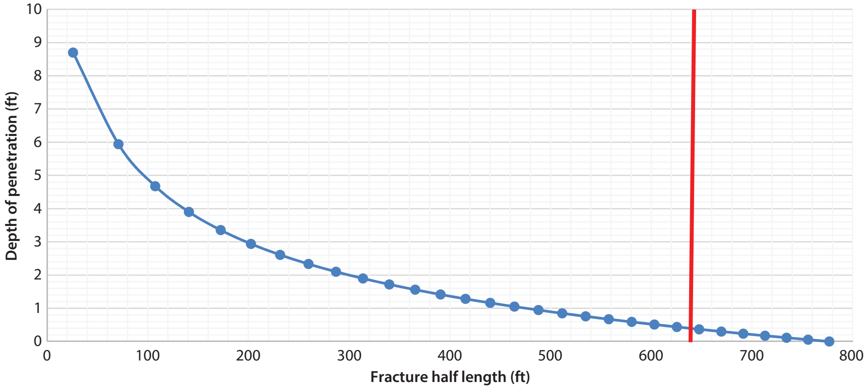

Plot 2 Fracture half-length vs. depth of penetration.

Those sections of the hydraulic fracture that are close to the wellbore will experience exposure to higher pressure for longer durations of time during the treatment.

For a fracture to propagate, significant treatment pressures must be applied from the surface to provide sufficient pressure differential at the tip of the fracture. Farther from the wellbore, pressure is diminished due to turbulence and friction pressure. The magnitudes of pressure experienced in each section of wellbore will progressively increase as the fracture penetrates deeper in the reservoir [2].

Taking the effect of both of these aspects into consideration, a plot has been developed to obtain a visualization of distribution of fracturing fluid within the reservoir. Since the viscosity of fracturing fluid is much higher than the reservoir fluids, the relative permeability of the fracturing fluid is high. As a result, fingering takes place which leads to deeper penetration of the fracturing fluids into the reservoir. **Plot 2** was obtained for the depth of penetration of fluids over the fracture half length.

4.3 *Closing of Fractures*

At the conclusion of a hydraulic fracturing treatment, the surface pumps are shut down, which causes the pressure in the fracture to decline instantaneously. Due to the existence of stresses within the rock, the fractures close off. Ideally, the segment of fracture that closes is directly dependent upon proppant distribution within the fracture [3]. For simplicity, in this model the assumption is to provide uniform distribution of proppants.

The length of fracture that closes is the section where proppants have not been placed [4]. A criteria was used to find the region of fracture where proppants were unable to reach. The criteria is that proppants can penetrate in the fracture only until the width of fracture is twice the diameter of proppant.

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In **Plot 2**, a red line has been drawn at a distance of 133.56 feet from the end of the fracture half length. It means the amount of fracturing fluid lost on the right side of the red line is potentially unrecoverable. Its volume has been calculated to be 19.31 bbls, which is 4.29% of the volume of injected fracturing fluid.

4.4 Chemical Interaction of Fracturing Fluids

Once the well is producing, subsequent to hydraulic fracturing treatment, a comingled flow might occur from reservoir and fracturing fluids. After a certain amount of time, only the flow of formation fluids is contributing and dominating. From observation, it is unlikely to be due to all the fracturing fluids being produced. As production continues, the pressure transience gets deeper into the reservoir. The pressure differential should be enough for the fracturing fluid to flow within the reservoir. However, fracturing fluids react with reservoir rock and fluids over time, which decrease their mobility, and thus require higher differential pressure to overcome the capillary pressure and flow within the reservoir. In reality, applying such high differential pressures in the reservoir may not be practical, leading to unproduced injected fracturing fluids within the reservoir. This phenomenon is a major factor in high volumes of fracturing fluid remaining in the reservoir.

Calculated Values:

- Additional irrecoverable volume of injected fracturing fluid = 455.49 bbls
- Recoverable volume of injected fracturing fluids = 786.67 bbls
- Total recoverable oil = 3121.86 bbls (Virgin zone) + 3540.02 bbls (Affected zone) = 6661.88 bbls

5 Impact of Parameters under Control

The data analysis shows that approximately 45% to 80% of injected fracturing fluids are recoverable under certain conditions. From 20% to 55% of that fluid stays in the reservoir, of which 4.29% is due to the closing of fractures, and 15.71% to 50.71% is caused by the interaction of fracturing fluid with reservoir fluids and rock. It is very evident that we get a higher percentage of loss of fracturing fluid due to the interaction of those injected fluids with reservoir rock and fluids. The fracturing fluid can be more easily recovered by both decreasing viscosity of fracturing fluid post treatment and increasing the time for comingled flow.

