OVERVIEW OF SOLUTIONS TO PREVENT LIQUID-LOADING PROBLEMS IN GAS WELLS

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ABSTRACT

OVERVIEW OF SOLUTIONS TO PREVENT LIQUID-LOADING PROBLEMS IN GAS WELLS

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Every gas well ceases producing as reservoir pressure depletes. The usual liquid presence in the reservoir can cause further problems by accumulating in the wellbore and reducing production even more. There are a number of options in well completion to prevent liquid loading even before it becomes a problem. Tubing size and perforation interval optimization are the two most common methods. Although completion optimization will prevent liquid accumulation in the wellbore for a certain time, eventually as the reservoir pressure decreases more, the well will start loading. As liquid loading occurs it is crucial to recognize the problem at early stages and select a suitable prevention method. There are various methods to prevent liquid loading such as; gas lift, plunger lift, pumping and velocity string installation. This study set out to construct a decision tree for a possible expert system used to determine the best result for a particular gas well. The findings are tested to confirm by field applications as attempts of the expert system.

Keywords: Gas production, liquid loading, artificial lift, decision tree, expert system

ÖZ

GAZ KUYULARINDA SIVI DOLUMUNUN ENGELLENMESİ İÇİN
ÇÖZÜM YÖNTEMLERİNE GENEL BAKIŞ

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Rezervuar basıncının azalmasıyla zamanla gaz kuyularının üretimleri azalır. Formasyon sıvıları zaman içinde kuyu dibinde biriktiğinden ötürü, hidrostatik basınç yaratarak üretimin beklenenden erken düşmesine yol açar. Bu ve benzeri problemler ciddi üretim sorunları oluşturmadan önce doğru yöntemler kullanılarak engellenmelidir. Kuyuda doğru üretim dizisinin kullanımı bu konudaki başlıca önem taşır. Kullanılan çeşitli yöntemler kuyu dibinde sıvı birikmesini belirli bir süre engelleyecek, ancak rezervuar basıncı azalmaya devam ettikçe kuyu yeniden sıvı ile dolmaya başlayacaktır. Sıvı dolumunun erken safhalarda teşhis edilmesi ve kuyu özelliklerine uygun bir mücadele yöntemi seçilmesinin önemi büyüktür. Bu sorun ile mücadele için kuyuya gaz enjekte etme, sıvıyı bir serbest bir piston yardımıyla kaldırma, pompalama, üretim dizisinin küçültülmesi gibi bir dizi yöntem kullanılmaktadır. Bu araştırmada teorik verilerle elde edilenler sorunun sistematik çözümü için bir karar mekanizması oluşturulması üzerinde kullanılmıştır. Saha verileri ile doğrulanmaya çalışılan bu karar mekanizmasının belli durumlar için en iyi çözümün bulunmasına çalışılmıştır.

Anahtar kelimeler: Gaz üretimi, sıvı dolumu, yapay kaldırma, karar ağacı, uzman sistem

to Me,

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Symbols	Definition
A_t	Tubing area (ft^2)
A_d	Droplet area (ft^2)
C_d	Drag coefficient
d	Droplet diameter (ft)
F_G	Downward gravity force (lbf)
F_D	Upward drag force (lbf)
g	Acceleration due to gravity (= 32.17 ft/s^2)
h	Thickness of liquid droplet (in)
ID	Tubing internal diameter (ft)
GLR	Gas-liquid ratio (scf/bbl)
OD	Tubing outer diameter (ft)
P	Wellhead pressure (psia)
P_R	Reservoir pressure (psia)
P_{wf}	Well flowing pressure (psia)
q	Gas flowrate (Mscf/d)
R	Gas constant (= 10.73 psia-ft^3/lb-mol ^oR)

T	Wellhead temperature (°F, R)
TR	Turner Ratio
V	Velocity (ft/s)
V	Volume (ft^3)
V_g	Velocity of gas (ft/s)
V_d	Velocity of droplet (ft/s)
V_t	Terminal velocity (ft/s)
V_c	Critical velocity (ft/s)
z	Gas Compressibility factor
γ	Specific gravity
σ	Interfacial tension (dyne/cm, lbf/ft)
ρ	Density (lbf/ft^3)
μ	Viscosity ($lbf\text{-}sec/ft^2$)

Subscripts:

a	Air
c	Critical
g, G	Gas
l, L	Liquid
t	Tubing
w	Water

CHAPTER 1

INTRODUCTION

Liquid loading, by definition, is the inability of a gas well to remove liquids that are produced with the gas from the wellbore. The produced liquid will accumulate in the well, therefore creating a hydrostatic pressure in the well against formation pressure and reducing production until the well ceases production. In order to reduce these effects of liquid loading on gas production, loading problems should be diagnosed in time and dealt properly and efficiently.

One fact about liquid loading is that it can present itself as a problem for high rate/high pressure wells as well as low rate/low pressure wells. The differences depend on tubing string size, surface pressure, amount and density of liquids produced along with gas. Therefore it is important to recognize liquid loading symptoms at early stages, and design proper solution for the gas wells in order to minimize the negative effects of liquids filling up the wellbore.

1.1 Multiphase Flow

In order to understand the liquid loading phenomena properly and dealing with it effectively, it must be understood how liquid and gas behave when flowing together upwards in the production string of the well. This concept is called “multiphase flow”. Multiphase flow is, basically, a flow phenomenon that denotes there is more than one fluid phase flowing through a media; in this case the media being the production string of the gas well. Multiphase flow is usually represented by four main flow regimes which are bubble flow, slug flow, transition flow, annular-mist flow. These flow regimes occur when certain flow velocity of liquid and gas phases and the amount of these phases relative to each other in the media, again in this case the gas well producing.

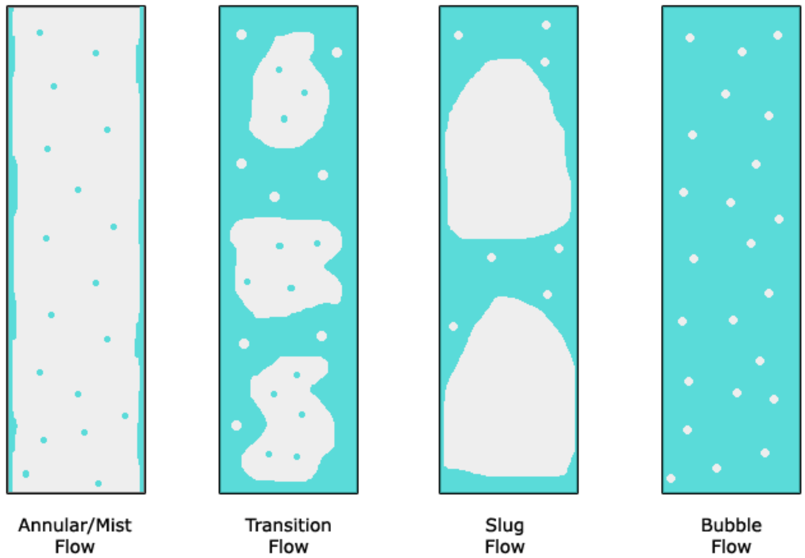

Figure 1.1 – Basic Profile of Multiphase Flow in the Well

Annular-Mist Flow: The gas phase is the dominant phase in the well and the continuous one. Liquid is present among the gas as a mist. Inside of the tubular is covered with a thin layer of liquid travelling up the pipe. In this flow, the pressure gradient is determined from gas.

Transition Flow: Although the flow starts to change from mist to slug therefore the continuous phase changes from gas to liquid or vice versa. Liquid particles may still be in gas as mist form but the presence of liquid determines pressure gradient.

Slug Flow: The gas is found as large slugs in liquid but the dominant and continuous phase is liquid. Gas slugs may cause drops in pressure gradient therefore liquid and gas both determine pressure gradient.

Bubble Flow: The tubular in the well is almost completely filled with liquid. Gas is present as small bubbles in the liquid therefore it can cause pressure drops in the liquid, decreasing pressure gradient along the well. However, the liquid is the continuous phase along the tubular and completely determines pressure gradient, although presence of gas bubbles may cause drops in pressure.

Considering these flow regimes, one must remember that during its lifetime; it is rarely the case for only one flow regime is present in a gas well. Usually, a gas well may go through almost all of these flow regimes during its productive life. Also more than one flow regime may be present at the same time in the well, since gas bubbles will be expanding when travelling up along the production string. Also it should not be forgotten that flow velocity is directly related to cross-sectional area, so flow regimes may differ above and below the production packer, if there is one. Another point to consider is the flow regime seen at the surface may not be the flow regime near the perforations, considering bottomhole conditions would be different downhole.

As stated above, as gas velocity decreases the flow regimes goes from mist to bubble. Since the liquid presence is much more in bubble flow, the amount of produced liquid will increase as the flow regimes changes. This means, of course, as the gas rate declines with decreasing reservoir pressure, the amount of liquid produced along with gas will dramatically increase, increasing the cost of well also. At some point, the increasing amount of liquid will start to accumulate in the well as the flow regime downhole shifts to bubble flow and increasing the bottomhole pressure in the well. The well will eventually be unable to overcome that pressure and stop producing altogether.

1.2 Liquid Loading Concept

As mentioned before, the gas, which is the dominant phase initially in the well, will carry the produced liquid present in the reservoir to the surface as long as the gas velocity is high enough to let it do so. A high gas velocity will cause mist flow in the well in which liquid is dispersed in the gas. This also means the liquid in the well will be low relative to the gas and will be carried out without accumulating downhole. This will result in a low pressure gradient in the well since there is more gas than liquid. At this point, it should be noted that when a well is flowing at a high gas rate, and therefore velocity, the frictional pressure loss will be high also. This pressure loss will not be a big problem since the component is small due to low percentage of liquid compared to gas. As the gas velocity drops with time, the liquid carried out along with gas will start to drop and accumulate in the well, causing the pressure gradient component to increase. Since high pressure gradient means a high hydrostatic pressure in the well, the reservoir pressure will encounter a much larger pressure against itself downhole. Obviously, this will cause a decline in the gas rate and cripple gas production. Lower the gas rate falls, more liquid will be accumulated and this holdup will become a cycle, causing the well cease producing eventually.

1.3 Source of Liquids

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

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

1.3.1 Water Coning

If the production rate of any vertical or deviated gas well is high enough to result in a drawdown pressure high enough to pull the contact water in the reservoir below the gas even if the perforations do not extend to the underlying zone. Horizontal wells generally reduce water coning effects but it can still occur and it is commonly called as *water cresting* instead of *water coning*.

1.3.2 Aquifer Water

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

1.3.3 Condensed Water

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

1.3.4 Condensed Hydrocarbons

Just like water, hydrocarbons that are in liquid phase at atmospheric conditions can also enter the well in vapor phase. As the gas solution flows to the surface, vapor state hydrocarbons may start condensing when or if conditions drop below dew point. At this time, the condensed hydrocarbons are shortly called *condensate*. Condensate, although less than water, has a much higher pressure gradient than gas, so it will create a higher hydrostatic pressure and eventually start loading up the well just like water.

1.3.5 Water Production from Another Zone

Especially in open-hole completions and some cases wells with multiple perforations, it is possible to produce liquids from another zone unintentionally.

1.3.6 Free Formation Water

Different than the condition stated above, water can also be produced along with gas from the same perforations, if there is free water in the reservoir.

As mentioned, there are different sources for liquid loading, and there exist various solution methods for removing liquids or eliminating liquid loading problems in gas wells. However, there is an uncertainty in which methodology will give the best result for a particular gas well. This study aims to address this issue.

CHAPTER 2

LITERATURE REVIEW

A producing gas well ceasing production prematurely because of liquid loading would mean a financial loss and the inefficient use of resources. In order to overcome this issue, first, it must be identified properly. It is known that as reservoir pressure declines it is easier for the well to be killed by loaded liquids since the velocity of the gas passing through the production string will decrease. In 1969, Turner *et al.*[1] analyzed whether the gas flow rate would be sufficient to remove the liquids continuously from gas wells. Two physical models are proposed for the analysis of the removal of liquids; liquid film along the walls of the pipe and spherical liquid droplets entrained in the flowing gas core. A comparison of these two models with the field test data concluded that liquid droplet theory yielded a better model for predicting the onset of liquid loading. It is also concluded that there exists a gas velocity sufficient to remove the droplets continuously to avoid load-up, but a 20% increase should be added to insure removal of all drops. Coleman *et al.*[2] proposed a new look at predicting load-up in 1991, which is basically Turner *et al.*'s model without the 20% increase in the minimum gas flow rate, known as critical rate. It is also stated that liquid/gas ratios below 22.5 bbl/MMscf have no influence in determining the onset of load-up, meaning the gas flow rate is the dominant factor.

In 2000, Nosseir *et al.*[3] suggested a new approach for accurate prediction of loading in gas wells under different flowing conditions. Turner *et al.*'s basic concepts are adopted but different flow conditions are considered resulting in different flow regimes. Wide variation of flow conditions in gas wells would make it difficult to assume a constant flow regime for all wells and conditions, therefore their new approach mostly consisted of a case by case basis. Upon calculating the critical flow rate, it is stated the appropriate equation should be applied for each case. In wells with the possibility of having more than one flow regime, it is recommended that the calculations are carried out at the wellhead pressure since gas slippage will be at maximum near the surface, and also water should be considered as the loading phase to guarantee removing all the droplets of lighter phases also.

A new view on continuous removal of liquids is proposed in 2001, when Li *et al.*[4] adopted the liquid droplets entrained in gas core theory but predicted the liquid droplets tend to be flat instead of spherical *(shown in Figure 2.1)* and deduced new simple formulas for the continuous removal of these droplets accordingly, for field application. Models and approaches by Turner *et al.* and Coleman *et al.* did not take the deformation of a free falling droplet into consideration. The results calculated from these formulas were smaller than findings of Turner *et al.* However, they stated that predicted results were in accord with the practical production performance of China's gas wells dealing with liquid loading problems.

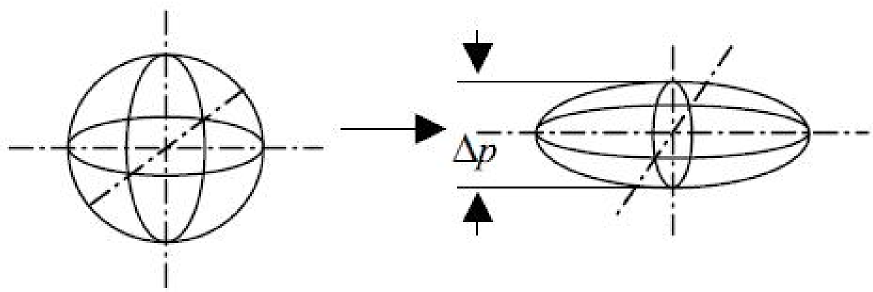

Figure 2.1 – Shape of entrained drop movement in high-velocity gas[4]

In 2003, Veeken et a*l.*[5] accepted Turner's method, but devised a ratio term called "*Turner Ratio"* (TR) which is the ratio of actual flow rate and minimum flow rate predicted by Turner *et al.* for continuous removal of liquids. Veeken *et al.*'s correlation data included deviated wells, also and the predicted the critical rate for deviated wells is about the same for vertical wells. An inflow performance parameter is also added to their *Turner Ratio* equation which allows evaluating critical flow rate at bottom-hole conditions. Veeken *et al.*'s model showed a much higher flow rate is needed than Turner's (and therefore Coleman's) model predicted to remove liquids properly and continuously at low pressures. Belfroid *et al.*[6] (2008) stated that when making predictions on critical flow rates, inclination angle, flow regime transitions, tubing outflow and reservoir inflow relations should be taken into account. Also, they argued that the influence of dynamic disturbances on the stability is not taken into account by the classical prediction models. Belfroid *et* al.

concluded that the onset of liquid loading is determined by the transport of the liquid film. They stated for larger inclinations the effect of gravity is reduced and therefore critical gas rate will be lower; however, at large inclinations, the liquid film starts to thicken at the bottom of the tube compared to top, which increases the critical gas flow rate. This results in erroneous flow rate calculations in classical models. Also it is concluded that high permeability reservoirs will show liquid loading behavior much faster than low permeability reservoirs. Their results regarding critical flow rate were much higher than classical models especially in high permeability low pressure reservoirs.

In 2009; Sutton *et al.*[7] proposed a guideline for the proper application of critical velocity calculations. They stated that although field personnel generally uses conditions at the top of the well as an evaluation point for calculating critical flow rate for a well, a change in geometry downhole or other conditions may lead to erroneous conclusions. Using conditions at the bottom with fundamental equations requires accurate correlations for PVT properties such as surface tension and density for gas and liquid phases. They concluded that for almost every case, the critical velocity can be calculated using water properties since water has a higher density than liquid hydrocarbons; gas will be able to lift hydrocarbons if it is able to lift water. The evaluation point for determining critical velocity can be either the wellhead or bottom. They stated wellhead conditions should be used in high pressure wells (P_{whf} greater than 1000 psia) and bottom conditions should be used in low pressure wells (P_{whf} less than 100 psia) when calculating critical velocity. For wells producing free water, using bottom conditions would be more accurate. Also according to the study, the original safety factor Turner *et al.* provided is needed to ensure the well is unloaded along the entire flow path.

The general aim of all these research is to determine the conditions for removing liquids in gas wells continuously. However, as liquid loading problems in a well progress after a certain point it may be impossible to keep the well flowing on its own. When that happens, there are a variety of solutions that can be used in order to solve liquid loading problems of the well. Lea & Nickens[8] (2004) compiled some of these solutions in a study to describe and discuss the problems of liquid accumulation in a gas well. Some of these methods include sizing production strings to change the flow pattern and increase gas velocity, installing a compressor, plunger lift mechanism, and foaming. They proposed nodal analysis as a liquid loading prediction method and stated at initial stages surfactants can be tried as a cost effective solutions after evaluating economics. Smaller diameter tubing may be used to increase the flowing velocity; however, eventually has to be downsized even more. Plunger lift may be preferred over tubing sizing since it can be used in already installed larger tubing. It is concluded although there are several methods; none of them is the ultimate or only solution since solving liquid loading problems is more of a case by case project involving different reservoir parameters, wellhead conditions and liquid properties.

As Belfroid *et al.*[6] have stated in their study, "even though virtually all of the world's gas wells are either at risk of or suffering from liquid loading, the modeling of liquid loading behavior is still quite immature and the prediction of the minimum stable gas rate not very reliable". Therefore, predicting onset of liquid loading and solving load-up problems are critical and only credible when approached on a case by case basis and constructed a methodology accordingly.

CHAPTER 3

STATEMENT OF PROBLEM & SCOPE

This study is undertaken to investigate the effects of liquid loading on depleting gas wells, determine certain methods to minimize these effects in order to propose a decision tree as the algorithm of a possible expert system to choose a proper solution for each individual gas well. The critical rate theory for unloading liquids from wells is discussed due to discrepancies in different models. The objectives of the study are;

- Determine the best methods to predict liquid loading and recognize the symptoms early on to avoid production losses.
- Evaluating completion methods and production practices to find an optimum design when dealing with gas wells with liquid loading.
- Compare solutions on liquid loading solutions and artificial lift methods to see the advantages and disadvantages on particular cases.
- Design a decision tree for the algorithm of a possible expert system for systematic selection of proper liquid loading solutions under various conditions

CHAPTER 4

THEORY

4.1 Predicting Liquid Loading

Over the life of a typical gas well, gas flow rate will eventually decrease while liquids produced along with gas will increase. At some point, this situation would cause accumulation of liquids at the bottom of the well since the producing gas rate would be insufficient to lift all of the liquid, which will lead to erratic flow behavior and inevitably loss of production. If the symptoms of liquid loading are recognized at early stages, losses in gas production that may eventually cost the life of the well may be avoided. A proper analysis of the decline curve of a gas well can be informative about downhole flow problems of the well.

The changes in the general shape of the decline curve (*as seen in Figure 4.1)* of the well can be an important indication of loading, if properly analyzed. Characteristically, a typical decline curve of a dry gas production well should be a smooth exponential curve as reservoir depletes over time. During decline of the curve sharp changes and fluctuations indicate possible liquid loading downhole due to erratic flow behavior caused by liquid slugs. *Figure 4.1* shows the expected decline curve and possible fluctuations due to liquid loading. Eventually these sharp declines will cause the well to deplete earlier than reservoir estimations and possibly die prematurely. Installing methods remedial for liquid loading can restore the decline curve of the well to its original shape.

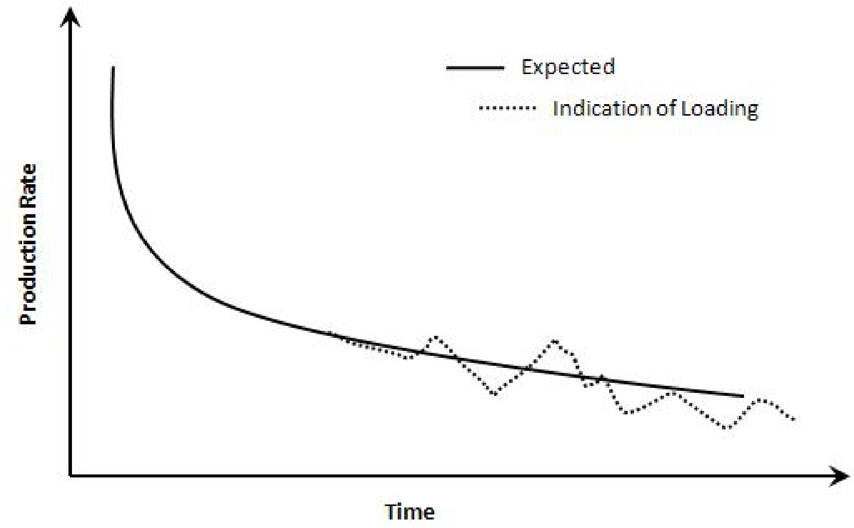

Figure 4.1 – A Typical Gas Well Decline Curve along with Indication of Loading

If liquids begin accumulating in the bottomhole, the increased pressure caused by hydrostatic head pressure of the liquid on the formation will cause a drop in surface tubing pressure. In wells with packerless completion, the increased pressure in the tubing would cause gas bubbles to start accumulating in the tubing-casing annulus, causing an increase in the casing surface pressure, contrary to tubing pressure. Therefore, in packerless completions an increase in casing surface pressure and a corresponding decrease in tubing surface pressure could indicate possible liquid loading. Although this method is a good indicator when the pressures are observed closely, a pressure survey should give definitive data on the matter to see if the well is really began loading.

