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

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
Faculty of Engineering
Chulalongkorn University
Academic Year 2015

การประเมินการประยุกต์ใช้ท่อขดขนาดเล็กในงานบริการหลุม

นายธนาวิทย์ อุนสกุล

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
ปีการศึกษา 2558

Thesis Title	EVALUATION ON THE APPLICATIONS OF SMALL SIZE COILED TUBING IN WELL SERVICES
By	Mr. Thanawit Ounsakul
Field of Study	Petroleum Engineering
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ในปัจจุบัน ความคุ้มค่าในการผลิตน้ำมันและก๊าซธรรมชาติมีความสำคัญอย่างยิ่งยวดในภาวะวิกฤตราคาน้ำมัน หลุมผลิตน้ำมันและก๊าซธรรมชาติมักมีการอัตราการไหลที่ลดลงหรือหยุดไหลลงได้เมื่อหลุมถูกใช้งานเป็นเวลานาน ปัญหาอัตราการไหลที่ลดลงมักเกิดจากการอุดตันของขยะที่เกิดขึ้นเองระหว่างผลิตน้ำมันและก๊าซธรรมชาติ ดังเช่น ตะกรัน ทราย หรือน้ำ ท่อขดมักถูกนำมาใช้ในงานบริการหลุม และเป็นอุปกรณ์ที่ดีในการใช้กำจัดขยะเหล่านั้น แต่เนื่องด้วยขนาดที่ใหญ่ทำให้ไม่สามารถใช้งานบนแท่นผลิตขนาดเล็กได้ ดังนั้นการผลิตจากหลุมจำนวนมากต้องหยุดไปเพราะอุปสรรคในการผลิต

การใช้ท่อขดขนาดเล็กจึงเป็นทางออกสำหรับปัญหา วัตถุประสงค์ในการศึกษานี้จึงมุ่งเน้นเพื่อที่จะหาขอบข่ายที่ท่อขดขนาดเล็กสามารถนำมาประยุกต์ใช้ได้ โดยทำการศึกษาและประเมินสภาพการใช้งานด้วยคอมพิวเตอร์โปรแกรม โดยที่คอมพิวเตอร์โปรแกรมช่วยคำนวนหาขอบเขตในการใช้งานบริการหลุมผลิตประเภทต่างๆ การศึกษาการประยุกต์ใช้ท่อขดขนาดเล็กในงานบริการหลุมนี้ ทำการศึกษาสำหรับท่อขดขนาด หนึ่งนิ้ว และ หนึ่งนิ้ว สองหุน

ผลที่ได้จากการศึกษานี้สามารถแสดงให้เห็นว่าท่อขดขนาดเล็กสามารถนำมาใช้งานบริการหลุมได้ โดยที่ท่อขดขนาดหนึ่งนิ้วสามารถใช้ในงานบริการหลุมที่มีความเอียงน้อยได้ดี และท่อขดขนาด หนึ่งนิ้ว สองหุนสามารถใช้ในงานที่หลากหลายและครอบคลุมทุกสภาพหลุมที่ทำการศึกษา

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
สาขาวิชา	วิศวกรรมปิโตรเลียม	ลายมือชื่อ อ.ที่ปรึกษาหลัก	....
ปีการศึกษา	2558		

5571206521 : MAJOR PETROLEUM ENGINEERING

KEYWORDS: COILED TUBING / WELL SERVICES

THANAWIT OUNSAKUL: EVALUATION ON THE APPLICATIONS OF SMALL SIZE COILED TUBING IN WELL SERVICES. ADVISOR: ASST. PROF. JIRAWAT CHEWAROUNGROAJ, Ph.D., 116 pp.

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 and prevent all the reserve to be fully produced. In order to fight this impedance, the use of conventional coiled tubing (CT) unit is a common practice. The use of conventional CT unit is impossible on the small platform, low crane rating and without barge support. These are commonly found in most of the marginal field development. Hence, many wells reach their abandonment state before producing all reserve.

The use of small size CT is a promising practice, although has its own limit. Therefore, the objective of this study is to evaluate the range of applications for well services with small size CT. The evaluation utilizes the computer modeling which is used to determine the hydraulic and mechanic operating conditions. The determination of operating conditions involves critical velocity, system pressure losses, runability, capability to push/pull and combined stresses in various well scenarios. The effects of operating parameters in various oil & gas well scenarios are investigated for 1" and 1.25" CT.

The proper choice for the CT size (i.e. fit for purpose CT) is the key for successful operations. The study found the small size CT is more suitable for well services than the industry used to believe. The 1" CT is viable for well servicing in the low inclination well scenarios with the lower requirement on pumping rate. For small wellbore in particular, the use of large size CT can lead to the severe pressure losses in annuli, reduce efficiency of the cleanout or unloading. Although, the 1.25" CT is not the best choice for such conditions, but can be used in all of well services applications and scenarios.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
Field of Study:	Petroleum Engineering		
Academic Year:	2015		

ACKNOWLEDGEMENTS

The author expresses his gratitude to Chulalongkorn University and expresses his appreciation to the following people.

Special thanks to Asst.Prof.Dr. Jirawat Chewaroungroaj, the thesis advisor, for his guidance and support during the development of this thesis.

Special gratitude to Chevron Thailand Exploration and Production for providing financial support for this study.

Thanks to the committee members for their evaluation of this work and their subsequent valuable comments and suggestions.

Thanks to faculty and staff of the Department of Mining and Petroleum Engineering for all help and support in difficult times.

Thanks to Halliburton Landmark for their software's technical support.

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List of Abbreviations

API	American Petroleum Institute
BHA	Bottom hole assembly
BHP	Bottom hole pressure
cm	Centimeter
CoF	Coefficient of friction
Cp	Centipoise
CSG.ID.	Inner diameter of casing
CT	Coiled Tubing
CTD	Coiled Tubing Drilling
CT.ID.	Inner diameter of CT
CT.OD.	Outter diameter of CT
CTU	Coiled Tubing unit
ERD	Extended reach drilling
ESV	Equivalent slip velocity
ft	Feet
ft/s	Feet per second
HPHT	High pressure high temperature
HUD	Hang up depth
KOP	Kick off point
gpm	Gallon per minute
ICoTA	Intervention and Coiled Tubing Association
Kft	Kilo-feet
Kips	Kilo-pound
Kpsi	Kilo-pound per square inch
PBYL	Pipe body yield load
POOH	Pull out of hole
ppf	Pound per foot
PUW	Pull out weight

PV	Plastic viscosity
RIH	Run in hole
RIW	Run in weight
ROP	Rate of penetration
Scf/m	Standard cubic feet per minute
SF	Safety factor
SMYS	Specified Minimum Yield Strength
TD	Total depth
YP	Yield point

Nomenclatures

A	Cross-sectional area
A'	Angular speed
A_i	Inside cross-sectional area
A_o	Outside cross-sectional area
A_{Ann}	Annular flow area
C_d	Nozzle coefficient
C_{ang}	Correction factor for wellbore inclination
C_{Conc}	Correction factor for concentration of particle
C_f	Coefficient of friction
C_{mw}	Correction factor for fluid density
C_{size}	Correction factor for particle size
D_{50}	Mass-median-diameter
E	Young Modulus
f	Friction factor for CT
F_a	Friction factor for annulus
$F_{Axial,T}$	Axial Force from true tension
$F_{Axial,E}$	Axial Force from effective tension
F_{bottom}	Bottom pressure force due to fluid pressure applied on the cross-sectional area of BHA
F_{bs}	Buckling stability force
F_D	Drag force
F_N	Side force
$\mathrm{F_{Sin}}$	Critical (Sinusoidal) buckling load
F_T	Axial force at the bottom of section calculated by Buoyancy method
ΔF_{area}	Change in force as a result of a change in area
g_c	Acceleration due to gravity
G_{CT}	Geometry factor for CT
G_{Ann}	Geometry factor for Annulus

I	Moment of inertia of tubular
k	Fraction of hanging weight
K	Consistency factor
L	CT or Annulus section length
$\dot{m}$	Mass flow rate of gas
n	Flow behavior index
$N_{Re\ Ann}$	Reynolds number for annulus
$N_{Re\ CT}$	Reynolds number for CT
N_{Rec}	Critical Reynolds number
P_B	Minimum burst pressure
$P_{Bottom\ Hole}$	Bottom hole pressure
P_c	Collapse Pressure (psi)
P_i	Internal pressure
$P_{Hydrostatic}$	Hydrostatic pressure
P_{Pump}	Pump pressure
P_o	External pressure
P_{Return}	Return pressure
P_{Total}	Total pressure loss or System pressure loss
$\Delta P_{surface}$	Pressure drop in the surface equipment
ΔP_{CT}	Pressure drop inside the CT
ΔP_{BHA}	Pressure drop inside the bottom hole assembly
ΔP_{Ann}	Pressure drop in annulus of CT
ΔP_{Gas}	Frictional pressure loss due to gas
Q_{Crit}	Critical flow rate
r	Radial clearance between wellbore and CT
R	Gas constant
t	Wall thickness
t_{min}	Specified minimum wall thickness
T	Temperature of the fluid
$\mathrm{T_{Max}}$	Tension limit
$\lvert T \rvert$	Trip speed

$\lvert V \rvert$	Resultant speed
V_a	Average fluid velocity in annulus
v_{crit}	Critical flow velocity
V_{CT}	Average fluid velocity in CT
v_{cut}	Cutting velocity
v_{slip}	Slip velocity
$\bar{v}_{slip}$	Uncorrected equivalent slip velocity
W_{air}	CT weight in air
W_e	CT weight in fluid
WOB	Weight on bottom
Z	Compressibility factor
$\left(\frac{r}{R}\right)$	Curvature ratio (Inner radius of CT/Reel radius)
$\Delta\alpha$	Change in azimuth over section length
$\Delta\beta$	Change in inclination over section length
μ_a	Apparent viscosity
ρ	Metal density of CT
ρ_f	Density of fluid
ρ_l	Liquid phase density
ρ_g	Gas phase density
θ	Wellbore inclination
Ø	Average inclination over section length
σ	Surface tension
σ_y	Yield stress
σ_{axial}	Axial stress
σ_h	Hoop stress
σ_r	Radial stress

CHAPTER I

INTRODUCTION

1.1 Background

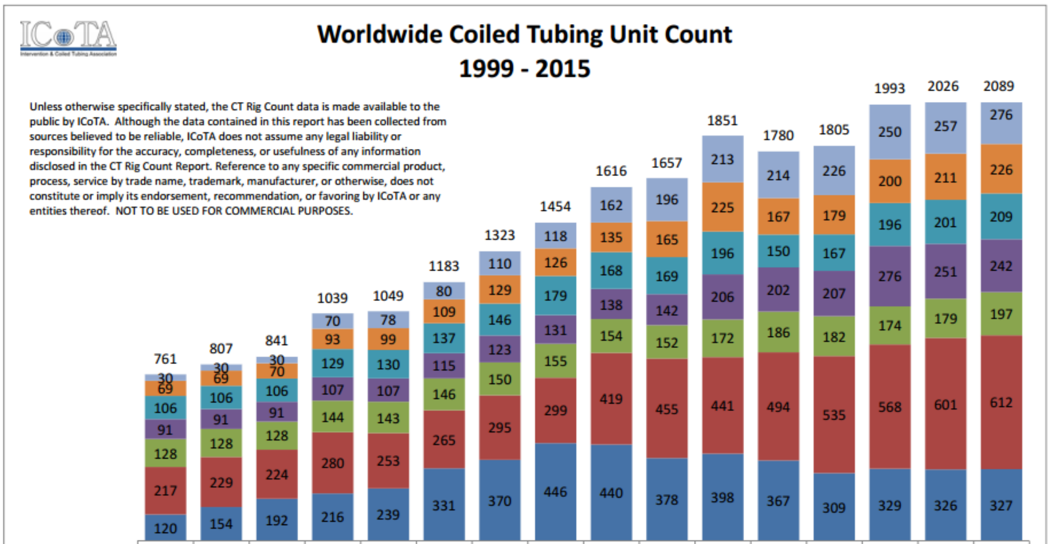
Coiled Tubing (CT) is the continuously mill tubular and then coiled into a reel for storage, transportation and ease for well intervention. The continuously hollow tubing allows the ability to pump fluid through the CT, making the CT advantageously safe and efficient to operate under pressure in comparison to the jointed pipe. The API CT have the size ranged from 0.75” to 3.5”, whereas, the non-API CT can be as small as 0.25” and as large as 6.625” [1]. The CT milled with various size and material. Each particular size has its own limit to perform such an operation.

In addition, CT also offers the easy rigging, smaller foot print, shorten tripping time and ability to circulate continuously. In many occasions, the conventional operation is replaced by the use of CT, such as CT Drilling (CTD), CT Completions (CTC). Most of the CT applications involve in the pumping of fluid through the CT. The hydraulic horse power (i.e. pressure & flow rate) transferred by the pumping fluid into down hole is then converted into work. The examples of work generated from hydraulic horse power are jetting force, rotating the motor, solid transportation, liquid unloading, fluid squeezing into formation. On the other hand, CT applications which are not requiring the fluid to be able to pump through can be distinguished as “Conveyance”. The well services’ applications are:

- Sand cleanout
- Scale milling / jetting
- Well unloading
- Well stimulation
- Cement Plug
- Conveyance for Logging

- Perforation
- Fishing

Coiled Tubing Unit (CTU) becomes popular tool for well services as it is able to provide wide range of services. The recent statistic provided by Intervention and Coiled Tubing Association (ICoTA) is shown in Figure 1.1. It can be seen the continuous growth of worldwide CTU count since 1999.



	1999	2000	2001	2002	2003	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Annual Total	761	807	841	1039	1049	1183	1323	1454	1616	1657	1851	1780	1805	1993	2026	2089
Russia & CIS	30	30	30	70	78	80	110	118	162	196	213	214	226	250	257	276
Far East	69	69	70	93	99	109	129	126	135	165	225	167	179	200	211	226
Middle East	106	106	106	129	130	137	146	179	168	169	196	150	167	196	201	209
Latin America	91	91	91	107	107	115	123	131	138	142	206	202	207	276	251	242
Europe/Africa	128	128	128	144	143	146	150	155	154	152	172	186	182	174	179	197
USA	217	229	224	280	253	265	295	299	419	455	441	494	535	568	601	612
Canada	120	154	192	216	239	331	370	446	440	378	398	367	309	329	326	327

Figure 1.1 Worldwide coiled tubing unit count 1999-2005 [2]

Another growing area is the CT size, in order to counter the technical challenges and new requirement in the past few decades. These challenges are due to advancement in drilling technology which allows deeper, directional, high pressure-high temperature (HPHT), deep water well can be drilled easily. The consequence is the ability to service the well after drilled becomes another challenging mission. The requirement then moves toward the ability to perform services in deeper, more deviated, more challenging well conditions. The demand of higher flow rate and deep well extended reaching (ERD) drive the mill of larger tubing. The bigger CT is needed to answer to all new challenges. The CT were manufactured with the size ranged from 0.75 inches to 3.5 inches [3]. It can be seen from the sales by size from the 2 major CT manufacturers that more than 60 percent of CT usage is the sizes bigger than 1.25 inches.

In order to evaluate the viable application for small size CT the well services operation scenarios are conducted by WELLPLAN^{TM}. The suitable operating conditions in term of appropriate CT size and intervention depth are determined from simulation results. In addition, the sensitivity analysis on CT's parameters such as coefficient of friction (CoF) and yield strength affect the viability.

1.2 Objectives

To evaluate the range of applications for small size Coiled Tubing by determination of hydraulic and mechanic operating envelope.

1.3 Outline of methodology

This study based on computer simulation using the Commercial software (WELLPLAN^{TM} from LANDMARK). In order to completely investigate all point of view for hydraulic and mechanic feasibility for small size Coiled Tubing with variation in operation parameters, the integrated study which include all aspects is presented hereafter. The considerations, parameters taken from the literatures, industry standards are integrated into study process. The summary of work process to investigate the feasibility of small size API CT (1" and 1.25") shown as the following steps:

- The hydraulic considerations were evaluated for each size of CT, The critical flow rate for solid transportation was determined for each well scenario. Similarly, the optimum gas rate was determined for well unloading. These liquid and gas rates were then useful in frictional pressure losses calculation. The CT can be called hydraulically feasible providing that the pump pressure is lesser than the burst pressure rating of the CT.

- The mechanic considerations then evaluated for each size of CT. The first consideration on mechanic conditions was the runability of the CT. Therefore, the effective tension for each well scenario was studied. Then the combine of all stresses applied on CT were considered. The plot of pressure-tension was constructed to determine if the CT able to withstand both hydraulically and mechanically stresses. The possibility of using CT to provide the solid-liquid transportation and be able to run in/out of the well safely was then evaluated. Basically, evaluation was based on the pressure-tension plot in comparison to the pre-defined boundary.

1.4 Outline of thesis

Chapter I introduces the background of CT, objectives of study and methodology of this study.

Chapter II presents the review of literatures related to the CT applications, benefits of using smaller size CT, and CT limits.

Chapter III presents important theory related to hydraulic and mechanical considerations of CT.

Chapter IV presents the research methodology and simulation parameters.

Chapter V presents the results and discussions for the simulation study. The sensitivity analysis performed on the well scenarios. In addition, the recommendation to use small CT based on applications and well scenarios.

Chapter VI concludes the thesis and recommendation for adopting this study in pragmatic.

CHAPTER II

LITERATURE REVIEW

This chapter discussed the CT applications, which stated principle of requirement for CT in well services. The literatures related to the benefits of using small size CT are reviewed. In addition, the review on the CT limitations and mitigations to use CT beyond the limit are presented.

2.1 Applications for well services

In oil and gas business, CT is a versatile tool and can be used in wide range of applications. The CT became integral component well services. Well service applications account for 75% of CT usage worldwide [4]. The CT's ability to service the live well is the key success for utilization in well services. The applications can be divided into 2 categories based on pumping requirement. The pumping applications make use of circulating system which including batch mixer, pump and/or nitrogen convertor. The comprehensive reviews on CT applications in well services [4-6] discussed hereafter in 2.3.1 and 2.3.2.

2.1.1 Pumping application

2.1.1.1 Milling operation

Milling is a typical well services operation, which provides or regains access to the well bore. There are several obstructions that restricted the well intervention or production. The common found obstruction for milling such as scale, salt, bridge plug, etc. The typical milling operation involves the circulation of fluid while slowly penetrating into the obstruction. The circulating of power fluid drives the motor and mill bit to allow the penetration. The solid particle entrained with the circulating fluid and transported out of wellbore.

2.1.1.2 Sand cleanout operation

Solid production is typical oil and gas production problem. The accumulation of the solid in well bore can impede the fluid flow and reduce well productivity. In most cases, well bore can accumulate all kinds of solid such as formation sand or fines, gravel pack failure, proppant flow-back and fracture operation screen-out. The typical sand cleanout operation involves the circulation of fluid while slowly penetrating into the solid fill as shown in Figure 2.1.

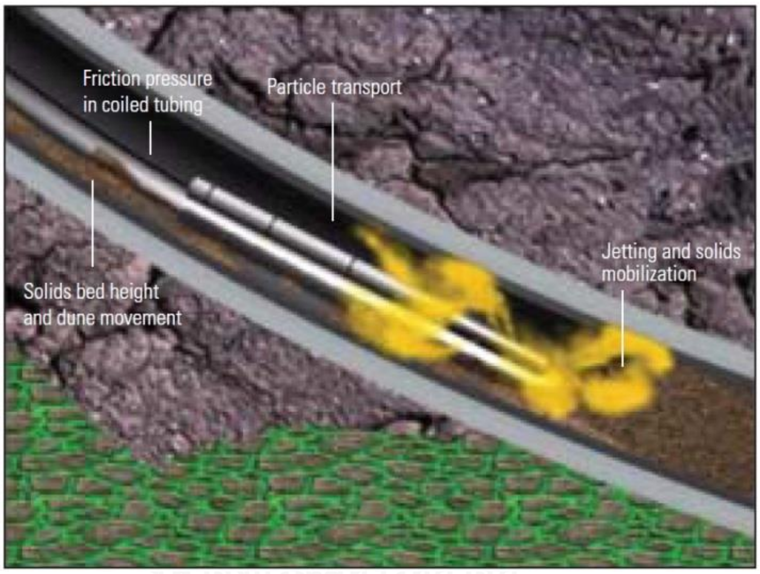


Figure 2.1 Sand cleanout application [5]

The jetting force from the nozzle tool attached to CT agitates the fill bed. In the case of high consolidation fill, the jetting force alone might not enough, but requires the mechanical removing aid from motor and mill bit. The solid particle entrained with the circulating fluid and transported out of wellbore.

2.1.1.3 Well unloading operation

Another typical problem for oil & gas production is the development of fluid column with higher hydrostatic pressure than the reservoir pressure. This phenomenon exhibits the severe problem in especially gas well. The fluid column can be introduced to the well bore since the completion or workover as overbalance completion fluid following the completion or workover operation. In many cases, the well is loaded with the produced fluid such as hydrocarbon and formation water that produced with hydrocarbon.

Using CT for well unloading is a more cost-effective approach in comparison to installing gas lift completion and facility. The CT is run into the well bore during the well unloading operation. The operation involves in circulation of nitrogen to displace the well bore fluid. The continuous injection of nitrogen can be performed while RIH into the wellbore or station at a certain depth. The nitrogen entrains the liquid droplet and transport out of wellbore. The displacing gas lowers down the hydrostatic pressure and allows natural flow of hydrocarbon to the well bore.

2.1.1.4 Stimulation operation (acidizing)

The use of CT to counter the formation damage problems is another area for CT utilization. The acid stimulation treats the damage due to plugging of formation or creates the channel to bypass damage zone. Although, the conventional bull-heading method can also perform the similar operation, but CT can provide the better zone selectivity. The process involves setting straddle packer across the zone and injecting of the treatment fluids as shown in Figure 2.2.

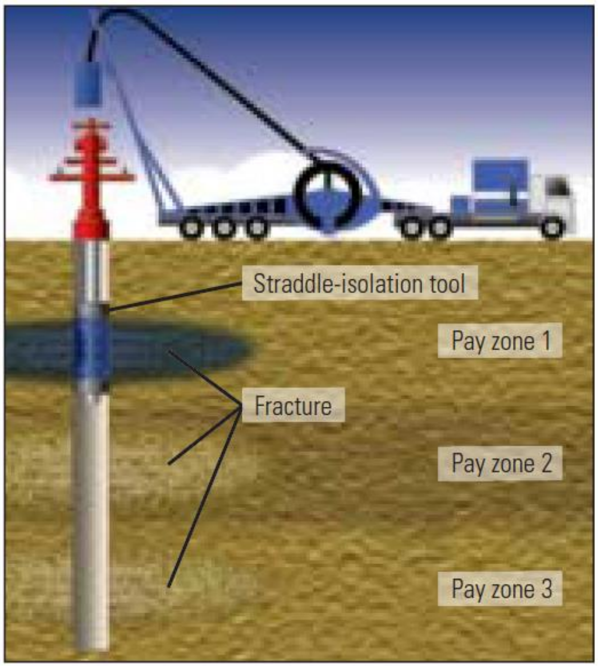


Figure 2.2 Stimulation with straddle isolation tool [5]

2.1.2 Mechanic application

2.1.2.1 Fishing operation

Fishing is the lost in hole removal operation. The parted, dropped, stuck tools or equipment that lost in hole during well services operation can be removed out of the well bore during fishing operation. The slickline is always the first tool used for fishing or recover downhole tool as the most economic tool. The CT can close the slickline gap for fishing in deviated well and the application of high tensile pulling. The CT also has the ability to push fish into rat hole instead of retrieving out of well bore.

2.1.2.2 Logging and perforation

The logging and perforation typically performed by the use of electric line unit. CT can be used as conveyance of logging tools and perforation gun. The memory logging tools can be deployed directly below the conventional CT. The surface read out logging tools requires the CT with fiber optic or electric cable feed inside for data acquisition purpose. The obvious benefit of CT conveyance is the capability to access highly deviated or horizontal section. The longer perforation gun length can be accommodated with CT.

2.2 Requirement of small size CT

The demands 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 2.2.1 to 2.2.4.

2.2.1 Economic viable

The smaller size of CT incurred the least cost. Since it uses fewer raw materials for fabrication, smaller equipment in use, less man power to operate, require less overall operation time and hence reduction in operation cost. There has been the field cases studied for the use of small CT for various types of well intervention. Most of the paper published the essential constraints that drive some operation to go toward the use of small size CT. Those constraints are the main reasons of why the minimum achievable size of the CT is required.

Sundranurthy et al. [6] revealed the field case and the operation with 1” CT in Thailand and Malaysia. The operation performed with 23 runs in various applications such as milling, logging, and perforation without major issue. Ultimately, the substantial reduction in operation cost was recognized. The wells which ready for plug and abandon due to economic and technical challenges were resurrected for production.

Jelinek et al. [7] reported the field cases in German and Netherlands that had the economically justification by using the 0.75” CT intervene the depleted well. Moreover, the well intervention with smaller size CT restricted to kill the well unintentionally, especially in the depleted marginal gas well from the high volume of fluid pump in, and hence the hydrocarbon can be produced after the investment had paid up front.

2.2.2 Crane capacity

The platform crane capacity is limited. Mitigation to the low or de-rated crane capacity could be very costly and sometime have to compromise the safety. Arangath et al. [8] summarized the alternative technique to overcome the limitation imposed by platform crane capacity. The proposed techniques are the following:

- Upgrading the platform crane capacity
- Using jack up barge
- Installation of modular crane
- Cutting the CT and re-join on the platform
- Spooling CT directly from the supply vessel to the well head platform
- Performing the well interventions with the CT reel and pumping equipment placed on a dynamically positioned vessel, with the only injector head and well control equipment on the platform

- Performing the well interventions with the CT reel and pumping equipment placed on a barge, with the only injector head and well control equipment on the platform.

Long et al. [9] expressed the constraints because the low deck load capacity and available deck space is insufficient for CT operations and could also overcome with CT operation from work boat. The mitigation plans followed the technique are required, such emergency disconnect.

2.2.3 High pressure well intervention

The high pressure snubbing is another requirement [3] for smaller size of CT, "from the fact that smaller tubing has higher burst and collapse pressure, making it more suitable for high-pressure application in general".

2.2.4 Better results in small tubing

There are some clear advantages of the smaller CT in comparison to bigger CT [1]. Gas lifting in small completion is an example. The large size of CT acts like a choke to the annulus flow area. As a result, the excessive pressure can be loss in the annulus.

2.3 Limitation of small size

Portman [3] concluded in his work that the predominant factor for CT size selection is the completion size. There are many factors effecting the proper size selection and minimization for each application. The factors governing the deep reach capability of Coiled Tubing intervention are the following:

- Size and weight of the CT
- Size of the Completion
- Well geometry, particularly inclination
- The Content of the well
- The Condition of the tubing and liner wall

Portman [10] conducted the study on limitation of small size CT and the technology that enable the small size CT to be used. The limitation can be categorized as hydraulic and mechanical limit. Flow rate limitation (Hydraulic) is a concern. The maximum flow rate (Q) is direct proportional to the tubing diameter (D). There are 2 methods to mitigate the flow rate limitation:

- The use of friction reducer can be greatly help to increase the flow rate. In experiment, the reduction of 40-80% frictional pressure loss can be achieved. The less frictional pressure losses allow small diameter CT to be used at flow rates historically associated with larger diameter CT.
- Reducing flow rate required for the operation through the use of proper solid cleanout technique (i.e. wiper trip technique), specialized fluid (i.e. to reduce the friction and transport solid), efficient nozzle, and proper stimulation technique.

Push/Pull limitation (Mechanic): To push the CT require rigidity and there are two methods that can be used to mitigate the Push/Pull limitation:

- Increase push/pull availability for a certain size of CT can be considered from the simple relationship below. Cross sectional area (A), Yield Strength (σ_y) should be maximized while the density (ρ) should be reduced. The overpull and CT's properties can be expressed as below:

$$Overpull = SMYS \times A - k\,W \qquad (2.1)$$

$$Overpull = (SMYS - k\,L\,\rho\,g)\,A \qquad (2.2)$$

where

SMYS	Specified minimum yield strength (psi)
k	Fraction of hanging weight
W	Coiled Tubing weight (lbf)

A Cross-sectional area (in^2)

ρ Metal density of CT (lb/in^3)

L Depth of CT (feet)

- Reducing friction through the use of friction reducer, low friction coating, vibrating tools and tractor.

Engel and Rae [11] studied the techniques of transporting solid particle out of well bore using CT. On each technique, its inherent drawback was discussed and can be summarized as Table 2.1. The conventional method refers to the use of typical brine fluid in direct circulation. This method require highest pump rate in order to achieve the solid transportation capability. The reverse circulation involves pumping through the annulus and taking return inside the CT, which is not preferable method due to the well control issues. Concentric CT has major drawback on the weight. Foam and suspension fluid are degradable in well temperature. They concluded from their work that large diameter CT is not pre-requisite for large bore cleanout. The other techniques can help particle entrainment and subsequently displacement from the well at low velocity.

Table 2.1 Summary of sand cleanout techniques and associated issues

Technique	Drawbacks
Conventional high velocity	Excessive pump pressure loss
Reverse circulation	Loss well control
Concentric CT	Heavy weight
Foam	Uncertainty of losses
Wiper trip technology	High Cost
Suspension Fluid	No track record.

Leising and Walton [12] stated the inefficient of CT solid removal using viscous fluid in Laminar flow due to inability to agitate the cutting bed by pipe rotation. Alternatively, a high flow rate for turbulent hole cleaning is more effective. Therefore, conventional non-viscous brine is selected in this study at which represents the most conservative case and requires highest fluid flow velocity.

The several well service applications can be performed using CT intervention. The benefits of using small size CT has shown earlier from literature reviews. The field cases reviewed exhibit the economic approach to service the well using small size CT. The study of the limitation for small size CT could provide the recommendation use of small size CT in different applications and well scenarios. The ultimate goal to the industry is a valuable research on the versatile tool for well services with the aim to produce more hydrocarbon reserve. The reduction in the size makes the cost for operation reduced, pushing back the abandonment threshold in the marginal field. Also, gaining the benefit of less damaged to the reservoir due to smaller amount of fluid to pump in, hence more hydrocarbon can be produced.

CHAPTER III
THEORY AND CONCEPT

This chapter discusses the theories and concept for the study. The requirements for CT on each application are different. Then it became necessity to clearly state the unique requirement for each application listed in Chapter I. The requirements for each application can be listed as below:

Table 3.1 Work requirement for each application

Applications	Solid Transportation	Well Unloading	Runability	Push/Pull
Milling	Yes	Yes	Yes	High
Sand cleanout	Yes	Yes	Yes	Low
Unloading	No	Yes	Yes	Low
Stimulation	No	Yes	Yes	Low
Fishing	No	No	Yes	High
Logging	No	No	Yes	Low
Perforation	No	No	Yes	Low

Table 3.1 elaborates the requirement for each well services application. There are four main area of requirement which are solid transportation, well unloading, runability and push/pull capacity. These requirements refer to as hydraulic considerations and mechanical considerations. We can group these applications into 3 group based on the pumping requirement. The first group of applications require high pumping rate. The second group requires the injection of gas. The last group does not require pumping anything through the CT.

The first and second group of application listed in Table 3.1, require pumping fluid through the CT. There are several kinds of fluid to be pump into the CT. The objectives of pumping are also different. Brine, gel, acid, solvent and nitrogen are examples of fluid being pumped. Brine in particular is the common fluid being used as well control and formation damage control fluid. It can be used as based fluid for mixing the other workover fluid (e.g. gel, acid). Gel used for sweeping and chasing the brine or for better hole cleaning purpose. However, the most fundamental objective of pumping powered fluid is to transfer the hydraulic power to transport the downhole solid and lift the wellbore's fluid.

The group 1 applications listed in table 3.1 are milling and sand cleanout. These applications require the hydraulic viability. The CT must be able to deliver the required pump rate (i.e. Critical Flow Rate) to transport solid particle from wellbore. The other objectives are such as driving the motor or jetting power downhole. Consequently, the CT must be able to withstand the pump pressure which associated to the critical flow rate.

The applications listed in group 2 are such as well stimulation and well unloading. Although the well stimulation with acid could require low pumping rate, but the work after treatment is somewhat important. The left behind of unspent acid slurry could create the secondary and tertiary reaction. These later reactions create the precipitation as a result the damaging to the formation. These applications depend on the ability to lift fluid off from well bore. The hydraulic conditions for injecting gas are considered.

The applications in group 3 are such as fishing, logging and perforation. These applications can be exempted for the hydraulic consideration. The rationale behind the exemption is because of the low requirement in the pump rate, hence, negligible effect on pressure losses and incomparable to the magnitude of CT's burst pressure.

3.1 Hydraulic limitation

3.1.1 Critical flow velocity

The solid transportation capability plays an important role in the success of the milling and sand cleanout operation. The solid removal from downhole can be in the form of formation fines, drilling cuttings, proppant, scale and milling debris.

There are many parameters govern the solid transportation analysis which can be listed as below.

- Deviation
- CT size
- Flow regime
- Hole size
- Fluid density
- Fluid rheology
- Velocity (flow rate)
- Pipe eccentricity
- Solid density
- Solid shape
- Solid size

The critical fluid flow velocity is the minimum velocity at which the solid from wellbore start the upward movement. Larsen's correlation [13] can be used to estimate the critical velocity as:

$$v_{crit} = v_{cut} + v_{slip} \qquad (3.1)$$

It can be seen from the Eq. 3.1 above that the critical velocity is depend on the cutting velocity which given as equation below.

$$v_{cut} = \frac{ROP}{36\left[1-\left(\frac{CTOD}{CSGID}\right)^2\right]C_{Conc}} \qquad (3.2)$$

In well services during the solid cleanout operations, the penetration rate can be kept very low (i.e. close to '0') in order to clean out the solid from the well bore. Hence, we can neglect cutting velocity in this study and the critical fluid flow velocity become the function of corrected equivalent slip velocity (v_{slip}).

$$v_{crit} = v_{slip} \tag{3.3}$$

$$v_{crit} = \bar{v}_{slip} C_{size}\, C_{mw} C_{ang} \tag{3.4}$$

The uncorrected equivalent slip velocity $(\bar{v}_{slip})$ is a function of apparent viscosity and defined as Eq. 3.5 and 3.6 as below.

$$\bar{v}_{slip} = 0.00516\mu_a + 3.006 \qquad \text{for } \mu_a < 53\ cp \tag{3.5}$$

$$\bar{v}_{slip} = 0.02554(\mu_a - 53) + 3.28 \qquad \text{for } \mu_a > 53\ cp \tag{3.6}$$

Figure 3.1 describes the relationship between the uncorrected equivalent slip velocity and apparent viscosity. The figure is generated from Eq. 3.5 and 3.6. It can be seen that the uncorrected equivalent slip velocity $(\bar{v}_{slip})$ is going to be higher as the apparent viscosity (μ_a) is higher.

