Sudan University of Science & Technology College of Petroleum Engineering & Technology

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Research title:

Prediction of Liquid Loading in Gas Well (A1), and Solve It by Using Velocity String

التنبؤ بزمن حدوث تجمُّع السوائل في قعر بئر الغاز (A1)

ومعالجته باختيار أفضل قطر لأنبوب الانتاج لزيادة سرعة سريان الغاز

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Novmber – 2016

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Project submitted to the College of Petroleum Engineering and Technology Sudan University of Science and Technology in partial fulfillment of the requirements for degree of B.Sc. in petroleum engineering.

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بسم الله الرحمن الرحيم

الاستهلال

قال الله تعالى :

(اللَّهُ الَّذِي خَلَقَ سَبْعَ سَماواتٍ وَمِنَ الْأَرْضِ مِثْلَهُنَّ يَتَنَزَّلُ الْأَمْرُ بَيْنَهُنَّ لِتَعْلَمُوا أَنَّ اللَّهَ عَلى كُلِّ شَيْءٍ قَديرٌ وَأَنَّ اللَّهَ قَدْ أَحاطَ بِكُلِّ شَيْءٍ عِلْماً)

سورة الطلاق الآية (12)

DEDICATION

Every challenging work needs self-efforts as well as guidance of elders specially those who were very close to our heart.

Our humble effort we dedicate it to our sweet and loving:

Fathers & Mothers

Whose affection, love encouragement and prays of days and nights make us able to get such success and honor,

Along with all hard working and respected

Teachers

ACKNOWLEDGEMENTS

We would like to thank God first and foremost for his blessing on us to accomplish this work.

Also we are grateful to the Sudan University of Science & Technology, as well as College of Petroleum Engineering & Technology generally for the opportunity to achieve this work.

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In addition; for his wisdom and authoritative knowledge those have the upper hand in accomplishing the research in its current view.

ABSTRACT

Human development is closely linked to energy consumption, natural gas is environmental friend energy source compared with other sources, so it demand increases by a day, and represent almost one third of the global primary energy consumption today. To meet this increase in demand must produce large quantities of natural gas equivalent demand quantity. The most prominent problems facing production from gas wells is Liquid Loading. It is inability of the produced gas to remove the coproduced liquids from the wellbore and occurs when the gas velocity is insufficient for lifting liquid from the well. The liquid will accumulate at bottom hole and creating static column, therefore creating back pressure against formation pressure and reducing production until it ceases. The primary objective of this research is to predict when the liquid loading will occur by comparing between test flow rate and critical flow rate by using Turner (1969) & Sutton (2008) correlations, with design simply computer program by using visual basic to predict the problem and solve it by using Velocity String. By using PIPESIM program we calculate pressure and temperature distribution along production tubing .Then we use EXCEL to calculate critical gas flow rates, then we plot critical and test gas flow rates versus years, and the intersection of the two curves (critical gas flow rates curve and test gas flow rates curve) represent in which year the problem of liquid loading will occur(at this intersection point the test gas flow rate become less than the critical gas flow rate and then the liquid loading will occur).by Using Nodal Analysis we integrated IPR and TPR curves for several diameters of coiled tubing to determine the optimal size of the coiled tubing for this well to solve the problem. The principle of this method is to study the impact of production tubing size on gas flow rate, the smaller optimum size helped increase production rate, and therefore gas stream be able to lift liquids from bottom hole and prevent the well from loading.

By using Turner model we found that the liquid loading occured in 2018, and it occured in 2019 when we use Sutton model and also found that the coiled tubing inside diameter (1.75 inches) can delay the year of occurring liquid loading but does not solve it finally when the production is from both: this selected ID and annulus, and solve it finally when the gas stream is from selected ID only.

التجريد

التنمية البشرية ترتبط ارتباطاً وثيقاً باستهلاك الطاقة . ويعتبر الغاز الطبيعي مصدر طاقة صديق للبيئة مقارنةً بالمصادر الأخرى ، والطلب عليه يتزايد يومياً ، ومؤخراً أصبح استهلاك الغاز الطبيعي يمثل نحواً من ثلث الاستهلاك العالمي للطاقة . ولمقابلة هذه الزيادة في الطلب لابد من انتاج كميات من الغاز الطبيعي توازي كمية الطلب . يُعدُّ تجمع السوائل المنتجة في قعر البئر من أبرز المشاكل التي تواجه الانتاج من آبار الغاز ، حيث تبدأ السوائل بالتجمع مما يقلل سرعة الغاز ويغير طور السريان حتى يعجز الغاز عن رفع هذه السوائل ، أي أن معدل انتاج الغاز يهبط عن أقل معدل مسموح به لرفع السوائل المتجمعة وهو ما يُسمى بـالمعدل الحرج . مما يحدث تجمع للسوائل داخل قعر البئر ويقل الانتاج تدريجيا حتى تتوقف البئر من الانتاج نهائيا.لذا يجب التنبؤ بحدوث هذه المشكلة اثناء عمليات إكمال البئر بالطرق المناسبة ووضع الحلول لها . الهدف الاساسي من هذه الدراسة هو ان نتنبأ بزمن حدوث تجمع السوائل في البئر و ذلك بمقارنة معدلات انتاج الغاز المتوقعة من البئر والمحسوبة بواسطة ال Decline Curve Analysis بمعدلات انتاج الغاز الحرجة المحسوبة بطريقتي(Turner (1969 و Sutton(, 2008) ونصمم برنامج حاسوبي بسيط باستخدام لغة الـ (Visual Basic) لنتنبأ بزمن حدوث مشكلة تجمع السوائل في البئر ونحل هذه المشكلة بطريقة الـ(Velocity String). ويتم ذلك باستخدام برنامج الـ(PIPESIM) لحساب توزيع الضغط والحرارة خلال انبوب الانتاج

ثم نأخذ من هذه القيم المحسوبة قيم الضغط والحرارة عند رأس البئر ونحسب كثاقة الغاز والسرعة الحرجة والمعدل الحرج لكل سنة من السنوات وذلك باستخدام ال (Excel) .ثم نمثل معدلات انتاج الغاز المتوقعة من البئر ومعدلات انتاج الغاز الحرجة مقابل السنوات ونقطة التقاطع بين المنحنين (منحنى معدلات الغاز الحرجة ومنحنى معدلات انتاج الغازالمتوقعة من البئر) تمثل السنة التي ستحدث فيها المشكلة . باستخدام ال(Nodal Analysis) نرسم منحنيات ال(IPR) و ال(TPR) لعدة اقطار لل(coiled tubing) لنحدد القطر الأمثل لحل هذه المشكلة.

ومبدأ عمل هذه الطريقة هو : دراسة أثر قطر أنبوب الانتاج على معدل الانتاج . ووجد أن القطر كلما كان صغيراً مناسباً ساعدَ ذلك على زيادة معدل الانتاج وبالتالي يمكن للغاز أن يرفع السوائل من قعر البئر إلى السطح ويحمي البئر من تجمع السوائل فيها .

وعندما طبقنا طريقة(Turner) وجدنا أن مشكلة تجمع السوائل في البئر تبدأ في الحدوث في العام 2018 بينما تحدث في العام 2019 عندما قمنا بتطبيق طريقة (Sutton) , .وتوصلنا أيضا إلى أن استخدام ال(coiled tubing) بقطر داخلي يساوي 1.75 بوصة يؤخر من زمن حدوث مشكلة تجمع السوائل لكن لايحلها نهائيا وذلك عندما يكون الانتاج عن طريق القطر الداخلي للcoiled tubing والفراغ الحلقي بين انبوب الانتاج الاصلي و (coiled tubing كلاهما معا و لكن يمكن ان تحل بصورة نهائية عندما يكون الانتاج عن طريق القطر الداخلي لل(coiled tubing) فقط.

NOMENCLATURE

A	Tubing cross-sectional area (ft^2)
API	American Petroleum Institute
Bg	Gas formation volume factor
Bo	Oil formation volume factor
B_{ob}	Correlating number
Bw	Water formation volume factor
Cd	Drag coefficient (=0.44)
dt	Tubing ID (inches)
EVR	Erosional velocity ratio
Fd	Upward drag force (lbf)
Fg	Downward gravity force (lbf)
GLR	Gas Liquid Ratio
GOR	Gas Oil Ratio
ID	Inner Diameter
P	Surface (Wellhead) pressure (psia)
Ppc	Pseudoreduced pressure (psi)
Pr	Reservoir pressure (psia)
Psc	Pressure at standard condition (psi)
PVT	Pressure-Volume-Temperature
Pwf	Well flowing pressure (psia)
Q	Gas flowrate (MMscf/d)
Qc	Gas critical rate (MMscf/d)
R	Gas constant (= 10.73 psia-ft3/lb-mol°R)
Rs	Gas solubility
T	Surface (Wellhead) temperature (ºF,°R)
Tpc	Pseudoreduced temperature (ºF,°R)
Tsc	Temperature at standard condition (ºF,°R)
Vc	Critical velocity (ft/s)

Z	Gas Compressibility factor
γg	Gas specific gravity
σ	Surface tension (dyne/cm)
ρl	Liquid density (lbf/ft3)
ρo	Oil density (lbm/ft3)
ρg	Gas density (lbm/ft3)
ρw	Water density (lbm/ft3)
μ	Viscosity (lbf-sec/ft2)

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Chapter One

Introduction

Chapter 1

Introduction

Liquid loading is inevitable, not always obvious at his early stage that causes production loss in gas well. Very few gas wells produce completely dry gas (single phase), the most gas wells produce both: gas and liquid.

Liquid Loading is the inability of the produced gas to remove the produced liquids from the wellbore (James 2008). Under this condition, produced liquids will accumulate in the wellbore leading to reduced production and shortening of the time until when the well will no longer produce.

1.1. Background of problem:-

Liquid loading is a serious problem that causes production loss in gas wells. The gas phase hydrocarbons produced from underground reservoirs will have liquid phase material associated with them. Liquids can come from condensation of hydrocarbon gas (condensate) or from interstitial water in the reservoir matrix. In either case, the higher density liquid phase must be transported to the surface by the gas. In the event the gas Phase does not provide sufficient transport energy to lift the liquid out of the well, the liquids will accumulate in the wellbore. The accumulation of the liquid will impose an additional backpressure on the formation that can significantly affect the production capacity of the well. In low-pressure wells, the liquid may completely kill the well.

1.1.1. Multiple flow in gas well:-

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

i. Bubble Flow: - The tubing is almost completely filled with liquid. Free gas is present as small bubbles, rising in the liquid. Liquid contacts the wall surface and the bubbles serve only to reduce the density. Show in (figure 1.1).

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

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

iv. Annular-Mist Flow: The gas phase is continuous and most of the liquid is entrained in the gas as a mist. The pipe wall is coated with a thin film of liquid, but pressure gradient is determined predominately from the gas flow.

The well may initially have a high gas rate so that the flow regime is in mist flow in the tubing but may be in bubble, transition, or slug flow below the tubing end to the mid-perforations. As time increases and production declines, the flow regimes from perforations to surface will change as the gas velocity decreases. Liquid production may also increase as the gas production declines.

Flow at the surface will remain in mist flow until the conditions change sufficiently at the surface to force the flow regime into transition flow. At this point, the well production becomes somewhat erratic, progressing to slug flow as gas rate continues to decline.

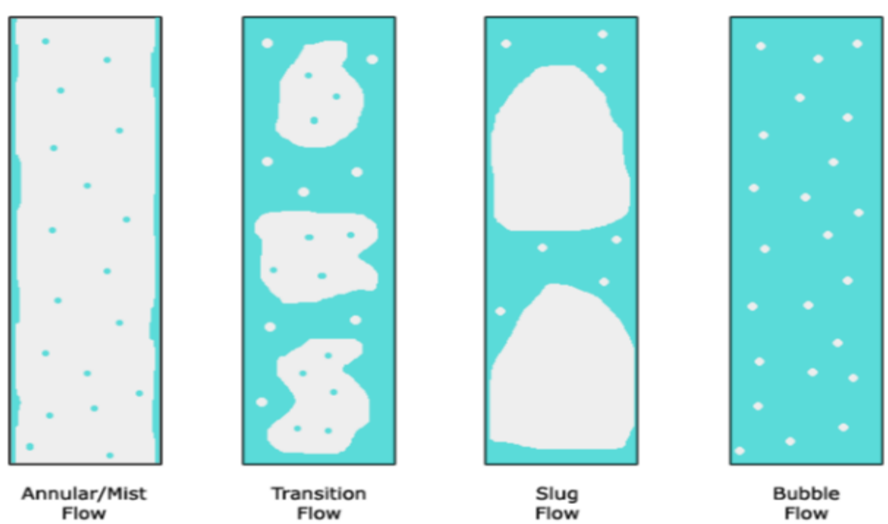

Figure 1.1 Basic profile of Multiphase flow in the well.

1.1.2. Source of liquids:-

Small number of gas wells produce dry gas. This means that almost gas well produces liquids along with gas even if the produced amount of liquids is very small.

Produced liquids along with gas may have several sources depending on the conditions and type of the reservoir from which gas is produced:

i. **Water coning:** If the gas rate of vertical or horizontal wells is high enough, this may result high decline pressure enough to pull water production from an underlying zone, even if the perforations do not extend to the underlying zone. Horizontal wells generally reduce water coning effects but it can still occur, this case it is commonly termed cresting instead of coning.

ii. **Aquifer water:** 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.

iii. **Free water formation:** It is possible for water to enter the well through the perforations with the produced gas. This can be a result of thin imbedded layers of gas and liquid.

iv. **Water production from another zones:** It is possible to produce liquids from another zone unintentionally, especially in an openhole completion or in a well having several sections perforated.

v. **Water of Condensation:** Reservoir have 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.

vi. Hydrocarbon Condensates: 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.

1.1.3. Symptoms of Liquid Loading in Gas Wells:-

Here we are going to explain some signs that give us indication to the occurrence of loading of the well. Some of these signs can be observed more clearly than others. James et al. (2003, p.13-23) discussed these symptoms as:

i. Erratic production and Increase in Decline rate: The shape of a well's decline curve can indicate downhole liquid loading problems. Decline curves should be analyzed over time, looking for changes in the general trend. Figure 1.2 shows two decline curves. The smooth exponential type decline curve is characteristic of normal gas-only production considering reservoir depletion. The sharply fluctuating curve is indicative of liquid loading in the wellbore.

