TECHNICAL UNIVERSITY OF CRETE

SCHOOL OF MINERAL RESOURCES ENGINEERING

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EFFECT OF TUBING DESIGN ON OPTIMUM PRODUCTION

A Thesis By:

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The undersigned hereby certify that they have read and recommended for acceptance to the Faculty of Mineral Resources Engineering a thesis by Chnur Abubakr Arif titled "EFFECT OF TUBING DESIGN ON OPTIMUM PRODUCTION" in partial fulfillment of the criteria for the degree of Master of Science.

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Abstract

Tubing design plays a major role in the production of the Well/field and economy of the whole project. In this project, the key factors in designing the tubing will be discussed in detail, from the reservoir, type of fluids, flow assurance, flexibility in operation, safety, etc.

Tubing strings must be sized correctly among almost 10 different tubing sizes that have been tried in this project to allow the fluids to flow effectively or to permit the installation of effective artificial lift equipment.

The results will be applied to some existing Wells, with aim of increasing the production and minimizing the cost of production per barrel of oil.

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Introduction

Tubing is the normal flow conduit used to transport produced fluids to the surface or fluids to the formation. Its use in wells is normally considered a good operating practice. The use of tubing permits better well control because circulating fluids can kill the well; thus, workovers are simplified, and their results enhanced. Flow efficiency typically is improved with the use of tubing. Furthermore, tubing is required for most artificial lift installations. Tubing with the use of a packer allows isolation of the casing from well fluids and deters corrosion damage of the casing. Multi-completions require tubing to permit individual zone production and operation. Governmental rules and regulations often require tubing in every well. Permission may be obtained for the omission of tubing in special cases (tubingless completions). These special completions typically are flowing wells with relatively small casings. Tubing strings are generally in outside diameter (OD) sizes of 2.3/8 to 4.1/2 in. but may be as large as 20 in. or as small as 1.050 in. [1]

The proper selection, design, and installation of tubing string are critical parts of any well completion. Tubing strings must be sized correctly to enable the fluids to flow efficiently or to permit the installation of effective artificial lift equipment.

The tube must be constructed to withstand all stresses and conditions encountered during normal well operating, with a sufficient leeway for unexpected load circumstances. It must endure the strains of tension, rupture, and collapse, as well as the corrosive effects of well fluids during the course of the well's life. Furthermore, the tubing must be handled and installed in such a way that it generates the well without failing or causing undue operating difficulties. It is hoped that these requirements will be met for as long as possible before another well configuration is required. The reason to run smaller tubing is to increase the velocity for a given rate and sweep the liquids out of the well and the tubing. In general, faster velocity reduces the liquid holdup (% liquid by volume in the tubing) and lowers the flowing bottomhole pressure attributed to gravity effects of the fluids in the tubing. However, tubing too small for the production rate can cause excess friction and require a larger flowing bottomhole pressure. There are many other methods of deliquefying a gas well, and tubing design must be compared to other possible methods before making a final decision. [12]

Tubing Specifications [13]:

The grade, exterior diameter, weight, and connection of tubing are all factors to consider. With the exception of P grade tubing, which has a tensile strength of 105,000psi and is referred to as P105, API tube grades correlate to casing grades.

	Tubing size		Nominal Weight		Grade	Wall Thickness in	Inside Diam. in	Threaded coupling				Collapse Resistance psi	Internal Yield pressure psi	Joint Yield Strength		Capacity Table	
	Nam. in	OD in	T&C Non Upset Ib/ft	T&C Upset Ib/ft				Drift Dia. in	Coupling outside Dia. Non upset in	Upset Reg. in	Upset spec. in			T&C Non Upset Ib	T&C Upset Ib	Barrels per linear ft	Linear ft per barrel
A	0.75	1.05	1.14	1.2	H-40	0.113	0.824	0.73	1.313	1.66		7200	7530	6360	13300	0.0007	1516.13
					J-55							9370	10360	8740	18290		
					C-75							12250	14120	11920	24940		
					N-80							12710	15070	12710	26610		
B	1	1.315	1.7	1.8	H-40	0.113	1.049	0.955	1.66	1.9		6820	7080	10960	19760	0.0011	935.49
					J-55							8860	9730	15060	27160		
					C-75							11590	13270	20540	37040		
					N-80							12270	14160	12910	39510		
C	1.25	1.66	2.3	2.4	H-40	0.125	1.41	1.286	2.054	2.2		5220	5270			0.0019	517.79
					H-40	0.14	1.38					5790	5900	15530	26740	0.0018	540.55
					J-55	0.125	1.41					6790	7250			0.0019	517.79
					J-55	0.14	1.38					7530	8120	21360	36770	0.0018	540.55
					C-75	0.14	1.38					9840	11070	29120	50140	0.0018	540.55
					N-80	0.14	1.38					10420	11810	31060	53480	0.0018	540.55
D	1.5	1.9	2.75	2.9	H-40	0.125	1.65	1.516	2.2	2.5		4450				0.0026	378.11
					H-40	0.145	1.61					5290		19090	31980	0.0025	397.14
					J-55	0.125	1.65					5790				0.0026	378.11
					J-55	0.145	1.61					6870		26250	43970	0.0025	397.14
					C-75	0.145	1.61					8990	10020	35800	59960	0.0025	397.14
					N-80	0.145	1.61					9520	10680	38180	63980	0.0025	397.14
E	2.065	2.063	3.25		H-40	0.156	1.751					5240	5290			0.003	335.75
					J-55							6820	7280				
					C-75							8910	9920				
					N-80							9440	10590				
F	2.375	2.375	4		H-40	0.167	2.041	1.947	2.875	3.063	2.91	4880	4920	30130		0.004	247.12
			4.6	4.7	H-40	0.19	1.995	1.901				5520	5600	35960	52170	0.0039	258.65
			4		J-55	0.167	2.041	1.947				6340	6770	41430		0.004	247.12
			4.6	4.7	J-55	0.19	1.995	1.901				7180	7700	49450	71730	0.0039	258.65
			4		C-75	0.167	2.041	1.947				8150	9230	56500		0.004	247.12
			4.6	4.7	C-75	0.19	1.995	1.901				9380	10500	67430	97820	0.0039	258.65
			5.8	5.95	C-75	0.254	1.867	1.773				12180	14040	96560	126940	0.0034	295.33
			4		N-80	0.167	2.041	1.947				8660	9840	20260		0.004	247.12
			4.6	4.7	N-80	0.19	1.995	1.901				9940	11200	71930	104340	0.0039	258.65
			5.8	5.95	N-80	0.254	1.867	1.773				12890	14970	102990	135400	0.0034	295.33
			4.6	4.7	P-105	0.19	1.995	1.901				13250	14700	94410	136940	0.0039	258.65
			5.8	5.95	P-105	0.254	1.867	1.773				17190	19650	135180	177710	0.0034	295.33
G	2.875	2.875	6.4	6.5	H-40	0.217	2.441	2.347	3.5	3.668	3.46	5230	5280	52780	72480	0.0058	172.76
			6.4	6.5	J-55	0.217	2.441	2.347				6800	7260	7258	99660	0.0058	172.76
			6.4	6.5	C-75	0.217	2.441	2.347				8900	9910	98970	135900	0.0058	172.76
			8.6	8.7	C-75	0.308	2.259	2.165				12200	14060	149360	185290	0.005	201.72
			6.4	6.5	N-80	0.217	2.441	2.347				9420	10570	105570	144960	0.0058	172.76
			8.6	8.7	N-80	0.308	2.259	2.165				12920	15000	159310	198710	0.005	201.72
			6.4	6.5	P-105	0.217	2.441	2.347				12560	13870	138560	190260	0.0058	172.76
			8.6	8.7	P-105	0.308	2.259	2.165				17220	19690	209100	260810	0.005	201.72
H	3.5	3.5	7.7		H-40	0.216	3.068	2.943	4.25	4.5	4.18	4070	4320	65070		0.0091	109.37
			9.2	9.3	H-40	0.254	2.992	2.867				5050	5080	79540	103610	0.0087	114.99

			10.2		H-40	0.289	2.922	2.797				5680	5780	92550		0.0083	120.57
			7.7		J-55	0.216	3.068	2.943				5290	5940	89470		0.0091	109.37
			9.2	9.3	J-55	0.254	2.992	2.867				6560	6980	109370	142460	0.0087	114.99
			10.2		J-55	0.289	2.922	2.797				7390	7950	127250		0.0083	120.57
			7.7		C-75	0.216	3.068	2.943				6690	8100	122010		0.0091	109.37
			9.2	9.3	C-75	0.254	2.992	2.867				8530	9520	149140	194260	0.0087	114.99
			10.2		C-75	0.289	2.922	2.797				9660	10840	173530		0.0083	120.57
			12.7	12.95	C-75	0.375	2.75	2.625				12200	14060	230990	276120	0.0073	136.12
			7.7		N-80	0.216	3.068	2.943				7080	8640	130140		0.0091	109.37
			9.2	9.3	N-80	0.254	2.992	2.867				9080	10160	159090	207220	0.0087	114.99
			10.2		N-80	0.289	2.922	2.797				10230	11560	185100		0.0083	120.57
			12.7	12.95	N-80	0.375	2.75	2.625				12920	15000	246390	294530	0.0073	136.12
			9.2	9.3	P-105	0.254	2.992	2.867				12110	13330	208800	271970	0.0087	114.99
			12.7	12.95	P-105	0.375	2.75	2.625				17200	19690	323390	386570	0.0073	136.12
I	4	4	9.5	11	H-40	0.226	3.548	3.423	4.75	5		3580	3960	72000		0.0122	81.78
					H-40	0.262	3.476	2.351				4420	4580		123070	0.0117	85.2
					J-55	0.226	3.548	3.423				4650	5440	99010		0.0122	81.78
					J-55	0.262	3.476	3.351				5750	6300		169220	0.0117	85.2
					C-75	0.226	3.548	3.423				5800	74200	1350101		0.0122	81.78
					C-75	0.262	3.476	3.351				7330	8600		230750	0.0117	85.2
					N-80	0.226	3.548	3.423				6120	7910	144010		0.0122	81.78
					N-80	0.262	3.475	3.351				7780	9170		246140	0.0117	85.2
J	4.5	4.5	12.6	12.75	H-40	0.271	3.958	3.833	5.2	5.563		3930	4220	104360	144020	0.0152	65.71
					J-55							5100	5800	143500	198030		
					C-75							6430	7900	195680	270240		
					N-80							6810	8430	208730	288040		

Table 1: Different Tubing sizes and specifications

Non-upset (NUE) and external upset (EUE) ends are available on tubing. Because cutting threads into the tubing ends does not diminish body strength, EUE tubing is more commonly used.

Internal diameter (ID): the ID is calculated from the OD and wall thickness and is used to calculate pressure losses and velocities.

The diameter of a 42” long mandrel that goes through the tubing-joint is the drift diameter. It's a crucial characteristic since it determines the maximum OD of any equipment that can pass through the tubing string.

Maximum outside diameter: it depends on the nominal diameter and the connection type. It is critical as it determines the string's size that we can run in a given casing.

Nominal size: is the outside diameter of the pipe body. The most used sizes are: 2-⅜”, 2⅞”, 3-½” and 4-½”.

Nominal weight: is the average linear weight of the tubing, connection included. It is expressed in lb/ft. It determines the tubing wall thickness.

Steel grade: there are mainly two different types of steel used to manufacture tubing:

- API standard steels and grades for tubing: J55, C75, L80, N80, C90, and P105. The letter is a characteristic of the chemical composition and sometimes the thermal treatment. The number following the letter is the minimum body yield stress in 1000psi and it is the minimum body yield stress guaranteed by the manufacturer.
- Stainless steel, alloys, and special pipe:

When carbon dioxide and/or hydrogen sulfide are part of the produced fluids, it could necessary to use stainless steel, alloys, and special pipe.

API tapered triangular threaded connections:

API proposes two types NUE & EUE coupling:

- With an increased wall thickness and diameter (called Upset) giving better tensile strength. It is called an External Upset End (EUE)
- No increase in diameter at the end of the pipe body, it is a called Non-Upset End (NUE)

Mechanical properties of tubing pipe:

The pipe that runs into the well is subjected to varying pressures and temperatures, as well as its weight, all of which cause stress changes. The following are the key mechanical features of tubing pipe:

- Tensile strength is the maximum longitudinal stress a metal can withstand without tearing.
- Collapse pressure: the minimum differential pressure applied from outside that the tubing can withstand without permanent distortion, given in psi or MPa.
- Internal yield pressure, also known as burst pressure, is the internal differential pressure that causes tubing to fail.

CHAPTER ONE

Inflow and Outflow Performance

1.1 Typical Production system:

- ✓ Reservoir
- ✓ Wellbore
- ✓ Tubular goods and associated equipment
- ✓ Surface wellhead, flowlines, and processing equipment
- ✓ Artificial lift equipment

The Reservoir is the porous, permeable media in which the reservoir fluids are stored and through which the fluids will flow to the wellbore. It also furnishes the primary energy for the production system. The wellbore serves as the conduit for access to the reservoir from the surface. It is composed of the drilled wellbore, which normally has been cemented and cased. The cased wellbore houses the tubing and associated subsurface production equipment, such as packers. The tubing serves as the primary conduit for fluid flow from the reservoir to the surface, although fluids also may be transported through the tubing-casing annulus.

The wellhead, flowlines, and processing equipment represent the surface mechanical equipment required to control and process reservoir fluids at the surface and prepare them for transfer to a purchaser. Surface mechanical equipment includes the wellhead equipment and associated:

- ✓ Valving
- ✓ Chokes
- ✓ Manifolds
- ✓ Flowlines
- ✓ Separators
- ✓ Treatment equipment
- ✓ Metering devices
- ✓ Storage vessels

1.2 Flow through production system

Recognizing the various components of the production system and understanding their interaction generally leads to improved well productivity through analysis of the entire system. As the fluid flows from the reservoir into and through the production system, it experiences a continuous pressure drop.

The pressure starts at the average reservoir pressure and ends in the stock tank near atmospheric pressure or at the pressure of the transfer line. The reservoir fluids are produced to the surface in either circumstance, resulting in a significant pressure reduction. The pressure reduction depends on the production rate and, at the same time, the production rate depends on the pressure change. [4]

A systematic strategy to integrating the production system components is essential to effectively design a well completion or anticipate the production rate. This is accomplished using systems analysis (also known as nodal analysis), which allows the petroleum engineer to examine production systems as well as design well completions. Understanding the flow of reservoir fluids through the production system, particularly inflow performance (IPR), which is the reservoir pressure-rate behavior of the individual well, and outflow performance or vertical lift performance (VLP), which is the flow of reservoir fluids through the piping system, is critical for proper well and reservoir management.

Nodal analysis has long been the established method of evaluating well performance, and it is critical to understanding the behavior of not only the well but the entire system. Nodal analysis enables the creation of inflow-outflow plots at any point in the system. Sensitivity analyses can be performed on any system variable, providing an understanding of where production enhancements opportunities exist.

While the fluid flows through the reservoir until it reaches the surface there are some pressure losses in the production system which can be split into three parts [2]:

1. **From the boundary of a reservoir to the perforation system** is the pressure reduction inside the reservoir (pressure draw down) this pressure is consumed in order to establish the flow of fluid (water oil, or gas) through the pores medium.

2. **From the perforation level up to the wellhead** the pressure is consumed to bit the gravity and friction (it is a function of flow rate itself).
3. **From the wellhead to the separator** the distance of this part is dependent on where the separators located. Each of those pressure losses are highlighted in green in the figure below:

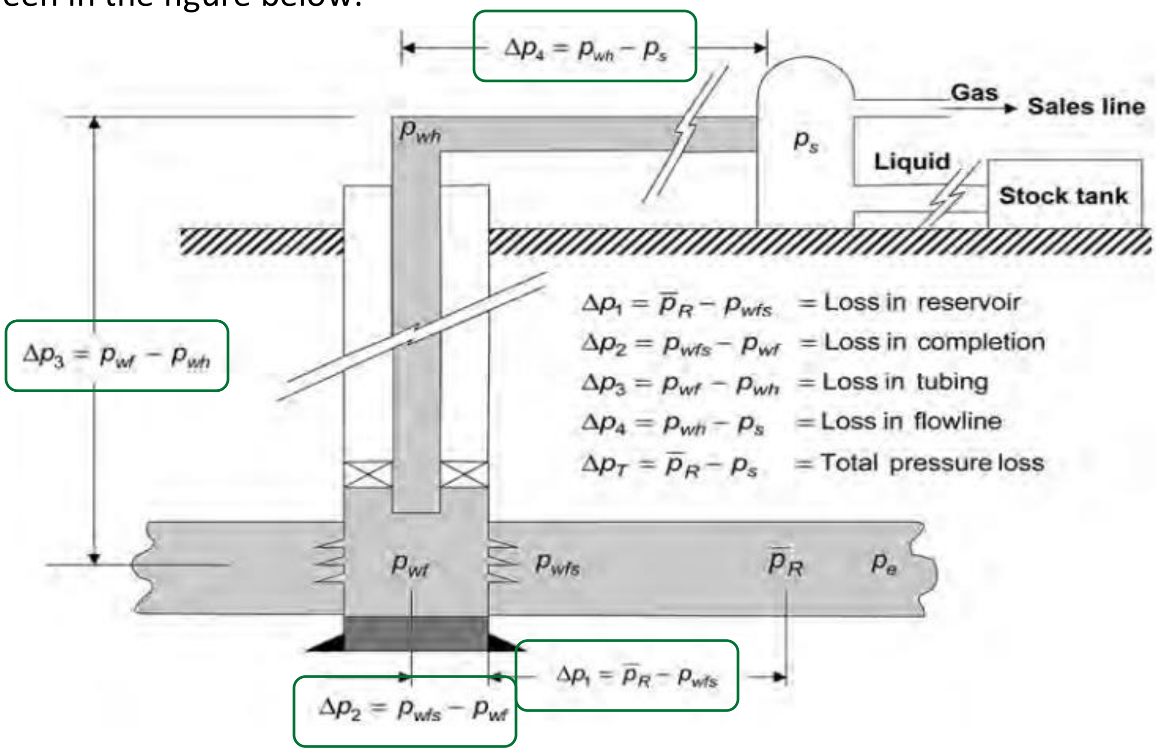


Figure 1.2.1: Production system and associated pressure losses [1]

$$P_{Res.} = (\Delta P)_{system} + P_{Sep.}$$

$$\Delta P_{system} = \Delta P_1 + \Delta P_2 + \Delta P_3 + \Delta P_4$$

The pressure at the boundary is not necessarily known so we have an average value (it has a fixed value) and we called, on the other hand, the pressure at separator can be controlled by us. So you know the pressure at the initial and the last point, so you know the total delta P now compute the flow rate in order to meet all physical loss both in the porous medium as well as in the wellbore itself.

To design a well completion or predict the production rate properly, a systematic approach is required to integrate the production system components. Systems analysis, which allows the petroleum engineer to both analyze production systems and design well completions, accomplishes this. This chapter focuses on the flow of reservoir fluids through the production system, particularly inflow performance, which is the reservoir pressure-rate behavior of the individual well, and outflow performance, which is the flow of reservoir fluids through the piping system.

1.3 Pressure losses in the production system:

From figure 1.3.1: inside the reservoir, there is the pressure loss which follows the logarithmic arch by the time we get into the damaged zone if there is any (in most cases there will be some) then there is a pressure drop in the sand face area close to the wellbore due to the skin factor, so it looks like your fluid just arrived the perforation system (all those pressure losses happens in the reservoir).

Then the fluid will pass through the set of pipes (inside the wellbore) tubing, the pressure losses go further down (and its slope depend on gravity as well as the friction and it is not constant) because the density will change as the fluid will go upward for some reason (for example phase changes) and a part of that pressure drop there might have some extra pressure drop which happens when there's a restriction in the stream (for example if there is SPM or SSSV) all of those should be taken into account in designing tubing string.

Also, when the fluid arrives at the surface it could be some pressure losses due to the choke itself (if it is fully closed then the pressure after choke is atmospheric but if it was partially close there going to be some pressure drop and this is the pressure drop at the surface until the fluid arrives at the separator. This is the typical shape of the distribution of pressure in the production system.

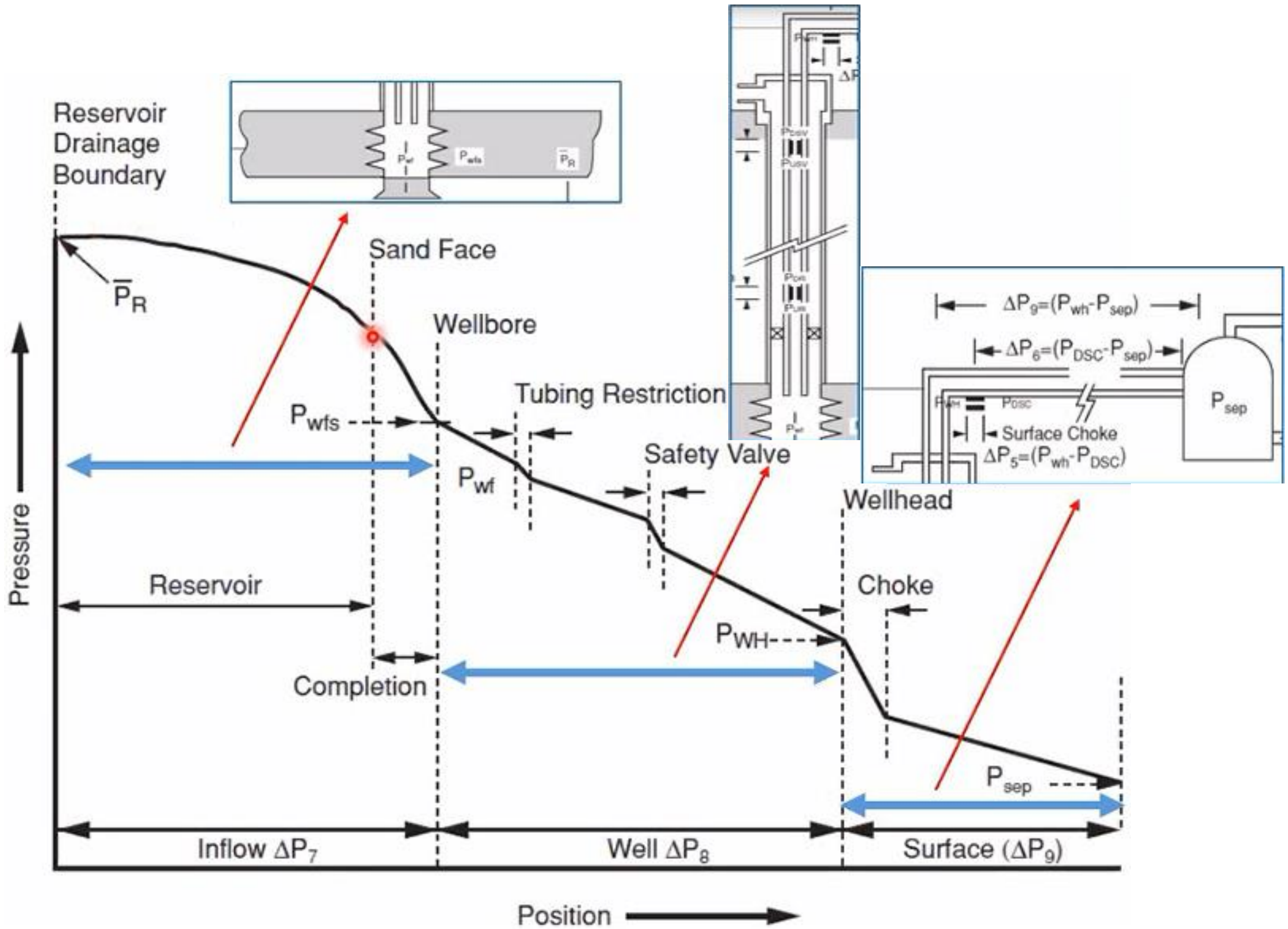


Figure 1.3.1: the pressure declining at it starts flowing from the boundary of a reservoir until the separator [2]

So the pressure at the boundary and at the separator is known and we are looking for the flow rate that passes through the whole system due to what might apply in the system and separator so that the pressure at the end exactly matches that value. This is exactly what we do in nodal analysis.

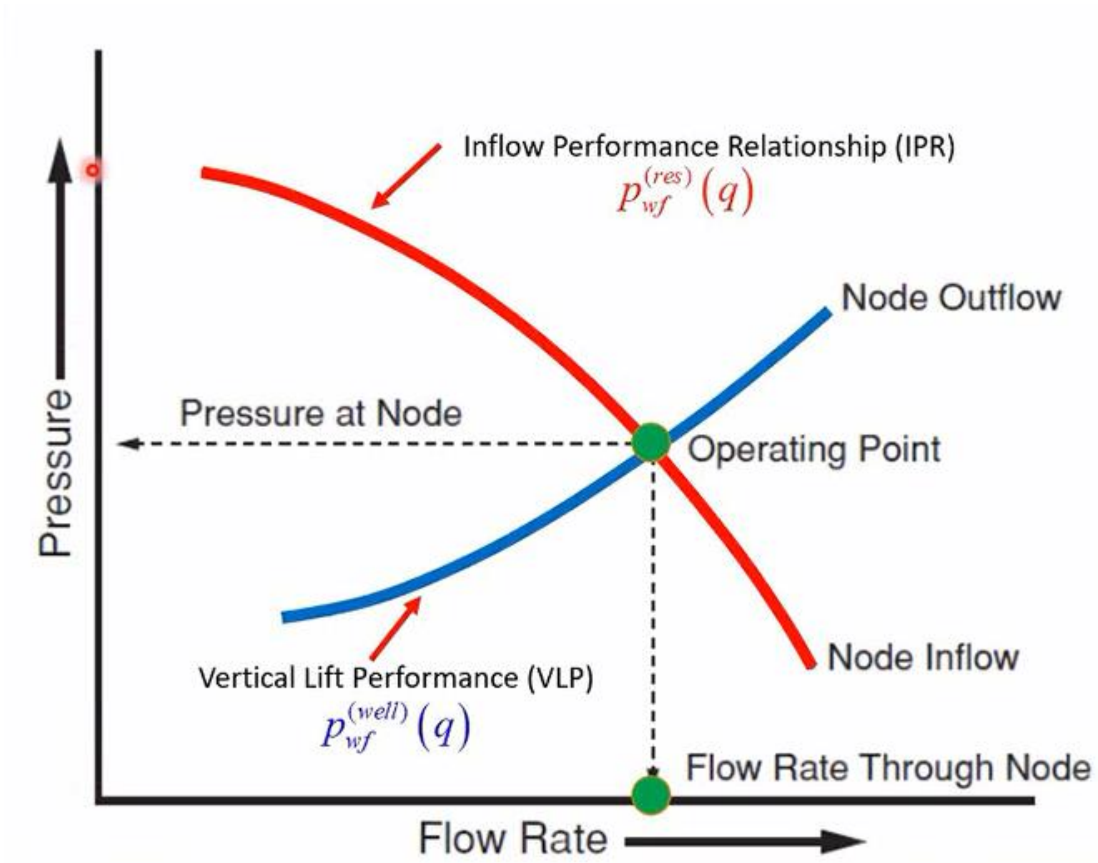


Figure 1.3.2: Splitting the system into two parts [2]

The red part is what happens in the reservoir, while the blue part is what happens in the pipes, in the border, and in the surface network. The node is going to be exactly at that point inside the well at the bottom hole so we can plot a chart that relates the flow rate in the reservoir together with the pressure at the bottom hole, for the flow rate of zero the pressure is going to be exactly initial pressure for slightly higher flow rate it should be lower pressure this is IPR (red curve) which simply describes the performance of the reservoir (fingerprint of a reservoir). The other part started from regulated pressure at the separator (without flow the pressure is only due to gravity because no flow means no friction) but if we have flow then the pressure is hydrostatic (gravity) and the friction and the plot will give us the blue curve VLP (this is going up as the IPR goes down, and the intersection of the two is the expected flow rate and the value of pressure at that point is expected pressure as well at the node (which here assumed to be bottom).

1.4 Inflow Performance Relationship (IPR) [4]:

Starting from Darcy's law:

$$q = \frac{kh(\bar{p}_R - p_{wf})}{141.2\ \mu_o B_o(\ln\frac{r_e}{r_w} - n + S)}$$

$$n = 0.5 \text{ for steady state, while it is } = 0.75 \text{ for semi steady state}$$

$$q = J(\bar{p}_R - p_{wf})$$

$$J = \frac{k_o h}{141.2\ \mu_o B_o(\ln\frac{r_e}{r_w} - n + S)}$$

Where:

J = productivity index, STB/day/psi

k_o = effective permeability of the oil, md

S = skin factor

h = thickness, ft

The productivity index is a useful approach for estimating future well performance since most of the well's life is spent in a flow regime that is close to the pseudo steady state. It is also feasible to assess if a well has been damaged due to completion, workover, production, injection operations, or mechanical difficulties by monitoring the productivity index over time. If a measured J falls unexpectedly, one of the concerns listed above should be investigated. Comparing the productivity indices of multiple wells in the same reservoir should also reveal that some of the wells may have encountered unexpected challenges or damage during the drilling process.

Muskat and Evinger (1942) and Vogel (1968) observed that when the pressure drops below the bubble point pressure, the IPR deviates from that of the simple straight-line relationship as shown in Figure below:

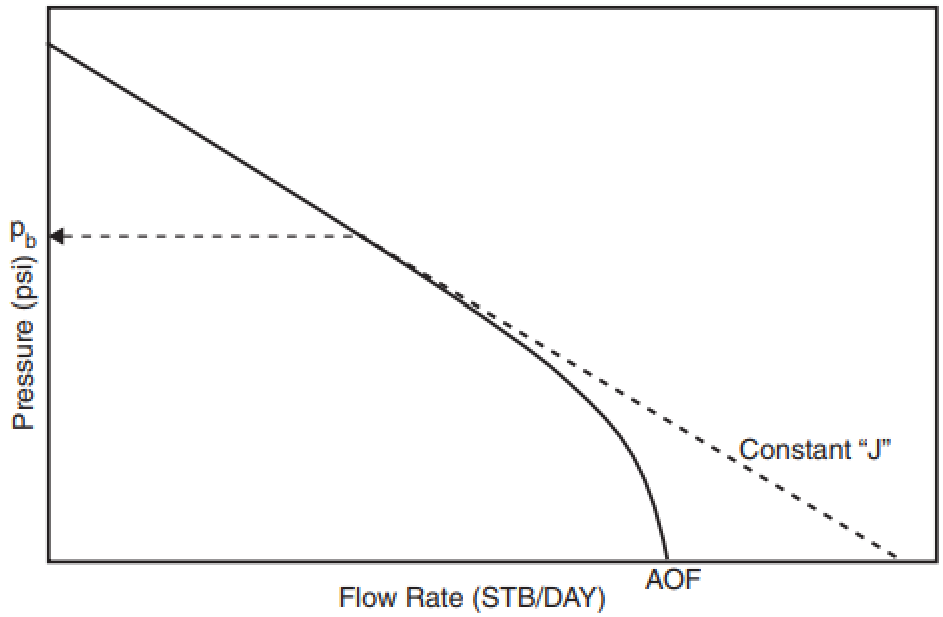


Figure 1.4: IPR below pb [4].

We use these to measure IPR curve, and in this case, IPR is a straight line (as long as we have oil flowing reservoir), but if your reservoir was saturated (producing both oil and gas) this is not valid so in this case, we need to use Vogel's equation.

Vogel method

Vogel (1968) used a computer model to generate IPRs for several hypothetical saturated oil reservoirs that are producing under a wide range of conditions. Vogel normalized the calculated IPRs and expressed the relationships in a dimensionless form. He normalized the IPRs by introducing the following dimensionless parameters:

Dimensionless pressure = $\frac{p_{wf}}{\bar{p}_R}$

Dimensionless flow rate = $\frac{Q_o}{(Q_o)_{max}}$

Where $(Q_o)_{max}$ is the flow rate at zero wellbore pressure, i.e., the AOF. Vogel plotted the dimensionless IPR curves for all the reservoir cases and arrived at the following relationship between the above dimensionless parameters:

$$\frac{Q_o}{(Q_o)_{max}} = 1 - 0.2\left(\frac{p_{wf}}{\bar{p}_R}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}_R}\right)^2$$

Q_o= oil rate at p_{wf}

$(Q_o)_{max}$ = maximum oil flow rate at zero wellbore pressure, i.e., the AOF

$\bar{p}_R$ = current average reservoir pressure

p_{wf}= wellbore pressure

1.5 Vertical Lift Performance (VLP):

Named also Outflow or Vertical Flow Performance (VLP), describes the bottom-hole pressure as a function of flow rate. The VLP depends on many factors including fluid PVT properties, well depth, tubing size, surface pressure, water cut, and GOR. It describes the flow from the bottom hole of the well to the wellhead, and it is a relationship between the flow rate and the pressure. VLP curve shows how much pressure is required to lift a certain amount of fluid to the surface at the given wellhead pressure.

To build the VLP curve we need to calculate the bottomhole pressure given the wellhead pressure for the different well rates in a range from 0 to AOF.

In order to flow from the bottom of the well to the surface, fluid needs to overcome several pressure drops

- Hydrostatic losses: due to the density of the fluid column
- Frictional losses: due to the viscous drag
- Kinetic losses: due to the expansion and contraction of the fluid and the change in the cross-sectional area, this leads to acceleration and deceleration of the fluid.

So the bottomhole pressure should equal to the summation of separator pressure, hydrostatic losses and friction losses [2].

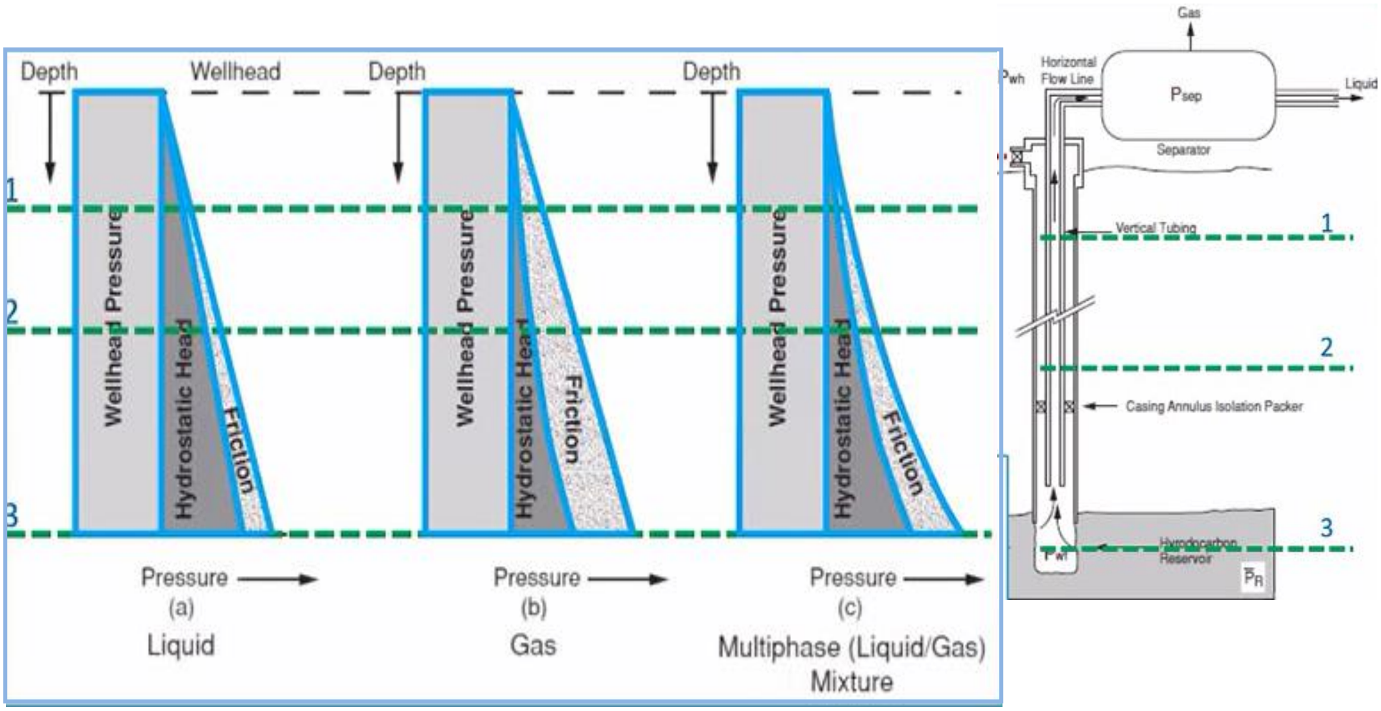


Figure 1.5.1: VLP curves for different phases [2]

The hydrostatic head exhibits near triangular form because when you have a liquid in your reservoir its density practically is constant which means the gravity term of that (gravity of hydrostatic pressure) changes linearly with depth so it exhibits a linear shape like (first plot on the left)we get that chart when considering hydrostatic pressure but in drilling engineering when you have an incompressible liquid, friction is more or less a linear because it is a liquid, on the other hand for the gas (hydrostatic head will exhibit the curved shape due to compressibility of the gas)and friction is much more significant because in gas phase frictional pressure loss in a gas phase is higher than what you get in oil flow (as shown in the plot in the middle), and also it becomes more complex if you have two phase flow with the hydrostatic and frictional pressure loss (last plot).

1.6 Factors that Affect the VLP:

- Pressure losses in the Tubing section should take into considers:

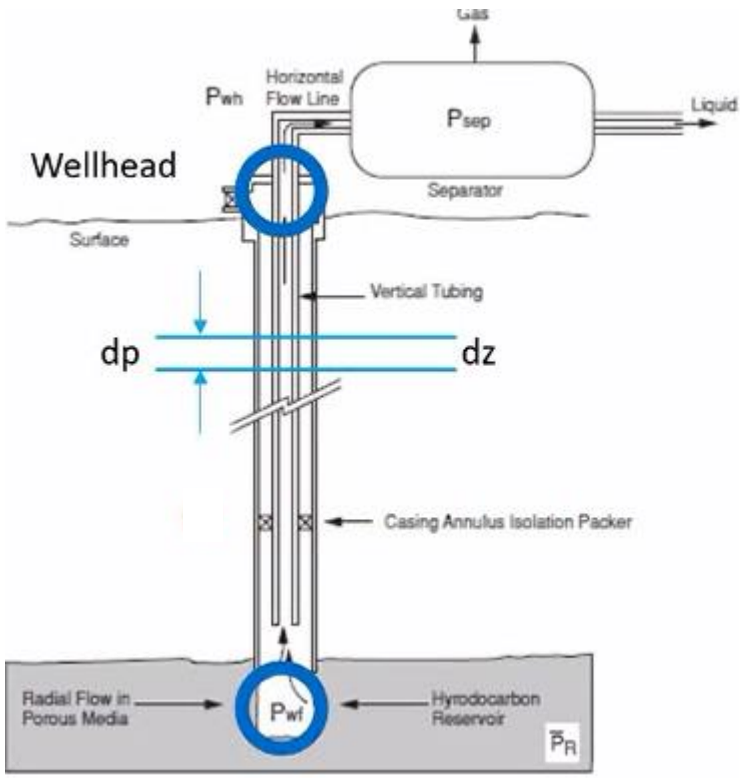


Figure 1.6.1: Pressure losses along tubing [2]

$$\mathrm{dp} + \text{Hydrostatic} + \text{Fluid acceleration} + \text{Friction} = 0$$

$$\mathrm{dp} + \rho \cdot g \cdot dz + \frac{1}{2}\rho \cdot du^2 + \frac{f_M \cdot \rho \cdot u^2}{2D} dL = 0 \quad [2]$$

- The hydrostatic head lost between two close points (the section of dz) energy might be lost due to the acceleration of the fluid and friction, acceleration is almost ignored (when we discuss oil, the change in velocity is small and even du^2 is very small). On the other hand, when you have gas the velocity is significantly very high but in this case, the density is much less and the final fluid acceleration term is ignored, so we need to consider hydrostatic term and friction, so in two phases the density should be the average of two phases (for the section that we are considering)and that section is above Pb then the flow will consist of oil by 99% and only 1% gas so the average density is very close to liquid density, but if bubble point happened at that depth(there is too much gas that has come out of the solution)and the density becomes less as the pressure goes down, and volume percentage goes up and it is a really complex calculation you cannot do it and you need to use a computer.

