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Investigation of New Tool to Unload Liquids from Stripper-Gas Wells

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Abstract

Liquid loading in low production gas wells is a common problem faced in many producing regions around the world. The techniques available to remove liquids from the wellbore impose significant capital and operational costs. This study investigates a new method for unloading and restoring continuous production of low rate (stripper) gas wells. The performance of a patented vortex flow modifier tool was examined using a 125-ft vertical flow loop of 2-inch diameter clear PVC. The vortex device was found to alter the basic flow structure in the pipe resulting in improved liquid flow. The tool was observed to reduce tubing pressure loss by up to 17 precent and lower the minimum gas velocity required to lift liquids up the tubing string.

Introduction

The production of natural gas is usually accompanied by the production of brine and/or hydrocarbon liquids. These liquids are transported to the surface as small droplets by the natural gas. However as the reservoir pressure declines, the drag force exerted by the gas is no longer sufficient to carry these liquids to the surface and they are instead held up in the wellbore. Accumulation imposes a backpressure on the formation that can significantly reduce the production capacity, and can eventually kill the well. A minimum or *critical gas flowrate* must therefore be maintained to prevent the onset of liquid load-up.

Numerous authors[1-3] have offered predictions for determining the critical velocity. Turner[1] *et. al's* correlations are the most widely used. It is based on determining the velocity of the gas that would exert a drag force sufficient to balance the gravitational force of a liquid droplet. That is,

$$v_t = \sqrt[4]{\frac{4(\rho_l - \rho_g)g\sigma}{\rho_g^2 C_D}} \quad \text{.............................}(1)$$

and the expression for the critical gas flowrate is,

$$Q_c = 2.821\text{x}10^6 \frac{Apv_t}{zT} \quad \text{...........................}(2)$$

It is evident from these equations that liquid unloading can be achieved by,

- Increasing the gas rate.
- Reducing the area for flow.
- Reducing the surface tension or density of the liquid phase.

A number of techniques[4-8], such as the use of soap sticks, plungers. rod pumps, or swabbing, are available as corrective action to return the well to production. The external interference due to these methods comes at the expense of additional capital and operating costs.

In additional to the methods listed, unloading can also be achieved by reducing the pressure drop in the tubing string. This would increase the value of C_D, which would translate into more efficient use of the existing reservoir energy. As a result unloading would occur at lower gas rates.

Mingaleeva[9] studied the lowering of pressure drop in self-twisting helical flow. He observed the mechanism from an energy standpoint, and concluded that the liquids and gases will flow through a path of least resistance. Also the power spent to overcome the hydraulic drag for raising an air column in a helical trajectory, was compared to the motion and rising of an equivalent air mass at the same velocities by a straight column, was significantly lower. Therefore he concluded that the helical path was more favorable from an energy-use viewpoint. As a result the air column suffered a lower pressure drop when is moved in a helical path.

This paper examines the use of a flow-modifying device that creates a helical flow to unload liquids. Laboratory experiments were conducted using a 125-ft vertical flow loop on 2-in. diameter clear PVC. In these experiments, the effects of gas and water flow rates on the flow-modifying device were considered and compared with the behavior in normal pipe flow.

Test facility

The flowloop used in this project consists of a tubing string of 10-ft lengths of transparent PVC pipe, with an inside diameter of 2.049-in. These lengths are coupled together with PVC unions to a height of 125 ft. The unions have the same inside diameter as the pipe to prevent accumulation of liquid at the couplings.

The flow-modifying unit is attached by a union to the bottom of the tubing string, and hangs inside a 24-in diameter vessel with a S/S height of 50 in. A 15-in. by 11-in. oval opening on the vessel allows access to the inside of the wellbore that is used to change the flow modifying devices. This vessel helps simulate flow conditions through a tubing string that hangs just below the perforations in a packed wellbore. This analogy of the vessel to a wellbore is shown in **Fig. 1.**

To eliminate exit effects of liquid fallback into the loop, a Y-bend is installed on the top of the tubing string. Therefore, after passing through the tubing string the produced air/water mixture overflows into a 4-in. nominal diameter return line. A choke is used to control the wellhead pressure.

After passing through the wellhead choke, the carry-over air/water mixture is introduced into a separating vessel where the air, after being separated, is vented to the atmosphere.

A Positive Displacement (PD) pump is used to transfer water from a 50-gallon tank the wellbore. The use of a PD pump allows for testing at a wide range of pressures and flowrates. Compressed air is controlled by a choke before it is metered and introduced into the wellbore through a separate line.

A 1½-in Model D and ½-in Elite-Type Micromotion Coriolis Meters continuously measure the water and gas mass flow rates respectively. The bottomhole and wellhead pressures are measured by both pressure transducers and locally by pressure gauges. Temperature signals are taken as a second variable from the gas meter.

Fig. 2 shows the schematic diagram of the experimental apparatus that is used to simulate a producing gas well.

Instrumentation. The flow loop is equipped with a 1½-in Model D (Sensor Model S150) and a ½-in Elite Type (Sensor Model CMF050) Micromotion Coriolis to measure the gas and liquid mass rates. Pressure fluctuations in the system are measured with Barton's absolute pressure transducers located on the wellbore and on the wellhead at the top of the tubing string. These transducers are calibrated to measure pressures between 0 and 150 psig. The estimated average uncertainties in this experiment were ±0.1% for the pressure, and ±0.35 and ±0.2% of the air and water flowrates respectively.

The signals from the pressure transducers and flow meters are fed into the Data Acquisition System (DAQ). The DAQ consists of a Pentium 333 MHz system equipped with a Strawberry 16- Channel Acquisition Card. Data are recorded in 8-bit blocks at 15 Hz.

Flow Visualization. To view changes taking place in the wellbore, two sight glasses are installed opposite each other. One sight glass serves as the lighting source while the other is used for viewing. Flow through the tubing is viewed continuously using cameras installed at the wellbore, and at approximately 5-ft, 60-ft, and at 125-ft.

A monitoring system allows switching between cameras. The flow may be viewed at each floor individually, or all four locations can be viewed simultaneously on the television screen. A VHS recorder is used to record the changes at different locations in the tubing string.

Operating Procedures

Two different procedures were followed when evaluating the flow-modifying tool. One allowed the determination of the operational envelope of the tool, whereas the second method determined the critical velocity.