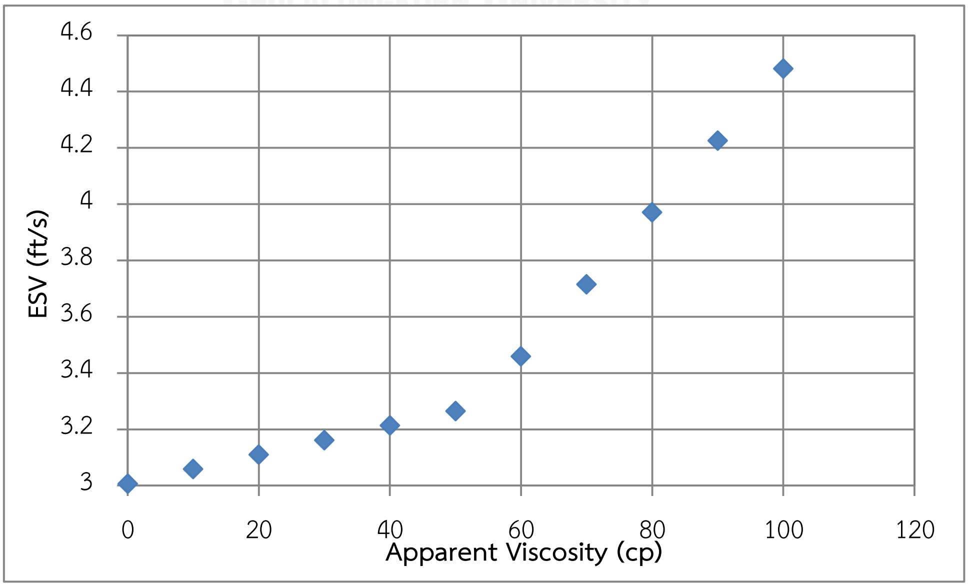


Figure 3.1 Equivalent slip velocity v.s. apparent viscosity

Leising and Walton [12] stated the inefficient of CT solid removal using viscous fluid in laminar flow due to inability to agitate the cutting bed by pipe rotation. Alternatively, a high flow rate for turbulent hole cleaning is more effective. Therefore, non-viscous brine (i.e. $\mu_a < 53\ cp$) was used in this study at which resulted in lesser critical fluid flow velocity.

The cutting size correction factor (C_{size}) is governed by mean solid particle's size (D_{50}). The cutting size can be corrected from Eq. 3.7 below:

$$C_{size} = -1.04D_{50} + 1.286 \qquad (3.7)$$

Figure 3.2 describes the relationship between the correction factor for solid size and average solid size. The figure is generated from Eq. 3.7. As the D_{50} is getting smaller, the critical fluid flow velocity going to increase. In this study, the worst case of cleaning wells at which filled with the 0.05 inches (i.e. 1270 micron) of medium particle size distribution (D_{50}) was selected. This is equivalent to the correction factor close to 1.3 times.

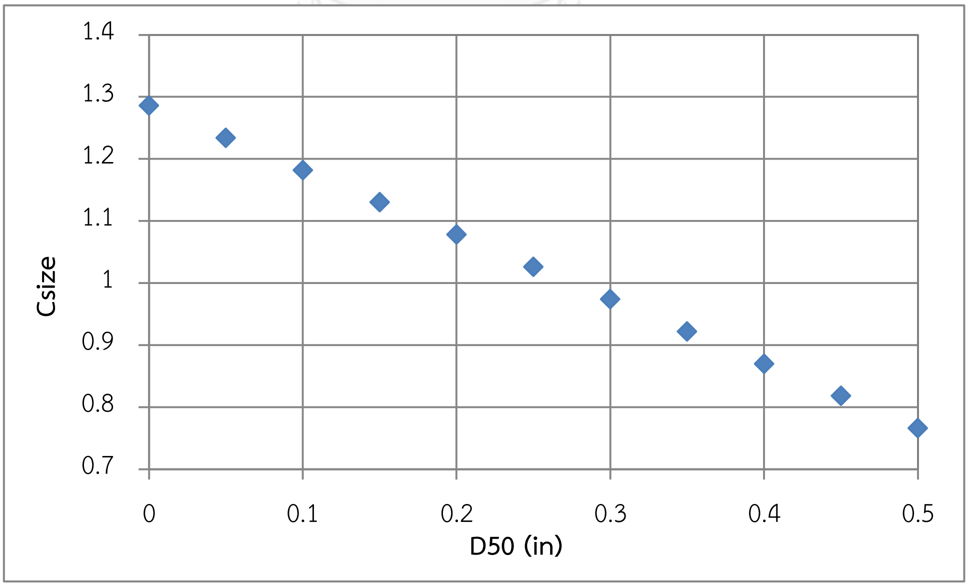


Figure 3.2 Correction factor for solid size v.s. average solid size

Last parameter that affects the critical flow rate is the fluid density. The correction for fluid density can be expressed as:

$$C_{mw} = 1 - 0.0333(\rho_f - 8.7) \qquad \text{for } \rho_f \geq 8.7 \qquad (3.8)$$

$$C_{mw} = 1 \qquad \text{for } \rho_f < 8.7 \qquad (3.9)$$

Figure 3.3 describes the relationship between the correction factor for fluid density and fluid density. The figure is generated from Eq. 3.8 and 3.9. The correction for fluid density is also straight forward where the worst case is when cleaning out performed with low fluid density.

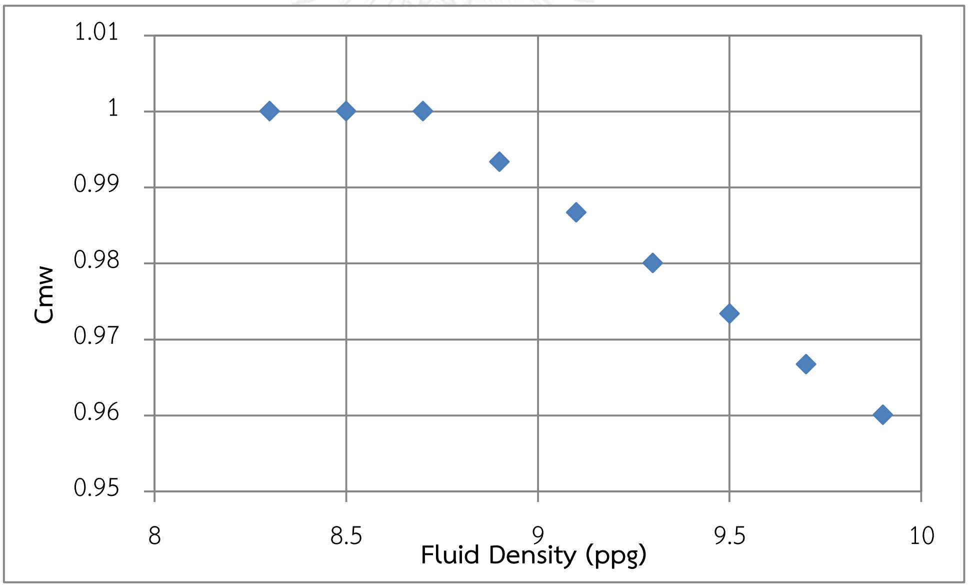


Figure 3.3 Correction factor for fluid density v.s. fluid density

In summary, the $\bar{v}_{slip}$, C_{size} *and* C_{mw} were controlled and constant in this study. Therefore the Eq. 3.4 can be reduced into non-linear equation at which the inclination as the function of critical flow velocity (v_{crit}) as below.

$$v_{crit} = Constant\ x\ C_{ang} \tag{3.10}$$

$$v_{crit} = Constant\ x\ (0.03420\theta_{ang} - 0.000233\theta_{ang}{}^{2} - 0.213) \tag{3.11}$$

The relationship between critical flow rate and critical flow velocity can be expressed as:

$$Q_{Crit} = A_{Ann}\, v_{crit} \tag{3.12}$$

Substitute Eq. 3.11 into Eq. 3.12:

$$Q_{Crit} = A_{Ann}\, Constant\ x\ (0.03420\theta_{ang} - 0.000233\theta_{ang}{}^{2} - 0.213) \tag{3.13}$$

3.1.2 Maximum gas velocity

The ability to transport the wellbore fluid is a requirement for application in group 2 (i.e. well unloading and stimulation). The critical flow velocity (v_{crit}) for gas, is defined as the required velocity for the entraining of liquid droplet. This parameter must be in consideration especially for the well unloading applications where the return to surface of liquid is required. In prediction of critical velocity for liquid unloading the Turner's model (1969) can be used.

$$v_{crit} = \frac{1.92\,[\sigma(\rho_l - \rho_g)]^{0.25}}{\rho_g{}^{0.5}} \tag{3.14}$$

where:

v_{crit}	Critical gas velocity (ft/s)
σ	Surface tension (dynes/cm)
ρ_l	Liquid phase density (lbm/ft3)
ρ_g	Gas phase density (lbm/ft3)

Bottom Hole Pressure (BHP) is required to be reduced below the reservoir pressure in order to well being unloaded. The maximum gas velocity can be determined based on the minimum BHP. There are many parameters that affect the lower of BHP during CT gas lift such as nitrogen injection rate, Injection depth, CT size, well geometry and gas production [14].

The CT size affect the BHP, consider the first case at the 16000 ft - depth of injection in vertical well. It can be seen from the Figure 3.4 that smaller CT is more helpful to reduce the BHP first significantly. BHP is reduced due to the decrease annulus liquid density, when the nitrogen arriving in. For the case of 1”CT, at around 500 scf/m the BHP reach the minimum value. The further step-up of the nitrogen injection rate causes the increment BHP due to the frictional pressure loss. Similarly, in the case of 1.25” CT, the minimum BHP is achieved at around rate of 800 scf/m. The further step-up of the nitrogen Pump rate also resulted in the excessive pressure loss.

It can also be seen the effect of CT depth from Figure 3.4. Very similar to well unloading operation by conventional gas lift completion, the depth of gas injection plays important role in successful operation. It can be concluded that as the depth of injection is greater, the BHP can be more reduced.

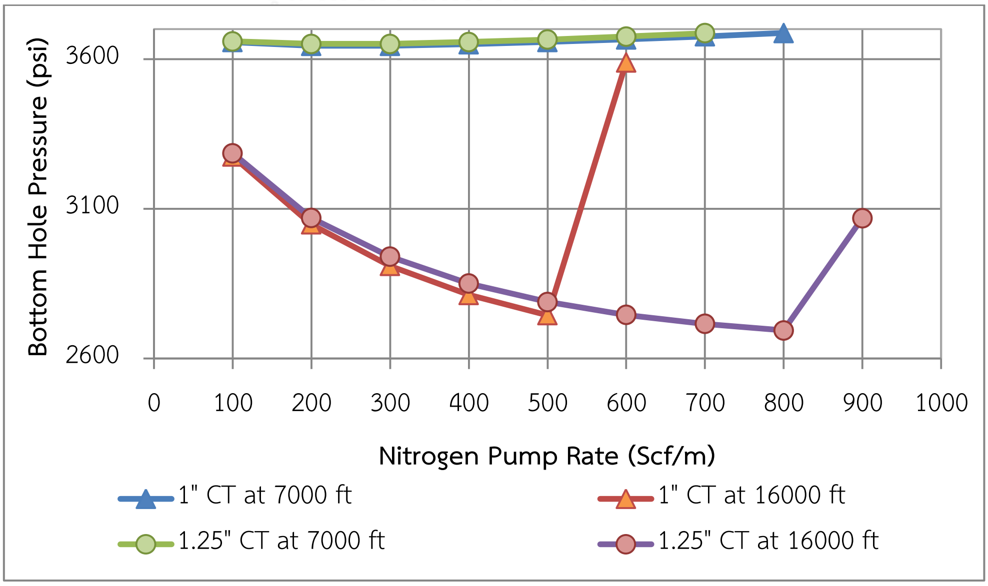


Figure 3.4 The effect of CT size and CT depth on BHP in vertical well

3.1.3 Pressure losses

In general, the flow in pipe can be divided into 3 terms which are kinetic, hydrostatic and friction component. The kinetic component is typically insignificant and negligible in comparison to the other 2 components. Consider the nodal analysis for the node at the bottom hole, the inflow/outflow can be expressed as:

$$P_{Pump} - \Delta P_{surface} + P_{Hydrostatic} - \Delta P_{CT} - \Delta P_{BHA} = P_{Bottom\ Hole} \tag{3.15}$$

$$P_{Bottom\ Hole} - P_{Hydrostatic} - \Delta P_{Ann} = P_{Return} \tag{3.16}$$

Eq. 3.15 and 3.16 can be equated; the hydrostatic component is canceled and can be written as:

$$P_{Pump} = P_{Return} + \Delta P_{CT} + \Delta P_{Ann} + \Delta P_{BHA} + \Delta P_{Surface} \tag{3.17}$$

Return pressure can be manipulated via the use of surface equipment such as unloading unit to create zero back pressure. Hence, return pressure can be set as zero psi. The pumping pressure then equals to the system pressure loss. System pressure loss comprises of the pressure loss in surface equipment, CT, bottom hole assembly, nozzles and annuli.

$$P_{Pump} = P_{Total} \tag{3.18}$$

The system pressure loss ($\mathbf{P}_{\mathbf{Total}}$) is the flow rate dependence. Hence the critical flow rates need to be pre-determined from Section 3.1.1 and 3.1.2. In other word, the frictional pressure loss during pump downhole the fluid limit the maximum flow rate for any applications. In WELLPLAN™ [15], the analysis steps for the determination of pressure losses in various segments of the circulating system are as following:

Step1: Calculate the CT and annular pressure losses are based on the rheological model selected using the rheology model calculations. The rheological model used for this study is Power-law. Pressure loss inside CT is a main contributor to system pressure loss. This is due to the fact that, it is the longest section with small flow area. Despite several friction factor correlations [16], the frictional pressure losses inside CT in WELLPLAN™ is based on McCann and Islas's work [17]. For each scenario, the calculations can be summarized in Table 3.2 and 3.3.

Table 3.2 Summary table for CT and annular flow pattern determination

Parameters	Coiled Tubing	Annulus
Average Velocity	$V_{CT} = \left(\frac{4}{\pi}\right)\left(\frac{Q}{D^2}\right)$	$V_{Ann} = \left(\frac{4}{\pi}\right)\left(\frac{Q}{CSG.ID.^2 - CT.OD.^2}\right)$
Geometry Factor	$G_{CT} = \left(\frac{3n+1}{4n}\right)^n \; 8^{n-1}$	$G_{Ann} = \left(\frac{2n+1}{2n}\right)^n \; 8^{n-1}$
Reynolds Number	$N_{Re\,CT} = \frac{\rho\, {V_{CT}}^{(2-n)} CT.ID.^n}{g_c\, G_{CT}\, K}$	$N_{Re\,Ann} = \frac{\rho\, {V_{Ann}}^{(2-n)} (CSG.ID.^2 - \; CT.OD.^2\,)^n}{g_c\, (\frac{2}{3}) G_{Ann}\, K}$
Critical Reynolds Number	$N_{Rec} = 3470 - 1370\, n$	$N_{Rec} = 3470 - 1370\, n$

where:

$\mathrm{CT.ID.}$ Inner diameter of CT (ft)

$\mathrm{CT.OD.}$ Outter diameter of CT (ft)

$\mathrm{CSG.ID.}$ Inner diameter of casing (ft)

ρ Fluid density (lb/ft3)

g_c Acceleration due to gravity, 32.174 (ft/sec^2)

V_a Average fluid velocity in annulus (ft/sec)

V_{CT} Average fluid velocity in CT (ft/sec)

Table 3.3 Summary table for CT and annular pressure loss calculation

Parameters	Coiled Tubing	Annulus
Friction Factor	Laminar $f = \frac{16}{N_{Re\ CT}}$ Turbulent $f = \frac{1.06\ a}{N_{Re\ CT}^{0.8b}} \left(\frac{r}{R}\right)^{0.1}$ $a = \frac{\log(n)+3.93}{50}$ $b = \frac{1.75-\log(n)}{7}$	Laminar $F_a = \frac{24}{N_{Re\ Ann}}$ Turbulent $F_a = \frac{a}{N_{Re\ Ann}^{b}}$ $a = \frac{\log(n)+3.93}{50}$ $b = \frac{1.75-\log(n)}{7}$
Frictional Pressure Loss	$\Delta P_{CT} = \frac{\rho}{g_c} V_{CT}^2 f L \left(\frac{2}{CT.ID.}\right)$	$\Delta P_{Ann} = \frac{\rho}{g_c} V_a^2 F_a L \left(\frac{2}{CSG.ID.-CT.OD.}\right)$

where:

f	Fanning friction factor for CT
F_a	Friction factor for annulus
L	CT or Annulus section length (ft)
$\left(\frac{r}{R}\right)$	Curvature ratio
n	Flow behavior index $= 3.219 \log\left(\frac{YP+2PV}{YP+PV}\right)$
K	Consistency factor $\left(\frac{lb}{ft^2} sec^n\right) = \frac{YP+2PV}{(100)(1022^n)}$
PV	Plastic viscosity (CP)
YP	Yield point (lb/100 ft2)

Step 2: Calculate the nozzle pressure loss from

$$\Delta P_{Nozzle} = \frac{\rho\, V^2}{2\, C_d{}^2\, g_c} \tag{3.19}$$

where:

ρ Fluid density (lb/ft3)

V Average fluid velocity (ft/sec)

C_d Nozzle coefficient

g_c Acceleration due to gravity, 32.174 (ft/sec^2)

Step 3: Calculate tool joint pressure losses (not applicable in this study) and determine pressure losses from Bottom Hole Assembly.

Step 4: Calculate the pressure losses in the surface equipment using the pipe pressure loss equations for the selected rheological model.

Step 5: Calculate the total pressure loss by adding all pressure losses together. The system pressure loss can be written as:

$$P_{Total} = \Delta P_{CT} + \Delta P_{Ann} + \Delta P_{Nozzle} + \Delta P_{BHA} + \Delta P_{Surface} \qquad (3.20)$$

where:

P_{Total} System pressure loss (psi)

ΔP_{CT} Pressure loss in CT (psi)

ΔP_{Ann} Pressure loss in annuli area between CT and tubing (psi)

ΔP_{Nozzle} Pressure loss in nozzle (psi)

ΔP_{BHA} Pressure loss in bottom hole assembly (psi)

$\Delta P_{Surface}$ Pressure loss in surface equipment (psi)

For gas frictional pressure loss, the gas is Newtonian fluid and the fluid behavior is similar to brine. The frictional pressure loss can be derived from the mass flow rate and can be expressed as:

$$\Delta P_{Gas} = P_1^2 - P_2^2 = f\ \left(\frac{L}{D_e}\right)\left(\frac{\dot{m}^2 ZRT}{g_c A^2}\right) \qquad (3.21)$$

where:

ΔP_{Gas}	Frictional pressure loss due to gas (psi)
$\dot{m}$	Mass flow rate of gas (lbm/sec)
A	Cross-sectional area of the pipe or annulus (in)
Z	Compressibility factor (fraction)
R	Gas constant (lbf-ft)/(lbm °R)
T	Temperature of the fluid (°R)

3.2 Mechanical limitation

3.2.1 Runability

In order to drill the well, the drillability of the drill pipe is considered. The ability to drill must covered the entire drilling operations scenario such as tripping in/out, rotating on/off bottom, sliding and backreaming. The aspects to be considered are the following:

- Buckling Limit
- Tensile Limit
- Torque Limit

Similarly, the ability to run the CT in and out of hole is essential for well services. The CT's runability should cover all well services operations with CT. The well services operation scenario are tripping, pushing and overpulling. In contrast to drillability (i.e. jointed pipe), the makeup torque is not considered in well services with CT. There are several factors influence the runability such as:

- Size and weight of CT
- Size of completion
- Well Geometry
- Content of the well
- Condition of the tubing

The axial force of CT is important consideration on the ability to run and perform the operations (i.e. "pushing" or "pulling"). The axial compressive force is considered during RIH and pushing downward. Similarly, the axial tensile force is considered during POOH and overpulling. There are two methods for the determination of axial force [18]. The first method is based on the true tension or so called *"Pressure-Area Method"*. The axial force from this method can be expressed as:

$$F_{Axial,T} = \sum[w_{air}L\ \cos\theta \pm F_D + \Delta F_{area}] - F_{bottom} - WOB \qquad (3.22)$$

where:

$F_{Axial,T}$	Axial Force from true tension (lbf)
w_{air}	Air weight of the CT (lbm/ft)
L	Length of CT hanging below (ft)
θ	Wellbore inclination (degree)

F_D	Drag force (lbf), positive value during pulling and become negative while pushing.
ΔF_{area}	Change in force as a result of a change in area (lbf)
F_{bottom}	Bottom pressure force due to fluid pressure applied on the cross-sectional area of BHA (lbf)
WOB	Weight on bottom (lbm), 'zero' while RIH or POOH

The drag force given in Eq. 3.22 can be expressed as:

$$F_D = F_N \times C_f \times \frac{|T|}{|V|} \quad (3.23)$$

where:

$\|T\|$	Trip speed (ft/hour)
$\|V\|$	Resultant speed $= \sqrt{(T^2 + A^2)}$ (ft/min)
A	Angular speed $= diameter \times \pi \times \frac{RPM}{360}$ (ft/min)
F_N	Side force (lbf)
C_f	Coefficient of friction
F_D	Drag force (lbf)

WELLPLAN™ calculate side force based on the softstring model as Eq. 3.24 below:

$$F_N = \sqrt{(F_T \times \Delta\alpha \times \sin\emptyset)^2 + (F_T \times \Delta\beta + WL \sin\emptyset)^2} \quad (3.24)$$

where:

F_N Side force (lbf)

F_T Axial force at the bottom of section calculated by Buoyancy method (lbf)

$\Delta\alpha$ Change in azimuth over section length (degree)

$\Delta\beta$ Change in inclination over section length (degree)

$\emptyset$ Average inclination over section length (degree)

L Section length (ft)

W Bouyed weight of the section (lbm/ft)

The effective tension is another method to determine axial force. The second method adopts the buckling stability in the calculation and is so called *"Buoyancy Method"*. The relationship between effective and true tension can be written as Eq. 3.25. It can be seen from Eq. 3.25 and Figure 3.5 that, the difference between effective tension and true tension is buckling stability force.

$$F_{Axial,E} = F_{Axial,T} + F_{bs} \quad (3.25)$$

$$F_{bs} = P_o A_o - P_i A_i \quad (3.26)$$

Substitute Eq.3.26 into Eq. 3.25, the relationship between effective and true tension can be written as:

$$F_{Axial,E} = F_{Axial,T} + P_o A_o - P_i A_i \quad (3.27)$$

Substitute Eq. 3.22 into 3.27, the effective tension can be rewritten as

$$F_{Axial,E} \quad = \quad \sum[w_{air}L\ \cos\theta \pm F_D + \Delta F_{area}] - F_{bottom} - WOB + P_oA_o - P_iA_i \qquad (3.28)$$

where:

A_i Inside cross-sectional area (in^2)

A_o Outside cross-sectional area (in^2)

$F_{Axial,E}$ Axial Force from effective tension (lbf)

F_{bs} Buckling stability force (lbf)

P_i Inside pressure (psi)

P_o Outside pressure (psi)

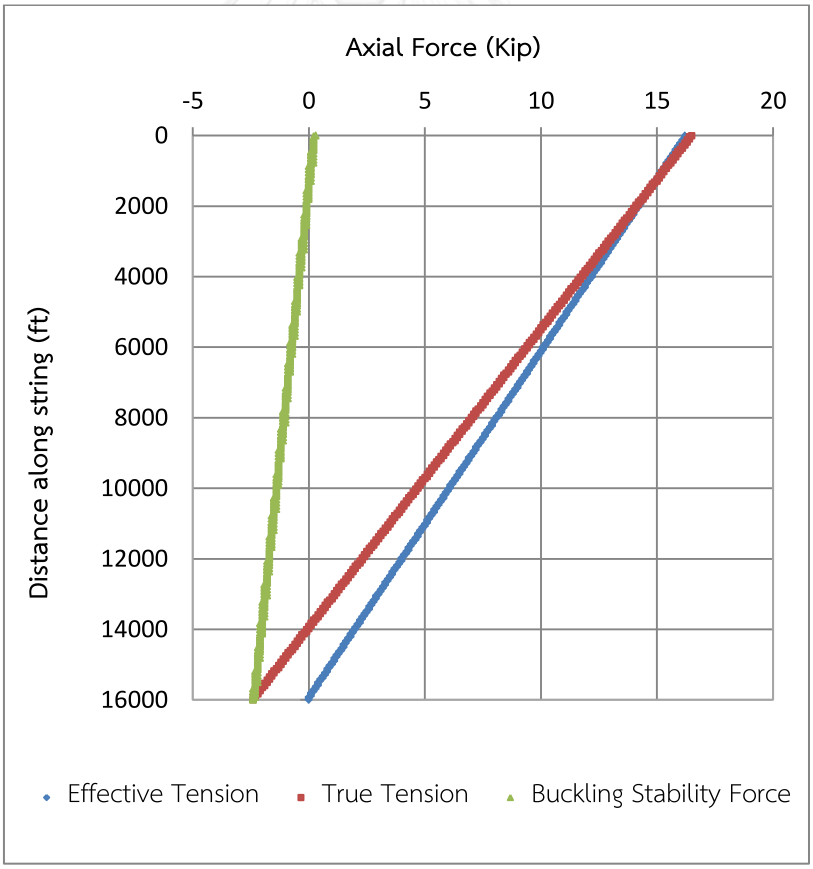


Figure 3.5 True and effective tension along string for 1”CT in Well#1

3.2.1.1 Buckling limit

WELLPLAN™ [15] uses the effective tension for the determination of buckling. The rationale behind the using of effective tension (i.e. buoyancy method) is that, the calculation of "critical buckling force" is also based on hydrostatic pressure. The critical buckling force is the axial compressive force that starts the initiation of the buckling. The axial compressive force to initiate the buckling is different for different well scenarios. As the axial compressive force becomes larger, the CT keeps changing the shape. When the axial force becomes greater than the first buckling force (i.e. critical buckling force), the initiation of sinusoidal buckling occurs. Further increase of axial compressive force can cause the CT to become helical buckling and eventually become lock-up.

In this study, the sinusoidal buckling is selected as the lower limit in the runability study. The sinusoidal buckling force for inclined well based on study performed by Wu and Juvkam-Wold [19] can be expressed as:

$$F_{Sin} = 2\left(\frac{E\,I\,W_e\,\sin\theta}{r}\right)^{0.5} \qquad (3.29)$$

where:

F_{Sin}	Critical (Sinusoidal) buckling load (lbf)
E	Young Modulus (psi)
I	Moment of inertia of tubular (in^4)
W_e	CT weight in fluid (lbm/in)
r	Radial clearance between wellbore and CT (in)
θ	Wellbore inclination (degree)

3.2.1.2 Tension limit

The Pipe Body Yield Load (PBYL) is the axial tension load and based on yield strength. In the absence of pressures or torque the stress is produced in the tube equal to the specified minimum yield strength (SMYS). The PBYL can be expressed as:

$$PBYL = \frac{\pi}{4}(CT.OD.^2 - CT.ID.^2)\,SMYS \tag{3.30}$$

$$PBYL = \pi \times (CT.OD.^2 - t) \times t \times SMYS \tag{3.31}$$

The maximum tension for the CT, when the 20% safety factor is included, can be written as follow:

$$T_{Max} = 80\% \times PBYL \tag{3.32}$$

Substitute Eq. 3.30 into Eq. 3.32, the maximum tension can be written as:

$$T_{Max} = 80\% \times A \times SMYS \tag{3.33}$$

where

T_{Max}	Tension limit (lbf)
SMYS	Specified mimimum wall thickness (in)
PBYL	Pipe Body Yield Load (lbf)
A	Cross-sectional area (in2)
CT. OD.	Outer diameter of CT (in)
CT. ID.	Inner diameter of CT (in)
t	Wall thickness (in)

3.2.2 Coiled tubing limits analysis

3.2.2.1 Operating envelope

The CT limits analysis is based on the burst, collapse, tension and tri-axial limit. The considerations of ovality, corrosion, CT life are not considered in this study. The CT limits in two aspects which are pressure and tension are in consideration. Since there are three external forces applied to the CT which are internal pressure, external pressure and axial force (P_i, P_o and F_a). The differential pressure can be used to simplify the presentation and represent in the vertical axis. The difference between internal and external pressure for CT is defined as:

$$\Delta P = P_i - P_o \tag{3.34}$$

The positive differential pressure represents the "Burst Loading". Therefore, the upper boundary of pressure limit is defined by the burst pressure. During the CT operation, if the internal pressure is higher than external pressure, it said CT under burst pressure loading. The minimum internal pressure that can cause the CT to rupture is called "Burst Rating". The API 5C3 adopt Barlow's equation in order to calculate the burst pressure.

$$P_B = 2 \times SMYS \frac{t_{min}}{CT.OD.} \tag{3.35}$$

where

P_B	Minimum burst pressure (psi)
SMYS	Specified mimimum wall thickness (in)
CT. OD.	Outter diameter of CT (in)
t_{min}	Specified minimum wall thickness (in)

The lower boundary of pressure limit is defined by the collapse. During the CT operation, if the internal pressure is lesser than external pressure, it said CT under collapse pressure loading. There are four collapse regimes defined by American Petroleum Institute [20]. There are several factors affect the collapse pressure. They are ovality, tensile loading, utilization (e.g. CT life), pressure and corrosion. The collapse pressure for new and round CT has the relationship with $\mathrm{CT.OD.}/\mathrm{t_{min}}$ ratio and shows in Figure 3.6.

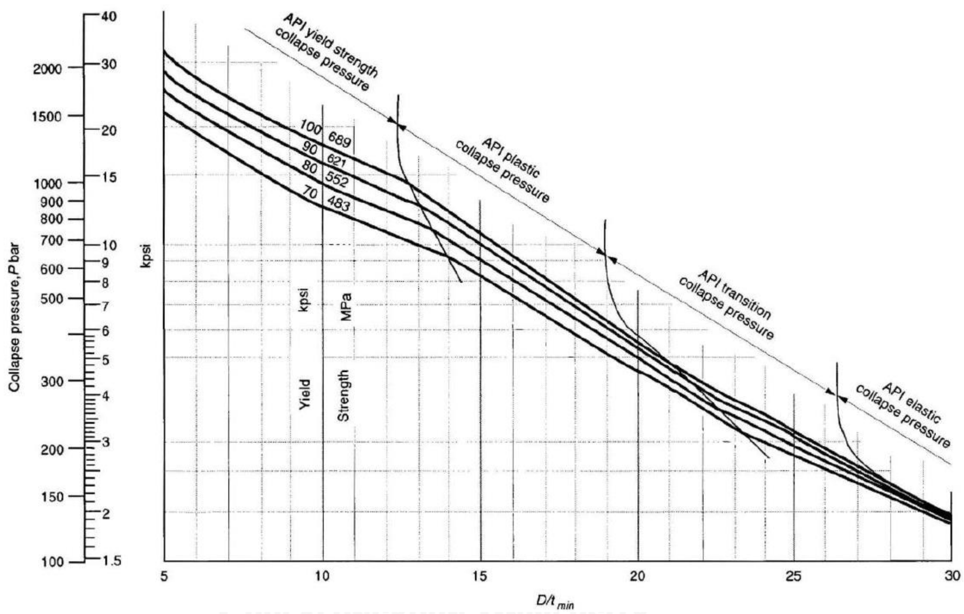


Figure 3.6 Collapse pressure rating for brand new CT [20]

The collapse regimes can be listed in order of increasing $\mathrm{CT.OD.}/\mathrm{t_{min}}$ as following:

- Yield strength collapse
- Plastic collapse
- Transition collapse
- Elastic collapse

It can be seen later for the $\mathrm{CT.OD.}/t_{\mathrm{min}}$ ratio that the CT in our study is in the yield strength collapse regime. The calculation for the yield strength collapse pressure can be expressed as:

$$P_c = 2\,SMYS \left[\frac{CT.OD./t_{min} - 1}{\left(CT.OD./t_{min}\right)^2}\right] \tag{3.36}$$

Since the tensile loading affects the collapse, then the bi-axial criterion is used for the calculation. The collapse pressure with respect to axial load can be expressed as:

$$P_o = P_c \times K \tag{3.37}$$

where:

P_c Collapse Pressure (psi)

P_o Operating external pressure (psi)

K Correction factor = $\left[\left(1/_{SF}\right)^{4/3} - \left(Load/_{PBYL}\right)^{4/3}\right]^{3/4}$

The horizontal axis is represented by the axial force. The tension and compression limit is defined by the Pipe Body Yield Load discussed earlier in Section 3.2.1.

3.2.2.2 Tri-axial limit

In order to evaluate the viability of a CT string for a given applications, one must assess the effect of combination force on it. The tri-axial limit is a theoretical value that allows a combination of three-dimensional stress and to be compared with a uniaxial failure criterion (i.e. yield strength). If the combined stress exceeds the yield strength, a yield failure can occur.

Newman [21] addressed three major types of CT limits such as CT life (i.e. fatigue and corrosion), pressure-tension, diameter and ovality limits. The external force exerted by the internal-external pressure, simultaneously with the axial load either compression or tension cause the local stress field on the CT. The stress field composed of the Radial, Axial and Hoop stress as shown in Figure 3.7. The CT working envelope defines a limit curve within which tubing is safe to operate under the combined loading of axial force and pressure difference.