- Similar to friction coefficient is a function of <u>viscosity</u>, and now we have the viscosity of two phases system, and this is too difficult to get the value for that's why we split it into many sections (as simulation) then we find the values and the software will do that for us.
- the gas velocity and oil velocity are different in the pipe because its viscosity is very small compare to the liquid phase, suppose we have 50 $\times$50 fractions of the volume of each phase if they traveled at the same speed then the flow rate will be going to be equal and each one will occupy half of the cross-section, but if the gas travels faster under that constrain that we have the same flow rate so the gas will get a small section in the pipeline and it makes a huge difference in average density, therefore, the hydrostatic term is affected friction term affected as well but the major change is in the hydrostatic term and this called <u>slip or hold up effect</u> and we need to be very careful about that.
- various flow regimes need to consider that might appear when you have two phase flow, when gas is just a small fraction we expect to get the bubble flow (there are bubbles spread inside the liquid phase), if we have even more gas flowing then slugs of gas might appear in there, and even if you have more gas it goes to crazy shape which is churn flow at the end when the gas dominates rather than the liquid then we get annular flow, frictional flow calculation is entirely different for each phase regime, that's why we consider all those effects.
- Another important effect that the software considers is Temperature in the wellbore we don't have a constant temperature (so we need to consider temperature variation to the well) because the formation temperature outside the well decreasing as the well goes up so the heat dissipates from the fluid to the formation and if the fluid becomes cooler the bubble point pressure changes as well the density and viscosity also will change so it has a major effect on the frictional term (because the temperature has the most effect on viscosity rather than other volumetric properties) so we consider temperature changes, we account it (if the pressure of the formation is lower than the pressure of a fluid some heat will

dissipate there) then the fluid become cooler, we need to take into account two phenomenon, firstly; how much heat is wasted(dissipated from the fluid to the formation)?it is a function of productivity of the system so we need to compute the overall heat transfer coefficient and this is the productivity coefficient, and secondly; what is the effect of that heat amount is lost in the formation on the temperature of fluid? Heat capacity (CP) exactly relates to changes in temperature with the heat of the fluid. Moreover, when the fluid is vaporized (when the gas comes out from the oil) it takes heat from the fluid itself to feed this vaporization process (so some heat is hidden due to phase change) and that hidden heat is named by latent heat.

In many cases, the reservoir is unable to furnish sufficient energy to produce fluids to the surface at economic rates throughout the life of the reservoir. When this occurs, artificial lift equipment is used to enhance production rates by adding energy to the production system. This component of the system is composed of both surface and subsurface elements. This additional energy can be furnished directly to the fluid through subsurface pumps, by reducing the backpressure at the reservoir with surface compression equipment to lower wellhead pressure, or by injecting gas into the production string to reduce the flowing gradient of the fluid. [1]

1.7 Artificial Lift

Artificial lift is a method used to lower the producing bottomhole pressure (BHP) on the formation to obtain a higher production rate from the well. This can be done with a positive displacement downhole pump, such as a beam pump or a progressive cavity pump (PCP), to lower the flowing pressure at the pump intake. It also can be done with a downhole centrifugal pump, which could be a part of an electrical submersible pump (ESP) system. A lower bottomhole flowing pressure and higher flow rate can be achieved with gas lift in which the density of the fluid in the tubing is lowered and expanding gas helps to lift the fluids. The Artificial lift can be used to generate flow from a well in which no flow is occurring or used to increase the flow from a well to produce at a higher rate. Most oil wells require artificial lift at some point in the life of the field, and many gas wells benefit from an artificial lift to take liquids off the formation so gas can flow at a higher rate. [1]

Description of Gas Lift: The principle of gas lift is that gas injected into the tubing reduces the density of the fluids in the tubing, and the bubbles have a “scrubbing” action on the liquids. There are two basic types of gas lift in use today—continuous and intermittent flow. [11]

1.8 Advantages of Gas Lift [1]:

- Gas lift is the best artificial lift method for handling sand or solid materials. Many wells produce some sand even if sand control is installed. The produced sand causes few mechanical problems in the gas-lift system; whereas, only a little sand plays havoc with other pumping methods, except the PCP type of pump.
- Deviated or crooked holes can be lifted easily with a gas lift. This is especially important for offshore platform wells that are usually drilled directionally.
- Gas lift permits the concurrent use of wireline equipment, and such downhole equipment is easily and economically serviced. This feature allows for routine repairs through the tubing.
- The normal gas-lift design leaves the tubing fully open. This permits the use of BHP surveys, sand sounding and bailing, production logging, cutting, paraffin, etc.
- High-formation GORs are very helpful for gas-lift systems but hinder other artificial lift systems. Produced gas means less injection gas is required; whereas, in all other pumping methods, pumped gas reduces volumetric pumping efficiency drastically.
- The gas lift is flexible. A wide range of volumes and lift depths can be achieved with essentially the same well equipment. In some cases, switching to annular flow also can be easily accomplished to handle exceedingly high volumes.

CHAPTER TWO

PIPESIM Software

3.1 Introduction of PIPESIM [5]:

With the interactive graphical schematic and templates of the PIPESIM steady-state multiphase flow simulator, well models can be created in a thorough, fast and efficient way to help increase production and understand reservoir potential. The PIPESIM simulator models multiphase flow from the reservoir to the wellhead and considers artificial lift systems, including rod pumps, ESP, and gas lift. Well performance modeling capabilities in the simulator enables users to:

- Design optimal well completions and artificial lift systems.
- Diagnose problems that are limiting well production potential.
- Optimize production from existing wells by quantifying actions to increase flow rates

Nodal analysis: In addition to nodal analysis, the PIPESIM simulator offers a variety of other well-specific simulation tasks, addressing a wide range of well modeling workflows.

Modeling completions: The PIPESIM simulator includes all the standard completion model types for vertical, horizontal, and fractured wells, and allows for complex multilayered completions using a wide variety of reservoir inflow parameters and fluid descriptions. Intelligent completions, such as downhole flow control valves, can be applied to control flow from individual layers to reduce backpressure on other potential contributing layers.

Artificial lift design: The most suitable artificial lift method can be determined and then detailed gas lift, rod pump, or ESP design can be examined. The sophisticated sensitivity tools allow artificial lift parameters (injection gas and ESP stages) to be analyzed so that optimal production can be obtained.

The PIPESIM simulator offers the ability to design new rod pump systems, including pumping unit, motor, pump, rod string, and tubing. The objective is to select the best combination of various design parameters for a specific production well. These designs can also be added to the flow system model to analyze their impact on the performance of the entire system. The rod pump diagnostics module uses existing well production data and surface-measured dynamometer cards to fully analyze the pumping unit balance condition, rod string loading, pump efficiency, and pump operating condition.

For gas lift, the PIPESIM simulator includes new functionality for mandrel spacing and valve selection design to help you determine the best depth for valve installation—using industry-standard methods. A manufacturer's valve database is included to provide you with the most accurate information. Additionally, you can redesign your valve placement with the mandrels in place.

3.2 PIPESIM well performance capabilities

- Well design and completion modeling
- Select the optimal tubing and casing size.
- Design water or gas injection wells.
- Determine the optimal horizontal completion length.
- Model multilayer and multilateral wells.
- Perform a completion design with detailed quantification of production improvements by reducing skin effects.
- Match completion parameters and pressure-temperature profiles, using automated regression.
- Perform detailed sensitivity analysis to identify parameters impacting production.
- Flow modeling
- Model tubular, annular, or mixed flow.
- Generate pressure temperature profiles.
- Flow correlation comparison.
- Data matching.
- Identify wellbore flow assurance issues such as erosion, corrosion, and solids formation (scale, wax, hydrates, and asphaltenes).
- Generate vertical flow performance (VFP) tables for reservoir simulators.

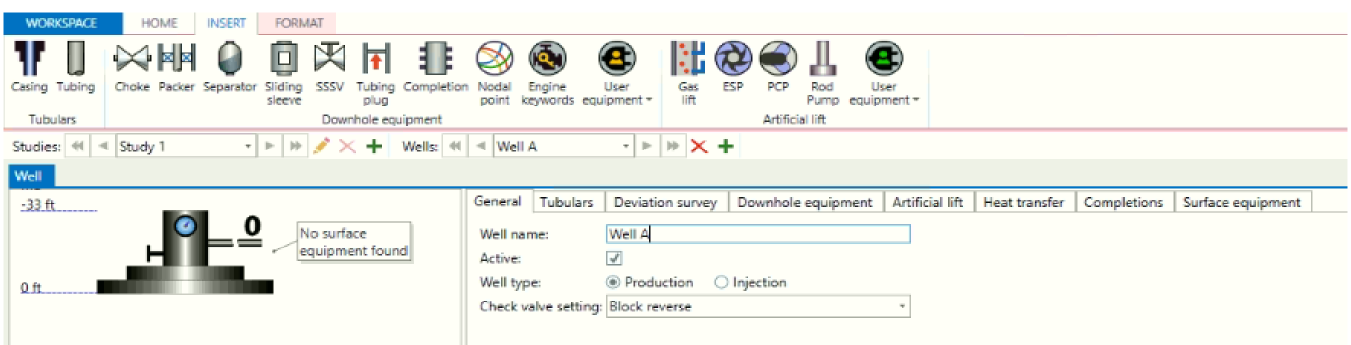
- Diagnose liquid loading in gas wells and evaluate measures to alleviate the problem.
- Model the effects of cross flow between zones.
- Well equipment and systems modeling
- Model downhole equipment such as chokes, subsurface safety valves, separators, and chemical injectors.
- Design artificial lift systems including gas lift, ESPs, PCPs, and rod pumps, comparing the relative benefits of each system.
- Model the effects of coiled tubing gas injection or velocity strings.
- Optimize production of intelligent completions through modeling downhole flow control valves.

3.3 Working on PIPESIM:

Build the well model

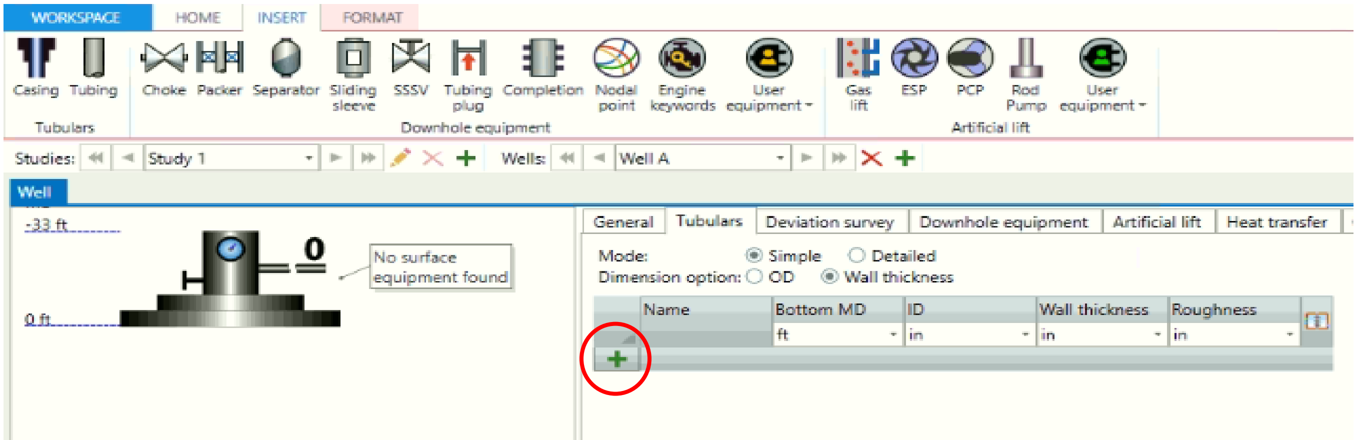
In this task, you will build a model of an oil production well. Although this task could be performed in a network centric workspace, you will use the well centric mode for it. Do the following:

1. Launch PIPESIM and select the option to create a new, well centric workspace. From the GENERAL group of the well editor:

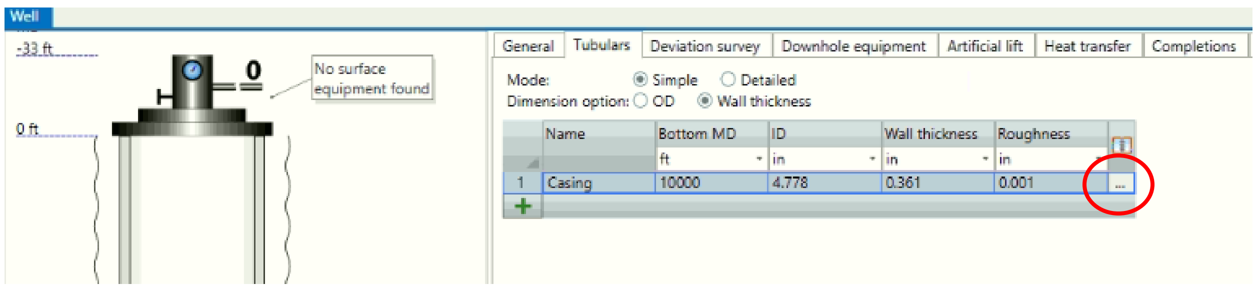


Choose production (because for injection and production Pressure flow rate are different that’s why it gave two options)

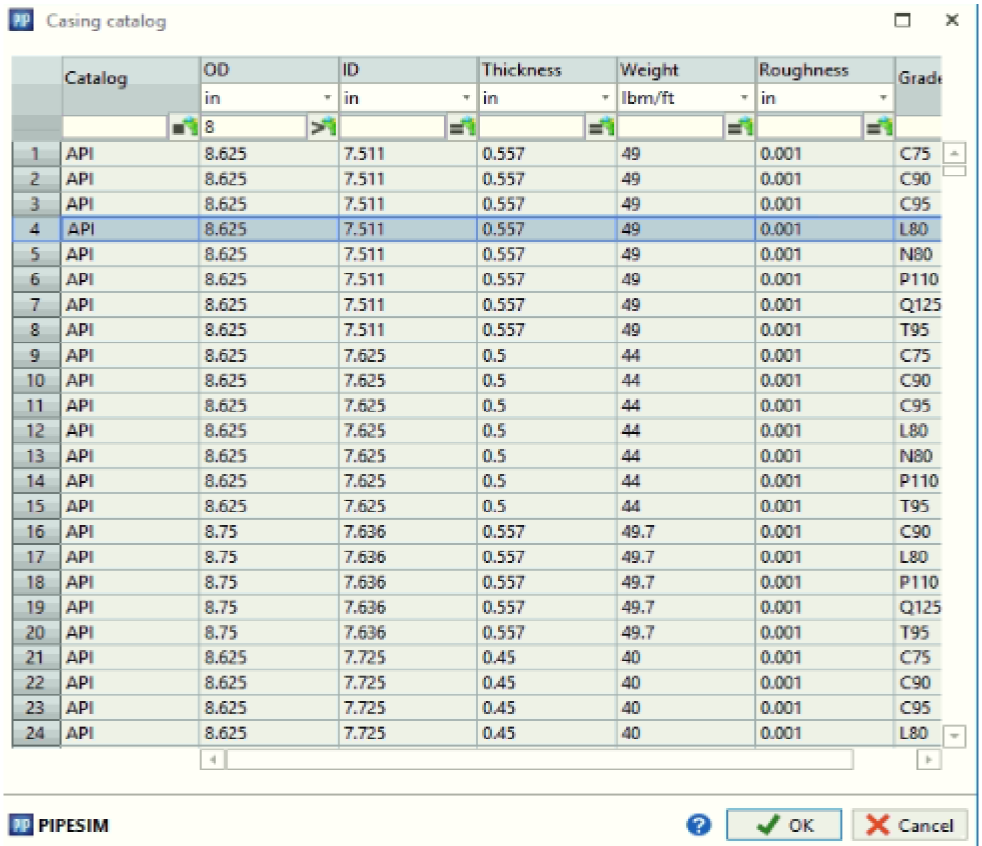
2. The Insert tab is active. From the Tubular group of the Well editor, add casing to the well by clicking Casing and dragging the casing onto the wellhead. Or by clicking on the red circle as shown in the figure.



3. On the Tubulars tab of the well editor, click on the (...) on the far right to open the Casing Catalog (red circle) as shown below.



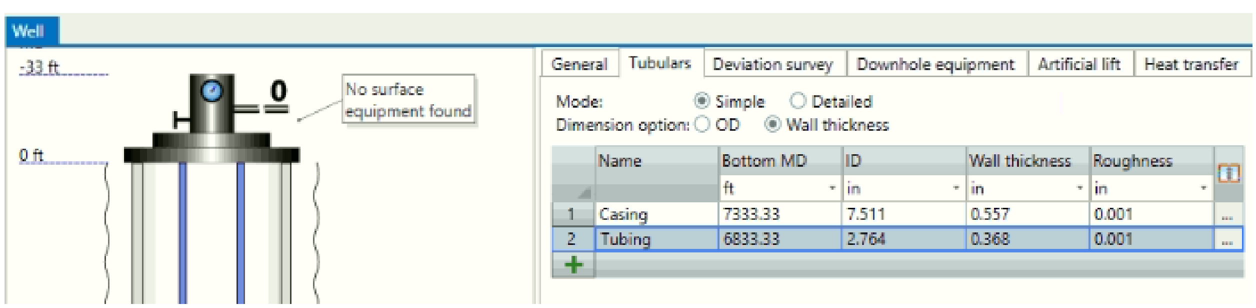
4. In the Casing catalog, go to the OD column and select Greater than from the dropdown list and type in a value of 8 in the text field. This will filter the catalog to display only casings with an OD (Outside Diameter) greater than 8 in, as below



	Catalog	OD	ID	Thickness	Weight	Roughness	Grade
		in	in	in	lbm/ft	in	
		8					
1	API	8.625	7.511	0.557	49	0.001	C75
2	API	8.625	7.511	0.557	49	0.001	C90
3	API	8.625	7.511	0.557	49	0.001	C95
4	API	8.625	7.511	0.557	49	0.001	L80
5	API	8.625	7.511	0.557	49	0.001	N80
6	API	8.625	7.511	0.557	49	0.001	P110
7	API	8.625	7.511	0.557	49	0.001	Q125
8	API	8.625	7.511	0.557	49	0.001	T95
9	API	8.625	7.625	0.5	44	0.001	C75
10	API	8.625	7.625	0.5	44	0.001	C90
11	API	8.625	7.625	0.5	44	0.001	C95
12	API	8.625	7.625	0.5	44	0.001	L80
13	API	8.625	7.625	0.5	44	0.001	N80
14	API	8.625	7.625	0.5	44	0.001	P110
15	API	8.625	7.625	0.5	44	0.001	T95
16	API	8.75	7.636	0.557	49.7	0.001	C90
17	API	8.75	7.636	0.557	49.7	0.001	L80
18	API	8.75	7.636	0.557	49.7	0.001	P110
19	API	8.75	7.636	0.557	49.7	0.001	Q125
20	API	8.75	7.636	0.557	49.7	0.001	T95
21	API	8.625	7.725	0.45	40	0.001	C75
22	API	8.625	7.725	0.45	40	0.001	C90
23	API	8.625	7.725	0.45	40	0.001	C95
24	API	8.625	7.725	0.45	40	0.001	L80

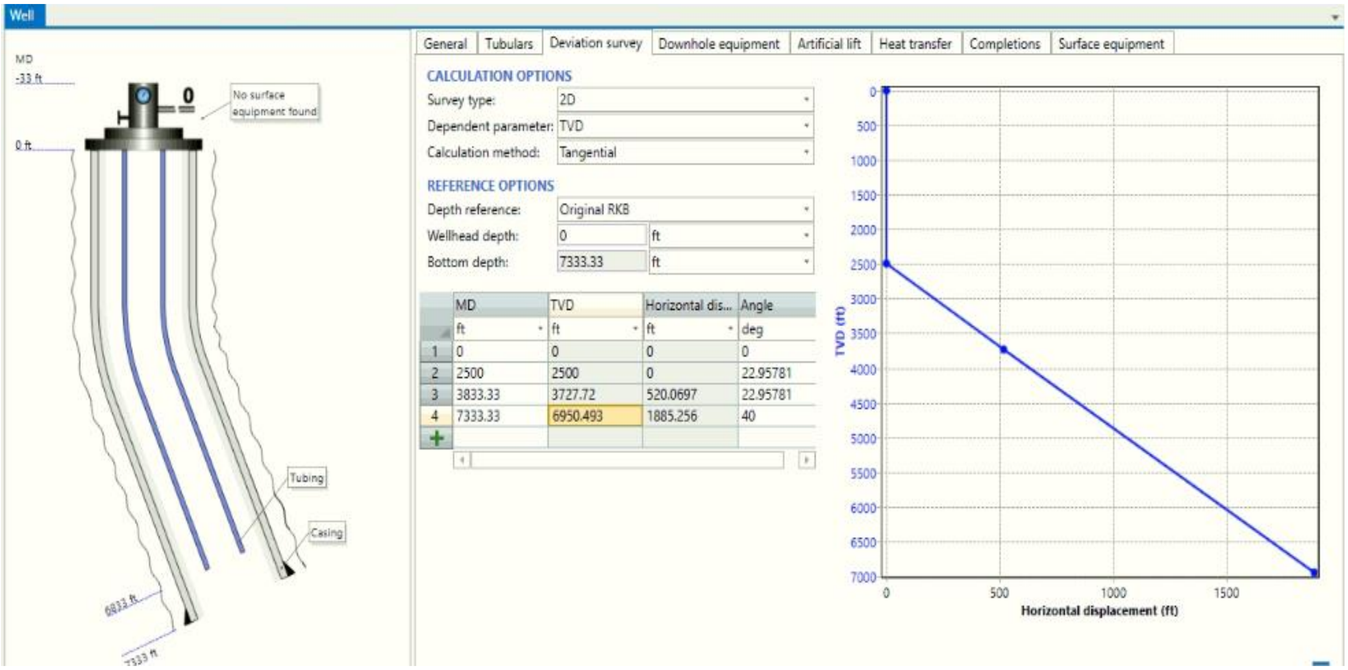
5. Select the L80 grade of casing, and clicking OK.
6. Click red circled area (in the second step- the same way we did for casing) to add a tubing string.

7. Specify the values shown below. By using the catalog as we did for casing.

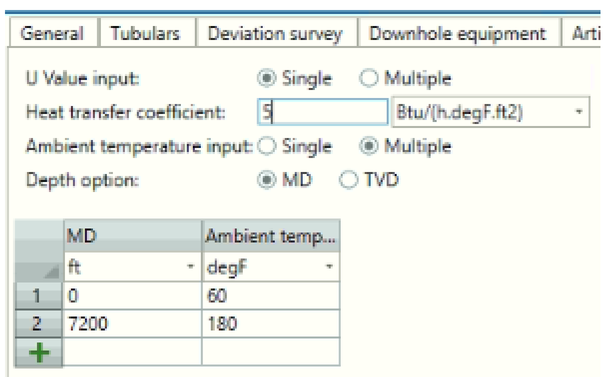


	Name	Bottom MD	ID	Wall thickness	Roughness
		ft	in	in	in
1	Casing	7333.33	7.511	0.557	0.001
2	Tubing	6833.33	2.764	0.368	0.001

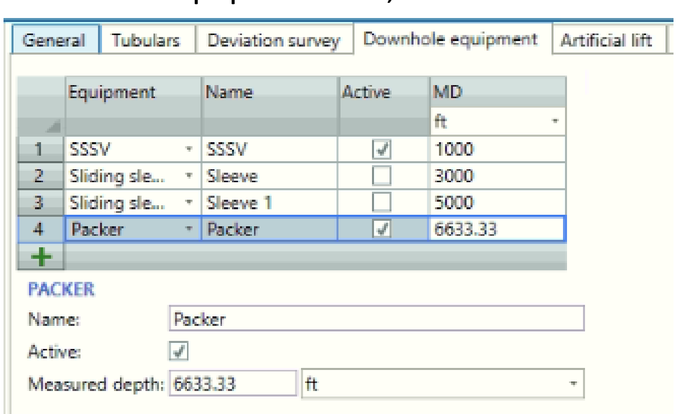
8. On the Deviation survey tab, change the Survey type to 2D. Ensure Angle is selected as the Dependent parameter



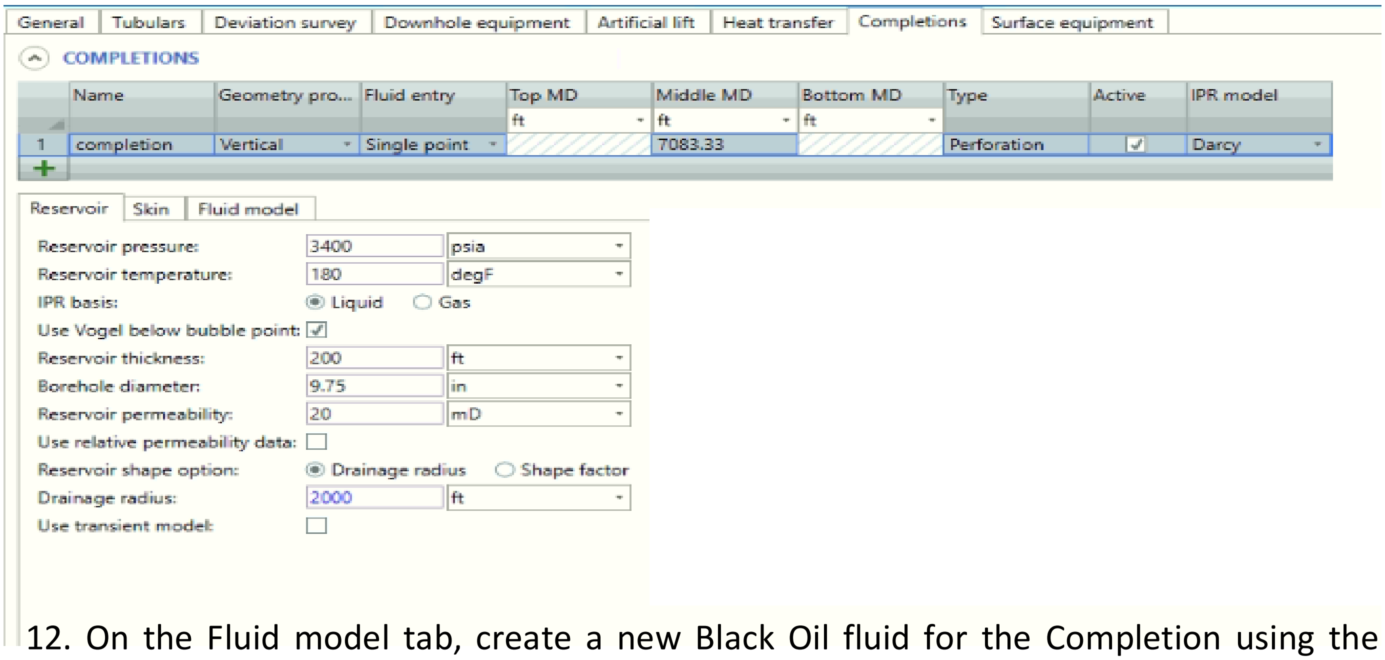
9. On the Heat transfer tab, configure the Heat transfer parameters as shown in the following figure.



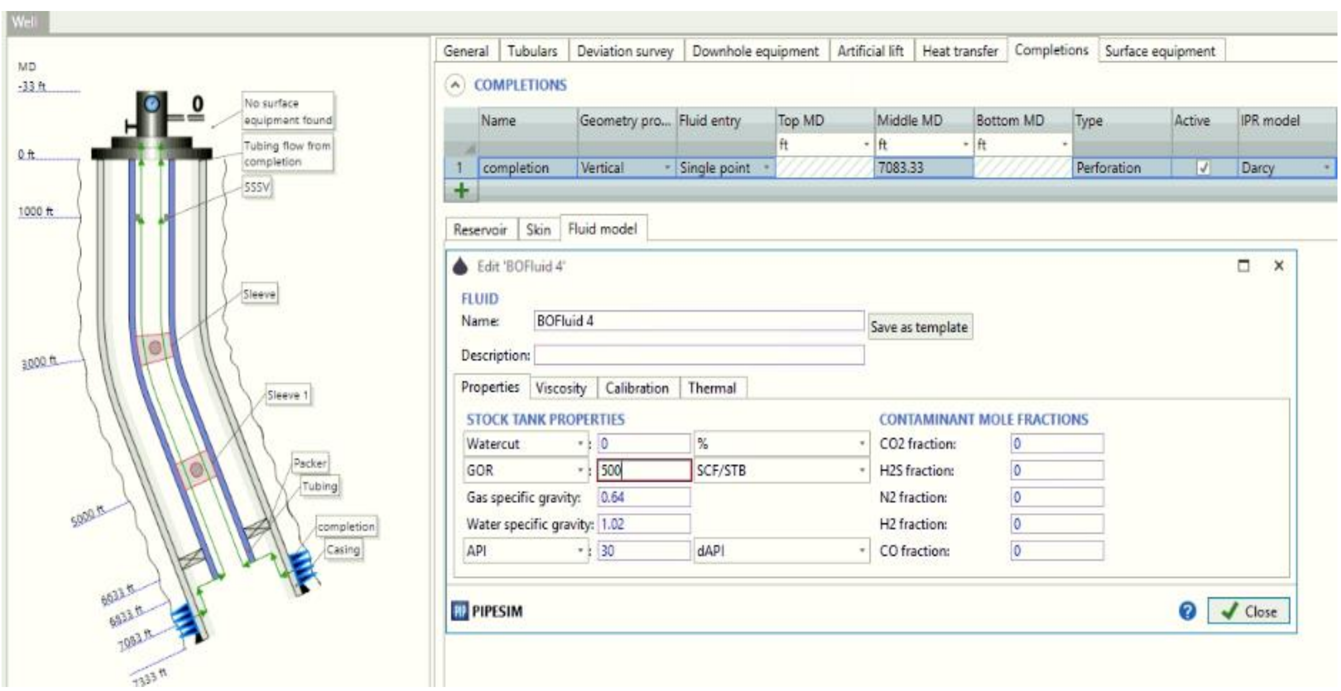
10. On the Downhole Equipment tab, we fill the box as below:



11. On the Completions tab, add a completion to the well by dragging it from the Insert tab or clicking the green plus on the left corner. Enter the Completion information as shown in the following figure.



12. On the Fluid model tab, create a new Black Oil fluid for the Completion using the parameters shown in the following figure (You may or may not choose to create the fluid by editing an existing template). Leave the defaults for all the other tabs on the Fluid editor, and exit the dialog box.



CHAPTER THREE

CASES OF STUDY

The field is characterized by:-

- H= 200 feet
- 2-5 mD permeability
- The reservoir has light sour crude oil
- Dissolved gas content of [300-400 scf/bbl] separator measurement
- Asphaltene deposit problem.

All depths are in MDBRT (in meters) unless otherwise stated. Upon the demand of the company's operator, the data has been shared with limited access.

3.1 Well A

3.1.1 General Information:

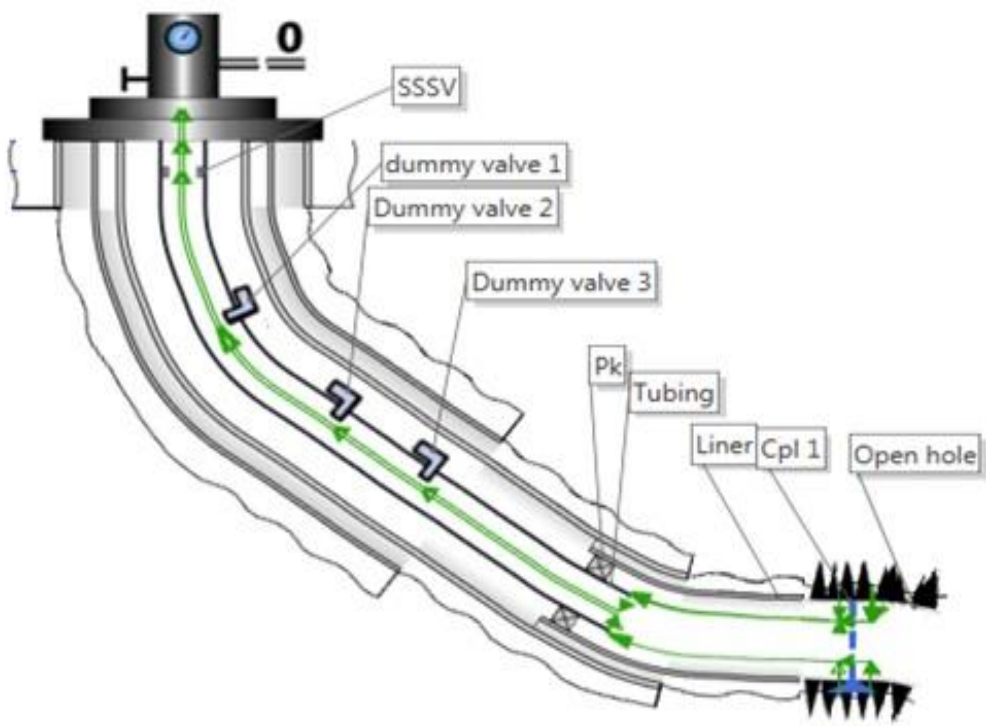
- Well name: A, Ast1
- Elevation: RT: 15m
- Final depth A : 4100m MD
- Final depth Ast1: 4213m MD

3.1.2 Well Design Characteristics

Hole size (inch)	Casing size (inch) (OD)	Drilled MD (m)	
		From	To
20	18.5/8	0	400
16	13.3/8	400	1500
12.1/4	9.5/8	1500	2900
8.1/2	7 liner	2900	3600
6	1ST OPEN HOLE	3500	4100
	2ND OPEN HOLE (Side track)	3520	4213

3.1.3 Well Diagram constructed by PIPESIM

The diagram of well A has been constructed, by using PIPESIM software, and after running different tubing sizes from (1.05in outer diameter, 0.824in inner diameter) to (4.5in outer diameter, 3.958in inner diameter) and selecting the best tubing size which is (3.5in outer diameter, 2.992in inner diameter) as the best selection that gives optimum liquid production rate.



3.2 Well B

3.2.1 General Information:

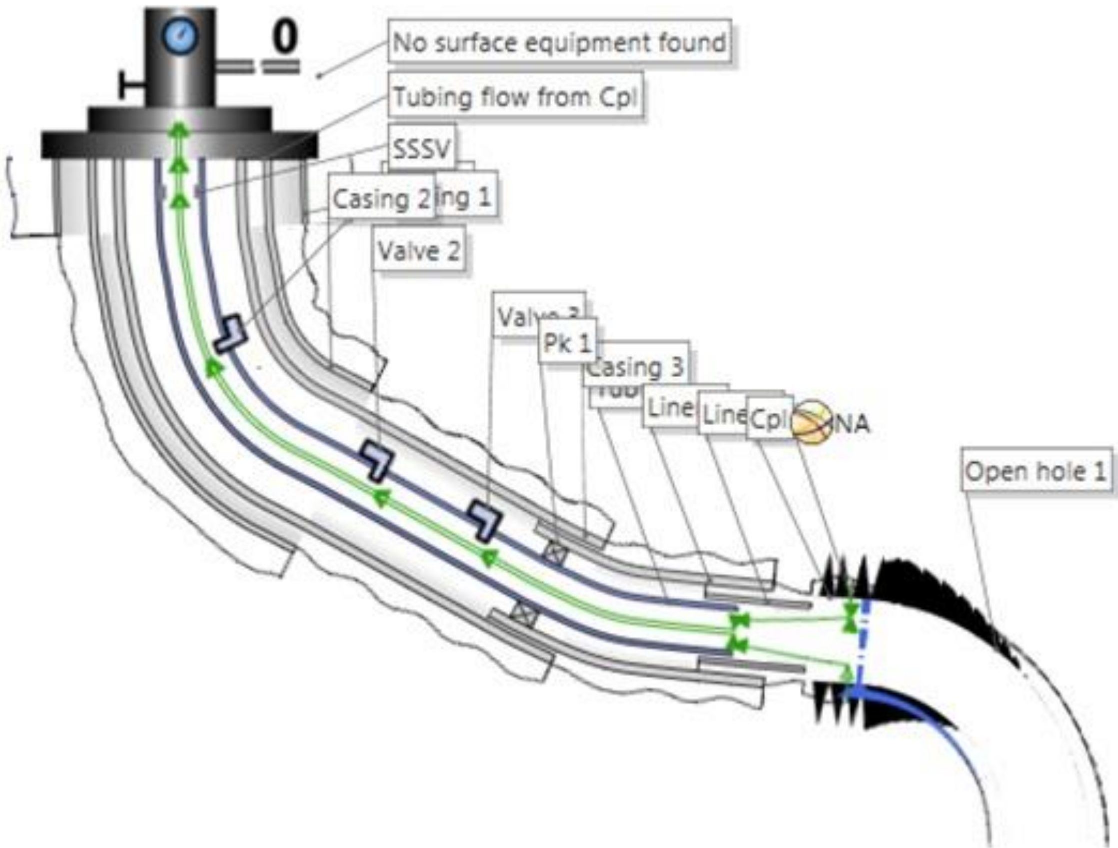
- Final depth: 4689m MD
- Elevation: RT: 15m

3.2.2 Well Design Characteristics

<table>
<tr><th rowspan="2">Hole size (in)</th><th rowspan="2">Casing size (in) (OD)</th><th rowspan="2">Grade</th><th colspan="2">Drilled MD (m)</th></tr>
<tr><th>From</th><th>To</th></tr>
<tr><td>20</td><td>18.5/8</td><td>X56</td><td>0</td><td>210</td></tr>
<tr><td>16</td><td>13.3/8</td><td>L80</td><td>210</td><td>1200</td></tr>
<tr><td>12.1/4</td><td>9.5/8</td><td>L80</td><td>1200</td><td>2983</td></tr>
<tr><td>8.1/2</td><td>7.5/8 liner</td><td>L80</td><td>2983</td><td>3996.5</td></tr>
<tr><td rowspan="2">6</td><td>5 Liner
(3708 to 3980)</td><td>L80</td><td>3996.5</td><td>4659</td></tr>
<tr><td colspan="4">OPEN HOLE</td></tr>
</table>

3.2.3 Well Diagram constructed by PIPESIM

The final well B diagram has been shown below after selecting the best tubing diameter which is (3.5in outer diameter, 2.992in inner diameter) and installing packer, SSV and gas injected valves based on the given data of well B, by using PIPESIM software.



