COILED TUBING IN ARTIFICIAL LIFT OPERATIONS

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ABSTRACT

Coiled Tubing has been used in oil and gas operations for many years, and has proven to be a very efficient, reliable, and economic tool. The coiled tubing technology has been utilized for drilling, completions, workover, stimulation, and plugging & abandonment work for decades, with considerable success. Coiled tubing for use in artificial lift operations has been somewhat limited, but in the economic environment existing today, new opportunities have been recognized.

This paper is focused on three main segments: CT-Lift in normal, rod-pumped wells where sand and scale may be problematic; CT-Lift in monobore wells or where damaged casing may preclude other options; and CT-Lift in gas well deliquification, where the coiled tubing essentially provides lift options both as a velocity string and as a reciprocating pump string to lift liquids which accumulate at the bottom of a well.

HISTORY AND EVOLUTION OF CT-LIFT TECHNOLOGY

CT-Lift as a form of coiled tubing usage began in 1994 when the idea to use CT as a production string was seen as a possible option to replace sucker rods in oil wells.
At that time the only known application using CT in artificial lift was to de-water gas wells, using CT for velocity strings.

While developing the idea of using CT as static production string by the use of hydraulic pulses, a novel idea started to take shape, that being to use CT reciprocating axially as a "hollow sucker rod" string. With no boxes or pin connections, tubing wear and rod connection wear are no longer problems.

Both CT applications, one static and one dynamic, have been tested since the late 1990's. While most of the tests showed encouraging results, market conditions delayed further applications.

Additional technology testing and rising price of oil during the last couple of years have again made attractive the commercial application of CTLift, in gas and oil wells.

LESSONS LEARNED

Fatigue analysis based on reciprocating motion, yield of CT material and cross sectional areas, makes it possible to predetermine life of CT string in a given well conditions. See Figures 1&2, below.

Also it is important to maintain compatibility between the ID of the coiled tubing string and the pump plunger OD. A recent experience confirmed that a minimum difference needs to be observed between these two diameters, especially in deeper applications because of force / pressure /area relationships.
Transferring fluid from the pump to surface, through the ID of the coiled tubing, requires compression forces that can induce "buckling".

The buckling effect can be severe and depending on pump plunger diameter, ID of coiled tubing, and pump depth. See Figure 7.

Experience shows that the most typical combination is using 1 1/4" or 1 1/2" OD CT inside 2 7/8" production tubing (or 2 7/8" csg in the case of Slim Holes or Monobores).

Throughout the years CT Lift was tested using a wide range of pumping units on surface; from a small D-25 Figure 5 &6 to 114, 456, 640, Conventional units, Mark II's, and Rotaflex, to a modern, new design of hydraulic pumping unit Figure 4

With existing technologies and materials, CTLift can be safely deployed to depths up to 6,500 ft. Further testing might prove that even deeper pump setting depths may be achieved.

Considerations regarding ability to remove solids to surface via CT versus standard configuration sucker rods inside production tubing are shown in Figures 8 & 9, below showing that if you are below the curves the solids corresponding to the sieve size on the X axis will not be transported up the tubing and will accumulate over the pump and accelerate failures.

Figures 8 and 9 are developed from the following force balance:

$$\frac{g}{g_C}\left(\rho_{solids} - \rho_{lauid}\right)\frac{\pi d^3}{6} = \frac{1}{2g_C}\rho_{liquid} C_D A_d V^2$$

The A is the area of the tubing/annulus open to flow. The V is the settling velocity of the solids in the tubing liquids. The Cd is the drag coefficient of the solids in the liquids as a function of Reynolds Number. The relationship of the Cd to Reynolds number is available from fluid dynamics.

Example

Using Figure 8, and checking for 2 3/8"s tubing and ¾"s rods the settling rate is about 78 bpd for 30 sieve size solids so if the pumping is below this, then solids will not come up the tubing/rod annulus and will stay above the pump contributing to early failure. Suppose then instead trials are made to pump 50 bpd with 2 3/8"s and 7/8"s rods and this is below the solids settling velocity or settling rate.

So suppose CT is used as "rods" with an approximate ID of 1 inch.