Determination of Operational Envelope. With the wellbore free of liquid and the wellhead choke completely open, gas was passed through the flowloop until the wellhead and bottomhole pressures had stabilized. Water was then introduced into the wellbore. Once the liquid level reached the bottom of the flow-modifying device, it started flowing up the tubing string. This was accompanied by an increase in the bottomhole pressure. The liquid rate was then increased until the desired bottomhole pressure was achieved. This was between 20 and 21 psi in our investigation. The flow was allowed to stabilize for 5 minutes to ensure the average bottomhole pressure was within the required range.

If the pressure exceeded 21 psi, then the liquid rate was decreased. Conversely, if the pressure fell below the 20 psi, the liquid rate was increased. The flow was allowed to restabilize. The procedure was repeated until the average bottomhole pressure fell within the desired range.

Once the desired pressure had been achieved, the values for the different flow variables being fed into the DAQ system were recorded for 5 minutes. Simultaneous video recordings were made for the flow visualizations at the different points along the tubing string. The procedure was repeated at increasing gas flowrates.

Once a complete set of tests had been run, i.e. until the maximum gas flowrates of the test facility had been reached, the experiment was repeated using different flow modifying devices. The experiment was also repeated considering bottomhole pressures of approximately 10 and 30 psi.

Critical Rate Determination. The determination of the critical gas rate involved determining the annular mist-flow transition. This transition is marked by an increased turbulence in the liquid film, a decrease in the film thickness and the development of waves at the gas/liquid interface[10]. Droplets are torn off the film and entrained into the gas. Determination of this transition point depended largely on visual observations and personal judgment.

With the wellbore free of liquid and the wellhead choke completely open, gas was passed through the flowloop until the wellhead and bottomhole pressures had stabilized. Water was then introduced into the wellbore at a low rate, approximately 2 lb/min. Once the liquid level reached the bottom of the flow-modifying device, two conditions were possible. Either the gas would unload the liquid or it would load up the wellbore. In case the liquid could not be unloaded, bottomhole pressure would increase significantly, +5 psi. If this happened, then the gas rate was increased.

Once the well was continuously unloading liquids and the bottomhole and wellhead pressure had stabilized, the liquid flow into the wellbore was stopped. The wellhead choke was simultaneously closed. This allowed a backpressure to be exerted by the choke to stop the fluid acceleration. As the pressure was allowed to rise, a point was reached when the fluid acceleration was completely stopped and the liquid started to fall back down the tubing. Once this happened, the wellhead choke was opened slightly to allow liquid to be transported up the tubing.

Once the wellbore had been unloaded and the only liquid in the tubing was the wavy film, the wellhead choke was closed slightly to cause liquid fallback. Once this happened, the wellhead choke was reopened slowly until the liquid started to rise. The wellhead pressure and the gas rates were recorded. These conditions were maintained until the flow loop was completely dry, usually approximately one hour, to ensure that the correct critical gas rate had been determined. The procedure was repeated at different gas rates.

Results and Discussion

Operational Envelopes and Pressure Drop Curves. The operational envelope, i.e. the relationship between the gas and liquid flowrates in **Fig. 3**, defines the maximum unloading capabilities with no wellhead backpressure. The bottomhole pressure is maintained at approximately 20 psig. In the region above the curves, the liquid unloading ability decreases and the well starts to load up. In the area below the curve, the well will be continuously unloaded.

Looking at the operational envelopes, it is clear that the tool outperforms the plain tubing. The enhanced abilities of the unit were pronounced at low gas/high liquid rates, Region 1, when compared with results when no tool was used.

Also, as the gas rate is increased, the amount of liquid that can be removed continuously decreases. This is contrary to static or intermittent unloading, where higher gas rates cause the well to unload faster as water influx is not continuous. The difference in behavior can be explained by considering the pressure components entering the fixed volume of the wellbore, i.e. the bottomhole pressure is due to the pressure of the gas plus the hydrostatic head due to the liquid.

Therefore at low gas rates, liquid holdup would be greater and would result in a higher hydrostatic head. Consequently, as the gas rate is increased, the liquid holdup would have to decrease to maintain the same bottomhole pressure. This would result in a decrease in the hydrostatic component of the total bottomhole pressure, causing the liquid holdup to decrease. As the gas rates are increased, all tools achieve comparable liquid unloading. Therefore, at these conditions the maximum liquid holdup for all of the tools is expected to be the same.

To further explain this decline, the no-slip liquid holdup relationship with increasing gas rates is considered. As can be seen in **Fig. 4**, the liquid hold-up follows an exponential decline that eventually straightens out to follow a linear trend. This confirms that there is a flow-regime change as the gas rate is increased.

At low gas rates, liquid transference occurs predominantly in the slug flow regime. Increasing the gas rates changes the regime to churn and then to annular. In both slug and churn liquid flow, a degree of gas slip occurs because of the high in-situ gas velocities. Therefore, as the gas rate increases and more and more area is available to the gas, the in-situ velocity will decrease. As a result, the velocity of the gas and liquid will become the same, resulting in further decline in liquid holdup to be linear.

Enhanced flow capabilities can be achieved at the expense of increased pressure loss through the tubing. A higher-pressure loss would eventually mean lowering the ultimate recovery from a gas field. Therefore, enhanced recovery at the expense of increased pressure drop is not desirable.

To ensure that the flow-modifying tools do actually pose a benefit, we evaluated the pressure drop through the tubing string, **Fig. 5**. These results confirmed the usefulness of the flow-modifying tool, as a lower pressure drop was experienced when the tool was utilized.

Effect of Pressure on Flow Performance. The flow-modifying tool was tested at approximately 10, 20 and 30 psig bottomhole pressures. As shown in **Fig. 6**, the operational envelope expands as the bottomhole pressure is increased. This is largely a reflection of the increase in energy possessed by the gas, enabling it to transfer more liquid. The increase in the maximum liquid unloading capacity is accompanied by an increase in the overall pressure drop, **Fig. 7**.

Critical Velocity. The critical rates of the flow-modifying tool were compared with values obtained when no tool was used, as well as with Turner's, Coleman's, and Li's terminal velocity correlations. As shown in **Fig. 8**, Turner's prediction overstates the minimum rate required to lift liquid to the wellhead. However, when no flow-modifying tool is used, the results offer an excellent match to Coleman's correlation. This provides credence to Coleman's conclusions that Turner's +20% adjustments can be neglected for pressures less than 500 psia. Critical rates predicted by Li are significantly lower than the values we observed.

