New Technology for Unloading Gas Wells

Final Report

July 1, 2005

to

December 31, 2006

by

Richard L. Christiansen

February 2007

Penn State Sub-Contract No. 2970-CSM-DOE-2098
DOE Award Number DE-FC26-04NT42098

Petroleum Engineering Department
Colorado School of Mines
Golden, CO 80401-1887
U.S.A

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Abstract

When initially completed, many natural gas wells are capable of blowing water and hydrocarbon liquids to the surface. But, with depletion of the reservoir pressure, there comes a time when liquids can no longer be lifted to the surface by the flowing gas and they begin to accumulate in the bottom of the well, dramatically inhibiting or stopping gas production. Tests in 2004 with the flow loop at the Colorado School of Mines (CSM) showed that constrictions in the well could help lift liquids, especially those that accumulate below the end of tubing (EOT). The primary objective of this project was to explore the benefits and alternate designs of constrictions below the EOT.

Using the flow loop in the High Bay Laboratory at the Colorado School of Mines, critical flow rates were measured for gas-water flow in a vertical annulus. This constricted geometry was chosen because it preliminary tests showed that it provided many of the benefits of constrictions and it could be easily implemented commercially. Indeed, some operators in the Rocky Mountains have used this approach below the EOT. The flow loop tests showed that the critical flow rate for the annular geometry was 20% to 50% lower than expected using the Turner-Hubbard-Dukler correlation for critical velocity combined with the cross-sectional area of the annulus.

A second objective of this project was to study transient phenomena and their effects on liquid lifting. Unfortunately, we made no progress on this objective because I left CSM.

The third objective of this project was to deliver short courses using the flow loop for demonstrations of liquid lifting problems and solutions. Three two-day short courses (October 2005, March 2006, and November 2006) were held with about 10 participants in each course. In addition, a half-day short course was delivered for 50 participants from the 2006 Gas Well De-Liquification Workshop that was held in Denver at the end of February 2006. These short courses were as beneficial for us as they were for the participants. The feedback from industry on our research directions was especially valuable.

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Introduction

Removal of water and hydrocarbon liquids from gas wells is increasingly recognized as an important topic for mature gas reservoirs. Accumulation of these liquids in the bottom of a gas well (often referred to as liquid loading) can cause two conditions: increased back-pressure on the reservoir, and reduction to gas relative permeability in the near-well region. Both of these conditions lead to reduced productivity. There are many approaches for reducing liquid loading: some are costly (pumps), and some are not (soap sticks).

In our previous research, we observed that liquid loading starts in the casing below the end of tubing (EOT) where the cross-sectional area is relatively larger, and the velocities are correspondingly smaller than in the tubing. We found that constrictions in the casing below the EOT could help lift liquids from the casing to the tubing. We tested a number of variations on this idea, including circular baffles, golf balls, and dead-end tubing extensions. We chose to focus attention on the third variation.

Dead-end tubing extensions have been implemented by a number of producers in the Rocky Mountain region. With dead-end tubing extensions, produced fluids flow up the annular gap between the casing and the tubing extension to the top of the perforated interval. At the top of the perforated interval, the fluids pass through a "cross-over sub" and into the tubing for the rest of the journey to the surface. This approach responds to two questions: Where should the EOT be placed in a long interval (1000 feet or more) of perforations? How can liquids below the EOT be lifted to the tubing? Hanging a dead-end tubing extension on the bottom of the tubing reduces the cross-sectional area for flow, which reduces the critical flow rate for lifting liquids. And, because the dead-end extension forces produced fluids to flow in the annular gap between the casing and the tubing, the EOT is effectively eliminated.

Although dead-end tubing extensions have been implemented by some producers, the benefits of the approach at the start of this project were not clearly defined. We were able to explore with flow-loop tests some of the variations in design that have been considered for dead-end tubing extensions. Results of these tests will be summarized below.

Following the Executive Summary, the approaches are reviewed that were used for the five tasks of this project. Then, the results of the five tasks are presented, followed by conclusions and references.

