SPE 74832

Artificial Lift Solutions Using Coiled Tubing

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This paper was prepared for presentation at the SPE/ICoTA Coiled Tubing Conference and Exhibition held in Houston, Texas, U.S.A., 9–10 April 2002.

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Abstract

The versatility of coiled tubing continues to expand its field of application. The latest sector that has seen the advent of this unique tubing material is the artificial lift business. The concept of replacing jointed sucker rod with continuous coiled tubing has been investigated, evaluated and successfully applied.

There are a number of design and operational advantages benefiting oil and/or gas producers that can be achieved with this new system. Completion size limitations, connection failures and completion repair issues are just some of the motivators for this innovation. Being a new application, there are still a number of design and operational parameters to study. However, test installations have already shown strong promise.

This paper will summarize the operational benefits of this new system and will focus on a recent installation and pumping performance in a high volume oil producer in the Permian Basin. It will also address a number of areas for technological improvement that are planned to advance this innovation.

Introduction

Coiled tubing rod strings (CTRS) offer a new means of dealing with some very old problems in the field of artificial lift. Utilizing conventional surface mechanical systems and standard downhole pumps, CTRS allows the operator to employ a different approach to transmit lifting energy, as well as having more options for completing their wells.

The innovation of CTRS is that the operator uses a continuously milled tubing product (coiled tubing) to connect to his downhole reciprocating pump for mechanical actuation. The resultant productive fluid flow is carried to surface inside of the coiled tubing string. The two main advantages being the elimination of conventional sucker rod connections and their associated problems, as well as a true slim-hole completion option.

To evaluate the CTRS system, a test well installation was arranged in the Permian Basin in West Texas. Many details of this new methodology were successfully worked out and documented through this process.

CTRS Concept

The CTRS concept was originally developed in Argentina and was subsequently patented in various jurisdictions – including the US and Canada. An international oil company and a US based consulting firm were looking to develop a method to complete slim-hole wells in Argentina when they came up with the idea[5,6,7].

Using coiled tubing (CT) to replace conventional sucker rod, and configuring a standard rod pump such that the output flow travels to surface inside the CT (Figure 1) allows for a significant reduction in the size of completion needed for a given productive flow rate. It also reduces the tubular components needed for the completion as the CTRS string doubles as both the rod string and the production tubing (Figure 2).

A number of other physical benefits are anticipated from this innovation and are currently being evaluated.

CTRS Completion Details

For most applications the downhole components of a CTRS completion consist of a CTRS string, a pump and an anchor. All of these components are deployed and landed in one trip in the hole. At surface, the CTRS string extends through the wellhead to the bridle and is hung off using a polished rod clamp. In this way, the CTRS also acts as its own polished rod through the stuffing box. Connected to the top of the CTRS string is a fitting with a curved steel tubular swivel joint, which in turn is connected to a flexible pressure

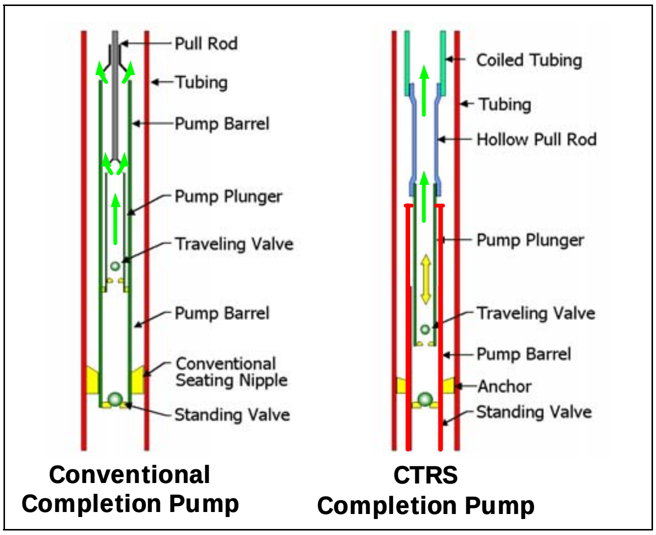

Figure 1: Pump Configurations

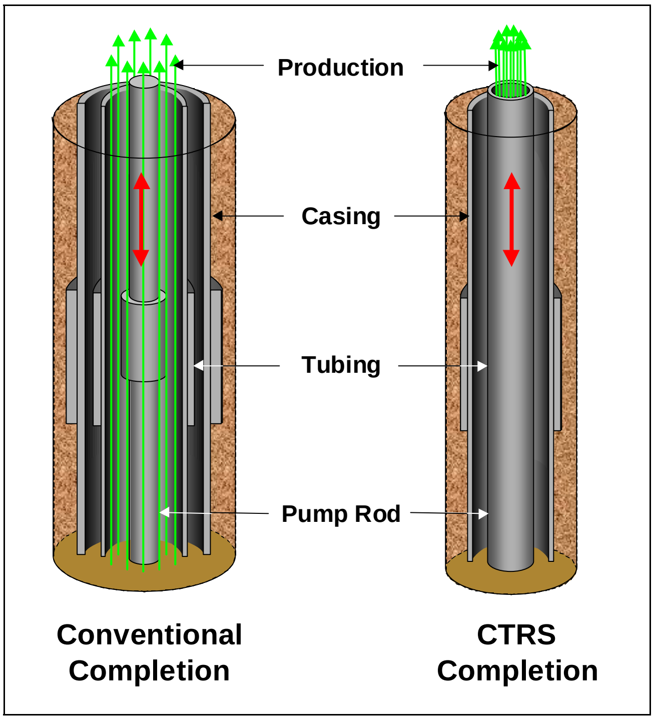

Figure 2: Completion Size Issues

hose that finally ties into the surface flow line (Figure 3). It is important to note that when the CT is being installed, a set of straightening rollers is used to ensure that the residual curvature is removed from the string.

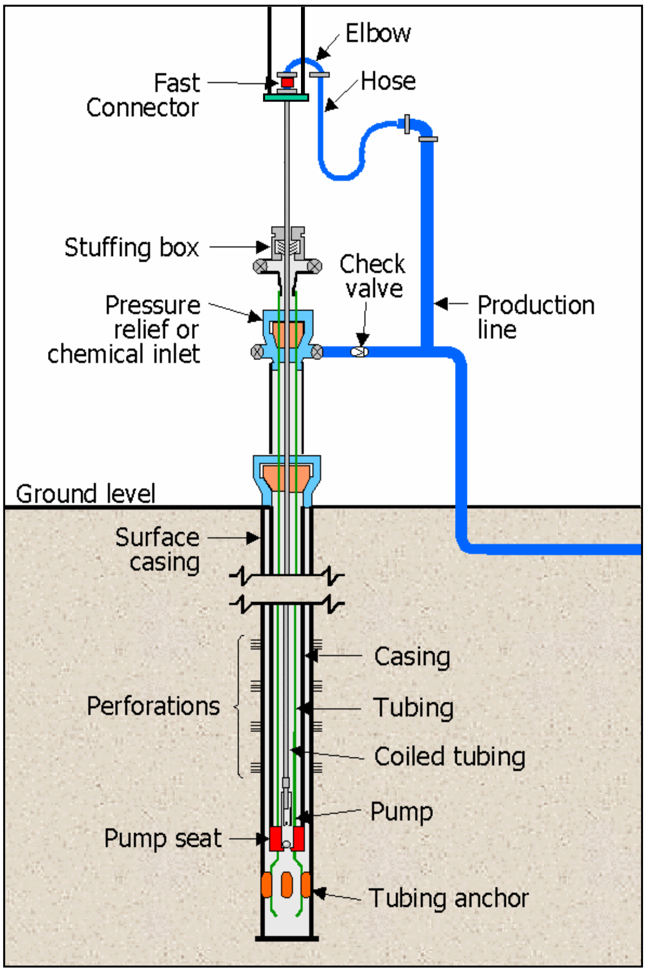

Figure 3: CTRS Completion Details

Mechanical Issues

There are a number of mechanical benefits with CTRS completions due to the fact that only one downhole connection is required – as opposed to the multiple of sucker rod couplings in a conventional completion. The single CTRS connector joins the bottom of the CT string to the pump and therefore is only loaded by the weight of the fluid and any resultant inertia through the pump cycle.