The critical-velocity criterion is by far the most important criterion when evaluating the liquid unloading capabilities of a well. The findings confirm that the flow-modifying tool enhances the ability to start lifting liquids at lower rates.

Further analysis of the critical velocity thresholds reveals that the values obtained with the flow- modifying tools lie parallel to values predicted by the different critical-rate correlations.

Wellhead Backpressure Analysis. The effect of pressure loss in a flowing gas well on the liquid unloading abilities is shown in **Fig. 9**. The plots show that increased liquid unloading is accompanied by an increase in the pressure loss in the tubing. The tool is more efficient as it unloads a greater amount of liquid and suffers the smallest pressure loss in the tubing string.

A 17 percent, 8.6 percent, and 5.0 percent reduction in tubing-pressure loss was achieved at 10psig, 20psig, and 30psig respectively. These values were achieved by iteration until the curves by the flow modifying tools overlapped those made by plain tubing.

Conclusions

The results show that the flow-modifying tools are able to lower the pressure drop through the tubing string. As a result, production is enhanced, and the lower pressure drop improves the ultimate recovery from gas wells. Experimental evidence has shown the following:

1. The flow-modifying tools enhance liquid unloading at lower gas rates.
2. The tubing string experiences lower pressure drops when the flow-modifying tools are used.
3. The critical velocity is lowered with the use of flow-modifying devices.
4. A 17% reduction in tubing pressure loss is experienced at low-pressure conditions.

Nomenclature

V	=	Velocity, ft/s
Q	=	Gas FlowRate, SCFD
σ	=	Surface Tension, lb_f/ft
ρ	=	Density, lb_m/ft^3
g	=	Gravitational Acceleration, 32.2ft/s^2
C_D	=	Drag Coefficient
A	=	Flow area of Conduit, ft^2
p	=	Pressure, psi
T	=	Temperature, ^{o}R
z	=	Gas Compressibility Factor

Subscripts

g	=	Gas
l	=	Liquid
c	=	Critical
t	=	Terminal

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Figures

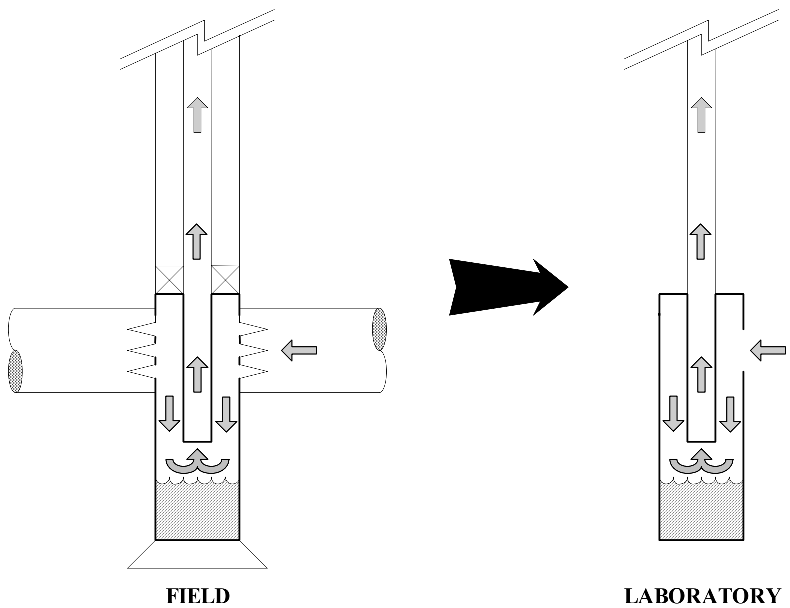
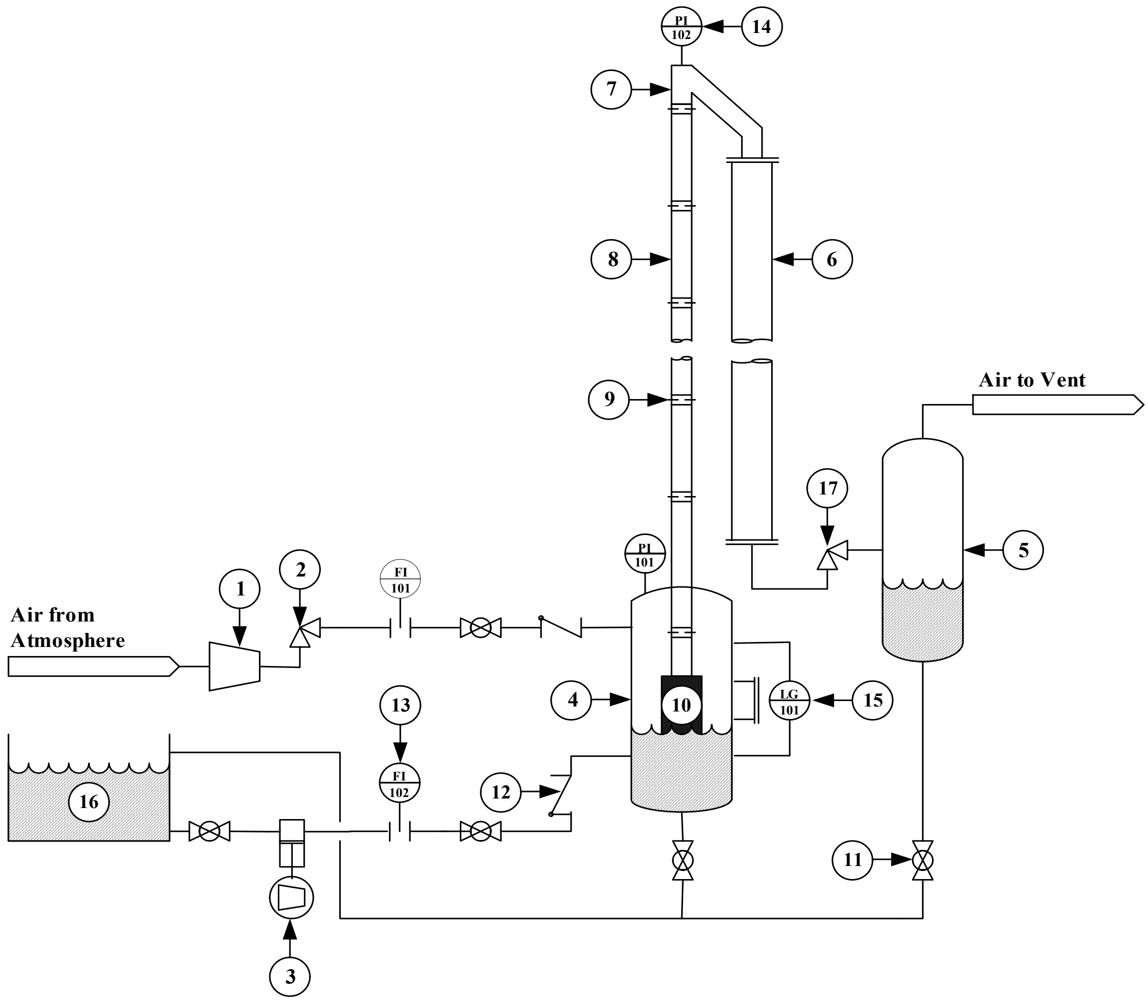


