Tripping Operations in Hydrostatically Overbalanced Wells

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Contents

Introduction ii

1 Scope 1

2 Normative References 1

3 Terms, Definitions, and Abbreviations 1
3.1 Terms and Definitions 1
3.2 Abbreviations 7

4 Tripping Operations Overview 7

5 Planning 8
5.1 General 8
5.2 Risk Assessment 8
5.3 Contingency Plans 9

6 Equipment 9
6.1 General 9
6.2 Valves 11
6.3 Rotating Control Devices 11
6.4 Trip Tanks 11
6.5 Mud Buckets 12
6.6 Alarms 12

7 Volume Management 13
7.1 General 13
7.2 Drilling Fluid Considerations 13
7.3 Fluid Transfers 14
7.4 Trip Sheets 14

8 Well Control 15
8.1 General 15
8.2 Well Barrier Elements 16
8.3 Kick Indicators 16
8.4 Trip Margins 17
8.5 Flow Checks 17

9 Tripping Operational Guidelines 18
9.1 General 18
9.2 Training 19
9.3 Conventional Tripping Operations 19

Bibliography 22

Introduction

These guidelines (recommended practices) represent a composite of the practices employed by various operating companies, service companies, and drilling contractors in overbalanced tripping operations. In some cases, a reconciled composite of the various practices employed by these companies was utilized.

Recommended practices set forth herein are considered acceptable for accomplishing the job as described; however, they do not present all the operational practices that can be employed to accomplish the same objectives. Individuals and organizations using this standard are cautioned that operations must comply with requirements of federal, state, or local regulations. These requirements should be reviewed to determine whether violations can occur.

The objective of these guidelines (recommended practices) within is to assist the oil and gas industry in promoting personnel safety, public safety, wellbore integrity, and preservation of the environment for land drilling operations.

It provides information and guidance on procedures related to tripping activities in overbalanced wells, which have inherent hazards and risks within the operation(s) and therefore require detailed care and attention to improve reliability and reduce risk to acceptable levels. The principles and recommendations have general relevance, regardless of classification, and are applicable to onshore tripping operations.

Competent and technical judgment must be used in combination with these recommendations. Each operator, service provider, and drilling contractor involved in tripping operations should review and apply these guidelines (recommended practices) according to their own policies and procedures.

Overbalanced tripping operations are being conducted with full regard for personnel safety, public safety, and preservation of the environment in such diverse conditions as urban sites, wilderness areas, very hot barren deserts, cold weather areas including the arctic environment, and wildlife refuges. As tools and equipment continually improve and develop, the technology has been applied in many geologic formations, including oil and gas reservoirs and on sour wells, thus driving the need for globally accepted standards and safe operating best practices.

This purpose of this document is to provide information and to recommend practices and procedures for planning, equipment considerations, and execution of tripping operations in overbalanced wells. It is also intended to assist operators, service providers, and drilling contractors in developing their own internal rig-specific procedures for safe tripping operations.

Tripping Operations in Hydrostatically Overbalanced Wells

1 Scope

This document provides guidelines for onshore tripping operations when the well is hydrostatically overbalanced using a fluid column without supplemental surface pressure to control inflow.

This document applies to land drilling rigs with and without surface blowout preventers (BOPs) installed for land drilling operations.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata).

API Standard 53, *Well Control Equipment Systems for Drilling Wells*

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

For the purposes of this recommended practice the following definitions apply.

3.1.1
accumulator
Pressure vessel charged with inert gas and used to store hydraulic fluid under pressure.

3.1.2
alarm
An audible and/or visual indication to the user that an equipment malfunction, process deviation or other abnormal condition requires a prompt response from the user.

3.1.3
alarm flooding
An alarming condition determined by the user, during which the alarm rate is greater than the user's ability to effectively manage.

3.1.4
alarm shelving
The ability for the user to temporarily prevent the audible and/or visual reporting of an active alarm for a period of time.

3.1.5
alarm suppression
The ability for the user to inhibit audible and/or visual reporting of an alarm.

3.1.6
annulus
annular
Space between the outer diameter of the drill string and the inside diameter of the hole being drilled, the last string of casing set in the well.

3.1.7
blowout
An uncontrolled flow of well fluids, formation fluids, or both, from the wellbore.

NOTE An uncontrolled flow underground is also considered a blowout.

3.1.8
blowout preventer
BOP
Sealing ram or annular type device, which is within the scope of API 16A, installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars or in an open hole during well drilling, completion, and testing operations.

