International Journal of Scientific & Engineering Research, Volume 9, Issue 7, July-2018
ISSN 2229-5518

Optimization of Gas-Well Production Practices with Special Reference to Kailashtilla Gas Field, North – East, Bangladesh

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Abstract— Production optimization is one of the most important aspects of petroleum production system. Extraction of the most of the oil or gas out of the reservoir is the ultimate goal of production operation. That is why production optimization techniques are applied in petroleum production practices. Sometimes production optimization becomes unavoidable for some wells in order to make the production system a more economically successful venture. In this study, petroleum production optimization analysis has been done on the well no-04 of Kailashtilla Gas Field. The analysis has been performed with a target to find out the best optimization method that should be used for increasing the deliverability of the well. The nodal analysis approach has been followed during this study. The measured sp. gr. of produced water is 1.0054 and average reservoir pressure is just around 3565 psia. Calculated skin factor is 58. It has been deduced that skin effect mainly caused from formation damage and inadequate number of perforations. Inflow performance relationship (IPR) curve and vertical lifting performance (VLP) curve have been developed using FEKETE software to find out deliverability of the well at present condition(10.505 MMscf/d). It is the flow rate obtained based on the gas reservoir characteristics and production system of well no-4 of Kailashtilla Gas Field. Different parameters of the reservoir and the well such as skin and tubing radius have been changed and each time IPR and VLP curve were developed to measure the well deliverability with an intention to find out which of the optimization methods or combination of methods give the best deliverability. It has been found that the critical size (radius) for tubing is 3.5 inches at present condition. Comparing all the results, it has been deduced that reducing skin to ≤30 while using a tubing of 4 or 4.5 inches (critical tubing size based on skin factor) could provide higher deliverability ranging from 13.326MMScf/d to 20.193MMScf/d without changing the wellhead pressure.

Index Terms— Nodal analysis; Skin; IPR curve; Formation damage; Inadequate number of perforations; VLP curve; Well deliverability; Production optimization; Matrix acidizing; Hydraulic fracturing.

◆

1 INTRODUCTION

Energy is the base of modern civilization. The invention, production and utilization of the newest technologies completely depend on energy. Oil and gas are the main sources of the energy. With the continuous production of petroleum, the total reserve is diminishing but the demand for energy is increasing. The reservoirs have to deliver petroleum for longer time and in higher rate than ever before. Therefore, to obtain an increased optimum production level of a gas well using production optimization techniques is essential for better performance of the reservoir.

Production optimization can be defined as the activities which are used to increase the productivity of a gas or oil field [1]. It means the determination and implementation of the optimum values of parameters in the production System to maximize hydrocarbon production rate or to minimize operating cost under various technical and economic constraints [2].

We can not produce oil or gas at any rate we want. It should be a compatible to reservoir's delivery capacity and wellbore fluid flow system [3]. The production rate also depends on parameters like reservoir rocks and fluid properties, well type, well equipment, reservoir pressure etc. So by analyzing all the involved parameters properly, optimum production rate could be achieved [4]. Production can be increased by reducing wellhead pressure. In this regard, a previous research work related to this field has been done concerning "Evaluation of natural gas production optimization in Kailashtilla gas field in Bangladesh using decline curve analysis method" where an attempt had made to decrease the wellhead to 2000,1500,1300 and 1000 psia to obtain optimized production rate of 19.637,24.198,25.496 and 26.922 MMscf/d respectively [5]. But it can create various problems like sand production, water conning, formation damage which perhaps have not been taken into consideration. If the pressure drawdown near the well is small, it may not cause any sand production. But, excessive drawdown can cause the produce sand at a very high level [6]. Increasing pressure drawdown can affect formation stability which usually results into fines and sand migration into the wellbore region. Hydraulic fracturing can be used to solve this problem by reducing pressure losses in the reservoir sand near the wellbore [1]. Sand production is highly problematic because it requires an additional processing facility and it can damage to production equipment. Also, the pressure drawdown at the perforations is likely to cause water to flow towards the perforations [7]. To achieve the optimum production rate and overcome the problems related to production operation, application of production optimization methods [8]. Also, after producing oil or gas from a well for a certain period of time, recovery may not satisfy physical or economic constraints and the well will be shut down. In such condition, workover is done if the preliminary analysis indicates that more economic extraction is possible. The objectives of production optimization may be to enhance reservoir inflow performance or to reduce outflow performance. The expected result is higher hydrocarbon production with smaller amount of pressure drawdown [1]. A group of researchers have worked on "Long Term Optimization of Gas Well Production" with an intension to select suitable tubing size for a well at different reservoir pressure. Their work includes nodal analysis, sensitivity analysis and development of an algorithm [9].Another work has been done on “Oil production optimization: a mathematical model” which intends to optimize the cost of production of oil by developing a mathematical model which considers the cost associated with the system failure (leakage) [10]. The aim of this study is to optimize the deliverability of well no- 04 of Kailashtilla Gas Field (KTL-04) without changing wellhead pressure.