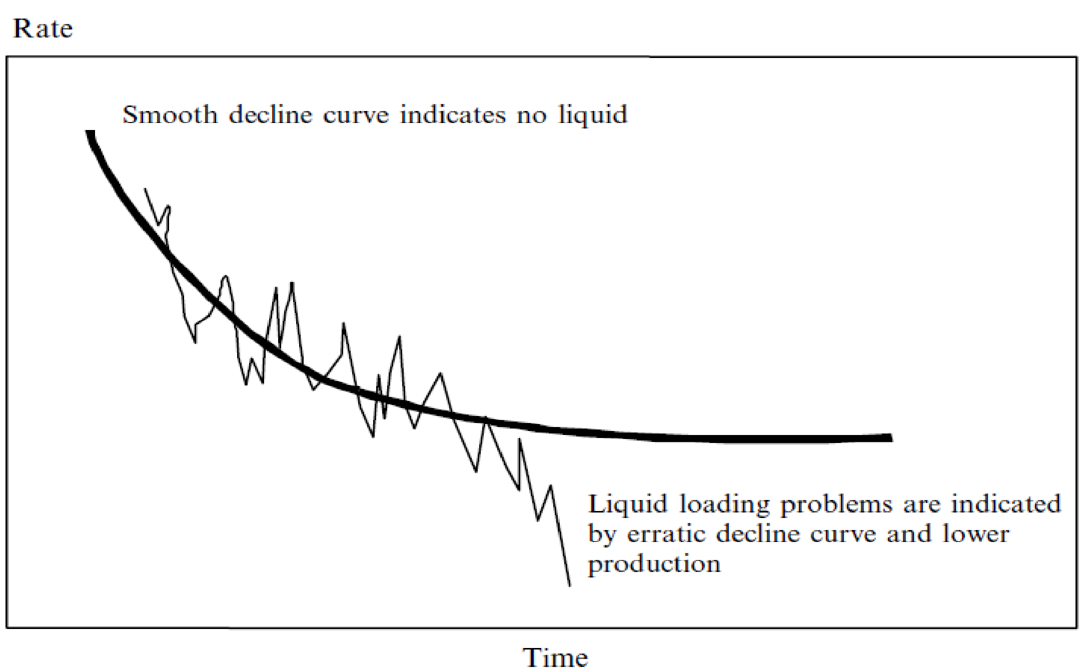

Figure 1.2: Decline Curve as indicator of Liquid Loading (James et al. 2003:18)

ii. Drop in Tubing Pressure with Rise in Casing Pressure: If liquids begin to accumulate in the bottom of the wellbore, the added pressure head on the formation lowers the surface tubing pressure. In addition, as the liquid production increases, the added liquid in the tubing being carried by the gas (liquid hold-up) increases the gradient in the tubing and again provides more backpressure against the formation, thereby reducing the surface tubing pressure. In packer less completions where this phenomenon can be observed, the presence of liquids in the tubing is shown as an increase in the surface casing pressure as the fluids bring the reservoir to a lower flow, higher pressure production point. As gas is produced from the reservoir, gas percolates into the tubing casing annulus. This gas is exposed to the higher formation pressure, causing an increase in the surface casing pressure.

iii. Pressure Survey Showing Tubing Liquid Level: Flowing or static well pressure surveys are perhaps the most accurate method available to determine the liquid level in a gas well and thereby whether the well is loading with liquids. Pressure surveys measure the pressure with depth of the well either while shut-in or while flowing. The measured pressure gradient is a direct function of the density of the medium and the depth; and, for a single static fluid, the pressure with depth should be nearly linear. Because the density of the gas is significantly lower than the density of water or condensate, the measured gradient curve will exhibit a sharp change of slope when the tool encounters standing liquid in the tubing. Thus, the pressure survey provides an accurate means of determining the liquid level in the wellbore.

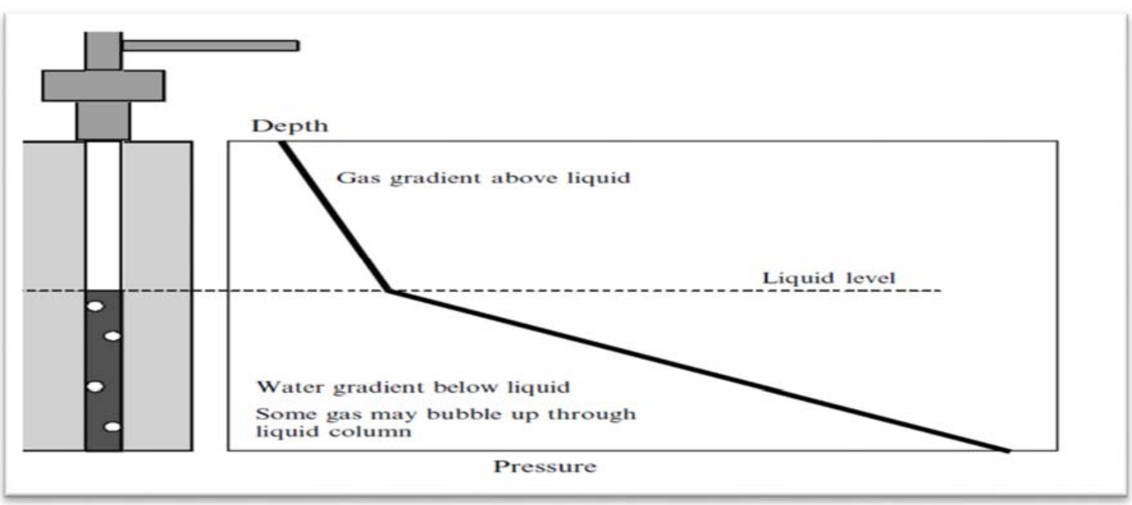

Figure 1.3: Pressure Survey Schematic to determine Liquid Loading (James et al. 2003:20).

iv. **Liquid Production Ceases**: Some high-rate gas wells readily produce liquids for a time and then drop off to much lower rates. As the gas production declines, the liquid production can cease. In these cases, the well is producing gas at rates below the "critical" rate that can transport the liquids to the surface. The result is that the liquids continue to accumulate in the wellbore, and the gas bubbles through the accumulated liquids.

1.1.4. Deliquifying Techniques Presented:

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.

- **Plunger lift:**

Plunger left is the introduction of an interface to optimize the production of fluid to the surface using the wells own natural energy. (Figure 1.4) It is normally comprised of a simple Piston/Plunger which travels from the end of the tubing up to the surface. The OD of the plunger and the interface with the tubing wall is varied based on application. Continuous flow plungers rise to the surface using only the energy from the produced gas and not from a shut in period, they require velocity of over 10 ft/s in order to continually arrive to surface. Conventional plungers use pressure stored in the well and in the annulus if available in order to establish the velocity necessary to cause the differential to bring the plunger to surface, staged plunger systems where multiple plunger system are used in the same wells and a transfer of fluid from stage to stage is completed optimizing the lift cycle.

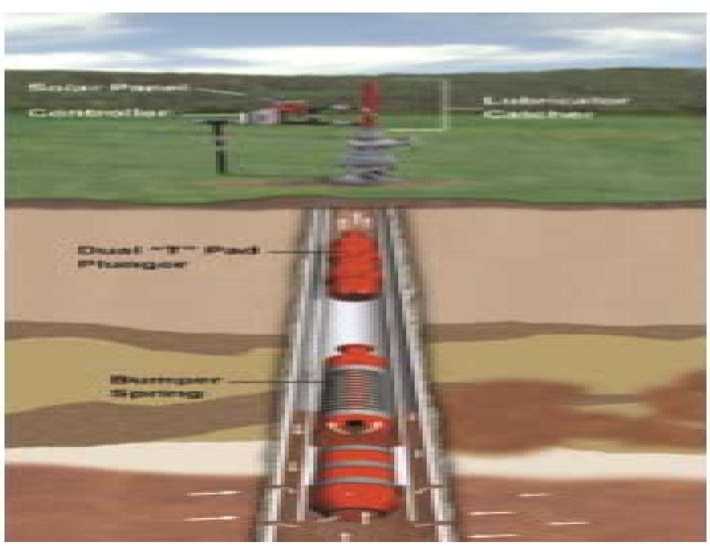

Figure 1.4 plunger lift

Plunger lift is typically considered the least expensive way to lift liquid loaded gas wells however there is an experience component that is very important in order to be able to operate the wells which requires adequate support either through internal company experience or from a vendor.

- **Gas left:-**

Gas left is a means of injecting high pressure gas into the production at as deep as possible injection point. Typically in Gas Wells the goal is to inject sufficient volume to increase the rate above the injection point to above critical velocity. The gas lift system does not have the issues that many pumping systems to in the presence of high GLR production and as has been noted by many it is the closest system to natural flow. If a high pressure gas source is present the economics can be very difficult to beat. There are many different types of Gas Lift systems that work well in a gas production environment including the extended perforation systems which allows for gas lift in extended perforation zones effectively unloading the entire perforated interval rather than only optimizing the production above the packer

- **Velocity String :-**

A velocity string is simply "the next size down" for the completion. When a well is new, the production tubing is sized to handle initial gas flow rates and pressures. As wells deplete, pressure and flow rate decline. Therefore, a reasonable solution is to reduce the size of the completion to try to maintain the gas velocities required for liquid transport. Installing a smaller tubing inside the original tubing (i.e., velocity string) will create higher gas velocities and may prevent liquid loading. The installation can be up to the surface or just up to any point in tubing. By installing the velocity string, the 2-phase flow changes from liquid dominant to gas dominant, which leads to higher velocity as shown in (Figure 1.5).

Unfortunately, these results in a more restrictive completion, which effectively chokes the well, are reducing the overall flow rate. Besides reduced flow capability, velocity strings are only able to extend the life of a well for a limited period of time.

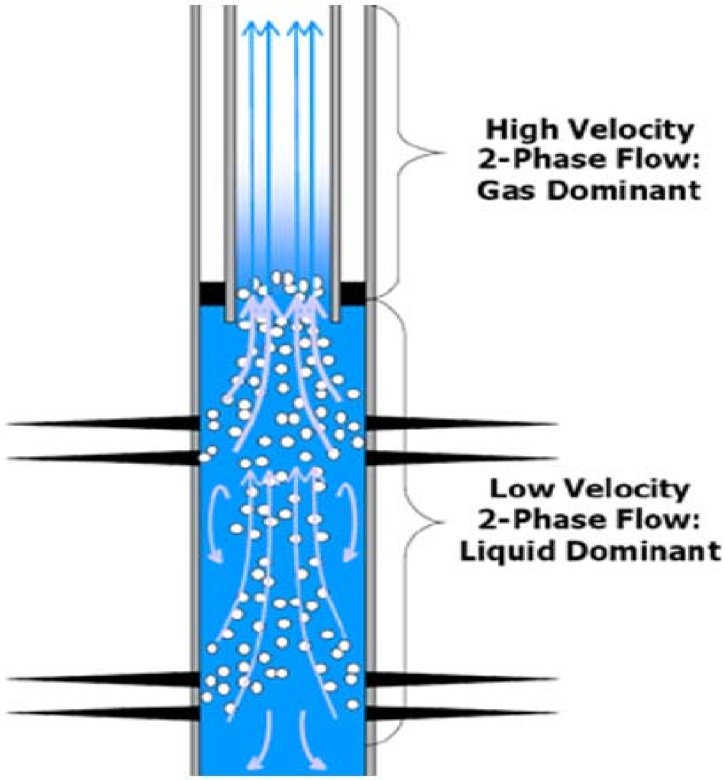

Figure 1.5 Effect of a velocity string on production

1.2. Problem Statement:-

This study was undertaken to predict liquid loading by determining the critical gas flow rate of (A1 well) and compared it with predicted flow rate from the well to know when the liquid loading will occur by using Turner and Suttton methods and solve it by using Velocity String method.

1.3. Objectives:-

The following objectives are met by this study:

i. To predict Liquid Loading with different methods (Turner et al. and Sutton et al).

ii. To develop a software designed by Visual Basic to predict liquid loading in gas wells by the above methods.

iii. To solve this problem after predict it by selecting the optimum Coiled Tubing size.

1.4. Methodology:

By using PIPESIM software, the temperature and pressure distribution will be calculated.

↓

Gas density , the critical velocity and critical flow rate will be calculated by using EXCEL software.

↓

Software will be developed, designed by VISUAL BASIC to predict liquid loading in gas wells.

↓

By using PIPESIM software, optimum Coiled Tubing size will be selected.

↓

The critical velocity and critical flow rate will be calculated by using EXCEL software with the new diameter size.

1.5. Project Layout:

This project report has been divided into five chapters:- Chapter one represents a brief introduction related to our project. Chapter two explains the literature review with latest publications related to prediction of liquid loading. Chapter three customized our topic which called by theoretical background**.** In Chapter four we analyze the collected data and make prediction calculations of liquid loading by using Turner and Sutton methods, then solve the problem. Also we make software by visual Basic language to predict liquid loading. In chapter five we show our results, make comparison between different prediction methods (Turner, Sutton methods) and explain how we solve this problem. Lastly we put our future Recommendation.

Chapter Two

Literature Review & Theoretical Background

Chapter 2

Literature Review & Theoretical Background

2.1. Literature Review:-

Calculate critical velocity is method presented to predict the onset of liquid loading. The droplet of liquid in annular flow inside gas well affected by two forces: (1) weight acts downward and (2) the drag force from the gas acts upward (Figure 2.1). When the drag is equal to the weight, the gas velocity is at "critical". Theoretically, at the critical velocity the droplet would be suspended in the gas stream, moving neither upward nor downward. Below the critical velocity, the droplet falls and liquids accumulate in the wellbore

The critical velocity is generally defined as the minimum gas velocity in the production tubing required to move liquid droplets upward.

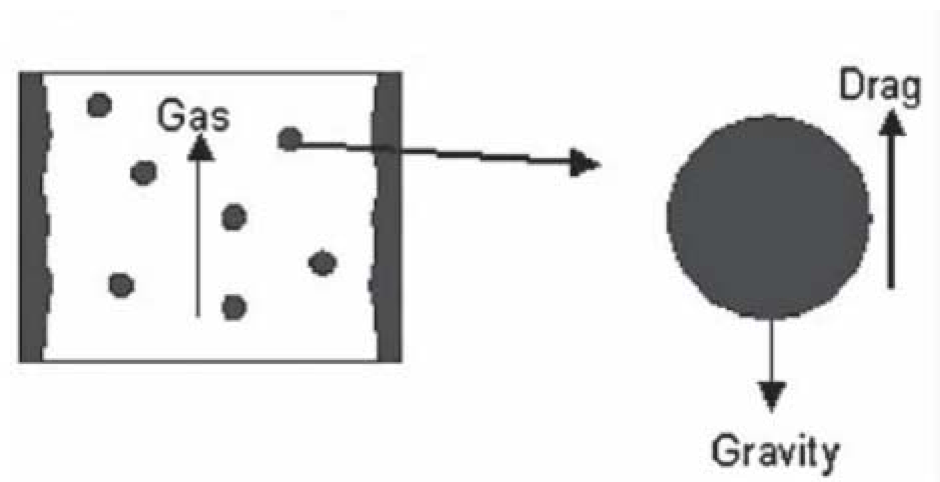

Figure 2.1 the concept of gas velocity at 'critical' (James et al. 2003:18)

Many authors developed correlations to calculate this critical velocity:

Jack O. Duggan (1961) presented for the first time an empirical correlation for the gas velocity required to keep a gas well unloaded from field observations in gas wells in Texas. He established that a minimum velocity of 5 ft/sec at the wellhead will keep the well unloaded by observing the flowing performance of a number of wells having various fluid contents and producing under a wide range of operating conditions.

Turner et al. (1969) developed Duggan correlation by performed an analysis, and showed the existence of two proposed physical models for the removal of gas well liquids: (1) Liquid film movement along the walls of the pipe. (2) Liquid droplets entrained in the high velocity gas core. Based on field data from producing gas wells, they found that the liquid droplet model better predicts the load up of gas wells producing liquids, and therefore is the governing mechanism for this process. It is also concluded that there exists a gas velocity sufficient to remove the largest drops can exists to avoid load-up, but a 20% increase should be added to insure removal of all drops.

Coleman et al. (1991) is presented four series papers. Some of their important conclusions are that the minimum flow rate or critical rate required to keep low pressure gas wells unloaded can be predicted adequately with Turner's liquid droplet model without the 20% upward adjustment, but they provide no explanation of why this may occur. Another important conclusion reached by them is that variables such as temperature, gas and liquid gravity and interfacial tension have little effect on the critical rate, whereas wellbore diameter and pressure have a direct and significant impact.

Nossier et al. (1997) focused on their studies on impact of flow regimes and change in flow on gas well loading. They followed the path of turner droplet model but they made different form turner model by considering the impact of flow regimes of the drag coefficient (Cd). Turner model takes the value of Cd to be 0.44 in all flow regimes (laminar, transition, turbulent.). Which in turn determine the expression of the drag force and hence critical velocity equations. On comparing nosier observed that turner model values were not matching with the real data for highly turbulent flow regime.