The velocity (rate) needed for the 2 3/8"s and 7/8"rods is:

Area for flow for 1" ID CT is .785 sq/in
Area for flow between 2 3/8's and 7/8's rods is 2.533 sq in
Rate,settling = 78 bpd/(Area between tubing and rods) in bpd/sq in from Figure 8

Rate needed is 78 bpd/ 2.533 bpd/sq in = 30.8 bpd/sq in
V with 58 bpd in 2 3/8's tubing / 7/8's rods is 58/2.533 bpd/sq in = 22.98 bpd/sq in
V with 58 bpd in 1" CT is 58/.785 bpd/sq in = 73.8 bpd/sq in

So the velocity in the 1" string exceeds the needed settling velocity **so use of CT with 1" ID will lift 30 sieve solids up the tubing/rod annulus.**

GAS WELL DELIQUIFICATION

An important consideration for the use of Coiled Tubing Lift is in gas well deliquification or dewatering. Considerable work has been done on this subject, and Coiled Tubing Lift has proven to be a viable alternative. Installations in Canada have proven the concept, where the fluid velocity increase when using Coiled Tubing is sufficient to lift the liquids from the well.

This process is further described below:

Turner (Ref 1) modeled the rise of droplets in an upward gas stream to find the minimum (critical) velocity and rate to lift droplets upward. When they no longer rise, then the gas and liquid stream is said to be liquid loaded. The equations of the Turner development are as follows:

$$V_{C,water} = 5.321\frac{\left(67 - .0031P\right)^{1/4}}{\left(.0031P\right)^{1/2}} \ ft/s$$

$$V_{C,cond} = 4.043\frac{\left(45 - .0031P\right)^{1/4}}{\left(.0031P\right)^{1/2}}\ ft/s$$

$$q_{t,condensate}(MMscf\ /\ D) = \frac{.0676P\,d_{ti}^{\ 2}}{(T+460)\,Z}\frac{(45 - .0031P)^{1/4}}{(.0031P)^{1/2}}$$

$$q_{t,water}\,(MMscf\ /\ D) = \frac{.0890P\,d_{ti}^{\ 2}}{(T+460)Z}\frac{(67 - .0031P)^{1/4}}{(.0031P)^{1/2}}$$

Example: Assume 4 ½ casing, and 2 7/8's tubing, GG: .7, 100 F, WHP: 100 psia, the critical rate is 608 MscfD. So flow up the casing would have to be 0.6 MMscfD before liquids are entrained up the casing or another way of saying would have to exceed this rate to not be liquid loaded. What about flow up the 2 7/8s? According to Turner, 468 MscfD and higher would be required to prevent liquid loading.
Now assume that the flow of gas is up a 1" ID CT. Now only 78 MscfD or more is needed to lift liquids with the gas up the CT when gas is allowed to flow up the 1" ID CT. Note: CT must be used with caution as small ID CT can eliminate liquid loading but if too small the additional friction generated can be just as bad as liquid loading.

Nodal Example of Use of Smaller Tubing ID to Combat Liquid Loading.

Figure 10 is tubing diameter study for gas well The curve sloping downward to the right is the gas inflow curve from the formation or the IPR. The 1.995 and 2.441" ID examples are still sloping down to the right at the points of intersection with the IPR and as such are unstable or still liquid loaded. The 1" ID and the 1.3" ID are both non-liquid loaded but the 1" ID shows less production and a greater upward slope due to friction. As such one would choose the 1.3 " ID CT for this example and this time in the life of the reservoir.

SUMMARY AND CONCLUSIONS

The use of Coiled Tubing Lift offers several options available to Operators in today's Oil and Gas operations, including:

*Use CT Lift in producing sand and scale particles in pumped fluid, due to increased fluid velocities, reducing particle build-up and "sanding-up" of rod-pumped wells

* Consider CT Lift options for wells with damaged casing or frequent workovers due to rod problems, pump problems, worn tubing issues, etc.

* CT Lift provides offerings for alternative well cleanout, chemical circulation, and preventive maintenance.

*CT Lift can be used for Deliquification of liquid-loaded gas wells, as a pumping method and as a velocity string method of removing fluids from the well and improving production.

