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Revitalizing Reservoirs Nitrogen Kick-off Techniques for Reactivating Inactive Wells

V.V.Srimannarayana, Assistant Professor, Department of Petroleum Technology, Aditya University, Surampalem, India-533437

Appala Raju Gali, Student-Master of Technology, Department of Petroleum Technology, Aditya Engineering College, Surampalem, India-533437

Abstract

This study explores the use of nitrogen (N2) injection to rejuvenate inactive wells and enhance reservoir productivity. We analyze the mechanism of N2 injection and its effectiveness in stimulating production from dormant wells through case studies and field applications. Our findings highlight the cost-effectiveness and environmental benefits of N2 kickoff in extending the life of mature reservoirs and maximizing hydrocarbon recovery. By examining operational conditions such as gas injection rate and pressure, we identify optimal conditions using Wellflo® simulations. Key factors like water cut, reservoir pressure, gas oil ratio, and productivity index (J) are considered to predict production outcomes.

A new metric, the Optimum Economic Factor (OEF), assesses the efficiency of each operation based on production rate, operation length, and nitrogen usage. Our decision matrix, incorporating all examined factors, reveals trends: higher gas injection rates are needed for wells with higher water cut, lower gas oil ratio, lower productivity index, and lower reservoir pressure. We also studied the effects of wellhead pressure, well depth, and coiled tubing size, finding increased frictional pressure gradients with larger coiled tubing.

Optimizing nitrogen unloading operations can significantly reduce costs, particularly by paying for coiled tubing packages on an hourly basis instead of daily rates. Our decision matrix facilitates planning and execution, optimizing nitrogen usage and reducing manpower requirements. Overall, our study demonstrates that proper optimization can make nitrogen unloading economically viable in mature oil fields.

1. INTRODUCTION

1.1 Overview of the importance of reactivating inactive wells for maximizing hydrocarbon recovery.

An inactive well is one that hasn't produced oil or gas, injected fluids, or disposed of waste for 6 or 12 months, depending on the type of well and its potential risks to the public or environment. At the end of this period, the well is considered inactive. For more than 1 year, suspended for various reasons, this reactivation job can be defined as reactivating inactive wells. This typical reactivation is executed without doing reservoir intervention such as water shut off, reperforation, adding perforation, stimulation, fracturing, N2 Kick off etc. The scope of this reactivation includes cleaning the wellbore by the sand fill up, fish/junk, screen job, swabbing job, and a downhole pump as an artificial lift.

Many years back, the reactivation job of suspended wells has been executed for many wells. Unfortunately, the success ratio of these reactivation jobs is not promising yet, success ratio < 30%. This fact becomes our background to perform massive reactivation to achieve a higher success rate. More wells reactivated, more oil will be delivered. Looking at current condition of suspended well, the potency looks promising because of more attics wells located up dip in main closure not active (idle) has lower surrounding well with a good oil production performance

Hydrocarbon is a scarce natural resource that is currently the main source of energy in the world. Even though the oil and gas industry is more than 150 years old, there are several challenges that are still being faced in its extraction and production. One of the challenges is the problem faced as the reserves mature such as reduction in reservoir pressure, increase in water cut and water and gas coning. The practical and theoretical approach of any challenge costs time and financial resources that have to be recovered later. This poses large strain on companies to reduce their operating costs in order to maximize return of investment.

1.2 Introduction to nitrogen kick-off techniques as a method for revitalizing reservoirs.

Gaseous nitrogen has countless applications in the oil and gas industry. While established uses for nitrogen gas, such as tank and pipeline blanketing, nitrogen purging, and inserting operations continue to sustain the industry, the use of nitrogen in drilling operations to boost dwindling reservoir pressures and maintain maximum productivity has become increasingly popular. Nitrogen lifting involves the use of nitrogen gas to achieve improved pressure within oil wells with diminishing productivity. As part of enhanced oil recovery methods, gas lifting can be used to reduce hydrostatic formation pressure and boost output.

Nitrogen gas can be introduced into oil and gas reservoirs in a procedure known as nitrogen lifting. This technique can be used to restore satisfactory pressures to wellbores when natural formation pressures fall as wells age. In many cases, liquids may accumulate within an active well preventing the easy flow of formation fluids. In these instances, nitrogen gas can be pumped into the reservoirs to remove these stagnating liquids and improve flow. The nitrogen gas is channeled through coiled tubes to pump out the accumulated fluids inhibiting optimal productivity.

2. LITERATURE REVIEW

2.0 INACTIVE WELLS: CAUSES AND CHALLENGES:

Inactive wells, also known as abandoned or orphaned wells, pose several challenges and arise from various causes:

Economic Factors: Economic viability is a primary reason for well abandonment. If a well is no longer profitable to operate, maintain, or repair, operators may choose to abandon it. This can happen due to declining oil or gas reserves, changes in market prices, or high operational costs.

Regulatory Compliance: Regulatory requirements dictate proper abandonment procedures for wells that are no longer in use. Failure to comply with these regulations can result in penalties and legal liabilities for operators. Therefore, some operators may opt to abandon wells to avoid compliance costs or complications.

Technological Obsolescence: Advances in drilling and extraction technologies can render older wells obsolete. In some cases, newer technologies enable operators to access previously untapped reserves more efficiently, making older wells economically unviable in comparison.

Environmental Concerns: Wells that are no longer in use can pose environmental risks if not properly maintained or abandoned. Leaks from inactive wells can contaminate soil, groundwater, and surface water with oil, gas, or other hazardous substances, leading to environmental damage and cleanup costs.

Financial Distress: Financially troubled operators may abandon wells due to an inability to cover operating and maintenance costs. This can occur during periods of low oil and gas prices, economic downturns, or when companies face bankruptcy or insolvency.

Ownership Changes: Changes in ownership or corporate restructuring can result in wells being abandoned if new owners prioritize different assets or if they lack the resources or expertise to maintain the wells effectively.

2.1 **Challenges associated with inactive wells include:**

Environmental Risks: Inactive wells can leak pollutants into the surrounding environment, posing risks to ecosystems and public health. Identifying and remediating these risks can be costly and time-consuming.

Liability Issues: Abandoned wells can become liabilities for governments, landowners, and taxpayers if the responsible operators are unable or unwilling to cover the costs of proper abandonment and cleanup.

Regulatory Compliance: Ensuring compliance with regulations governing well abandonment and environmental protection can be challenging, particularly for regulatory agencies with limited resources and enforcement capabilities.

Financial Burden: The cost of properly abandoning and remediating inactive wells can be substantial, especially for governments or regulatory agencies tasked with addressing orphaned wells where responsible operators cannot be identified or held accountable.

Technical Complexity: Abandoning wells safely and effectively requires specialized knowledge, equipment, and techniques. Technical challenges may arise, particularly for older wells with outdated infrastructure or in remote locations with limited access to resources.

Addressing these challenges requires collaboration among government agencies, industry stakeholders, and environmental groups to develop and implement effective policies, regulations, and remediation strategies. Additionally, innovative approaches such as well plugging and reclamation programs, financial incentives, and technology development can help mitigate the impacts of inactive wells on the environment and public safety.

The phases of production can be further divided into reservoir surveillance, remedial activities and workovers (Devold 2013) . Reservoir surveillance is required to ensure the long and healthy life of a reservoir through monitoring of production and injection zones. At the same time, surveillance of secondary and tertiary recovery methods is an integral part of this phase (Satter and Thakur 1994). Remedial activities is the phase in which any intervention is conducted to restore the well to its potential capacity of production or injection. Any major problem that cannot be fixed through rigless intervention, have to be resolved using rig intervention which is called a workover (Khreibeh et al. 2018). The main disadvantages of workover are its high cost and time requirements, thus operating companies prefer to solve most of the wells' issues using rigless intervention. Issues that can be resolved using rigless intervention includes but are not limited to well testing (short and long term), fishing, tubing clearance, stimulation, logging, killing, water shut off and liquid unloading (Khurana et al. 2003).

Liquid unloading is required when a naturally flowing well dies (i.e. the reservoir pressure is insufficient to lift the fluid in the tubing to the surface). This can occur if the reservoir pressure has depleted with time, or amount of water has increased in the tubing, either due to higher water cut or gravity segregation as shown in Figure 2-1. It is also required when the well is handed over to the production team post workover operations (Salim and Li 2009).

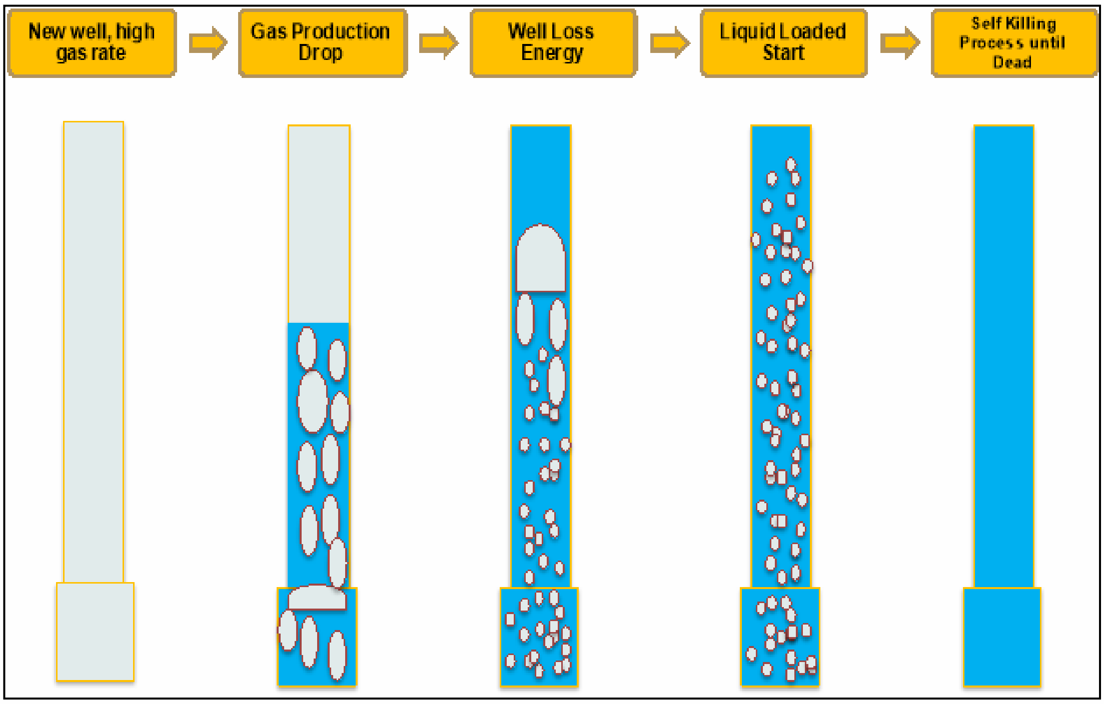

Figure 2-1: Liquid loading process in a gas well (Bell, 2018)

A permanent solution to fix such a problem is to change the well from natural lift to artificial lift by conducting a workover. However, as mentioned earlier, due to its high costs and time requirements, it is not the first step taken to tackle this problem. Instead, rigless intervention is recommended at this stage. In the olden days a method called "rock
the well" was popular in the industry. In this method, injection took place at the surface flow line, which created vacuum in front of the tubing head, forcing the tubing fluid to fill the void, which would start the well in the process.

In addition, if gas lift valves were installed during the initial completion, gas will be injected into the annulus which will force the liquid level to go down in tubing. The injected gas will also aid in reducing back pressure on well from an existing flowline.

However, nowadays it is more popular to lift the well by injecting gas into the liquid, reducing the liquid density while providing extra pressure support along with reservoir pressure to flow the well. The gas can be injected either inside the tubing by coiled tubing or in the casing if gas lift mandrels are present. In case of gas injection using coiled tubing, it can be injected inside the tubing section, before wireline entry guide, or into the open hole in special cases (Hailin et al. 2009b).

When the gas is being injected into the tubing, there is almost negligible probability to inject into the formation or damage it in any other ways. However, when the injection takes place in the open hole section of the well, several precautions need to be taken in order to avoid damaging and fracturing the formation, similar to the mechanism of operation shown in Figure 2-2.

Gas can be injected into the tubing continuously or intermittently using the gas lift mandrels (GLM) depending on requirements and reservoir conditions. On the other hand, if the reservoir conditions are not favorable then using rigless intervention such as coiled tubing will only provide a temporary solution.

When the well dies due to water segregation as a result of the producer well being shut for a period of time, then using coiled tubing gas injection to start the well is a decent option. However, when the well dies due to increase in

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water cut from reservoir or reduction in reservoir pressure, then the well requires a permanent solution that can only be provided through workover or through continuous or intermittent gas injection through gas lift mandrels, if present. The difference between the two scenarios is that in the first case, the well will be able to flow naturally after conducting the unloading operation. But in the second case, the well will cease to flow shortly after conducting unloading operation.

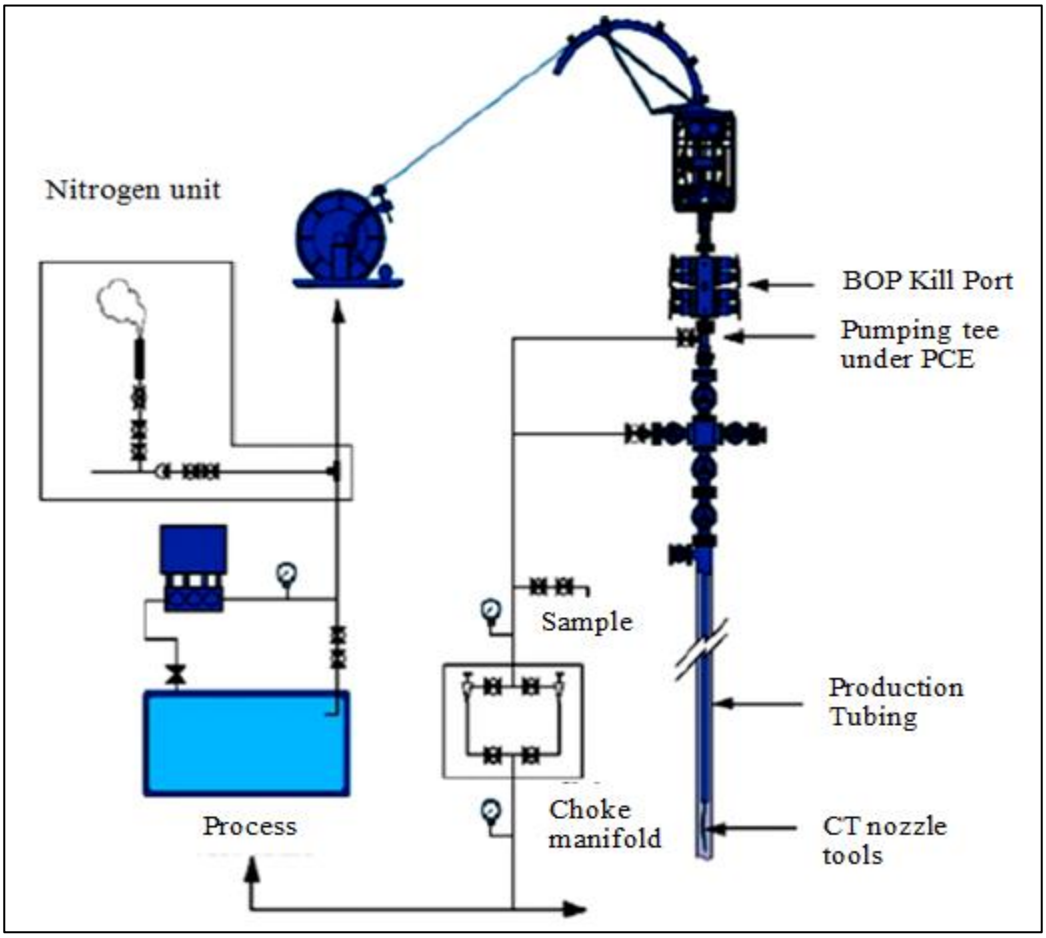


Figure 2-2: Coiled tubing gas injection in open-hole completion well

Gas injection using coiled tubing can be conducted in relatively faster manner compared to rig intervention. The whole operation, including mobilization, rig up, pressure tests, operation, rig down and demobilization, can be completed in a week's time depending on the required depth of injection and kill fluid density. The cost of rigless intervention is far less than rig intervention as well as lesser equipment and personnel are required to conduct the job. Moreover, the operation is conducted in daylight only, whereas the rig operation is 24 hours.

In addition, the job is faster because it does not require stopping and connecting joints, unlike a rig operation or workover. At the same time, constant circulation in the well bore can be maintained. Furthermore, it has the ability to perform many wireline services in highly deviated and horizontal well bores by installing an Electric Line (E-line) inside coiled tubing (Khurana et al. 2003). Therefore, due to these advantages of rigless intervention, this project will be focusing on the rigless intervention to conduct such an operation.

Injection with coiled tubing has several advantages over injection through GLVs. First, it can be rigged up to any well type without requiring any changes to surface facilities, well head or well completion unlike permanent gas lift

(GL) setup as shown in Figure 2-3. Second, it does not require prior simulations or calculations to estimate the optimum injection point and injection rate that are dependent upon reservoir conditions.

In case the reservoir conditions do not change in the expected manner, the calculations computed in order to find optimum GLV location would not be accurate. On top of that, changing the location of GLV will require further rig intervention. Another important consideration to be kept in mind is that the GLMs and GLVs are weak points in tubing completion and pose an integrity threat to the system (Molnes and Sundet 1993).

GLVs require frequent intervention using wireline or slickline to ensure they are not stuck in GLMs. Also, if one of the upper GLVs does not operate as expected, the whole operation would need to be delayed until valve is replaced, otherwise it would pose integrity risk of tubing collapse due to high injection pressure in the annulus.

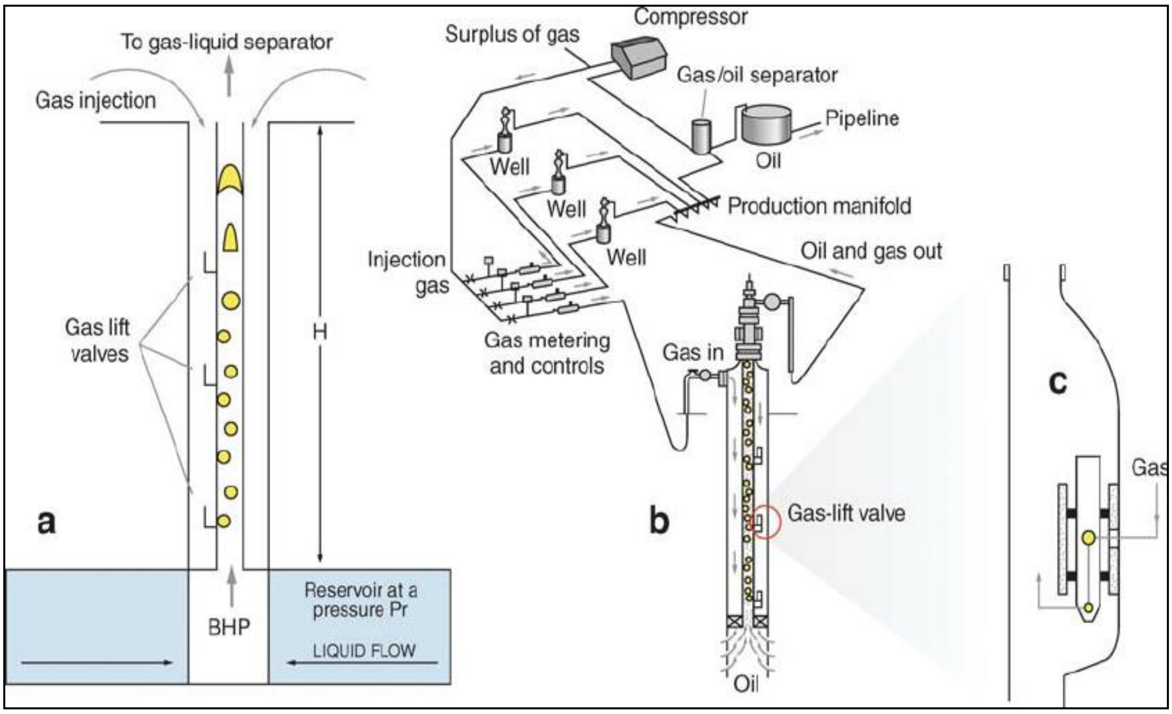


Figure 2-3: Permanent Gas Lift System Surface Facilities – a) Gas lift installation schematic b) Required Surface Facilities c) Gas lift Valve schematic (S. Guet and G. Ooms, 2006)

However, this is not the case with nitrogen injection using coiled tubing; the simulation can be conducted few days before the job, with latest reservoir conditions and optimize the operation based on the results. Moreover, the highest pressure of nitrogen is inside the coiled tubing so it does not pose immediate threat to the tubing or casing integrity. There is a rule of thumb that states injection rate should be 400 scf/(stb-1000-ft). If the well produces value lower than this, then there may be too much liquid compared to gas (Lea Jr and Rowlan 2019). It is due to these factors that injection with coiled tubing will be focused in this project.

When gas is injected with coiled tubing inside well’s tubing, the gas entering the coiled tubing annulus faces less restrictions and relatively smooth surface. That allows the injection conditions to be quite different than if the injection was into the open hole section of the well. In addition, the well head will have a relatively continuous mixture of nitrogen with hydrocarbon liquid. However, in case of injection into the open hole, gas comes to the surface in purges as the well trajectory causes gas to be stored in a higher area until enough gas is accumulated to let it flow as shown in Figure 2-4. Another important consideration is to ensure that the nitrogen pumping pressure from the surface, combined with hydrostatic head is not high enough to fracture the formation or unseat the packer.

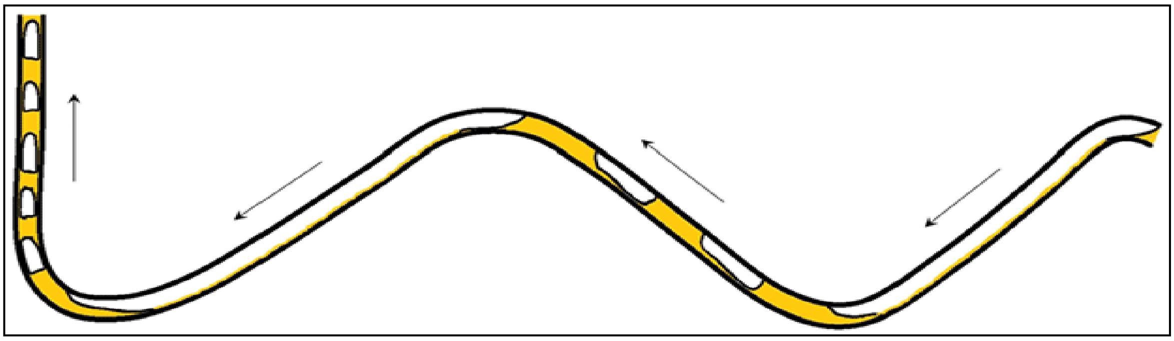


Figure 2-4: Impact of Well trajectory on artificial lift (Zhang, 2010)

The operation procedure to pump nitrogen into the tubing also differs from when the injection is into the open hole. When the coiled tubing is inside completion tubing, it is stopped every few hundred feet while pumping nitrogen to lift all the liquid above the injection point.

When the surface starts receiving only nitrogen, it means that all liquid above the injection point has already been lifted and only then the coiled tubing is moved further below by a few hundred feet to reach the new injection point. This process is continued until the final injection point is reached which is far from the wireline entry guide at the end of the tubing. However, in case of injection into the open hole, the coiled tubing cannot be stopped at an interval due to high probability of having a stuck due to hole collapse. The pump's injection pressure is higher as nitrogen is getting injected deeper and is facing more forces. This is another reason for concentrating on this topic in this project.

In order to optimize the operation of nitrogen injection using coiled tubing, all the issues faced during and after the job have to be identified. This can only be achieved once all affecting parameters, either from reservoir aspect or operation aspect, have been examined thoroughly.

Current Applications: Nitrogen is an inert gas that does not pose any serious threat to the well completion or any other infrastructure at the site. It is also not a pollutant to the environment as it makes 78% of our atmosphere. Moreover, the cost of liquid nitrogen can be flexible depending on the type of extraction process. Hence, it is not surprising that it is used in several well operations for different reasons.

Fiazudeen (2012) explored and proved via simulation that there is an increase of 23% in the maximum achievable MD reached by a coiled tubing in a horizontal well with the aid of nitrogen gas. Fiazudeen took advantage of the low density of nitrogen gas to reduce the weight of coiled tubing. This led to buoyancy effect acting from the higher density annular fluid, reducing drag force on the coiled tubing. Also, the lower weight of coiled tubing caused a traverse wave motion which helps the coil to worm through the open hole.

(Howell, et.al., 1988) discussed the advantages of using coiled tubing for logging a horizontal well. A coiled tubing can be easily converted to carry logging tools along with having real time data with the addition of an optic cable within. The use of such a coiled tubing for logging operation provides constant velocity and circulation and aids in lubrication of tools. This leads to better stability of open hole while allowing access to horizontal section of wells. (John, et.al., 2017) used a liquid jet compressor (LJC) along with nitrogen lift to conduct logging in a low pressure well in an offshore field. The liquid jet compressor reduced the requirement of nitrogen by 60% which is important in the case of offshore operation where limited space is provided for operations. The LJC was placed in the flowline to reduce the backpressure on the well.

Hall and Decker (1995) discussed the design procedure of gas lift valves (GLVs) in wells complete with GLMs. The design should not be dependent upon experience or industry practice alone rather must involve simulation. Hence, they simulated the optimum design procedure of GLVs in a well. Proper placement of GLVs in a well eliminates excessive gas injection, multi-point injection, unstable gas injection rate, etc.

(Zhou, et.al., 2015) greatly summarized the pros and cons of performing nitrogen lifting using coiled tubing in a horizontal well. One of the main pros is the ability to change the location of the gas injection when coiled tubing is utilized. However, the optimum gas injection rate and pressure as well as coiled tubing run-in-hole (RIH) speed has been a mystery. In this paper, (Zhou, et.al., 2015) studies some crucial factors affecting the operation. The findings of the simulation are that as the injection rate of N_2 increases, it reduces the P_{wf} and annulus hydrostatic pressure. However, after a certain threshold limit, any increase in N_2 would cause higher frictional loss in the annulus and increase P_{wf}. Other finding is that as gas injection depth increases, the minimum attainable P_{wf} is decreased. Also, smaller sized coiled tubing is preferred in small wellbores to reduce unwanted frictional loss.

The physics behind the different phases of an unloading operation is key to optimizing the activity itself. (Han, et.al.,2018) divided the process into three stages, liquid rising in tubing, liquid slug production, and liquid production by entrainment. In each stage, coiled tubing, coiled tubing-tubing annulus, thin liquid film, slug and bubble are the prime components. Simulation is used to show the process of unloading. At the same time, one of the major operational challenges is to know the critical gas unloading velocity, which is the minimum velocity of gas to unload the well. (Li, et.al., 2014) summarize the work on the subject and discuss the gaps in them.

(Fuladgar, et.al., 2014) studied the effect of coiled tubing size and flowline on the operation. The production of operation increases with larger coiled tubing until a threshold limit is reached. After the limit is approached, well's production decreases due to increased frictional losses in the coiled tubing-tubing annulus. On the other hand, any decrease in back pressure, the production rate increases greatly.

Although there are several studies already done on the subject, there are plenty of factors that still need to be addressed. This study will focus on analyzing previous operations to history match well models with real time well data to simulate the wells using Wellflo® (Weatherford, 2011). A sensitivity analysis will be conducted on all the contributing parameters to have a complete understanding of the phenomenon. It will also allow us to state significance of each parameter based on their impact on the operation. Lastly, this will further suggest on how to improve the entire operation's plan and activity to increase efficiency and decrease the required time and cost.

3. Fundamentals of nitrogen gas lifting

The nitrogen gas lifting operation is conducted to reinstate flow of a dead or killed well. The well can be killed by drilling/completion operations, or to secure the well due to integrity requirements. The well is considered dead when the reservoir pressure is not enough to overcome the hydrostatic head pressure in the completion tubing. When the reservoir pressure depletes to the point where the well will not produce by natural energy, some method of artificial lift must be used. The three main methods of artificial lift are: 1) gas lift, 2) plunger lift, and 3) pumping. All artificial lift methods increase flow rate in flowing wells. The mechanism of any gas lifting is to reduce flowing pressure losses to aid the well flow. The factors that affect the choice of artificial lift method fall under five headings: well geometry, reservoir conditions, well fluid factors, environmental concerns, and economics.

The well geometry factors are depth, hole deviation and casing diameter. The reservoir factors are current and future IPR, sand production, average reservoir pressure, rate of pressure decline and future recovery plans (secondary and tertiary). The fluid factors are water cut, GOR, wax problems, fluid viscosity and availability of high-pressure gas. The environmental factors are well location (urban or rural) and offshore wells. The economic factor is the profitability criteria based on company policy (Osisanya, S., 2019). Nitrogen gas lifting method has been selected as the artificial lifting method in our research. The process of choosing optimum nitrogen gas lifting operational parameters is very important to the success of the operation. The basics and operational aspects of the project are briefly described in the following sections.

3.1 Gas lifting theory

In a conventional gas lifting operation, high pressure gas is injected down the casing annulus into the tubing string. The light fluid column exerts less hydrostatic head pressure on the bottomhole. Thus, reservoir pressure becomes sufficient to lift the reservoir fluid to the surface. The gas lifting system requires a supply of lift gas (usually natural gas) as well as a compressor on the surface to inject the gas into the well.

When the gas is injected at the casing head, the unloading valves open, unload the well and close. During production, the operating valve open and increase gas content in the tubing. This reduces the flowing fluid's mixture density and hydrostatic pressure on the bottomhole which makes the reservoir pressure sufficient to lift the fluid to the surface. Some of the key advantages of gas lift system are as follows:

1) Can handle large liquid volumes in high J wells
2) Can handle large volumes of solids with minor problems
3) Applicable in offshore, but challenging
4) The utilized gas is recyclable

Gas lifting can be conducted by continuous gas injection or intermittent gas injection. The main features of both injection types are presented in Table 3-1.

Table 3-1: Features of continuous and intermittent gas flow

Condition	Continuous Flow	Intermittent Flow
Production Rate (bbl/day)	100 – 75000	Up to 500
Static BHP (psi)	More than 0.3 psi/ft	Less than 0.3 psi/ft
Flowing BHP (psi)	More than 0.08 psi/ft	Greater than 150 psi
Injection gas (scf/bbl)	50 – 250 per 1000ft of lift	250 – 500 per 1000ft of lift
Injection pressure (psi)	More than 100 psi per 1000-ft of lift	Less than 100 psi per 1000-ft of lift
Gas injection rate	Large volumes	Smaller volumes

3.2 Reasons for using coiled tubing

The idea behind starting a dead well using gas lifting is fairly straightforward but the success of operation is crucially dependent upon the location of injection point. When gas lift valves from well completion are being used to inject gas, the well's fluid have large area to flow through inside the tubing. The presence of any flow restriction in the completion tubing causes unnecessary pressure drop which reduces the efficiency of a gas lifting operation. In addition, sometimes the main objective of the operation is not only to start the well but also test it using downhole sensors and logging tools. The addition of such sensors and tools in the downhole are considered to be flow restrictions that impact flow negatively and adds burden to continue the fluid movement. In such cases, gas injection through gas lift valves may not be a viable option especially if tubing collapse pressure, casing burst pressure, packer unsetting pressure or gas lift valves limitations are reached (Christie et al. 2015).

The wells included in the study are all horizontal or highly deviated wells which cannot be accessed completely using slickline or wireline alone. At the same time, use of tractors was not a feasible option because of past history of such conveyance methods. The open hole is not of regular shape because it is carbonate reservoir that limits the traction of E-Line (Electric Line) tractors in the downhole. Once the tractors are loaded with several sensors and logging tools, the additional pulling weight stresses the tractors further and overburdens it. However, in case of coiled tubing, it can be pushed through areas of reasonably uneven borehole (Al-Ebrahim et al. 2016).