3.3 Well C

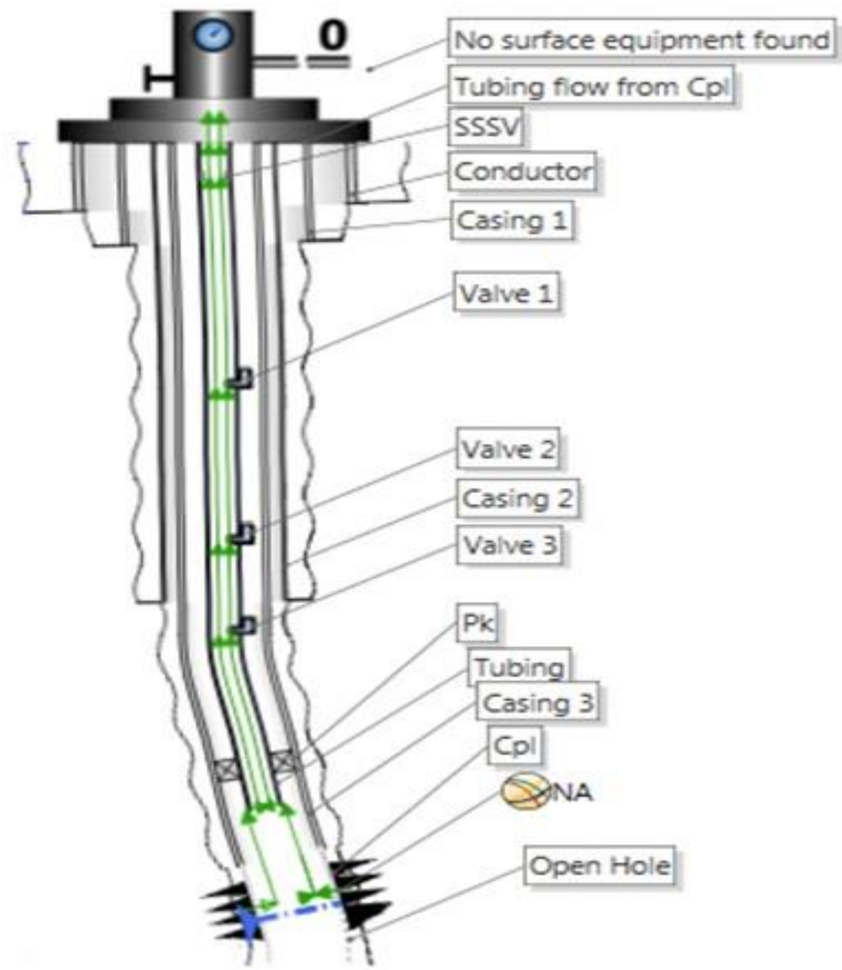
3.3.1 General Information:

- Well name: C, Cst1
- Final depth: 3310m MD
- Elevation: RT: 15m

3.3.2 Well Design Characteristics

Hole size (inch)	Casing size(in) (OD)	ID (in)	Grade	Drilled MD (m)	
				From	To
Conductor	30		X56	0	121.5
26	20	19	K55	0	440
16	13.3/8	12.415	L80	440	1913
12.1/4	9.5/8	8.535	L80	1013	2680
8.1/2	OPEN HOLE			2670	3310

3.3.3 Well Diagram constructed by PIPESIM



3.4 Well D

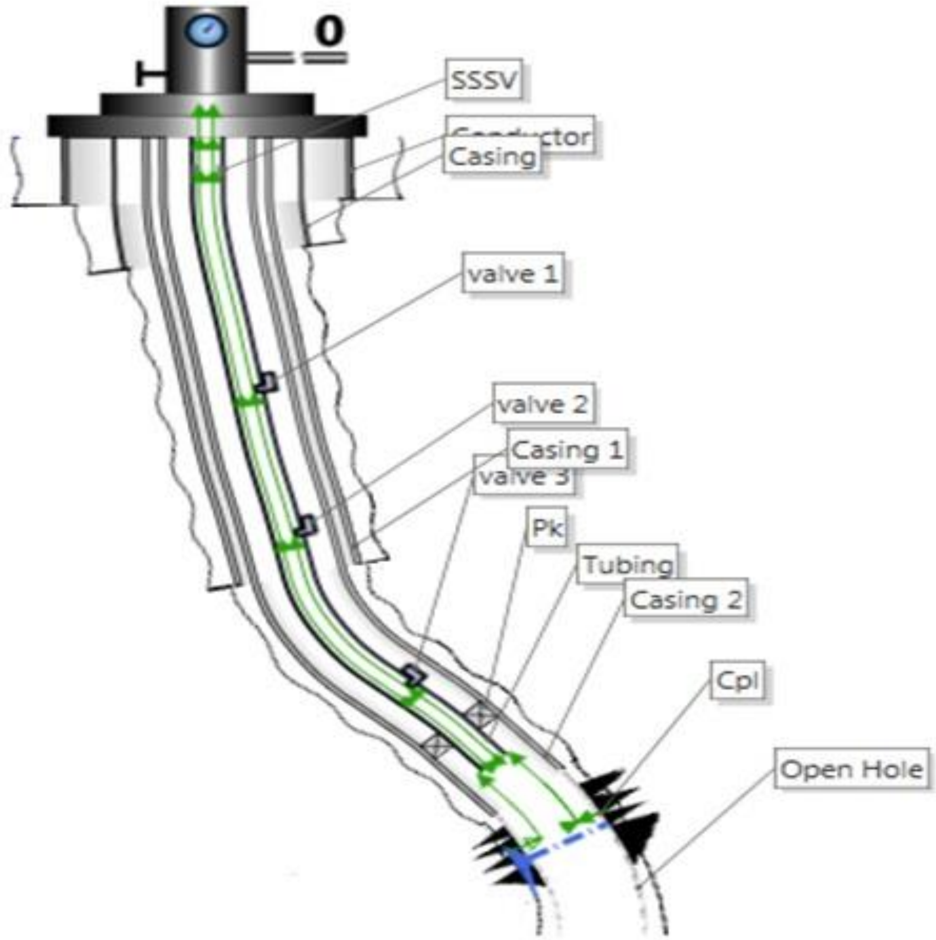
3.4.1 General Information:

- Well name: D, Dst1
- Elevation: RT: 15m
- Final depth: 3712m MD

3.4.2 Well Design Characteristics

Hole size (in)	Casing size (in) (OD)	ID (in)	Grade	Drilled MD (m)	
				From	To
Conductor	30		X56	0	122
26	20	19	X56	0	440
16	13.3/8	12.415	L80	440	1893
12.1/4	9.5/8	8.535	L80	1893	3180
8.1/2	OPEN HOLE			3180	3712

3.3.3 Well Diagram constructed by PIPESIM



3.5 Well E

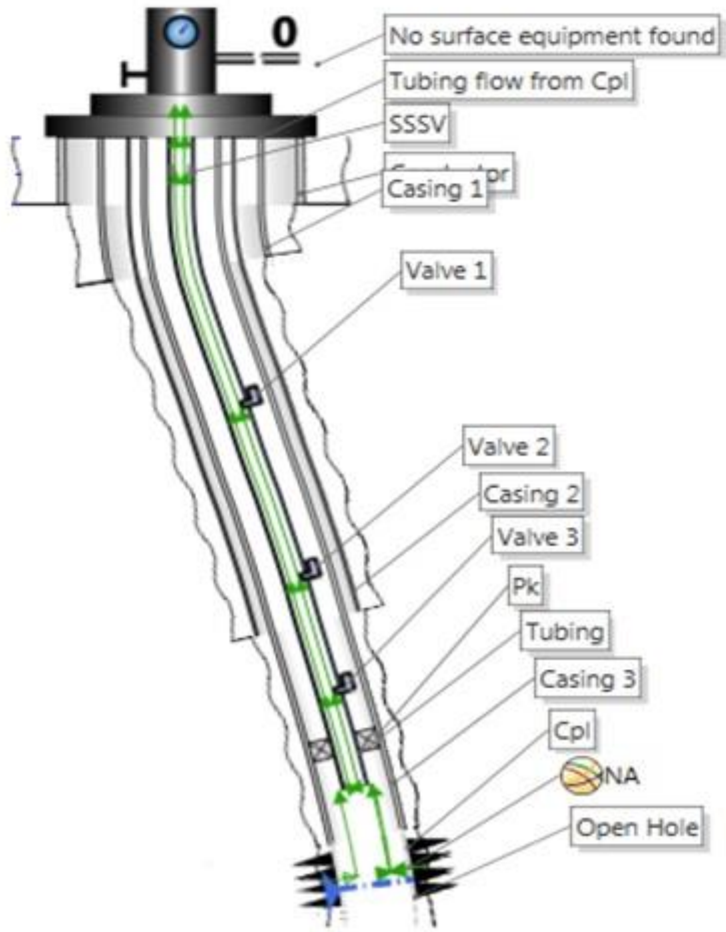
3.5.1 General Information:

- Well name: E, Est1
- Elevation: RT: 15m
- Final depth: 3234m MD

3.5.2 Well Design Characteristics

Hole size (inch)	Casing size (inch) (OD)	ID (inch)	Grade	Drilled MD (m) BRT	
				From	To
Conductor	30		X56	0	122
26	20	19	X56	122	450
16	13.3/8	12.415	L80	450	1891
12.1/4	9.5/8	8.535	L80	1891	2952
8.1/2	OPEN HOLE			2952	3234

3.5.3 Well Diagram constructed by PIPESIM



CHAPTER FOUR

RESULTS AND CONCLUSIONS

In this chapter: we conclude the result of running different tubing sizes (shown in Table 1) ranges from (1.05in outer diameter, 0.824in inner diameter) to (4.5in outer diameter, 3.958in inner diameter), different reservoir permeability ranges from 2-5 mD (due to not have exact value; ranges from 2mD to 5mD), and trying different outlet pressure (Separator pressure) on PIPESIM software, and finding the optimum values.

Moreover, showing the effect of water cut, skin factor, reservoir pressure depletion and gas lift as an artificial lift method on the liquid flow rate for the selected tubing size.

4.1 Well A

❖ Effect of Different Tubing sizes

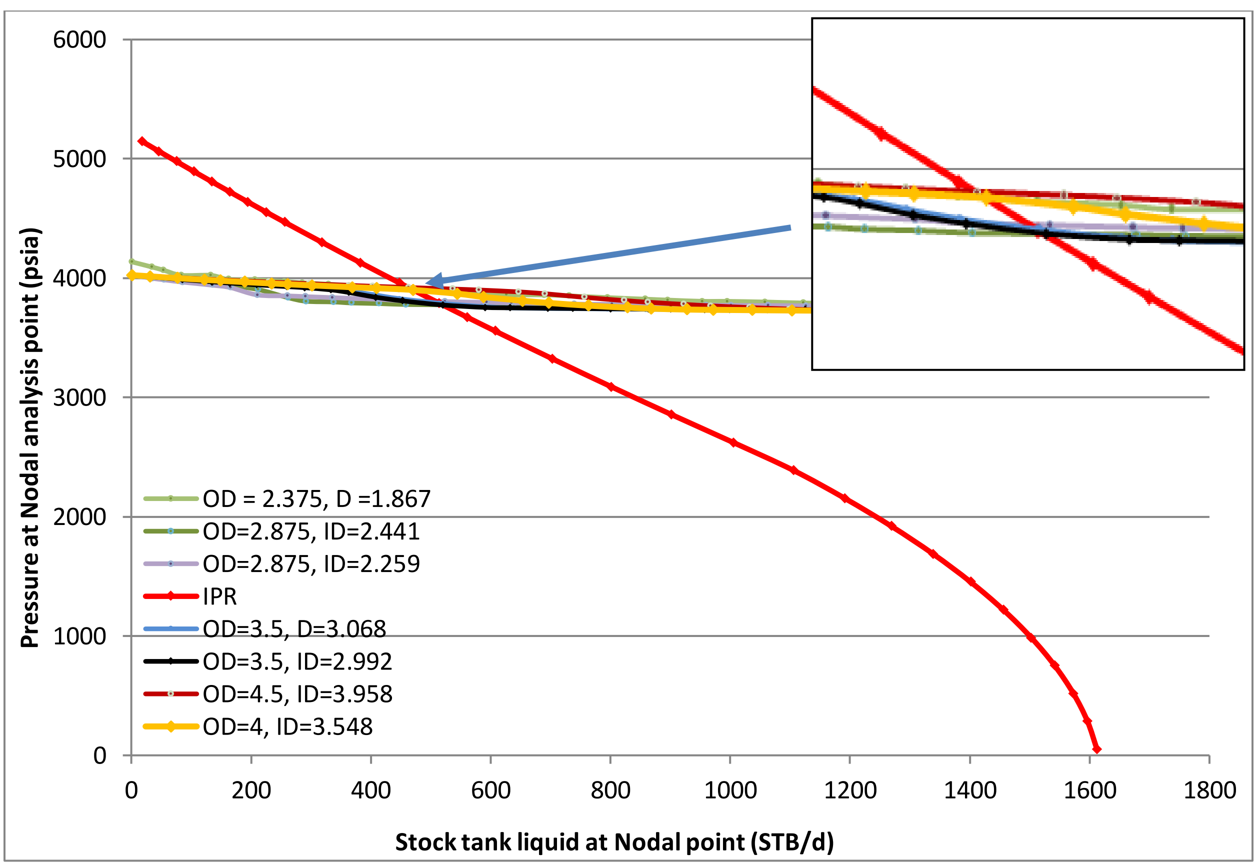


Figure 4.1.1: Effect of different tubing sizes when k= 2mD, outlet P= 61 bar, S=0, Wt%=0 at Well A

The basic idea of tubing design is to have a large enough tubing diameter such that extreme friction will not occur and a small enough tubing such that the velocity is high and liquid loading will not occur. Appendix A (Table A.1) Shows the different liquid flow rate, Pressure at Nodal point (bottom hole), and bubble point Pressure for reservoir permeability ranges from (2-5mD) and outlet Pressure of (61 bar), with 0% water cut and having no skin factor. By running different tubing sizes (taken from Table 1 on page 11) for each permeability value shows however when k=2mD the Liquid flow rate reaches its highest value (526.7354 STB/d) with the increase of Tubing Diameter (OD=2.875in, ID= 2.441in).In addition to that for other permeability ranges the Liquid flow rate almost reaches its optimum value when tubing OD=3.5in, ID=2.992in, so we started working on other factors by running that completion.

However we expect higher flow rate when the diameter is higher, but with the diameter increases the holdup effect becomes higher which leads to have more gas in the column and it needs to consider because it is the matter of bubble point pressure.

A large tubing size may exhibit below critical flow and a smaller tubing size may indicate that the velocity will increase to be above criticism. Tubing sizes approaching and less than 1 inch, however, are not generally recommended as they can be difficult to initially unload due to the high hydrostatic pressure exerted on the formation with small amounts of liquid.

- ❖ Effect of water cut

However, the water cut affects the IPR curve and increases AOF as well as VLP (Figure 4.1.2), but decreases the oil flow rate due to impacting the mixture density thus promoting increased slippage and increased hydrostatic head.

As the water cut rises up the VLP is getting worse and moving counter clock wise, for each VLP we are getting different IPR which means that the water cut has effect on our reservoir as far as the pressure and liquid flow rate is going to change, however the total liquid production rate in this well increases (due to having enough outlet pressure to allow heavy fluid to flow otherwise indeed expected the flow rate goes down as the water cut increase), but on the other hand as shown in tables at Appendix B the oil production is going to decrease.

We have a dramatic decrease of oil rate from (520 stb/d)when the water cut is 0 to only (122 stb/d) when the water cut is 90 and this resemble the future oil flow rate of that well at high water cut for the selected tubing size and outlet pressure.

The faster pressure goes down as the fluid goes up due to having heavier fluid in the case of having high water cut so the bubble point depth is going to be even more down in the result the bubble point happens early in the deep point of the well. There is a big difference in the bubble point depths and therefore in the average density of oil and gas which expected to be lighter, so water percentage goes up and hydrocarbon percentage goes down.

Higher water cut is going to affect hydrostatic head because it has affected by depth and density, so with having more water in the liquid the average density is going to be affected and the friction in the result.

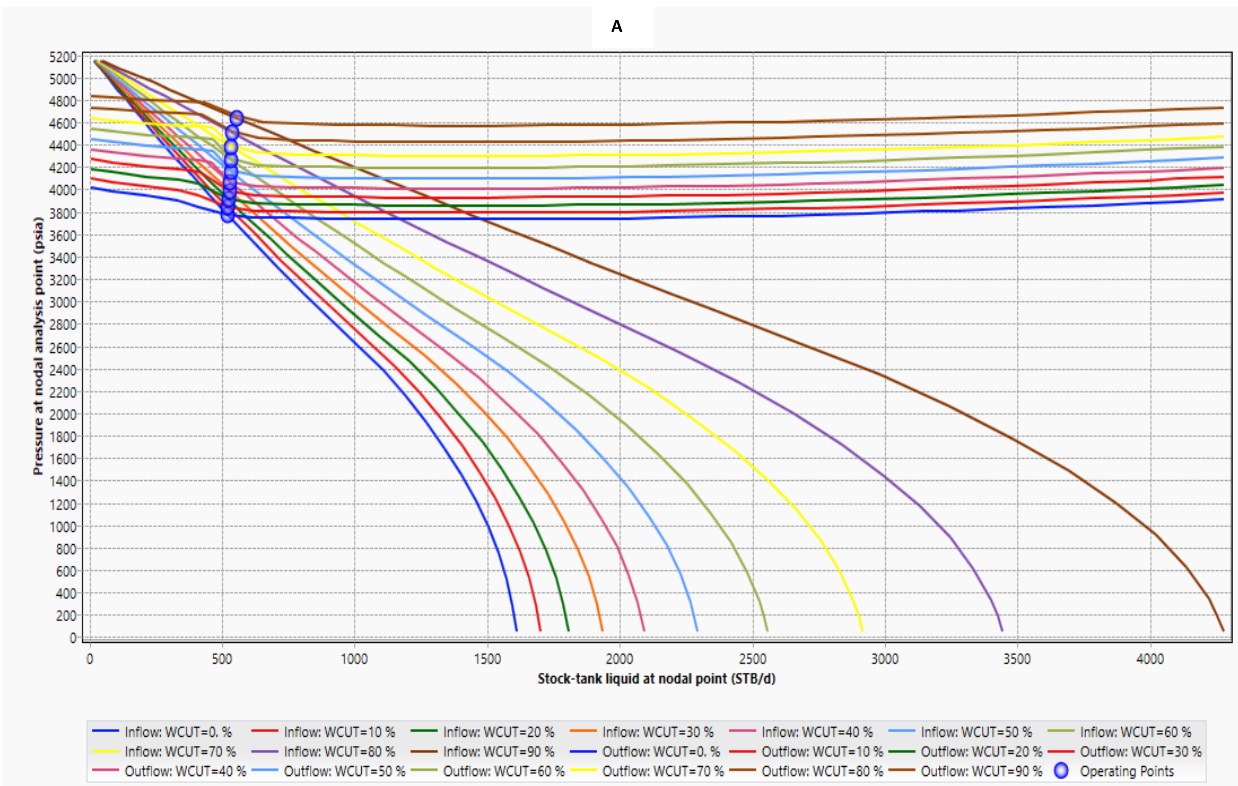


Figure 4.1.2: Effect of water cut when k=2mD, S=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well A

❖ Effect of skin factor and reservoir pressure

The causes of low oil production from wells include skin, low permeability, and a high rate of pressure depletion among other factors. Skin is a major challenge in oil production because it causes additional pressure drop around the wellbore. Hence, there is a drop in oil flow from the reservoir to surface facilities [10]. Skin could be a result of formation damage, poor production practices as shown in figure 4.1.3. More detailed data and the effect of water cut and skin factor has been shown in Table B.1 (at Appendix B).

In addition to, the depletion in reservoir pressure has a great impact on the production rate as shown in Figure 4.1.5.

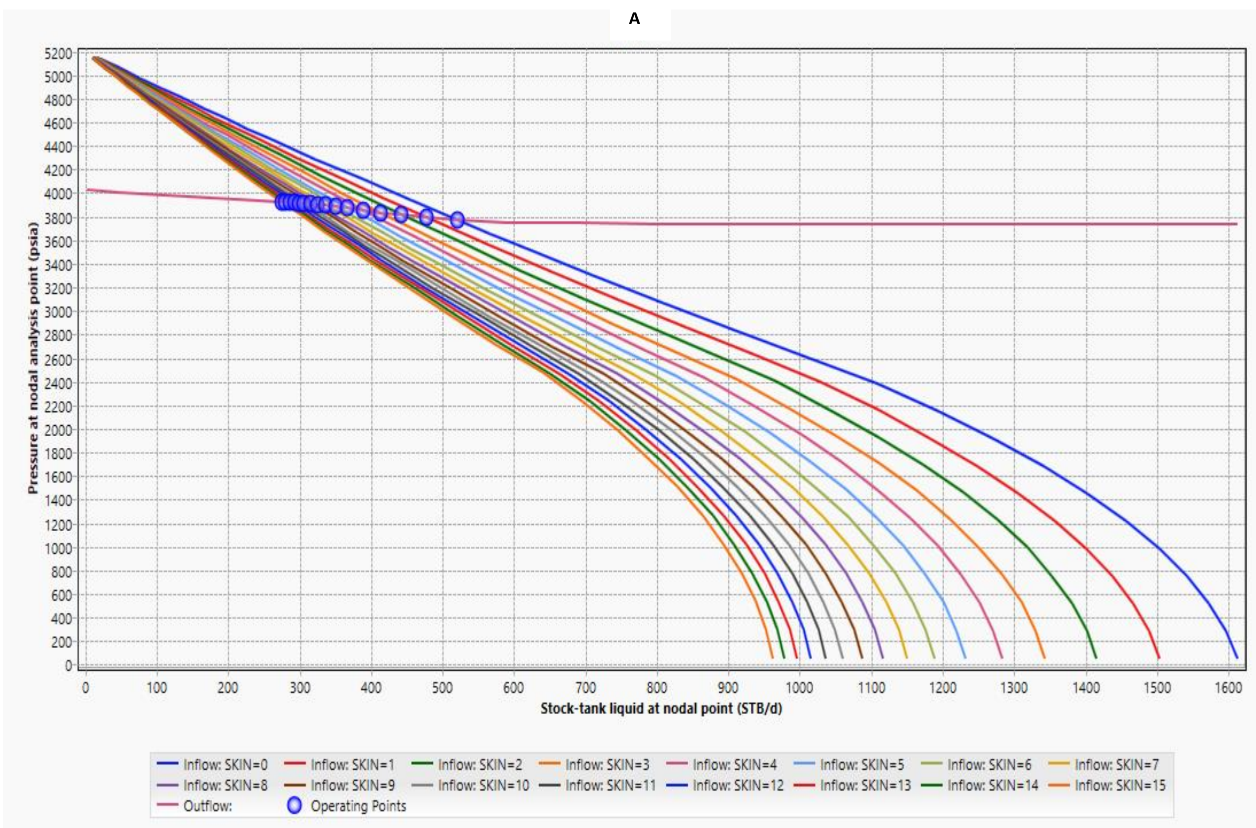


Figure 4.1.3: Effect of skin factor when k=2mD, wt%=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well A

❖ Effect of outlet pressure (Separator pressure)

The low pressure at the wellhead increases the velocity of the gas and will also put some of the liquid back in the gaseous state. The lower bottom hole producing pressure from deliquefying wells and lowering surface pressures can result in substantial production and reserves increases.

Figure 4.1.4 shows however, lower outlet pressure results higher liquid flow rate, but when it reaches 16 bar the well starts flowing below bubble point pressure (more detailed data have been showing at Appendix C; Table C.1)

The estimated bubble point pressure in this well from Vogel model is 2540 psi, so it means as the liquid travels and the intersection of VLP w IPR at the strait part of IPR means that our reservoir is undersaturated so the fluid gets inside the wellbore at a pressure slightly above the Pb but after we minimized the outlet pressure to 30 bar very soon as the liquid transfer to up due to the inclination of the well it consumes pressure in order to meet gravity so very soon its pressure goes down to the bubble point and it may happen at the lowest part of the tubing, which means that the fluid is liquid from the reservoir up to that point then the gas comes out from that point and that makes the average density above that point up to the surface smaller which looks easier for the fluid to be lifted up and looks like natural gas lift, so simply it means the phase change indeed is a good change for our well.

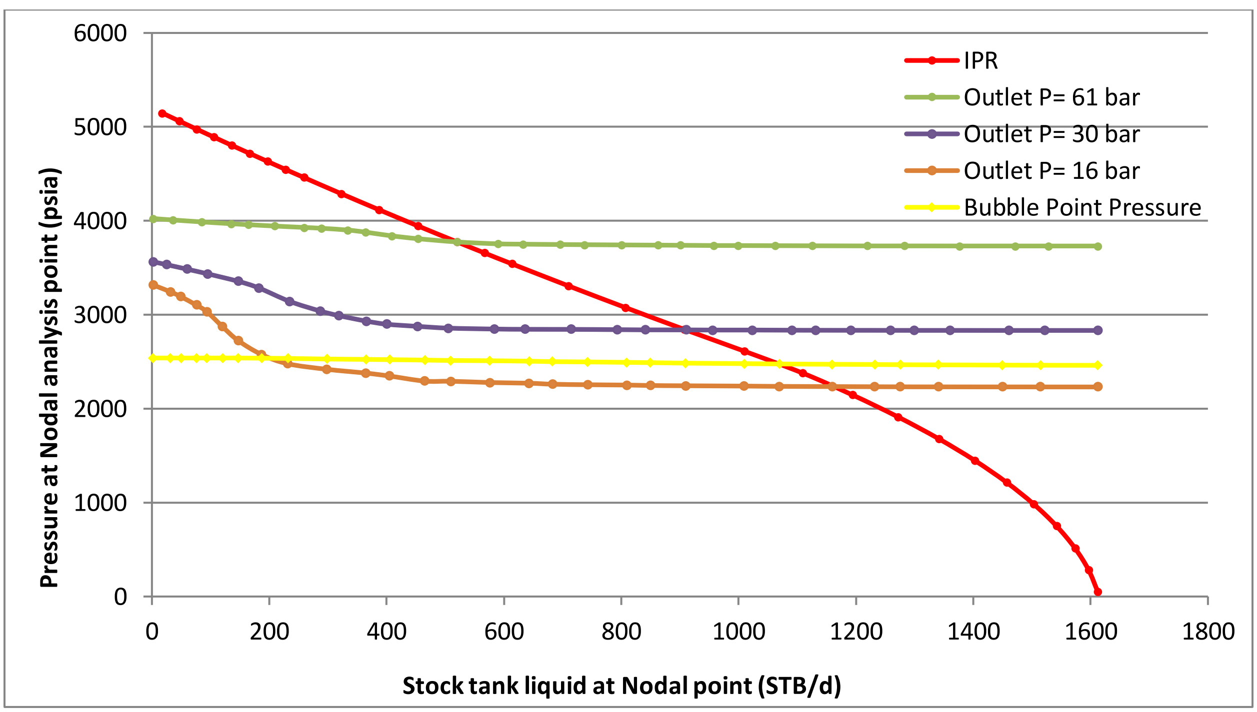


Figure 4.1.4: Effect of outlet Pressure when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well A

❖ Effect of Reservoir Pressure

With reservoir pressure depletion, based on Vogel equation (mentioned at chapter one) the curvature of the IPR diminishes. On the other hand, the operating flow rate depletes as well.

The figure below gives the expected flow rate after the reservoir pressure declines, which means without the water cut the energy of the reservoir decrease as the reservoir pressure goes down. Approach the bubble point the flow rate reduces from (1094 stb/d) to (225 stb/d) as the pressure declines from (5000 psi)to (3000 psi) and this is the decline period of our well, and below that reservoir pressure there is no expected flow rate and the well becomes dead.

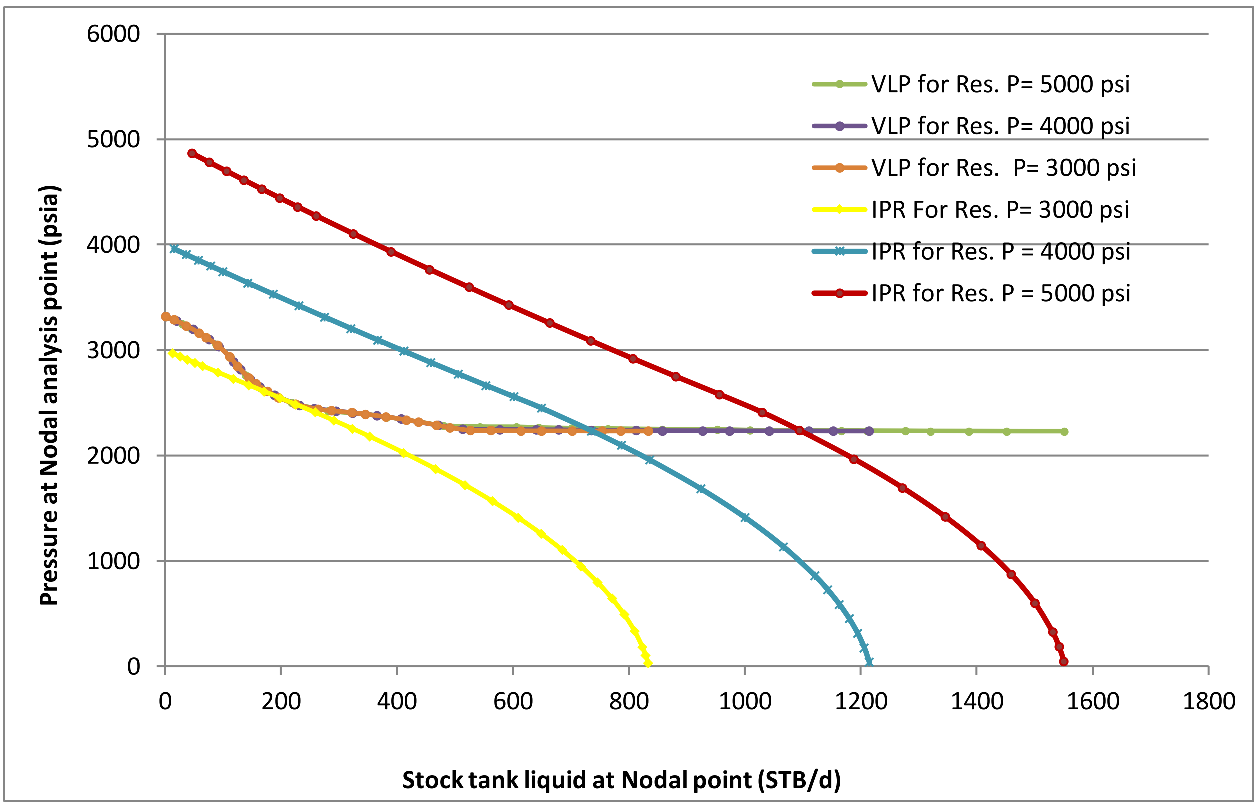


Figure 4.1.5: Reservoir pressure effect when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well A

❖ Effect of artificial lift- Gas lift

In many cases, the reservoir is unable to furnish sufficient energy to produce fluids to the surface. When this occurs, artificial lift equipment is used to enhance production rates by adding energy to the production system [9]. This additional energy can be furnished directly to the fluid through subsurface pumps, by reducing the backpressure at the reservoir with surface compression equipment to lower wellhead pressure, or by injecting gas into the production string to reduce the flowing gradient of the fluid. The Gas lift method is working in this field, so by injecting gas to the tubing string through the first dummy valve we can enhance the liquid production rate as shown below:

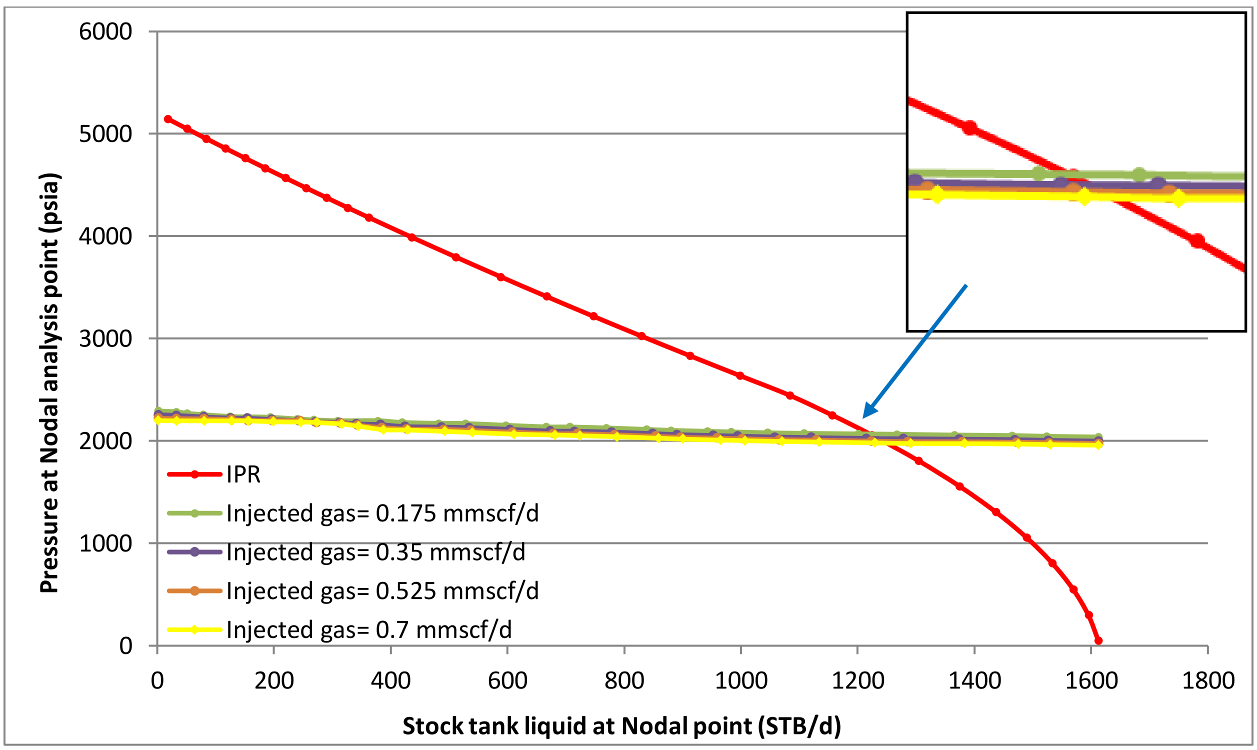


Figure 4.1.6: Effect of injected gas when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well A

The IPR curve must be determined for a specific wellhead pressure in the sensitivity analysis. The operating point of selected tubing size is determined by the point of intersection of the IPR and VLP curves. The ideal tube size is the one that has the highest flow rate.

Due to the compressibility of the injected gas as the liquid flows inside the tubing, then the liquid starts to expand which leads to increasing the velocity and with the higher velocity we are going to have more friction and the flow rate increase due to the fact that velocity increase, hydrostatic part is going to increase as well because it is a function of average density and depth (since the depth is constant so the change in density affects hydrostatic part).

Expected flow rate for various injection rates of gas is shown in Figure 4.1.7, the more gas introduced to the system the more oil is going to be produced. However, maximum liquid flow rate which is the blue line is when we inject (2.45 mmscf/d) of gas after that we are going to get the worse result, practically there will never be enough gas, even if there will be a big number of injected gas there is going to be a big number of well flow rate. Start from the first point and up to the point which that you don't have enough increase (1.75 mmscf/d) beyond that point the liquid flow rate is increasing with low value, nevertheless if you don't take that point (1.75 mmscf/d) and take the real optimum point (2.45 mmscf/d) wasting gas after that doesn't make big change.

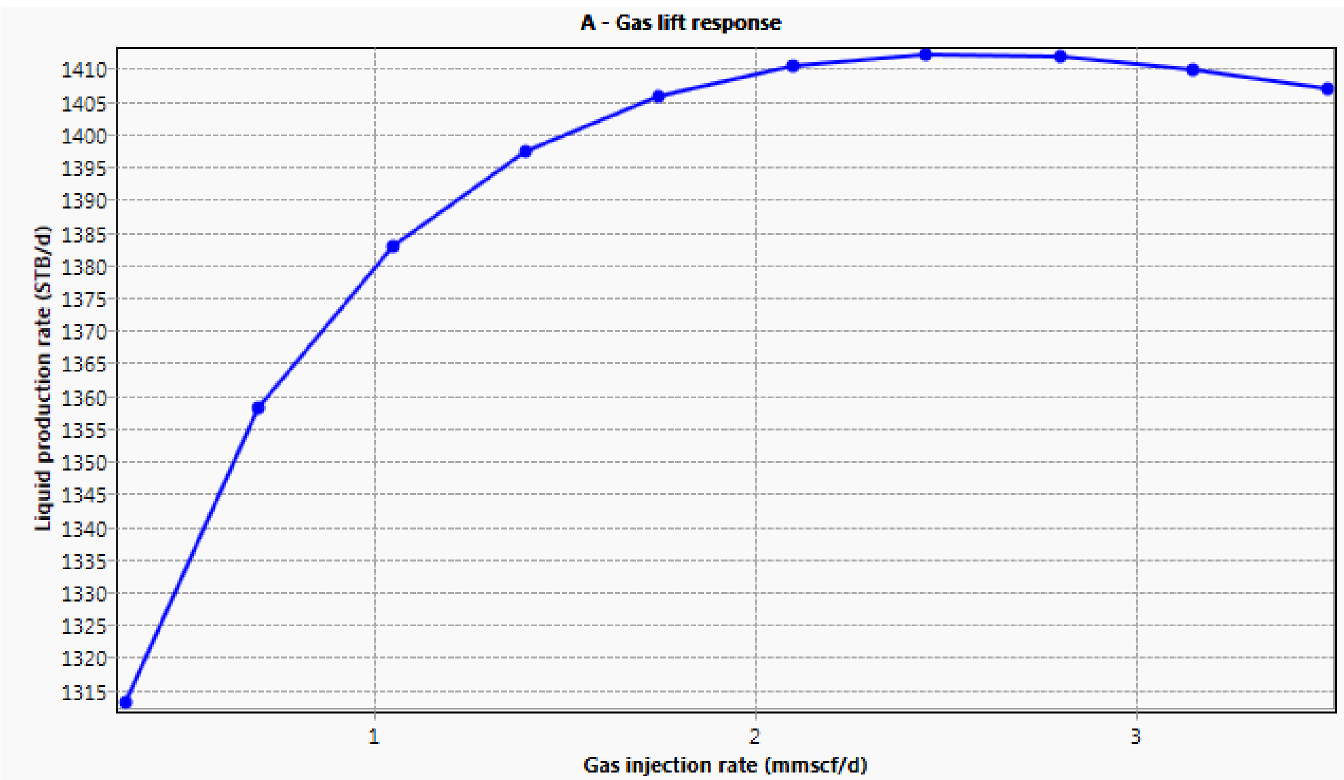


Figure 4.1.7: Various injected gas rate to Well A when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992

Because the other wells are located in the same field and by taking into consideration the above factors we are repeating the same procedures for the other wells.

