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EVALUATION ON THE APPLICATIONS OF SMALL SIZE COILED TUBING IN WELL SERVICES

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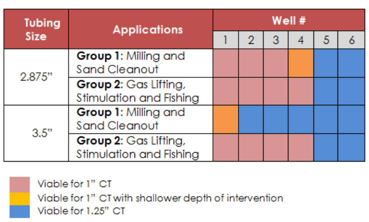
Graphical abstract



Abstract

Today, one of the most important key for hydrocarbon production in the oil & gas industry is economic justification. In the later state of the well's production, the aging wells may introduce many problems such as scale, sand and liquid load-up. These impede the hydrocarbon production, preventing all the reserve to be fully produced. In order to fight this impedance, the use of small size coiled tubing is a promising practice, although has its own limit. The objective of this paper is to evaluate the limit of well services applications of small size Coiled Tubing (1" and 1.25") in various oil & gas well scenarios. The evaluation utilizes the computer modeling which is used to determine the hydraulic and mechanic operating conditions. Our study found the viability of 1" CT in the low inclination well scenarios with the lower pumping rate requirement, while 1.25" CT can be used in all of well services applications and scenarios.

Keywords: Oil and Gas, Well Services, Simulation, Coiled Tubing, Produce to limit

1.0 INTRODUCTION

Coiled Tubing (CT) is the connectionless, continuous tubing that coiled into a reel for ease of well services. The continuously hollow tubing allows the ability to pump fluid through the CT, making the CT more advantageously safe and efficient to operate under pressure in comparison to the jointed pipe. The CT being manufactured with the size ranged from 0.75" to 3.5" [1]. It can be seen from the sales by size from the 2 major CT manufacturers that more than 60% of CT usage is the sizes bigger than 1.25" [1]. The demand of the higher flow rate and deep well, drive the manufacturing of the larger tubing. In contrast, there are also many factors driving toward the requirement of smaller size of the CT. These factors are elaborated in 1.1 to 1.3.

1.1 Economic Viable

The smaller size of CT incurred the least cost. Since it uses a fewer raw materials to manufacture, smaller equipment in use, less fluid to be pumped-in, less man power to operate, lesser operation time and hence reduction in operation cost. Jelinek *et al*. [2] reviewed the field cases in German and Netherlands. Sand cleanout, salt wash, stimulation and gas lift had performed successfully in the depleted wells, by using the small size CT. Stanley *et al*. [3] reviewed cases history in Thailand and Malaysia. The small size CT diminishes the candidates for plug and abandon. The well services with small size CT restrict the unintentionally well loading. This is especially true in the depleted marginal gas well where the production could not be restarted as the liquid load-up. Ultimately, the hydrocarbon can be produced after the investment had paid up front.

1.2 Crane/Platform Capacity

The capacity of offshore crane is very limited and may not enough for CT size required. The mitigation to the low crane capacity could be very costly and requires much more supporting equipment or vessel [4]. Long et.al [5] explained the constraints due to the low deck load capacity and available deck space is insufficient for large CT and could be overcome with CT operation from work boat. The operation from work boat introduces higher risk. The present review [6] shows that, the alternative techniques to overcome the limitation imposed by platform crane capacity are available with small size CT.

1.3 High Pressure Intervention

The high pressure snubbing is another requirement [1] for smaller size of CT, the smaller size CT can withstand the higher pressure. Simply the higher burst and collapse rating making the small size CT are more suitable for high-pressure application.

2.0 APPROACH OF SIMULATION

There are many CT applications exist, but listed in Table 1 is narrowed down for well services. The applications can be divided into 2 group of application. The first group of application required the high pump rate and high push/pull forces, which is consisting of milling, sand cleanout. The second group of application which comprised of gas lifting, stimulation and fishing operation requires much lower pump rate but still need high push/pull downhole,

Table 1 Well Services applications and considerations on viability for applications

Applications	Pump Rate	Push/Pull Force
Group 1: Milling and Sand Cleanout	High	High
Group 2: Gas Lifting, Stimulation and Fishing	Low (Negligible)	High

Table 2 Well Configurations

Well #	Total depth (Kft)	Kick-off point (Kft)	Inclination angle(°)	Build up rate (°/100 ft)
1	16	7	0	6
2	16	7	20	6
3	16	7	40	6
4	16	7	60	6
5	16	7	90	6
6	16	10	90	6