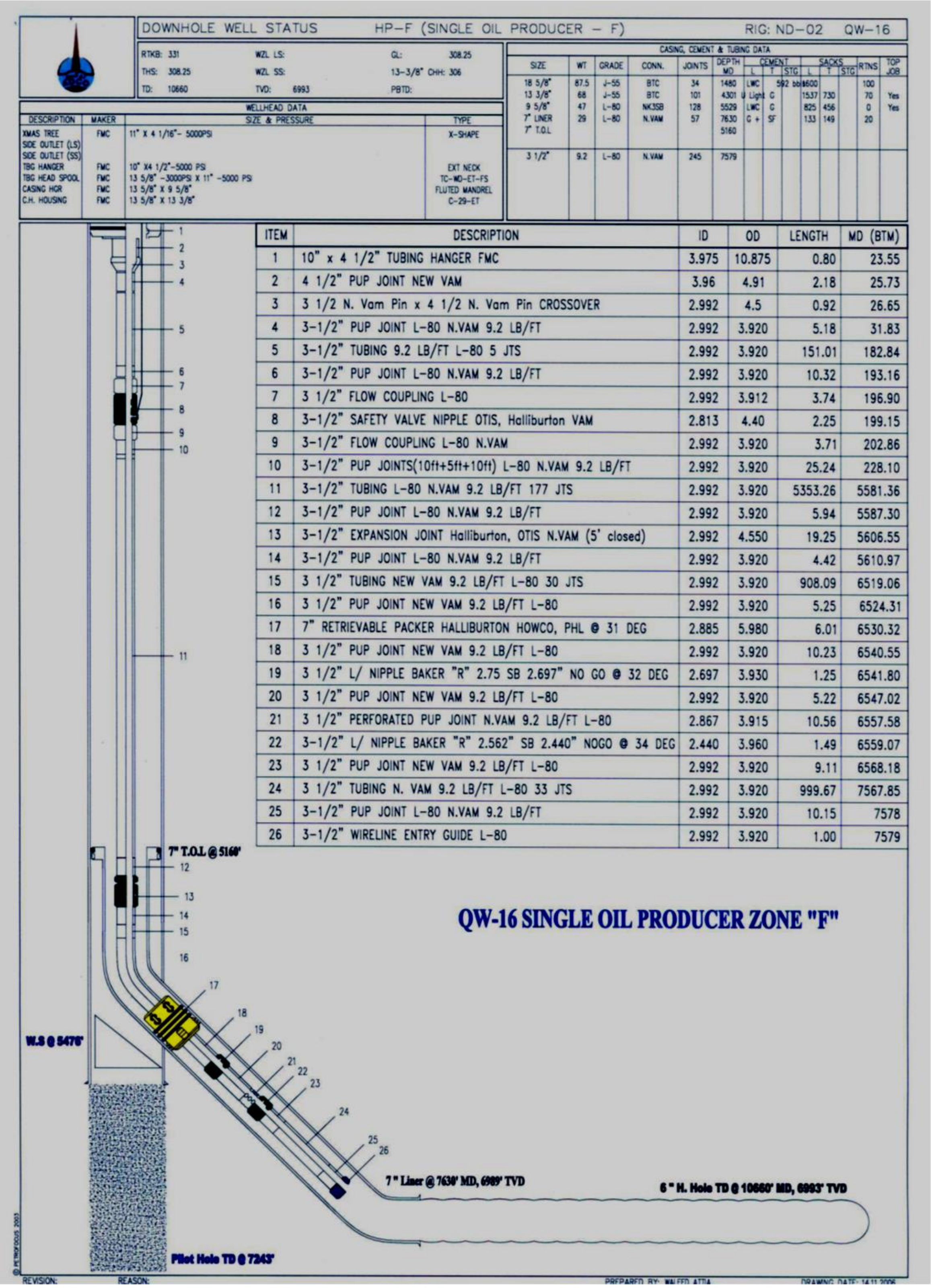
When it comes to conducting a complex job, such as production logging of a dead well, which has high water cut and/or low reservoir pressure, continuous gas lifting is required while logging. However, when coiled tubing is inside the completion tubing, the annulus between them is quite small to efficiently use the gas lift valves. Thus, the coiled tubing is used to simultaneously inject nitrogen as well as convey logging tools inside the well (Al-Ebrahim et al. 2016).

3.3 Reasons for using nitrogen gas

Gas injection helps to flow the higher density liquid by reducing its density and providing an extra boost along with reservoir pressure. The injected gas can be a lean gas or any inert gas. Lean gas is mostly taken from the gas produced in the field, but is dependent on whether the surface facilities had already been designed for it. Nitrogen is an excellent inert gas because it is readily available and can be carried in gas tanks to remote locations. Being an inert gas, it does not react with hydrocarbon or other components in the crude oil. In addition, it is not very miscible with hydrocarbon and that makes it even more suitable for the job (Shouldice 1964).

3.4 Types of completions

Traditionally, completion types referred to the tubing running in the vertical and low deviated section of the wells. These types of completion include single tubing, dual string, concentric tubing and artificial lift. However, during the course of this project, we will be looking at the completions ran in horizontal or highly deviated sections of the well. These types of completion include liner, slotted liner, sand control screen, etc. They are also run with inflow control devices (ICDs) and inflow control valves (ICVs) which control flows in different sections of the hole. A typical downhole well status is shown in Figure 3-2



ITEM	DESCRIPTION	ID	OD	LENGTH	MD (BTM)
1	10" x 4 1/2" TUBING HANGER FMC	3.975	10.875	0.80	23.55
2	4 1/2" PUP JOINT NEW VAM	3.96	4.91	2.18	25.73
3	3 1/2 N. Vam Pin x 4 1/2 N. Vam Pin CROSSOVER	2.992	4.5	0.92	26.65
4	3-1/2" PUP JOINT L-80 N.VAM 9.2 LB/FT	2.992	3.920	5.18	31.83
5	3-1/2" TUBING 9.2 LB/FT L-80 5 JTS	2.992	3.920	151.01	182.84
6	3-1/2" PUP JOINT L-80 N.VAM 9.2 LB/FT	2.992	3.920	10.32	193.16
7	3 1/2" FLOW COUPLING L-80	2.992	3.912	3.74	196.90
8	3-1/2" SAFETY VALVE NIPPLE OTIS, Halliburton VAM	2.813	4.40	2.25	199.15
9	3-1/2" FLOW COUPLING L-80 N.VAM	2.992	3.920	3.71	202.86
10	3-1/2" PUP JOINTS(10ft+5ft+10ft) L-80 N.VAM 9.2 LB/FT	2.992	3.920	25.24	228.10
11	3-1/2" TUBING L-80 N.VAM 9.2 LB/FT 177 JTS	2.992	3.920	5353.26	5581.36
12	3-1/2" PUP JOINT L-80 N.VAM 9.2 LB/FT	2.992	3.920	5.94	5587.30
13	3-1/2" EXPANSION JOINT Halliburton, OTIS N.VAM (5' closed)	2.992	4.550	19.25	5606.55
14	3-1/2" PUP JOINT L-80 N.VAM 9.2 LB/FT	2.992	3.920	4.42	5610.97
15	3 1/2" TUBING NEW VAM 9.2 LB/FT L-80 30 JTS	2.992	3.920	908.09	6519.06
16	3 1/2" PUP JOINT NEW VAM 9.2 LB/FT L-80	2.992	3.920	5.25	6524.31
17	7" RETRIEVABLE PACKER HALLIBURTON HOWCO, PHL @ 31 DEG	2.885	5.980	6.01	6530.32
18	3 1/2" PUP JOINT NEW VAM 9.2 LB/FT L-80	2.992	3.920	10.23	6540.55
19	3 1/2" L/ NIPPLE BAKER "R" 2.75 SB 2.697" NO GO @ 32 DEG	2.697	3.930	1.25	6541.80
20	3 1/2" PUP JOINT NEW VAM 9.2 LB/FT L-80	2.992	3.920	5.22	6547.02
21	3 1/2" PERFORATED PUP JOINT N.VAM 9.2 LB/FT L-80	2.867	3.915	10.56	6557.58
22	3-1/2" L/ NIPPLE BAKER "R" 2.562" SB 2.440" NOGO @ 34 DEG	2.440	3.960	1.49	6559.07
23	3 1/2" PUP JOINT NEW VAM 9.2 LB/FT L-80	2.992	3.920	9.11	6568.18
24	3 1/2" TUBING N. VAM 9.2 LB/FT L-80 33 JTS	2.992	3.920	999.67	7567.85
25	3-1/2" PUP JOINT L-80 N.VAM 9.2 LB/FT	2.992	3.920	10.15	7578
26	3-1/2" WIRELINE ENTRY GUIDE L-80	2.992	3.920	1.00	7579

Figure 3-2: Typical Horizontal Well Completion

4. DESIGN AND PLANNING

Factors influencing the design and planning of nitrogen kick-off operations.

4.1 Operation controlling parameters

The success of a complex operation such as nitrogen lifting using coiled tubing in highly deviated or horizontal well depends on several factors. The factors involved can be divided into three categories namely; (1) reservoir characteristics, (2) well type and (3) operation constraints. The categories are explained in detail below.

4.2 Reservoir characteristics

These are the natural characteristics of the reservoir that cannot be changed through intervention. There are several characteristics that are specific to the reservoir itself, but only a few of them will be studied during the course of this study. The effects of these characteristics on the operation are discussed as follows:

4.3 Hydrocarbon oAPI Gravity

Hydrocarbon °API gravity is an indirect measure of density of hydrocarbon compared to water. It compares the heaviness or lightness of hydrocarbon liquid with water. °API gravity is defined as follows:

$$\text{API gravity} = \frac{141.5}{SG} - 131.5 \quad \text{.................................} \quad (4\text{-}1)$$

Where S.G: Specific gravity of that liquid

Gas is released from well fluid due to reduced pressure. The release of gas reduces the mobility of the hydrocarbon as well as makes it heavier. Such effects would lead to reduction in success rate of nitrogen lifting job.

4.4 Average reservoir pressure

Average reservoir pressure represents the amount of driving force available to deliver the reservoir fluid out of reservoir during production. It reduces with time due to production of hydrocarbon. The reduction can be sudden if weak or no pressure support system is in place. In case if a strong pressure support system is available, the reservoir pressure will deplete very gradually. An example of a natural pressure drive system is an aquifer connected to the reservoir.

The reservoir pressure also dictates the state in which hydrocarbon is present in the reservoir. If the reservoir pressure is higher than bubble point pressure of the hydrocarbon, then the gas and liquid stay mixed as a single fluid. But, if the reservoir pressure is lower than bubble point pressure of the hydrocarbon, gas is released from liquid hydrocarbon. This increases the density and reduces the viscosity of the liquid, making it harder to flow. The different types of reservoirs are black oils, volatile oil, condensate, wet gas and dry gas reservoirs. They have been explained in depth in Appendix A.

4.5 Fracture pressure

Fracture pressure is the pressure level, above which the injection fluid are capable of inducing rock formation fractures hydraulically. The fracture pressure does not only deform the rock formation, but also creates fissures that are highly permeable and allow easier fluid flow. Fractures can aid in hydrocarbon production, especially in unconventional reservoirs. However, incorrect and unwanted fractures can cause harm to the production. For example, they can leave large amount of hydrocarbon back in reservoir due to lower sweep efficiency of injection water/gas and cause early water/gas breakthrough into the well. Fracture pressure of the formation can be derived from the fracture gradient of the formation. It can be variable throughout a heterogeneous field but it can still be considered to be an average value. During the complex operation of nitrogen injection in to open hole section of a highly deviated or horizontal well, the injection pressure should not exceed the fracture pressure of the formation because fracturing is not an objective of the operation and to prevent any permanent damage to the reservoir. Fracture gradient can be determined in the following methods

Hubbert and Willis:

$$F_{min} = \frac{1}{3}\left(1 + \frac{2P}{D}\right) \ldots\ldots\ldots\ldots \text{(4-2)}$$

$$F_{max} = \frac{1}{2}\left(1 + \frac{P}{D}\right) \ldots\ldots\ldots\ldots \text{(4-3)}$$

Mathews and Kelly:

$$F = \frac{K_i\sigma}{D} + \frac{P}{D} \ldots\ldots\ldots\ldots \text{(4-4)}$$

Ben Eaton

$$F = \left(\frac{S-P}{D}\right) * \left(\frac{\gamma}{1-\gamma}\right) + \frac{P}{D} \ldots\ldots\ldots\ldots \text{(4-5)}$$

F: fracture gradient, psi/ft

P/D: pore pressure gradient, psi/ft

K_i: Matrix stress coefficient

σ: vertical matrix stress, psi

S: overburden stress, psi

γ: Poisson's ratio

4.6 Water Cut

Water is denser than hydrocarbon which leads it to sink in a mixture of hydrocarbon and water. In a highly deviated or horizontal zone, gravity segregation causes separation of the three fluid types. This increases the difficulty of nitrogen lifting process which needs to be solved using more advanced equipment and tools. The availability of higher quantity of water is one of the prime reasons of well's inability to flow naturally which makes it of key importance in the selection of tools, equipment and operation designing of such a complex job.

4.7 Well Types

A horizontal well can be equipped with different well completion configurations. The completion type in the lower section of a horizontal well is dependent upon the consolidation, competence, permeability and heterogeneity of the formation. Figure 4- shows an open hole completion of a horizontal well. It is used in consolidated and competent formation with medium to high permeability.

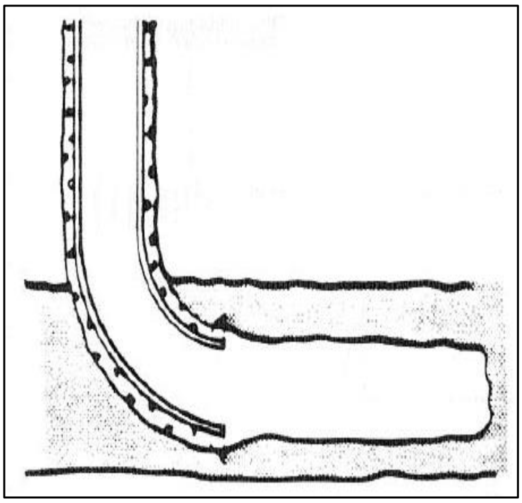


Figure 4-3: Open hole completion (Osisanya, S., 2019)

Figure 4-5 shows a pseudo-open-hole completion of a horizontal well, equipped with slotted liner. This is the most common form of open hole completion in the world. It prevents hole collapse and allows easy re-entry. However, it should not be used where stimulation is required or water breakthrough is anticipated.

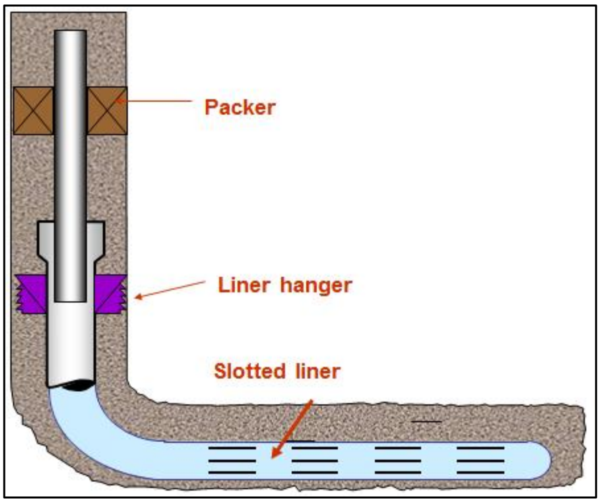


Figure 4-5: Pseudo Open hole completion - Slotted Liner (Osisanya, S., 2019)

Figure 4-6 shows a typical cased hole completion. It is used when a conventional well is turned horizontal. It provides full zonal isolation and flow control options. However, it is an expensive type of completion and can reduce productivity due to formation damage from cement and perforation.

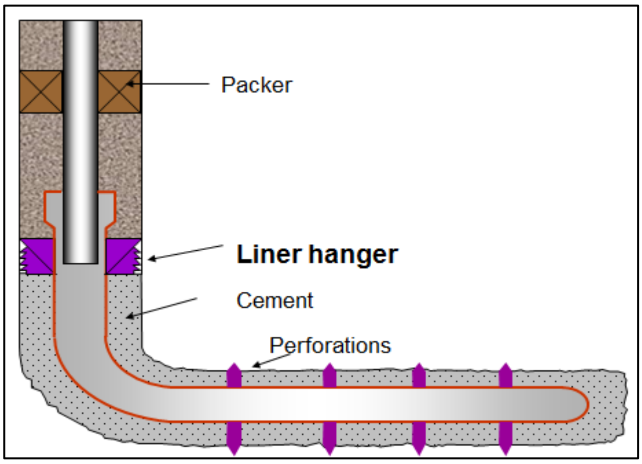


Figure 4-6: Cased hole completion (Osisanya, S., 2019)

4.8 Completion Types

Other horizontal or highly deviated section completions like Inflow control devices (ICDs) and Inflow control valves (ICVs) can be opened and closed based on logging data to prevent unwanted fluid flow (water or gas). However, if nitrogen lifting is required from an open hole equipped with ICV or ICD, then it depends on the water cut from each of its section. In sections with high water cut, more amount of gas or higher pressure would be required to lift off the well and vice versa.

4.9 Open hole length

When the vertical section of well is required to be gas lifted, the coiled tubing or gas lift valves are operated sequentially from top to bottom. First the top section of liquid is lifted, followed by the next ones until the deepest injection point is reached. When this procedure is followed properly, liquid is unloaded in sections and the gas is not strained by extreme pressures. However, if the gas is directly injected at the lower section, the gas will be unable to lift the liquid and bypass it. A similar scenario occurs in the open hole, however it is not possible to inject gas sequentially in the open hole. The coiled tubing needs to be moved continuously to avoid mechanical or differential stuck.

The total length of the tapered coiled tubing reel is more than 13000-ft through which nitrogen passes to enter the well. Once nitrogen gas enters the well, it encounters the open hole, liner and annulus between coiled tubing and completion tubing until it reaches the surface. The injected nitrogen gas is subjected to pressure losses at every encounter. Therefore, surface gas injection pressure should be greater than all the combined pressure losses. At the same time the gas injection pressure should be able to assist liquid flow.

In addition, this total pressure should not exceed the fracture pressure of the reservoir rock itself. Coiled tubing length and annulus length and area is uniform and does not change throughout the operation. However, length of open hole changes depending on the position of coiled tubing. If the coiled tubing is deep inside the open hole, greater surface pressure would be required to initiate liquid lifting from that section due to greater amount of liquid to be lifted (Zhou, et.al., 2011). It is here that pump's capacity, formation fracture pressure, coiled tubing and surface facilities ratings constraint the operation. Therefore, for every operation there is a cut off well length after which lifting cannot be conducted in the open hole without damaging reservoir or the tools that are being used in operation. It is due to these reasons that the well length is added in the list of important parameters for such kind of operation.

4.10 Operation constraints

Once the job requirements have been identified based on reservoir and well constraints, then the operation requirements are determined. This includes the equipment and tools being used in the operation to successfully complete the job with high level of certainty. The equipment to be used will be coiled tubing, injection pump, batch mixer, BOP, stripper, nitrogen gas tank and crane. The tools to be used in the operation will be downhole assembly of coiled tubing, downhole sensors, etc. All of these tools and equipment have specific ratings that would be based on previously mentioned constraints. The following sections discuss the data that needs to be collected to ensure operation success.

4.11 Pump injection pressure

The injection pump is chosen based upon the operation's need. A safety margin has to be added in the operation's pumping requirement prior to choosing the optimum pump. Special request can also be a part of operation's need which specifies a certain type of pump operating method. Operating method refers to simplex, duplex and triplex pumps. Pumping capacity refers to the injection pressure and rate that can be provided by the pump to the system. As mentioned earlier, this pressure is dependent upon the fracture pressure of the reservoir rock and pressure ratings of the tools and equipment involved in the process. An example of this can be that if the fracture pressure of the reservoir is 1000 psi, and the expected pressure loss in the system from pump to open hole is 200 psi, then the maximum pressure that should be applied from pump is 1200 psi. However, if the pump lines and other equipment are not pressure tested or rated to that certain pressure, then operation will be forced to stay within the lowest pressure rating in the system to avoid any complication.

4.12 Coiled tubing size

Choosing the right size of coiled tubing is an integral part of ensuring a successful operation. Some of its constraints include minimum restriction size in well's completion, the annulus size between coiled tubing and well's tubing, required flow rate, required pressure rating, burst and collapse rating, availability of appropriate surface facilities, such as truck, crane or injector, etc. Once all of these constraints are met, then coiled tubing can be selected. After the operation is completed, the difference between surface injection pressure and downhole pressure sensors tells us the pressure drop inside the coiled tubing. This pressure drop varies with coiled tubing size and injection pressure. In addition, it also needs to be compared to the simulation that is run before the operation to estimate the error in it, if any – This is job evaluation.

4.13 well head data

The well head and Christmas tree are rated to have a maximum working pressure. Therefore, it is another constraint to be met during the job planning phase. If the produced fluid is connected to the station through flowlines, then there is a backpressure on the flowline itself. The pressure of fluid returning from the well needs to be at least equal to the flowline's backpressure to flow the well. During a N_2 gas lifting operation the following parameters are measured continuously: gas injection pressure (P_{gi}), gas injection rate (Q_{gi}) and well head pressure (WHP).

4.14 Data acquisition

From the time of exploration of a field, data is gathered and stored in different software and database for use at a later date. There is absolutely no data that can be rendered useless. There are two main reasons of collecting data: (1) to update well/field simulation model and (2) to identify and resolve existing problems.

4.15 well test

Well testing is a planned process of acquiring production/injection data of a well. The data is analysed to better understand the hydrocarbon properties and reservoir characteristics. Figure 4-7 shows the bottomhole pressure of a producer and injector well when the well is shut. The bottomhole pressure of a producer well increases when the well is shut, while the bottomhole pressure of an injector well decreases when the well is shut.

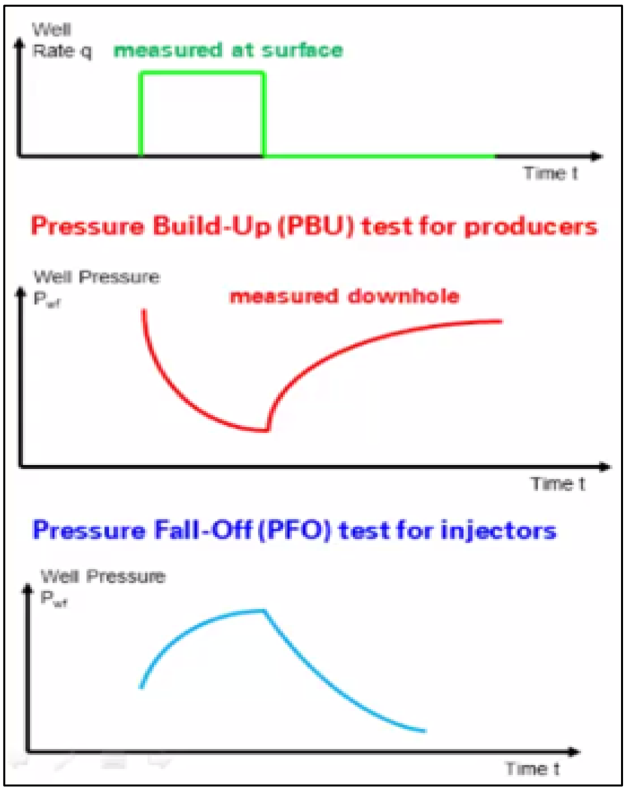


Figure 4-7: Typical Pressure Build-up (PBU) or Pressure Fall-off (PFO) well test (Osisanya, S., 2019)

4.16 Real time data

Although well testing is conducted on a monthly basis, it is only for acquiring the production data of the well. The data from well testing can be misinterpret leading to unrelated remedial actions. Therefore, it is important to conduct other tests on a periodic basis that helps to monitor the reservoir on a well-to-well basis. This gives indications of well's physical condition as well. For example, if there is any scale deposit or sand entering in the system. Most of these tests are conducted using slickline which makes the tool not to enter or pass through the highly deviated or horizontal section of the well. In order to reach such sections, coiled tubing or e-line tractor can be used. When tools are run in these sections, casing collar locator and gamma ray sensors are ran along with them. These tools give the exact depth or the location of coiled tubing or tractor. Therefore, any problem identified in the downhole can be assigned to the exact location. This greatly enhances the chances of a successful intervention operation. Other real time data acquired includes the pump injection pressure, point of injection, surface injection rate, etc. There are sensors equipped at the well head, Christmas tree and flowline permanently as well. These senses tubing head pressure, injection pressure, annulus pressures, backpressure from flowline to wing valve, etc. All the data is gathered in a database and is used to aid in fine tuning well and field models.

4.17 Multiphase flow

The reservoir is at a higher temperature and pressure than the surface facilities. At reservoir conditions, large amount of gas is dissolved in the hydrocarbon liquid. As the fluid travels up the tubing, gas is evolved out of the liquid. The density difference between the gas and liquid causes the gas to move upwards faster than liquid. As the direction of flow is against gravity, the heavier fluid, (liquid), is forced downwards causing holdup. This causes the well to die.

The main forces acting on reservoir fluid are buoyancy forces, gravity, hydrostatic head and friction. Buoyancy forces are caused by expansion of reservoir fluid which aids in hydrocarbon flow. Gravity, hydrostatic head and frictional forces act against the flow and oppose hydrocarbon flow. There are several methods that calculate the pressure gradient of these hydrocarbon fluids that allow measuring the pressure drop over any interval of the well. However, as the fluid changes its composition due to liberated gas, flow regimes change as well, which does not necessarily change the forces acting upon the hydrocarbon fluid.

4.18 Simulation modeling

A computerized simulation of any well engineered equipment plays an integral part during its design phase. Powerful simulation software is able to predict any possible flaws that can be encountered by the equipment in reality. Simulation can be run even before the equipment is physically made. This reduces the number of prototypes required before finalizing a design. In oil and gas industry, the timeline of witnessing a problem physically in reality can take a few months to years. At the same time, several problems can cause irreversible damage to the reservoir. In addition, modeling is conducted frequently, if not continuously, to improve current procedures and predict future requirements throughout the lifecycle of the reservoir.

4.19 Modeling types

The oil and gas industry relies on two main types of simulation namely; static and dynamic modeling. Static modeling is mainly run for parameters that do not change with time greatly. These include geological properties and features. It can also be conducted on other parameters that do change with time such as reservoir properties. However, in that case all the data has to be collected at a specific time only. Thus, comparison can be made between data comprising of similar parameters but collected at different times. Dynamic modeling is conducted to see how specific parameters are going to change with time when other parameters change or stay constant.

An important requirement for a reasonable and accurate simulation is to have a well-built reservoir model. This is only made possible by creating initial reservoir model during the time of exploration and then updating it with time as wild cats and other well data are available. Geological data are used to create contour maps, identify formation tops, detect faults and fractures, locate different geologic layers and structures, etc. A well model is created based on other parameters such as the total length, trajectory, hole size, completion type, average permeability, average porosity, water cut, saturations, etc. When a model is created, its authenticity is verified by history matching with past production and injection data. The reservoir and well models are fine-tuned several times until the historical data matches the simulation results. It is only then that the simulation of future scenarios can be considered to be credible. During the course of this project, simulating mobile coiled tubing will require dynamic simulation. However, due to the inaccessibility to such software, static simulation at different depths will be conducted instead.

4.20 PVTflex®

Prior to well model construction, all the PVT properties of reservoir fluid need to be simulated and stored into a file that is readable by the simulation software. PVTFlex® is used to simulate the PVT properties of the reservoir fluid. It is a PVT simulation tool that uses industry-standard theory and robust algorithms to predict fluid properties. It is based on correlations and Equations of State (EOS) that are devised by experimental data. It supports both Black Oil and Compositional fluid models. The PVT data, obtained from compositional analyses of bottom hole sample, is added in PVTFlex® software in the section shown in Figure 4-8. Appendix A show more details about the software.

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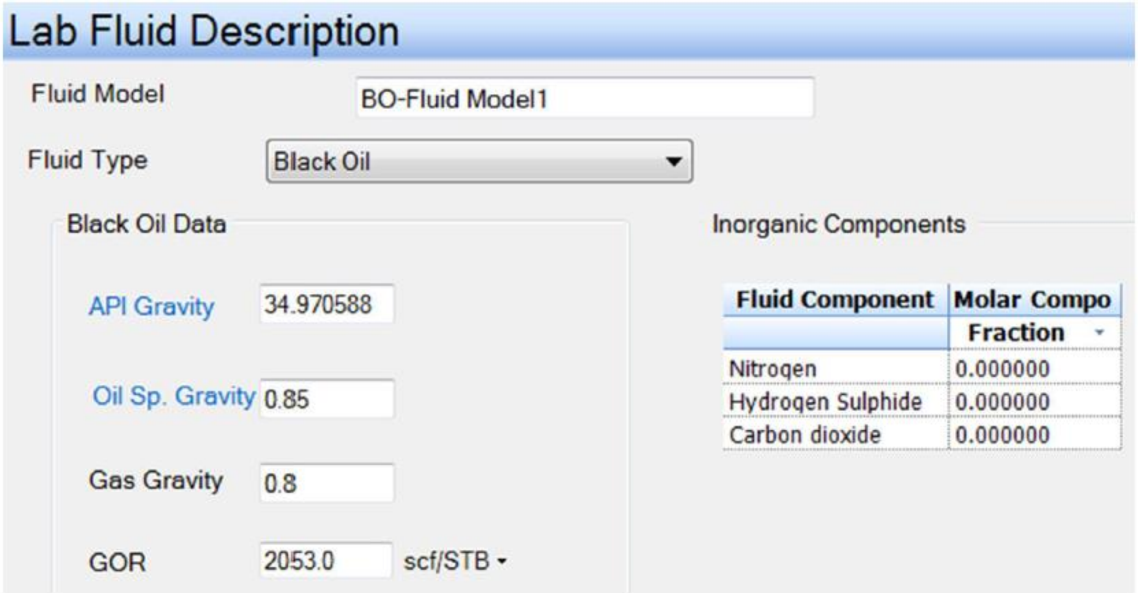


Figure 4-8: Fluid description for PVTFlex® (Weatherford, 2011)

5. Field applications and case studies

Firstly, nitrogen lifting operation data will be collected for several wells. Data shall be taken from three fields' horizontal wells to give better representative results. The results will consist of operational data, well type and reservoir parameters. Well models will then be created in Wellflo® software using the well type and reservoir parameters. Nitrogen lifting operation will be simulated in the software on these well models and sensitivity analysis will be conducted using variation of different parameters. An optimization of nitrogen lifting operation for specific well conditions will then be concluded in to a decision matrix. The real operation data will then be compared to the decision matrix. The verification of decision matrix will be established based on the similarity of operational data with the decision matrix.

Procedure:

1. Data Acquisition
2. Collect well data from 50 wells in a field (Field X)
3. Refine the data to establish a representative overall/general data for the field
4. Create a well model using the refined representative well data
5. Use the well model to simulate nitrogen lifting operation using coiled tubing
6. The values in the created data were varied to simulate different operating conditions
7. Select optimum parameters for different operating conditions from each simulation based on Optimum Economic Factor (OEF)
8. Develop Decision Matrix based on the optimum parameters for different operating conditions

5.1 Data acquisition

This section describes the procedure of acquiring the data required to initiate the study including well data, reservoir type and parameters. Initially, previously conducted operational data was to be taken and analyzed to identify the faults present in the operation. However, different fields and contractors' method of data representation did not match well enough to determine errors in the job procedure and execution. Thereafter, an approach to simulate the operation and match with operational data was devised. But the vast differences between different fields and reservoir layers, along with various well completion types posed a severe challenge of finding trends in extremely heterogeneous operational data. Thus, a final approach was chosen and it is explained in the following sections.

5.2 Field selection

Initially it was established that well parameters will be studied from 5 different onshore fields. However, even the same reservoir layers in different fields have drastic variation in their parameters. Therefore, it was decided to narrow down the reservoir data collection to be from a single onshore field. In addition, each field in question has several reservoir layers and every producer well is mostly producing only from one of these layers. Therefore, the choice of layers and well was critical to maintain credibility of the research. Three reservoir layers were chosen from a single field due to the intensive amount of available data of the required parameters. They will be referred to as Layer A, Layer B and Layer C throughout the project for confidentiality reasons.

5.3 Reservoir parameters

A large amount of well data was collected in order to find the most representative well and reservoir parameters for each specific reservoir layer. However, it was more feasible to fine-tune a well's properties instead of searching for a representative well for the whole field. Therefore, all the collected well data was organized and tabulated and a field scale average of each zone's parameters was deduced. These averages were used to create the representative well of a specific reservoir layer in the subject field. Table 5-2 shows the values of different parameters for several wells which were modified to achieve a representative well. These parameters consist of well number, well's depth, reservoir layer, wellhead pressure, liquid production rate, oil production rate, water cut, gas oil ratio (GOR), bottom-hole flowing pressure, productivity index and reservoir pressure.