3.1.9
well control drill
A training method to determine that rig crews are familiar with operating practices to be followed in the use of blowout prevention equipment. A “dry run” of blowout preventive action.

3.1.10
bottom-hole assembly
BHA
Assembly composed of the bit and a combination of specialized tools and subs that is connected to the bottom of a string of drill pipe.

NOTE Specialized tools and subs include components such as stabilizers, reamers, drill collars, measurement and formation evaluation tools, directional drilling tools, etc.

3.1.11
Bottom hole pressure
BHP
A pressure exerted at the current well depth in the wellbore.

NOTE For conventional operations this is typically generated by hydrostatic pressure and annular friction pressure

3.1.12
casing
Pipe installed in the wellbore and cemented or secured by some other means.

3.1.13
casing shoe
A short, heavy cylindrical section of steel, filled with cement, which is placed at the end (bottom) of a string of casing designed to guide the casing past irregularities in the open hole.

choke manifold
Assembly of valves, chokes, gauges, and lines used to control the rate of flow and pressure from the well when the BOPs are closed.

3.1.14
circulate
Cycling fluid from the surface through the pipe and back to the surface through the annulus.

3.1.15
critical equipment
An engineered system or component determined to be essential in preventing the occurrence of or mitigating the consequences of an uncontrolled event.

NOTE Such equipment can include vessels, machinery, piping, blowout preventers, wellheads and related valving, flares, alarms, interlocks, fire protection equipment, and other monitoring, control, and response systems.

3.1.16
diverter
Device used to direct flow from the wellbore to the pre-selected side outlet(s).

3.1.17
drill string
The sum total of all components from the drill bit to and including the stabbing valve at surface.

3.1.18
drill pipe safety valve
Full-opening valve located on the rig floor with threads to match the drill pipe connections or other tubulars in use.

NOTE This valve is used to close off the drill pipe to prevent flow and can be crossed over to fit other connections and sizes of tubulars being installed in the well. Commonly referred to as a FOSV (full-opening safety valve)

3.1.19
equivalent circulating density
ECD
The sum of pressure exerted at a specific depth by hydrostatic head of fluid, drilled solids, and friction pressure losses in the annulus expressed as a density.

3.1.20
flow check
An observation method for a prescribed period of time to monitor the stability of the primary well barrier.

3.1.21
flow line
Piping that exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.

3.1.22
flow sensor
flow paddle
Device installed in the flow line to register the percentage of flow returning from the wellbore.

3.1.23
fluid density
The weight per unit of fluid; e.g., pounds per gallon (lb/gal).

3.1.24
shut-in
To close-in a well with the blowout preventer.

3.1.25
hazard
A source, situation, or act with the potential to produce harm in terms of injury, ill health, or damage to or loss of assets.

3.1.26
hydrostatic barrier
Hydrostatic pressure of a fluid column sufficient to prevent formation fluid influx into the wellbore.

3.1.27
hydrostatic pressure
Pressure that is exerted at any point in the wellbore due to the weight of the column of fluid above that point.

3.1.28
influx <noun>
A quantity of formation fluids present in the wellbore.

3.1.29
kick <verb>
An unplanned, unexpected flow of liquid or gas from the formation into the wellbore.

3.1.30
lost circulation
lost returns
The loss of drilling fluid to the formation.

3.1.31
managed pressure drilling
MPD
An adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. It is the intention of MPD to avoid continuous influx of formation fluids to the surface.

3.1.32
management of change
MOC
A change control process used to safely manage unplanned changes that are not like-for-like or kind-for-kind in people, organization, practices, procedure, equipment, or materials in the approved plan or guideline.

NOTE An MOC process ensures that changes (and the resulting risks, if any) are reviewed, evaluated, approved, and documented by the responsible and accountable parties (prior to initiating or continuing the operation.

3.1.33
mud bucket
Device used to enclose pipe connections to deflect fluid released when a joint or stand of pipe containing liquid (wet string) is unscrewed.

3.1.34
weighted pill
Fluid volume pumped into the annulus to produce additional hydrostatic pressure in the wellbore to prevent an influx into the well.

3.1.35
operator
The lease owner or their designated agent who is responsible for the overall operation of the lease.

3.1.36
overbalance
The amount by which pressure exerted by the hydrostatic head of fluid in the wellbore exceeds formation pressure.

3.1.37
pit volume indicator
A device installed in the drilling fluid tank to register the fluid level in the tank.