Executive Summary

With depletion of pressure in gas reservoirs, there comes a time when liquids (water and/or hydrocarbon condensate) can no longer be lifted to the surface by the flowing gas and the liquids begin to accumulate in the bottom of the well, dramatically inhibiting or stopping gas production. This liquid loading of gas wells has huge economic significance: about 50% of US production comes from wells with liquid loading. The general goal of this project was to better understand liquid loading and to find ways to reduce it.

The primary objectives of this project were to study effects of constrictions on lifting liquids below the end of tubing (EOT), to study transient effects during liquid loading, and to organize short courses to demonstrate key principles for unloading gas wells. Listed below are three tasks specific to these objectives.

Task 1: Constrictions below EOT. Use the existing flow loop in the High Bay Lab at CSM to experimentally study designs of constrictions for application to stripper gas wells.

Task 2: Transient Design Simulation of Gas Well Loading and Unloading. Use commercial flow line simulating software to investigate the effect of condensation, transient fluid flow, and transient heat transfer on performance of stripper gas wells.

Task 3: Liquid-Lifting Short Course. Organize short coursea on lifting liquids from gas wells using the CSM Flow Loop for hands-on demonstrations.

Accomplishments for each of these tasks are summarized below.

Task 1: Constrictions below EOT. Critical flow rates were measured for dead-end tubing extensions of two diameters in 4-1/2" casing. Critical flow rates were found to be 20% to 30% less than expected based on the Turner-Hubbard-Dukler correlation combined with the annular cross-sectional area.

Task 2: Transient Design Simulation of Gas Well Loading and Unloading. Unfortunately, we made no progress on this objective because I left employment with the Colorado School of Mines. Consequently, a portion of the project funds was not spent.

Task 3: Liquid-Lifting Short Course. Three two-day short courses (October 2005, March 2006, and November 2006) were held with about 10 participants in each course. In addition, a half-day short course was delivered for 50 participants in the 2006 Gas Well De-Liquification Workshop that was held in Denver at the end of February 2006.

Experimental - Description of Approaches

Task 1: Constrictions below EOT. An existing flow loop in the High Bay Lab in the Petroleum Engineering Department at the Colorado School of Mines was used to experimentally study the relationship between pressure drop and flow rate for foam flow.

The layout of the flow loop is shown in Figure 1. In brief, gas from the blower mixes with recycle liquid at the bottom of the test section, then the combined stream travels up inside the vertical test section, from which it is re-circulated to the gas-liquid separator. At the gas-liquid separator, the gas exits up to the blower, and the liquid exits down to the recycle pump. The vertical test section and portions of the recirculation lines are made of transparent PVC pipe to allow visual assessment of flow. The flow loop operates near ambient pressure and temperature.

For tests with dead-end tubing, the test section consisted of 4-1/2" OD transparent PVC casing, which has a 4.00" ID. The length of the casing was 10 feet for most tests; in a few tests, the casing was 20 feet long. Dead-end tubing of three outside diameters (2-3/8", 2-7/8", 3-1/2") was mounted inside the casing. For tests with 10-foot-long casing, the dead-end tubing was about 9' 10" long. For tests with 20-foot-long casing, the dead-end tubing was about 19' 10" long. The dead-end tubing could be centered in the casing, or placed against the casing, or in any intermediate position.

Two different methods were tested to determine the critical flow rate. In the first method (Fixed-Charge Method) that we used, 1 liter of water was charged to the bottom of the flow loop. Gas flow rate was incrementally increased, starting at a rate well below the expected critical flow rate. Any produced water was recycled to the base of the test section. Data obtained with this method, which were reported in quarterly reports, did not clearly indicate a critical flow rate.