Fig. 1 – Analogy between a Wellbore and Vessel



1. Positive Displacement Pump
2. Gas Choke
3. Variable Speed PD Pump
4.Wellbore
5. Liquid/Gas Separating Vessel
6. 4-in Clear PVC Return Line
7. Y-Bend
8. 2-in Clear PVC Tubing String
9. 2-in Union
10. Vortex Unit
11. Ball Valve
12. Check Valve
13. Flow Indicator
14. Pressure Indicator
15. Liquid Gauge
16. Water Reservoir
17. Wellhead Choke

Fig. 2 - Schematic Diagram of Test Facility

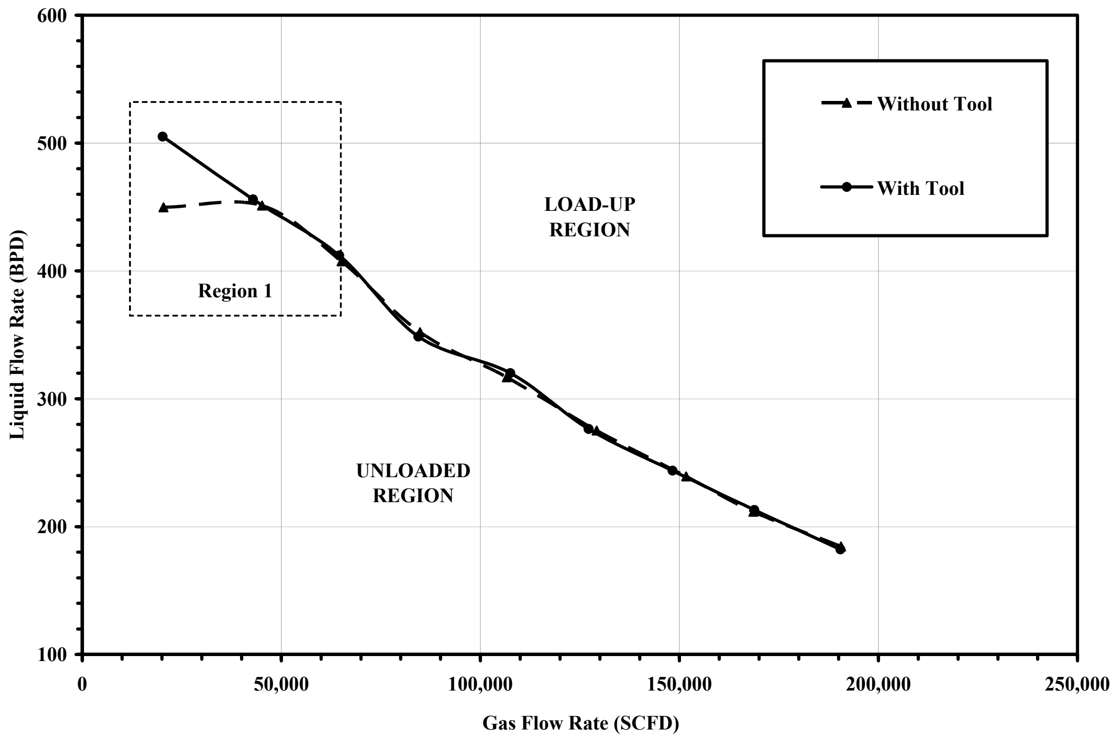


Fig. 3 – Effect of Number of Inlets on the Operational Envelope ($P_{BH} \approx$ 20-21 psig)

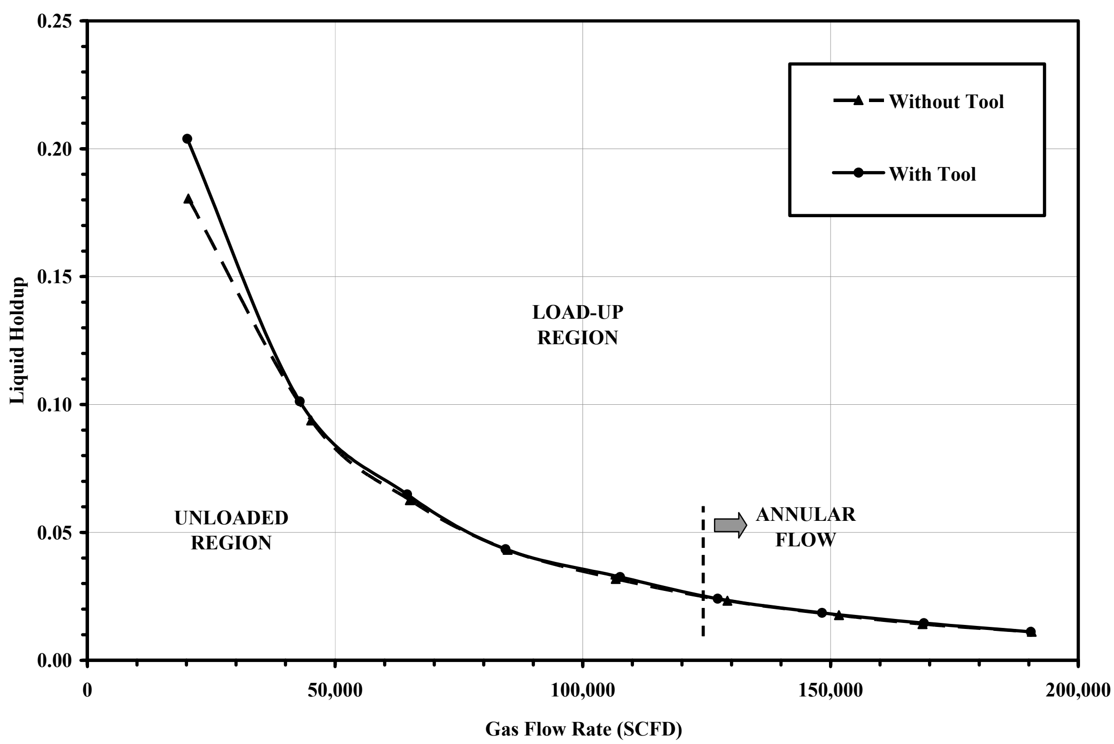


Fig. 4 – Change in Liquid Hold-Up with Increasing Gas Rates ($P_{BH} \approx$ 20-21 psig)