#	Depth (ft)	Layer	P_{wh} (psi)	Liquid Rate (stb/d)	Oil Rate (stb/d)	BS&W (%)	GOR (scf/stb)	P_{wf} (psi)	J (stb/d/psi)	P_{Res} (psia)
1	9500	B	465	2,679	182	93	3,924	3,654	6.62	4,078
2	10230	A	1,115	531	521	2	1,544	2,431	1.45	2,822
3	11138	A	385	1,716	714	58	1,479	2,237	1.73	3,361
4	8245	B	415	2,611	958	63	1,440	2,580	6.64	3,000
5	9720	C	395	2,684	617	77	1,426	2,858	5.57	3,375
6	10203	A	415	2,747	1,206	56	1,350	2,879	2.29	4,078
7	11242	C	665	865	812	6	1,279	2,777	3.21	3,047
8	8700	A	385	2,664	890	66	1,276	2,777	5.91	3,260
9	9700	A	435	2,018	1,270	37	1,258	2,031	1.39	3,543
10	10200	A	415	2,865	652	77	1,257	3,024	6.77	3,472

Table 5-2: Field well properties

The well numbers are changed due to confidentiality reasons. The depth of well is the measured depth which is the deepest point of well. The reservoir layers have been renamed to A, B and C. Wellhead sensors were used to record flowing well head pressure. Well testing using MPFM was used to measure liquid rate, oil rate, gas oil ratio (GOR). Downhole sensors were utilized to measure bottomhole flowing pressure and reservoir pressure.

5.4 PVT Properties

The PVT properties integrated in the study are for a specific reservoir layer in the same field. The PVT properties include bubble point pressure, solution gas oil ratio, formation volume factor, viscosity, interfacial tension, density, etc. The data was acquired from previously conducted PVT studies on bottomhole hydrocarbon samples.

5.5 Well completion selection

It is established that the representative well needs to replicate the most common well within that reservoir layer of the specific field. The true vertical depth (TVD) of a certain reservoir layer is almost constant within the field. The representative well had to be a horizontal well with approximately 4000-ft of open hole as per the average open-hole length of all wells in the field. The deviation angle of well trajectory can vary but should be approximately 2-4^o/100-ft. The well has to be a single oil producer, without any artificial lift. In addition, the well could not be equipped with any kind of lower completion such as Inflow control devices (ICDs) or Inflow Control Valves (ICVs). Lastly, the most common production tubing in the field was 3.5'' and that had to be reflected in the representative well.

5.6 Data refining

The acquired data was scrutinized to identify anomalies and omit such data sets. The main irregularities were observed in reservoir parameters data. For example, a large change in P_{Res} or GOR was identified between the last two consecutive well tests. It was deduced that the data was inconsistent due to invalid data reporting. The refining of data helped in making the research more credible.

5.7 Well model formation

A well model was created in simulation software, WellFlo®, using the refined data of the representative well. An average of the refined data was taken to be incorporated in the representative well. Appendix E shows the step-by-step method of creating the representative well in the software. Figure 5-9 is the final look of the representative well in the WellFlo® software which shows its reservoir and well properties.

The lower right section of Figure 5-9 displays the reservoir properties, which are added in the layer data and fluid properties tab. These properties include productivity index, absolute open flow, bottom completion (if any), layer temperature and pressure and IPR curve model. The middle of Figure 5-9 shows wellbore characteristics namely; well type, flow type, lift method, temperature model, gas in annulus, well trajectory and well and riser flow correlation.

The separator on top right side of Figure 5-9 represents fluid properties of reservoir such as oil API gravity, gas gravity, water gravity, PVT method, gas oil ratio and water cut. Finally, a flow line connected to wellhead represents the return line from the well, indicating the back pressure on the well.

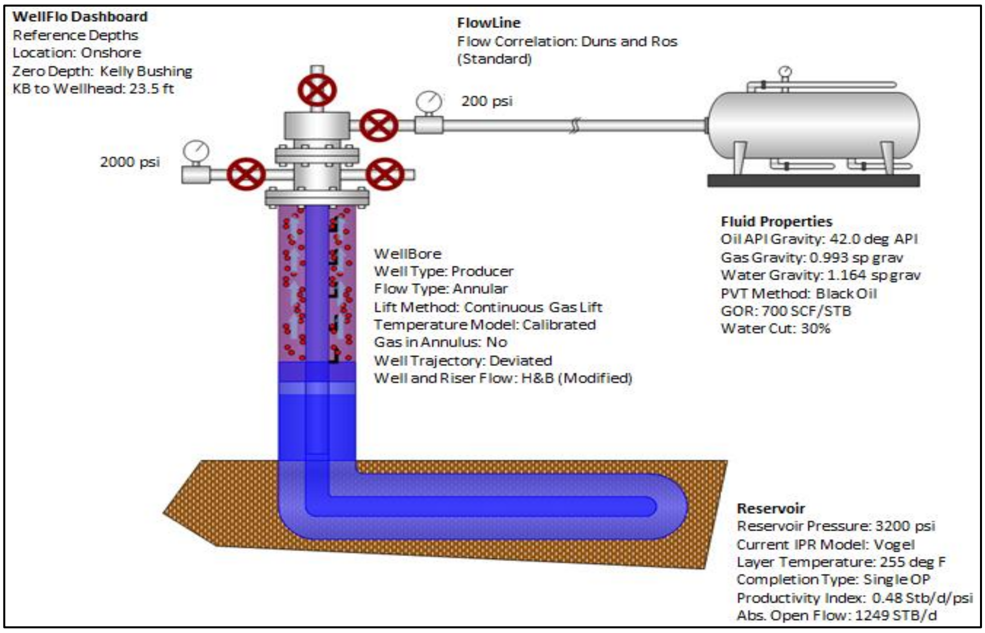
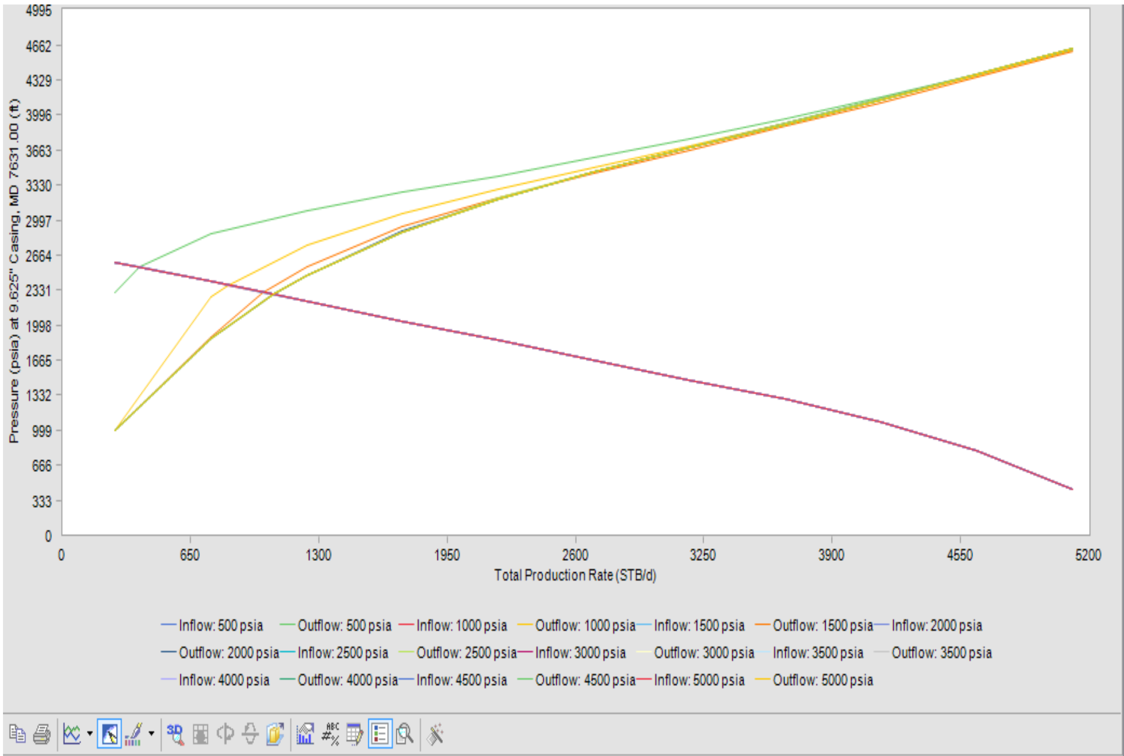


Figure 5-9: Reservoir Properties and well parameters used in simulation (Weatherford, 2011)

5.8 Simulation of nitrogen lifting operation on representative well model

First, the representative well model was history matched. Then the nitrogen lifting operation was simulated on it. The main factors used to simulate the different operating conditions are the gas injection rate and gas injection pressure. The range used for gas injection rate is from 0.1 MMscf/d to 0.7 MMScf/d, with increments of 0.1 MMscf/d. The range used for gas injection pressure is from 500 psi to 3000 psi, with increments of 500 psi. These ranges were chosen based on actual available equipment's limitation. Thus, the results of simulation showed forty-two results for each operation based on the different gas injection rates and pressure. Figure 5-10 shows the results for a simulation of operation at different gas injection pressures at 0.1 MMscf/d gas injection rate.



Operating Pressure	Liquid Rate	Oil Rate	Water Rate	Formation Gas Rate	Injection Gas Rate	Water Cut	Produced GOR	Injection MD	Status	Sens 1:Casing head pressure
(psia)	(STB/d)	(STB/d)	(STB/d)	(MMSCF/d)	(MMSCF/d)	(Fraction)	(SCF/STB)	(ft)		(psia)
2551.49	396.3	103	293.3	0.04	0.3	0.74	3342.74	2282.15	Stable	500
2380.74	840.3	218.5	621.8	0.09	0.3	0.74	1804.44	4414.45	Stable	1000
2312.82	1016.9	264.4	752.5	0.11	0.3	0.74	1565.98	6303.12	Stable	1500
2291.07	1073.4	279.1	794.3	0.12	0.3	0.74	1506.19	7630.01	Stable	2000
2291.07	1073.4	279.1	794.3	0.12	0.3	0.74	1506.19	7630.01	Stable	2500
2291.07	1073.4	279.1	794.3	0.12	0.3	0.74	1506.19	7630.01	Stable	3000
2291.07	1073.4	279.1	794.3	0.12	0.3	0.74	1506.19	7630.01	Stable	3500
2291.07	1073.4	279.1	794.3	0.12	0.3	0.74	1506.19	7630.01	Stable	4000
2291.07	1073.4	279.1	794.3	0.12	0.3	0.74	1506.19	7630.01	Stable	4500
2291.07	1073.4	279.1	794.3	0.12	0.3	0.74	1506.19	7630.01	Stable	5000

Figure 5-10: Simulation of Nitrogen Lifting Operation on Representative Well Model

5.9 Simulation of different reservoir and operating conditions on representative well model

First, the reservoir and operation parameters range were carefully decided based on range of refined data and actual available equipment's limitation. Then, the values in the created data were varied to simulate different operating conditions. These steps are described in details in the following sections.

5.10 Parameter range selection

A maximum and minimum of each reservoir and operation parameter was taken from the refined acquired data to decide the range of a specific parameter. These ranges were used in simulation as the boundaries of different parameters.

Table 5-**3** shows the ranges used in the simulation model for the different parameters namely; water cut, gas oil ratio, productivity index and reservoir pressure.

Three values of each parameter are stated for each layer, as well as for the average for all layers. It can be seen from the table that WC varies from 0% to 93%, GOR varies from 300 to 2670 scf/stb, J varies from 0.45 to 17.5 stb/d/psi, while P_{Res} varies from 2618 to 4516 psi in different layers. This range is dependent upon the variation of real well data gathered in Table 5-2. The range of water cut is 0, 30, 60 and 90. This range has been chosen as per the variation in the three reservoir layers. It is important to understand that even if the well is actually having low water cut, it can require severe nitrogen lifting post drilling or workover operation, especially if there are large amounts of losses during rig operation.

Table 5-3: Parameters average and simulation ranges

Parameter	Value Type	All	Layer A	Layer B	Layer C	Study Range
Water Cut (%)	Average	45	51	60	25	0 30 60 90
	Minimum	0	0	0	0	
	Maximum	78	62	93	46	
Gas Oil Ratio (scf/stb)	Average	786	750	815	703	700 1200 1700 2200
	Minimum	300	300	450	516	
	Maximum	2050	1326	2670	1050	
Productivity Index (stb/d/psi)	Average	4.7	4.8	4.7	4.6	0.4 4.8 17
	Minimum	0.4	0.5	0.5	0.4	
	Maximum	17.5	16.5	15.7	17.5	
Reservoir Pressure (psi)	Average	3300	3158	3309	3550	2500 3200 3900 4600
	Minimum	2618	2760	2618	3318	
	Maximum	4516	3778	4516	3796	

The reservoir pressure of a specific layer is almost constant throughout the field, unless there is a major change in the geological deposition of rocks, or presence of any structural faults, or presence of external pressure support. However, as the data was collected from three different reservoir layers, the reservoir pressure varies between 2500 to 4500 psi. Therefore, the selected values of reservoir pressures were 2500, 3200, 3900 and 4600 psi.

The coiled tubing sizes chosen for simulation were 1.25'', 1.5'', 1.75'' and 2'' based on actual available equipment limitation. The flow line pressures were varied from atmospheric pressure (15 psi) to 500 psi to reenact actual operating conditions.

5.11 Varying reservoir and operating conditions

Some reservoir properties (WC, P_{Res}, GOR and J) or equipment (CT size, flow line pressure) were changed prior to running each simulation. It is important to understand that only one parameter was changed in each simulation, while all other parameters were kept constant. This enabled us to clearly identify any change in the operation due to a certain parameter. At the same time, the key varying operating factor were gas injection rate and gas injection pressure which resulted in achieving forty-two results for each operating condition. **Error! Reference source not found.** shows the different parameters chosen for a sample set of wells to conduct the simulation.

Case number	Reservoir Pressure (psi)	Gas Oil Ratio (scf/stb)	Water Cut (%)	Productivity Index (stb/d/psi)
10	3900	500	0	0.48
11	3900	1000	0	0.48
12	3900	1500	0	0.48
13	3900	2000	0	0.48

Table 5-4: Parameter set for different well simulations

Operating Pressure (psi)	Liquid Rate (stb/d)	Oil Rate (stb/d)	Water Rate (stb/d)	Gas Rate (MM scf/d)	Produced GOR (scf/stb)	Injection MD (ft)	Payback Ratio (stb/d/MMscf/d)	Lift gas injection rate (MM scf/d)	Top/start node pressure (psi)	Injection Pressure (psi)	Gas Oil Ratio (scf/stb)
2477	569	569	0	0.28	675	12571	5690	0.1	500		
2282	646	646	0	0.32	809	12571	779	0.2	500		
2042	743	743	0	0.37	903	12571	962	0.3	500		
1938	784	784	0	0.39	1009	12571	417	0.4	500		
1872	811	811	0	0.41	1116	12571	263	0.5	500	**500**	
1823	830	830	0	0.42	1222	12571	193	0.6	500		
1787	845	845	0	0.42	1328	12571	146	0.7	500		
3169	292	292	0	0.15	842	12571	2920	0.1	1000		
2987	365	365	0	0.18	1047	12571	730	0.2	1000		
2862	414	414	0	0.21	1223	12571	499	0.3	1000		
2756	457	457	0	0.23	1374	12571	425	0.4	1000		**700**
2572	530	530	0	0.27	1441	12571	735	0.5	1000		
2493	562	562	0	0.28	1566	12571	319	0.6	1000	**1000**	
2437	585	585	0	0.29	1696	12571	223	0.7	1000		
3560	135	135	0	0.07	1235	12571	1359	0.1	1500		
3448	180	180	0	0.09	1606	12571	449	0.2	1500		
3374	210	210	0	0.11	1927	12571	294	0.3	1500		
3289	244	244	0	0.12	2138	12571	339	0.4	1500	**1500**	
3211	275	275	0	0.14	2314	12571	314	0.5	1500		
3085	326	326	0	0.16	2340	12571	505	0.6	1500		

2992	363	363	0	0.18	2427	12571	371	0.7	1500		
3785	45	45	0	0.02	2682	12571	458	0.1	2000	**2000**	
3816	33	33	0	0.02	6467	12571	-123	0.2	2000		
3748	60	60	0	0.03	5438	12571	272	0.3	2000		
3692	83	83	0	0.04	5310	12571	224	0.4	2000		
3644	102	102	0	0.05	5398	12571	190	0.5	2000		
3593	122	122	0	0.06	5396	12571	204	0.6	2000		
3495	161	161	0	0.08	4825	12571	393	0.7	2000		

Table 5-5: Simulation Result - Tabular Form

6. PERFORMANCE EVALUATION

6.1 Results gathering

The data gathering process includes compiling several different types of data and sorting it out to remove any unreasonable results. It is imperative to know that only a few of the most representative results will be gathered here, while the rest will be available in appendix section.

The decision matrices above in Table 6-6 and Table 6-7 show 192 results each. There were 7 iterations for each of these results. The gas injection rate with the highest Optimum Economic Factor (OEF) is chosen in each result. This enabled us to identify any trends within the different simulations. The different trends and other observations of decision matrix are discussed in the following sections.

				Productivity index - 0.5 stb/d/psi					**Productivity index -5 stb/d/psi**					**Productivity index - 17 stb/d/psi**			
		GOR (scf/stb)		**Injection rates with pressures (MMscf/d)**													
				1	**5**	**9**	**13**		**17**	**21**	**25**	**29**		**33**	**37**	**41**	**45**
Reservoir Pressure (psi)	**2500**	A	**700**	0.6	0.7	0.7	0.7	Q	0.5	0.7	0.7	0.5	GG	0.2	0.6	0.7	0.6
		B	**1200**	0.4	0.4	0.7	0.1	R	0.2	0.5	0.7	0.7	HH	0.1	0.1	0.6	0.5
		C	**1700**	0.1	0.2	0.7	0.1	S	0.1	0.1	0.1	0.7	II	0.1	0.1	0.7	0.4
		D	**2200**	0.1	0.2	0.7	0.1	T	0.1	0.1	0.1	0.6	JJ	0.1	0.1	0.3	0.4
				2	**6**	**10**	**14**		**18**	**22**	**26**	**30**		**34**	**38**	**42**	**46**
	3200	E	**700**	0.5	0.7	0.7	0.6	U	0.5	0.7	0.6	0.5	KK	0.1	0.2	0.4	0.5
		F	**1200**	0.2	0.7	0.7	0.5	V	0.2	0.5	0.3	0.4	LL	0.2	0.2	0.1	0.4
		G	**1700**	0.1	0.2	0.7	0.4	W	0.1	0.1	0.1	0.4	MM	0.1	0.1	0.1	0.4
		H	**2200**	0.1	0.1	0.7	0.1	X	0.3	0.1	0.1	0.4	NN	0.1	0.1	0.1	0.3
				3	**7**	**11**	**15**		**19**	**23**	**27**	**31**		**35**	**39**	**43**	**47**
	3900	I	**700**	0.5	0.7	0.7	0.7	Y	0.1	0.7	0.7	0.7	OO	0.1	0.1	0.1	0.4
		J	**1200**	0.2	0.7	0.7	0.7	Z	0.2	0.2	0.3	0.7	PP	0.2	0.1	0.2	0.1
		K	**1700**	0.1	0.4	0.7	0.4	AA	0.1	0.1	0.1	0.3	QQ	0.1	0.1	0.1	0.1

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		L	2200	0.1	0.1	0.7	0.4	BB	0.1	0.1	0.1	0.2	RR	0.1	0.1	0.1	0.1
				4	**8**	**12**	**16**		**20**	**24**	**28**	**32**		**36**	**40**	**44**	**48**
	4600	M	**700**	0.7	0.7	0.7	0.7	CC	0.1	0.1	0.5	0.7	SS	0.1	0.1	0.1	0.1
		N	**1200**	0.6	0.5	0.7	0.7	DD	0.2	0.1	0.2	0.7	TT	0.1	0.1	0.1	0.1
		O	**1700**	0.1	0.1	0.7	0.5	EE	0.1	0.1	0.1	0.7	UU	0.1	0.1	0.1	0.1
		P	**2200**	0.1	0.1	0.6	0.5	FF	0.1	0.1	0.1	0.7	VV	0.1	0.1	0.1	0.1
	Water Cut (%)			**0**	**30**	**60**	**90**		**0**	**30**	**60**	**90**		**0**	**30**	**60**	**90**

Table 6-6: Decision Matrix for Gas Injection Rates with Pressures using OEF

		uctivity index - 0.5 stb/d/psi					**Productivity index - 5(stb/d/psi)**				**Productivity index– 17(stb/d/psi)**			
		GOR (scf/stb)	**Percentage Cost Optimization (%)**											
			1	**5**	**9**	**13**	**17**	**21**	**25**	**29**	**33**	**37**	**41**	**45**
Reservoir Pressure – (psi)	**2500**	**700**	49	66	82	40	13	37	33	31	4	-2	1	4	**Leg-end**
		1200	44	67	82	53	15	35	36	86	14	38	1	7	0
		1700	47	69	80	53	14	37	11	86	12	17	53	9	25
		2200	100	100	80	100	100	100	100	100	100	100	42	9	50
			2	**6**	**10**	**14**	**18**	**22**	**26**	**30**	**34**	**38**	**42**	**46**	75
	3200	**700**	56	68	87	51	16	46	9	9	7	8	-1	0	100
		1200	52	68	87	52	17	39	12	37	3	6	12	19	-1
		1700	47	70	86	53	15	40	12	36	12	7	10	9	
		2200	100	100	86	100	9	100	100	35	100	100	100	11	
			3	**7**	**11**	**15**	**19**	**23**	**27**	**31**	**35**	**39**	**43**	**47**	
	3900	**700**	52	67	87	58	23	39	8	30	7	4	7	-2	
		1200	52	66	86	58	17	41	13	12	3	8	3	10	
		1700	52	68	86	60	15	38	13	18	11	6	11	9	
		2200	100	100	85	60	100	100	100	100	100	100	100	100	
			4	**8**	**12**	**16**	**20**	**24**	**28**	**32**	**36**	**40**	**44**	**48**	
	4600	**700**	80	60	80	59	20	12	10	31	6	4	3	5	
		1200	79	61	80	59	14	37	14	30	12	7	5	5	
		1700	80	64	80	60	12	24	13	29	9	5	4	10	
		2200	100	100	100	100	100	100	100	28	100	100	100	100	
Water cut (%)			**0**	**30**	**60**	**90**	**0**	**30**	**60**	**90**	**0**	**30**	**60**	**90**	

Table 6-7: Decision Matrix for Percentage of Cost Optimization

Scenarios	Reservoir Pressure (psi)	Gas oil ratio (scf/stb)	Water Cut (%)	Productivity index (stb/d/psi)
1	2500	700 - 2200	0	0.5
2	3200	700 - 2200	0	
3	3900	700 - 2200	0	
4	4500	700 - 2200	0	
5	2500	700 - 2200	30	
6	3200	700 - 2200	30	
7	3900	700 - 2200	30	
8	4500	700 - 2200	30	
9	2500	700 - 2200	60	
10	3200	700 - 2200	60	
11	3900	700 - 2200	60	
12	4500	700 - 2200	60	
13	2500	700 - 2200	90	
14	3200	700 - 2200	90	
15	3900	700 - 2200	90	
16	4500	700 - 2200	90	
17	2500	700 - 2200	0	5
18	3200	700 - 2200	0	
19	3900	700 - 2200	0	
20	4500	700 - 2200	0	
21	2500	700 - 2200	30	
22	3200	700 - 2200	30	
23	3900	700 - 2200	30	
24	4500	700 - 2200	30	
25	2500	700 - 2200	60	
26	3200	700 - 2200	60	
27	3900	700 - 2200	60	
28	4500	700 - 2200	60	
29	2500	700 - 2200	90	
30	3200	700 - 2200	90	
31	3900	700 - 2200	90	
32	4500	700 - 2200	90	
33	2500	700 - 2200	0	17
34	3200	700 - 2200	0	
35	3900	700 - 2200	0	
36	4500	700 - 2200	0	
37	2500	700 - 2200	30	
38	3200	700 - 2200	30	
39	3900	700 - 2200	30	
40	4500	700 - 2200	30	
41	2500	700 - 2200	60	

42	3200	700 - 2200	60	
43	3900	700 - 2200	60	
44	4500	700 - 2200	60	
45	2500	700 - 2200	90	
46	3200	700 - 2200	90	
47	3900	700 - 2200	90	
48	4500	700 - 2200	90	

Table 6-8: Variable Gas Oil Ratio Decision Matrix Scenarios

6.2 Effect of GOR

The effect of Gas Oil Ratio (GOR) can be observed clearly from the decision matrix in Table 6-6 above. In order to focus only on the effect of GOR over the operation, it is imperative to keep all the other parameters constant. This is achieved by choosing a specific vertical series where all parameters stay unchanged, except GOR. Table 6-8 consists of such scenarios. Therefore, any series from 1 to 48 depicts the effect of GOR on optimum gas injection rate.

Firstly, as we go down along the Table 6-6, in a specific productivity index (J) value, it is observed that the gas injection rate required to have the highest OEF is lowered. In the first set of values on top left corner of Table 6-6, denoted by scenario 5, where reservoir pressure (P_{res}) is 2500 psi, J is 0.5 stb/d/psi, and the water cut (WC) is 30%, it can be seen that as GOR increases from 700 to 1200 to 1700 to 2200 scf/stb, the optimum gas injection rate behaves in a decreasing factor with 0.7, 0.4, 0.2, 0.2 MMscf/d, respectively.

Figure 6-11 exhibits the decreasing trend in graphical representation. Although the decreasing trend is clearly visible with the initial increase in GOR, i.e. from 700 to 1700, but as GOR increases further, i.e. from 1700 to 2200, the OEF gas injection rate remains same i.e. 0.2 MMscf/d. This shows that there is a limit to this inverse trend. It can also be termed as a threshold limit.

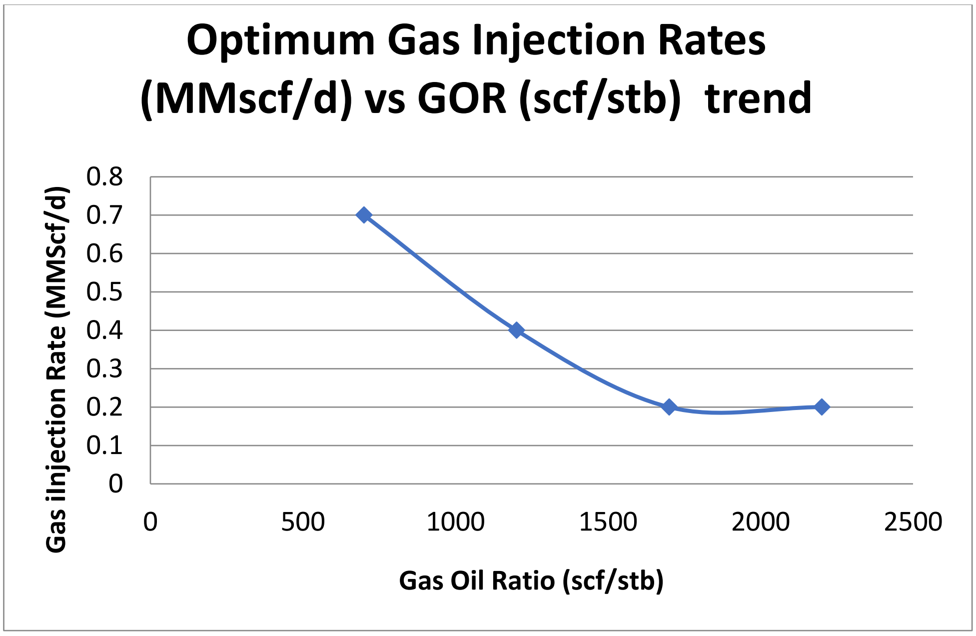

Figure 6-11: Optimum Gas Injection Rates (MMscf/d) vs GOR (scf/stb) trend

A similar graphical representation was used to depict the effect of GOR on gas injection rates in several other cases, where other parameters are also changing. Figure 6-12 confirms the initial observation of the inverse relation between GOR and required gas injection rate. The fact that the series represented in the graph are from varied reservoir parameters, produced a similar result tells us that GOR is an important factor in deciding the optimum gas injection rate for such an operation.

The phenomenon can be explained if the operation is looked upon through fluid properties perspective. As the gas injection rate increased, the Gas Liquid Ratio (GLR) increases as well. Larger amount of gas will be assisting in lifting reservoir's liquid which reduces the bottom hole flowing pressure and increases the drawdown. Thus, the production rate of well will increase. At the same time, it is imperative to know that GLR has a threshold limit, after which the well's production will be affected adversely. One of the findings of Zhou is that for relatively small sized wellbore, there is an optimum nitrogen rate at which the minimum bottom hole flowing pressure can be reached. Any further increase in nitrogen injection rate above the optimum rate would increase the friction pressure loss in the annulus and consequently increase the bottom hole flowing pressure (Zhou et.al., 2011).

In addition, a very high gas injection rate might cause reversal in fluid flow direction, causing the gas to be injected into the well, instead of lifting reservoir liquid. In the worst case, injecting with extreme gas rate or pressure might lead to killing the well (Brown, 1967).

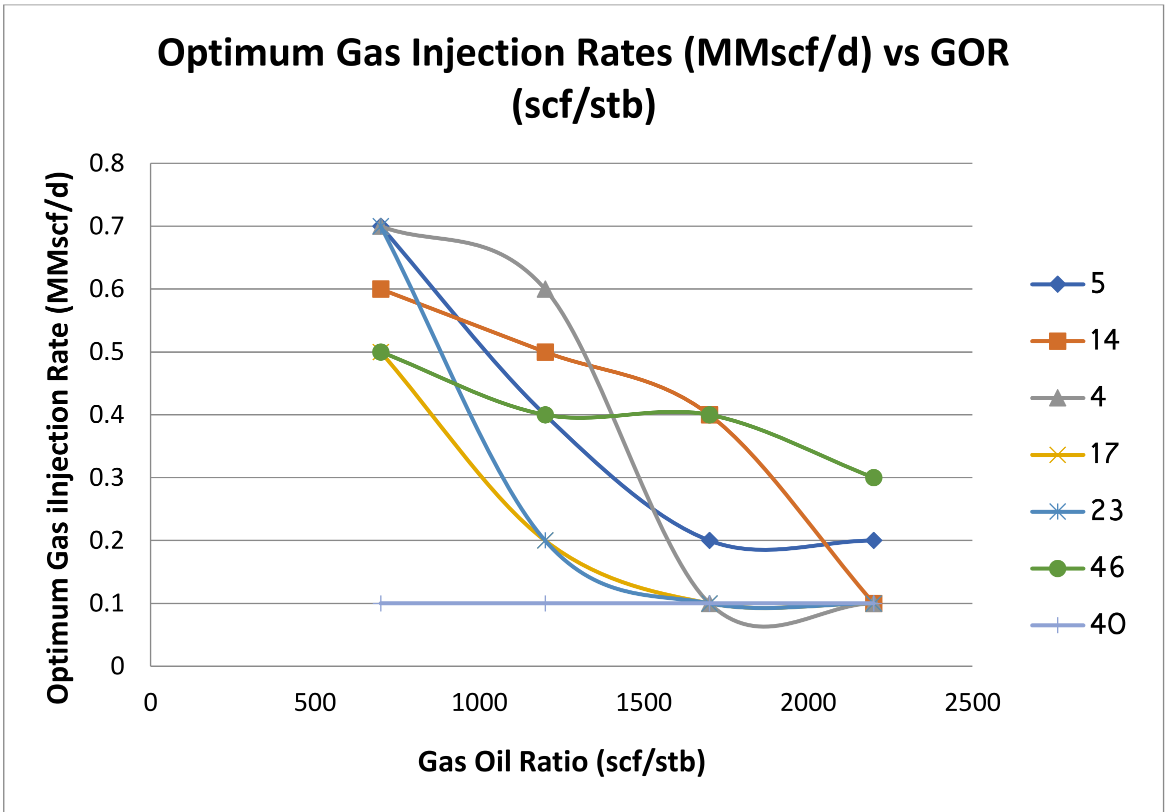

Figure 6-12: Optimum Gas Injection Rate vs Gas Oil Ratio for Several Cases

As the reservoir's GOR increases, the liquid has greater energy within. Therefore, a lower effort is required from external source to lift the well. Moreover, it also shows that a well with higher GOR is harder to kill and will stay flowing for longer period of time. Furthermore, there will be lesser chances of requiring any kind of artificial lift system. Thus, it can be concluded that as long as the other parameters remain constant or similar, the higher GOR wells will require lesser external effort to be lifted Hogan, 2015).