Li et al. (2001) presented a modification to Turner's critical gas velocity formula, considering that the liquid droplets entrained in the high velocity gas core, tend to be flat shape because a pressure difference exist between the fore and aft portion of the droplet, the droplet is deformed under the applied force and its shapes changes. By this assumption, they calculated the drag coefficient to have value of 1.0 instead of 0.44 as Turner proposed for a spherical shape droplet. The results calculated under this assumption leads to smaller values of critical gas velocities than the ones calculated with Turner's assumption, however, the predicted results match with practical data of gas wells in China (Figure 2.2).

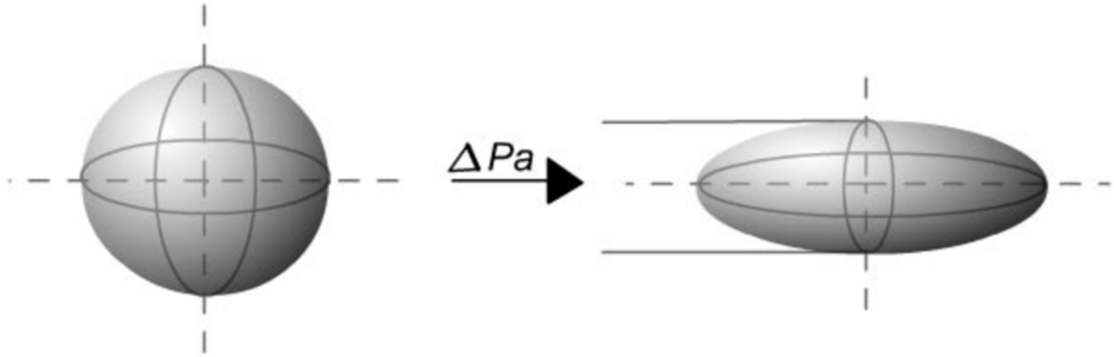

Figure 2.2 Shape of Entrained Drop in a High Velocity Gas

Matanović et al. (2004) Focused on reducing the flow area of a gas well's existing production string increases flow velocity and improves the ability to unload liquids. Installation of coiled tubing is now proven alternative. Since this is typically packerless completion coiled tubing and annular pressure can be monitored to ensure that stable flow is occurring.

Sutton et al. (2008) suggested a guideline for the proper application of critical velocity calculations. They declared 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 down-hole 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 nearly 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 declared wellhead conditions should be used in high pressure wells (greater than 1000 psia) and bottom conditions should be used in low pressure wells (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, Turner et al. provided for an 18.92% safety factor in his original work to determine critical velocity and to ensure the well is unloaded along the entire flow trajectory.

De Jonge and Tousis (2007) said that Installation of velocity strings or micro string installations in combination with surfactant injection are techniques that can be used to unload liquids from depleted gas wells. The authors also described the equipment, engineered and technologies used for installation of these strings by hanging off either below SSSV or at surface as well as the offshore operation challenges experienced and they prepared a decision tree to assist in selecting the suitable installation type and technique for liquid unloading of depleted gas wells based on numerous velocity and micro string installations, performed on continental Europe and the North sea.

Desheng Zhou (2010), For liquid loading problem in gas well besides entrained liquid -droplet and liquid -film mechanism liquid -droplet concentration may be a third mechanism There is a threshold value of liquid -droplet concentration above it, liquid -droplet concentration starts to affect liquid loading and critical -gas velocity varies with the concentration value. on the basis of this mechanism ,.an empirical model is presented in this paper ,to calculate the critical velocity and rate for liquid loading unlike traditional model the presented model includes the effect of liquid amount on Liquid loading in gas wells The model is simple and easy to use ,it composed of two parts separated by a threshold value of liquid hold-up below this value the model is the same as Turner model above it the critical velocity increases with increase of liquid hold-up this model covers more well than Turner model and consistent with conclusion of Coleman et al. (Figure 2.3).

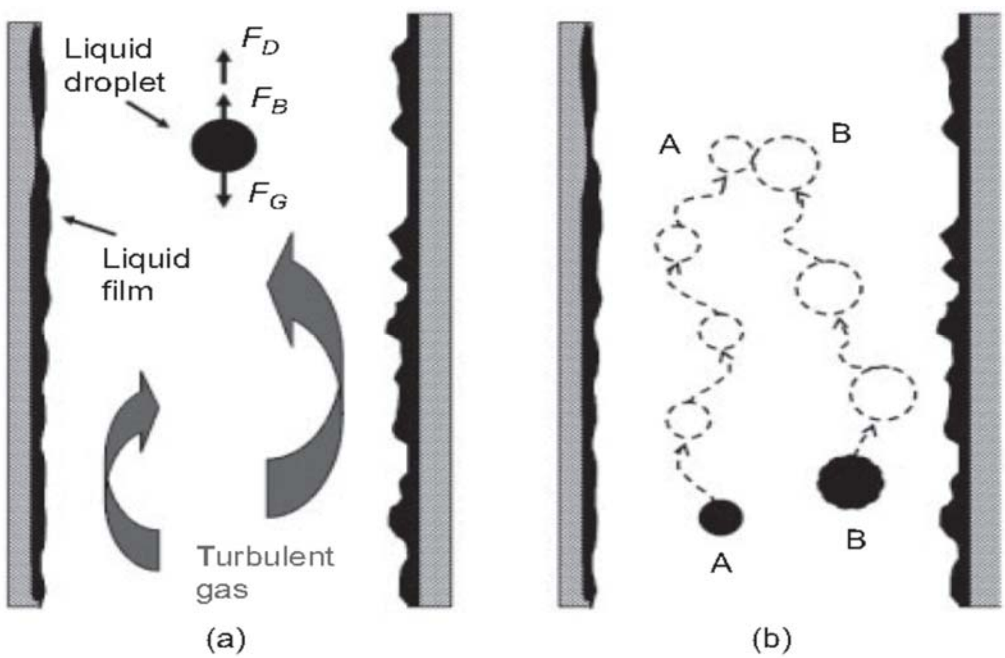

Figure 2.3 Encountering two liquid droplets in turbulent gas stream (Zhou & Yuan 2010:175)

Ikechukwu, O. and Ikiensikimama, S. (2013), developed a software, designed using Visual Basic to predict liquid loading in gas wells called (LOADquest). The software has an input data section for Guo et al.'s Four Phase Mist Flow Model and Turner et al.'s Entrained Droplet models and the output section. Also incorporated is a sensitivity analysis capability which can help operators or service providers to determine the most effective method of unloading a loaded well.

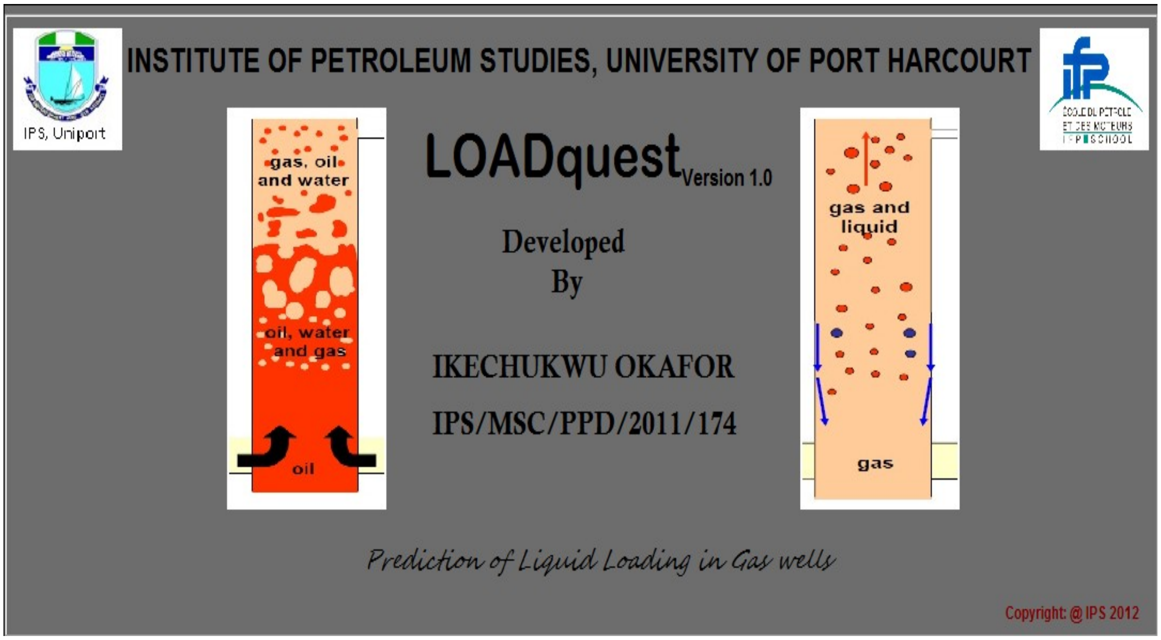

Figure 2.4 Software Welcome Screen

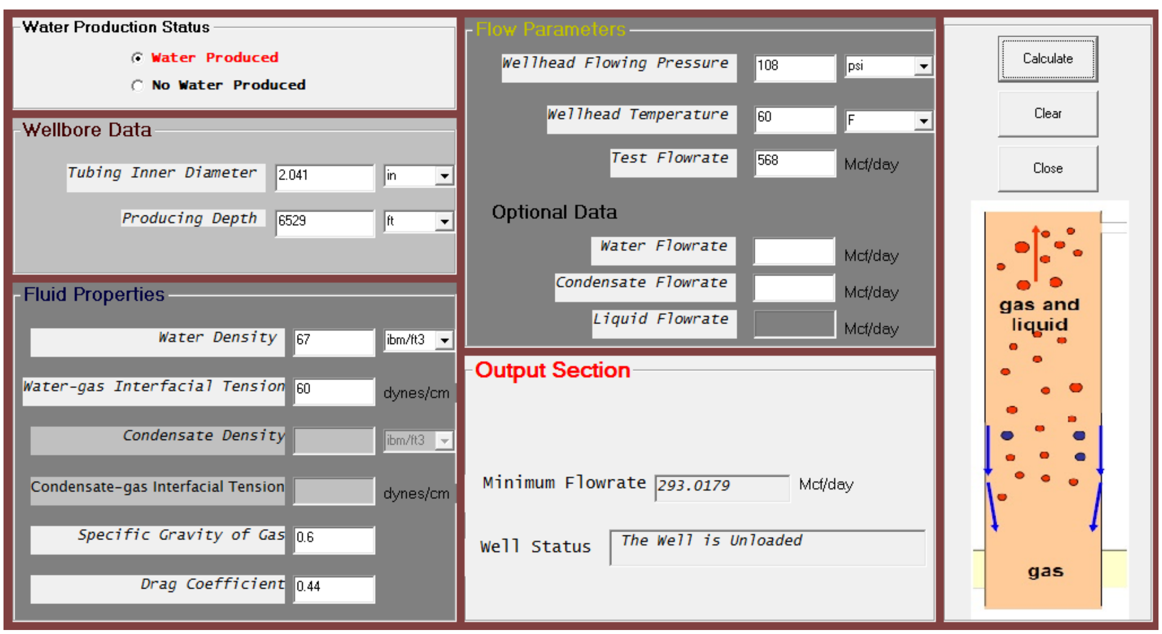

Figure 2.5 Turner et al. Prediction Model Input and Result Screen

2.2. Theoretical Background

2.2.1. Introduction:-

The natural gas well loading phenomenon is considered as one of the most serious problems in the natural gas industry. Very few gas wells produce completely dry gas. The liquids are directly produced into the wellbore because of coning from an underlying zone. Not only the produced liquid comes from the reservoir, in some cases, both hydrocarbons (condensate) and water can condense from the gas stream as the temperature and pressure change during travel to the surface.

In general, liquid loading of a gas well can be defined as: the inability of the produced gas to remove the produced liquids from the wellbore.

The process of liquid loading can be explained in four major steps as follow (Neves and Brimhall 1989):

i. At early stages, a gas well has enough energy, due to high initial reservoir pressure, to carry the liquids all the way to the surface. At this stage the gas velocity is greater than the critical velocity required to continuously remove the liquids in the gas stream and the liquid droplet is suspended and transported to the surface. As the gas velocity is high, gas carried liquid as small mist-like droplet, thus the flow pattern on this stage is called mist-annular wellbore flow pattern (Fig. 1.1(a)).

ii. As production continues, reservoir pressure declines, resulting in the decline of gas flow rate which induces a decrease in gas velocity in the well until the gas velocity falls below the critical gas velocity value, marking the onset of liquid loading (Fig. 1.1(b)). Consequently, liquid droplets suspended in the gaseous phase will begin to move downward. The liquid begins to accumulate at the bottomhole.

iii. The accumulated liquid at the bottomhole causes back pressure to the reservoir, causing gas inflow to decline as the bottomhole pressure decreases which induces the decrease of drawdown pressure from reservoir to the wellbore. The in-situ gas velocity actually may increase because of the reduction of the effective area for the gas phase to flow due to the liquid accumulation. This phenomenon results in a larger pressure drop across the accumulated liquid at the bottomhole. The pressure drop increases until the downstream pressure reaches the pressure necessary to blow down the liquids up to the surface (Fig. 2.4 (c)).

iv. The well cycles back and forth between the second and third stage. However as time passes, the time differential between produced liquid slugs at the surface become greater as a consequence of the time required by the reservoir to reach a pressure high enough to blow the liquid slugs up the string. Eventually, the additional backpressure exerted at the sand-face on the accumulated of liquid will overcome the available reservoir pressure; the well is unable to produce and dies (Fig. 1.1 (d)). 4

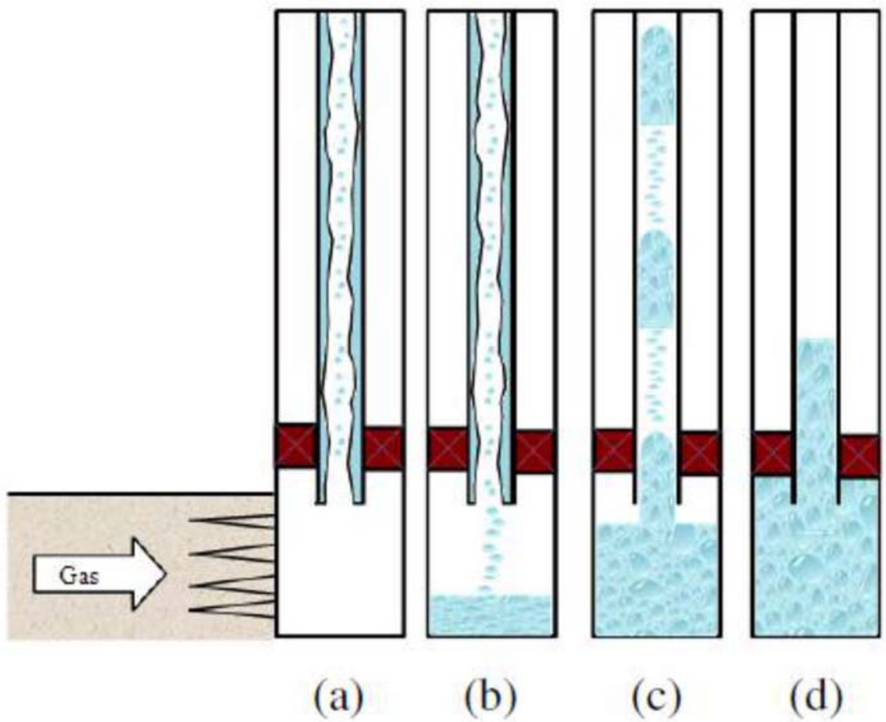

Figure 2.4 Stages of liquid loading process. (a) 1st stage, (b) 2nd stage, (c) 3rd stage and (d) 4th stage

It is thus very important to identify the liquid loading in a proper way and the liquid loading, if can be predicted, would lead to saving valuable reserves and well life. The understanding of the causes and symptoms of liquid loading and the behavior of gas well under liquid loading condition would provide a better insight to manage the gas well production, overcoming the liquid loading problem, and ultimately improve the recovery from the gas well.