If the system is large and complex systems, it requires a sophisticated approach for production optimization. But, in case of single well or other small systems, simple nodal analysis can be adequate [8]. The intersection point of the IPR (inflow performance relationship) with the VLP (vertical lifting performance) yields the well deliverability, which is the expected production rate for the well in a given operating condition. The point also gives the flowing bottomhole pressure [3]. The ultimate goal of a production optimization is to maximize the well deliverability in a cost-effective manner. Different optimization methods such as matrix acidizing, hydraulic fracturing, acid fracturing, increasing perforation height, changing tubing radius etc are used to achieve this. Sometimes artificial lift method is used to get more production when natural reservoir energy is not enough to deliver hydrocarbon to the surface [11]. After applying each optimization method IPR-VLP curve is developed to get the new well deliverability.

Application of proper optimization method at proper time and in proper manner ensures the utilization of the reservoir for maximum time and assures maximum petroleum production. That is why the importance of production optimization is undeniable and its application is sometimes unavoidable.

2 METHODS & MATERIALS

Production optimization intends to increase the well deliverability in an economically feasible manner. Well deliverability measurement through nodal analysis requires the development of IPR curve and VLP curve. Different equations are used to develop these curves and applications of those equations depend on different parameters of the reservoir, well, flowing fluid and fluid flow type. Another important factor in petroleum production is productivity index that reflects the efficiency of the production system. Productivity index can be increased in different methods that ultimately results in production optimization. IPR curve and VLP curve are developed and well deliverability is measured using FEKETE F.A.S.T Virtue Well (Version 2.9.1) software.

Most of the data that have been used to measure the well deliverability have been collected from Kailashtilla Gas Field of Sylhet Gas Fields Limited (SGFL) of Bangladesh. Some of the data have been obtained from previous thesis/project works, papers and books. Collected data include reservoir data, well data, production data, PVT data, fluid properties, pressure data, temperature data and some analysis reports that has been done on KTL-04.

2.1 NODAL ANALYSIS

The combination of IPL curve and VLP curve which includes the entire pressure drop associated with fluid flow from reservoir to surface. This combination comprises all the components of a petroleum production system. It can also be used for well diagnosis and identification of the parts which are malfunctioning. This is called well performance analysis or nodal analysis [1].

The procedure consists of selecting a node and dividing the system into two parts at this point. Usually the system is divided between reservoir and piping system namely reservoir dominated part and piping system dominated part [12].

2.2 INFLOW PERFORMANCE RELATIONSHIP (IPR) CURVE

Inflow performance relationship (IPR) curve is one of the two curves that are required to be developed for obtaining deliverability. It shows the relationship between well production rate q and bottomhole flowing pressure pwf. It is developed based on flow of the fluid from the reservoir to the wellbore. Reservoir fluid flow type, boundary pressure or reservoir average pressure and other reservoir and fluid properties play a vital role in developing IPR curve. In case of single phase flow, IPR curve is a straight line. But, when the flow in the reservoir is a multiphase flow, the relationship does not remain linear anymore. Due to production, the major pressure drop occurs near the wellbore [13].

Equation for IPR curve for gas reservoir is given below [3]:

$$\overline{P}^2 - P_{wf}^2 = \frac{1424\overline{\mu z}T}{kh}\ln\left(\frac{0.472r_e}{r_w}+s\right)q + \frac{1424\overline{\mu z}TD}{kh}q^2 \quad (2.1)$$

2.3 VERTICAL LIFTING PERFORMANCE (VLP) CURVE

Vertical lifting performance (VLP) curve also shows the relationship between the production q and bottomhole flowing pressure (pwf). But unlike the IPR curve, it is developed based on the flow of the fluid from the wellbore to the surface through the production tubing at a specific wellhead pressure. VLP is also named as tubing performance relationship (TPR) or wellbore flow performance or outflow performance relation. The resulting flowing pressure at the other end of the tubing can then be determined. As the fluid flows from the wellbore to the wellhead, pressure drop occurs. The pressure drop is a function of the mechanical configuration of the wellbore, the properties of the fluids, and the production rates [14]. It happens in three forms such as frictional pressure loss, potential pressure loss and kinetic pressure loss [3].

$\Delta P_{total} = \Delta P_f + \Delta P_p + \Delta P_k$ (total pressure drop)

ΔP_f =Frictional pressure drop

ΔP_p = Potential pressure drop

ΔP_k = Kinetic pressure drop

$P_{wf} = P_{tf} + \Delta P_{total}$

P_{wf} = Bottomhole flowing pressure

P_{tf} =Tubing flowing pressure (wellhead pressure)

2.4 WELL DELIVERABILITY

Well "deliverability" is defined as the capacity of a well to produce oil or gas against all the restrictions of the production system through which the fluid must flow. These restrictions must be overcome by the energy in the reservoir [15].