This segmental force balance progresses uphole along the CT string. For the CT under axial force, the axial stress can be calculated as.

$$\sigma_{axial} = \frac{F}{A} \tag{3.38}$$

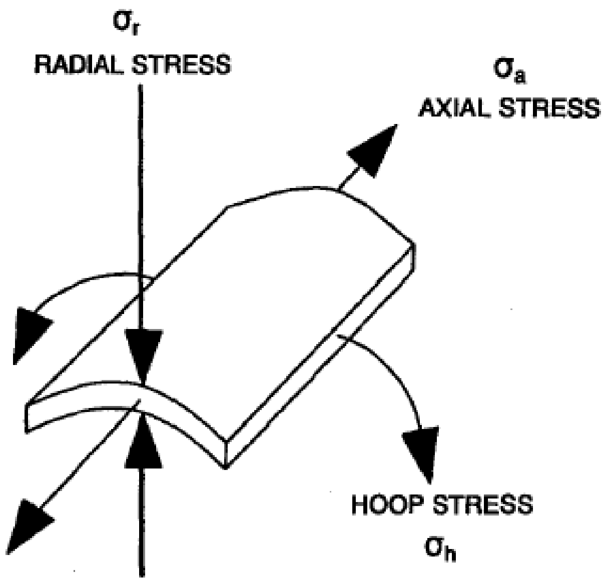


Figure 3.7 Three principal type of the CT stress [21]

The critical point, at which yielding would first occur, is always at the inner surface of the tubing. At the inner surface of the tube, the radial stress and hoop stress can be derived as following:

$$\sigma_r = -P_i \tag{3.39}$$

$$\sigma_h = \frac{r_o^2 + r_i^2}{r_o^2 - r_i^2} P_i - \frac{2r_o^2}{r_o^2 - r_i^2} P_o \tag{3.40}$$

Von Mises Criterion as it is widely accepted criterion of yielding for ductile isotropic material. The criterion can be derived from the basic assumption that the distort strain energy for combined stresses (3 principle stresses) equal to maximum elastic distortion energy in simple tension. When applying to CT, its mathematical expression is:

$$2\,\sigma_y{}^2 = (\sigma_{axial} - \sigma_h)^2 + (\sigma_h - \sigma_r)^2 + (\sigma_r - \sigma_{axial})^2 \tag{3.41}$$

Eq. 3.41 can be solved for the internal pressure (P_i) and can be expressed as:

$$P_i = \frac{\gamma \pm \sqrt{\gamma^2 - 4\alpha\delta}}{2\alpha} \tag{3.42}$$

where:

$\gamma = P_o(2\beta^2 + 3\beta + 1) + \sigma_a(\beta - 1)$

$\alpha = \beta^2 + \beta + 1$

$\delta = P_o^2(\beta + 1)^2 + P_o\sigma_a(\beta + 1) + \sigma_a^2 - SMYS^2$

$\beta = \dfrac{r_o{}^2 + r_i{}^2}{r_o{}^2 - r_i{}^2}$

CHAPTER IV
RESEARCH METHODOLOGY AND SIMULATION PARAMETERS

The main limitations in the use of small size CT to perform well services are the severe pressure losses and limited push/pull ability. The severe pressure losses prevent the use of high flow rate which can impact negatively to the effectiveness of solid and fluid transportation. Ability to pump affects the depth of intervention. On the other hand, the push/pull ability affects the size of CT to be used. For these reasons, the aspect and details methodology are discussed in this chapter.

It is important to mention that the commercial software in used in this study is WELLPLAN^{TM} from the LANDMARK. The software is comprised of comprehensive set of tools for modeling, analyzing the well operations and tubular design.

4.1 Research methodology

The hydraulic considerations 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. As mentioned earlier in Chapter III, the applications can be categorized into 3 groups according to their pumping requirement. The milling and sand cleanout are in group 1 of application, which require high pump rate in order to transport the solid out of well bore. The well unloading and stimulation are the application in second group, which require the injection of nitrogen gas through the CT. The fishing, logging and perforation are in the last group, which do not require pumping through with high pump rate.

The process to evaluate the hydraulic viability is shown in Figure 4.1. The critical rates for both solid and fluid transportation are determined based on the parameters provided in simulation parameters discussed in Section 4.2. The fluid and gas flow velocity is determined in Sections 5.1.1 and 5.1.2 for 6 well patterns with 2 completion sizes for pressure loss in group 1 and 2 application, respectively. The applications in group 3 can be exempted for the hydraulic consideration. The rationale behind the exemption is because of the low requirement in the pump rate, hence, negligible pumping pressure. The CT can be called hydraulically feasible providing that the pump pressure is lesser than the 80% of CT internal yield pressure which is discussed in Section 5.1.3 -5.1.4.

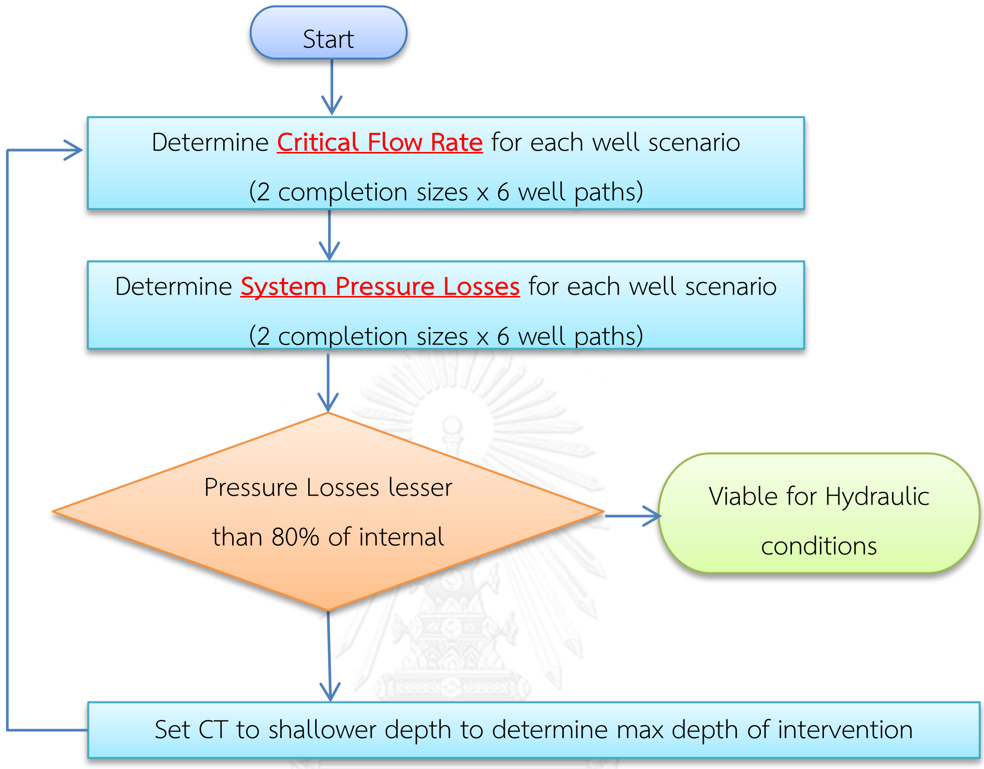


Figure 4.1 Hydraulic consideration flowchart

All application groups require the mechanic viability. The mechanic considerations are evaluated for each scenario. The workflow for evaluation illustrated in Figure 4.2. The first consideration on mechanical aspect is the runability of the CT. The runability of CT in any well scenarios described in Section 4.3 is based on the effective tension of the CT. The effective tension for running in hole (RIW) must be higher than the buckling limit of the CT. On the other hand, the pulling out weight (PUW) must be lesser than the CT tension limit. The effective tension and related parameters are going to be discussed in Section 5.2.1. Moreover, for the applications which an extra push/pull capacity to perform operation can be evaluated based on the same effective tension. An example of application that requires extra force are milling and fishing. The milling operation requires extra push to deliver weight on bit. The fishing operation requires extra pulling capacity to over pull the stuck fish.

Lastly, the combination of all stresses applied on CT is considered. The plots of pressure-tension are shown in Section 5.2.2 to determine if the CT able to withstand both hydraulically and mechanically stress. The possibility of using CT to provide the solid-liquid transportation and be able to run in/out of the well safely can then be determined from whether or not the pressure-tension stays within the pre-defined boundary.

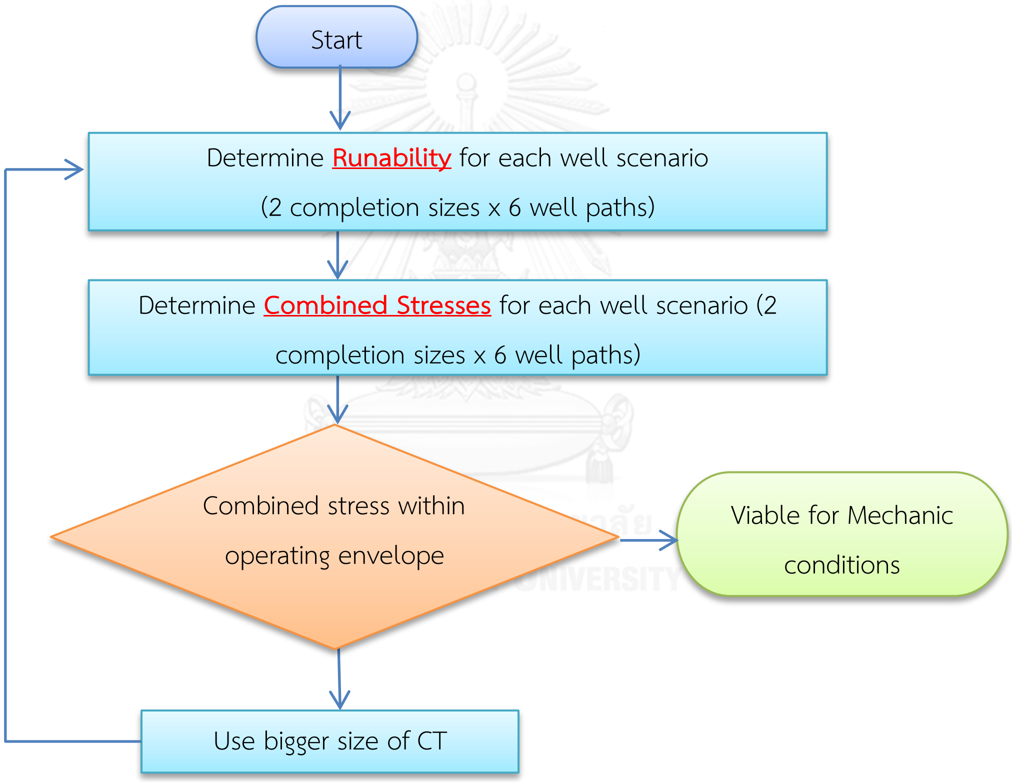


Figure 4.2 Mechanical consideration flowchart

As high-lighten here before the summary of considerations for each of the well services application is listed in Table 3.1 and again there are 4 main areas of consideration as the following:

- Capability to deliver the require flow rate

- Capability to withstand pumping pressure
- Capability to run in and out of the well. The other considerations are in some applications such as Push/Pull capacity during milling and fishing, respectively.
- CT's operating parameters must be within the tri-axial Limit.

4.2 Simulation parameters

4.2.1 Coiled tubing

The evaluation is based on the small size of CT which typically used in many literature reviewed [6, 7]. The CT manufacturing ranged from 0.25" to 3.5". The small size CT is the size between 0.25" to 1.25". On the low side, it can be further cascaded down as Capillary CT for the size between 0.25" – 0.75" [1]. Stanley and Terry [1] concluded the primary applications for the capillary CT as chemical injection and gas injection. Although, 0.75" and smaller size had shown increased utilization, the conventional well service applications are not promising. On the high side, there are more than 60% usages of CT with the size larger than 1.25". Therefore, the CT sizes selected for this study are 1" and 1.25" outer diameter.

The minimum yield strength for the CT is typically in the range of 70 Kpsi – 90 Kpsi. The 80 Kpsi is commonly used in the well services and adopted in this study. At this yield strength, the hardness would be too susceptible to the Sulfide Stress Cracking (SSC) problem and provides high enough strength to perform the well services application.

The wall thickness of CT is selected so that we can achieve the highest push/pull capacity. It can be seen from Eq. 2.1 that the cross-section areas play an important role in push/pull capacity. The highest available wall thickness is selected for both sizes. The wall thickness for 1"CT is in the range between 0.075 to 0.125 in., hence 0.125 in. is selected. Similarly, the 1.25" CT has range in between 0.075 to 0.175 in. and 0.175 in. is selected. In the case the push/pull are not adequate for the application, the bigger size of CT needs to be considered. The weight of CT and inner diameter is associated with the wall thickness and hence automatically selected. The CT specifications and properties used in this study are summarized in Table 4.1 and 4.2.

Table 4.1 CT specification requirements and performance properties from American Petroleum Institute [22]

Specification Requirement							Performance Properties *	
CT. OD. (in) **D**	Grade	Wall Thickness (in) **t**	Min. Wall Thickness (in) t_{min}	Weight (lb/ft)	CT. ID. (in) **d**	D/t_{min} Ratio	PBYL (lb)	Internal Yield Pressure (psi)
1	80 K	0.125	0.12	1.17	0.75	8.55	27,490	19,200
1.25	80 K	0.175	0.17	2.01	0.9	7.49	47,280	21,760

* The performance properties shown apply to new pipe, and do not take into account additional deformation, axial load, residual stresses, or ovality caused by spooling or service cycling

Table 4.2 Collapse pressure (psi) for new CT [20]

CT O.D. (in)	Min. Wall Thickness (in)	D/t_{min} Ratio	Ovality $(D_{Max} - D_{Min})$ / D				
			0	0.2		0.05	
			L = 0	L = 0	$L = \frac{PBYL}{2}$	L = 0	$L = \frac{PBYL}{2}$
1	0.12	8.55	*16530*	11500	7870	8890	6080
1.25	0.17	7.49	*18520*	13500	9240	10640	7280

4.2.2 Surface equipment

The pressure losses from surface equipment should be accounted for in the evaluation. The pressure losses from surface equipment are constitution of pressure losses from pump, piping from pump to the CT's reel and CT on the reel. The parameters input into WELLPLAN^{TM} (Figure 4.3) are described hereafter.

The Pump Discharge Line is selected as 2” Hammer union FIG2002 as typical use for handling high pressure pumping [23]. The FIG2002 discharge line has the pressure rating upto 20,000 psi, which are higher than maximum pumping pressure.

The reel dimension has the effect on the pressure loss calculation. The curvature of CT on the reel can be measured as curvature ratio$\left(\frac{r}{R}\right)$. In other word, the ratio is dimension between the inner radius of CT to the reel diameter. It can be seen from the Table 3.2 that the higher curvature resulting in the higher pressure loss. Reel dimension is selected as per standard reel size using for 1” and 1.25” CT The standard reel [23][23][23][23]with the 60 inches- core diameter, 100 inches-flange and 60 inches drum width is selected as per typical operation use [23].

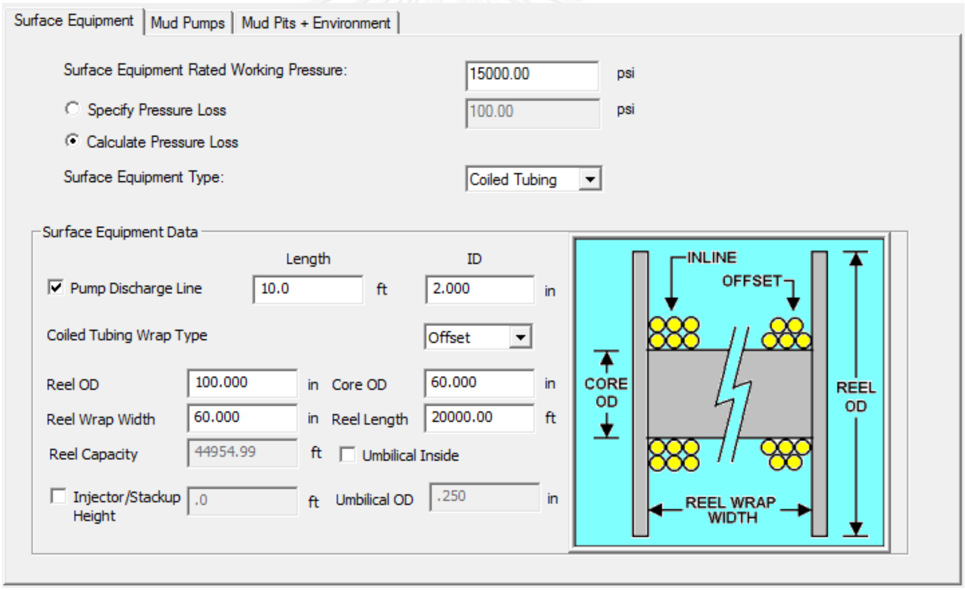


Figure 4.3 Input parameters in WELLPLAN^{TM} for surface equipment

4.2.3 Wellbore parameters

The well bore parameters such as solid and fluid inside wellbore play an important role on the simulation. The Critical Flow Velocity (v_{crit}) as discussed in Section 3.1.1 is dependent of well bore parameters. It can be seen from the Eq. 3.4 that the solid size and fluid density correction factor contributed to the demand of higher or lower critical flow velocity (v_{crit}). The worst case scenario can occur when both of these values (C_{size} and C_{mw}) are highest. As a result the higher v_{crit} and hence higher pump pressure is required.

Consider the Figure 3.2, the highest correction is required for solid size is when the solid size getting smaller. The correction value of 1.3 is the highest correction factor which occurs at the vertical axis interception. In pragmatic, there are large varieties of solid particle size in CT cleanout application ranging from large pebble to fine sand size. The smallest fine can be as small as the size of pore throat (i.e. 7×10^{6} inches or 2 micron). In this study, the worst case of cleaning wells at which filled with the 0.05 inches (i.e. 1270 micron) of medium particle size distribution (D_{50}) is selected. This is equivalent to the correction factor close to 1.3 times, resulting in the tremendously raise the requirement of critical fluid flow velocity.

The fluid density correction factor ranged to the fluid density to transport the solid. Consider Figure 3.3, the correction factor is highest when the fluid density is getting close to water's density. Although the fluid density in well intervention with CT is not used primarily as the well control fluid, but the fluid should be containing with salt in order to prevent the formation damages. The amount of salinity varies among each formation's cation exchange capacity. Therefore the fluid selected for the worst case scenario considers being 2% KCL brine with the weight of 8.43 ppg.

The well services works that require solid transportation is limit to the application in group 1 (shown in Table 3.1). The specific gravity of solid particle in well bore has wide range for well services work. The possible solid particles found for application in group 1 are shown in Table 4.3. The specific gravity of solid particle affects the cutting velocity in Eq. 3.1 and selected at 2.9 S.G. which represent calcite. The bed porosity is selected at 30% which is typically used in many literature [12, 13, 24]. The summary of wellbore parameters used in this study is shown in Table 4.4.

Table 4.3 The common found solid particle in well services application

Application	Material	Specific Gravity
Scale Milling	Calcite	2.7 – 2.9
	Barium Sulfate	4.3 - 5
Sand Cleanout	Quartz Sand	2.65
	Clay	2.7 – 2.8

Table 4.4 Input parameters for well bore's solid properties

Wellbore Parameters	
Diameter of solid particle	0.05 in
Density of solid particle	2.9 S.G.
Bed Porosity	30%

4.2.4 Operation and design limit parameters

Tripping speed affects the effective tension. The tripping speed is selected as normal tripping speed for CT at 80 ft/min both in and out of well. The Rate of Penetration (ROP) through the "filled" or "obstruction" is selected as typical milling cleanout operation speed at 10 ft/hr, while rotary speed cannot be achieved with CT's operation is kept as 0 RPM. The pump rate is arbitrary adjusted subject to the Critical Fluid Flow Rate. The summary of operation parameters is shown in Table 4.5.

Table 4.5 Operation parameters

Operation Parameters	
Tripping Speed	4800 ft/hr
Rate of Penetration	10 ft/hr
Rotary Speed	0 RPM
Pump Rate	Critical Flow Rate

The operating envelope for CT is defined by design factors which accounted for safety factors (SF). The safety factor should be greater than one in order to have rating higher than the load. The safety factor is required to cope with the uncertainty and the minimum safety factor is called “design factor”.

$$SF = \frac{Rating}{Load} \quad (4.1)$$

An example for the Axial Force, the safety factor can be expressed as:

$$SF_{Axial} = \frac{Axial\ rating}{Axial\ load} = \frac{Yield\ stress}{Axial\ stress} \quad (4.2)$$

In this study the design factors adopt the standard from Norwegian Offshore Sector [25] as shown in Table 4.6. The NORSOK is widely used and accepted in oil & gas industry.

Table 4.6 Design factors

Failure Mode	General Design	NORSOK (D-010)
Tri-axial	1.2 – 1.3	1.25
Burst	1.1 – 1.25	1.25
Collapse	1.0 – 1.1	1
Axial Tension	1.25 – 1.6	1.25
Axial Compression	1.25 – 1.6	1.25

4.2.5 Well scenarios

The well type to be considered in this study is tubing less monobore completion. This completion type is used in many marginal gas field developments [26]. The two sizes of tubing in consideration are 2.875” and 3.5” tubing. The conventional, monobore and gas lift completion shows in Figure 4.4 below.

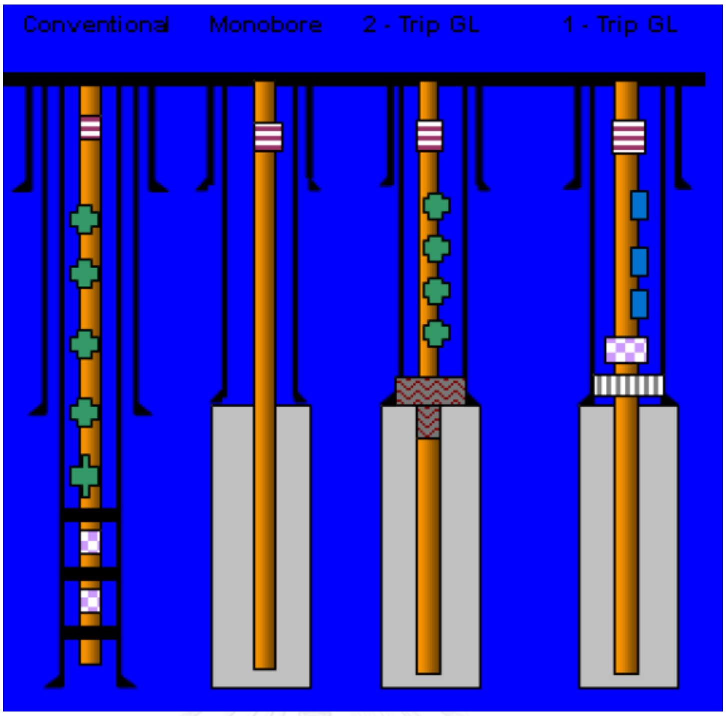


Figure 4.4 Typical completion use in marginal field development [26]

The 6 well paths used in this study shows in Table 4.7 and Figure 4.5. There are 3 commons ranges of Build Up Rate (BUR) used in Oil & Gas well drilling [27]. The 6 wells used in this study are designed with the Long Radius with 6deg/100ft BUR to have final maximum inclination at TD. The walk rate is zero (i.e. DLS is equal to BUR).

Table 4.7 Summary of well path

Well	Trajectory	KOP (ft)	Inclination (deg)	TD (ft)	TVD (ft)
1	Vertical	7,000	0	16,000	16,000
2	Deviated	7,000	20	16,000	15,471
3	Deviated	7,000	40	16,000	13,998
4	Deviated	7,000	60	16,000	11,827
5	Deviated	7,000	90	16,000	7,955
6	Deviated + Deep KOP	10,000	90	16,000	10,955

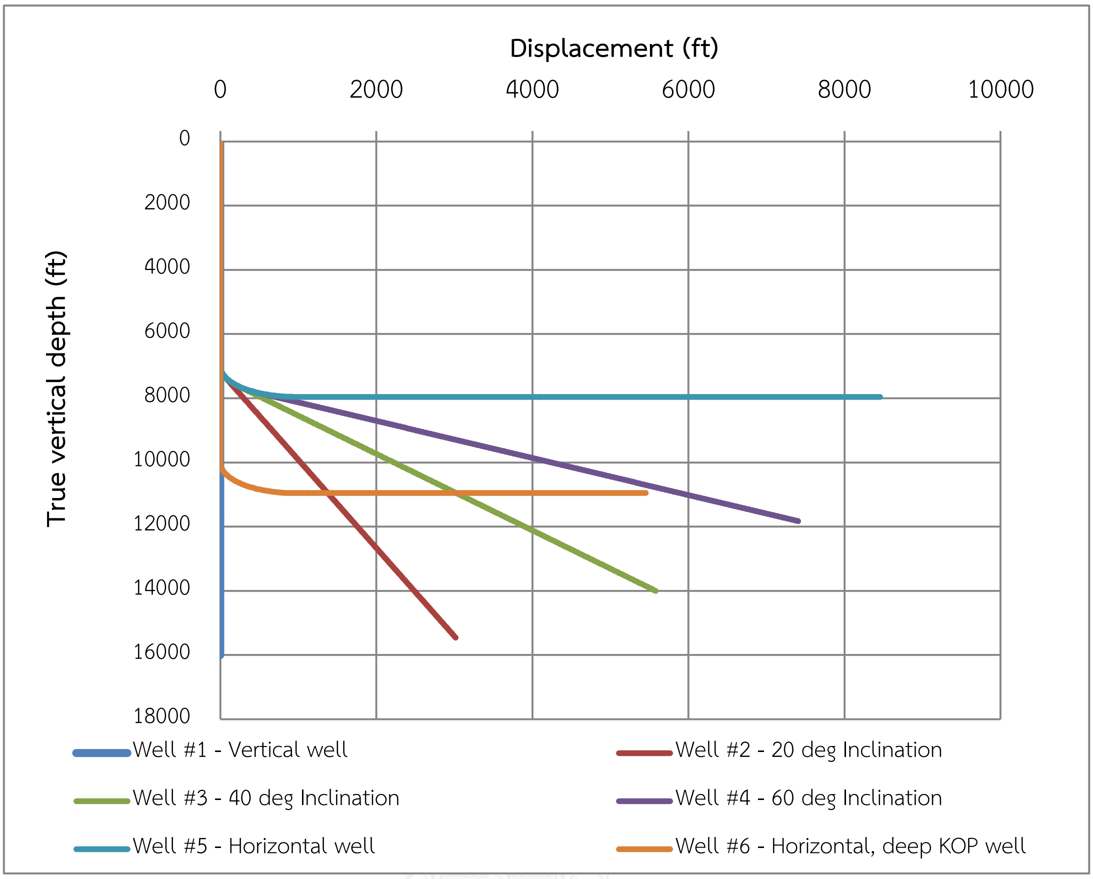


Figure 4.5 Well path comparisons

The coefficient of friction has the effect on the drag force and ultimately to the effective tension (Eq. 3.23). The drag force is direct proportion to frictional coefficient. The typical coefficients of friction are listed in the Table 4.8. The selection for the study is straight forward where we selected the “water-wet steel” (i.e. the fluid in wellbore assume 8.43 ppg KCL) as our base case. The oil-wet steel is adopted when consider the effect of friction reducer fluid.

Table 4.8 Coefficient of friction for steel

Surface	C_f
Water-wet steel	0.3 – 0.35
Lubricated water-wet steel	0.2 – 0.25
Oil-wet steel	0.15 – 0.20
Steel on rock	0.40 – 0.50

CHAPTER V

SIMULATION RESULT AND DISCUSSION

The discussions on considerations and limitation are summarized in this chapter. Based on the simulation parameters each well scenario was simulated. Under the constraint provided in hydraulic and mechanic conditions, the maximum intervention depth for each application was obtained. Moreover, the mitigation approach from literature was investigated for the case that is unable to attain the operating conditions.

5.1 Hydraulic consideration

5.1.1 Critical flow rate

The well scenarios in this study, wells are comprised with the vertical section, build up section and hold angle section. The required fluid flow velocity varies as per the inclination of those sections. The critical flow rate is determined for each case at the worst case scenario. The worst case scenario occurs at the well total depth where the wells have the highest angle. The CT is required to be able to deliver the critical flow rate in order to transport the solid and liquid droplet out from well bore.

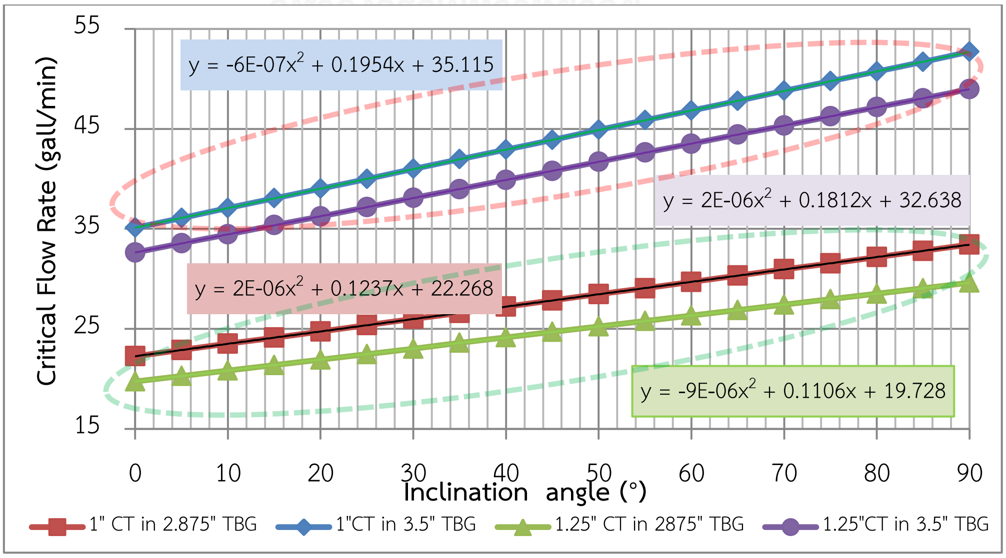


Figure 5.1 Critical rate in various wellbore inclinations for small CT in 2.875” and 3.5” tubing

The Critical Flow Rates for 1” and 1.25” CT are derived for all 12 well scenarios and depicted in Figure 5.1. It can be seen from the figure that as the wellbore’s inclination increases, the higher critical flow rate is required. Although the critical flow rate derived in Eq. 3.13 is non-linear equation, but the small magnitude of constant coefficient in front of power term make the term negligible. Therefore it appears from the plot in Figure 5.1 that the critical flow rate is linearly proportion to the inclination.

It can be summarized from the Table 5.1 that, for a given size of completion tubing, the annulus area is smaller for bigger CT. Hence, less critical flow rate is required. On the other hand, the step changes in tubing size contribute more area changes. It can be observed from the plot in Figure 5.1 that there are 2 groups of data shows in red and green oval. The shift change in the flow rate can also be explained by Eq. 3.13, which is the effect of flow area. Obviously, for the same size of CT, the higher flow rate is required for the larger size of completion. The 1.25”CT in 2.875” Tubing where the annular flow area is smallest requires the lowest critical flow rate. Likewise, the 1” CT in 3.5” tubing has the biggest annular flow area, hence requires the highest critical flow area.

Another observation can be made is the slope or critical rate per degree of inclination is increase when the annulus area increases. Therefore, the 1.25”CT in 2.875” Tubing where the annular flow area is smallest had lowest slope (0.11 gpm/deg). Likewise, the 1” CT in 3.5” tubing has the biggest annular flow area, hence the largest slope (0.195 gpm/deg). The determined critical flow rate can be used as an input for pressure losses determination in Section 5.1.3.

Table 5.1 Annulus area between CT and tubing

CT.OD. (in.)	CSG. OD. (in.)	CSG. ID. (in.)	Annulus Area (in^2)
1	2.875	2.441	3.89
1	3.5	2.992	6.24
1.25	2.875	2.441	3.45
1.25	3.5	2.992	5.80

5.1.2 Optimum gas rate

The optimum gas rate determination is discussed in Section 3.1.2 based on the Bottom Hole Pressure (BHP). Although the gas injection depth can be selected to any desired depth with the CT, the depth is selected as per maximum gas rate requirement which is at the total depth of the well. This maximum depth poses as worst case scenario on the hydraulic consideration for liquid transportation. In addition, the well is full of brine and effect of reservoir productivity is neglected.

Figures 5.2 – 5.5 illustrate the BHP for the various injection rates when injecting nitrogen through CT at TD. The nitrogen reaches nozzle and exits the CT then goes up in the annulus. The nitrogen mixes with the wellbore fluid and creates the mixture flow through the annular flow area. The displacement of nitrogen into annulus reduces the annulus fluid density. As a result, the effect of nitrogen injection rate on BHP reduction can be observed. The figures indicate the lowering of BHP while increasing of injection rate to a certain pressure. It can be seen from Figures 5.2 and 5.3 that for 1” CT, the BHP reaches minimum value when the nitrogen pump rate is around 400 - 500 Scf/m. On the other hand, the BHP is lowest at 600 - 800 Scf/m in case of using 1.25” CT as can be seen from Figures 5.4 and 5.5. The further increment of injection rate beyond these points (i.e. optimum injection rate) will result in the increment of BHP. This can be described by the increase of frictional pressure loss. In many cases, the excessive injection rate beyond the optimum rate will suppress the hydrocarbon flow from reservoir.

Likewise to critical flow rate, the optimum gas rates are low for small tubing (i.e. 2.875”), increasing as the tubing size increases. The maximum gas rates are also lower for small CT given the same size of tubing. This can conclude that the annular flow area affects the optimum gas rate. Based on the bottom hole pressure, the optimum gas rate for each well scenarios can be concluded. These maximum gas rates are used in Section 5.1.4 to calculate the pressure loss.