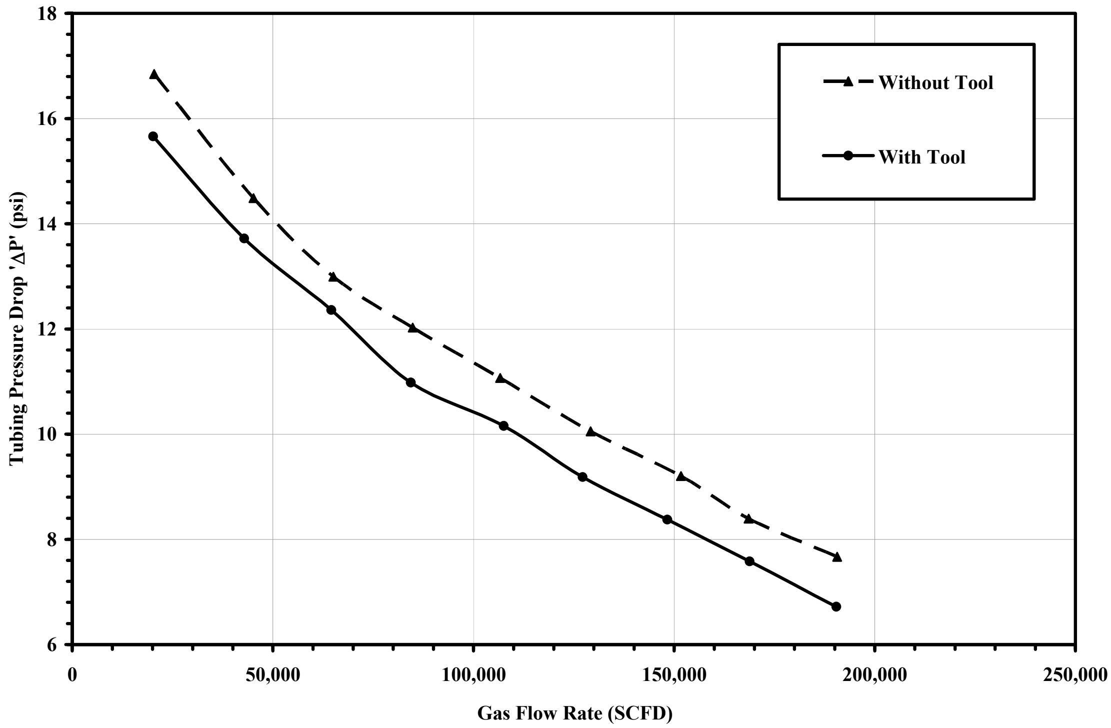
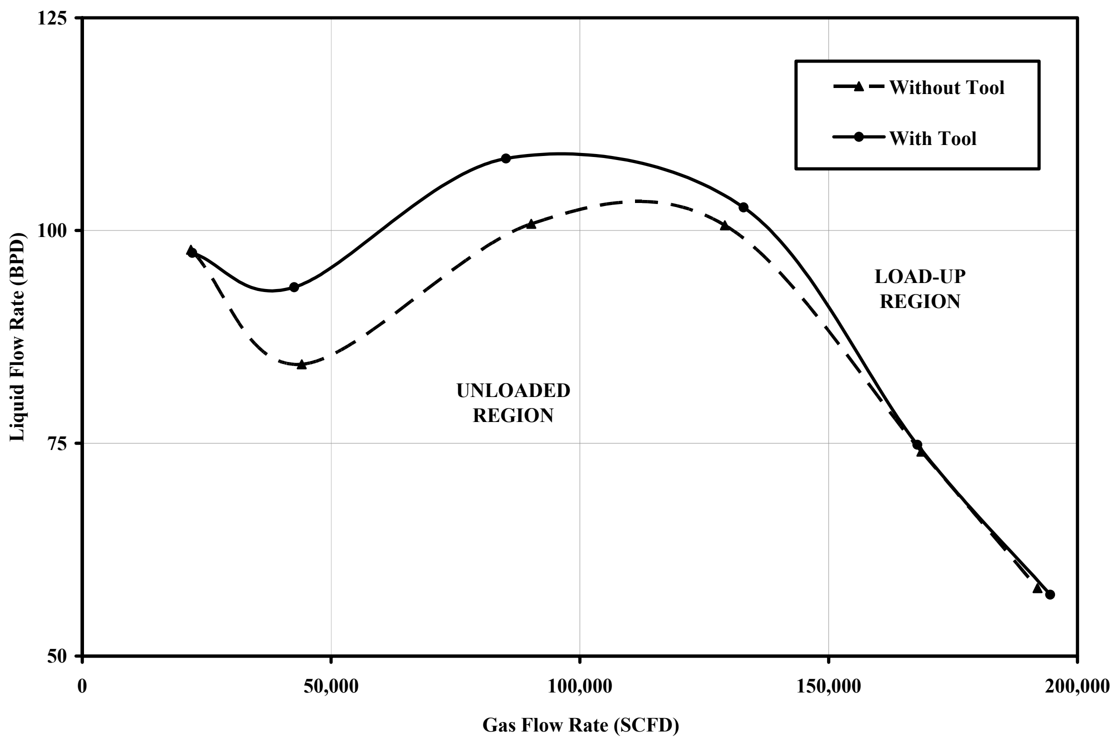
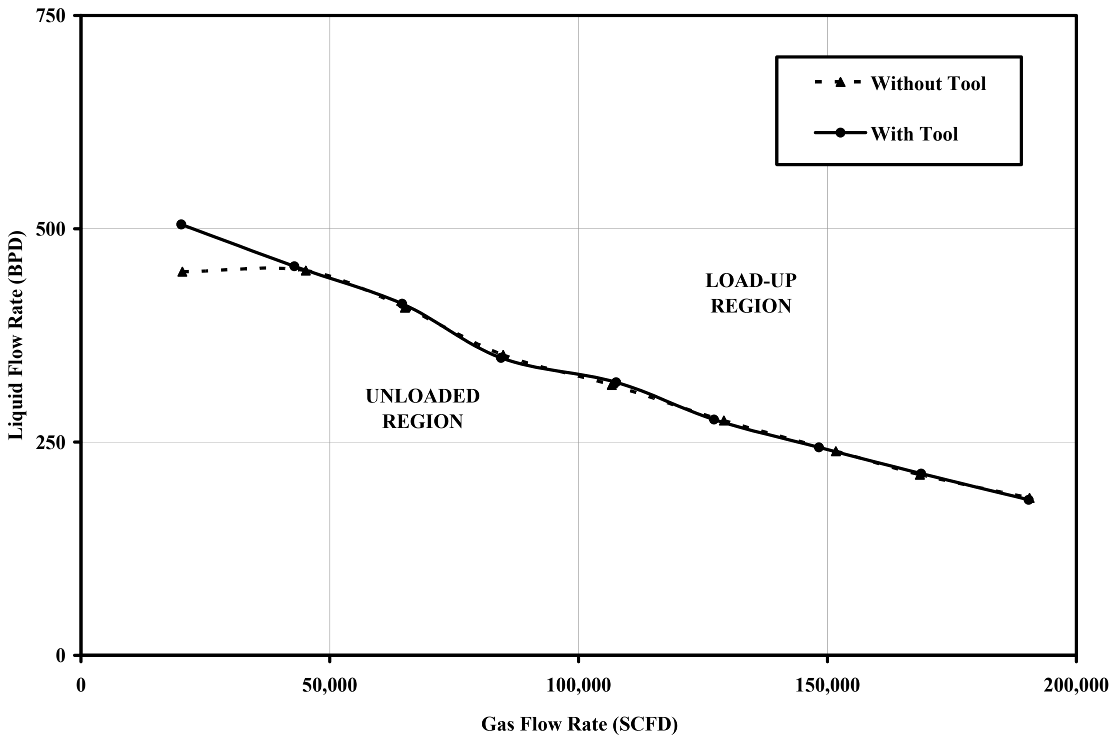