3.1.38
pit volume totalizer
PVT

Device that combines all the individual pit volume indicators and registers the total drilling fluid volume in the various tanks.

3.1.39
primary well barrier
The first well barrier that prevents flow from a formation.

NOTE 1 For overbalanced drilling the primary well barrier is the drilling fluid hydrostatic column.

NOTE 2 This term is referred to as “primary well control” in RP 59.

3.1.40
secondary well barrier
Second well barrier that prevents flow from a source.

3.1.41
risk
The probability that a specified undesired event will occur.

risk assessment
A systematic process to identify the potential causes of harm or hazards, and the precautions that can be taken to prevent or mitigate the hazards.

3.1.42
rotating control device
RCD
Drill-through equipment designed to allow the rotation of the drill string and containment of pressure using seals or packers that seal against the drill string (drill pipe, casing, etc.).

NOTE Commonly referred to as a rotating head.

3.1.43
space-out
A procedure conducted to position a predetermined length of drill pipe above the rotary table so that a tool joint is located above the blowout preventer rams on which drill pipe is to be suspended (hung-off) and so that no tool joint is opposite a set of preventer rams after drill pipe is hung-off.

3.1.44
snubbing
Pulling or running pipe under pressure through a sealing element where special equipment is used to apply external force to push the pipe into the well, or to control the pipe movement out of the well.

3.1.45
stripping
Adding or removing the drill string or coiled tubing drill string through a sealed control device.

3.1.46
surging
A rapid increase in pressure downhole that occurs when drill stem is lowered too fast or when the mud pump is brought up to speed after starting.

3.1.47
swabbing
The lowering of the hydrostatic pressure in the wellbore due to upward movement of tubulars and/or tools..

3.1.48
tour
Designates the work period of a rig crew.

NOTE Often pronounced as if it were spelled "t-o-w-e-r."

3.1.49
trip margin
An incremental increase in drilling fluid density to provide an increment of overbalance in order to compensate for effects of swabbing.

3.1.50
trip tank
Low-volume (100 barrels [15.9 m^3] or less) calibrated tank that can be isolated from the remainder of the surface drilling fluid system to which returns can be directed for purposes of accurate measurement.

3.1.51
tripping
The process of removing and/or replacing tubulars from the well.

3.1.52
tubulars
Drill pipe, drill collars, tubing, and casing.

3.1.53
underbalance
A condition where the pressure exerted in the wellbore is less than the pore pressure in any part of the exposed formations.

3.1.54
well barrier
Envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to environment.

3.1.55
well barrier element
Physical component (mechanical or non-mechanical) that can be combined with other dependent items to form a well barrier.

NOTE This includes hydrostatic, mechanical, or solidified chemical materials (usually cement).

3.1.56
well control
Activities implemented to prevent or mitigate an unintentional release of formation fluids and gases from the well to its surroundings.

3.1.57
well control equipment
Equipment within the scope of API 16A, API 16C, API 16D, and the supporting auxiliary equipment referenced in the scope of this document.

3.2 Abbreviations

ALARP as low as reasonably practicable

BHA bottom-hole assembly

BOP blowout preventer

ECD equivalent circulating density

ERP emergency response plan

FOSV full-opening safety valve

HSE health, safety, and environment

MOC management of change

MPD managed pressure drilling

OEM original equipment manufacturer

PVT pit volume totalizer

RCD rotating control device

4 Tripping Operations Overview

4.1.1 Hydrostatically overbalanced operations are designed to prevent formation fluids from entering the wellbore.

4.1.2 Prior to performing tripping operations, company and rig-specific procedures should be developed, documented, and agreed upon by the drilling contractor and the operator.

4.1.3 If kick indications or formation fluids are present further investigation shall be required.

4.1.4 Hydrostatically overbalanced operations are designed to manage drill gas or background gas. A continuous flare while circulating can indicate that additional formation gas has entered the annulus, indicating that the well could be hydrostatically underbalanced. At this point the primary well barrier should be monitored to determine if it is still effective.

4.1.5 For wireline, stripping with pressure, and snubbing operations, API 54 and API 59 should be used in creating rig-specific procedures for these operations.

5 Planning

5.1 General

5.1.1 To safely manage inherent risks, hydrostatically overbalanced tripping operations task and work instruction plans should include the following prior to starting tripping operations:

a) shut-in procedures;

b) contingency plans;

c) evacuation plans.