A flowing or static well pressure survey done with electronic downhole gauges is possibly the most accurate method to determine whether the well is loading with liquids. Pressure surveys, by using downhole gauges, measure the pressure with the corresponding depth of the well while the well is flowing or shut in. The data can be used to construct a pressure gradient graph, which is a function of the density of the fluid in the well at that particular depth. The constructed pressure gradient curve will exhibit a sharp change when the fluid in the well turns to liquid from gas since the density of liquids are much higher than the density of gases occupying the well. The pressure vs. depth graph *(Figure 4.2)* will also give the liquid level, since the point where the sharp change occurs is basically the point where the liquid is loaded in the well.

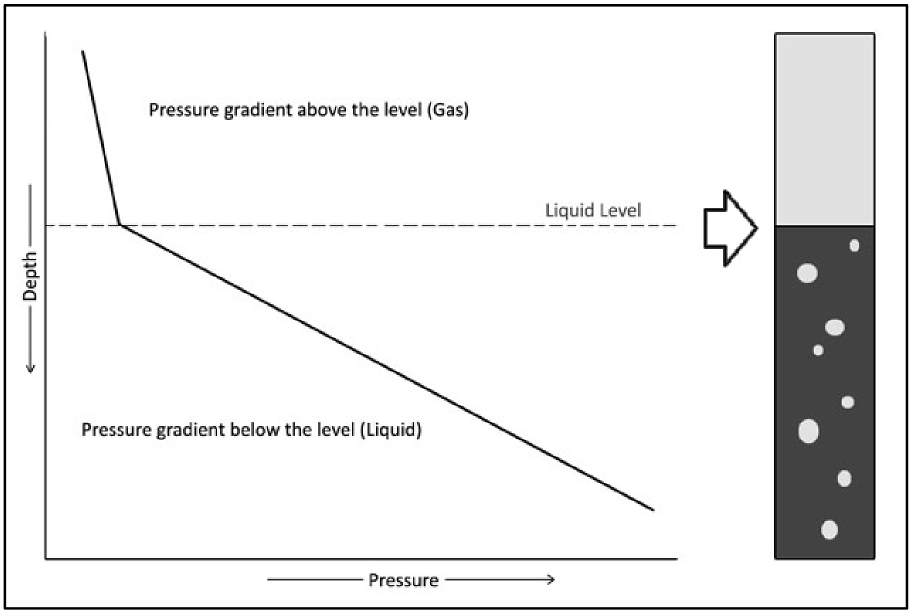

Figure 4.2 – A Typical Pressure Survey Graph

In summary, a gas well suffering from liquid loading problems gives many indicators which provide early warning. The producing gas wells should be monitored regularly in order to catch these indicators at early stages to prevent liquid loading problems from damaging the reservoir permanently and causing premature declines in production.

4.2 Critical Rate Theory

As stated earlier, when producing gas phase hydrocarbons from a reservoir, some liquid phase hydrocarbons which we called condensate and also liquid phase water may be produced along. Presence of liquids in the well will put a pressure against the reservoir pressure and if the well is unable to unload the liquid, it will die unless some certain measures are taken. Also, even if the flowing pressure of the well is high enough to unload the liquids, there still may be slugging of discontinuity in the flow due to the flow regime. At this point, the first thing to consider should be determining if the well will be able to unload this liquid on its own. The answer to that question lies within the critical velocity theory. Many authors have suggested several methods to determine if the flow rate of a well is sufficient to remove the liquid phase materials produce on a continual basis. In 1969, Turner *et al.*[1] proposed two physical models for removal of liquids; (1) liquid forming a continuous film inside the wall of the production string moved upward by interfacial stress and (2) liquid droplets present in the string as free falling particles moving up because of the high velocity of the gas. After developing these two models, Turner *et al.* compared the actual field data with the models independently to see which one is a closer match and which is the controlling mechanism for the removal of the liquids.

4.2.1 The Continuous Film Model

Liquid phase accumulation on the walls of string during a two-phase flow is of interest in the analysis of liquid removal according to the work of Turner *et al.* The annular liquid film must be moving upward along the wall of the string in order to keep the well from loading. The minimum gas rate necessary to accomplish this is by calculating the velocity of the liquid, the velocity of the gas and the shear stress in between. Turner concluded that the predictions of the film model do not provide a clear definition between the adequate and inadequate rates.

4.2.2 Liquid Droplet Model

The studies of Turner *et al.* state that the existence of liquid drops in the gas stream present a different problem, which is basically determining the minimum gas flow rate that will lift the drops out of the well to the surface *(Figure 4.3)*. According to the study, a free falling particle reaches a terminal velocity which is the maximum velocity it can attain against gravity. Therefore, that terminal velocity, or in other terms the *critical gas velocity* which is determined by the flow conditions necessary to remove the liquids on a continual basis, is based on drag & gravitational forces on the droplet.

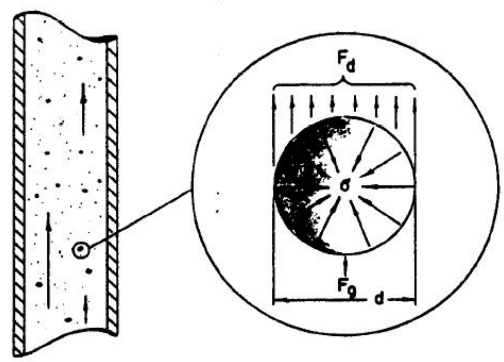

Figure 4.3 – Liquid Droplet Movement[1]

The step by step derivation of Turner *et al.*'s liquid droplet model can be found in Appendix A. Their expressions on the liquid droplet model can be summarized as follows:

$$v_t = 1.593 \frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{{\rho_g}^{1/2}} \tag{1}$$

According to Turner *et al.*[1], analysis of data revealed that these factors required an upward adjustment of 20% to fit the field data. Then the equation becomes:

$$v_t = 1.912 \frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{{\rho_g}^{1/2}} \tag{2}$$

However, in 1991, Coleman *et al.*[2] suggested that 20% (18.92% to be exact) safety factor is unnecessary and stated that the initial equation (1) fits better to the field data. Coleman *et al.* also concluded wellhead conditions can be used for predicting load-up conditions, unless tubing/packer has significant distance from the completion interval, flowing conditions of the largest segment should be used to predict the wellbore critical rate. For field applications, Turner *et al.* consolidated some of the fourth root variables into constants. Using constants for the fourth root of surface tension and density for both condensate and water; two simple separate equations for condensate and water can be used. Combining these findings and following the work of both Turner *et al.* and Coleman *et al.* the following critical rate equation is being used to determine load-up:

$$q_c = \frac{3.06\, P\, v_g\, A}{T\, z} \tag{3}$$

Where:

$$V_g(for\ water) = \frac{5.62\ (67-0.0031P)^{1/4}}{(0.0031P)^{1/2}} \tag{4}$$

$$V_g(for\ condensate) = \frac{4.02\ (45-0.0031P)^{1/4}}{(0.0031P)^{1/2}} \tag{5}$$

Turner *et al.* finally stated that the liquid/gas (L/G) ratio has no influence in determining the liquid load-up onset in the well as long as the L/G ratio is below 130 bbl/MMscf. Coleman *et al.* stated that the liquid/gas ratio has no effect if it is below 22.5 bbl/MMscf.

4.3 Tubing Size Optimization

Proper tubing size selection is crucial to effectively produce gas from the reservoir and maximize recovery. Tubing size selection may be somewhat simpler in vertical wells with a single pay zone and single fluid flowing through the wellbore. However, in wells with multiple reservoirs and liquid loading problems, tubing size selection can become quite complex. At first glance at the critical rate and terminal velocity equations, smaller tubing sizes can be economically favorable with time where liquid loading will be more problematic since reservoir pressure will deplete eventually, causing the well to load-up with liquids produced from the reservoir. The aim is to determine a simple, field applicable model to properly select optimum tubing size if possible.

Using critical rate equation of Turner *et al.* and applying the field data, terminal velocity and then critical rate of the well can be calculated for different sizes of tubing string and can be plotted *(Figure 4.4)*. The critical rate than can be compared with the actual producing rates of the well and determined if the gas can lift the liquid from the wellbore with smaller tubing inside. Gunawan *et al.*[9] showed that field data validates Turner method when predicting critical gas flowrates with different tubing sizes. It is seen in *Figure 4.5* that the data set fits better with the 20% adjustment Coleman *et al.* deem unnecessary.

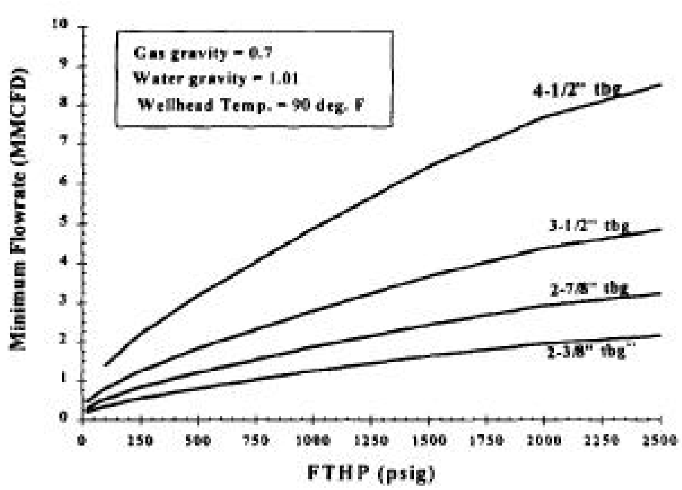

Figure 4.4 – Critical Flowrates for Different Tubing Sizes [9]

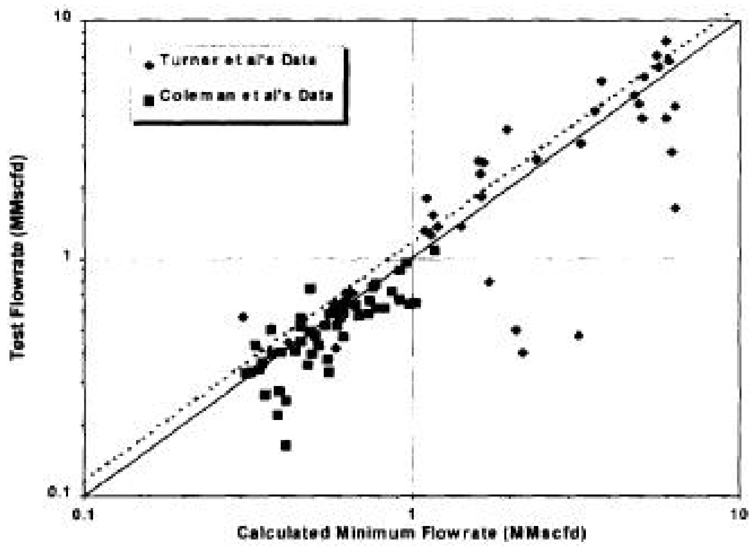

Figure 4.5 – Critical Gas Flowrates for Turner & Coleman[9]

4.3.1 Nodal Analysis

Liquid load-up can also be determined by nodal analysis. Since critical gas rate equations only give a simple idea for the minimum rates, nodal analysis will be more detailed since normally in a well, gas may have to flow against many restrictions other than liquid itself, such as different tubing sizes, sub surface safety valves, rock matrix of reservoir etc. Each component that gas and liquids flow through will have pressure loss depending on flowrate. In order to determine overall well performance, all of these components must be considered as a system. Nodal analysis divides this system into two subsystems at a certain location called *nodal point* or simply *node*. One of these subsystems considers inflow from reservoir to the nodal point selected while the other subsystem considers outflow from the nodal point to the surface. Each subsystem gives a different curve plotted on the same pressure-rate graph *(Figure 4.6)*. These curves are called the *inflow curve* and the *outflow curve*, respectively. The point where these two curves intersect denotes the optimum operating point where pressure and flowrate values are equal for both of the curves.

It is possible the nodal point can be located anywhere in the system. However, practically, locating nodal point at the bottom hole (at the mid-perforation depth) is very common since that way the inflow curve represents the flow from reservoir into the hole and the outflow curve represents the flow from the bottom hole to the surface.

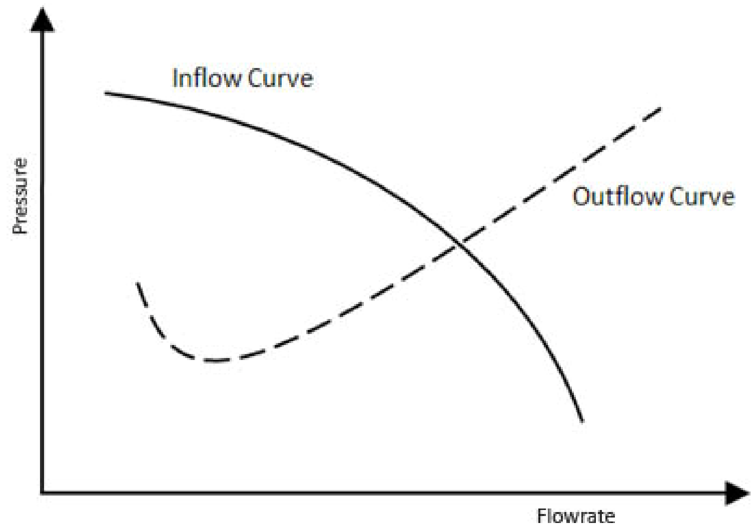

Figure 4.6 – Typical Nodal Analysis Curves

The nodal analysis can be used with both single and multiphase flow equations; moreover, correlations of different components such as well completion and skin effects and also effects of surface components can be implemented into nodal analysis. The information gathered can be used to determine and evaluate overall well performance for a variety of different conditions that eventually will lead to optimum completion and production practices. It is an important practice not only for analyzing the effects of liquid loading but also for finding possible solutions to the problem. As mentioned, nodal analysis can be used to analyze the effects of different tubing sizes and different flow conditions. Moreover, it is useful for determining the effects of surface pressure on the system, since excessive surface pressure can cause a backpressure on the reservoir.

As mentioned above, the nodal point, the point that divides the nodal analysis system into to subsystems, is commonly placed at the bottom hole. In that case, the outflow curve that can also be called the *tubing performance curve* (TPC) shows the relationship between the pressure drop in the tubing string and surface pressure value. The pressure drop in the tubing string basically consists of the surface pressure value, the hydrostatic pressure of the "loaded liquid" in the string and the frictional pressure loss due to flow *(Figure 4.7)*.

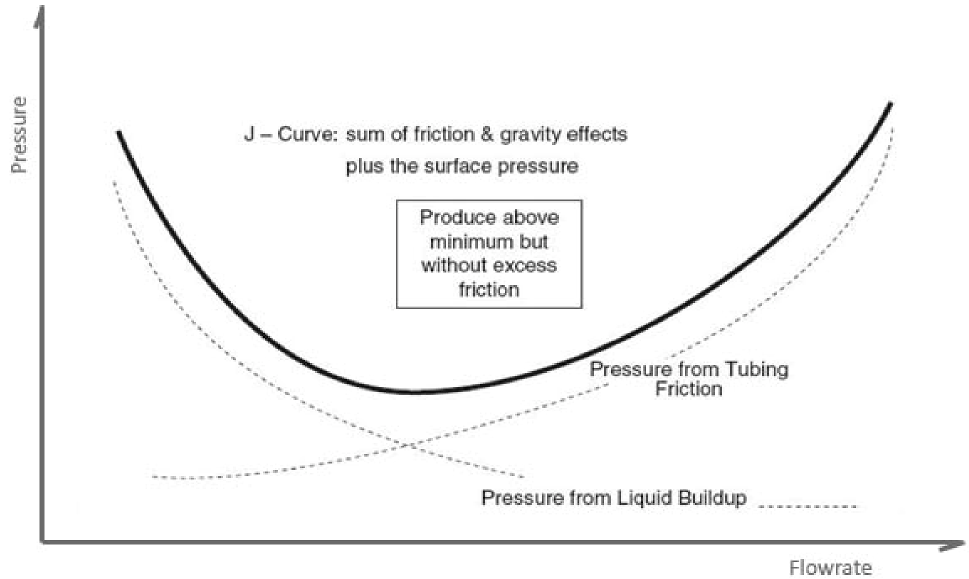

Figure 4.7 – Tubing Performance Curve[10]

The TPC passes through a minimum at the middle of the curve. The total tubing pressure loss increases due to increased friction losses at the higher flowrates to the right of that minimum point. The flow to the right of the minimum is generally in the mist flow regime that effectively transports small droplets of liquids to the surface because of higher rates. At the far left of the TPC the flow rate is low and the total pressure loss is dominated by the hydrostatic pressure of the liquid column loaded in the well. The flow regime at the left-most section of the curve is typically bubble flow, which allows liquids to accumulate in the wellbore. Slightly to the left of the minimum in the TPC, the flow is often in the slug flow regime. In this regime liquid is transported to the surface periodically in the form of large slugs. Fluid transport remains inefficient in this unstable regime as portions of the slugs fall back to the wellbore as the pressure drops and must be lifted again. This fall-back results in a higher producing bottomhole pressure. It is common practice to use the tubing performance curve alone, in the absence of up to date and accurate reservoir performance data, to predict gas well liquid loading problems. The general idea when interpreting the curve is that flowrates to the left of the minimum are unstable and prone to liquid loading problems. Flow rates to the right of the minimum of the tubing performance curve are considered to be stable and significantly high enough to effectively transport produced liquids to the surface.[10] This method is considerably inexact but in the absent of accurate reservoir data it can be useful for predicting and determining liquid loading problems. When reservoir performance data is present, the intersection point of the tubing outflow curve and the reservoir inflow performance curve allows an accurate determination of the point the well is flowing and what would be the optimum pressure and rate values. Calculating bottom hole flowing pressure for different tubing sizes for different production rates and plotting these values on the same graph with the reservoir inflow (IPR) curve to determine the optimum tubing size for the well to produce gas and remove the liquid effectively as shown in *Figure 4.8*.

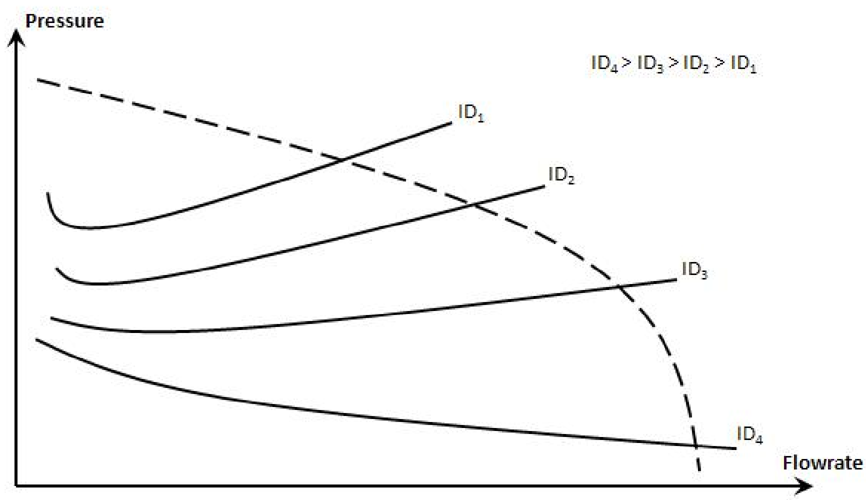

Figure 4.8 – Nodal Analysis Graph for Different Tubing Sizes[10]

After constructing the nodal analysis plot for all the different tubing sizes, the optimum flowing tubing pressure and desired production rate could be selected accordingly. Also, analyzing the plot would give information about the expected flow conditions for certain pressure and production rate values. Calculating the critical rate values for each tubing size would let us predict if the selected tubing would be able to lift the liquid that enters the well continuously or let the well load up and die. One significant advantage of using nodal analysis determining proper tubing size is that it would allow to see the lifespan of the tubing selected, therefore it can be predicted if the selected tubing size will be adequate to lift the liquid and produce effectively not only today, but for an acceptable period of time.

An important thing to consider is calculating the critical rate both at surface and downhole conditions for a selected tubing size to make sure the gas flows above the critical velocity from bottom to top and no other restrictions are contributing to load-up. Also selecting a smaller tubing diameter may not cause a sudden increase in the production rate, but the new decline curve of the well will give an idea when conclusions are made on the new string installed.

4.4 Well Completion & Production Rate Optimization

Proper optimization of wells for both oil and gas production is a highly complex issue that involves countless parameters for different cases. Also, it is important to remember that there is no "absolute solution" when dealing with oil or gas wells since processing and interpretation of wellbore data is not an exact matter. Considering circumstances it is not possible to propose an optimized completion design that could fit every case. Obviously, the best way to address this issue would be dealing with a single well based on problems encountered by offering certain remedial measures and solutions. When dealing with gas wells having liquid loading problems, there are a few key factors that need attention regarding completion optimization.

4.4.1 The Setting Depth of the End of Completion

It is generally recommended that the end of the tubing string in the well should be set right at the top of the perforations. Many studies, like Christiansen et al.'s[11] (2005) suggest that the liquid transport is severely constrained in the casing-tubing junction because the gas velocity is much lower than the critical velocity needed due to large cross-sectional area of the casing. Also, if the perforations are flooded with water continuously, the permeability of the formation will severely decrease due to fluid invasion *(Figure 4.9 – a)*. There are possible measures to be taken to overcome this issue to a certain level but setting the tubing just at the top of the perforations (or pay zone in open-hole completions) would be the better solution *(Figure 4.9 – b)*. On the other hand, setting the tubing too deep could cause problems. According to Lea *et al.*[10] (2008), it is not recommended for the end of the tubing to pass the top one-third of perforations. If the tubing is set too deep *(Figure 4.9 - c)*, liquid would collect over the perforations during shut-in. When the well brought back on production, the large volume of collected liquid must enter the tubing string where the cross-sectional area of the tubing string is relatively small. Therefore the high level of the collected liquid will cause greater hydrostatic head pressure making the well very difficult to flow. If the end of the string is set below the entire perforation interval, the pressure during shut-in cannot push the liquids below to enter the tubing string and it would be impossible for the well to flow and unload the collected liquid.