Before you abandon any well, please give CT Lift some consideration!

REFERENCES

1.) Turner, R. G.; Hubbard, M. G. and Dukler, A. E. “Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells”, J. Pet. Tech., Nov. 1969. pp.1475-1482.

2.) Falk, K.; Birkelbach, L;Rowland, Leniek S.; et al. “Artificial Lift Solutions Using Coiled Tubing”, SPE 74882, SPE/ICoTA Coiled Tubing Conference, Houston, Texas 2002

3.) Solanet, Fernando; Paz, Luis – YPF Petrol; Leniek, Bert – Zeitecs / Coiled Tubing Americas; SPE 56671; SPE-ATC , Houston, Texas, 1999

4.) Patterson, John, J. Curfew, M. Brock, D. Braaten, J. Dittman, and B. Williams: "Progress Report #3 'Fluid Slippage in Down-Hole Rod-Drawn Oil Well Pumps'," Proc, Forty-Seventh Annual Southwestern Petroleum Short Course, Lubbock, Texas (2000), 117-136

5.) Lea, James F.: "Modeling Forces on a Beam Pump System When Pumping Highly Viscous Cmde," paper SPE 20672 presented at the 1990 Annual Technical Conference and Exhibition, New Orleans, 23-26 September

6.) Gibbs, S.G.: "Predicting the Behavior of Sucker-Rod Pumping Systems," JPT (July 1963) 769-778

7.) Sas-Jaworsky II, Alex and Troy D. Reed: "Predicting frictional pressure losses in CT Annuli: An Improved Method," Worid Oil (April 1998) 79-84

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Parameters

- 6540 ft CT
- 1.25 In ODx0.100 to 0.131 wall (tapered various sections)
- 300 ft fluid level above pump intake
- CT filled with fresh water
- 3 SPM
- 120 inch stroke
- 1.75” pump bore
- QT-900 CT (90 ksi)

Figure 1

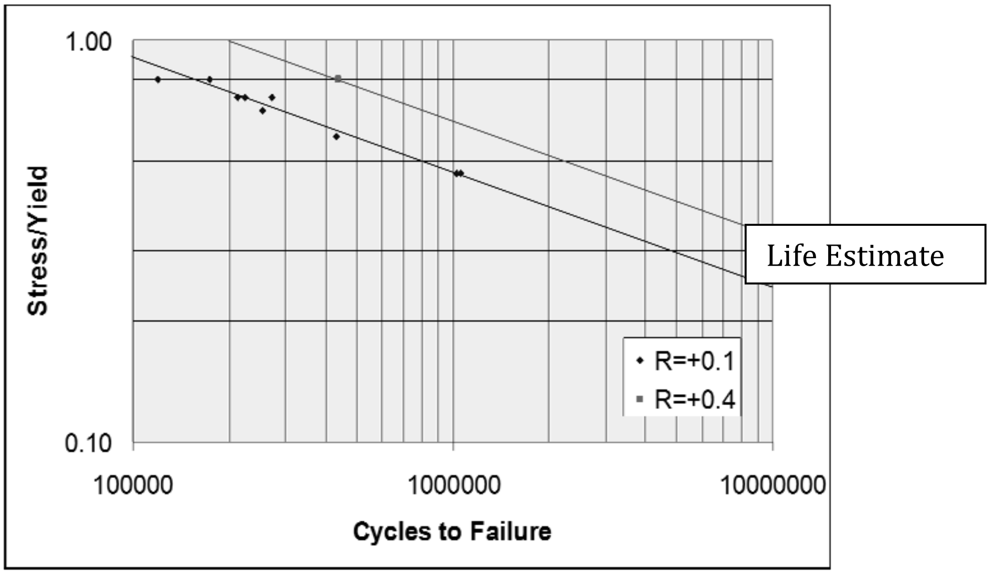


Figure 2

	Parameter	Units	Annulus
Upstroke/Valve closed	Topside force	lbf	2266
	Bottomside force	lbf	312
	Net force	lbf	1954
Downstroke/Valve open	Topside force	lbf	153
	Bottomside force	lbf	4598
	Net force	lbf	-4445
	yield strength	psi	90000
	CT weight (dry)	lbf	8942
	Neutral buoyancy depth	ft	3244
Stress at surface	Stress cycle amplitude	psi	17713
	Average stress	psi	21303
	Max stress	psi	30160
	Min stress	psi	12447
	R stress ratio		0.41
	Pump rate	spm	3
	Life	cycles	1.00E+07
	Static Life	years	6.3
	Dynamic max stress	psi	31160
	Life	cycles	1.00E+07
	Dynamic life	years	6.3