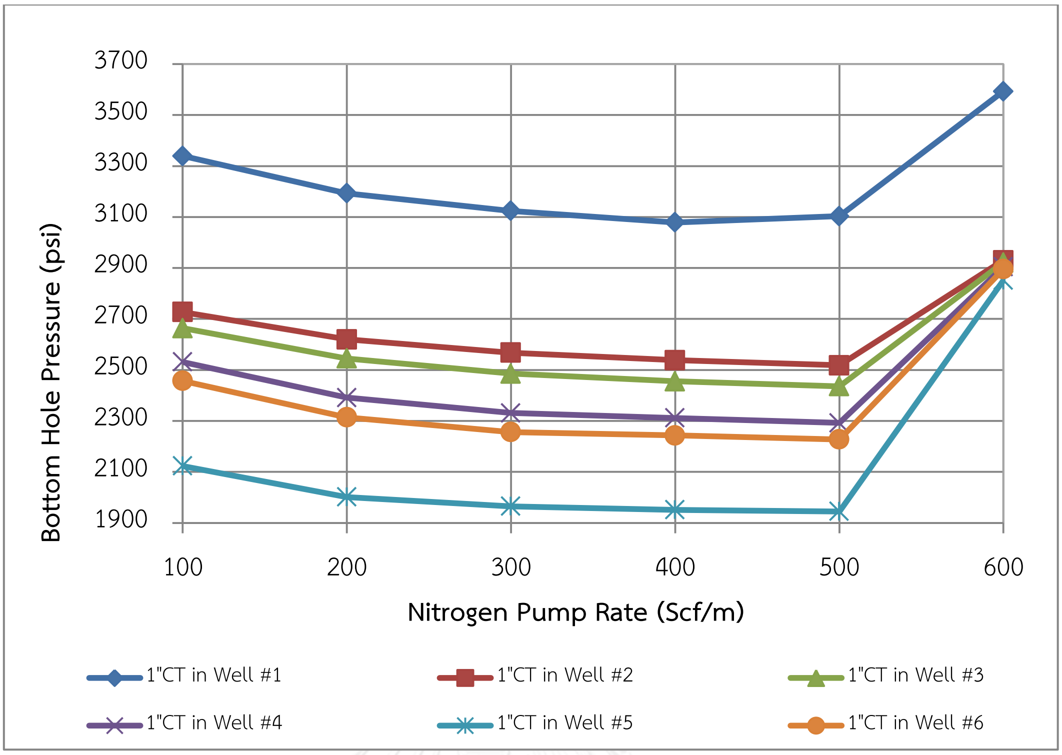


Figure 5.2 Bottom hole pressure v.s. nitrogen pump rate for 1” CT in 2.875” tubing

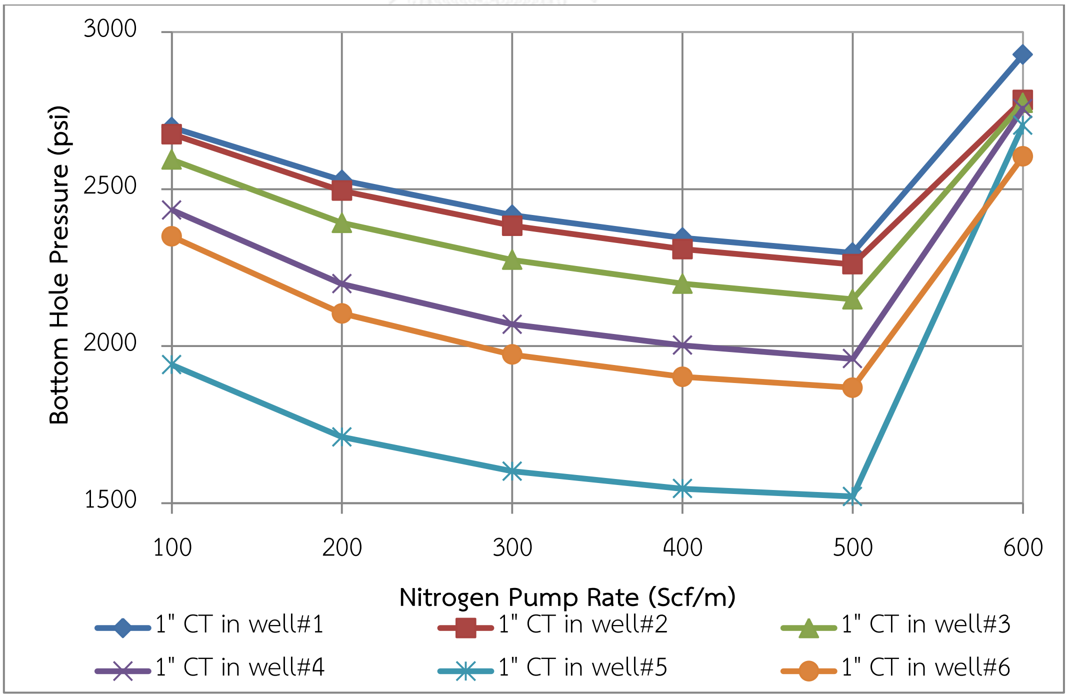


Figure 5.3 Bottom hole pressure v.s. nitrogen pump rate for 1” CT in 3.5” tubing

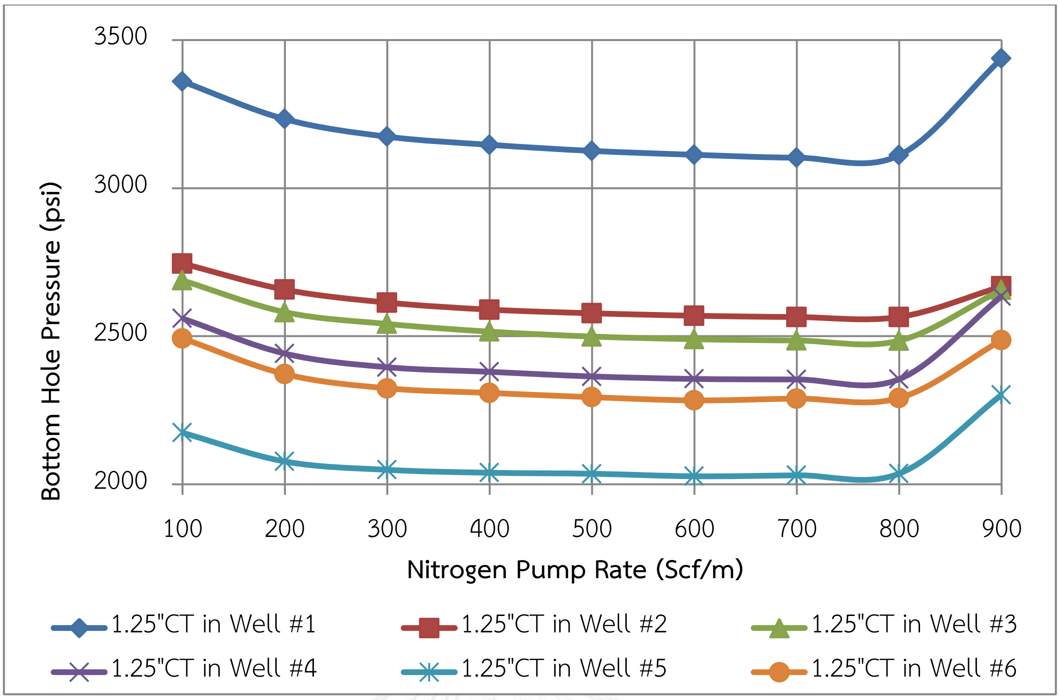


Figure 5.4 Bottom hole pressure v.s. nitrogen pump rate for 1.25” CT in 2.875” tubing

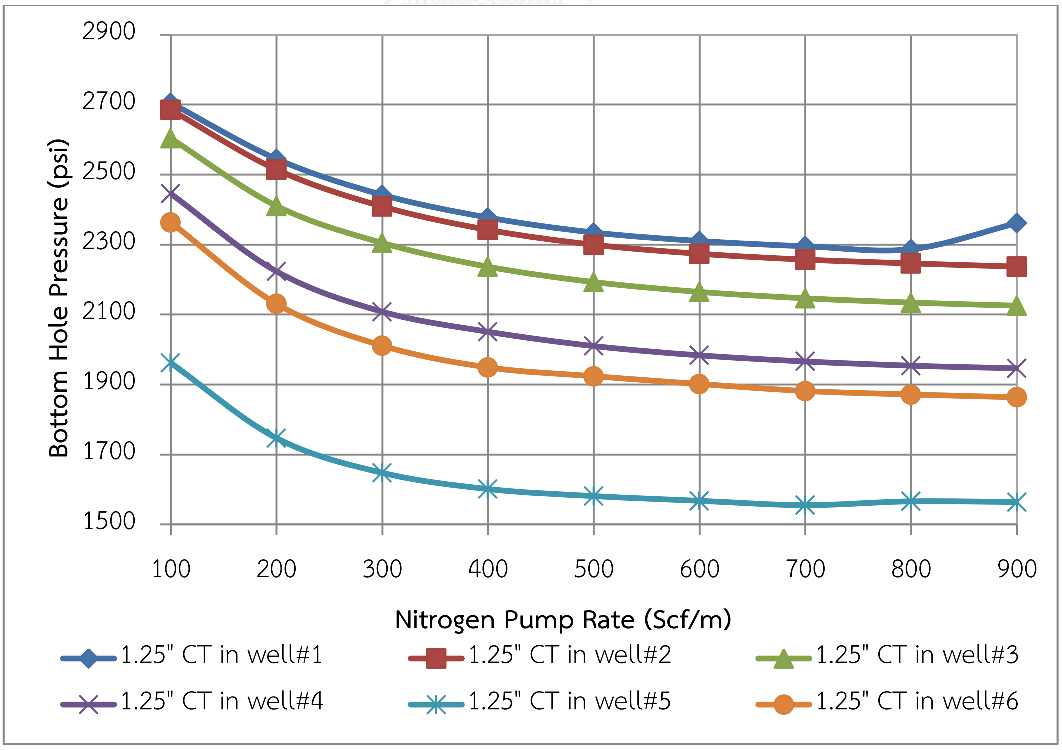


Figure 5.5 Bottom hole pressure v.s. nitrogen pump rate for 1.25” CT in 3.5” tubing

5.1.3 Pressure losses

5.1.3.1 Pressure losses in group 1 application

Based on the critical rate determined in Sections 5.1.1 and 5.1.2, the frictional pressure for each pump rate can be determined. The maximum depth of intervention, achievable flow rates and corresponding pressures for each scenario were simulated and shown in Figures 5.6 – 5.9. There are several parameters effect on the pressure losses for application in group 1 as following:

Pressure Limit: The system pressure loss is limited at 80% of internal yield pressure as per recommended practice by American Petroleum Institute [22]. The 80% of internal pressure is represented in red line as the maximum limit of pressure losses. Maximum working pressure for 1”CT and 1.25”CT at 80% of internal yield are 15,360 psi and 17,408 psi, respectively.

Effect of CT size: Figure 5.6 – 5.9 illustrated the pressure losses with respect to different pump rates for 1”CT in 2.875” tubing. The pressure losses due to annulus and BHA are negligible. As a result, the main contributor for the system pressure loss is the frictional pressure loss in CT (i.e. CT string in reel and CT string in hole). This can simply explain by the frictional pressure loss equation from Table 3.2. While the other parameters are fixed (fluid density, frictional factor), the pressure drop in CT is inversely proportion to the inner diameter of CT. The non-linearity phenomenon are due to the critical velocity. The simplified relationship can be expressed as:

$$P_{CT} \propto \left(\frac{V_{CT}^2 L}{CT.ID.}\right) \qquad (5.1)$$

$$P_{CT} \propto {Q_{CT}^2 L}\Big/{CT.ID._{CT}^3} \qquad (5.2)$$

It can be implied from the Eq. 5.2 that, the larger CT.ID. resulted in the lower pressure loss in CT. This can be seen from the comparison between 1”CT and 1.25” CT in the same well scenario. An example, for a given well #1 scenario (i.e.

Figure 5.6) the 1"CT has higher pressure loss inside CT around 7000 psi in comparison to 4000 psi using 1.25" CT at the same pump rate (ie. Figure 5.8).

<u>Effect of tubing size:</u> Unlike pressure loss in CT, the pressure loss in annulus is not significant. This may be explained by the effect of tubing size or the relationship to annular flow area given in Table 5.2 and more simplified expression as below.

$$P_{Ann} \propto \left(\frac{V_{Ann}^2 L}{CSG.ID. - CT.OD.}\right) \qquad (5.3)$$

$$P_{Ann} \propto \left(\frac{L}{CSG.ID. - CT.OD.}\right)\left(\frac{Q_{Ann}^2}{A_{Ann}^2}\right) \qquad (5.4)$$

In ideal case, the pump rate in CT is the same as the flow rate return to the annulus. The velocity in annulus is reduced once fluid exit to the annulus to around 7%-18% (Table 5.2) of the velocity in CT and this is the reason of much smaller in pressure loss magnitude in annulus.

$$Q_{Pump} = Q_{crit} \qquad (5.5)$$

$$\frac{V_{CT}}{V_{Ann}} = \frac{CSG.ID.^2 - CT.OD.^2}{CT.ID.^2} \qquad (5.6)$$

Nevertheless, the tubing size effects the flow area as shown in Eq. 5.6. For a given size of CT, the bigger the tubing results in the lower pressure loss in annulus.

Table 5.2 The comparison of velocity in CT and annulus

CT.OD. (in.)	CT.ID. (in.)	CSG. OD. (in.)	CSG. ID. (in.)	V_{Ann}/V_{CT}
1	0.75	2.875	2.441	0.11
1	0.75	3.5	2.992	0.07
1.25	0.9	2.875	2.441	0.18
1.25	0.9	3.5	2.992	0.11

Figure 5.6 describes the pressure loss associated with the pump rate for 1”CT in 2.875” tubing. The critical flow rate determined in Section 5.1.1 showed that the Well #1 would require the critical rate of 22 gpm at the TD. The CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel. At this pump rate the system pressure loss is equivalent to 9,044 psi at which lower than the maximum pressure. Hence, 1”CT can deliver the desired pump rate at the TD of 2.875”tubing and is viable for solid cleanout requirement.

Well #2 would require the critical rate of 25 gpm at the TD. The CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel. At this pump rate the system pressure loss is equivalent to 12,000 psi at which lower than the maximum pressure. Hence, 1”CT can deliver the desired pump rate at the TD of 2.875”tubing and viable for solid cleanout requirement.

Well #3 would require the critical rate of 27 gpm at the TD. The CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel. At this pump rate the system pressure loss is equivalent to 13,600 psi at which lower than the maximum pressure. Hence, 1”CT can deliver the desired pump rate at the TD of 2.875”tubing and viable for solid cleanout requirement.

Well #4 would require the critical rate of 30 gpm at the TD. The system pressure loss when CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel is equivalent to 16,460 psi at which higher than the maximum pressure. Hence, 1”CT cannot deliver the desired pump rate at the TD of 2.875”. This is due to effect of pumping high flow rate in long annular section. Consequently, intervention depth is adjusted to the shallower depth. The maximum pressure is reached at the depth of 15,000 ft. with the required pump rate of 30 gpm.The CT section is 15,000 ft. in the wellbore, while 5,000 ft. left in the reel. It can be seen that as more CT left in the reel, the more surface pressure loss is contribute to the system pressure.

Well #5 would require the critical rate of 33 gpm at the TD. The system pressure loss when CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel is equivalent to 16,684 psi at which higher than the maximum pressure. Hence, 1”CT cannot deliver the desired pump rate at the TD of 2.875”tubing. This is due to effect of pumping high flow rate in long annular section. Consequently, intervention depth is adjusted to the shallower depth. The maximum pressure is reached at the depth of 10,500 ft. with the required pump rate of 30 gpm. The CT section is 10,500 ft. in the wellbore, while 9,500 ft. left in the reel. It can be seen that as more CT left in the reel, the more surface pressure loss is contribute to the system pressure.

Well #6 in Figure 5.6 would require the critical rate of 33 gpm at the TD. The system pressure loss when CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel is equivalent to 15,882 psi at which higher than the maximum pressure. Hence, 1”CT cannot deliver the desired pump rate at the TD of 2.875”tubing. This is due to effect of pumping high flow rate in long annular section. Consequently, intervention depth is adjusted to the shallower depth. The maximum pressure is reached at the depth of 11,500 ft. with the required pump rate of 32 gpm. The CT section is 11,500 ft. in the wellbore, while 8,500 ft. left in the reel. It can be seen that as more CT left in the reel, the more surface pressure loss is contribute to the system pressure.

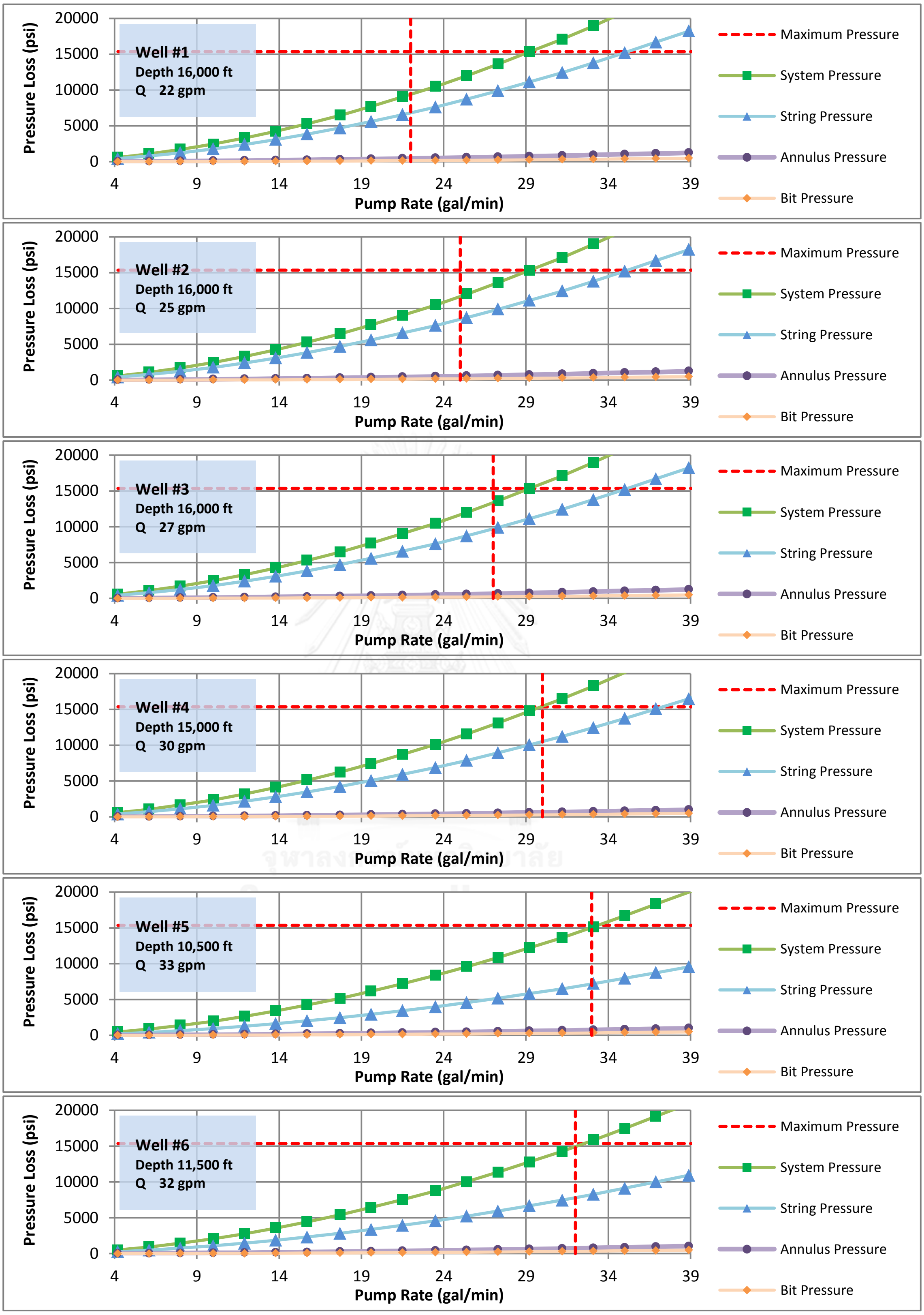


Figure 5.6 Pressure losses for 1.0” CTOD in 2.875” tubing

Figure 5.7 describes the pressure loss associated with the pump rate for 1”CT in 3.5” tubing. The critical flow rate determined in Section 5.1.1 shows that the Well #1 would require the critical rate of 35 gpm at the TD. The system pressure loss when CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel is equivalent to 16,516 psi at which higher than the maximum pressure. Hence, 1”CT cannot deliver the desired pump rate at the TD of 2.875”tubing. This is due to effect of pumping high flow rate in long annular section. Consequently, intervention depth is adjusted to the shallower depth. The maximum pressure is reached at the depth of 8,500 ft. with the required pump rate of 35 gpm. The CT section is 8,500 ft in the wellbore, while 11,500 ft left in the reel.

Well #2 - 5 would require the critical rate of 39, 43, 47 and 53 gpm at the TD, respectively. The system pressure losses when CT section is 16,000 ft. in the wellbore, while 4,000 ft left in the reel are higher than the maximum pressure. Hence, 1”CT cannot deliver the desired pump rate at the TD of 2.875”tubing. This is due to effect of pumping high flow rate in long annular section. Consequently, intervention depth is adjusted to the shallower depth. The maximum pressure is reached at the depth of 7,200 ft. with the required pump rate of 36 gpm. Similarly for Well #6 which require the critical rate of 53 gpm at the TD. The system pressure loss when CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel is equivalent to 28,400 psi at which higher than the maximum pressure. Hence, 1”CT cannot deliver the desired pump rate at the TD of 2.875”tubing. This is due to effect of pumping high flow rate in long annular section. Consequently, intervention depth is adjusted to the shallower depth. The maximum pressure is reached at the depth of 10,000 ft. with the required pump rate of 35 gpm. The CT section is 10,000 ft. in the wellbore, while 10,000 ft. left in the reel. It can be seen that as more CT left in the reel, the more surface pressure loss is contribute to the system pressure.

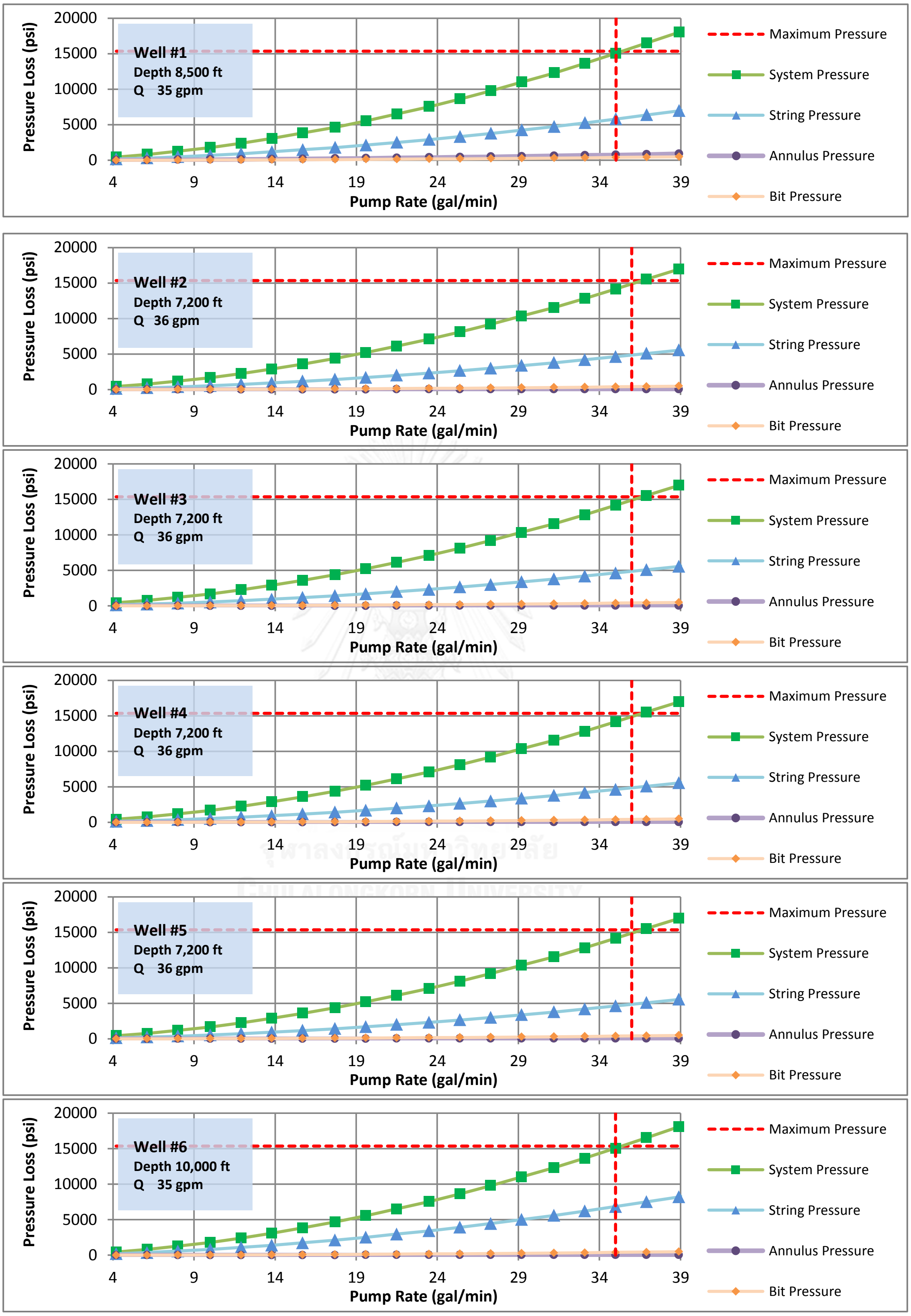


Figure 5.7 Pressure losses for 1.0” CTOD in 3.5” tubing

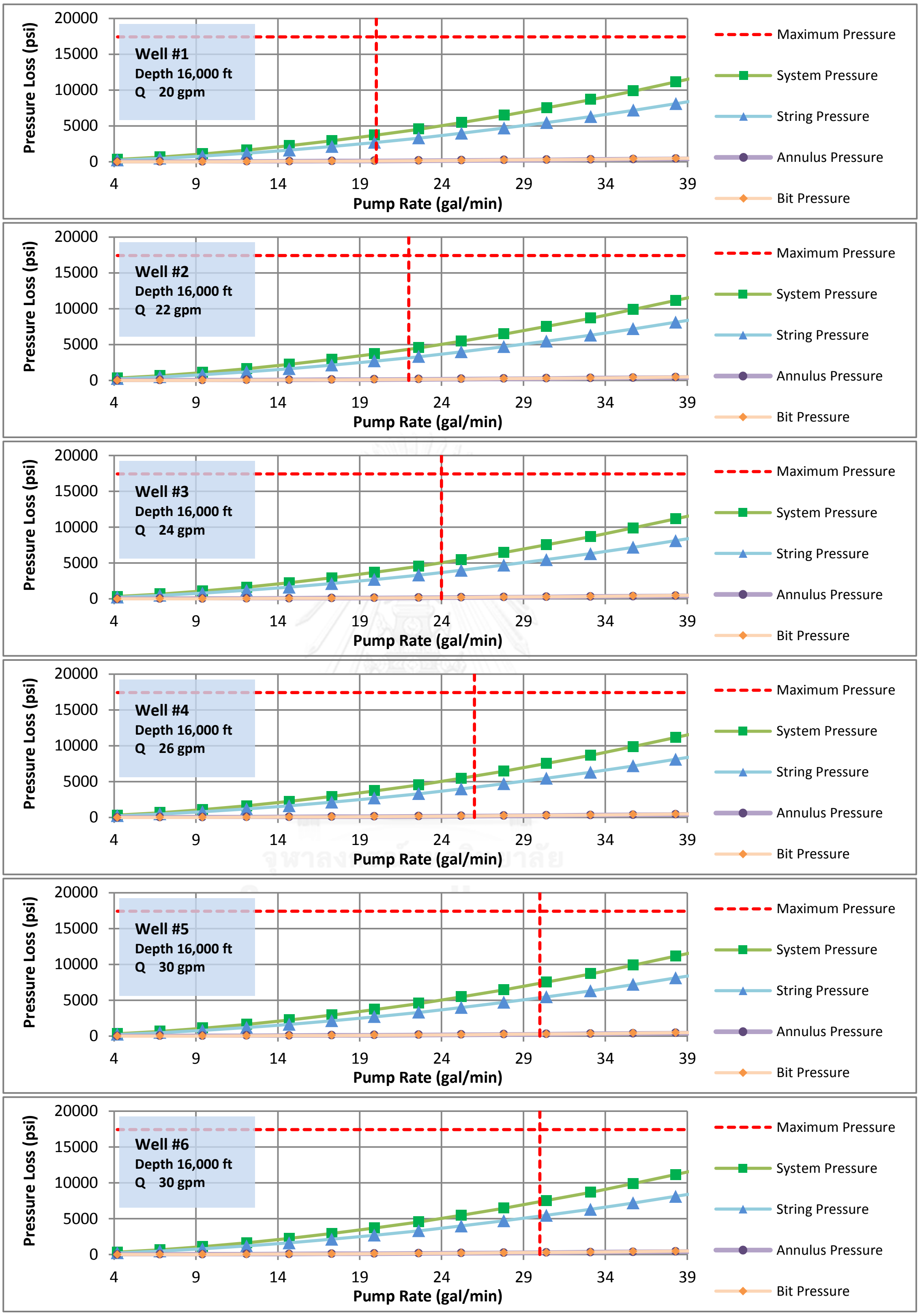


Figure 5.8 Pressure losses for 1.25” CTOD in 2.875” tubing

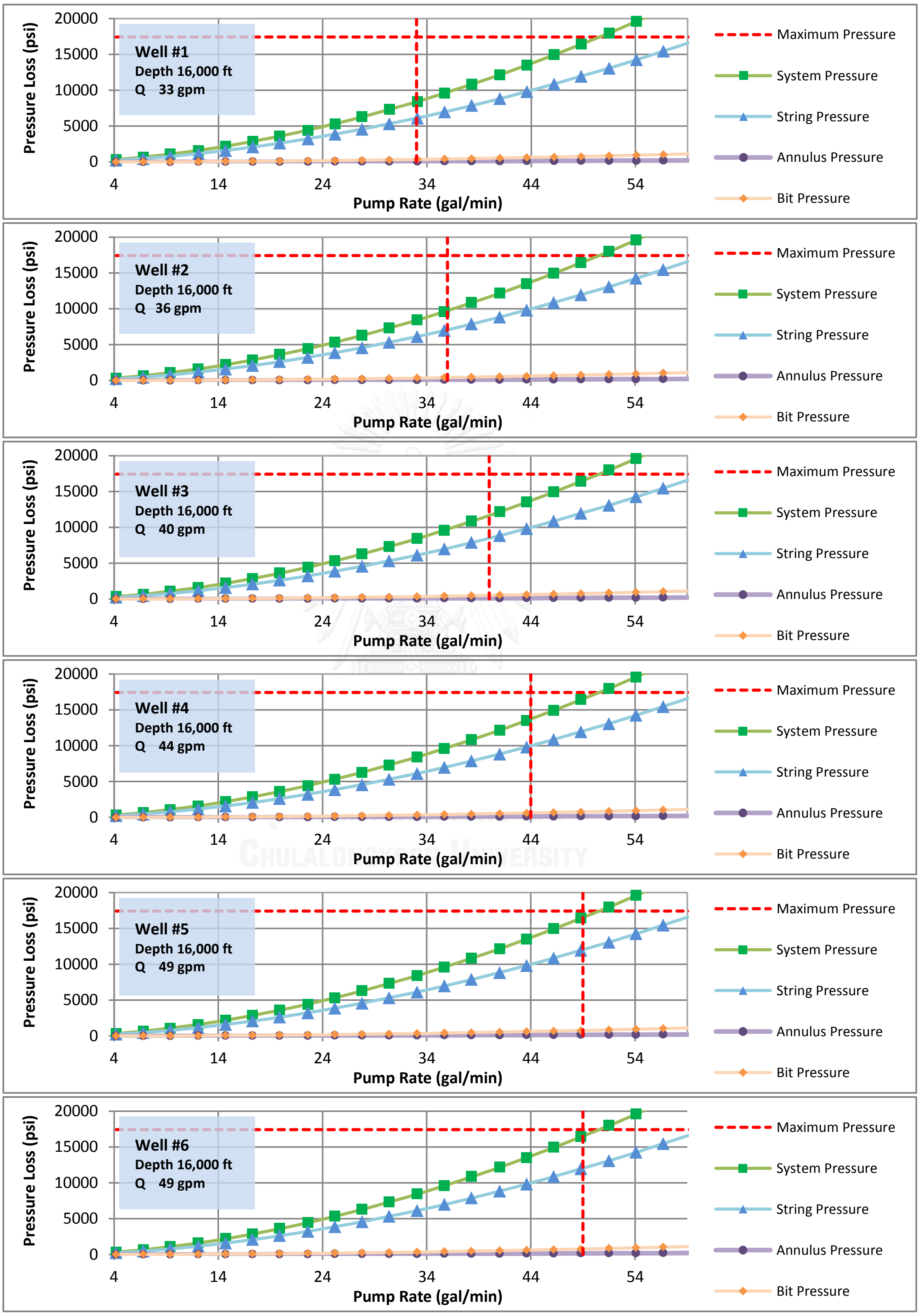


Figure 5.9 Pressure losses for 1..25” CTOD in 3.5” tubing

Figure 5.8 – 5.9 describes the pressure loss associated with the pump rate for 1.25”CT in 2.875” and 3.5” tubing. The critical flow rate determined in Section 5.1.1 can be achieved at the TD for all well scenarios. The system pressure loss when CT section is 16,000 ft. in the wellbore, while 4,000 ft. left in the reel is lower than the maximum pressure. Hence, 1.25”CT can deliver the desired pump rate at the TD for both completion scenarios.

The maximum depth of intervention corresponding to and deliverable pumping rate can be summarized in Table is shown in Table 5.3. The system pressure losses, CT pressure loss, annular pressure loss and pressure loss in BHA are presented.