In the spring of 2005, we found that another approach gives a relatively clear indication of the critical flow rate. In the this method (Constant-Water-Rate Method), water was circulated at a constant rate while gas rates were incrementally decreased, starting from flow rates well above the expected critical rate. At each gas flow rate, sufficient time was allowed to reach equilibrium loading of water in the test section. At the highest gas flow rate, volume of water in the test section was very small, less than 100 ml. With each incremental decrease of gas rate, the volume of water in the test section increased. We defined the critical flow rate as the rate at which the volume of water in the test section continued to increase without obtaining an equilibrium condition. This method provided a fairly objective indication of critical flow rate.

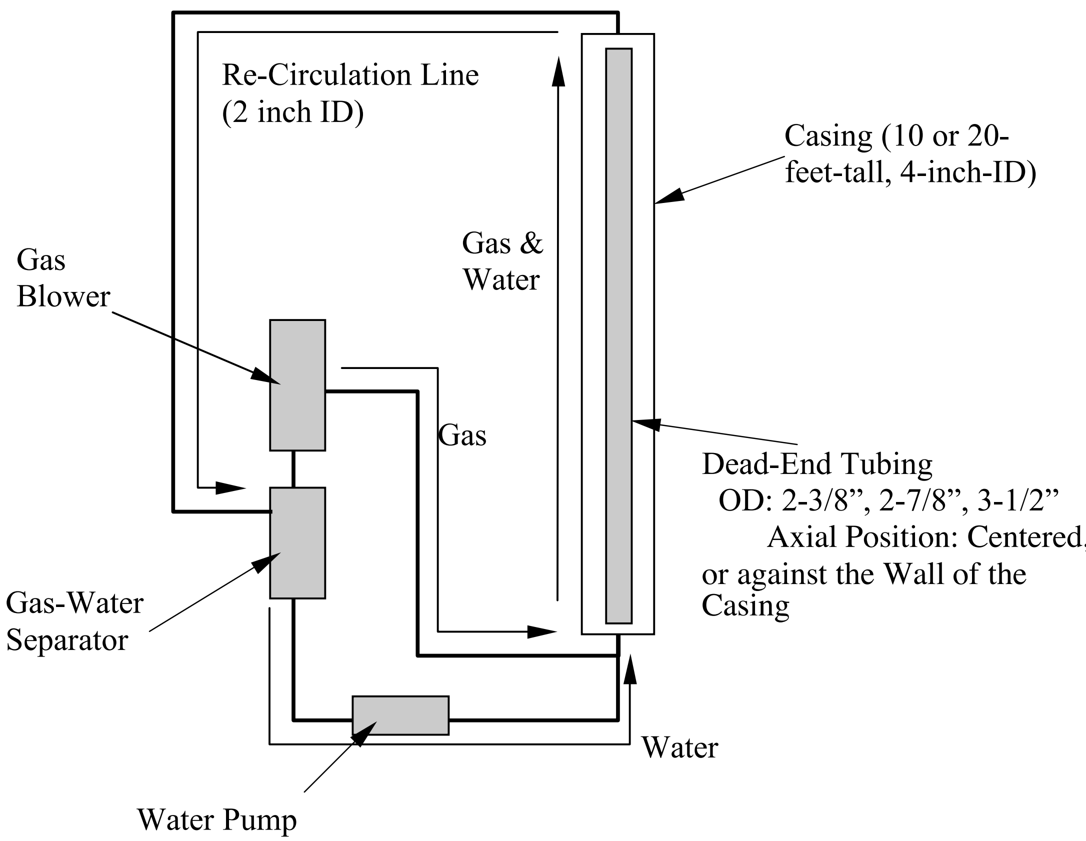

Figure 1. Schematic of Flow Loop.

Task 2: Transient Design Simulation of Gas Well Loading and Unloading. We planned to use commercial simulation software to investigate the effect of liquid condensation, phase behavior, transient liquid accumulation, transient multiphase fluid flow, transient heat transfer, and pumping on performance of stripper gas wells.

Task 3: Liquid-Lifting Short Course. The intent of these short courses is to provide a new opportunity for learning about multi-phase flow based on a broad set of demonstrations with the flow loop. The set of demonstrations includes topics such as critical flow and critical flow rates, foam flow, annulus flow, vortex flow, and plungers.