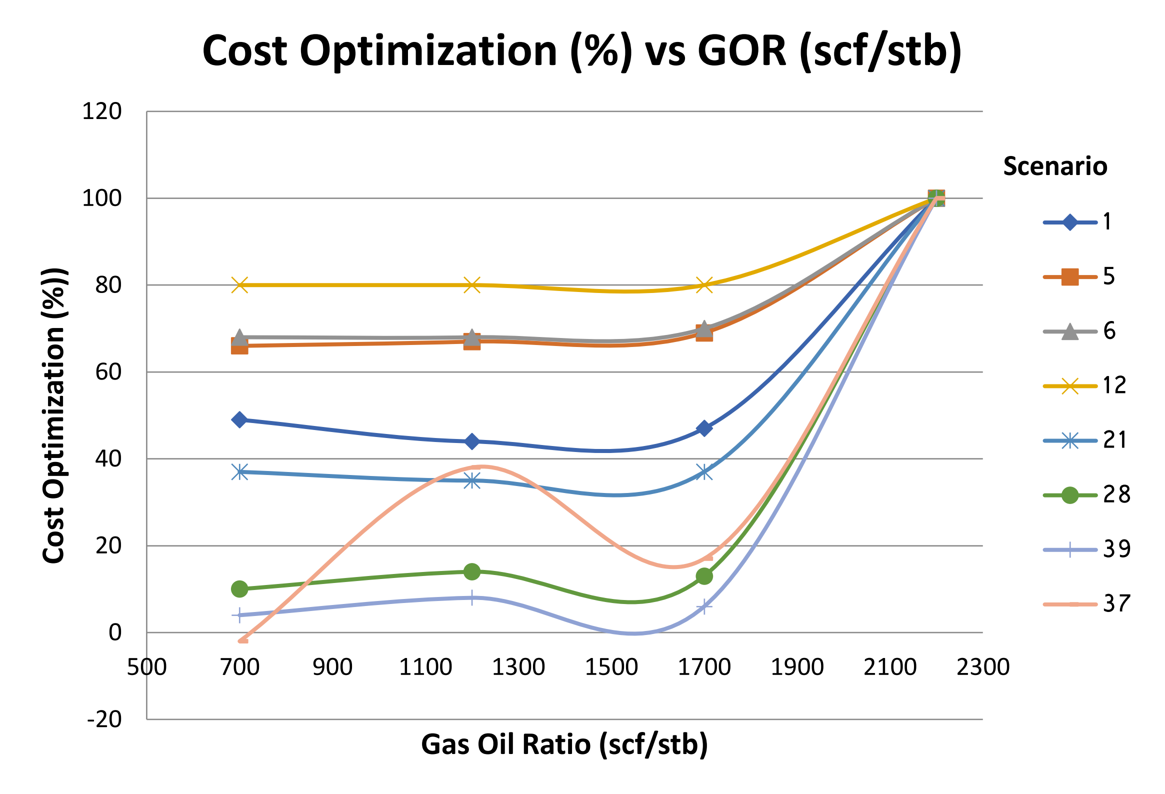

Figure 6-13: Cost Optimization (%) vs GOR (scf/stb)

When we observe Table 6-7 for trends, we can see that major costs can be saved when the reservoir's GOR is higher. The top 3 GORs, 700, 1200 and 1700 scf/stb, have similar percentages of cost saving, but as soon as higher GOR is reached, 2200 scf/stb, then the savings increase drastically. It is clearly visible in Figure 6-13 that in almost every case, i.e. 38 out of 48 scenarios, that the case with highest GOR is 100% more economic compared to the base case.

Therefore, the same result can be achieved by spending half the cost which further means that greater number of similar operations can be conducted with same budget, increasing the effective utilization of each coiled tubing package. The increase in economic efficiency is a major incentive to the operating companies to perform proper research prior to conducting such an operation.

6.3 Effect of water cut

The water cut is in the bottom row of a decision matrix as it can be seen in Table 6-6. Therefore, in order to see an effect of increase in water cut, we need to see the decision matrix in rows form. The series of rows have been indicated by alphabets, A to VV, as listed in Table 6-9.

During our analysis, we observed that several scenarios are starting from a specific optimum gas injection rate. It can also be seen that as water cut increases, the optimum gas injection rate also increases, until the highest water cut (90%) is reached, at which point the optimum gas injection rate lowers again. This trend shows that water cut is also an important factor to be considered before planning such an operation. At the same time, there is a threshold limit to the effect of water cut on the nitrogen lifting activity.

It is also visible in the trends that in several cases, the lowest and highest water cut scenarios have similar optimum gas injection rates. As mentioned earlier, initially at zero water cut level, a large amount of gas is not required to flow the well. At higher water cuts, and lower reservoir pressure and gas oil ratio, large amount of injection gas will be required to flow the well. At the same time, the low production rate and high cost of injected gas will both lead to a reduction in optimum economic factor. Thus, a smaller gas injection rate is chosen as optimum in high water cut wells.

Since water is denser than oil, it requires more energy to flow than oil. Compared to a well with only oil column, a well with water column also exerts higher hydrostatic pressure on the bottom hole. Therefore, least amount of external energy is required to lift a well with only oil, and most external energy will be required when the well is loaded with only water. Thus, it can be deduced that as water cut increases, larger amount of external energy is required to flow the well. This external energy is injected nitrogen gas in our case.

Hence, the trend of increase in optimum gas injection rate with increase in water cut is logical. However, the reduction in optimum gas injection rate for the highest water cut, 90% in our case, is due to the selection criterion we have utilized. The Optimum Economic Factor (OEF) takes production rate, operation time and quantity, which dictates cost of nitrogen used in to account.

If the production rate of well is low, OEF does not recognize the benefit of increasing the gas injection rate to higher levels, due to which the lowest and highest water cut scenarios have similar optimum gas injection rates.

However, in some cases with higher reservoir pressure and gas oil ratio (GOR), the optimum gas injection rate is higher as well. This trend exhibits that although water cut has great significance for the operation's success, other parameters also play major role in the process.

Scenarios	**Reservoir Pressure (psi)**	**Gas oil ratio (scf/stb)**	**Water Cut (%)**	**Productivity index (stb/d/psi)**
A	2500	700	0 - 90	0.5
B	2500	1200	0 - 90	
C	2500	1700	0 - 90	
D	2500	2200	0 - 90	
E	3200	700	0 - 90	
F	3200	1200	0 - 90	
G	3200	1700	0 - 90	
H	3200	2200	0 - 90	
I	3900	700	0 - 90	
J	3900	1200	0 - 90	
K	3900	1700	0 - 90	
L	3900	2200	0 - 90	
M	4500	700	0 - 90	
N	4500	1200	0 - 90	
O	4500	1700	0 - 90	
P	4500	2200	0 - 90	
Q	2500	700	0 - 90	5
R	2500	1200	0 - 90	

<table>
<tr><td>S</td><td>2500</td><td>1700</td><td>0 - 90</td><td rowspan="14"></td></tr>
<tr><td>T</td><td>2500</td><td>2200</td><td>0 - 90</td></tr>
<tr><td>U</td><td>3200</td><td>700</td><td>0 - 90</td></tr>
<tr><td>V</td><td>3200</td><td>1200</td><td>0 - 90</td></tr>
<tr><td>W</td><td>3200</td><td>1700</td><td>0 - 90</td></tr>
<tr><td>X</td><td>3200</td><td>2200</td><td>0 - 90</td></tr>
<tr><td>Y</td><td>3900</td><td>700</td><td>0 - 90</td></tr>
<tr><td>Z</td><td>3900</td><td>1200</td><td>0 - 90</td></tr>
<tr><td>AA</td><td>3900</td><td>1700</td><td>0 - 90</td></tr>
<tr><td>BB</td><td>3900</td><td>2200</td><td>0 - 90</td></tr>
<tr><td>CC</td><td>4500</td><td>700</td><td>0 - 90</td></tr>
<tr><td>DD</td><td>4500</td><td>1200</td><td>0 - 90</td></tr>
<tr><td>EE</td><td>4500</td><td>1700</td><td>0 - 90</td></tr>
<tr><td>FF</td><td>4500</td><td>2200</td><td>0 - 90</td></tr>
<tr><td>GG</td><td>2500</td><td>700</td><td>0 - 90</td><td rowspan="16">17</td></tr>
<tr><td>HH</td><td>2500</td><td>1200</td><td>0 - 90</td></tr>
<tr><td>II</td><td>2500</td><td>1700</td><td>0 - 90</td></tr>
<tr><td>JJ</td><td>2500</td><td>2200</td><td>0 - 90</td></tr>
<tr><td>KK</td><td>3200</td><td>700</td><td>0 - 90</td></tr>
<tr><td>LL</td><td>3200</td><td>1200</td><td>0 - 90</td></tr>
<tr><td>MM</td><td>3200</td><td>1700</td><td>0 - 90</td></tr>
<tr><td>NN</td><td>3200</td><td>2200</td><td>0 - 90</td></tr>
<tr><td>OO</td><td>3900</td><td>700</td><td>0 - 90</td></tr>
<tr><td>PP</td><td>3900</td><td>1200</td><td>0 - 90</td></tr>
<tr><td>QQ</td><td>3900</td><td>1700</td><td>0 - 90</td></tr>
<tr><td>RR</td><td>3900</td><td>2200</td><td>0 - 90</td></tr>
<tr><td>SS</td><td>4500</td><td>700</td><td>0 - 90</td></tr>
<tr><td>TT</td><td>4500</td><td>1200</td><td>0 - 90</td></tr>
<tr><td>UU</td><td>4500</td><td>1700</td><td>0 - 90</td></tr>
<tr><td>VV</td><td>4500</td><td>2200</td><td>0 - 90</td></tr>
</table>

Table 6-9: Variable Water Cut Decision Matrix Scenarios

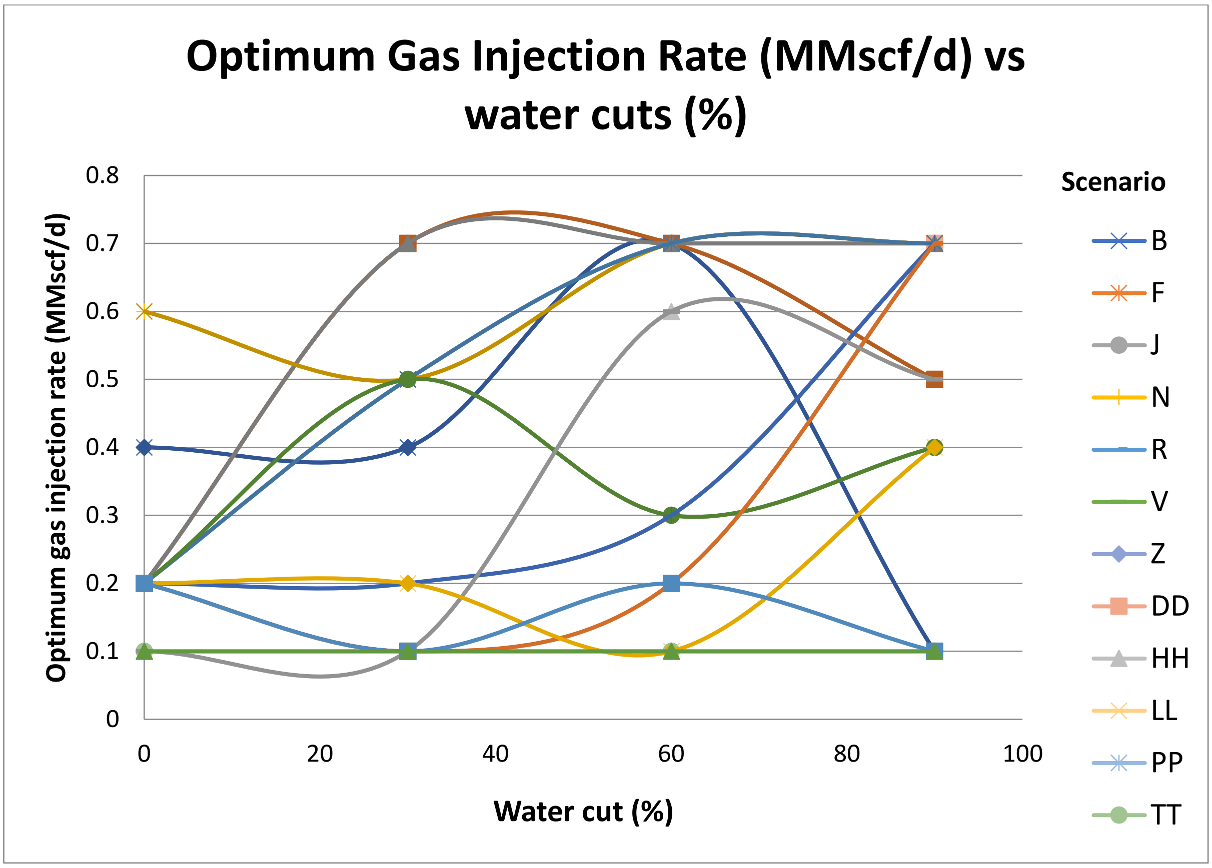

Figure 6-14: Optimum Gas Injection Rate vs Water Cut

The effect of water cut on the operation is more complex in terms of its trends as shown in Figure 6-14. Therefore, its analysis will be broken down in to smaller groups. It can also be noticed from the initial observations, that for scenarios with lower water cut and higher GOR (greater than 1200 scf/stb), the optimum gas injection rate was far lower than other scenarios. This lead us to study combined effect of GOR and water cut in depth which showed that at low GOR of 700 scf/stb, and at all reservoir pressures and productivity index (J), as water cut increased, optimum gas injection rate increased as well, with very few exceptions. Consequently, we will form grouping based on GOR to study their effect together.

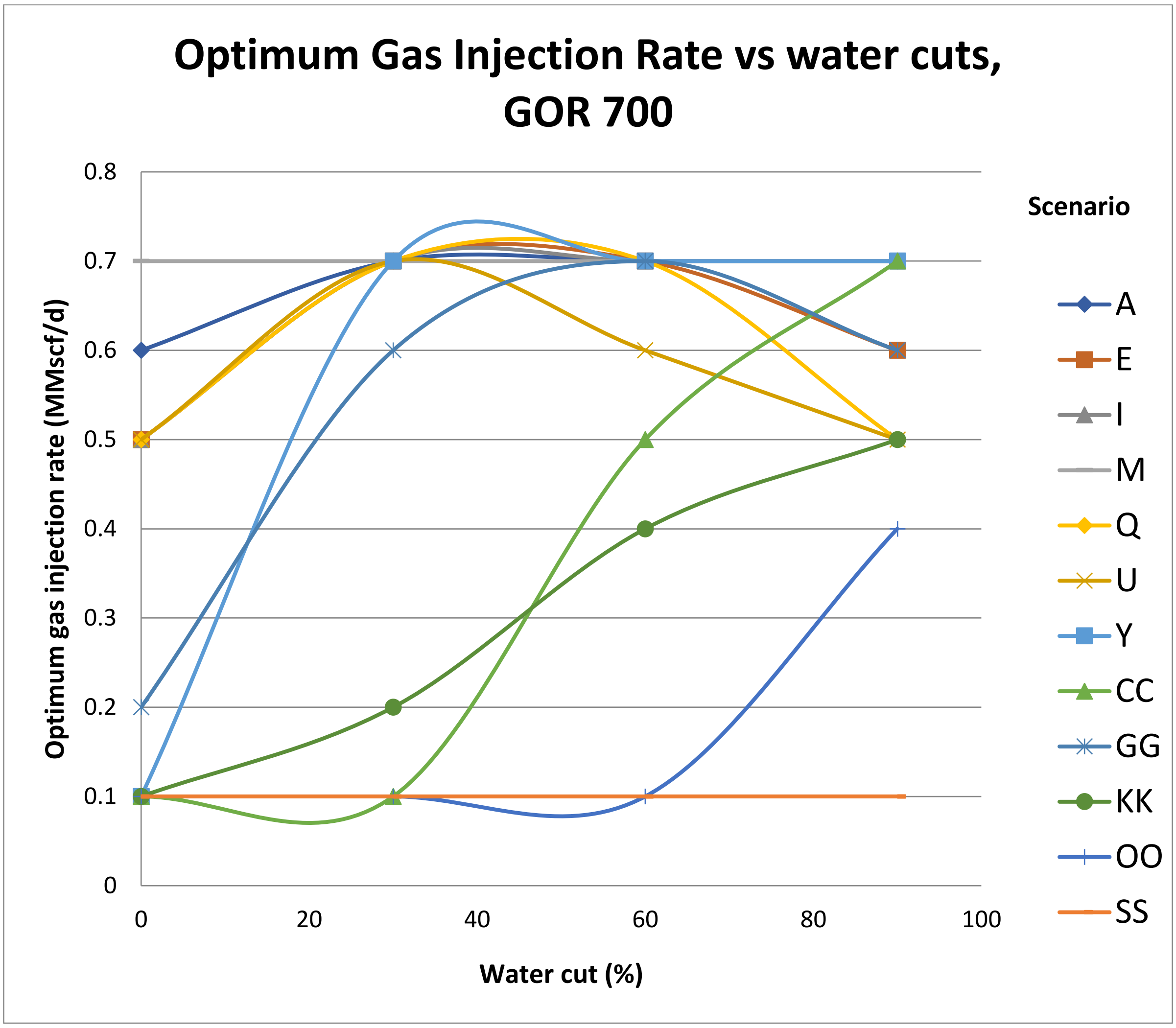

Figure 6-15: Optimum gas injection rate vs water cut, GOR 700 scf/stb

Figure 6-15 shows a plot of optimum gas injection rate against water cut with a constant GOR of 700 scf/stb. As it can be seen from the trend, the curves can be divided into two groups. The first group exhibits an increase in its required optimum gas injection rate initially with an increase in water cut, from 0% to 50%, and then a decrease in optimum gas injection at water cuts higher than 50%. Group 2 shows a relatively unstable increase in optimum gas injection required from 0 to 60%, and then a jump at 90% of water cut. These trends are captured more clearly when the plots of the two groups are segregated. The group 1 trend is shown in the Figure 6-16.

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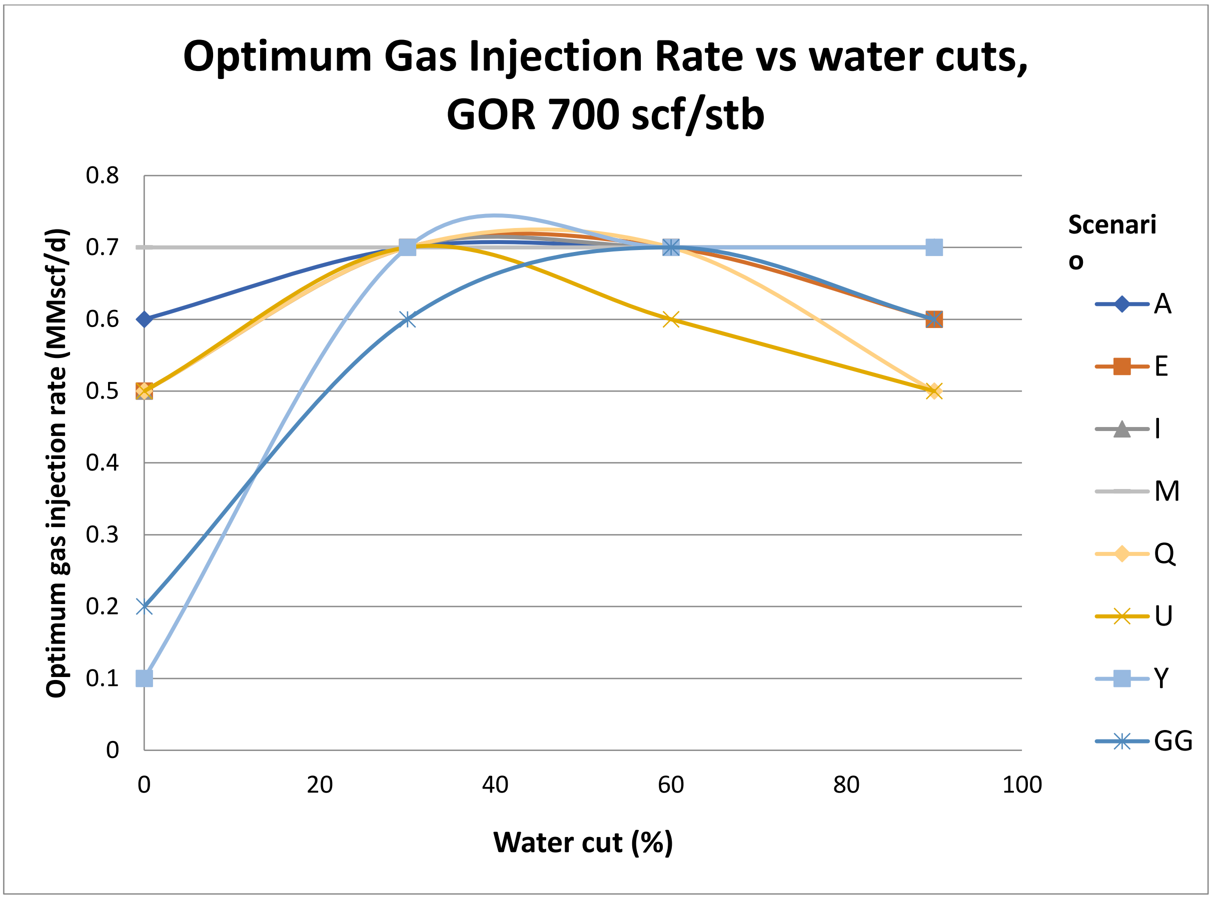

Figure 6-16: Optimum gas injection rate vs water cut, GOR 700 Group 1

The trend shown in Figure 6-16 is followed by wells with operating conditions of different series namely; A, E, I, M, Q, U, Y and GG. It can be seen from Table 6-6 and Table 6-9 that these scenarios are with well conditions of GOR 700 scf/stb, for all of J = 0.5, and partly J = 4.8 and 17 stb/d/psi.

The phenomenon can be understood if we broke down the chain of energy involved in the process. The reservoir's source of energy is reservoir pressure and GOR. At the same time, J helps to use this energy efficiently. For instance, even with large GOR and reservoir pressure, if J is low, then the reservoir's energy will be insufficient to flow the well. In this case, with the GOR being low, the well has lower energy from gas expansion. Hence, the well requires larger input from external sources of energy to aid in well flow, which is depicted in Figure 6-16.

As the energy increases, especially for higher J value, the well does not behave like this. Moreover, the effect of J is also partly visible in this grouping as well. At low J, i.e. the deliverability from reservoir to well bore is insufficient, the well requires large amount of gas injection to unload well by creating a greater drawdown. Due to the same reason, as J increased to 4.8 and 17 stb/d/psi, only the wells with lower reservoir pressure followed this trend. The group 2 of GOR 700 scf/stb is shown in the Figure 6-17 below.

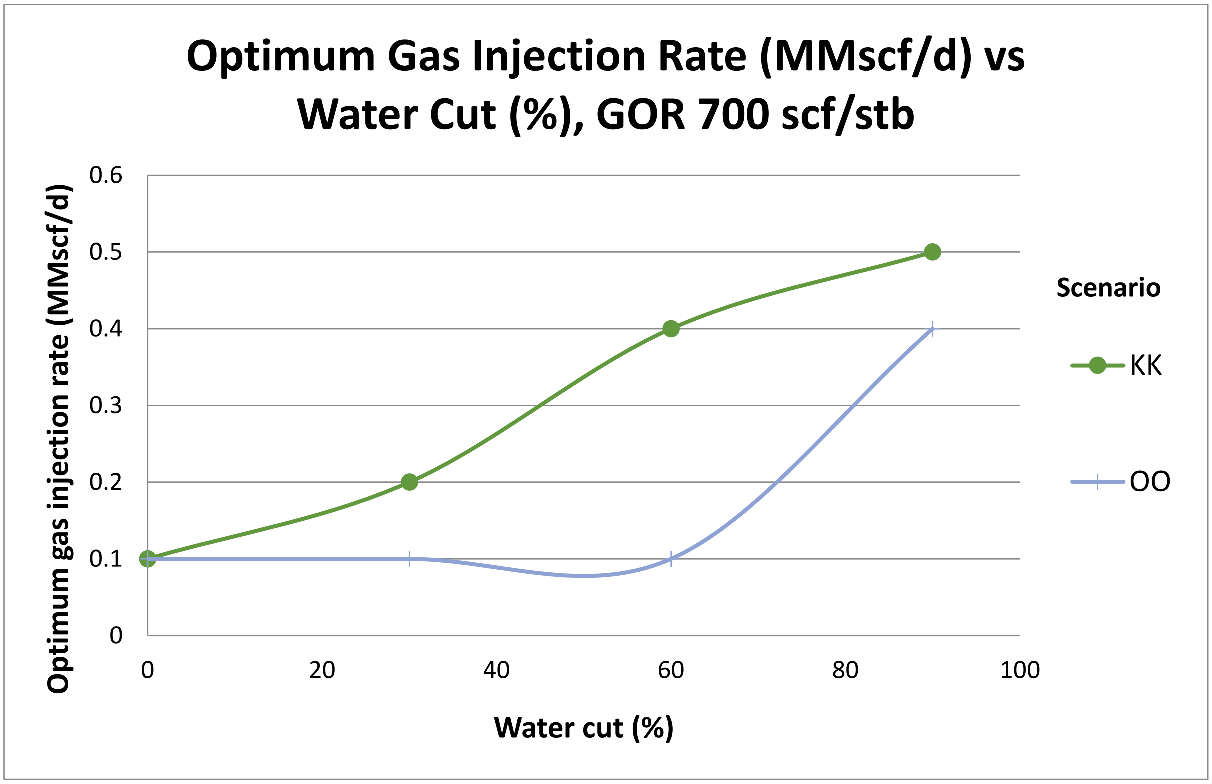

Figure 6-17: Optimum gas injection vs water cut, GOR 700 scf/stb - Group 2

The results of group 2 can be seen in Figure 6-17 and it can be observed that at lower water cut, the well does not require large gas injection rate to be optimum, proving that any external energy added to the system is efficiently used by the well to help in flowing the well. At the same time, as the water cut increases, the required gas injection rate also increases. Table 6-9 shows that scenarios KK and OO are cases with J of 17 stb/d/psi.

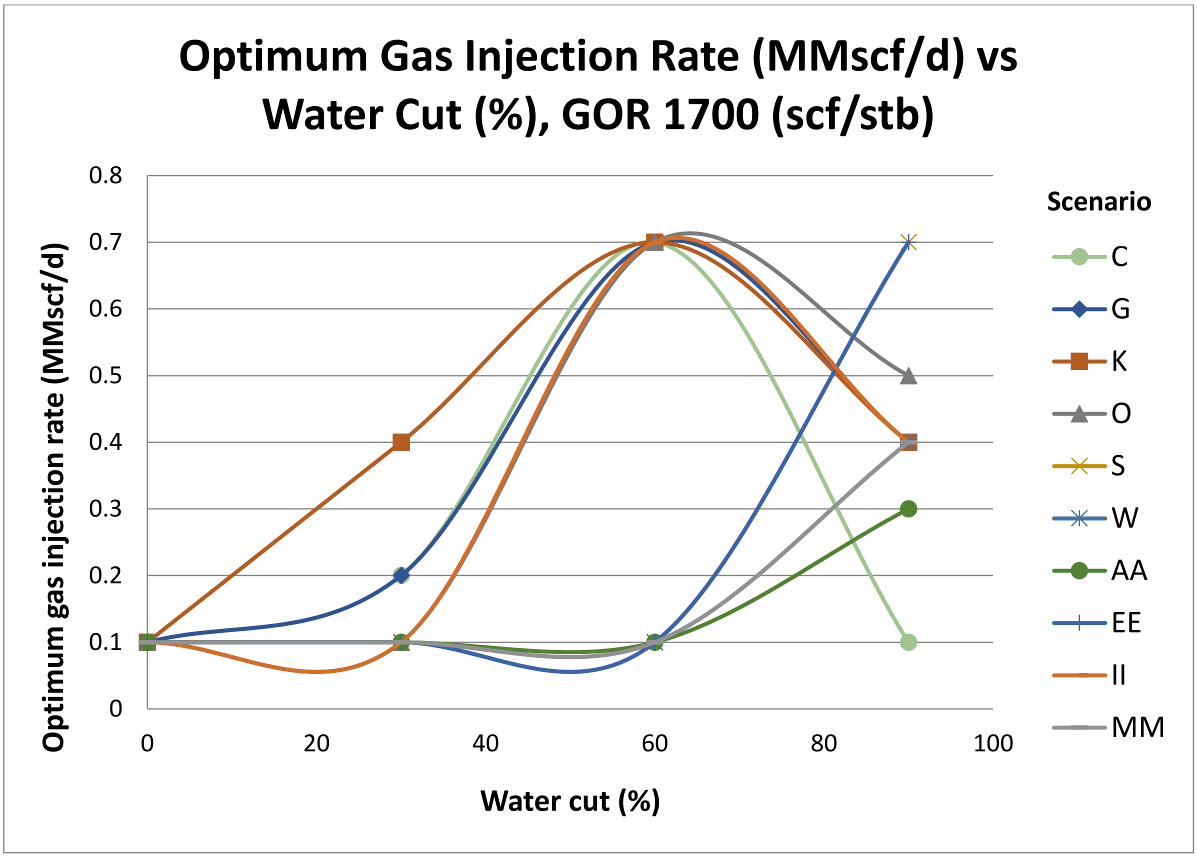

Figure 6-18: Optimum Gas Injection Rate vs water cut, GOR 1700 scf/stb

Figure 6-18 above shows the plot for well with higher GOR of 1700 scf/stb. The scenarios plotted are C, G, K, O, S, W, AA, EE, II, and MM, from Table 6-9. The trends are clearly visible that makes grouping of the two trends simpler. The first group exhibits an increase in its required optimum gas injection rate initially with an increase in water cut, from 0% to 60%, and then a decrease in optimum gas injection at water cuts higher than 60%. The second group shows a constant optimum gas injection rate until 60% of water cut, after which a sharp increase is observed in optimum gas injection rate as water cut increases to 90%. This trend is captured more clearly when the plots of the two trends are segregated as presented in below figures.

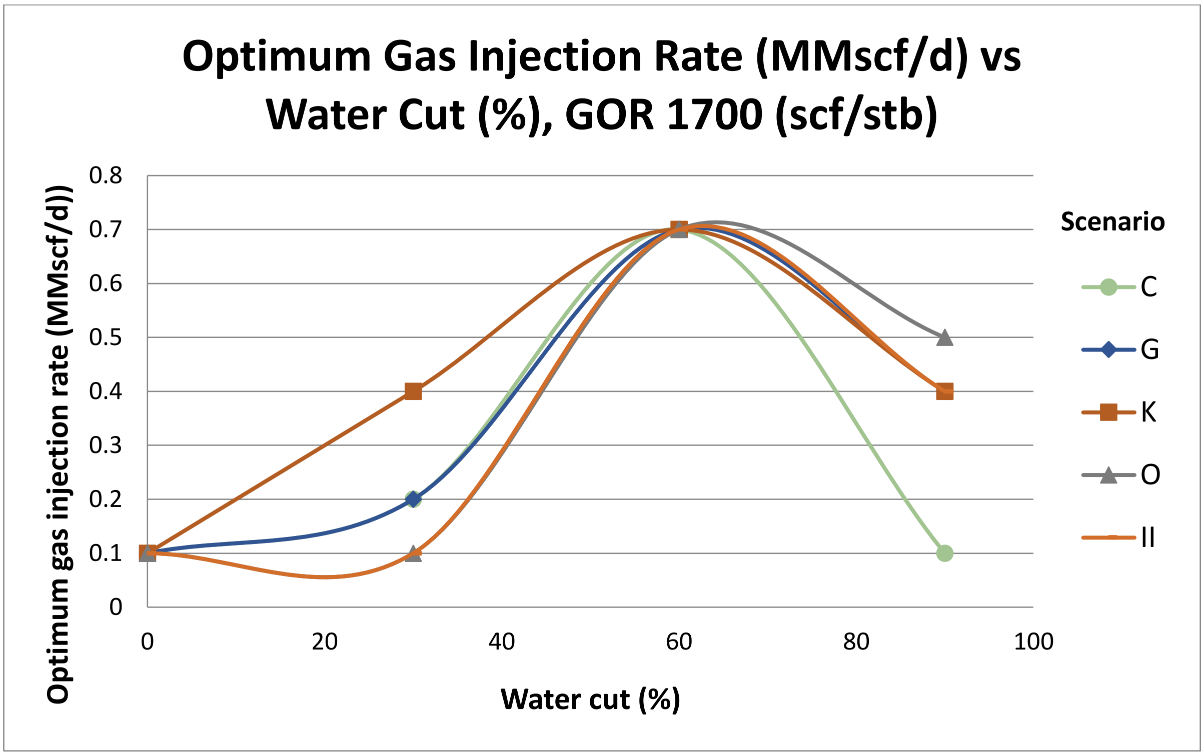

Figure 6-19: Optimum Gas Injection Rate vs water cut, GOR 1700- Group 1

The trend followed by Group 1 of GOR 700 case is also visible in higher GOR with increasing water cuts as shown in Figure 6-19. The scenarios following this trend are C, G, K, O and II. It can be seen from Table 6-9 that these series are with well conditions of GOR 1700 scf/stb, for all of J = 0.5, and partly J =17 stb/d/psi. This shows that when the wells have lower value of J, as the water cut increases, it is harder for the reservoir to deliver as much liquid to the wellbore. It could be partly due to the density of water, relative permeability of the two liquids, as well as other fluid properties. Therefore, the limiting factor for optimum gas injection is not reservoir's lower energy; instead, it is the productivity index (J) of reservoir. This shows the importance of J on the operational parameters of this operation. The group 2 of GOR 1700 scf/stb is shown in the Figure 6-20.

