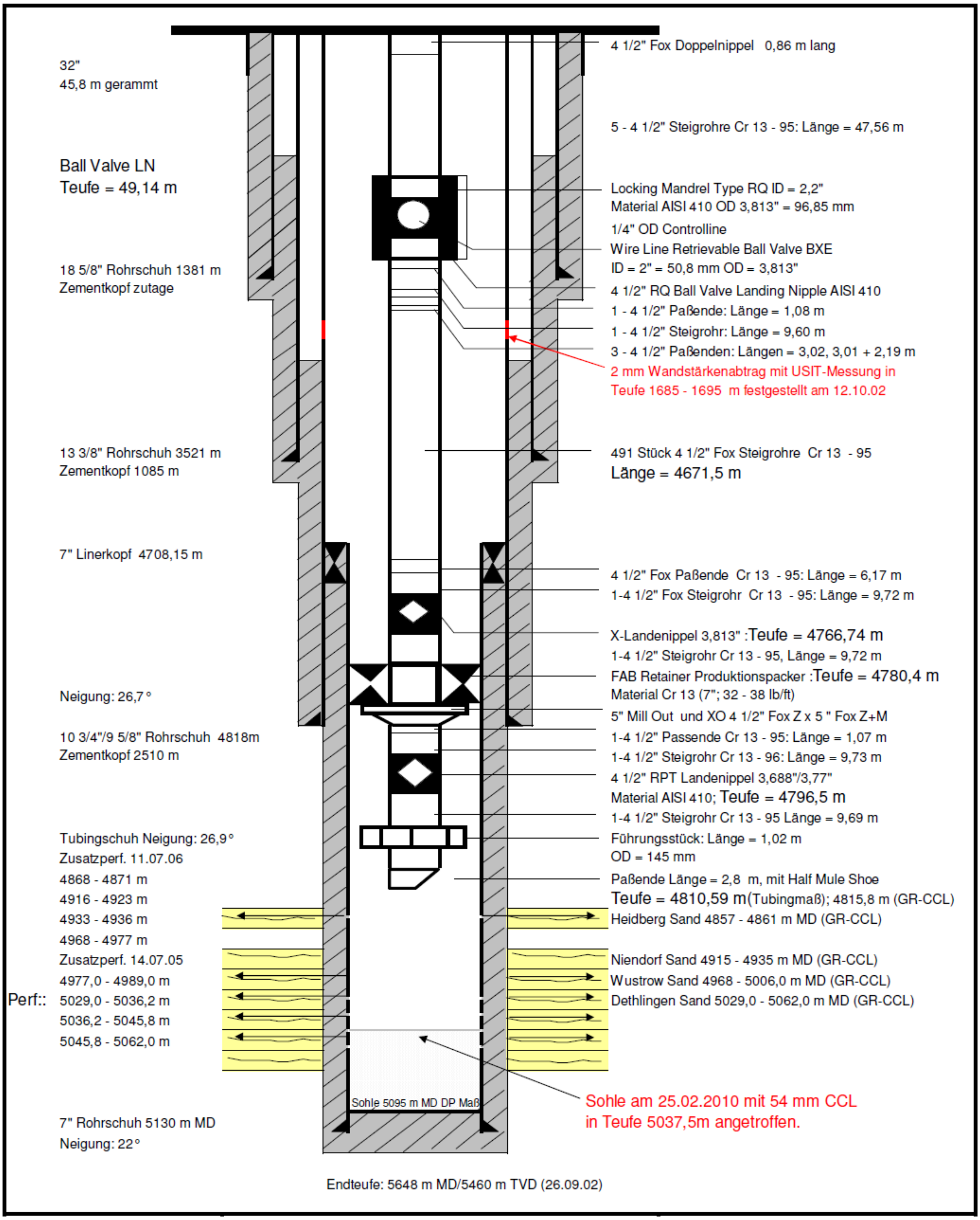

Figure 22: Completion Schematic of Well II [20]

6 Decision for a Velocity String

If a well is in its decline phase, it suffers in most cases from liquid loading problems. In this chapter solutions for corrective measurements are discussed. When it is technically not feasible to subject a reservoir with a further treatment, the only remaining possibility, is to change the completion of the well. In this kind of measurement a smaller diameter coiled tubing string (velocity or siphon string) or a string of jointed pipes is installed inside the production tubing. Beside of this, there is a further possibility to carry out the water from the well: a chemical solution can be pumped down into the bottom of the well to modify the interfacial surface tension between the gas and the water. [19] [21]

6.1 General Function of a Velocity String

The intention behind the installation of a velocity string with a smaller diameter than the production string minimizes the cross sectional flow area. When the cross sectional flow area gets smaller, the gas velocity in the tubing will increase. This means: the higher the gas velocity on the bottom of the well, the more energy for transporting the liquid up to the surface is given. Therefore the liquid is not able to accumulate on the bottom of the well anymore and the production is guaranteed. [21]

Important for the liquid discharge is the velocity of the streaming gas in the production string. According to the equation of continuity (I) the velocity is defined by:

$$v = \frac{q}{A} = \frac{4 * q}{d_i^2 * \pi} \qquad (I)$$

<u>Where</u>:

v: velocity of the gas [m/s]

q: flow rate (volume of the gas per time unit) [m^3/h]

A: cross sectional area of the streamed conduit [m^2]

d_i: inner diameter of the streamed conduit [m]

Replacing the area by the term $A = \frac{d^2 * \pi}{4}$, then the squared diameter influences the velocity.

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

$$V = \frac{z * n * R * T}{p} \qquad (II)$$

Where:

V: volume of the gas for the particular section [m^3]

z: coefficient of compressibility [1/bar]

n: amount of the gas molecules [mol]

R: general gas constant [$m^3 bar^2/mol*K$]

T: absolute gas temperature [K]

p: pressure of the gas [bar]

The equation (I) and (II) state, that under low pressure the flow rate is increased, without changing the amount of gas. Therefore the behavior of the velocity on the lowest portion of the well completion is of most importance. The higher the velocity on the bottom of the well, the better the flowing condition is in the upper section of the well. A velocity of 7 to 12 [ft/sec] has turned out to be an ideal value for the lower third of the tubing. It should be noted, that the velocity is completely depending on its associated liquid holdup. To put it another way the liquid holdup must be determined to get the applicable velocities for a given well. [19] [22]

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

$$LH = \frac{V_{free\ water}}{V_{pipe-segment}} \qquad (III)$$

If the LH reaches a value of one, there is only liquid present and if the LH reaches a value of zero, there is only gas in the pipe. According to experience the LH should have a value of 0.2 or less. In Figure 23 the relationship between the mixture velocity and the liquid holdup for different tubular configurations is shown. The combined tubing-data-sets clearly show the relationship between the velocity and the LH in terms of a rough curve. For the lower velocities a rapid variation of liquid holdup is to recognize. Not to forget that this leads on the other side to a greater mixture density and a higher bottomhole pressure. Therefore it should be tried to have a velocity greater than 5 feet per seconds [ft/sec]. The liquid holdup is also related to the flow regimes, values lower than 5 [ft/sec] cause the discharge of the liquid with a churn or annular flow pattern. [19] [22]

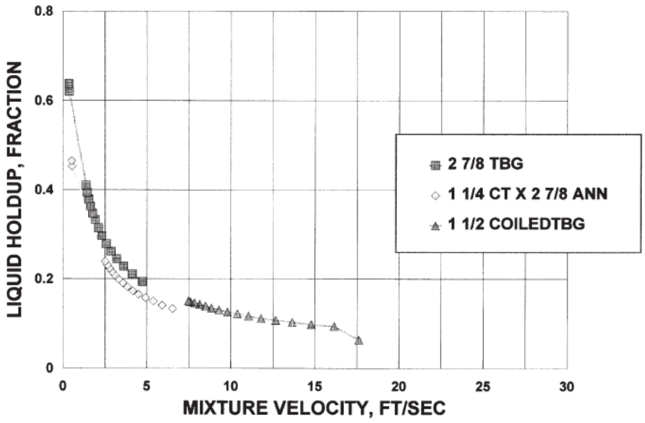

Figure 23: Velocity versus Liquid Holdup [22]

Another important factor that influences liquid loading is the minimum critical velocity. Liquid loading begins when the velocity of the production flow decreases beneath the minimum critical velocity which is necessary to lift liquids to the surface. A numerous studies have been published for establishing predictable LL rates, for example including those done by Turner [23] and Coleman [24] in the past and some more effective modeling has been done recently in Europe in collaboration with the NAM (Nederlandse Aardolie Maatschappij). [25] [9]

By knowing the exact values the minimum velocity for the liquid discharge can be mathematically described by the equation IV: [19]

$$v_{min} = 5.34 * \sigma^{0.25} * \sqrt[4]{\frac{z * R * T * (\rho_w * z * R * T - p_w)}{p_w^2}} \qquad (IV)$$

<u>Where</u>:

v_{min}: minimum velocity for the liquid discharge [m/s]

σ: interfacial surface tension between the gas phase and the water phase [N/mm^2]

z: coefficient of compressibility [1/bar]

R: general gas constant [$m^3bar^2/mol*K$]

T: temperature in the well [K]

p_w: flowing pressure on the bottom of the well [bar]

ρ_w: density of the liquid [kg/cm^3]

The flow rate for a production tubing with the cross section A is defined by the equation V: [19]

$$q_g = 5.34 * A * \frac{T_n}{p_n} * \sqrt[4]{\frac{\left(\rho_{w*z*R*T-p_w}\right) * R * p_w^2 * \sigma}{T^3 * z^3}} \qquad (V)$$

<u>Where</u>:

q_g: production rate of the liquid based on standard state conditions [m^3(SSC)/h]

A: cross section of the production tubing [m^2]

p_n & T_n: standard state conditions [bar], [K]

The above stated considerations should give an overview of opportunities to reach the ideal velocity of the gas with the right selection of the equipment. Due to the first equation the flow rate is reverse proportional to the cross section. Therefore by reducing the flow area the velocity of the gas flow rate can be increased. It should be noted that by the production through a smaller tubing size, the frictional pressure drop will increase, consequently resulting in a lower production rate. The pressure drop as a consequence of the friction is given by the equation VI. [19] [26] [27]

$$\Delta p = \frac{f * L * \rho * v^2}{d_i * 2} \qquad (VI)$$

<u>Where</u>:

Δp: frictional pressure drop [bar]

f: friction coefficient [-]

L: length of the pipe [m]

ρ: density of the liquid [kg/m^3]

v: velocity of the liquid [m/s]

d_i: inner diameter of the pipe [m]

The friction coefficient for a turbulent flow is a function of the Reynolds-Number and the pipe roughness and can be found in the Moody-Diagram.

The Reynolds-Number is given by the equation VII and the friction factor is calculated by the equation VIII: [27]

$$N_{Re} = \frac{v * d_i * \rho}{\mu} \qquad (VII)$$

Where:

v: velocity of the liquid [m/s]

d: inner diameter of the pipe [m]

ρ: density of the liquid [kg/m^3]

μ: viscosity [kg/m*s]

$$f = \frac{64}{N_{Re}} \qquad (VIII)$$

Neither the friction factor nor the pipe length and the density of the liquid are the essential factors for the frictional pressure loss in a pipe. With a constant flow rate and a reduced pipe diameter the pressure loss through the pipe rises to the power of five. This is due to the fact that the diameter is already integrated into the velocity of the gas (according to the equation I). [19] [27]

6.2 Designing a Velocity String

The function of a velocity string is dependent on a number of parameters. These parameters include for example: the present and future reservoir pressure, the liquid and gas production rate, the wellhead and flowing bottom hole pressure and the like. To be sure that the design of the velocity string will restore a loaded well to production and how long it will maintain production, the reservoir inflow performance with the tubing outflow performance is compared. This is also known as Nodal Analysis. [21] [28]

The reservoir IPR (inflow performance relationship) indicates the relation between the flowing bottomhole pressure (sand face pressure) and the amount of gas (flow rate) from the reservoir into the well (Figure 24). In the literature a number of methods are described to design the reservoir IPR for oil and gas wells. Cerberus for example designs the reservoir IPR based on the equation of Darcy for oil wells. For sure this can lead to limitations as most of the velocity strings are installed in gas wells with high gas-liquid ratios (GLRs). It is to note that the IPR is only determined by the reservoir properties, mainly by the reservoir pressure. Therefore it is not dependant on the tubing performance curve. [21] [28]

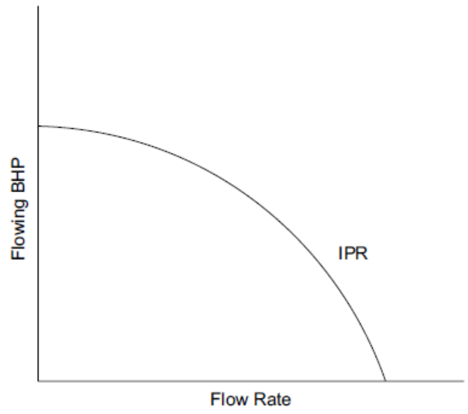

Figure 24: Reservoir Inflow Performance Relationship (IPR) curve [21]

The tubing performance curve (Figure 25) on the other hand illustrates the performance of a certain tubing size, depth and wellhead conditions. Therefore it is different for each design of a velocity string. Such curve illustrates the relation between the amount of gas produced to the surface and the downhole pressure that is required to produce this gas for a given fixed well head pressure. Due to its shape it is often called “J-curve”, intake pressure curve (IPC) or vertical lift performance curve (VLPC). The J-curve is divided at the inflection (loading) point, where the slope is zero, into two different parts. On the left side of the schematic there is the contributory part of the hydrostatic, whereas on the right side of the schematic there is the contributory part of the tubing frictional losses. Furthermore, the minimum flow rate which corresponds to the minimum velocity (as determined by the 10 [ft/sec] rule of thumb or the Turner et.al. (1969) correlation) is also marked on the J-curve. A lot of different multiphase models are available to get the tubing performance curve in oil and gas wells. For the J-curve, Cerberus again uses multiphase models for oil wells. Their matches are fairly good because the errors are less than 20 [%] up to a GLR of about 5,000. It is to remark that each model only applies to specific conditions and therefore the model has to be selected accordingly to this. [21]

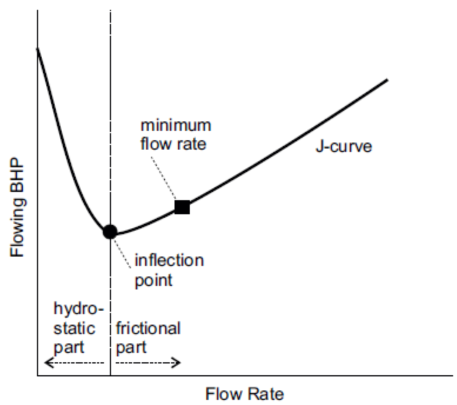

Figure 25: Tubing Performance Curve (J-curve) [21]

6.2.1 Design Evaluation

At the point where the IPR and the J-curve cross each other, the actual production rate is given. Afterwards this intersection point has to be compared with the minimum gas flow rate on the J-curve. Three different situations can happen: [21]

- The well flows, without loading up
- The well flows, but it loads up and maybe stop production after some time
- The well does not flow

A well will flow faster than the minimum gas flow rate and will not suffer from liquid loading problems when the intersection point is on the right side of the minimum gas flow rate (Figure 26). [21]

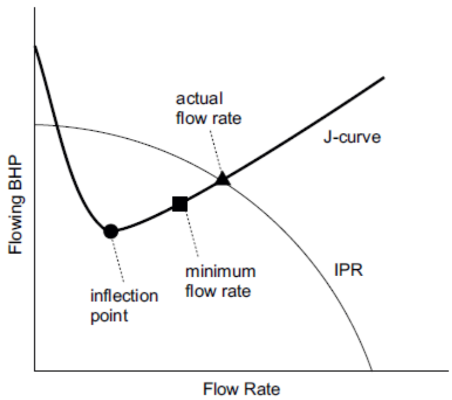

Figure 26: Intersection Point to the Right of the Minimum Gas Flow Rate [21]

A well will flow but suffer from liquid loading and in the end eventually kills itself when the intersection point lies between the inflection point and the minimum gas flow rate (Figure 27). [21]