It is reasonable to anticipate that eliminating multiple couplings should result in a significant reduction in down time and service activity typically required retrieving and repairing rod strings that have failed due to coupling failure. While the concept is sound, only time and experience will prove the validity of this claim.

Not having any couplings also means that the CTRS material is “slick” or uniform in diameter along its length. This is anticipated to have two main advantages over conventional jointed rods.

The first advantage from this is that contact wear associated with a sucker rod working back and forth in completion will be minimized if not eliminated. As seen in figure 4, in the Conventional Completion, the geometry created by the coupling / rod configuration can result in relatively high stress concentrations at the contact points if the completion is not perfectly vertical. For CTRS applications this normal force is well distributed and will have a better chance of staying below any critical level for accelerated abrasive wear to take place.

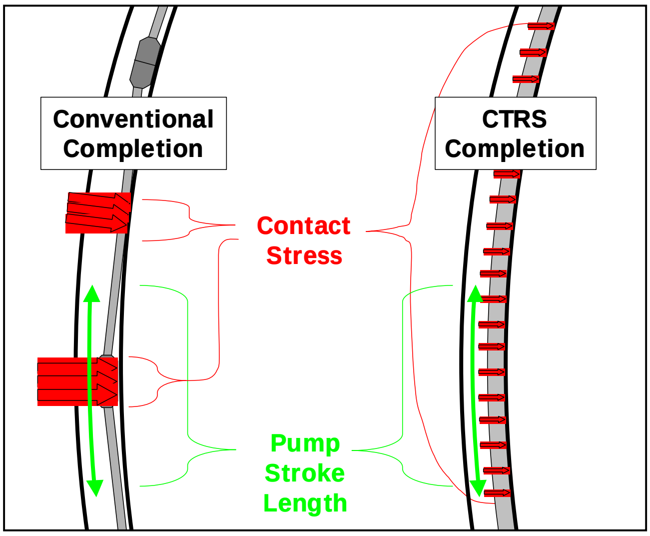

Figure 4: Contact Stress Distribution

Another physical differentiation affecting wear is the difference in stiffness between sucker rod and CTRS. While CTRS can be specified in sizes ranging from 1" to 3 ½", typical diameters will range from 1 ¼" to 1 ¾".

To illustrate this difference, we will compare the stiffness characteristics of 1" sucker rod with 1 ¾"; 0.156" wall CTRS.

First of all, we will determine the cross-sectional area of each where:

D_1 = sucker rod OD
D_2 = CTRS OD
t = CTRS wall thickness

<u>Sucker Rod Cross-sectional Area:</u>

$$A_{SR} = D_1^2\ \pi / 4$$
$$= 1^2\ \pi / 4$$
$$= \underline{0.785\ in^2}$$

<u>CTRS Cross-sectional Area:</u>

$$A_{CTRS} = (D_2^2 - (D_2 - 2t)^2)\ \pi / 4$$
$$= (1.75^2 - (1.75 - 2 \times 0.156)^2)\ \pi / 4$$
$$= (3.06 - 2.07)\ \pi / 4$$
$$= \underline{0.777\ in^2}$$

Therefore in this example both are nearly equivalent in area but the sucker rod is slightly larger and therefore slightly heavier and stronger than the CTRS (by 1% assuming similar density and yield / ultimate strength properties).

Now, looking at the polar moment of inertia for each of these examples we have:

<u>Sucker Rod Moment of Inertia:</u>

$$I_{SR} = \pi\ D_1^4 / 64$$
$$= \pi\ 1^4 / 64$$
$$= \underline{0.049\ in^4}$$

<u>CTRS Moment of Inertia:</u>

$$I_{CTRS} = \pi\ (D_2^4 - (D_2 - 2\ t)^4) / 64$$
$$= \pi\ (1.75^4 - (1.75 - 2 \times 0.156)^4) / 64$$
$$= \underline{0.25\ in^4}$$

<u>Ratio of Polar Moments of Inertia:</u>

$$\text{Ratio} = I_{CTRS} / I_{SR}$$
$$= 0.25 / 0.049$$
$$= \underline{5.10\ \text{or}\ 510\ \%}$$

What we have seen here is that even though the material cross-sectional area of each of these samples are almost identical, the buckling stiffness of CTRS is over 5 times that of comparable strength sucker rod. It is obvious that this relationship will hold true for other CTRS versus sucker rod comparisons due to the tube vs rod geometry issues.

Assuming that with both sucker rod and CTRS there is compressive stress at some point in the string during the down stroke, steel to steel contact will result from sinusoidal or helical buckling. Material stiffness defines the amount of rod deformation in the down-stroke and the normal force is calculated as follows[(3)]:

$$\text{Normal force} = (ID_T - D_R) \times F_A^2 / 4EI$$

Where:

ID_T = inside diameter of the tubing
D_R = diameter of the rod
F_A = the axial force

For comparison sake, consider two comparable wells, one with sucker rod and the other with CTRS – using the same 1" sucker rod and 1.75" CTRS as in the previous part of this example. We will specify that each is installed in 6.4 lb/ft, 2 7/8" tubing and that in the down stroke there is a 500 lb resistive load.

Sucker Rod Normal Force:

$$NF_{SR} = (ID_T - D_R) \times F_A^2 / 4EI$$
$$= (2.441 - 1) \times 500^2 / (4 \times 30E6 \times 0.049)$$
$$= \underline{0.061 \text{ lb/in}}$$

CTRS Normal Force:

$$NF_{CTRS} = (ID_T - D_{CTRS}) \times F_A^2 / 4EI$$
$$= (2.441 - 1.75) \times 500^2 / (4 \times 30E6 \times 0.25)$$
$$= \underline{0.0056 \text{ lb/in}}$$

Ratio of Normal Forces:

$$\text{Ratio} = NF_{CTRS} / NF_{SR}$$
$$= 0.056 / 0.61$$
$$= \underline{0.092 \text{ or } 9.2\%}$$

Therefore the normal force resulting using CTRS will be less than 10% that of a conventional rod string. Also, keep in mind that the above calculation results in a liner stress or a value of "force per length". In actuality the sucker rod force will manifest at contact points – rather than be fully distributed. It would be difficult to specify exactly which points of the sucker rod will be contacting during this action but we can look at this further to define the upper and lower boundaries of the magnitude of this contact condition.

To identify the range over which this phenomenon will be bound we can look at one case where the entire 25-ft length of sucker rod is in contact. For the other end of this range we can see what happens if only the coupling is contacting.

Total Normal Force for Sucker Rod in Full Contact:

$$NF1_{25ft} = \text{length} \times \text{NF per length}$$
$$= 25 \times 0.061 \times 12$$
$$= \underline{18.3 \text{ lbs}}$$

Taking a moment to evaluate CTRS under these conditions we have:

Total Normal Force for CTRS in Full Contact:

$$NF2_{25ft} = \text{length} \times \text{NF per length}$$
$$= 25 \times 0.056 \times 12$$
$$= \underline{1.68 \text{ lbs}}$$

Getting back to the sucker rod analysis, we have seen that conventional sucker rod under these loading conditions will develop 18.3 lbs of normal force along a 25-ft length if the entire length contacts the completion. Using this loading, and for a moment considering only the couplings in contact with the completion, the resultant linear contact stress would be as follows (with a 4" coupling):

$$NF_{coupling} = 18.3 / \text{coupling length}$$
$$= 4.58 \text{ lbs/in}$$

Obviously the loading is not likely to occur only at the coupling contacts, nor is it likely to be fully distributed along the length of the rod. Therefore the actual value will likely fall somewhere between 0.061 lbs/in and 4.58 lbs/in. Comparing this with the previously calculated value of 0.0056 lb/in for CTRS, the normal force is significantly higher for sucker rod – even in the best case scenario. Past work has verified the relationship between normal force and tubing or rod wear[1,4] and that with linear increases in contact pressure there will be an exponential increase in wear.

Higher stiffness also should help the efficiency of the pumping operation. Being stiffer, CTRS should require less sinker bar weight or be more effective in large diameter completions.

Flow Issues

Another area where CTRS stands to offer operational benefits is in the fluid dynamics of the system.