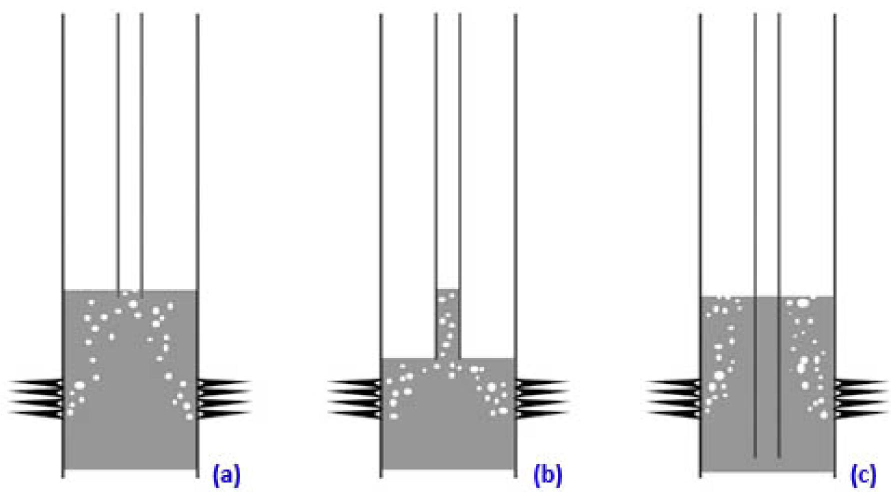

Figure 4.9 – The Effect of Setting the End of Tubing[10]

4.4.2 The Effects of Perforation Interval

Determining the impact of perforation interval on liquid loading in gas wells is particularly crucial in water drive gas reservoirs. There are basically two possibilities which are either perforating long intervals and producing at high rates in order to minimize abandonment pressure or perforating limited intervals at the top and producing at low rates to prevent water coning which would result early abandonment for the gas well. An important issue to consider when choosing either approach should be determining the aquifer encroachment rate if it is a water drive gas reservoir. It is known that lowering reservoir pressure by producing gas at higher rates than aquifer encroachment could increase ultimate recovery significantly. That means the possibility of surpassing the aquifer encroachment rate by gas production rate is an important consideration on ultimate gas recovery.

The study by McMullan & Bassiouni[12] (2000) showed that one of the main characteristics that affects recovery when trying to optimize the perforation interval is reservoir permeability (Figure 4.10). However, vertical to horizontal permeability ratio, fluid density contrast, relative permeability and formation dip did not alter their conclusions according to the sensitivity analysis. In their investigations, basic single-phase fluid flow equations provided insight on the relativity of gas and water flow into the well. Using work of Craft & Hawkins[13] it can be summarized as Darcy's law on steady-state radial flow for both water and gas:

$$q_w = \frac{0.00708\, k_w\, h_w\, (P_e - P_w)}{\mu_w\, B_w \ln\left({}^{r_e}/_{r_w}\right)} \qquad (6)$$

$$q_g = \frac{6.88\times10^{-7}\, k_g\, h_g\, (P_e^2 - P_w^2}{T\, Z\, \mu_g \ln\left({}^{r_e}/_{r_w}\right)} \qquad (7)$$

These two Darcy equations describe steady-state conditions and one dimensional radial flow of water and gas; therefore they are not adequate to describe the complex three-dimensional, unsteady-state multiphase flow, which is exactly the case in a typical gas reservoir. However, using these equations provide insight on the nature of water and gas flow relative to each other.

The analysis of the study showed that unless the perforation interval extends to a water zone, a small water-gas ratio can be expected until nearly the entire perforation interval is flooded with water[12]. As gas has an extremely lower viscosity relative to liquids, in high permeability reservoirs, very high gas rates can be achieved even from a very thin layer of flowing interval that produces gas *(Figure 4.10)*. Also, it is stated that increased perforation interval does not have a crucial impact on ultimate gas recovery however; in high permeability systems longer perforation intervals may cause increased ultimate water production *(Figure 4.11).* Their findings favor the well to be completed with sufficiently long perforation intervals, not extending to water zone/zones, in order to obtain maximum gas flow rate and insure maximum gas recovery.

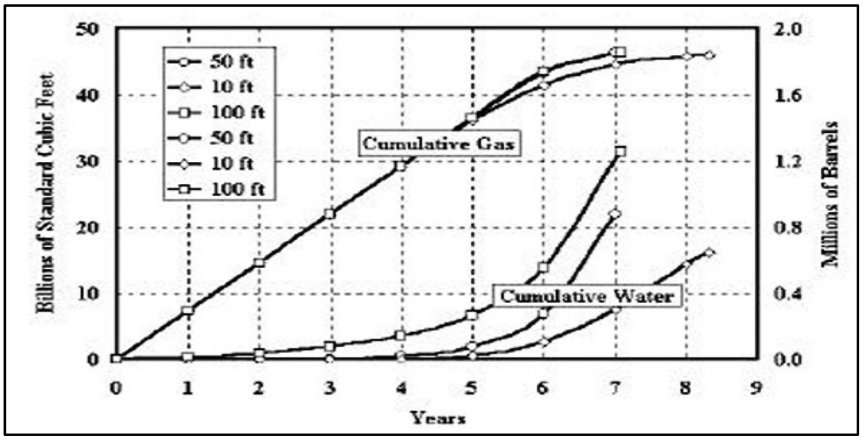

Figure 4.10 – Impact of Length of Perforation Interval on Cumulative Water and Gas Production in Years[12]

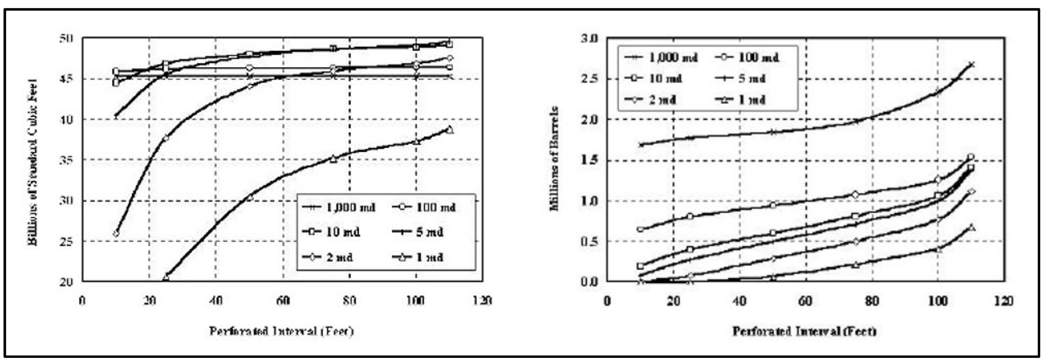

Figure 4.11 – Impact of Perforated Interval and Permeability on Ultimate Gas (left) and Water (right) Recovery[12]

4.4.3 The Effects of Production Rate

Although gas production rate is dependent considerably on the length of perforation interval due to deliverability, it is another subject of interest since ultimate gas recovery is directly related with gas production rate. McMullan & Bassiouni showed in their model that generally higher production rates do not impair ultimate gas recovery, therefore in low water disposal situations gas rates should be maximized to insure maximum ultimate gas recovery. In low to moderate permeability reservoirs, it is shown that when gas production rate increases, water production in the well is decreased because gas flows much easier through perforations due to significantly lower viscosity. However, this case does not necessarily applies to reservoirs that have permeability values of 1000 millidarcies or more, since permeability that high causes a significant increase in water production rate also. It is obvious that constraining gas production rates will increase the life of a well, but the economic consequences of delayed recovery are also significant. Restrained gas production rates will cause the well to have an increased life but could also mean decreased ultimate gas recovery since it can have detrimental effects on the reservoir *(Figure 4.12)*.

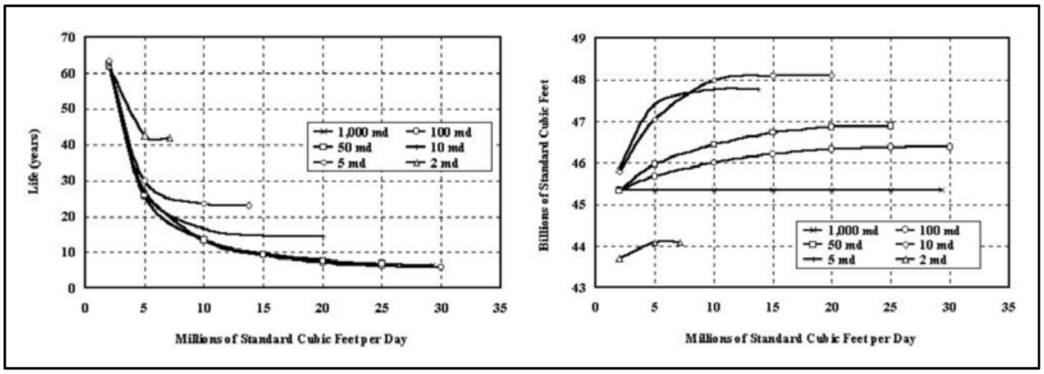

Figure 4.12 – Impact of Gas Production Rate and Permeability on Well Life (left) and Ultimate Gas Recovery (right) [12]

These findings are in consistency with the effects of length of perforation interval on ultimate gas recovery. However, in high water disposal cost situations, it should be recognized that long perforation intervals and elevated gas production rates in high permeability reservoirs could lead to elevated water production and therefore much higher well costs.

4.5 Overview of Solutions to prevent Liquid Loading

Liquid loading in a gas producing well is a progressing problem as reservoir pressure depletes continually with produced gas and eventually the well will inevitably need an artificial lift method to lift the loaded liquid from the well to resume gas production. Although a properly designed tubing string can increase gas velocity to exceed critical velocity and lift the produced liquids, this may not be a long term solution since, as mentioned, the reservoir pressure will keep decreasing to a point where it would be impossible for the kinetic energy of the gas alone will not be sufficient enough to lift the produced liquids completely. Different solutions should be evaluated and compared in order to find the best course of action when dealing with wells that have liquid loading problems to achieve the highest ultimate gas recovery possible for the well. In this section, several well-known solutions or remedial measures to prevent liquid loading in gas wells will be discussed and evaluated in order to find which particular solution is the best solution to which particular case.

4.5.1 Velocity String Application

A velocity string is basically a tubing string with a smaller diameter run inside the original large-diameter production string. It is used as a remedial measure, since reducing the flow area of gas will cause the velocity to increase and exceed the critical velocity which is needed for continuous removal of produced liquids in the wellbore. Application may differ as velocity string installation can be up to the surface of just up to a certain point in the current production string, as seen in *Figure 4.13*.

The study of Arachman *et al.*[14] (2004) showed that especially for big-bore completions velocity string installation can be very beneficial. It is generally less expensive than other solutions and treatment methods for liquid loading, since it could be done in a live-well with coiled tubing. However, velocity string applications are critical because as diameter of the tubing decreases, the pressure loss value due to friction will increase which would cause high pressure drop and limited gas production rates. The solution to this problem would be installing the velocity string from the perforation interval up to a certain point instead of installing it all the way to the surface. If the velocity string is too short, however; it could be insufficient to lift the produced liquids effectively and would need replacing with another longer or smaller string. Also, it may not be a permanent solution as reservoir pressure continues to deplete an even smaller diameter tubing string would be needed. These criteria make the velocity string an inexpensive solution with critical design considerations.

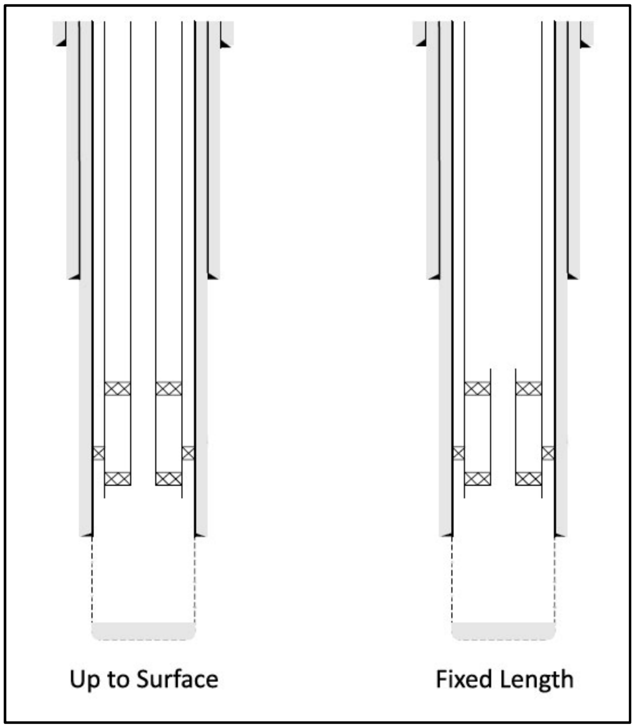

Figure 4.13 – Velocity String Application Schematic[14]

4.5.2 Compression

Compression is a vital application in all gas well production practices as lowering the surface pressure will also lower bottom hole flowing pressure causing an increase in gas production rate. Compressing the well can substantially increase the ultimate gas recovery. However, this lifting method requires an initial investment for the compressor and also has relatively expensive operating costs for maintenance and power needed for keeping the compressor running. Using this lifting method as a liquid loading solution can provide beneficial.

As mentioned, compressors increase gas production rate by lowering the surface pressure and bottom-hole flowing pressure. This means an increase in gas velocity and therefore better removing of liquids collected at the bottom of the wellbore. The removal of liquids and the decrease in the bottomhole pressure exposes more of the gas in the reservoir to production which was initially unavailable.

In order to lower surface pressure with the help of compression, energy is required in terms of horsepower. Energy needed in terms of horsepower is directly related to the ration of suction and discharge pressure also known as the *compression ratio*. As suction pressure of the compressor decreases or the discharge pressure increases, the amount of energy needed increases dramatically. Lea[10] constructed the table for the energy required to compress gas at different surface pressure to a pipeline that has 1000 psig as well as the percentage of compressed gas required to power the compressor:

Table 4.1 – Compression Horsepower and Fuel Gas[10]

Suction, psig	Suction, psia	Discharge, psia	Compression Ratio	Horsepower/ MMCFD	% Fuel Gas Required
0	14.7	1014.7	69.0	309	5.9%
10	24.7	1014.7	41.1	253	4.9%
25	39.7	1014.7	25.6	216	4.2%
50	64.7	1014.7	15.7	181	3.5%
125	139.7	1014.7	7.3	130	2.5%
300	314.7	1014.7	3.2	75	1.4%

Combining the amount of horsepower required at a given pressure *(Table 4.1)* with the critical rate equations of Turner *et al.*, it is possible to estimate the minimum amount of energy required to keep the well dry by removing produced liquids. *Figure 4.14*, sensitivity analysis for different tubing sizes shows the compressor energy requirement to keep the gas velocity above critical.

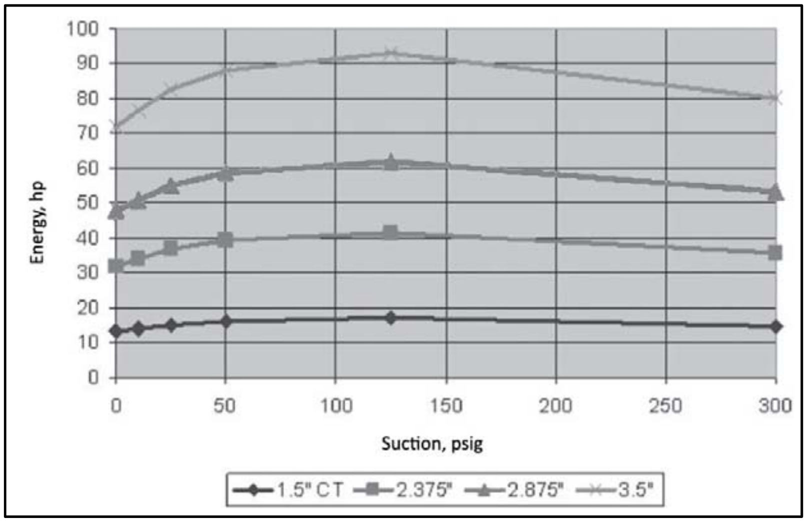

Figure 4.14 – Energy Required for Different Tubing Sizes to Stay above Critical Rate[10]

The effect of permeability can be variable in compression applications. In high permeability reservoirs the aim of installing a compressor can be accelerating the production rate as well as keeping the well dry. Wells with high productivity values can maintain production rates above critical until the very end of their life. These factors are important regarding the optimization of compression applications. Also, anything that causes a significant pressure drop due to friction in the way of suction from the surface to the bottomhole will impair the efficiency of the compressor. Restriction in the surface and in the well would cause increased energy requirements and reduced power in lifting therefore would cause quicker loading of the well.

Compression and reducing surface pressure is generally one of the first solutions used during the production life of a gas well regardless if it has liquid loading problems. The importance of compression applications is that it could be used not only for keeping the well free of liquids but also increasing production rate that has decreased with depleting gas reservoir. Moreover, compression applications could be used with other methods and remedial treatments such as foaming agents, gas lift, plunger lift, beam pumping, electrical submersible pumps and velocity strings. However, different wells will give different responses to any particular application and it is crucial that the compressor type, size and properties are selected properly and optimized for maximum efficiency. System nodal analysis can be a useful tool determining the best course of action when choosing compressors.

4.5.3 Plunger Lift

Plunger lift is an intermittent artificial lift method and a liquid loading solution that uses the energy of the gas reservoir to produce the liquids collected at the bottomhole. A plunger is a piston type tool that travels freely in the tubing string and fits the inside diameter of the pipe. It travels up when the well pressure is sufficient enough to lift and travels back down due to gravitational force. The plunger lift installation operates as a cyclic process when the well pressure is built-up during shut-in and is flowing when the pressure is sufficient to lift the plunger and the liquid column collected above the plunger. During shut-in period, the plunger is at the bottom on a spring assembly, the gas pressure accumulates in the annulus and liquids accumulate at the bottom of the tubing. The pressure accumulated in the annulus depends on different parameter such as shut-in period, reservoir pressure and reservoir rock permeability. After a certain period of time, when the pressure is increased sufficiently, the motorized surface valve (motor valve) is opened to allow flow of gas through the tubing lifting the plunger to the surface, unloading the liquids accumulated in the tubing string and producing the gas accumulated in the annulus. All this cyclic process requires an installation of surface equipment that consists of valves and downhole equipment that consists of a plunger and a spring mechanism.

A typical conventional plunger installation *(Figure 4.15)* includes components which are:

- A spring assembly called the *bumper spring* that can be installed via wireline to catch the falling plunger and help it land at the bottom without damaging itself
- A surface catcher/lubricator system designed to catch the plunger when it rises up to surface and allow flow to continue by holding it as long as the well is flowing.
- A motorized valve at the surface that is controlled electronically to open and close the well when needed.
- An electronic sensor at the surface to monitor plunger arrival.
- An electronic controller with logic that will set cycles that consists of production and shut-in periods for best operation by opening and closing the motor valve. It

will also record the data from the sensor to help determining the condition of the plunger.