4.2 Well B

❖ Effect of Different Tubing sizes

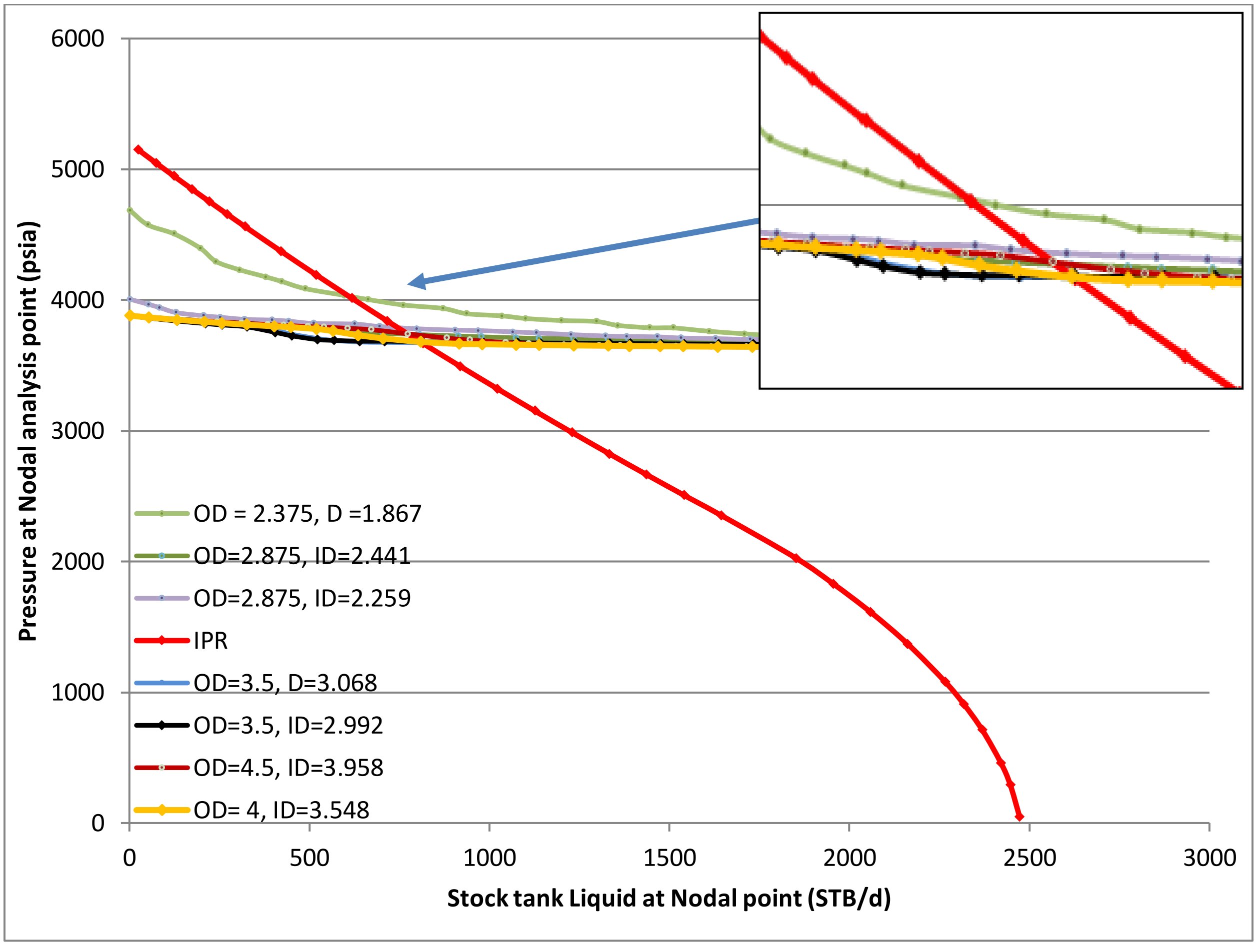


Figure 4.2.1: Effect of different tubing sizes when k= 2mD, outlet P= 61 bar, S=0, Wt%=0 at Well B

❖ Effect of water cut

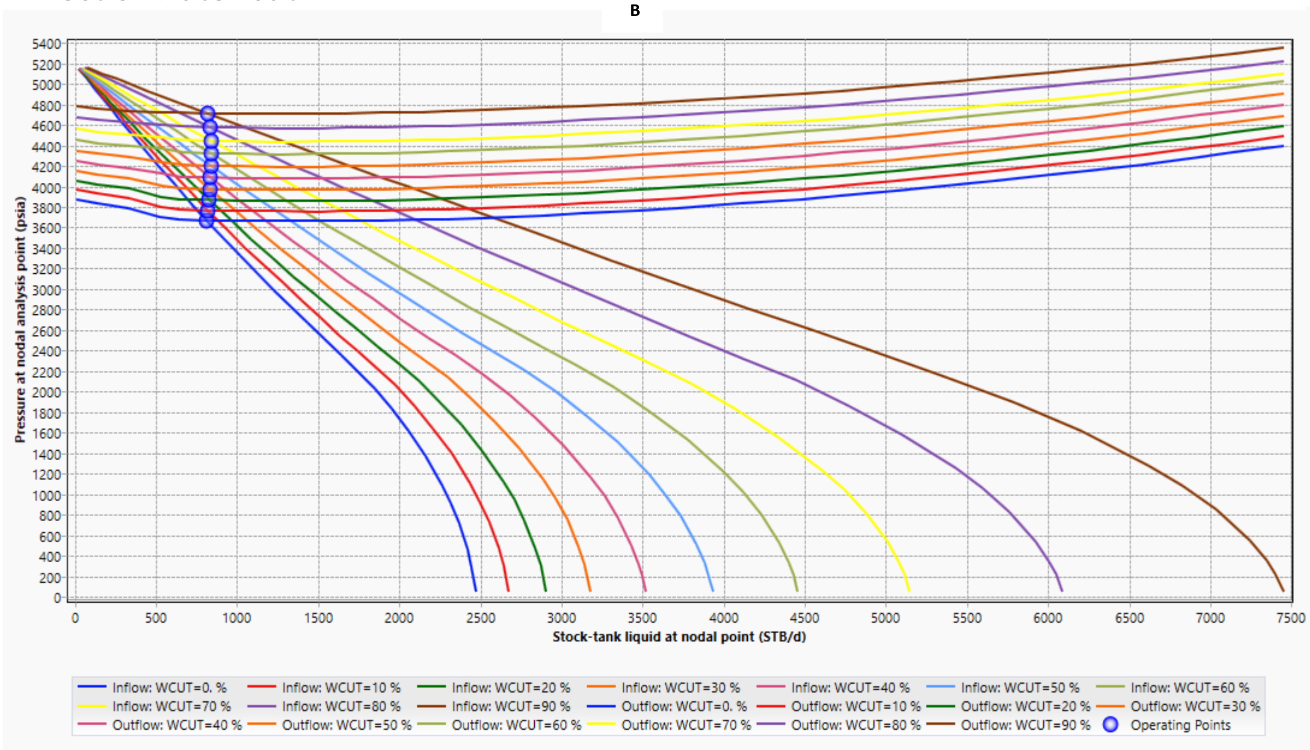


Figure 4.2.2: Effect of water cut when k=2mD, S=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well B

❖ Effect of skin factor

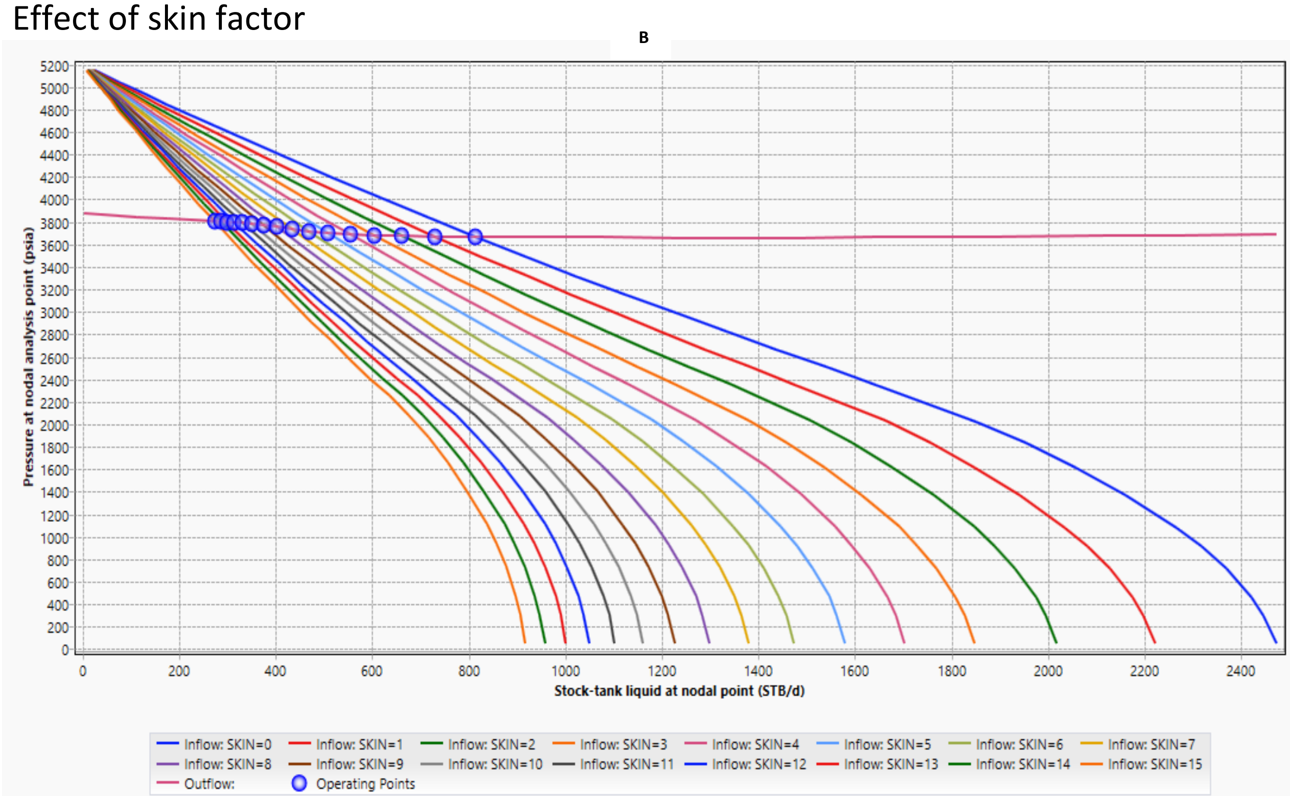


Figure 4.2.3: Effect of skin factor when k=2mD, wt%=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well B

❖ Effect of outlet pressure (Separator pressure)

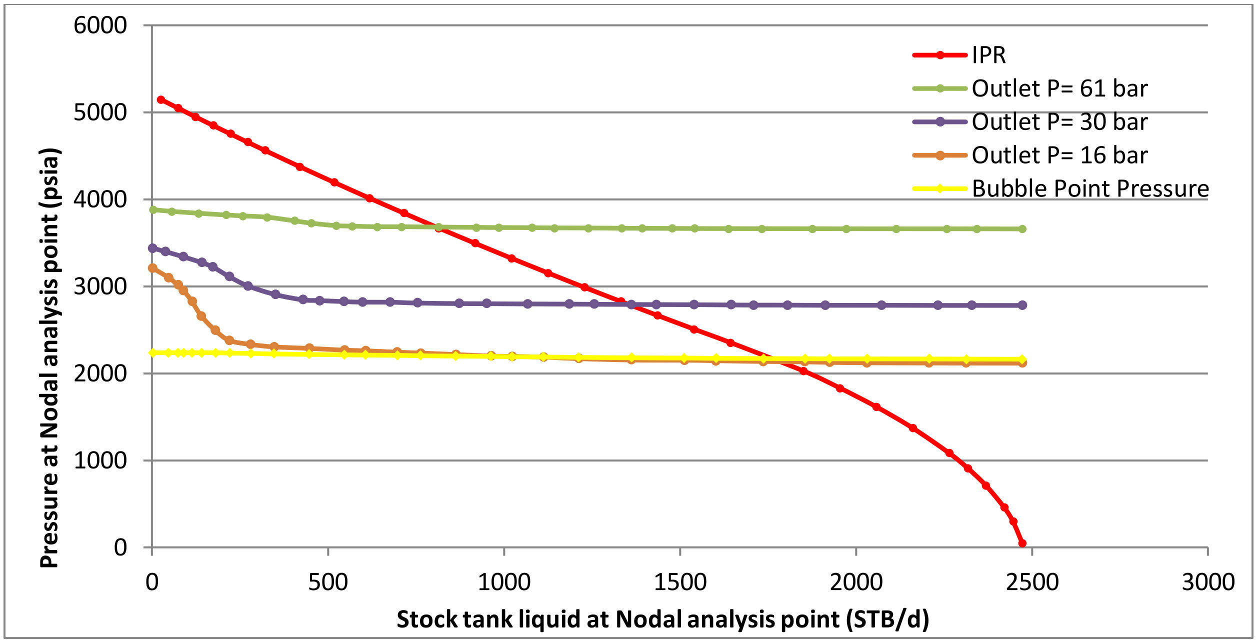


Figure 4.2.4: Effect of outlet pressure when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well B

❖ Effect of Reservoir Pressure

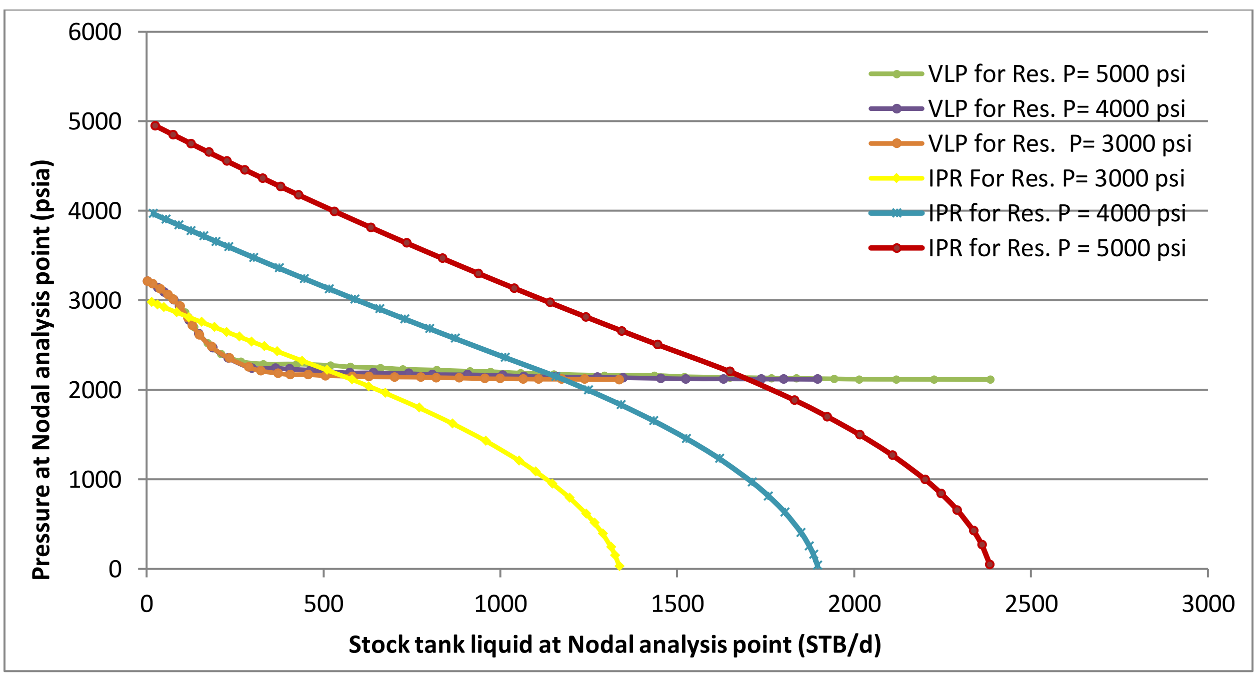


Figure 4.2.5: Reservoir pressure effect when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well B

❖ Effect of artificial lift- Gas lift

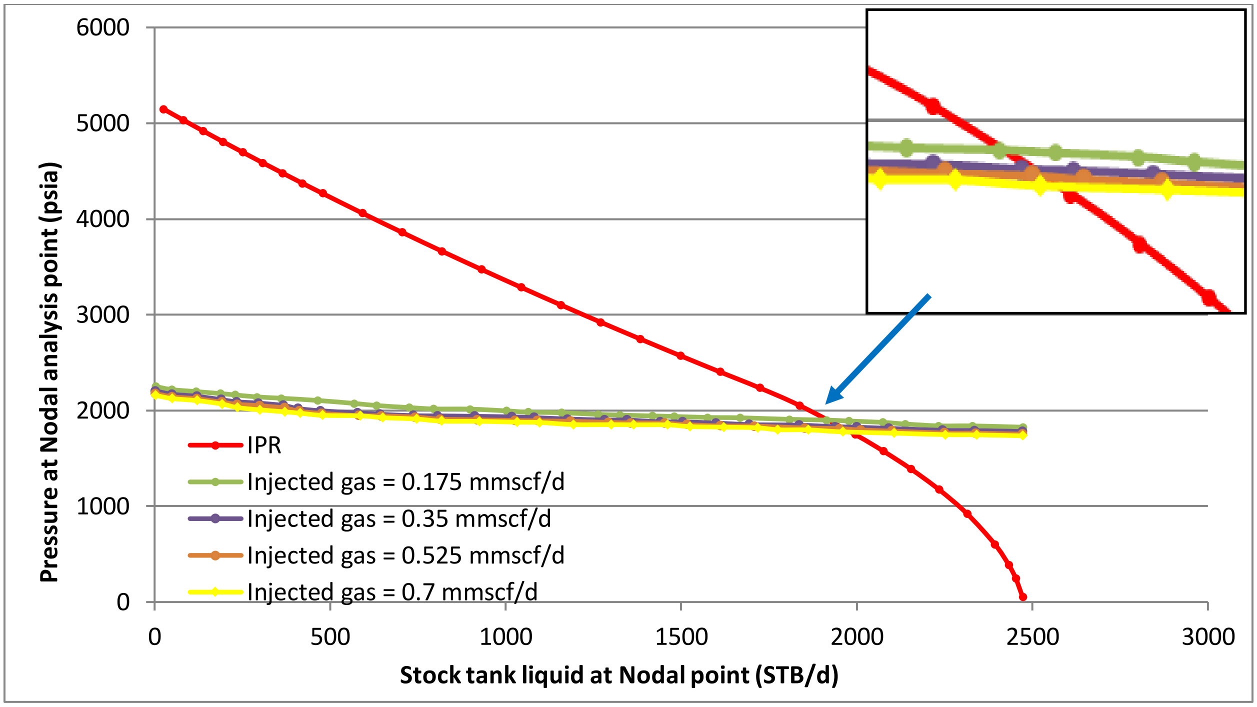


Figure 4.2.6: Effect of injected gas when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well B

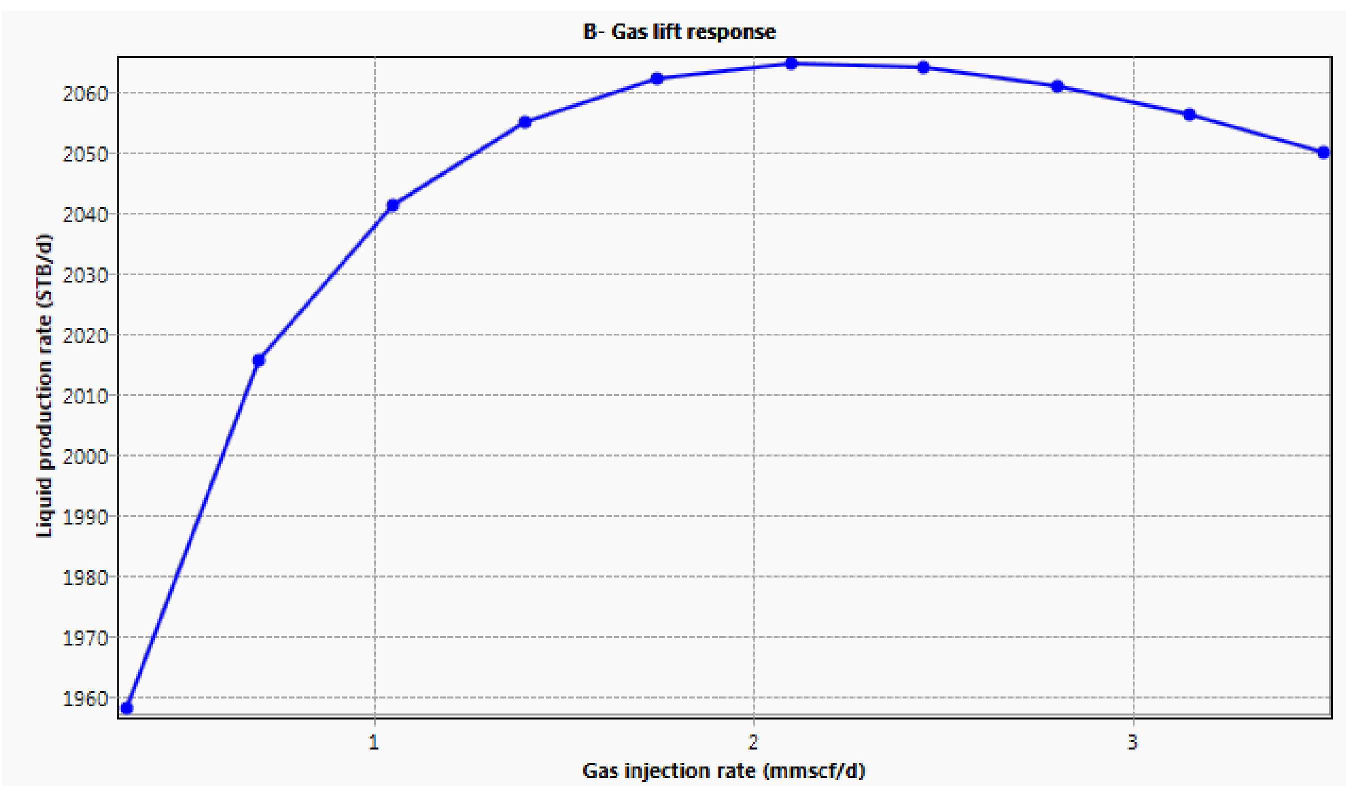


Figure 4.2.7: Various injected gas rate to Well B when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992

5.3 Well C

❖ Effect of Different Tubing sizes

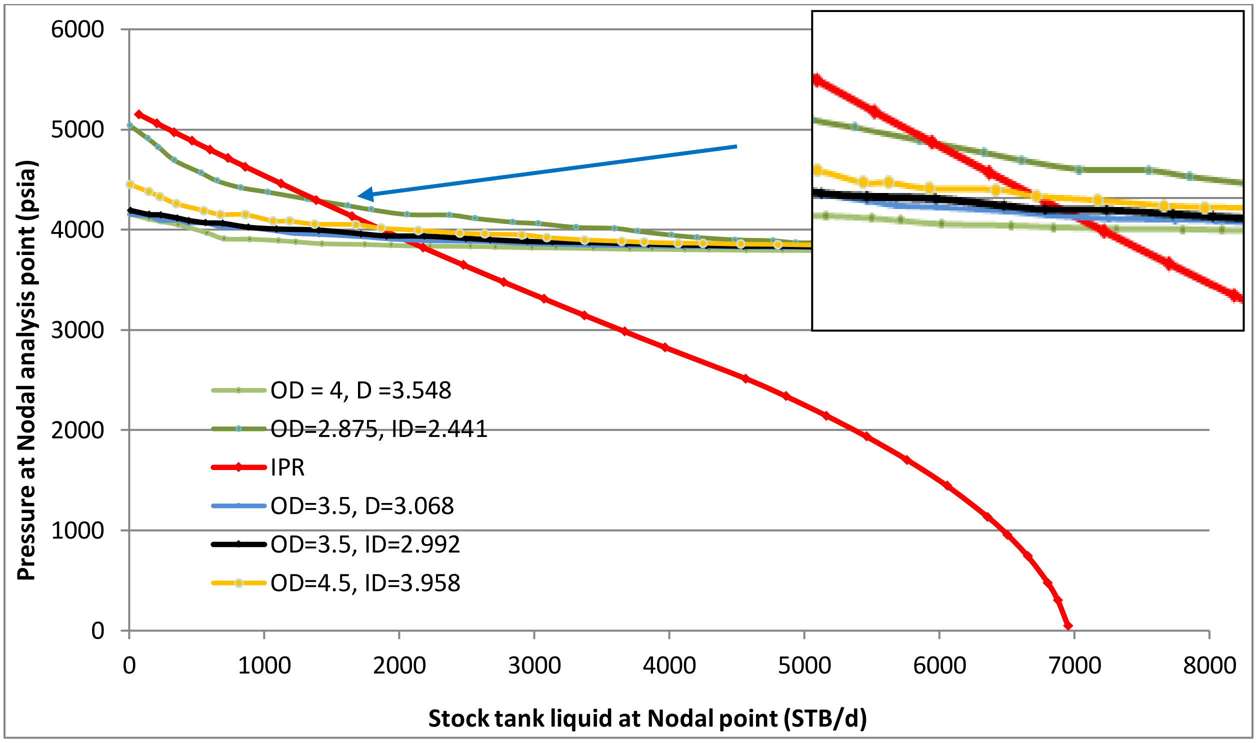


Figure 4.3.1: Effect of different tubing sizes when k= 2mD, outlet P= 61 bar, S=0, Wt%=0 at Well C

❖ Effect of water cut

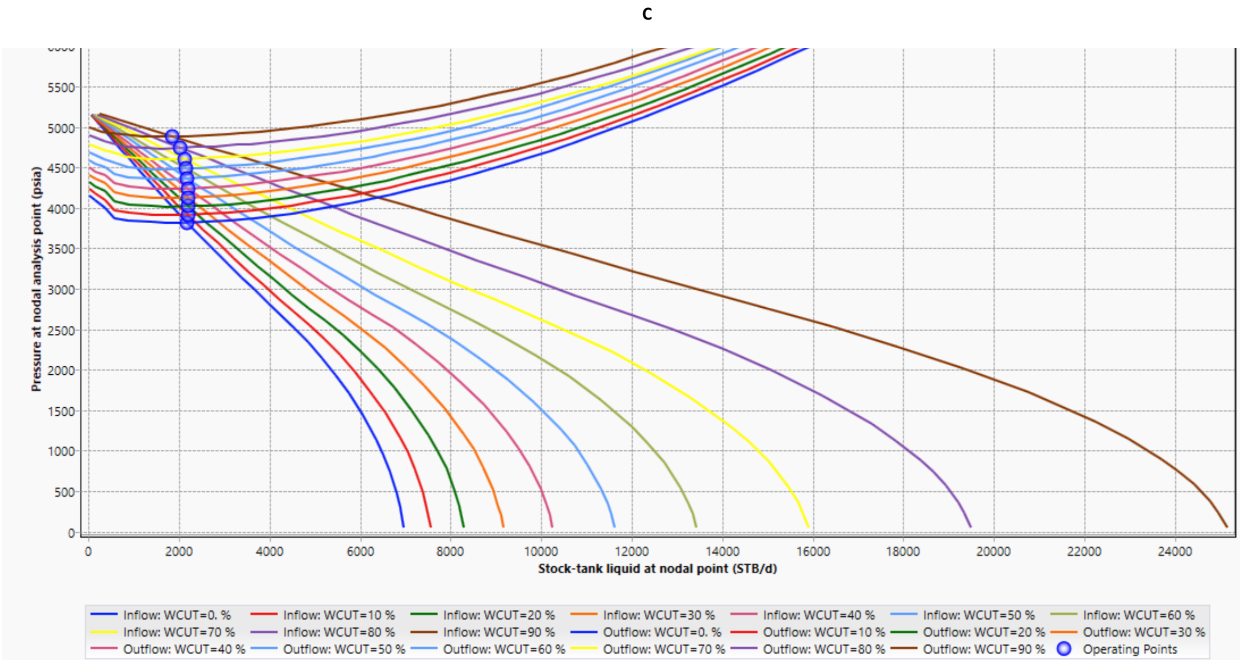


Figure 4.3.2: Effect of water cut when k=2mD, S=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well C

❖ Effect of skin factor

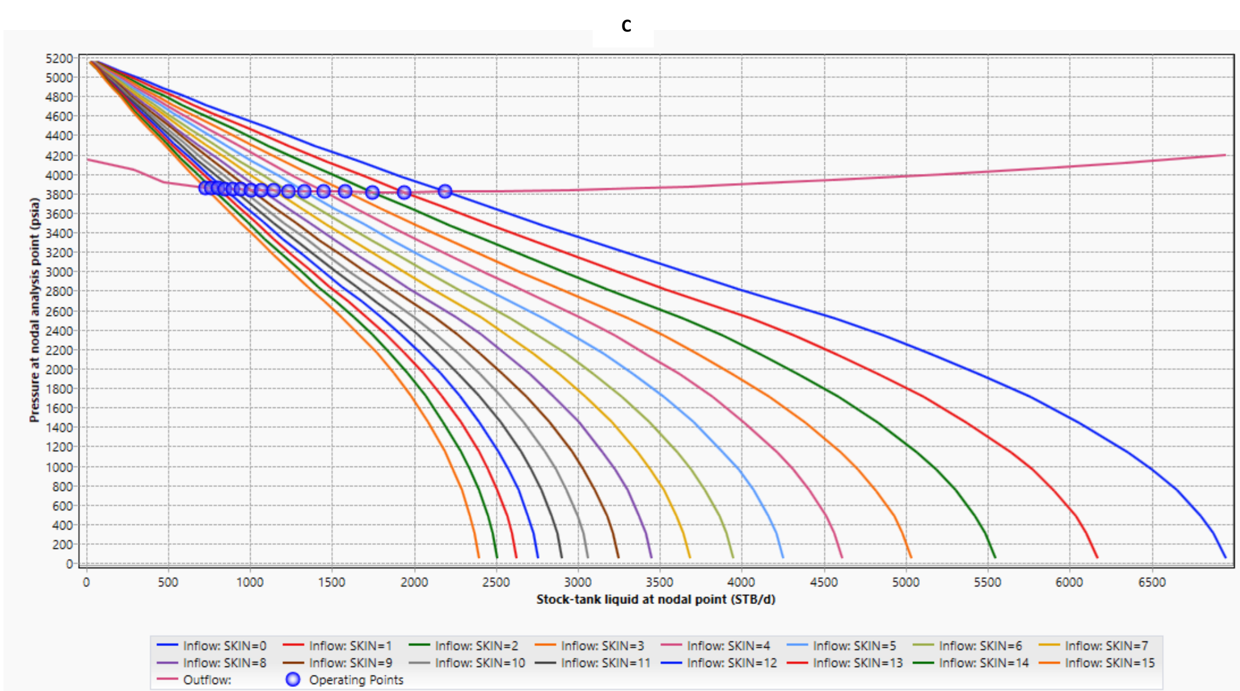


Figure 4.3.3: Effect of skin factor when k=2mD, wt%=0, Outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well C

❖ Effect of outlet pressure (Separator pressure)

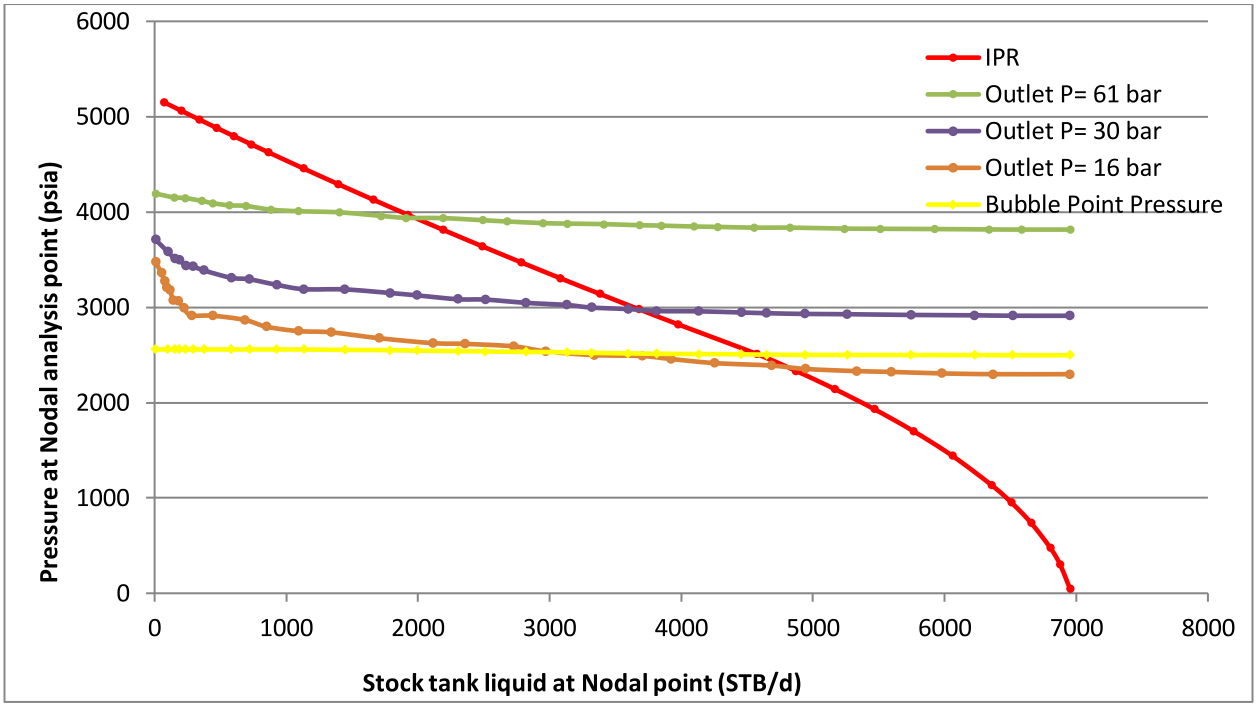


Figure 4.3.4: Effect of outlet pressure when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well C

❖ Effect of Reservoir Pressure

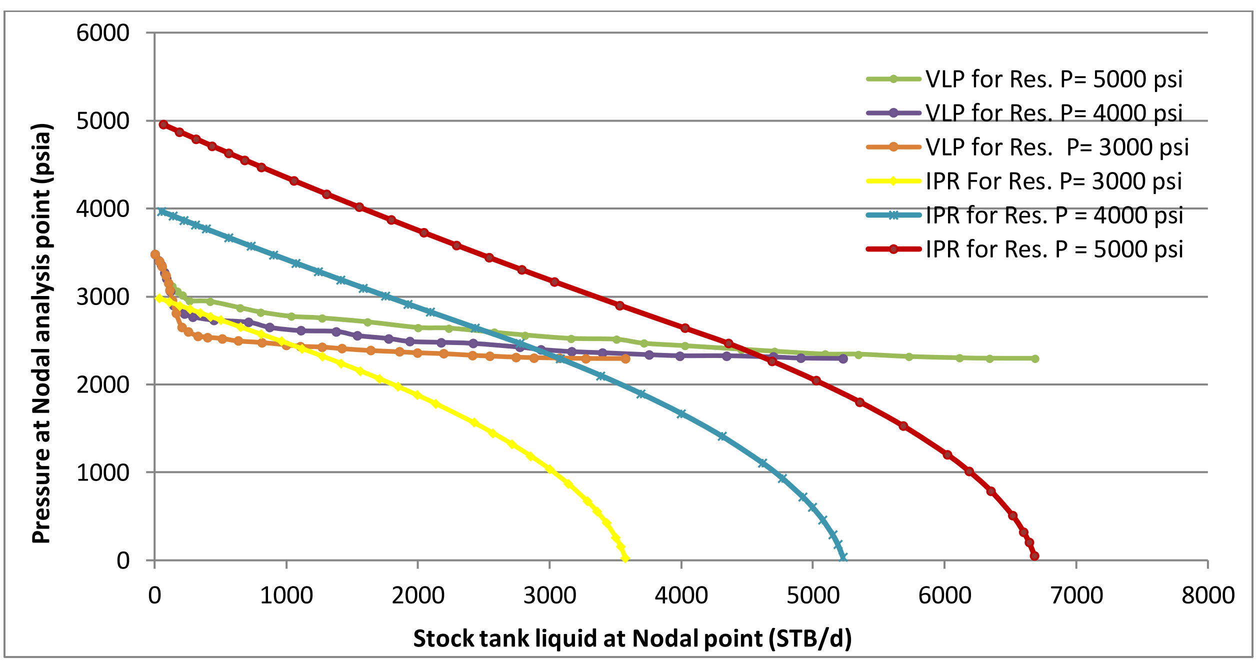


Figure 4.3.5: Reservoir pressure effect when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well C

❖ Effect of artificial lift- Gas lift

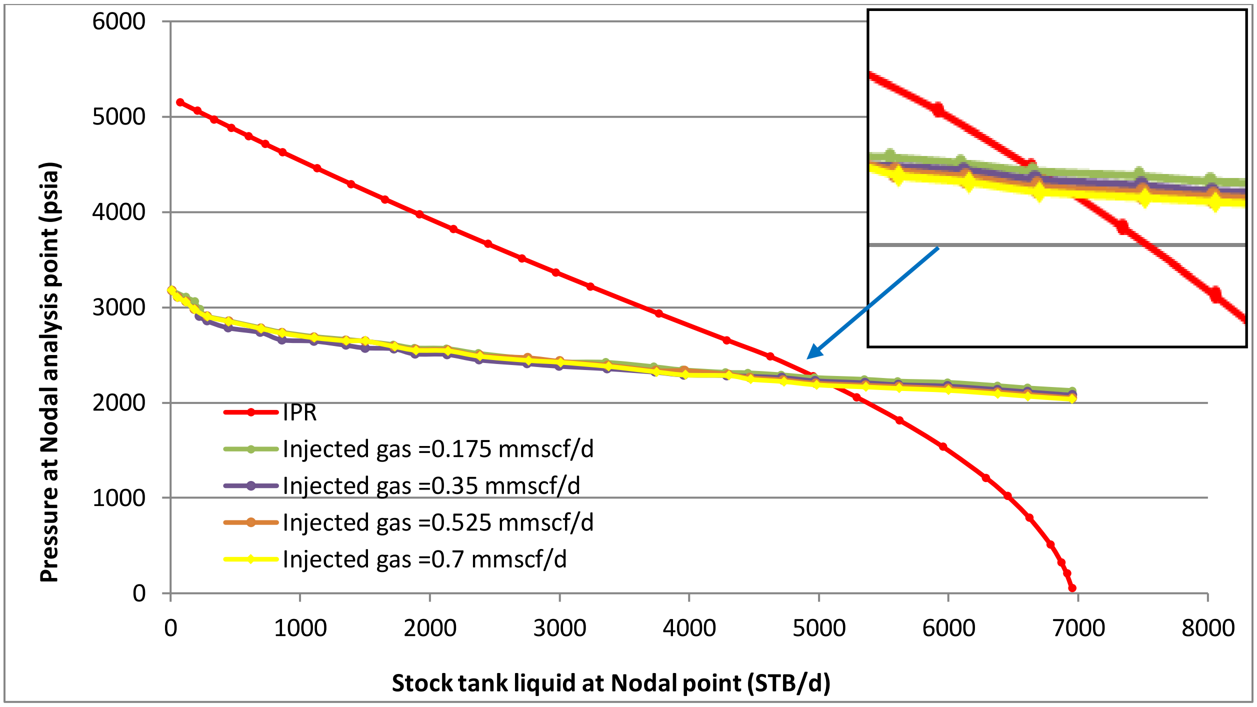


Figure 4.3.6: Effect of injected gas when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well C

