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A Review on Gas Well Optimization Using Production Performance Models—A Case Study of Horizontal Well

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Abstract

This study considered the solution methods to determine optimal production rates and the rates of lift gas to optimize regular operational objectives. The foremost tools used in this research are offered as software platforms. Most of the optimization hitches are solved using derivative-free optimization based on a controlled well Performance Analysis, PERFORM. In line with production optimization goal to maximize ultimate recovery at minimum operating expenditure, pressure losses faced in the flow process are reduced between the wellbore and the separator. Nodal analysis is the solution technique used to enhance the flow rate in order to produce wells, categorize constraints and design corrective solution. A hypothetical case is considered and sensitivity analysis using the IPR Models for horizontal gas wells provides the effect on pressure and liquid drop out. The gas lift method is economically valuable as it produced an optimal economic water cut of 80 percent with 2 - 4 MM scf/day rate of gas injection; thus, 1800 - 2000 STB/day gas was produced.

Keywords

Well Optimization, Production Performance, Well Deliverability, Horizontal Well

1. Introduction

Oil production technology is the series of activities related to the production or injection wells often described by a performance or injection capacity indicator.

The engineers in Production section frequently deal with one or multiple wells at a given time and with the delivery of oil and gas from the well to the point of sale. Most importantly, it often goes beyond economic motivation to accelerate production by increasing productivity or injecting into wells. Optimization of production wells ensures that these wells and installations operate at maximum capacity to maximize productivity.

There are numerous adverse effects associated with low flowing bottom hole pressure, such as precipitation of scale, deposition of paraffin and asphaltene, gas and water coning. It is therefore important from the outset to recognize and understand that stimulation and the rise in index of presumptive productivity will not automatically lead to an increase in the production rate of the well; but instead, increasing the appropriate portion of the productivity index with an increase in production rate and/or a decrease in drawdown, is dependent on the needs of each separate well. Consequently, optimization of the production goal is to increase productivity and improve the overall value of assets (short-term), while meeting all physical and economic/financial constraints.

In early optimization research, reservoir models and linear methods of programming were presented. Aron of sky and Lee proposed these linear programming models to optimize benefits and planned the production of several similar reservoirs. Wellhead choke is usually chosen so that the pressure fluctuations in the pipeline for the downstream will not have any impact on the well flow rate. To ensure this situation, choke flow must be in critical flow conditions. In other words, choke flow is at acoustic velocity. In order for this condition to exist, the pressure in the downstream pipeline should be about 0.55 or less from the inlet pipe or tubing. The low flow rate in this situation is only a function of the upstream or tubing pressure [1].

An integrated approach to improve productivity with reservoir management will balance the short-term optimization goals of production and long-term reservoir development task; to have a more rational impact on the field development. Well performance analysis plays a vital role in production management and optimizing the performance of a gas well. The problems facing in this analysis can be divided into two types: the behaviour of the well when designing for completion (with emphasis on short-term) and initial production state on productivity of the well. The second concern is related to long-term behaviour of the well. At this stage, changes in productivity of the well are taken into account and projected as the reservoir pressure reduces [2].

This study considered the solution methods to determine optimal production rates and the rates of lift gas to optimize regular operational objectives.

2. Statement of Problem

At some point in the life of the well, recovery may not correspond to physical or economic constraints, and the closure or shut-in of the well will be required. At this stage, corrective measures or changes will be made if the preliminary analysis provides for the creation of an additional economic value. The objectives of production optimization can be to improve the efficiency of the reservoir inlet or to reduce the output flow efficiency. The results can be more production with reduction in pressure drop/drawdown. As a rule, the production of sand and high water influx indicate the need to revitalize the environment of the downhole gas well.

To optimize field performance, it is necessary to understand the pressure at the reservoir inflow, vertical lift of the wellbore and the surface pressure of the facilities. Production optimization refers to various dimensions/measures, analysis, modeling, prioritization and implementation to improve gas and oil field performance.