2.2.2. Liquid Loading Prediction Methods:-

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.

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.
Discussed below are the basics of Turner et al. model and Sutton et al. model which have been applied in this project.

2.2.2.1. Turner Method:-

Turner, Hubbard, and Dukler (1961), after studying the earlier observations, proposed two physical models for the removal of gas well liquids. The models are based on:

- This model assumes that annular liquid film should have to be continuously moved upward along the wells to achieve liquid unloading. The model calculates the minimum flow rate requirement to move the film upward. Turner concluded that the predictions of the film model do not provide a clear definition between the adequate and inadequate rates (Figure 3.2).

- Liquid droplets entrained in the high velocity gas core. The minimum gas flow rate that will lift the drops out of the well to the surface. 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 3.3).

Applying this concept of liquid droplets in a flowing core of natural gas column, the critical velocity, Vc of the drop is, which assumes a fixed droplet size, shape and drag coefficient and includes the 20% adjustment suggested by Turner, based on field results matching.

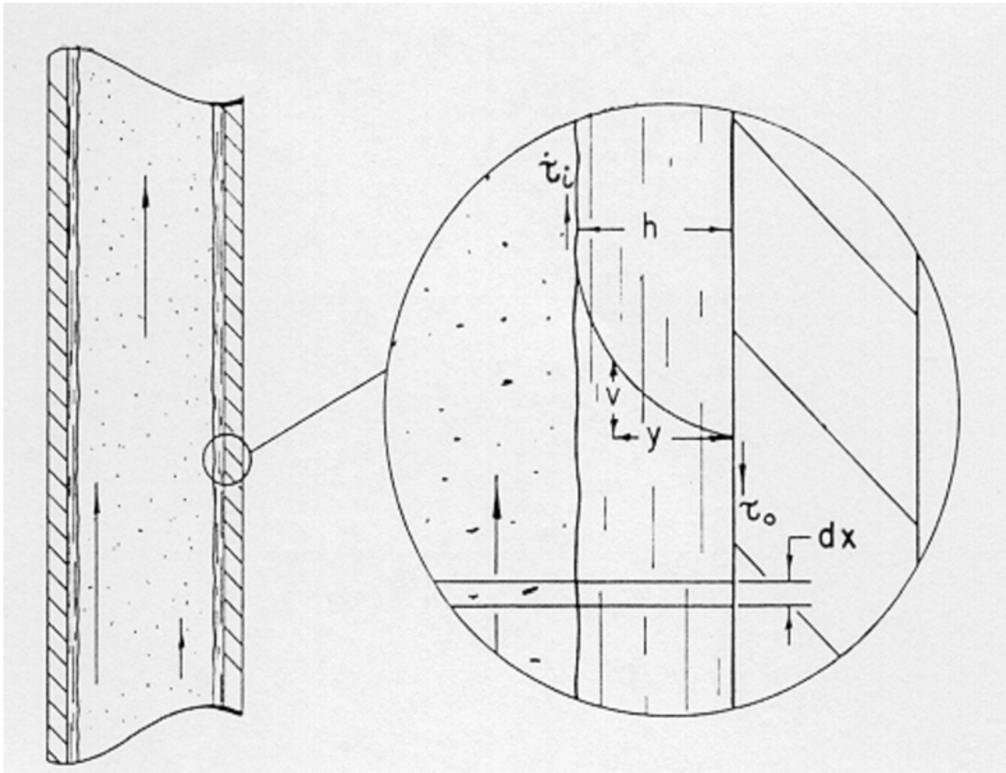

Figure 2.5 Liquid Film movement (Turner et al. 1969:1482)

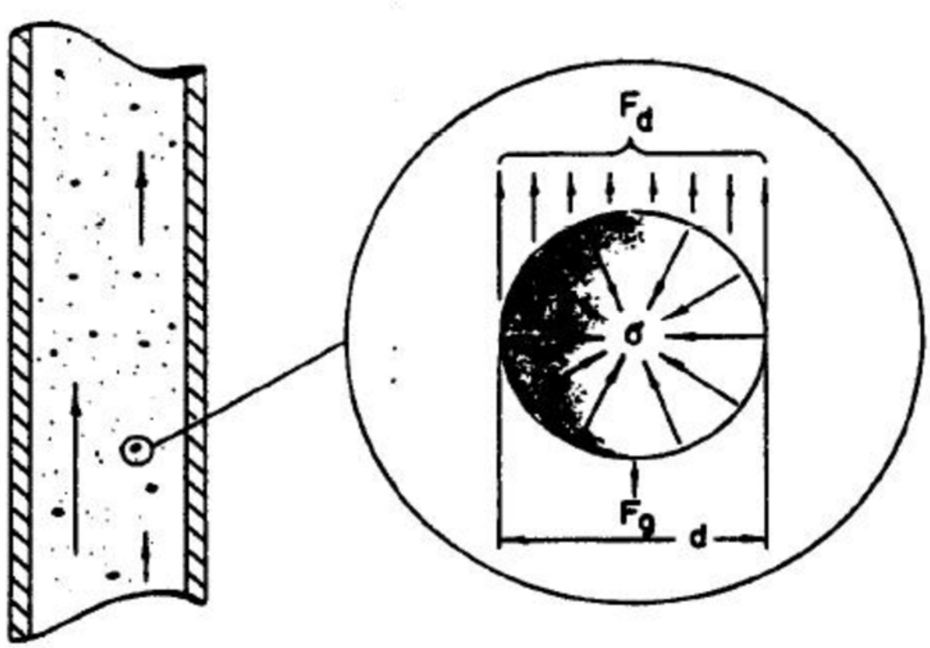

Figure 2.6 Liquid Droplet Movement (Turner et al. 1969:1477)

$$V_c = \frac{1.912\ \sigma^{\frac{1}{4}}\ (\rho l - \rho g)^{1/4}}{\rho^{\frac{1}{2}}} \tag{2-1}$$

Where:

V_c = critical velocity, ft/sec

σ = surface tension, dynes/cm

ρl = liquid density, lbm/ft^3

ρg = gas density, lbm/ft^3

Inserting typical values of:

Surface Tension = 20 and 60 dyne/cm for condensate and water, respectively.

Density = 45 and 67 lbm/ft^3 for condensate and water, respectively.

Gas Z factor = 0.9

$$\rho_g = \frac{P\ M_a\ \gamma_g}{Z\ R\ T} \tag{2-2}$$

By substituting the above typical values, a simplified pressure equation was developed:

$$\rho_g = 0.0031 * \mathrm{p} \tag{2-3}$$

The critical velocity can be converted to the critical rate at standard conditions for a given pressure, P, and tubular dimensions using the following equation:

$$Q_c = \frac{V_c\ A}{B_g} \tag{2-4}$$

Where B_g is the gas formation volume factor defined as follows:

$$B_g = \frac{Z\ T\ P_{sc}}{P\ T_{sc}} \tag{2-5}$$

Substituting for standard conditions, pressure P_{sc} = 14.65 psi and temperature T_{sc} = 520 ºR, Eq. 2.11 can be written as:

$$Q_c = \frac{3.06\ \mathrm{P}\ V_c\ \mathrm{A}}{(T+460)\ Z} \tag{2-6}$$

Where:

$$\mathrm{A} = \frac{\pi\ dt^2}{4*(12)^2} \tag{2-7}$$

T = surface temperature, ºF

P = pressure at the evaluation point, psi

A = tubing cross-sectional area, ft^2

dt = tubing ID, inches

2.2.2.2. Sutton Method:-

Gas compressibility factor:

The gas compressibility factor or Z-factor is more important in gas well calculations and it has significant effect of the gas density calculation. Z factor depend on pseudoreduced pressure and pseudoreduced temperature:

$$Tpc = 187+330 * \gamma_g-71 * \gamma_g^2 \quad (2\text{-}8)$$

$$Ppc = 706-51.7 * \gamma_g -11.1 * \gamma_g^2 \quad (2\text{-}9)$$

$$Tpr = \frac{T}{Tpc} \quad (2\text{-}10)$$

$$Ppr = \frac{P}{Ppc} \quad (2\text{-}11)$$

Several equation are constructed to reproducing of Z-factor chart and the most accurate one is trial and error or iterative. One of the simplest equations which give values of sufficiently accurate for two phase flow equation was published by Brill and Beggs and modified by Standing, the equation is:

$$Z = A + (1-A)\ e^{-B} + C\ Ppr^{D} \quad (2\text{-}12)$$

Where:

$$A = e^{(0.715 - 1.128 * Tpr + 0.42 * Tpr\ 2)} \quad (2\text{-}13)$$

$$B = 0.132-0.32 * \log(Tpr) \quad (2\text{-}14)$$

$$C = Ppr * (0.62 - 0.32 * Tpr) + Ppr^{2\,*} \left(\frac{0.066}{Tpr-0.85} - 0.33\right) \quad (2\text{-}15)$$

$$D = 1.93 * \sqrt{Tpr - 0.94} - 0.36 * Tpr - 0.101 \quad (2\text{-}16)$$

Then we can make Sutton calculations for densities

$$\rho_g = \frac{P\ M}{R\ T\ Z} \quad (2\text{-}17)$$

Gas solubility:

Standing (1947) proposed a graphical correlation for determining the gas solubility as a function of pressure, gas specific gravity, API gravity, and system temperature. The proposed correlation has an average error of 4.8%. Standing (1981) expressed his proposed graphical correlation in the following more convenient mathematical form:

$$Rs = \gamma_g * \left(\left(\frac{P}{18.8} + 1.4\right) * 10^{x}\right)^{1.2084} \qquad (2\text{-}18)$$

$$X = 0.0125\ API - 0.00091\ (T - 460) \qquad (2\text{-}19)$$

Condensate Formation volume factor:

Glaso (1980) proposed the following expressions for calculating the oil formation volume factor based 0n temperature and gas solubility

$$Bo = 1.0 + 10^{A} \qquad (2\text{-}20)$$

$$A = -6.58511 + 2.91329 * \log (B_{ob}^*) - 0.27683 \log (B_{ob}^*)^2 \qquad (2\text{-}21)$$

B_{ob}^* is a correlating number and is defined by the following equation:

$$B_{ob}^* = R_s \left(\frac{\gamma o}{\gamma g}\right)^{0.526} + 0.968\ (T - 460) \qquad (2\text{-}22)$$

Where

T = temperature,

°R = specific gravity of the stock-tank oil

Water formation volume factor:

The water formation volume factor can be calculated by the following mathematical expression:

$$B_w = A1 + A2 * p + A3 * p2 \qquad (2\text{-}23)$$

Where the coefficients A1 - A3 are given by the following expression:

$$Ai = a1 + a2\ (T - 460) + a3\ (T - 460)^2 \qquad (2\text{-}24)$$

Ai	a 1	a 2	a 3
A1	0.9947	$5.8(10^{-6})$	$1.02(10^{-6})$
A2	$-4.228(10^{-6})$	$1.8376(10^{-8})$	$-6.77(10^{-11})$
A3	$1.3(10^{-10})$	$-1.3855(10^{-12})$	$4.285(10^{-15})$

Table 2.1 Values of coefficients

Water Density:

Water density can be calculated from below expression:

$$\rho_w = \frac{62}{Bw} \qquad (2\text{-}25)$$

Oil condensate density:

$$\rho_o = \frac{62.4 * \gamma o + 0.0136 * Rs * \gamma g}{Bo} \qquad (2\text{-}26)$$

Chapter Three

Methodology

Chapter 3
Methodology

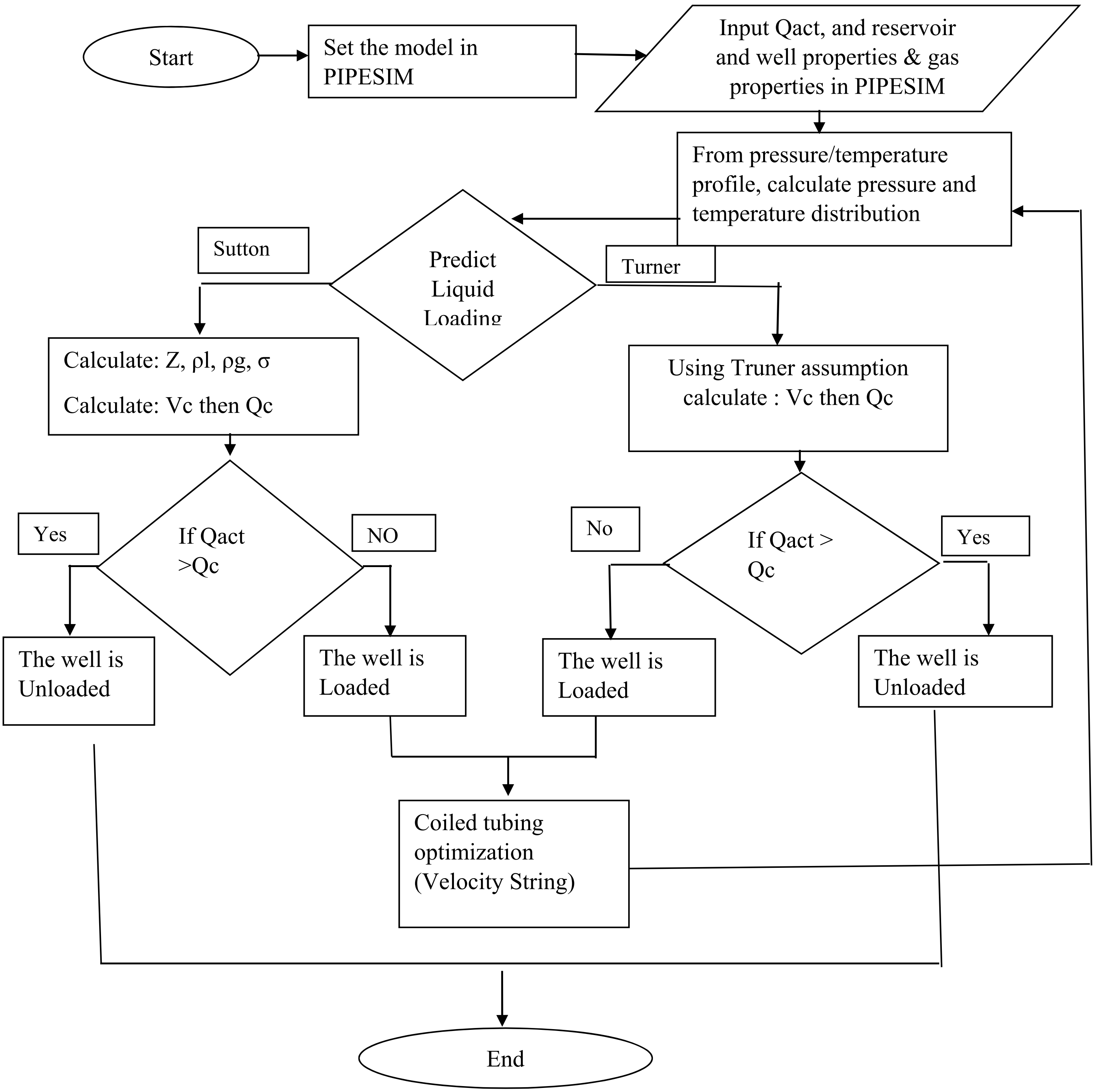

Figure 3.1 Flow chart of the project

3.1. Pipesim Software:-

The figure below shows the form of the model that was used in PIPESIM soft-ware in order to calculate the pressure and temperature distribution.