First of all, in conventional sucker rod installations the productive flow is required to travel up the sucker rod / production tubing annulus to reach surface. While this is a relatively large annulus overall, the sucker rod couplings create restrictions to flow (Figure 5).

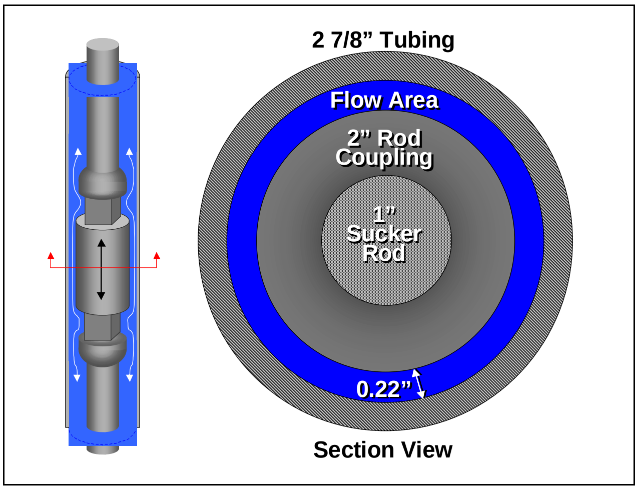

Figure 5 : Sucker Rod Flow Profile

Considering a 4,000 ft completion with 25 ft sucker rods, there are then going to be roughly 160 couplings where this restricted flow condition will occur. Two consequences can be attributed to this pressure drop. One is that the efficiency of the pumping operation may be adversely affected. The other is that in areas where asphaltines and paraffins are present, it is possible that this repeated pressure surging of the fluid as it moves up the hole can result in a favorable condition for the deposition of these materials.

The overall size of the annulus may further contribute to deposition when compared to an alternative CTRS completion.

Again, using the above 4,000 ft sample completions, The respective flow path volumes are as follows:

Vol_{SR} = 19.3 bbls

Vol_{CTRS} = 8.1 bbls

If we pump each of these completions at the same rates as before – i.e. – 600 BFPD, the bottoms up times are as follows:

<u>Sucker Rod Bottoms-up Time:</u>

$B.U.T._{SR} = Vol_{SR} \times Q$
$= 19.3 \times 600 / 1{,}440$
$= \underline{8.04\ \text{min}}$

<u>CTRS Bottoms-up Time:</u>

$B.U.T._{CTRS} = Vol_{CTRS} \times Q$
$= 8.1 \times 600 / 1{,}440$
$= \underline{3.38\ \text{min}}$

<u>Bottoms-up Time Ratio:</u>

$Ratio = B.U.T._{CTRS} / B.U.T._{SR}$
$= 3.38 / 8.04$
$= \underline{0.42 \text{ or } 42\%}$

Therefore the fluid in the CTRS completion reaches surface in 42% the time that it would take in the conventional completion. When temperature is an issue for the depositional environment it is possible that this will help prevent or at least reduce the build up of paraffin and asphaltine.

CTRS Case History

The rest of this paper will detail the installation and performance of a CTRS completion in a high volume oil well in West Texas.

Field History

The Goldsmith Field is located in north-central Ector County, Texas, and is situated on a large NW-SE trending anticline on the eastern side of the Central Basin Platform. Production is from six reservoirs: Grayburg, San Andres, Clearfork (5600'), Tubb, Devonian, and Ellenburger. The two most prolific reservoirs are the San Andres (4200') and the Clearfork (5600').

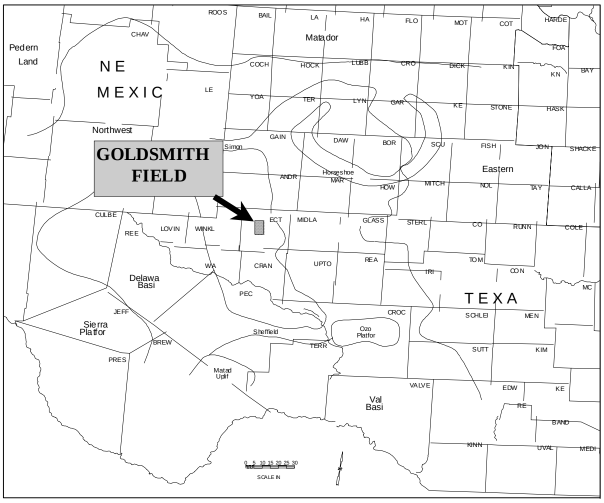

Figure 6 : Goldsmith Field

The first well drilled in the Goldsmith Field was a gas well completed in the San Andres Formation in Dec. 1934. The Scharbauer No. 1 or "A-1" was drilled in Section 20, Block 44 T-1-N and produced 40 bopd and 25 MMcfpd.

San Andres formation data:

- Field-wide waterflooding operations began in the late 1950's
- average depth of 4,200 feet, with a slight formation dip of 100 to 150 feet per mile
- approximately 1,100 feet of dolomite, anhydrite, and shale
- Oil leg of reservoir is about 100-125' thick, with large transition zone into the water column

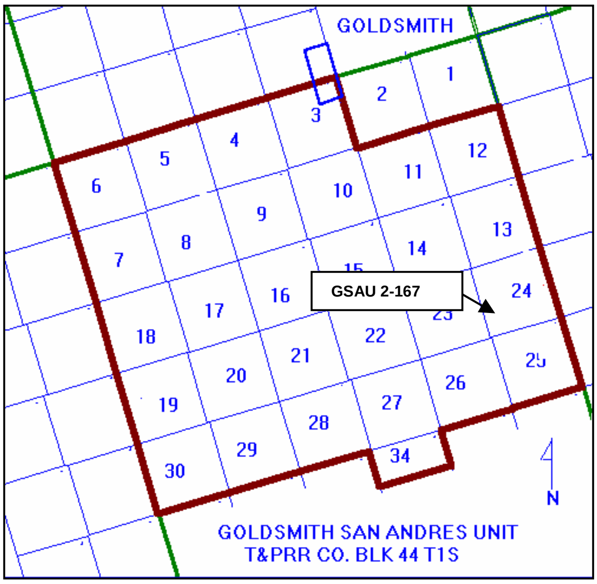

Figure 7 : CTRS Well Location

Field Performance Criteria

Some of the issues associated with the Goldsmith field:

- Moving 500-800 BFPD with conventional rod pumping systems resulting in rod on tubing wear due to rod buckling.
- Over loaded gearboxes
- Limited on tubing size in many wells by 4 ½" casing or liners.
- Slim-line sub-pumps are expensive and can be worn out in 3-4 years

Service Date	Main Job Description
11/13/95	TUBING FAILURE
8/14/97	TUBING FAILURE
4/9/98	TUBING FAILURE
8/1/98	OTHER
9/30/98	POLISH ROD FAILURE
12/29/98	TUBING FAILURE
1/26/99	ROD FAILURE
4/8/99	PUMP FAILURE
1/10/00	TUBING FAILURE
7/5/01	WORKOVER

Table 1: GSAU 2-167 Service History

CTRS features:

- Able to move the same volumes with less HP
- Gear box will not be overloaded
- Rod on tubing wear will be minimized
- CT option eliminates rod boxes
- Any contact with the outer string (either tubing or casing will be spread over a larger area reducing the abrasive forces
- CT is stiffer than same weight/foot rod

CTRS Completion Design

Well Details

The GSAU 2-167 is a vertical well completed with 5 ½" 14 lb/ft J-55 casing plugged back to a depth of 4,214 ft. A 4 ½" 11.6 lb/ft J-55 tie back liner is cemented from surface to 4,003 ft. There are 26 perforations distributed from 4,143 ft to 4,204 ft producing an average 622 BFPD and 4 MCFPD. (Figure 8)