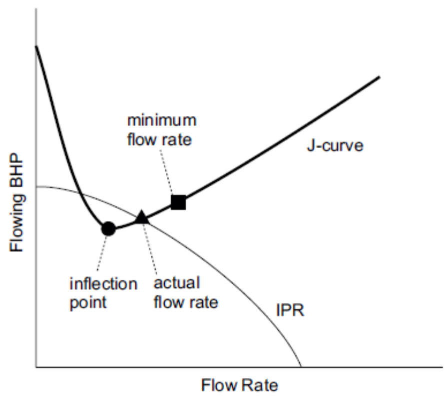

Figure 27: Intersection Point Lies between the Inflection Point and the Minimum Gas Flow Rate [21]

When the IPR and the J-curve do not cross each other or they cross to the left of the inflection point, the flowing bottomhole pressure is too low for the well to flow for that particular tubing size, depth, and wellhead pressure (Figure 28). Therefore another velocity string design should be taken into considerations. [21]

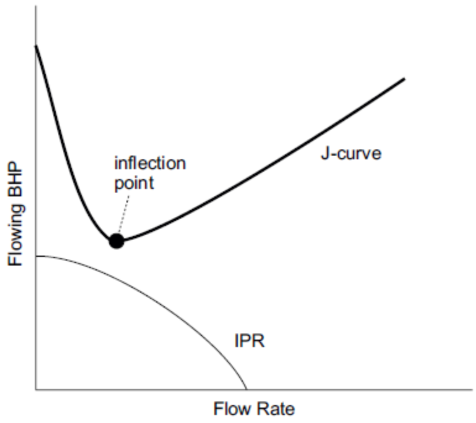

Figure 28: No Intersection Point or Intersection Point to the Left of the Inflection Point [21]

6.2.2 Compare Several Designs

The function of the existing production tubing in the well has to be analyzed in the first instance to legitimate the installation of a velocity string in the end. To do so, the J-curve for the existing production tubing (no coil tubing installed) has to be compared with IPR (Figure 29). When the well has already started with loading up, a moderate velocity string has to be installed before the well starts to kill itself. [21]

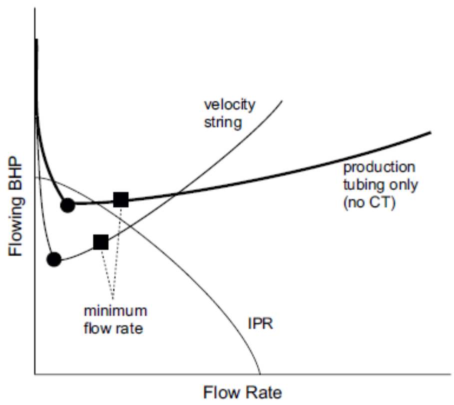

Figure 29: J-Curve with the Production Tubing Only [21]

When installing a velocity string (Figure 30) it is to notice that the intersection point between the reservoir IPR curve and the IPC with the velocity string is moved to the left. Therefore the well is producing with a lower rate. Nevertheless, the reservoir pressure will continue to decrease in the future, changing the IPR curve. This means that the tubing IPC does not longer intersect with the IPR curve and so the well cannot produce, whereas with the velocity string the well is still able to produce. The actual flow rate at the future pressure should be still greater than the minimum flow rate. With the installation of the velocity string the well should be able to flow as long as possible to get back the costs of the installation. [21] [28]

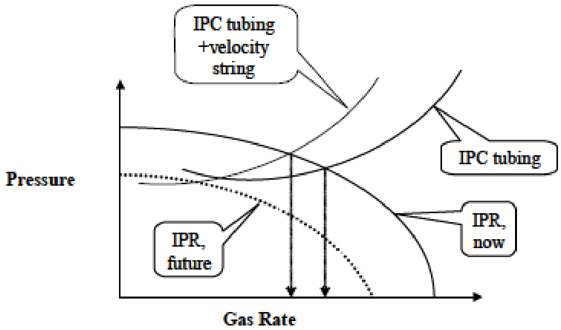

Figure 30: J-Curve Compared with the Future Reservoir Pressure [28]

To sum up, there is always the choice between a higher production rate over a shorter period of time and a lower production rate over a significantly longer period of time, meaning a higher ultimate recovery in the end. The latter period can even be elongated if the velocity string is installed into the completion up to the surface. Hereby the annulus between the velocity string and the production tubing can be used for the flow path. This can lead to an extended period of time and a higher overall production rate by using a variation of different diameters (velocity string/tubing annulus to only the velocity string or visa versa). [28] [26]

6.3 Options for a Velocity String

The installation of a velocity string is a cost effective solution to liquid loading in a gas well and can be carried out under pressure which means there is no need to kill the well. The installation itself, the maintenance and attention afterwards will be dramatically diminished. Furthermore, stable rates can be seen and the reserves will increase as it allows to produce the well much longer than flowing up conventional tubing or casing. When designing a velocity string the following considerations should be made: [4] [28] [26]

- Production life of the well: when considering the size of the velocity string the decline of the reservoir pressure in the future should be taken into account.
- Flow path: the production through the velocity string itself or through the annulus between the velocity string and the production tubing or a combination of them is possible.
- Hang-off-systems: the velocity string can be installed on the surface or below the SSSV or in the SSSV landing nipple profile.
- Gas composition: if there is CO_2 or H_2S produced with the gas then chrome material should be considered to give protection against corrosion.

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

Figure 31 sketches a velocity string which clearly shows the casing, the production tubing, the production-packer and the area of the perforation. The entrained liquids are depositing on the wall of the velocity string but in the end they are captured by the passing gas and carried to the surface. [29]

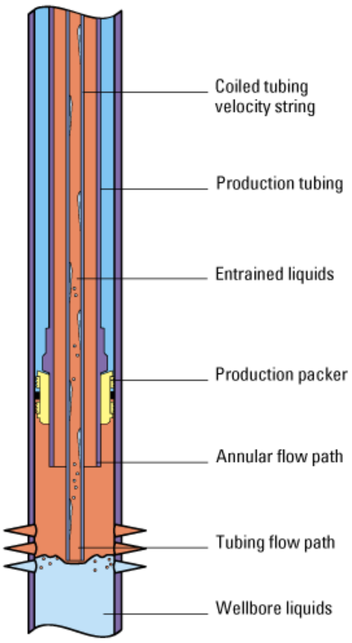

Figure 31: Schematic of a Velocity String [29]

An important point for the planning phase of a velocity string is always the technical realization and execution of the velocity string installation. In the following sub-chapters the different possibilities for hanging-off a velocity string as coiled tubing or as jointed pipes are discussed.

6.3.1 Coiled Tubing Velocity Strings

In many areas coiled tubing hang-offs have been used very often to elongate the producing lives of gas wells. It should be considered that not all wells react identically to the same hang-off installation. The coiled tubing itself can be run and hung-off into the existing completion very fast and simple. When it is run down to the bottom of the well, the mechanical restriction can be bypassed, and in the end the usage of a packer, for sealing off, is not necessary. For the installation of a velocity string there is no need to move in a work-over rig, as the coiled tubing unit is self-contained and able to snub against well pressure. It is possible to perform a work-over after the installation of the coiled tubing. As mentioned before the flow out of the well can be selected: "*For example flow up the coiled tubing may be combined with or substituted with flow up the coiled tubing/ production tubing annulus. Dual completions are possible with a tubing and packer configuration for flow up the tubing/ casing annulus separate from the coiled tubing or coiled tubing/ production tubing annulus*". [4]

6.3.2 Coiled Tubing Velocity String Hanging at the Spool

Before the coiled tubing unit is rigged up to the well, the well production equipment should be made ready. In Figure 32 a sketch of the bottom elements of a velocity string is displayed. Essential for the coiled tubing hang-off is the so called pump-off plug (aluminum) which is put into the coiled tubing before it is run down to the bottom of the well. When the coiled tubing is lowered into the completion the pump-off plug avoids entering of gas into the CT. In this way, the coiled tubing can be unreeled and cut without the need of special safety valves on the tubing. The cutting procedure is important for the attachment of the necessary hang-off system. Depending on the reservoir pressure it is possible to use a single- or a dual pump-off plug, which is fixed into the CT with shear pins. After the setting procedure of the CT, a pressure differential with nitrogen is applied, to shear off the plug. Afterwards the well is ready for production. Instead of the plug it is also possible to use a pump-off nozzle (wash nozzle) which makes it possible to pump through the tubing, during the way down, before hanging-off the tubing. Due to this, bridges or some other kinds of stoppages can easily be pumped through. This configuration makes a stimulation job possibly prior to the hang-off. The tail end of the CT velocity string has a conical shape, in this case a bull nose, to avoid rising on the existing profiles. Eventually a landing-nipple (LN) profile is positioned above the pump-off plug. This enables a later removal of the string by sealing off with a plug (pump down dart) or for hanging-off a measuring device in this profile. [4] [19] [26] [30]

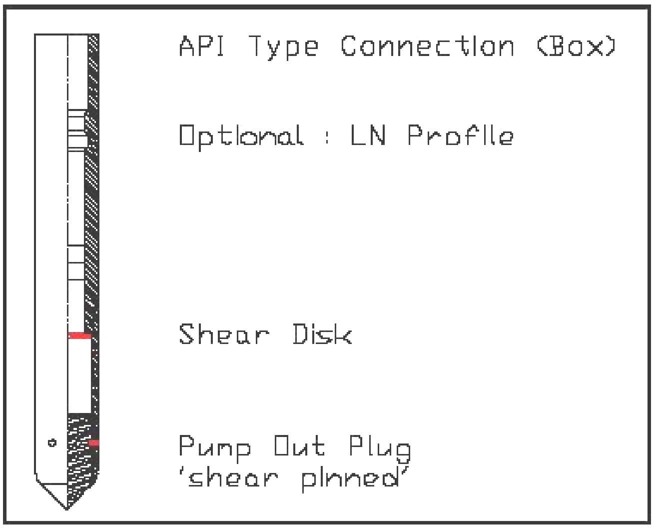

Figure 32: Bottom Elements of a Velocity String [19]

The first possibility for hanging of a CT velocity string is to use a surface CT hanger. This hanger is installed into the Christmas tree underneath the master and swab valve, so that their function is still maintained (Figure 33). To be able to remove the wellhead without any incident the well needs to be killed or shut in by barriers. One of the most common CT hang-off systems is the so called “wrap around hanger”, which was specially developed for such operations (Figure 34). Basically they consist of slips, an annulus pack-off and a hanger bowl. For such operation the use of a work window is very common. This work window is a part of the CT unit and is mounted on top of the wellhead and hanger assembly to fit the coiled tubing slips and access the tubing. The blow out preventer (BOP) of the coiled tubing is attached on top of the work window to guarantee well control while running into the well. The remaining parts of the coiled tubing, such as the gooseneck, the stripper rubber and the guide assembly are fixed above the BOP. The stripper rubber, on the one hand, makes it possible to run the coiled tubing into the well by allowing pressure on the coiled tubing annulus. The guide assembly, on the other hand, assures that slippages are not developing while running the tubing in the hole. When the tubing has reached the desired depth the pack-off on the hanger is set and pressure above the hanger is bled down. After this the work window is raised and the hanger bowl is cleaned. The coiled tubing slips are secured around the tubing and released into the hanger assembly. The tubing is lowered into the well until the weight indicator registers zero. Once it is clear that the tubing is secure, a cut is made with the cutter in the coiled tubing BOP`s. The work window, BOP stock, coiled tubing assembly is then removed from the wellhead. The final cut for the coiled tubing is made to ensure there is no interference with the well production equipment. The rest of the production equipment is installed over the coiled tubing hanger. The pump-off plug is pumped out of the coiled tubing with Nitrogen. If bottom-hole data is accurate, the surface pressure and cumulative volumes for the Nitrogen can be estimated at the point where the plug is released. When the pump-off plug is pumped out, more Nitrogen can be pumped contributing the well to unload. Now the well is ready to be put on-line again. [4] [19] [26]

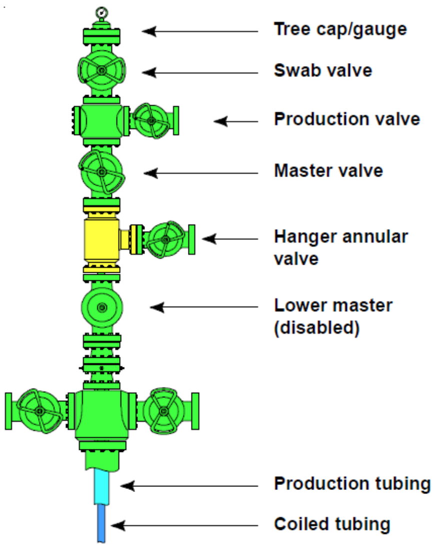

Figure 33: Christmas-Tree with Surface Hanger Configuration [4]

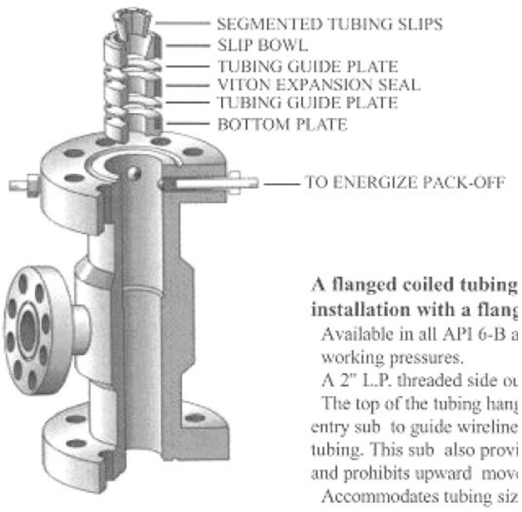

Figure 34: Wrap Around Hanger [19]

6.3.3 Coiled Tubing Hanging Below the SCSSV

Another wide spread method for the installation of a velocity string is the usage of a packer hanger (Figure 35 & 36). Hereby the packers are used to hang off the velocity string in the tubing, anywhere below the SSSV. To put it another way, shortly below the SSSV there is no landing-profile, and therefore a packer has to be used to carry the whole weight of the velocity string and itself on the plain wall of the production tubing. The big advantage of this kind of installation is to maintain the functionality of the SSSV. [19] [20]

The coiled tubing unit is rigged up on the well site and before the installation of the packer the SSSV has to be removed from the well. The BHA (bottom hole assembly) is picked up and run to a pre-determined cutting depth. By reaching this depth the CT is hang off in the blow out preventer (BOP) and there the slips and the pipe rams are activated and inflow is tested. The CT is cut and the packer hanger and disconnect tool is connected to it held by the slips in the BOP. The velocity string hanger is run into the well until the setting depths is reached (final depths of the velocity string). The hanger is activated by a short upward movement followed by an afterwards re-setting. Thereby the cutters and the sealing elements find their position and execute a high pressure on the inner side of the production tubing. The pressure depends on the weight of the velocity string: the higher the weight of the velocity string, the higher the pressure on the production tubing. In the end the pump-off plug is pumped out of the velocity string and the upper part of the CT is disconnected and pulled out of the hole. After the installation of the velocity string the SSSV has to be reinstalled. [19] [20] [26]

When the packer is hung-off in its end position, it seals of the annulus between the velocity string and the production tubing, and therefore only the production through the velocity string is possible. For such a kind of installation the point of time has to be accurately selected. It should be considered a priori that above the velocity string, an unchanged high cross section is existent afterwards. As a result the velocity of the gas is immediately reduced on the front end of the velocity string. Certainly this area is not so critical for the discharge of liquids, as the velocity of the gas in the upper sections is higher, due to the reduced pressure. Additionally the inner pressure loads ("Berstbelastung") onto the production tubing has to be taken into considerations, because of the weight of the velocity string. Such pressure loads occur particularly when very long velocity strings have to be used, as it is necessary for the deep formations of the Rotliegend. In the end this can lead to plastic deformations of the production tubing. Another possibility for hanging-off the velocity string is to use a hanger, whose sealing elements can be later on exchanged, without removing the whole string. This is very helpful and time-saving, if there is a leakage occurring in the velocity string. [19] [20] [26]

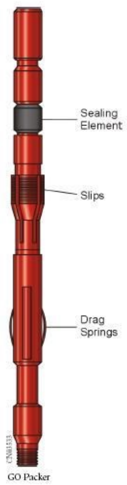

Figure 35: Go Packer [19]

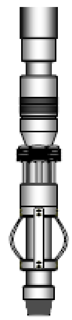

Figure 36: Packer Hanger [26]

6.3.4 Combination of CT and SCSSV

The third possibility is a special SSSV which is inserted into the velocity string. This SSSV is called concentric safety valve (CSV) and it is a surface controlled subsurface safety valve (SCSSSV) according to the API (American Petroleum Institute). The CSV is fit into the present profile of the SSSV and can be both, operated and controlled, by the existing hydraulic control line from the surface. Furthermore the CSV is able to simultaneously shut of annular and concentric flow paths. Normally the CSV has a closed position, which means that a spring pushes the flow tube upwards and therefore the flapper valve is closed and sealed of. If now hydraulic pressure is applied on the surface through the control line, the flow tube is pushed downwards and the flapper is opened (Figure 37). A decrease of the hydraulic pressure in the control line allows the spring to immediately close the CSV. The concentric safety valve is installed together with the CT into the production tubing. When the concentric safety valve is lowered into the existing SSSV LN-profile by the CT running-tool, pressure is delivered via the control line to shear of the screws of the anti-preset-mechanism. Such kind of completion provides on the one hand production and on the other hand injection through the CT and the annulus. The costs for such a CT application with the special inserted CSV are very high, as only one third of the overall costs accumulate for the valve only. Above all methods it is certainly the most expensive one and technically tainted with the highest risk. Therefore this kind of installation has been hardly used until now. [19]

Figure 37: Insert Safety Valve [31]

The advantages and disadvantages of the above described methods are summarized and shown in Table 3.