For determining well deliverability first IPR and VLP curves are developed. Then those two curves are combined in one graph .The intersection point of the curves gives the expected rate (deliverability) and the flowing bottomhole pressure [3].

2.5 PRODUCTION OPTIMIZATION

Production optimization can be done in different ways. In this work two methods were followed such as reducing skin and changing the tubing size.

2.5.1 REDUCING SKIN

If it is determined that skin is positive, the formation damage can be reduced by acid treatment. The type of acid used depends on the nature of the reservoir rock and the type of plugging materials which must be removed. If the formation is limestone, treatment with hydrochloric acid will invariably remove the skin because of the solubility of the rock itself. In sandstone reservoirs, in which the rock matrix is not soluble, special mud acids are used. As a result of a successful acid job, the skin factor can be reduced to zero or may even become negative [3], [16].

Low-volume hydraulic fracturing is used to stimulate high-permeability reservoirs for a single well [17]. The impact of hydraulic fracturing can be measured as a negative skin and that can reduce overall skin factor. It can be measured using following method [3].

Fracture conductivity, $F_{CD} = \dfrac{k_f w_f}{k x_f}$ (2.2)

k_f = Fracture permeability

x_f = Fracture half-length

w_f = Fracture width

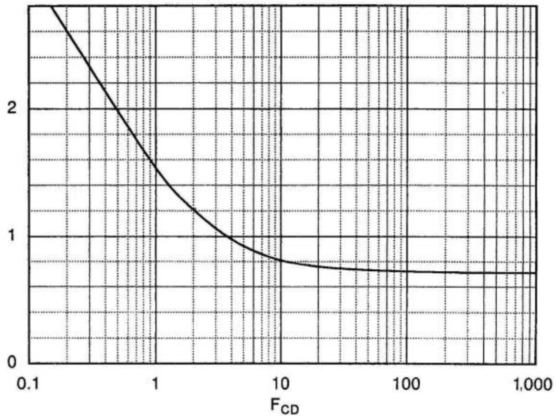

Fig-2.1:Cinco-Ley & Samaniego Chart [3]

Using the value of F_{CD} we can measure the value of skin factor s_f that results from hydraulic fracturing.

2.5.2 CHANGING TUBING RADIUS

The production rate usually increases by increasing the tubing size that results in increased productivity index of the flowing well. However, when the tubing size exceeds the critical tubing size, the increase in tubing size may lead to a decrease in production rate. The tubing size of the gas well should meet the requirement of carrying liquid in order to avoid the down hole liquid accumulation due to slippage and the increase in flowing bottom pressure that may cause a decrease in production rate [18].

After considering any of the optimization methods, IPR curve and VLP curve are developed to find out new well deliverability rate for the well. The results have been compared to decide on which optimization method or combinations of the methods are suitable for KTL-04.

3 RESULTS & DISCUSSION

The goal of this section is to find out the best optimization process for well no-04 of Kailashtilla Gas Field (KTL-04). Different properties of the reservoir and the fluids have been measured to understand the overall process. Required data which were not available from the field have also been measured during this study. Well deliverability has been measured at present condition and for different optimized conditions using fekete F.A.S.T. VirtuWellsoftware. The obtained results have been compared in the discussion parts to decide which optimization process will be the best for the well (KTL-04).

3.1 DETERMINATION OF WATER PROPERTIES OF THE RESERVOIR

Water salinity, S = 7700 ppm [Source: Kailashtilla gas field]

Water density (at standard condition) equation [19]:

$$\rho_w = 62.368 + 0.43603 \times S + 1.60074 \times 10^{-3} \times S^2 \quad (3.1)$$

By using above equation 3.1,

Measured water density (at standard condition) = 62.7067 lbm/ft^3 [Water salinity=7700ppm]

Measured water density (at standard condition) = 62.37 lbm/ft^3 [Water has no salinity]

So, Water Sp.Gr. = 1.0054

3.2 RESERVOIR PRESSURE MEASUREMENT

Reservoir average pressure can be measured using the findings from flow after flow test. In this study, we used two approaches for measuring reservoir pressure such as Rawlins-Schellhardt analysis and Houpeurt analysis.