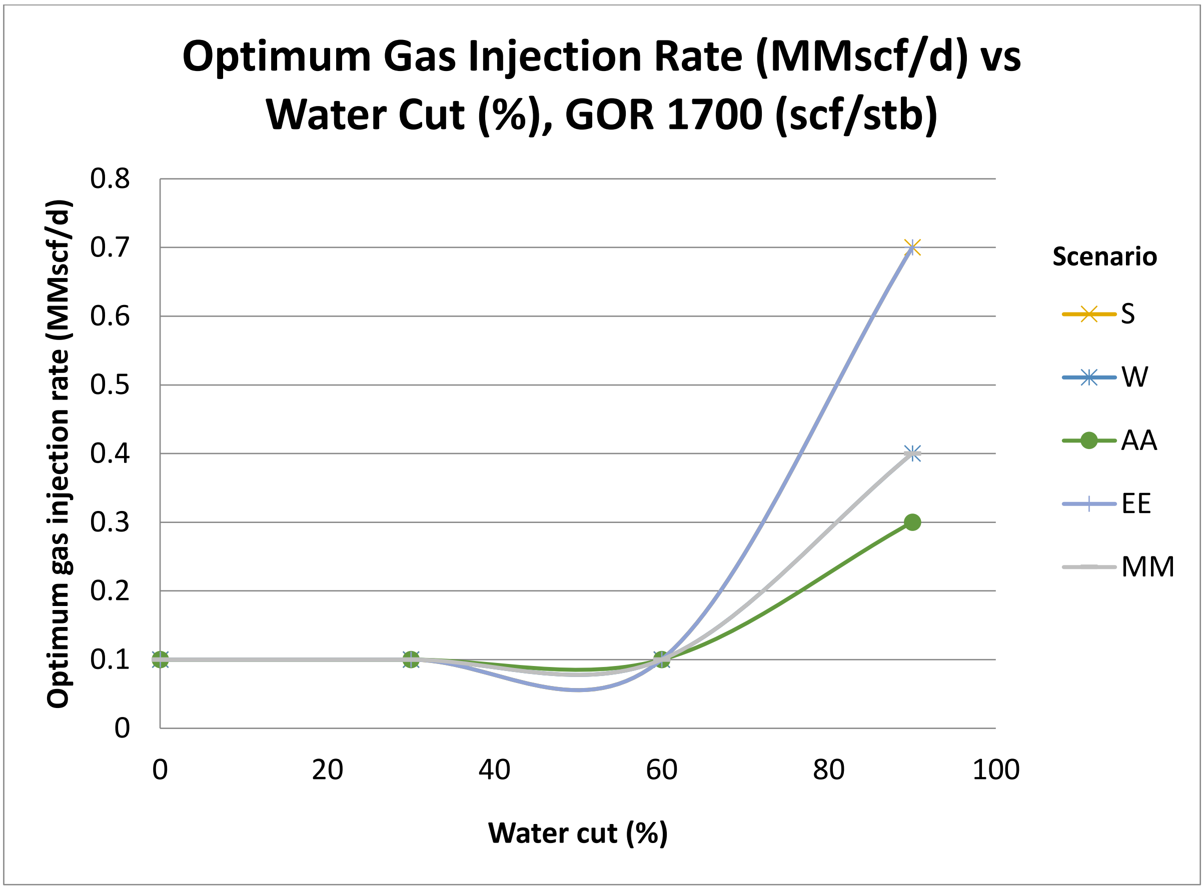

Figure 6-20: Optimum Gas Injection Rate vs water cut, GOR 1700- Group 2

In the group 2 of GOR 1700 scf/stb presented in Figure 6-20, it can be observed that the optimum gas injection rate at lower water cut stays constant. This observation was missing from the case with GOR 700 scf/stb. The main difference between the two cases is in GOR. The variation in initial section of the plot indicates the importance of GOR on this operation. As GOR increased, the requirement of optimum gas injection rate decreased to the minimum. At the same time, the maximum value of optimum gas injection rate decreased. In addition, the number of cases that entered group 2 increased drastically, from 3 to 8 scenarios, all of which are of varying reservoir pressures but mostly have J of 5 stb/d/psi. This analysis shows the importance of GOR, J and reservoir pressure all together.

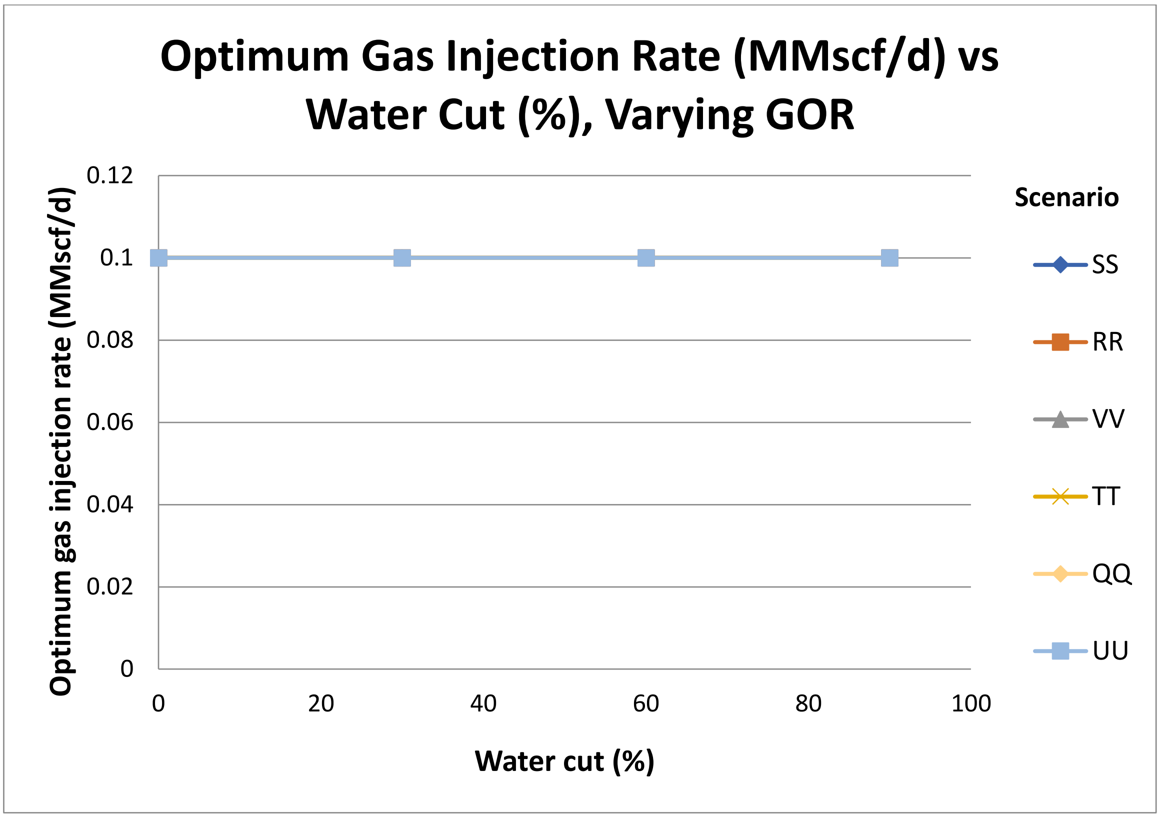

Figure 6-21: Optimum Gas Injection Rate vs water cut- Anomaly

An anomaly was found in the trends as shown in Figure 6-21 which showed several scenarios have a constant value of 0.1 MMscf/d as optimum gas injection rate. This trend can be justified as series SS to UU have highest reservoir pressure and productivity index (J) value, and the combination of these two parameters support flowing the well without any impact of water cut variation or GOR.

The high reservoir pressure indicates higher energy to flow the well till the surface. At the same time highest J value, implies the reservoir ability to easily transfer fluid to the well bore. A combination of both the factors aids in successful unloading of well with minimum gas injection rate. This shows the collaborated effects of different parameters on the success of operation.

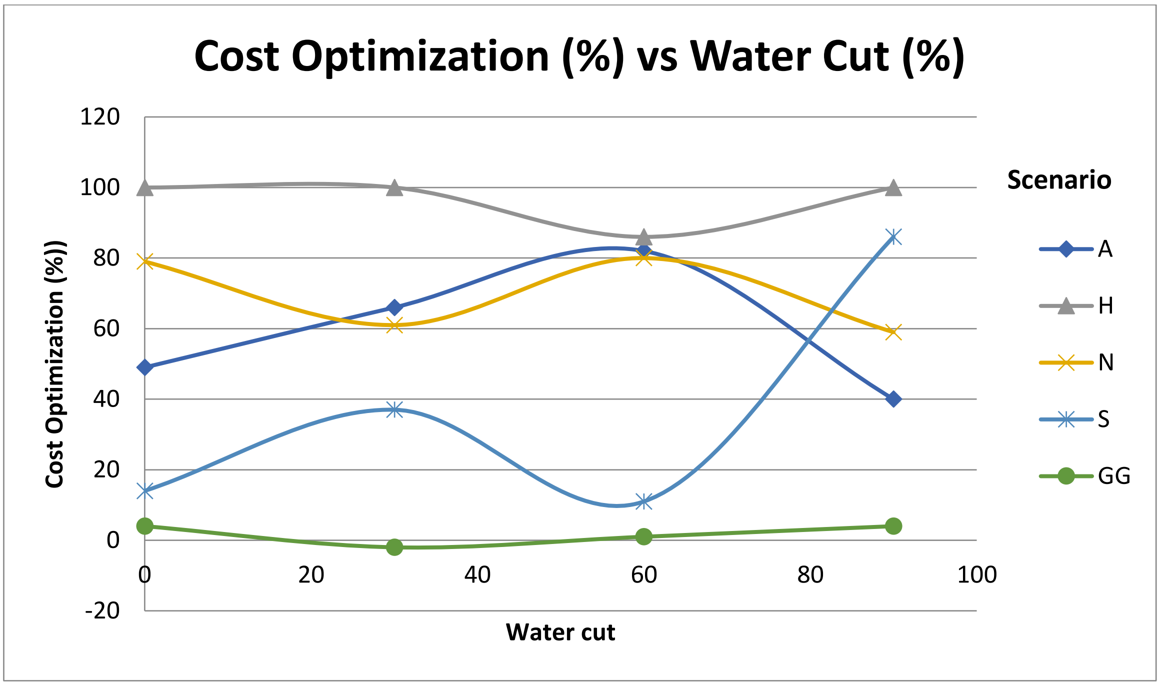

Figure 6-22: Cost Optimization (%) vs Water Cut (%)

The extremes are clearly visible in terms of financial savings when effect of water cut on nitrogen lifting operation is studied as shown in Figure 6-22. One extreme is when cost savings of 100% can be made when operation is conducted rather than conventional method. Such a case occurs when reservoir has high gas oil ratio, irrespective of the water cuts, reservoir pressure and productivity index. This shows the importance of GOR on the operation as a whole. The other extreme case is when there is 0% financial benefit when operation is conducted in this manner, instead of the conventional method. Such a case occurs at high productivity index values and lower gas oil ratios. However, at low and mid-range J values, conducting the operation is of great economic benefits.

6.4 Effect of productivity index

The productivity index (J) is an indication of the capability of reservoir's deliverability of fluid to the well bore. Although it is a little tricky to keep a track of J from decision matrix, but the graphical representation allows easier visualization of the operation's dependence upon the parameter. The total number of cases is 64, and they are denoted by roman numerals, from I to LXIV, listed in Table 6-10. The following is the resulting plot for the effect of J against optimum gas injection rate.

Scenarios	**Reservoir Pressure (psi)**	**Gas oil ratio (scf/stb)**	**Water Cut (%)**	**Productivity index (stb/d/psi)**
I	2500	700	0	0.5 - 17
II		1200		0.5 - 17
III		1700		0.5 - 17
IV		2200		0.5 - 17
V	3200	700		0.5 - 17
VI		1200		0.5 - 17
VII		1700		0.5 - 17

VIII		2200		0.5 - 17
IX	3900	700		0.5 - 17
X		1200		0.5 - 17
XI		1700		0.5 - 17
XII		2200		0.5 - 17
XIII	4500	700		0.5 - 17
XIV		1200		0.5 - 17
XV		1700		0.5 - 17
XVI		2200		0.5 - 17
XVII	2500	700	30	0.5 - 17
XVIII		1200		0.5 - 17
XIX		1700		0.5 - 17
XX		2200		0.5 - 17
XXI	3200	700		0.5 - 17
XXII		1200		0.5 - 17
XXIII		1700		0.5 - 17
XXIV		2200		0.5 - 17
XXV	3900	700		0.5 - 17
XXVI		1200		0.5 - 17
XXVII		1700		0.5 - 17
XXVIII		2200		0.5 - 17
XXIX	4500	700		0.5 - 17
XXX		1200		0.5 - 17
XXXI		1700		0.5 - 17
XXXII		2200		0.5 - 17
XXXIII	2500	700	60	0.5 - 17
XXXIV		1200		0.5 - 17
XXXV		1700		0.5 - 17
XXXVI		2200		0.5 - 17
XXXVII	3200	700		0.5 - 17
XXXVIII		1200		0.5 - 17
XXXIX		1700		0.5 - 17
XL		2200		0.5 - 17
XLI	3900	700		0.5 - 17
XLII		1200		0.5 - 17
XLIII		1700		0.5 - 17
XLIV		2200		0.5 - 17
XLV	4500	700		0.5 - 17
XLVI		1200		0.5 - 17
XLVII		1700		0.5 - 17
XLVIII		2200		0.5 - 17
XLIX	2500	700	90	0.5 - 17
L		1200		0.5 - 17

LI		1700		0.5 - 17
LII		2200		0.5 - 17
LIII	3200	700		0.5 - 17
LIV		1200		0.5 - 17
LV		1700		0.5 - 17
LVI		2200		0.5 - 17
LVII	3900	700		0.5 - 17
LVIII		1200		0.5 - 17
LIX		1700		0.5 - 17
LX		2200		0.5 - 17
LXI	4500	700		0.5 - 17
LXII		1200		0.5 - 17
LXIII		1700		0.5 - 17
LXIV		2200		0.5 - 17

Table 6-10: Variable Productivity Index Decision Matrix Scenarios

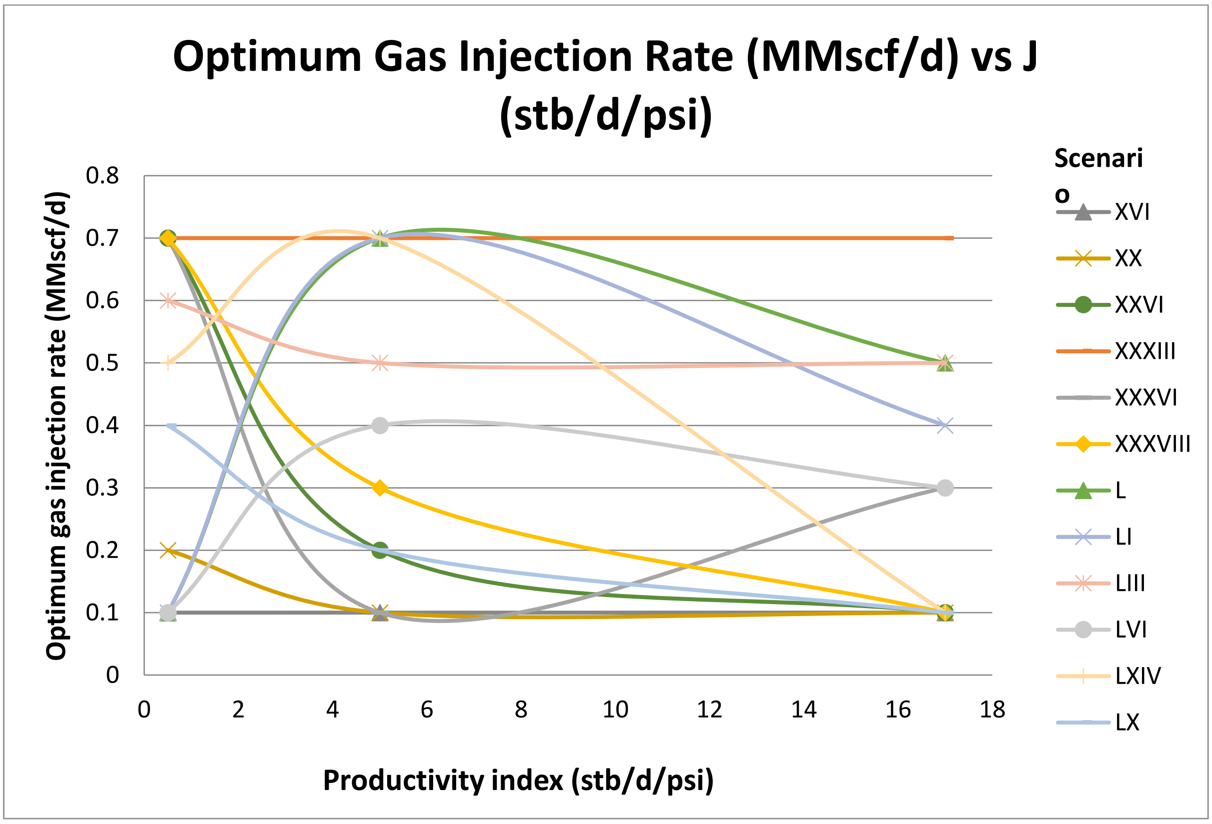

Figure 6-23: Optimum gas injection rate vs Productivity Index

Although the plot presented in Figure 6-23 is a little crowded, grouping will reduce the harshness in observing its trends. The grouping will be based upon water cuts. The first group, group 1, will comprise of data from first 3 water cut values, 0, 30 and 60%. The second group, group 2, will comprise of data from last water cut, 90%. The two groups are exhibited and analysed in following sections.

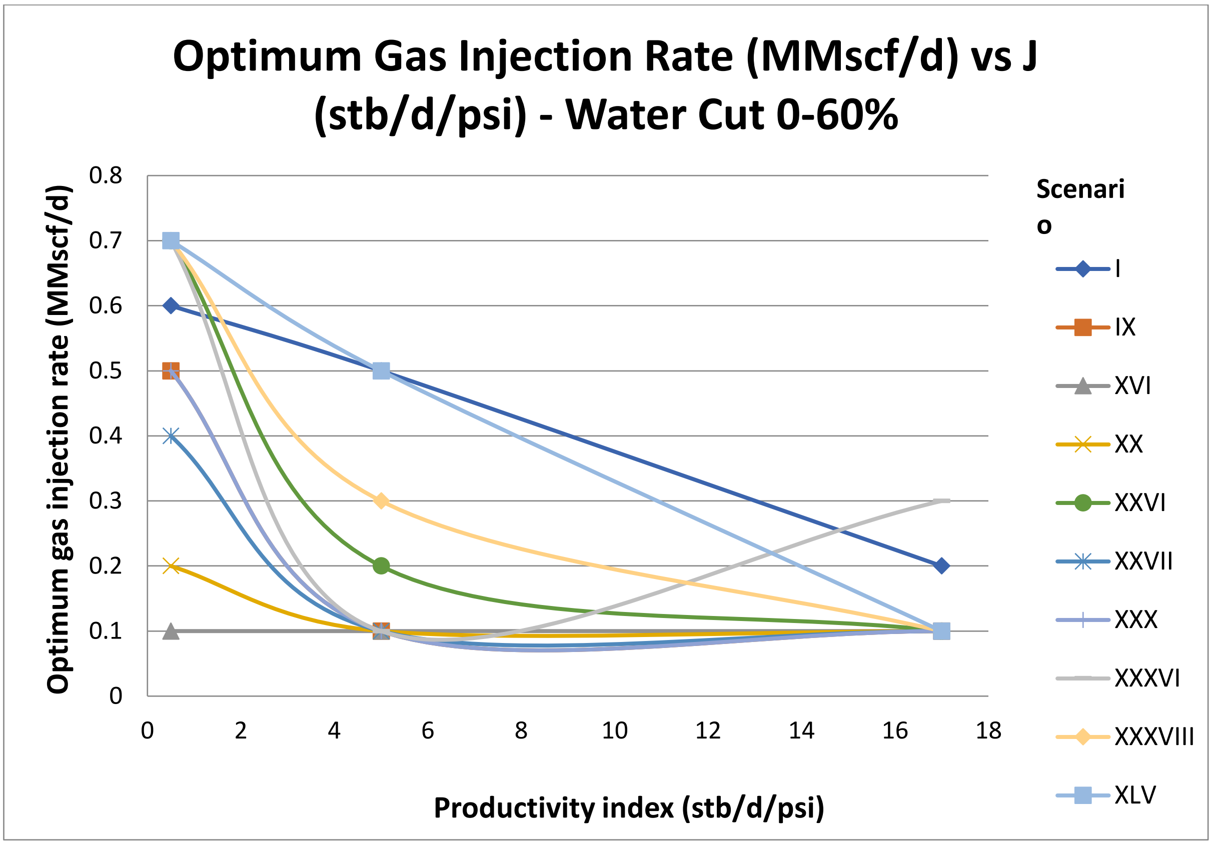

Figure 6-24: Optimum gas injection rate vs J- WC 0-60% Group 1

The group 1 comprises of random cases with varied GOR and reservoir pressure, but water cut ranging from 0 to 60%. The general trend visible in Figure 6-24, shows that in almost all the cases, as the productivity index of reservoir increases, the optimum gas injection rate decreases, except in a few cases. The trend shows that J is an important factor in optimization of this operation. Great economic benefits can be reaped if wells' productivity index could be increased for such operations. The fact that GOR and reservoir pressure were randomly varied, and yet the productivity index maintained its trend shows that J is more important than GOR and reservoir pressure in the planning of such operation, especially at low to medium water cut level.

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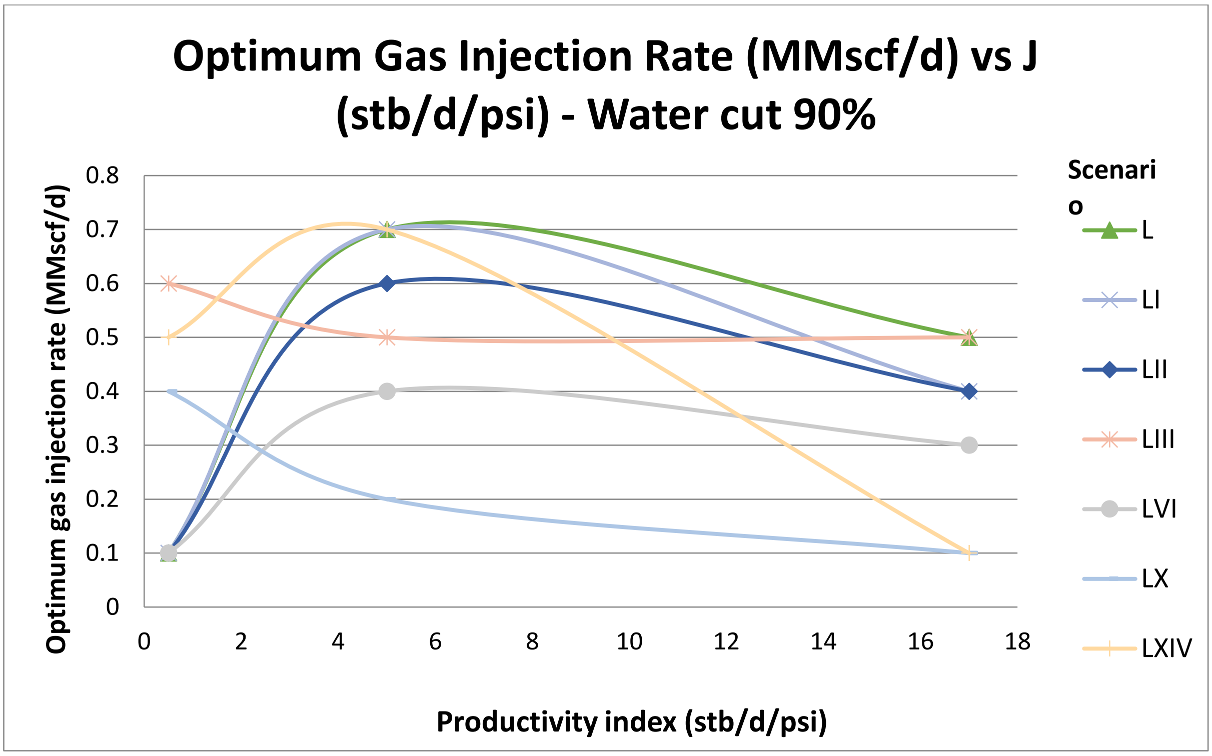

Figure 6-25: Optimum Gas Injection rate vs J - WC 90% - Group 2

Figure 6-25 shows a variety of trends for optimum gas injection rate against productivity index at higher water cut. It is worth mentioning, that the water cut is 90% in this scenario, which leads to increased hydrostatic column of fluid in the system. At the same time, the low productivity index (J) value means that the amount of fluid entering the well bore is relatively less.

Thus, even if lower bottom-hole pressure is achieved by injecting more gas, then the reservoir will not be able to provide sufficient influx of hydrocarbon to well bore. As the J increases, higher gas injection is required to optimize the operation as the well's ability to deliver fluid to wellbore improves greatly. Thus, a lower bottom-hole pressure will actually produce much more fluid.

As the J increases to 17 stb/d/psi, the optimum gas injection rate decreases again, however it is due to another limiting factor such as change in the flow regime due to large increase in gas quantity. If gas dominates the flow, then liquid will be choked in the downhole.

Effect of reservoir pressure is also visible in Figure 6-25. When LII and LVI are compared, both have same water cut, GOR and J, the decrease in gas injection rate can be observed clearly from the graph. Although effect of reservoir pressure is the next section, it is pertinent to understand that different parameters can be more dominant at different stages of well life. Thus, it can be seen that J is less dominant at higher water cuts.

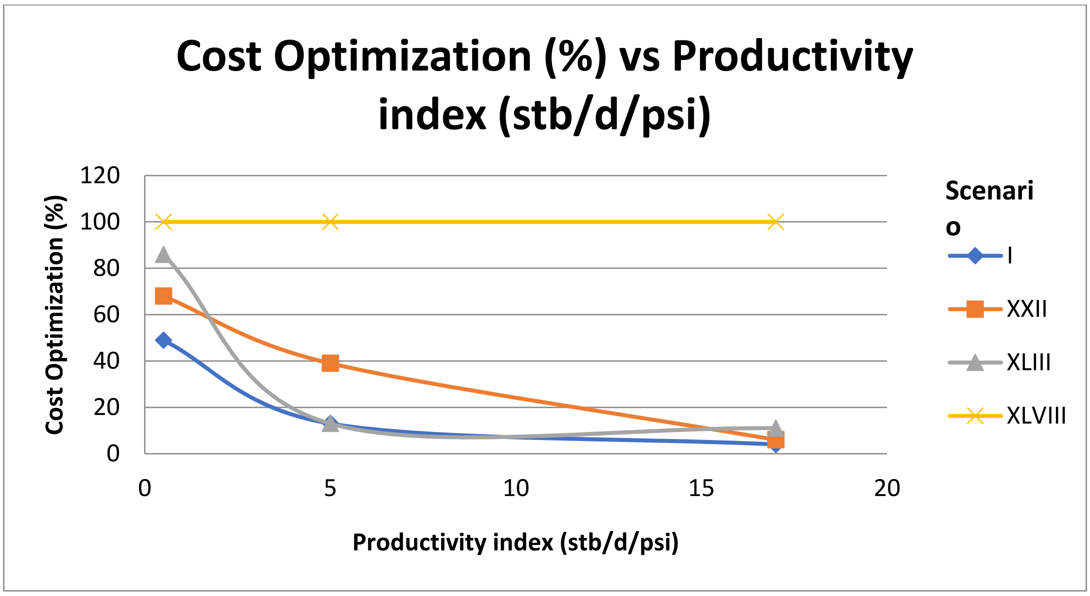

Figure 6-26: Cost Optimization (%) vs Productivity index (stb/d/psi)

The trend observed from series LX, shows that the optimum gas injection rate decreases with an increase in J. One of the reasons for such behavior is that J was the limiting factor in the operation. Moreover, it is the same trend as Group 1. The reservoir pressure is 3900psi, water cut is 90%, and GOR is 2200 scf/stb in this case.

Figure 6-26 shows the cost optimization against the productivity index. It is evident from the plot that an increase in productivity index reduces the cost optimization of the operation. Thus, following the optimum gas injection rates as per decision matrix is most beneficial financially when reservoir has low productivity index. However, when reservoir has high GOR, such as in scenario XLVIII, the cost optimization is steady at 100%.

6.5 Effect of reservoir pressure

The reservoir pressure is the pressure of the fluids present in the pores of reservoir. It is one of the main energy sources for the reservoir fluids. The total number of scenarios represented in decision matrix is 64, and they are denoted by lowercase roman numerals, from “i" to “lxiv” in Table 6-11. The resulting plot for the effect of reservoir pressure on optimum gas injection rate is represented in Figure 6-27.

The trend visible in Figure 6-27 shows that there are several possible results which harden to generalize a single rule applicable to all scenarios. Hence, the method of grouping will be followed again. Grouping will be based on J values of the scenarios. The first group, group 1 will be studied in the following section.