The main objective of this study is to optimize well productivity by analyzing a producing well. The study emphasizes on simple objective functions that optimize weighted daily flows.

3. Literature Review

In oil and gas fields, production of hydrocarbon is often limited to the conditions of the reservoir, networks of pipeline, treatment plants for the fluids, economic and safety considerations, or a blend of these considerations. The field operators is faced with the charge to develop optimum operational approaches to accomplish definite operational goals. The ultimate goal of almost all efforts to form an oil and gas field is to develop an optimal strategy for the development, management and operation of the field. Optimizing production operations for certain fields can be an important factor if the production volumes are to be increased to reduce production costs. Though it may be useful for individual wells to perform nodal analysis for prediction, but large systems require a more complex method to accurately predict reaction of a complex system for production [3]. The interaction of the flow between the wells can play a significant part in some problems of rate distribution. In most cases, the problem of distribution of rates is expressed as a general nonlinear limited optimization and solved by the method of sequential quadratic programming. Various compositions have been investigated by different researchers [4].

The application of optimization methods in the oil industry (upstream) was reported earlier, but it began to flourish in the 1950s.

3.1. Deliverability of Gas Well

Well deliverability is designed from the inflow performance relationship (IPR) and from the curve intersection of the vertical lifting performance (VLP). The IPR includes the environments and constraints of the reservoirs, while the VLP reflects on wells that are producing.

In order to optimize the production of gas, pressure drop occurs when the reservoir fluid moves from the reservoir to the surface through the well, the production tubing and processing facilities [5]. This concept combines the flow of the reservoir, as shown by most wells IPR, with the tubing performance capacity curve that embodies substantially all of the pressure drop connected with well tubing connections. This combination brings the components of the oil production system together and can also be applied during the diagnosis, analysis and identification of incorrect or defective parts of the well system. This approach is known in the petroleum industry as well performance analysis or also as nodal analysis.

Well performance analysis is used not only for determining a specific well IPR and performance of tubing; but can also be used to test a number of different options for modification. These options include the diameter of the tubing, the pressure at the well head, the type and size of choke, the density of perforations, horizontal and complex wells and hydraulic fracturing. If all options are properly taken into account, they can lead to economic optimization: the additional cost among design can be balanced with the increase in well productivity or performance.

One of the main problems of the oil and gas producer is how long it will be without necessary intervention. Intervention is costly and can alter any previous economic task. Sometimes it may be even more economical to abandon the well and drill a new well or simply move to another area.

3.2. Horizontal Wells

There are wells that hit the reservoir 90 degrees vertically and extend the tunnel. It has been discovered that not all reservoirs are good candidates for horizontal technology. Thus, horizontal wells are suitable for thin deposits (less than 500 feet thick), deposits with lower productivity than vertical wells, narrow forms with horizontal and vertical permeability, reservoirs that have fractures, and reservoirs with water or gas coning. Horizontal wells are mostly drilled as an alternative to hydraulic fractured vertical well. Brown and Economides [6] presented a series of studies comparing characteristics of horizontal well and fractured vertical well.

A more advanced concept is that a horizontal well can be drilled exactly in a favorable direction, that is, usually at maximum horizontal permeability. In very anisotropic sediments, this will still bend the solution in favor of horizontal wells.

4. Methodology

Production data, well details and reservoir data for this research were collected from an offshore gas field (**Table 1**) that has been completed.

Table 1. Reservoir data for IPR models.

IPR type	Reservoir pressure/psia	Reservoir temp/˚f	Wellbore radius/in	Reservoir radius/Ft	Reservoir thickness/Ft	Reservoir skin	Turbulence factor/$(1{\cdot}bpd^{-1})$	Horizontal tunnel length/Ft	Avg. vertical perm/mD	Avg. horizontal perm/mD
Giger *et al.* (1985)	2900	165	5	1000	21	0	0	2000	1	5

Categories of Horizontal IPR Types

Horizontal IPR's are classified based on flow regimes (Table 2), and can be disaggregated thus:

Table 2. Categories of horizontal IPR types.