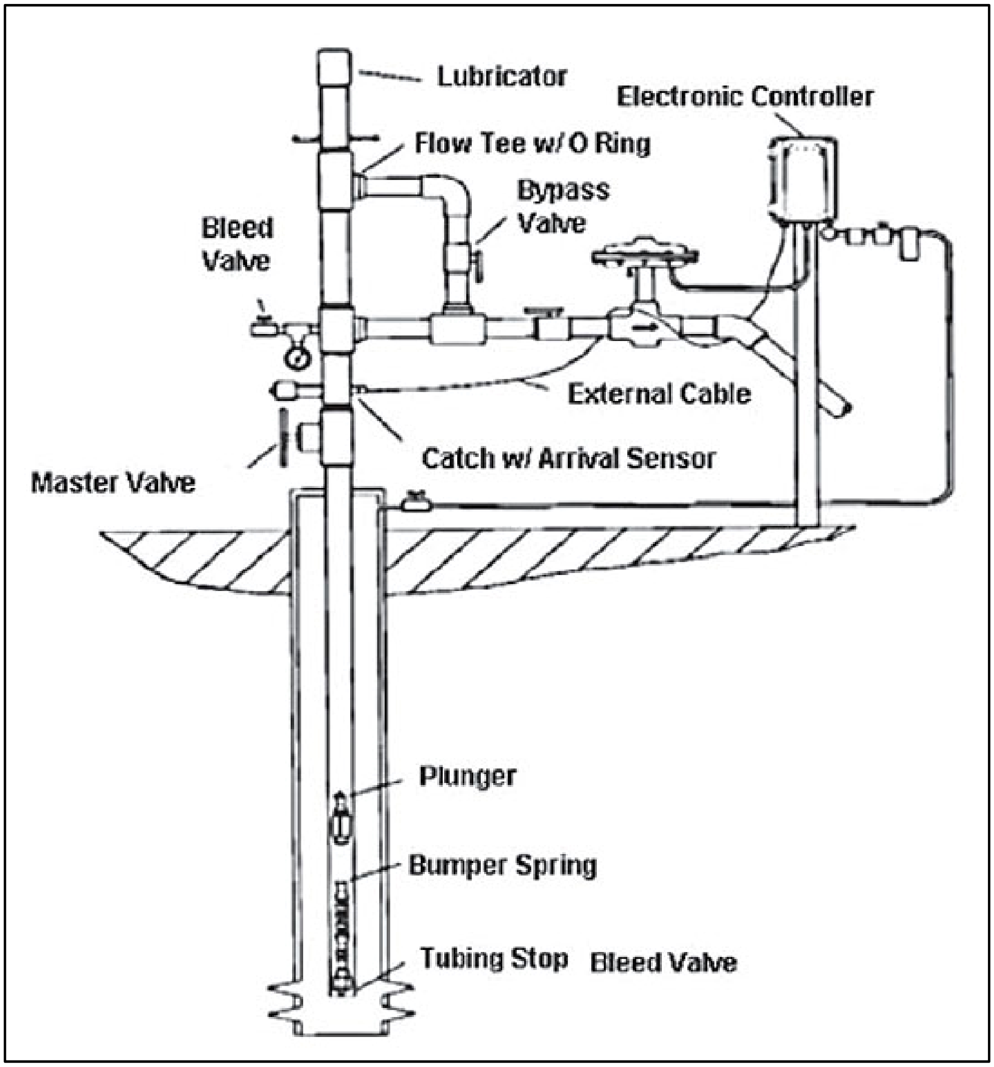

Figure 4.15 – A Typical Plunger Lift Installation[10]

As mentioned, a typical conventional plunger lift application consists of cycles with production and shut-in periods which are needed for building gas pressure in the casing and lifting the liquids accumulated in the tubing efficiently. Although these periods may have small differences due to different properties of different gas wells, the steps (also shown in *Figure 4.16*) are generally as follows:

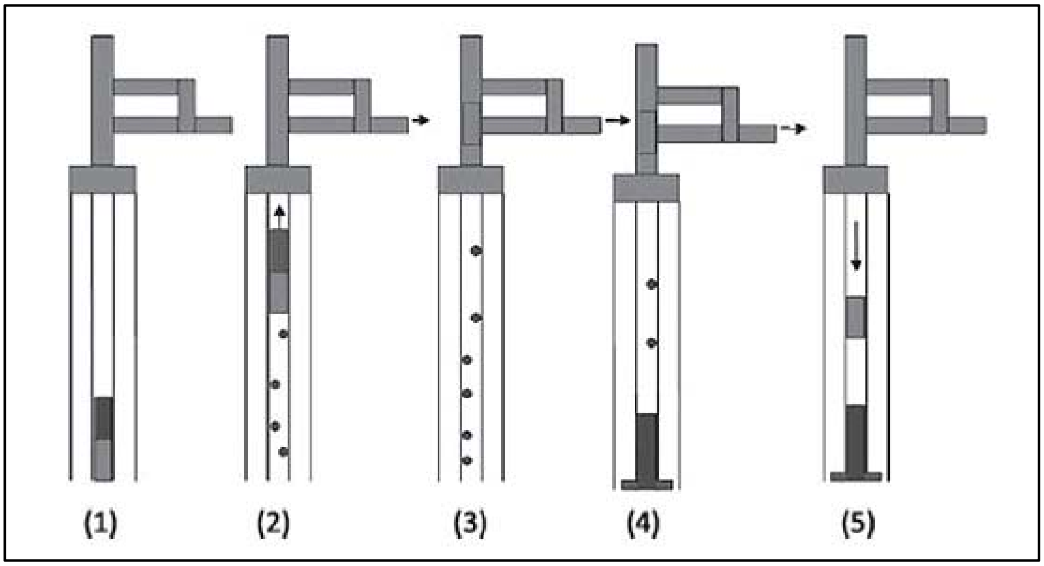

Figure 4.16 – A Simple Illustration of Plunger Lift Cycles[10]

(1) The well is shut-in and the pressure inside the casing is building. The motorized valve at the surface will open when the pressure inside the casing is sufficient to lift the plunger and the accumulated liquid column at a velocity exceeding critical.

(2) The valve is open and the plunger begins to rise with the liquid column. The gas built in the annulus expands into the tubing string providing the required energy for lifting.

(3) All of the liquid collected above the plunger reaches surface and flow through the surface line. The plunger is held at the surface due to pressure and flow rate underneath. The well continues producing gas during this period until the pressure decreases and the valve is closed.

(4) The flow velocity begins to decrease as liquids enter the well from perforations and start accumulation at the bottom. At this "decline" period, a large amount of liquid will be accumulated at the bottom of the hole and in the tubing string if the well is open to flow too long and will require a larger build-up pressure.

(5) The motor valve at the surface closes and the well is shut. The plunger falls to the bottom of the well onto the spring. The pressure starts increasing in the annulus once again until the next cycle.

Using plunger lift as an artificial lift method to overcome liquid loading solutions requires initial capital costs which are relatively inexpensive. However, operating costs will add up to the initial capital costs and field testing this method to see if it is suitable for the well would be costly. In order to determine the feasibility of plunger lift installation, there are certain methods that proven useful. Lea *et al.*[8, 10] developed a rule of thumb regarding the gas/liquid ratio (GLR) of the well to determine if the collected energy of the gas pressure would be sufficient to lift the accumulated liquid effectively. This simple GLR rule states that the well must have a gas/liquid ratio of 400 scf per bbl for each 1000 ft of depth that liquids have to be lifted. As an example, a 7000 ft deep gas well would require a GLR of 2800 scf/bbl for the plunger lift installation be feasible. This simple rule of thumb may be useful, however; it can give false indications when conditions are close to predicted values. To overcome the shortcomings of the GLR rule of thumb, charts of feasibility of plunger lift *(Figure 4.17)* can be used that are developed by Beeson *et al.*[15] (1957) for different tubing sizes. Another chart that can be used to determine the maximum possible production rate that can be achieved with a particular tubing size at a certain depth is the depth vs. fluid production charts[16] that can be found in product manuals. These charts can be found in Appendix B.

There is a rather new type of plunger consists of two pieces that is designed to fall to the bottom of the well while the well is still producing gas. In conventional plunger applications as soon as the plunger begins falling back down it constricts flow of gas. In this two-piece plunger that consists of a ball at the bottom and a piston at the top the flow continues around the ball and through the piston as these two pieces fall down free from each other. When travelling up, however; the ball is pushed upwards not allowing the liquid to go through the piston and the pieces act as one unit. The plunger pieces can fall down at the bottom at a velocity of 1000 ft/min or more, while the conventional type plungers are advised not to exceed 750 ft/min to avoid damages to the string and the equipment itself. This will allow the plunger system to move faster and make more trips to the surface allowing it to lift more liquid from the bottom of the well than conventional plunger applications.

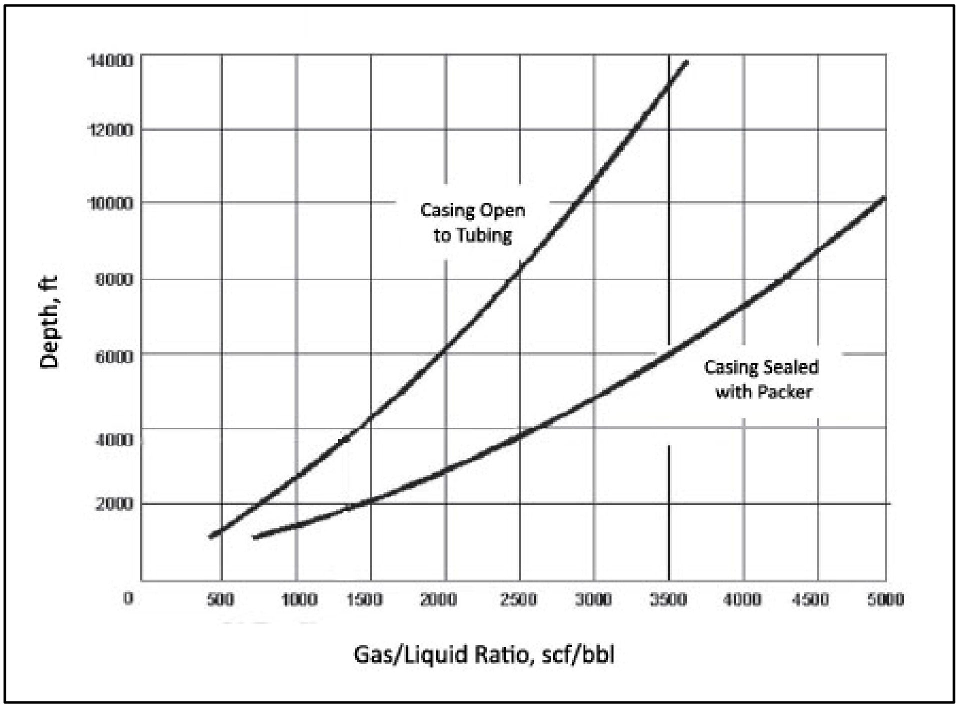

Figure 4.17 – Gas Requirement for Plunger Lift with or without Packer[16]

In plunger lift applications there is also one more issue to consider, which is the use of plunger lift in completions with packer installed. When proposing plunger lift installation to a particular well, packerless completions are highly preferred over completion with packer because the large volume of tubing/casing annulus allows much more gas to be stored in the well. However, perforating the tubing string above the packer and draining the annulus fluid may improve the efficiency system by allowing annulus to be used for storage. If the reservoir energy is sufficient to produce enough gas to lift the accumulated liquids with the help of a plunger, plunger lift installation can still be used with completion with packer installed. However, the gas requirement (gas to liquid ratio) of the well will be significantly higher than packerless completions and this is an important factor to consider.

4.5.4 Gas Lift

Gas lift is another artificial method used to treat wells having liquid loading problems. Gas from another source is injected to the well at some depth and additional gas increases gas production rate of the well allowing the well to remove liquids more easily. The increased gas velocity will be above critical velocity therefore the liquids will not accumulate at the bottom of the wellbore. An important issue about this application is that gas lift will lower the density of the fluids above the injection point. Therefore, the end of injection string should be determined carefully.

Due to the nature of this method, gas lift may be unable to reduce the bottomhole flowing pressure to lower values than most pumps do. However, there are certain elements that make gas lift a favored artificial method. First of all, among all artificial lift methods, gas lift is the closest one to the natural flow of the well since the well could keep flowing by itself with a little boost from an outer gas source. Moreover, in cases where the remaining gas in the reservoir is still high enough with respect to liquid volume, the GLR ratio of the well will be too high for conventional pump systems to work effectively because of gas interference problems, commonly known as *gas lock*. For gas lift installation, on the other hand, a high GLR reduces the volume of gas injection needed to lift the accumulated liquids. In horizontal or deviated wells where pumps cannot work efficiently due to increased frictional pressure, and wells with solids such as sand where pumps will be clogged and damaged are conditions which will be more suitable for a gas lift installation for lifting liquids.

Fundamentally, for lifting accumulated liquids from gas wells, there are two types of gas lift techniques used excessively in the industry which are *continuous gas lift* and *intermittent gas lift*. In continuous gas lift, the flow from surface to the point where gas is injected into the wellbore is continuous and the higher pressure gas from the outer source mixes with the gas inside the well, making it easier to lift the liquid column in the production string *(Figure 4.18)*. This application can be utilized with either a conventional smaller tubing string and a simple valve mechanism or a coiled tubing application.

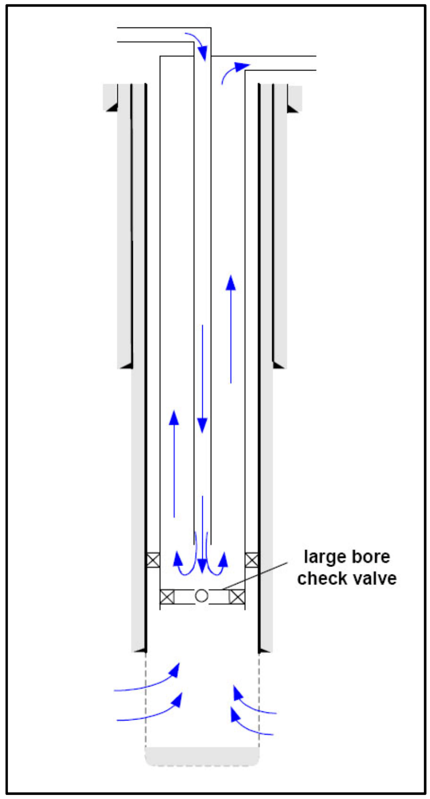

Figure 4.18 – Continuous Gas Lift Schematic[14]

In intermittent gas lift, on the other hand, is used with an automated logic system and multiple check valves *(Figure 4.19)*. The system inject gas from another source into the well from a certain depth until the pressure at the bottom is sufficient to lift the accumulated liquid column to the surface, and then flows the well, producing the injected gas and the gas from the reservoir, lifting the liquids to the surface along the way. When the pressure drops to a certain value, the system closes the well once again to pressurize it with the outer gas source and this cycle repeats. Generally, continuous gas lift applications are converted to intermittent gas lift some time along the life of a well when the bottomhole pressure of the well declines to a point where it can no longer lift the liquids continuously even with the aid of an outer gas source and the pressure needs to be built-up before the well can be flown. The point when it is time to convert continuous flow gas lift system to intermittent flow differs as it is a decision based on the remaining reservoir energy, GLR, production flow rate and the production string of the well. Using nodal analysis, which mentioned before, can be beneficial for determining the optimum point to make the conversion, and also the optimum tubing size to be used.

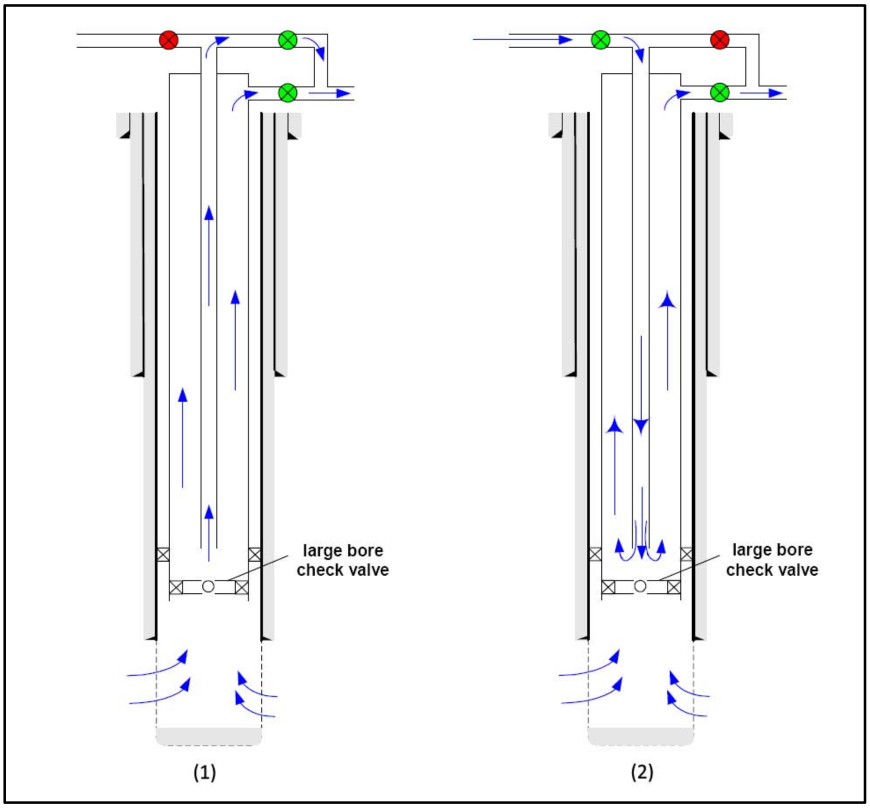

Figure 4.19 – Intermittent Flow Gas Lift Schematic[14]

A typical gas lift installation requires certain components[12]:

- An outer gas source with higher pressure.
- A surface injection system with appropriate valves and tubular.
- A surface production system.
- A gas production well with an inner string and gas lift components.

Despite its certain advantages, gas lift installation may not be applicable or feasible in many liquid producing gas wells due to its basic requirement: an outer high pressure flowing gas source. Unless the well is close to another gas well producing dry gas at high rates, or the well itself has another higher-pressure gas pay zone; only option left for gas lift to be utilized is with installation of compressors which has rather high capital costs and have to be monitored regularly. If the conditions comply, gas lift is a very useful method for gas wells with high GLR and production rates just under the critical values. Otherwise, field application of gas lift would unlikely prove useful.

4.5.5 Foaming

Foams are used in a wide variety of useful applications in oil business. They are used in drilling and well completion operations as circulation fluids, fracturing fluids and more. Foams are also used in producing gas wells as a medium for removing liquids. The main difference of using foam as a liquid loading treatment from other applications is the need to generate the foam the bottom of the hole by injecting surfactants and mixing with liquids downhole.

Foam is basically an emulsion of liquid and gas. Surface active agents, commonly known as surfactants are used in water to enable more gas to be dispersed. The excess amount of gas dispersed in liquid results in a drastic decrease in the density of the liquid, making the reservoir pressure to be able to lift the foam all the way to the surface. Campbell *et al.*[17] (2004) describes the effect of foaming using the critical velocity equation of Turner *et al.*[1] *(Equation 1)*. According to Campbell, the surface tension is reduced, reducing critical velocity required to remove liquids accumulated at the bottom.

Wells having loading problems with water reacts better to foaming than hydrocarbons since water foams better and more easily than liquid hydrocarbons. That is due to the polarity of the water molecules and the attraction in between. Also, according to Lea[10], wells with GLR between 1000 and 8000 scf/bbl are better candidates for foaming; though there is no upper limit, in higher gas/liquid ratios wells may give better performance with other methods as bottomhole flowing pressure would be lower. Although generally a simple and inexpensive method, conditions such as increased complex chemical costs for foaming of liquid hydrocarbons, possibility of emulsion at the bottomhole, and the possible need for an injection system to increase efficiency make the optimization of foaming agents a challenge. Solesa and Sevic[18] showed that for proper optimization of foaming agents in field applications of gas wells with liquid loading problems extensive laboratory tests, field trials and nodal system analysis may be required *(Figure 4.20)*.

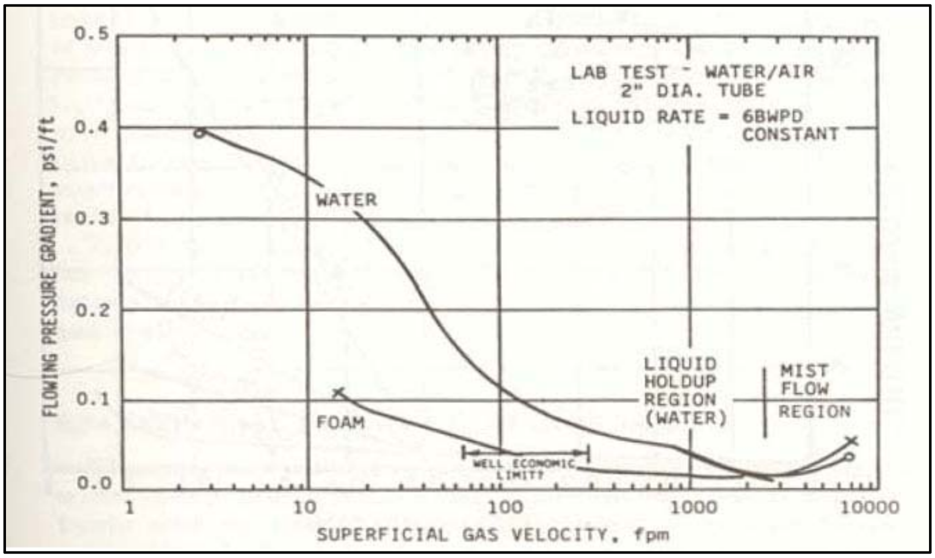

Figure 4.20 – Flowing Pressure Gradient of Water and Foam[18]

4.5.6 Beam Pumping

Beam pumping is maybe the most common method used to lift oil from wells worldwide, and the conventional surface equipment of beam pumping is possibly the best known image for oil field operations. Beam pumping is also a useful method commonly used in gas wells having liquid loading, especially for the cases where the well is loading with liquid hydrocarbons which are as valuable as the produced gas. In water loading gas wells in areas where water disposal costs are high, however; beam pumping may not be beneficial.

The main principle of using beam pumping as a liquid loading solution is installing the beam pump below the production zone, making it possible to produce liquids from tubing string and gas from casing *(Figure 4.21)*. Since the gas in the well flows up the casing to the surface, the well cannot have a packer that would seal the casing/tubing annulus. A gas anchor may be used below the beam pump to help separating the gas from the liquid and making it difficult to enter the tubing string. This would prevent possible gas lock problems with the beam pump. A gas anchor is a simple tool with perforations that is used to separate gas and make it easier to drain the liquid.