Table 6-11: Variable Reservoir Pressure Decision Matrix Scenarios

Scenarios	Reservoir Pressure (psi)	Gas oil ratio (scf/stb)	Water Cut (%)	Productivity index (stb/d/psi)
i	2500 - 4500	700	0	0.5
ii	2500 - 4500	1200	0	
iii	2500 - 4500	1700	0	
iv	2500 - 4500	2200	0	
v	2500 - 4500	700	30	

vi	2500 - 4500	1200	30	
vii	2500 - 4500	1700	30	
viii	2500 - 4500	2200	30	
ix	2500 - 4500	700	60	
x	2500 - 4500	1200	60	
xi	2500 - 4500	1700	60	
xii	2500 - 4500	2200	60	
xiii	2500 - 4500	700	90	
xiv	2500 - 4500	1200	90	
xv	2500 - 4500	1700	90	
xvi	2500 - 4500	2200	90	
xvii	2500 - 4500	700	0	5
xviii	2500 - 4500	1200	0	
xix	2500 - 4500	1700	0	
xx	2500 - 4500	2200	0	
xxi	2500 - 4500	700	30	
xxii	2500 - 4500	1200	30	
xxiii	2500 - 4500	1700	30	
xxiv	2500 - 4500	2200	30	
xxv	2500 - 4500	700	60	
xxvi	2500 - 4500	1200	60	
xxvii	2500 - 4500	1700	60	
xxviii	2500 - 4500	2200	60	
xxix	2500 - 4500	700	90	
xxx	2500 - 4500	1200	90	
xxxi	2500 - 4500	1700	90	
xxxii	2500 - 4500	2200	90	
xxxiii	2500 - 4500	700	0	17
xxxiv	2500 - 4500	1200	0	
xxxv	2500 - 4500	1700	0	
xxxvi	2500 - 4500	2200	0	
xxxvii	2500 - 4500	700	30	
xxxviii	2500 - 4500	1200	30	
xxxix	2500 - 4500	1700	30	
xl	2500 - 4500	2200	30	
xli	2500 - 4500	700	60	
xlii	2500 - 4500	1200	60	
xliii	2500 - 4500	1700	60	
xliv	2500 - 4500	2200	60	
xlv	2500 - 4500	700	90	
xlvi	2500 - 4500	1200	90	
xlvii	2500 - 4500	1700	90	
Xlvii	2500 - 4500	2200	90	

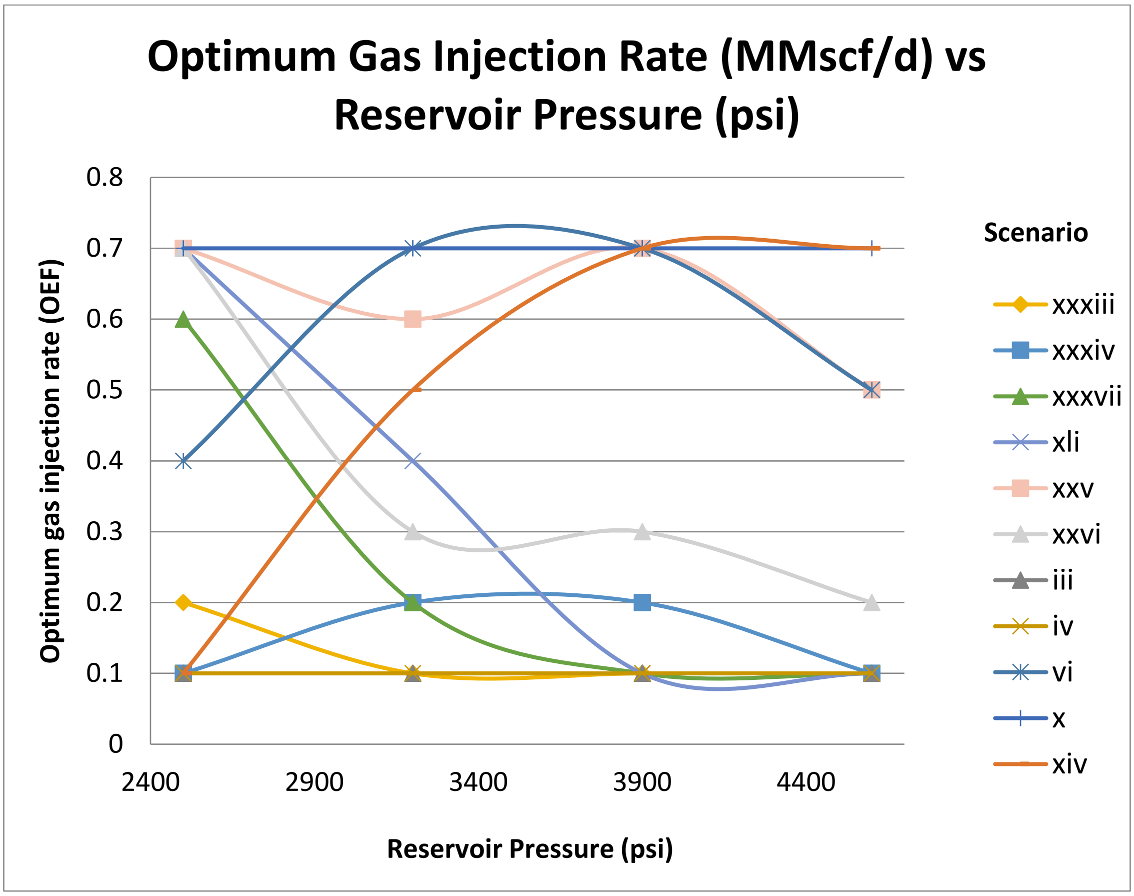

Figure 6-27: Optimum gas injection rate vs Reservoir Pressure

Figure 6-28 shows the effect of reservoir pressure on optimum gas injection rate on well while keeping a constant productivity index (J). The general trend shows that the optimum gas injection rate is first increasing and then decreasing with increase in reservoir pressure. This trend indicates that initially as the reservoir pressure increases, the fluid possesses higher energy level. As J is quite low, the deliverability of reservoir to well bore is not sufficient. However, with an increase in gas injection rate, and decrease in bottom-hole pressure, optimum gas injection rate for the operation can be achieved. However, as the reservoir pressure increases to 4600 psi, the reservoir does not require high level of external energy to flow and kick off the well. Thus, the reduction in optimum gas injection rate is observed.

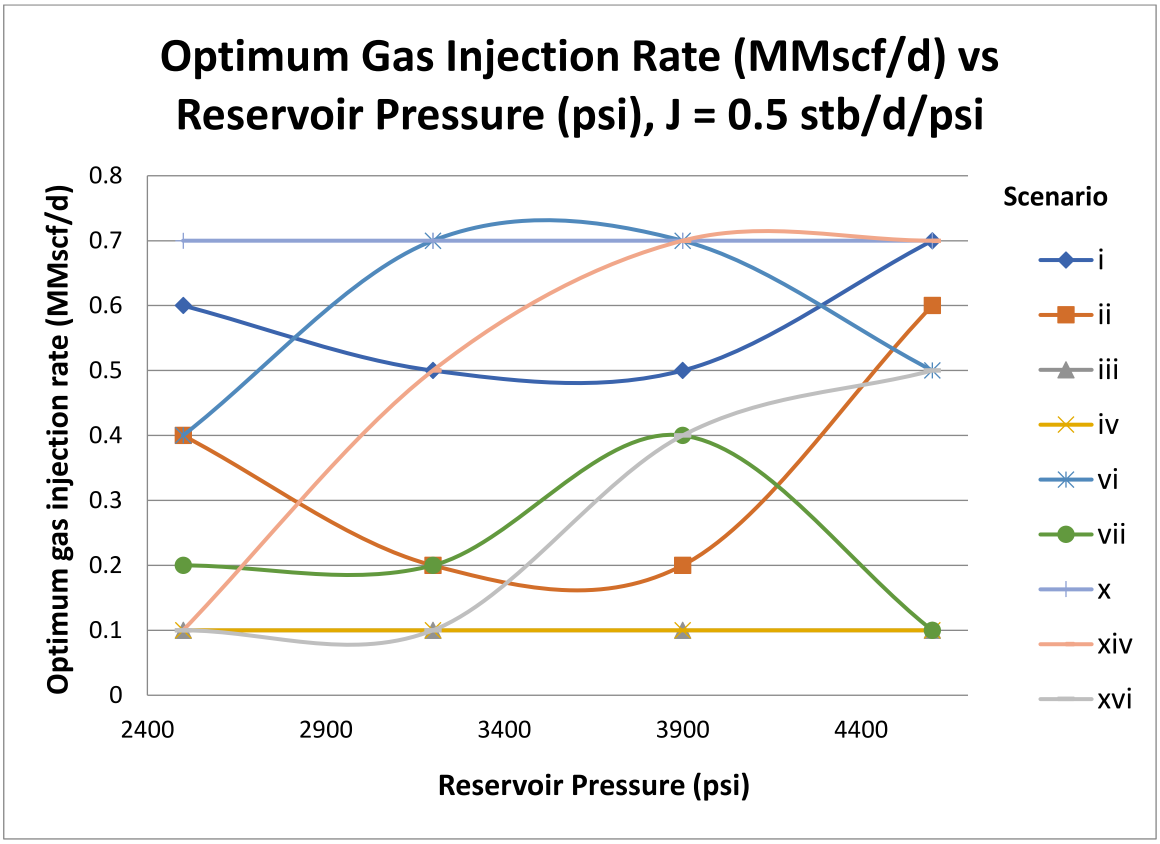

Figure 6-28: Optimum gas injection rate vs Reservoir Pressure- J=0.5 stb/d/psi

6.6 Effect of coiled tubing size

Coiled tubing (CT) is an integral part of this operation and its size can greatly influence the success of this operation. There are several factors linked to the size of CT such as its strength, flexibility, maximum reach in well, maximum internal pressure, etc. In addition, the annulus between CT and tubing is the primary region of well flow to the surface. A smaller area of flow can help reservoir liquid flow, similar to velocity strings. However, there is an upper limit to this phenomenon after which gas will take larger area of the annulus and create back pressure to the liquid, which is counterproductive to our operation's objective. It is due to these reasons that a simulation was conducted to study the effect of CT size on the operation. Four sizes of CT were used in the simulation, 1.25', 1.5', 1.75' and 2'. These specific sizes were chosen due to their popularity in the region and client companies. The reservoir parameters were

1. Reservoir pressure: 3200 psi
2. Gas Oil Ratio: 700 scf/stb
3. Productivity Index: 5 stb/d/psi
4. Water Cut: 50%

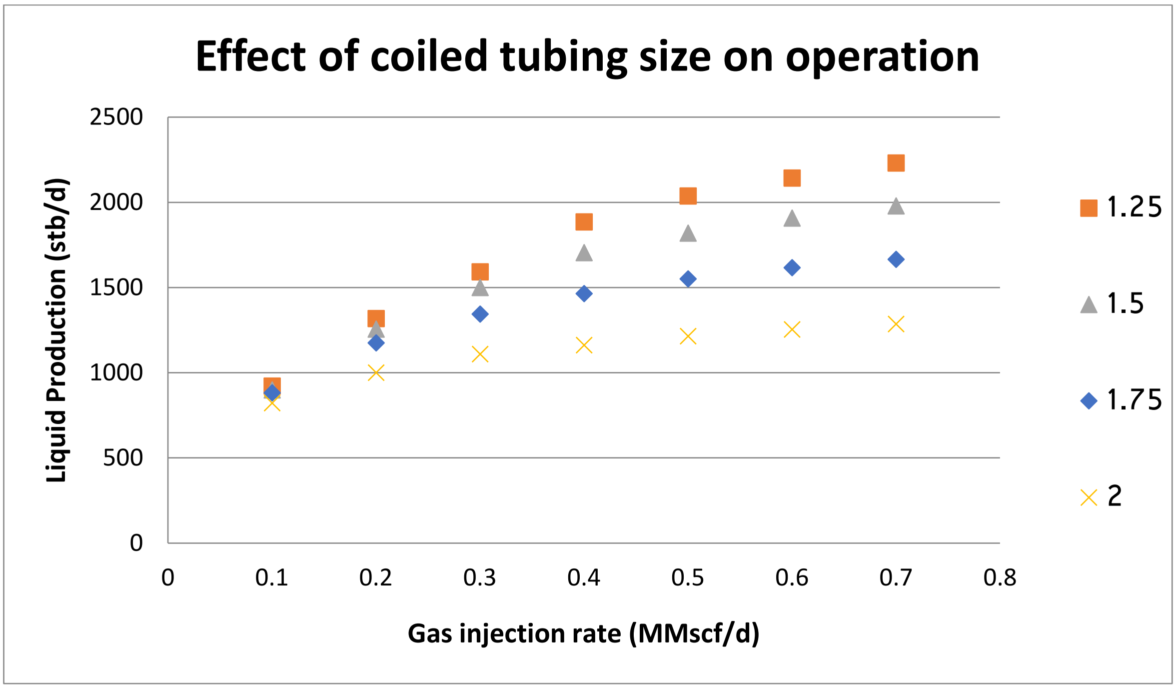

Figure 6-19: Effect of Coiled tubing size on operation – Simulation

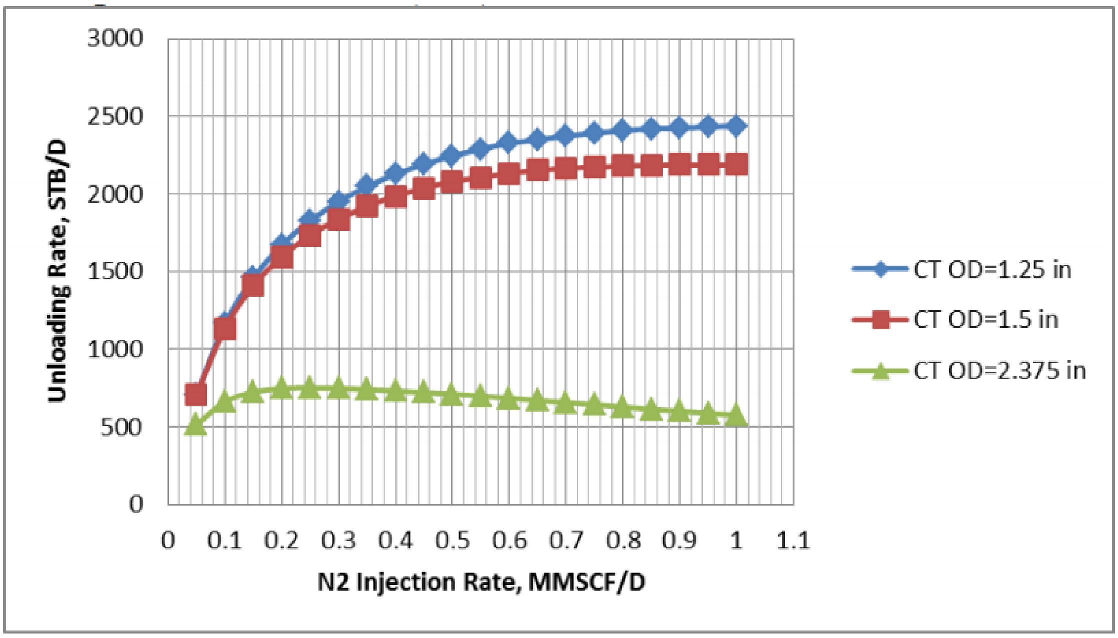

Figure 6-20: Unloading rate vs N_2 Injection Rate for Different Coiled Tubing Sizes – Fuladgar, et.al (2014)

The graph of liquid production rate against gas injection rate is plotted in Figure 6-. It can be seen that as gas injection rate increases, the liquid production rate increases as well. The shape of the curve shows that a point of inflection will be present, after which an increase in gas injection rate will reduce liquid production rate. The second observation that can be made from Figure 6- is that the small sized CT can flow the well more easily, especially at higher gas injection rates.

At lower gas injection rates, it is possible that the gas will not be enough to lift the well in a large flow area. However, as the gas injection rate increases, the reservoir fluid can is given sufficient energy to be able to flow in the larger CT – tubing annulus. Moreover, the point of inflection for larger sized CT will be much before smaller sized CT because higher gas injection rate in a smaller flow area will quickly create back pressure on the liquid, making it uneconomic and inefficient faster compared to a smaller sized CT. The findings from the simulation were similar to the results from (Fuladgar, et.al., 2014) in Figure 6-. A comparison of the two results is shown in Figure 6-, which clearly shows that coiled tubing of 1.25-inch is best suited for such an operation.

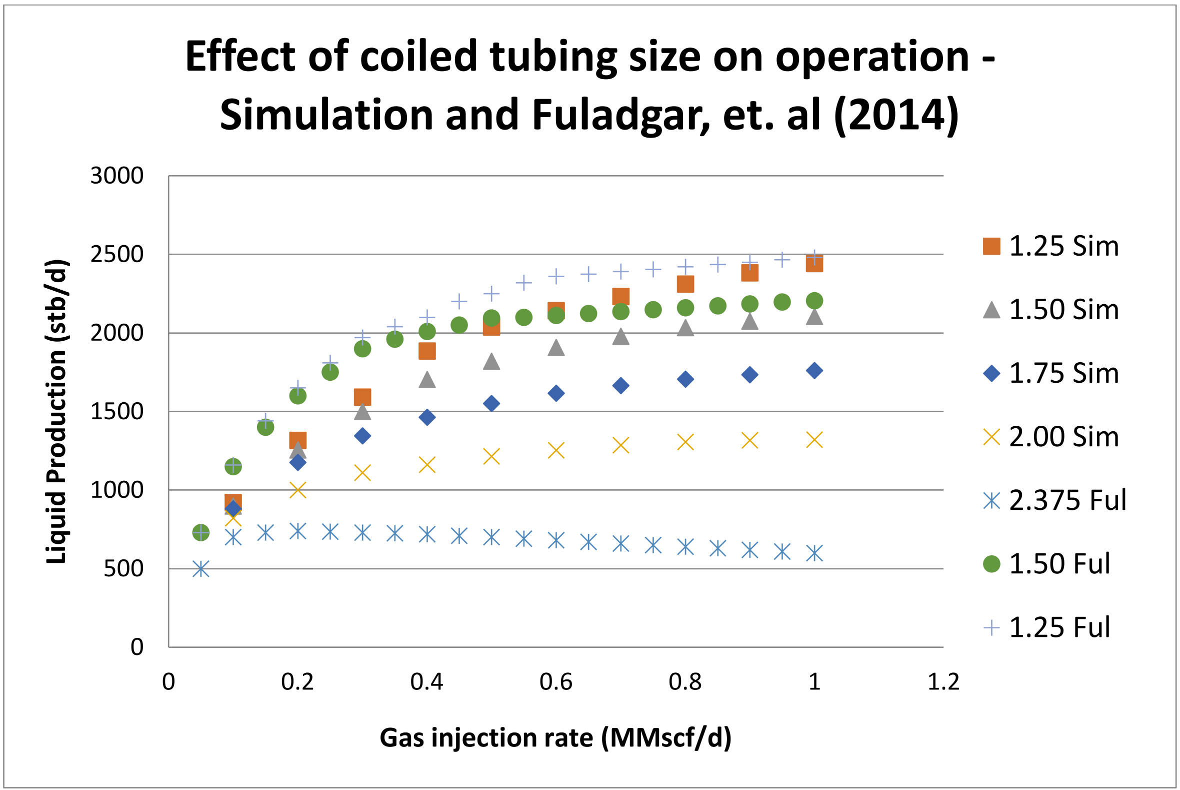

Figure 6-21: Effect of coiled tubing size on operation - Simulation and Fuladgar, et. al (2014)

6.7 Effect of flow-line pressure

A typical producer well does not only produce the reservoir fluid to the surface, instead it produces till the station where it is separated in to different phases. When the well is flowing to the station, the back pressure in the flow line is due to the separator or any other well connected to the same header (especially in case of a commingled flowline shared between wells). One of the reasons for a well to die the back pressure created on it during flowing period. During our operation, it is possible to flow the well to the station or connect it to a portable separator, along with tanks. When the well is connected to a portable separator, the back pressure created on the well head is not more than 100 psi. At the same time, the well has to be flowed for a short distance only, instead of a few kilometers in case of the flowing to the station. In our study, we wanted to examine the effect of flow line pressure, thus we chose six possible values of flow line pressure which are 80, 180, 280, 530, 780 and 1030 psi. The results are displayed in Figure 6-.

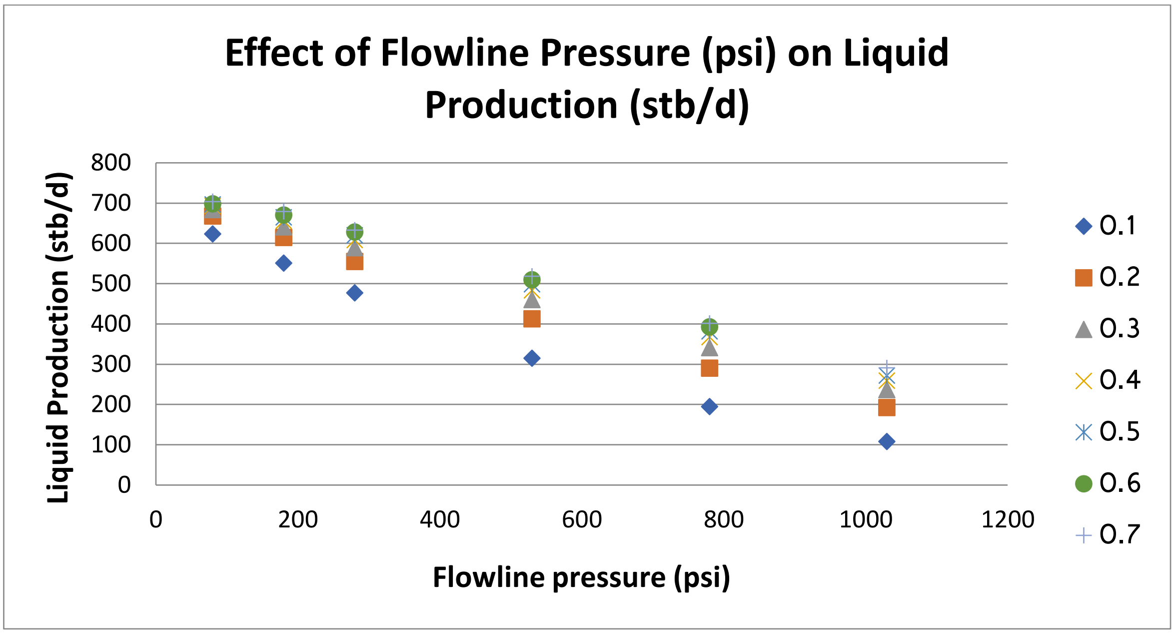

Figure 6-22: Effect of Flowline Pressure on Operation

The operation was conducted at different gas injection rates as well as flow line pressure. It can be observed that for a particular gas injection rate, the production rate reduces with increase in flow line pressure. This can be caused by backpressure of the system or even due to a physical barrier in the line. Therefore, it would be better to conduct this operation with a portable separator, which is almost at 1 or 2 atmospheric bar pressure. The short distant from separator to green burner or flare almost eliminates back pressure, which aids in our operation.

6.8 Verification of decision matrix

The Decision Matrix was used to plan and optimize a logging while nitrogen lifting operation. The well characteristics and reservoir parameters were used to decide the optimum gas injection rate while logging was conducted. Table 6-12 shows the well parameters of the selected well.

Well Type	Single Oil Producer
Measured Depth (ft)	10868 ft
Tubing Depth (ft)	3.5-inch tubing till 8919 ft
Reservoir Pressure (psi)	3926 psi
Gas Oil Ratio (scf/stb)	1210 scf/stb
Productivity Index (stb/d/psi)	5.1 stb/d/psi
Water Cut (%)	62%
Minimum Restriction (inch)	2.25-inch @ 8882’ MD
H_2S content	0%
Static Formation Temperature	200 ºF

Table 6-12: Well Properties

6.9 Operation parameter selection

The decision matrix from Table 6-6 is used to find the optimum gas injection rate based on the different well characteristics and reservoir properties. As per the decision matrix, the optimum gas injection rate of a well with reservoir pressure of 3900 psi, gas oil ratio (GOR) of 1200 scf/stb, productivity index (J) of 5 stb/d/psi and water cut of 60% is 0.3 MMscf/d. Since the parameters of the subject well were closest to this data set, 0.3 MMscf/d will be chosen as the gas injection rate for the operation.

Secondly, the size of minimum restriction was 2.25-inch at the R-nipple in the well completion. The coiled tubing size to be utilized for the operation had to be smaller than the minimum restriction size, at the same time should have been able to reach the end of open hole without getting locked up. At the same time, there had to be clearance between the minimum restriction and the coiled tubing to allow the reservoir fluid flow to the surface. A simulation was conducted by the contractor company to ensure the completion of the job with different sizes of coiled tubing. 1.5-inch sized coiled tubing was then selected based on all the constraints.

6.10 Job program

1. Deploy Wireline dummy tool and check for well accessibility through open hole section
2. Deploy Wireline PNX tool and perform Nitrogen lifting by pumping 4000 gal of liquefied nitrogen (LN_2) and proceed with logging for the horizontal open hole section while well is at flowing and shut-in conditions
3. Coiled tubing achieved targeted depth with 100% accessibility of open hole during dummy run.

6.11 Job execution

The first day of operation, a dummy run was conducted using coiled tubing with dummy downhole tools. The post job panel plot is presented in Figure 6-

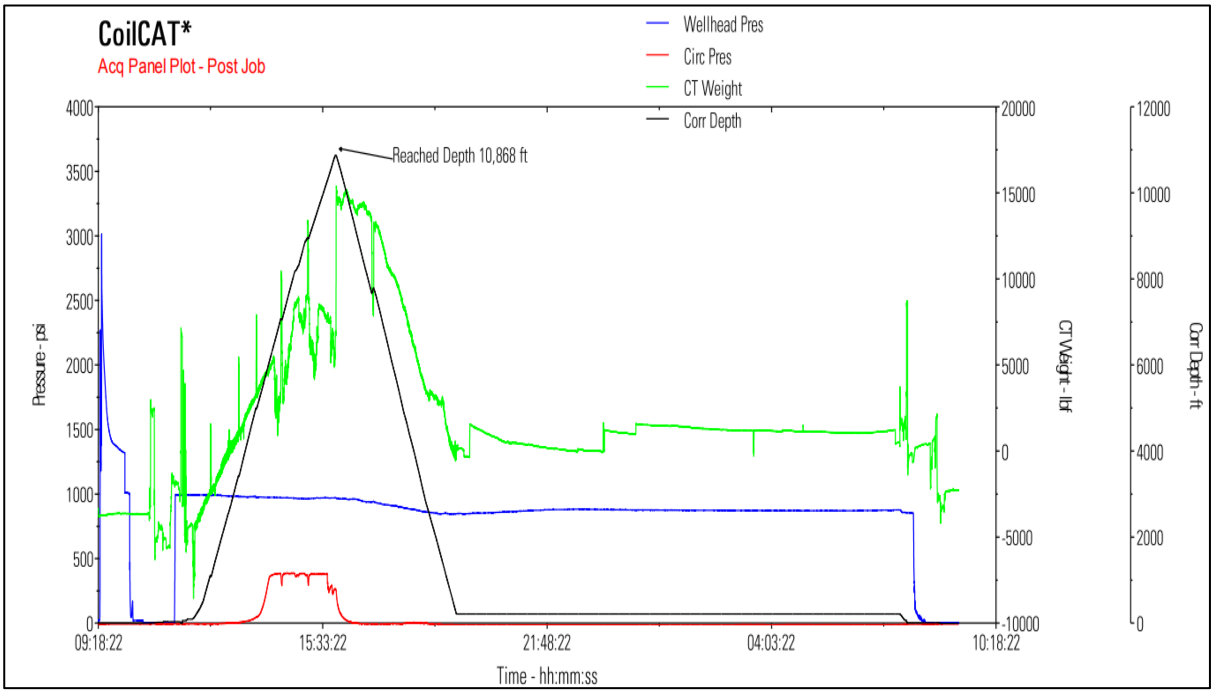

Figure 6-23: Dummy run post job plot

The main operation was conducted after the dummy run. In order to prepare the coiled tubing from dummy run to main operation, several components are added in the bottom hole assembly namely; connector head, cross over, wired check valve, multi-cycle disconnect and logging tools.

Nitrogen was pumped throughout the operation and the coiled tubing depth was dependent upon the rate of returns from the well. At the same time, once the logging commenced, nitrogen was continuously pumped to ensure the well will stay flowing. The plot during the main operation is present in the Figure 6-29.

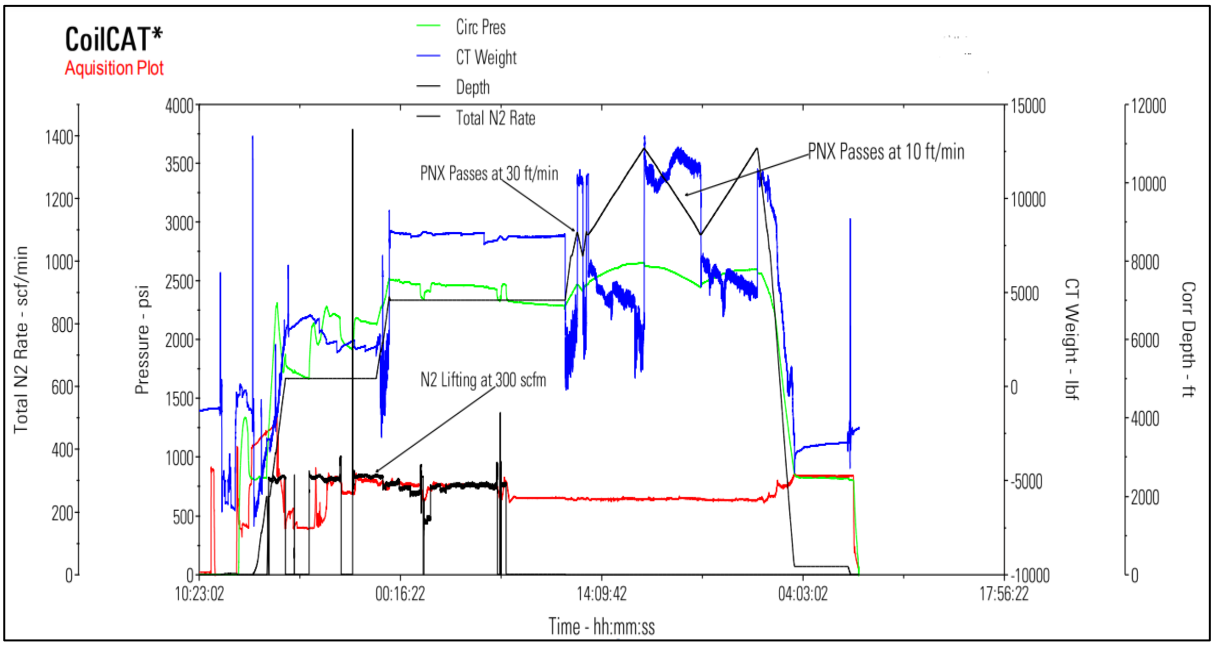

Figure 6-29: Main run post job plot

6.12 Job summary

The operation was designed to perform logging for the horizontal open hole section with pulse neutron (PNX) tool using 1.5-inch coiled tubing across 6-inch open hole section (8969-10868 ft) in order to monitor water saturations across reservoir layer. Nitrogen kick off was conducted while logging due to the water loading of well.

The job was performed without any major Health Safety and Environment (HSE) issues. The coiled tubing nitro-log operation was completed successfully. The success of this operation authenticates the feasibility of decision matrix.

6.13 Economics analysis

The economics of any operation is one of the vital factors to be considered before it can be ranked as optimum. There are quite a few elements with economic importance that are involved in such an operation. Firstly, there is daily operational charge of the coiled tubing unit. Secondly, there is a total amount of nitrogen that will be used throughout the operation. Lastly, there is the loss of production from the subject producer well. The producer well is however, already in the process of intervention, therefore the loss of production will not be a deciding factor in the economics of this project. On the other hand, time is always a constraint due to manpower commitment and logistical requirement.

It is possible to manipulate with these factors to find the optimum parameters for the subject operation. Nevertheless, there are few factors that are fixed and cannot be changed readily. Some of these factors include well tubing size, maximum pumping pressure, minimum injection pressure, coiled tubing size, reservoir fracture pressure, well tubing integrity, well accessibility, location limitations, manpower restrictions, etc. During the course of this project, the well will be assumed to have lifted once it has produced twice the well volume (bottoms up). Therefore, if the tubing and open hole volume is 200 bbl, then it will be assumed that the well has been lifted after it has produced 400 bbl of liquid to the surface.

The next step is to factorize the economic aspect of the simulation. This is achieved by first calculating the cost of operation of the base case scenario. The cost of such kind of operation is shown in **Error! Reference source not found.**, as follows:

$$Total\ cost = \frac{70000+(15000*No.of\ days)+(Required\ N2*10.2)}{3.65} \quad \ldots(0\text{-}6)$$

Total cost: Cost of operation

AED 70000: Cost of mobilization + Rig up of equipment

AED 15000: Daily Coiled tubing and nitrogen package charge

Required N_2: Amount of N_2 used in operation

10.2dhs/gal: Cost of N_2 per gallon

3.65 $/AED: Conversion of cost from dirhams to Dollars

Once the total cost of operation is calculated, it is then required to be factorized to be part of OEF as shown in **Error! Reference source not found.**, as follows:

$$Cost\ Factor = \frac{Cost\ of\ Simulated\ case - Cost\ of\ base\ case}{Cost\ of\ base\ case} \quad \ldots\ldots\ldots\ldots (0\text{-}7)$$

This leads us to formulate OEF as follows in **Error! Reference source not found.**:

$$OEF = (Differential\ Liquid\ Factor * 0.6) - (Cost\ factor * 0.4) \quad \ldots\ldots\ldots (0\text{-}8)$$

The OEF gives greater importance to differential liquid factor than cost of operation, with a ratio of 6:4. The optimum gas injection rate and pressure is based upon the case with the highest OEF. The value of OEF is comparable between all the simulation results

7. CHALLENGES AND MITIGATION STRATEGIES

7.1 Challenges

Nitrogen kickoff operations, commonly used in the oil and gas industry for well stimulation and enhanced oil recovery, can encounter several challenges:

Fluid compatibility: Ensuring the compatibility of nitrogen with the reservoir fluid is crucial. Incompatibility issues can lead to formation damage, reduced effectiveness of the kickoff operation, or even reservoir plugging.

Nitrogen purity and quality: The purity and quality of the nitrogen injected into the well are critical. Contaminants or impurities in the nitrogen stream can affect its performance and may lead to operational issues such as corrosion or reduced efficiency.

Pressure management: Managing the pressure during nitrogen kickoff operations is essential to prevent formation damage, blowouts, or casing failures. Controlling the pressure gradient between the wellbore and formation is crucial for safe and effective nitrogen injection.

Injection rate and volume: Optimizing the injection rate and volume of nitrogen is necessary to achieve the desired stimulation or recovery objectives. Injecting nitrogen too quickly or in excessive volumes can lead to poor distribution within the reservoir or cause undesirable effects such as channelling.

Temperature control: Temperature variations can affect the behaviour of nitrogen in the wellbore and reservoir. Proper temperature control measures must be implemented to prevent issues such as phase changes, hydrate formation, or thermal cracking of reservoir fluids.

Reservoir heterogeneity: Variations in reservoir properties such as permeability, porosity, and fluid composition can affect the distribution and effectiveness of nitrogen injection. Reservoir heterogeneity may lead to uneven stimulation or recovery results and requires careful planning and monitoring.