Steady state flow	Pseudo-steady state flow	Transient state flow
Giger *et al.* (1984) Economides *et al.* (1991) Joshi (1988) Benard and Dupuy (1991)	Kuchuk (1988) Bubu and Odeh (1989)	Goode and Thambynaya (1987)

5. Well Performance IPR Models Used

Giger et al. [7] IPR model

Giger *et al.* [7] presented the first mathematical model for analyzing productivity of horizontal wells intersecting fractures, in which flow in the rock matrix and fractures were formulated for the short and long horizontal wells and then combined to obtain a radial flow equation for the whole flow path from external boundary to wellbore.

It is applied to a reservoir in steady state and used to calculate the sand-face pressure and flow rate pairs for isotropic and anisotropic reservoirs. For anisotropic reservoirs, Muskat method is used to calculate equivalent reservoir permeability and adjust the rest of the parameters. The method can be applied to both oil and gas wells.

Jones et al. [8] IPR:

$$\frac{P_{\mathrm{R}} - P_{\mathrm{wf}}}{q_{\mathrm{g}}} = a + bq_{\mathrm{g}} \tag{1}$$

where, a = Laminar flow coefficient, b = Turbulence coefficient, P_{R} = Average Reservoir pressure, P_{wf} = Bottomhole Pressure and q_{g} = Gas flow rate.

This model, mostly applied to gas wells, is used to account for turbulence in a producing gas well. Jones *et al.* [8] can also be used in oil wells with high GOR. Therefore, this model is suitable for reservoir above bubble point. Vogel equation can be used to adjust Jones equation below bubble point pressure for solution gas drive reservoirs.

6. Results and Discussion

The offshore well data was utilized to analyze solution methods in determining optimal production rates. Decline curve analysis was applied to identify the natural gas production optimization in horizontal well. Applying Giger's model, the results for pressure effect in horizontal wells were presented in Figure 1 and that of Economides *et al.* were presented in Figure 2.