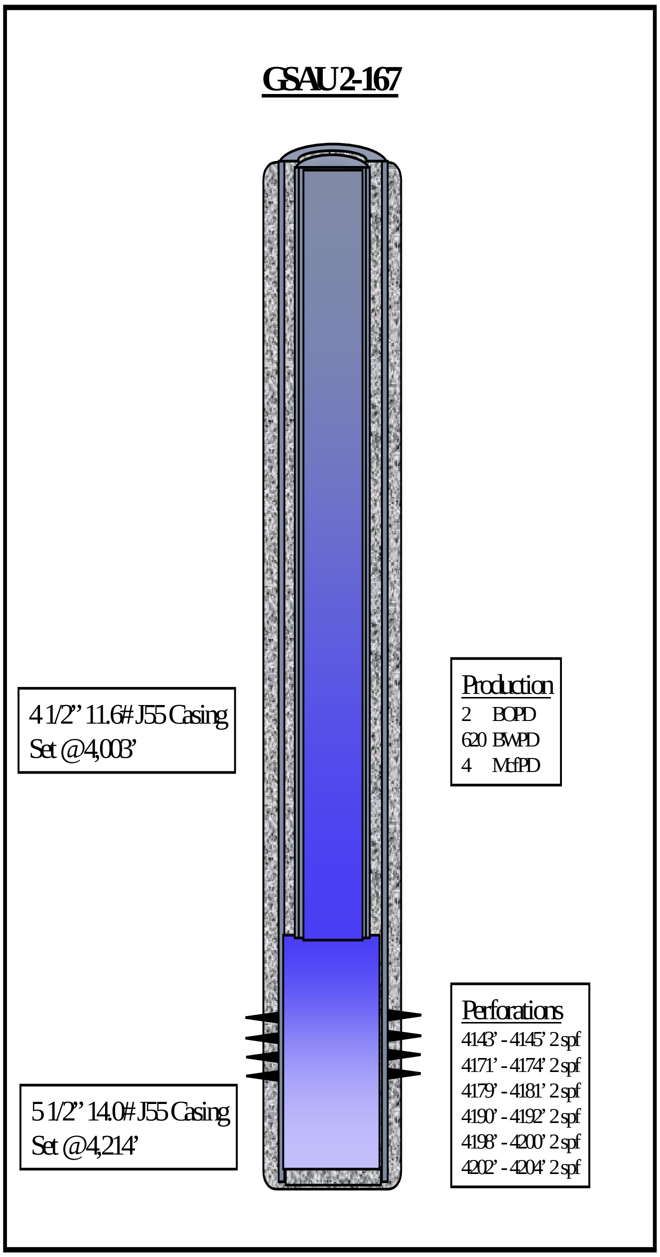

Figure 8: GSAU 2-167 Wellbore Schematic

The GSAU was originally completed with a 2 ¼" x 2 ½" x 24' tubing rod pump run on 2 7/8" J-55 tubing. The tubing was anchored with a 4 ½" TAC at 3,976'. A 2 7/8" perforated sub and a 2 7/8" BPMA were installed below the pump placing the end of the assembly at 4,012'. The lifting energy was transferred to the pump by the following rod design:

- 1 ½" x 26' Polish Rod
- 1 ¼" x 18' Fiberglass Pony Rod
- 55 – 1 ¼" Fiberglass rods
- 48 – 1" API class "D" rods

- 11 – 1 5/8” Weight Bars
- 2 ¼” x 2’ Plunger

Unfortunately, the completion experienced several failures due to tubing wear, sucker rod wear and gear box overloading.

The repetitive failures led to an investigation into alternative artificial lift applications. The other available methods were electrical submersible pumps (ESP’s) and CTRS. The ESP’s were eliminated as a viable method due to equipment cost, operating cost and the expected life of the slim-line ESP’s required for 4 ½” casing. A technical investigation into the feasibility of a CTRS was undertaken and deemed as a viable option. The study encompassed the design of the rod pump, pump anchor, coiled tubing, hardware and production equipment.

A long-stroke pumping unit (LSPU) was available in the field, and due to the relatively high production requirement, was chosen for the pumping unit. The unit’s operating specifications are as follows:

- 4.5 strokes per minute (spm)
- 288” stroke
- 36,000 lbs. capacity

Based upon the ROTOFLEX® 900 specifications and the required 620 BPD production rate, the remaining CTRS completion components were designed.

Rod Pump

The CTRS completion utilizes conventional rod pumps with a hollow pull tube to produce the well. The surface equipment and the well’s production determined the majority of the rod pumps variables. The exception was the rod pump’s plunger diameter. The theoretical pump displacement equation [10] was used to calculate the minimum plunger diameter.

<u>Theoretical Pump Displacement:</u>

$$V = 0.1484\ A_p\ S_p\ N$$

Where:

V = Theoretical pump displacement (BPD)
A_p = Area of the plunger (in^2)
$= (\pi/4)\ D^2$
S_p = Effective plunger stroke (in)
$\approx 0.85\ S$
S = Surface stroke (in)
N = Strokes per minute (spm)

Substituting the known values and solving for the plunger diameter, the equation yields:

$$D^2 = (620) / [(0.1484)\ (\pi/4)\ (0.85)\ (288)\ (4.5)]$$

$$D^2 = 4.83\ \text{in}^2$$

$$\underline{D = 2.20\ \text{in}}$$

The calculated diameter is the minimum diameter required achieving the desired production rate. To ensure that the production objective is obtained, a larger plunger diameter should be installed. Substituting a 2 ¼” diameter into the theoretical pump displacement equation and using the surface stroke length instead of the effective plunger stroke length, a maximum production rate of 765 BPD is determined. If this production rate were achieved, at the specified conditions, the system would be running at 100% efficiency. However, it is known that the full surface stroke is not transmitted to the plunger due to losses from inertia and helical deformation[11]. To account for this phenomenon, a factor of 0.85 is applied to the surface stroke length to calculate the effective plunger stroke length. Calculating the production using a 2 ¼“ plunger diameter and the effective plunger stroke length, yields an effective production rate of 650 BPD. This production rate is satisfactory, and with acceptable fluid slippage in the pump[12] of approximately 24 BPD, the tubing rod pump specifications were determined. The final specifications were a 2 ¼” x 2’ plunger with 0.006” clearance on the bottom of a 1 ½” x 31’ hollow pull tube contained in a 33’ barrel.

Pump Anchor - Initial Installation

The added benefit of being able to run the CTRS without production tubing posed a problem of how to anchor the pump. Since the production tubing is eliminated, the barrel of the tubing pump had to be anchored similar to an insert pump. One obstacle encountered was that common insert pump anchors are only available for casing sizes up to 3 ½”. An additional hurdle was that if these anchors were scaled up in size, they had to be picked up and rotated to set. This was determined to be an undesirable step with a coiled tubing unit and efforts were undertaken to design an appropriate anchor.

Complicating the design are the variable forces applied to the anchor. Since the fluid is produced through the coiled tubing, the differential hydrostatic pressure of the fluid is applied to and removed from the anchor on every stroke. This downhole condition required the construction of a sturdy anchor that still allowed fluid to migrate around it.

Upon evaluation of the requirements, a modified 4 ½” x 2 3/8” Model “B” TAC was used as the pump anchor. Once installed, the anchor could be retrieved by shearing pins with 15,000 lbs overpull. A joint of 2 7/8” tubing with a 2 7/8” mud anchor would be connected below the anchor and a snap latch seal receptacle would be installed on top. The receptacle would accept a snap latch stinger assembly made up to the bottom of the pump barrel.

The snap latch stinger assembly is a basket-collet type latch system. In order to be able to pull the pump and leave the anchor, the collets were designed to release with a 5,300 lbs overpull. As an additional operational consideration, a 21,500 lbs shear sub was installed between the pump and the stinger assembly for the unlikely event that both the stinger assembly and the anchor became stuck.

Unfortunately, the design of the anchor required it to be set using a workover rig and jointed pipe. While this was not the ideal situation, the anchor was deemed to be the best available at that time. It was decided that the anchor design would undergo further investigation with the goal to design an anchor that could be set with coiled tubing while simultaneously installing the pump.

Coiled Tubing

The selection of the coiled tubing string is critical to obtaining the correct CTRS design. The coiled tubing is the conduit for the produced fluids to the surface and is exposed, both internally and externally, to any corrosive conditions in the well. These conditions may limit the grade of coiled tubing that can be utilized, adversely affecting the maximum depth of the CTRS. Additionally, the coiled tubing's geometry must be optimized to ensure the mechanical energy is applied downhole, that helical deformation is minimized and that the required production rate is achievable. These variables must be determined based upon the operational limits of the pump unit, the wellbore geometry and an acceptable fatigue life of the coiled tubing.