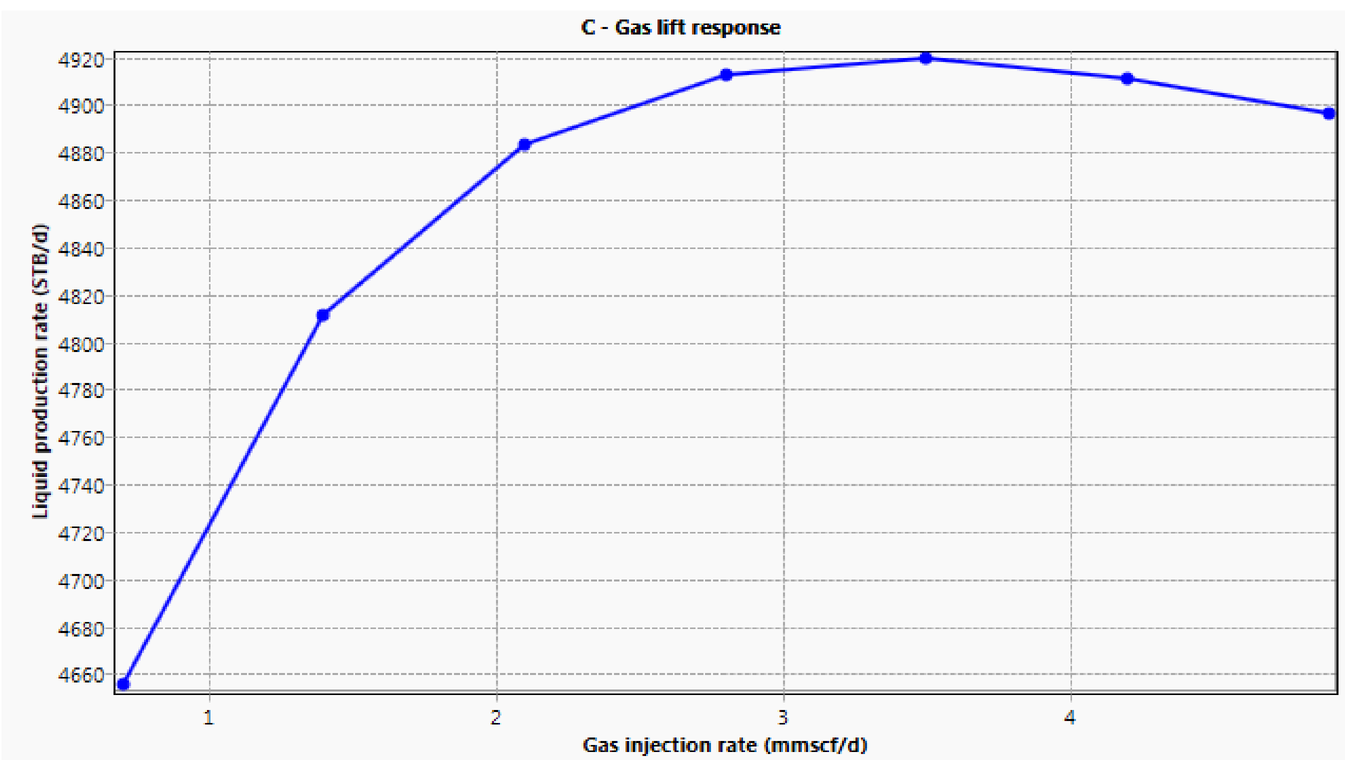


Figure 4.3.7: Various injected gas rate to Well C when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992

5.3 Well D

❖ Effect of Different Tubing sizes

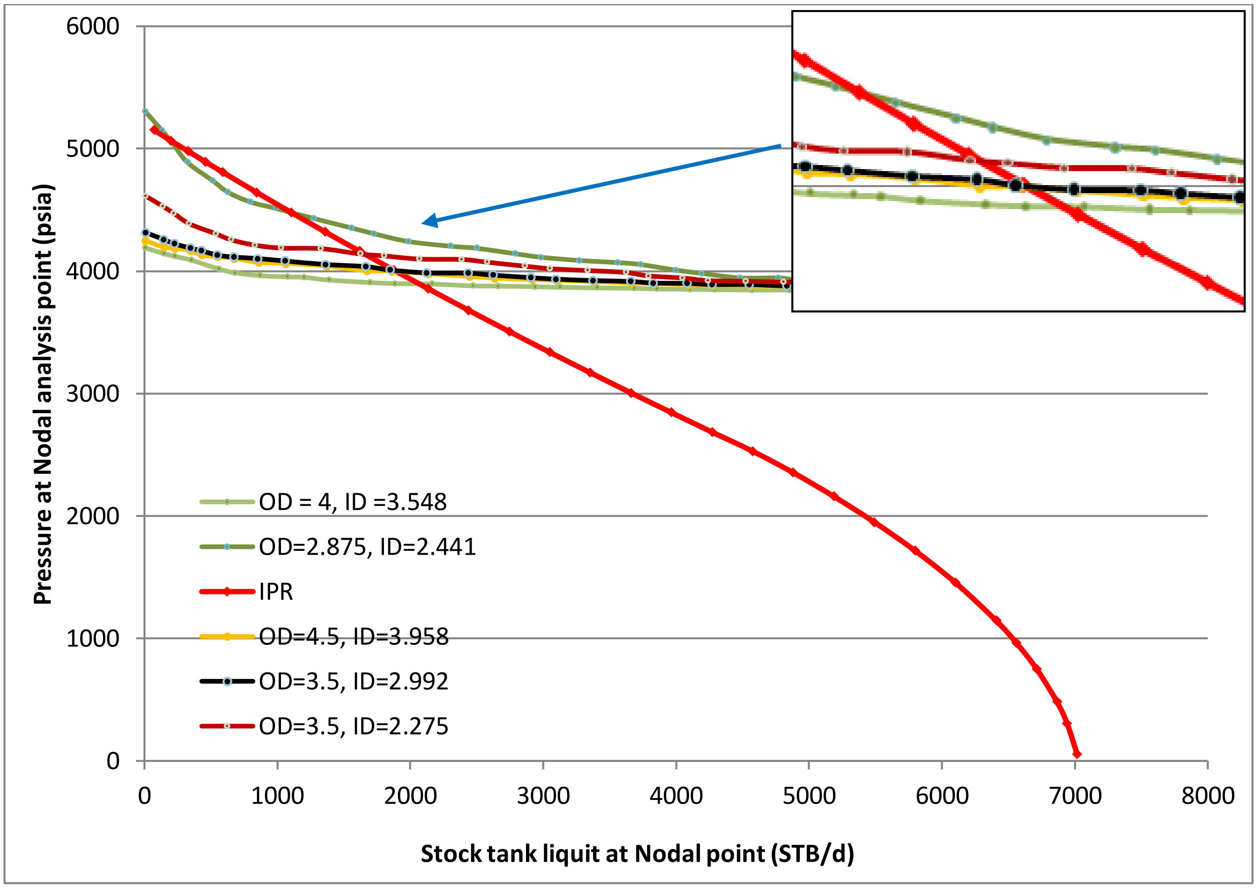


Figure 4.4.1: Effect of different tubing sizes when k= 2mD, outlet P= 61 bar, S=0, Wt%=0 at Well D

❖ Effect of water cut

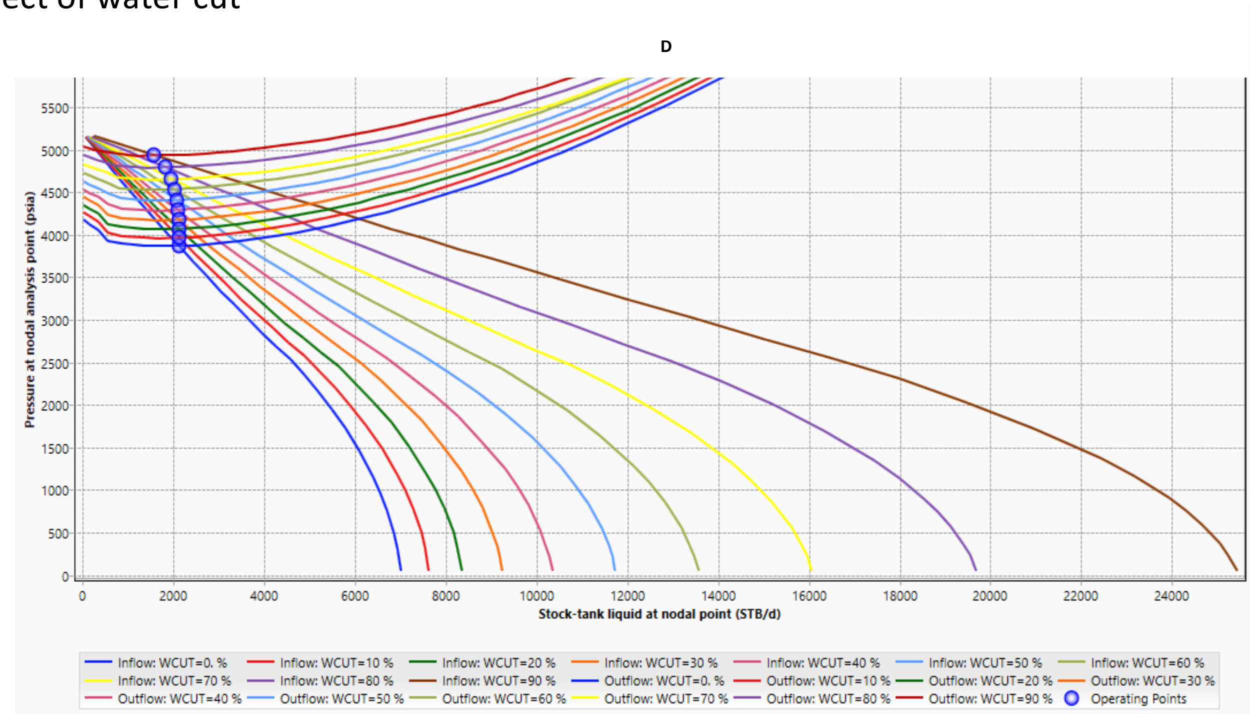


Figure 4.4.2: Effect of water cut when k=2mD, S=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well D

❖ Effect of skin factor

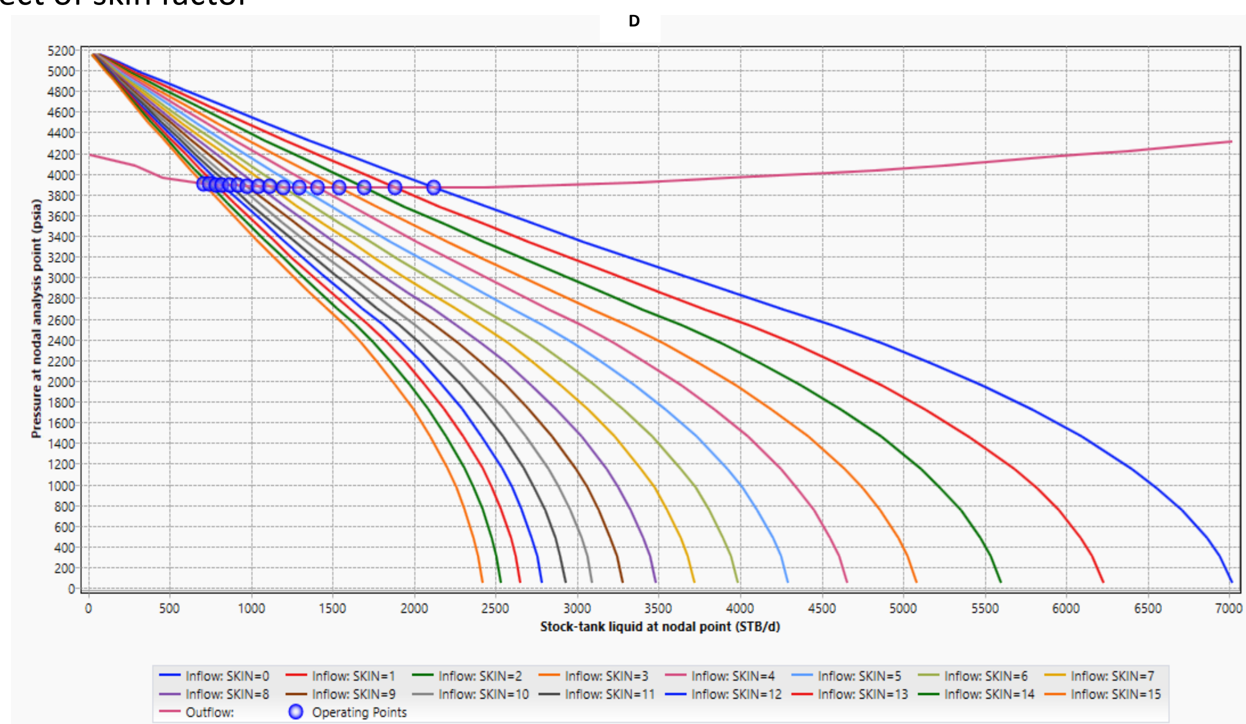


Figure 4.4.3: Effect of skin factor when k=2mD, wt%=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well D

❖ Effect of outlet pressure (Separator pressure)

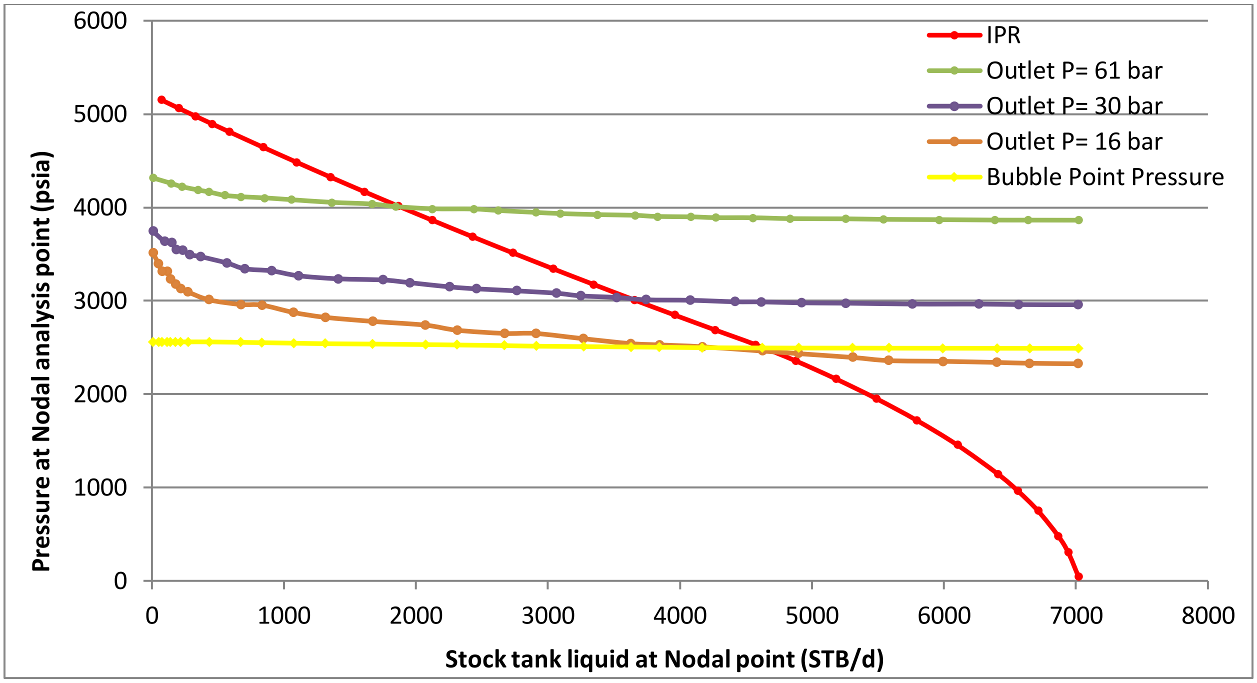


Figure 4.4.4: Effect of outlet pressure when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well D

❖ Effect of reservoir pressure

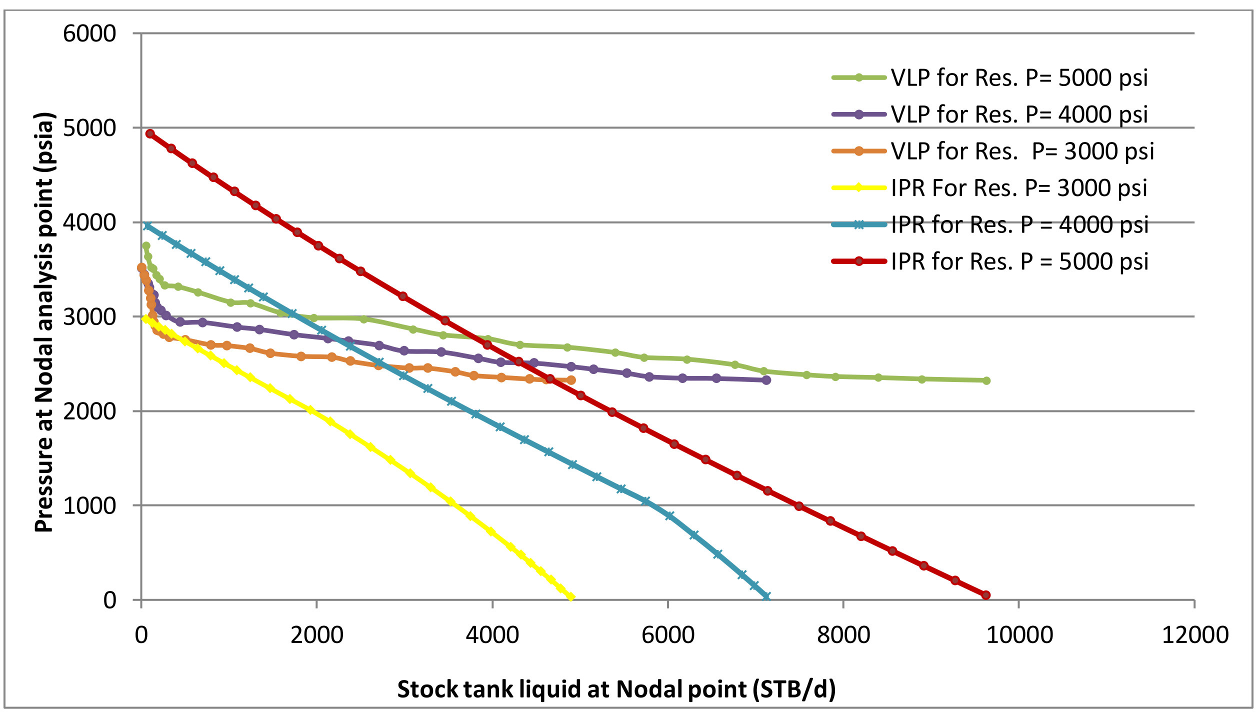


Figure 4.4.5: Reservoir pressure effect when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well D

❖ Effect of artificial lift- Gas lift

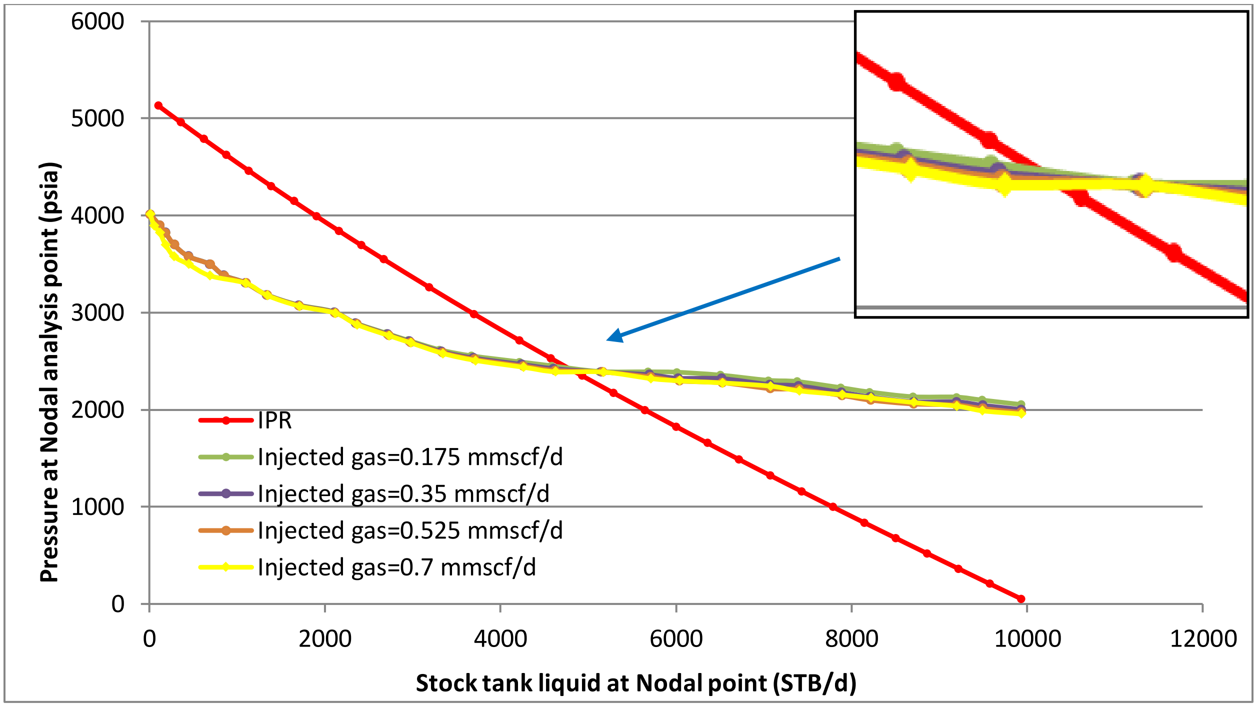


Figure 4.4.6: Effect of injected gas when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well D

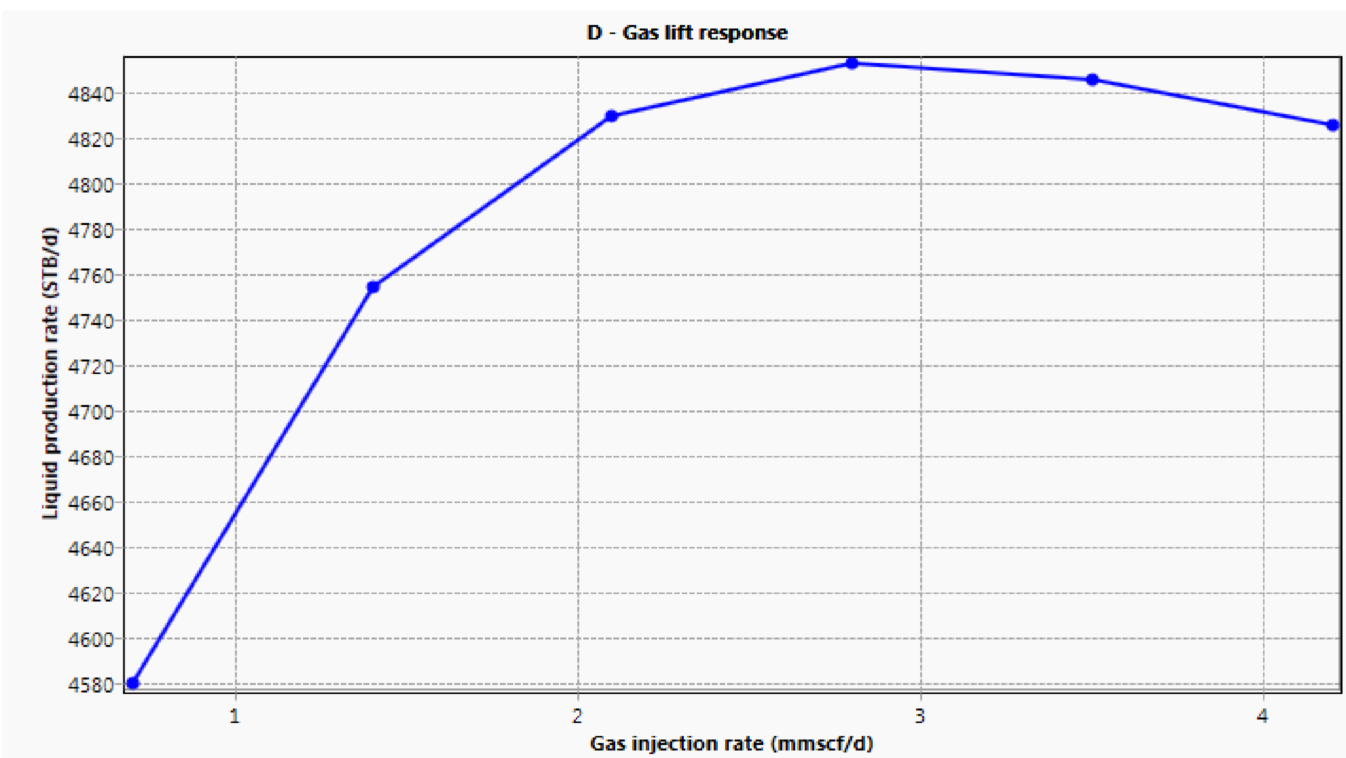


Figure 4.4.7: Various injected gas rate to Well D when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992

5.5 Well E

❖ Effect of Different Tubing sizes

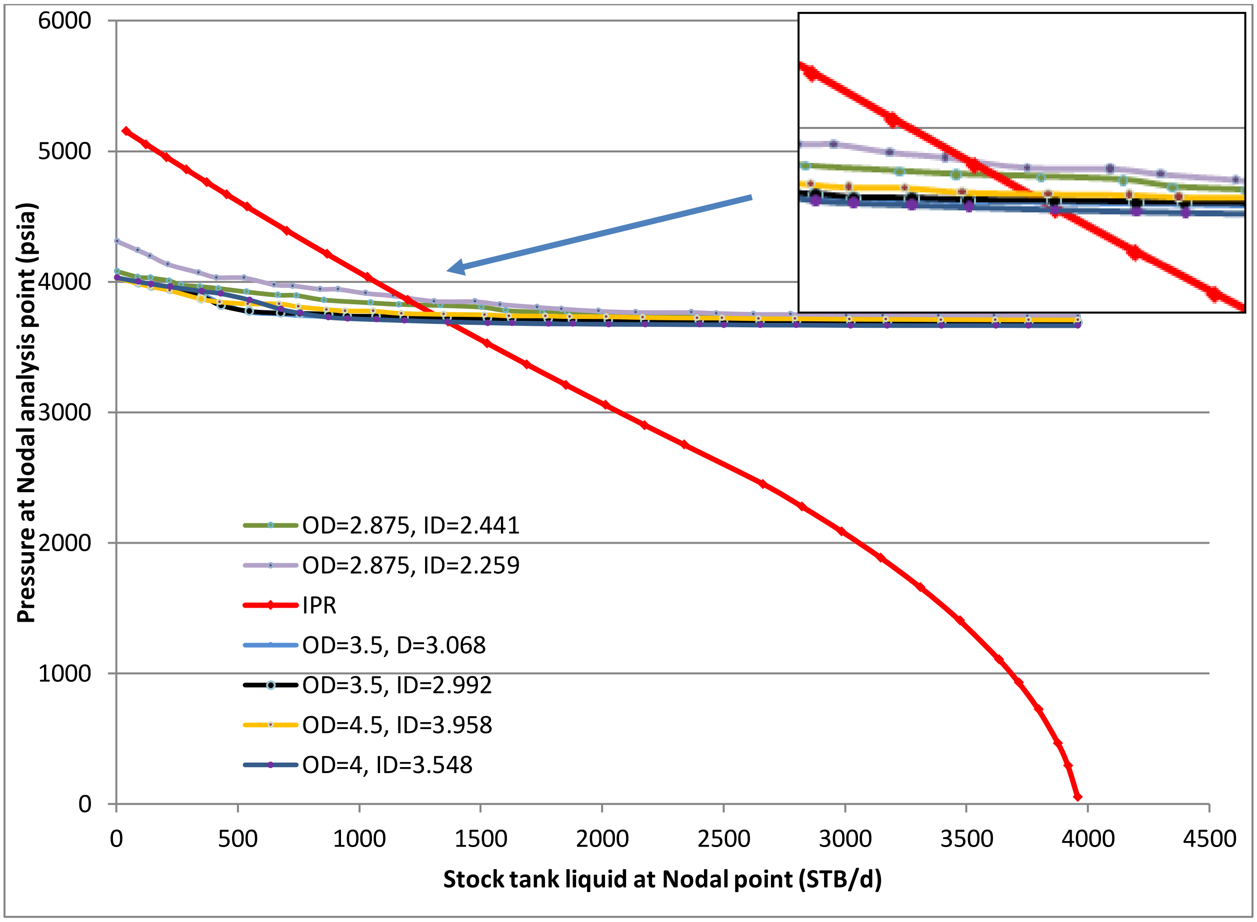


Figure 4.5.1: Effect of different tubing sizes when k= 2mD, outlet P= 61 bar, S=0, Wt%=0 at Well E

❖ Effect of water cut

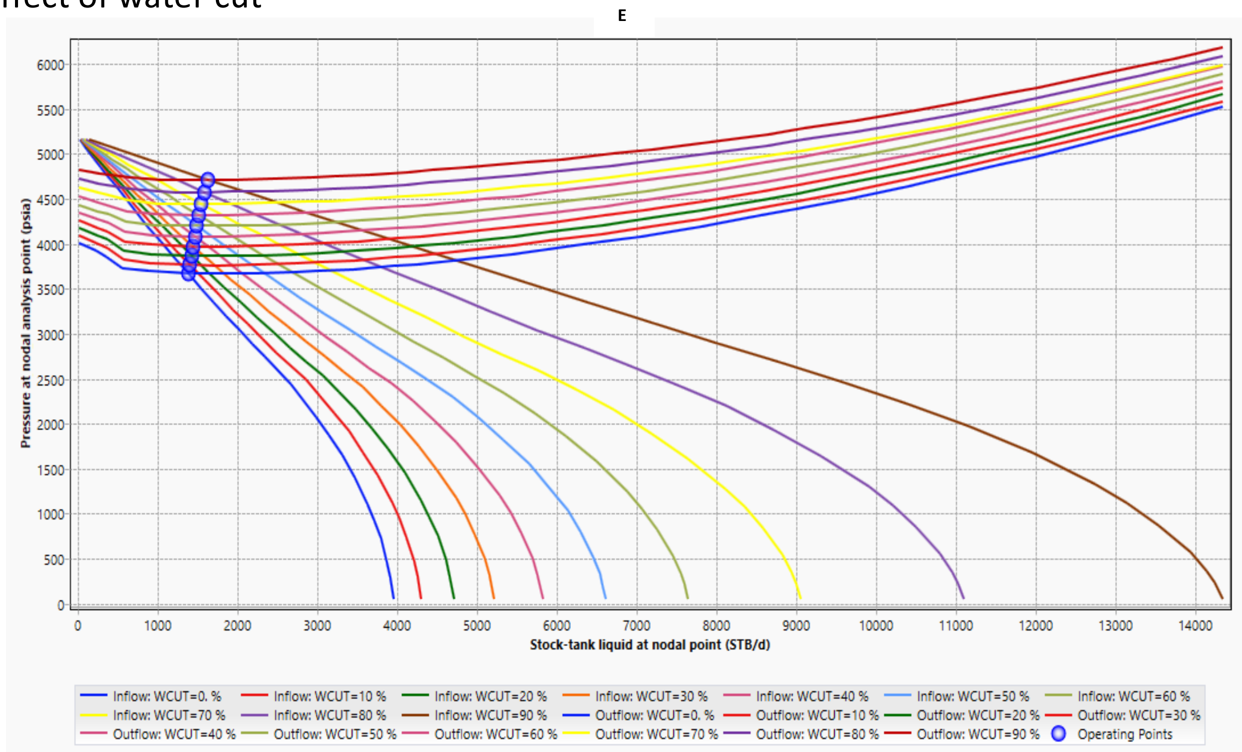


Figure 4.5.2: Effect of water cut when k=2mD, S=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well E

❖ Effect of skin factor

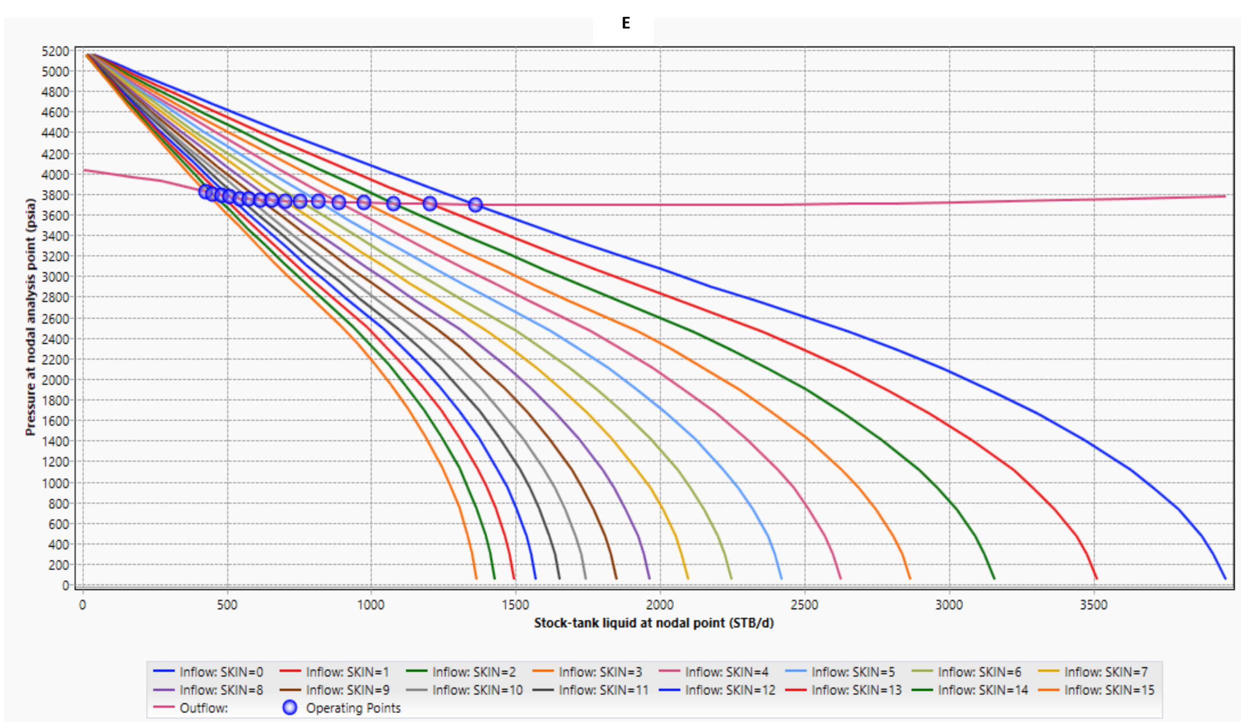


Figure 4.5.3: Effect of skin factor when k=2mD, wt%=0, outlet P= 61 bar, Tubing OD= 3.5 & ID=2.992 at Well E

❖ Effect of outlet pressure (Separator pressure)

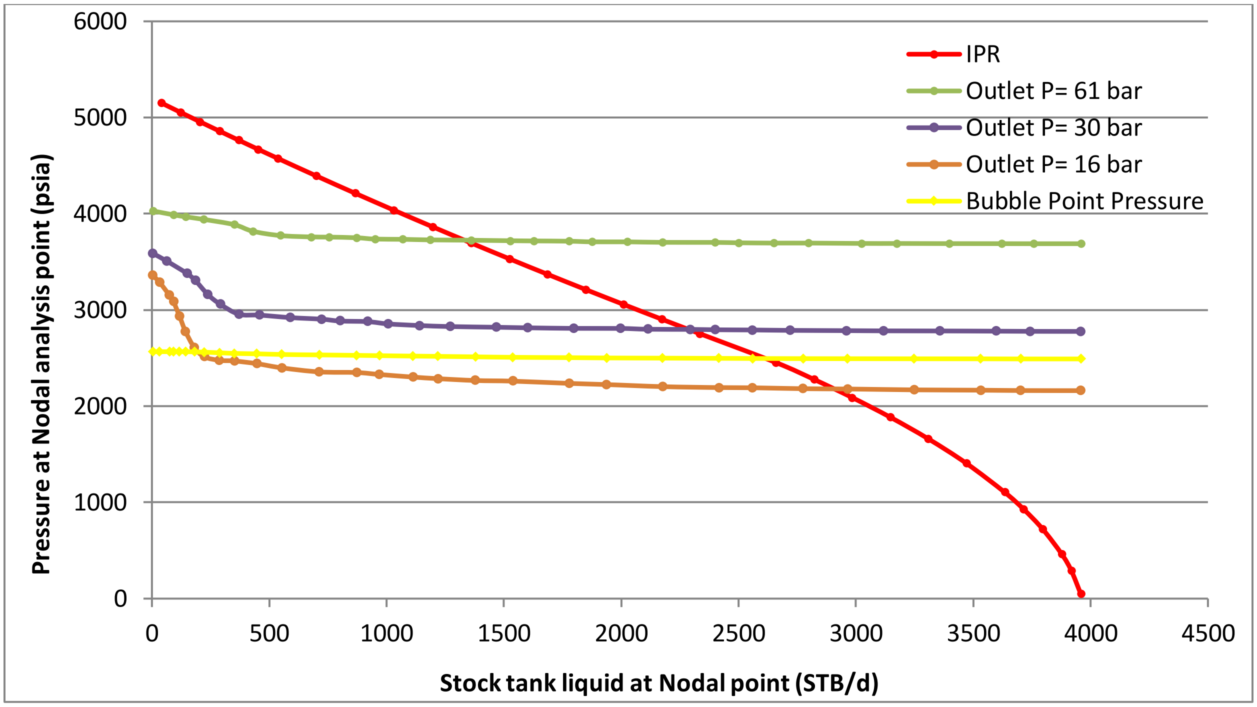


Figure 4.5.4: Effect of outlet Pressure when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well E

❖ Effect of Reservoir Pressure

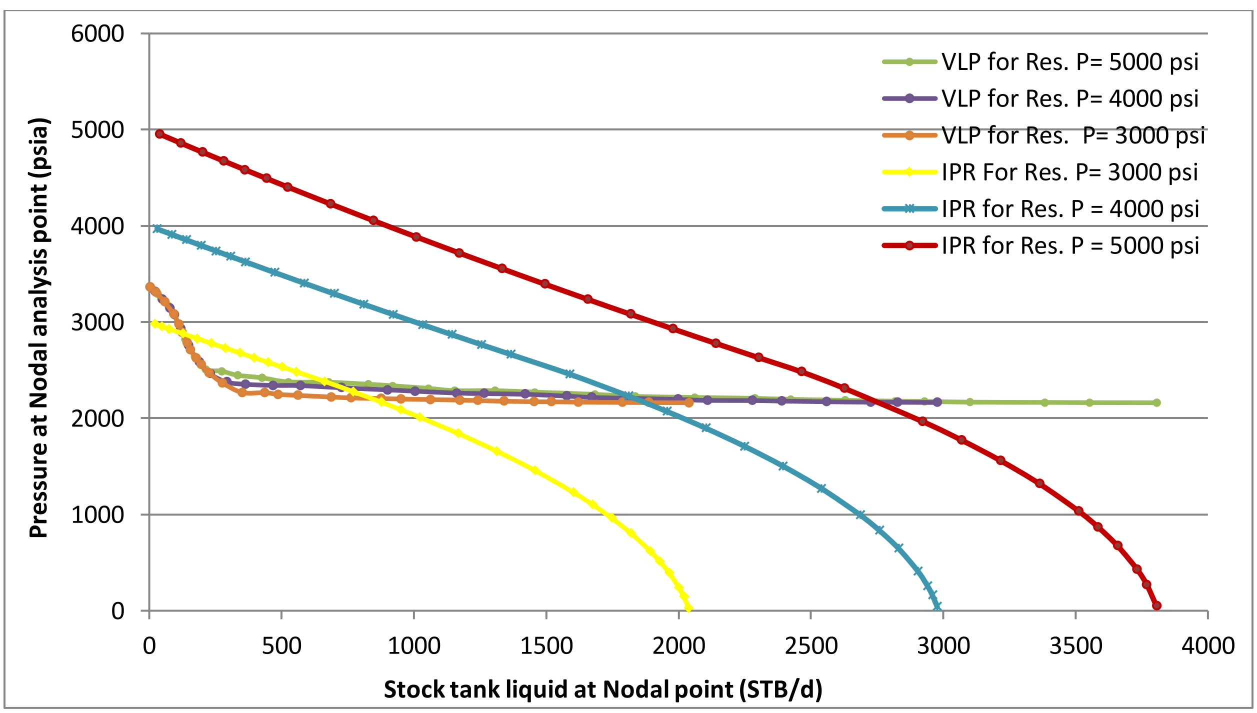


Figure 4.5.5: Reservoir pressure effect when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well E