Effect of Pressure in horizontal wells using Giger et al. IPR Model

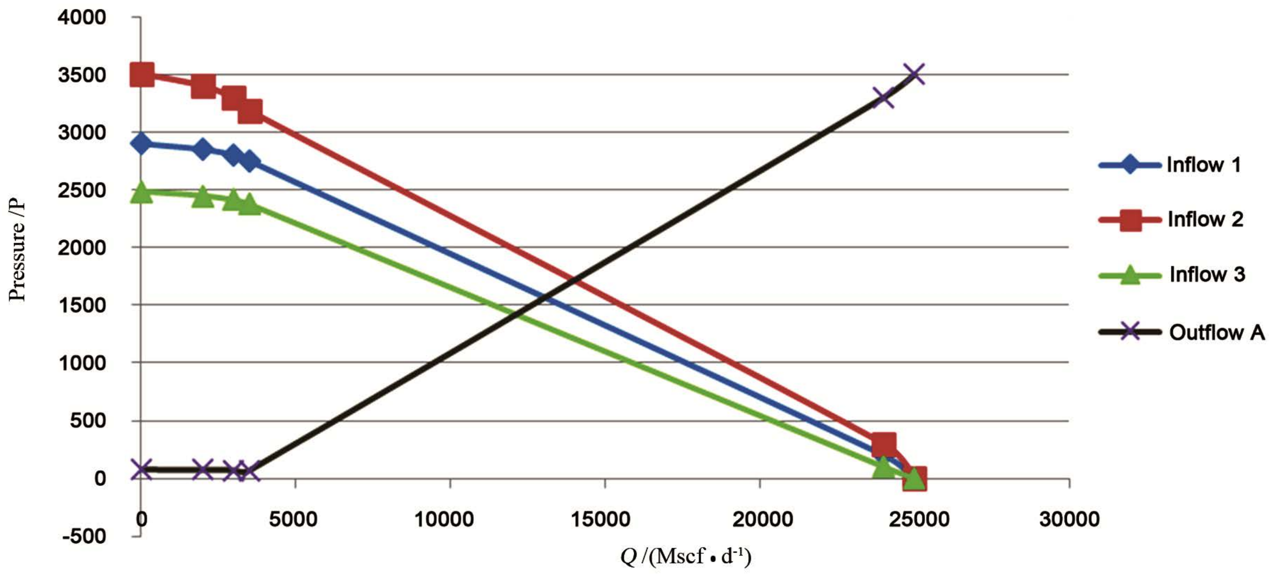

Figure 1. Plot of differential graph using Giger *et al.* model.

Solution Points Flow Rates [bbl/D]

(A)	**Reservoir Pressure [psig]**	
(1)	**2900.0**	**3508**
(2)	**2850.0**	**3401**
(3)	**2800.0**	**3293**
(4)	**2750.0**	**3185**

Solution Point Pressures [psig]

(A)	**Reservoir Pressure [psig]**	
(1)	**2900.0**	**2486.3**
(2)	**2850.0**	**2449.0**
(3)	**2800.0**	**2411.7**
(4)	**2750.0**	**2374.4**

Completion Pressure Drop at Solution Points [psig]

(A)	**Reservoir Pressure [psig]**	
(1)	**2900.0**	**76.7**
(2)	**2850.0**	**74.3**
(3)	**2800.0**	**71.9**