From sensitivity analysis, 344.94 bbls of incremental oil per 1 cp of decrease in fracturing fluid viscosity post treatment is achieved as per **Plot 3**. However, 5.26 bbls of incremental oil per 1 hr of increase in time of comingled flow is achieved as per **Plot 4**. This means the performance of stimulated well is highly sensitive to the viscosity of fracturing fluids post treatment. Breaker is one of the additives of fracturing fluid for decreasing its viscosity post treatment. Hence, the performance of the stimulated well is dependent on the performance of breaker.

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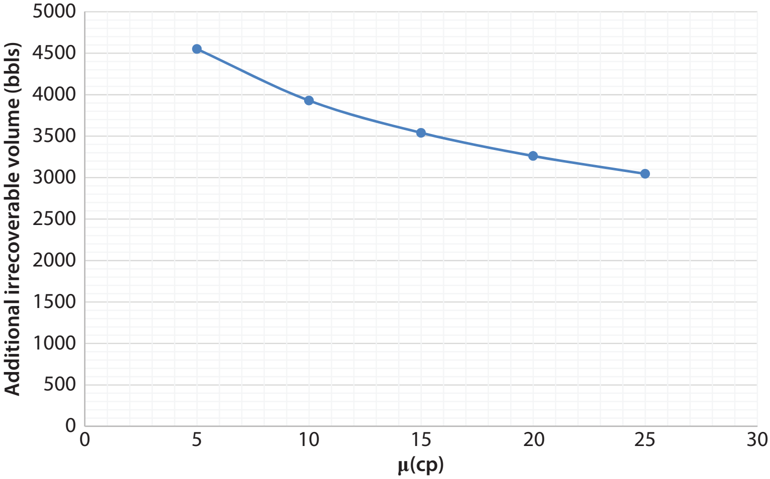
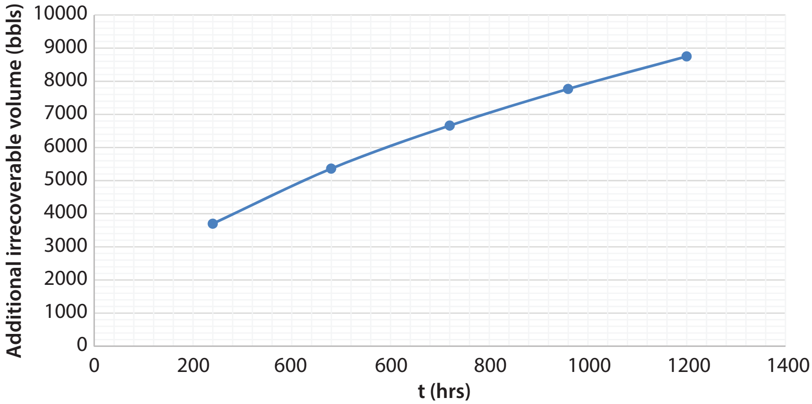


Plot 3 μ vs. recoverable oil volume.



Plot 4 Time vs. additional irrecoverable fracturing fluid volume.

6 Loss in Incremental Oil Production

The fracturing fluid that stays back in the reservoir acts as a restriction to the reservoir fluids flowing into the fracture. As a result, there is skin associated with fluids not flowing back. That skin can cause a decrease in production rate over time and therefore lessen the cumulative oil production.

In the case of **Plot 5**, an incremental production of 36,676 bbls of oil could be achieved over the duration of 900 days if the formation damage due to unproduced fracturing fluid had been avoided [5].