Formation integrity: Assessing the integrity of the formation and wellbore is essential before conducting nitrogen kickoff operations. Weak formations or compromised wellbore integrity can result in fluid loss, sand production, or casing damage during nitrogen injection.

Equipment reliability: Ensuring the reliability and functionality of nitrogen injection equipment, including pumps, compressors, valves, and surface piping, is crucial for the success of kickoff operations. Equipment failures or malfunctions can disrupt operations and lead to downtime and cost overruns.

Safety and environmental considerations: Nitrogen kickoff operations involve handling a potentially hazardous gas and must be conducted with strict adherence to safety protocols and environmental regulations. Mitigating risks such as gas leaks, fire hazards, and environmental contamination is paramount to protect personnel, assets, and the environment.

Addressing these challenges requires comprehensive planning, risk assessment, and implementation of best practices in nitrogen kickoff operations. Close monitoring and continuous evaluation of operational parameters are essential to identify and mitigate potential issues effectively. Additionally, ongoing research and development efforts aim to improve techniques, technologies, and methodologies for optimizing nitrogen injection for well stimulation and enhanced oil recovery.

7.2 Mitigation strategies

Mitigating technical, operational, and logistical challenges in nitrogen kickoff operations requires a comprehensive approach that addresses various aspects of the process. Here are some strategies for each category:

Technical challenges:

Reservoir characterization: Conduct thorough reservoir characterization to understand the geological and petrophysical properties of the reservoir. This includes identifying heterogeneities, fluid behaviour, and potential barriers to nitrogen distribution.

Fluid compatibility testing: Perform laboratory tests to assess the compatibility of nitrogen with reservoir fluids and formation materials. This helps prevent issues such as formation damage or fluid incompatibility during injection.

Modeling and simulation: Utilize reservoir simulation and modeling techniques to predict the behaviour of nitrogen in the reservoir. This allows for the optimization of injection parameters such as rate, volume, and pressure to maximize effectiveness.

Temperature control: Implement temperature control measures to ensure that nitrogen remains in its gaseous state throughout the injection process. This may involve surface heating or insulation to maintain reservoir temperature conditions.

Operational challenges:

Quality control: Establish rigorous quality control procedures to ensure the purity and quality of nitrogen delivered to the wellsite. Regular testing and monitoring of nitrogen composition help prevent operational issues caused by impurities or contaminants.

Pressure management: Implement effective pressure management strategies to control the pressure gradient between the wellbore and formation. This includes monitoring and adjusting injection pressures to prevent formation damage or casing failures.

Injection rate optimization: Optimize injection rates based on reservoir characteristics and performance objectives. This may involve conducting injection tests, analyzing pressure responses, and adjusting injection parameters accordingly. Heavy slugs are expected during kick off operations and this may lead to separator overflow

Wellbore integrity: Conduct comprehensive wellbore integrity assessments before and during nitrogen kickoff operations. This helps identify potential integrity issues such as leaks, casing corrosion, or mechanical failures that could compromise operation safety and effectiveness. Always monitor Annulus pressures during the operations as unexpected packer failure may arise during kick off operations.

Logistical challenges:

Equipment readiness: Ensure that nitrogen injection equipment is properly maintained, tested, and ready for operation. This includes regular inspections, preventive maintenance, and contingency planning to address equipment failures or malfunctions. Pressure safety relief valves are tested and certified for N_2 tanks. Maintain Proper insulation on N_2 tanks.

Supply chain management: Establish robust supply chain management practices to secure a reliable source of nitrogen and other necessary materials. This involves coordinating with suppliers, monitoring inventory levels, and implementing backup plans to mitigate supply disruptions. Especially for offshore operations, well planning and supply chain management is necessary to supply N_2 on time for the operations.

Personnel training and competency: Provide comprehensive training and competency assurance programs for personnel involved in nitrogen kickoff operations. This includes training on safety protocols, operational procedures, and emergency response to ensure that personnel are prepared to handle various challenges effectively.

Contingency planning: Develop contingency plans to address unexpected challenges or emergencies that may arise during nitrogen kickoff operations. This includes identifying potential risks, establishing response protocols, and allocating resources to mitigate adverse impacts on operations and safety.

By implementing these strategies, operators can enhance the efficiency, safety, and effectiveness of nitrogen kick-off operations while mitigating technical, operational, and logistical challenges. Regular monitoring, evaluation, and continuous improvement efforts are essential to optimize performance and achieve desired outcomes in well stimulation and enhanced oil recovery projects.

8.ENVIRONMENTAL CONSIDERATIONS:

Environmental considerations play a significant role in nitrogen (N2) kickoff operations, particularly in ensuring that the process is conducted safely and responsibly to minimize potential impacts on the environment. Here are several key environmental considerations:

Air quality: Nitrogen gas itself is non-toxic and inert, but the combustion of hydrocarbons in the presence of oxygen can produce nitrogen oxides (NOx), which contribute to air pollution. Operators must implement measures to minimize NOx emissions during nitrogen kickoff operations, such as optimizing combustion efficiency and using emissions control technologies.

Greenhouse gas emissions: While nitrogen gas itself is not a greenhouse gas, the equipment used in N2 kickoff operations, such as pumps, compressors, and generators, may produce emissions of greenhouse gases such as carbon dioxide (CO2) and methane (CH4). Operators should strive to minimize these emissions through the use of cleaner fuels, energy-efficient equipment, and emission reduction technologies. In some operations, N2 kick off and flow to clean operations are combined, where well fluids are flared using vertical flare stack and green burners. Un controlled flow of fluids may arise during operations causing unburned gases, spillage of fluids etc.

Spill prevention and response: Accidental spills of nitrogen or other chemicals used in kickoff operations can pose risks to soil, water, and wildlife. Operators must have robust spill prevention and response plans in place to minimize the likelihood of spills and to quickly contain and remediate any spills that occur. In some areas N2 kick off of water injector wells been diverted to water pits, uncontrolled flow of fluids may cause spillage to outside of pits and nearby areas thereby causing environmental pollution.

Water management: Water is often used in conjunction with nitrogen during kickoff operations to enhance well stimulation. Operators should carefully manage water usage to minimize impacts on local water sources, ecosystems, and aquatic habitats. This may include using recycled or treated water where possible and implementing measures to prevent water contamination or depletion.

Habitat protection: Kickoff operations may take place in or near sensitive habitats, such as wetlands, wildlife habitats, or protected areas. Operators should conduct thorough environmental assessments to identify potential impacts on these habitats and implement mitigation measures to minimize disturbances and protect biodiversity.

Noise and visual impact: Nitrogen kickoff operations can generate noise and visual disturbances, particularly in residential or recreational areas. Operators should implement measures to minimize noise levels, such as using sound barriers or scheduling operations during off-peak hours, and to mitigate visual impacts through screening or landscaping.

Regulatory compliance: Operators must comply with environmental regulations and permit requirements governing nitrogen kickoff operations, including air quality standards, water discharge limits, habitat protection measures, and spill prevention protocols. Compliance with these regulations helps ensure that operations are conducted in an environmentally responsible manner.

By considering these environmental factors and implementing appropriate mitigation measures, operators can minimize the environmental footprint of nitrogen kickoff operations and contribute to sustainable resource development. Collaboration with regulators, environmental stakeholders, and local communities is essential to address environmental concerns effectively and to achieve a balance between energy production and environmental protection.

9: FUTURE TRENDS AND INNOVATIONS:

9.1 Emerging technologies and advancements in nitrogen kickoff techniques.

Emerging technologies and advancements in nitrogen kickoff techniques aim to improve efficiency, effectiveness, and environmental sustainability. Here are some notable developments:

Nitrogen foam fracturing: Foam fracturing involves blending nitrogen with surfactants and water to create a stable foam that enhances fracture propagation and fluid mobility in the reservoir. This technique reduces fluid consumption, minimizes formation damage, and improves well productivity compared to conventional water-based fracturing.

Smart injection systems: Advanced injection systems equipped with sensors, real-time monitoring capabilities, and automated controls optimize nitrogen injection parameters such as rate, pressure, and volume. Smart injection systems improve operational efficiency, ensure precise delivery of nitrogen into the reservoir, and enable rapid adjustments in response to changing reservoir conditions.

Nitrogen membrane separation units: Membrane separation units selectively separate nitrogen from air, allowing on-site generation of high-purity nitrogen gas. These units eliminate the need for nitrogen transportation and storage, reduce operational costs, and enhance safety by minimizing the handling of compressed gases.

Reservoir characterization technologies: Advanced reservoir characterization techniques, such as seismic imaging, electromagnetic surveys, and microseismic monitoring, provide detailed insights into reservoir properties, fluid behavior, and geomechanical characteristics. Accurate reservoir characterization enhances the design and optimization of nitrogen kickoff operations, leading to improved reservoir performance and recovery efficiency.

Chemical additives and surfactants: Innovative chemical additives and surfactants enhance the performance of nitrogen kickoff operations by reducing friction, improving fluid mobility, and enhancing reservoir stimulation. Tailored chemical formulations mitigate formation damage, improve wellbore cleanup, and optimize nitrogen foam stability, leading to more effective reservoir treatment and production enhancement.

In-situ gas generation technologies: In-situ gas generation technologies, such as in-situ combustion and microbial enhanced oil recovery (MEOR), produce nitrogen or other gases within the reservoir through chemical reactions or microbial activity. These technologies eliminate the need for external gas supply, reduce operational costs, and enhance reservoir sweep efficiency, particularly in mature or low-pressure reservoirs.

Data analytics and artificial intelligence (AI): Data analytics and AI algorithms analyse vast amounts of operational and reservoir data to identify patterns, optimize nitrogen injection strategies, and predict reservoir performance. AI-driven decision support systems improve reservoir management, reduce uncertainties, and enhance the effectiveness of nitrogen kickoff operations through data-driven insights and predictive analytics.

Carbon capture and storage (CCS): Integrated nitrogen kickoff and CCS technologies capture carbon dioxide (CO2) produced during hydrocarbon recovery and inject it into the reservoir along with nitrogen for enhanced oil recovery. This approach reduces greenhouse gas emissions, mitigates climate change impacts, and enhances the sustainability of nitrogen kickoff operations by promoting carbon-neutral or carbon-negative energy production.

These emerging technologies and advancements demonstrate ongoing innovation and research efforts aimed at optimizing nitrogen kickoff techniques, increasing energy efficiency, and reducing environmental impacts in the oil and gas industry. Collaboration among industry stakeholders, research institutions, and government agencies is essential to accelerate the adoption and deployment of these technologies and to address global energy and environmental challenges effectively.

9.2 Potential areas for further research and development in n2 kick off operation

Further research and development in nitrogen (N2) kickoff operations can focus on several key areas to address existing challenges, improve efficiency, and enhance environmental sustainability. Here are some potential areas for future exploration:

Fluid-rock interactions: Investigate the complex interactions between nitrogen and reservoir fluids, rock formations, and pore structures. Understanding how nitrogen behaves in different reservoir conditions, including variations in temperature, pressure, and fluid composition, can optimize injection strategies and improve reservoir performance.

Enhanced reservoir characterization: Develop advanced techniques for reservoir characterization, including high-resolution imaging, geochemical analysis, and geomechanical modeling. Enhanced reservoir characterization provides valuable insights into reservoir properties, heterogeneities, and fluid behavior, enabling more accurate prediction of nitrogen injection outcomes and reservoir response.

Optimization of injection parameters: Explore novel approaches for optimizing nitrogen injection parameters such as rate, pressure, volume, and injection interval spacing. Advanced modeling, simulation, and optimization algorithms can identify optimal injection strategies tailored to specific reservoir conditions, production goals, and operational constraints.

Erosion and corrosion mitigation: Develop innovative materials, coatings, and corrosion inhibitors to mitigate erosion and corrosion issues associated with nitrogen kickoff operations. Advanced materials science and surface engineering technologies can enhance the durability and integrity of wellbore components exposed to high-pressure nitrogen injection.

Integrated multi-phase flow modeling: Develop integrated multi-phase flow models that accurately simulate the behavior of nitrogen, reservoir fluids, and formation gases during kickoff operations. These models consider complex fluid-rock interactions, phase behavior, and flow dynamics to optimize injection strategies, predict reservoir performance, and minimize environmental risks.

Smart injection systems: Innovate smart injection systems equipped with advanced sensors, actuators, and control algorithms for real-time monitoring and adaptive control of nitrogen injection operations. Smart injection systems optimize injection parameters, detect anomalies, and adjust operational settings to maximize efficiency, safety, and environmental performance.

Sustainable nitrogen generation: Research alternative methods for sustainable nitrogen generation, such as renewable energy-powered nitrogen production, biological nitrogen fixation, or electrochemical nitrogen synthesis.

Sustainable nitrogen generation reduces dependence on fossil fuels, minimizes carbon emissions, and enhances the environmental sustainability of kickoff operations.

Environmental impact assessment: Conduct comprehensive environmental impact assessments to evaluate the potential ecological, air quality, water usage, and carbon footprint implications of nitrogen kickoff operations. Integrated life cycle assessments (LCAs) provide valuable insights into the environmental risks and benefits associated with different nitrogen injection techniques and deployment scenarios.

By addressing these research areas, the oil and gas industry can advance nitrogen kickoff operations, improve reservoir recovery efficiency, and minimize environmental impacts. Collaboration among industry stakeholders, research institutions, and regulatory agencies is essential to drive innovation, promote knowledge exchange, and accelerate the adoption of sustainable nitrogen injection technologies.

10: CONCLUSION

Summary of key findings and insights.

Being a common operation, it is expected to have answers to all questions for nitrogen lifting operation. However, due to the large number of parameters involved in the operation, it is difficult to optimize all of them at in parallel.

This research is an initial work showing the potential of using the decision matrix in optimizing this nitrogen lifting operation in horizontal / highly deviated well at different reservoir and surface conditions. The objectives of this research are:

1) Analysis of nitrogen lifting operation performance based on successful and unsuccessful cases
2) Formation of Decision matrix based on the analysis of nitrogen lifting operations
3) Verification of decision matrix based on data set and simulation results

To achieve those objectives the following research method was followed:

1) Identifying the exact problem and defining its different aspects
2) Gather all the data available before conducting an operation – Reservoir and Operation constraints
3) Simulate PVT data from PVT Flex and simulate the operation using Wellflo® to obtain results for different factors including; reservoir pressure, productivity index, water cut, gas oil ratio, coiled tubing size and flow line size.
4) Gather different results produced from simulation and select the optimum result from each simulation to input in Decision Matrix
5) Use literature review and critical analysis skills to identify and reason the trends present in decision matrix.

Conclusions

From the results obtained from this research the following conclusions are drawn:

1) Well model was created using WellFlo® incorporating PVT properties from PVTFlex®
2) Optimum Economic Factor was formulated as a Deciding Factor
3) From the results, following were concluded:
    a. Optimum gas injection rate was reduced with increase in Gas Oil Ratio
    b. Optimum gas injection rate was increased with increase in Water cut
    c. Optimum gas injection rate was reduced with increase in Reservoir Pressure

   d. Optimum gas injection rate was reduced with increase in Productivity Index
4) Limiting agent as a priority in our well scenario in terms of decrease in influence: Gas oil ratio, Water cut, Productivity Index, Reservoir Pressure
5) Use of Coiled tubing package on an hourly basis, instead of daily rental charges can lead to significant cost reduction

Recommendations

The following recommendations in the field of Nitrogen Lifting operation in Horizontal / Highly deviated well research can be considered for future studies:

1) Effect of Dogleg Severity and depth
2) Use of other gas instead of Nitrogen
3) Using emulsified fluids to study the effect of emulsions on lifting can be explored.
4) Mechanical integrity of the coiled tubing with depth was not studied before and would be vital in the future to understand the long-term use of such equipment in downhole conditions and the life expectancy of the equipment.

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APPENDIX A

A.1. Fluid types – PVT Properties

Table 0-1 describes some PVT properties of different fluid types. The initial pressure assumes pressure above bubble point or dew point

Table 0-1: Fluid types - PVT properties (Mcain, 2011)

Fluid Type	Initial Gas- Oil Ratio*, scf/stb	Stock Tank Oil Gravity, °API	C7+, Mole%
Dry Gas	>100,000	No liquid	< 0.5
Wet Gas	15,000 – 100,000	>35	0.5 – 4
Gas Condensate	3,200 – 15,000	30 to >70	4 – 12.9
Volatile Oil	1,900 – 3,200	30 to > 60	12.9 – 18
Indeterminate	1,500 – 1,900	-	18 – 26.5
Black Oil	<1,500	<10 to >60	>26.5

Each of the reservoir fluid types can be found in the Figure 0-1. A single-phase gas reservoir is at Point A that represents the virgin reservoir. As the gas is produced from the reservoir, its fluid's temperature remains constant; however, it decreases in pressure and follows the dashed line toward A1. In such cases, the reservoir never enters the two-phase envelope and as a result, the reservoir is entirely gas throughout its entire life cycle. In case the produced fluid decreases both in temperature and pressure, then it will follow the trend towards A2. It does enter the two phase envelope and some liquids will be produced.

The retrograde gas condensate reservoirs also start out as gas but at a different point, point B. As the fluid is produced, the fluid remaining in the reservoir drops into the dew point, where two phased fluid is present, denoted by B1. At this point liquids start to be produced in the reservoir. The amount of liquids continue to increase until it reaches B2 and then vaporization of that retrograde liquid in the reservoir begins to occur until it reaches abandonment pressure (B3).

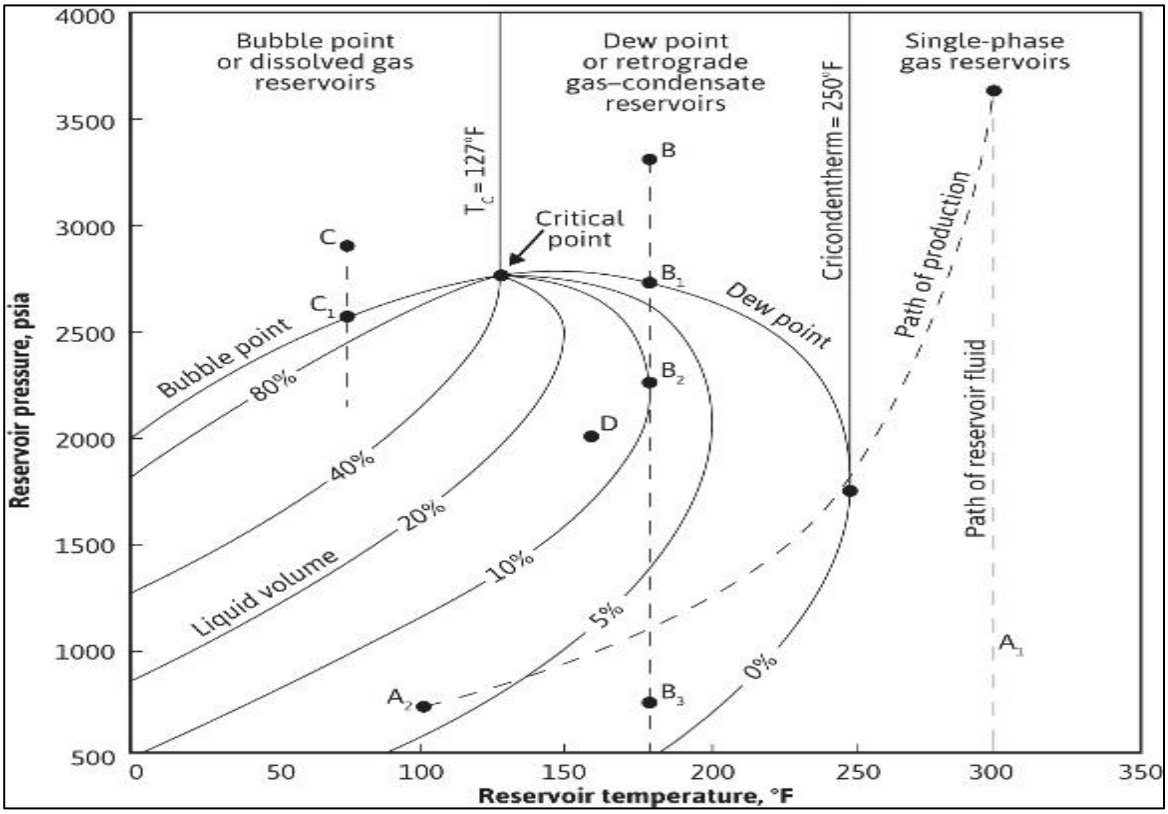

Figure 0-1: Phase envelope - Two phase diagram for different reservoir fluids (Rogers and Terry, 2014)

The third, under-saturated reservoirs (also called dissolved gas reservoirs) differ from the first in that the fluid exists as a liquid in the reservoir at initial conditions. As pressure declines to bubble point pressure, denoted by C1, the first bubbles of 'dissolved' gas begin to appear (at which point the reservoir is said to be saturated). As pressure continues to drop, the liquid volume in the reservoir decreases and more gas is liberated out of the oil. As oil is the primary product, pressure maintenance strategies in this reservoir type is crucial.

Finally we come to our saturated oil reservoirs. At initial conditions, this reservoir already has both liquid and gas present. These phases have separated overtime due to density differences resulting in a 'gas cap' over the reservoir. Typically, the reservoir is produced in the oil zone, allowing the expansion of the gas cap to assist in maintaining a high reservoir pressure.

A.2. Black oil properties

Bubble Point (P_b) - The pressure and temperature conditions at which the first bubble of gas comes out of solution in oil. When the reservoir is saturated, a slight decrease in pressure and temperature will allow gas to be released from it. In case of an under-saturated reservoir, there is a margin in which the pressure can be lowered before reaching bubble point.

Solution Gas Oil Ratio (R_s) - Dissolved gas in wellbore or reservoir fluids. As the pressure and temperature decrease, gas is liberated from oil which is its R_s. Its unit is (scf/stb)

Oil Formation Volume Factor (B_o) - The volume of oil and dissolved gas within reservoir is different from oil volume at surface due to the difference in pressure and temperature. However, both the volumes are important for us as the surface volume is the one used for exporting and consumption, and the reservoir volume relates to original oil in place and reserves. Oil formation volume factors are almost always greater than 1.0 because the oil in the formation usually contains dissolved gas that comes out of solution in the wellbore with dropping pressure. Its unit is (bbl/stb).

Equation 0-1: Oil formation volume factor

$$B_{o}=\frac{Volume\ of\ Oil\ @\ Res.Conditions}{Volume\ of\ Oil\ @\ Surface\ Conditions}$$

Gas Formation Volume Factor (B_g) - The volume of gas within reservoir is different from gas volume at surface due to the difference in pressure and temperature. This factor is used to convert surface measured volumes to reservoir conditions, just as oil formation volume factors are used to convert surface measured oil volumes to reservoir volumes. Its unit is (res.cu.ft/scf).

Equation 0-2: Gas Formation Volume Factor

$$\mathbf{B}_{g}=\frac{\textbf{Volume of Gas @ Res.Conditions}}{\textbf{Volume of Gas @ Surface Conditions}}$$

A.2.1. Oil Density (lbm/ft^3)
Density of reservoir oil is given by the following equation

Equation 0-3: Density of oil

$$\rho_o = \frac{350.161\gamma_o + 0.0764\gamma_g R_s}{5.614589B_o}$$

A.2.2. Black-Oil Correlations

These correlations are formulated for non-volatile liquids, black oils. They are based on fluids with similar characteristics, especially fluids produced at the same location. They are used to estimate

1. Saturation Pressure
2. Solution Gas-Oil-Ratio
3. Formation Volume Factor
4. Viscosity

A.2.2.1. Tuning of Correlations

The correlations are made on a general scale to make it useable on a larger spectrum of reservoir's range. They are derived empirically and are based on petroleum fluids from a specific region. Therefore, in order to use them properly and effectively, field and experimental data of well/reservoir is required to tune the correlation. Tuning will lead to getting the best possible match between field/experimental data and the results obtained with correlations. The data required to tune the correlations can be attained using laboratory PVT data of fluid

1. Simulate experiments / flashes
2. Data fitting using nonlinear regression algorithm

A.2.2.2. General Considerations

1. Gas viscosity data is not measured but calculated by correlation
2. Must make a sensible choice of tuning parameter
3. Must take the form of the correlation equation into account

Example: Go to the Tuning section and perform different runs using different correlations

To check numerical results, click on Graph Data button. It can be observed from the Figure 0-2 below, there are several results from different correlations. After comparison to actual lab data, the correlations giving mismatching data can be discarded.

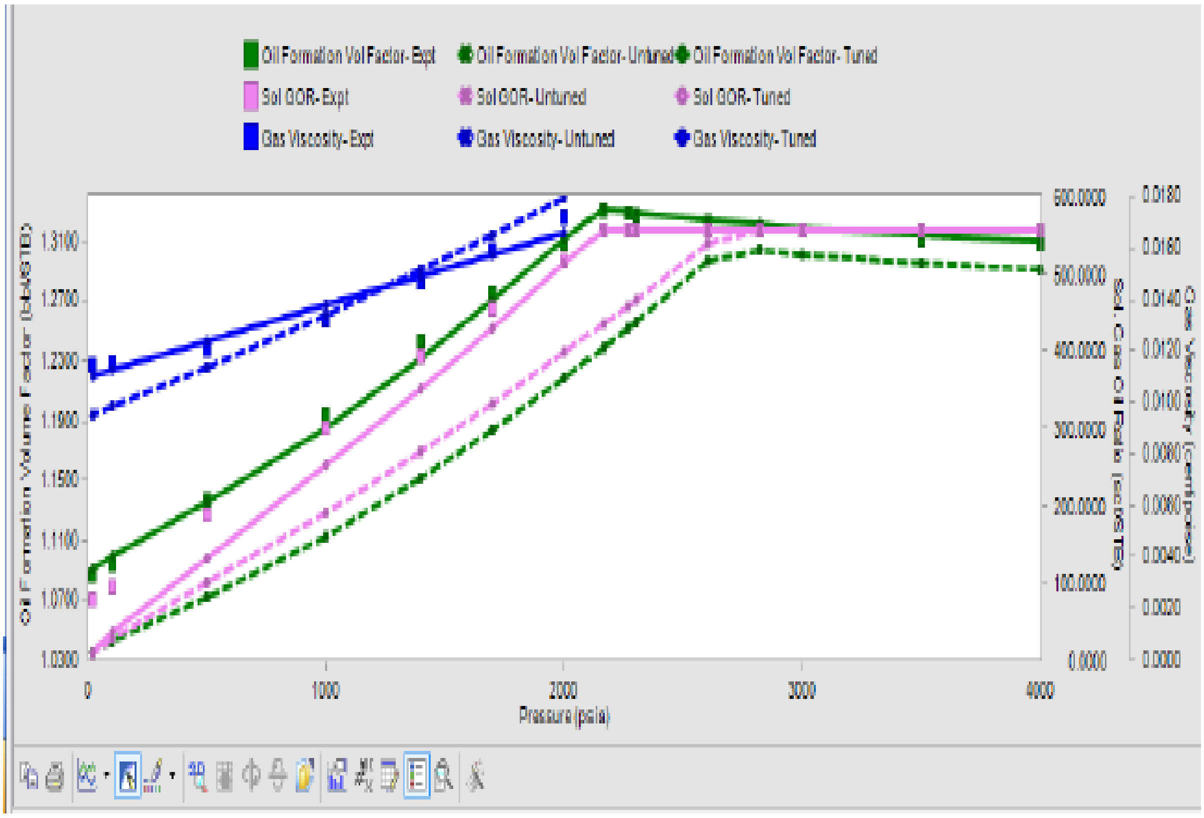

Figure 0-2: Comparisons of results from several correlations with actual data (Weatherford, 2011)

After the mismatched data is cleared out, the graph is greatly simplified and matches with the actual data as shown in Figure 0-3.

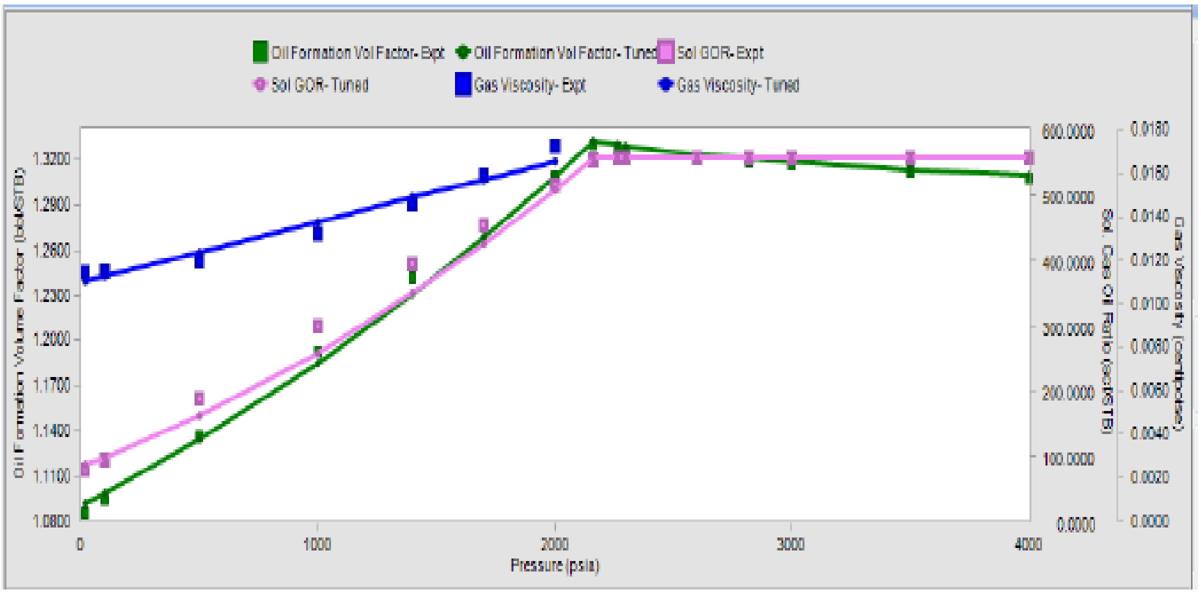

Figure 0-3: Results of matching correlation with actual data (Weatherford, 2011)

APPENDIX- B

B.1. Frictional pressure drop

Pressure drop or pressure gradient is present in all sorts of piping and tubing. It is highly dependent upon the fluid's velocity, geometry of tubing, flow regime and roughness of walls.

B.1.1. Fluid velocity

The fluid velocity and pressure gradient are directly proportional, such that the higher the fluid velocity, the greater is the pressure gradient.

B.1.1.1. Geometry of tubing

The wall of a conduit is primary source of friction which increases pressure drop gradient. Thus, the ratio of surface area of conduit's wall to its cross-sectional area perpendicular to flow direction is a key factor. The ratio is termed as hydraulic radius.

B.1.1.2. Flow regime

A turbulent flow loses more energy than laminar flow. Thus, pressure gradient is higher with higher Reynold's number.

B.1.1.3. Roughness of walls

Pressure drop gradient is higher in tubing with rougher walls. This roughness is called roughness factor of the conduit.

The Darcy- Weisbach equation incorporates all the above-mentioned factors to calculate pressure drop, ΔP, in a circular conduit per unit length, L, as follows

Equation 0-4: Darcy-Weisbach equation

$$\frac{\Delta P}{L} = f\frac{\rho v^2}{2d}$$

Where ρ is fluid density, d is pipe diameter, v is the average velocity, and f is the friction factor.

The equation is simplified due to the simple geometry of pipe, straight and circular pipe, which is captured in the diameter, d.

The other two factors, roughness and flow regime are established by friction factor, which has been found experimentally and plotted in the Moody diagram, depicted in Figure 0-4.