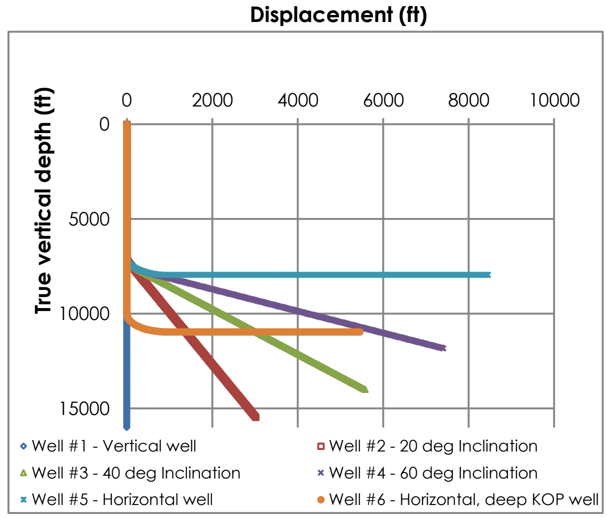


Figure 1 Well Paths

WELLPLAN is the simulation software used for the evaluation of the well services possibility with 1" and 1.25" CT. The CT with 20,000 ft. long is used in this study. The well type in consideration is based on slim-hole monobore completion (2.875" and 3.5" tubing) which is common use in marginal gas field development [7]. The well scenarios are illustrated in Figure 1 with the details well configurations shown in Table 2. The 6 well paths used in this study are designed with build and hold angle pattern. The common range of Build Up Rate (BUR) with Long Radius (i.e. 6deg/100ft) is selected, in order to have the final maximum inclination at the total depth. The walk rate is zero (i.e. Dog Leg Severity is equal to BUR).

In order to evaluate the viability of well services application, the mentioned hydraulic and mechanic aspects for small size CT listed in Table 1 are in consideration. The summary of the evaluation process for the applications of 1" CT and 1.25" CT in various well scenarios will be further elaborated in 2.1 and 2.2.

2.1 Hydraulic Consideration

The hydraulic consideration for small size CT is based on the required pump rate, associated pressure losses and the pressure limitation to achieve the objective of such application. The Group 1 applications require the hydraulic viability. The CT must be able to deliver the require pump rate (i.e. Critical Flow Rate) and withstands the pump pressure (i.e. burst rating) to counter frictional pressure losses. The process to evaluate the hydraulic viability is shown in Figure 2.

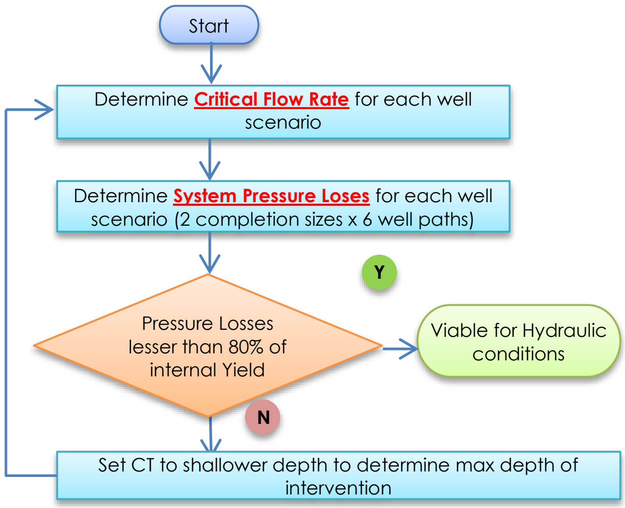


Figure 2 Flowchart for hydraulic consideration

The applications listed in Group 2 can be exempted for the hydraulic consideration. The rational behind the exemption is because the low requirement in the pump rate, hence, negligible effect on pressure losses and incomparable to the magnitude of CT's burst pressure.

2.2 Mechanical Consideration

Both application groups require the mechanic viability. The mechanic consideration will then evaluated for each size of CT.

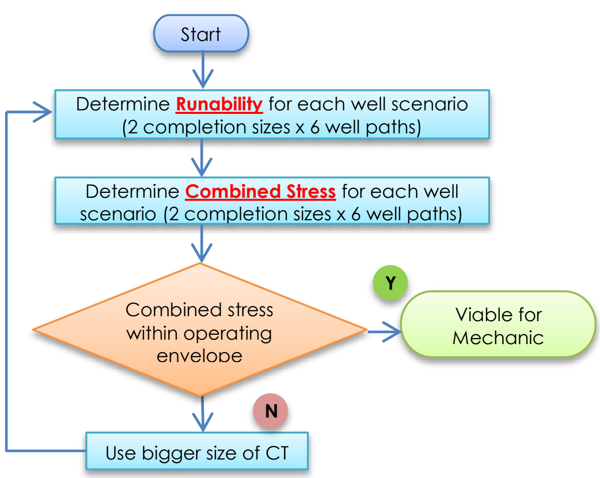


Figure 3 Flowchart for mechanical consideration

The considerations on mechanical aspect are the runability, available push/pull capacity of each size of the CT and then the operating envelope.