Table 3: Advantages & Disadvantages of the Different Hang-off Systems [19]

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

6.3.5 Jointed-Pipes Velocity Strings

Jointed pipes can also serve as a velocity string which is installed in live wells with the use of coiled tubing equipment. There are a number of applications whereby the advantages of the jointed pipe outweigh the implementation of coiled tubing. In Table 4 the advantage and disadvantages of CT verses Jointed pipes are listed up. Determining the optimum tubular size contains the same multi phase flow modeling as with CT velocity string design. For the running equipment a support tower set up is used. This tower set up is needed for raising the tubing sections from the catwalk with the elevator into the vertical position and to allow connecting the jointed pipe sections above the injector head. The down hole tools for a jointed pipe velocity string is very similar to CT velocity strings. The tail end of it typically contains two wireline retrievable plugs or a dual pump out sub, which establishes the double barrier against well fluids when entering the wellbore. In addition to this, a so called wireline entry guide (WEG) is also added at the bottom of the tail pipe, to guarantee an easy re-entry into the velocity string when carrying out a well service operation in the future. For hanging-off the jointed pipe velocity string either a nipple lock or a WR-SSSV hanger can be used. The first one depends on the number and location of nipple profiles inside an upper completion. With the use of a standard hydraulic GS running/ pulling tool the velocity string with the so called “Nipple Lock” is landed (locked) into the relevant nipple profile. Afterwards the GS tool is simply released from the lock by circulating through the tool and then picking up the running tool. This is a relatively easy operation to carry out. The second option for hanging-off large diameter velocity strings is the use of a WR-SSSV hanger. This kind of hangers are landed off and locked into the existing SSSV nipple, while the access to the original control line (hydraulic oil) is still maintained. For such a configuration a smaller WR-SSSV nipple profile is integrated above the new hanger to enable a smaller SSSV to be run with wireline or CT to land into the newly introduced nipple profile at the top of the insert string. [26]

Table 4: Advantages & Disadvantages of CT and Jointed Pipe [19]

Type	Advantages	Disadvantages
Coiled Tubing	• Lower weight • Fast running-in and running–out • Availability	• Is transported in one part • Reduced inner-diameter due to the welded joint • Buckling problems • Corrosion problems when from carbon steel
Jointed Pipes	• Single pipes are easily transported • Clean inner profile • Corrosion resistant when from chrome steel	• High weight • Loss of time when build-in and build-out

7 Industrial State of the Art

The Rwe-Dea has assigned three different service companies of Germany to propose them solutions for their velocity string installation. In this chapter the different proposals of the companies are described separately.

7.1 Company A

Company A has two different proposals for the velocity string installation. Both of these recommendations differ in their construction, installation and their constituent parts. The first proposal is composed of the capillary deliquification safety system from Company A and the second proposal is a simple Plug in Plug System.

7.1.1 Capillary Deliquification Safety System

The major advantage of the capillary deliquification safety system (Figure 38) is on the one hand the delivery of surfactants, chemicals and liquids to a predetermined point within the completion while on the other hand it maintains the application and functionality of a downhole safety device. By having an appropriate safety valve landing nipple profile, this system can be easily implemented. The profile can be either a proper safety valve landing nipple or within a tubing retrievable safety valve (TRSV) where the communication of the control system is activated to operate an installed wireline retrievable safety valve (WLRSV). The feature of the deliquification safety system is the part of the injection which works via the control system for the WLRSV. To put it another way when the control line pressure reaches a predetermined pressure, a regulator installed below the WLRSV opens and allows chemical injection. This system can be a cheap method of installing a semi-permanent injection system without the need of changing the wellhead. The design of the WLRSV is conceived to shut in the well some meters beneath the surface and is easily opened with hydraulic control pressure. While such an execution, the safety valve is held in the open position during the injection by the applied chemical injection pressure and the safety valve is closed when the injection is stopped. [32]

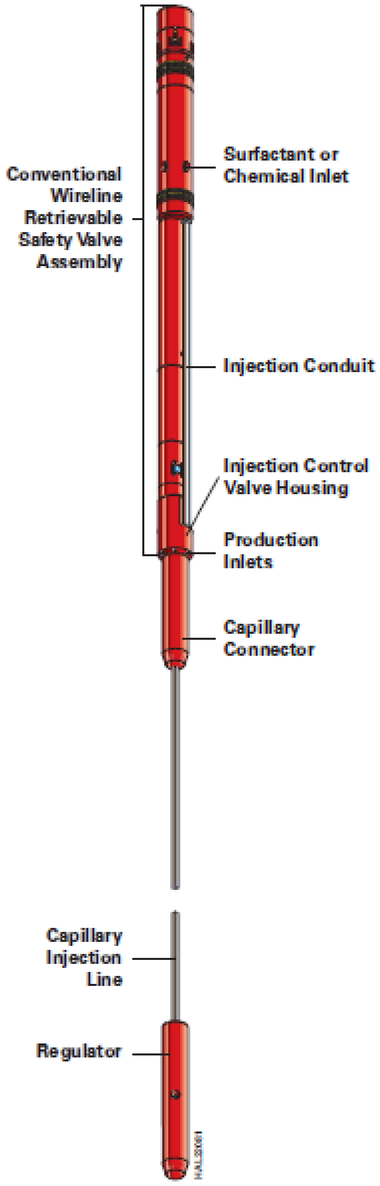

Figure 38: Parts of the Capillary Deliquification Safety System [32]

According to Company A the capillary deliquification safety system has the following benefits: the first point is that there is no need and requirement for wellhead modification; secondly the system can be used within the existing safety valve landing nipple profile or tubing-retrievable safety valve and the third point is the fast installation with the standard intervention techniques. [32]

To give a short overview of the simple installation, the different steps are summed up below and a picture of the procedure (Figure 39) is given. Generally this should only give a short impression and is not a detailed workflow for an installation. [32]

1. The existing safety system is shown – the WLRSV assembly installed in the safety valve landing nipple profile (SVLN)
2. The WLRSV assembly is pulled from SVLN
3. The capillary injection line is run after the space-out
4. The rams on the capillary injection line are closed after space-out
5. The capillary injection line is attached to the injection of the WLRSV
6. Both, the injection WLRSV and capillary injection line, are run and set in the existing SVLN

Figure 39: Steps of Installation [33]

Chemical injection valve

The first proposal from Company A is a method that allows automatic and continuous delivery of surfactants whereupon the safety legislation of the required subsurface safety valve is sustained during the whole injection process. The principle is based on the typical downhole completion (Figure 40) with a WLRSV installed in the safety valve landing nipple. This downhole safety valve is operated by the control line. According to Company A this system is unique in the industry as the existing control line is used for capillary deliquification. [33]

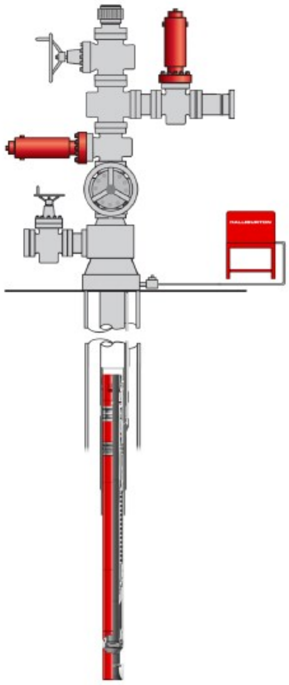

Figure 40: Typical Downhole completion [33]

As mentioned before the surfactants are injected into the well via a control line. Therefore, during the way downward, the surfactant enters first the WLRSV, then coming to the foam injection back pressure valve, after this entering the capillary tubing and in the end enters the downhole foam injection valve. To have a better understanding for the flow application Figure 41 below is listed. The capillary tubing (1/4 [“], 3/8 [“] or 1/2 [“]) is generally run inside the existing tubing or casing and is made of stainless steel. Furthermore the capillary tubing is providing the surfactants to a specified point within the wellbore. For the installation of the capillary tubing generally a method which is similar to running coiled tubing into a live wellbore is used. The capillary deliquification safety system is operated via the control line for the safety valve. When the control line pressure is applied, the WLRSV opens and after reaching a predetermined pressure the foam injection back pressure valve opens, and the downhole foam injection valve starts to inject.

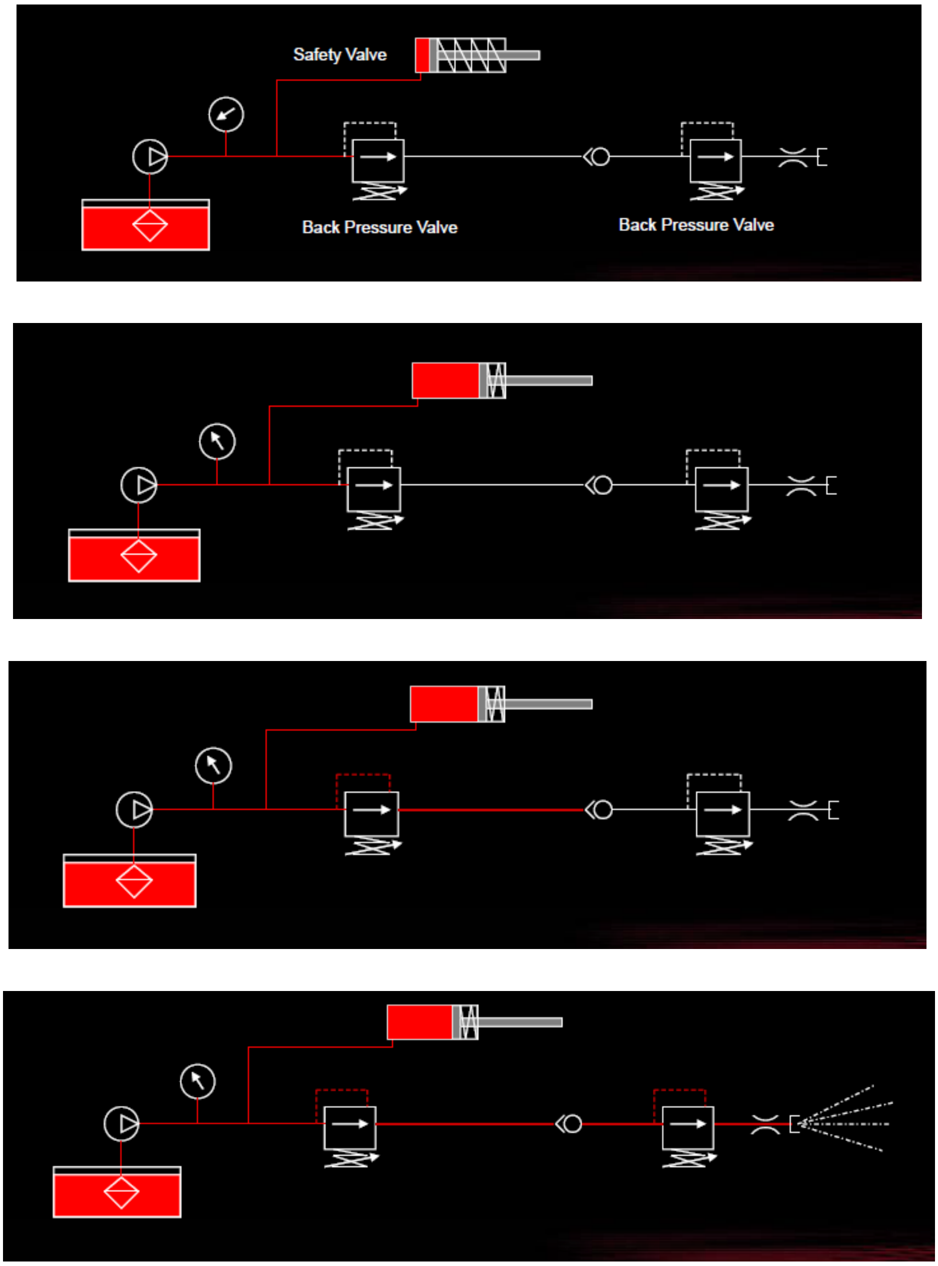

Figure 41: Stages of the Foam Injection Process [33]

The installation process of the system starts with the downhole injection valve which is run into the well with a capillary coil. After this the slip rams are closed and the capillary tubing is cut and the coil is removed. The WLRSV including the foam injection back pressure valve are connected to the capillary tubing and the assembly is run into the well via slickline. Once reaching the safety valve landing nipple the keys will lock the assembly in place. The assembly is set in the safety valve landing nipple profile. After this the WLRSV can now be opened through the existing surface control line. The Flapper will open (Figure 42). The control line pressure increase will open the foam injection back pressure valve and subsequently the downhole foam injection valve. The capillary deliquification safety system is operational and the well is protected. Unfortunately the length of the capillary string is determined by the breaking strength of the same. The longer the string, the heavier it is and its own weight will eventually break the string. Therefore the capillary diameter, the wall thickness and the material strength are important factors that need to be considered before the installation itself. For a better understanding the parts of the system are sketched in Figure 43. Whereby, the foam injection back pressure control valve housing contains the foam injection back pressure valve, which makes it possible to open the safety valve without starting the foam injection. After the control pressure is increased, the foam injection back pressure valve opens and foam injection starts into the capillary line down to the reservoir. The duty of the connector is to provide a pressure tight connection between the safety valve and the capillary. It also takes the full weight of the capillary string. [33]

For this installation the foaming agent would be placed on the surface nearby the wellhead. It is pumped from the surface down through the existing control line to the downhole safety valve and from there to the capillary string and then to the reservoir. The pump system has a dual function: firstly it operates the downhole safety valve and acts as a safeguarding system, which means that the downhole safety valve is shut in case of an emergency. Secondly, it pumps the foaming agent down the capillary at a predetermined flow rate. The disadvantage of the foaming agent is very often the creation of corrosion problems. This means that the foamer induces also oxygen which per default causes corrosion of the capillary items. Not at all, the existing materials of the well completion including the surface equipment can suffer from corrosion problems too. Therefore the agent is sometimes mixed with corrosion inhibitors and the fluid that is produced to the surface is treated with a de-foaming agent. Furthermore, the foam injection back pressure valve (FIBPV) needs periodic maintenance, which means that the safety valve has to be pulled to surface to replace the FIBPV. [33]