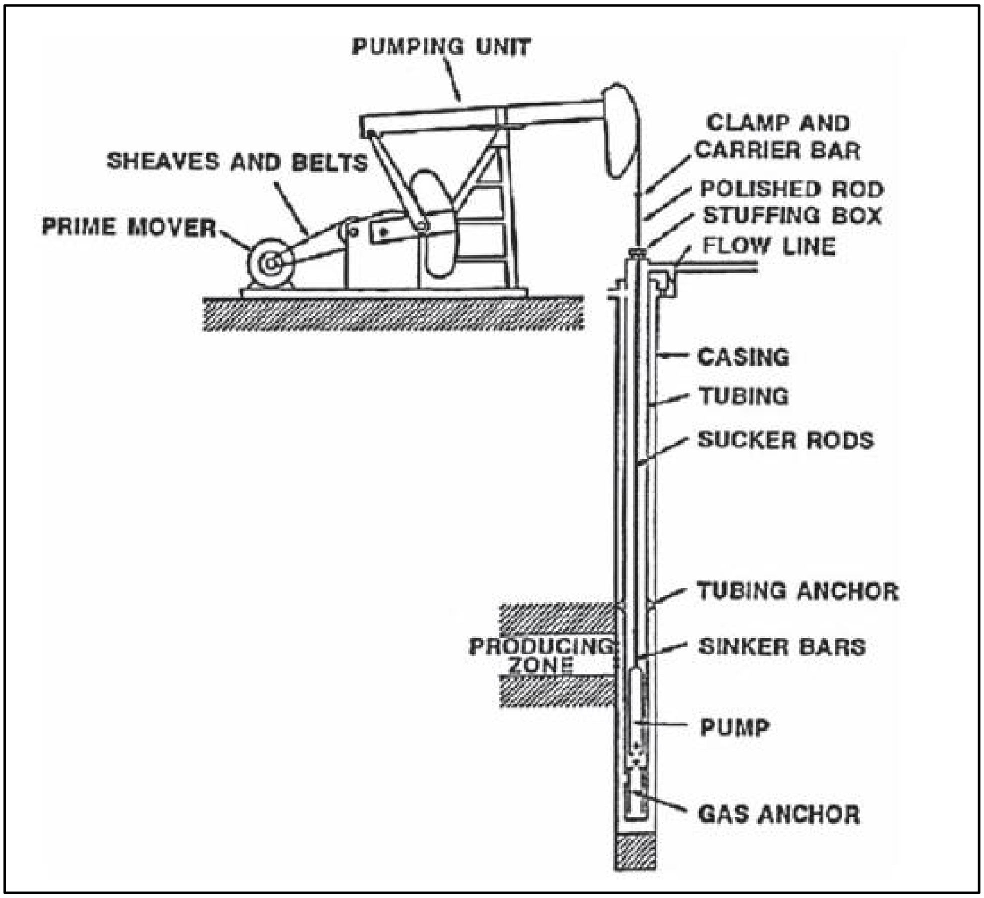

Figure 4.21 – A Simple Beam Pumping System[12]

The beam pumping unit is designed to change rotary motion into reciprocating motion to give the sucker rods their movement up and down the hole. Beam pumping units are generally energized with movers using electrical energy. Electricity is preferred due to the ability of beam pump to put electrical energy to good use by high efficiency. However, in certain remote areas where electricity can only be provided with the presence of a generator, a gas driven engine that uses a portion of natural gas produced from the well can be utilized to power the beam pumping unit.

An important consideration about beam pumping is, as mentioned, keeping the produced gas from entering the tubing string where liquids are produced. Entrance of excess amounts of gas into the tubing string may result in gas locking, reduced efficiency and production.

The simplest yet maybe the best solution would be setting the end of tubing and therefore the pump below the perforations. Due to natural movement, gas will quickly start travelling up the casing while liquids migrate slowly down the hole. However, there may be cases where setting the pump below the perforations is not possible. In these cases, using a gas anchor or another type of gas separator below the pump may keep the produced gas from entering into the tubing string.

Beam pumps are used worldwide in different artificial lift applications, and using beam pumps can be a useful method for treating gas wells with liquid loading problems. If gas separation issues are solved properly with the use of downhole gas separator equipment, beam pumping may lift the accumulated liquids from the bottom of the well efficiently. However, if the lifted liquids are water or another liquid that cannot be reused and need to be disposed; beam pumping may be impractical and expensive especially in high water disposal cost situations.

There are other methods or treatment techniques that are used in gas well to solve problems due to liquid loading. These methods include *blowing the well down*, which is flowing the well to atmosphere, using electrical submersible pumps for artificial lifting and shutting the well for using the built-up gas pressure to lift liquid as slugs. However, these methods are temporary measures rather than solutions to liquid loading problems. As an example; blowing the well down on a regular basis is inefficient due to the need of constant monitoring and personnel. Also, blowing the well down requires the well to be flown to atmosphere which would result in gas and liquid to pollute the environment. Electrical submersible pumps are large applications with high costs and need low gas liquid ratios that the income from the produced gas cannot cover the operation costs, let alone the initial capital cost. Therefore, these methods are not mentioned in detail.

CHAPTER 5

DECISION MAKING: EXPERT SYSTEM

5.1 General Information

In the light of the theoretical information and studies conducted by several authors, the aim of this study is to highlight the necessity of the decision making process and propose a systematic approach for selecting proper solutions for problems commonly related to liquid loading concept.

In order to design a proper "*expert system*", a decision tree should be constructed as the algorithm of the expert system. The aim of this process is to develop the decision tree that shows the basis of the expert system.

5.2 Summary of Theory: Design Process

Over the years, several authors have observed the behavior of gas wells showing symptoms of liquid loading. In chapter 4, it is explained that after seeing the initial indications of liquid accumulation in a gas well initial response should be carrying out a downhole pressure survey without any delay. After confirming the gas well at hand is having problems associated with liquid loading, the logical next step would be trying to find the optimum solution to the problem. However, in order to do as such; it should be defined whether the remaining reservoir energy would be sufficient for the well to produce gas on its own even with the presence of liquid production on the side. This should be defined using inflow performance and tubing performance curves with logistically available tubing sizes. If the remaining energy allows the well to flow on its own with smaller tubing size, this option should be considered prior to any artificial lift method since it would probably be the low cost option. Changing tubing size with workover or velocity string is a question of logistics and economics depending on the availability of coiled tubing application.

Unless the remaining reservoir energy makes it unfeasible for the gas well to produce with its own power; the next step would be to determine the artificial lift method to be used to get rid of the accumulated liquids on the bottom of the gas well causing the problem. The possible presence of an outer high pressure gas source near the target gas well makes gas lift applications the favored solution since –depending on the distance of the gas source- it would be an inexpensive solution especially in cases with two different gas producing intervals in the same gas well. In the absence of an outer high pressure gas source however, one of the remaining options should be chosen: plunger lift, compression, foaming or pumping.

The selection criterion for the next step mainly depends on gas-liquid ratio of the production well. As it is stated in *Chapter 4*, for gas wells with high gas-liquid ratio, the favorable solution would be either plunger lift or compression. That is mainly due to the impracticality of other solutions in high gas environments. Lea[10] states that *"wells with GLR between 1000 and 8000 scf/bbl are better candidates for foaming"* and adds in higher GLR situations other methods such as plunger lift may give a better performance. The other question for gas wells with high GLR ratio is determining the better solution between plunger lift and compression. Although it is stated that in high permeability systems the effects of compression would be limited; the question at hand is more of an economics issue rather than technicality. Plunger lift is a low capital cost solution that has to be monitored constantly for possible stuck problems, whereas the initial investment costs for compression could be relatively high. When selecting a proper method, the intent of the client would make the difference.

As stated above, the "moderate" gas-liquid ratio solution is generally foaming. Although there are possible options regarding the use of foaming in gas wells as a liquid loading solution method, the practice differs mainly because of the type of the accumulated liquid in the wellbore. For water loaded gas wells, a solution as simple as dropping soap sticks from the surface would prove to be useful; if the loaded liquid consists of hydrocarbons, there may be a need to inject complex chemicals to the bottom to reduce the density of the liquid, thus reducing the pressure gradient of the liquid. That means, for foaming, the most important issue after gas-liquid ratio is the liquid type.

For gas production wells at the end of their productive lives, gas-liquid ratio would be a lot lower. That makes pumping the liquids out of the gas well possible and also feasible since there would be no more gas locking problems that are related to high gas content in the production string. Obviously, it should be decided whether the cost to remove the liquids from the well by pumping is economically feasible considering the decreased amount of produced gas from the well. However, it is widely known that especially beam pumping is a relatively low cost solution; therefore it could keep the well free of liquids for a long time without the need of a high capital investment.

All the information gathered from theoretical findings and field trials related to solving production problems associated with liquid loading can be summarized to systematically approach a gas well to find the proper solution. This attempt leads to the development of the following decision tree, *in Figure 5.1,* for a prospective *"expert system"*.

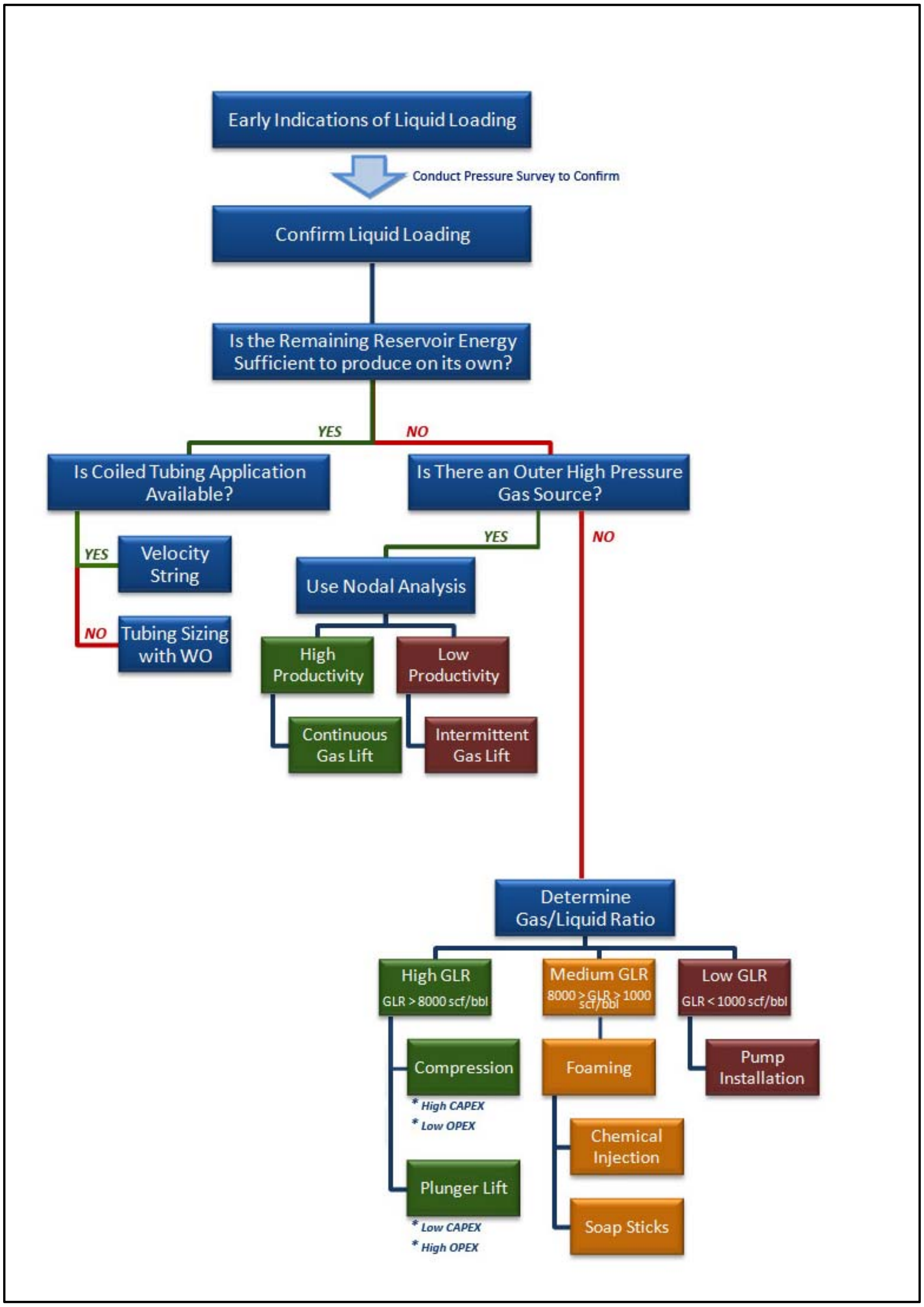

Figure 5.1 – Decision Tree for the Expert System

CHAPTER 6

CASE STUDY

6.1 Background Information

Wells #10 and #28 are two relatively deep vertical gas wells with moderate to serious liquid loading problems in the same block, producing from the same reservoir. The wells have depths of 10500 and 10300 ft, respectively and both wells have tubing strings with an outer diameter of 2 7/8 inches as production string in 6 5/8" inch casing. The casing tubing annulus is sealed with a packer at the end of completion. The general information on the wells #10 & #28 are as follows:

Table 6.1 – General Well Information of #10 and #28

	#10	**#28**
Well Depth ,ft	10500	10300
Tubing String Depth ,ft	9550	9650
Perforation Interval ,ft	9720 – 9760	9800 – 10010
Casing Size ,in	6 5/8	6 5/8
Tubing Size ,in	2 7/8	2 7/8
Packer/Completion	Permanent Production P.	Permanent Production P.

The reservoir from where both wells are producing gas along with water and condensate has an average permeability of 1 millidarcy. Both wells are connected to a surface pipeline system with a line pressure of 300 psia. Gas samples collected from the wells show a specific gravity of 0.65 for well #10 and 0.66 for well #28. Also, the water samples that are gathered from the wells have densities of 8.52 ppg, 8.48 ppg for well #10 and 8.54 ppg, 8.51 ppg for well #28; so an average density value of 8.5 ppg for water is used in calculations to simplify the model.

6.2 Well #10

After producing gas for quite a time, daily gas production rate of #10 has started to decline as reservoir pressure depletes. The well has begun showing erratic flow behavior and eventually, due to the high pressure of the surface lines that #10 has been flowing in; the well ceased production. The erratic behavior the well has been showing is, as mentioned earlier, a symptom of possible accumulation of liquids at the bottom of the well. The ever declining tubing head pressure was another sign promoting liquid accumulation. Since the well was completed with a packer installed at the end of the tubing string, the casing pressure could give no indication. In *Figure 6.1*, tubing head pressure against time clearly shows the erratic flow behavior of the well.

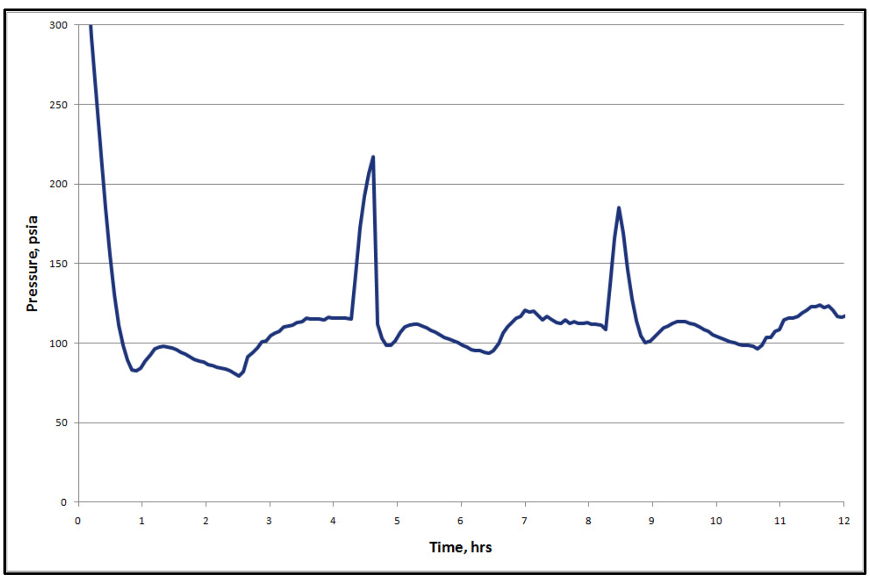

Figure 6.1 – Tubing Flowing Pressure Showing Erratic Flow in #10

In the light of these clues, our decision tree suggests taking a pressure survey in order to confirm the presence of liquids in the well. Several pressure surveys with both static and flowing well conditions have been performed in order to determine if the well is actually suffering from liquid loading. In pressure survey #1 *(Figure 6.2)*, performed in static well conditions at a depth of 9500 feet, it is clear that there is liquid accumulation in the production string. According to the survey, the static liquid level in the well is at 4150 feet.

Table 6.2 – Well #10 Pressure Survey #1 Sample Data

Depth, ft	**Temperature, °F**	**Pressure, psia**
0	72	1067
1640	82	1109
3280	118	1149
4920	161	1499
6560	199	2200
9190	257	3348
9500	266	3491

After gathering data of the pressure survey, the pressure vs. depth chart can be plotted to see clearly the pressure gradient of the wellbore and the liquid level.

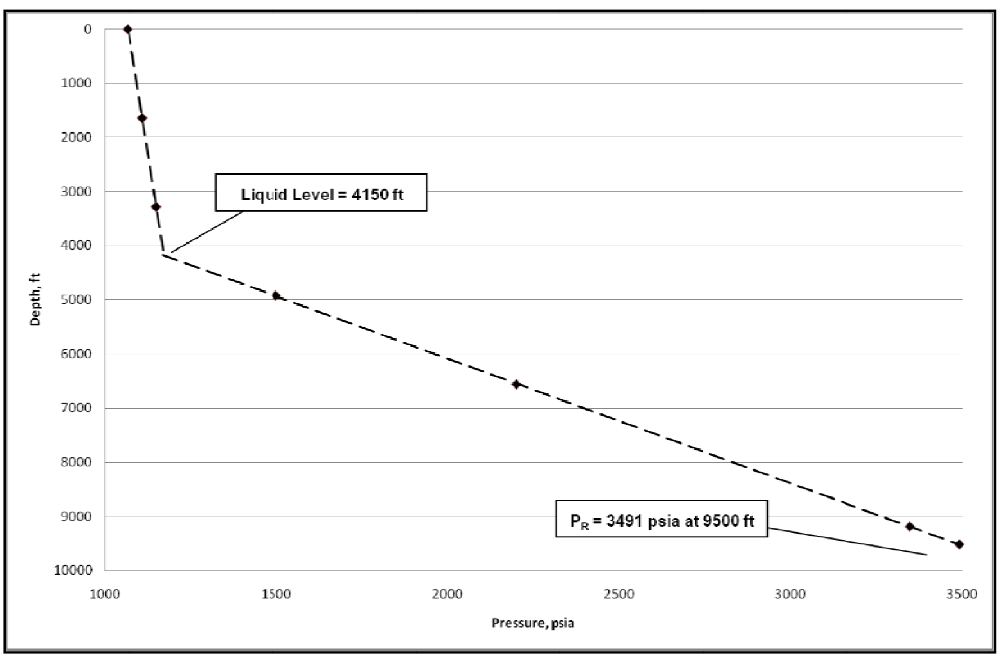

Figure 6.2 – Pressure Survey for #10 Showing Liquid Level

After discovering that the problems associated with the well is due to liquids accumulated at the bottomhole and the inability of the well to lift those accumulated liquids to surface; Turner's[1] critical rate equation (1) has been applied:

$$v_t = 1.593 \frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{{\rho_g}^{1/2}}$$

Considering the well produces an average of 550 bbl liquid in a 30 day period and 96% of this produced liquid is water; and taking into account - as mentioned earlier - when water is present at the wellbore as accumulated liquid, even if there are also condensed hydrocarbons present, critical velocity should be calculated according to water since the water density is higher than condensate, thus making it sure that the result of the equation will be adequate for condensate, also. Using bottom-hole conditions as proposed in the theory, gas compressibility "z" is calculated as 0.74. Surface tension of water under bottom-hole conditions is taken as 60 dynes/cm. The well data gathered is applied to the equation without the 20% adjustment which would actually be Coleman's[2] equation:

$$V_g = \frac{1.593(60)^{1/4}\,(63.5 - 0.00297P/z)^{1/4}}{(0.00297P/z)^{1/2}}$$

$$V_g = \frac{4.43\,(63.5 - 0.0039P)^{1/4}}{(0.0039P)^{1/2}}$$

Adding the 20% adjustment as Turner stated, the equation becomes:

$$V_g = \frac{5.32\,(63.5 - 0.0039P)^{1/4}}{(0.0039P)^{1/2}}$$

The well starts slugging and loading up when flowing to the surface line with a pressure of 300 psia and although the well is kept unloaded with a combination method of blowing the well down and flowing the well intermittently into the surface pipeline, it starts loading-up after a short while. The production data gathered as the well is blown down to atmosphere shows that the well has a potential daily production rate of 0.6 MMscf/d when flowing on 24/64 choke with a pressure of 210 psia and 1.05 MMscf/d when the well is flowing full open with a flowing pressure of 80 psia at the wellhead.