3.0 RESULTS AND DISCUSSION

3.1 Critical Flow Rate

The critical flow rate (Q_{crit}) is the first parameter to be determined. The critical flow rates are difference for each application. The critical flow rate for milling and sand cleanout applications is the minimum pump rate (i.e. liquid rate) at which the solid from wellbore start the upward movement. On the other hand, the critical gas rate is considered for the gas lifting application. The definition of the critical gas rate is the minimum gas velocity required for entraining the liquid droplet. The critical flow rates due to liquid are resulting in the higher system pressure losses in comparison to gas. Therefore the study of pressure loss due to gas can be excluded as discussed in 2.1. The pressure losses in this study then based on the critical flow rate due to liquid.

The critical flow rate [8] is the function of many parameters. The parameters include the inclination angle (C_{inc}) and annulus area (A_{ann}), which can be expressed as Eq. (1).

$$Q_{crit} = A_{ann}\,(V_{Cut} + V_{slip}C_{density}C_{size}C_{inc}) \quad (1)$$

The other parameters such as cutting velocity (V_{Cut} as a function of rate of penetration), slip velocity (V_{slip} as a function of fluid viscosity), fluid density ($C_{density}$) and cutting size (C_{size}) are kept constant for all scenarios. The critical flow rate for such solid cleanout requirement is determined for each inclination and results are shown in Figure 4.

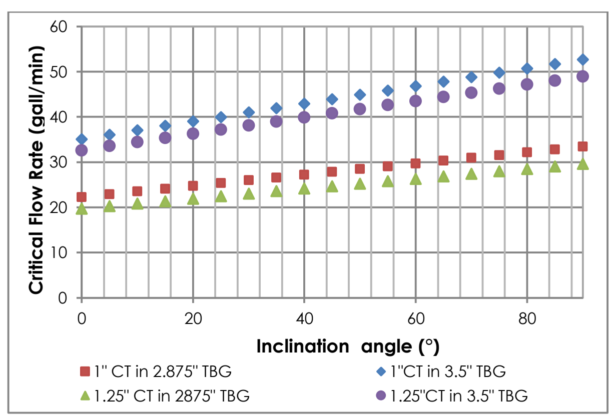


Figure 4 Critical Flow Rate for solid cleanout (milling and sand cleanout applications) in 2.875" and 3.5" tubing

3.2 Pressure Losses

Based on the critical flow rate from 3.1, the frictional pressure for each flow rate can be determined. The system pressure losses(ΔP_{System}) consist of the pressure loss in CT (ΔP_{CT}), bottom hole assembly (ΔP_{BHA}), CT's annuli (ΔP_{Annuli}) and surface equipment($\Delta P_{Surface}$). The system pressure loss can be expressed as

$$\Delta P_{System} = \Delta P_{CT} + \Delta P_{BHA} + \Delta P_{Annuli} + \Delta P_{Surface} \quad (2)$$

The pressure drop in CT [9] is the main contributor for system pressure losses and can be determined from Eq. (3).

$$\Delta P_{CT} = 32\, fL\rho (Q_{Crit})^2/(\pi d^5) \qquad (3)$$

The system pressure losses are due to the pumping of 8.3 lb/gal KCl brine at pre-determined critical rate. The system pressure losses are shown in Figure 5. The limitation of pumping pressure for 1" CT and 1.25"CT are defined at 80% of internal yield. The pressure limits are 15,360 and 17,408 psi for 1" CT and 1.25" CT, respectively.

It can be observed from the Eq. (3) and simulation results shown in Figure 5 that, the system pressure losses are rate dependence. The higher pump rate causes the increment of system pressure losses. Moreover, the deeper intervention depth causes the higher frictional pressure in annuli. Consider the pump rate for 1" CT which cannot be higher than 27 gal/min without the shallowing of intervention depth. This is especially true in the case of 3.5" tubing, where the required pump rate is much higher than 27 gal/min. The brine cannot be pumped to achieve the higher rate due to the excessive frictional pressure losses. As a result, the pump pressure cannot be maintained within 80% of the internal yield pressure. The maximum depth of intervention is needed to be trade off with higher flow rate. Therefore, 1" CT will not meet the solid cleanout application in all well scenarios with 3.5" completion and horizontal well with 2.875" completion.