Table 5.3 Summary of maximum pump rate and intervention depth (ft) and required pump rate (Q, gal/min) for group 1 application

CT.OD.	Tubing Size	Well #1	Well #2	Well #3	Well #4	Well #5	Well #6
1"	2.875"	16000 (Q = 22)	16000 (Q = 25)	16000 (Q = 27)	15000 (Q = 30)	10500 (Q = 33)	11500 (Q = 32)
1.25"		16000 (Q = 20)	16000 (Q = 22)	16000 (Q = 24)	16000 (Q = 26)	16000 (Q = 30)	16000 (Q = 30)
1"	3.5"	8500 (Q = 35)	7200 (Q = 36)	7200 (Q = 36)	7200 (Q = 36)	7200 (Q = 36)	10000 (Q = 35)
1.25"		16000 (Q = 33)	16000 (Q = 36)	16000 (Q = 40)	16000 (Q = 44)	16000 (Q = 49)	16000 (Q = 49)

5.1.3.2 Pressure losses in group 2 application

The maximum gas injection rates determined in Section 5.1.2 is used for the calculation of system pressure loss due to gas. Although the maximum gas injection rate required for the liquid transportation is high, but frictional pressure is still low in comparison to application in group 1. The system pressure loss plot due to gas injection is shown in Figure 5.10. It can be seen that the system pressure loss is much lesser than 80% of internal yield pressure. Therefore, both size of CT can be used in all of our well scenarios with the viability to inject the required gas at total depth. The summary of viability for group 2 application's hydraulic consideration is shown in Table 5.4.

Table 5.4 Summary of maximum intervention depth (ft) and required pump rate (Q, scf/min) for group 2 application

CT.OD.	Tubing Size	Well #1	Well #2	Well #3	Well #4	Well #5	Well #6
1"	2.875"	16000 (Q=400)	16000 (Q=400)	16000 (Q=400)	16000 (Q=400)	16000 (Q=400)	16000 (Q=400)
1.25"		16000 (Q=600)	16000 (Q=600)	16000 (Q=600)	16000 (Q=600)	16000 (Q=600)	16000 (Q=600)
1"	3.5"	16000 (Q=500)	16000 (Q=500)	16000 (Q=500)	16000 (Q=500)	16000 (Q=500)	16000 (Q=500)
1.25"		16000 (Q=800)	16000 (Q=800)	16000 (Q=800)	16000 (Q=800)	16000 (Q=800)	16000 (Q=800)

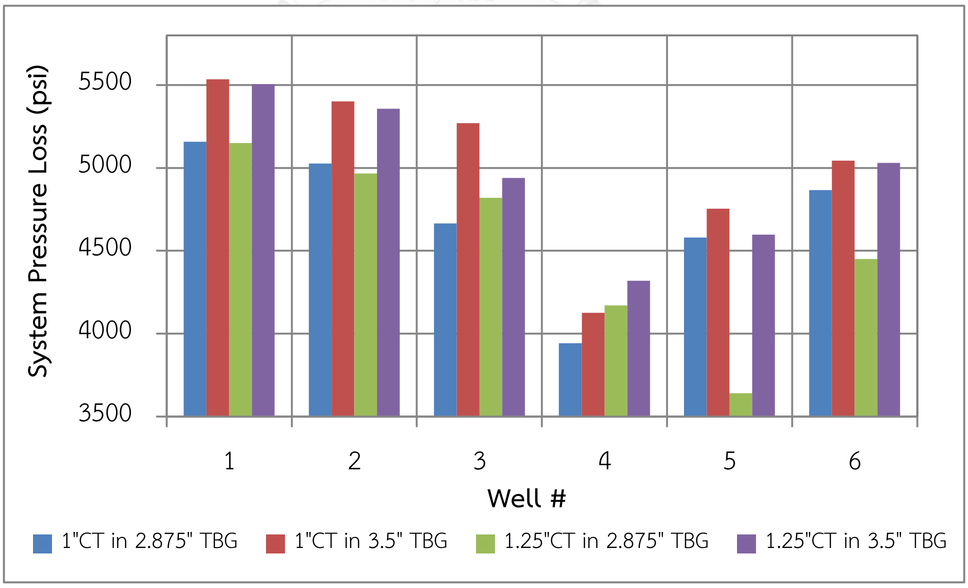


Figure 5.10 System pressure loss for gas lifting

5.2 Mechanical consideration

5.2.1 Runability

The runability for CT in well scenarios can be determined based on Section 3.2.1. The maximum depths of intervention for each scenario were simulated and given in Figures 5.11 – 5.22. There are several parameters effect on the runability which described hereafter.

The lower limit: The buckling force (i.e. compressive axial fore) is used as the lower limit. The buckling limit is described earlier in 3.2.1. When the CT is in compression with the axial compressive force is more than the buckling force, the CT forms the buckling. It can be seen from the Eq. 3.28 that for any given sizes of CT, the buckling force is zero in vertical well. This means that the initiation of sinusoidal buckling occurs as soon as axial compressive force applied. The buckling force becomes higher for the higher wellbore's inclination. The radial clearance between wellbore and CT also affect the buckling limit. The higher buckling limit is attained when the radial clearance is lowered or the weight of CT is higher. In other word, the buckling limit is higher for the 2.875" tubing scenarios.

The upper limit: On the other hand, the tension limit (i.e. tensile axial force) is used as upper boundary. The upper boundary shown in is defined from 80% of Pipe Body Yield Load (PBYL). The PBYL for 1" and 1.25" CT are 27,490 lb and 47,280 lb, respectively. Hence, the tension limit for 1" and 1.25" CT are 21,992 lb and 37,824 lb, respectively.

Effect of CT size: There are few parameters associated to CT size that affect the axial force. The first obvious parameter is the weight in air of the CT. The bigger the CT size has the associated higher weight in air. Hence, higher axial force can be observed when use the bigger size of CT. The simulation results for 1.25" CT shows higher effective tension as can be seen in all well scenario. The another parameter is drag force, which in our case, there is no change in the azimuth (i.e. $\Delta\alpha = 0$). Therefore, the Eq. 3.24 can be reduced to

$$F_N = F_T \times \Delta\beta + WL\ sin\emptyset \quad (5.7)$$

Angular speed is also fixed as zero (i.e. no rotation on CT), hence the resultant speed is the same value as trip speed. Substitute Eq. 5.7 into Eq. 3.23 and reduced form can be expressed as:

$$F_D = F_T \times \Delta\beta + WL\ sin\emptyset \times C_f \quad (5.8)$$

It can be seen from the Eq. 5.8 that, the higher CT weights will result in the larger drag force. Therefore, during RIH the axial compressive force will be lesser with larger CT. On the other hand, the axial tensile force will be higher than small CT during POOH.

<u>Effect of wellbore inclination:</u> It can be seen from the Eq. 3.22 that, the larger inclination angle (i.e. $\lim_{\theta\to 90}\cos\theta\ \cong 0$), the lower weight. Therefore, the effective tension is highest in vertical where the weight is highest (i.e. $\cos 0 = 1$) and the drag force is lowest (i.e. $\sin 0 = 0$).

<u>Effect of tubing size:</u> The WELLPLAN™ adopt the softstring model based on Johancsick et al. (1983) where the clearance between CT and tubing has no effect on drag force. Hence, the effective tensions are the same for 2.875” and 3.5” well scenarios. The following illustrations in Figure 5.11 – 5.16 are the effective tension for 1” CT plotted together with buckling and tension limit for runability evaluation for 6 well patterns.

Figure 5.11 illustrates the effective tension along the 1” CT in Well #1. The effective tension described by Eq. 3.28 is highest at 16.2 Kips in the section close to surface where the whole string weight is suspended below this section. In Well #1, the inclination of the wellbore is zero resulting in the highest weight. It can also be seen from Eq. 3.28 that the drag force contributes to the effective tension during RIH and POOH. Although the different direction of tripping results in different effective tension, but there is no drag tension as described by Eq. 3.23 due to no side force.

Consequently, the effective tensions during RIH and POOH are the same and stack on top of each other. The CT used in this study which discussed earlier in Section 4.2.1 has the uniform internal and external diameter (i.e. not tapered). Hence, there is no change in force due to the change of area($\Delta F_{area} = 0$). The effective tension is lowest at 0 Kips in the bottom most section, where no weight suspended below and no drag force. The effective tension during RIH is within the buckling limit at the bottom most section. Likewise, the effective tension during POOH is within the tension limit at the surface section. Hence, the 1”CT has the ability to run in and out of the wellbore of Well #1.

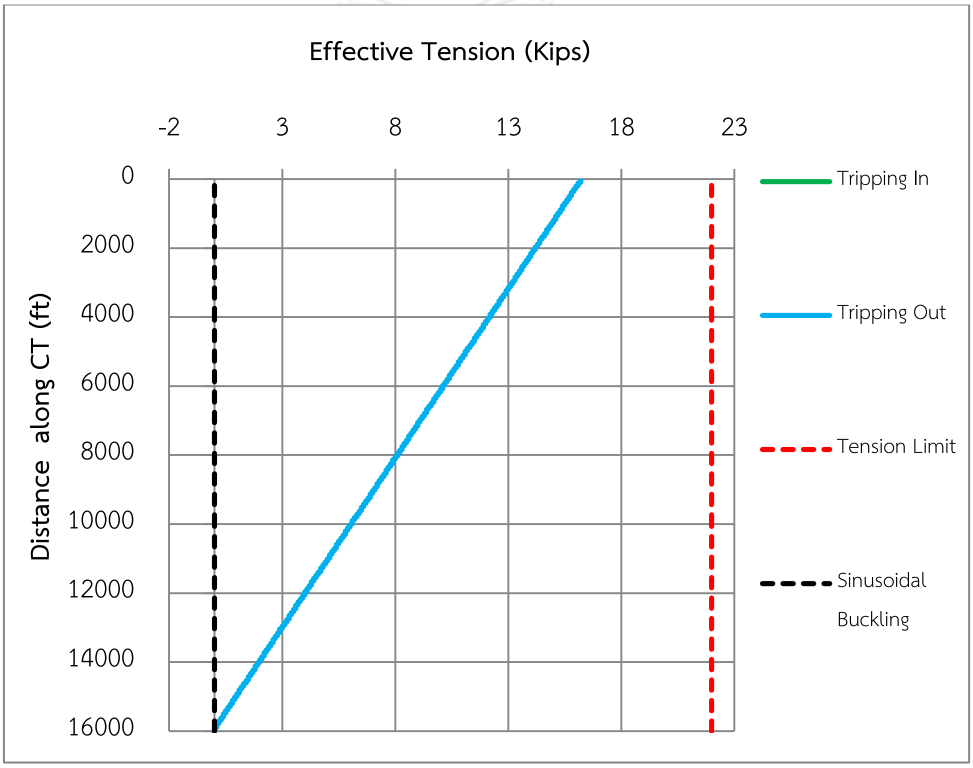


Figure 5.11 Effective tension for 1” CT in Well #1

Figure 5.12 illustrates the effective tension along the 1” CT in Well #2. The effective tension for surface section is highest at 16.2 kips during POOH which similar to scenario in Well#1. Although, the lesser weight is suspended and reduces the axial weight, but more weight is supported by wellbore and hence increase of the drag force. The increment of drag force can be seen from the separation of effective tension during RIH and POOH. The drag force is occurring in the build section and hold section, but not in the vertical section above the kick-off depth. The low separation in this scenario implies the low drag fore. The effective tension is lowest at 0 kips for the bottom most section where the drag force is minimal. The effective tension during RIH is within the buckling limit at the bottom most section. Likewise, the effective tension during POOH is within the tension limit at the surface section. Hence, the 1”CT has the ability to run in and out of the wellbore of Well #2.

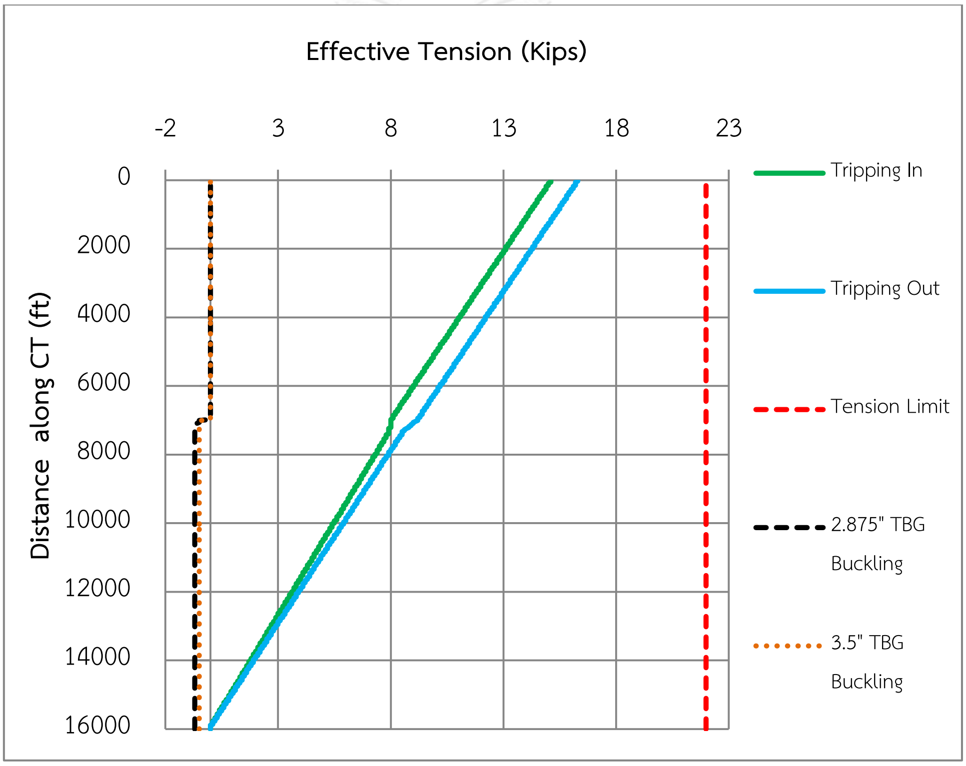


Figure 5.12 Effective tension for 1” CT in Well #2

Figure 5.13 illustrates the effective tension along the 1” CT in Well #3. The effective tension for surface section is highest at 15.2 Kips which is lower than scenario in Well #2. Although, the lesser weight is suspended and reduces the axial weight due to wellbore inclination, but more weight is supported by wellbore and hence increase of the drag force. The increment of drag force can be seen from the separation of effective tension during RIH and POOH. The drag force is occurring in the build section and hold section, but not in the vertical section above the kick-off depth. The higher separation in this scenario implies the higher drag force for deviated well. The effective tension is lowest at 0 kips for the bottom most section where the drag force is minimal. The effective tension during RIH is within the buckling limit at the bottom most section. Likewise, the effective tension during POOH is within the tension limit at the surface section. Hence, the 1”CT has the ability to run in and out of the wellbore of Well #3.

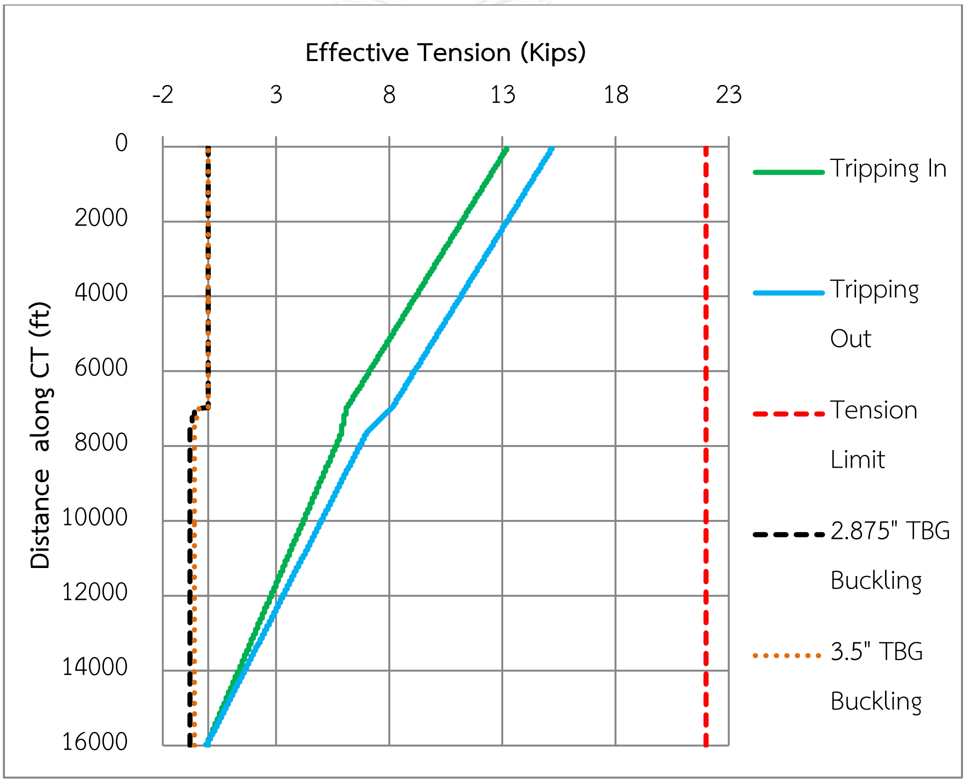


Figure 5.13 Effective tension for 1” CT in Well #3

Figure 5.14 illustrates the effective tension along the 1” CT in Well #4. The effective tension for surface section is highest at 13.2 Kips which is lower than scenario in Well #3. Although, the lesser weight is suspended and reduces the axial weight due to wellbore inclination, but more weight is supported by wellbore and hence increase of the drag force. The increment of drag force can be seen from the separation of effective tension during RIH and POOH. The drag force is occurring in the build section and hold section, but not in the vertical section above the kick-off depth. The higher separation in this scenario implies the higher drag force for deviated well. The effective tension is lowest at 0 kips for the bottom most section where the drag force is minimal. The effective tension during RIH is within the buckling limit at the bottom most section. Likewise, the effective tension during POOH is within the tension limit at the surface section. Hence, the 1”CT has the ability to run in and out of the wellbore of Well #4.

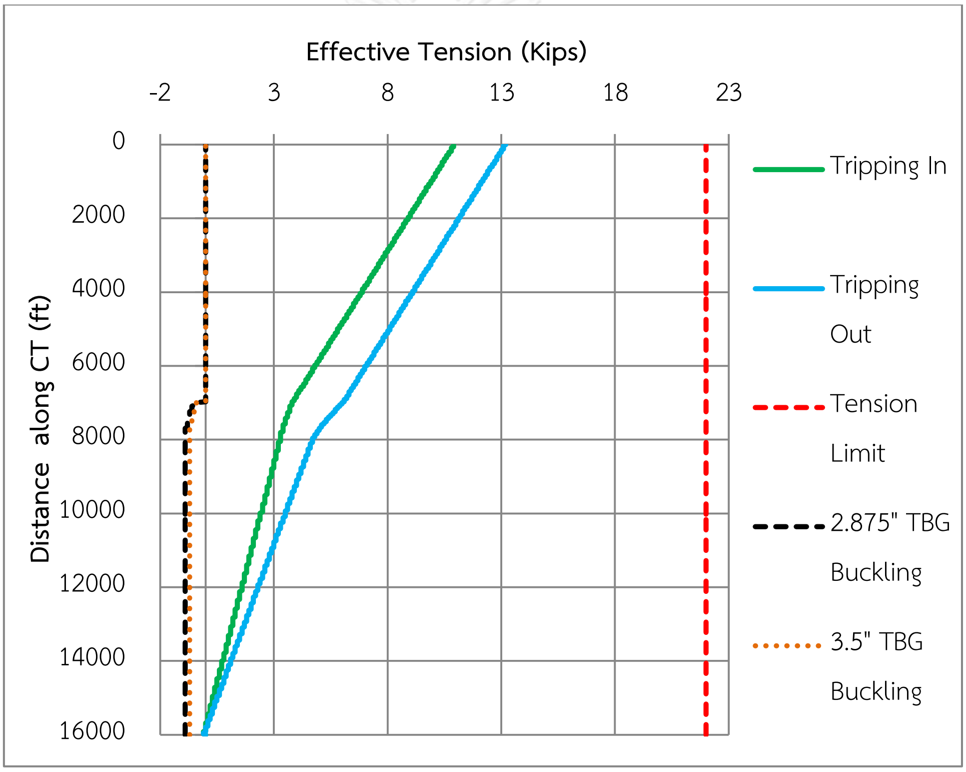


Figure 5.14 Effective tension for 1” CT in Well #4

Figure 5.15 illustrates the effective tension along the 1” CT in Well #5. The effective tension for surface section is highest at 8.9 kips which is significantly lower than scenario in Well #4. The increment of drag force can be seen from the separation of effective tension during RIH and POOH. The drag force occurring in the build section and hold section becomes highest in all scenarios. The higher separation in this scenario implies the higher drag force in deviated well. The effective tension is as low ast -0.9 kips in the CT section at 7000-8000 ft from surface where the drag force is highest. Although, the effective tension during POOH is within the tension limit at the surface section, the effective tension during RIH exceeds the buckling limit at this section. Hence, the 1”CT cannot RIH beyond 7000 ft in the wellbore of Well #5. The inclination impedes the accessibility to total depth.

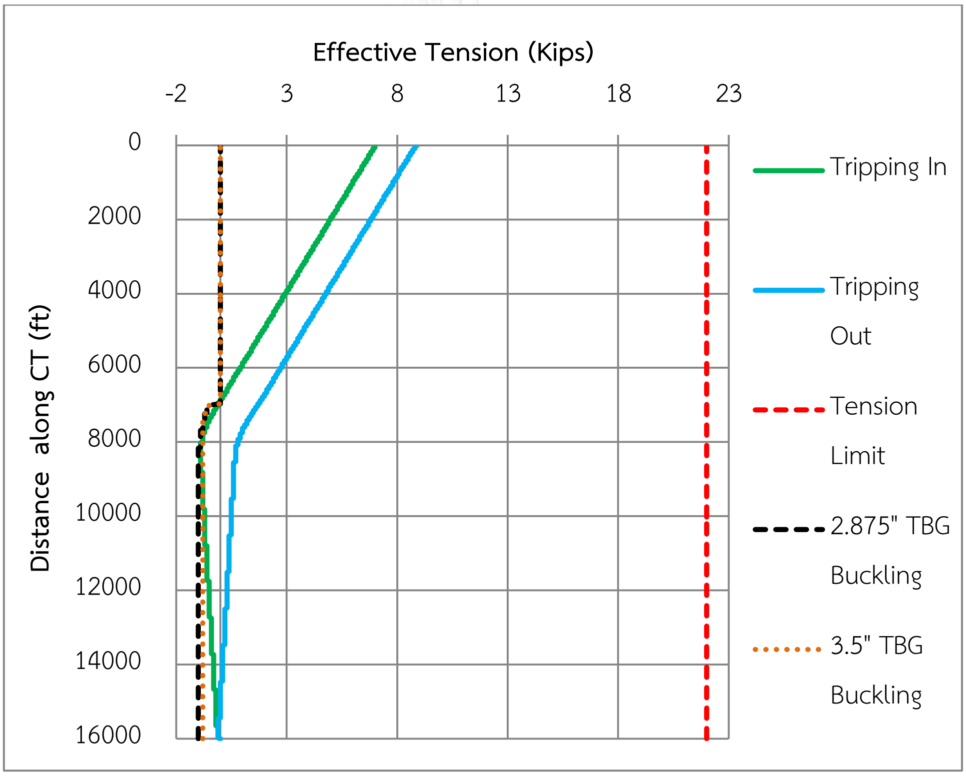


Figure 5.15 Effective tension for 1” CT in Well #5

Figure 5.16 illustrates the effective tension along the 1” CT in Well #6. The effective tension for surface section is highest at 11.8 kips which is slightly higher than scenario in Well #5. The effect of drag force can be seen from the separation of effective tension during RIH and POOH. The drag force is occurring in the build section and hold section, become second highest in all scenarios The effective tension is as low as -0.85 kips in the CT section at 11,000 - 12,000 ft from surface where the drag force is highest. Although, the effective tension during POOH is within the tension limit at the surface section, the effective tension during RIH exceeds the buckling limit at this section. Hence, the 1”CT cannot RIH beyond 11,000 ft in the wellbore of Well #6. The inclination impedes the accessibility to total depth.

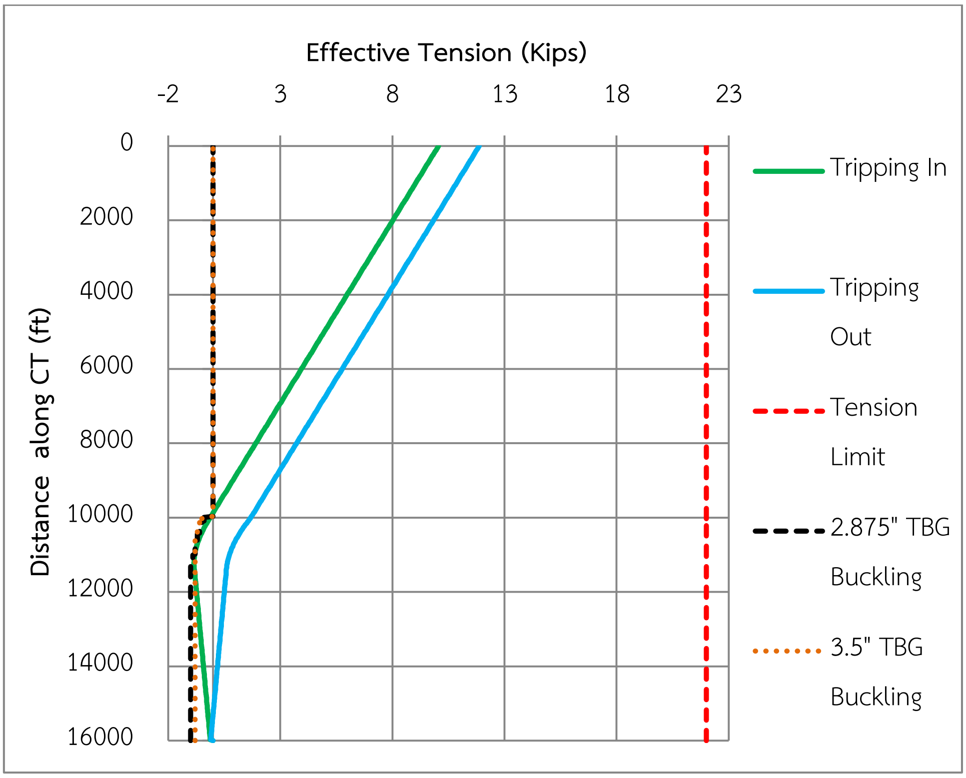


Figure 5.16 Effective tension for 1” CT in Well #6

Figure 5.17 illustrates the effective tension along the 1.25” CT in Well #1. The effective tension is highest at 28 Kips in the uppermost section. The effective tension is lowest at 0 Kips in the bottom most section. The effective tension during POOH and RIH are within the runability limits. Hence, the 1.25” CT has the ability to run in and out of the wellbore of Well #1.

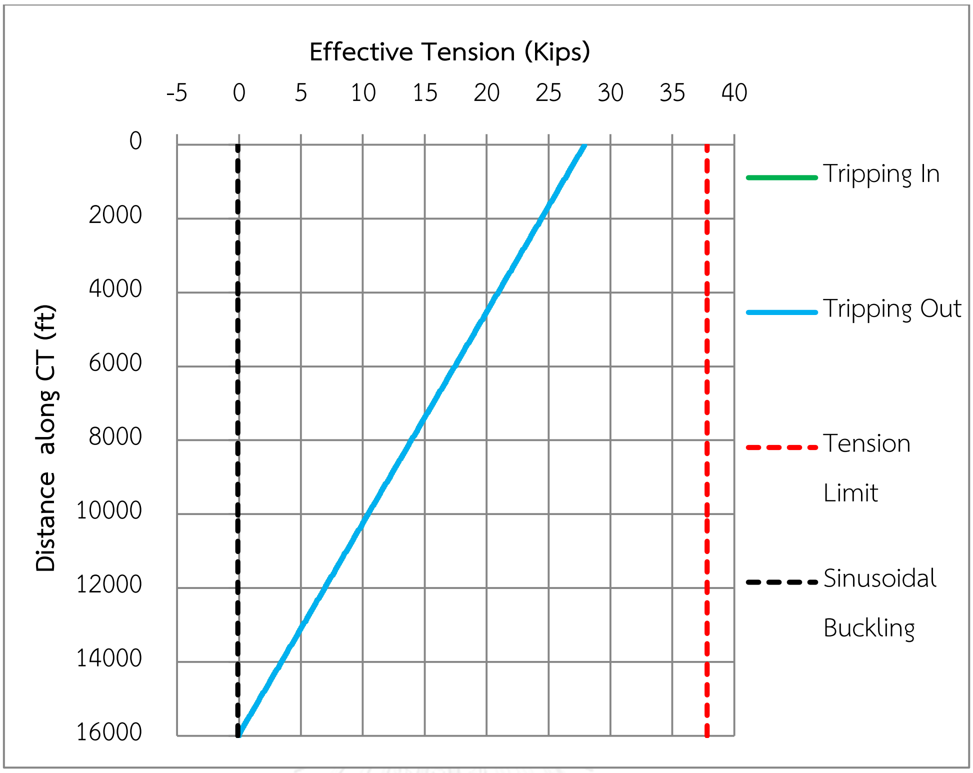


Figure 5.17 Effective tension for 1.25” CT in Well #1

Figure 5.18 illustrates the effective tension along the 1.25” CT in Well #2. The effective tension is highest at 28 Kips in the uppermost section. The effective tension is lowest at 0 Kips in the bottom most section. The effective tension during POOH and RIH are within the runability limits. Hence, the 1.25” CT has the ability to run in and out of the wellbore of Well #2.

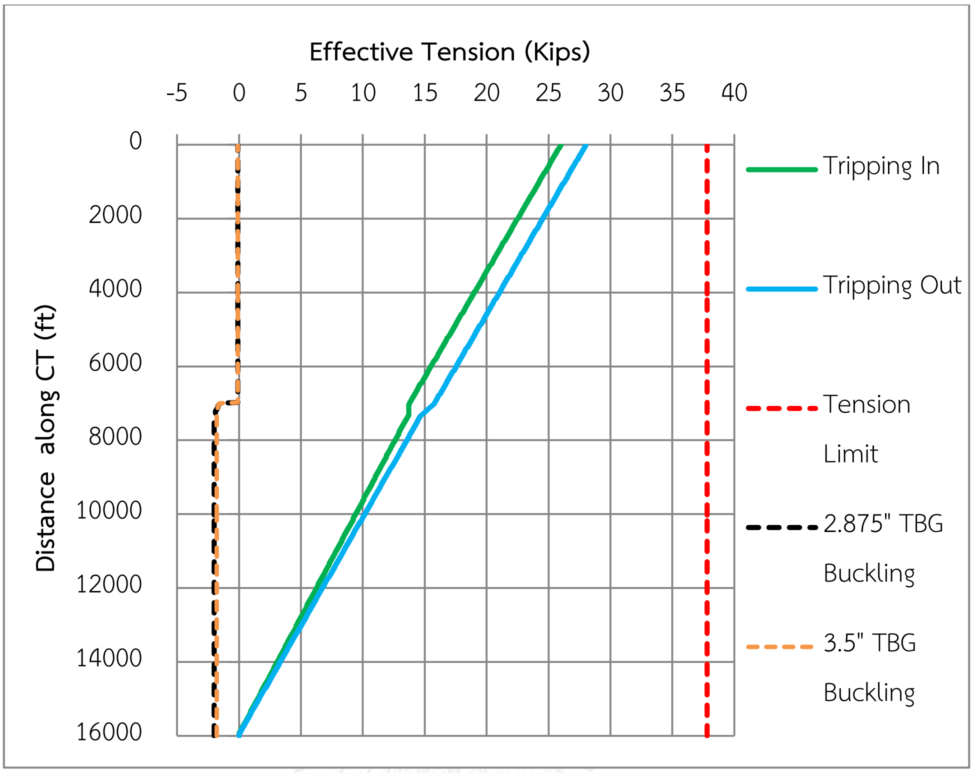


Figure 5.18 Effective tension for 1.25” CT in Well #2

Figure 5.19 illustrates the effective tension along the 1.25” CT in Well #3. The effective tension is highest at 26.2 Kips in the uppermost section. The effective tension is lowest at 0 Kips in the bottom most section. The effective tension during POOH and RIH are within the runability limits. Hence, the 1.25” CT has the ability to run in and out of the wellbore of Well #3.

Figure 5.20 illustrates the effective tension along the 1.25” CT in Well #4. The effective tension is highest at 23 Kips in the uppermost section. The effective tension is lowest at 0 Kips in the bottom most section. The effective tension during POOH and RIH are within the runability limits. Hence, the 1.25” CT has the ability to run in and out of the wellbore of Well #4.