Figure 3

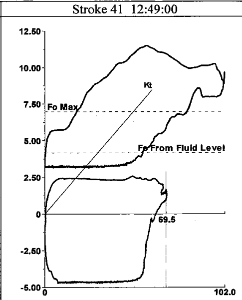
Figure 4 - CT-Lift System on Modern, Hydraulic Long Stroke Pumping Unit

Figure 5 - CT-Lift System on Old Field, Old Pumping Unit

Figure 6 - CT-Lift System on Old Field, Old Pumping Unit

Dynamometer Analysis

Multiple dynamometer runs were performed to insure data quality and consistency. Summary dynamometer cards are presented with analysis.

12/02/10	Stroke 41 12:49:00	
Surface Loads Card Pump Loads Card		High negative pump loads/low surface loads indicate the coil is spaced out too low and the coil is stacking out on bottom. The coil was re-spaced multiple times with the same results each time. Testing was shut down for the day waiting on a crane to re-space the coil.

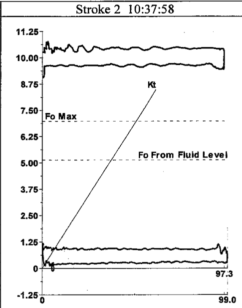
12/03/10	Stroke 2 10:37:58	
Surface Loads Card Pump Loads Card		The coil was re-spaced using a crane. This dyno was run while the crane was stroking the coil. The coil is no longer stacking out on bottom but the loads indicate there is no pump action present.