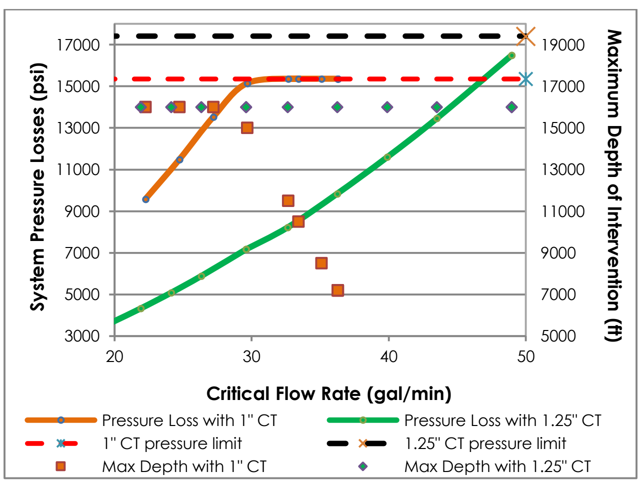


Figure 5 System Pressure Losses and Max depth of intervention v.s. Critical Flow Rate

On the other hand, 1.25" CT can achieve the required pump rate. The system pressure losses at the total depth can be maintained lower than the 80% of the internal yield pressure. The 1.25" CT is hydraulically viable and can be utilized in all well scenarios for application in group 1. The Table 3 shows the summary of hydraulic viability and associated depth of intervention in all well scenarios.

Table 3 Summary of the hydraulic viability and the possible Intervention interval for each scenario

CT O.D.	Tubing Size	Well # 1	2	3	4	5	6
1"	2.875"						
	3.5"						
1.25"	2.875"						
	3.5"						

Possible intervention to well total depth

Possible intervention beyond kick-off depth, but cannot reach total depth

Possible intervention to shallower than kick-off depth

3.3 Runability

The consideration on runability of the CT for well services operation is limited to only effective tension while running in hole (RIH) and pulling out of hole (POOH). Unlike, the drillability (i.e. with jointed pipe), which the torque is another concern. The CT undertakes the action of an axial force while tripping. The axial force [10] for the CT can be expressed as:

$$F_{Axial} = \sum\left(\Delta L\, W \cos(inc) + F_{Drag}\right) - F_{Bottom} \qquad (4)$$

The increment of axial compressive force, cause the change in the shape of CT. The continuously changing in the shape of CT such as bending, sinusoidal buckling, helical buckling and lockup are due to more axial compressive force applied to the CT. The buckling developed on CT lead to high friction forces and eventually can cause the CT to be lockup. Therefore, the critical value of the axial force which defines the buckling limit is need as the lower boundary. On the other hand, the tension limit is used as upper boundary. The tension limit is defined from 80% of Pipe Body Yield Load (PBYL). The PBYL for 1" and 1.25" CT are 27,490 lbf and 47,280 lbf, respectively for our cases. Hence, the tension limit for 1" and 1.25" CT are 21,992 lbf and 37,824 lbf, respectively.

The effective tension during RIH and POOH for all well cases are plotted along with the buckling and tension. An example of effective tension plot for 1" CT in 2.875" well is shown in Figure 6 and 7. The evaluation for runnable scenario is simply the case where the effective tension falls in between these 2 limits. The available push/pull capacity is the separation of these tensions to the buckling (i.e. pushing capacity) or tension limit (pulling capacity).

The effective tension during RIH and POOH in Well#1 (i.e. vertical well) are the same as no drag force involved. Unlike the case in Well#2 - Well#6, where difference of effective tension between the RIH and POOH can be noticed, especially for CT in up hole section. In all cases, the effective tensions are almost the same for CT section near the total depth. It can also be seen from the Eq. (4) and Figure 6 that the effective tension is decreased when the inclination increase. This is simply explained by the decreased of axial weight and higher force due to pressure in case of Well#2 - Well#5. In comparison between Well#5 and Well#6 where the vertical depth in Well#6 is deeper, resulting in higher axial weight and hence higher effective tension.