TABLE-3.1
Flow After Flow Test Data [Source: SGFL]

P_r	$FBHP$	$P_r^2 - FBHP^2$	Flow rate q $MMscf/d$
3785	15	14326000	154
3785	100	14316225	154
3785	200	14286225	154
3785	300	14236225	154
3785	400	14166225	153
3785	500	14076225	153
3785	600	13966225	152
3785	700	13836225	151
3785	800	13686225	150
3785	900	13516225	149
3785	1000	13326225	148
3785	1100	13116225	146
3785	1200	12886225	144
3785	1300	12636225	143
3785	1400	12366225	141
3785	1500	12076225	139
3785	1600	11766225	136
3785	1700	11436225	134
3785	1800	11086225	131
3785	3648	1018321	22.69
3785	3690	710125	15.63
3785	3714	532429	13.25

Here,

P_r = Reservoir pressure ($psia$)
$FBHP$ = Flowing borehole pressure ($psia$)
q = Gas flow rate ($MMscf/d$)

3.2.1 RAWLINS-SCHELLHARDT ANALYSIS FOR RESERVOIR PRESSURE MEASUREMENT

From Rawlins-Schellhardt analysis [20] (using pressure squared method) we get the following curve:

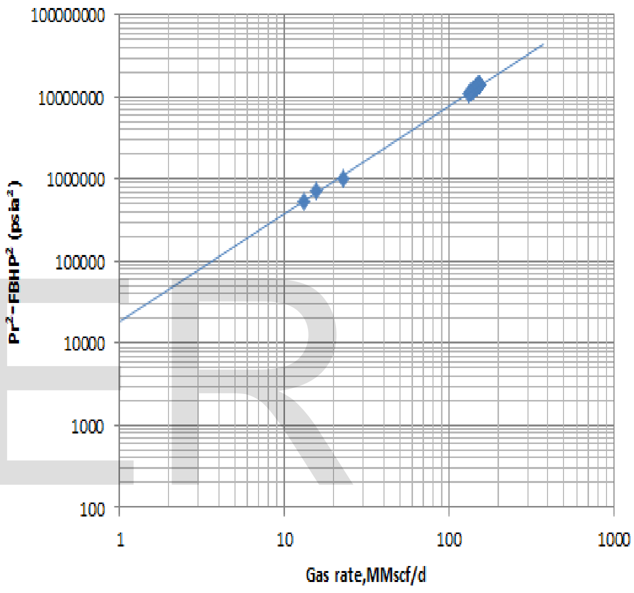

Fig-3.1: Rawlins-Schellhardt analysis

From the graph we get,

n = 0.7835

So,
$C = 4.32 \times 10^{(-4)} \; (MMscf/d)/psia^{2n}$

Where,
n = Inverse slope of deliverability curve
C = Stabilized performance coefficient $(MMscf/d)/psia^{2n}$

Pressure can be measured using following equation [20]:

$$q = C(\overline{P}^2 - P_{wf}^2)^n \quad (3.2)$$

Data obtained from the calculation have been used in this equation for measuring pressure.

Flow rate, $q = 10 \ MMscf/d$

In this equation sand face flowing pressure, P_{SF} has been used instead of borehole flowing pressure, P_{wf} . P_{SF} has been obtained from Fekete software.

$P_{SF} = 3511 \ psia$

So reservoir average pressure, $\overline{P} = 3564 \ psia$

3.2.2 HOUPEURT ANALYSIS FOR RESERVOIR PRESSURE MEASUREMENT

From Houpeurt analysis [20] (using pressure squared method) we get:

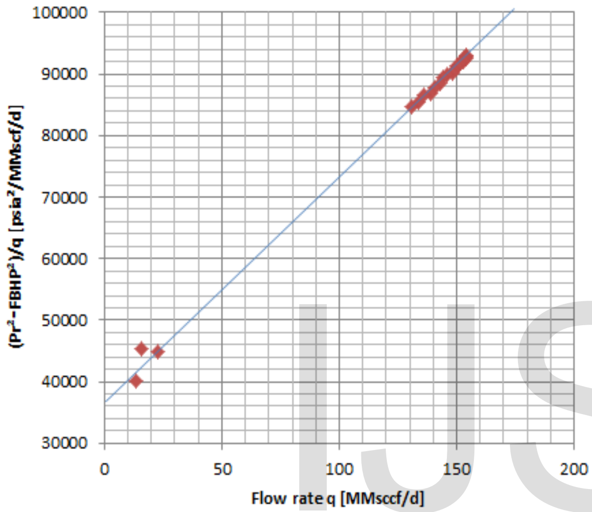

Fig-3.2: Houpeurt analysis

From the graph we get,

Intercept, $a = 3.68 \times 10^4 \ psia^2/(MMscf-d)$

Slope, $b = 3.62 \times 10^2 \ psia^2/(MMscf-d)^2$

Where,

a = Stabilized deliverability coefficient

b = Deliverability equation coefficient

Pressure can be measured using following equation [20]:

$$\overline{P}^2 - P_{wf}^2 = aq + bq^2 \qquad (3.3)$$

So measured reservoir average pressure, $\overline{P} = 3568 \ psia$

We can see that, pressures measured from both methods are almost same which certifies the accuracy of the measured pressure related to this field.