❖ Effect of artificial lift- Gas lift

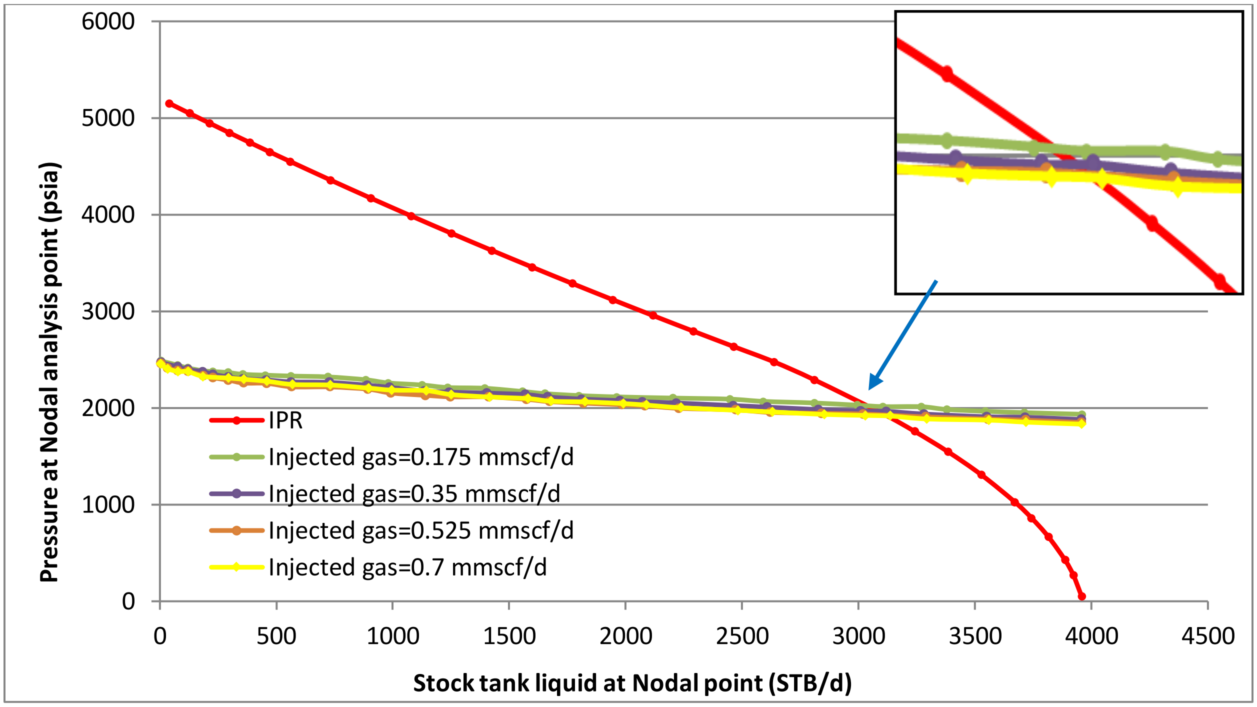


Figure 4.5.6: Effect of injected gas when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992 at Well E

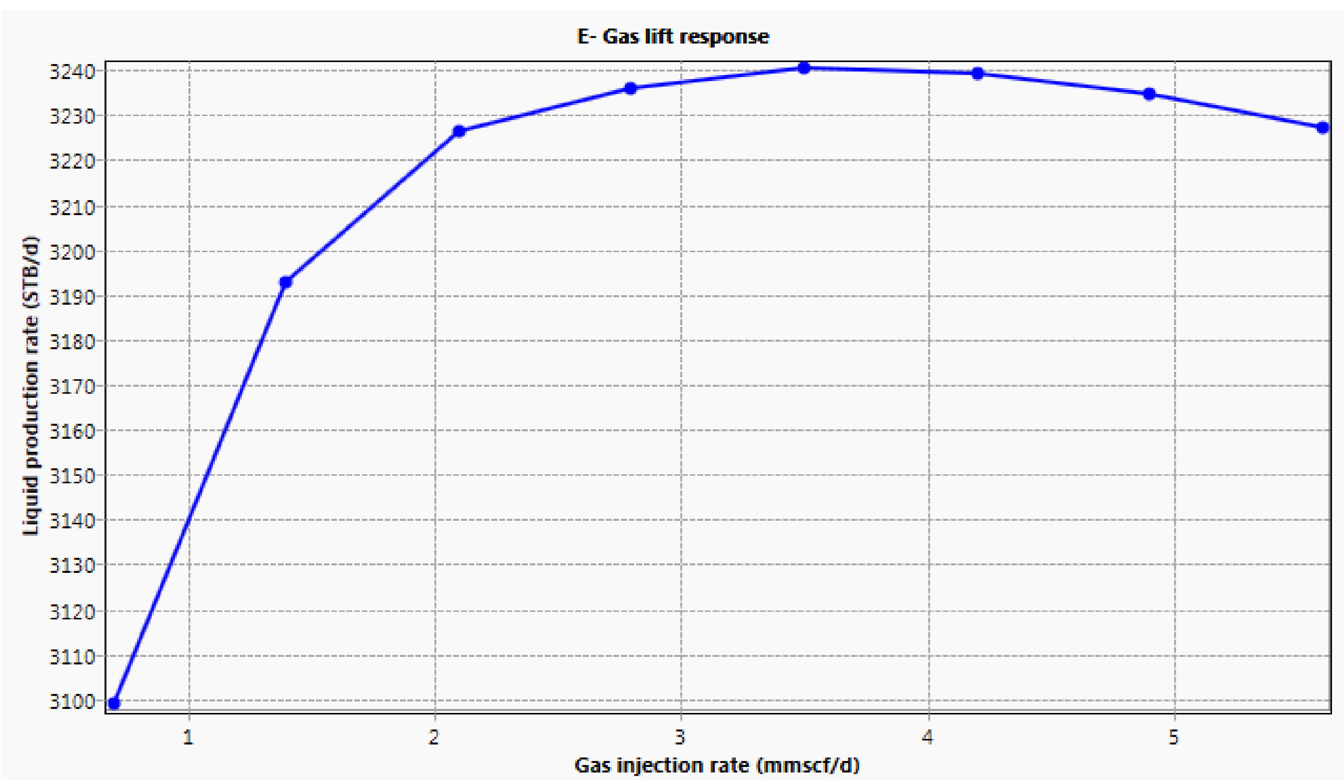


Figure 4.5.7: Various injected gas rate to Well E when k=2mD, wt%=0, skin factor= 0, Tubing OD= 3.5 & ID=2.992

Summary:

In this project we have covered the principles of well tubing optimization, by taking 5 wells that exist, as the case study.

- Selection of the best tubing size in order to enhance the oil production rate. This is by running 19 different tubing sizes for each well by using PIPESIM software.
- Due to not having exact value of permeability in that field we have checked the effect of reservoir permeability as well by running different tubing sizes.
- On the top of the tubing optimization and selecting the worst case scenario of reservoir permeability in that field we have checked for different water cut and skin factor effects at the mid-end life of each well.
- Showing the effect of outlet pressure (Separator pressure) on optimum production.
- Showing the effect of reservoir pressure depletion at the mid-end life on the production rate.
- Describing and showing the effect of Gas lift as an artificial lift in the future on each well.

Conclusions:

Tubing string selection, design, and installation are key components of each well completion. Tubing strings require proper size to allow for efficient fluid flow or for installing the effective artificial lift equipment.

Thus the pressure loss in the tubing can be a significant proportion of the total pressure loss, so fluid acceleration, hydrostatic and friction losses are three elements for pressure drops that require to be considered for designing tubing.

The idea is to optimize the flow rate or to identify which design is affecting the system, and finding the expected flow rate for various values of the parameters. The inside diameter of the tubing must provide a produced fluid velocity to minimize the total pressure loss. A tubing diameter that is excessively small results in significant friction losses and reduces productivity, and the oil flow rate reaches its maximum rate as the diameter increase to its optimum size. Beyond that it starts decreasing due to the effect of friction and hydrostatic head under the effect of average density of the fluid and later the appearance of slip or fluid hold up inside the tubing.

On the top of tubing design, the skin factor is also another factor that has a great impact on the oil production rate which it reduces when the skin factor increase. In the case of having skin, the area near wellbore for flow reduce so the velocity increases and because pressure drop is a function of velocity leads to worse IPR and affects its intersection with VLP. The more skin the lower is flow rate.

Probably over the time water cut starts to increase up to water break through one day (the more water cut the heavier is fluid) causes higher the hydrostatic pressure loses in the wellbore. This result in the pressure draw down due to the fact that the column becomes heavier and it changes the average density of the fluid inside the tubing and causes more friction (which is a function of density, viscosity and velocity) and hydrostatic loss (which is a function of depth and density). Higher percentage of water cut leads to worse the intersection of IPR and VLP.

Without the water cut and skin factor the energy of the reservoir declines as the reservoir pressure goes down which leads to low flow rate, this is the decline period of our wells. Based on Darcy equation, since the other parameters are constant in this field so the production rate is a function of pressure drop in the reservoir, after starting producing by time the IPR will moves clockwise which contribute to low oil flow rate from wells.

In the production of a reservoir containing oil and gas in solution, it is preferable to maintain the flowing bottomhole pressure above the bubble point so that single phase oil flows through the reservoir pore space. By changing the separator pressure (minimize the outlet pressure means that you allowed extra pressure to be consumed in the system for flow purposes so we are going to reduce its pressure) so we are going to have more flow rate because lower separator pressure is better VLP shape which has been affected, without any change in IPR because due to not having intervention in the reservoir but we changed separator pressure more clockwise rotation of VLP is better.

However, the use of gas injection as an artificial lift method result in higher flow rate up to optimum value but it causes increasing in the Gas to oil ratio (GOR) of the fluid; this leads to reduce the bottomhole pressure (Pwf) as well. How? By considering pressure losses equation, when there is a bubble point pressure at a section of the tubing it means above that two phases (liquid and gas) exist, because of that the viscosity reduces and the hydrostatic head affects as well, and due to density difference the friction term is going to be affected also.

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Appendix A: Effect of different tubing sizes on Production rate and Bubble point pressure at nodal point (downhole) in each well for different Permeability values range(2-5mD), and outlet P=61bar

		Tubing size			Nominal weight						When Permeability k (mD) = 2			When Permeability k (mD) = 2.5		
		OD (in)	ID (in)	Wall thickness (in)	T & C Non-Upset (lb/ft)	Grade	Tubing Head Pressure (bar)	Tubing Head pressure (psi)	Skin factor	Water cut %	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)
A		1.05	0.824	0.113	1.14	H-40, J-55, C-75, N-80	61	884.7318	0	0	228.9304	4543.525	2479.247	245.43	4633.882	2477.273
B		1.315	1.049	0.113	1.7	H-40, J-55, C-75, N-80	61	884.7318	0	0	339.3122	4244.136	2487.923	378.9112	4341.176	2485.777
C	C_1	1.66	1.41	0.125	2.3	H-40, J-55	61	884.7318	0	0	464.9178	3915.626	2497.388	550.1057	3979.632	2496.189
	C_2	1.66	1.38	0.14	2.3	H-40, J-55, C-75, N-80	61	884.7318	0	0	457.1588	3935.571	2496.814	539.4346	4001.75	2495.553
D	D_1	1.9	1.65	0.125	2.75	H-40, J-55	61	884.7318	0	0	500.5762	3824.421	2500.01	609.9685	3856.524	2499.725
	D_2	1.9	1.61	0.145	2.75	H-40, J-55, C-75, N-80	61	884.7318	0	0	496.0078	3836.013	2499.677	602.3275	3872.104	2499.277
E		2.063	1.751	0.156	3.25	H-40, J-55, C-75	61	884.7318	0	0	508.2588	3804.95	2500.57	623.999	3827.943	2500.545
F	F_1	2.375	2.041	0.167	4	H-40, J-55, C-75, N-80	61	884.7318	0	0	521.9533	3770.218	2501.568	648.5003	3778.188	2501.973
	F_2	2.375	1.995	0.19	4.6	H-40, J-55, C-75, N-80, P-105	61	884.7318	0	0	519.597	3776.172	2501.397	645.302	3784.702	2501.787
	F_3	2.375	1.867	0.254	5.8	H-40, C-75, P-105	61	884.7318	0	0	513.3371	3792.004	2500.942	634.1329	3807.4	2501.135
G	G_1	2.875	2.441	0.217	6.4	H-40, J-55, C-75, N-80, P-105	61	884.7318	0	0	526.7354	3758.134	2501.915	660.3522	3754.24	2502.661
	G_2	2.875	2.259	0.308	8.6	C-75, N-80, P-105	61	884.7318	0	0	523.8849	3765.432	2501.706	654.9988	3765.119	2502.349
H	H_1	3.5	3.068	0.216	7.7	H-40, J-55, C-75, N-80	61	884.7318	0	0	513.7602	3791.009	2500.97	663.2848	3748.331	2502.83
	H_2	3.5	2.992	0.254	9.2	H-40, J-55	61	884.7318	0	0	520.1527	3774.816	2501.436	662.8017	3749.388	2502.8

						C-75 P-105 N-80										
	H_3		2.922	0.289	10.2	H-40 J-55 C-75 N-80					523.3248	3766.798	2501.666	662.1955	3750.545	2502.767
	H_4		2.75	0.375	12.7	C-75 N-80 P-105					525.941	3760.14	2501.858	660.715	3753.616	2502.679
I	I_1	4	3.548	0.226	9.5	H-40 J-55 C-75 N-80	61	884.7318	0	0	470.5424	3901.159	2497.804	626.1844	3823.562	2500.671
	I_2		3.476	0.262		H-40 J-55 C-75 N-80					473.0616	3894.666	2497.99	633.7345	3808.112	2501.114
J		4.5	3.958	0.271	12.6	H-40 J-55 C-75 N-80	61	884.7318	0	0	462.6451	3921.452	2497.22	589.1846	3899.089	2498.502

Tubing Size		When Permeability k (mD) = 3			When Permeability k (mD) = 3.5			When Permeability k (mD) = 4			When Permeability k (mD) = 4.5			When Permeability k (mD) = 5		
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point Pressure psi**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**
A		257.44	4703.1	2475.71	266.53	4757.61	2474.45	273.9445	4801.081	2473.45	279.600	4837.294	2472.6	284.3146	4867.455	2471.882
B		410.089	4421.723	2483.91	434.776	4489.82	2482.28	454.9162	4547.591	2480.87	471.613	4596.992	2479.65	485.5881	4639.801	2478.581
C	C_1	624.072	4041.967	2494.84	687.486	4102.60	2493.42	742.868	4158.974	2492.05	790.491	4212.162	2490.72	832.6418	4260.865	2489.488
	C_2	609.579	4067.204	2494.11	669.062	4130.24	2492.63	720.7148	4188.22	2491.21	765.335	4241.935	2489.87	804.5577	4290.921	2488.627
D	D_1	709.882	3894.134	2499.08	800.502	3934.82	2498.23	882.7038	3976.262	2497.29	957.383	4017.414	2496.3	1024.842	4057.896	2495.296
	D_2	698.989	3912.808	2498.54	785.041	3957.65	2497.58	862.7263	4002.12	2496.55	932.856	4045.802	2495.49	995.4316	4088.652	2494.417
E		732.022	3856.414	2500.16	831.448	3889.47	2499.53	924.9485	3921.83	2498.85	1009.41	3957.563	2498.01	1087.259	3993.001	2497.152
F	F_1	771.787	3789.077	2502.09	890.776	3803.04	2502.01	1004.218	3820.533	2501.74	1112.26	3840.286	2501.37	1214.948	3861.703	2500.905
	F_2	766.678	3797.76	2501.84	883.142	3814.03	2501.69	993.9127	3833.726	2501.37	1098.85	3855.576	2500.93	1198.015	3878.956	2500.412
	F_3	749.163	3827.377	2500.99	857.584	3851.29	2500.63	959.3624	3877.802	2500.11	1142.57	3935.842	2498.79	1142.567	3935.842	2498.786
G	G_1	793.290	3752.827	2503.13	923.25	3756.02	2503.35	1052.045	3759.98	2503.48	1178.28	3765.89	2503.49	1301.719	3773.517	2503.425
	G_2	783.151	3769.877	2502.64	909.252	3776.24	2502.77	1032.187	3785.107	2502.76	1151.36	3796.127	2502.63	1267.291	3808.306	2502.431
H	H_1	799.998	3741.617	2503.45	937.299	3735.83	2503.93	1074.726	3731.455	2504.29	1211.89	3728.201	2504.57	1347.18	3727.675	2504.735
	H_2	799.557	3742.251	2503.44	935.995	3737.8	2503.88	1072.693	3733.954	2504.22	1209.23	3731.261	2504.48	1343.267	3731.607	2504.623
	H_3	798.305	3744.362	2503.37	934.478	3739.89	2503.82	1070.591	3736.591	2504.15	1204.76	3736.166	2504.34	1339.17	3735.743	2504.505
	H_4	795.332	3749.443	2503.23	929.933	3746.42	2503.63	1064.067	3744.826	2503.91	1195.32	3746.786	2504.04	1326.393	3748.523	2504.139
I	I_1	787.405	3762.72	2502.85	936.924	3736.35	2503.92	1075.693	3730.133	2504.33	1215.63	3724.006	2504.69	1354.531	3720.162	2504.95
	I_2	792.355	3754.363	2503.09	936.557	3736.92	2503.9	1074.927	3731.18	2504.30	1214.28	3725.645	2504.64	1353.171	3721.648	2504.907
J		737.341	3847.448	2500.42	901.769	3787.13	2502.46	1061.948	3747.553	2503.83	1212.49	3727.64	2504.59	1352.787	3721.959	2504.898

Table A.1: Different tubing sizes and the effect of permeability at Well A

		Tubing size OD (in)	Tubing size ID (in)	Wall thickness (in)	Nominal weight T & C Non-Upset (lb/ft)	Grade	Tubing Head Pressure (bar)	Tubing Head pressure (psi)	Skin factor	Water cut %	When Permeability k (mD) = 2: Liquid Flow rate (stb/d)	When Permeability k (mD) = 2: Pressure at Na (psi)	When Permeability k (mD) = 2: Bubble Point Pressure (psi)	When Permeability k (mD) = 2.5: Liquid Flow rate (stb/d)	When Permeability k (mD) = 2.5: Pressure at Na (psi)	When Permeability k (mD) = 2.5: Bubble Point Pressure (psi)
A		1.05	0.824	0.113	1.14	H-40 J-55 C-75 N-80	61	884.7318	0	0	260.8742	4677.531	2174.14	273.2408	4759.855	2172.042
B		1.315	1.049	0.113	1.7	H-40 J-55 C-75 N-80	61	884.7318	0	0	417.4856	4379.628	2181.741	451.5547	4485.33	2179.042
C	C_1	1.66	1.41	0.125	2.3	H-40 J-55	61	884.7318	0	0	635.3449	3982.582	2191.892	727.2436	4078.378	2189.44
	C_2		1.38	0.14		H-40 J-55 C-75 N-80					620.5632	4008.943	2191.217	706.8171	4107.94	2188.684
D	D_1	1.9	1.65	0.125	2.75	H-40 J-55	61	884.7318	0	0	720.3884	3832.68	2195.73	854.5383	3897.18	2194.078
	D_2		1.61	0.145		H-40 J-55 C-75 N-80					708.7144	3853.134	2195.206	836.4009	3922.73	2193.424
E		2.063	1.751	0.156	3.25	H-40 J-55 C-75 N-80	61	884.7318	0	0	743.6865	3792.025	2196.772	890.4875	3846.663	2195.372
F	F_1	2.375	2.041	0.167	4	H-40 J-55 C-75 N-80	61	884.7318	0	0	785.2585	3720.065	2198.616	963.0242	3745.83	2197.956
	F_2		1.995	0.19	4.6	H-40 J-55 C-75 N-80 P-105					779.9053	3729.412	2198.377	953.7172	3758.61	2197.628
	F_3		1.867	0.254	5.8	H-40 C-75 P-105					761.5889	3761.044	2197.566	922.8184	3801.602	2196.527
G	G_1	2.875	2.441	0.217	6.4	H-40 J-55 C-75 N-80 P-105	61	884.7318	0	0	807.6154	3681.766	2199.598	1005.373	3687.429	2199.453
	G_2		2.259	0.308	8.6	C-75 N-80 P-105					797.6906	3698.721	2199.164	988.1788	3711.046	2198.848
H	H_1	3.5	3.068	0.216	7.7	H-40 J-55 C-75 N-80	61	884.7318	0	0	814.8459	3669.332	2199.917	1023.967	3661.978	2200.106
	H_2		2.992	0.254	9.2	H-40 J-55 C-75 P-105 N-80					813.6948	3671.302	2199.867	1022.26	3664.156	2200.05
	H_3		2.922	0.289	10.2	H-40 J-55					812.8878	3672.626	2199.833	1020.318	3666.88	2199.98

						C-75 N-80										
	H_4		2.75	0.375	12.7	C-75 N-80 P-105					810.2986	3677.106	2199.718	1014.52	3674.822	2199.776
I	I_1	4	3.548	0.226	9.5	H-40 J-55 C-75 N-80	61	884.7318	0	0	808.5517	3680.006	2199.643	1025.101	3660.276	2200.149
	I_2		3.476	0.262		H-40 J-55 C-75 N-80					811.3804	3675.266	2199.765	1024.366	3661.38	2200.121
J		4.5	3.958	0.271	12.6	H-40 J-55 C-75 N-80	61	884.7318	0	0	772.6056	3741.888	2198.057	1010.159	3680.805	2199.623

Tubing Size		Permeability k (mD) = 3			Permeability k (mD) = 3.5			Permeability k (mD) = 4			Permeability k (mD) = 4.5			Permeability k (mD) = 5		
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point Pressure psi**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**
A		281.9456	4820.073	2170.508	288.4129	4865.898	2169.341	293.4114	4901.909	2168.424	297.3883	4930.958	2167.684	300.6238	4954.852	2167.076
B		476.5377	4568.112	2176.93	495.7513	4634.165	2175.245	510.897	4688.005	2173.873	523.1188	4732.694	2172.734	533.5286	4770.013	2171.783
C	C_1	801.1865	4164.636	2187.234	862.0006	4240.554	2185.294	911.6396	4308.288	2183.563	953.5961	4367.817	2182.042	989.1763	4420.411	2180.699
	C_2	776.1226	4195.11	2186.455	831.9006	4272.168	2184.486	878.6499	4338.912	2182.78	916.9751	4398.141	2181.268	949.7052	4450.085	2179.942
D	D_1	968.5472	3964.155	2192.363	1066.845	4028.449	2190.718	1151.602	4089.227	2189.163	1224.343	4146.404	2187.7	1288.18	4199.017	2186.355
	D_2	943.9961	3993.341	2191.616	1035.665	4060.377	2189.901	1114.095	4123.081	2188.297	1181.857	4180.763	2186.822	1240.232	4234.188	2185.456
E		1021.459	3901.916	2193.957	1134.7	3959.456	2192.484	1235.265	4014.117	2191.085	1322.59	4067.629	2189.715	1399.934	4117.836	2188.431
F	F_1	1128.288	3777.362	2197.148	1279.909	3813.579	2196.22	1420.395	3850.486	2195.274	1548.393	3889.185	2194.283	1665.796	3927.757	2193.295
	F_2	1114.334	3793.534	2196.733	1261.235	3832.077	2195.746	1394.973	3872.793	2194.703	1516.64	3913.95	2193.649	1628.048	3954.378	2192.614
	F_3	1067.995	3847.41	2195.353	1198.543	3894.961	2194.135	1314.834	3943.479	2192.893	1418.861	3991.052	2191.675	1512.459	4036.78	2190.505
G	G_1	1198.066	3696.99	2199.208	1383.9	3710.561	2198.86	1561.951	3727.579	2198.424	1731.891	3746.949	2197.927	1894.917	3767.345	2197.404
	G_2	1170.235	3728.938	2198.389	1342.983	3750.945	2197.825	1505.732	3776.087	2197.18	1658.595	3803.512	2196.478	1801.574	3832.222	2195.742
H	H_1	1232.323	3657.908	2200.21	1439.239	3656.268	2200.252	1644.133	3656.936	2200.235	1846.284	3659.55	2200.168	2044.989	3663.997	2200.054
	H_2	1229.365	3661.222	2200.125	1434.715	3660.733	2200.138	1637.655	3662.434	2200.094	1837.166	3666.384	2199.993	2032.783	3672.202	2199.843
	H_3	1226.323	3664.642	2200.037	1429.837	3665.58	2200.013	1630.515	3668.559	2199.937	1827.514	3673.864	2199.801	2020.168	3680.917	2199.62
	H_4	1216.499	3675.982	2199.747	1414.931	3680.043	2199.642	1609.157	3686.903	2199.467	1798.236	3696.039	2199.232	1981.746	3707.363	2198.942
I	I_1	1236.568	3652.986	2200.336	1448.461	3647.356	2200.481	1660.058	3643.364	2200.583	1871.179	3640.549	2200.655	2081.259	3639.117	2200.692
	I_2	1235.461	3654.176	2200.306	1446.685	3649.064	2200.437	1657.434	3645.629	2200.525	1867.558	3643.37	2200.583	2076.169	3642.541	2200.604
J		1234.835	3654.96	2200.286	1447.831	3647.835	2200.468	1661.731	3641.991	2200.618	1875.644	3637.221	2200.741	2089.792	3633.31	2200.841

Table A.2: Different tubing sizes and the effect of permeability at Well B

		Tubing size OD (in)	Tubing size ID (in)	Wall thickness (in)	Nominal weight T & C Non-Upset (lb/ft)	Grade	Tubing Head Pressure (bar)	Tubing Head pressure (psi)	Skin factor	Water cut %	When Permeability k (mD) = 2 Liquid Flow rate (stb/d)	When Permeability k (mD) = 2 Pressure at Na (psi)	When Permeability k (mD) = 2 Bubble Point Pressure (psi)	When Permeability k (mD) = 2.5 Liquid Flow rate (stb/d)	When Permeability k (mD) = 2.5 Pressure at Na (psi)	When Permeability k (mD) = 2.5 Bubble Point Pressure (psi)
A		1.05	0.824	0.113	1.14	H-40 J-55 C-75 N-80	61	884.7318	0	0	348.7331	4963.748	2502.446	356.9409	5006.044	2501.249
B		1.315	1.049	0.113	1.7	H-40 J-55 C-75 N-80	61	884.7318	0	0	613.437	4788.689	2507.402	639.164	4855.807	2505.501
C	C_1	1.66	1.41	0.125	2.3	H-40 J-55	61	884.7318	0	0	1114.885	4466.566	2516.535	1204.882	4562.284	2513.819
	C_2		1.38	0.14		H-40 J-55 C-75 N-80					1071.543	4493.997	2515.756	1153.874	4588.343	2513.08
D	D_1	1.9	1.65	0.125	2.75	H-40 J-55	61	884.7318	0	0	1439.736	4264.174	2522.281	1597.177	4364.47	2519.433
	D_2		1.61	0.145		H-40 J-55 C-75 N-80					1388.387	4295.85	2521.381	1532.966	4396.547	2518.522
E		2.063	1.751	0.156	3.25	H-40 J-55 C-75 N-80	61	884.7318	0	0	1559.584	4190.551	2524.373	1750.683	4288.254	2521.597
F	F_1	2.375	2.041	0.167	4	H-40 J-55 C-75 N-80	61	884.7318	0	0	1836.388	4023.03	2529.136	2133.618	4101.019	2526.918
	F_2		1.995	0.19	4.6	H-40 J-55 C-75 N-80 P-105					1798.854	4045.602	2528.494	2079.207	4127.412	2526.168
	F_3		1.867	0.254	5.8	H-40 C-75 P-105					1679.288	4117.779	2526.442	1910.174	4209.858	2523.824
G	G_1	2.875	2.441	0.217	6.4	H-40 J-55 C-75 N-80 P-105	61	884.7318	0	0	2059.963	3889.871	2532.926	2477.485	3936.077	2531.611
	G_2		2.259	0.308	8.6	C-75 N-80 P-105					1969.384	3943.676	2531.394	2337.847	4002.711	2529.714
H	H_1	3.5	3.068	0.216	7.7	H-40 J-55 C-75 N-80	61	884.7318	0	0	2197.849	3808.831	2535.233	2729.734	3817.089	2534.998
	H_2		2.992	0.254	9.2	H-40 J-55 C-75 P-105 N-80					2186.559	3815.495	2535.044	2709.81	3826.384	2534.734
	H_3		2.922	0.289	10.2	H-40 J-55 C-75					2174.834	3822.278	2534.85	2689.328	3835.973	2534.46

						N-80										
	H_4		2.75	0.375	12.7	C-75 N-80 P-105					2139.191	3843.279	2534.252	2623.989	3866.787	2533.583
I	I_1	4	3.548	0.226	9.5	H-40 J-55 C-75 N-80	61	884.7318	0	0	2227.441	3791.575	2535.725	2795.47	3786.253	2535.876
	I_2		3.476	0.262		H-40 J-55 C-75 N-80					2222.534	3794.35	2535.646	2786.832	3790.294	2535.761
J		4.5	3.958	0.271	12.6	H-40 J-55 C-75 N-80	61	884.7318	0	0	2232.121	3788.779	2535.805	2813.56	3777.931	2536.114

Tubing Size		Permeability k (mD) = 3			Permeability k (mD) = 3.5			Permeability k (mD) = 4			Permeability k (mD) = 4.5			Permeability k (mD) = 5		
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point Pressure psi**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**
A		362.4192	5035.616	2500.413	366.6396	5057.273	2499.8	369.8116	5073.913	2499.33	372.2856	5087.079	2498.957	374.269	5097.769	2498.655
B		657.2838	4904.165	2504.132	670.7018	4940.697	2503.098	680.7064	4969.343	2502.288	689.4664	4992.037	2501.645	696.0285	5010.85	2501.113
C	C_1	1270.154	4637.325	2511.691	1320.524	4696.798	2510.006	1361.154	4744.859	2508.644	1392.985	4784.987	2507.507	1419.524	4818.604	2506.555
	C_2	1215.204	4660.903	2511.023	1260.807	4718.927	2509.378	1297.054	4765.727	2508.052	1326.418	4804.35	2506.958	1350.655	4836.72	2506.042
D	D_1	1718.957	4447.005	2517.09	1812.65	4516.579	2515.116	1888.835	4574.734	2513.466	1951.301	4624.128	2512.065	2004.626	4666.227	2510.872
	D_2	1642.292	4479.229	2516.175	1729.259	4546.863	2514.256	1798.296	4603.72	2512.644	1855.076	4651.683	2511.284	1902.406	4692.665	2510.123
E		1898.815	4371.936	2519.221	2018.267	4442.372	2517.221	2114.933	4502.86	2515.505	2195.135	4554.842	2514.03	2262.717	4599.923	2512.752
F	F_1	2374.238	4176.349	2524.777	2573.955	4244.973	2522.827	2742.424	4306.405	2521.081	2883.685	4362.119	2519.499	3006.656	4411.43	2518.099
	F_2	2304.106	4204.953	2523.964	2491.708	4273.966	2522.003	2644.312	4336.851	2520.217	2775.498	4392.032	2518.65	2888.569	4441.06	2517.258
	F_3	2095.667	4290.383	2521.537	2245.056	4361.301	2519.523	2368.137	4423.073	2517.769	2471.362	4476.996	2516.239	2558.753	4524.375	2514.894
G	G_1	2846.743	3986.208	2530.184	3170.468	4037.904	2528.713	3454.009	4088.852	2527.264	3704.806	4137.613	2525.878	3927.379	4183.671	2524.569
	G_2	2651.394	4064.333	2527.962	2920.255	4124.213	2526.259	3152.022	4180.517	2524.658	3354.055	4232.76	2523.174	3528.911	4281.513	2521.789
H	H_1	3232.112	3834.053	2534.515	3702.703	3857.002	2533.862	4143.51	3882.985	2533.122	4553.151	3911.482	2532.311	4934.086	3941.111	2531.467
	H_2	3200.072	3846.649	2534.156	3656.828	3872.404	2533.423	4082.018	3901.169	2532.604	4475.341	3931.876	2531.73	4838.877	3963.816	2530.821
	H_3	3166.755	3859.804	2533.782	3610.286	3888.079	2532.977	4020.161	3919.508	2532.082	4397.624	3952.443	2531.145	4744.448	3986.24	2530.183
	H_4	3070.022	3897.863	2532.698	3476.129	3933.585	2531.682	3845.174	3971.522	2530.602	4180.199	4010.1	2529.504	4484.405	4048.6	2528.409
I	I_1	3350.925	3787.787	2535.833	3884.183	3796.085	2535.596	4398.916	3807.975	2535.258	4892.021	3822.66	2534.84	5362.603	3839.886	2534.349
	I_2	3336.428	3793.406	2535.673	3862.05	3803.598	2535.382	4367.89	3816.989	2535.001	4850.818	3833.466	2534.532	5310.104	3852.103	2534.001
J		3392.022	3771.795	2536.288	3954.352	3772.714	2536.262	4506.949	3776.272	2536.161	5044.8	3782.943	2535.971	5565.719	3792.14	2535.709

Table A.3: Different tubing sizes and the effect of permeability at Well C

		Tubing size OD (in)	Tubing size ID (in)	Wall thickness (in)	Nominal weight T & C Non-Upset (lb/ft)	Grade	Tubing Head Pressure (bar)	Tubing Head pressure (psi)	Skin factor	Water cut %	When Permeability k (mD) = 2: Liquid Flow rate (stb/d)	When Permeability k (mD) = 2: Pressure at Na (psi)	When Permeability k (mD) = 2: Bubble Point Pressure (psi)	When Permeability k (mD) = 2.5: Liquid Flow rate (stb/d)	When Permeability k (mD) = 2.5: Pressure at Na (psi)	When Permeability k (mD) = 2.5: Bubble Point Pressure (psi)
A		1.05	0.824	0.113	1.14	H-40 J-55 C-75 N-80	61	884.7318	0	0	317.6677	4986.257	2495.811	324.6156	5024.871	2494.719
B		1.315	1.049	0.113	1.7	H-40 J-55 C-75 N-80	61	884.7318	0	0	563.6709	4824.367	2500.39	585.9422	4886.468	2498.633
C	C_1	1.66	1.41	0.125	2.3	H-40 J-55	61	884.7318	0	0	1042.471	4517.858	2509.073	1120.849	4610.054	2506.46
	C_2		1.38	0.14		H-40 J-55 C-75 N-80					1000.791	4544.046	2508.331	1072.415	4634.676	2505.762
D	D_1	1.9	1.65	0.125	2.75	H-40 J-55	61	884.7318	0	0	1359.985	4320.333	2514.676	1501.241	4418.668	2511.886
	D_2		1.61	0.145		H-40 J-55 C-75 N-80					1309.595	4351.427	2513.794	1438.05	4450.14	2510.993
E		2.063	1.751	0.156	3.25	H-40 J-55 C-75 N-80	61	884.7318	0	0	1477.063	4248.649	2516.711	1651.87	4344.12	2514.001
F	F_1	2.375	2.041	0.167	4	H-40 J-55 C-75 N-80	61	884.7318	0	0	1755.526	4080.404	2521.491	2028.781	4160.156	2519.225
	F_2		1.995	0.19	4.6	H-40 J-55 C-75 N-80 P-105					1717.032	4103.539	2520.833	1974.473	4186.325	2518.481
	F_3		1.867	0.254	5.8	H-40 C-75 P-105					1597.798	4175.356	2518.793	1808.344	4267.233	2516.184
G	G_1	2.875	2.441	0.217	6.4	H-40 J-55 C-75 N-80 P-105	61	884.7318	0	0	1984.212	3944.595	2525.352	2380.42	3991.887	2524.007
	G_2		2.259	0.308	8.6	C-75 N-80 P-105					1891.551	3999.435	2523.792	2236.64	4060.328	2522.061
H	H_1	3.5	3.068	0.216	7.7	H-40 J-55 C-75 N-80	61	884.7318	0	0	2132.116	3857.931	2527.818	2642.617	3868.344	2527.521
	H_2		2.992	0.254	9.2	H-40 J-55 C-75 P-105 N-80					2120.099	3864.872	2527.62	2620.971	3878.48	2527.233
	H_3		2.922	0.289	10.2	H-40 J-55 C-75					2107.594	3872.128	2527.414	2598.627	3888.982	2526.934

						N-80										
	$\mathbf{H_4}$		2.75	0.375	12.7	C-75					2069.712	3894.32	2526.782	2532.241	3920.084	2526.049
						N-80										
						P-105										
I	$\mathbf{I_1}$	4	3.548	0.226	9.5	H-40	61	884.7318	0	0	2164.005	3839.287	2528.348	2715.501	3834.326	2528.489
						J-55										
						C-75										
						N-80										
	$\mathbf{I_2}$		3.476	0.262		H-40					2159.06	3842.08	2528.269	2705.689	3838.943	2528.358
						J-55										
						C-75										
						N-80										
J		4.5	3.958	0.271	12.6	H-40	61	884.7318	0	0	2170.094	3835.776	2528.448	2734.726	3825.459	2528.742
						J-55										
						C-75										
						N-80										