Fig. 5 – Effect of Number of Inlets on the Tubing Pressure Loss (P_{BH} ≈ 20-21 psig)

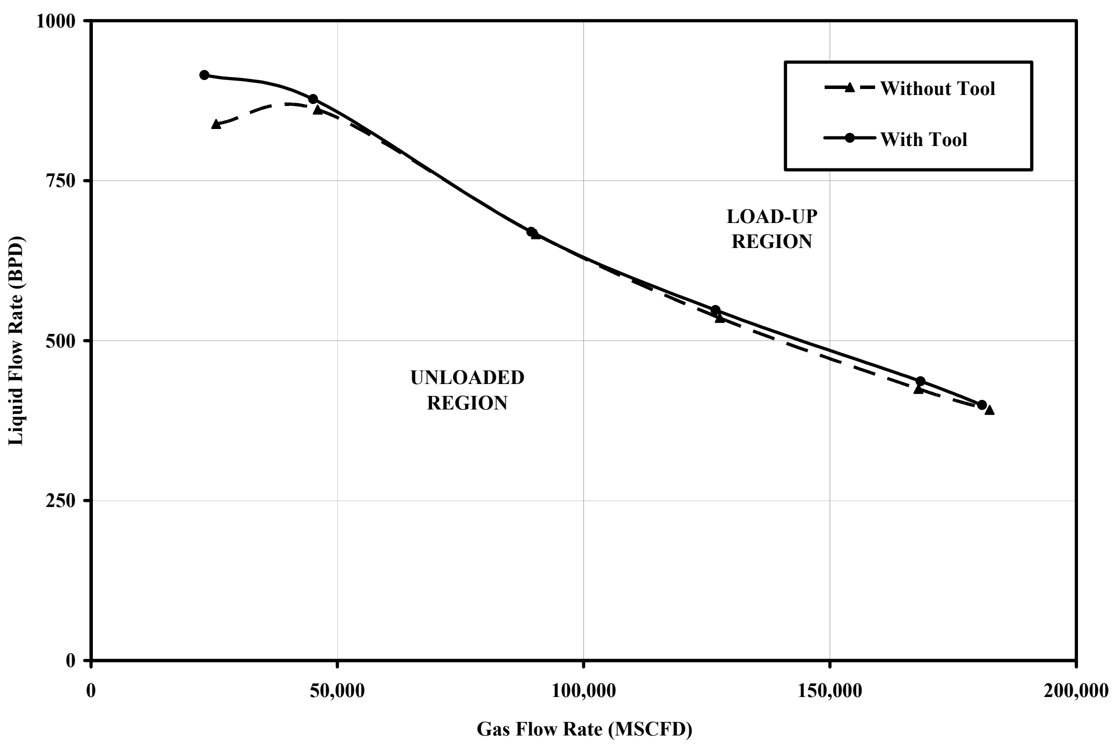


(a)

Fig. 6 – Effect of Pressure on the Operational Envelope at (a) 10 psig (b) 20 psig (c) 30 psig



(b)



(c)