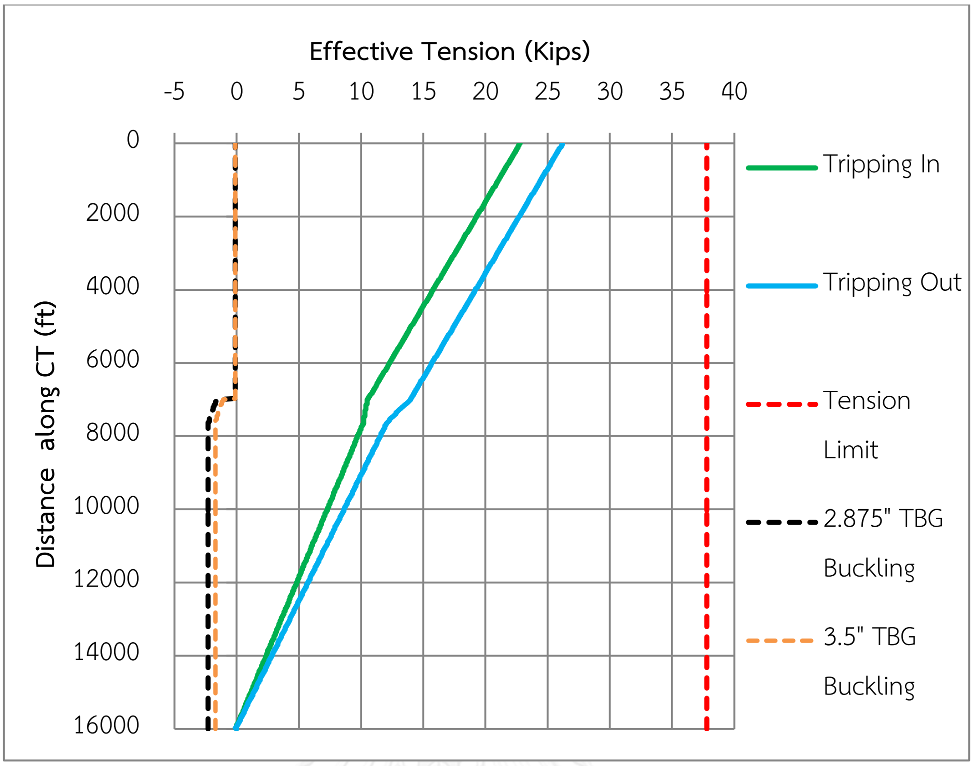


Figure 5.19 Effective tension for 1.25” CT in Well #3

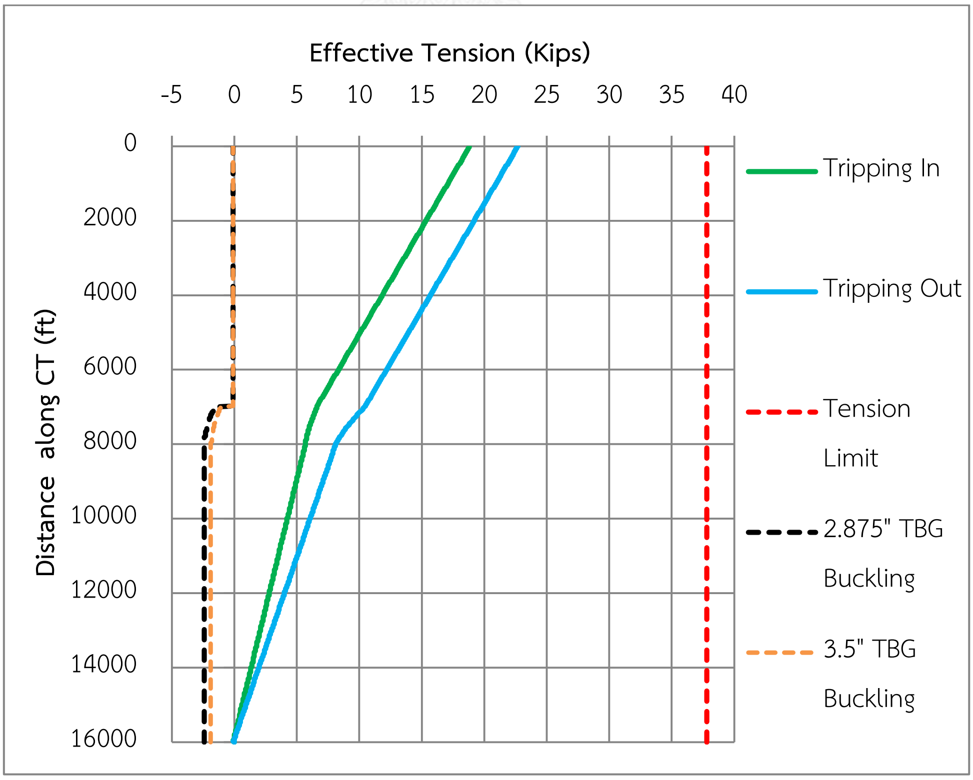


Figure 5.20 Effective tension for 1.25” CT in Well #4

Figure 5.21 illustrates the effective tension along the 1.25” CT in Well #5. The effective tension is highest at 15.3 Kips in the uppermost section. The effective tension is lowest at -1.5 kips in the CT section at 7000-8000 ft from surface where the drag force is highest. The effective tension during POOH and RIH are within the runability limits. Hence, the 1.25” CT has the ability to run in and out of the wellbore of Well #5.

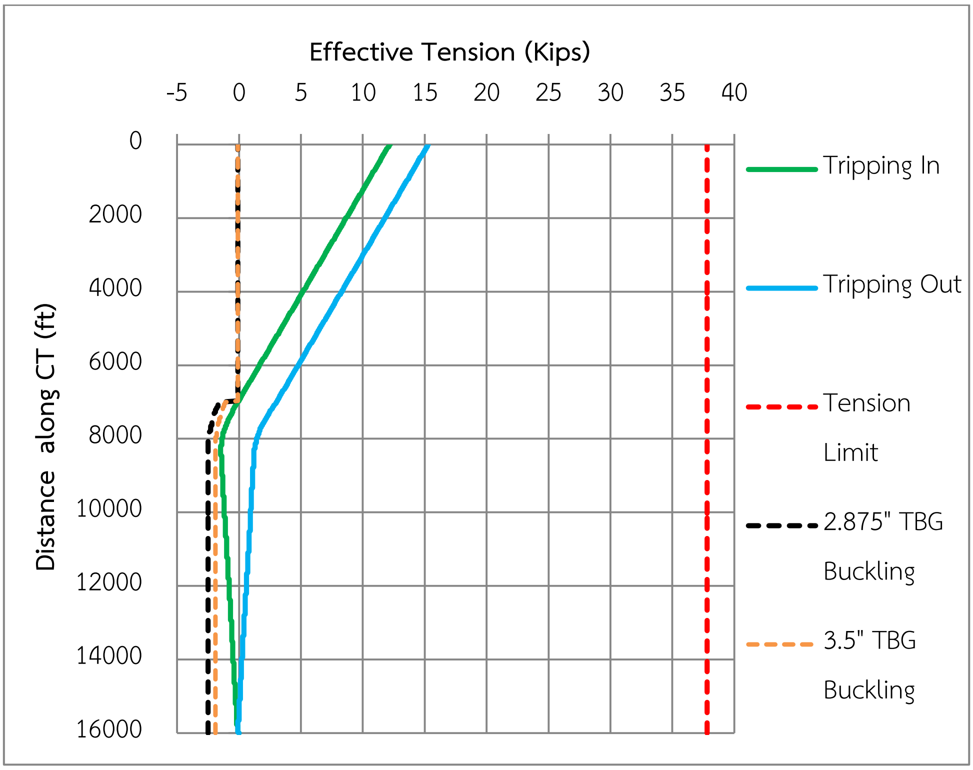


Figure 5.21 Effective tension for 1.25” CT in Well #5

Figure 5.22 illustrates the effective tension along the 1.25” CT in Well #6. The effective tension is highest at 20 Kips in the uppermost section. The effective tension is lowest at -0.9 kips in the CT section at 10,000-11,000 ft from surface where the drag force is highest. The effective tension during POOH and RIH are within the runability limits. Hence, the 1.25” CT has the ability to run in and out of the wellbore of Well #6.

Figure 5.22 Effective tension for 1.25” CT in Well #6

The summary of maximum runability for all well scenarios is shown in Table 5.5.

Table 5.5 Summary of maximum runability

CT.OD.	Tubing Size	Well #1	Well #2	Well #3	Well #4	Well #5	Well #6
1"	2.875"	16000	16000	16000	16000	7000	11000
1.25"		16000	16000	16000	16000	16000	16000
1"	3.5"	16000	16000	16000	16000	7000	11000
1.25"		16000	16000	16000	16000	16000	16000

5.2.1.1 Effect of friction reducer

There are recommendations by Portman [10] to apply friction reducer in attempt to broarder the pushing/pulling limit. The friction reducer is typically the additive waer-soluble brine lubricant. Once this lubricant pumped together with the

CT's fluid, the friction reducer coated the surface and function as lubricant. In typical cased well, the coefficient of friction is around 0.3 – 0.35, whereas lubricated water-wet steel can be 30% lower.

The effect of friction reducer on the runability of 1"CT in Well #5 and Well #6 are study. The 1" CT in these wells having the problem to RIH to TD due to low buckling limit. The effects of friction reducer fluid are illustrated in Figure 5.23-5.24.

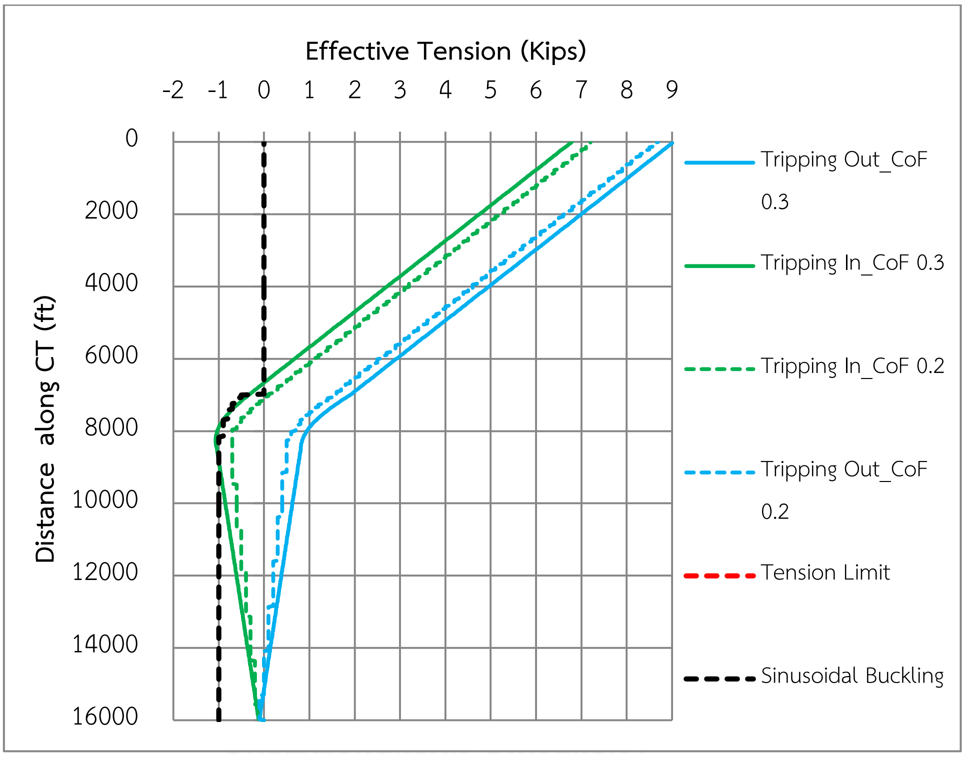


Figure 5.23 Effective tension for 1" CT in Well #5, before and after apply friction reducer

It is found better runability results in the simulation (1"CT in Well #5 and Well # 6) according to the recommendation. The original well condition is water wet steel which have the CoF of 0.3. The condition after applied friction reducer assumes CoF of 0.2. The 1" CT could reach the HUD at 7,000 ft in Well #5 before applying friction reducer. Similarly, 1" CT could reach HUD at 11,000 ftin Well #6. The effective tension during RIH can be increased with use of friction reducer (i.e. drag force reduced). The CT string becomes more in tensile than compression and it allows the CT to RIH without exceeding buckling. Likewise, the effective tension during POOH becomes lesser due to the reduction of the drag force.

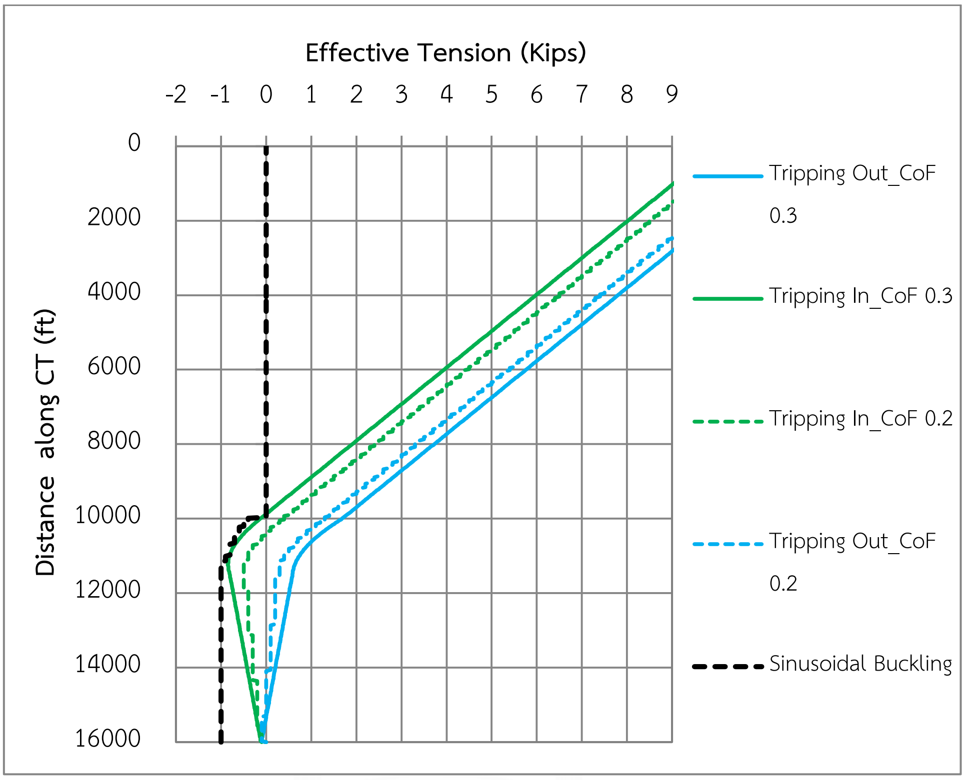


Figure 5.24 Effective tension for 1” CT in Well #6, before and after apply friction reducer

5.2.1.2 Effect of high strength CT

The recommendation to use high yield strength CT to allow higher push/pull by Portman [10] is another aspect studied. The higher strength CT is selected as 100 Kpsi specified minimum yield strength. The highest weight available for this 100 Kpsi SMYS CT is 1.04 ppf which is considerably lower than 1.17 ppf. There are 3 effects associated to the lesser of CT weight when using high strength 1” CT. The lower weight results in the lower of side force, hence drag force is smaller. This can be seen from the smaller separation of effective tension during RIH and POOH becomes smaller in comparison to the 80 Kpsi SMYS CT. The second effect on lesser CT weight is the lowering of effective tension. This can be observed from the effective tension in the surface section which suspending the whole string weight. Thirdly, the lesser CT weight results in the smaller buckling limit.

The comparisons between the 1” CT with 80 kpsi and 100 kpsi SMYS are shown in Figures 5.25 and 5.26. The use of higher strength material grants the benefit of smaller wall thickness and hence the lowering of effective tension during POOH can be anticipated. Similarly, the run in weight also increase due to lesser drag force. The CT string is becoming lesser in compression. The higher SMYS CT will cause smaller buckling limit, but it can help to mitigate the buckling problem in Well #6. Since the CT becomes in tensile mode, then the effective tension not exceeding the new buckling limit.

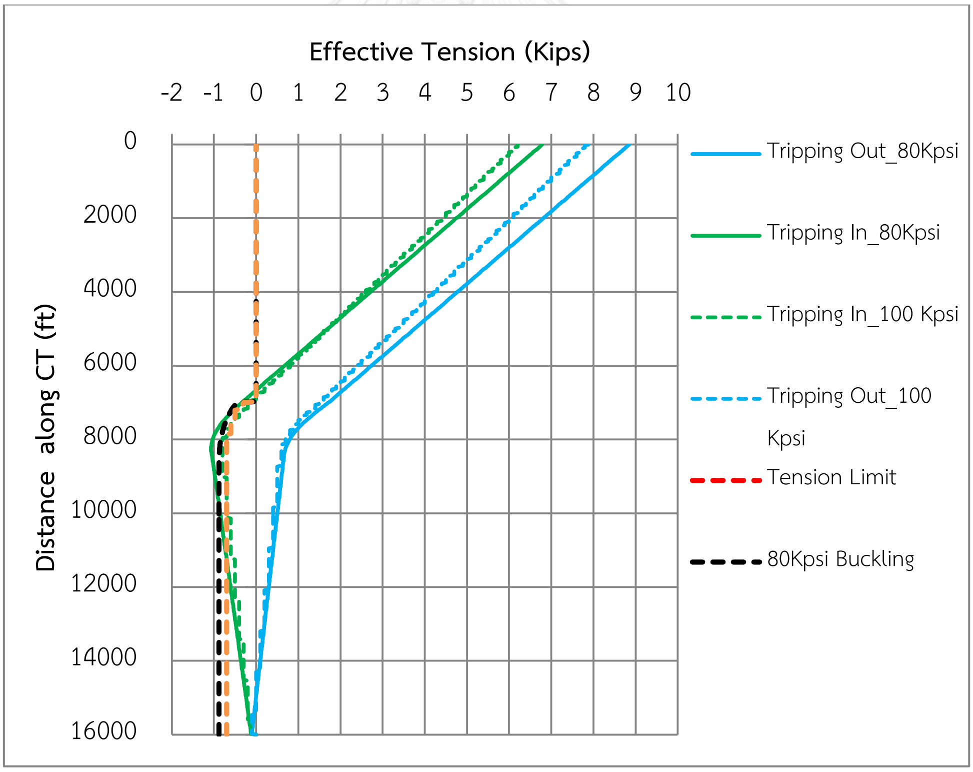


Figure 5.25 Effective tension for 1” CT in Well #5 with 80 Kpsi and 100 Kpsi minimum yield strength

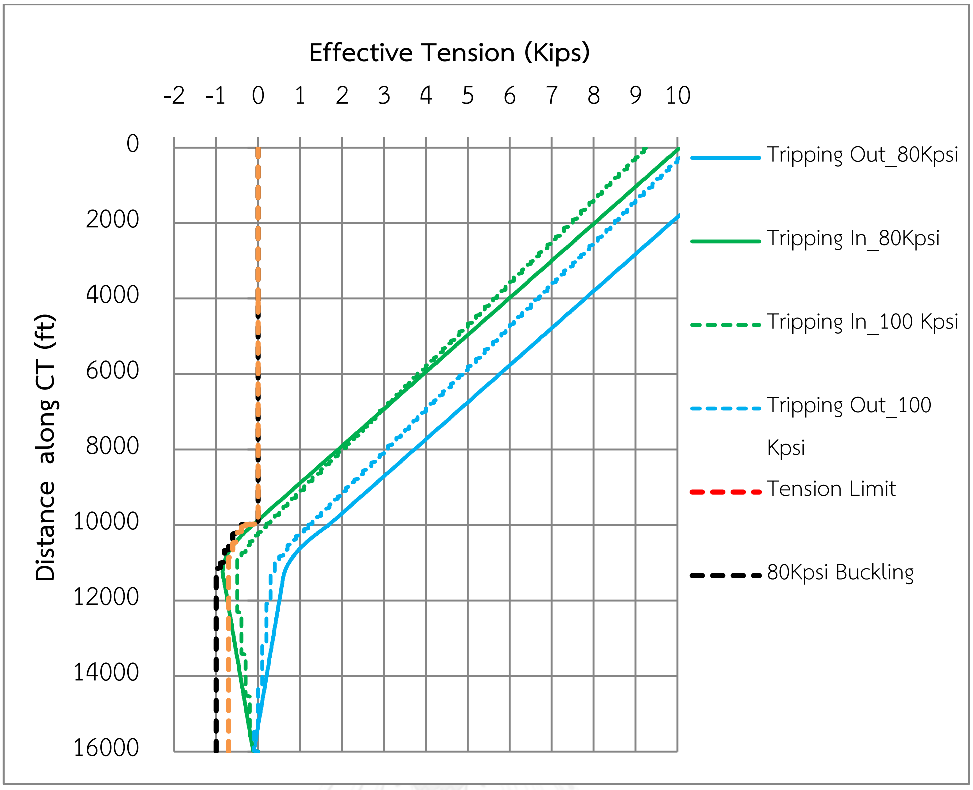


Figure 5.26 Effective tension for 1" CT in Well #6 with 80 Kpsi and 100 Kpsi minimum yield strength

5.2.2 Push/pull capacity

The pushing on bottom is evaluated based on available weight on bottom to push the CT section off bottom until it forms the buckling. The variation of well parameters resulted in the difference of axial compression force and hence pushing capacity. Figure 5.27 shows the pushing capacity on bottom for all well scenarios.

The parameters described in Eq. 3.28 affect the available pushing force. Well bore inclination is one of the parameter that governs the pushing capacity. Simulation result depicted in Figure 5.28 shows that variation in well bore inclination has large effect on the pushing capacity. The pushing capacity increases dramatically until inclination reach 60 deg and flattening beyond this inclination. The increment of well bore inclination resulted in decreasing of the CT weight and increasing of drag force. Therefore, the lower axial compression force can be anticipated. In summary, the available pushing force is very limited for the vertical well and more available pushing capacity in deviated well. The pushing capacity is highest for Well #5 and Well #6 where the axial compression force are lowest.

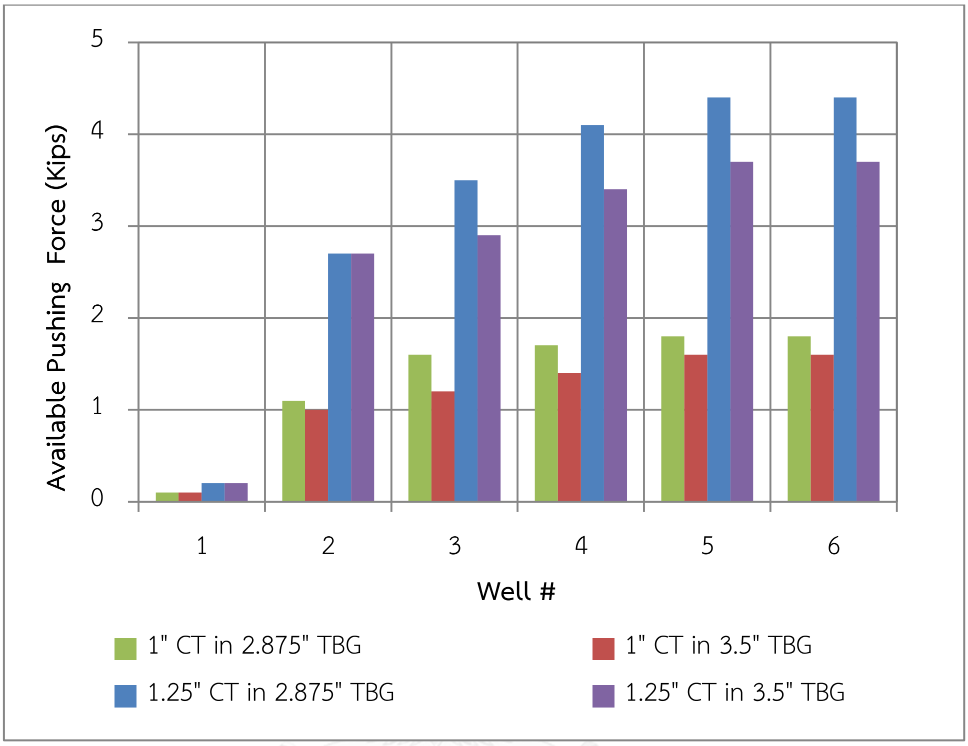


Figure 5.27 Available pushing force in all well scenarios

Another sensitivity study was performed on the kick-off depth and illustrated in Figure 5.29. The additional 2 horizontal wells with shallower and deeper kick-off depth added for kick-off depth variation study (i.e. 4,000 ft. and 11,000 ft.). The buckling limits are constant for the same well inclination (i.e. 90 deg). In contrast, the variation of kick-off depth causes no change in the compressive axial force. Thus, variation of kick-off depth results in no alteration of pushing capacity. However, it can be noticed the radial clearance affect the pushing capacity. This is owing to the buckling limit is governed by the radial clearance. Therefore, for a given size of CT, the pushing capacity increase when reduce the radial clearance.

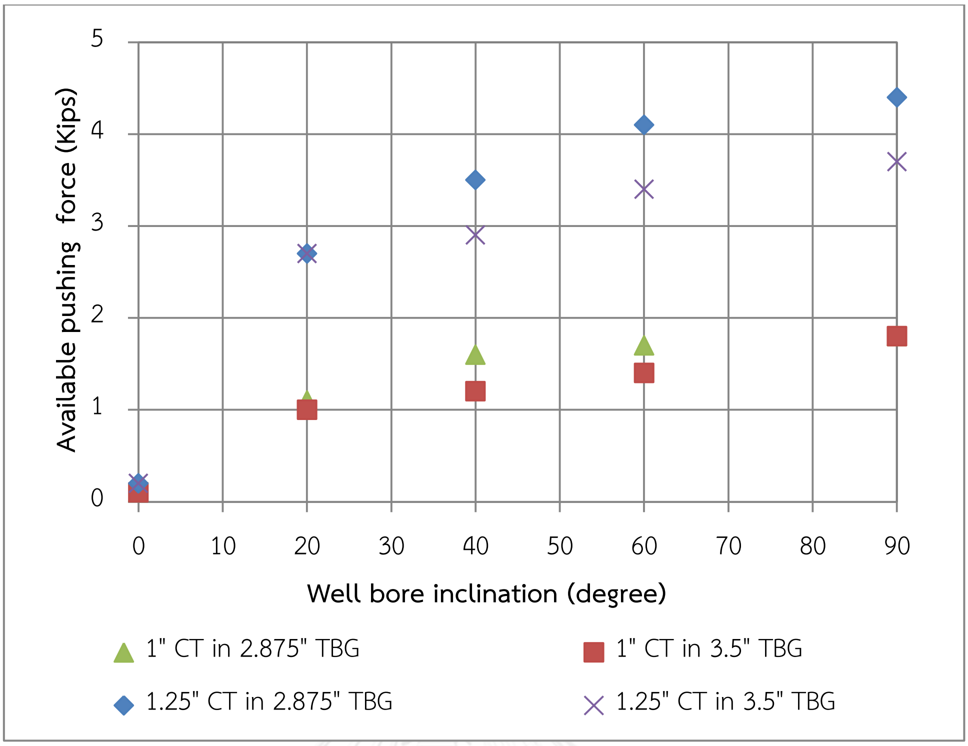


Figure 5.28 Effect of well bore inclination on pushing capacity

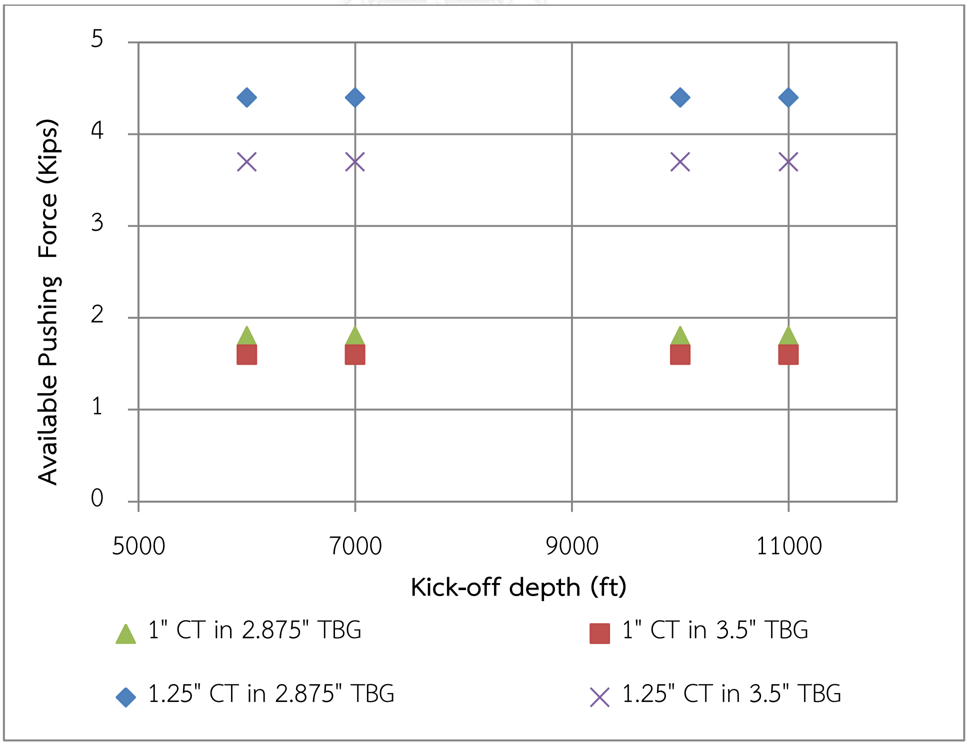


Figure 5.29 Effect of kick-off depth on pushing capacity

In general, 1.25” CT shows the higher capability to push and highest in Well#5 and Well#6. The ability to push on 1.25” CT is greater than the 1” CT. Therefore, for the application that required more weight on bottom 1.25” CT is more preferable.

The pulling on surface is evaluated based on available weight on surface to pull the CT section on surface until it reaches the tensile limit. The tensile limit for a given size of CT is the same. Thus, axial tension force defines the pulling limit. The variation of well parameters resulted in the difference of axial tension force and hence pulling capacity. Figure 5.30 shows the pulling capacity on bottom for all well scenarios. The parameters described in Eq. 3.28 affect the available pulling force. Well bore inclination is one of the parameter that governs the pullng capacity. Simulation result depicted in Figure 5.31 shows that variation in well bore inclination affect the pullng capacity. The pulling capacity tends to have no change until the inclination reach 40 deg and exponentially increase beyond this inclination. The increment of well bore inclination resulted in decreasing of the CT weight. Therefore, the lower axial tension force can be anticipated. In summary, the available pulling force is very limited for the vertical well and more available pulling capacity in deviated well. The pulling capacity is lowest in vertical and slightly deviated well (Well #1 – Well#4) and highest for Well #5 where the axial tension force are lowest.

Another sensitivity study was performed on the kick-off depth and illustrated in Figure 5.32. The additional 2 horizontal wells with shallower and deeper kick-off depth added for kick-off depth variation study (i.e. 4,000 ft. and 11,000 ft.). The tension limits are constant for the given size of CT. In contrast, the variation of kick-off depth causes changing in CT weight. Thus, increment of kick-off depth results in lower of pulling capacity.

The pulling capacity for 1”CT is also lesser than 1.25”CT. The available pulling capacity of 1” CT is around 5-14 kips. Although the capacity is relatively lower than 1.25”CT, it is significantly higher than the slickline pulling capacity (i.e. 1 Kips). Therefore, application that requires more pulling weight (i.e fishing) the 1.25” CT is more preferable.

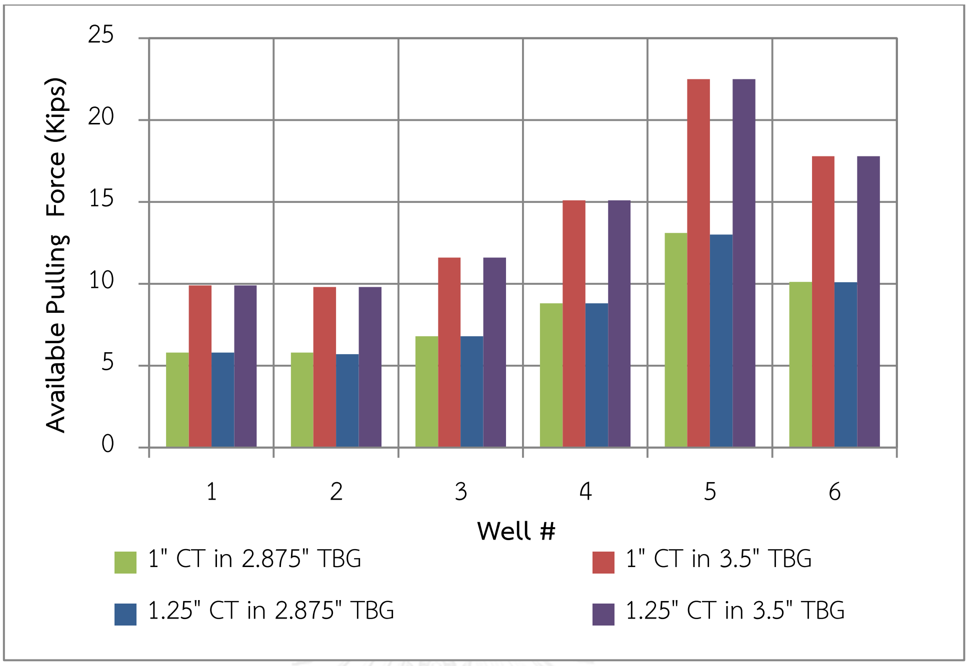


Figure 5.30 Available pulling force in all well scenarios

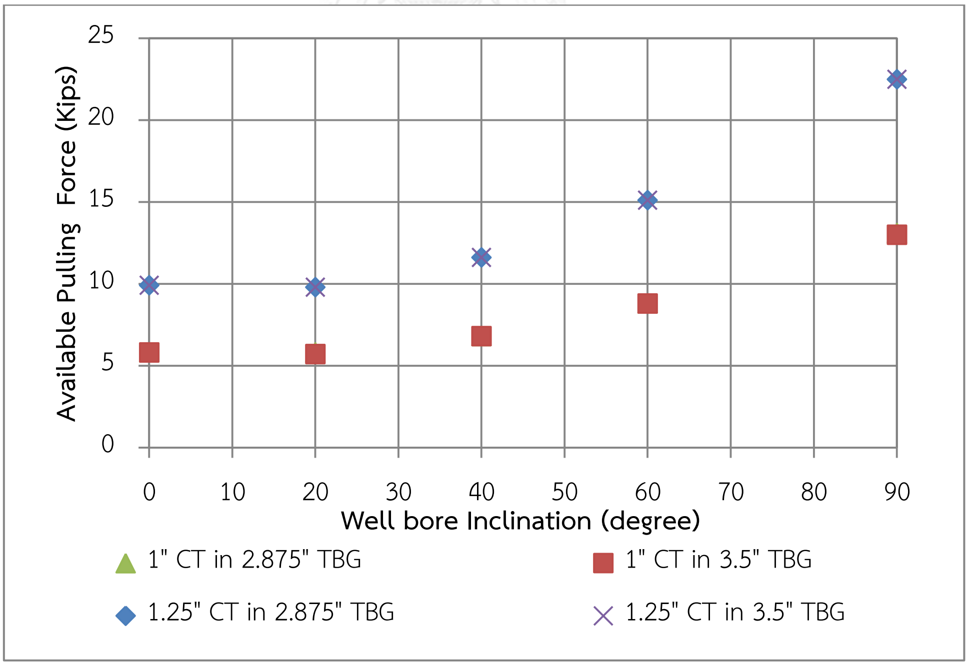


Figure 5.31 Effect of well bore inclination on pulling capacity

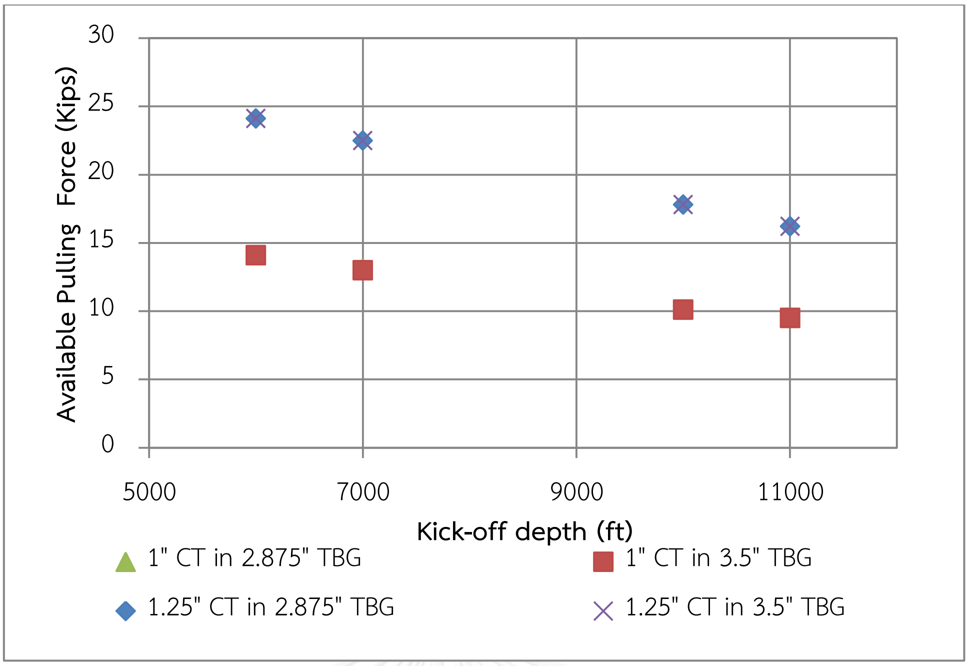


Figure 5.32 Effect of kick-off depth on pushing capacity

5.2.3 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 can 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 5.3, 5.4 and 5.5, the possible intervention interval which requires both hydraulically and mechanically aspect are shown in Table 5.6 and 5.7. The intervention depth is adjusted to the worst condition either the pumpability or runability, whichever shallower.