		Permeability k (mD) = 3			Permeability k (mD) = 3.5			Permeability k (mD) = 4			Permeability k (mD) = 4.5			Permeability k (mD) = 5		
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point Pressure psi**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**
A		329.3748	5051.69	2493.961	332.8344	5071.389	2493.404	335.4628	5086.469	2492.978	337.5285	5098.389	2492.641	339.014	5108.093	2492.367
B		601.4263	4931.117	2497.37	612.8341	4964.682	2496.421	621.793	4990.763	2495.683	628.6573	5011.735	2495.09	634.2475	5028.872	2494.606
C	$\mathbf{C_1}$	1178.467	4680.896	2504.453	1222.79	4736.783	2502.87	1256.807	4782.271	2501.582	1284.478	4819.699	2500.523	1307.337	4850.975	2499.637
	$\mathbf{C_2}$	1125.031	4703.787	2503.804	1165.028	4758.088	2502.267	1196.637	4801.798	2501.029	1221.905	4837.795	2500.01	1243.171	4867.79	2499.162
D	$\mathbf{D_1}$	1607.811	4499.364	2509.597	1692.375	4565.396	2507.725	1759.101	4620.912	2506.152	1814.052	4667.726	2504.826	1859.819	4707.643	2503.695
	$\mathbf{D_2}$	1535.825	4529.545	2508.742	1610.926	4594.864	2506.89	1672.399	4648.539	2505.369	1721.108	4694.159	2504.077	1763.268	4732.539	2502.99
E		1784.054	4425.956	2511.679	1889.075	4494.565	2509.733	1975.142	4552.404	2508.094	2045.629	4602.049	2506.687	2104.701	4644.925	2505.472
F	$\mathbf{F_1}$	2250.58	4234.423	2517.115	2431.54	4302.227	2515.19	2583.02	4362.553	2513.478	2709.302	4416.717	2511.941	2818.439	4464.566	2510.584
	$\mathbf{F_2}$	2181.012	4262.726	2516.312	2348.964	4331.283	2514.365	2487.131	4392.212	2512.636	2605.528	4445.472	2511.126	2705.604	4492.839	2509.782
	$\mathbf{F_3}$	1975.266	4346.931	2513.921	2109.016	4416.055	2511.96	2218.913	4475.827	2510.265	2310.234	4527.734	2508.793	2387.507	4573.019	2507.509
G	$\mathbf{G_1}$	2724.92	4043.888	2522.529	3025.347	4096.432	2521.035	3290.297	4146.725	2519.606	3517.541	4196.148	2518.202	3720.371	4241.96	2516.901
	$\mathbf{G_2}$	2526.653	4123.091	2520.278	2775.427	4182.47	2518.591	2986.812	4238.689	2516.994	3167.249	4291.101	2515.506	3325.571	4338.667	2514.156
H	$\mathbf{H_1}$	3124.796	3886.426	2527.007	3574.147	3910.364	2526.326	3992.064	3937.708	2525.548	4378.847	3967.09	2524.712	4736.812	3997.562	2523.846
	$\mathbf{H_2}$	3090.693	3899.851	2526.625	3526.188	3926.479	2525.867	3928.192	3956.451	2525.015	4298.458	3988.165	2524.113	4638.98	4020.74	2523.187
	$\mathbf{H_3}$	3055.997	3913.395	2526.24	3477.28	3942.968	2525.398	3864.112	3975.448	2524.475	4218.422	4009.336	2523.511	4542.607	4043.75	2522.533
	$\mathbf{H_4}$	2954.838	3953.073	2525.111	3337.822	3989.989	2524.061	3683.538	4028.977	2522.953	3995.517	4068.28	2521.835	4277.503	4107.134	2520.731
I	$\mathbf{I_1}$	3250.21	3837.684	2528.394	3764.998	3846.565	2528.141	4259.55	3859.248	2527.78	4731.771	3874.862	2527.336	5180.903	3892.801	2526.825
	$\mathbf{I_2}$	3234.099	3843.963	2528.215	3741.527	3854.374	2527.919	4226.809	3868.778	2527.509	4688.502	3886.059	2527.017	5126.029	3905.74	2526.457
J		3293.781	3820.708	2528.877	3839.704	3821.799	2528.846	4373.856	3825.995	2528.726	4892.675	3833.152	2528.523	5394.556	3842.858	2528.247

Table A.4: Different tubing sizes and the effect of permeability at Well D

		Tubing size OD (in)	Tubing size ID (in)	Wall thickness (in)	Nominal weight T & C Non-Upset (lb/ft)	Grade	Tubing Head Pressure (bar)	Tubing Head pressure (psi)	Skin factor	Water cut %	When Permeability k (mD) = 2: Liquid Flow rate (stb/d)	When Permeability k (mD) = 2: Pressure at Na (psi)	When Permeability k (mD) = 2: Bubble Point Pressure (psi)	When Permeability k (mD) = 2.5: Liquid Flow rate (stb/d)	When Permeability k (mD) = 2.5: Pressure at Na (psi)	When Permeability k (mD) = 2.5: Bubble Point Pressure (psi)
A		1.05	0.824	0.113	1.14	H-40 J-55 C-75 N-80	61	884.7318	0	0	335.7195	4803.779	2500.973	348.3927	4869.805	2499.105
B		1.315	1.049	0.113	1.7	H-40 J-55 C-75 N-80	61	884.7318	0	0	558.0425	4551.232	2508.127	594.9785	4643.61	2505.509
C	C_1	1.66	1.41	0.125	2.3	H-40 J-55	61	884.7318	0	0	916.3097	4159.066	2519.256	1023.397	4264.114	2516.272
C	C_2	1.66	1.38	0.14	2.3	H-40 J-55 C-75 N-80	61	884.7318	0	0	888.3056	4189.098	2518.402	988.1697	4294.73	2515.403
D	D_1	1.9	1.65	0.125	2.75	H-40 J-55	61	884.7318	0	0	1100.361	3964.119	2524.797	1270.956	4052.246	2522.291
D	D_2	1.9	1.61	0.145	2.75	H-40 J-55 C-75 N-80	61	884.7318	0	0	1073.816	3991.955	2524.005	1233.207	4084.245	2521.382
E		2.063	1.751	0.156	3.25	H-40 J-55 C-75 N-80	61	884.7318	0	0	1158.442	3903.591	2526.518	1354.682	3981.641	2524.298
F	F_1	2.375	2.041	0.167	4	H-40 J-55 C-75 N-80	61	884.7318	0	0	1267.39	3790.899	2529.725	1529.552	3835.889	2528.445
F	F_2	2.375	1.995	0.19	4.6	H-40 J-55 C-75 N-80 P-105	61	884.7318	0	0	1252.541	3806.11	2529.292	1506.635	3854.916	2527.903
F	F_3	2.375	1.867	0.254	5.8	H-40 C-75 P-105	61	884.7318	0	0	1207.046	3853.133	2527.954	1432.397	3916.558	2526.15
G	G_1	2.875	2.441	0.217	6.4	H-40 J-55 C-75 N-80 P-105	61	884.7318	0	0	1334.681	3721.938	2531.689	1650.595	3736.479	2531.275
G	G_2	2.875	2.259	0.308	8.6	C-75 N-80 P-105	61	884.7318	0	0	1307.31	3749.893	2530.893	1602.5	3775.981	2530.15
H	H_1	3.5	3.068	0.216	7.7	H-40 J-55 C-75 N-80	61	884.7318	0	0	1363.809	3692.309	2532.533	1714.176	3684.687	2532.75
H	H_2	3.5	2.992	0.254	9.2	H-40 J-55 C-75 P-105 N-80	61	884.7318	0	0	1360.856	3695.4	2532.445	1709.023	3688.891	2532.63
H	H_3	3.5	2.922	0.289	10.2	H-40 J-55	61	884.7318	0	0	1357.89	3698.33	2532.361	1703.421	3693.495	2532.499

						C-75 N-80										
	H_4		2.75	0.375	12.7	C-75 N-80 P-105					1348.586	3707.927	2532.088	1686.729	3707.045	2532.113
I	I_1	4	3.548	0.226	9.5	H-40 J-55 C-75 N-80	61	884.7318	0	0	1364.284	3691.959	2532.543	1722.908	3677.675	2532.95
	I_2		3.476	0.262		H-40 J-55 C-75 N-80					1363.178	3693.008	2532.513	1720.828	3679.336	2532.902
J		4.5	3.958	0.271	12.6	H-40 J-55 C-75 N-80	61	884.7318	0	0	1358.642	3697.673	2532.38	1720.027	3679.867	2532.887

Tubing size		Permeability k (mD) = 3			Permeability k (mD) = 3.5			Permeability k (mD) = 4			Permeability k (mD) = 4.5			Permeability k (mD) = 5		
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point Pressure psi**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point Pressure (psi)**
A		357.3356	4916.969	2497.77	363.7197	4952.539	2496.764	368.8526	4980.05	2495.986	372.8512	5002.111	2495.362	376.0633	5020.173	2494.852
B		621.7891	4713.434	2503.531	641.8223	4768.074	2501.984	657.5316	4811.802	2500.746	670.1612	4847.596	2499.733	680.539	4877.351	2498.891
C	C_1	1107.064	4352.047	2513.776	1173.917	4425.919	2511.68	1228.731	4488.366	2509.909	1273.462	4542.312	2508.38	1311.368	4588.799	2507.062
	C_2	1065.971	4382.075	2512.924	1127.775	4455.026	2510.855	1178.03	4516.6	2509.109	1219.472	4569.225	2507.617	1254.565	4614.373	2506.337
D	D_1	1409.546	4134.127	2519.964	1524.009	4207.899	2517.868	1619.247	4274.073	2515.989	1700.688	4332.496	2514.331	1772.014	4384.099	2512.867
	D_2	1362.273	4167.814	2519.007	1467.925	4242.382	2516.889	1555.79	4308.47	2515.013	1630.708	4366.522	2513.365	1694.362	4418.193	2511.899
E		1517.954	4057.258	2522.149	1655.607	4127.286	2520.158	1771.766	4191.736	2518.328	1871.422	4250.119	2516.67	1957.401	4302.982	2515.169
F	F_1	1761.296	3887.185	2526.985	1966.265	3939.957	2525.484	2148.003	3991.889	2524.007	2306.565	4043.334	2522.544	2447.954	4092.075	2521.159
	F_2	1728.931	3909.653	2526.346	1923.53	3965.468	2524.758	2094.827	4019.863	2523.212	2243.657	4072.9	2521.704	2375.647	4122.78	2520.287
	F_3	1625.474	3981.749	2524.295	1788.526	4046.59	2522.452	1929.387	4107.443	2520.722	2053.291	4163.066	2519.142	2161.256	4214.68	2517.676
G	G_1	1947.863	3758.911	2530.636	2225.642	3786.33	2529.856	2482.136	3817.912	2528.957	2719.639	3851.413	2528.003	2939.473	3885.559	2527.031
	G_2	1873.7	3809.74	2529.189	2123.312	3846.605	2528.14	2347.249	3887.826	2526.967	2551.142	3929.193	2525.79	2736.875	3969.989	2524.63
H	H_1	2059.011	3683.39	2532.787	2395.629	3687.174	2532.679	2724.019	3694.125	2532.481	3039.112	3705.743	2532.15	3347.223	3717.795	2531.807
	H_2	2049.898	3689.577	2532.611	2381.917	3695.135	2532.452	2705.068	3703.907	2532.202	3013.29	3717.407	2531.818	3313.032	3731.742	2531.41
	H_3	2040.582	3695.917	2532.43	2367.953	3703.263	2532.221	2685.018	3713.96	2531.916	2986.219	3729.702	2531.468	3278.135	3745.856	2531.008
	H_4	2012.139	3715.159	2531.882	2324.814	3728.309	2531.507	2623.371	3745.546	2531.017	2907.095	3765.661	2530.444	3176.225	3787.78	2529.814
I	I_1	2080.568	3668.755	2533.204	2436.531	3663.485	2533.354	2786.55	3662.413	2533.384	3131.277	3663.996	2533.339	3473.758	3666.22	2533.276
	I_2	2076.879	3671.293	2533.131	2431.156	3666.519	2533.267	2778.387	3666.562	2533.266	3119.872	3669.236	2533.19	3458.55	3672.403	2533.1
J		2081.528	3668.049	2533.224	2442.865	3659.848	2533.457	2803.863	3653.757	2533.631	3161.567	3650.396	2533.727	3518.847	3647.932	2533.797

Table A.5: Different tubing sizes and the effect of permeability at Well E

Appendix B: Effect of Skin factor and water cut on Production rate and Bubble point pressure at nodal point (downhole) in each well while permeability =2mD, and the tubing size is OD=3.5in, ID= 2.992in, and outlet P=61bar

Tubing size	Water cut%	Skin factor =0				Skin factor =1				Skin factor =2				Skin factor =3			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
H_2	0	520.153	3774.816	2501.436	520.153	450.6032	3812.401	2499.979	450.603	394.327	3851.234	2498.487	394.327	346.884	3894.232	2496.884	346.884
	10	521.945	3840.305	2496.764	488.333	452.4444	3875.657	2495.544	423.308	394.12	3918.213	2494.134	368.739	348.725	3952.596	2492.943	326.267
	20	524.692	3909.522	2492.514	454.887	453.5062	3946.471	2491.398	393.169	393.934	3990.208	2490.12	341.521	350.477	4016.762	2489.254	303.845
	30	527.448	3985.4	2488.6	418.593	454.3063	4024.187	2487.569	360.541	394.129	4066.832	2486.453	312.779	352.556	4086.09	2485.847	279.786
	40	530.099	4069.152	2484.988	379.055	454.7606	4109.712	2484.034	325.174	395.44	4147.109	2483.141	282.75	356.003	4158.837	2482.755	254.549
	50	532.508	4162.004	2481.645	335.85	454.4378	4204.443	2480.759	286.596	398.819	4230.375	2480.168	251.51	360.59	4237.377	2479.917	227.4
	60	534.497	4265.58	2478.544	288.528	455.4406	4305.343	2477.794	245.828	404.734	4318.263	2477.482	218.452	366.134	4324.177	2477.285	197.615
	70	535.443	4381.818	2475.658	236.447	461.3856	4408.431	2475.182	203.715	412.652	4415.182	2475.001	182.193	372.89	4421.314	2474.829	164.633
	80	538.630	4507.958	2473.032	180.466	473.8444	4517.059	2472.846	158.743	423.63	4523.172	2472.7	141.914	382.767	4528.563	2472.564	128.219
	90	556.385	4635.555	2470.769	121.875	491.2201	4641.071	2470.653	107.59	438.787	4646.588	2470.536	96.096	396.58	4650.901	2470.434	86.8465

Tubing size	Water cut%	Skin factor =4				Skin factor =5				Skin factor =6				Skin factor =7			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
H_2	0	314.055	3911.391	2496.027	314.055	288.027	3920.857	2495.396	288.027	266.348	3927.327	2494.858	266.348	247.836	3932.153	2494.372	247.836
	10	316.282	3966.961	2492.276	295.914	290.266	3975.341	2491.775	271.573	268.518	3981.091	2491.342	251.225	249.624	3986.841	2490.912	233.548
	20	318.425	4028.5	2488.74	276.057	292.552	4035.331	2488.35	253.627	270.611	4040.896	2487.989	234.605	251.792	4045.484	2487.654	218.29
	30	321.232	4094.241	2485.482	254.927	295.583	4099.141	2485.191	234.571	273.235	4105.125	2484.876	216.836	253.879	4110.865	2484.568	201.474
	40	324.81	4165.19	2482.476	232.244	298.55	4170.793	2482.215	213.466	275.862	4176.821	2481.946	197.244	256.591	4181.228	2481.709	183.465
	50	329.16	4242.782	2479.696	207.577	302.46	4248.25	2479.474	190.738	279.303	4254.423	2479.24	176.133	259.786	4258.523	2479.044	163.825
	60	333.955	4329.827	2477.093	180.248	306.901	4334.773	2476.912	165.641	283.456	4340.245	2476.723	152.984	263.618	4344.081	2476.561	142.277
	70	340.06	4426.467	2474.672	150.134	312.593	4430.697	2474.53	138.005	289.081	4434.674	2474.391	127.623	268.789	4438.276	2474.257	118.662
	80	348.989	4533.232	2472.437	116.9	320.579	4537.356	2472.318	107.38	296.917	4539.812	2472.222	99.4547	275.831	4543.554	2472.108	92.3866
	90	360.802	4655.898	2470.324	79.008	331.444	4659.286	2470.233	72.573	306.795	4661.659	2470.154	67.1732	285.128	4664.476	2470.071	62.4249

Tubing size	Water cut%	Skin factor =8				Skin factor =9				Skin factor =10				Skin factor =11			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
H_2	0	231.501	3937.701	2493.872	231.501	217.203	3942.277	2493.405	217.203	204.594	3946.262	2492.96	204.594	193.358	3949.908	2492.539	193.358
	10	233.049	3992.644	2490.485	218.04	218.762	3996.58	2490.111	204.673	206.076	4000.318	2489.745	2489.745	194.788	4003.711	2489.393	182.244

	20	235.095	4050.904	2487.306	203.814	220.639	4054.879	2486.991	191.282	207.836	4058.489	2486.686	180.182	196.443	4061.772	2486.393	170.305
	30	237.276	4115.043	2484.298	188.298	222.677	4118.843	2484.035	176.713	209.752	4122.275	2483.782	166.455	198.251	4125.394	2483.543	157.328
	40	239.805	4185.164	2481.485	171.462	225.048	4188.741	2481.267	160.91	211.987	4191.98	2481.058	151.573	200.352	4194.924	2480.855	143.252
	50	242.775	4262.233	2478.859	153.096	227.851	4265.577	2478.679	143.685	214.62	4268.577	2478.505	135.341	202.834	4271.361	2478.34	127.908
	60	246.359	4347.538	2476.406	132.961	231.176	4350.642	2476.257	124.765	217.746	4353.487	2476.113	117.516	205.761	4356.049	2475.974	111.047
	70	250.757	4442.6	2474.113	110.7	235.299	4445.452	2473.992	103.875	221.603	4448.007	2473.875	97.8269	209.406	4450.363	2473.762	92.4416
	80	257.354	4547.227	2471.995	86.1953	241.408	4549.873	2471.896	80.855	227.306	4552.273	2471.801	76.1276	214.414	4555.456	2471.695	71.8088
	90	266.06	4667.463	2469.985	58.2482	249.774	4669.241	2469.914	54.6809	235.373	4670.797	2469.846	51.5264	222.1	4673.228	2469.767	48.619

Tubing size	**Water cut%**	**Skin factor =12**				**Skin factor =13**				**Skin factor =14**				**Skin factor =15**			
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**
	0	183.283	3953.243	2492.125	183.283	179.852	3954.387	2491.956	179.852	165.95	3959.145	2491.351	165.95	158.454	3961.774	2490.975	158.454
	10	184.637	4006.832	2489.051	172.746	181.214	4008.85	2488.855	169.344	167.194	4012.361	2488.396	156.426	159.65	4014.807	2488.083	149.369
	20	186.197	4064.793	2486.108	161.422	182.778	4067.668	2485.899	158.068	168.598	4070.118	2485.562	146.164	160.987	4072.474	2485.301	139.567
	30	187.91	4128.254	2483.306	149.122	184.48	4131.932	2483.094	145.833	170.167	4133.294	2482.853	135.041	162.486	4135.523	2482.635	128.945
H_2	**40**	189.919	4197.621	2480.661	135.792	186.462	4202.038	2480.455	132.59	171.965	4202.359	2480.284	122.954	164.199	4204.462	2480.107	117.402
	50	192.253	4273.881	2478.177	121.237	188.793	4279.002	2477.982	118.184	174.072	4278.367	2477.864	109.77	166.205	4280.352	2477.713	104.808
	60	195.03	4358.394	2475.842	105.256	191.54	4364.044	2475.666	102.393	176.573	4362.574	2475.584	95.2932	168.585	4364.416	2475.462	90.9822
	70	198.47	4452.511	2473.652	87.6132	194.961	4458.468	2473.497	85.0161	179.679	4456.268	2473.441	79.3166	171.548	4457.941	2473.339	75.729
	80	203.192	4557.39	2471.607	68.0492	199.641	4563.416	2471.477	65.7941	183.906	4560.8	2471.437	61.5885	175.572	4562.277	2471.355	58.7963
	90	210.421	4674.954	2469.697	46.0611	206.815	4680.636	2469.596	44.2559	190.371	4677.988	2469.563	41.672	181.705	4679.337	2469.498	39.7723

Table B.1: Effect of skin factor and water cut on Liquid flow rate when k=2mD, outlet p= 61 bar at Well A

Tubing size	Water cut%	Skin factor =0				Skin factor =1				Skin factor =2				Skin factor =3			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	813.695	3671.302	2199.867	813.695	730.061	3673.305	2199.815	730.061	661.336	3676.274	2199.739	661.336	603.814	3680.236	2199.637	603.814
	10	820.817	3767.585	2192.162	738.735	735.626	3770.892	2192.089	662.063	666.127	3774.217	2192.016	599.514	608.418	3777.571	2191.943	547.576
	20	826.797	3868.971	2186.2	661.438	740.579	3872.783	2186.127	592.463	670.316	3876.463	2186.057	536.253	611.882	3880.205	2185.985	489.506
	30	831.734	3975.218	2181.446	582.214	744.917	3978.874	2181.384	521.442	674.11	3982.51	2181.323	471.877	614.566	3987.499	2181.239	430.196
	40	835.889	4085.721	2177.57	501.533	748.314	4089.539	2177.513	448.989	676.957	4093.231	2177.457	406.174	616.099	4099.553	2177.362	369.66
H_2	50	838.51	4201.119	2174.34	419.255	750.383	4204.923	2174.288	375.192	678.612	4208.56	2174.239	339.306	616.099	4216.547	2174.131	308.05
	60	838.51	4322.127	2171.596	335.404	750.383	4325.569	2171.554	300.153	678.612	4328.78	2171.515	271.445	612.094	4341.284	2171.361	244.838
	70	838.51	4445.657	2169.27	251.553	750.383	4448.56	2169.237	225.115	678.612	4451.399	2169.206	203.584	606.384	4468.896	2169.01	181.915
	80	833.404	4575.401	2167.239	166.681	744.568	4578.865	2167.203	148.914	669.073	4585.073	2167.139	133.815	598.877	4598.594	2167.001	119.775
	90	819.199	4711.701	2165.446	81.9199	731.279	4714.83	2165.416	73.1279	658.942	4718.413	2165.382	65.8942	598.877	4721.943	2165.349	59.8877

Tubing size	Water cut%	Skin factor =4				Skin factor =5				Skin factor =6				Skin factor =7			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	553.118	3689.62	2199.397	553.118	508.638	3701.883	2199.082	508.638	469.103	3717.094	2198.692	469.103	433.66	3735.174	2198.229	433.66
	10	556.239	3788.804	2191.696	500.615	510.412	3803.115	2191.382	459.371	469.103	3821.965	2190.968	422.192	433.66	3838.803	2190.599	390.294
	20	558.453	3892.887	2185.743	446.762	511.193	3909.177	2185.431	408.954	469.103	3928.431	2185.063	375.282	432.135	3948.276	2184.684	345.708
	30	559.448	4002.019	2180.993	391.614	511.193	4019.095	2180.705	357.835	468.387	4038.534	2180.377	327.871	429.997	4060.497	2180.006	300.998
	40	559.448	4115.482	2177.122	335.669	508.711	4135.942	2176.814	305.227	464.476	4157.073	2176.495	278.686	429.997	4168.808	2176.319	257.998
H_2	50	556.364	4236.079	2173.866	278.182	504.331	4257.175	2173.58	252.165	463.504	4270.276	2173.403	231.752	432.008	4274.92	2173.34	216.004
	60	550.833	4361.238	2171.116	220.333	501.266	4376.706	2170.926	200.506	465.808	4379.637	2170.89	186.323	434.397	4383.295	2170.845	173.759
	70	546.246	4485.364	2168.825	163.874	504.59	4488.382	2168.791	151.377	468.274	4491.868	2168.752	140.482	436.694	4495.045	2168.717	131.008
	80	548.657	4602.462	2166.961	109.731	506.317	4605.632	2166.928	101.264	469.808	4608.6	2166.898	93.9615	438.089	4611.36	2166.869	87.6178
	90	549.754	4724.112	2165.329	54.9754	506.317	4727.593	2165.296	50.6317	469.808	4729.976	2165.273	46.9808	438.089	4732.181	2165.252	43.8089

Tubing size	Water cut%	Skin factor =8				Skin factor =9				Skin factor =10				Skin factor =11			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	402.185	3753.973	2197.747	402.185	373.76	3774.636	2197.218	373.756	350.864	3785.928	2196.928	350.864	331.417	3792.924	2196.749	331.417
	10	401.054	3859.925	2190.135	360.948	373.76	3875.879	2189.785	336.384	352.107	3882.066	2189.649	316.896	333.066	3886.885	2189.543	299.76
	20	400.222	3966.258	2184.34	320.178	375.225	3974.094	2184.19	300.18	353.842	3978.907	2184.098	283.074	334.999	3982.324	2184.033	267.999
H_2	30	401.311	4068.907	2179.864	280.918	376.96	4074.239	2179.774	263.872	355.86	4077.467	2179.72	249.102	336.903	4080.636	2179.666	235.832
	40	403.069	4172.185	2176.268	241.841	379.11	4175.807	2176.213	227.466	357.799	4179.01	2176.165	214.679	338.781	4181.887	2176.122	203.269
	50	405.132	4277.65	2173.303	202.566	381.072	4280.76	2173.26	190.536	359.649	4283.746	2173.22	179.825	340.496	4286.341	2173.185	170.248
	60	407.032	4386.318	2170.808	162.813	382.799	4389.278	2170.771	153.119	361.306	4391.858	2170.74	144.522	341.996	4394.322	2170.709	136.798

	70	409.037	4497.982	2168.684	122.711	384.672	4500.508	2168.655	115.402	362.93	4503.02	2168.627	108.879	343.46	4505.367	2168.601	103.038
	80	410.288	4613.862	2166.844	82.0577	385.692	4616.267	2166.819	77.1384	363.869	4618.41	2166.797	72.7737	344.318	4620.429	2166.776	68.8636
	90	410.288	4734.213	2165.233	41.0288	385.692	4736.135	2165.215	38.5692	363.869	4737.87	2165.199	36.3869	344.318	4739.486	2165.183	34.432

Tubing size	**Water cut%**	**Skin factor =12**				**Skin factor =13**				**Skin factor =14**				**Skin factor =15**			
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**
H_2	**0**	314.367	3797.728	2196.626	314.367	299.21	3800.982	2196.542	299.21	285.303	3804.611	2196.449	285.303	272.945	3806.46	2196.402	272.945
	10	316.282	3889.923	2189.477	284.654	300.937	3893.548	2189.397	270.843	287.184	3895.881	2189.346	258.466	274.611	3898.246	2189.294	247.15
	20	318.059	3985.517	2183.972	254.448	302.7971	3988.059	2183.923	242.238	288.843	3990.862	2183.87	231.074	276.163	3993.209	2183.825	220.931
	30	319.906	4083.441	2179.619	223.934	304.5037	4086.104	2179.574	213.153	290.481	4088.52	2179.533	203.336	277.702	4090.79	2179.495	194.391
	40	321.653	4184.446	2176.083	192.992	306.156	4186.912	2176.046	183.693	292.026	4189.337	2176.009	175.216	279.159	4191.482	2175.977	167.495
	50	323.218	4288.92	2173.15	161.6094	307.615	4291.227	2173.119	153.808	293.461	4293.278	2173.091	146.73	280.507	4295.282	2173.064	140.254
	60	324.641	4396.606	2170.681	129.8567	308.911	4398.8	2170.654	123.564	294.664	4400.703	2170.631	117.866	281.634	4402.544	2170.608	112.654
	70	325.97	4507.474	2168.577	97.7911	310.178	4509.366	2168.556	93.0535	295.794	4511.197	2168.536	88.738	282.671	4512.897	2168.517	84.8012
	80	326.749	4622.26	2166.758	65.3499	310.841	4623.994	2166.74	62.1681	296.37	4625.677	2166.723	59.274	283.18	4627.188	2166.707	56.6359
	90	326.749	4740.952	2165.169	32.6749	310.841	4742.341	2165.156	31.0841	296.37	4743.679	2165.144	29.637	283.18	4744.89	2165.132	28.3179

Table B.2: Effect of skin factor and water cut on Liquid flow rate when k=2mD, outlet p= 61 bar at Well B

Tubing size	Water cut%	Skin factor =0				Skin factor =1				Skin factor =2				Skin factor =3			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	2197.849	3808.831	2535.233	2197.849	1951.095	3808.472	2535.244	1951.095	1751.442	3810.176	2535.195	1751.442	1587.276	3812.915	2535.117	1587.276
	10	2211.495	3907.55	2527.412	1990.346	1964.123	3906.615	2527.435	1767.71	1763.607	3907.857	2527.405	1587.246	1598.443	3910.291	2527.345	1438.599
	20	2219.646	4011.703	2521.269	1775.717	1972.378	4010.363	2521.298	1577.902	1771.876	4010.933	2521.286	1417.501	1606.037	4013.103	2521.239	1284.829
	30	2219.646	4121.944	2516.293	1553.752	1972.378	4120.607	2516.318	1380.665	1774.586	4119.713	2516.336	1242.21	1609.082	4121.292	2516.305	1126.358
	40	2216.165	4235.293	2512.222	1329.699	1972.378	4232.681	2512.267	1183.427	1771.046	4233.706	2512.249	1062.628	1606.154	4234.953	2512.228	963.6926
H_2	50	2197.786	4355.641	2508.773	1098.893	1955.451	4353.598	2508.804	977.7257	1759.169	4352.895	2508.815	879.5843	1595.491	4354.02	2508.798	797.7454
	60	2167.169	4480.018	2505.848	866.8675	1929.762	4477.689	2505.881	771.905	1735.677	4477.248	2505.887	694.271	1574.649	4477.995	2505.877	629.8598
	70	2136.122	4603.362	2503.404	640.8367	1896.517	4603.139	2503.407	568.955	1707.584	4602.141	2503.42	512.2752	1544.005	4604.698	2503.387	463.2016
	80	2040.463	4739.825	2501.177	408.0925	1814.723	4738.856	2501.188	362.945	1629.227	4739.417	2501.182	325.8453	1474.742	4740.899	2501.164	294.9484
	90	1873.327	4880.237	2499.234	187.3327	1662.88	4880.179	2499.234	166.288	1489.521	4881.292	2499.222	148.9521	1344.638	4883.184	2499.202	134.4638

Tubing size	Water cut%	Skin factor =4				Skin factor =5				Skin factor =6				Skin factor =7			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	1449.89	3816.292	2535.021	1449.89	1332.756	3820.774	2534.893	1332.756	1233.02	3824.667	2534.782	1233.02	1146.91	3828.289	2534.679	1146.91
	10	1460.269	3913.426	2527.268	1314.242	1342.844	3917.076	2527.178	1208.56	1242.169	3920.892	2527.084	1117.952	1154.885	3924.855	2526.987	1039.4
	20	1467.244	4015.96	2521.177	1173.796	1349.381	4019.218	2521.107	1079.505	1248.18	4022.769	2521.031	998.544	1160.435	4026.463	2520.951	928.348
	30	1470.192	4123.772	2516.258	1029.134	1352.036	4126.784	2516.2	946.425	1250.62	4130.149	2516.136	875.434	1162.574	4133.63	2516.07	813.802
	40	1467.641	4237.093	2512.191	880.585	1349.697	4239.892	2512.143	809.818	1248.435	4242.821	2512.093	749.061	1160.404	4246.158	2512.036	696.242
H_2	50	1457.904	4355.896	2508.769	728.952	1341.353	4357.97	2508.737	670.677	1240.057	4360.995	2508.69	620.029	1152.938	4363.69	2508.649	576.469
	60	1438.78	4479.641	2505.854	575.512	1322.977	4481.84	2505.823	529.191	1222.998	4484.471	2505.786	489.199	1136.61	4487.068	2505.749	454.644
	70	1409.194	4606.729	2503.361	422.758	1294.189	4609.268	2503.328	388.257	1195.293	4611.981	2503.294	358.588	1109.356	4614.915	2503.256	332.807
	80	1344.436	4742.996	2501.14	268.887	1233.368	4745.455	2501.111	246.674	1137.438	4748.223	2501.078	227.488	1054.148	4751.128	2501.044	210.83
	90	1222.225	4885.565	2499.176	122.223	1117.605	4888.269	2499.146	111.761	1027.515	4891.147	2499.115	102.752	949.2454	4894.102	2499.083	94.9245

Tubing size	Water cut%	Skin factor =8				Skin factor =9				Skin factor =10				Skin factor =11			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	1071.296	3832.349	2534.564	1071.296	1004.688	3836.342	2534.45	1004.688	945.787	3839.961	2534.347	945.787	893.477	3843.203	2534.255	893.477
	10	1078.635	3928.765	2526.891	970.772	1011.358	3932.749	2526.793	910.222	951.752	3936.535	2526.7	856.576	898.638	3940.07	2526.613	808.774
	20	1083.683	4030.344	2520.868	866.946	1016.066	4034.043	2520.788	812.853	956.077	4037.66	2520.71	764.862	902.553	4041.134	2520.635	722.043
H_2	30	1085.596	4137.127	2516.003	759.917	1017.684	4140.678	2515.935	712.379	957.518	4144.176	2515.868	670.262	902.553	4148.808	2515.78	631.787
	40	1083.464	4249.386	2511.981	650.079	1015.484	4252.757	2511.923	609.291	955.231	4256.104	2511.866	573.138	902.553	4258.104	2511.832	541.532
	50	1075.837	4367.037	2508.597	537.919	1008.144	4370.157	2508.549	504.072	948.116	4373.277	2508.5	474.058	893.712	4376.988	2508.443	446.856
	60	1060.334	4490.109	2505.707	424.134	993.312	4493.06	2505.665	397.325	933.771	4496.021	2505.624	373.508	880.583	4498.878	2505.584	352.233

	70	1033.962	4617.955	2503.217	310.189	967.551	4621.012	2503.178	290.265	908.465	4624.084	2503.138	272.54	855.78	4627.11	2503.099	256.734
	80	981.07	4754.126	2501.009	196.214	916.672	4757.143	2500.973	183.334	859.411	4760.162	2500.937	171.882	808.359	4763.133	2500.902	161.672
	90	880.674	4897.125	2499.05	88.0674	820.303	4900.105	2499.018	82.0303	766.728	4903.081	2498.985	76.6728	719.057	4905.962	2498.954	71.9057

Tubing size	**Water cut%**	**Skin factor =12**				**Skin factor =13**				**Skin factor =14**				**Skin factor =15**			
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**
	0	846.603	3846.007	2534.175	846.603	802.749	3851.278	2534.025	802.749	765.063	3852.903	2533.978	765.063	729.939	3855.875	2533.894	729.939
	10	850.957	3943.613	2526.526	765.862	807.734	3947.182	2526.438	726.96	769.329	3949.482	2526.382	692.396	733.719	3952.594	2526.305	660.347
	20	854.488	4044.507	2520.563	683.59	811.115	4047.881	2520.49	648.892	771.816	4050.963	2520.424	617.453	736.095	4053.95	2520.359	588.876
	30	854.488	4151.988	2515.719	598.141	811.115	4154.938	2515.663	567.78	771.816	4157.853	2515.607	540.271	736.095	4160.452	2515.557	515.266
	40	853.43	4262.119	2511.763	512.058	809.888	4265.024	2511.713	485.933	770.359	4267.986	2511.663	462.215	734.44	4270.653	2511.617	440.664
H_2	**50**	846.5	4379.115	2508.41	423.25	802.426	4382.567	2508.357	401.213	763.492	4384.913	2508.321	381.746	727.106	4388.134	2508.271	363.553
	60	832.686	4501.85	2505.542	333.075	789.373	4504.759	2505.501	315.749	750.217	4507.549	2505.462	300.087	714.525	4510.235	2505.424	285.81
	70	808.378	4630.097	2503.061	242.513	765.7	4632.996	2503.024	229.71	726.932	4635.841	2502.987	218.08	686.171	4643.006	2502.895	205.851
	80	762.465	4766.061	2500.868	152.493	721.144	4768.912	2500.834	144.229	654.803	4789.548	2500.591	130.961	618.159	4794.732	2500.53	123.632
	90	675.749	4909.016	2498.921	67.5749	637.668	4911.595	2498.893	63.7668	600.958	4915.161	2498.854	60.096	571.054	4916.957	2498.835	57.1054

Table B.3: Effect of skin factor and water cut on liquid flow rate when k=2mD, outlet p= 61bar at Well C

Tubing size	Water cut%	Skin factor =0				Skin factor =1				Skin factor =2				Skin factor =3			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	2120.099	3864.872	2527.62	2120.099	1885.565	3862.207	2527.696	1885.565	1695.055	3862.076	2527.7	1695.055	1537.916	3863.354	2527.663	1537.916
	10	2126.526	3963.666	2520.02	1913.874	1891.999	3960.724	2520.092	1702.8	1701.101	3960.412	2520.1	1530.991	1543.346	3961.642	2520.069	1389.011
	20	2126.526	4067.62	2514.054	1701.221	1891.999	4064.923	2514.112	1513.6	1701.101	4064.637	2514.118	1360.881	1543.346	4065.763	2514.094	1234.677
	30	2117.316	4177.291	2509.228	1482.121	1888.023	4172.668	2509.316	1321.616	1698.325	4172.038	2509.328	1188.827	1541.21	4172.69	2509.315	1078.847
H_2	40	2098.472	4291.73	2505.251	1259.083	1870.466	4287.985	2505.315	1122.28	1684.19	4286.428	2505.341	1010.514	1527.701	4287.514	2505.323	916.621
	50	2066.231	4410.92	2501.915	1033.115	1842.373	4407.381	2501.97	921.186	1658.482	4406.225	2501.988	829.241	1505.643	4406.503	2501.983	752.822
	60	2010.235	4536.321	2499.056	804.0938	1793.066	4533.104	2499.101	717.226	1614.385	4532.011	2499.116	645.754	1465.445	4532.321	2499.112	586.178
	70	1951.928	4658.54	2496.696	585.5783	1738.266	4656.732	2496.719	521.48	1562.578	4656.7	2496.719	468.774	1416.022	4657.824	2496.705	424.807
	80	1816.433	4793.497	2494.546	363.2867	1615.712	4792.583	2494.557	323.143	1450.259	4793.162	2494.55	290.052	1311.934	4794.721	2494.532	262.387
	90	1574.215	4933.712	2492.656	157.4215	1393.776	4934.337	2492.649	139.378	1244.65	4936.06	2492.63	124.465	1119.883	4938.491	2492.604	111.988

Tubing size	Water cut%	Skin factor =4				Skin factor =5				Skin factor =6				Skin factor =7			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	1406.082	3865.549	2527.601	1406.082	1293.629	3868.696	2527.511	1293.629	1197.094	3872.149	2527.413	1197.094	1113.581	3875.694	2527.312	1113.581
	10	1410.905	3963.801	2520.016	1269.814	1298.274	3966.524	2519.95	1168.446	1201.703	3969.552	2519.875	1081.533	1117.81	3972.762	2519.796	1006.029
	20	1410.905	4067.744	2514.052	1128.724	1298.274	4070.37	2513.995	1038.619	1201.703	4073.019	2513.938	961.363	1117.81	4076.092	2513.872	894.248
	30	1409.067	4174.404	2509.283	986.347	1296.635	4176.745	2509.238	907.644	1200.026	4179.398	2509.187	840.018	1116.042	4182.262	2509.133	781.23
	40	1396.797	4288.986	2505.298	838.078	1285.241	4291.143	2505.261	771.144	1189.352	4293.601	2505.219	713.611	1105.919	4296.312	2505.172	663.551
H_2	50	1376.619	4407.874	2501.962	688.309	1266.588	4409.806	2501.932	633.294	1171.782	4412.076	2501.897	585.891	1089.343	4414.691	2501.857	544.672
	60	1339.671	4533.571	2499.095	535.869	1232.149	4535.441	2499.068	492.859	1139.29	4537.788	2499.035	455.716	1058.601	4540.262	2499.001	423.441
	70	1292.463	4659.686	2496.681	387.739	1186.887	4661.998	2496.652	356.066	1095.871	4664.669	2496.617	328.761	1016.649	4667.567	2496.58	304.995
	80	1195.018	4796.908	2494.506	239.004	1095.098	4799.515	4799.515	219.02	1008.996	4802.318	2494.442	201.799	934.135	4805.288	2494.407	186.827
	90	1014.398	4941.358	2492.573	101.44	924.4417	4944.445	2492.539	92.4442	846.951	4947.69	2492.504	84.695	779.864	4950.925	2492.469	77.986