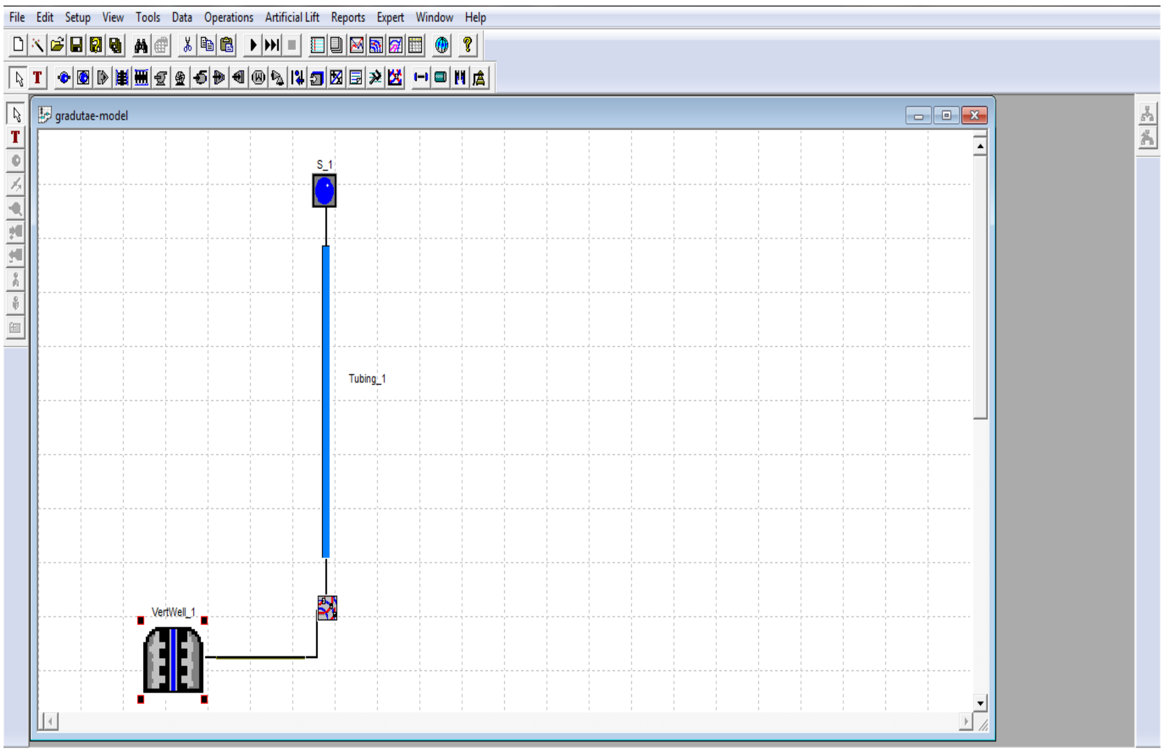

Figure 3.2 pipesim model

The following is the summary of the steps to find pressure and temperature with illustrative figure:

Step 1: by clicking on the (Vertwell_1) icon, window will appear as in the figure, then selected BACKPRESSURE EQUATION model because it gave the correct result after comparing it with other models and explanation of this choice come later, after choosing the model we enter values : pressure and temperature of the reservoir . Then, By clicking on the (Calculate Graph) values of Constant C and Slope N appears.

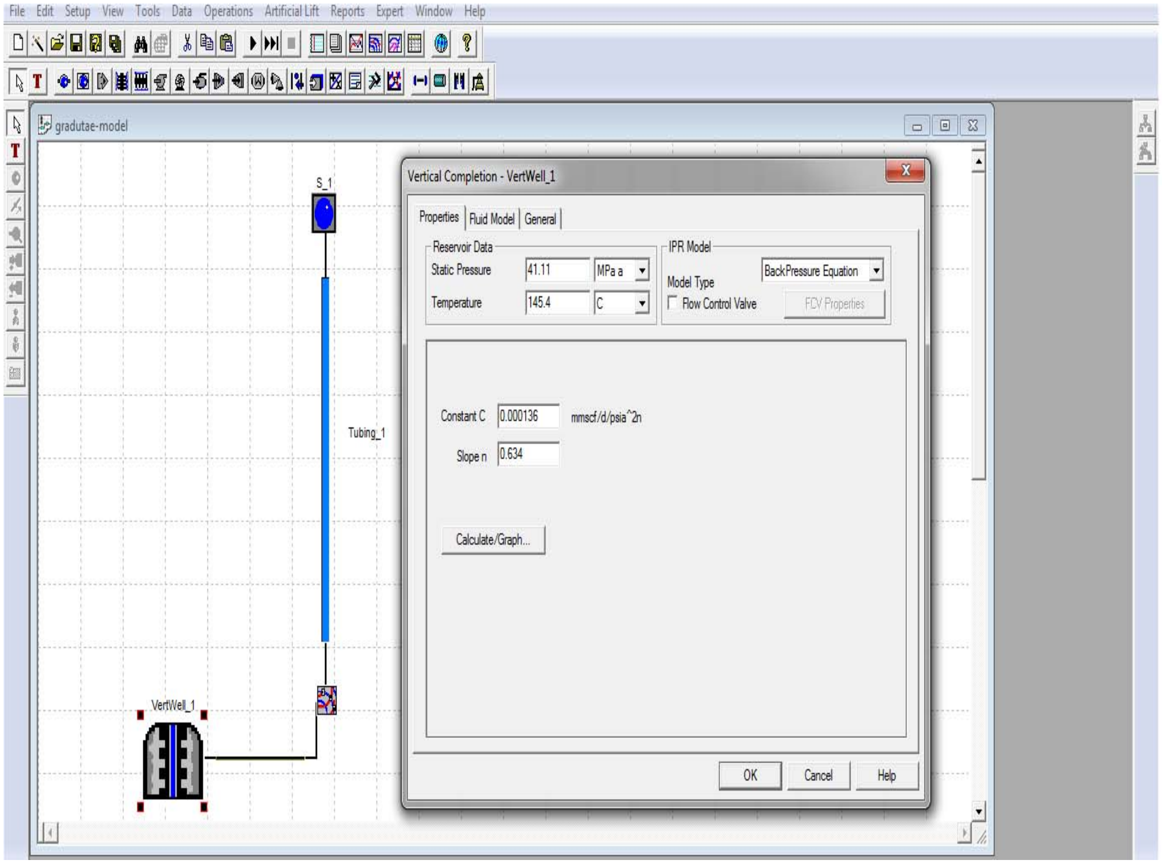

Figure 3.3 Formation values inputs

Step 2: by clicking on Setup icon menu appears, choose Black Oil , then enter the values of Water cut and Gas Oil Ratio (GOR).

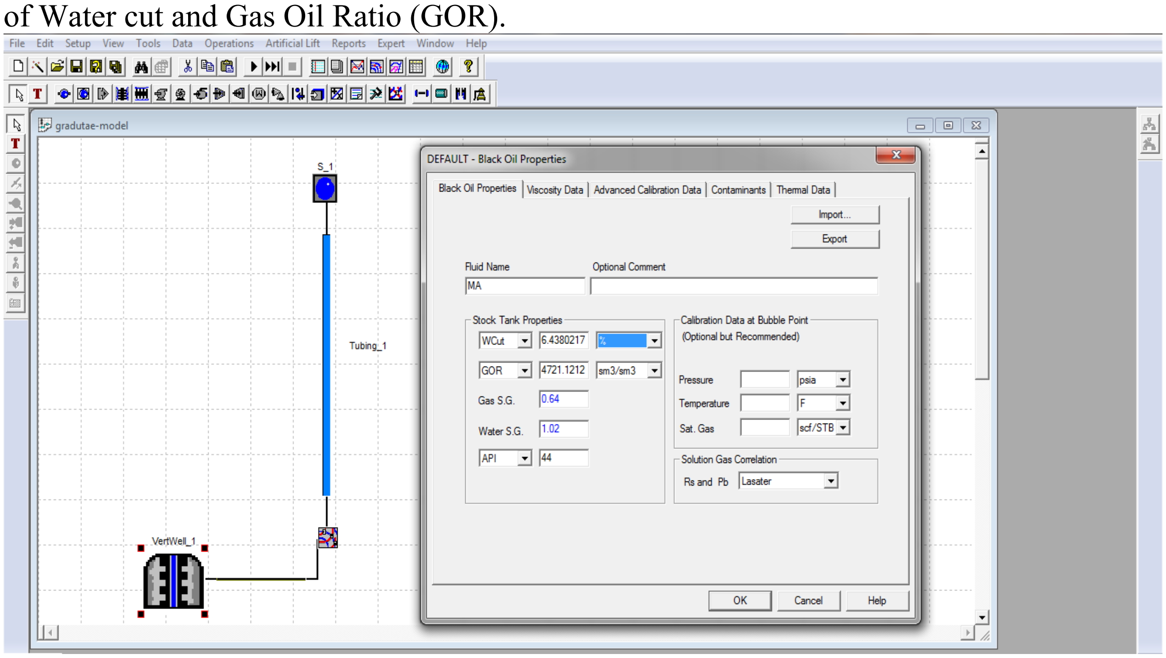

Figure 3.4 Stock tank properties values input

Step 4: by clicking Operation icon, menu appears, choose Pressure/Temperature Profile , then enter the value of Gas rate, then **run the model.**

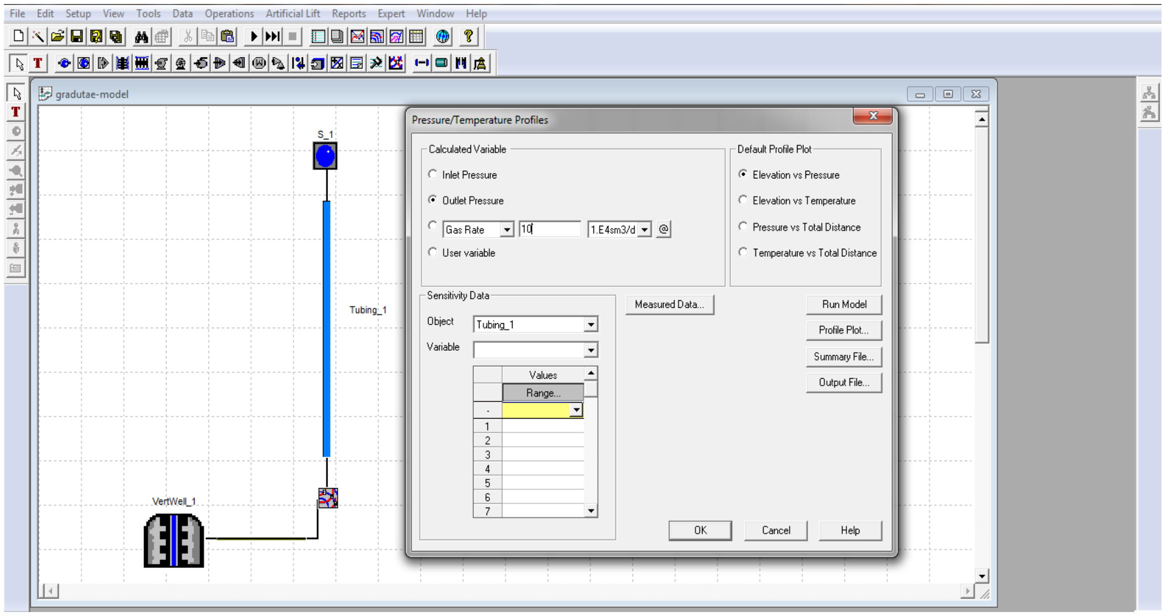

Figure 3.5 gas rate value input

This next figure show that the pressure distribution along the well.

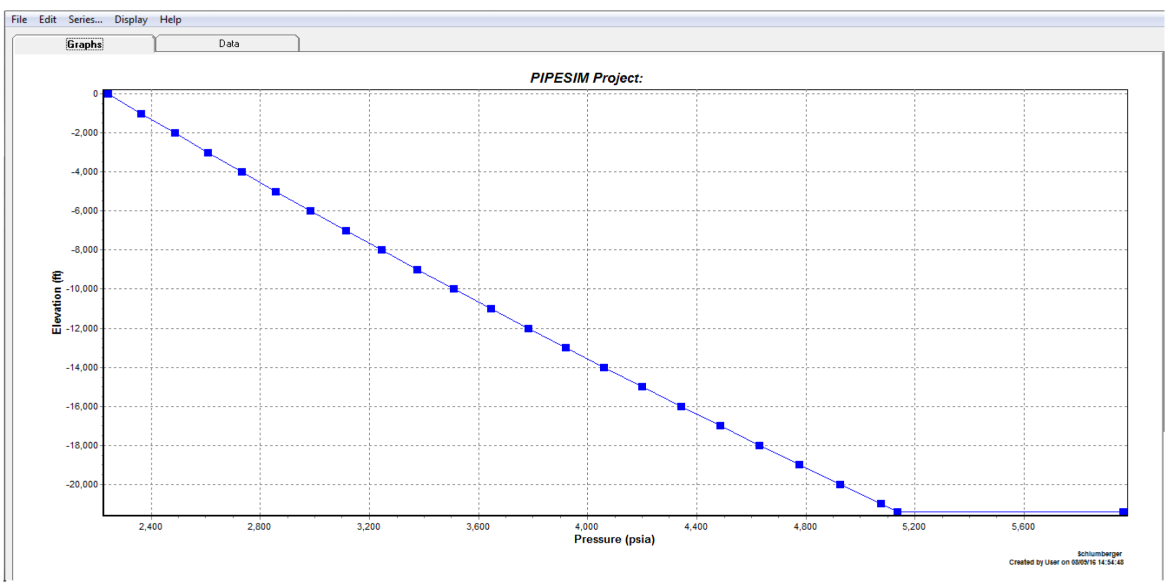

Figure 3.6 pressure distribution along the well

The next figure show that the Temperature distribution:-

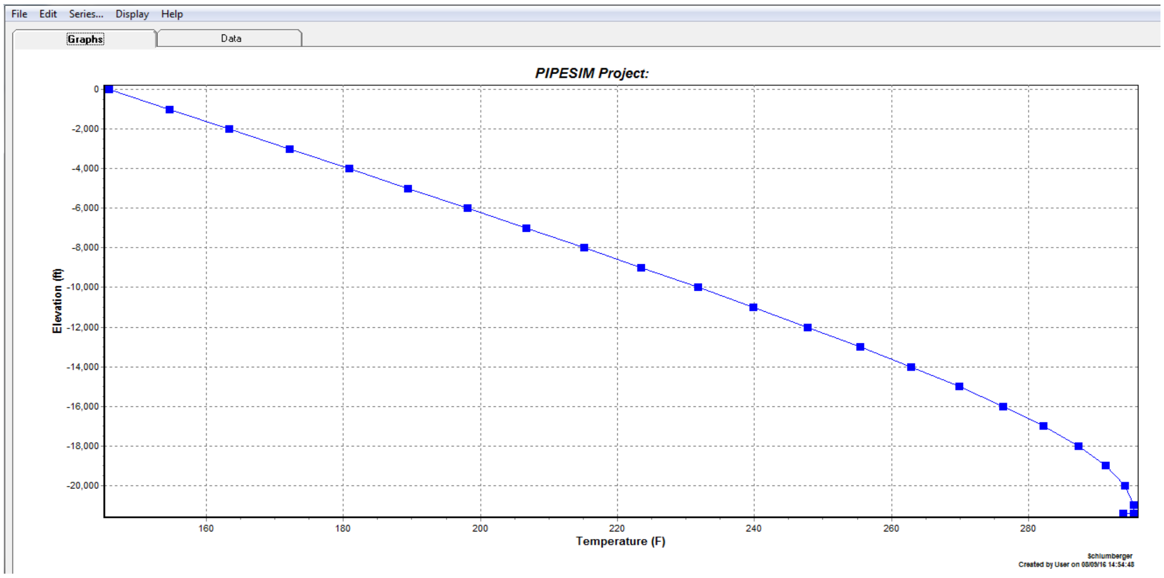

Figure 3.7 temperature distribution along the well

3.2. Excel software:-

From Excel Software we compute the gas densities, critical velocities, and the critical gas flow rates by equations in the previous chapter. These calculations for every year and depend on the Pressure and Temperature values that computed from pipesim as we explained above.