The industry has several programs that are capable of calculating all these parameters when using conventional sucker rods and can be manipulated to match an existing dynamometer reading. Unfortunately, these aren't yet set up to handle the different forces encountered with CTRS. One disparity is the fluid friction inside the coiled tubing. A fluid flow computer model is used to predict this with the understanding that the fluid is only moving half the time relative to the coiled tubing. Therefore, if the daily production is 500 bbls, half the time the fluid is stationary within the coiled tubing and the rest of the time the fluid rate is equivalent to 1,000 BPD. Another area of CTRS distinction is the force acting on the plunger to provide buoyancy. Conventional rod strings are always under the buoyant effect of the hydrostatic load. The CTRS design has to account for the fluid level in the coiled tubing annulus. Considering these changes, a force balance had to be studied to determine the peak polish rod load (PPRL) and minimum polish rod load (MPRL).

It should be noted that a waveform analysis program of concentric pipe containing variable fluids is being developed but is outside the scope of this paper. It is understood that there will be some helical deformation causing normal forces due to wall contact. At this time, these forces are not quantifiable, and due the geometry of the CTRS, will be considered negligible in the calculations.

Peak Polish Rod Load

It has been determined that the maximum value of the downward acceleration, which increases the load on the coiled tubing, occurs at the bottom of the stroke[13]. This maximum value is given by:

$$\alpha_1 = S\, N^2 / 70{,}500\ (1 \pm c/p)$$

Where:

α_1 = Maximum downward acceleration of the coiled tubing (ft/sec^2)
S = Surface Stroke (in)
N = Pump Speed (spm)
c/p = Crank-to-Pitman ratio
- positive for conventional units
- negative for air and Mark II units
- assumed negligible for an LSPU

An assumption is made that the traveling valve closes and the standing valve opens at the maximum downward acceleration[13]. A force balance at this instant yields the PPRL:

PPRL = (weight of the fluid column) + (weight of the plunger and hollow pull tube) + (weight of the coiled tubing) + (acceleration) + (friction term) – (buoyancy on the plunger)

The weight of the plunger and hollow pull tube will be considered negligible. Additionally, it is assumed that all associated gas is produced up the annulus.

Further defining each component of the equation:

<u>Weight of the Fluid (W_f):</u>

$$W_f = (0.052\, \rho_f\, D_p + P_{fl})\, A_p$$

Where:

ρ_f = Density of the fluid (lb/gal)
D_p = Depth of the pump (ft)
P_{fl} = Flow line pressure (psi)
A_p = Plunger area (in^2)

<u>Weight of the Coiled Tubing (W_{ct}):</u>

$$W_{ct} = L_{ct1}\, w_{ct1} + L_{ct2}\, w_{ct2} + \ldots\, L_{ctn}\, w_{ctn}$$

Where:

L_{ctn} = Length of nth tapered section (ft)
w_{ctn} = weight of nth tapered section (lb/ft)

Acceleration Term:

To determine the PPRL, the maximum downward acceleration needs to be calculated by multiplying α_1 by the W_{ct}.

Annular Friction Term(F_{fa}):

The friction between the coiled tubing and the annular fluid is calculated using a fluid flow model. The magnitude of the term depends on the fluid level and properties, annular area, stroke rate, stroke length and pump depth.

Buoyancy on the Plunger:

$F_b = 0.052\ \rho_f\ [(D_p - D_{fl})(A_{CTOD}) + (D_p)(A_p - A_{CTID})]$

Where:

F_b = Buoyancy Force (lbs)
D_p = Depth of the pump (ft)
D_{fl} = Annular fluid level depth (ft)
A_p = Plunger area (in^2)
A_{CTOD} = Coiled Tubing Outer Diameter
A_{CTID} = Coiled Tubing Internal Diameter

Substituting into the force balance equations yields the following PPRL equation:

$\underline{PPRL = W_f + W_{ct} + \alpha_1 W_{ct} + F_{fa} - F_b}$

Minimum Polish Rod Load

It has been determined that the maximum value of the upward acceleration, which decreases the load on the coiled tubing, occurs at the top of the stroke[13]. This maximum value is given by:

$\alpha_2 = S\ N^2 / 70{,}500\ (1 \pm c/p)$

Where:

α_2 = Maximum upward acceleration of the coiled tubing (ft/sec^2)
S = Surface Stroke (in)
N = Pump Speed (spm)
c/p = Crank-to-Pitman ratio
- negative for conventional units
- positive for air and Mark II units
- assumed negligible for the an LSPU

An assumption is made that the traveling valve opens and the standing valve closes at the maximum upward acceleration[13]. A force balance at this instant yields the MPRL:

MPRL =(weight of the plunger and hollow pull tube) + (weight of the coiled tubing) - (acceleration) - (friction term) – (buoyancy on the plunger)

Once again, the weight of the plunger and hollow pull tube will be considered negligible.

Weight of the Coiled Tubing (W_{ct}):

$W_{ct} = L_{ct1}\ w_{ct1} + L_{ct2}\ w_{ct2} + \ldots\ L_{ctn}\ w_{ctn}$

Where:

L_{ctn} = Length of nth tapered section (ft)
w_{ctn} = weight of nth tapered section (lb/ft)

Acceleration Term:

To determine the MPRL, the maximum upward acceleration needs to be calculated by multiplying α_2 by the W_{ct}.

Friction Term (F_f):

$F_f = F_{fa} + F_{fCT}$

Where:

F_{fa} = Annular fluid friction
F_{fCT} = Coiled tubing fluid friction

Both values of friction are calculated using a fluid flow model.

Buoyancy on the Plunger:

$F_b = 0.052\ \rho_f\ D_p\ (A_p - A_{CTID})$

Where:

F_b = Buoyancy Force (lbs)
D_p = Depth of the pump (ft)
A_p = Plunger area (in^2)
A_{CTID} = Coiled Tubing Internal Diameter

Substituting into the force balance equations yields the following MPRL equation:

$\underline{MPRL = W_{ct} - \alpha_2 W_{ct} - F_f - F_b}$

Calculations for GSAU 2-167

The production and well description had been defined (Figure 10), a pumping unit was selected and the rod pump specifications had been determined. A 1¾” x 0.175” 90K coiled tubing string was investigated using the force balance equations in order to ensure an appropriate CTRS design. The pump would be set at the end of the 4 ½“ at 4003’.

$\underline{PPRL = W_f + W_{ct} + \alpha_1 W_{ct} + F_{fa} - F_b}$

$W_f = (0.052\ \rho_f\ D_p + P_{fl})\ A_p$
$= [(0.052\ (8.93)\ (4003)) + 60]\ 3.976$
$= 7{,}629$ lbs

$W_{ct} = L_{ct1}\ w_{ct1} + L_{ct2}\ w_{ct2} + \ldots\ L_{ctn}\ w_{ctn}$
$= (4003)(2.951)$
$= 11{,}813$ lbs

$\alpha_1 = S\ N^2 / 70{,}500$
$= 288\ (4.5)^2 / 70{,}500$
$= 0.0827\ (\text{ft/sec}^2)$

$F_{fa} = 2.5$ lbs

$F_b = 0.052\ \rho_f\ [(D_p - D_{fl})(A_{CTOD}) + (D_p)(A_p - A_{CTID})]$

$= 0.052(8.93)[(4003-2247)(2.405) + (4003)(3.976 - 1.539)]$

$= 6{,}491$ lbs

Therefore, the expected peak polish rod load is:

$PPRL = 7{,}629 + 11{,}813 + 0.0827(11{,}813) + 2.5 - 6{,}491$

PPRL = 13,930 lbs

$\underline{MPRL = W_{ct} - \alpha_2 W_{ct} - F_f - F_b}$

$W_{ct} = 11{,}813$ lbs

$\alpha_2 = 0.0827\ (\text{ft/sec}^2)$

$F_f = F_{fa} + F_{fCT}$

$F_{fa} = 12.1$ psi

$F_{fCT} = 238.9$ psi

$F_f = 251$ psi

$F_b = 0.052\ \rho_f\ D_p\ (A_p - A_{CTID})$

$= 0.052\ (8.93)\ (4003)\ (3.976 - 1.539)$

$= 4{,}530$ lbs
Therefore, the expected minimum polish rod load is:

$MPRL = 11{,}813 - 0.0827(11{,}813) - 251 - 4{,}530$

MPRL = 6,055 lbs

Surface Production:

Typical Production Rates:

Oil:	5	bbl/day	SG oil:	0.850	
Water:	624	bbl/day	SG water:	1.074	
Gas:	200	Mscf/day	SG gas:	0.700	

Shut In Casing Pressure:	40	psig
Flowline Pressure:	60	psig
Flowline Temperature:	100	F

Wellbore Decription:

Casing:			Scab Liner:		
OD:	5.50	in	OD:	4.50	in
ID:	5.01	in	ID:	4.00	in
Weight:	14.0	lb/ft	Weight:	11.6	lb/ft
Depth:	4214	feet	Depth:	4003	feet

Fluid Level:		2247	feet
Perforation Depth:	Top:	4143	feet
	Bottom:	4202	feet
BHT Temperature:		155	F

Calculated Data:

Surface Production Rate:	629	bbl/day
Oil Cut:	0.79	%
Water Cut:	99.21	%
GLR:	318	scf/stbl
S.G. Produced Fluid:	1.072	
Density Produced Fluid:	375.28	lb/stbl
Mid-Perf BHP:	937	psi

Figure 9: GSAU 2-167 Design Parameters

The calculated polish rod loads compare favorably with an actual dynamometer card from the GSAU 2-167. (Figure 10).

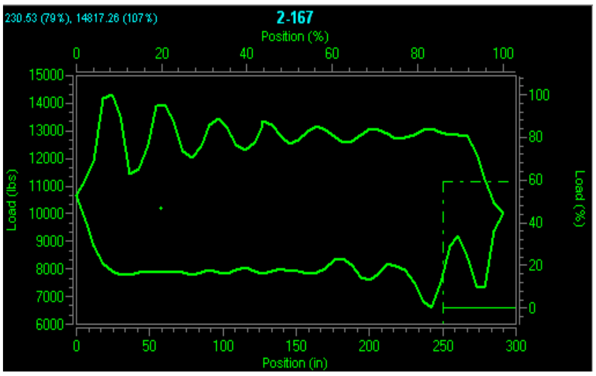

Figure 10: Initial Dynamometer Card

Since the calculated polish rod loads were within the operational parameters of the pumping unit, a completion design had been determined that would mechanically provide the required production. The last guideline to be investigated was the fatigue life to determine if the CTRS was an economical solution.

Fatigue Calculations

The coiled tubing industry has invested a great deal of time and effort into the study of coiled tubing plastic fatigue. As of yet, little effort has been made to study the effect of high-cycle fatigue on coiled tubing. Since extensive testing is required to determine the capability of the coiled tubing, in the interim a theoretical computer model has been developed. The model takes into account microscopic physical damage that can occur well below the material's ultimate yield strength when exposed to cyclic stresses(14). The model was used to estimate the fatigue life of the 1 ¾" x 0.175" 90K coiled tubing. (Figures 11 and 12). The model will continue to be used as a benchmark until sufficient data is collected to correlate it.

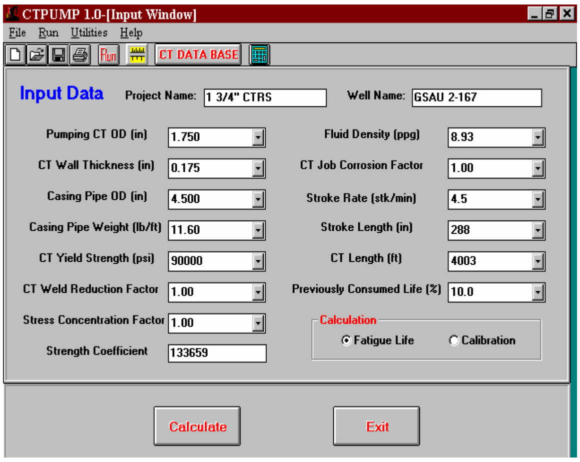

Figure 11: Elastic Fatigue Computer Model Input

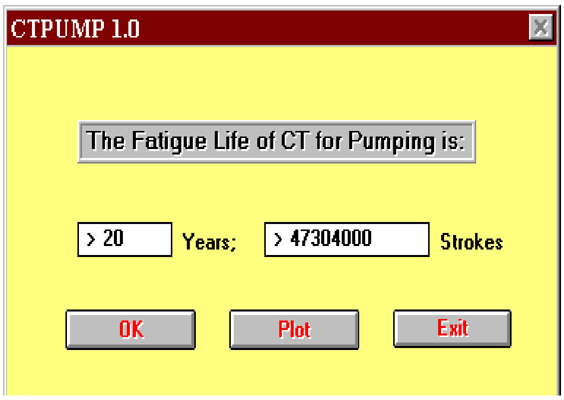

Figure 12: Elastic Fatigue Computer Model Output

Due to the fact that no analytical data exist to confirm the fatigue model, the API Modified Goodman Stress diagram was used to substantiate that the coiled tubing would not be over loaded(15) . Although the diagram is commonly used for steel sucker rods, the coiled tubing material is comparable to the steel used in the rods.

The maximum stress is calculated as:

$$S_{max} = \text{Max Load / Cross Sectional Area}$$
$$= 13{,}390 \text{ lbs} / 0.866 \text{ in}^2$$
$$= 16{,}086 \text{ psi}$$

The minimum stress is calculated as:

$$S_{min} = \text{Min Load / Cross Sectional Area}$$
$$= 6{,}055 \text{ lbs} / 0.866 \text{ in}^2$$
$$= 6{,}992 \text{ psi}$$

Applying the calculated values to the API Modified Goodman Diagrams corroborates that the coiled tubing is operating under allowable working conditions. (Figure 13).

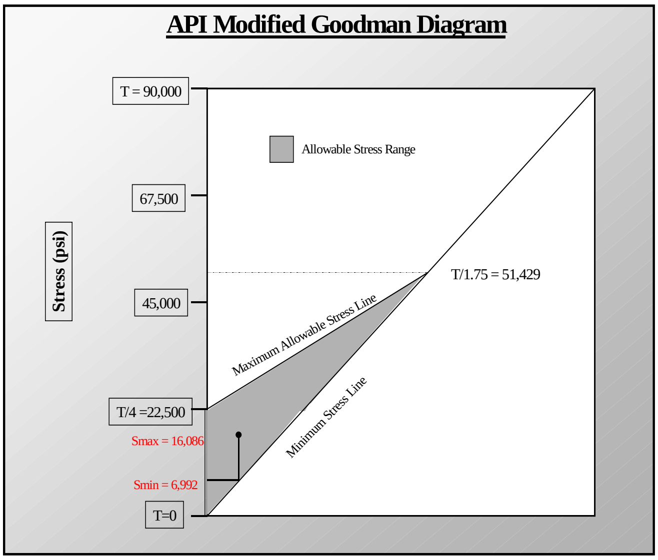

Figure 13: Modified Goodman Diagram

Surface Equipment & Hardware

On of the most critical parts of the CTRS completion is the connector attaching the coiled tubing onto the hollow pull tube. As with the anchor, the connector will undergo cyclic stresses with each stroke. Additionally, the connector will be subject to inertia resulting in helical deformation and side loading.

Connectors have been tested exhaustively in the coiled tubing industry. Installing an anchor capable of handling the repeated or cyclic loads was not the main concern. There are several styles of connectors available that can withstand these forces.

The main reservation in the connector was the o-ring seals. In order for the CTRS to operate properly, there had to be a constant hydraulic seal. The seal had to be capable of withstanding the loads and operating for an extended period of time. If the o-rings were rolled due to side loading they would eventually fail. Even a small leak would greatly reduce the efficiency of the system and would quickly fail entirely.