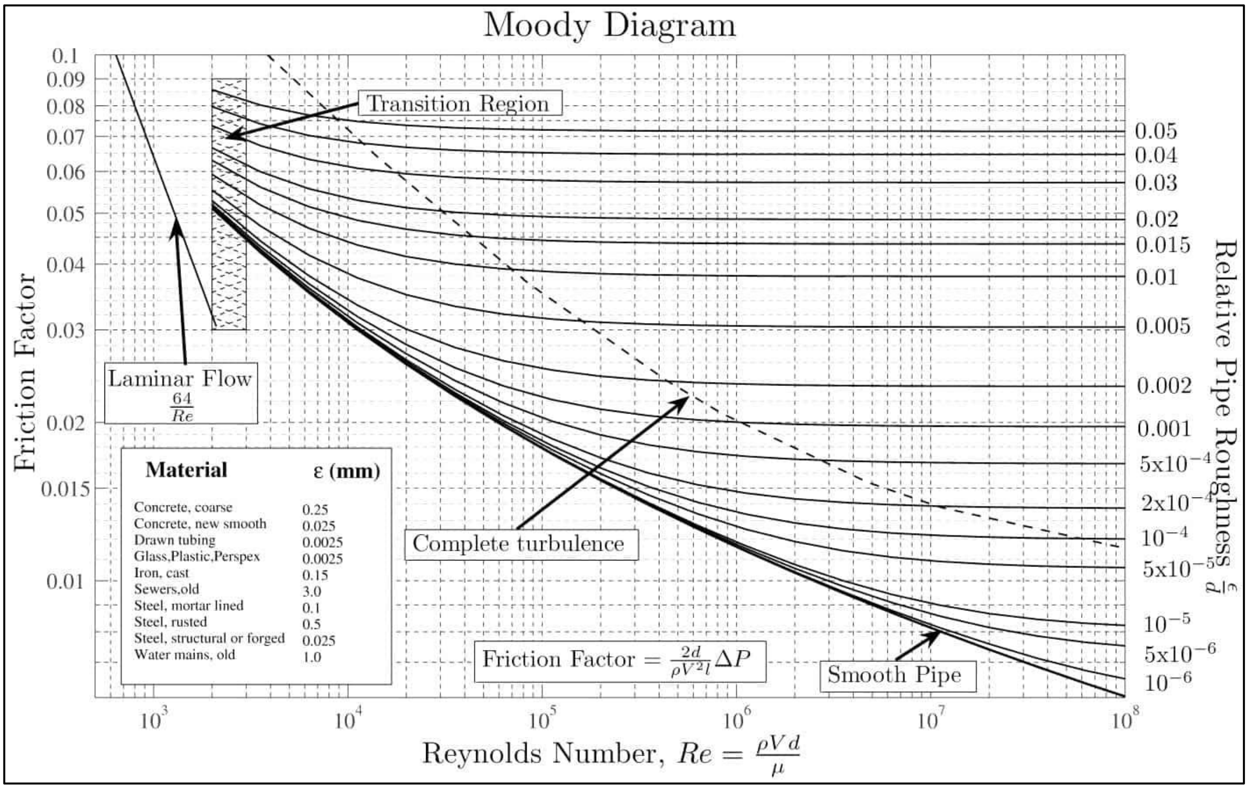

Figure 0-4: The Moody Diagram

The friction factor is linked to the Reynolds number in laminar flow. The Reynolds number is:

Equation 0-5: Reynolds number

$$Re = \frac{\rho v d}{\mu}$$

Flow is laminar when Re<2000. In the laminar range, the friction factor is

Equation 0-6: Friction factor- Laminar flow

$$f = \frac{64}{Re}$$

Combining last three equations results as:

Equation 0-7: Pressure drop- Laminar Flow

$$\frac{\Delta P}{L} = f\frac{\rho v^2}{2d} = \frac{64\rho v^2}{Re2d} = \frac{32\mu}{d^2}v$$

The final equation, Equation 0-7, proves the proportionality of pressure drop with fluid velocity during laminar flow, which is identical to Darcy's law which is also for laminar flow conditions. This shows that the pressure drop is proportional to the velocity in a pipe during laminar flow. This is the same result as Darcy's Law, which is also for laminar conditions. During turbulent flow, i.e. Re>2000, wall roughness also becomes quite significant. That is the reason of Moody diagram having multiple lines, one for a different value of wall roughness for turbulent flow.

The wall roughness is denoted by the ratio $\varepsilon/_{d}$, where Ɛ is the average height of roughness. For example, if the pipe was lined with well sorted sand particles, then Ɛ would be the radius of the sand grains. A chart of the roughness of various pipe materials is given in the lower left corner of Figure 0-4. The line that bounds the low end of the pressure gradient for a given Reynolds number describes the behavior of a smooth-walled pipe.

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APPENDIX-C

C.1. Inflow Performance Relationship

Inflow Performance Relationship (IPR) is defined as the well flowing bottom hole pressure (P_{wf}) as a function of production rate. It describes the flow in the reservoir to the bottom hole of the well. The lowest value of P_{wf} is zero, which achieves the highest flow rate of reservoir fluid, also known as absolute open flow (AOF).

In practice, it is not possible to achieve this rate, as the p_{wf} should have a finite value. The highest value of P_{wf} is same as reservoir pressure, at which the flow rate of reservoir fluid is zero. Figure 0-1 below shows a typical IPR curve.

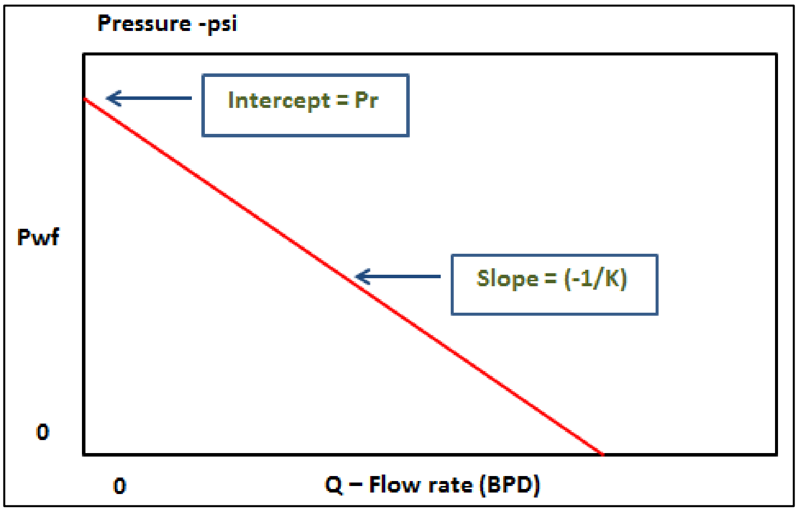

Figure 0-1: Typical Inflow Performance Relationship curve

Figure 0-1 is hypothetical since it does not take gas release from reservoir oil in to account when p_{wf} goes lower than bubble point pressure. The reservoir pressure depletes with time due to production and thus, the IPR curve shifts downwards as shown in Figure 0-2.

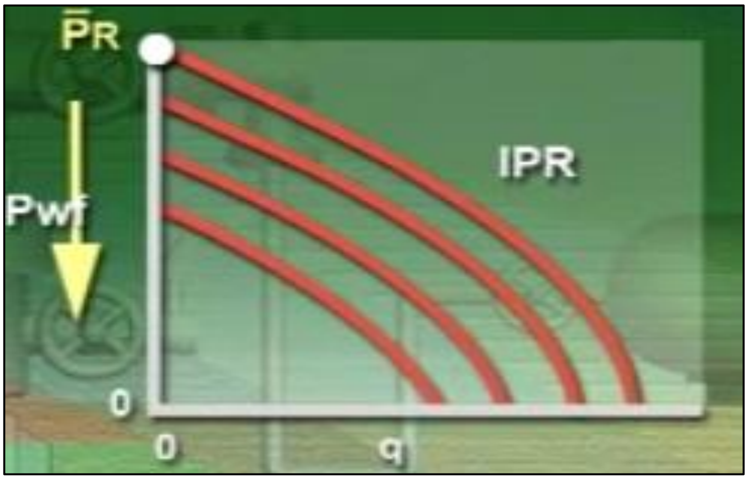

Figure 0-2: IPR of a reservoir with depletion

IPR is a straight line above the bubble point pressure. In this case, the productivity index (J), which is also the slope of curve, is constant. Below the bubble point, as gas is released from solution and reduces energy of liquid, the curve trends downwards. This particular shape of IPR is characteristic of reservoirs with solution gas drive as shown in Figure 0-2. Reservoirs with other drive systems, such as water drive, gas expansion, gravity segregation or a combination of these drives, will have a different shape of IPR curves.

C.2. Vertical Lift Performance

Vertical Lift Performance (VLP), is described by flowing bottom hole pressure (P_{wf}) as a function of flow rate. It represents the flow of fluid from the bottom of well to the surface. It depends on several factors such as tubing size, restrictions, well depth, fluid's PVT properties, GOR, water cut and flow line pressure.

IPR and VLP are mostly plotted together in a P_{wf} against flow rate curve as shown in Figure 0-3. Both curves relate wellbore flowing pressure to surface flow rate. IPR shows the reservoir's ability to bring fluid to well while VLP shows the well's ability to flow the fluid to the surface. The intersection of the two curves is called the operating point, which states the production rate of a well at certain operating conditions.

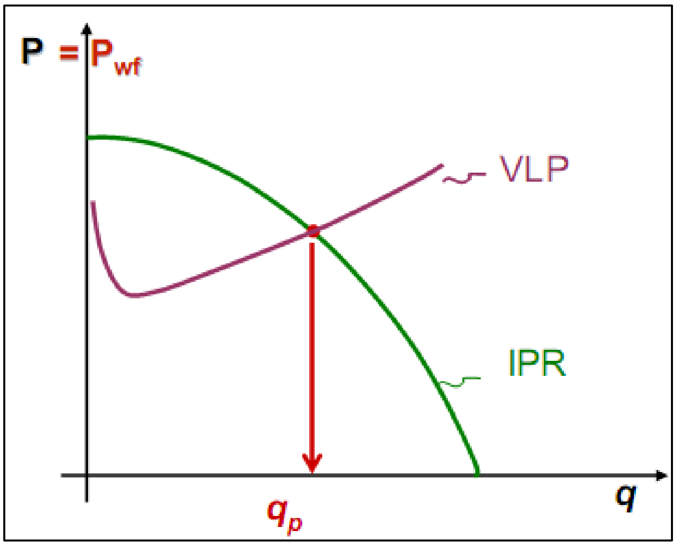

Figure 0-3: IPR vs VLP

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APPENDIX-D

D.1. Parameters Used to Build Well Model

As mentioned earlier, the parameters that are incorporated in a well model can be divided into two categories namely, reservoir parameters and well properties. Each of them is explained in the following sections along with the program's interface layout.

D.1.1. Well Properties

Well properties include the well type, flow type, fluid type and well orientation. The well type gives the options to choose between producer, injector and pipeline.

Figure 0-1: Well and Flow type (Weatherford, 2011)

Once the option of producer is chosen, it further provides an option to choose the artificial lift method, if any applies.

The next section allows choosing between flow paths of the produced/injected fluid. It can be either tubing, annular or a combination of both. The options of fluid type selection consist of heavy oil, black oil, volatile oil and dry gas. It is mainly dependent upon the API gravity of the produced fluid. The last category in this section is the well orientation that allows us to choose between vertical, horizontal or multi-frac flow as shown in Figure 0-1.

The next category to describe the well type includes adding the details from the drilling phase of the well.

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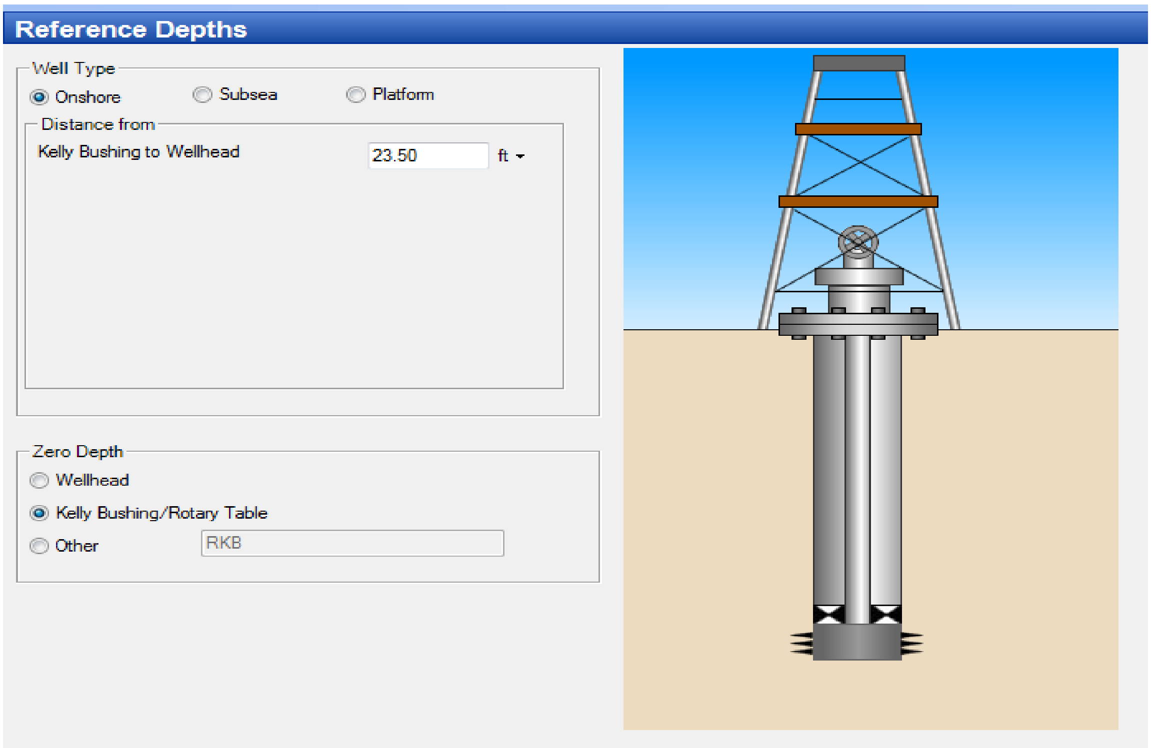

Figure 0-2: Reference Depths (Weatherford, 2011)

Firstly, it gives the option to choose the location of the well between onshore, subsea and platform. Next it requires adding the distance from Kelly bushing to wellhead. At the end it requires the zero depth to be used in the well model. The choice is to be made between wellhead, Kelly bushing/ rotary table or any other location. The data input interface is shown in Figure 0-2

The next requirement is in the wellbore category which requires the addition of deviation table from the drilling phase. This shows the deviation of the well as it is extended into the ground as shown in Figure 0-3.

	Measured Depth	True Vertical Depth	Segment Deviation from Vertical
	ft	ft	deg
1	0.00	0.00	0.0000
2	100.00	99.99	0.8103
3	200.00	199.96	1.4035
4	300.00	299.94	1.1459
5	400.00	399.93	0.8103
6	500.00	499.92	0.8103
7	600.00	599.91	0.8103
8	700.00	699.90	0.8103
9	800.00	799.89	0.8103
10	900.00	899.88	0.8103
11	1000.00	999.87	0.8103
12	1100.00	1099.86	0.8103
13	1200.00	1199.85	0.8103
14	1300.00	1299.85	0.0000
15	1400.00	1399.84	0.8103
16	1500.00	1499.83	0.8103
17	1600.00	1599.83	0.0000
18	1700.00	1699.83	0.0000
19	1800.00	1799.83	0.0000
20	2100.00	2099.82	0.4678
21	2200.00	2199.81	0.8103
22	2300.00	2299.81	0.0000
23	2400.00	2399.80	0.8103
24	2500.00	2499.79	0.8103
25	2600.00	2599.77	1.1459
26	2700.00	2699.76	0.8103
27	2800.00	2799.75	0.8103
28	2900.00	2899.74	0.8103
29	3000.00	2999.74	0.0000
30	3100.00	3099.73	0.8103
31	3200.00	3199.72	0.8103
32	3300.00	3299.72	0.0000
33	3400.00	3399.71	0.8103

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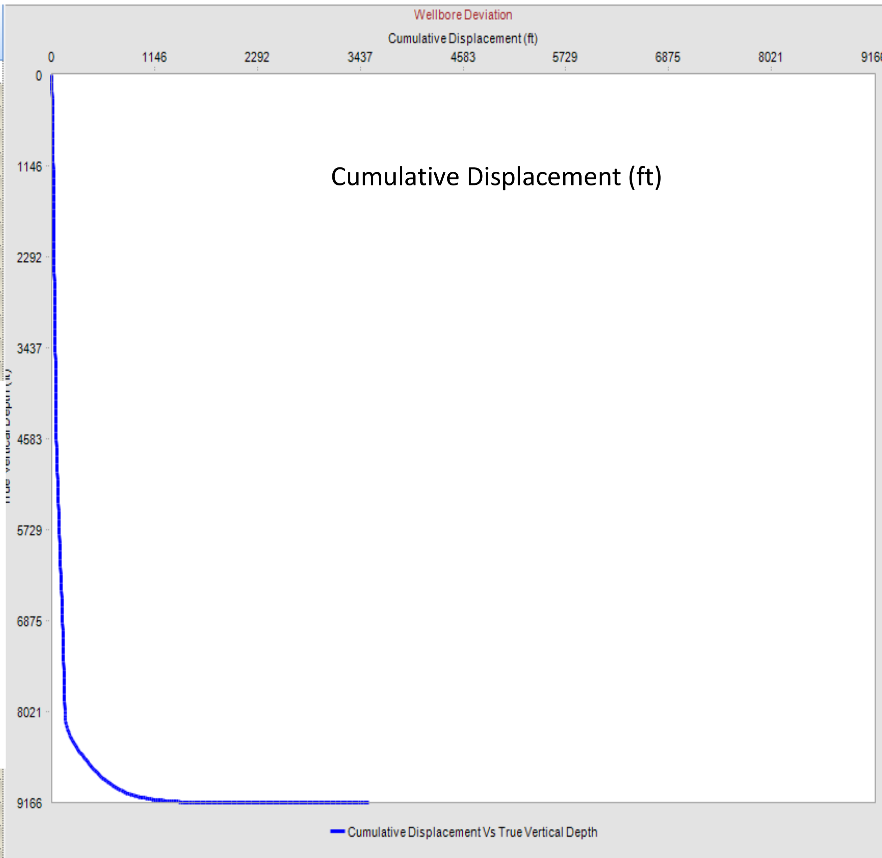

Figure 0-3: Wellbore Deviation

(Weatherford, 2011)

The true vertical depth (TVD) is used mainly in the hydrostatic pressure calculations. However, the deviation is required in other calculations, such as friction.

The category of equipment in wellbore section requires detailed input of the equipment in which the flow is contained. The flowing conduit is the 3.5-inch tubing in this case, as shown in Figure 0-4. It includes the location of starting and ending location of equipment, inner and outer diameter as well as its absolute roughness. Important information added here is location of flow. It can be either inside tubing or annular which means outside tubing. This identifies the exact flow path taken by the fluid path.

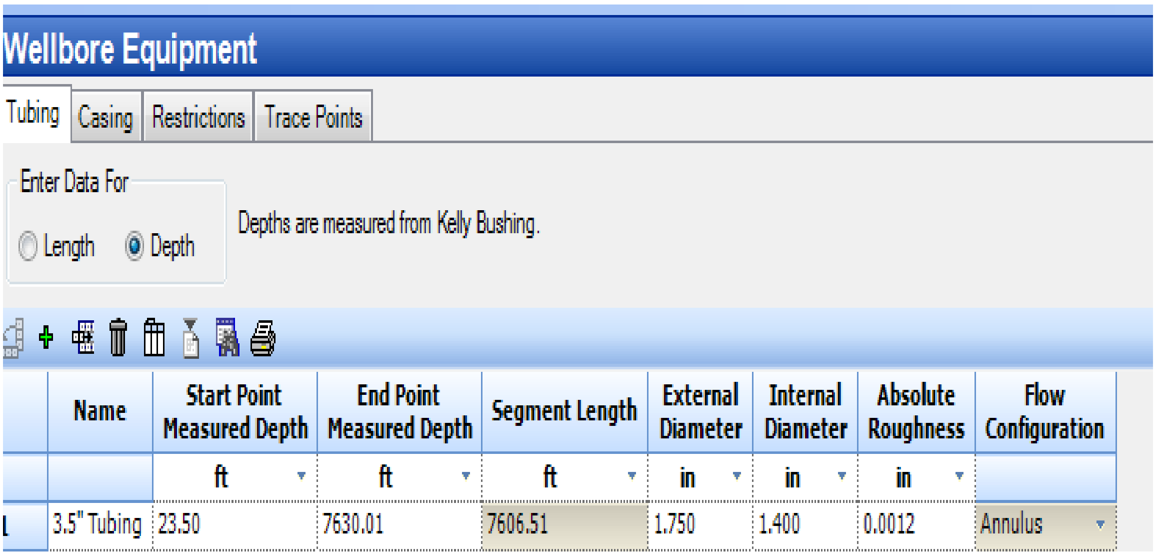

Figure 0-4: Wellbore- Equipment (Weatherford, 2011)

D.2. Reservoir Parameters

The reservoir parameters are divided into fluid properties, reservoir layers data, surface data and flow correlations. The fluid properties category involves input of PVT properties.

Firstly, the PVT calculation method has to be selected, which can be either black oil or compositional oil. In the next step, the specific gravity of oil and gas needs to be specified, along with °API gravity of the oil, water salinity and water gravity. In addition, composition of other inorganics, H_2S, CO_2 and N_2, are also required here. Further tuning of PVT data is also conducted in this category, as shown in Figure 0-5.

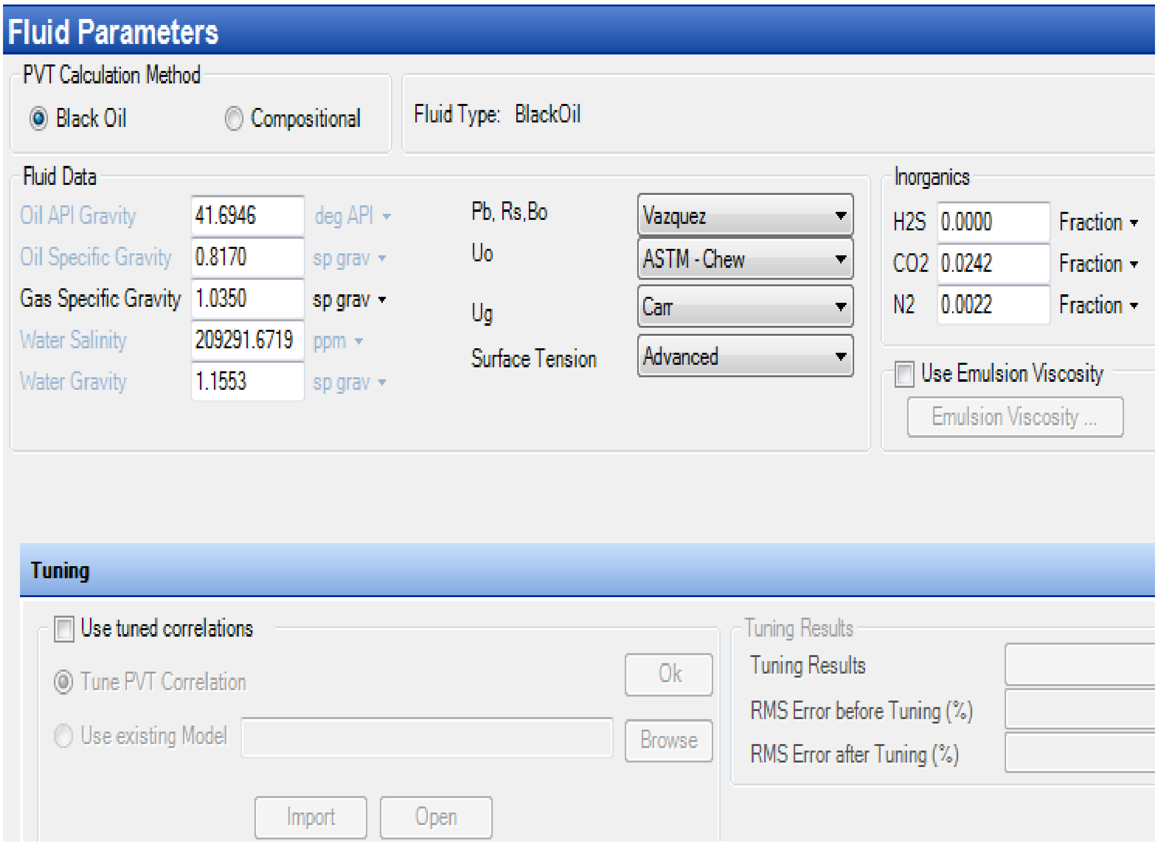

Figure 0-5: Fluid Parameters (Weatherford, 2011)

The next category is called reservoir and it is related to the information of reservoir layers. The values of pressure, temperature, mid-perf depth, water cut and gas oil ratio have to be specified in this section. Other key inputs required here are the IPR model type and Productivity Index as shown in Figure 0-6.

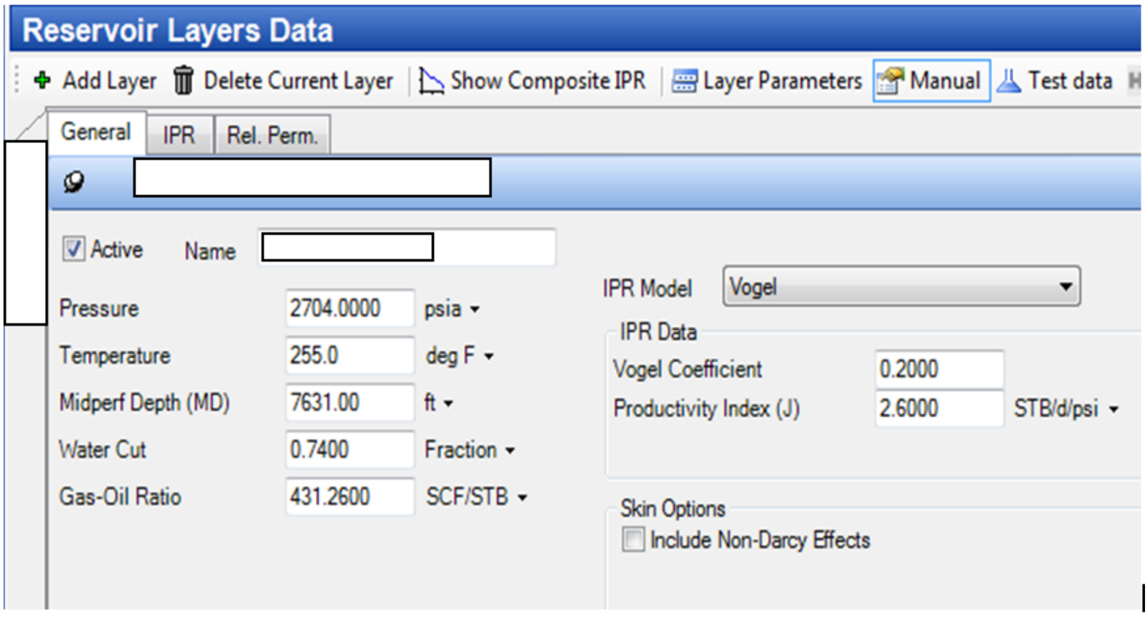

Figure 0-6: Reservoir Layers Data (Weatherford, 2011)

In the category of temperature model, the surface surrounding temperature and bottom hole temperature is used to create a temperature gradient and profile of the well as shown in Figure 0-7.

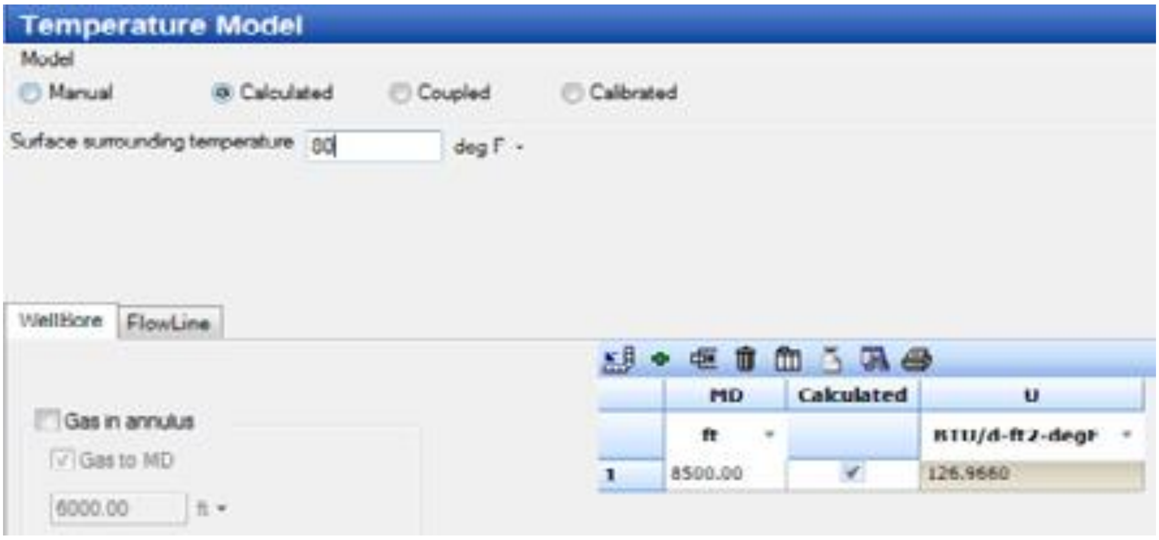

Figure 0-7: Temperature Model (Weatherford, 2011)

The flow correlations category allows the user to choose different flow regimes for different areas of the well. As the fluid moves from bottom to the top of well or from top to bottom of the well, the pressure and temperature changes significantly which changes the fluid phase distribution. The fluid behaves differently in different phases as well as when present in more than one phase.

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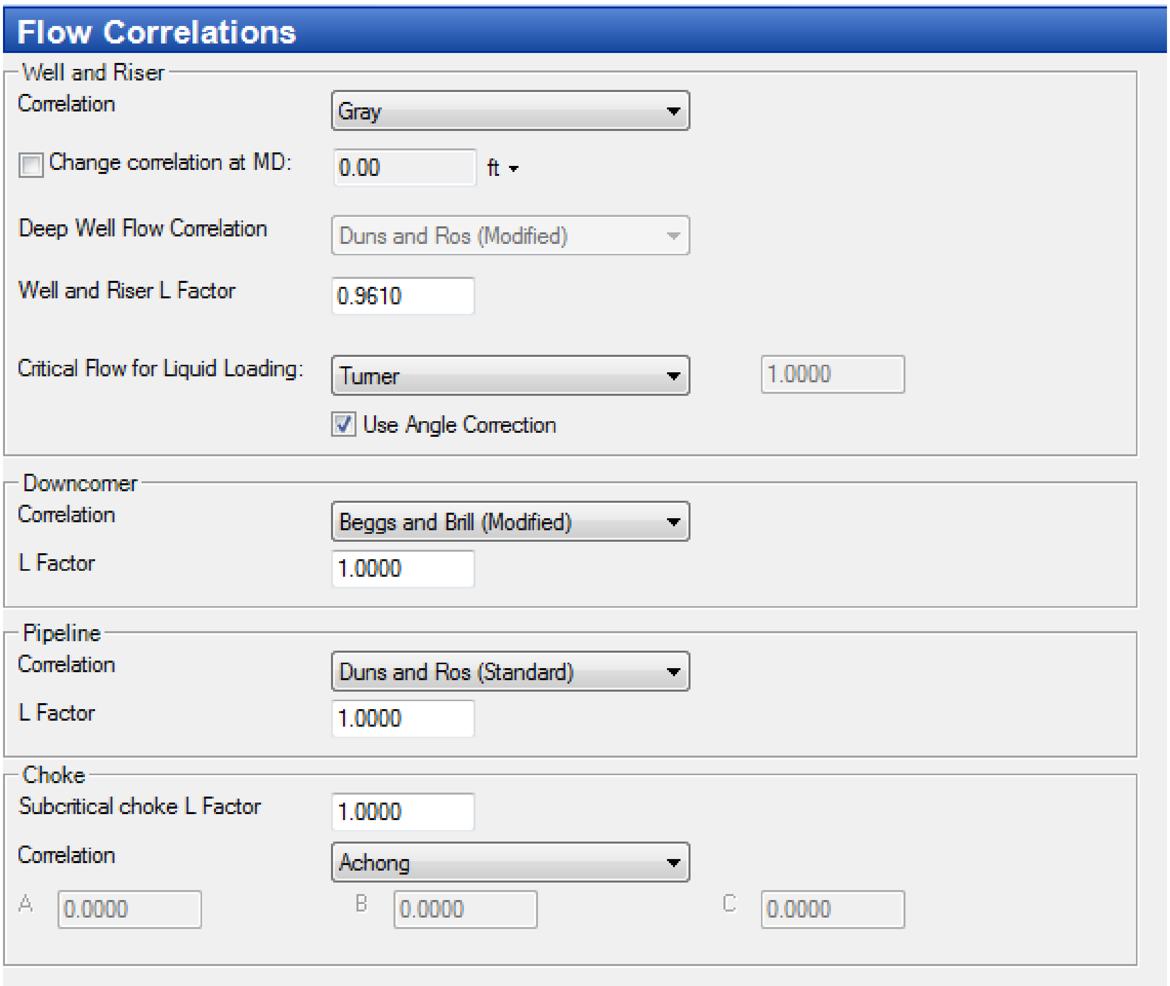

Figure 0-8: Flow correlations (Weatherford, 2011)

This is the reason of having different fluid flow regimes in different sections of the well. The locations at which the flow regimes are requested in this category are well and riser, downcomer, pipeline and choke as shown in Figure 0-8.