According to the Turner & Sutton Methods, we take only the values of pressure and temperature at the well head and used to specify the gas densities, critical velocities, and the critical gas flow rates. We apply these same steps for 18 years.

After we make the above steps, we plot the actual gas flow rates versus the critical gas flow rates to predict the liquid loading occurring (the years when the problem occurred).

Example for the first year calculations:-

TVD1 Ft	P1 Psi	T1 °F	Gas density lbm/ft^3	Vc ft/sec	Qc ft^3/sec
21,407.32	5,135.40	295.2475	15.91972	2.432692	2.542257
21,000.00	5,073.63	294.1055	15.72825	2.451288	2.534712
20,000.00	4,923.11	290.494	15.26165	2.497884	2.518329
19,000.00	4,774.09	285.9207	14.79969	2.54592	2.504326
18,000.00	4,626.48	280.5831	14.34209	2.595524	2.49201
17,000.00	4,480.21	274.6482	13.88864	2.646827	2.480802
16,000.00	4,335.25	268.2331	13.43927	2.699959	2.470295
15,000.00	4,191.60	261.4416	12.99396	2.755058	2.460125
14,000.00	4,049.27	254.351	12.55273	2.812265	2.450017
13,000.00	3,908.29	247.025	12.1157	2.871729	2.439739
12,000.00	3,768.71	239.5136	11.683	2.933605	2.429103
11,000.00	3,630.58	231.8559	11.2548	2.998059	2.417957
10,000.00	3,493.98	224.0825	10.83133	3.065265	2.406177
9,000.00	3,358.98	216.2172	10.41282	3.135409	2.393661
8,000.00	3,225.66	208.2787	9.999539	3.208689	2.380324
7,000.00	3,094.12	200.2812	9.591763	3.285318	2.3661
6,000.00	2,964.45	192.2361	9.189798	3.365522	2.35093
5,000.00	2,836.76	184.152	8.793958	3.449543	2.334768
4,000.00	2,711.15	176.0359	8.404574	3.537642	2.317577
3,000.00	2,587.16	167.8929	8.02021	3.63054	2.299098
2,000.00	2,463.83	159.7264	7.637858	3.729531	2.27883
1,000.00	2,341.21	151.5389	7.257736	3.835293	2.256637
0	2,219.39	143.3322	6.880117	3.9486	2.232383

Table 3.1 Turner et al. method result for first year

Depth	Temperature	Pressure	Q_c	V_c
ft	ºF	Psi	ft^3/sec	ft/sec
21,407.32	308.6809	5,068.52	2.881202	2.586797
21,000.00	307.5116	5,008.25	2.897237	2.584315
20,000.00	303.7517	4,861.41	2.936684	2.580639
19,000.00	298.9305	4,716.05	2.976447	2.579731
18,000.00	293.2693	4,572.05	3.016761	2.58084
17,000.00	286.9387	4,429.34	3.057832	2.583372
16,000.00	280.0785	4,287.87	3.099861	2.586824
15,000.00	272.7983	4,147.61	3.143043	2.590784
14,000.00	265.1879	4,008.58	3.187576	2.594901
13,000.00	257.3185	3,870.79	3.233662	2.598879
12,000.00	249.2461	3,734.27	3.281504	2.602467
11,000.00	241.0146	3,599.09	3.33131	2.605451
10,000.00	232.6579	3,465.29	3.383295	2.607647
9,000.00	224.2026	3,332.94	3.437679	2.608888
8,000.00	215.6692	3,202.14	3.494699	2.609024
7,000.00	207.0733	3,072.96	3.554599	2.607917
6,000.00	198.4273	2,945.49	3.617643	2.605434
5,000.00	189.7405	2,819.83	3.684112	2.601447
4,000.00	181.0202	2,696.07	3.754322	2.595826
3,000.00	172.2718	2,573.28	3.829537	2.588053
2,000.00	163.4988	2,451.01	3.910893	2.577685
1,000.00	154.7038	2,329.35	3.999224	2.564427
0.00	145.8888	2,208.37	4.095512	2.547956

Table 3.1 Sutton et al. method result for first year

3.3. (LILOpred.) software designed by Visual Basic to predict liquid loading:-

The following figures shows the softwear screens:

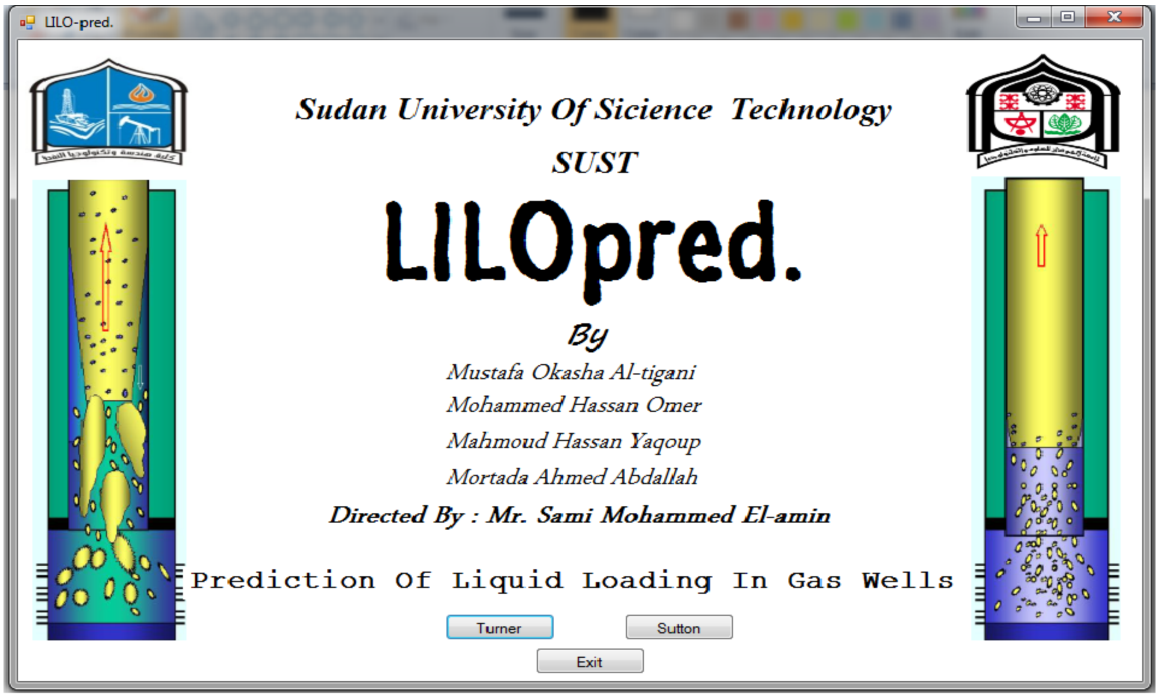

Figure 3.8 Welcome Screen (Our software)

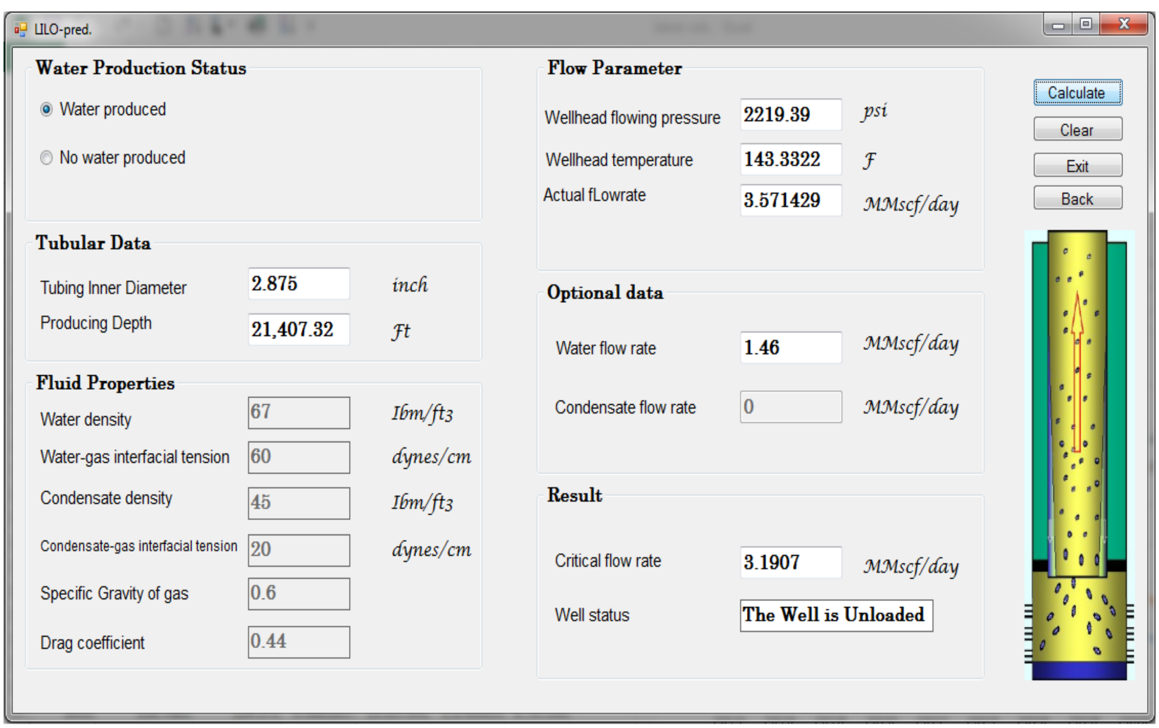

Figure 3.9 Turner et al. Model Input and Result Screen (Our software)

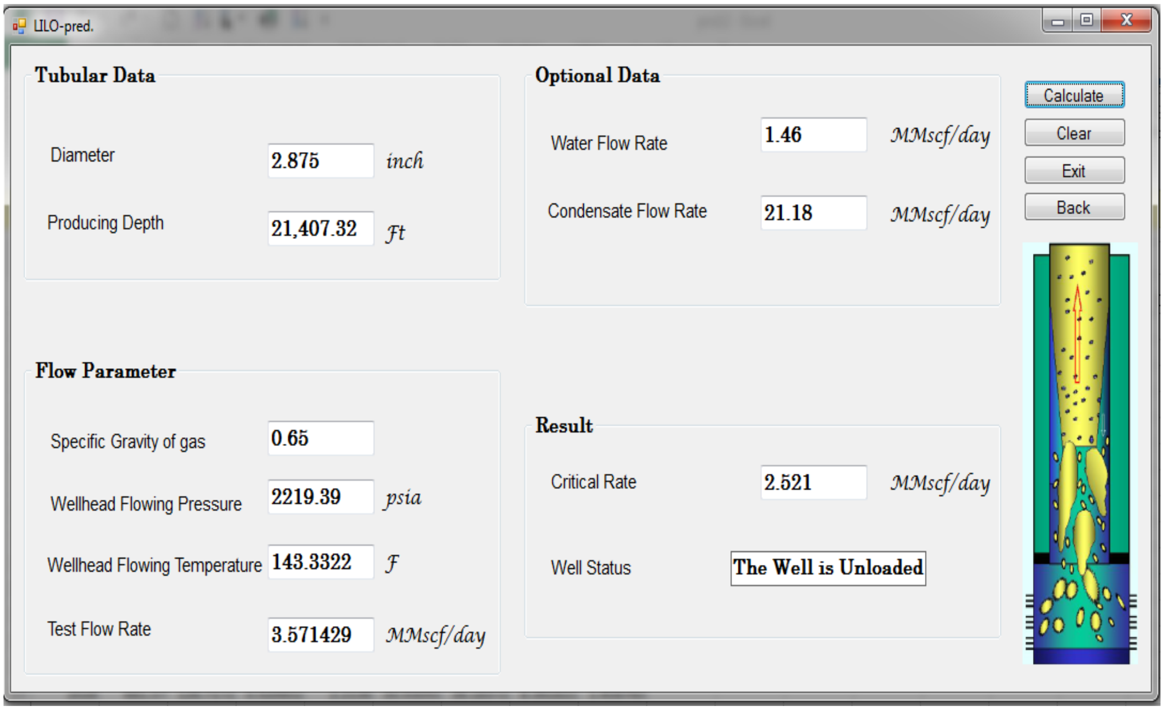

Figure 3.10 Sutton et al. Model Input and Result Screen (Our software)

3.4. Solve this problem by using COILED TUBING:-

The design for the velocity string depends on well conditions. The gas velocity must meet or exceed a minimum or critical velocity to prevent a well from loading up. There are two popular methods for determining the minimum gas velocity: a rule of thumb widely accepted in the petroleum industry, and a theoretical correlation presented by Turner et al. (1969).

The correlation presented by Turner et al. (1969) uses a theoretical analysis of the flow regime. In order to prevent liquid loading of the well, the liquid in the tubing must be suspended as a mist or the flow regime in the tubing must be in annular-mist flow. In these flow regimes, as long as the gas velocities exceed the settling velocity of liquid droplets, high gas velocities force the liquid out of the tubing (Rao 1999).

The optimum size of Coiled tube must achieve these Criteria:

- High flow rate.
- Erosional velocity ratio < 1.

- Low cost compared with other available tubing.

3.4.1. Erosion Prediction:-

Erosion has been long recognized as a potential source of problems in oil and gas production systems. Erosion can occur in solids-free fluids but, usually, it is caused by entrained solids (sand). Two erosion models are available in PIPESIM – API 14 E and Salama.

- **API 14 E:**

The API 14 E model comes from the American Petroleum Institute, Recommended Practice, number 14 E. This is a solids-free model which calculates only an erosion velocity (no erosion rate). The erosion velocity Ve is calculated with the formula:

$$\mathrm{Ve} = \frac{\mathrm{C}}{\sqrt{Pm}}$$

Where (pm) is the fluid mean density and C is an empirical constant. C has dimensions of (mass/(length*time2)) 0.5. Its default value in engineering units is 100, which corresponds to 122 in SI units. The current practice for eliminating erosional problems in piping systems is to limit the flow velocity to that calculated by this correlation.

- **Salama:**

The Salama model was published in Journal of Energy Resources Technology, Vol 122, June 2000, "An Alternative to API 14 E Erosional Velocity Limits for Sand Laden Fluids," by Mamdouh M. Salama. This model calculates erosion rate and erosional velocity. The parameters required for the model are Acceptable Erosion rate, Sand production ratio, Sand Grain Size, Geometry Constant and Efficiency. The equations in Salama's paper use a sand rate in Kg/day. This is obtained from the supplied volume ratio using Salama's 'typical value' for sand density - 2650 kg/m 3.

Chapter Four

Results & Discussion

Chapter 4

Results & Discussion

This chapter discusses the results obtained from applying the previous equations on (A1 well) production data, and explain its interpretation.

4.1. Turner application:-

The principle of these calculations is based on Turner assumption which listed in (Chapter 2, Section 2.2.2.). In accordance with results obtained from Turner method, it is observed that the critical gas flow rate will become greater than predicted gas flow rate from the well in 2018, so the liquid will begin to accumulate in the bottom hole, then increases backpressure on the formation, and the reservoir pressure decreases, so the gas flow rate decreases until the liquid loading occur, figure 4.1 illustrate these events, and the below table show the finally results from this method.