The proposed solution was to install a 4 groove roll-on connector with anti-rotation stops. The roll-on has been proven over many years as a reliable connector and provided four o-ring seals. In addition, a support sleeve was manufactured that slid over the coiled tubing and across the connector. Setscrews were designed to hold the sleeve in place. The theory was that the support sleeve would absorb any side loading, thereby greatly reducing the possibility the o-rings failing. (Figures 14)

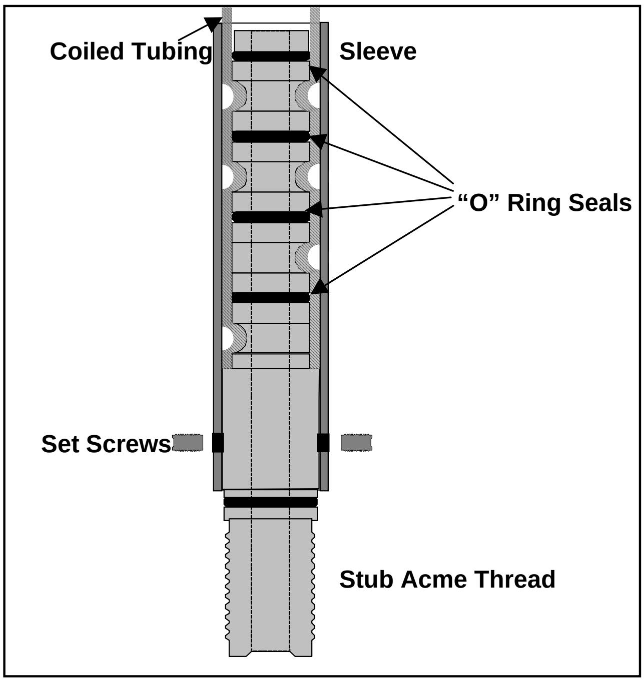

Figure 14: Roll-on Connector Diagram

Since the top connector would be attached to the coiled tubing above the bridle, it would be exposed to very low cyclic stress. The only force applied to the top connector would be the side loading due to the weight of the production hose.

To transfer the produced fluids from the coiled tubing to the flow line a reciprocating system had to be used. Installed on to the top connector is a 3,000 psi hydraulic hose. The hose needed to have enough slack to keep from getting taut during the stroke. To allow for the slack and to keep the hose from rubbing on the ground or entangling itself with the wellhead, a standpipe had to be installed. The standpipe would be tied directly into the flowline. (Figure 13).

Figure 15: Surface Production Equipment

CTRS Field Installation

On September 20, 2001 the CTRS was installed in the GSAU 2-167. The well had been prepared by setting the 4 ½"x 2 3/8" Model "B" TAC anchor at 3,990'. Attached below the anchor was a joint of 2 7/8" tubing with a 2 7/8" mud anchor.

The snap latch stinger assembly was made up to the bottom of the pump and everything was deployed into the well using deployment plates and drill pipe clamps.

While it is common to work with an open wellbore while installing a rod pump, it was a unique situation for coiled tubing operations. To alleviate the reservations of working with a well open to the atmosphere and the slight chance of losing control of the well, a kill truck was rigged up to lubricate fluid into the well.

The coiled tubing was stabbed into the injector and run through the straightener. The hydraulic pressure supplied to the straightener was optimized to remove all residual curvature from the coiled tubing.

With the coiled tubing straight, the roll-on connector was installed and made up to the pump. In order to keep the barrel of the pump from dropping into the well and possibly being damaged, the plunger had to be stroked out prior to deploying the assembly. A valuable lesson was learned during this procedure. Due to the size of the injector head and straightener, the pumping unit needed to be spaced back from the wellhead to allow room to operate. Fortunately, the a pumping unit skids easily back from the well.

The pump was deployed into the well and the injector head / straightener was made up to the wellhead. The assembly was run into the well and latched into the anchor. A pull test was performed to ensure the collets had engaged properly.

Figure 16: CTRS Installation Operation

With all downhole components installed, it was time to install the surface equipment. The injector head was stripped off the coiled tubing, which allowed a cut to be made above the wellhead. The coiled tubing was now standing in the well with all the weight on the anchor. The stuffing box was stripped over the coiled tubing and installed on the wellhead. The coiled tubing would function as the polish rod, eliminating the need for a 30’ 1 ¾” polish rod liner. Another option would be to install a conventional polish rod, but this would require an additional connection to the coiled tubing in an area of high stress.

With the a pumping unit skidded back over the well, the CTRS was spaced out using the crane. It should be noted that the coiled tubing was filled with water prior to installation to eliminate the need to calculate the stretch it would encounter with a column of fluid. Sucker rod clamps were installed on the coiled tubing and landed into the bridle. Prior to making the final connection to the flow line, the unit was run to ensure all the components were functioning properly.

The final phase of the installation was connecting the system to the production flow line. A connector was welded to the top of the coiled tubing and off-the-shelf fittings were used to secure the hose to the coiled tubing and stand pipe. A wick lubricator was secured on top of the stuffing box and the well was turned over to production.

CTRS Well Performance

Production

Soon after start up the CTRS system was able to achieve pump rates over 600 BPD. Figures 17 and 18 show that compared to the initial installation, the CTRS system functions well: in production and efficiency, which can be correlated from the dyno card depicted in the next section.

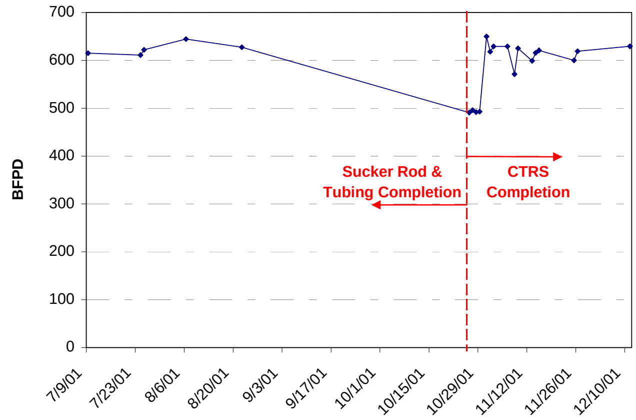

Figure 17: GSAU 2-167 Production History

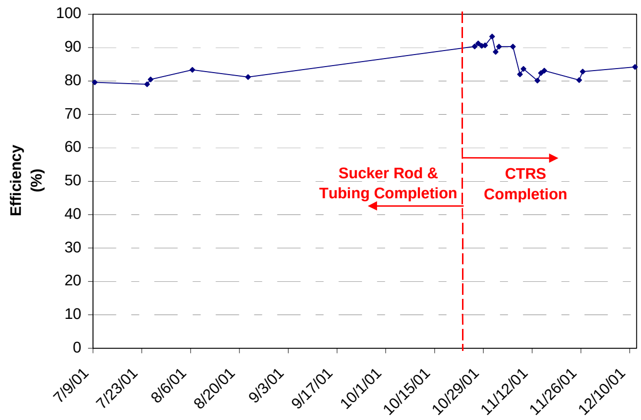

Figure 18: GSAU 2-167 Pump Efficiency History

Dynamometer Interpretation

The dynamometer card in Figure 19 shows that by modifying the input parameters, CTRS performance can be modeled using readily available conventional artificial lift programs. The software used here shows how well the predicted diagram matches the actual diagram. The model used a one inch sucker rod string with some sinker bars to represent the two drill collars that were used on the bottom of the CT string. The one inch string was used in the model. This is due to the cross sectional area of a one inch rod string is very close to that of the 1.75" CT string.

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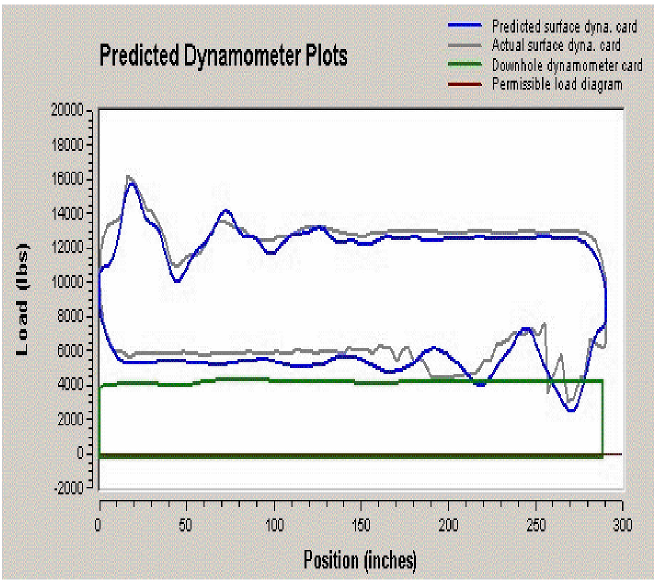

Figure 19: Dynamometer Card – Actual & Predicted

Polished Rod Monitoring

While CTRS completions can be installed using a polished rod liner, it was decided that for this installation the continuous CT string would act as its own polished rod section.