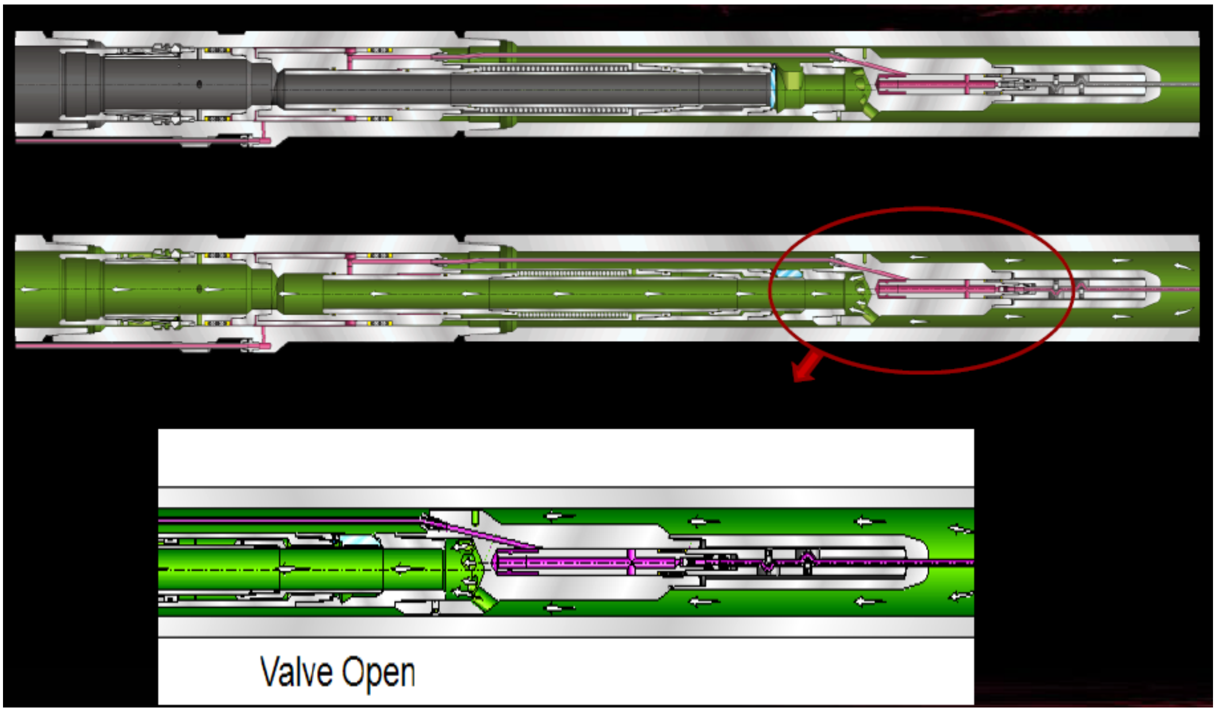

Figure 42: Detailed Drawings of the Flapper Valve [33]

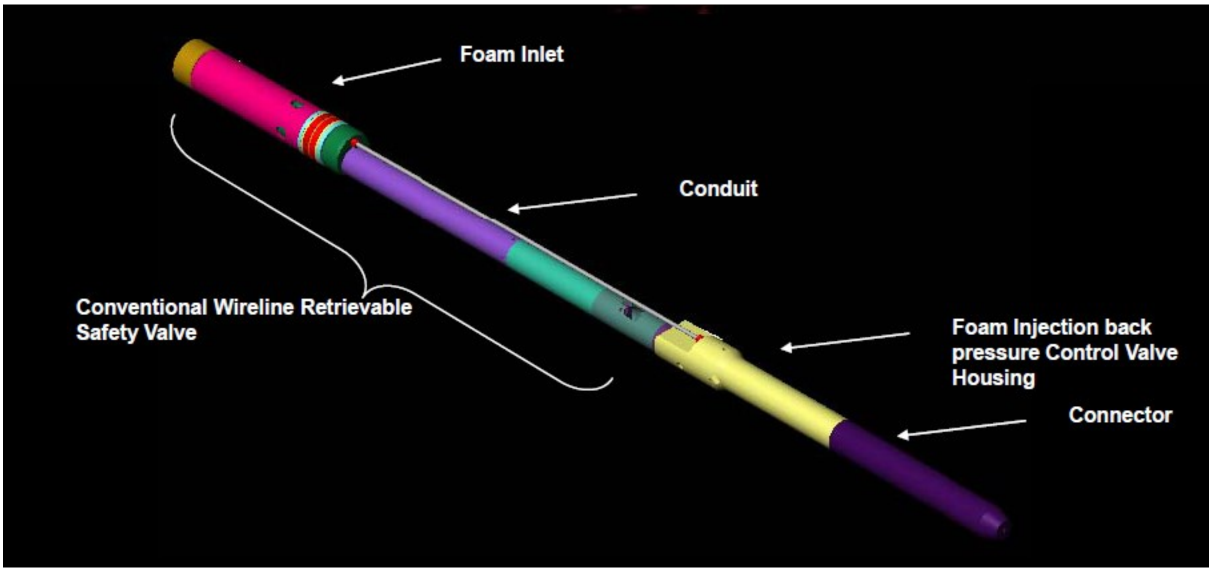

Figure 43: Identifying Parts of the Deliquification Safety System [33]

7.1.2 Plug in Plug System

The second proposal from Company A is called Plug in Plug System (Figure 44 and 45). This means that beneath the 3,688 [“] RPT plug a tailpipe with two integrated 1,750 [“] plugs (for the borehole safety) is installed. The 3,688 [“] plug is in the end a constituent part of the completion and the two 1,750 [“] plugs are pulled out of hole when the installation is completed. [33]

For the installation of this simple plug in plug method the following steps have to be carried out: [33]

- Run in hole with slickline and set plug (3.688 RN/ RPT) or permanent packer inside 4-1/2” with 2-3/8” tubing extension and up to 2 plugs pre-installed in 1.75” R and RN landing nipple
- Fill up 4-1/2” tubing with water and pressure test
- Run in hole the 2-7/8” velocity string with HWO-rig
- Connect 2-3/8” Tubing Retrievable Flapper Valve (TRFV) with special control line pack-off
- Run in hole with 4-6 x 2-7/8” pup joints and space out tubing hanger nipple
- Install special pack-off assembly to run ¼” control line inside the 2-7/8” pup joints
- Connect control line to 2-3/8” tubing hanger
- Set go packer
- Hang off in new tubing spool
- Functional test of 2-3/8” TRFV and ¼” control line for injection
- Run out slickline and retrieve protection sleeve out of TRFV
- Retrieve 1.75” R and RN plugs out of 2-3/8” tail pipe below packer
- Put well on production

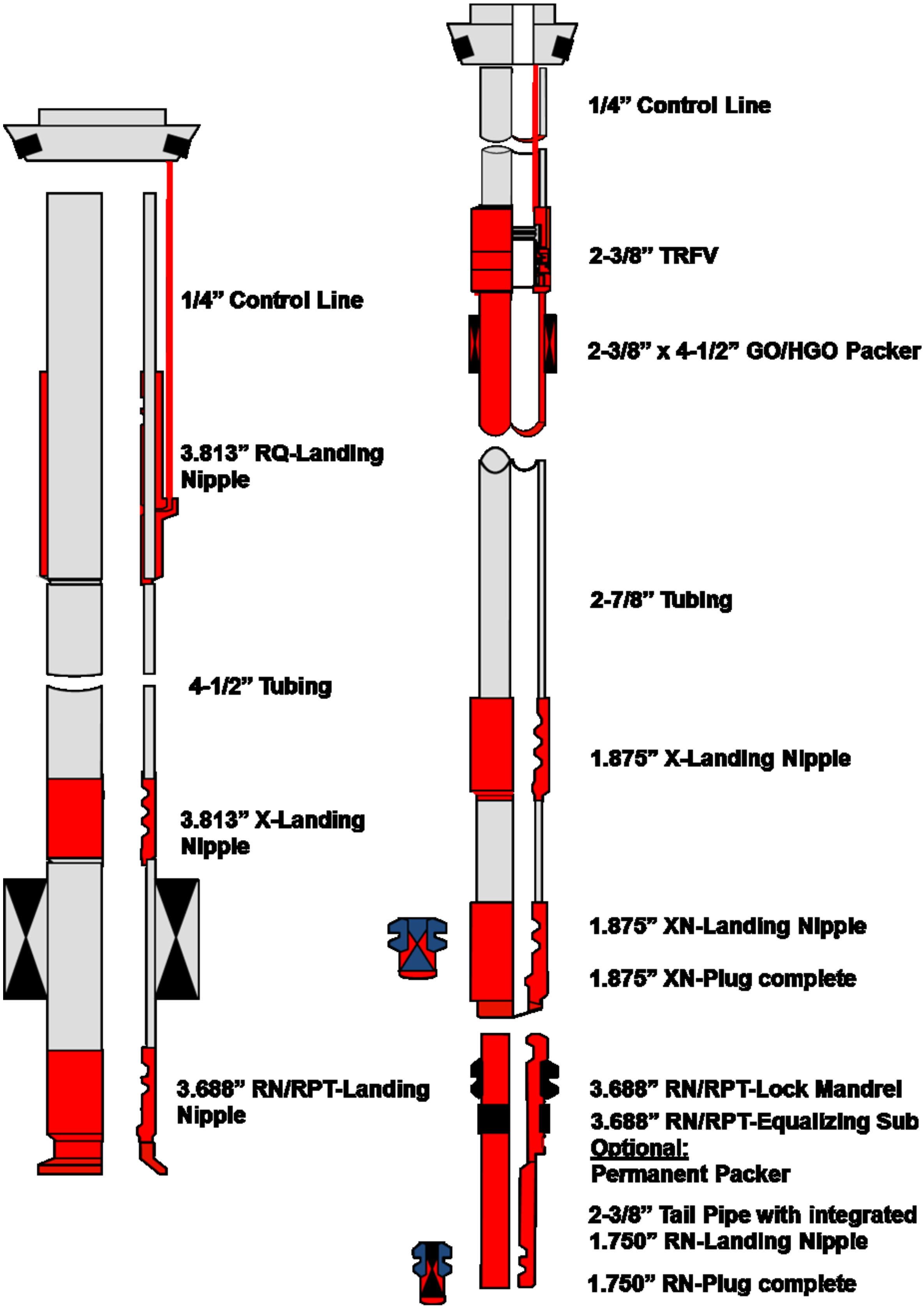

Figure 44: Exploded view of Plug in Plug System [33]

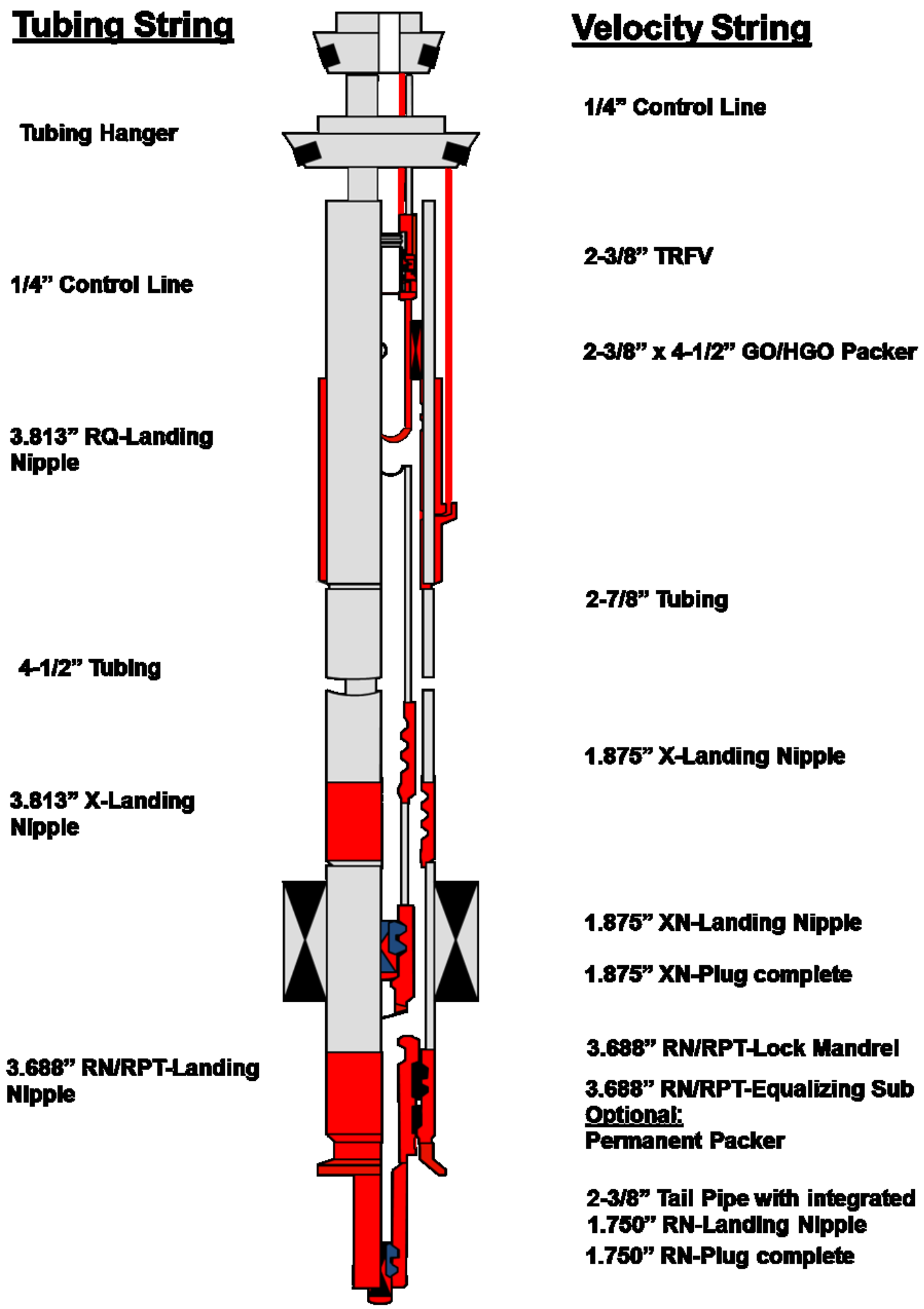

Figure 45: Plug in Plug System [33]

7.2 Company B

Company B has three proposals for the velocity string installation. Both of them can be applied on wells, suffering from: damaged control lines, liquid loading and damaged safety-valve landing nipples or sealbores. The first completion proposal is based on Company B`s damaged control-line system, where the completion schematic is shown in Figure 46. The second proposal is based on Company B`s capillary system, where the completion schematic is illustrated in Figure 47. The third proposal is a new invention from Company B, which is called the Company B`s Adapter System. Due to the requirements of the Rwe-Dea the adapter system was further developed from the first two proposals.

During the life of a well it can happen that the control line for the subsurface safety valve can leak, break or even plug up. In the past, the only way to get rid of this problem was to pull the tubing, which is an expensive operation. Company B`s damaged control line safety valve is able to bring the well back on production without the need of a workover and therefore significantly reduces the costs. This safety valve is a surface-controlled safety shut-in system and it can only be applied on sealbores and landing nipple profiles that are undamaged. [34]

7.2.1.1 Components

- Capillary Hanger: is needed to hang off the capillary control line from the wellhead. This device includes a backpressure valve profile and furthermore it has a similar bypass area as the new damaged control line safety valve. [34]

- Capillary control line: is going down along the tubing to a pod on the damaged control line valve. This pod diverts the flow of hydraulic fluid to a rod-and-piston mechanism that actuates the safety valve. [34]

- Stinger: is a weighted and centralized assembly that is attached to the end of the capillary line. It has a so called “female end” of the Company B`s wet-connect and it will join the capillary to the mating connection in the pod attached to the valve. According to Company B the “wet-connect” is unique because it can be mated and unmated, to put it another way, the capillary can be removed if necessary, and it is hydraulically locked in place when pressure is applied to the capillary string. Moreover the design of the wet-connect remedies the complications and additional leak paths that a hydraulically operated latch would create. The stinger also includes a dual-back check valves that prevent backflow through the capillary line. [34]

- Pod: is a special component because it includes the male end of the wet-connect and diverts the flow of hydraulic fluid from the centralized capillary sting to a flow path within the outer perimeter of the valve. [34]

- SSSV: can be landed on the one hand in the landing nipple from a previous wireline valve or on the other hand landed inside an existing tubing-mounted safety valve. A high percentage (95 %) of the maximum flow area can be obtained due to this design and the rod-piston actuated flapper valve. [34]

7.2.1.2 Installation Process

The damaged control line can be easily installed in a day and the installation includes the following steps. [34]

- The existing wireline is retrieved or the existing tubing valve is locked open (there is no need of communication)
- The existing control line is blocked
- The required barriers are installed in the tubing
- The wellhead is modified
- The barriers are retrieved
- The damaged control line safety valve is run in hole
- The capillary string is run in and spaced out
- The capillary string including the cap-string hanger is run
- The cap-string hanger is landed and wet mated
- The damaged control line safety valve is tested and the well is put on line again