Results and Discussion

Task 1: Constrictions below EOT. Results from constant-water-rate tests are shown in Figures 2 through 6. Figure 2 shows results for 3.50" OD dead-end tubing in the 10-ft-tall casing. The "e" in the legend refers to eccentricity of the dead-end tubing. If the tubing is centered, e=0. If the tubing is fully against the wall, then e=1. Tests were performed with two water flow rates: 4 and 8 bbl/day. To clarify interpretation of these figures, let us consider the right-most collection of data in Figure 2, indicated as solid triangles. The connecting line through the points was added to show association of points; the trend of the line has no other meaning. The vertical axis gives the gas flow rate, and the horizontal axis gives the time elapsed after a reference time. For this particular series of measurements, the dead-end tubing was against the wall (e=1) and the water flow rate was 4 bbl/day. Ten groups of solid triangles appear in Figure 2, starting on the left with a gas flow rate of about 120 mcf/day and elapsed time of about 15 minutes. Starting at 120 mcf/day, the gas rate remained fairly constant for a couple minutes; so, data collection was stopped. The gas rate was decreased to about 110 mcf/day at 20 minutes. Again, the gas rate remained fairly constant, so data collection was stopped after a couple minutes. The same pattern repeated until the gas rate was reduced to about 62 mcf/day. After that reduction, which occurred just before 1 hour of elapse time, the gas rate declined to just under 60 mcf/day. This decline in rate corresponded to increased liquid loading in the annular gap between the dead-end tubing and the casing. Finally, in the 10 step of this series, the gas rate quickly fell to zero from its initial value of about 55 mcf/day as the annular gap loaded with water. Thus, the response to this series of stepped gas rates shows that the critical flow rate is between 55 and 60 mcf/day. The other three series of tests in Figure 2 yield a critical flow rate in the same range. For the series of tests in Figures 3 and 4, the casing was 20 feet long. The critical flow rates for these tests are also between 55 and 65 mcf/day. For the 3.50" OD dead-end tubing in the 4.00" ID casing, the length of the casing had no effect on observed critical flow rate.

Figures 5 and 6 show results for a 2.88" OD dead-end tubing in 10-foot-long, and 20-ft-long casing, respectively. Critical flow rates from Figure 5 are between 70 and 80 mcf/day. Results in Figure 6 show that the critical flow rate for e=1 exceeded 140 mcf/day. For centered tubing, the critical flow rate is between 80 and 90 mcf/day. For the 2.88" OD dead-end tubing in the 4.00" ID casing, the length of the casing did affect the observed critical flow rate: the critical flow rate was higher for the longer section of casing. Also, the critical flow rate was sensitive to side-to-side positioning of the tubing.