This provides three benefits. In the first case it simplifies the surface hardware requirements. As 1.75" CT was used for the installation, a 2" polished rod liner would have been required. This is not a common size of liner and it also would have required the use of a modified stuffing box.

The second benefit of foregoing a polished rod liner is that it simplifies the installation requirements. As such, using the CT as its own polished rod section reduces the number of steps to land the completion.

Finally, this eliminates the need for a high load surface CT connection.

As with a properly aligned sucker rod installation, it is anticipated that there should be little wear on the CTRS polished rod section. CT has a smooth surface and even though it is slightly oval from being spooled, the stuffing box internals will form to the shape of the CT.

Having made this innovation to the CTRS process, it was felt that data needed to be collected on the CTRS sucker rod section to see if any appreciable wear could be detected. Table 2 shows data from the first two sets of measurement data using a digital micrometer at top, middle and bottom sections of the polished rod section. An average OD is reported due to the ovality of the CT.

In this installation, an off the shelf stuffing box was used with a wick system for lubrication.

Overall it can be seen that there has been no discernable wear. Due to measurement error and the difficulty assessing an average OD, one set shows a slight reduction in diameter, while the other two report a slight increase in diameter. Overall it is felt that the amount of wear will be minimal but measurements will continue to be taken.

Test Date:	10/30/01	1/10/02
	Avg. OD	Avg. OD
	(in)	(in)
Top Section:	1.738	1.729
Middle section:	1.745	1.755
Bottom portion:	1.741	1.752

1.738-1.729= .009 (loss)
1.745-1.755=-.010 (gain)
1.741-1.752=-.011 (gain)

Table 2: Sucker Rod Section Monitoring

Overall System Performance

On the initial installation, 9/20/01, the string was reciprocated with the crane to ensure that the system was functioning properly. Fluid came out the top with each stroke, so the wellhead connections were made. After turning the pumping unit on the polished rod clamp appeared to be coming off the carrier bar as if the CTRS was stacking out or possibly buckling. There were some problems getting the unit and POC lined out, so the decision was made to slow the SPM rate down, from the originally planned 4.1 to 3.2. The system seemed to settle out and function properly until about 10/8/2001. Note that no production data was achieved at this time, as this well is one of many on a common battery, so the well had to be worked into the schedule for the test manifold.

The CTRS system started stacking out again, possibly pump sticking, so the string and pump were pulled on 10/10/01. Upon inspection of the pump, a few pieces of metal were found in the pump and the pump was severely scared, in part due to the metal pieces, and in part due to the $FeSO_2$ from this well. The well also has about 2% H_2S. The metal pieces were sent to be analyzed, and found to have a different metallurgy than the CTRS. The metal appeared to be part of the pump, and possibly some other produced trash. After the pump was ready to be re-run, the system was reinstalled on 10/15/01.

Upon reaching setting depth, the string went further down than it was supposed to, which indicated that part of the down hole anchoring system had moved. A revised anchoring system was devised, run with a conventional pulling unit and work over string. Then the system was reinstalled on 10/24/01. To assist the down-stroke of the pump the operator added two drill collars above the pump to act as sinker bars.

This time the system worked continuously for about 10 weeks. During the holidays, it was found to be stacking out again.

On 1/10/02, the system was pulled again and it was discovered that the anchoring system had separated. A new anchoring system was devised and the system was run back in hole on 2/11/02. This time the anchoring system was more of permanent type. That is, it was based on a packer system, that had part set on wire line, and then the rest of the anchoring system was on the end of the pump so that it would latch like a packer, but could still be pulled with the pump.

CTRS Economics

As with any new technical innovation there needs to be economic motivation in order to justify and drive the process. It is anticipated that CTRS will be driven forward by a number of economic factors. In short these are:

- slimhole completion options
- reduced completion material costs
- elimination of coupling failures
- reduced tubing wear failures
- lower lifting power requirements

Some of the above points require consideration and discussion beyond the scope of this paper. This section will focus on the economic aspects directly related to the subject well in this paper.

The three options to produce the GSAU 2-167 was running sucker rods with a conventional pump unit or an LSPU, or installing a CTRS completion. The economics of each completion was examined. The pumping unit cost is not included in the analysis because, for reasons that will be described, either the LSPU or an ESP was needed to adequately meet the production requirements. As previously mentioned, the ESP was eliminated as an economical option due to the slim-line pump needed to run in the 4 ½” casing. The estimated electrical usage alone of the ESP would be $2,836.00 / month.

Conventional Sucker Rod Completion:

The GSAU 2-167 originally had a Lufkin 640-305-168 conventional pumping unit in place. In order to produce the required 620 BFPD, the stroke rate had to be 10.85 spm which produce a polish rod velocity of 1842 in/minute. This is 23% more than a 1,500 in/minute rule of thumb limit to minimize rod on tubing wear. Additionally, the designed rod string would be loaded to 99% of maximum stress. High strength rods could not be utilized due to the presence of H_2S. Even though this system was not a viable option, the economics were prepared for comparison sake. (All costs for the rod pumping systems are published list prices)

<u>**Component**</u>	<u>**Cost**</u>
1,615’ 7/8” “D” rods	$ 3,900.00
2,050’ ¾” “D” rods	$ 3,846.00
300’ 1 ½” Weight Bars	$ 1,076.00
1 ¾” x 24’ Pump	$ 7290.00
4000’ 2 3/8” J-55 Tubing	$ 8,200.00
Installation	$ 2,500.00~
<u>**Total =**</u>	<u>**$26,815.00**</u>

LSPU / Sucker Rod Completion:

With the LSPU and conventional rods, the maximum produced fluids would have been 658 BFPD with the unit running at 4.35 spm. This would have produced an acceptable polish rod velocity of 1253 in/minute.

<u>**Component**</u>	<u>**Cost**</u>
1,390’ 7/8” “D” rods	$ 3,357.00
2,475’ ¾” “D” rods	$ 4,643.00
100’ 1 ½” Weight Bars	$ 403.00
2 ¼” x 33’ Pump	$ 8,163.00
4000’ 2 3/8” J-55 Tubing	$ 8,200.00
Installation	$ 2,500.00~
<u>**Total =**</u>	<u>**$27,266.00**</u>

CTRS Completion:

With the LSPU unit and the CTRS, the maximum produced fluids would have been 697 BFPD with the unit running at 4.35 spm. Again, this would have produced an acceptable polish rod velocity of 1253 in/minute.

<u>**Component**</u>	<u>**Cost**</u>
4,500’ 1 ¾” CTRS String & hardware	$ 16,000.00
2 ¼” x 33’ Pump	$ 5,000.00
Installation	$ 11,000.00
<u>**Total =**</u>	<u>**$ 32,00.00**</u>

As can be seen, the CTRS completion was the most expensive option. The most noticeable difference was the installation cost. This is attributed to two factors. The first is tha as this was the first CTRS installation for the crew, the learning curve was high and the installation took all day. Subsequent installations have been faster and conceivably two completions could be installed in a day with proper planning. This alone would cut the installation costs in half. Secondly, a conventional service coiled tubing unit was used for the operation. In time, if CTRS is accepted as a viable completion technique, a more specific equipment package will be utilized that should allow for a reduction in operating costs.

Conclusion

The Goldsmith GSAU 2-167 CTRS installation was the first of its kind in the Permian Basin. In addition it was a unique application due to the prolific fluid pumping requirements – in excess of 600 BPD. Many goals were attained through this project. The key results of this effort were:

- With the exception of the anchoring system, CTRS was shown to perform as anticipated – both mechanically and hydraulically.
- Installation procedures were developed, successfully implemented and refined
- Many of the CTRS performance benefits can be shown to be valid but will require longer field histories to be proven out
- Continued improvements are underway for CTRS anchoring systems

Acknowledgements

The authors would like to acknowledge and thank the following companies for their support on this project and their permission to publish this paper:

- ChevronTexaco
- BJ Services
- Coil Tubing Americas

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