3.3 NON-DARCY COEFFICIENT MEASUREMENT

Non-Darcy coefficient is measured by the following equation [20]

$$b = \frac{1.422 \times 10^6 \overline{\mu z} TD}{kh} \qquad (3.4)$$

Data obtained from the field have been used in this equation for measuring non-Darcy coefficient, D.

Here,

Permeability, k =226 md

Net thickness, h =150 ft

Reservoir temperature, T =159 °F

Average viscosity, $\overline{\mu_g}$ and average compressibility factor, $\overline{z}$ have been measured using an online tool [21].

$\overline{\mu_g}$ =0.0219

$\overline{z} = 0.901$

From equation 3.4, we get, $D = 0.67 \ (MMscf/d)^{-1}$

3.4 SKIN FACTOR MEASUREMENT

Skin factor can be measured from equation (2.1) [3].

$$\overline{P}^2 - P_{wf}^2 = \frac{1424 \overline{\mu z} T}{kh} \ln\left(\frac{0.472 r_e}{r_w} + s\right) q + \frac{1424 \overline{\mu z} TD}{kh} q^2 \ (2.1)$$

Here,

wellbore radius, $r_w = 0.583 \ ft$

Reservoir radius, $r_e = 3313 \ ft$

Inserting all the required values in the equation we get skin factor at present condition.

Skin factor, S =58

3.4.1 PSEUDO SKIN MEASUREMENT

Pseudo skin sb is measured from following figure.

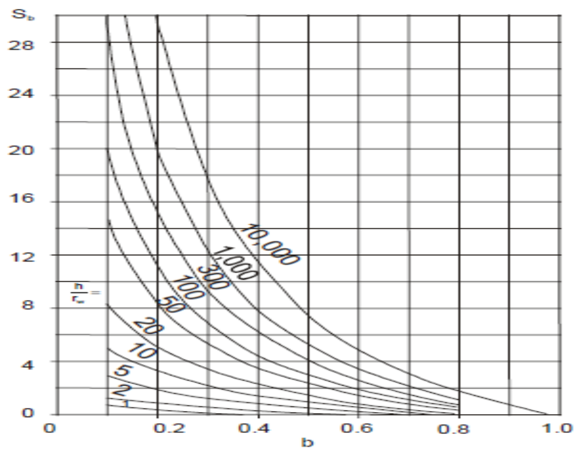

Fig-3.3: Pseudo skin factor S_b as a function of b and h/rw (After Brons and Marting) [16]

Perforation height, h_{perf}= 104 ft [Source:Kailshtilla Gas Field]

$$b = \frac{h_{perf}}{h} = 0.69$$

$$\frac{h}{r_w} = 257$$

So pseudo skin, s_b =1.4

The obtained value of pseudo skin indicates that skin due to partial penetration is very small. Also there is no phase change in the reservoir. As formation damage is almost inevitable [22] and when skin factor is more than 20 to 30, the cause could be limited perforations [23], so we can say that major causes for skin effect are formation damage and inadequate number of perforations. Further analysis can give more specific and precise information about the reasons of skin.

3.5 DELIVERABILITY MEASUREMENT

For the present condition we get both IPR and VLP curve using fekete F.A.S.T. VirtuWellsoftware. IPR & VLP have been developed against flowing sandface pressure.