The first step of the installation process begins by isolating the old control line and removing the old wireline retrievable safety valve or locking up the old tubing retrievable safety valve. The old control line is blocked off by using a suitable seal-end to prevent any foreign material from entering the system. After this the so called “Renn-gate", which is a wellhead penetration from Company B, can be installed without the removal of the existing wellhead. The Renn-gate is an insitu solution, which is kept in place by the lower master valve. To meet the policies of the companies the well is plugged to allow wellhead work. The backpressure valve is then run down the wellhead and located into the backpressure profile. The check valve is tightened resulting in a sealing off of the wellbore. Once the well is safely shut off, the existing bonnet assembly is unbolted and then removed, followed by the removal of the existing gate, upper and lower seat assembly. The pre-drilled modified lower seat is then installed with a new capillary tube attached and followed by the installation of a new upper seat. Between the upper and lower seat a new gate assembly is installed, before the modified bonnet is located on the existing bolt threats and connected to the capillary tube through the pre-drilled port. Pressure fittings are then threaded into the modified bonnet before the hand wheel assembly is connected. The damaged control line is run in hole using a standard slickline running tool. Once the damaged control line lock assembly is latched into the safety valve nipple profile the running tool is released. A probe attached to the bottom of the running tool is holding the flapper valve open during running. As the running tool is pulled from the lock, the probe is pulled upwards and the safety valve flapper closes. The damaged control line is also retrievable should any need for servicing or other arise. The stinger assembly is comprised of a unique connection which affixes the new control line and then is followed by a weight bar, the centralizers and in the end completed by a female wet connector peace. The assembly is run in hole until it centralizes in the damaged control line and locks in place. It takes 20 [kg] (kilogram) to engage the connector. The control line to surface is linked by the port. At the surface the control line is flaked to allow correlation between the distance of the latch and the surface. This is then noted and used in the next stage as the control line hanger is prepared to be installed. An upward pull of 200 [kg] is made to release the wet connect and pull up to space out. The flecked mark on the control line is located and based on wellhead specific sizes the control line is cut. This is designed to have a very small amount of slag between the connection points of the control line hanger and the damaged control line. The control line hanger is connected to the top side peace of the control-line and the CLH is then run in hole on slickline using a special RQXE running tool. It is run in hole to the same flecked depth knowing the wet connect will latch to the port in the middle of the damaged control line. As this lower connection is made, it is slacked off until the control line hanger latches into place. The dogs latch to the tie page threats and the CLH is set. Then the RQXE running tool is released and pulled out of hole. There is now a hydraulic link from the safety valve to the control line hanger landed in the wellhead. The Renn-gate provides the bridge between the control line hanger and the surface, thus allowing for surface control of the damaged control line safety valve. As the control line is pressured at surface, the pressure travels through the Renn-gate to the control line hanger and then is transferred by the central quarter inch control line and down to the damaged control line. This operates and functions in exactly the same method as the proven tools. Hydraulic pressure actuates the rod piston and flow tube which moving downwards opens the flapper valve and allows the well to flow. The whole damaged control line system is designed to be retrievable, easy to control and service. It also provides minimum disruption to the flowing characteristics of the well. During the developing phase all outstanding parts where designed to provide maximum flow areas and minimum turbulence with carefully formed internal components. The wellbore hydraulic connection again is proven technology to provide clean, undisrupted route to surface. [34]

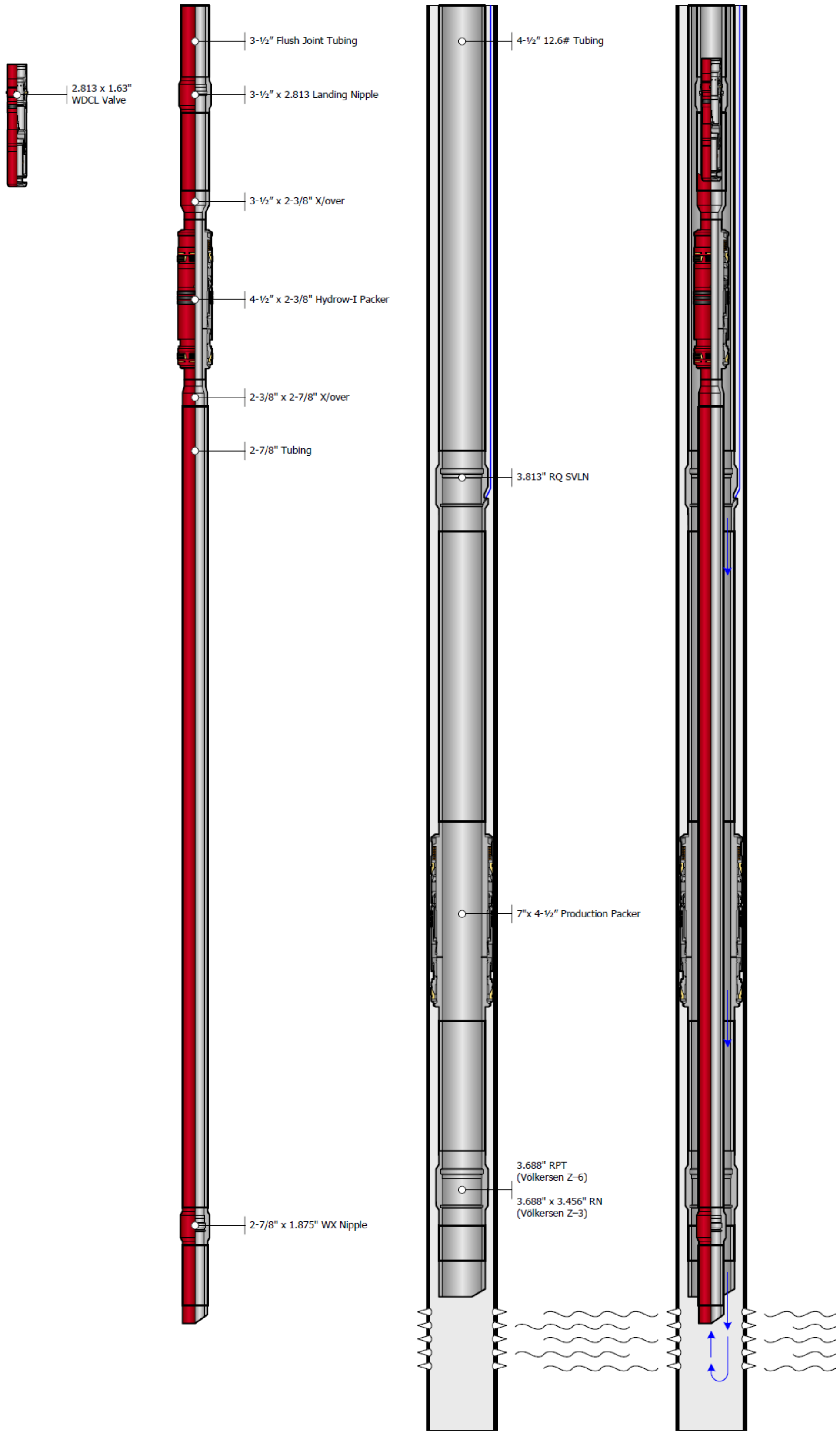

Figure 46: Completion Schematic with Damaged Control Line System [34]

7.2.2 Company B`s Opti-Chem System

If a well suffers from liquid loading, salt and mineral buildup and corrosion problems, the adding of chemicals can bring back live to the well. So far, the only way to bring such chemicals into a wellbore with a surface-controlled safety valve was to pull out the existing tubing and replace it by another. The Company B`s opti-chem safety valve makes it possible to have a capillary-injection system and a surface-controlled safety valve in one, without the need of a workover.

7.2.2.1 Components

- Capillary Hanger: is needed to hang off the capillary control line from the wellhead and the safety valve. This device includes a backpressure valve profile and furthermore it has a similar bypass area as the new opti-chem safety valve. [34]

- Capillary-Line: is going down along the tubing to a pod on the opti-chem system. This pod routes the flow of chemicals through the valve and in the end to the injection line below. [34]

- Stinger: is a centralized assembly that is attached to the end of the capillary line. It has a so called "wet-connect" which adds the capillary to the mating connection in the pod. The "wet-connect" is unique because it can be mated and unmated, to put it another way, the capillary can be removed if necessary and it is hydraulically locked in place when pressure is applied to the capillary string. Moreover the design of the wet-connect remedies the complications and additional leak paths that a hydraulically operated latch would create. The stinger also includes a dual-back check valves that prevent backflow through the capillary line. [34]

- Pod: this component mates to the capillary stinger and to the capillary hanger below the valve. When the safety valve goes in the open position the connection is completed. After this the pod directs the injected chemical through the open valve to the injection tubing below the valve. [34]

- Original safety valve, locked open: The original safety valve always remains in the open position. A new path is created between the original control line and the Renaissance valve inside the original valve.

- Opti-Chem SSSV: can be landed inside an existing safety-valve landing nipple or tubing-mounted safety valve. For this reason the possible maximum flow area is maintained. [34]

- Renaissance capillary hanger: this device is added to the bottom of the SSSV and supports the capillary injection line running to the bottom of the well. [34]
- Capillary-injection valve: at the very bottom of the chemical injection capillary line, this system is run. The chemical injection valve is a proven system and suitable for the toughest environments. Furthermore it enables precise chemical injection volumes and prevents chemical siphoning. [34]

7.2.2.2 Installation Process

The opti-chem system can be easily installed in a day and the installation includes the following steps. [34]

- The existing wireline safety valve is retrieved or the existing tubing-mounted safety valve is locked open and communicated
- The required barriers are installed in the tubing
- The wellhead is modified
- The barriers are retrieved
- The chemical injection valve and the lower capillary string are run in hole
- The opti-chem safety valve is installed on top of lower capillary string
- Land and lock in opti-chem savety valve and lower capillary string
- The safety valve is tested through the original control line
- The upper capillary string is run and spaced out
- The upper capillary string with cap-string is run
- The cap-string is landed and wet mate
- A chemical injection test is conducted and the well is put on line

The renaissance gate also called "Renn-gate" is a unique new wellhead penetration from Company B that can be installed without the removal of the existing wellhead. The Renn-gate is an insitu solution, done with the lower master valve in place. Firstly a backpressure check valve is run down the wellhead and located into the backpressure profile. This check valve is tightened resulting in the sealing off of the wellbore. Once the well is safely shut off, the existing bonnet assembly is unbolted and then removed, followed by the removal of the existing gate, upper and lower seat assembly. The pre-drilled modified lower seat is then installed with the new capillary tube attached and furthermore the new upper seat is also installed. A new gate assembly is fitted between the upper and lower seats, before the modified bonnet is located on the existing bolt threats and connected to the capillary tube through the pre-drilled port. Pressure fittings are then threaded into the modified bonnet before the hand wheel assembly is connected. First the chemical injection valve is affixed to the end of the chemical injection control line and run in the hole to place the valve across the perforations. The chemical injection control line is then cut and affixed to the bottom of the safety valve. The safety valve is run in hole, using standard slickline running tool. Once the safety valve is latched into the landing nipple profile, the running tool is released. The opti-chem safety valve is also retrievable, if any need for servicing should arise. The control-line stinger assembly is comprised of a unique connection which affixes the ¼ [“] control line and then is followed by a weight bar, a centralizers and in the end completed by a female quick connector peace. The assembly is run in hole until it is centralized and locked in place. It takes 20 [kg] to engage the connector. The control line to surface is linked by the port. The control line is flagged at surface to allow a correlation between the distance of the latch and the surface. This is noted and used in the next stage as the control line hanger is prepared to be installed. An over pull of 200 [kg] is made to release the quick connect and pull up to space out. The flagged mark on the control line is located and based on wellhead specific sizes the control line is cut. This system is designed to have a very small amount of slag between the connection points of the control line hanger and the opti-chem safety valve. The control line hanger is connected to the top side peace of the chemical line. The control line hanger is then run in hole by using a standard running tool on slickline. It is run in hole to the same flagged depth knowing the quick connect will latch onto the port in the middle of the opti-chem safety valve. As this lower connection is made, it is slacked off until the control line hanger latches into the place. The dogs slatch to the backpressure valve profile and the CLH is set. After this the running tool is released and pulled out of hole. There is now a new control line from wellhead to the port in the WCS safety valve. The Renn-gate, which is installed in the first instance, provides the path between the hanger and the surface. The whole opti-chem system is designed to be retrievable, easy to control and service. The operating parameters of the safety valve, surface control panel and emergency shut down system are not affected. The opti-chem safety valve is actuated using the existing control line at surface. Pressuring up on the existing control line opens the opt-chem safety valve. Pumped at surface the chemical treatment travels through the Renn-gate, the capillary tube and the pre-drilled lower seat to the control line hanger and then is transferred by the central quarter inch control line down to the opti-chem safety valve. The chemicals are then directed through the port to the outer body, where they pass the flapper assembly before turning back to center and through the lower seal system at the bottom of the opti-chem system. The chemical flows down the control line to the chemical injection valve where the chemical provides its treatment. In this instance the foaming agent causes the liquid to loose density allowing the natural reservoir pressure to produce the water and gas. There is enough flow area for the produced fluids and gas to flow up the tubing. The continuous foam injection prolongs the productive live of the well. [34]

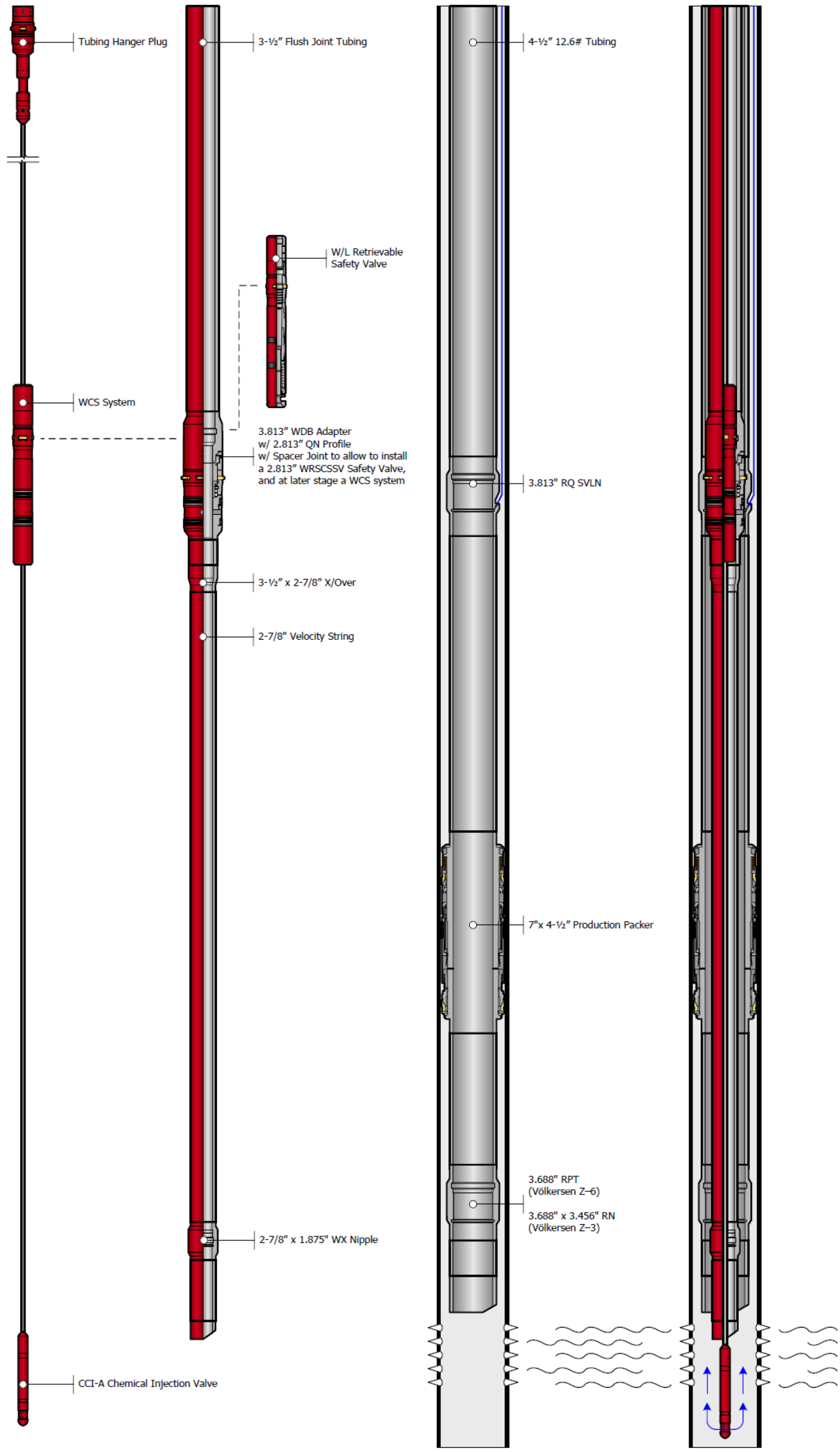

Figure 47: Completion Schematic with WCS System [34]

7.2.3 Company B`s Adapter Systems

In this chapter the operating cycle for the installation of the new Adapter System is described. It should be mentioned that this description is only a draft from Company B because at that time the adapter (shown in the appendix) is a brand new development and has never been installed in a well till now.