(4)	**2750.0**	**69.5**

At the recommended solution point, using Giger Et Al IPR model, we observed very high flow rate of 3508 bbl/D and an equally excessively high pressure drop of 74.3 psig, which further increased at the completion intervals, with a higher pressure drop of 76.7 psig. However, a recommended pressure drop of 71.9 is required to maintain an optimal production rate. Based on the system analysis, further reduction in pressure only leads to lower liquid drop out and reduced flow rates.

Effects of pressure in horizontal wells using Economides et al. IPR Model

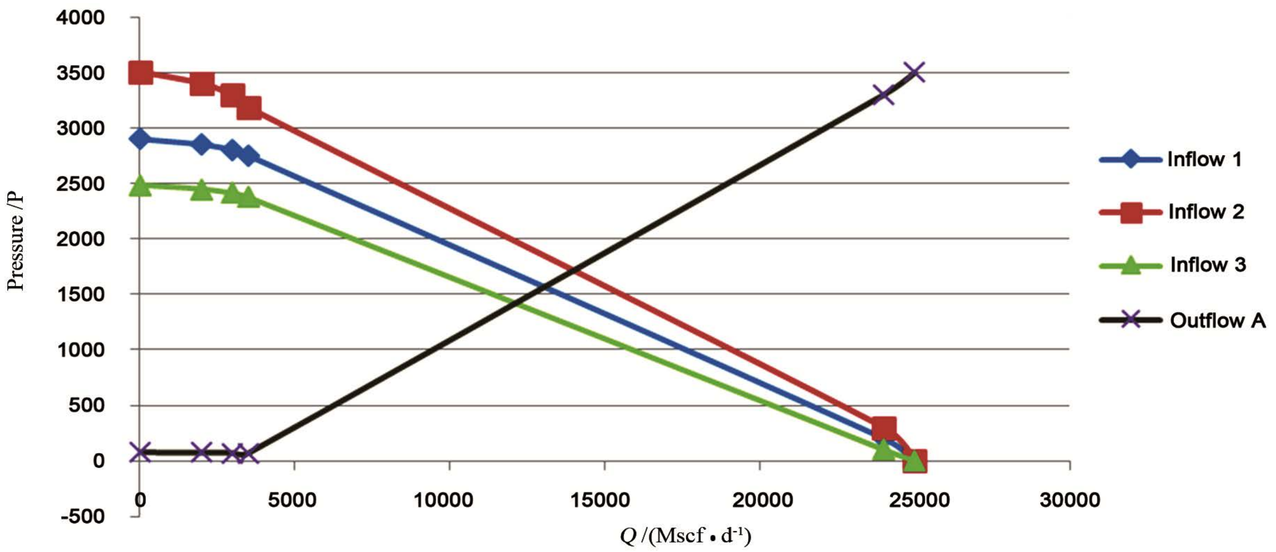

Figure 2. Sensitivity analysis plot using economides *et al.* model.