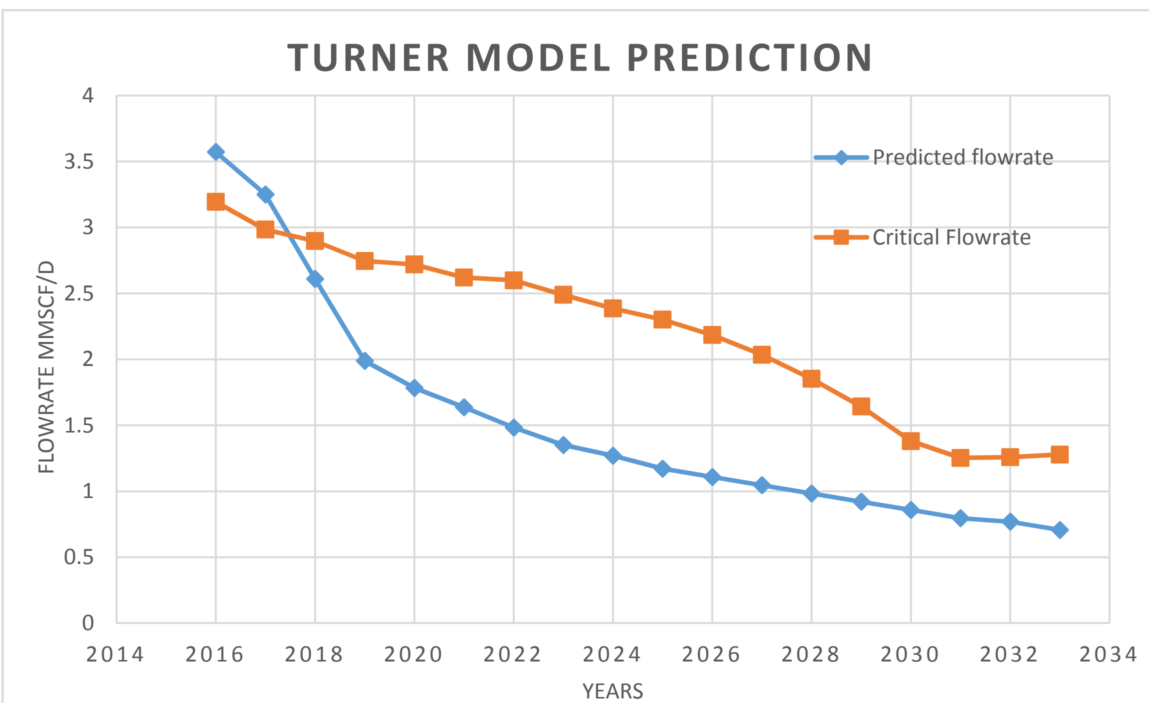

Figure 4.1 Turner Model Prediction loading

Years	**Pressure (psi)**	**Temperature (°F)**	**Gas Density (lbm/ft3)**	**Vc (ft/sec)**	**Qc (MMscf/D)**	**Actual Q (MMscf/D)**
2016	2,219.39	143.3322	6.8801171	5.6487178	3.1935617	3.571429
2017	1,905.97	140.8873	5.9085024	6.1199764	2.9834602	3.25
2018	1,764.18	136.621	5.4689689	6.3725622	2.896057	2.609826
2019	1,555.55	132.4806	4.8222025	6.804236	2.745597	1.988157
2020	1,517.35	131.1676	4.7037695	6.8926414	2.7189875	1.784051
2021	1,400.12	130.1642	4.3403794	7.1858203	2.6200966	1.636563
2022	1,371.82	129.1906	4.2526485	7.2621023	2.5986761	1.483058
2023	1,251.22	128.3614	3.8787749	7.6153493	2.4890083	1.350789
2024	1,144.80	127.823	3.5488785	7.9718207	2.3860975	1.269371
2025	1,064.57	128.0391	3.3001589	8.2748555	2.3010105	1.171161
2026	955.2828	127.5832	2.9613767	8.7469558	2.1842922	1.108666
2027	824.8987	127.1558	2.557186	9.4276994	2.0344368	1.046171
2028	680.5785	126.7172	2.1097934	10.39724	1.8525021	0.983676
2029	532.3525	126.321	1.6502928	11.776702	1.6423993	0.921181
2030	372.9947	125.2969	1.1562836	14.095798	1.379772	0.858686
2031	306.572	124.9287	0.9503732	15.560149	1.2526638	0.796191
2032	309.1581	124.7522	0.9583901	15.494462	1.2582777	0.76941
2033	318.7683	124.375	0.9881817	15.257391	1.2783653	0.707143

Table 4.1 Finally Turner model calculations results

4.2. Sutton application:-

In Sutton et al. method, some parameters will change; because we don't use the typical values which stated by Turner, but here these parameters are calculated by using the previous equations that are listed in Chapter 3.

These parameter are: gas compressibility factor or (Z-factor), Turner gave this factor a typical value, using this value does not give an accurate results, so Sutton et al. proposed equations to calculate this factor. Also the value of gas density will change; because it depend on (Z-factor) value, also gas solubility, oil Formation volume factor, water density and condensate density were calculated from previous equations in (Chapter 2, Section 2.2.2.) instead of depending on typical values; to ensure accurate results.

In accordance with results obtained from Sutton et al. method, it noted that the critical gas flow rate will become greater than predicted gas flow rate of the well in 2019, thus the liquid begins to accumulate in the bottom hole and then liquid loading occurs, figure 4.2 shows the year when liquid loading will occur. The table below shows the detailed results for this method.

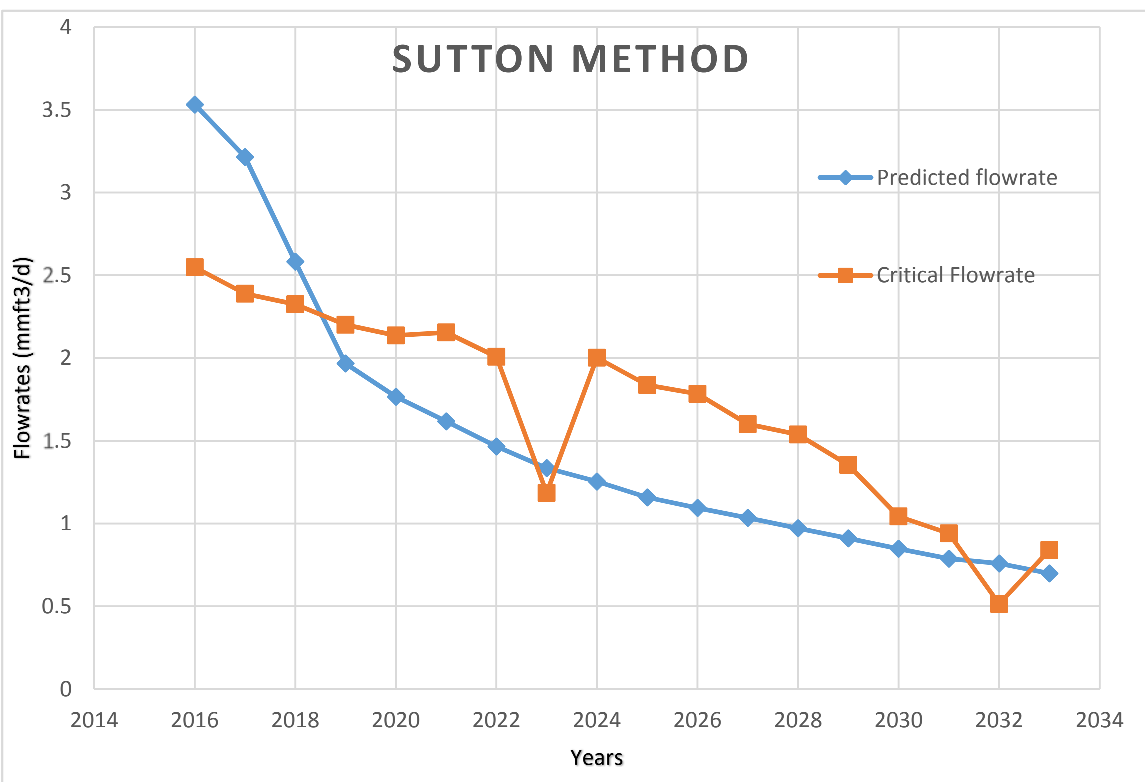

Figure 4.2 Finally Sutton Model Prediction loading

Years	Pwh	Twh	Z	Pg	Pl	Σ	Vc	Qc
	(psi)	(ºF)		(lbm/ft3)	(lbm/ft3)	(dyne/cm)	(ft/sec)	(MMscf/D)
2016	2,219.39	143.3322	0.820352	7.866649	45.39735	35.11784	4.124629	2.557174
2017	1,905.97	140.8873	0.827501	6.7246	46.52732	35.27468	4.53223	2.40195
2018	1,764.18	136.621	0.829889	6.250825	47.06685	35.54837	4.739638	2.334898
2019	1,555.55	132.4806	0.838632	5.492254	47.86697	35.81399	5.113471	2.213359
2020	1,517.35	131.1676	0.840074	5.360045	48.01893	35.89822	5.187852	2.1915
2021	1,400.12	130.1642	0.848281	4.906432	48.46247	35.96259	5.453096	2.108601
2022	1,371.82	129.1906	0.849725	4.807016	48.57569	36.02504	5.518302	2.090579
2023	1,251.22	128.3614	0.859755	4.339366	49.02569	36.07824	5.840407	1.997353
2024	1,144.80	127.823	0.869631	3.928801	49.41369	36.11278	6.166706	1.909408
2025	1,066.57	128.0394	0.877844	3.624751	49.68558	36.0989	6.439743	1.839637
2026	957.10	127.5834	0.889287	3.213366	50.06353	36.12815	6.870057	1.739827
2027	826.31	127.1558	0.903812	2.731653	50.49208	36.15558	7.488578	1.612168
2028	681.57	126.7172	0.920652	2.2136	50.93093	36.18372	8.361821	1.458765
2029	533.15	126.3208	0.938443	1.699881	51.33215	36.20915	9.588211	1.284522
2030	385.50	125.9129	0.956265	1.20706	51.67253	36.23532	11.42795	1.087133
2031	317.60	125.5332	0.964351	0.986735	51.80939	36.25967	12.66401	0.984821
2032	320.17	125.3344	0.963998	0.995426	51.80783	36.27243	12.60908	0.989186
2033	329.84	124.8992	0.962737	1.027597	51.79689	36.30035	12.40989	0.840161

Table 4.2 Sutton model calculations results

4.3. Coiled Tubing application:-

We perform NODAL analysis to select an optimum tubing size. The available tubing size have IDs of 1 inches, 1.5 inches, 1.75 inches, and 2 inches. By applying NODAL analysis in this well, we observed that the optimum size of Coiled tube is 1.75 ID because of these Criteria:

- It has high flow rate.
- Erosional velocity ratio < 1.
- Low cost compared with other available tubing.

Tubing inside diameter Inches	1	1.5	1.75	2
Nodal solution rate MMscf/d	1.4832	3.5862	4.5757	5.3349
Nodal solution pressure PSI	5,751.50	5,065.06	4,585.29	4,129.16
Erosional Velocity Ratio Maximum	0.9974	1.1122	0.8993	0.9433

Table 4.3 Coiled Tubing diameter size selection

The figure below represent the outlet pressure sensitivity to determine the suitable outlet pressure that required to select optimum tubing sizing.

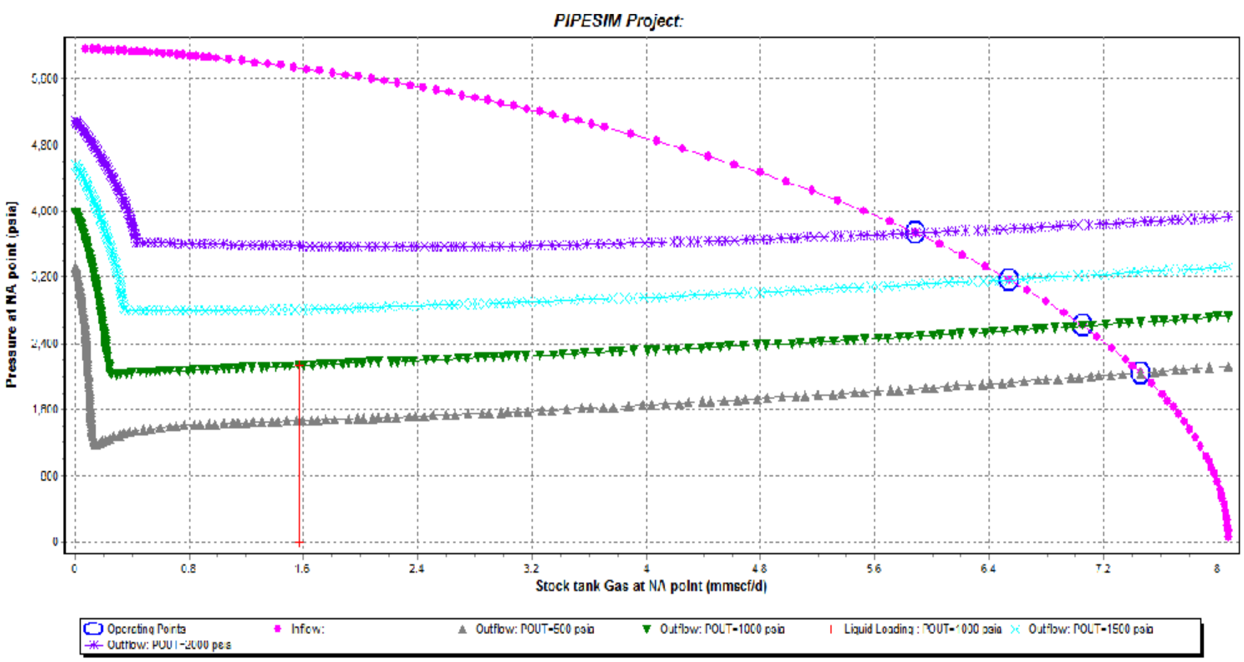

Figure 4.3 Select optimum outlet pressure using PIPESIM software

Outlet Pressure (psi)	Q (Mscf/d)	P (psi)
2000	2548.99	4466.61
1500	2865.31	4097.91
1000	3132.13	3737.26
500	3354.02	3392.41

Table 4.4 Operation point for various outlet pressure

After outlet pressure was selected, by perform Nodal Analysis in PIPESIM software we observed that tube has 1.75 inch gave higher rate and lower EVR than other.