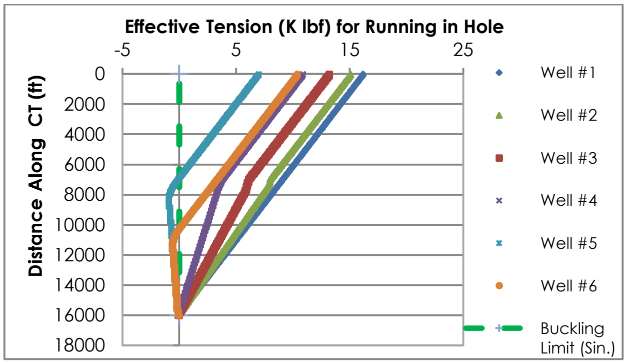


Figure 6 Effective Tension of 1"CT and Buckling Limitv.s. distance along CT inside 2.875" Tubing during RIH

There is a concern for the utilization of 1" CT in Horizontal well (Well#5 and Well#6). The Effective tensions during RIH of 1" CT are beyond buckling limit in both 2.875" and 3.5" completion scenarios. This could cause CT to be locked up and damage the CT. Therefore, 1" CT is not suitable for the intervention in those wells. In contrast, the intervention will have abundant of pushing capacity in Well#1 – Well#4.

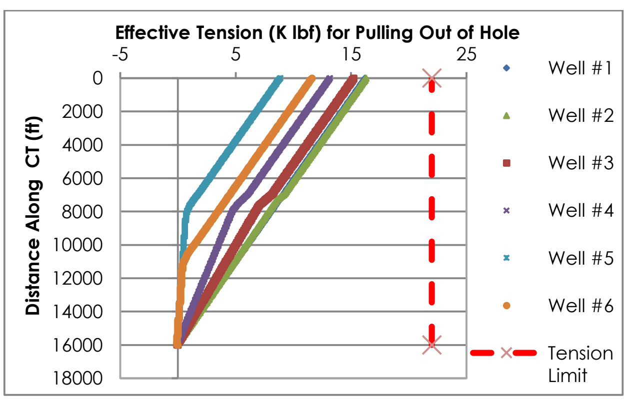


Figure 7 Effective Tension of 1"CT and Tension Limit v.s. distance along CT inside 2.875" Tubing during POOH

The effective tension during POOH in all wells scenario are not the concern with at least 5 Klbf available pulling capacity. On the other hand, the effective tensions for RIH and POOH are not the concern as 1.25" CT has larger wall thickness area. Hence, the push/pull capacity is higher. The runability of 1" and 1.25" CT can be summarized in Table 4.

Table 4 Summary of the runability and the possible Intervention interval for each scenario

CT O.D.	Tubing Size	Well # 1	2	3	4	5	6
1"	2.875"						
	3.5"						
1.25"	2.875"						
	3.5"						

Possible intervention to well total depth
Possible intervention beyond kick-off depth, but cannot reach total depth
Possible intervention to shallower than kick-off depth

3.4 Operating Envelope

So far the individual considerations were discussed in previous sections as pressure losses and runability. The final consideration is the integration from both aspects. It is most important that the CT be able to achieve runability and deliver the critical pump rate to transport solid/fluid within CT's internal yield limit at the same time. Integrating the results from Table 3 and 4, the possible intervention interval with both hydraulically and mechanically aspect are shown in Table 5.

All scenarios in Table 5 are then verified again if the combined stress (i.e. pressure and tension) will be within the operating envelope. The operating envelope is constructed from the tension, compression, burst, collapse and triaxial limit of the CT. The combined stresses applied on CT are now considered. The plots between differential pressure and axial force are constructed to determine if the CT able to withstand both hydraulically and mechanically stress at the same time.

Table 5 Summary of the integrated aspect and the possible Intervention interval for each scenario

CT O.D.	Tubing Size	Well # 1	2	3	4	5	6
1"	2.875"						
	3.5"						
1.25"	2.875"						
	3.5"						

Possible intervention to well total depth
Possible intervention beyond kick-off depth, but cannot reach total depth
Possible intervention to shallower than kick-off depth

An example of the pressure-tension plot is shown in Figure 8. The pressure-tension plots of 1" CT during pumping on bottom with 8.3 lb/gal KCl brine in Well#1 – Well#4 are within the predefined envelope. The already failed cases (i.e. Well#5 and Well#6) are repeated and fail again in the combined stress.