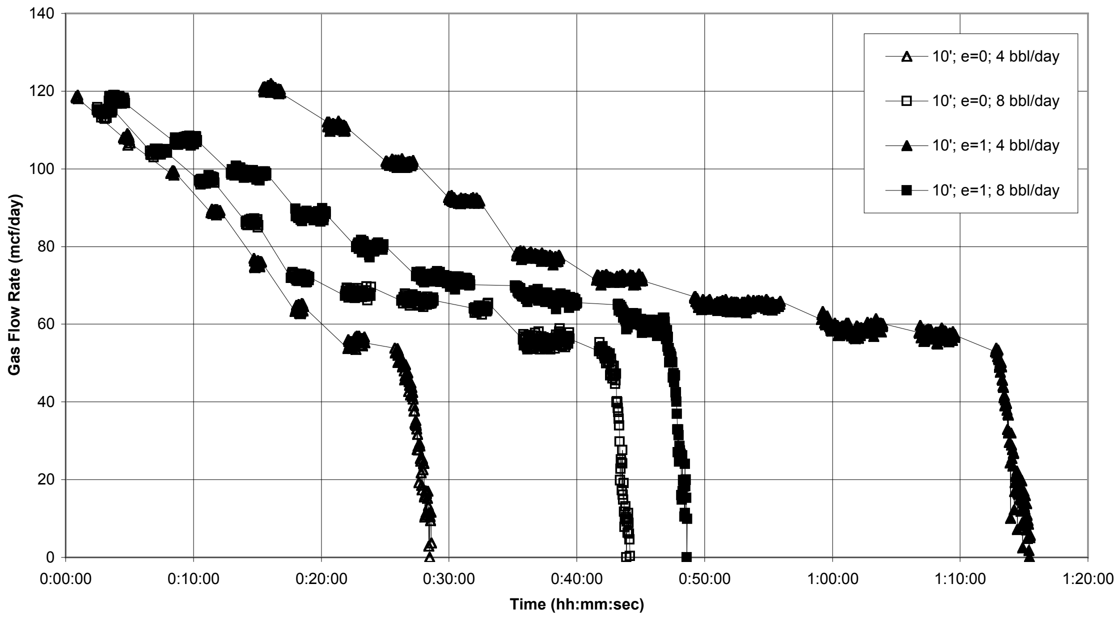

Figure 2. Results from Constant-Water-Rate Tests for 3.50" OD Dead-End Tubing in 4.00" ID by 10-Ft-Long Casing.

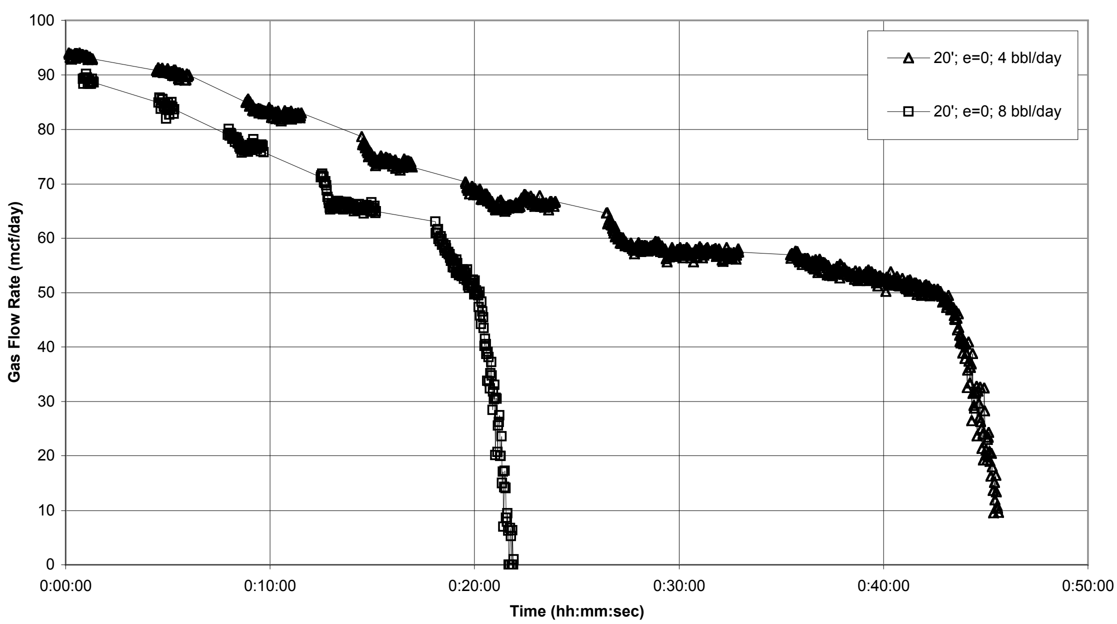

Figure 3. Results from Constant-Water-Rate Tests for 3.50" OD Dead-End Tubing in 4.00" ID by 20-Ft-Long Casing.