All scenarios in Tables 5.6 – 5.8 are then verified again whether the combined stresses (i.e. pressure-tension) are within the operating envelope. These simulate the static condition at the deepest possible on each well scenario. The cross-plot of the pressure and tension are given by effective differential pressure in y-axis and true tension in x-axis. Unlike the runability evaluation, the true tension described in Eq. 3.22 is used. There are 72 scenarios (3 application groups, 2 sizes of CT, 2 sizes of completion and 6 well paths) in total to be plotted in pressure-tension envelope described later in this section.

Table 5.6 Summary of maximum pump rate and intervention depth (ft) and required pump rate (Q, gal/min) for group 1 application

CT.OD.	Tubing Size	Well #1	Well #2	Well #3	Well #4	Well #5	Well #6
1"	2.875"	16000 (Q = 22)	16000 (Q = 25)	16000 (Q = 27)	15000 (Q = 30)	7000 (Q = 22)	11000 (Q = 25)
1.25"		16000 (Q = 20)	16000 (Q = 22)	16000 (Q = 24)	16000 (Q = 26)	16000 (Q = 30)	16000 (Q = 30)
1"	3.5"	8500 (Q = 35)	7200 (Q = 36)	7200 (Q = 36)	7200 (Q = 36)	7000 (Q = 36)	10000 (Q = 35)
1.25"		16000 (Q = 33)	16000 (Q = 36)	16000 (Q = 40)	16000 (Q = 44)	16000 (Q = 49)	16000 (Q = 49)

Table 5.7 Summary of maximum pump rate and intervention depth (ft) and required pump rate (Q, scf/min) for group 2 application

CT.OD.	Tubing Size	Well #1	Well #2	Well #3	Well #4	Well #5	Well #6
1"	2.875"	16000 (Q=400)	16000 (Q=400)	16000 (Q=400)	16000 (Q=400)	7000 (Q=400)	11000 (Q=400)
1.25"		16000 (Q=600)	16000 (Q=600)	16000 (Q=600)	16000 (Q=600)	16000 (Q=600)	16000 (Q=600)
1"	3.5"	16000 (Q=500)	16000 (Q=500)	16000 (Q=500)	16000 (Q=500)	7000 (Q=500)	11000 (Q=500)
1.25"		16000 (Q=800)	16000 (Q=800)	16000 (Q=800)	16000 (Q=800)	16000 (Q=800)	16000 (Q=800)

Table 5.8 Summary of maximum intervention depth (ft)) without pumping for group 3 application

CT.OD.	Tubing Size	Well #1	Well #2	Well #3	Well #4	Well #5	Well #6
1"	2.875"	16000	16000	16000	16000	7000	11000
1.25"		16000	16000	16000	16000	16000	16000
1"	3.5"	16000	16000	16000	16000	7000	11000
1.25"		16000	16000	16000	16000	16000	16000

The results of combined pressure-tension stresses are shown in Figures 5.31 – 5.54. The operating envelope is constructed from the tension, compression, burst, collapse and tri-axial limit of the CT. The combined stresses applied on CT are now considered. The plots between differential pressure and axial force are constructed for determination of CT's viability to withstand both hydraulically and mechanically stresses at the same time.

The operating envelope is constructed by tension, compression, burst, collapse and tri-axial limit. The pressure and tension limits are described in Section 3.2.2. These limits are governed by CT properties in Section 4.2.1. There are four quadrants indicate different combined failure mode. The failure modes according to quadrant are burst-tension (Q1), burst-compression (Q2), collapse-compression (Q3) and collapse-tension (Q4). The operating envelopes are different between 1" and 1.25" CT and given by the CT limit discussed in Section 3.2.2. The operating envelope is constructed as following:

Tension rating: Pipe body yield load can be calculated from Eq. 3.32 as below:

1" CT: $\mathrm{PBYL} = \frac{\pi}{4}(1^2 - 0.75^2) \times 80{,}000 = 27{,}490\ lbf$

1.25"CT: $\mathrm{PBYL} = \frac{\pi}{4}(1.25^2 - 0.9^2) \times 80{,}000 = 47{,}280\ lbf$

Burst rating: Internal yield pressure can be calculated as per Eq. 3.35 as below:

1" CT: $\mathrm{P_B} = 2 \times 80{,}000\ \frac{0.12}{1} = 19{,}200\ \mathrm{psi}$

1.25"CT: $\mathrm{P_B} = 2 \times 80{,}000\ \frac{0.17}{1.25} = 21{,}760\ \mathrm{psi}$

Collapse rating: The yield strength collapse pressure can be calculated as per Eq. 3.36 as below:

1" CT: $P_C = 2 \times 80{,}000\ \left[\frac{8.55-1}{(8.55)^2}\right] = 16{,}530\ psi$

1.25" CT: $P_C = 2 \times 80{,}000\ \left[\frac{7.49-1}{(7.49)^2}\right] = 18{,}520\ psi$

For the collapse pressure with the load condition can be calculated from Eq. 3.37 as below:

1” CT 25% PBYL: $P_O = \left[\left({}^{1}/_{1.25}\right)^{4/3} - \left({}^{0.25}/_{1}\right)^{4/3}\right]^{3/4} \times 16{,}530 = 13{,}844\, psi$

1” CT 50% PBYL: $P_O = \left[\left({}^{1}/_{1.25}\right)^{4/3} - \left({}^{0.50}/_{1}\right)^{4/3}\right]^{3/4} \times 16{,}530 = 9{,}298\, psi$

1” CT 75% PBYL: $P_O = \left[\left({}^{1}/_{1.25}\right)^{4/3} - \left({}^{0.75}/_{1}\right)^{4/3}\right]^{3/4} \times 16{,}530 = 2{,}479\, psi$

1.25” CT 25% PBYL: $P_O = \left[\left({}^{1}/_{1.25}\right)^{4/3} - \left({}^{0.25}/_{1}\right)^{4/3}\right]^{3/4} \times 18{,}520 = 15{,}510\, psi$

1.25” CT 50% PBYL: $P_O = \left[\left({}^{1}/_{1.25}\right)^{4/3} - \left({}^{0.50}/_{1}\right)^{4/3}\right]^{3/4} \times 18{,}520 = 10{,}418\, psi$

1.25” CT 75% PBYL: $P_O = \left[\left({}^{1}/_{1.25}\right)^{4/3} - \left({}^{0.75}/_{1}\right)^{4/3}\right]^{3/4} \times 18{,}520 = 2{,}778\, psi$

Triaxial rating: For the tri-axial eclipse, the Eq. 3.42 is used for the calculation the results are shown in Table 5.9 and 5.10 below:

Table 5.9 1” CT tri-axial limit load

Axial Force (lbf)	Burst Yield (psi)	Collapse Yield (psi)
27,490	9476.2	27.2
25000	12025.0	-3382.3
20000	14551.4	-7637.4
15000	15732.8	-10547.3
10000	16153.2	-12696.2
5000	16007.5	-14279.0
0	15375.3	-15375.3
-5000	14279.0	-16007.5
-10000	12696.2	-16153.2
-15000	10547.3	-15732.8
-20000	7637.4	-14551.4
-25000	3382.3	-12025.0
-27,490	-27.2	-9476.2

Table 5.10 1.25” CT tri-axial limit load

Axial Force (lbf)	Burst Yield (psi)	Collapse Yield (psi)
47,280	9752.2	29.0
45000	11638.0	-2328.5
40000	14114.0	-5838.9
35000	15633.7	-8393.0
30000	16636.1	-10429.7
25000	17282.4	-12110.5
20000	17652.8	-13515.2
15000	17792.4	-14689.2
10000	17728.5	-15659.7
5000	17477.5	-16443.1
0	17048.1	-17048.1
-5000	16443.1	-17477.5
-10000	15659.7	-17728.5
-15000	14689.2	-17792.4
-20000	13515.2	-17652.8
-25000	12110.5	-17282.4
-30000	10429.7	-16636.1
-35000	8393.0	-15633.7
-40000	5838.9	-14114.0
-45000	2328.5	-11638.0
-47,280	-29.0	-9752.2

Table 5.11 1” CT limit load

Failure Mode	Rating	Design Factor	Limit Load
Tri-axial	N/A	1.25	N/A
Burst	19,200 psi	1.25	15,360 psi
Collapse	16,530 psi	1	19,200 psi
Axial Tension	27,490 lbf	1.25	21,992 lbf
Axial Compression	27,490 lbf	1.25	21,992 lbf

The design factors given in Section 4.2.4 used for derating and can be summarized into Tables 5.11 and 5.12. It can also be illustrated in pressure-tension plots in Figures 5.33 and 5.34.

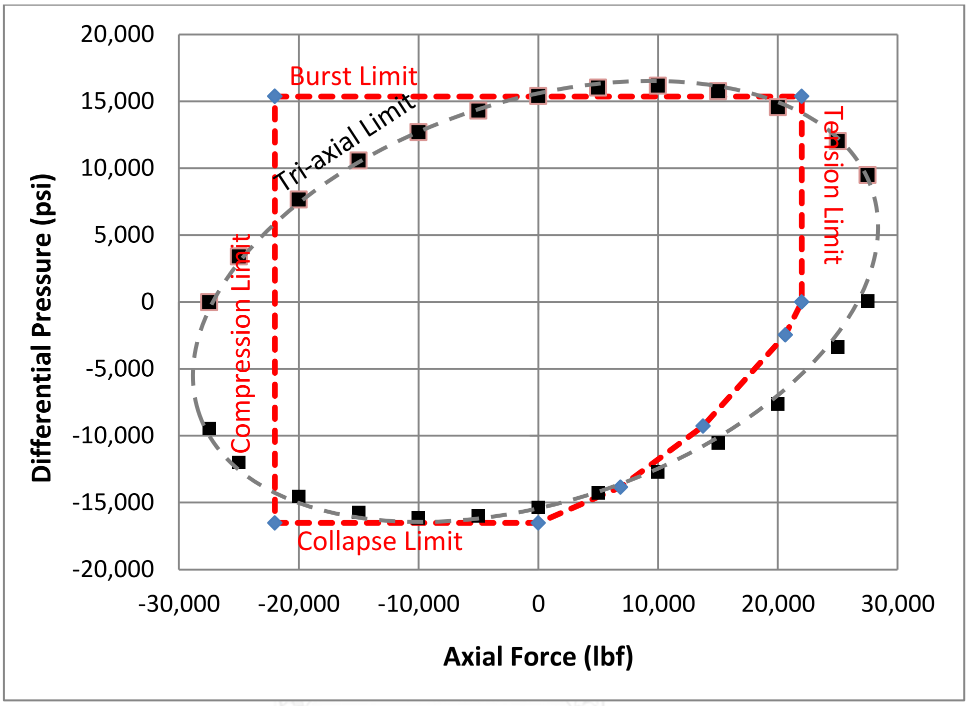


Figure 5.33 Operating envelope for 1” CT

The operating envelope for 1.25”CT is more boarders in axial force limit, whereas the pressure limit is not too different. The higher axial rating is due to the bigger cross sectional area as discussed in Section 4.2.1.

Table 5.12 1.25” CT limit load

Failure Mode	Rating	Design Factor	Limit Load
Tri-axial	N/A	1.25	N/A
Burst	21,760	1.25	17,408
Collapse	18,520	1	21,760
Axial Tension	47,280	1.25	37,824
Axial Compression	47,280	1.25	37,824

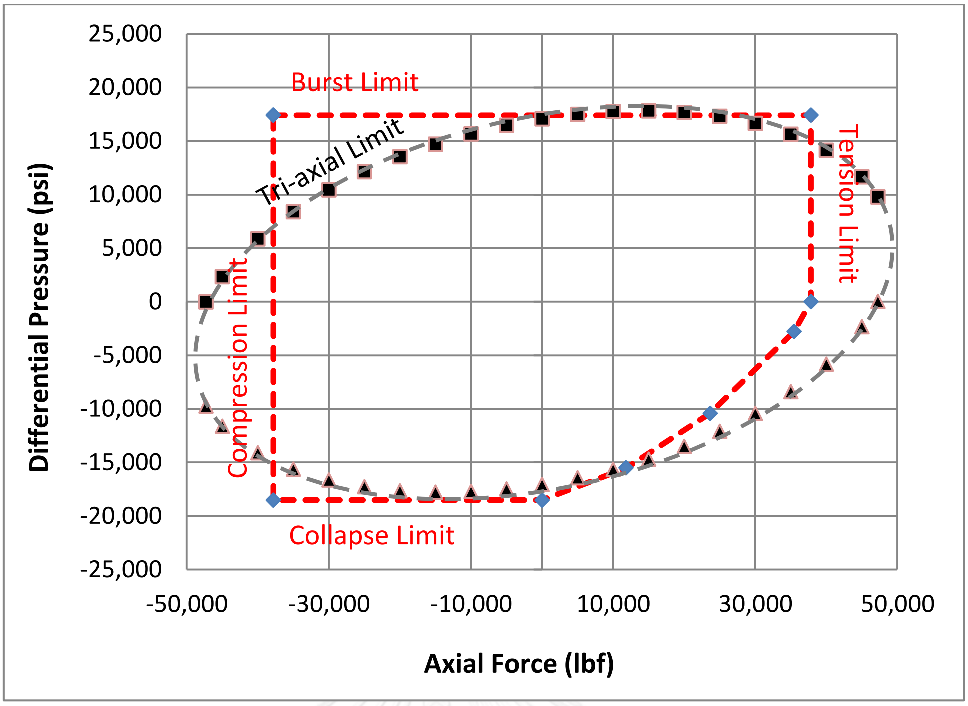


Figure 5.34 Operating envelope for 1.25” CT

The operating envelopes are plot together with the pressure-tension for each group application in all scenarios (illustrated in Figures 5.35 – 5.57). The pressure-tension conditions for group 1, 2 and 3 are shown in blue line, green line and orange line, respectively. It can be seen that all the operation can perform within load limit after depth adjusted. In addition, all group of application are mainly operating in the first quadrant region (i.e. burst-tension).

Figure 5.35 describes the operating condition for 16,000 ft of 1”CT in Well #1 with 2.875” tubing. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 at around 9,000 psi in the surface section. The differential pressure is much lower in the surface section at around 5,100 psi for application in group 2. The lower slope of operating condition for group is due to lesser frictional pressure loss inside CT. The internal and external pressures for application in group 3 are the same due to no pumping requirement for the applications. The surface axial forces in all groups are highest at around 16 kips in tensile. The CT in the bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at around 2 kips in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

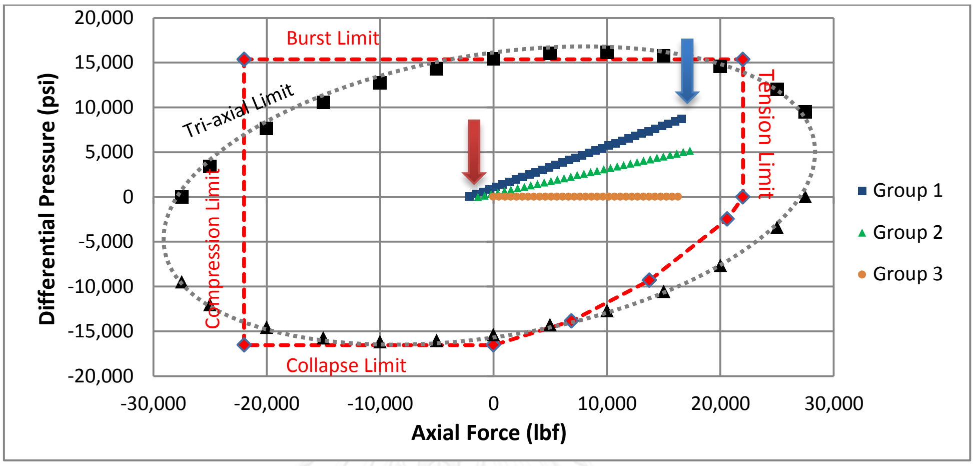


Figure 5.35 Operating envelope for 1” CT in Well #1 with 2.875” tubing

Figure 5.36 describes the operating condition for 16,000 ft of 1”CT in Well #2 with 2.875” tubing. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 at around 11,000 psi in the surface section. The differential pressure is much lower in the surface section at around 5,000 psi for application in group 2. The internal and external pressures for application in group 3 are the same, due to no pumping requirement for the applications. The surface axial forces in all groups are highest at around 16 kips in tensile. The CT section at the KOP is marked with green arrow. The small hicup can be noticed at this point. This is due to the change of wellbore inclination resulted in the lesser axial force below KOP. The increases of the slope toward the bottom section imply the rate of reducing in axial force is higher than rate of reducing pressure. The CT in the bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at around 2 Kips in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

Figure 5.37 describes the operating condition for 16,000 ft of 1”CT in Well #3 with 2.875” tubing. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 at around 13,600 psi in the surface section. The differential pressure is much lower in the surface section at around 4,600 psi for application in group 2. The internal and external pressures for application in group 3 are the same, due to no pumping requirement for the applications. The surface axial forces in all groups are highest at around 14.5 kips in tensile. The CT section at the KOP is marked with green arrow. The small hicup can be noticed at this point. This is due to the change of wellbore inclination resulted in the lesser axial force below KOP. The increases of the slope toward the bottom section imply the rate of reducing in axial force is higher than rate of reducing pressure. The CT in bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at around 2 Kips in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

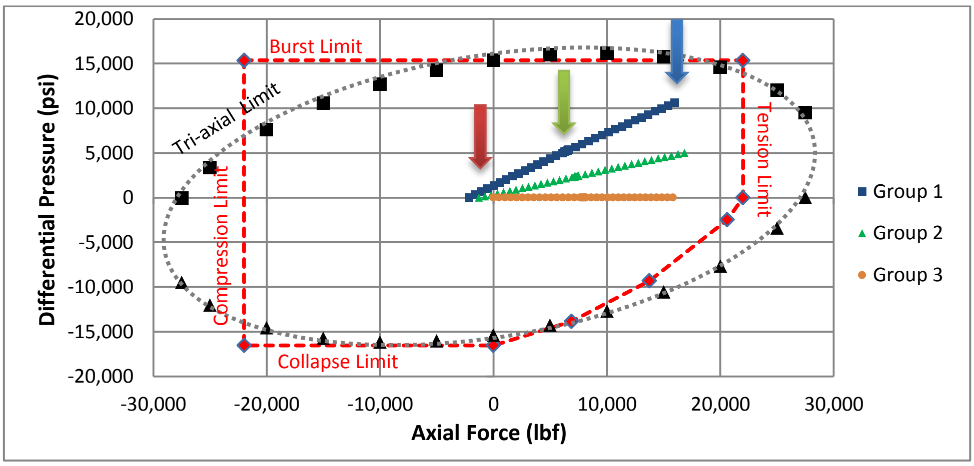


Figure 5.36 Operating envelope for 1” CT in Well #2 with 2.875” tubing

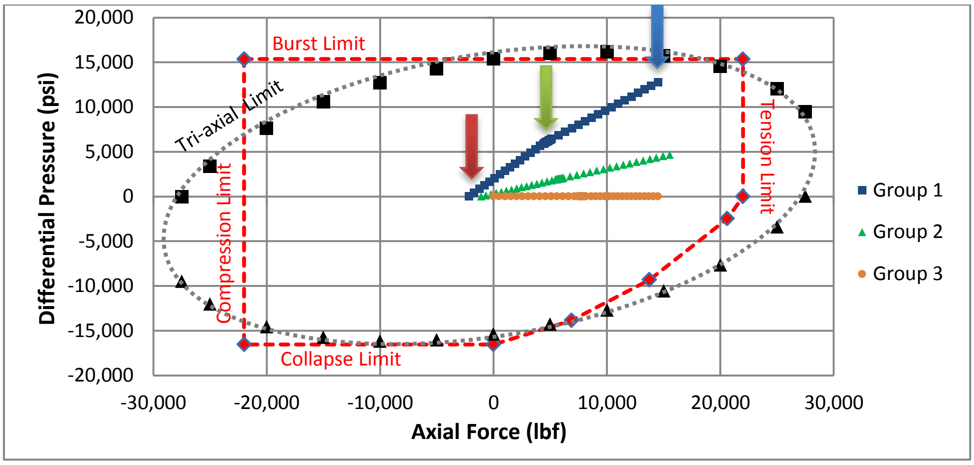


Figure 5.37 Operating envelope for 1” CT in Well #3 with 2.875” tubing

Figure 5.38 describes the operating condition for of 1”CT in Well #4 with 2.875” tubing. The maximum depth for Group 1 application is at 15,000 ft for the critical pumping rate at 30 gpm. The maximum depths for group 2 and 3 are at 16,000 ft. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 at around 15,000 psi in the surface section. The differential pressure is much lower in the surface section at around 3,900 psi for application in group 2. The internal and external pressures for application in group 3 are the same, due to no pumping requirement for the applications. The surface axial forces in all groups are highest at around 12 kips in tensile mode. The CT section at the KOP is marked with green arrow. The small hicup can be noticed at this point. This is due to the change of wellbore inclination resulted in the lesser axial force below KOP. The increases of the slope toward the bottom section imply the rate of reducing in axial force is higher than rate of reducing pressure. The CT in the bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at around 2 Kips in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

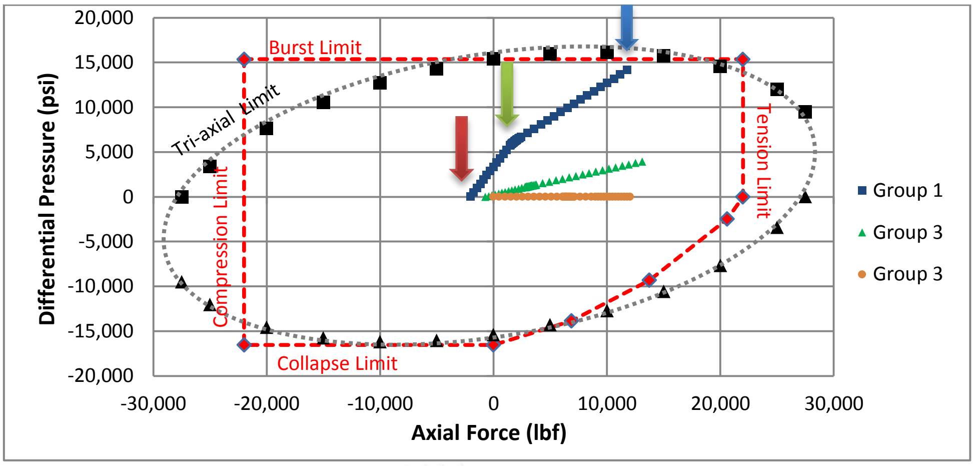


Figure 5.38 Operating envelope for 1” CT in Well #4 with 2.875” tubing

Figure 5.39 describes the operating condition for 7,000 ft of 1”CT in Well #5 with 2.875” tubing. The maximum depths for all groups are limited to this depth due to the buckling of CT as discussed earlier. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 at around 4,000 psi in the surface section. The differential pressure is much lower in the surface section at around 2,400 psi for application in group 2. The internal and external pressures for application in group 3 are the same, due to no pumping requirement for the applications. The surface axial forces in all groups are highest at around 7.2 kips in tensile. The CT in the bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at around 1 Kips in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

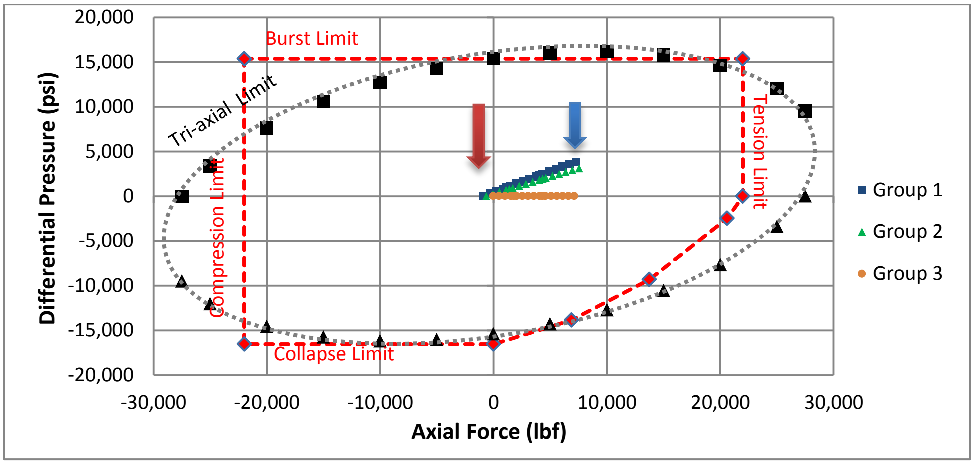


Figure 5.39 Operating envelope for 1" CT in Well #5 with 2.875" tubing

Figure 5.40 describes the operating condition for 11,000 ft of 1"CT in Well #6 with 2.875" tubing. The maximum depths for all groups are limited to this depth due to the buckling of CT as discussed earlier. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 at around 7,500 psi in the surface section. The differential pressure is much lower in the surface section at around 2,400 psi for application in group 2. The internal and external pressures for application in group 3 are the same, due to no pumping requirement for the applications. The surface axial forces in all groups are highest at around 12 kips in tensile. The CT in the bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at around 1 Kips in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

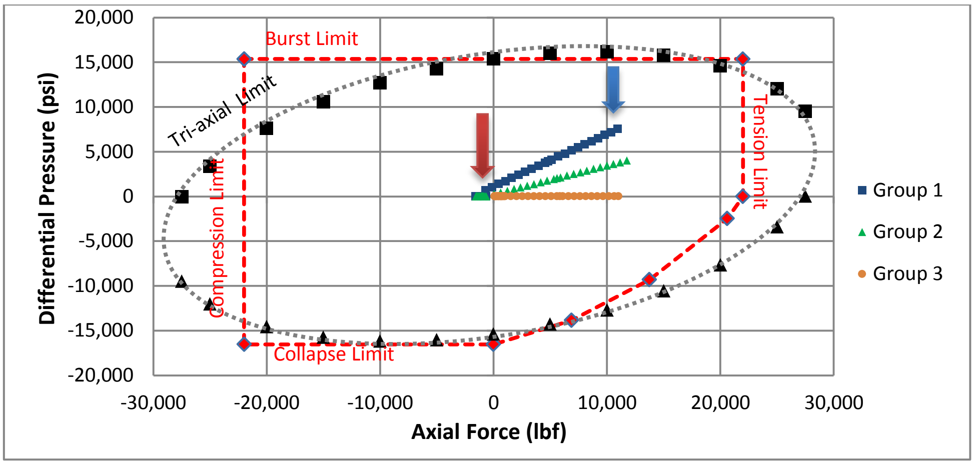


Figure 5.40 Operating envelope for 1” CT in Well #6 with 2.875” tubing

Figure 5.41 describes the operating condition for 8,500 ft of 1”CT in Well #1 with 3.5” tubing. The maximum depth for application in group 1 is limited to this depth due to the excessive pressure loss as discussed earlier. The maximum depths for group 2 and 3 are at 16,000 ft as no concern of pumping pressure. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 at around 15,000 psi in the surface section. The differential pressure is much lower in the surface section at around 6,000 psi for application in group 2. The internal and external pressures for application in group 3 are the same, due to no pumping requirement for the applications. The surface axial forces in all groups are highest for group 2 and 3 at around 17 kips in tensile. The CT in the bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at around 1 Kips in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

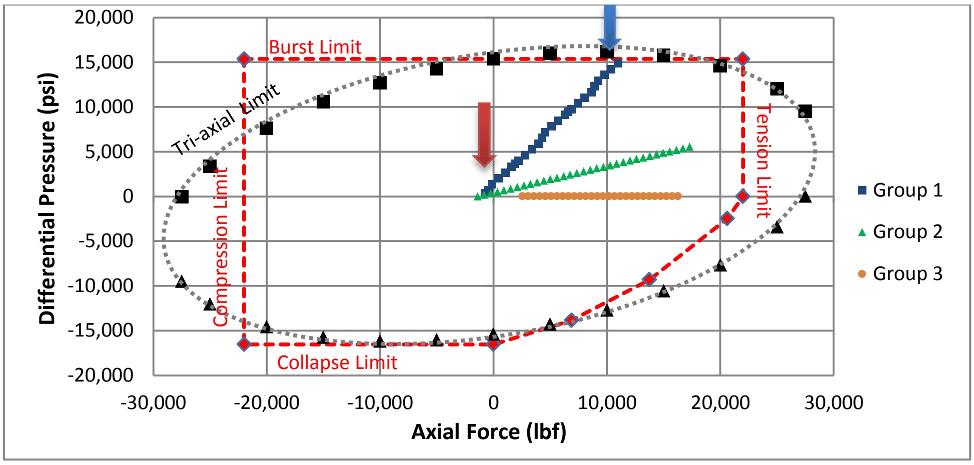


Figure 5.41 Operating envelope for 1” CT in Well #1 with 3.5” tubing

Figures 5.42 -5.44 describe the operating condition for 7,200 ft of 1”CT in Well #2-4 with 3.5” tubing. The maximum depth for application in group 1 is limited to this depth due to the excessive pressure loss as discussed earlier. The maximum depths for group 2 and 3 are at 16,000 ft as no concern of pumping pressure. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 at around 15,000 psi in the surface section. The differential pressure is much lower in the surface section at around 5,000 psi for application in group 2. The internal and external pressures for application in group 3 are the same, due to no pumping requirement for the applications. The surface axial forces in all groups are highest for group 2 and 3 at around 13-17 kips in tensile. The CT in the bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at around 1 Kips in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

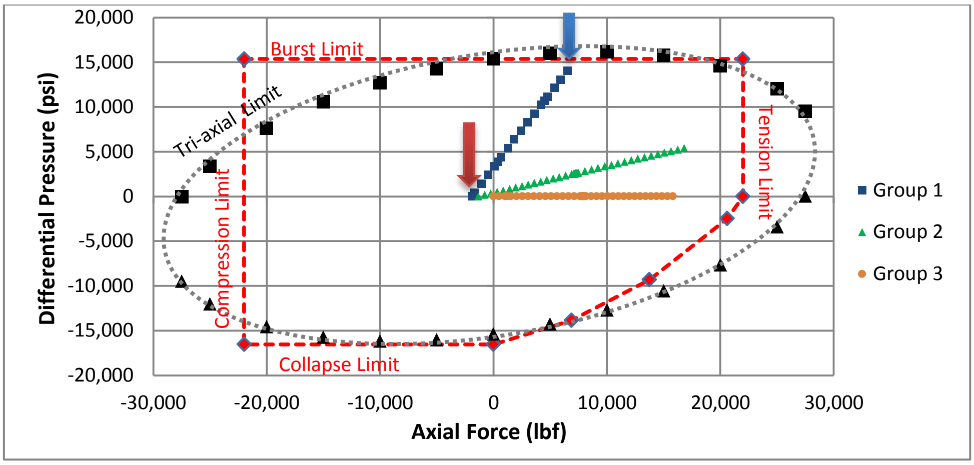


Figure 5.42 Operating envelope for 1” CT in Well #2 with 3.5” tubing

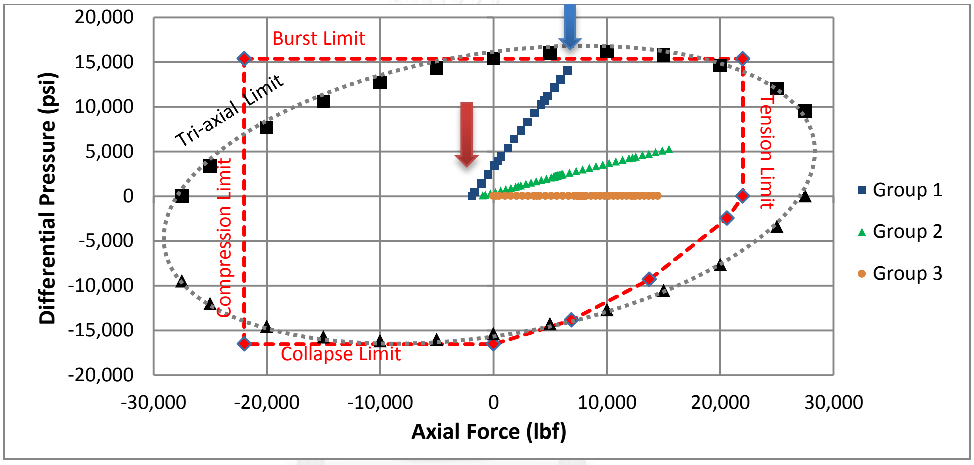


Figure 5.43 Operating envelope for 1” CT in Well #3 with 3.5” tubing

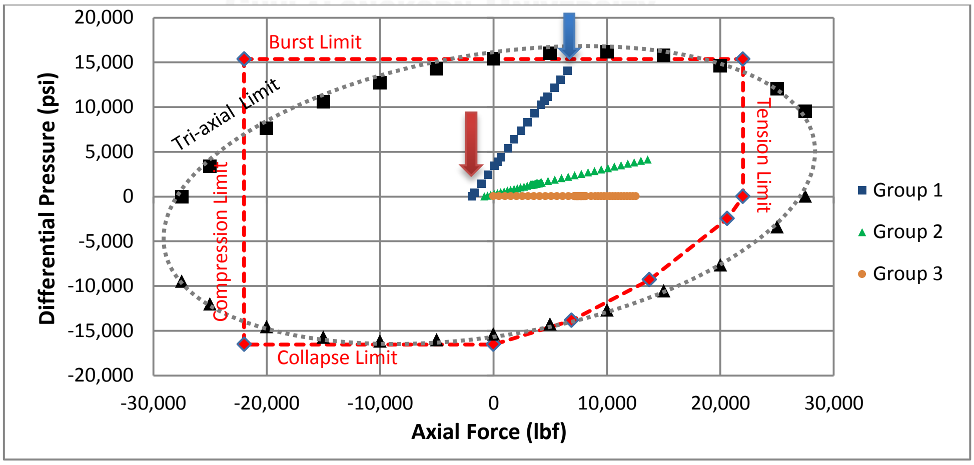


Figure 5.44 Operating envelope for 1” CT in Well #4 with 3.5” tubing

Figures 5.45 -5.46 describe the operating conditions for 7,000 and 11,000 ft of 1”CT in Well #5 – 6, respectively. The maximum depths for all groups are limited to this depth due to the buckling of CT as discussed earlier. The pressure-tension plots in all groups of application are within the operating envelope.