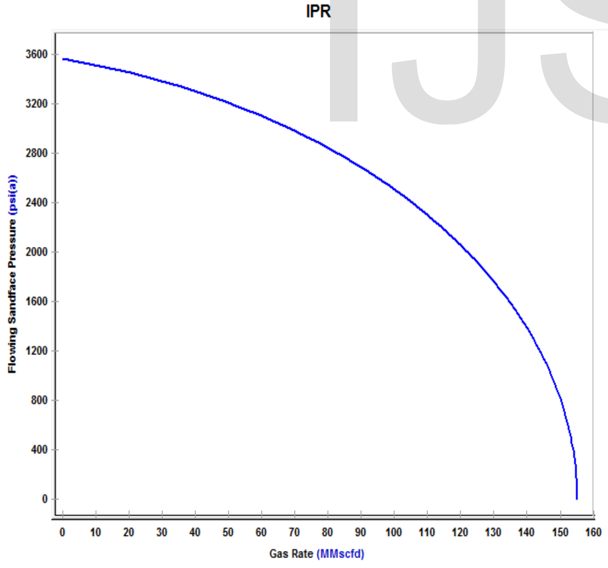

Fig-3.4: IPR curve at present condition

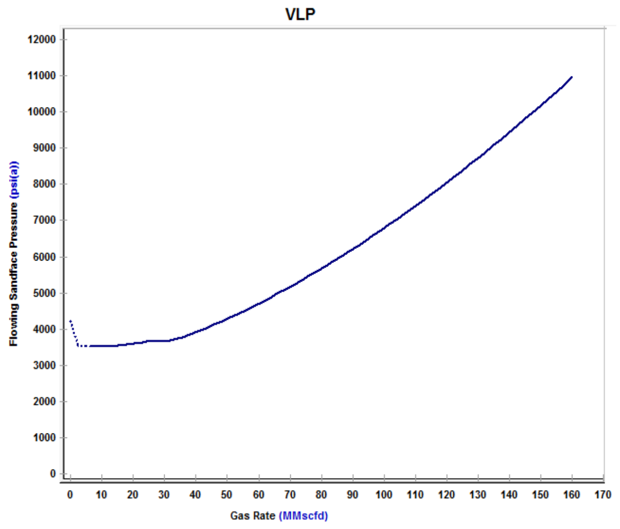

Fig-3.5: VLP curve at present condition

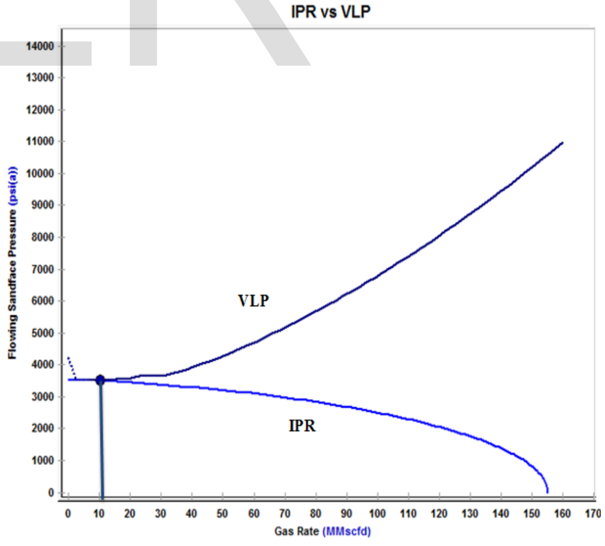

Fig-3.6: IPR curve vs VLP curve at present condition

From the IPR curve vs VLP curve we get that the well deliverability at present condition is 10.505 $MMscf\ /\ d$ at the sandface flowing pressure of 3509 psia. Actual flow rate of the well in the field at this condition is slightly less than the obtained deliverability which is 10 $MMscf\ /\ d$. The deviation occurred most probably because of the assumptions that the reservoir is homogeneous and circular which are not true in practical.

3.6 OPTIMIZATION APPROACH

Several methods can be applied to increase the well deliverability. In this study two methods have been considered such as reducing skin and changing tubing radius [16].

3.6.1 REDUCING SKIN (OTHER PARAMETERS ARE CONSTANT)

The measured skin S =58, which is high. Formation damage can be reduced by acidizing and in case of inadequate perforations, the number of perforations can be increased [3].

Besides overall skin factor can be reduced by the application of hydraulic fracturing and the effect is measured in term of fractured skin factor sf which has a negative value. Skin factor can be lessened by using any of these methods or by a combined application of them.

For considering S = 55, we get the following curve from the software:

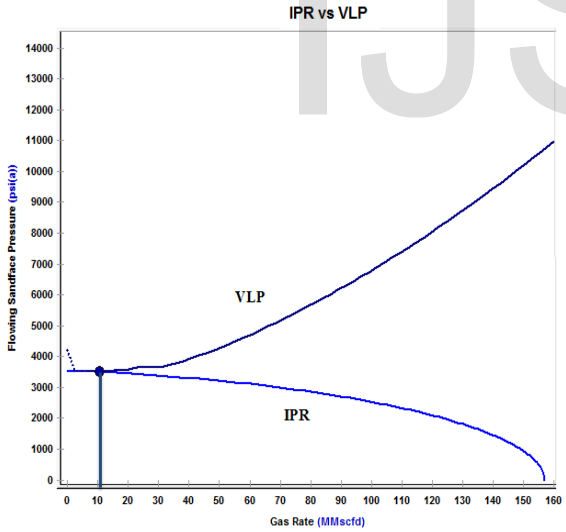

Fig-3.7: Deliverability for S =55

Therefore, for S =55, we get deliverability is 10.712 $MMscf\ /\ d$

For taking S =50, we get the following curve from the software:

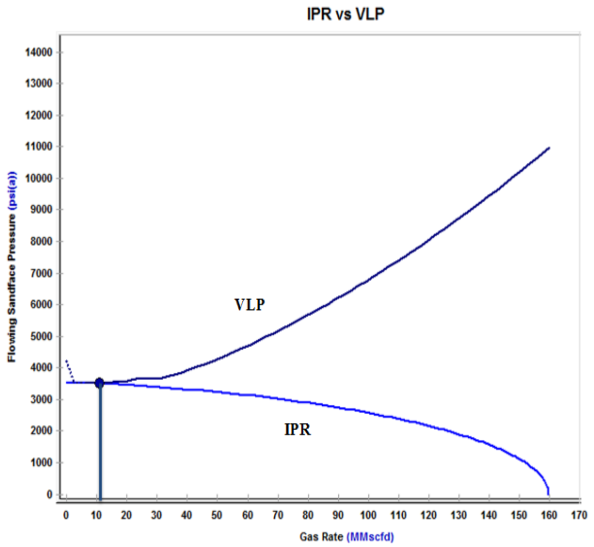

Fig-3.8: Deliverability for S=50

So , for S =50, we get deliverability is 11.081 $MMscf\ /\ d$

For considering S =45, we get the following curve from the software:

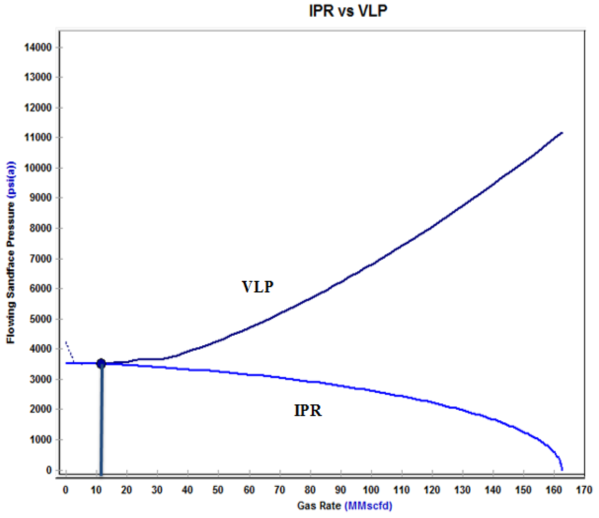

Fig-3.9: Deliverability for S =45

So, for S =45, we get deliverability is 11.447 $MMscf\ /\ d$

Deliverability has been measured for more reduced skin factors and the results have been presented in the following table 3.2.

TABLE 3.2
Well deliverability at different skin (other parameters are constant)

Skin	Deliverability (MMscf/d)	Δq_d
55	10.712	-
50	11.081	0.369
45	11.447	0.366
40	11.817	0.37
35	12.188	0.371
30	12.56	0.372
25	12.924	0.364
20	13.286	0.362
15	13.639	0.353
10	13.973	0.334
5	14.297	0.324
0	14.593	0.296
-5	14.866	0.273
-8.5	15.049	0.183

Here
Δq_d =Difference between two consecutive deliverability
Deliverability is given in $MMscf\ /\ d$

From the table we can see that well deliverability increases with decreasing skin. But the rate of growth is not same throughout the process. Rate of growth increases till S=30.After that it starts to decrease slightly.

Skin reduction using acidizing depends on rock reservoir geology, solid particles that plug the pore, acidizing treatment design and related economic cost. If the acid volume or inject rate are not selected precisely then it can result in additional formation damage [7]. It would be convenient for this system if the skin can be reduced to 30 or less. If the skin is reduced to less than -8.5 then effective wellbore radius exceeds reservoir radius.

3.6.2 CHANGING TUBING RADIUS (OTHER PARAMETERS ARE CONSTANT)

At present the tubing radius of this well is 3.5 inches.

If an increased tubing of 3.75 inches is used then we get the following result:

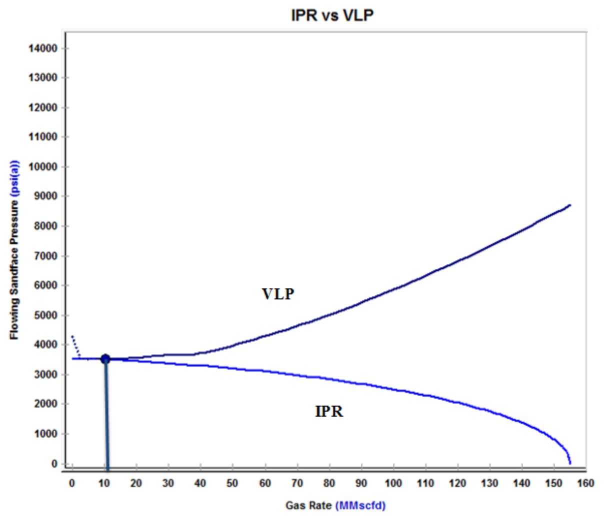

Fig-3.10: Deliverability for a tubing radius of 3.75 inch

So, for a tubing radius of 3.75 inches, we get well deliverability is 10.299 $MMscf\ /\ d$.