Fig. 6 – Continued

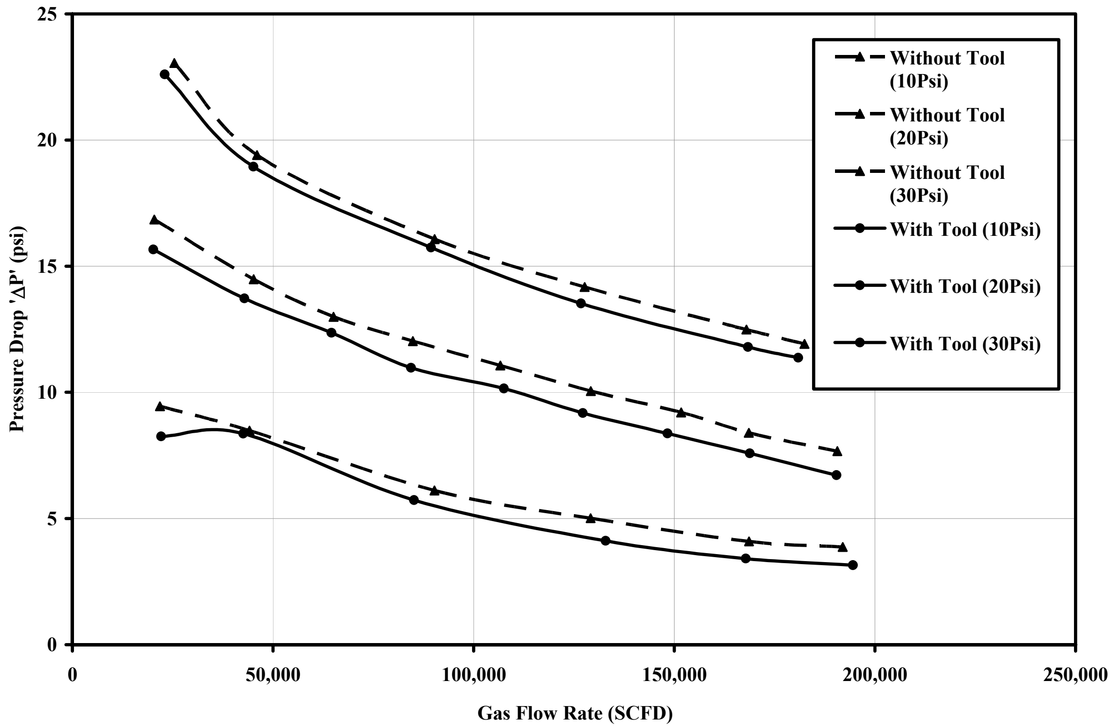


Fig. 7 – Effect of Pressure on the Tubing Pressure Drop

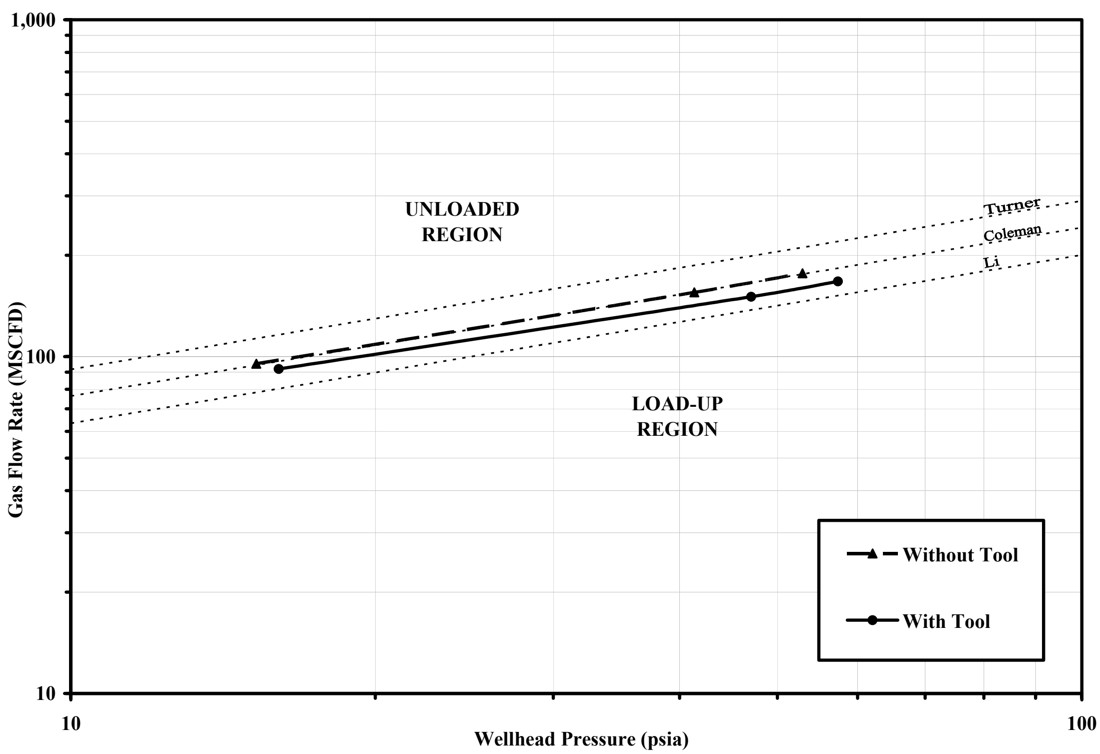
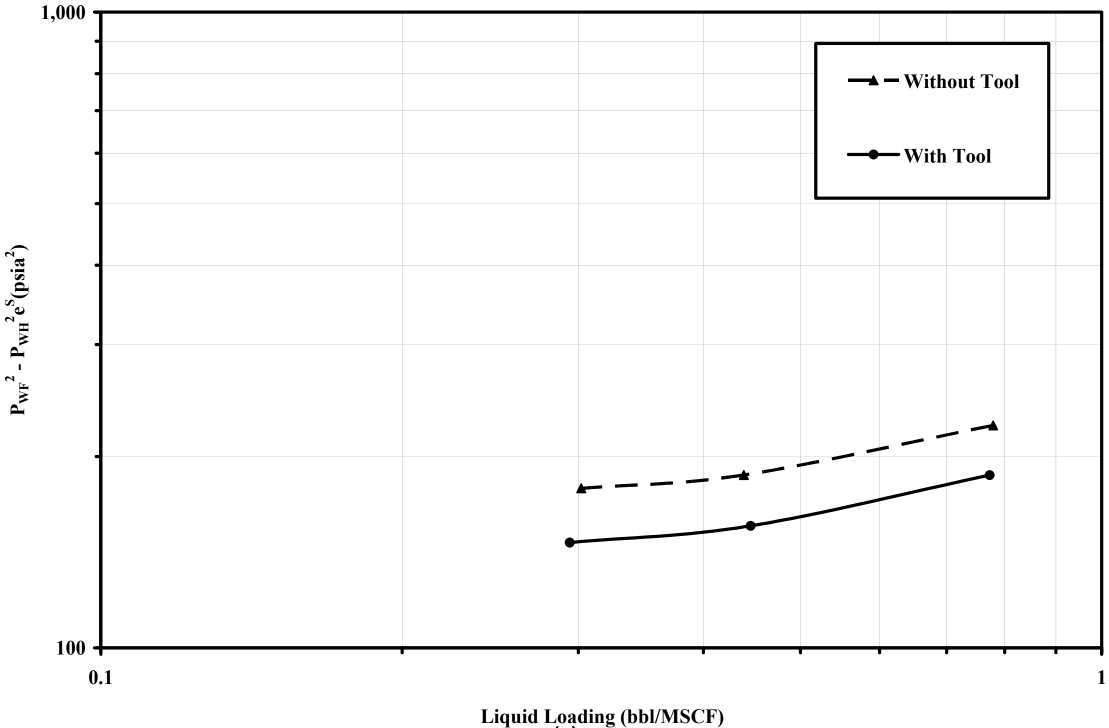
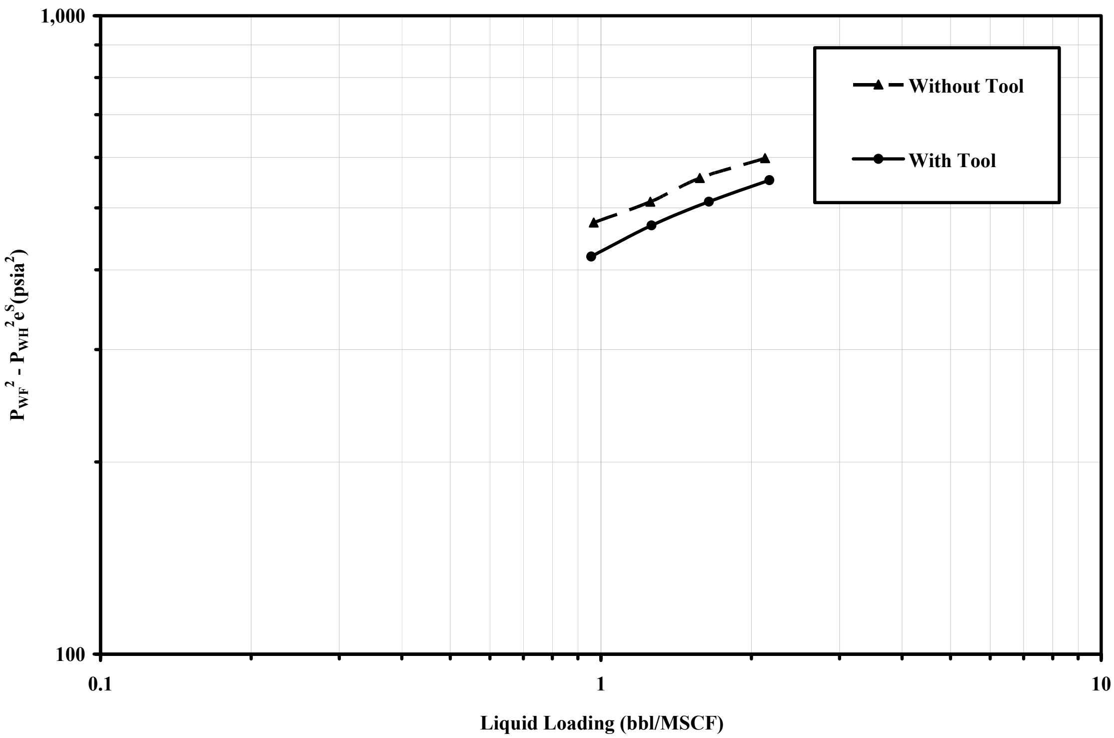