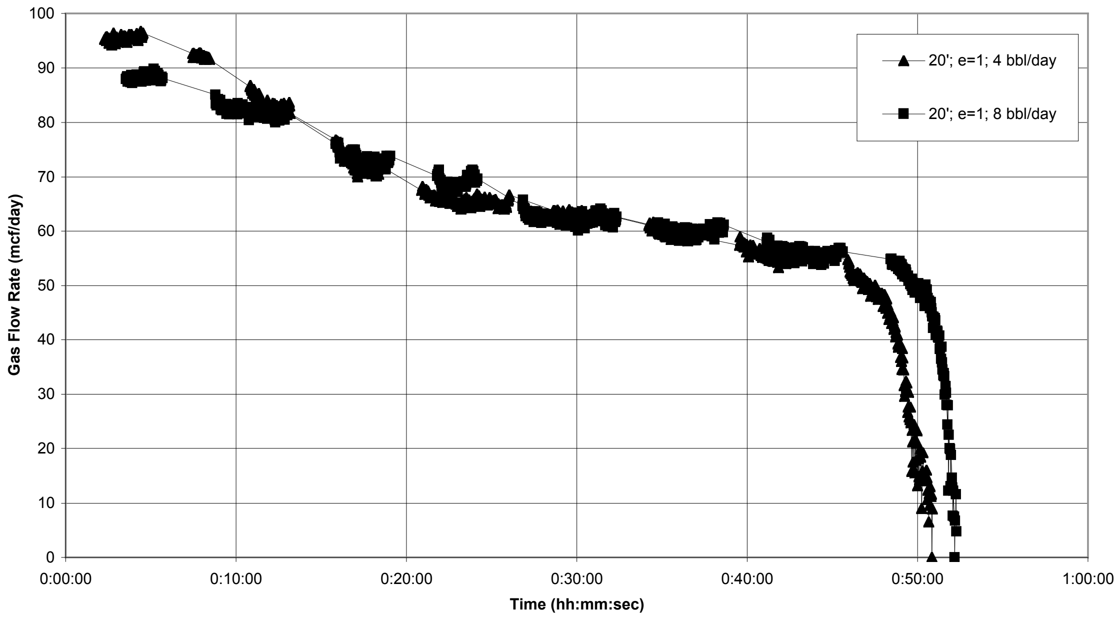

Figure 4. Results from Constant-Water-Rate Tests for 3.50" OD Dead-End Tubing in 4.00" ID by 20-Ft-Long Casing.