Figure 7

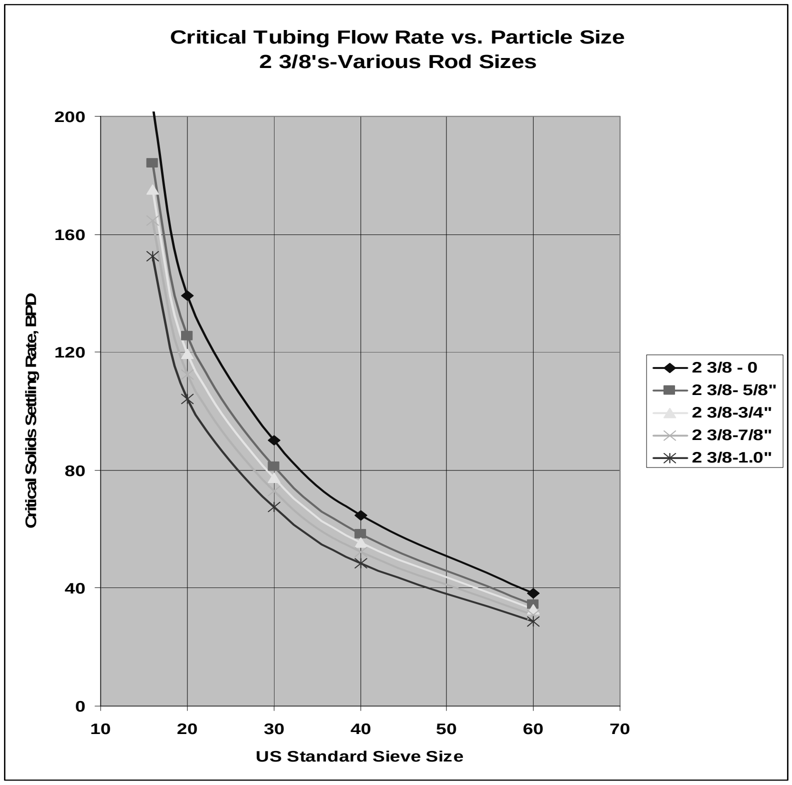


Figure 8 - Settling Velocity for 2 3/8's Tubing

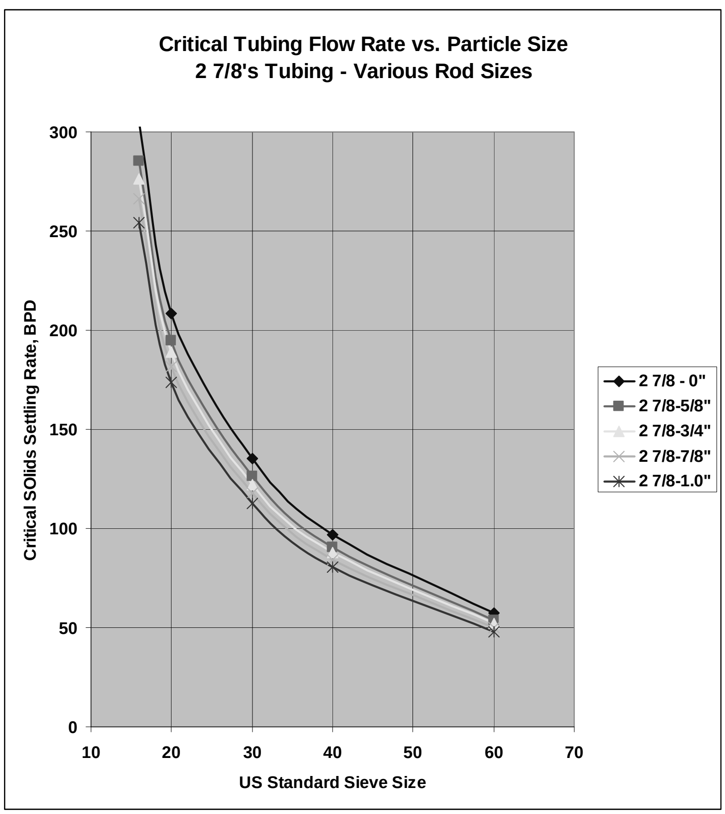


Figure 9 - Settling Velocity for 2 7/8s

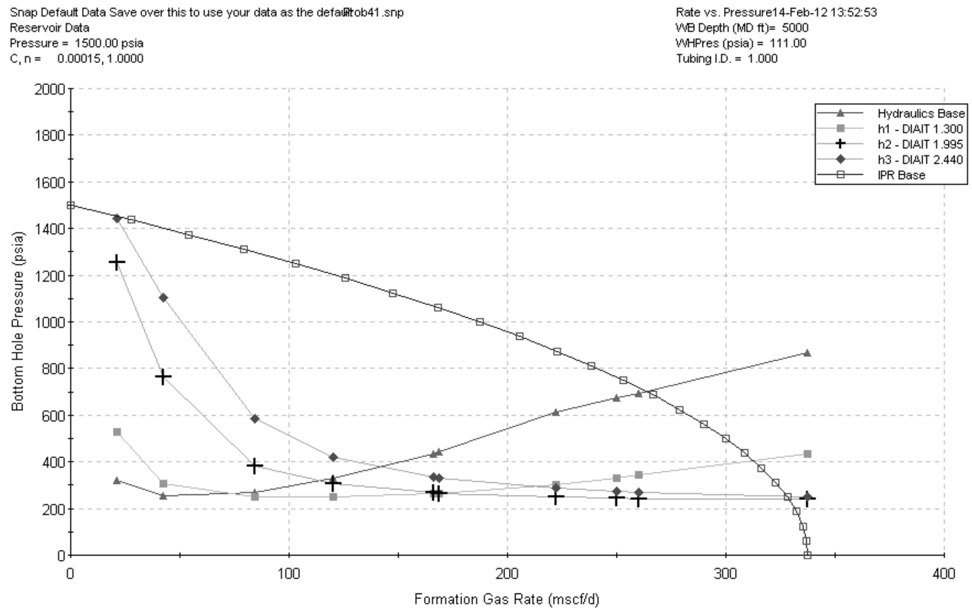


Figure 10 - Effect of tubing sizes on liquid loading and friction. Nodal Analysis. From SNAP program, a Ryder Scott Program.