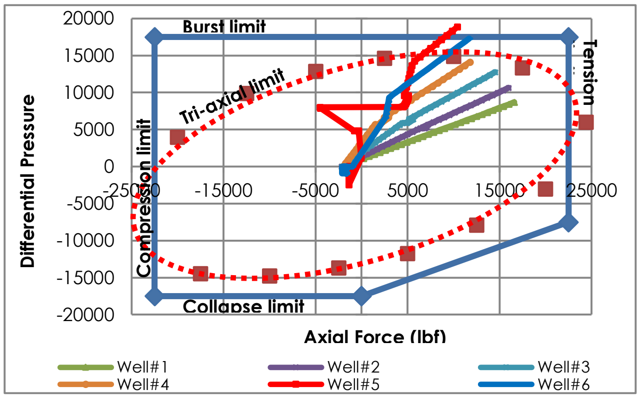


Figure 8 Tension-Pressure plot and the operating envelope for 1" CT in 2.875" tubing of Well #1 - #6

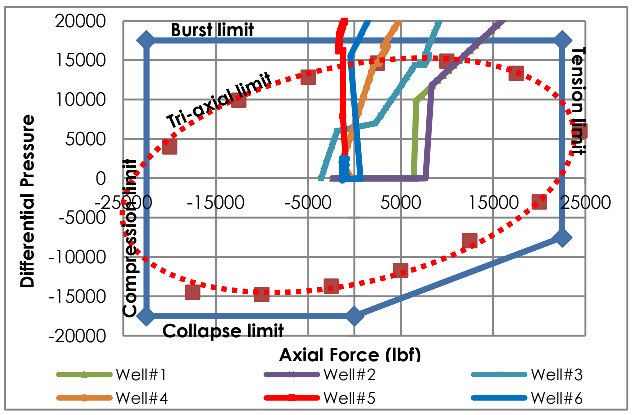


Figure 9 Tension-Pressure plot and the operating envelope for 1" CT in 3.5" tubing of Well #1 - #6

Another example for 1" CT in 3.5" tubing are shown in Figure 9. The pressure-tension plot shows all cases fail on hydraulic condition at the well's total depth as discussed earlier in 3.2. The results of integrated stress from pressure and tension are verified. The applications and recommended CT's size for each well scenario are listed in Table 6.

Table 6 Well Services applications and recommended CT size

Tubing Size	Applications	Well # 1	2	3	4	5	6
2.875"	**Group 1**: Milling and Sand Cleanout						
	Group 2: Gas Lifting, Stimulation and Fishing						
3.5"	**Group 1**: Milling and Sand Cleanout						
	Group 2: Gas Lifting, Stimulation and Fishing						

Viable for 1" CT
Viable for 1" CT with shallower depth of intervention
Viable for 1.25" CT

4.0 CONCLUSION

Based on the simulation study and analysis of well services application with 1" and 1.25" CT, the following conclusion can be drawn.

Higher Critical Flow Rate is required for high inclination and larger completion size to affects cleanout, as a consequence the higher frictional pressure losses.

The 1" CT is not suitable for hydraulic applications in 3.5" tubing wells. This is due to large annuli flow area (i.e. between 1"CT and 3.5" tubing) required higher critical flow rate. Moreover, the 1" CT is also unable to perform the intervention in horizontal well (Well#5 and Well#6), due to low buckling limit.

1" CT can be utilized in the low inclination well scenarios with the lower pumping rate requirement, while 1.25" CT can cover all of well services applications in our well scenarios.

Nomenclature

A_{ann}	Area of annulus (in²)
$C_{density}$	Correction factor for fluid density
C_{inc}	Correction factor for inclination angle
C_{size}	Correction factor for cutting size
d	Internal diameter of coiled tubing (in)
CT O.D.	Outer diameter of coiled tubing (in)
f	Friction factor
F_{Axial}	Axial force (lbf)
F_{Bottom}	Force due to fluid pressure (lbf)
F_{Drag}	Drag force (lbf)
inc	Inclination angle (degree)
L	Length between pressure point (ft)
ΔL	Length of coiled tubing (ft)
ΔP_{Annuli}	Pressure loss in annuli of coiled tubing (psi)
ΔP_{BHA}	Pressure loss in bottom hole assembly (psi)
ΔP_{CT}	Pressure loss in coiled tubing (psi)
$\Delta P_{Surface}$	Pressure loss in surface equipment (psi)
ΔP_{System}	System pressure loss (psi)
Q_{crit}	Critical flow rate (gal/min)
V_{Cut}	Cutting velocity (ft/s)
V_{slip}	Slip velocity (ft/s)
W	Weight per foot of coiled tubing (lb/ft)
ρ	Density of fluid (lb/gal)

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