Fig. 8 – Critical Rate Comparisons

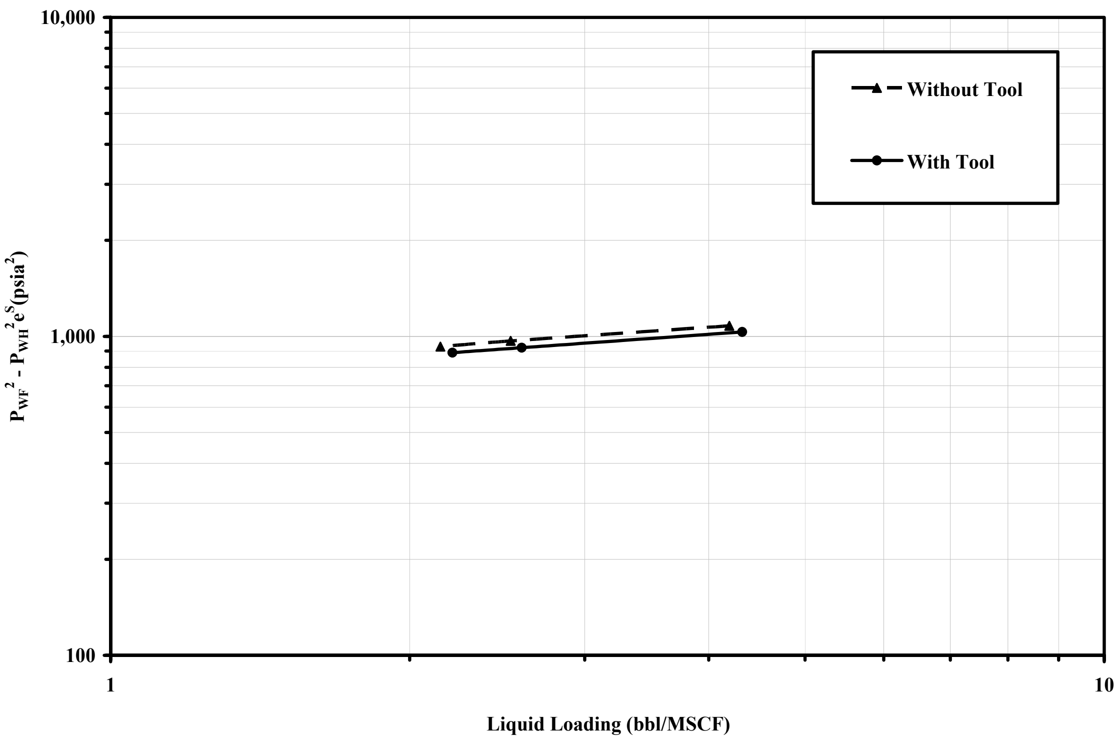


(a)



(b)

Fig. 9 - Pressure Loss at Different Liquid Loadings at (a) 10 psig (b) 20 psig (c) 30 psig



(c)

Fig. 9 – Continued