5.1.2 An MOC process should be used to manage the risks associated with unplanned changes or events that deviate from planned tripping operations according to company policies and procedures.

5.2 Risk Assessment

5.2.1 Each company should evaluate the workplace hazards and risks and develop and implement measures to manage identified risks. See API 54 for additional guidance on occupational hazards related to tripping operations such as the following:

a) housekeeping;

b) egress route;

c) dropped objects;

d) tubular handling;

e) V-door opening;

f) safety clamps;

g) ice plugs.

5.2.2 The level of risk assessment required to complete an operation or task safely is determined by several factors including, but not limited to: type and complexity of the operation or task, number of personnel involved, competencies of persons involved, etc.

5.2.3 Job tasks, including potential simultaneous operations and critical equipment installation and removal shall be planned and risk assessed before operations commence. Planning and risk assessment shall be communicated during a safety meeting with the crew and other involved personnel.

5.2.4 Each company should determine the best method to conduct a risk assessment appropriate for the task which may include, but are not limited to: a documented process, a visual or verbal process, the Job Safety Analysis, or other company-specific process to recognize risk.

5.2.5 Hazards that cannot be prevented shall be mitigated to as low as reasonably practicable (ALARP).

5.2.6 Efforts should be made to prevent identified hazards through an appropriate hierarchy of controls as follows:

a) elimination;

d) substitution;

e) engineering controls;

f) administrative controls;

g) personal protective equipment.

5.2.7 All personnel shall have the authority to initiate Stop Work when an identified risk cannot be mitigated, an unsafe act or condition is observed, or there is uncertainty or confusion about work instructions.

5.2.8 The operator and contractor shall be responsible for developing, documenting, and communicating site-specific emergency response plans (ERPs). These plans should include emergency responses, and evacuation and egress during well blowouts. Refer to API 54 for additional information.

5.2.9 Documented handover notes detailing well-, safety-, and equipment-related information should be provided to oncoming crews prior to shift changes.

5.3 Contingency Plans

5.3.1 Well control contingency plans related to tripping operations should be developed to address circumstances that can deviate from the original plan. These plans should be communicated and understood by the appropriate personnel.

5.3.2 Well control contingency plans at a minimum should address the following:

a) methods to identify a failed primary well barrier and procedures to secure the well;

b) identifying surface equipment needed to secure the well;

c) identifying surface equipment and procedures needed to maintain or restore the primary well barrier;

d) identifying length, dimensions, and spacing in the drill string or BHA that can potentially compromise the BOP's ability to seal and secure the well.

6 Equipment

6.1 General

6.1.1 Equipment installation, commission, operation, maintenance, inspection, and removal should follow OEM or current equipment owner procedures or recommended practices.

6.1.2 A maintenance, inspection, and testing program should be in place to ensure at a minimum the following equipment can function on demand:

a) BOP(s);

b) kelly valves;

c) top drive equipment;

d) drill pipe safety valves;

e) riser above the RCD;

f) RCD;

g) pit volume indicators;

h) trip tank;

i) mud bucket and drain lines;

j) mud/gas separator (MGS);

k) flow/vent/flare lines;

l) choke manifold;

m) accumulator;

n) BOP remote;

o) auxiliary escape;

p) hoisting tools;

q) hooks;

r) elevator links (bails);

s) elevators, and related equipment;

t) tag lines and hand-free devices;

u) rotary table;

v) drill string handling equipment;

w) lift subs;

x) drill collar clamps;

y) weight indicators;

z) communications systems.

6.1.3 Prior to and during tripping operations, critical equipment should be monitored to ensure they are functioning within operating limits.

6.1.4 Well control equipment shall be installed, inspected, and maintained in accordance with API 53.

6.1.5 The pit volume totalizer and recording devices shall be available in accordance with API 53.

6.2 Valves

6.2.1 On a kelly rig, a minimum of two kelly valves shall be installed, with the bottom valve being capable of use for stripping operations.

6.2.2 On a top-drive rig, a minimum of two IBOPs shall be installed.

6.2.3 A lower valve wrench shall be readily available on the rig floor or in the driller's cabin. The lower valve should be actuated manually daily to verify free motion.

6.2.4 A drill pipe safety valve shall be readily available on the rig floor and equipped with crossovers, if necessary, to screw into the current drill string member in the rotary table.