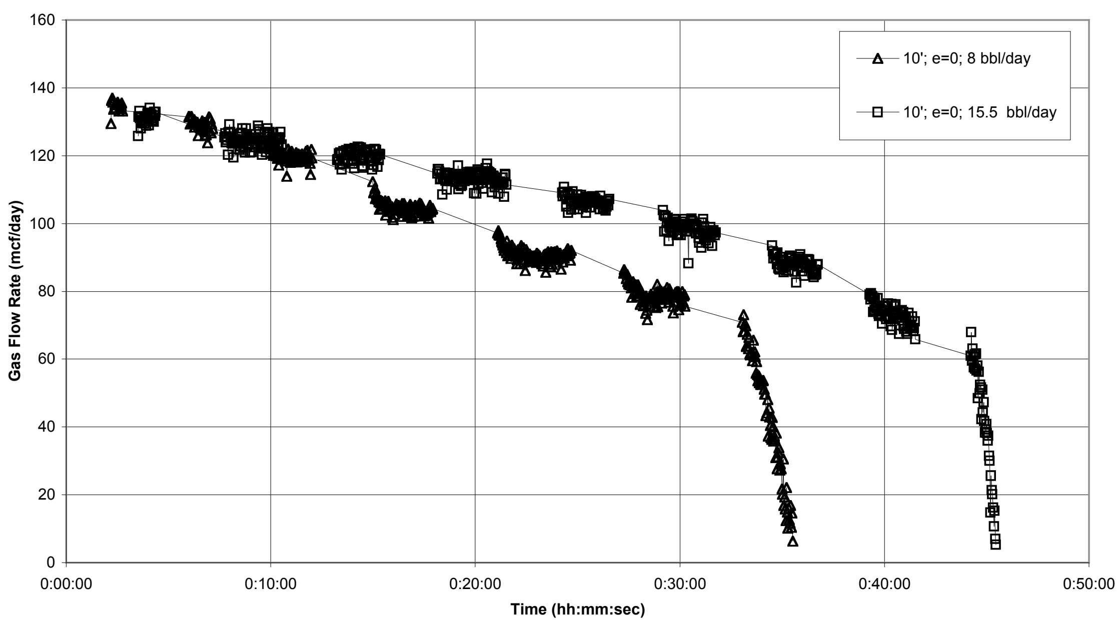

Figure 5. Results from Constant-Water-Rate Tests for 2.88" OD Dead-End Tubing in 4.00" ID by 10-Ft-Long Casing.

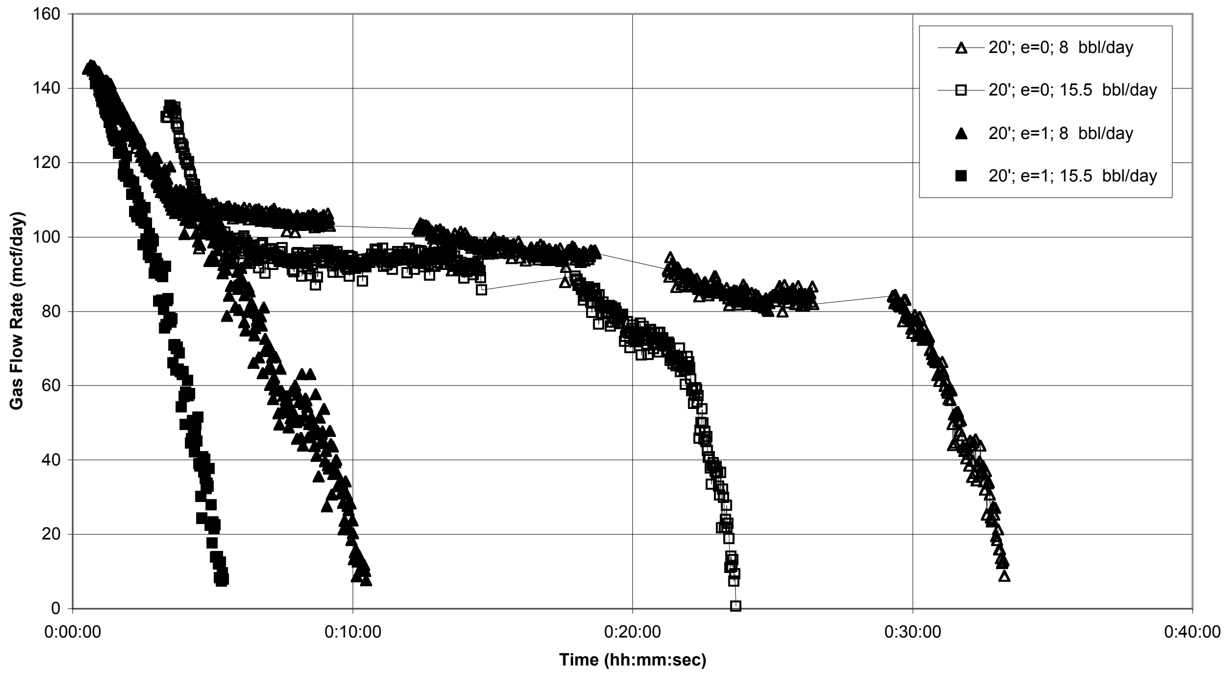

Figure 6. Results from Constant-Water-Rate Tests for 2.88" OD Dead-End Tubing in 4.00" ID by 20-Ft-Long Casing.

These results for critical flow rates are summarized in Table 1, and they are compared to the estimated rates based on the THD (Turner, Hubbard, and Dukler, 1969) correlation for critical velocity (without the 20% correction),[1]

$$v_c = 0.567\left[\frac{(\rho_l - \rho_g)\sigma_{gl}}{\rho_g{}^2}\right]^{1/4} \tag{1}$$

combined with the cross-sectional area of the annular gap. The definitions and units of Equation 1 are as follows:

v_c = critical velocity, ft/s
ρ_l, ρ_g = liquid and gas densities, g/cm3
σ = gas-liquid surface tension, dyne/cm

[1] We have found that the THD correlation without the 20% correction gives good estimates of critical flow rates for flow in a tube at the low absolute pressures (about 12 psia) at which the flow loop operates.