Using the critical rate equations of both Turner *et al.* and Coleman *et al.*, critical rate required for different tubing sizes are plotted in *Figure 6.3* and *Figure 6.4.*

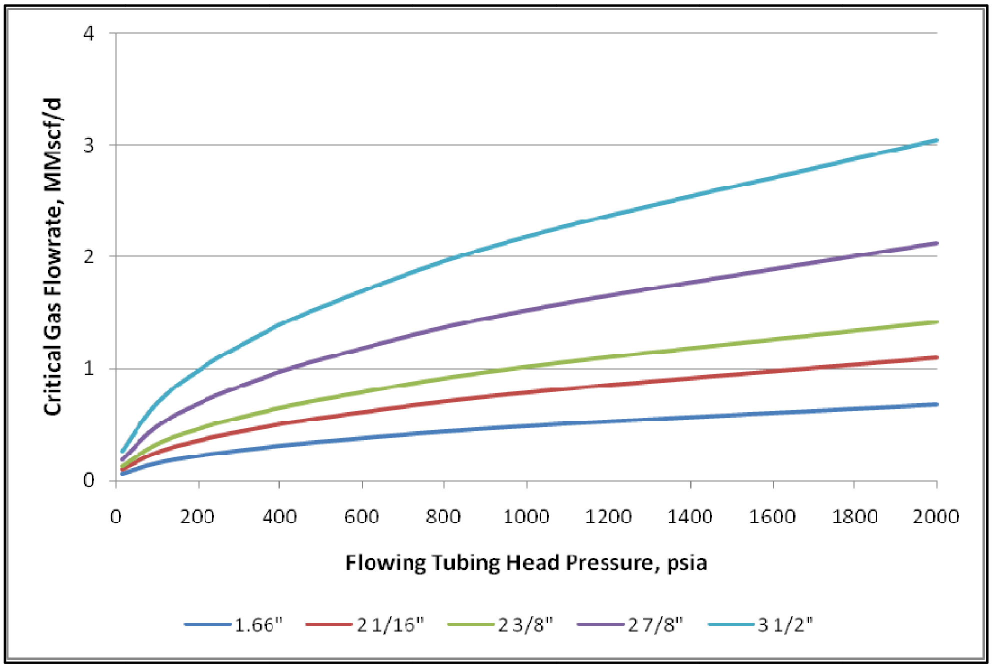

Figure 6.3 – Turner *et al.*'s Critical Flowrate for Different Tubing Sizes

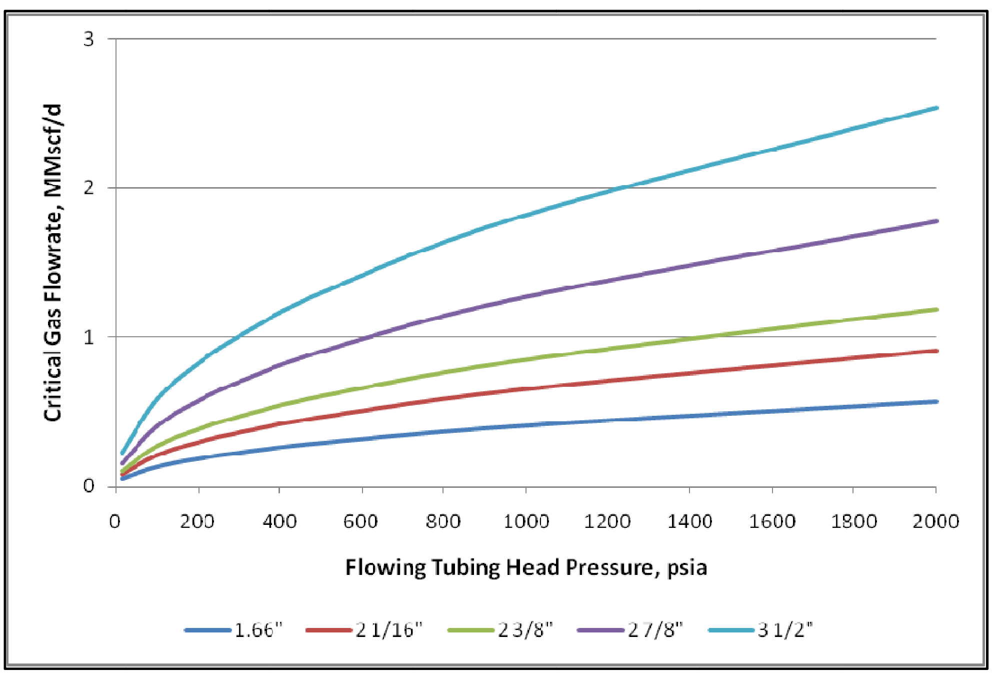

Figure 6.4 – Coleman *et al.*'s Critical Flowrate for Different Tubing Sizes

Coleman *et al.* suggested in their studies that for high flowing wellhead pressures Turner *et al.*'s 20% upward adjustment may be required but for wells with low flowing wellhead pressure the adjustment is unnecessary. After examining the critical rate plots and comparing with actual well data, it is seen that although the actual gas flowrate values are close to Coleman *et al.*'s critical rate estimations, the well is unable to lift the liquids in the flow path entirely. The more recent study of Sutton *et al.* shows that the 20% upward adjustment should be used to ensure the entire flow path (production string) is free of liquids.

The flow data gathered during a blow-down operation showed that the well is flowing with a rate of 1.05 MMscf/d and a flowing tubing head pressure (FTHP) of 80 psia. In these conditions, the well is able to lift the liquids accumulated at the bottom, but when it is flowing into the surface pipeline which has a pressure of 300 psia, the well starts loading due to backpressure caused by the high pressure of the surface line. The well may need certain artificial lift methods in the future, but it is clear from the data and the plots generated using critical rate equations that the flowrate of the well is at the borderline and with a relatively inexpensive tubing sizing operation or velocity string installation it can match the required critical rate. Inflow performance curve is calculated from single point tests and can be found in detail in *Appendix C*. As for tubing performance curves, a 3rd party program "*Pipephase"* is used to construct the curves to predict the required tubing size.

Assuming the pressure of the surface lines will remain unchanged at 300 psia; the nodal analysis with inflow performance and outflow tubing curves are constructed. IPR curves are plotted with and without turbulence effects, and TPR curves are plotted for various tubing sizes ranging from 1.66" to 3 ½" including the current tubing size. The generated Nodal Analysis curves are shown in *Figure 6.3.*

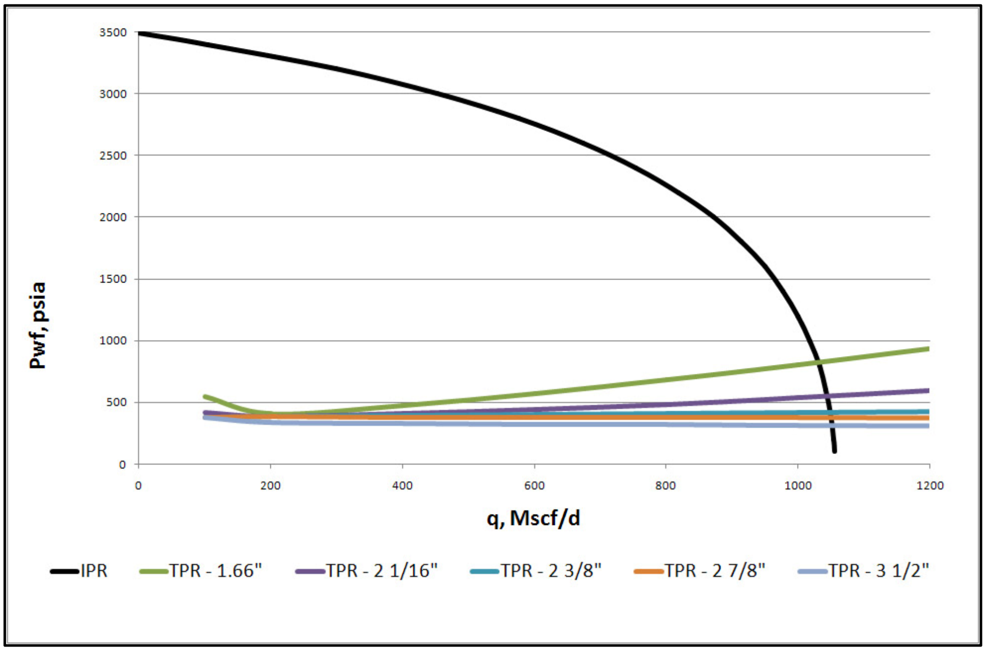

Figure 6.5 – Nodal Analysis for #10 with Different Tubing Sizes

As can be seen in the nodal analysis and the critical flow chart shown in *Figure 6.3*; the cross points of IPR & TPR curves are under critical conditions according to Turner et al.'s model. The plot shows that for tubing string with diameters larger than 2 3/8 inches, the flowing bottomhole pressure values give indications of loading. Examining the data gathered from nodal analysis, selecting a smaller size tubing string will help the unloading process.

6.3 Well #28

Similar to well #10, well #28 is a gas production well that started having problems due to liquid accumulation. The well has been showing erratic flow behavior also *(Figure 6.6)*, and as reservoir pressure continues to decline, #28 is struggling with liquid loading problems as the liquids accumulated at the bottom cannot be lifted properly. The case in well #10 showed that even with proper tubing sizing and reducing the wellhead flowing pressure, the solution would be relatively temporary depending on the remaining energy of the formation. That would lead to the conclusion that the remaining energy of the formation is on the verge of inability to lift the liquid accumulated at the bottom of the wellbore. Unable to produce effectively on its own due to severe liquid loading problems, the next step in the decision tree is followed to compare various methods for looking for a permanent solution on liquid loading.

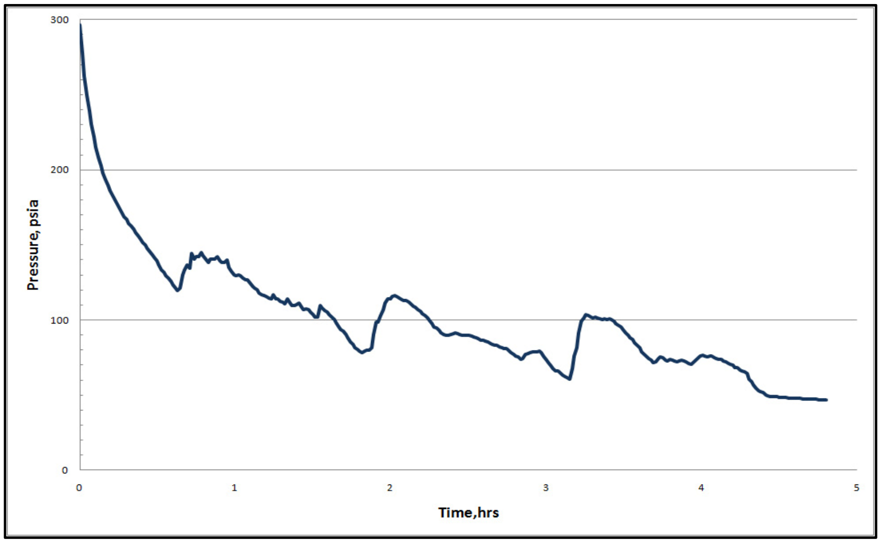

Figure 6.6 – Erratic Flow Behavior shown in Pressure vs. Time Graph of #28

Like the former well, a pressure survey in static conditions has been carried out to confirm the indications of liquid loading in the well, and also determine the pressure at the bottom, as shown in *Figure 6.7*. The pressure survey done in #28 showed that the liquid level is deeper than that of #10. The liquid level is at 7200 ft which indicated the reservoir pressure is lower, pointing out the need to find a different solution to the matter.

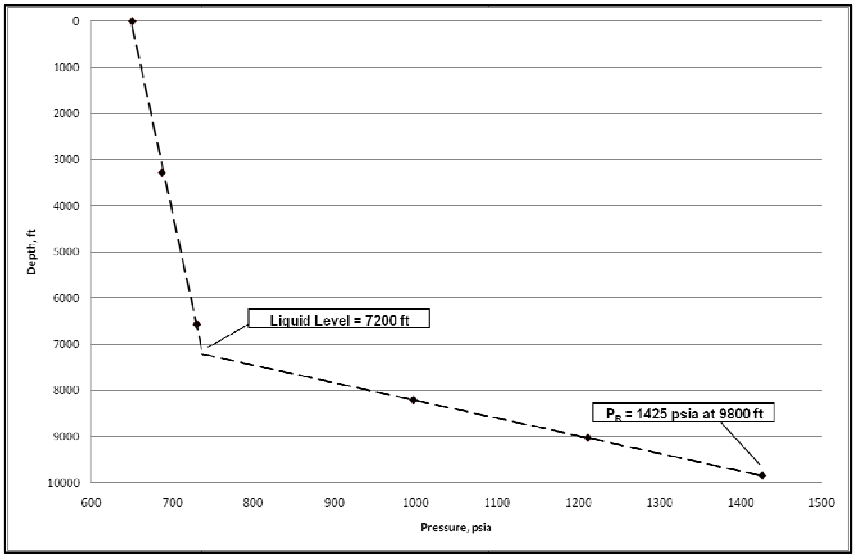

Figure 6.7 – Pressure Survey for #28 Showing Liquid Level

Using the data at hand, inflow and outflow curves that belong to #28 have been plotted using the same procedure as in well #10. In *Figure 6.8*, nodal analysis with different tubing sizes is shown to observe the flow conditions with various tubing diameters.

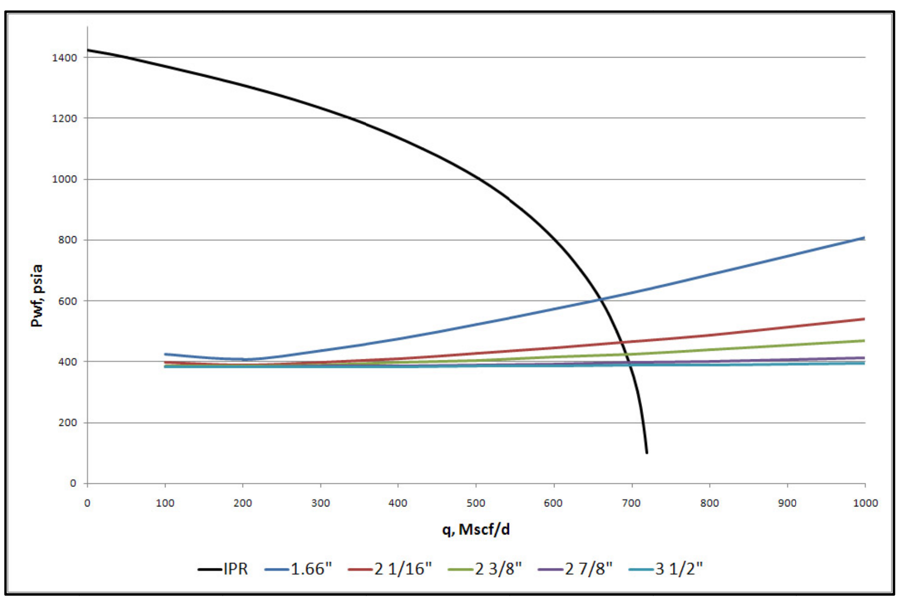

Figure 6.8 – Nodal Analysis for #28 with Different Tubing Sizes

As it can be clearly seen from nodal analysis, the inflow performance of the well #28 is low due to lower reservoir pressure. The analysis also shows that outflow curves that belong to different tubing sizes are close to each other with the exception of 1.66" outer-diameter tubing. As mentioned, since the reservoir pressure is quite low and the reservoir is depleting and keeping in mind that the well is flowing with a pressure of 20-25 psia when open to atmosphere; a lift method should be selected instead of installing a smaller diameter tubing string, since a smaller diameter tubing string will become insufficient after a short time. *Figure 6.9* shows the comparison of actual flow rates with Turner's critical rates at the junction points of IPR-TPR curves for various tubing sizes. The graph simply shows that the "ideal" conditions will not meet critical conditions due to low deliverability:

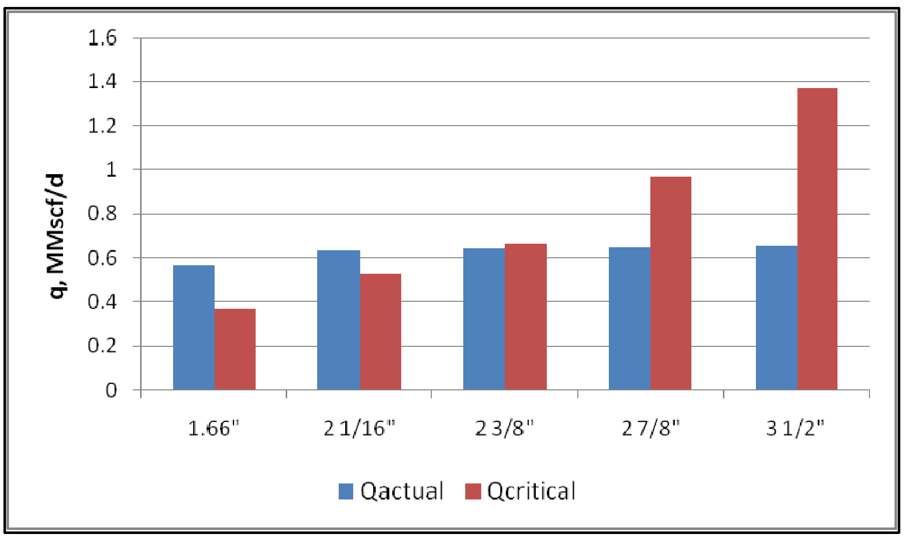

Figure 6.9 – Actual Rates vs. Critical Rates for #28

According to Lea *et al.*, as mentioned earlier, selecting the proper artificial lift to solve liquid loading problems is mostly a matter of the gas/liquid ratio of the well. In order to determine the GLR of the well; gas and liquid production rate has been recorded. *Table 6.3* shows a portion of the production data which gives different GLR values at different times:

Table 6.3 – Production Data of Well #28

Days	Gas Rate, MMscf/d	Liquid Production, bbl	GLR, scf/bbl
1	0.571	11	51915
2	0.592	12	49296
3	0.585	10	58477
4	0.544	9	60459
5	0.544	10	54441
10	0.570	9	63315
15	0.589	4	147269
20	0.386	0	-

The erratic flow behavior can be clearly seen from the production data also. It is seen in *Figure 6.10* that the well is lifting some of the liquids initially since the gas rate is relatively high and as rate decline the liquid lifted to surface is decreasing and rate starts declining even more shortly after that. Also, from *Figure 6.10* it can be seen that daily condensate production is very low compared to water, so it's fair to take all the liquid accumulation as water since; as stated before, due to higher density of water. Plotting gas production rate along with liquid production would help to see the effects of loading on the rate more clearly:

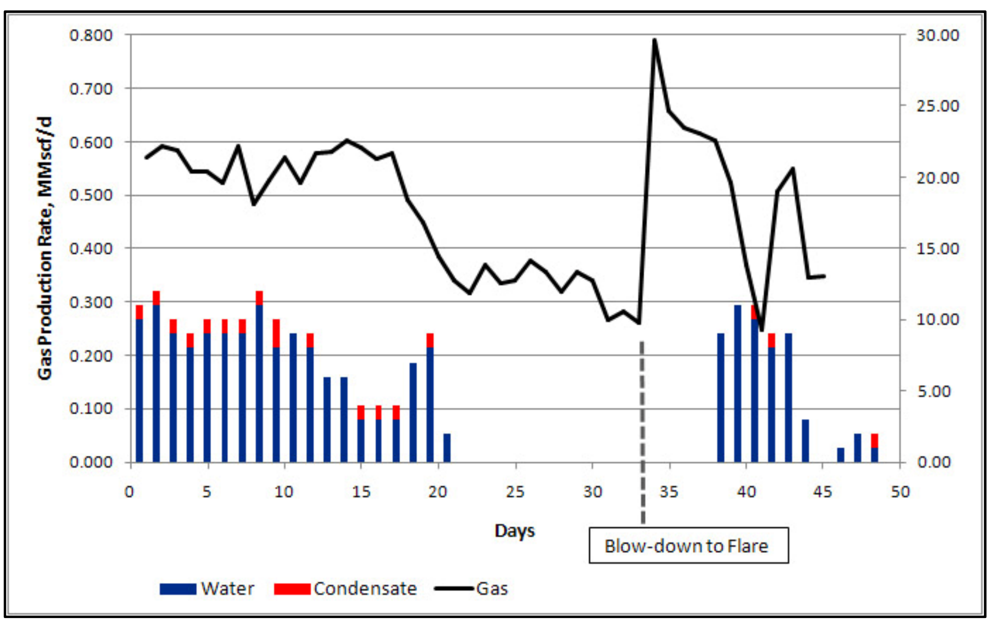

Figure 6.10 – Gas and Liquid Production Chart of #28

It is clear in the plot that the liquid is accumulated in the production string as the well continues to flow and after a while the backpressure caused by the hydrostatic pressure of the liquid column causes bubble flow in the well so that no liquids are lifted as the gas rate declines. Around the 33rd day, the well is blown-down to flare as a remedial measure to get rid of the liquids accumulated in the production string; and as a result gas rate increases sharply and liquids are lifted once again. It can be said that blowing the well down is successful as the gas rate is increased but since blow-down is not a long-term solution but only a remedial treatment that requires constant monitoring and manpower. Also, blowing down the well would be temporary since as blow-down, liquids continue to enter the well as some of them are lifted to surface, the most still accumulate down at the bottom of the well as the production data and the continued erratic flow behavior is evidence to that condition.

Following the decision tree in order to find a more “permanent” solution to the issue at hand, the next step is to determine possibility of a gas lift application. Knowing that gas lift requires an outer high pressure gas source to inject to the well having liquid problems; the lack of an outer high pressure source near #28 makes this installation costly and inapplicable. Since gas lift application is not the logical choice, gas/liquid ratio of the gas well should be determined as the decision tree suggests. According to gas and liquid production data, the well has an average GLR value of 50000 scf/bbl. The high GLR makes it nearly impossible to use pumps because of the high probability of gas-locking. The GLR is too high, meaning there is too much gas in the well as opposed to liquids that beam pumps, ESPs, and such will have severe gas interference problems like gas locking. Another possibility is to inject surfactants down the string which is also known as foaming. According to Lea *et al.*, the wells with GLR between 1000 and 8000 scf/bbl are better candidates for foaming, and although there is no upper limit; the wells with higher GLR will work best with other methods such as plunger lift or compression. Deciding between plunger lift and compression is more of a question of capital and operational costs and logistic availability than technicality. Plunger lift application, the low capital cost solution, is seen to be the best option to follow according to the wishes of the client.

As, the high GLR of the well #28 makes it a better candidate for plunger lift, as mentioned above, the only problem is that for plunger lift, packerless completions are favored due to increased capacity of wellbore storage. The entire casing volume could be used to store gas during pressure build-up period and during flow gas rate would be higher. The well #28 has a permanent production packer installed at the end of tubing. Although this restricts the amount of gas and requires a higher GLR than packerless completions do; the plunger lift feasibility charts (in Appendix B) show that the high GLR of the well is a benefit and plunger lift would be feasible even with a packer installed. With a 10000 ft production string, according the feasibility charts, it requires a minimum gas liquid ratio of 4000 scf/bbl for a packerless completion and 6000 scf/bbl with packer installed. The well is clearly a good candidate for plunger lift, although it is completed with a packer. However, because of the common problems associated with plungers, the plunger lift has not been installed due to the possibility of a stuck plunger. The risk of a stuck plunger in the tubing string would lead to high costs of possible workover operations in well #28 and therefore it is thought that the risk of a stuck plunger that would need fishing operations will endanger the well and may even cause the loss of the well. In the light of these possibilities, a new approach has been proposed which is installing the automated logic controlled wellhead to the well #28 without the plunger and its components, creating an automated intermittent flow in the well.

The idea is based upon the working mechanisms of plunger lift and gas lift installations. The need of a motorized valve and the build-up periods that allow the well to flow at higher rates are the key elements of this so-called new method. The idea is simple yet effective, the well is shut-in until the pressure builds up and the well is flown to lift the liquids accumulated at the bottom to the surface.