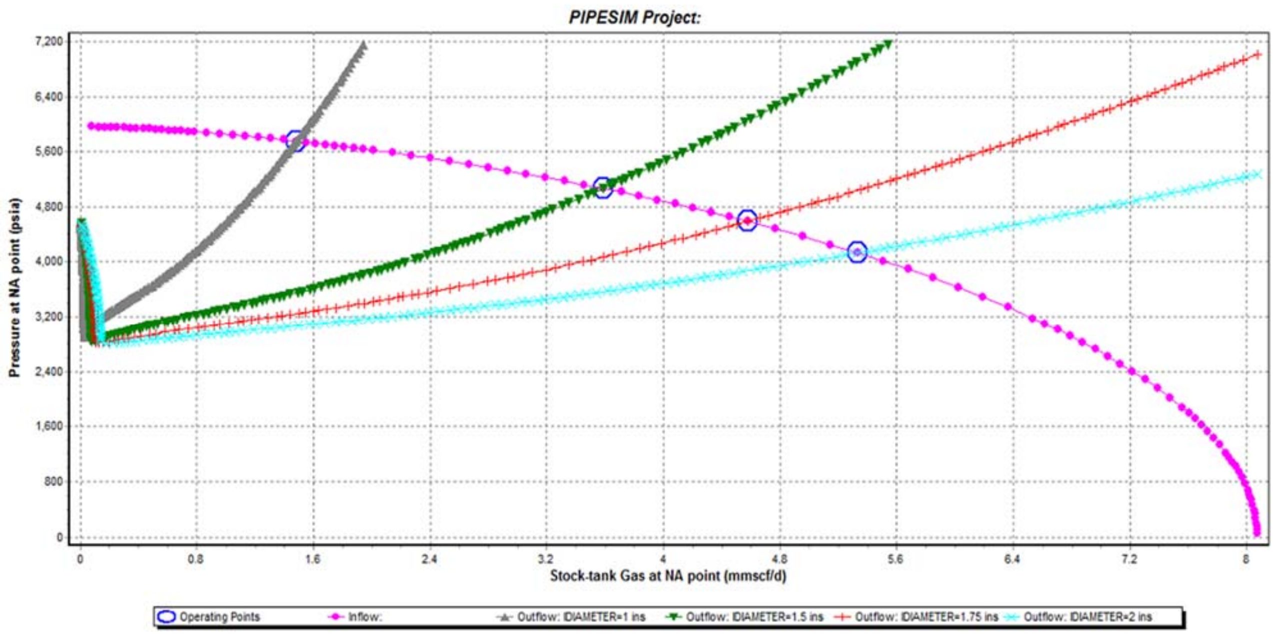

Figure 4.4 Select optimum Coiled tube size

Year	**Pwh**	**T**	**Z**	**Pg**	**ρl**	**Vcr**	**Qcr(ID)**	**Qcr (Annular)**	**Qcr (ID+Ann)**
	Psi	°F		(lbm/ft3)	(lbm/ft3)	Ft/sec	(MMscf/D)	(MMscf/D)	(MMscf/D)
2016	2,326.66	139.1453	0.814302	8.366189	45.023	3.983688	0.973041	1.681536	1.534702
2018	2,025.73	123.246	0.803619	7.582125	46.13733	4.267966	0.944778	1.63345	1.490816
2020	1,659.50	107.7375	0.804201	6.37642	47.61734	4.76504	0.887077	1.534421	1.400434
2022	1,583.09	101.7233	0.802614	6.16009	47.95701	4.876742	0.877071	1.517404	1.384903
2024	1,488.63	97.3074	0.805156	5.820004	48.36846	5.049024	0.857924	1.484491	1.354863
2026	1,192.63	93.8022	0.831882	4.541537	49.59155	5.806439	0.769894	1.332324	1.215984
2028	930.8742	91.0608	0.863182	3.433216	50.61725	6.763683	0.677957	1.173333	1.070876
2030	440.4838	88.3493	0.935877	1.505796	52.12999	10.40594	0.457473	0.791815	0.722673
2032	78.3961	86.4673	0.989857	0.254255	52.66406	25.56417	0.189767	0.328478	0.299795

Table 4.5 Coiled tube calculation

4.3.1. Case one:

Tubing size with ID=1.75 inch was selected, and the flow rate is set only from inside diameter and not from both this diameter and annulus, after applied this size in (A1 well) data, results below were obtained. Figure 4.3 show that the predicted gas flow rates of the well are still greater than the critical flow rates; because there is a decrease in effective flow area which increase gas velocity adequately to lift all liquids from the wellbore, so the liquid loading does not occur. Thus, flow from coiled tube only solve the problem finally in this project.

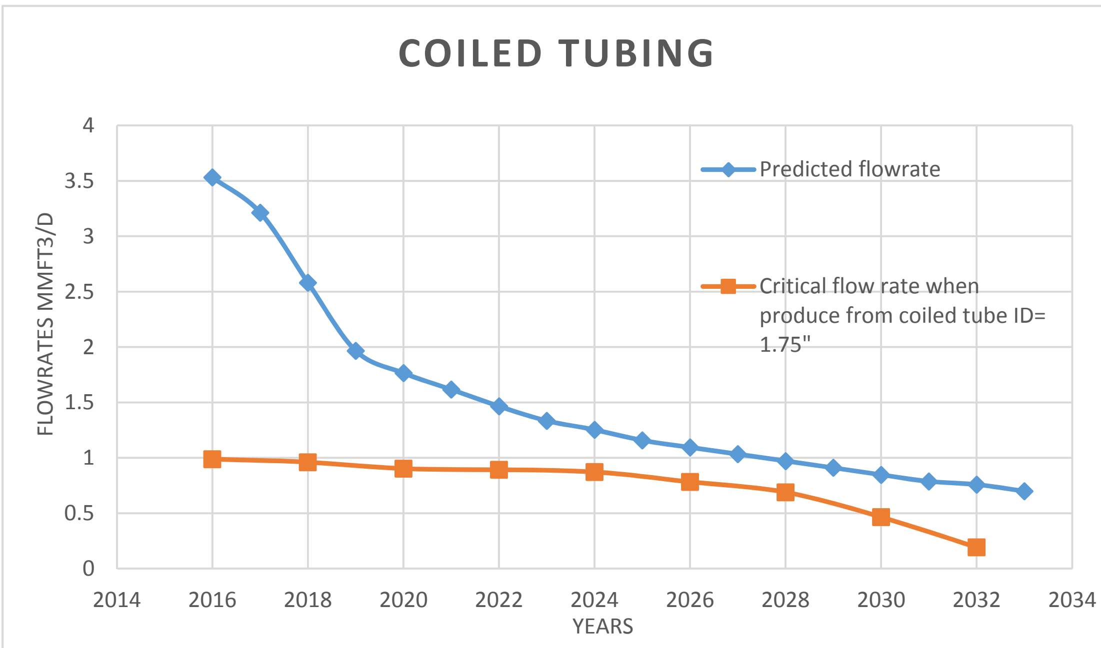

Figure 4.5 Flow rates inside Coiled Tubing

4.3.2. Case two:-

In this case the flow is from annulus only, after applied it on (A1 well) production data, we observed that liquid loading will occur in 2022; because there is a change in the effective flow area (the flow area increased) and therefore the gas velocity decreased and could not lift the liquids, so here the problem will occur late compared with the case of well without using Coiled Tubing, so we find that the gas stream flow through the annulus only delays the problem and not solve it.

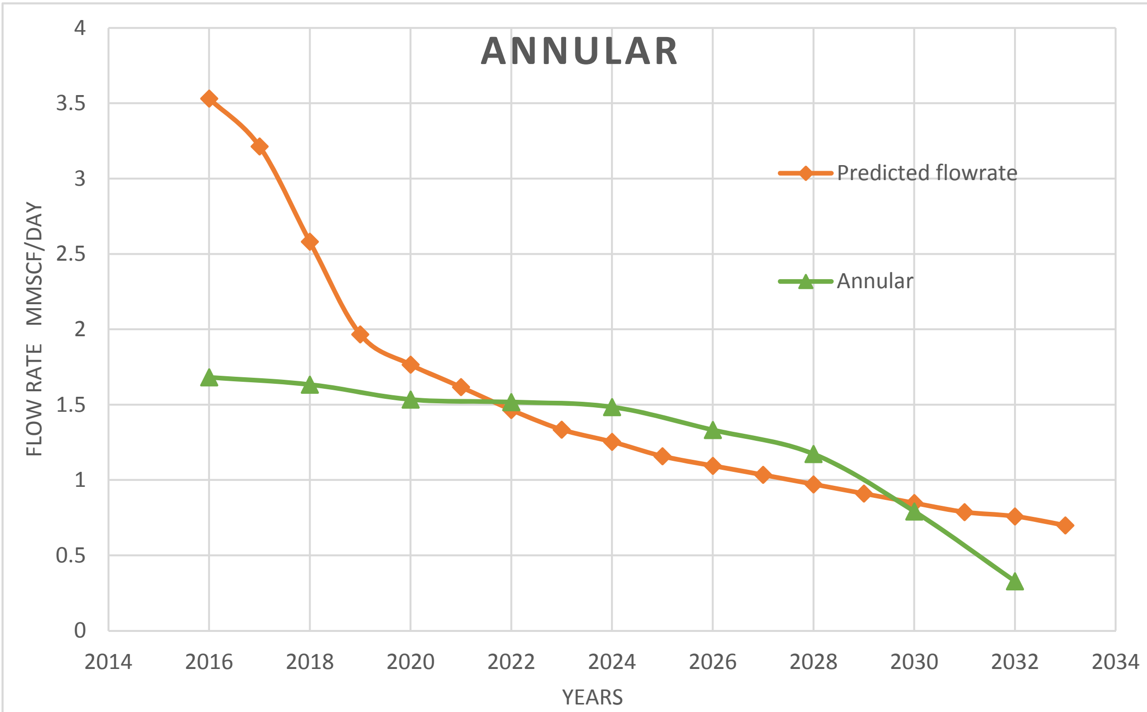

Figure 4.6 Flow rates from annular only

4.3.3. Case three:-

In this case the flow is from both: annulus and coiled tube, after applied this case on (A1 well) production data, we noted that liquid loading will occur in 2023. Thus, decreasing diameter of tubing causes increasing in gas velocity and gas flow rate, it works to delay the occurrence of the loading but does not solve it final solution.

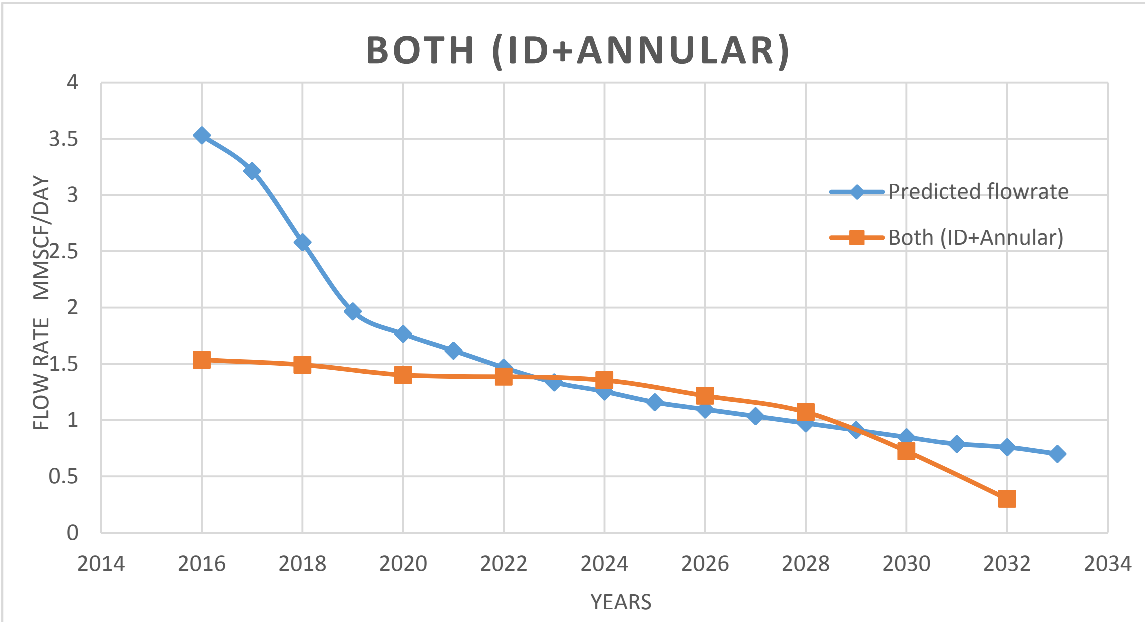

Figure 4.7 Flow rates From Both (Coiled tubing & Annular)

Figure below summarized results of all methods and make comparison between their.

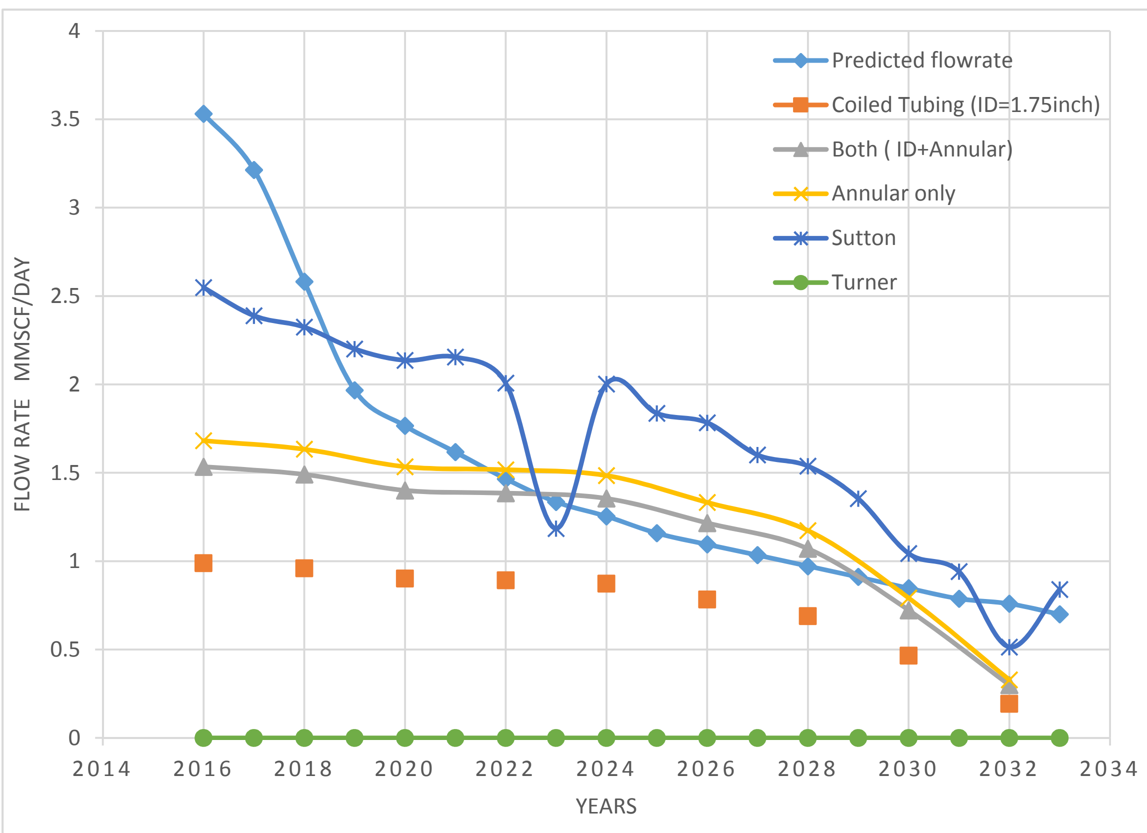

Figure 4.8 Comparison between all methods

Chapter Five

Conclusions & Recommendations

Chapter 5

Conclusions & Recommendations

The purpose of this study was to predict Liquid Loading with different methods (Turner et al. and Sutton et al), to develop a software designed by Visual Basic to predict liquid loading in gas wells by the above methods to solve this problem after predict it by selecting the optimum Coiled Tubing size.

5.1. Conclusions:-

The following conclusions were made based on the analysis of our experimental data:-

i. We used Wellhead conditions as evaluation point to calculate critical velocity and critical flow rate; because the pressures of this well are greater than (1000 psia).

ii. Turner model was applied, and predicted that the liquid loading occurred in 2018. Sutton model was applied, and predicted that the liquid loading occurred in 2019.

iii. Selected smaller diameter of Coiled Tubing (ID=1.75”) can delay the year of occurring liquid loading but does not solve it finally when the production is from both: this selected ID and annulus, and solve it finally when the gas stream is from selected ID only.

5.2. Recommendations:-

i. There are other prediction methods for liquid loading (i.e. Li, Coleman, Desheng Zhou, etc.) can be used if sufficient data for applied these methods are available.

ii. Our solving method classified as: temporary solution, and there are permanent solutions can be used, like: Plunger Lift and Gas lift methods.

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