Tubing size	Water cut%	Skin factor =8				Skin factor =9				Skin factor =10				Skin factor =11			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	1040.705	3878.927	2527.22	1040.705	976.289	3882.391	2527.122	976.289	919.181	3885.86	2527.023	919.181	868.29	3888.917	2526.936	868.29
	10	1044.259	3976.231	2519.711	939.833	979.655	3979.544	2519.63	881.69	922.222	3982.788	2519.55	830	871.025	3985.958	2519.472	783.922
	20	1044.259	4079.273	2513.803	835.407	979.655	4082.311	2513.738	783.724	922.222	4085.287	2513.674	737.778	871.025	4088.192	2513.612	696.82
H_2	30	1042.548	4185.318	2509.074	729.783	977.744	4188.278	2509.018	684.42	920.241	4191.288	2508.961	644.169	868.907	4194.206	2508.905	608.235
	40	1032.882	4299.212	2505.123	619.729	968.501	4302.106	2505.073	581.101	911.162	4305.059	2505.023	546.697	860.025	4307.972	2504.973	516.015
	50	1017.088	4417.456	2501.814	508.544	953.197	4420.3	2501.77	476.598	896.523	4423.16	2501.726	448.261	845.865	4426.005	2501.682	422.933
	60	987.848	4542.947	2498.963	395.139	925.342	4545.724	2498.924	370.137	869.687	4548.544	2498.885	347.875	820.028	4551.345	2498.845	328.011

	70	947.215	4670.524	2496.542	284.164	886.037	4673.506	2496.504	265.811	831.71	4676.437	2496.466	249.513	783.107	4679.432	2496.428	234.932
	80	868.454	4808.34	2494.371	173.69	810.599	4811.397	2494.335	162.12	759.188	4814.44	2494.3	151.838	713.433	4817.396	2494.265	142.687
	90	721.24	4954.155	2492.434	72.124	669.79	4957.312	2492.4	66.979	623.735	4960.597	2492.364	62.373	583.492	4963.513	2492.332	58.349

Tubing size	**Water cut%**	**Skin factor =12**				**Skin factor =13**				**Skin factor =14**				**Skin factor =15**			
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**
H_2	**0**	822.61	3891.981	2526.849	822.61	782.014	3893.858	2526.795	782.014	744.552	3896.591	2526.718	744.552	710.607	3899.032	2526.648	710.607
	10	824.954	3989.02	2519.397	742.459	783.649	3991.676	2519.332	705.284	746.036	3994.327	2519.267	671.432	711.826	3996.921	2519.203	640.643
	20	824.954	4091.002	2513.551	659.964	783.649	4093.437	2513.499	626.919	746.036	4095.995	2513.444	596.829	711.826	4098.249	2513.395	569.46
	30	821.313	4198.639	2508.82	574.919	779.636	4201.55	2508.765	545.745	741.691	4204.455	2508.709	519.184	707.281	4207.162	2508.658	495.097
	40	813.72	4311.131	2504.919	488.232	772.265	4313.906	2504.872	463.359	734.594	4316.593	2504.826	440.757	700.321	4319.241	2504.781	420.193
	50	800.161	4428.909	2501.638	400.081	759.061	4431.66	2501.595	379.531	721.772	4434.277	2501.555	360.886	687.827	4436.876	2501.515	343.913
	60	775.328	4554.114	2498.806	310.131	735.043	4556.825	2498.768	294.017	698.513	4559.47	2498.731	279.405	665.171	4562.059	2498.695	266.068
	70	739.566	4682.262	2496.392	221.87	700.209	4685.125	2496.355	210.063	664.626	4687.808	2496.321	199.388	614.989	4704.076	2496.112	184.497
	80	668.974	4822.168	2494.209	133.795	603.04	4842.034	2493.975	120.608	569.648	4845.643	2493.933	113.93	540.378	4848.444	2493.9	108.076
	90	545.693	4967.102	2492.293	54.569	514.595	4969.322	2492.269	51.46	485.52	4971.926	2492.241	48.552	459.286	4974.373	2492.215	45.929

Table B.4: Effect of skin factor and water cut on Liquid flow rate when k=2mD, outlet p= 61bar at Well D

Tubing size	Water cut%	K= 2 mD, Outlet P =61 bar, Skin factor =0				Skin factor =1				Skin factor =2				Skin factor =3			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	1360.856	3695.4	2532.445	1360.856	1203.187	3700.575	2532.297	1203.187	1077.11	3706.163	2532.138	1077.11	975.306	3710.224	2532.023	975.306
	10	1382.609	3788.82	2524.315	1244.348	1221.716	3794.491	2524.175	1099.545	1093.378	3800.148	2524.036	984.04	988.516	3805.944	2523.894	889.664
	20	1402.109	3889.257	2517.894	1121.687	1239.971	3893.6	2517.8	991.977	1109.828	3898.735	2517.69	887.862	1003.552	3903.921	2517.578	802.842
	30	1422.307	3993.988	2512.728	995.6146	1257.966	3997.865	2512.654	880.576	1126.142	4002.381	2512.568	788.299	1018.394	4007.189	2512.476	712.876
H_2	40	1441.717	4104.295	2508.457	865.0301	1275.704	4107.452	2508.403	765.422	1142.286	4111.43	2508.334	685.372	1032.904	4115.902	2508.258	619.743
	50	1461.362	4219.886	2504.865	730.6808	1293.46	4222.335	2504.827	646.73	1158.353	4225.861	2504.773	579.176	1047.706	4229.62	2504.715	523.853
	60	1481.581	4340.558	2501.803	592.6326	1311.58	4342.651	2501.774	524.632	1175.017	4345.431	2501.735	470.007	1062.667	4348.829	2501.687	425.067
	70	1514.86	4461.031	2499.229	454.4581	1340.773	4462.984	2499.204	402.232	1200.462	4465.815	2499.168	360.139	1085.091	4469.144	2499.125	325.527
	80	1541.025	4592.714	2496.911	308.205	1364.56	4594.048	2496.895	272.912	1221.703	4596.411	2496.867	244.341	1104.197	4599.259	2496.834	220.839
	90	1574.849	4729.813	2494.869	157.4849	1395.447	4730.543	2494.861	139.545	1249.744	4732.24	2494.843	124.974	1129.437	4734.5	2494.818	112.944

Tubing size	Water cut%	Skin factor =4				Skin factor =5				Skin factor =6				Skin factor =7			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	888.73	3717.281	2531.822	888.73	816.77	3722.205	2531.681	816.77	755.503	3726.657	2531.555	755.503	702.523	3730.994	2531.431	702.522
	10	901.873	3811.011	2523.769	811.686	828.899	3815.705	2523.654	746.009	766.397	3820.31	2523.541	689.757	712.268	3825.12	2523.423	641.041
	20	915.325	3909.014	2517.468	732.26	840.982	3913.814	2517.365	672.785	777.38	3918.515	2517.264	621.854	722.466	3922.903	2517.169	577.973
	30	928.769	4012.002	2512.384	650.138	853.02	4016.732	2512.293	597.114	788.292	4021.425	2512.204	551.805	732.451	4025.812	2512.12	512.716
H_2	40	941.925	4120.26	2508.183	565.155	865.089	4124.702	2508.107	519.054	799.39	4129.05	2508.033	479.634	742.631	4133.233	2507.961	445.579
	50	955.251	4233.806	2504.65	477.626	877.201	4237.93	2504.586	438.6	810.431	4242.007	2504.523	405.216	752.718	4245.975	2504.462	376.359
	60	969.016	4352.404	2501.637	387.606	889.709	4356.159	2501.584	355.884	821.818	4359.998	2501.53	328.727	763.106	4363.694	2501.479	305.242
	70	988.811	4472.708	2499.079	296.643	907.339	4476.378	2499.032	272.202	837.659	4480.058	2498.985	251.298	777.331	4483.686	2498.938	233.199
	80	1005.874	4602.411	2496.796	201.175	922.653	4605.706	2496.758	184.531	851.276	4609.058	2496.718	170.255	787.892	4613.598	2496.665	157.578
	90	1028.626	4737.094	2494.79	102.863	943.088	4739.87	2494.76	94.3088	869.669	4742.729	2494.729	86.9669	806.15	4745.588	2494.698	80.615

Tubing size	Water cut%	Skin factor =8				Skin factor =9				Skin factor =10				Skin factor =11			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	Oil Flow rate (stb/d)
	0	656.462	3734.773	2531.323	656.462	615.831	3738.613	2531.214	615.831	578.773	3744.724	2531.04	578.773	543.989	3754.882	2530.751	543.989
	10	665.467	3828.871	2523.33	598.92	624.205	3832.631	2523.238	561.784	585.931	3839.854	2523.061	527.338	549.346	3852.57	2522.748	494.412
	20	674.627	3927.087	2517.079	539.702	632.511	3931.158	2516.991	506.009	593.284	3938.817	2516.826	474.627	555.312	3952.571	2516.53	444.25
H_2	30	683.812	4029.904	2512.042	478.669	641.056	4033.774	2511.968	448.74	600.531	4042.308	2511.805	420.372	560.999	4057.068	2511.523	392.7
	40	693.13	4137.245	2507.893	415.878	649.61	4141.064	2507.827	389.766	607.56	4150.419	2507.667	364.536	566.058	4166.585	2507.391	339.635
	50	702.45	4249.7	2504.405	351.225	658.177	4253.366	2504.348	329.089	613.985	4264.172	2504.181	306.993	570.334	4281.286	2503.917	285.167
	60	711.856	4367.308	2501.428	284.742	666.788	4370.782	2501.379	266.715	619.908	4382.981	2501.208	247.963	573.351	4401.433	2500.949	229.34
	70	724.684	4487.229	2498.893	217.405	678.393	4490.648	2498.849	203.518	626.585	4505.622	2498.657	187.975	576.4	4524.967	2498.409	172.92

	80	734.124	4616.837	2496.626	146.825	686.853	4619.969	2496.59	137.371	631.203	4635.131	2496.411	126.241	588.896	4643.378	2496.314	117.779
	90	750.617	4748.433	2494.667	75.0617	701.818	4751.198	2494.637	70.1818	658.195	4754.132	2494.605	65.8195	619.992	4756.513	2494.579	61.9992

Tubing size	**Water cut%**	**Skin factor =12**				**Skin factor =13**				**Skin factor =14**				**Skin factor =15**			
		Liquid Flow rate (stb/d)	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**	**Liquid Flow rate (stb/d)**	**Pressure at Na (psi)**	**Bubble Point pressure (psi)**	**Oil Flow rate (stb/d)**
	0	510.512	3770.688	2530.301	510.512	480.732	3785.239	2529.887	480.732	453.025	3801.653	2529.419	453.025	427.662	3818.186	2528.949	427.662
	10	515.435	3867.752	2522.375	463.891	484.406	3883.797	2521.981	435.965	455.784	3900.942	2521.56	410.206	429.271	3919.296	2521.109	386.344
	20	520.263	3968.33	2516.191	416.211	488.017	3985.494	2515.822	390.414	458.203	4003.899	2515.425	366.562	430.508	4023.535	2515.003	344.407
	30	524.401	4074.091	2511.198	367.08	490.792	4092.186	2510.852	343.554	459.648	4111.631	2510.481	321.753	430.508	4132.781	2510.077	301.356
H_2	40	527.836	4184.39	2507.086	316.702	492.507	4203.782	2506.754	295.504	459.648	4224.613	2506.398	275.789	431.291	4242.17	2506.098	258.775
	50	529.978	4300.2	2503.624	264.989	492.507	4320.9	2503.305	246.253	460.618	4337.771	2503.044	230.309	437.482	4343.411	2502.957	218.741
	60	529.978	4422.042	2500.659	211.991	494.386	4437.232	2500.446	197.754	470.165	4439.804	2500.41	188.066	446.409	4445.03	2500.337	178.563
	70	537.021	4537.458	2498.248	161.106	507.813	4541.883	2498.192	152.344	482.751	4544.303	2498.161	144.825	459.416	4547.436	2498.12	137.825
	80	556.126	4646.447	2496.278	111.225	526.589	4649.456	2496.242	105.318	499.896	4652.268	2496.209	99.9792	475.614	4655.028	2496.176	95.123
	90	585.479	4759.009	2494.552	58.547	554.341	4761.45	2494.526	55.4341	526.213	4763.753	2494.501	52.6213	500.635	4765.958	2494.477	50.0635

Table B.5: Effect of skin factor and water cut on Liquid flow rate when k=2mD, outlet p= 61bar at Well E

Appendix C: Effect of outlet pressure on Production rate and Bubble point pressure at nodal point (downhole) in each well while permeability =2mD, and the tubing size is OD=3.5in, ID= 2.992in, with S=0 and water cut %=0

Tubing Size	Water Cut %	Outlet Pressure = 61 bar				Outlet Pressure = 30 bar				Outlet Pressure = 16 bar			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)
	0	520.1527	3774.816	2501.436	520.1527	911.1803	2835.143	2528.443	911.1803	1159.39	2243.695	2539.476	1159.39
	10	521.9446	3840.305	2496.764	488.3329	923.0244	2918.738	2520.806	863.6061	1188.722	2331.6	2532.639	1112.214
	20	524.6923	3909.522	2492.514	454.8865	937.0411	3009.21	2513.864	812.4709	1220.736	2428.883	2526.195	1058.528
	30	527.4484	3985.4	2488.6	418.5928	952.3799	3110.267	2507.484	756.0533	1249.379	2540.772	2519.779	992.0259
	40	530.0985	4069.152	2484.988	379.0547	971.4477	3220.12	2501.666	695.0766	1278.044	2669.144	2512.495	914.8221
H_2	50	532.5078	4162.004	2481.645	335.8502	992.9772	3344.867	2496.259	626.9754	1308.638	2819.021	2505.669	826.8996
	60	534.4966	4265.58	2478.544	288.5277	1022.132	3480.587	2491.321	552.8428	1346.954	2986.977	2499.358	729.4473
	70	535.4426	4381.818	2475.658	236.4473	1058.997	3635.362	2486.705	469.2011	1390.64	3185.479	2493.364	617.405
	80	538.6304	4507.958	2473.032	180.4658	1113.23	3807.841	2482.44	375.1612	1457.241	3405.051	2487.85	492.7541
	90	556.3846	4635.555	2470.769	121.8754	1190.201	4013.042	2478.349	263.5468	1548.898	3669.458	2482.525	345.0552

Table C.1: Effect of outlet pressure when k=2mD, water cut%=0, skin factor=0 at Well A

Tubing Size	Water Cut %	Outlet Pressure = 61 bar				Outlet Pressure = 30 bar				Outlet Pressure = 16 bar			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)
	0	813.6948	3671.302	2199.867	813.6948	1361.326	2780.261	2222.773	1361.326	1736.805	2216.185	2236.891	1736.805
	10	820.8165	3767.585	2192.162	738.7349	1384.07	2907.685	2211.089	1245.663	1766.794	2366.064	2223.057	1590.115
	20	826.7971	3868.971	2186.2	661.4376	1405.161	3045.358	2201.992	1124.129	1800.607	2521.007	2212.085	1440.485
	30	831.734	3975.218	2181.446	582.2138	1427.93	3189.362	2194.749	999.551	1836.209	2685.919	2203.304	1285.346
	40	835.8888	4085.721	2177.57	501.5333	1452.513	3340.488	2188.826	871.5079	1873.647	2861.761	2196.085	1124.188
H_2	50	838.5102	4201.119	2174.34	419.2551	1479.459	3499.65	2183.875	739.7294	1916.939	3046.062	2190.065	958.4697
	60	838.5102	4322.127	2171.596	335.4041	1511.947	3665.066	2179.691	604.7787	1954.875	3252.522	2184.794	781.9501
	70	838.5102	4445.657	2169.27	251.5531	1558.012	3833.105	2176.151	467.4037	2002.375	3468.752	2180.259	600.7126
	80	833.4041	4575.401	2167.239	166.6808	1611.357	4014.329	2173.013	322.2714	2055.032	3702.94	2176.23	411.0064
	90	819.1988	4711.701	2165.446	81.91988	1690.572	4202.589	2170.267	169.0572	2127.246	3951.19	2172.656	212.7246

Table C.2: Effect of outlet pressure when k=2mD, water cut%=0, skin factor=0 at Well B

Tubing Size	Water Cut %	Outlet Pressure = 61 bar				Outlet Pressure = 30 bar				Outlet Pressure = 16 bar			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)
H_2	0	2186.559	3815.495	2535.044	2186.559	3595.369	3024.251	2557.626	3595.369	4252.704	2675.988	2567.595	4252.704
	10	2199.455	3914	2527.254	1979.509	3657.132	3151.868	2546.022	3291.419	4346.884	2810.707	2554.449	3912.195
	20	2207.064	4018.042	2521.132	1765.651	3719.738	3286.65	2536.917	2975.79	4445.536	2954.183	2544.113	3556.428
	30	2207.064	4127.705	2516.183	1544.945	3786.679	3427.986	2529.578	2650.675	4551.437	3106.128	2535.759	3186.006
	40	2202.581	4240.905	2512.126	1321.548	3850.21	3579.862	2523.462	2310.126	4666.458	3267.509	2528.835	2799.875
	50	2183.384	4360.923	2508.691	1091.692	3910.162	3742.483	2518.266	1955.081	4792.587	3439.709	2522.969	2396.293
	60	2151.114	4485.153	2505.776	860.4454	3980.787	3911.617	2513.846	1592.315	4927.649	3625.68	2517.882	1971.06
	70	2120.715	4607.567	2503.35	636.2145	4113.686	4075.781	2510.189	1234.106	5135.328	3811.548	2513.597	1540.598
	80	2024.194	4743.431	2501.135	404.8388	4215.869	4264.481	2506.789	843.1737	5284.892	4036.214	2509.492	1056.978
	90	1856.4	4883.112	2499.202	185.64	4363.61	4462.056	2503.785	436.361	5458.351	4280.588	2505.765	545.8351

Table C.3: Effect of outlet pressure when k=2mD, water cut%=0, skin factor=0 at Well C

Tubing Size	Water Cut %	Outlet Pressure = 61 bar				Outlet Pressure = 30 bar				Outlet Pressure = 16 bar			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)
H_2	0	2120.099	3864.872	2527.62	2120.099	3519.598	3081.329	2549.963	3519.598	4166.744	2739.465	2559.74	4166.744
	10	2126.526	3963.666	2520.02	1913.874	3573.915	3208.991	2538.587	3216.523	4256.041	2872.645	2546.887	3830.437
	20	2126.526	4067.62	2514.054	1701.221	3629.11	3343.507	2529.666	2903.288	4347.787	3015.1	2536.768	3478.23
	30	2117.316	4177.291	2509.228	1482.121	3681.865	3486.565	2522.437	2577.305	4444.48	3166.387	2528.579	3111.136
	40	2098.472	4291.73	2505.251	1259.083	3731.57	3638.783	2516.435	2238.942	4546.835	3327.793	2521.779	2728.101
	50	2066.231	4410.92	2501.915	1033.115	3780.805	3799.284	2511.374	1890.402	4651.648	3501.508	2515.993	2325.824
	60	2010.235	4536.321	2499.056	804.0938	3829.249	3968.534	2507.036	1531.7	4766.48	3686.668	2511.009	1906.592
	70	1951.928	4658.54	2496.696	585.5783	3937.49	4131.407	2503.466	1181.247	4947.718	3871.422	2506.816	1484.316
	80	1816.433	4793.497	2494.546	363.2867	4002.242	4318.787	2500.143	800.4484	5048.795	4096.669	2502.77	1009.759
	90	1574.215	4933.712	2492.656	157.4215	4081.994	4515.906	2497.196	408.1994	5165.321	4337.74	2499.138	516.5321

Table C.4: Effect of outlet pressure when k=2mD, water cut%=0, skin factor=0 at Well D

Tubing Size	Water Cut %	Outlet Pressure = 61 bar				Outlet Pressure = 30 bar				Outlet Pressure = 16 bar			
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point Pressure (psi)	Oil Flow rate (stb/d)
H_2	0	1360.856	3695.4	2532.445	1360.856	2293.104	2792.024	2558.236	2293.104	2774.881	2329.772	2566.616	2774.881
	10	1382.609	3788.82	2524.315	1244.348	2343.588	2921.649	2545.677	2109.229	2873.521	2471.15	2555.453	2586.169
	20	1402.109	3889.257	2517.894	1121.687	2395.602	3060.104	2535.794	1916.482	2955.588	2621.077	2545.305	2364.47
	30	1422.307	3993.988	2512.728	995.6146	2450.737	3207.514	2527.79	1715.516	3042.194	2780.855	2535.99	2129.536
	40	1441.717	4104.295	2508.457	865.0301	2510.796	3363.51	2521.165	1506.478	3138.371	2951.578	2528.257	1883.023
	50	1461.362	4219.886	2504.865	730.6808	2581.388	3526.618	2515.603	1290.694	3246.986	3134.4	2521.701	1623.493
	60	1481.581	4340.558	2501.803	592.6326	2667.056	3697.885	2510.851	1066.822	3370.334	3332.527	2516.013	1348.133
	70	1514.86	4461.031	2499.229	454.4581	2802.13	3866.163	2506.883	840.6391	3538.362	3537.806	2511.124	1061.509
	80	1541.025	4592.714	2496.911	308.205	2958.45	4055.259	2503.26	591.6899	3720.965	3773.673	2506.598	744.1929
	90	1574.849	4729.813	2494.869	157.4849	3200.611	4254.385	2500.047	320.0611	3983.236	4028.906	2502.51	398.3236

Table C.5: Effect of outlet pressure when k=2mD, water cut%=0, skin factor=0 at Well E

Appendix D: Effect of artificial lift (gas lift method) on Production rate and Bubble point pressure at nodal point (downhole) in each well while permeability =2mD, and the tubing size is OD=3.5 in, ID= 2.992 in, with S=0 and water cut %=0, and outlet p= 16bar

Tubing Size	Water Cut %	Gas injected quantity = 5,000(NM^3/d) =0.175 (mmscf/d)						Gas injected quantity = 10,000(NM^3/d) = 0.35 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	0	1200.367	2127.888	2540.384	494.7886	1200.367	0.593929	1214.356	2087.072	2540.695	637.2184	1214.356	0.7738106
	10	1239.267	2200.391	2533.719	499.9263	1159.505	0.579668	1255.779	2156.013	2534.076	646.8837	1174.955	0.7600594
	20	1282.351	2283.355	2527.444	506.3804	1111.955	0.563073	1301.867	2235.525	2527.847	659.0423	1128.878	0.7439785
	30	1331.024	2376.868	2521.5	514.5814	1056.881	0.543852	1354.777	2324.361	2521.961	674.3566	1075.742	0.7254342
	40	1384.28	2484.361	2515.804	525.589	991.001	0.52086	1415.628	2425.401	2516.34	694.352	1013.458	0.7036971
	50	1439.348	2608.155	2509.449	541.3578	909.7623	0.492507	1483.83	2537.428	2510.718	722.145	937.9726	0.6773527
	60	1509.198	2747.91	2503.26	562.9817	817.8264	0.460422	1564.472	2667.659	2504.571	761.7659	847.9377	0.6459304
	70	1599.364	2910.209	2497.448	595.1446	710.9637	0.423127	1671.905	2815.936	2498.849	819.7134	743.5517	0.6094997
	80	1743.905	3077.726	2492.259	644.9429	591.3299	0.381374	1852.523	2955.498	2493.909	905.6059	628.8108	0.5694551
	90	1923.086	3317.14	2486.821	754.956	431.081	0.325447	2079.085	3171.978	2488.597	1098.049	467.2587	0.5130734

Tubing Size	Water Cut %	Gas injected quantity = 15,000(NM^3/d) =0.525 (mmscf/d)						Gas injected quantity = 20,000(NM^3/d) = 0.7 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	0	1223.309	2060.581	2540.895	778.1636	1223.309	0.951935	1229.707	2041.467	2541.038	918.2411	1229.707	1.129168
	10	1266.238	2127.485	2534.303	792.1346	1184.741	0.938475	1273.566	2107.296	2534.463	936.4463	1191.597	1.115868
	20	1314.011	2205.301	2528.1	809.7651	1139.408	0.922654	1322.666	2183.54	2528.281	959.3337	1146.913	1.100273
	30	1368.886	2292.671	2522.237	832.0048	1086.945	0.904344	1378.979	2269.763	2522.436	988.293	1094.959	1.082141
	40	1432.453	2391.755	2516.644	860.9437	1025.503	0.882901	1444.445	2367.513	2516.862	1025.924	1034.088	1.060897
	50	1505.661	2502.716	2511.267	900.5754	951.8186	0.857185	1521.799	2477.243	2511.505	1076.608	962.0555	1.035758
	60	1588.727	2632.423	2505.146	958.6434	861.1586	0.825545	1607.157	2605.81	2505.582	1152.465	871.2255	1.004058
	70	1701.656	2777.553	2499.42	1042.619	756.8993	0.789158	1721.888	2751.436	2499.808	1262.85	765.9896	0.967331
	80	1899.84	2902.481	2494.626	1162.756	645.1562	0.75016	1923.205	2876.4	2494.978	1420.59	653.2343	0.927979
	90	2152.927	3103.674	2489.433	1432.761	484.4239	0.694064	2188.476	3070.798	2489.835	1769.743	492.6996	0.871952

Table D.1: Effect of artificial lift when k=2mD, skin factor=0, outlet pressure= 16bar at Well A

Tubing Size	Water Cut %	Gas injected quantity = 5,000(NM^3/d) =0.175 (mmscf/d)						Gas injected quantity = 10,000(NM^3/d) = 0.35 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	0	1807.093	2105.084	2237.376	445.8405	1807.093	0.805676	1836.306	2053.324	2237.592	539.5999	1836.306	0.990871
	10	1859.325	2239.371	2225.861	453.5779	1673.392	0.759014	1901.935	2181.639	2226.393	553.47	1711.742	0.947398
	20	1912.248	2377.977	2214.843	463.3941	1529.798	0.7089	1963.017	2313.454	2216.088	571.8711	1570.414	0.898075
	30	1973.73	2521.749	2206.099	475.6636	1381.611	0.657183	2037.367	2446.483	2207.382	594.4147	1426.157	0.847729
	40	2044.495	2673.502	2198.946	491.6594	1226.697	0.603118	2123.351	2587.736	2200.25	623.7228	1274.011	0.79463
	50	2128.804	2833.047	2192.979	513.4115	1064.402	0.546477	2226.015	2736.52	2194.3	663.4631	1113.008	0.73844
	60	2227.15	3005.954	2187.851	545.4392	890.8601	0.48591	2352.644	2893.888	2189.242	720.9217	941.0576	0.678429
	70	2360.385	3182.154	2183.499	596.1347	708.1154	0.422132	2529.642	3048.745	2185.01	810.1981	758.8925	0.614854
	80	2498.37	3397.474	2179.394	699.2282	499.6739	0.349386	2719.751	3246.895	2180.956	992.4408	543.9502	0.539839
	90	2682.887	3634.618	2175.672	1001.282	268.2887	0.268633	2975.132	3469.586	2177.248	1525.418	297.5132	0.453832

Tubing Size	Water Cut %	Gas injected quantity = 15,000(NM^3/d) =0.525 (mmscf/d)						Gas injected quantity = 20,000(NM^3/d) = 0.7 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	0	1851.159	2026.561	2237.702	632.6059	1851.159	1.171055	1861.995	2006.837	2237.781	724.9407	1861.995	1.349837
	10	1923.098	2151.545	2226.552	652.3297	1730.789	1.129046	1935.91	2131.072	2226.66	750.7631	1742.319	1.30807
	20	1989.673	2279.824	2216.737	678.8279	1591.738	1.080517	2007.077	2257.903	2217.161	784.9572	1605.661	1.260376
	30	2068.602	2410.012	2208.004	711.5635	1448.021	1.03036	2088.215	2386.903	2208.398	827.8776	1461.751	1.210151
	40	2163.171	2544.518	2200.908	753.4985	1297.903	0.977968	2185.399	2520.55	2201.272	882.8458	1311.239	1.157623
	50	2277.151	2686.04	2194.992	810.1023	1138.575	0.922363	2305.567	2658.118	2195.374	956.2254	1152.784	1.102322
	60	2419.957	2834.012	2189.986	891.3647	967.9828	0.862826	2455.794	2802.376	2190.379	1061.6	982.3176	1.042829
	70	2622.627	2975.891	2185.835	1016.269	786.7881	0.799589	2676.409	2933.964	2186.311	1220.814	802.9228	0.98022
	80	2843.445	3163.361	2181.824	1272.175	568.689	0.723473	2917.356	3113.633	2182.341	1548.716	583.4712	0.903632
	90	3141.493	3376.064	2178.142	2020.179	314.1493	0.634638	3243.757	3318.668	2178.691	2506.99	324.3757	0.813207

Table D.2: Effect of artificial lift when k=2mD, skin factor=0, outlet pressure= 16bar at Well B

Tubing Size	Water Cut %	Gas injected quantity = 5,000(NM^3/d) =0.175 (mmscf/d)						Gas injected quantity = 10,000(NM^3/d) = 0.35 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	0	4274.457	2664.759	2567.917	389.9408	4274.457	1.666787	4287.768	2657.987	2568.111	430.6275	4287.768	1.496432
	10	4375.886	2796.6	2554.798	393.4354	3938.298	1.549467	4391.069	2789.312	2554.978	437.5635	3951.962	1.379236
	20	4485.282	2936.042	2544.507	397.7706	3588.226	1.427292	4509.292	2925.383	2544.738	446.0218	3607.434	1.258995
	30	4606.519	3083.22	2536.199	403.2709	3224.563	1.300373	4640.34	3069.235	2536.468	456.7507	3248.238	1.133636
	40	4743.066	3238.557	2529.333	410.4932	2845.84	1.168199	4790.164	3220.876	2529.638	470.7772	2874.098	1.003061
	50	4898.655	3403.866	2523.526	420.4481	2449.328	1.029816	4964.487	3381.652	2523.871	490.0014	2482.243	0.8663035
	60	5077.615	3580.972	2518.514	435.1625	2031.046	0.883836	5170.444	3553.441	2518.903	518.231	2068.178	0.7217945
	70	5361.284	3753.841	2514.343	457.8047	1608.385	0.736327	5500.042	3718.439	2514.8	561.1195	1650.013	0.5758548
	80	5612.64	3966.924	2510.314	504.898	1122.528	0.566763	5813.663	3924.543	2510.817	650.0149	1162.733	0.4057939
	90	5922.929	4204.022	2506.601	644.4617	592.2929	0.38171	6217.477	4155.576	2507.131	911.929	621.7477	0.2169901

Tubing Size	Water Cut %	Gas injected quantity = 15,000(NM^3/d) =0.525 (mmscf/d)						Gas injected quantity = 20,000(NM^3/d) = 0.7 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	0	4296.717	2653.244	2568.247	471.1862	4296.717	2.024555	4305.628	2648.526	2568.382	511.5778	4305.628	2.202665
	10	4403.508	2783.272	2555.127	481.4701	3963.157	1.908143	4412.963	2778.61	2555.242	525.2483	3971.667	2.086113
	20	4523.807	2918.793	2544.88	494.0658	3619.046	1.788048	4535.755	2913.501	2544.995	541.9115	3628.604	1.966384
	30	4661.959	3060.2	2536.642	509.8765	3263.371	1.663917	4675.083	3054.847	2536.745	562.8998	3272.558	1.842123
	40	4818.831	3210.035	2529.824	530.5792	2891.299	1.534064	4837.308	3203.209	2529.942	590.1808	2902.385	1.712933
	50	5006.115	3367.637	2524.089	558.7433	2503.058	1.398568	5031.35	3359.107	2524.222	627.2552	2515.675	1.577971
	60	5230.071	3535.796	2519.153	599.9525	2092.028	1.255118	5267.595	3524.606	2519.311	681.2197	2107.038	1.435357
	70	5591.017	3695.384	2515.098	662.0019	1677.305	1.11038	5651.605	3679.933	2515.298	761.8618	1695.482	1.291723
	80	5943.632	3897.24	2511.141	790.6488	1188.726	0.939866	6031.148	3878.847	2511.359	929.3204	1206.23	1.120974
	90	6408.407	4124.2	2507.474	1168.236	640.8407	0.748654	6536.571	4103.204	2507.704	1419.897	653.6571	0.928127

Table D.3: Effect of artificial lift when k=2mD, skin factor=0, outlet pressure= 16bar at Well C

Tubing Size	Water Cut %	Gas injected quantity = 5,000(NM^3/d) =0.175 (mmscf/d)						Gas injected quantity = 10,000(NM^3/d) = 0.35 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	**0**	4208.448	2717.874	2560.358	390.583	4208.448	1.643749	4236.363	2703.351	2560.774	431.618	4236.363	1.828492
	10	4308.394	2847.371	2547.511	394.1315	3877.555	1.528267	4343.465	2830.296	2547.933	438.5342	3909.118	1.714283
	20	4415.802	2984.498	2537.431	398.538	3532.642	1.407893	4460.979	2964.234	2537.869	447.0726	3568.783	1.595506
	30	4532.477	3130.035	2529.277	404.1574	3172.734	1.282285	4590.795	3106.036	2529.738	457.9135	3213.556	1.471532
	40	4661.404	3284.702	2522.52	411.5705	2796.842	1.151099	4737.187	3256.321	2523.008	472.1391	2842.312	1.341968
	50	4805.645	3449.686	2516.798	421.831	2402.823	1.013586	4905.039	3416.243	2517.318	491.7103	2452.519	1.20593
	60	4969.184	3626.58	2511.857	437.0426	1987.674	0.868699	5100.243	3587.989	2512.402	520.5604	2040.097	1.061994
	70	5235.561	3798.339	2507.758	460.4175	1570.668	0.723164	5417.538	3752.314	2508.352	564.3499	1625.261	0.9172166
	80	5453.962	4011.561	2503.778	509.4337	1090.792	0.555687	5703.835	3959.272	2504.397	655.8109	1140.767	0.7481279
	90	5715.922	4247.744	2500.119	655.1621	571.5922	0.374486	6065.198	4190.786	2500.741	926.0624	606.5198	0.5616756

Tubing Size	Water Cut %	Gas injected quantity = 15,000(NM^3/d) =0.525 (mmscf/d)						Gas injected quantity = 20,000(NM^3/d) = 0.7 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	**0**	4254.892	2693.822	2561.047	472.3873	4254.892	2.009958	4263.906	2689.07	2561.183	513.1686	4263.906	2.188104
	10	4367.702	2818.636	2548.221	482.556	3930.932	1.896896	4382.692	2811.508	2548.397	526.4657	3944.423	2.076604
	20	4491.622	2950.567	2538.165	495.1053	3593.297	1.779062	4511.381	2941.883	2538.353	542.9538	3609.105	1.959578
	30	4630.095	3090.098	2530.044	510.9836	3241.067	1.656133	4656.668	3079.098	2530.256	563.7457	3259.667	1.837625
	40	4785.629	3238.231	2523.32	531.839	2871.378	1.527111	4823.999	3224.1	2523.563	590.8462	2894.399	1.710146
	50	4972.662	3393.742	2517.667	560.1544	2486.331	1.39273	5019.502	3377.957	2517.913	627.9119	2509.751	1.575904
	60	5189.497	3561.696	2512.774	601.9145	2075.799	1.249454	5252.053	3543.288	2513.034	682.2028	2100.821	1.433187
	70	5541.669	3720.934	2508.757	664.7891	1662.501	1.105213	5629.402	3698.849	2509.043	763.4902	1688.821	1.289399
	80	5871.426	3924.265	2504.812	796.0802	1174.285	0.934826	5989.631	3899.708	2505.103	933.3428	1197.926	1.118077
	90	6297.393	4153.014	2501.154	1182.678	629.7393	0.744779	6459.103	4126.733	2501.441	1432.741	645.9103	0.925423

Table D.4: Effect of artificial lift when k=2mD, skin factor=0, outlet pressure= 16bar at Well D

Tubing Size	Water Cut %	Gas injected quantity = 5,000(NM^3/d) =0.175 (mmscf/d)						Gas injected quantity = 10,000(NM^3/d) = 0.35 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	0	2809.25	2291.855	2566.909	411.2942	2809.25	1.155429	2828.471	2270.408	2567.074	472.7417	2828.471	1.337137
	10	2921.264	2425.128	2555.84	415.5617	2629.137	1.09257	2944.979	2401.977	2556.034	481.0514	2650.481	1.275018
	20	3023.257	2569.222	2546.43	421.3557	2418.605	1.019094	3059.534	2541.554	2546.962	491.9955	2447.627	1.204222
	30	3129.894	2719.017	2537.18	428.8749	2190.926	0.939634	3178.109	2685.173	2537.832	506.3261	2224.676	1.126413
	40	3253.206	2877.853	2529.528	438.6551	1951.924	0.856222	3316.876	2837.086	2530.231	524.8682	1990.126	1.044554
	50	3398.955	3046.726	2523.066	451.9728	1699.478	0.768118	3483.439	2998.201	2523.822	549.9507	1741.719	0.9578604
	60	3574.789	3228.345	2517.488	471.3848	1429.916	0.674041	3688.066	3171.063	2518.299	586.2516	1475.226	0.8648544
	70	3831.411	3409.282	2512.786	501.2502	1149.423	0.576149	3994.096	3338.408	2513.704	641.0976	1198.229	0.7681821
	80	4107.633	3632.694	2508.273	562.0179	821.5265	0.461713	4332.407	3551.356	2509.239	752.9323	866.4813	0.6524022
	90	4490.874	3883.775	2504.098	738.6789	449.0874	0.331732	4803.892	3794.66	2505.075	1077.575	480.3892	0.517656

Tubing Size	Water Cut %	Gas injected quantity = 15,000(NM^3/d) =0.525 (mmscf/d)						Gas injected quantity = 20,000(NM^3/d) = 0.7 (mmscf/d)					
		Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)	Liquid Flow rate (stb/d)	Pressure at Na (psi)	Bubble Point pressure (psi)	GOR at the outlet (scf/stb)	Oil Flow rate (stb/d)	Gas Flow rate (mmscf/d)
H_2	0	2841.717	2255.524	2567.188	533.7473	2841.717	1.51676	2852.505	2243.338	2567.281	594.3982	2852.505	1.695525
	10	2960.07	2387.142	2556.157	546.0673	2664.063	1.454759	2972.584	2374.778	2556.26	610.6502	2675.326	1.633689
	20	3080.451	2525.616	2547.102	562.0368	2464.361	1.385063	3097.124	2512.825	2547.215	631.52	2477.699	1.564718
	30	3204.028	2666.992	2538.182	583.0802	2242.82	1.307745	3221.873	2654.442	2538.423	659.3783	2255.311	1.487104
	40	3352.699	2814.159	2530.627	609.9836	2011.619	1.227056	3374.325	2800.426	2530.864	694.7479	2024.595	1.406584
	50	3532.79	2970.161	2524.259	646.2153	1766.395	1.141472	3560.744	2954.208	2524.508	742.176	1780.372	1.32135
	60	3755.49	3137.057	2518.781	698.4881	1502.196	1.049267	3795.775	3116.758	2519.069	810.0386	1518.31	1.229891
	70	4093.923	3295.186	2514.264	776.4626	1228.177	0.953634	4157.357	3267.8	2514.618	910.2536	1247.207	1.135276
	80	4470.802	3501.46	2509.833	936.1426	894.1604	0.837062	4560.714	3469.101	2510.218	1116.423	912.1428	1.018338
	90	5000.749	3738.8	2505.687	1398.842	500.0749	0.699526	5129.779	3702.233	2506.088	1713.58	512.9779	0.879029

Table D.5: Effect of artificial lift when k=2mD, skin factor=0, outlet pressure= 16bar at Well E