The production data after the installation of the intermittent flow logic control shows notable increase in the daily gas production. In a selected 30 day period, the cumulative gas production after the installation is measured as 30.2 MMscf/day where before installation it was measure as 15.4 MMscf/day. It is noticed that liquid production is also increased. *Table 6.4* is a day by day comparison of the production data of #28.

Table 6.4 – Daily Production Rates of #28 Pre and Post Logic Control

	Before Installation		After Installation	
Days	Gas Rate, MMscf/d	Liquid Production, bbl	Gas Rate, MMscf/d	Liquid Production, bbl
1	0.571	11.0	0.946	13.8
2	0.592	12.0	1.069	19.2
3	0.585	10.0	0.723	15.6
4	0.544	9.0	0.709	16.4
5	0.544	10.0	0.809	17.2
6	0.523	10.0	1.055	14.8
7	0.591	10.0	1.227	14.8
8	0.483	12.0	1.254	15.2
9	0.529	10.0	1.068	11.6
10	0.570	9.0	1.056	10.8
15	0.589	4.0	0.887	4.8
20	0.386	0.0	0.944	7.2
25	0.340	0.0	1.186	12.8
30	0.339	0.0	1.154	14.0

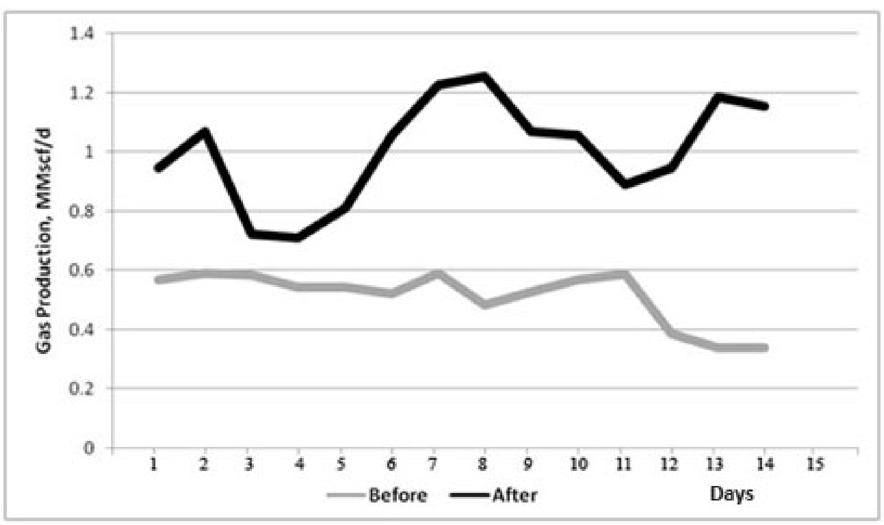

Figure 6.11 – Daily Gas Production Before and After Installation

It is seen that both gas and liquid production is increased and this is due to the ability of gas lifting the accumulated liquid more easily. The average GLR of the well is also increased to 70000 scf/bbl and this increase shows that as liquids are lifted from the well and the backpressure exerted by the hydrostatic column, the gas production rate is increasing. Below; 15 days of production is shown in the graph in *Figure 6.11* to show the improvement in production by comparing production rates before and after the installation.

CHAPTER 7

DISCUSSION OF RESULTS

In developing critical rates regarding well #10, equations derived by Turner *et al.* are used; a detailed development of these equations can be found in Appendix A. In the equations, data gathered from well tests and pressure surveys are used. Actual production data containing daily gas production rates, liquid production and flowing wellhead pressures are analyzed and compared with previous correlations of Turner *et al.* and Coleman *et al.*. Although it is advised that for lower flowing wellhead pressures (FTHP < 500 psig) equations proposed by Coleman *et al.* are used; production data showed that Turner *et al.*'s equation fits better when determining liquid loading during production, using average values of 63 lb/ft^3 for water density, 0.9 for z-factor and 0.65 for gas specific gravity.

The selection of Turner *et al.*'s critical rate equations (with 20% adjustment) is due to the flowing conditions of the wells. In order to determine which of the critical rate equations fits the field data, natural flow conditions of well #10 is applied to critical rate equations of Turner, Coleman and Li. The natural flow conditions of well #10 according to nodal analysis curves for a tubing string with 2 7/8" outer-diameter. Notice that the "actual" gas flowrate of the well with 2 7/8" tubing obtained from nodal analysis is higher than the current flowrate of the well. This is due to the accumulation of liquids in the wellbore, and the nodal analysis shows the case with no liquids present, which may be called as the potential flowrate the well can have without liquid accumulation at the bottom of the well. *Figure 7.1* shows that flowrate and the critical flowrates of different models. In these conditions, assuming the well is free of liquids and starts flowing; the well should not load-up and be free of liquid accumulation according to the models of Coleman *et al.*, Nosseir and Li *et al*. Turner *et al.*'s model is the closest to the actual data, and verifies our initial conception of the situation.

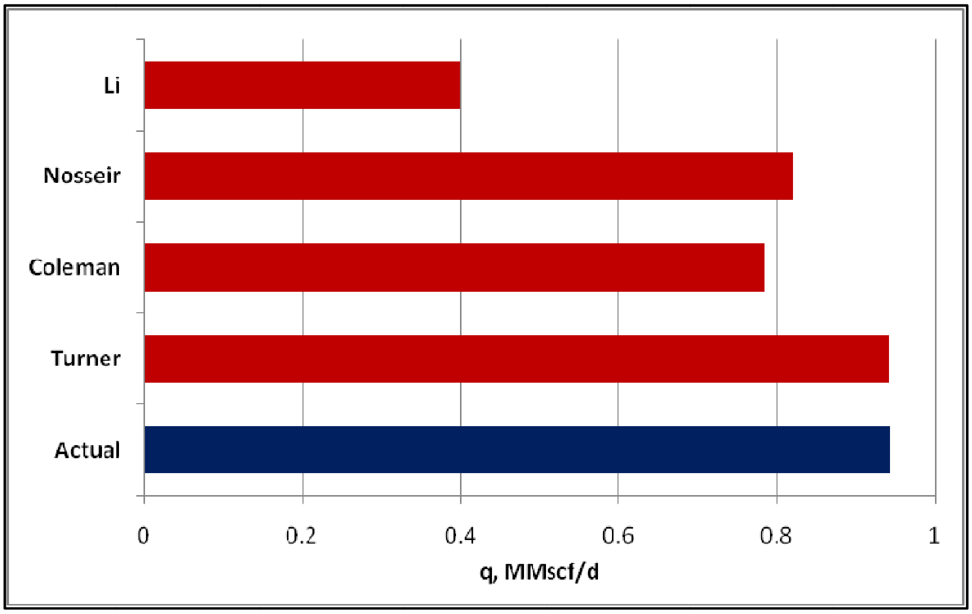

Figure 7.1 – Comparison of Critical Rate Equations

Changing cross-sectional flow area by installing a different tubing string with smaller diameter than the existing string would prove to be beneficial under certain conditions that should be analyzed using IPR-TPR curves for different tubing sizes. Comparing IPR-TPR analysis with critical rates required to keep the well free from liquid accumulation is necessary to observe if proposed tubing string would be successful or not. In this case, changing the current 2 7/8" tubing string to 2 3/8" is sufficient to obtain the required gas velocity; the effects will most likely be temporary. Keeping in mind that depletion of the reservoir is the main reason behind liquid loading; a long term solution can be achieved by installing a tubing string with a diameter of 2 1/16" or less. To have a better visual, the flowing conditions for different tubing sizes which are the contact points of inflow and outflow curves are compared against critical rates calculated by Turner *et al.*'s critical rate equation in *Figure 7.2*.

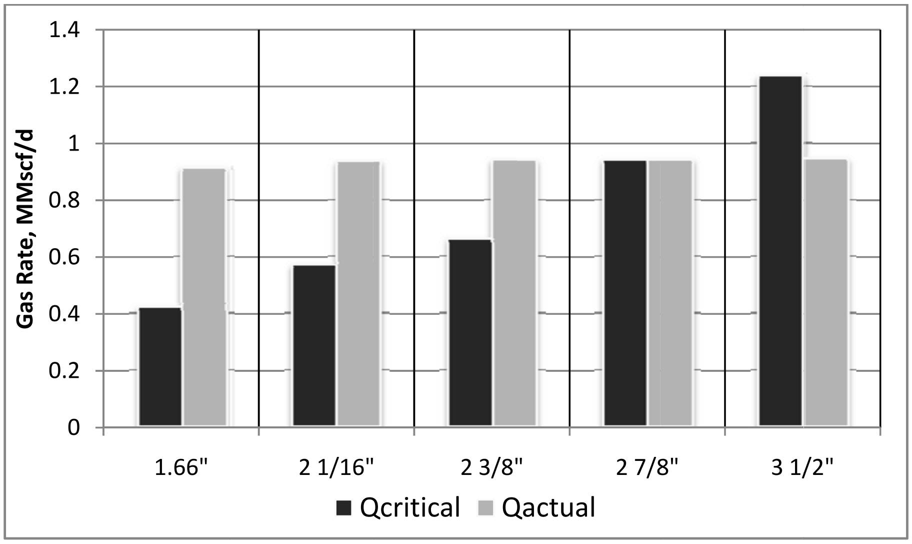

Figure 7.2 – Actual Rates vs. Critical Rates for #10

The data gathered from outflow curves for various tubing sizes shows that decreasing tubing size has little effect in decreasing the flowrate and does not necessarily constrain production rate due to limited deliverability of the low permeability reservoir. Therefore, a tubing string with smaller diameter, 2 1/16” or less, would be the solution to the liquid loading problems encountered in well #10 due to low velocity of gas. Along the way installing a compressor to use compression in combination with smaller diameter tubing string would be necessary in order to decrease flowing tubing wellhead pressure more for the ultimate gas recovery to be higher. All analysis on inflow deliverability and tubing performance suggests that, as the decision tree follows, the remaining energy on the formation is sufficient to continue production if certain conditions are met with small corrections such as sizing tubing string for an increase in gas velocity.

The problems encountered due to liquid accumulation in well #28 however, are more severe. The pressure survey shows that the bottomhole pressure is around 1500 psia, and that low pressure hinders the possibility of a tubing sizing solution for the well #28. The nodal analysis shows that inflow performance is low due to reservoir depletion and comparing gas flowrates for various tubing sizes with critical flowrates calculated using Turner *et al.*’s equation shows that only installing a tubing string with a diameter smaller than 2” (as an example 1.66”) will ensure the continuous removal of liquids from the wellbore. Installing a tubing string with diameter that small would probably constrict gas flowrate due to small cross-sectional area, but maintaining a steady decline curve is more important than increasing daily gas production for a short period of time. Although the inflow performance analysis shows that the remaining energy on the formation is enough to continue to produce on its own, since tubing sizing is just one of many methods analyzed in this study, another approach is adopted for #28, which is basically proposing to find a proper artificial lift method instead of enhancing natural flow for removal of liquids. This means following the steps of the decision tree as if the remaining reservoir energy is not sufficient for natural flow because a proper artificial lift method for liquid removal would help achieving a higher gas flowrate as opposed to 1.66" outer-diameter tubing string. Also, this leads to a small correction on the decision tree; the need to check if the "natural flow by tubing sizing" option would lead to a decrease in gas rate compared to possible artificial lift methods that can be used.

The selection criterion of a proper artificial lift method is a matter of effectiveness and power consumption as opposed to recovery. As stated by Lea *et al.* in his studies and mentioned earlier in this study; selecting the most suitable method is mostly relies on gas liquid ratio, since it basically shows the amount of liquid that should be lifted with a certain amount of gas. The high gas liquid ratio of well #28, which means low amount of liquids in respect to gas production, makes certain methods favorable and the others unfavorable. Methods like foaming and beam pumping are advised for wells with lower gas/liquid ratios, since it is possible to reach lower flowing bottom-hole pressures with methods like gas lift and plunger lift. In order to determine between these two methods, however; one should look into the power perspective. According to a study by Dotson and Nuñez[22] (2007), selection of artificial lift methods from the power perspective involves either the better use of remaining reservoir energy or applying an external energy to the well *(Figure 7.3)*. They concluded that highest ultimate recovery is achieved by pumping since the lowest bottom-hole pressure is reached. However, it is also feasible to harvest a portion of reservoir energy to lift liquids from wellbore, which can be approximated by plunger lift. Their research showed in tight reservoirs gas lift would require too much power to increase ultimate recovery.

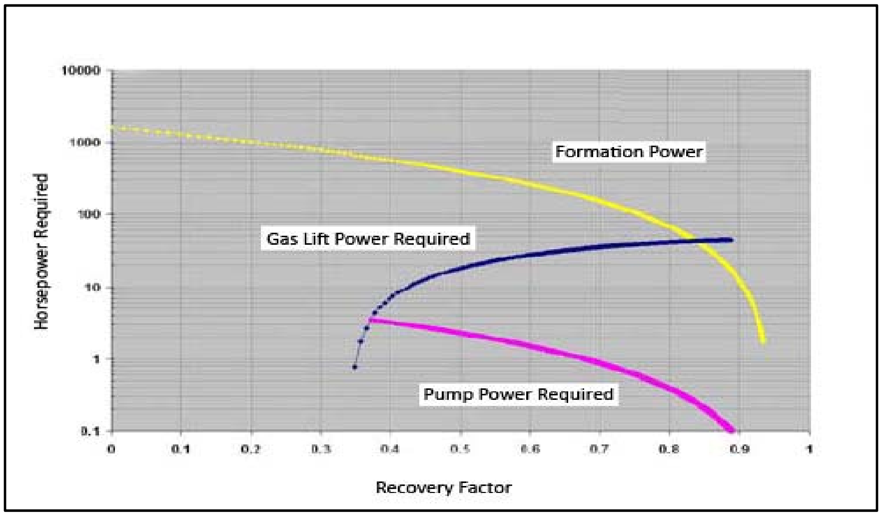

Figure 7.3 – Power vs. Recovery for Tight Reservoir[22]

Considering power requirements and without the existence of an external high gas source, plunger lift has more advantages over gas lift. However, as mentioned earlier, because of the common problems associated with plungers, the plunger lift has not been installed to avoid stuck problems that may occur in the well. Instead another approach has been adopted as a combination of automated control mechanism of plunger lift applications with intermittent flow. The motorized valves and cycles the build-up and flow periods allow the well to flow at higher rates. Although the idea is simple; the results show that it is effective; the well is shut-in until the pressure builds up and then it is flown to lift the liquids accumulated at the bottom to the surface. *Figure 7.4* shows the cycles consisting of several shut-in and flow stages in a 24 hour period.

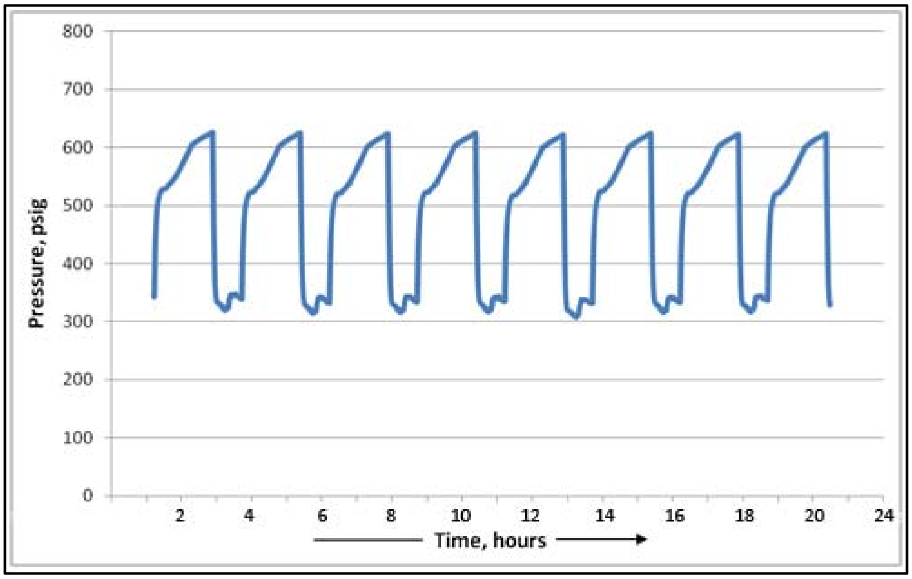

Figure 7.4 – Intermittent Flow Cycles for #28

The result is somewhat successful, due to increased daily gas production rates in the well, as well as increased liquid production, meaning the ability of the well to lift liquids more effectively. However, although there is a significant increase in the production rate, the well still shows erratic flow behavior and signs of liquid accumulation even if it is minimal or lower than the former case. The effective use of a plunger lift application would lift the accumulated liquid better since the flow behavior is most likely caused by *fallback*, which is the liquids falling back to the bottom in flowing period of the intermittent flow cycle as flowing pressure starts to decline. The presence of a plunger below the liquid column will keep the liquid from falling back to the bottom. However, the completion type and presence of a production packer downhole is a known disadvantage for plunger lift installation. Charts for Gas liquid ratio and plunger lift feasibility shows that current potential and GLR of the well is sufficient for plunger lift installation. Still, the tubing string could be perforated and the completion fluid in the casing tubing annulus could be drained for increasing the gas storage volume for more effective plunger lift application.

In brief, well #28 shows significant improvement after automated intermittent flow application is installed at the wellbore. The well still shows signs of liquid accumulation, and as the reservoir pressure depletes, the well will probably need the plunger lift to be installed as the decision tree suggests in the first place. However, until the well shows severe production problems and ceases to produce steadily, intermittent flow will be used as a liquid loading solution.

CHAPTER 8

CONCLUSIONS

The purpose of this study was to determine the methods for predicting the onset of liquid loading in gas wells, evaluating completion types for optimization and comparing various methods as a possible solution for loading. The following conclusions are drawn from the study based upon the analysis of actual field data of gas production wells and comparison of various studies on critical velocity theory to determine critical rates of gas wells having production problems due to liquid loading:

- The first thing to do after observing initial signs of liquid loading is a downhole pressure survey to confirm liquid accumulation at the bottom of the well. This is also essential to see if accumulated liquids flooded the entire perforation interval.
- Analyzing different critical rate theories is important to see which model fits which case. In this study, Turner et al.'s droplet model for determining critical rate fits flow behavior of two wells better, however for every individual case all models should be compared.
- Even though selected artificial lift method is unable to lift all accumulated liquids from the bottom; relieving the backpressure caused by the lifted portion may still prove to be useful if it provides a steady production increase.

This study was unable to analyze the effects of accumulated liquids in the reservoir due to insufficient reservoir data. It is known that accumulation of liquids in the reservoir decreases the effective permeability of gas due to increased skin factor. Further research on this field regarding the role of skin factor on liquid loading would of help in developing critical rate equations with the effects of skin factor.

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APPENDIX A

DEVELOPMENT OF CRITICAL VELOCITY EQUATIONS

This appendix summarizes the development of critical velocity equations of Turner et al.[1] to calculate the minimum gas velocity to remove liquid droplets from a vertical wellbore. Turner et al. analyzed two physical models to determine the minimum velocity which are liquid film movement along the walls of the production string and liquid droplets entrained in flowing gas core. It is stated before that liquid droplet model is adopted since it is known to fit field data best. When developing the model, Turner *et al.* used fluid flow equations developed by Hinze[20, 21] whom stated that "liquid drops moving relative to a gas are subjected to forces that try to shatter the drop, while the surface tension of the liquid acts to hold the drop together." Therefore, a droplet is subjected to two forces which are gravitational force (F_G) and drag force (F_D).

$$F_G = \frac{g}{g_c}(\rho_l - \rho_g)\frac{\pi d^3}{6} \tag{A1}$$

$$F_D = \frac{1}{2g_c}\rho_g C_d A_d (V_g - V_d)^2 \tag{A2}$$

Where;

F_G = gravitational force

F_D = drag force

C_D = drag coefficient

g_c = gravitational constant = 32.17 lbm-ft/lbf-s^2

According to the theory, the droplet is entrained in the gas core, meaning these two forces are equal to each other. The equation then becomes:

$$\frac{g}{g_c}(\rho_l - \rho_g)\frac{\pi d^3}{6} = \frac{1}{2g_c}\rho_g C_d A_d (V_g - V_d)^2 \tag{A3}$$

This equation gives the critical velocity equation as:

$$V_C = \sqrt{\frac{4g}{3}\frac{(\rho_l - \rho_g)}{\rho_g}\frac{d}{C_D}} \quad \text{(A4)}$$

Hinze[20] showed that the droplet diameter is dependent upon gas velocity and is expressed in terms of the dimensionless Weber number:

$$N_{WE} = \frac{V_C^2 \rho_g d}{\rho_l \sigma} \quad \text{(A5)}$$

Hinze showed that the droplet shatters when N_{WE} is greater than 30; thus solving the equation for a value of 30 for the largest droplet diameter gives:

$$d = 30\frac{\sigma g_c}{\rho_g V_c^2} \quad \text{(A6)}$$

Turner assumed the drag coefficient C_D as 0.44 valid for all turbulent conditions. Substituting droplet diameter found form Weber number, drag coefficient and converting surface tension from 1 lbf/ft to 0.00006852 dyne/cm gives the equation:

$$v_t = 1.593\frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{{\rho_g}^{1/2}} \quad \text{(A7)}$$

In order to simplify the equation for field application, Turner has taken typical values for temperature, gas gravity and z-factor thus consolidating the terms. Taking typical values of:

- Gas gravity = 0.6
- Temperature = 120 °F
- Z-factor = 0.9
- Water density = 67 lb/ft^3
- Water surface tension = 60 dyne/cm
- Condensate density = 45 lb/ft^3
- Condensate surface tension = 20 dyne/cm

Introducing these values to the equation, it becomes:

$$V_g(for\ water) = \frac{4.434\ (67 - 0.0031P)^{1/4}}{(0.0031P)^{1/2}} \tag{A8}$$

$$V_g(for\ condensate) = \frac{3.369\ (45 - 0.0031P)^{1/4}}{(0.0031P)^{1/2}} \tag{A9}$$

Turner found that a 20% adjustment should be made in these equations for the field data to be matched. With the 20% adjustment the equations become:

$$V_g(for\ water) = \frac{5.321\ (67 - 0.0031P)^{1/4}}{(0.0031P)^{1/2}} \tag{A10}$$

$$V_g(for\ condensate) = \frac{4.043\ (45 - 0.0031P)^{1/4}}{(0.0031P)^{1/2}} \tag{A11}$$

The study of Coleman *et al.* claimed that for wells with low flowing surface pressures this 20% adjustment is not needed. For both equations, with or without the adjustment; the critical rate equation can be written as:

$$q_c = \frac{3.06\ P\ v_g\ A}{T\ z} \tag{A12}$$

APPENDIX B

PLUNGER LIFT EQUATIONS AND FEASIBILITY CHARTS

This appendix gives a summary on plunger lift equations and presents plunger lift feasibility charts.