Solution Points Flow Rates [bbl/D]

(B)	Reservoir Pressure [psig]	
(1)	2900.0	1165
(2)	2850.0	1122
(3)	2800.0	1079
(4)	2750.0	1036

Solution Point Pressures [psig]

(B)	Reservoir Pressure [psig]	
(1)	2900.0	1881.6
(2)	2850.0	1868.8
(3)	2800.0	1856.0
(4)	2750.0	1843.2

Completion Pressure Drop at Solution Points [psig]

(B)	Reservoir Pressure [psig]	
(1)	2900.0	26.5
(2)	2850.0	25.6
(3)	2800.0	24.7
(4)	2750.0	23.8

A critical system analysis of the results from ECONOMIDES et Al IPR model, shows very low flow rate of 1165 bbl/D and an equally low pressure drop of 25.6 psig, which slightly increases at the completion intervals to 26.5psig. However, a recommended pressure drop of 24.7 is required to maintain an optimal production rate.

The sensitivity analysis were conducted to know the effect of reservoir pressure in the horizontal well using Joshi model (Figure 3) and Renard and Dupey model (Figure 4). In Table 3, the results of evaluation for some steady state models using the horizontal well data were presented.

Effect of Reservoir pressure in horizontal wells Using Joshi IPR Model

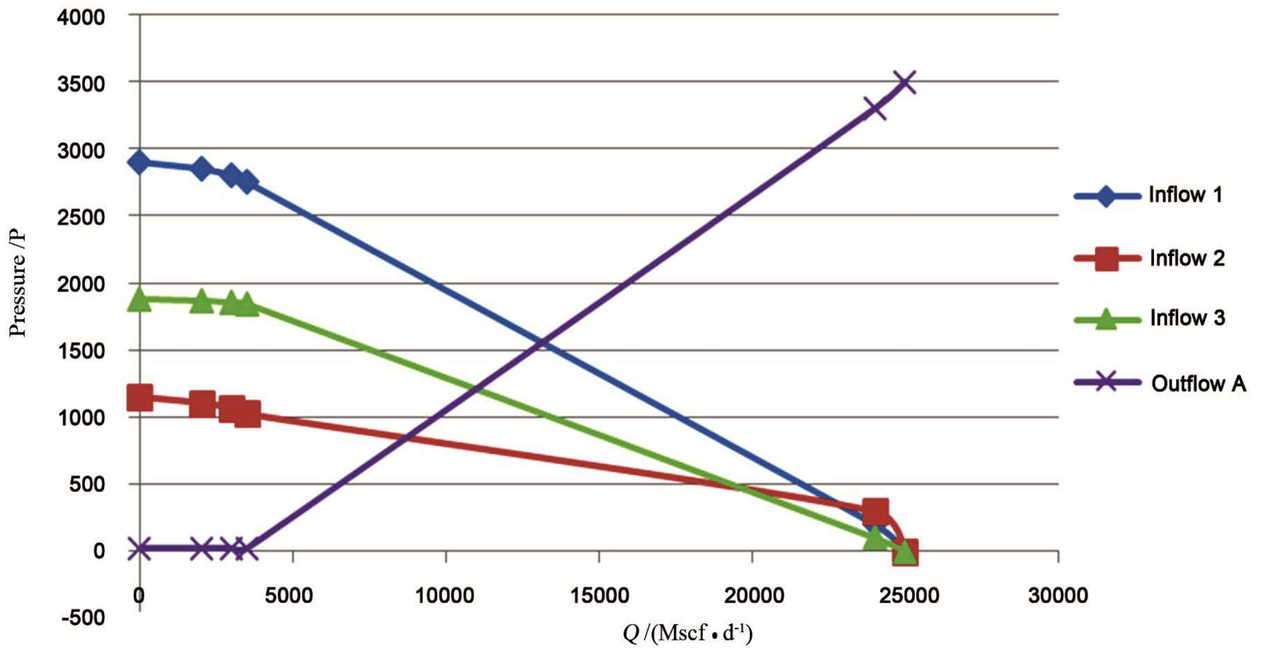

Figure 3. Sensitivity analysis plot using Joshi IPR model.

Solution Points Flow Rates [bbl/D]

(C)	**Reservoir Pressure [psig]**	
(1)	**2900.0**	**1151**
(2)	**2850.0**	**1108**
(3)	**2800.0**	**1066**
(4)	**2750.0**	**1024**

Solution Point Pressures [psig]

(C)	**Reservoir Pressure [psig]**	
(1)	**2900.0**	**1880.1**
(2)	**2850.0**	**1867.5**
(3)	**2800.0**	**1854.9**
(4)	**2750.0**	**1842.3**

Completion Pressure Drop at Solution Points [psig]

(C)	**Reservoir Pressure [psig]**	
(1)	**2900.0**	**26.2**
(2)	**2850.0**	**25.3**
(3)	**2800.0**	**24.4**
(4)	**2750.0**	**23.5**

From the solution point result using Joshi IPR model, we observed the least flow rate of 1161 bbl/D and an equally lower pressure drop of 25.3 psig, which further increased at the completion intervals to 26.2 psig.

However, Joshi IPR model is not recommended to model for the well case under consideration, since we obtained even lower production rates of 1066 Bbl/D at the solution pressure drop of 24.4 Psig.