6.2.5 The drill pipe safety valve shall be stored in open position with wrench accessible on the rig floor.

6.2.6 The IBOP shall be stored in the open position on the rig floor.

6.3 Rotating Control Devices

6.3.1 In hydrostatically overbalanced land operations, the rotating control device (RCD) shall not be considered a well barrier element.

6.3.2 Verification of the compatibility of fluid type and RCD element should be conducted in advance of operations.

6.3.3 Centered alignment of the drill string inside the RCD is essential for efficient operations and should be periodically confirmed after rig-up.

6.3.4 The RCD should have piping connectivity below the sealing element to enable filling the top of the wellbore with drilling fluids.

NOTE The piping connectivity below the RCD could facilitate bi-directional flow (to/from the top of the wellbore). However, the common mode of operation is to enable filling the top of the wellbore with fluids.

6.3.5 The RCD bearing and sealing elements are designed to accommodate certain tubular specifications (e.g. diameter, shape, smoothness). Therefore, the RCD bearing and sealing element needs to be removed from the rotating head bowl prior to pulling or running tubulars through the RCD which are outside the design specifications.

6.4 Trip Tanks

6.4.1 The trip tank placement should facilitate and include a recirculating pump to continuously deliver fluid to the top of the wellbore or the RCD.

6.4.2 A trip tank shall be used for tripping the drill string into and out of the wellbore when a BOP is installed, while logging, or to monitor drilling fluid volumes when performing open-hole operations.

6.4.3 When pulling the drill string out of the hole, the primary use of the trip tank is to measure the amount of drilling fluid required to fill the hole to determine if drilling fluid volume matches pipe displacement.

6.4.4 When running the drill string into the hole, the primary use of the trip tank is to measure the amount of drilling fluid displaced from the well by the drill string to determine if drilling fluid volume matches pipe displacement.

6.4.5 Other uses of a trip tank include measuring drilling fluid or water losses to the hole, monitoring the hole while logging or following a cement job, and calibrating drilling fluid pumps.

6.4.6 The functioning of the trip tank should be verified prior to tripping operations.

6.5 Mud Buckets

6.5.1 The mud bucket drain line should be routed to the trip tank. If any other drain path is used, provisions should be made to measure the fluids collected by that system.

6.5.2 The mud bucket drain line route should be verified prior to and monitored during the operation to accurately calculate proper displacement.

6.5.3 Wet displacement is a condition when tubulars are pulled from the wellbore and still contain drilling fluids inside the internal capacity of the tubular.

6.5.4 Wet displacement calculations are used when tubulars are pulled wet from the wellbore and the drilling fluid routed by the mud bucket does not drain into the same tank the wellbore is being filled from.

6.5.5 Dry displacement is a condition that can occur under two circumstances:

a) when tubulars are pulled from the wellbore and either do not contain drilling fluids inside the internal capacity of the tubular, or

b) when tubulars are pulled wet from the wellbore and the drilling fluid routed by the mud bucket drains into the same tank the wellbore is being filled from.

6.5.6 Dry displacement calculations are used when tubulars are pulled without fluids inside the tubular or when pulled wet from the wellbore and the drilling fluid routed by the mud bucket drains into the same tank the wellbore is being filled from.

6.6 Alarms

6.6.1 Audible and visual alarms shall be active and not muted during tripping operations.

6.6.2 The drilling contractor should determine which alarms should be active and the parameters chosen to configure the system. Parameters to be considered should include the following:

a) high and low trip tank levels;

b) flow sensor alarms;

c) gas alarms;

d) active system volume.

6.6.3 Contractor's shall have a defined process to manage unplanned changes to alarm parameters or alarm status(es) for the different states of the tripping operation. In absence of a defined process, an MOC process shall be followed.

6.6.4 Inadequate alarm management can lead to operational risks and have a detrimental effect on the driller's effectiveness to manage well control.

6.6.5 Excessive activation of alarms, especially nuisance or non-critical alarms, can lead to alarm flooding, which can have a detrimental effect on the driller's ability to identify and effectively respond to an influx.

6.6.6 Alarm flooding can habituate drillers to shelve or suppress alarms.

6.6.7 Alarm shelving should be controlled and limited to a predetermined period of time.

6.6.8 Alarm suppression should be controlled by a defined process or an MOC should be used.

6.6.9 The Drilling Contractor should have an alarm management philosophy in place that includes designs, processes, and procedures to manage nuisance alarms, alarm flooding, alarm shelving, and alarm suppression. In absence of a defined process, an MOC process shall be followed.