The observed critical flow rates for the annular geometry are 20% to 50% lower than estimated with Equation 1.

Table 1. Comparison of Measured Critical Flow Rates with Estimates using the Turner-Hubbard-Dukler (THD) Correlation.

Casing ID (in.)	Tubing OD (in.)	Measured Qc (Mcf/Day)	THD Qc (Mcf/Day)
4.00	2.88	70-90 (for e=0)	152
4.00	3.50	55-65 (for all e)	74

Task 2: Transient Design Simulation of Gas Well Loading and Unloading. As noted previously, we made no progress on this task because I left employment with Colorado School of Mines prior to completion of the project. A corresponding portion of the project funds was not spent.

Task 3: Liquid-Lifting Short Course. Three two-day courses were held (October 13 and 14, 2005; March 2 and 3, 2006; November 2 and 3, 2006) with about 10 participants in each course. These short courses were organized at the request of Marathon Oil Company; but in the third course, engineers from Chevron also participated. A portion of the time (3 to 4 hours) was allotted to general and specific discussion of liquid-lifting issues with a lot of participation by attendees. The remainder of the time was devoted to the following demonstrations with the flow loop:

Flow regimes (Bubble, Slug, Churn, Annular)
Loading-up of well with water and termination of gas flow
Breakup of water droplets (critical Weber number)
Critical flow rates (Compare flow loop observations with estimates from THD correlation)
Tubing-casing junction
Effect of tubing couplings and tubing inserts
Vortex tools
Plungers
Annular flow
Foam flow

The time for each demonstration varied from 30 minutes to 1 hour. The demonstrations inspired a lot of discussion.

In addition, a half-day course was delivered (February 27, 2006) for 50 participants from the 2006 Gas Well De-Liquification Workshop that was held in Denver from February 27 to March 1 of 2006. This short course contained many of the demos of the two-day courses, but at a much faster pace. A repeat of this short course was requested for the 2007 Workshop.

In addition to these short courses, we presented a paper at the 2005 SPE Annual Technical Conference and Exhibition on early results from this project (Christiansen et al., 2005). On January 26,2006, I gave an update on the project to the Production & Completions Study Group of the Denver Section of SPE.

Conclusions

1. Critical flow rate for flow the annular gap between tubing and casing was observed in a flow loop using a constant-water-rate method.

2. The critical flow rates obtained from these tests for 3.50" OD tubing in 4.00" ID casing were independent of eccentricity and length of the test section. For 2.88" OD tubing in 4.00" ID casing, the critical flow rates depended on eccentricity and length of the test section.

3. The observed critical flow rates are 20% to 50% less than estimated from the THD correlation (without the 20% correction).

Acknowledgements
Of course, the financial support from the Stripper Well Consortium is very much appreciated. Without it, none of this work could have been completed. In addition, I would like to recognize contributions of students: Eric Girija (an MS student who graduated in May 2006), Luke Riggins (a BS student who also graduated in May 2006), Garrett Elsener and Jed Wagner (both are BS students who will graduate in 2007). I also want to acknowledge support from Mr. Rob Lestz of Chevron, and Mr. Rob Sutton of Marathon Oil Company.

References

Christiansen, R. L., Girija, E., Riggins, L., Elsener, G., Sutton, R. P., and Smeenk, R.: "Lifting Liquid from Natural Gas Wells: Tubing-Casing Junction," Paper 96938 presented at the 2005 SPE Annual Technical Conference and Exhibition, Dallas, TX, October 9-12.

Turner, R.G., Hubbard, M.G., and Dukler, A., E., 1969 (November), "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells," *J. Petroleum Technology*, 1475-1482.