Sensitivity Analysis Using Benard & Dupuy IPR Model

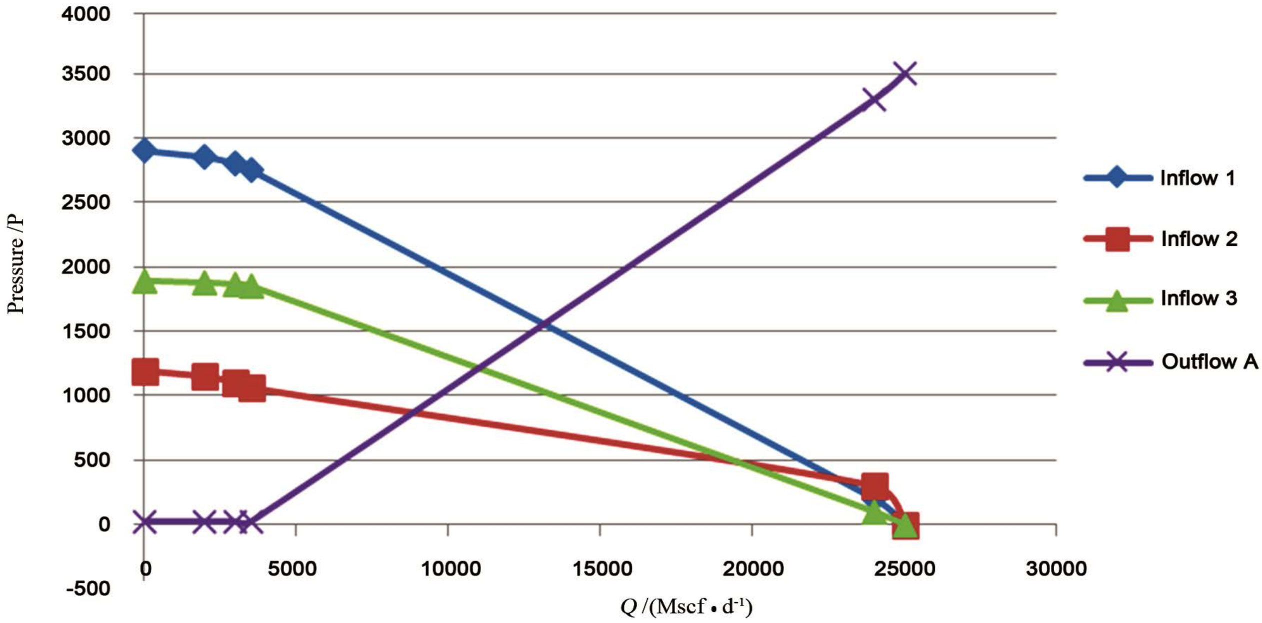

Figure 4. Sensitivity analysis for Renard & Dupey IPR.

Solution Points Flow Rates [bbl/D]

(D)	Reservoir Pressure [psig]	
(1)	2900.0	1193
(2)	2850.0	1149
(3)	2800.0	1105
(4)	2750.0	1061

Solution Point Pressures [psig]

(D)	Reservoir Pressure [psig]	
(1)	2900.0	1891.2
(2)	2850.0	1878.1
(3)	2800.0	1865.0
(4)	2750.0	1851.9

Completion Pressure Drop at Solution Points [psig]

(D)	Reservoir Pressure [psig]	
(1)	2900.0	27.0
(2)	2850.0	26.1
(3)	2800.0	25.2
(4)	2750.0	24.3

The result of the analysis shows that, lowering the well head pressure to 100 psi is recommended if the desired production optimization is to extend the well's life by 70% water cut, which can optimize production. The possible solution will be to change the size of the tubing. But, this is not recommended, since the well production did not cause an increase in the rate of gas production. The gas lift method is economical in this case, since it produced an optimum economic water cut of 80 percent when gas was injected at the rate of 2 - 4 MM scf/day to produce 1800 - 2000 STB/day of gas.

Table 3. Comparative evaluation of horizontal wells steady state models.

Correlation (IPR)	Pressure	Joshi	Economides	Giger *et al.*	Benard & dupuy
	psig	bbl/D	bbl/D	bbl/D	bbl/D
SOLUTION POINT	2900	1161	1186	3508	1193
FLOW RATE	2850	1108	1122	3401	1149
	2800	1066	1079	3293	1105
	2750	1024	1036	3185	1061
Correlation (IPR)	**Pressure**	**Joshi**	**Economides**	**Giger *et al.***	**Benard & dupuy**
	psig	psig	psig	psig	psig
SOLUTION POINT	2900	1880.1	1881.8	2486.3	1891.2
PRESSURE	2850	1887.6	1868.8	2449.0	1878.1
	2800	1864.9	1856.0	2411.7	1865.0
	2750	1842.2	1843.2	2374.4	1851.9
Correlation (IPR)	**Pressure**	**Joshi**	**Economides**	**Giger *et al.***	**Benard & dupuy**
	psig	psig	psig	psig	psig
COMPLETION	2900	28.2	26.5	76.7	27.0
PRESSURE DROP	2850	26.3	25.6	74.8	26.1
AT SOLUTION POINT	2800	24.4	24.7	71.9	25.2
	2750	23.6	23.8	69.6	24.3

7. Conclusion

This study considered the solution methods to determine optimal production rates and the rates of lift gas to optimize regular operational objectives. The foremost tools used in this research are offered as software platforms. The natural gas production optimization in horizontal well gas field has been identified by decline curve analysis. The necessary parameters to optimize the well performance have been identified in this study. The result of the analysis shows that, lowering the well head pressure to 100 psi is recommended if the desired production optimization is to extend the well's life by 70% water cut; which can optimize production. The possible solution will be to change the size of the tubing. But this is not recommended, since the well production did not cause an increase in the rate of gas production. To perform this analytical technique we need good reservoir engineering concept. The gas lift method is economical in this case, since it produced an optimum economic water cut of 80 percent when gas was injected at the rate of 2 - 4 MM scf/day to produce 1800 - 2000 STB/day of gas.

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