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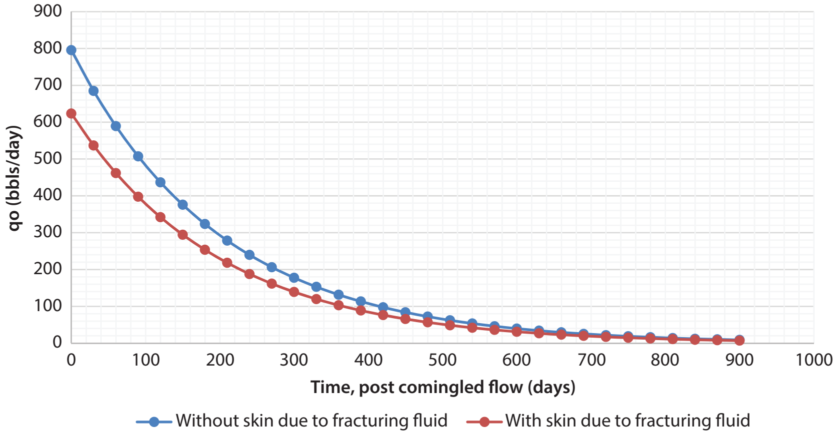

Plot 5 Decline curve.

7 Conclusions

We conclude that by combining the streamtube model approach with the knowledge of geomechanics of the field, the well performance after hydraulic treatment can be predicted with reasonable accuracy.

Partial flowback of fracturing fluids is primarily a result of:

- High pressure injection of viscous fracturing fluid leading to larger depths of penetration where it becomes very difficult to get enough pressure differential to overcome the capillary pressure of fracturing fluids. Furthermore, the interaction of fracturing fluid with reservoir rock and fluids substantially reduces the mobility of fracturing fluid. The situation is aggravated by high viscosity of fracturing fluids post treatment. This is a major contributor in the loss of fracturing fluid in the reservoir and its impact on overall well performance.
- The closing of fractures following treatment causes the injected fluid to be placed in sections of the reservoir which are relatively hard to access. This is a minor contributor in the loss of fracturing fluid in the reservoir and its impact on overall well performance.

In this model, 45% to 80% of injected fluid can potentially be recovered.

The skin caused by unproduced fracturing fluids can prevent us from producing tens of thousands of barrels of oil over the life of the well.

Wells with lower skin values are much more sensitive to the skin due to unproduced injected fracturing fluids.

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8 Limitations

All the estimates of the magnitude of loss of fracturing fluid are low when considering only one fracture. However, in reality, the estimates would increase substantially due to the complex geometry of fracture where a single fracture does not exist.

In actuality, the distribution of the proppants within the fracture is not uniform. For that reason, the fracture may close off in the early or middle region, making the rest of the length of the fracture highly ineffective. In that case the loss of fracturing fluid due to closing of fractures may be much more than what has been previously calculated. Usually, the concentration of proppants is greater in the lower parts of a fracture due to the effect of gravity.

One would encounter losses attributable to heterogeneity, natural fractures and faults in real life which have not been taken into account in this model. That could be one of the contributing factors for further losses of injected fracturing fluid impacting the observation of 2–26% flowback [6].

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Appendix - A

Calculations for Upgraded Visualization:

$$V_{avg} = -\frac{R^2 \partial p}{8\mu \partial x}$$

Where,

V_{avg} is average velocity in m/s
R is radius in m
μ is viscosity in kg/m/s
∂P is change of pressure in kg/m^2
∂x is change in distance in m

Calculations for Damage due to Fracturing Fluids:

$$S_{frac} = S + \left[\frac{k}{k_s} - 1\right] \ln\left[\frac{r_s}{r_w}\right]$$

S_{frac} is skin due to unproduced fracturing fluid and its unitless
S is total skin due to everything but unproduced fracturing fluid and its unitless
k is virgin reservoirs permeability in mD
k_s is damaged reservoir permeability in mD
r_s is radius of damaged region in ft
r_w is wellbore radius in ft

Calculations for Flowrate of Well:

$$q_0 = \frac{(P_{wf} - P_i) * \left(\frac{k_0}{\mu_0}\right) * h}{162.6 * B_O * \left[\log\left(\frac{1688\phi C_t {r_w}^2}{t}\right) - (0.868 * S)\right]}$$

Where,

q is flowrate in bbl/day
P_{wf} is wellbore flowing pressure in psi
P_i is the initial reservoir pressure in psi
k_o is relative oil permeability and its unitless
μ_o is oil viscosity in cp

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h is thickness of formation in ft
B_o is the formation volume factor in rb/stb
ϕ is porosity and it's unitless
C_t is the total compressibility of the reservoir in psi^{-1}
r_w is wellbore radius in ft
t is time in hrs
S is skin and its unitless

Calculations for change in flowrate of well with time:

$$q_t = q_i * \exp(-ta)$$

Where,
q_i is initial production rate in stb/day
q_t is production rate at time t in stb/day
t is time in days
a is decline factor and its unitless

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