7.2.3.1 Brief Description & Job preparation

The adapter system consists of the 3,813 [“] RQ adapter itself, a shear through Lock mandrel and an above installed 2,813 [“] safety valve landing nipple. The adapter seals off the existing 3,813 [“] safety valve landing nipple (SVLN) and directs the hydraulic from the existing controlline access to the new 2,813 [“] SVLN. The adapter consists of piston seals, which are compressed via the controlline- and wellbore pressure and therefore it compensates damages to the existing SVLN. [34]

The adapter is located and latched in the 3,813 [“] SVLN but the weight of the velocity string is hung off in the spool with a tubing hanger. This operation is achieved by the shear through and floating effect of the inner mandrels in the adapter. The available stroke accounts 30 [cm]. The distance between the new tubing hanger spool No Go and the 3,813 [“] RQ SVLN No Go has to be clarified a priori or if necessary approved via a dummy run. The tubing hanger is then spaced out accordingly to less than 30 [cm] above the No Go spool. For this purpose appropriate fittings (Paßenden) have to be manufactured before. [34]

After snubbing of the velocity string, installation of the adapter, landing of the tubing hanger, discharging of the dummies and pulling out of the plugs, a standard Company B`s wireline retrievable safety valve is installed into the 2,813 [“] QN landing nipple. [34]

7.2.3.2 Velocity String Installation

- The velocity string is installed referring to the program of the RWE Dea. Assuming that two 1,875 [“] X plugs have been set in the respective LN on the lower side of the velocity string.
- Adjusting of the WDB adapter equipment but in the 2,813 [“] SVLN a dummy has to be set before.
- Channeling (snubbing) of the equipment. The snubbing areas on the equipment are agreed with the Rwe Dea before. For the grip area the fittings (Paßenden) are intended. [34]

7.2.3.3 Installation and Space out of the Adapter & Landing of the Tubing Hanger

- Slowly encountering of the 3,813 [“] RQ No Go in the existing SVLN.
- When notice a decrease in load the lowering is immediately stopped and the pipe is marked. The shear through of the adapter is adjusted to 24,000 [#] and accounts 12 [in] equivalent to 30 [cm].
- Calculate the space out. After this the corresponding pipes are tripped out and the fittings and the tubing hanger are collected.
- Tubing hanger is channeled and the SVLN is carefully encountered.
- Before landing of the tubing hanger the adapter is landed in the 3,813 [“] RQ No Go of the SVLN and the Lock Mandrel is locked. This happens by supplying weight on the adapter and the above pictured shear pins sheer by 24000 [#] (Figure 48 &49).
- Shear pins are sheared off, the keys are activated and the locating No Go is deactivated (Figure 50).
- Landing and assembling of the tubing hanger in the spool. [34]

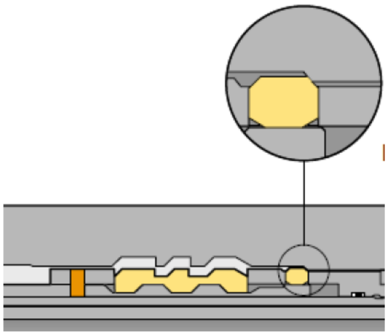

Figure 48: Lock Mandrel [34]

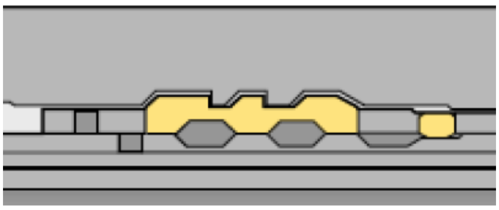

Figure 49: Sheared Off Pins in the Lock Mandrel [34]

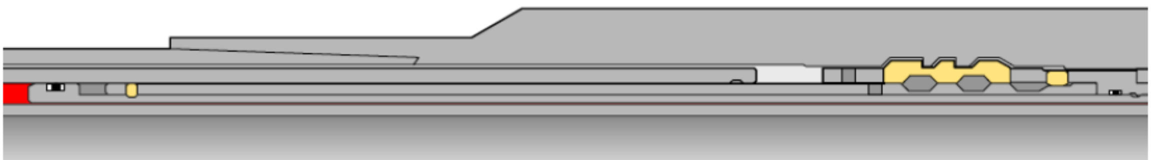

Figure 50: Floating Main Mandrel (Weight of the string is taken by the Tubing Hanger) [34]

7.2.3.4 Installation of the Wireline Safety Valve

- Construction of the slickline and extraction of the 2.813 [“] dummy and 1.875 X plugs.
- Implementation of the WVE safety valve. Thereby the controlline is flushed. By increasing of the pressure the panel pump is stopped and the pressure is released and at the same time the safety valve is run/ hammered into the 2.813 [“] SVLN.
- Releasing and withdrawal of the running tool. After this the telltale on the surface should be controlled. A not sheered off telltale is indicated by the correct seat of the Lock Mandrels. Subsequently the safety valve and the inflow are tested.

7.3 Company C

The system presented from Company C is called “Velox” Straddle and Velocity System. According to Company C it is defined as a modular, retrievable system that utilizes the existing technology and offers a low cost reliable tool. The Velox system is available in three different systems depending on the type of application. These Systems are the following: the Straddle System, the Long Straddle/ Velocity System and the Velocity String System itself. Furthermore the Velox Straddle and Velocity System features tubing patch, velocity and high tail pipe characteristics. It can be used to a temperature up to 250 [degF] and can handle weights up to 3,500 [psi]. What else should be mentioned is that it is a system of modular design, which has a long proven run history. The system utilizes not only common parts, but also the running and pulling tool is compatible with the Velox system and it is run and set in one trip. The different sizes that are available are: 3 ½ [“], 4 ½ [“], 5 ½ [“] and 7 [“]. [35]

7.3.1 Available Systems

As mentioned before, there are three different Systems available. The first system, which is run as a long straddle or as a velocity string including a lower pack-off, is displayed in Figure 51. It is composed of the Velox STV Pack-off, the coiled tubing or hard pipe, the setting sub, the Velox lower packs-off and last but not least the double pump open sub. When taken as a long straddle the system is used to extend the length of the perforated casing or tubing and when taken as a velocity string it is primarily designed for zonal straddle applications, where the isolation distance between the pack-offs is relatively long. By minimizing the ID of the production tubing it is suitable to lift out water from gas wells. [35]

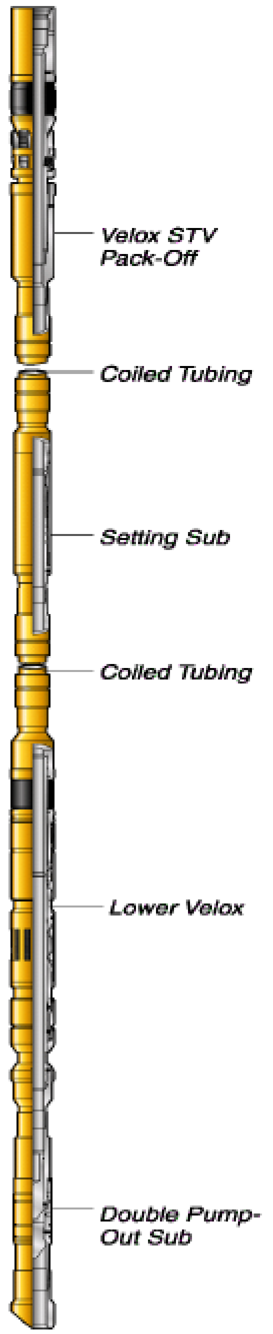

Figure 51: First System: Long Straddle or Velocity String with Lower Pack-Off [35]

The second system, called the Straddle System, is shown in Figure 52 and consists of the following components: the Velox upper pack-off, the coiled tubing or hard pipe, the setting sub, the Velox lower pack-off and the double pump open sub. This kind of system is primarily designed for relatively short distances between the pack-offs and therefore it is suitable for applications in perforations, for isolation of leaking gas lifting mandrels and for holed tubings. It is also recommended when there is insufficient tailpipe weight to allow deployment of the Velox STV straddle system. [35]

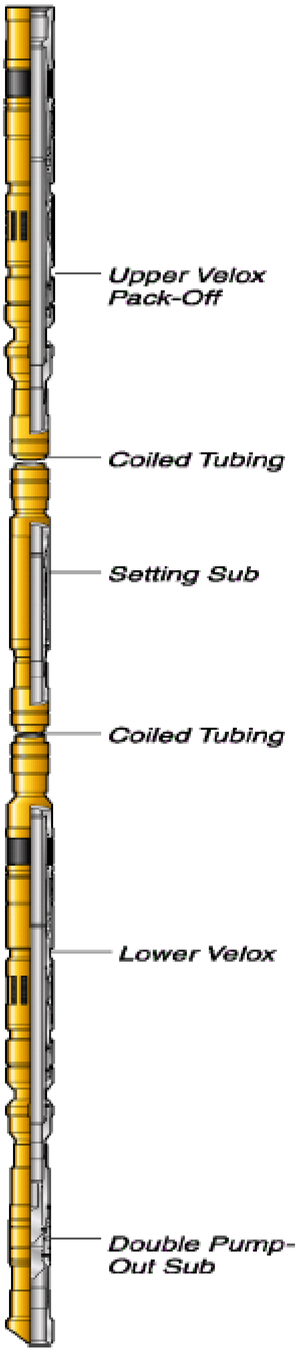

Figure 52: Second System: Straddle System [35]

The third system is run as a velocity string with no lower pack-off and it is adequate for liquid loaded wells (Figure 53). This system consists only of three components, as they are: the Velox STV pack-off, the coiled tubing or hard pipe and the double pump open sub.

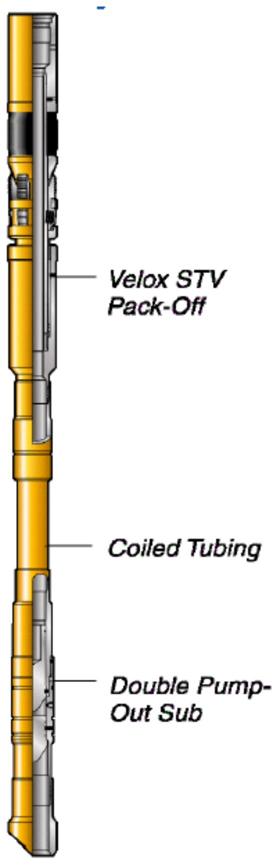

Figure 53: Third System: Velocity String [35]

According to Company C the benefits of these systems are the following: low cost compared to workover, one trip deployment on either coiled tubing or jointed tubing, retrievable, packing element on each pack-off located above the slips. [35]

7.3.2 Components

To get a better understanding for the different components of the three systems, they are described in detail below. The beginning makes the upper straddle pack-off, which is identical to the lower pack-off. The difference between the upper and lower one, is made by a simple conversion that will enable the straddle pack-off to be run as either an upper or as a lower pack-off. We have the ability to be run in boreholes with temperatures up to 250 [degF] and up to weights of 3,500 [psi]. Moreover, it is run in a single trip and set by a hydraulic mechanism that also can be released by a straight pull. The next component is the so called STV pack-off, which has a short and compact form. It can withstand pressure ratings and temperatures ranging from 60 to 250 [degF]. Furthermore it is also set by a hydraulic mechanism and run into the well in one trip. The setting sub between the pack-offs has a special function because it allows a tubing movement during setting and production operations. The inner diameter (ID) of the setting sub is compatible with the string and it has shear pinning capabilities and is suitable for pressure ratings up to 5,000 [psi]. The last component is the double pump open sub below the lower pack-off that provides a pressure barrier during running and facilitates straddle setting. Here again, this component is set in a single trip, has a double mechanical barrier, can handle variable pressure ratings and is once pumped open. [35]

Beside of the components, the auxiliary equipment like, the running and pulling tools, should be mentioned, too. As the names state their functionality exactly, they are needed to set the system into the well or pull it out of the wellbore. There is to distinguish between the Velox straddle running tool and the velox upper pack-off running tool. Depending on the application, the upper and lower pack-offs of both the velox STV and velox straddle systems can be set either simultaneously or individually. On the one hand the velox straddle running tool is used for simultaneous setting of both pack-offs and on the other hand the velox upper pack-off running tool is used for individually set the upper pack-off. When the velox running tool sets a system in place, the load is only carried by the body and therefore minimizes the stress on the grapple. The releasing mechanism itself can be hydraulically or mechanically. Prior running in hole it has the facility to make a pressure test between the running tool and the pack-off and furthermore allows the tubing pressure to set the pack-off. For the pulling tools, there is to distinguish between the hydraulic “GS” pulling tool and the wireline “GS” pulling tool. The hydraulic “GS” pulling tool has a field proven history and is build of high strength, which makes it also suitable for fishing operations. Hereby, the whole load is carried by the mandrel and therefore minimizes the stress on the collets. The design of this tool was improved during the last years. On the one hand it allows now to pump through the system to wash eventually sand or other debris from the reservoirs. On the other hand it allows heavy duty jarring. [35]

7.3.3 Operational Instructions

There are different setting methods for the Velox Straddle system which are described in greater detail in the following sub chapters.

Individual Setting of the Velox STV Straddle System:

The individual setting option allows the upper pack-off running tool to be dis-engaged after setting the Velox STV upper hydraulic pack-off and prior to setting the Velox lower hydraulic pack-off. This avoids the early releasing of the running tool during the application of increased pressure to pump open the Velox double pump-out sub. When the running tool is dis-engaged afterwards the individual setting of the Velox lower hydraulic pack-off is achieved by increasing the tubing pressure. [35]

Simultaneous Setting of the Velox STV Straddle System:

This kind of setting process permits both, the Velox STV upper hydraulic pack-off and the Velox lower hydraulic pack-off, to be set prior to dis-engaging the Velox straddle running tool. Again the running tool should be released before the application of increased pressure to pump open the Velox double pump-out sub. [35]

Surface Test:

When the appropriate Velox running tool is fitted to the straddle system it is possible to conduct, either a low pressure with approximately 100 [psi] or a 3.500 [psi] working pressure test prior to running the straddle system. A running tool clamp plus upper and lower pack-off clamps must be fitted if a 3.500 [psi] working pressure test is to be performed. [35]

Running the Velox STV Straddle System:

During the running process a running speed of no greater than 25 feet per minute [ft/min] is suggested and this should be reduced to 5 [ft/min] when running through some restrictions. When the predetermined setting depth is reached surface hydraulic tubing pressure is applied through the coil or working string. This tubing pressure is transferred to the running tool and afterwards into the setting chamber of the Velox STV upper hydraulic pack-off (individual setting) or both setting chambers on the Velox STV upper pack-off and the Velox lower hydraulic pack-off (simultaneous setting). [35]

Individual Setting of the Velox STV Upper and Velox Lower Hydraulic Pack-off:

When the Velox upper pack-off running tool is fixed to the straddle, the straddle is run down in hole at the appropriate running speed to the predetermined setting depth. After this surface pressure is applied down the running string which enables to set the slips on the Velox STV upper hydraulic pack-off. This tubing pressure should be maintained during slacking off the tailpipe weight to allow pack-off of the element on the Velox STV upper pack-off. This completes the setting sequence on the Velox STV upper hydraulic pack-off. At this stage the Velox upper pack-off running tool is released and there are a number of release options. Following the releasing of the running tool, the well needs to be pressurized from the top, to allow the setting of the lower Velox hydraulic pack-off. After setting the slips and pack-off of the element, increased well pressure is applied to complete pack-off and pump open the double pump-out sub. The running string is then pulled back to surface. [35]

Simultaneous Setting of the Velox STV Upper and Lower Hydraulic Pack-off:

When the Velox straddle running tool is fixed to the straddle, the straddle is run down in hole at the appropriate running speed to the predetermined setting depth. After this surface pressure is applied down the running string which enables to set the slips on the upper hydraulic pack-off. This tubing pressure should be maintained during slacking off the tailpipe weight and thereby compressing and packing off the element on the upper pack-off. In doing so the total tailpipe weight should not be slacked off as this will guarantee that the running tool does not release before setting the lower hydraulic pack-off. Afterwards an increased tubing pressure from the surface is applied to allow the setting of the lower pack-off slips and pack-off of the element. The process is completed when the lower hydraulic pack-off is set and the running tool is dis-engaged. Again there are a number of releasing options for the running tool. In the end the well is pressurized from surface to allow pumping open the double pump-out sub. The running string is the pulled back out of the wellbore. [35]

Retrieval of the Velox STV Straddle System:

A shorter length of the straddle system, less than 500 feet [ft], can be retrieved by a single trip operation. For longer straddles, greater than 500 [ft], especially where retrieval is being made by using coiled tubing, a two trip operation is necessary due to the weight of the straddle system and the distance between the pack-offs. Cutting the straddle conduit between the pack-offs, either mechanically or chemically, will enable retrieval of each pack-off. [35]

One-trip retrieval:

The bottom-hole assembly needs to consist of a flow release type GS pulling tool or a wireline type GS pulling tool to run into the well and to engage the internal fishing neck within the top sub of the Velox STV upper pack-off. Furthermore a jarring assembly should also be included within the bottom-hole assembly to support the recovery. When the GS profile is latched, an upward pull which is greater than the tailpipe weight hanging off the upper pack-off is needed to release it. Afterwards the upper pack-off element should have at least 30 minutes to relax before releasing the lower hydraulic pack-off shear ring. Once the upper pack-off has been released an additional upward movement is needed to release the lower hydraulic pack-off shear ring. Again the lower hydraulic pack-off should have at least 30 minutes to relax before the complete Velox straddle system is recovered from the well. Hereby a releasing speed of 25 [ft/min] is advised and reducing the speed to 5 [ft/min] when passing through any restrictions. [35]

Two-Trip Retrieval:

With the tubing, which is attached between the upper and lower pack-offs, the upper STV back-off is retrieved by a straight pull to release it. The bottom-hole assembly consisting of a flow release type GS pulling tool or a wireline type GS pulling tool is run in hole and engaged with the internal fishing neck within the top sub of the STV upper pack-off. Furthermore a jarring assembly is included into the bottom-hole assembly to support the recovery. When the GS profile is latched, an upward pull which is greater than the tailpipe weight hanging off the upper pack-off is needed to release it. Afterwards the upper pack-off element should have at least 30 minutes to relax before releasing the lower hydraulic pack-off shear ring.

Once the upper pack-off has been released an additional upward movement is needed to shear release the lower hydraulic pack-off shear ring. Again the lower hydraulic pack-off should have at least 30 minutes to relax before the complete Velox straddle system is recovered from the well. Hereby a releasing speed of 25 [ft/min] is advised and reducing the speed to 5 [ft/min] when passing through any restrictions. For the retrieval of the lower pack-off, an overshot-type of fishing tool, with an upward jarring capability can be run in hole to shear the shear ring on the lower hydraulic pack-off. Afterwards the element should have at least 30 minutes to relax. Hereby again a releasing speed of 25 [ft/min] is advised and reducing the speed to 5 [ft/min] when passing through any restrictions. [35]

Shear Ring Options:

Both the Velox upper and lower hydraulic pack-offs are equipped with the maximum shear ring value to suit the maximum differential pressure rating in the lightest casing weight. Some applications may have lower differential pressure requirements and or may be set in heavier casing weights. A lower shear ring value to suit these applications can be supplied. This will reduce pulling and jarring loads required to release the pack-offs. [35]

7.3.4 Case Histories

There are some companies which have installed the Velox system into their wells (Table 5). One example that extends the well life is taken from Arco Pickerrill. For this example the first system was used. Prior the installation the well was in a non-productive condition. After the installation the first well increased the production to 3.5 [Mscf/day] and the second well to a production of 2.5 [Mscf/day]. Another example is taken from BP Ravenspurn. For this wells the third system was used and the string had a lengths of 11,500 [ft]. The well was in a non-economical state for 6 months. After the installation the first well had a production of 5,0 [Mscf/day] and the second well had also a production of 5,0 [Mscf/day]. [35]

Table 5: Case Histories for the Velox Straddle & Velocity System [35]

Customer	Field / Well	Date	Size	String Length	Coil Co.	Coil Size	Deployment	Comments
Shell	Fulmar Alpha FA-06	Mar '99	51/2"	8,378ft	WelServ	2.785"	Coiled Tubing	Succesfull run
Arco	Pickerrill A8y	April '99	5 1/2"	11,226ft		2.375"	Coiled Tubing	2.5Mscf/day after install zero previously
Arco	Pickerrill A6z	April '99	5 1/2"	11,226ft		2.375"	Coiled Tubing	3.5Mscf/day after install zero previously
Shell	Lehman F-01	Jun '99	5 1/2"	5,900ft		2"	Coiled Tubing	
Shell	Lehman D 400	Jun '99	3 1/2"	6,704ft		2"	Coiled Tubing	
BP	Ravenspurn 26c-F7	Sep '00	5 1/2"	11,666ft	PSL	2.875"	Hyd.Work over	5Mscf/day after install zero previously
BP	Ravenspurn 26A-F12	Sep '00	5 1/2"	12,373ft	PSL	2.875"	Hyd.Work over	5Mscf/day after install zero previously

8 Field Experiment: Well Z1

The production site of the Rwe Dea in Lower Saxony has only one velocity string installation until now. To have a comparison for the possible installations in the future this chapter gives an overview of the starting situation and the type of velocity string installation.

8.1 Completion Background & Production History

In the year 1984/85 the well Z1 (completion schematic in the Appendix) was drilled to an end depth of 5,036 [m]. In doing so the gas bearing formation of the Wustrow-Sand was encountered. Approximately one year later the well was put on production. Until the year 2004 the well produced 1,012 milliard cubic meters [Mdr m^3] of gas. In Figure 51 the production history of the well Z1 from 1997 to 2003 is given. It shows the allocated dry gas rate (yellow) [m^3/hr] (cubic meters/ hour], the wellhead pressure (red) [bar] and the daily water (blue) allocated [m^3] versus time [dd.MM.YY]. [20]

The completion of well Z1 consists in the first instance of an 18 5/8 ["] (inch) casing, a 13 3/8 ["] casing and a 9 5/8 ["] casing, where all of them are cemented to the surface. A 7 ["] liner is set into the completion too, going from about 3,416 [m] till about 4,684 [m]. In the area of the reservoir a 5 ["] liner (perforated in two sections) is installed ending at a final depth of 5,033 [m]. The produced gas from the reservoir is flowing through a 4 ½ ["] tubing production string up to the surface. Some distance above the producing zone, exactly at a depth of 4,552 [m], a production packer is set used to seal off the flow of fluids through the annular space between production string and the production casing (the 7 ["] liner). Further important completion installations arranged from the bottom of the well to the surface are: the wireline entry guide, the RN- and X-landing nipple, the flow couplings and the ball-valve-landing-nipple. The last installation in the completion is the SSSV. In this case, it is a wireline-retrievable-ball-valve. [20]

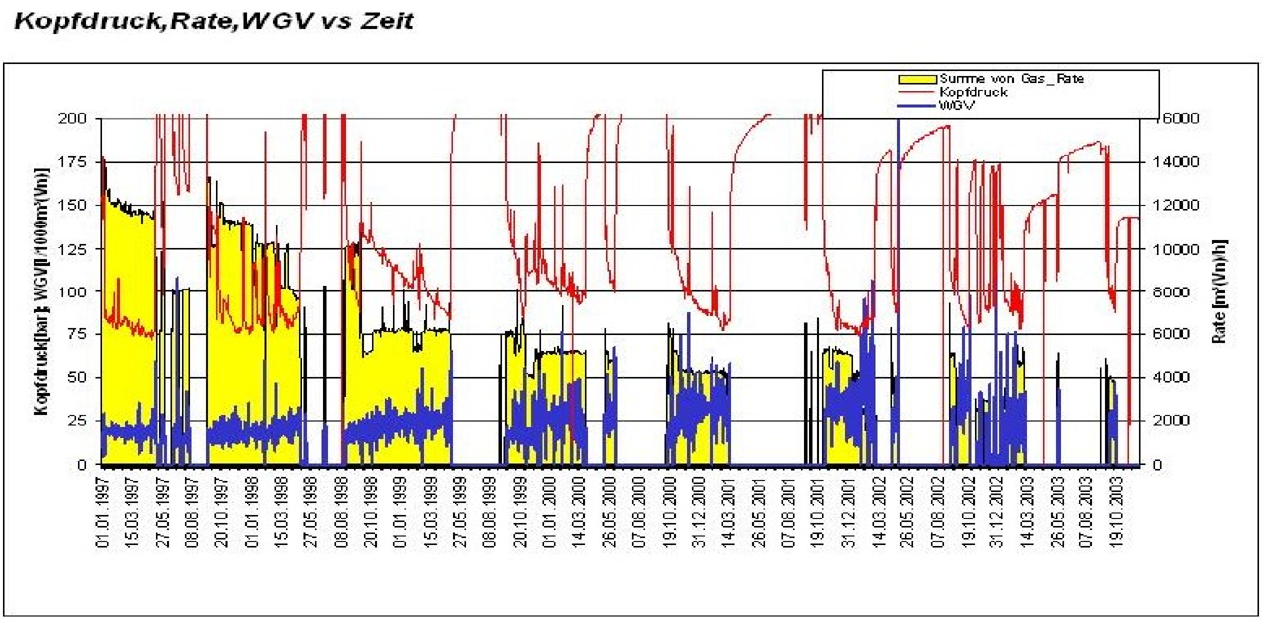

Figure 54: Production History of Well Z1 (1997-2003) [20]

8.2 Installation of the Velocity String

The production history of the well Z1 shows that the onset of liquid loading occurred in the year 2003. The gas rates in the well declined at an accelerated speed until the well completely loaded up in early 2004. After this the well was repeatedly shut-in for some weeks and brought back on line until it loaded up again. In the end it was decided to shut in the well until the velocity string was installed. [20]

The goal of the recommissioning of the well was to find a cheap completion that also meets the requirements of future standards. The engineers decided to simply hung off a coiled tubing string with a tension packer into the existing 4 ½ [“] production string (completion schematic is shown in the Appendix). One major criterion was to guarantee the safety of the well and the environment by maintaining the functionality of the SSSV. Therefore the coiled tubing velocity string was installed into the production tubing 5 [m] below the existing landing nipple profile for the SSSV. The end depth of the velocity string was fixed to reach up to 10 [m] above the perforation. Thus the velocity string reached a total length of approximately 4760 [m]. [20]

The used velocity string had to withstand all the chemical and mechanical conditions in the borehole. For this reason a new generation of coiled tubing chrome steel (Cr16-8) was applied. The analysis of the Prosper modeling (Inflow Performance versus Outflow Performance) resulted in a 2 [“] diameter coiled tubing string. At this time the BJ (Byron Jackson) Company offered a new generation of Coiled Tubing construction, which means a bigger working reel and therefore enabled the installation of such a long coiled tubing string, as well as the transportation of the reel to the location. [20]

8.3 Results

The implementation of the velocity string into the existing completion revived the gas production of the well again. This is especially shown on the production history in Figure 55. The advantage of this installation is the maintaining functionality of the SSSV and the very simple and cheap type of construction. One advantage of this installation is that there is no technical hardware across the wellbore, therefore problems with later services or the like can be avoided. A disadvantage is the less space in the wellbore to allow for example the lowering of a camera into the tubing to look for deposited materials or the like. Furthermore, there is no possibility to inject a surfactant into the wellbore in a later stage. After some month of production it can happen that liquid loading appears and production diminishes or even stops again. Therefore the injection of foam, in the presence of water, is needed to reduce the surface tension and therefore enabling an easier gas entrainment.

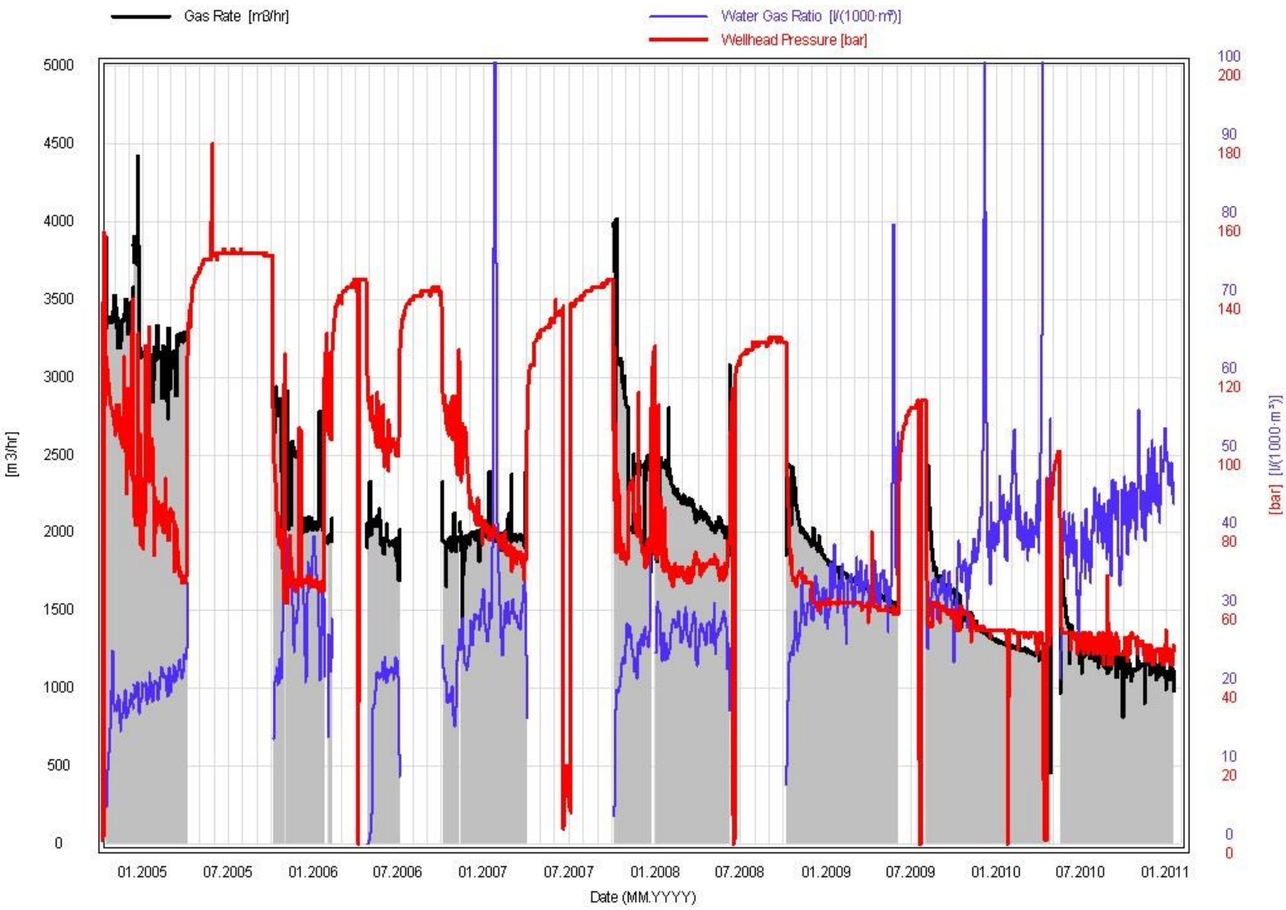

Figure 55: Production History of Well Z1 after Velocity String Installation [20]

9 Final Discussion

For the final discussion the initial situation for the velocity string installation and some important points, which should be considered, are shortly summarized.

Requirements from the Rwe-Dea company

The production district of the Rwe-Dea company wants to install a velocity string into two older wells that suffer from liquid loading and in the end abandoned their production completely. Due to the pressure losses the size of the velocity string should not be smaller than 2 7/8 [in] and furthermore the string has to be placed directly above the perforation. Beside of this, it should be mentioned that because of company requirements of safety systems, the SCSSV has to be a fix installation in the borehole to stop the flow in the event of a catastrophic failure. After the installation of the velocity string it can happen, only a few months later, that liquid loading appears again, therefore the company wants to have the possibility of foaming injection. Moreover, the Rwe-Dea wants to have the chance to lower a camera into the borehole to localize some deposited material, precipitations or water. The velocity string itself should not be installed into the tubing because of its length and corresponding weight. It is better to fix the velocity string into the wellhead.