If a reduced tubing of 3 inches is used then we get the following curve:

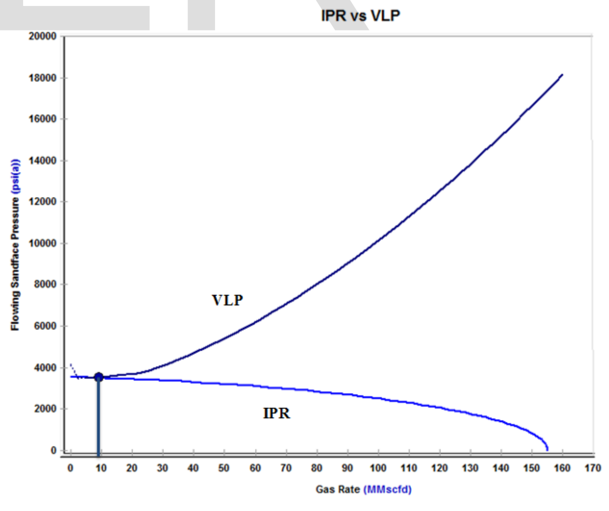

Fig-3.11: Deliverability for a tubing radius of 3 inches

For a tubing radius of 3 inches we get deliverability is 9.049 $MMscf\ /\ d$

It is notable that for both increasing and decreasing tubing radius from 3.5 inches well deliverability decreases. For increasing tubing radius, gas velocity gets reduced and slippage of the liquid carried by the gas occurs that accumulates in the downhole. It causes smaller gas production rate due to increase in pressure in the downhole. If a tubing of 4 inches radius is used then we get a deliverability of 7.477 $MMscf\ /\ d$. For bigger tubing radius (4.5 inches) the well deliverability becomes zero for the same reason [18].

So we can say that present tubing radius (3.5 inches) is best for KTL-04 while keeping other parameters constant.

3.6.3 COMBINED OPTIMIZATION APPROACH

Well deliverability has been measured for different tubing sizes using software while considering skin ≤ 30 and the results have been shown in table 3.3 to table 3.13.

Table 3.3
Deliverability for Different Tubing size (S =30)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	12.622
4	13.326
4.5	0

Table 3.4
Deliverability for Different Tubing size (S =25)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	12.958
4	14.105
4.5	0

Table 3.5
Deliverability for Different Tubing size (S =20)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	13.300
4	14.498
4.5	0

Table 3.6
Deliverability for Different Tubing size (S =15)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	13.644
4	15.551
4.5	13.425

Table 3.7
Deliverability for Different Tubing size (S =10)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	13.988
4	16.227
4.5	15.450

Table 3.8
Deliverability for Different Tubing size (S =5)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	14.328
4	16.981
4.5	17.041

Table 3.9
Deliverability for Different Tubing size (S =0)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	14.658
4	17.530
4.5	18.294

Table 3.10
Deliverability for Different Tubing size (S =-2)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	14.782
4	17.747
4.5	18.789

Table 3.11
Deliverability for Different Tubing size (S =-4)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	14.881
4	17.961
4.5	19.250

Table 3.12
Deliverability for Different Tubing size (S =-6)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	14.920
4	18.170
4.5	19.675

Table 3.13
Deliverability for Different Tubing size (S =-8.5)

Tubing size (inches)	Well deliverability $MMscf\ /\ d$
3.5	15.045
4	18.442
4.5	20.193

Hence, observing table from 3.3 to 3.13 we can say that for different conditions, the well gives the best deliverability for different tubing sizes. The best combinations are shown in table 3.14.

Table 3.14
Best Combined Optimization Approaches

Skin	Tubing size Inches	Deliver-ability $MMscf\ /\ d$
30	4	13.326
25	4	14.105
20	4	14.498
15	4	15.551
10	4	16.227
5	4.5	17.041
0	4.5	18.294
-2	4.5	18.789
-4	4.5	19.250
-6	4.5	19.675
-8.5	4.5	20.193

We have got table 3.14 for best combined optimization approaches. Based on related parameters and associated economic cost, any of these combinations can be chosen or any other combination can be developed in the similar way and can be used to optimize the gas production of KTL-04.

4. CONCLUSIONS

Well no-04 of Kailshtilla Gas Field (KTL-04) is producing at a rate of only 10 MMscf/d which is the only well that is producing gas from the new gas sand (NGS) zone. The NGS has a total gas reserve of 142 Bcf (according to the HCU-2002) [24]. The production is in the initial phase and still a huge reserve is left. To make sure the maximum production gas out of the total reserve without excessive production of water and reservoir damage, optimization method should be applied. Two parameters have been analyzed in this thesis work such as reducing skin and changing tubing radius. It has been found that reducing skin ≤30 would be convenient as individual stimulation method. For a combined optimization approach reducing skin ≤30 while using a tubing size of 4 or 4.5 inches can give better gas production rate that varies from 13.326 MMscf/d to 20.193 MMscf/d. Any of these optimization methods (individual or combined) could be selected or any other combination could be developed following similar path which suit the related parameters and economic cost for the optimization of KTL-04 that ultimately can ensure the best use of the reservoir for a longer period of time.

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