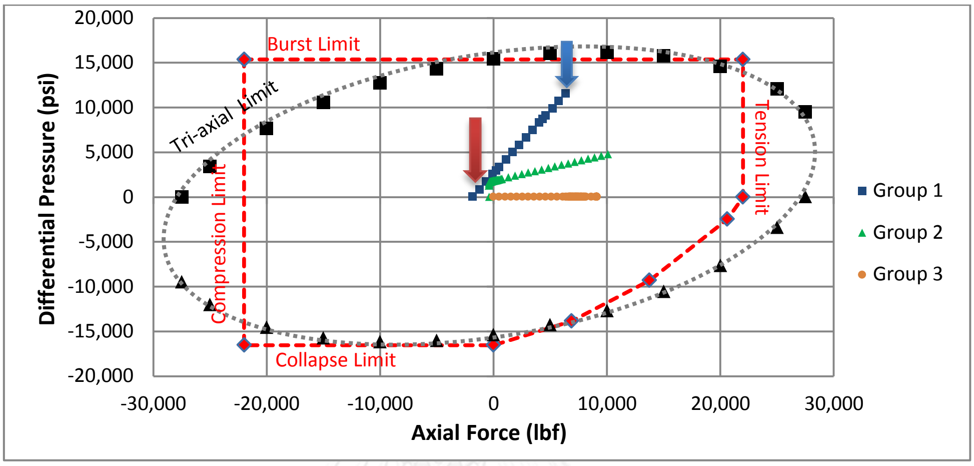


Figure 5.45 Operating envelope for 1” CT in Well #5 with 3.5” tubing

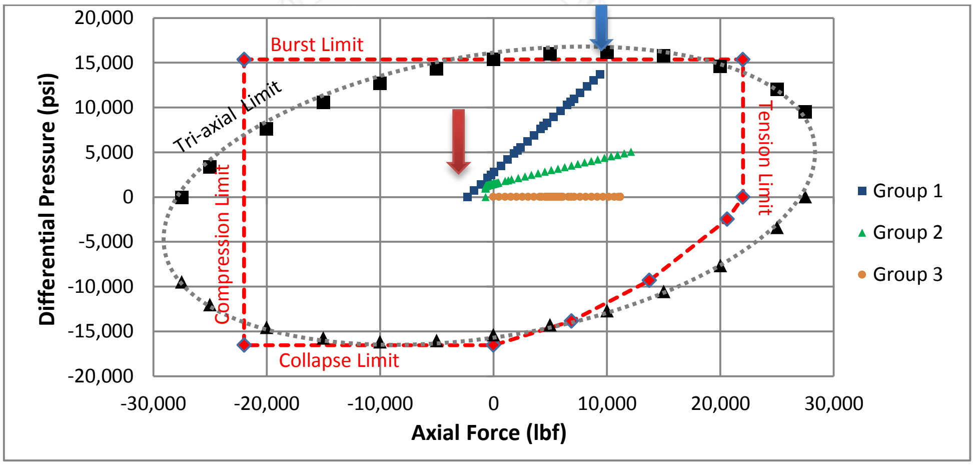


Figure 5.46 Operating envelope for 1” CT in Well #6 with 3.5” tubing

Figures 5.47 -5.58 describe the operating conditions of 1.25”CT in all well scenarios. The maximum depths for all groups are at the total depth (i.e.16,000 ft) as there is no constraint on the burst and buckling limit. The surface section is marked with blue arrow. The differential pressure is highest with application in group 1 in surface section. The differential pressure is much lower in the surface section for application in group 2. The internal and external pressures for application in group 3 are the same, due to no pumping requirement for the applications. The surface axial forces in all groups are highest and in tensile mode. The CT section at the KOP is marked with green arrow. The small hicup can be noticed at this point. This is due to the change of wellbore inclination resulted in the lesser axial force below KOP. The increases of the slope toward the bottom section imply the rate of reducing in axial force is higher than rate of reducing pressure. The CT in the bottom most section is marked with red arrow. The differential pressures are the same at zero psi. The CT is slightly in compression at in the bottom section of the well for application in group 1 and 2 due to the effect of fluid pressure applied on the cross-sectional area of BHA (F_{Bottom}). The pressure-tension plots in all groups of application are within the operating envelope.

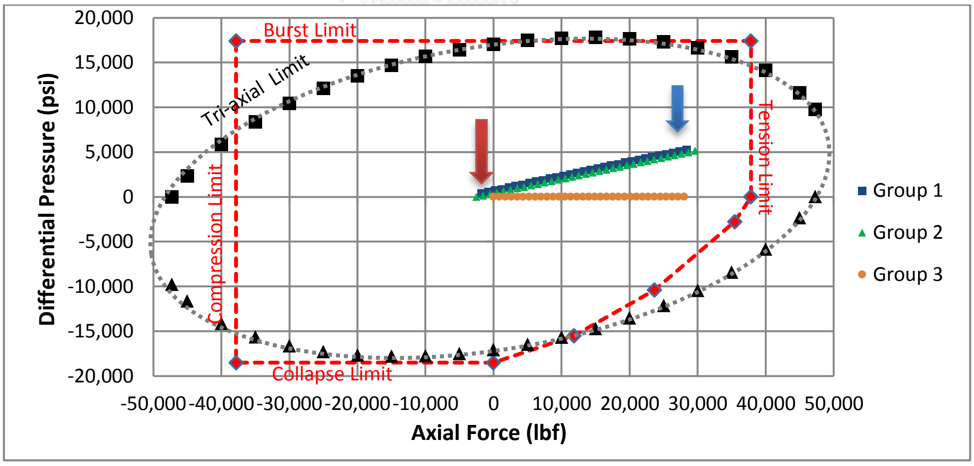


Figure 5.47 Operating envelope for 1.25” CT in Well #1 with 2.875” tubing

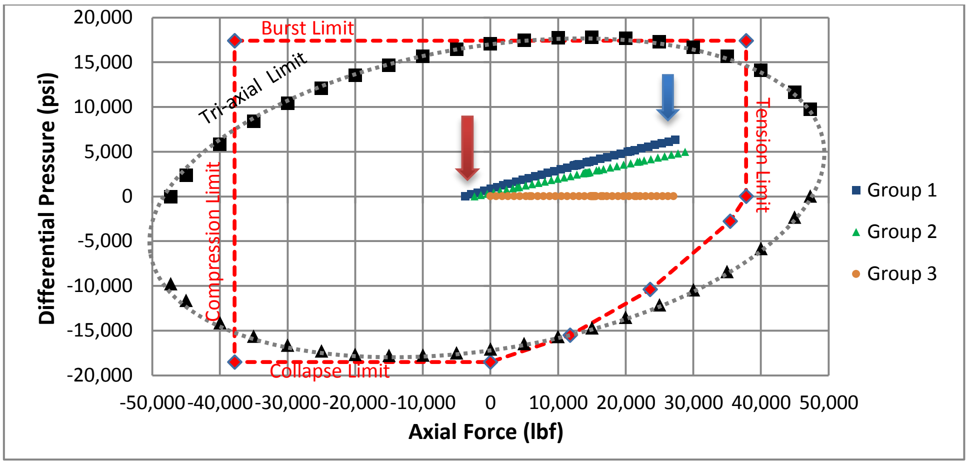


Figure 5.48 Operating envelope for 1.25” CT in Well #2 with 2.875” tubing

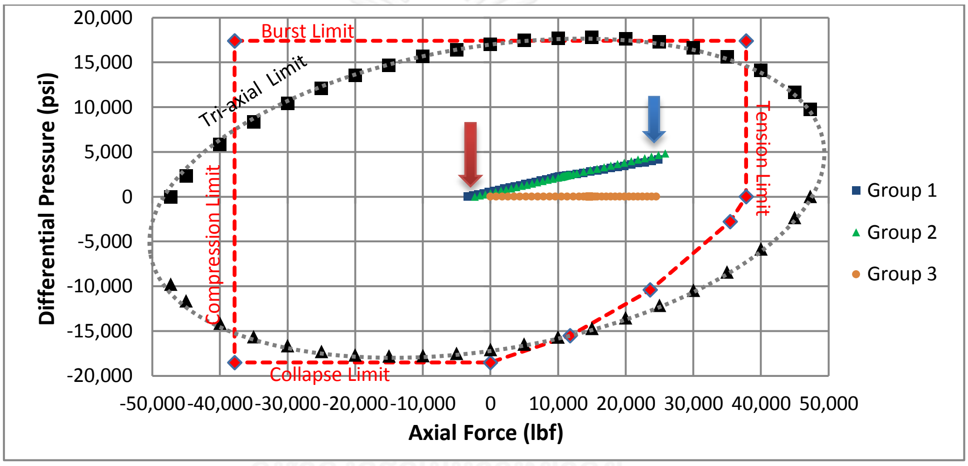


Figure 5.49 Operating envelope for 1.25” CT in Well #3 with 2.875” tubing

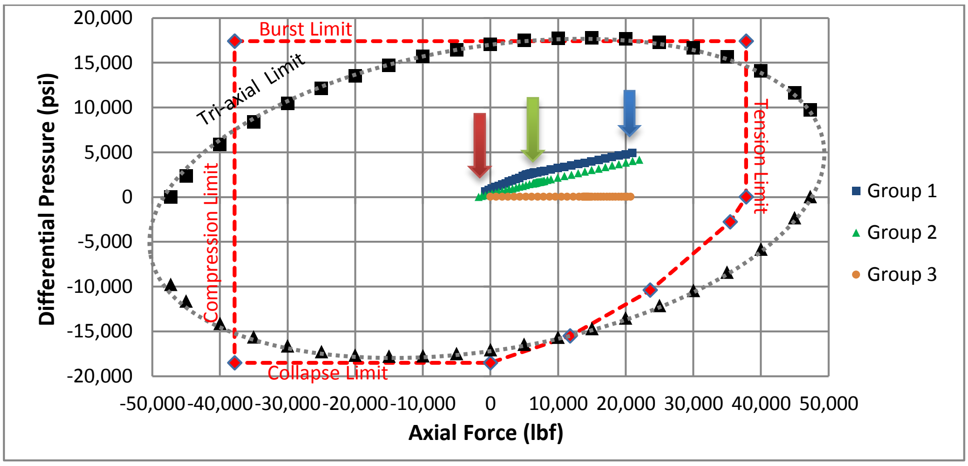


Figure 5.50 Operating envelope for 1.25” CT in Well #4 with 2.875” tubing

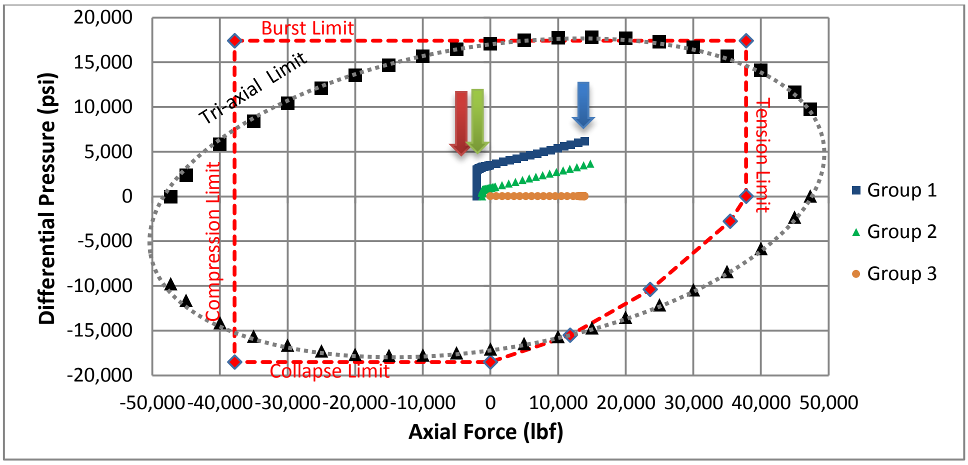


Figure 5.51 Operating envelope for 1.25” CT in Well #5 with 2.875” tubing

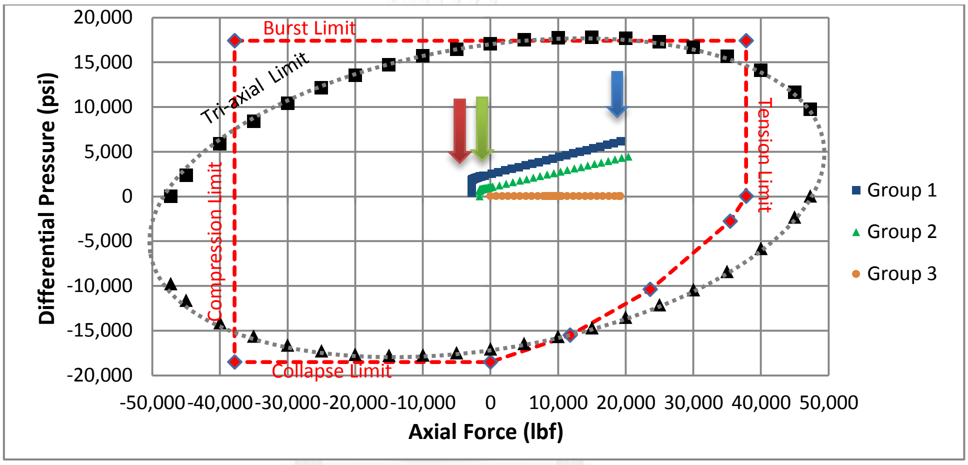


Figure 5.52 Operating envelope for 1.25” CT in Well #6 with 2.875” tubing

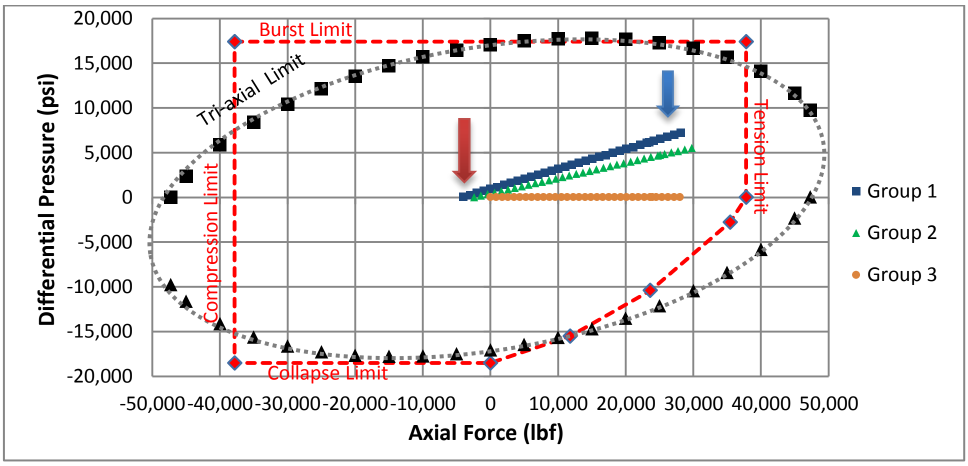


Figure 5.53 Operating envelope for 1.25” CT in Well #1 with 3.5” tubing

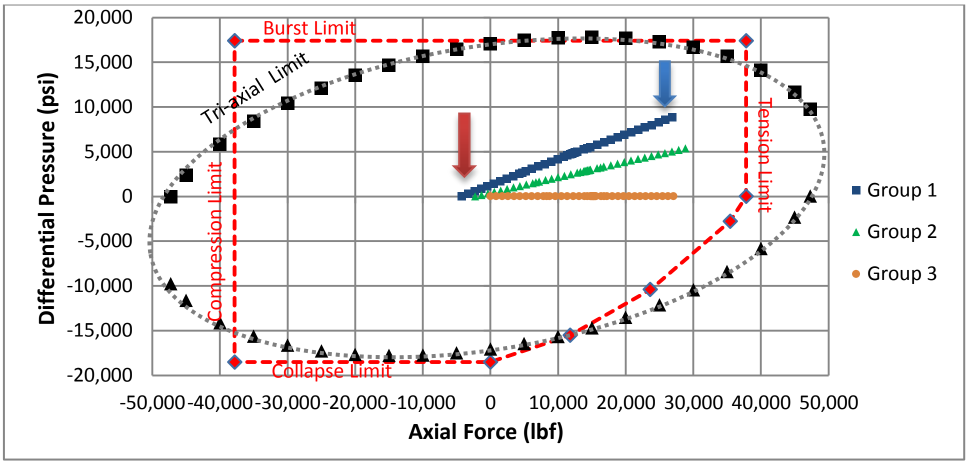


Figure 5.54 Operating envelope for 1.25” CT in Well #2 with 3.5” tubing

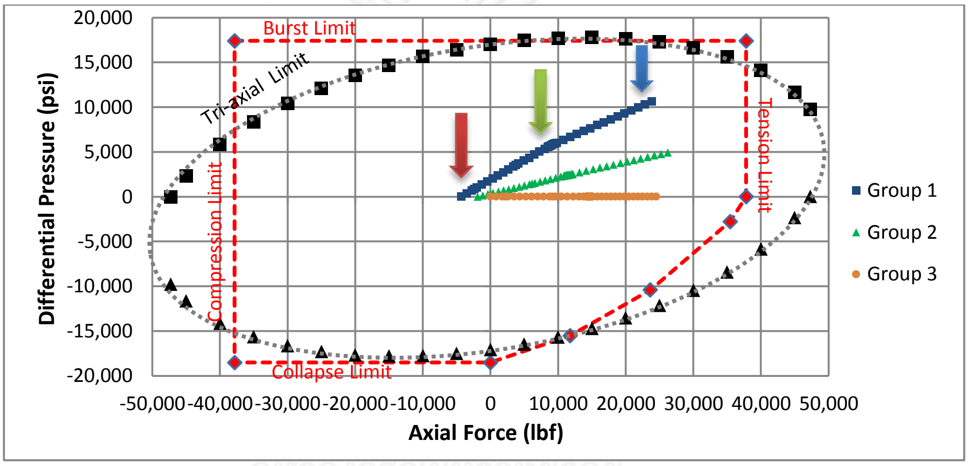


Figure 5.55 Operating envelope for 1.25” CT in Well #3 with 3.5” tubing

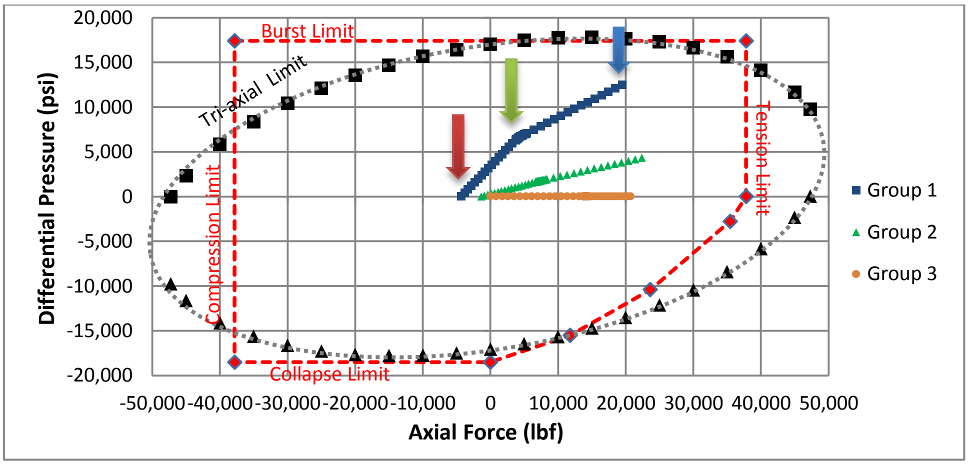


Figure 5.56 Operating envelope for 1.25” CT in Well #4 with 3.5” tubing

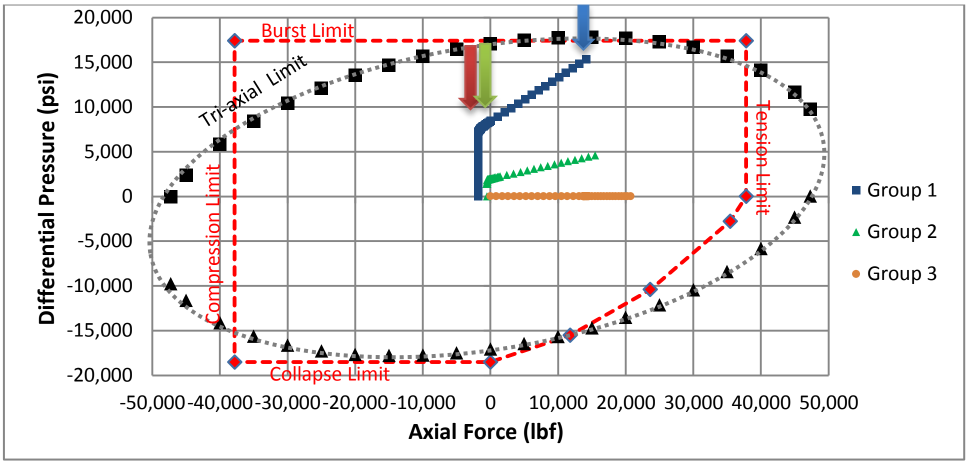


Figure 5.57 Operating envelope for 1.25” CT in Well #5 with 3.5” tubing

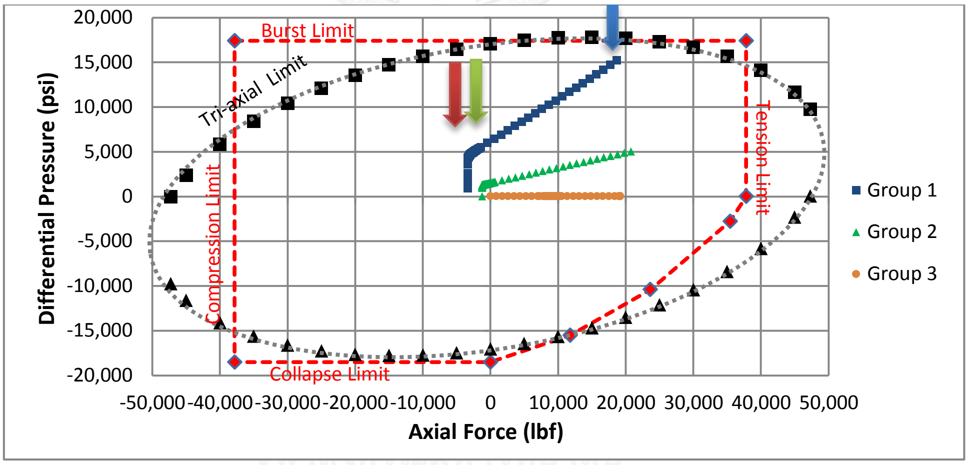


Figure 5.58 Operating envelope for 1.25” CT in Well #6 with 3.5” tubing

The group 1 application has potential to reach the burst failure mode. The burst failure mode can happen to uphole section of CT. The effective differential pressure (i.e. difference between internal and external pressures) is highest at this section. The internal pressure is as high as pump pressure. The external pressure is as low as zero on the return to surface. The pressure inside the CT then losses along the string and will be lower at the bottom hole section. The effective differential becomes zero at the bottom most assembly inside the nozzles. The axial force has the similar trend to the differential pressure. The uphole section of CT carries the entire weight of string below. Therefore, the tension is highest at uphole section of CT. The lower weight can be expected for the CT sections place deeper in the hole.

The application in group 2 has the lower requirement in pumping pressure. It can be seen that the differential pressure is much lower than the burst limit. The CT is in burst failure mode for uphole section where the pump pressure is dominant. The collapse failure mode occurs for the downhole section due higher hydrostatic pressure outside CT.

The application in group 3 has no pumping requirement. Therefore, the differential pressure is zero. As a result, the line is straight and not deviated from x-axis in operating envelope plot.

5.2.4 Viable applications

The main contributor to the system pressure loss is pressure loss inside CT. The pressure loss in CT comprises of the pressure drop in CT reel (i.e. surface pressure loss) and CT section in hole. There are 3 parameters that affect the magnitude of pressure drop inside CT which are the pump rate, the internal flow area of CT and the length of CT section. The internal flow area and length of the CT is specified in this study. 1" CT has disadvantage on higher demand of the critical flow rate and hence higher pump rate. For a given size of completion tubing, the annulus area is smaller with 1.25" CT. Hence, less flow rate is required for 1.25"CT to affect the well cleanout. On another aspect, for the same size of CT, the higher flow rate will be required for the larger size of completion. 1" CT has severe problem on pressure loss for solid cleanout application in several scenarios (Well #4 to Well #6 with 2.875" tubing and Well #1 to Well #6 with 3.5" tubing).

For a given CT.ID., the pressure loss can be minimized by shallowing the intervention depth. This depth adjustment will automatically lower the critical flow rate. The 1" CT. OD. cannot meet the solid cleanout requirement at total depth in 3.5" tubing and horizontal well with 2.875" tubing. The reason is solely the critical rate cannot be achieved within internal yield pressure. In contrast, 1.25"CT is viable for solid cleanout in all well scenarios.

In summary, 1" CT cannot deliver the required flow rate at total depth in 9 out of 12 well scenarios. The pump pressure cannot be maintained below 80% of internal yield pressure. 1. However, the pressure loss for applications in group 2 is relatively lower than applications in group 1. Therefore, 1” CT is hydraulically viable for this application. Nevertheless, the limitation is resided in the runability of 1” CT.

For the runability of 1”CT, the run in weight (RIW) in horizontal well (Well #5 and #6) is the most concern for the runability of CT to well’s total depth. The RIW of 1” CT in Well#5 is beyond buckling limit in both 2.875” and 3.5” completion. This could cause CT to be locked up and damage the CT. Therefore, 1” CT is not suitable to intervene horizontal well where the buildup section is shallow. Similarly, run in weight of 1” CT in Well #6 is very close to buckling limit. The mitigation of this problem is discussed earlier using the friction reducer and high strength CT. 1.

In summary, the 1” CT is not suitable for hydraulic applications in 3.5” tubing wells. This is because large annuli flow area (i.e. between 1”CT and 3.5” tubing) requires 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. Nevertheless, to use 1”CT in these well are risky and 1.25”CT are recommended to be used. The effective tensions along the 1.25”CT in horizontal well (Well #5 and #6) with 2.875” and 3.5”are better than the 1”CT’s performance and stay within limit. Therefore, 1.25” CT are more viable for the operation in horizontal well.

The 72 scenarios are verified with the operating envelope shown in Section 5.2.2. The summary table shown in Table 5.13 illustrates the possible smallest size of CT for each applications and well type. The table also shows the maximum allowable operating conditions for each group for a given size of CT. Liquid rate (gpm), Gas rate (scf/m), Push/Pull capacity (kips) are depicted for group 1-3, respectively.

Table 5.13 Summary of recommended CT size and maximum achievable operating conditions

Tubing Size	Applications	Well #					
		1	2	3	4	5	6
2.875”	**Group1:** Milling and Sand cleanout	Q_L 22	Q_L 25	Q_L 27	Q_L 26	Q_L 30	Q_L 30
	Group2: Well unloading and stimulation	Q_g 400	Q_g 400	Q_g 400	Q_g 400	Q_g 600	Q_g 600
	Group3: Fishing, Logging and perforation	Push/Pull 0.1/5.8	Push/Pull 1.1/5.8	Push/Pull 1.6/6.8	Push/Pull 1.7/8.8	Push/Pull 4.4/13	Push/Pull 4.4/10
3.5”	**Group1:** Milling and Sand cleanout	Q_L 33	Q_L 36	Q_L 40	Q_L 44	Q_L 49	Q_L 49
	Group2: Well unloading and stimulation	Q_g 500	Q_g 500	Q_g 500	Q_g 500	Q_g 800	Q_g 800
	Group3: Fishing, Logging and perforation	Push/Pull 0.1/9.9	Push/Pull 1/9.8	Push/Pull 1.2/12	Push/Pull 1.4/15	Push/Pull 3.7/23	Push/Pull 3.7/18

1” CT can services to the total depth

1.25” CT can services to the total depth

CHAPTER VI
CONCLUSION AND RECOMMENDATION

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

1. When comparing the critical flow rate between 1” and 1.25” CT, the smaller CT has slightly higher liquid flow requirement to affect cleanout. However, it requires smaller amount of gas flow requirement to affect the well unloading. The lowest bottom hole pressure for well unloading can be attained when pumping at the optimum gas rate. Further increment of gas injection beyond this point will result in excessive pressure loss. The well trajectory, tubing size and CT size affect the flow rate. Annular flow area and the inclination of well bore play an important role in hydraulic requirement. The higher critical flow rate is required for high inclination and larger completion size to affect cleanout and well unloading.
2. There are 2 factors affecting the lesser system pressure loss when CT is utilized in shallower depth. The first effect is the lower of pump rate. The pump rate requirement is lower for the shallower depth of intervention. The second effect is the shorter annular flow path, hence lesser pressure loss inside the annulus. The system pressure loss of 1” CT inside the 3.5” tubing is high due to the requirement of high velocity. The lowering of pump rate has to trade off with intervention depth. The system pressure loss of 1”CT inside the 2.875” tubing are exceeding 80% yield in Well #4, Well #5 and Well #6. The CT pressure loss is considered constant for the same size of CT, pump rate and fixed length. Consequently, pressure loss inside the annulus must be lowered in order to meet the pressure limit. Therefore, it is the limitation of CT depth to perform the job.
3. For the application in group 1, the 1” CT can be used in both tubing sizes for Well #1 to Well #4. The Well #5 to Well #6 required the larger CT to perform

the application. The use of 1” CT in 3.5” tubing is in contradiction to the usage of 1” CT in 2.875” tubing. The use is very limited to the depth shallower than the kick-off depth and impermissible in deeper section of the well due to the excessive pressure losses.

4. For the application in group 2, the 1” CT can deliver the required optimum gas rate without jeopardize the burst limitation. However, the depth of intervention for this group of application is limited by the runability of the CT itself rather than the hydraulic limit. Therefore, 1” CT is able to service in all sizes of tubing for the Well #1 to Well#4 and at the limited depth shallower than the kick-off depth for Well #5 and well #6.

5. The effective tension is used for runability evaluation. The CT size, wellbore inclination, tripping speed, coefficient of friction and side force contribute to the magnitude of the effective tension. Although the tubing size does not affect the axial force, but it has small effect on the buckling limit. The effective tension is decreased when the inclination increase. This is simply explained by the reduced in weight along section. It can be observed that the well with 90 degree wellbore inclination have significantly lower effective tension than any other cases. More comparison between Well #5 and Well #6 where the vertical depth in Well #6 is deeper, resulting in lesser inclined section and hence higher effective tension.

6. There is no effect of drag force was observed in Well #1. Therefore, the effective tensions are the same for both directions. Unlike the case in Well #2-6, where separation of run in weight and pick up weight can be noticed, especially for CT in buildup angle section. In all cases, the run in weight and pick up weight are almost the same for CT section near well’s total depth due to minimal drag force occurs. The use of friction reducer fluid to lesser the coefficient of friction is a valid mitigation for the well scenario that anticipates the high drag force. The use of higher strength CT with lower weight does reduce the side force, drag force and effective tension. Moreover, the buckling limit is also reduced with higher strength CT.

7. By the variation of well bore inclination, increasing inclination favors the push/pull capacity. It can be seen higher pushing capacity as the well bore inclination increase and flattening for inclination higher than 60 deg. The pulling capacity is exponentially increased for inclination higher than 40 deg. Regarding of kick-off depth, variation of kick-off depth result in no alteration of pushing capacity. In contrast, the increment of the kick-off depth lowers pulling capability.
8. For the application in group 3, the 1” CT can be used in both tubing sizes for Well #1 to Well #4. The Well #5 to Well #6 required the larger CT to perform the application. This is due to the runability problem. However, the push/pull capacity is limited for low inclination well with 1” CT. Hence, the use of 1”CT for pulling or pushing long fish or long logging toolstring which could anticipate the high drag force need to be strictly reviewed for case by case basis.

This integrated study is based on computer simulation in broad aspect of well engineering. The study is limited to only the evaluation of “brand new Coiled Tubing” at which the derating effect of used Coiled Tubing are not incorporate. The derating effect recommended by American Petroleum Institute [22] such as ovality, CT life and corrosion are not in the scope of this study. The use of small size CT is recommended for many well scenarios. In pragmatic, the well scenarios are more complex with many complication factors such as:

- Completion types, i.e. multi-zone completion, sand control completion, etc.
- More complex well paths with 3 dimensional aspect
- Unexpected wellbore conditions, scales or sand which introduce more drag force during tripping

Although, in practical cases may not be as simple as shown in this study. Nevertheless, the same study approach can be used as the guideline for evaluation on the use of small CT.

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