B.1 Minimum Casing Pressure

The moment the plunger and the liquid column above the plunger reaches surface, required minimum casing pressure at the surface is:

$$P_{C,min} = (14.7 + P_P + P_{wh} + P_C S_V)(1 + {}^{D}/_{K}) \qquad \text{(B1)}$$

Where;

P_P = pressure required to lift the plunger, psia

P_C = pressure required to lift 1 bbl of liquid overcoming friction, psia

S_V = liquid volume above plunger, bbl

K = factor of gas friction below the plunger

D = plunger depth, ft

K and P_c is calculated from:

$$K = 1.030 \times 10^6 \frac{Z(T_{avg}+460)OD_{tbg}}{\gamma_g f_g V^2} \qquad \text{(B2)}$$

$$P_C = [0.433\gamma_l L_s] + \left[3.594 \times 10^{-7} \frac{\rho_l f_l L_s V^2}{ID_{tbg}}\right] \qquad \text{(B3)}$$

B.2 Maximum Casing Pressure

The maximum casing pressure is then calculated by the equation:

$$P_{c,max} = \frac{A_{annular} + A_{tubing}}{A_{annular}} P_{c,min} \tag{B4}$$

These equations assume that all the potential energy of gas is converted into kinetic energy when lifting the plunger to surface. The losses due to efficiency and possible gas leaks around plunger of other components are omitted, though they can be taken into account with corrections.

B.3 Plunger Feasibility Charts

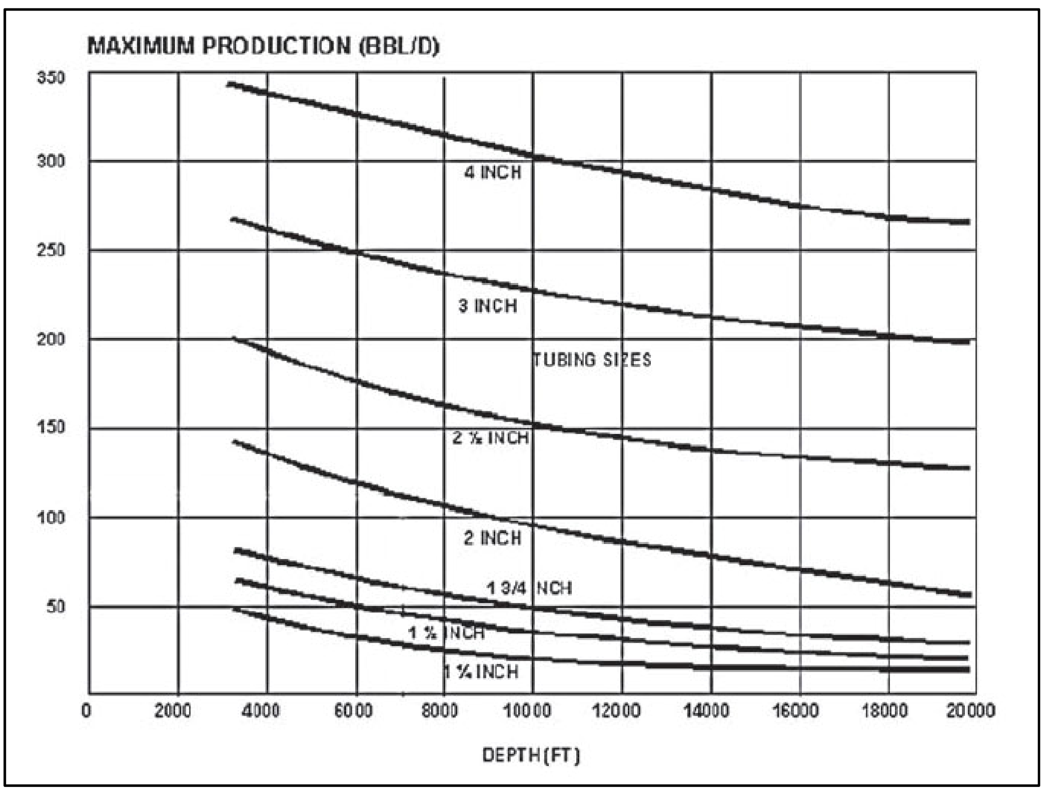

Figure B.1 – Liquid Production Chart for Plunger Lift[16]

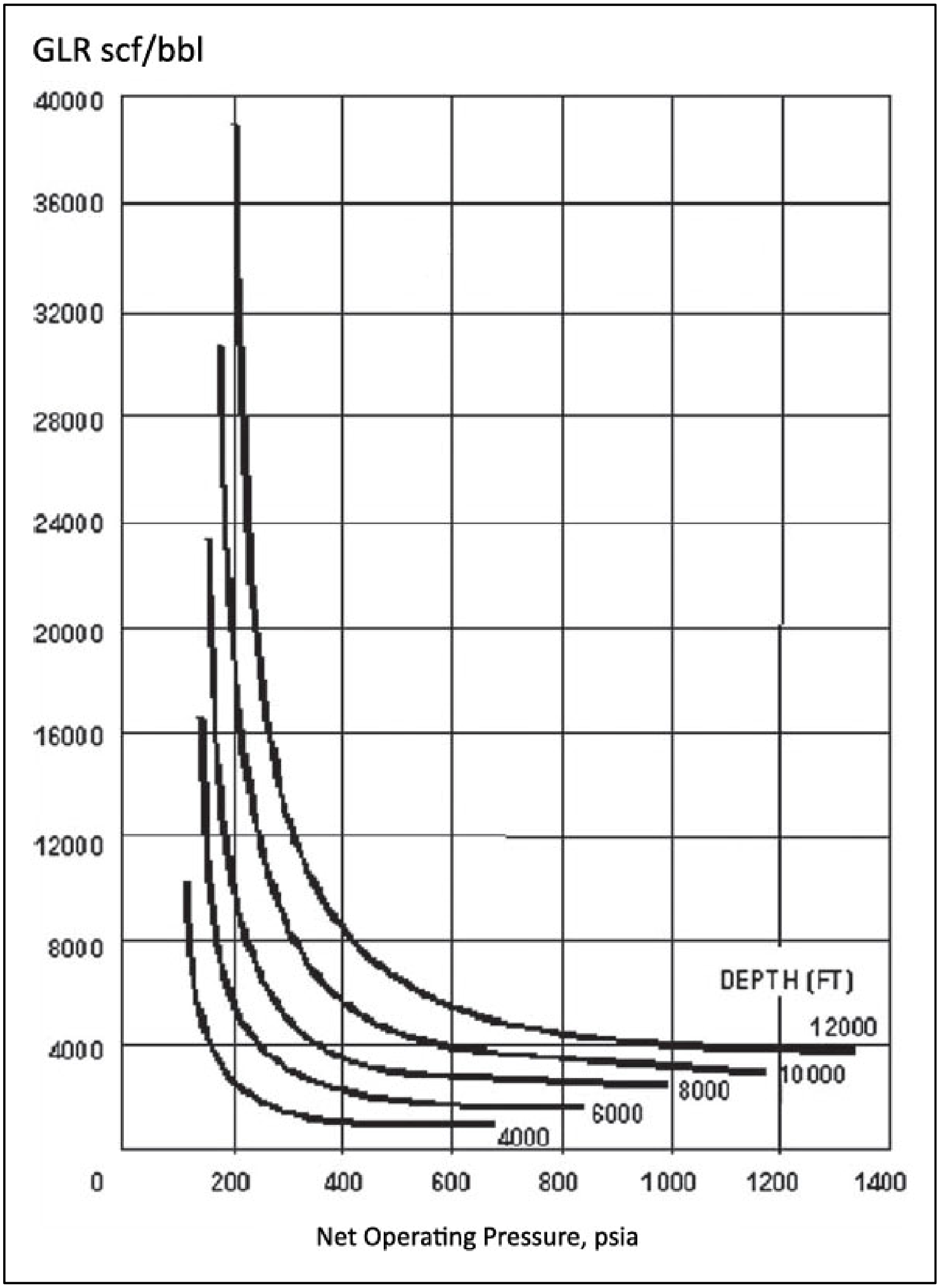

Figure B.2 – 2" Plunger Feasibility Chart for 2 3/8" Tubing[15]

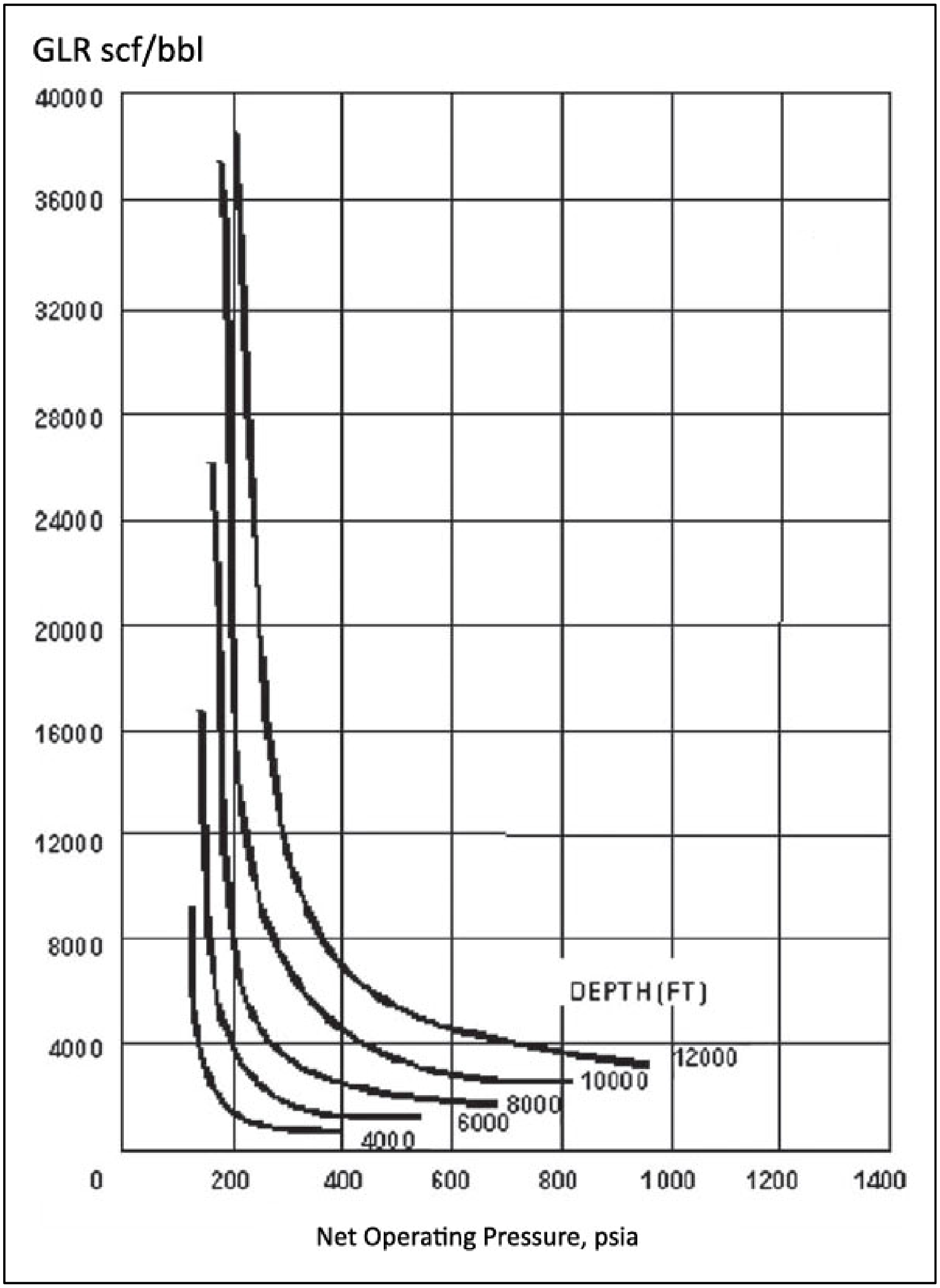

Figure B.3 – 2 ½” Plunger Feasibility Chart for 2 7/8” Tubing[15]

APPENDIX C

INFLOW PERFORMANCE CALCULATIONS OF WELLS #10 & #28

This Appendix summarizes the calculation of inflow performance curves for wells used in the case study section. Mishra and Caudle[23] proposed a simplified procedure on gas deliverability calculations using single point tests rather than isochronal tests which consume considerable amount of time especially on low permeability systems. In their work, they proposed an equation for determining the gas deliverability in unfractured gas wells:

$$\frac{q}{q_{max}} = \frac{5}{4}\left\{1 - 5^{\left[m(P_{wf})/m(P_R) - 1\right]}\right\} \tag{C.1}$$

Where, m(*P*) is the real gas pseudopressure evaluated at pressure, *P*, ($psia^2/cp$).

C.1 Well #10

Using the equation proposed in the study of Mishra and Caudle[23] (1984), the inflow performance curve of well #10 is calculated. For these calculations, the reservoir pressure is taken from the pressure survey carried out initially to prove liquid accumulation. Also, the data gathered during blow down operations are used to find absolute open flow potential, since the gas flow rate is measured as 1.05 MMscf/d when the well is flown to atmosphere. First real gas pseudopressure are calculated, Table C.1 shows pseudopressure and gas flow rate values for various flowing bottom hole pressures:

P_R = 3491 psia

P_R^2 = 1.22E+07 $psia^2$

$m(P_R)$ = 6.09E+08 $psia^2/cp$

Table C.1 – Calculated Inflow Performance Data for Well #10

P_{wf}	$m(P_{wf})$	$m(P_{wf})/m(P_R)$	q/q_{max}	q (Mscf/d)	q (MMscf/d)
3491	6.09E+08	1.00E+00	0.00E+00	0.000	0.000
3400	5.78E+08	9.49E-01	9.93E-02	104.810	0.105
3200	5.12E+08	8.40E-01	2.83E-01	299.007	0.299
3000	4.50E+08	7.38E-01	4.29E-01	453.040	0.453
2800	3.92E+08	6.43E-01	5.46E-01	576.000	0.576
2600	3.38E+08	5.55E-01	6.40E-01	674.727	0.675
2400	2.88E+08	4.73E-01	7.15E-01	754.401	0.754
2200	2.42E+08	3.97E-01	7.76E-01	818.966	0.819
2000	2.00E+08	3.28E-01	8.26E-01	871.443	0.871
1800	1.62E+08	2.66E-01	8.67E-01	914.158	0.914
1600	1.28E+08	2.10E-01	8.99E-01	948.907	0.949
1400	9.80E+07	1.61E-01	9.26E-01	977.081	0.977
1200	7.20E+07	1.18E-01	9.48E-01	999.757	1.000
1000	5.00E+07	8.21E-02	9.65E-01	1017.764	1.018
800	3.20E+07	5.25E-02	9.78E-01	1031.739	1.032
600	1.80E+07	2.95E-02	9.88E-01	1042.158	1.042
400	8.00E+06	1.31E-02	9.95E-01	1049.368	1.049
200	2.00E+06	3.28E-03	9.99E-01	1053.603	1.054
100	5.00E+05	8.21E-04	1.00E+00	1054.651	1.055

Using calculated inflow performance data for various flowing bottomhole pressure values, the inflow performance curve can be plotted to find gas deliverability. *Figure C.1* shows the plotted IPR curve of well #10.

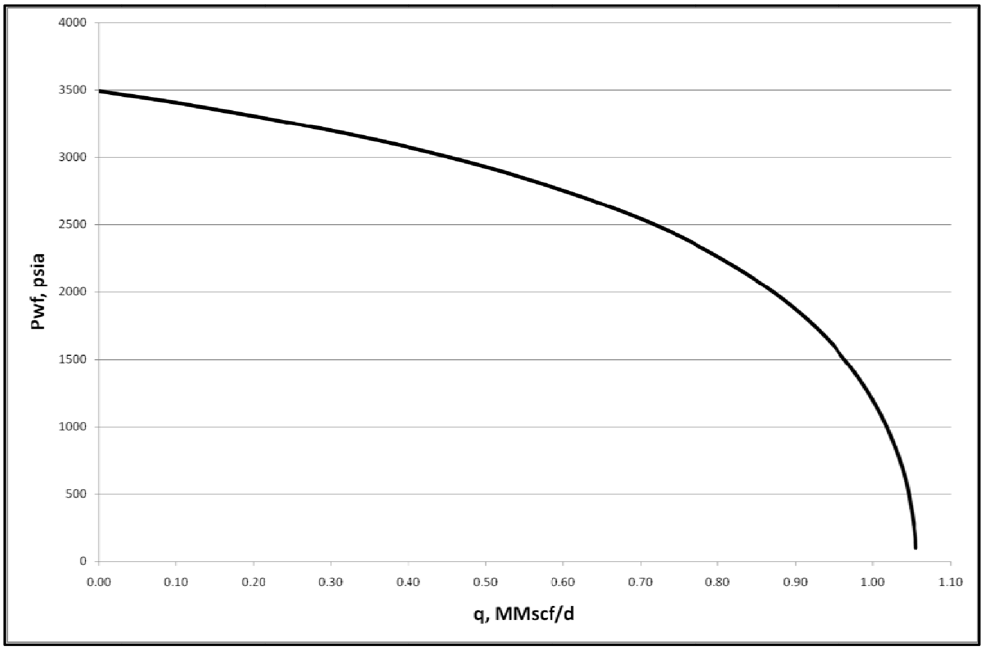

Figure C.1 – IPR curve of Well #10

C.2 Well #28

The same procedure is followed for well #28 for inflow performance calculations, as well #10. The reservoir pressure is taken from the downhole pressure survey and the gas flow rate is taken from the data gathered from blowing down the well to atmosphere. *Table C.2* shows the calculated data for inflow performance.

P_R = 1425 psia

P_R^2 = 2.03E+06 psia^2

$m(P_R)$ = 1.02E+08 psia^2/cp

Table C.2 – Calculated Inflow Performance Data for Well #28

P_{wf}	$m(P_{wf})$	$m(P_{wf})/m(P_R)$	q/q_{max}	q (Mscf/d)	q (MMscf/d)
1400	9.80E+07	9.65E-01	6.80E-02	48.994	0.049
1300	8.45E+07	8.32E-01	2.96E-01	212.940	0.213
1200	7.20E+07	7.09E-01	4.67E-01	336.439	0.336
1100	6.05E+07	5.96E-01	5.98E-01	430.353	0.430
1000	5.00E+07	4.92E-01	6.98E-01	502.363	0.502
900	4.05E+07	3.99E-01	7.75E-01	557.953	0.558
800	3.20E+07	3.15E-01	8.35E-01	601.070	0.601
700	2.45E+07	2.41E-01	8.81E-01	634.578	0.635
600	1.80E+07	1.77E-01	9.17E-01	660.564	0.661
500	1.25E+07	1.23E-01	9.45E-01	680.555	0.681
400	8.00E+06	7.88E-02	9.66E-01	695.663	0.696
300	4.50E+06	4.43E-02	9.82E-01	706.691	0.707
200	2.00E+06	1.97E-02	9.92E-01	714.202	0.714
100	5.00E+05	4.92E-03	9.98E-01	718.568	0.719

Using calculated inflow performance data, IPR curve for well #28 can be plotted to determine gas deliverability. Figure C.2 shows the plotted IPR curve for well #28.

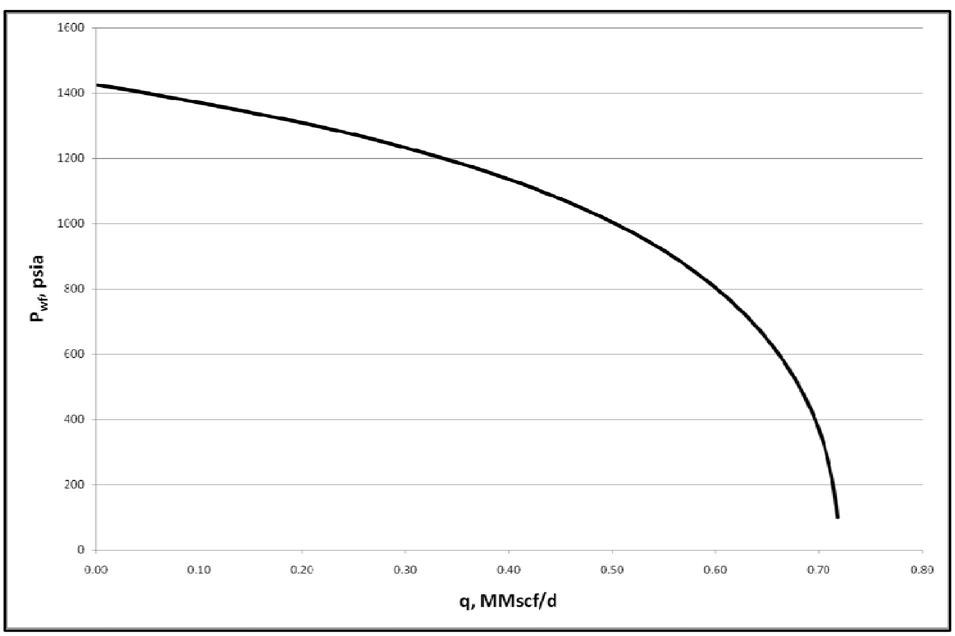

Figure C.2 – IPR curve of Well #28