Company A

The discussion is started with the two systems from the Company A. The major advantage of the capillary deliquification safety system is certainly the delivery of surfactants, chemicals and liquids to a predetermined point within the completion to handle problems like liquid loading. At the same time the system maintains the application and functionality of the downhole safety device. Furthermore, the foaming agent can be induced directly above the perforation as it is favored from the company. Another advantage of the system is the fast installation with standard intervention techniques, like coiled tubing and the like. Unfortunately the length of the capillary string is determined by the breaking strength of the same. The longer the string, the heavier it is and its own weight will eventually break the string. Therefore the capillary diameter, the wall thickness and the material strength are important factors that need to be considered before the installation itself. Another big disadvantage is that the foaming agent very often leads to the creation of corrosion problems. This means that the foamer induces also oxygen which causes corrosion of the capillary items. Not at all, it can happen that also the issues of the existing materials of the well completion including the surface equipment suffer from corrosion problems. Therefore the agent should be mixed with inhibitors and the fluid that is produced to the surface should be also treated with a de-foaming agent. What else has to be mentioned is the need of periodic maintenance of the foam injection back pressure valve (FIBPV), which means that the safety valve has to be pulled to surface to replace the FIBPV and service it.

The second proposal from the Company A is the Plug in Plug System. It is a very simple kind of installation where the sub surface safety device can be maintained and furthermore there is also the possibility of foaming injection by the use of the old control line. But the big disadvantage for this recommendation is that the foaming agent has to run all the way downwards the annulus of the velocity string and the tubing and therefore leads to the complete corrosion of it.

Company B

The proposal from Company B tries to meet the requests of the Rwe-Dea Company. This means that the old control line from the SSSV is used to direct the surfactant to the perforations, but this is a bad idea because of the aggressiveness of the surfactant and the associated risk of corrosion of the whole production equipment. Furthermore this control line should be used to activate the safety valve. Another company did a trial with such a kind of installation and they had a lot of troubles with corrosion and the functionality of the safety valves, therefore such installations are now obsolete. Therefore Company B proposed their damaged controlline valve to enable the activation of the valve with the control line positioned in the tubing. Later on Company B developed a new system, called the WDB adapter. This adapter is installed with a new SVLN (safety valve landing nipple) set above. Hereby the old control line is used to activate the valve. Later the standard wireline retrievable valve can be exchanged by a WCS (see chapter 7.2.2) valve, where the control line is going from the valve to the perforations. The big advantage of this kind of installation is that the surfactant remains in the controlline and therefore only the control line has to be manufactured from high-alloy steel. The old controlline activates still the valve for closing and opening of the flapper, therefore the foaming injection and the activation of the valve are separated.

Company C

From the Company C detailed information is not really available and therefore it is hard to argument for this kind of installation. The only thing that can be said is that they have the possibility of the velocity string and foaming agent installation. Their systems are defined as modular, retrievable systems that utilize the existing technology and offer a low cost reliable tool. Furthermore the company has long proven run history.

Discussion

For the final discussion the proposal of Company C is not considered, due to the less information and contact.

In the following two tables six and seven the advantages and disadvantages of Company A and Company B are summarized.

Table 6: Advantages & Disadvantages of the Systems of Company A

Company A	Advantages	Disadvantages
System 1	Possibility to deliver surfactants	Limitation of the capillary string due to its length and weight
	Maintains the functionality of the SSSV	Foaming agent can lead to corrosion of the capillary string and the completion equipment
	Surfactants are introduced directly above the formation	Need of inhibitors downhole and on surface
	Fast installation with standard intervention techniques	Periodic maintenance of the foam injection equipment
System 2	Simple installation	Foam runs down the annulus of the velocity string and leads to corrosion
	SSSV can be maintained	
	Possibility of foaming injection	

Table 7: Advantages & Disadvantages of Company B

Company B	Advantages	Disadvantages
System	Functionality of the SSSV	Has never been installed before
	Possibility to inject the foaming agent into the bottom of the well in an extra capillary string	
	Less corrosion problems due to a high alloy steel capillary string	

Due to the big disadvantages (table six and seven) from Company A, it is obvious to take the solution from Company B. The system from Company B had brought up the idea with the adapter to separately control the SSSV and inject the foaming agent. In the end this totally meets the requests of the Rwe-Dea, although this system has never been installed before. Such new developments should always be given a chance to be eventually successful in the future. But one must always be aware: the more equipment is installed, the more problems can occur and related to this more maintenance is needed. In the long run this could lead to additional costs in the future.

Options for the Future

Finally there is to mention that Company A and Company B offer a special device for new future well completions. Both of them enable the possibility of foam injection when needed. Company A, on the one hand, offers the so called “Injection Nipple”, which is a safety valve landing nipple that is installed in the new well. During the installation the wellbore has no communication with the control line. Only with a special communication tool, a hole can be punched to enable the communication. So each new well has the option to use a capillary deliquification system if required. On the other hand, Company B suggests an additional externally banded capillary-injection string that is added inside the control line for the tubing retrievable SSSV (TRSSSV). This extra externally banded cap string completes Company B`s Optimax chemical-injection sub, which is landed 100 [ft] below the TR-SSSV. When the well needs chemical injection in the future, the injection sub will be communicated to the tubing ID. [33] [34]

10 Summary

In chapter one the task setting of the Rwe-Dea company in Lower Saxony is descripted and furthermore the aims and objectives of this work are summarized.

In chapter two the background of liquid loading is shown. This means in detail: what is liquid loading and what are the problems associated with it. Where is the water coming from and how do we first recognize liquid loading in the daily production.

The third chapter summarizes current artificial lift methods which are also suitable for dewatering of gas wells. These different artificial methods are divided into two main groups: the reservoir supplied energy system group and the external supplied energy system group.

Chapter four gives a short description of the gas production in Northern Germany. In addition to this the geological conditions and some important parameters for the biggest gas field of the Rwe-Dea are given.

In chapter five the two sample wells for which the velocity string should be installed are described. This includes their completion background, production history and completion schematics.

Chapter six describes the intention behind the installation of a velocity string. Furthermore, the functionality of such a string is given and important parameters for the planning phase are summed up. In addition to this, different possibilities for the installation of the velocity string itself are given.

In chapter seven the industrial state of the art is described. Three different German service companies present their solution for the velocity string installation.

Chapter eight describes the gas well for which the Rwe-Dea has already installed a velocity string. This means the completion background and the production history are summed up. In addition to this the type and the procedure of the velocity string installation are given.

Chapter nine contains the final discussion of this work and shows a summary of the advantages and disadvantages of the different presented options of the German service companies.

11 Register

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11.2 List of Abbreviations

Listed according to the alphabet

#	number
%	percentage
“	inch
API	american petroleum institute
bar	bar
BHA	bottom hole assembly
BHP	bottom hole pressure
Bill.	Billion
BOP	blow out preventer
cf	cubic feet
CSV	concentric safety valve
CT	coiled tubing
ESPs	electrical submersible pump

FIBPV	foam injection back pressure valve
ft/sec	feet per seconds
g	gram
GLR	gas liquid ratio
hr	hour
HWO	hydraulic workover
IPC	intake pressure curve
IPR	inflow performance relationship
K	kelvin
l	liter
LH	Liquid holdup
LL	liquid loading
LN	landing-nipple
m	meter
m^3	cubic meter
MD	measured depth
mD	milly darcy
MMscf	million standard cubic feet
mol	amount of substance
OD	outer diameter
OGIP	original gas in place
PCP	progressive cavity pump
Psi	pound-force per square inch
pwf	flowing wellhead pressure
SCSSSV	surface controlled subsurface safety valve
SSC	standard state conditions
SSSV	subsurface safety valve
STB	stock tank barrel
SVLN	safety valve landing nipple
TRSV	tubing retrievable safety valve
TSFV	tubing retrievable flapper valve
TVD	true vertical depth
VLP	vertical lift performance
VLPC	vertical lift performance curve
WEG	wireline entry guide
WHP	well-head-pressure
WLRSV	wireline retrievable safety valve
WR-SSSV	wireline retrievable surface controlled subsurface safety valve

11.3 SI Metric Conversion Factors

ft x 0.3048 = m

psi x 6.8947 = kPa

psi x 0.06895 = bar

ft^3 x 0.02832 = m^3

bbl x 0.15898 = m^3

md x 0.00098692333 = μm^2

lbf x 4.448222 = N

lbm x 0.4535924 = kg

inch x 25.4 = mm

1000 g = 1 kg = 2.2046 pound

1 l = 0.001 m^3

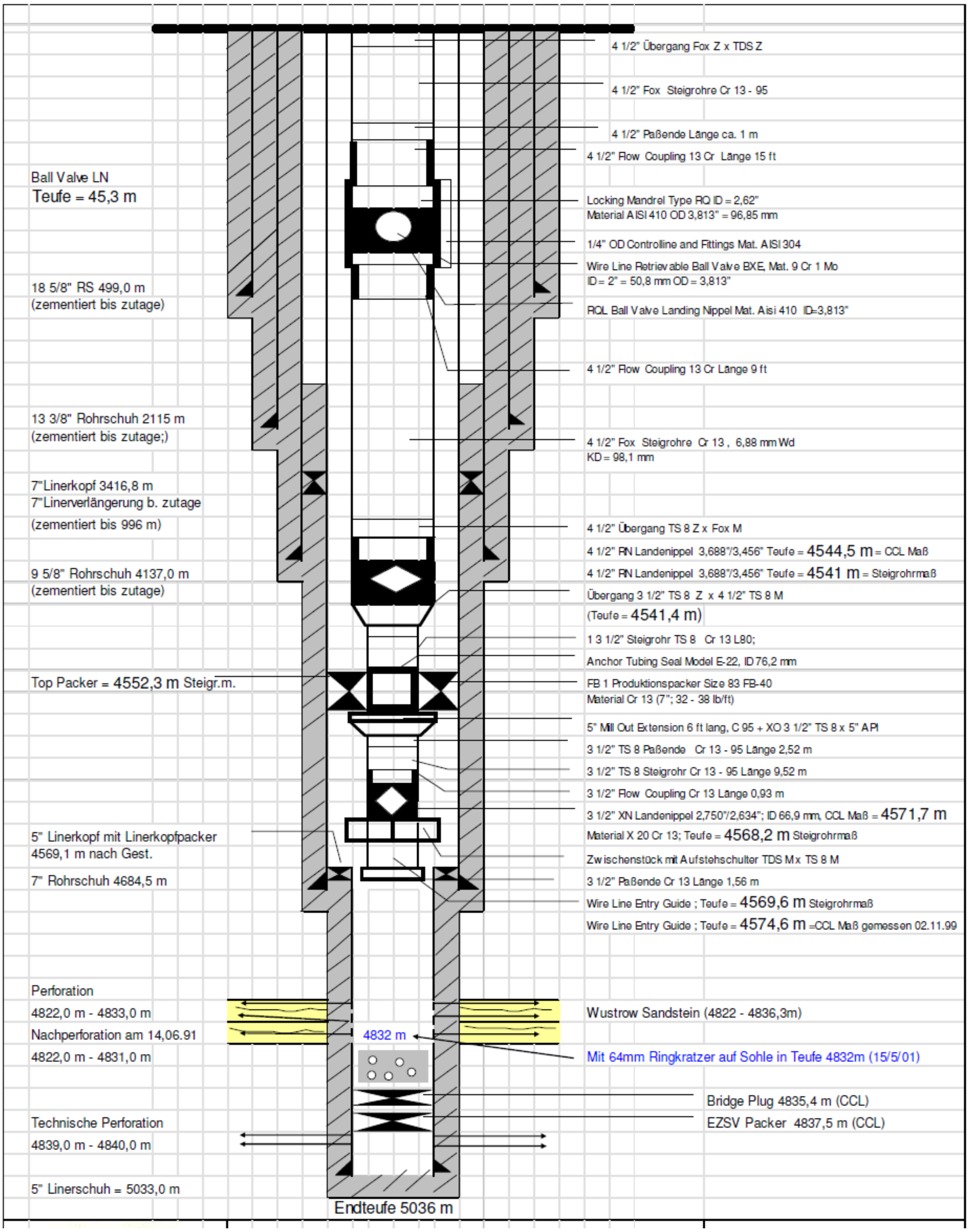
K = °C + 273, 15

11.4 List of Tables

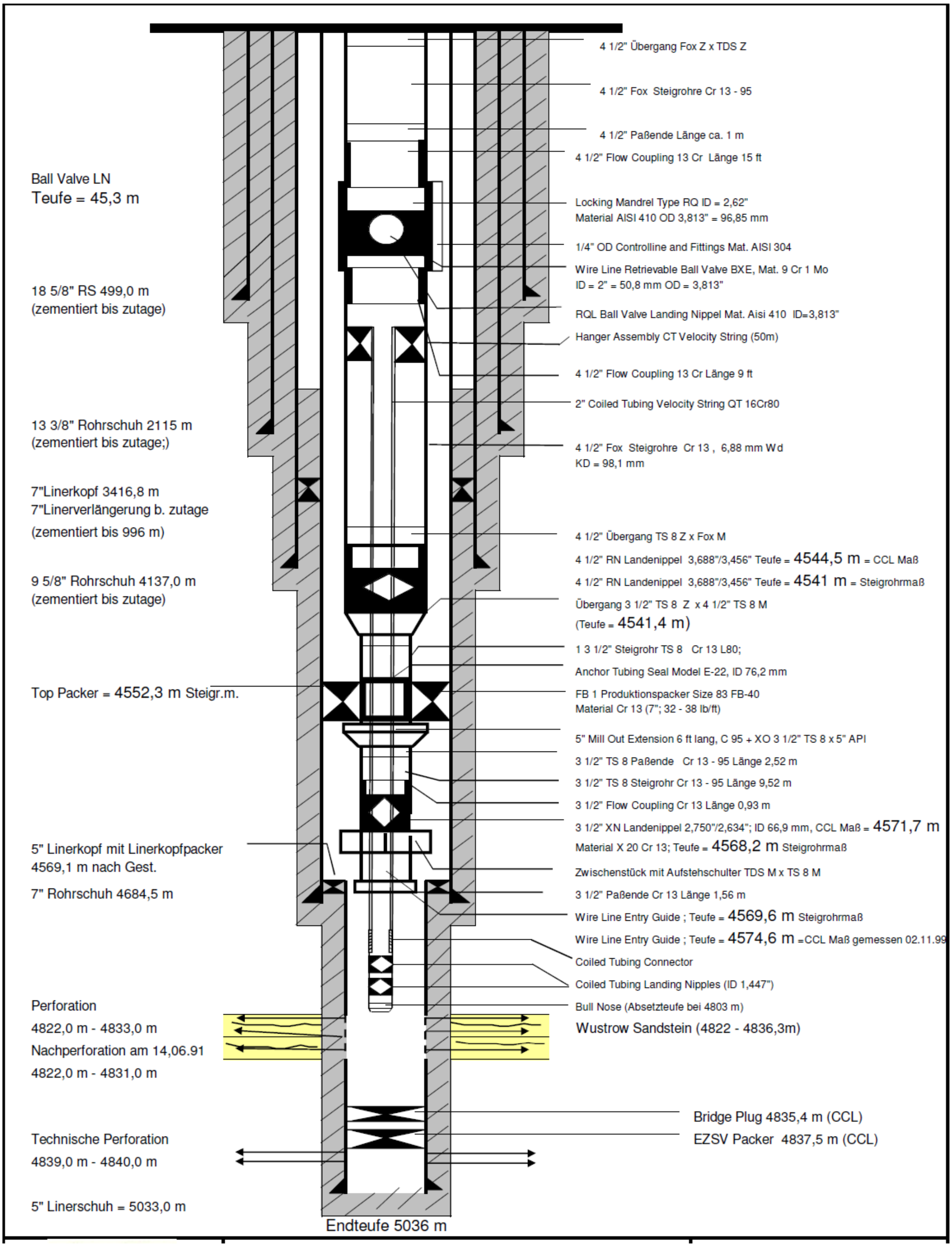
11.5 List of Figures

Appendix

Completion Schematic of Well Z1 [20]



Completion Schematic of Well Z1 with Velocity String [20]



Company B`s WDB Adapter [34]