7 Volume Management

7.1 General

7.1.1 During operations where tubulars are pulled from or placed into the well, fluid displacement should be measured and referenced to calculated values to ensure that the proper amount is being replaced into or displaced from the well.

7.1.2 If the hole fails to take the correct amount of drilling fluid, tripping operations should be suspended, and a safe course of action determined while observing the well.

7.1.3 Displacement and capacity volumes for tubulars used in the well shall be readily available for reference.

7.2 Drilling Fluid Considerations

7.2.1 Drilling fluid design and maintenance are integral parts of an effective primary well barrier.

7.2.2 Drilling fluid properties should be monitored and maintained during tripping operations.

7.2.3 Prior to starting tripping operations, a bottoms-up circulation is recommended to evaluate the integrity of the primary well barrier.

7.2.4 During tripping operations, the wellbore should be kept full with a drilling fluid density equal to or greater than the drilling fluid density designed for that particular hole section.

7.2.5 Insufficient fluid density and insufficient fluid level in the wellbore can reduce hydrostatic pressure below the formation pore pressure causing a kick to occur while conducting tripping operations.

7.3 Fluid Transfers

7.3.1 Fluid transfers during tripping operations have implications when managing drilling fluid volumes. Influxes have the potential to go unrecognized if the fluid transfer process and volumes are mismanaged.

7.3.2 Water and/or diesel additions into the active system should be suspended during tripping operations.

7.3.3 If water and/or diesel additions into the active system cannot be suspended during tripping operations, then the volume of water and diesel additions should be periodically measured and monitored throughout the tripping operation.

7.3.4 Solids control equipment involving active tanks should be suspended during tripping operations.

7.3.5 When solids control equipment cannot be suspended during tripping operations, then the volume of solids removed from the drilling fluid should be periodically measured and monitored throughout the tripping operation.

7.3.6 When building additional volume for the active system, the additional volume should be isolated from the active system. After the additional volume is built, the entire amount should be immediately transferred in the PVT total.

7.3.7 If the rig's equipment does not permit isolation of the mixing pit from the active system, the volume of materials added should be measured and monitored throughout the volume building operation.

7.3.8 Fluid transfers between the active system and trip tank should be measured and monitored using a procedure designed to accurately track volumes, as it can be difficult to recognize kick indications if mismanaged.

7.3.9 The volume changes caused by fluid transfers should be recorded on the trip sheet.

7.4 Trip Sheets

7.4.1 Trip sheets are used to measure and identify trend deviations due to gains or losses in the well. Trip sheets are also used to account for tubular displacements and fluid transfers when tripping tubulars in and out of the well.

7.4.2 Trip sheet volume measurements should be evaluated by comparing the calculated and measured volumes for hole-fill or well returns for a specific number of stands when removed or added to the well.

NOTE 1 The calculated volume is a mathematical calculation of the tubular displacement based on the design specification.

NOTE 2 The measured volume is the actual observable displacement during tripping operations.

7.4.3 Manual and digital trip sheets have their own inherent challenges that can affect their usability and accuracy; therefore, companies should take the appropriate measures to train their employees and periodically audit trip sheets for accuracy.

7.4.4 A trip sheet shall be completed when tripping in and out of the hole with both theoretical and actual displacement/hole-fill volumes recorded and compared after every 5 stands of drill pipe, every 3 stands of heavy weight drill pipe, after every stand of drill collars.

NOTE In certain situations, such as pulling wet pipe, it may be appropriate to compare theoretical and actual volumes more frequently.

7.4.5 Trip sheets shall be accessible at the well site until the end of the drilling operation.

7.4.6 When weighted pills are used, a U-tube effect is created in the wellbore displacing the fluid inside the drill string back into the mud tank/trip tank. The trip sheet should be used to account for and record variation in calculated volumes caused by weighted pills.

8 Well Control

8.1 General

8.1.1 Well control risks should be identified during risk assessments and pre-job planning. These identified hazards and risks should be communicated in pre-job meetings, monitored, and mitigated to ALARP.

8.1.2 Rig contractors should establish well control policies, procedures, and a competency management program to train personnel.

8.1.3 Rig contractors shall train personnel on well control methods and shut-in procedures. Well control drills should be conducted periodically to evaluate crew response capabilities. See API 59 for details regarding well control methods and drills.

8.1.4 The drilling fluid hydrostatic pressure in excess of the formation pore pressure is the primary well barrier in an overbalanced tripping operation.

8.1.5 The most common factors that cause the primary well barrier to fail are keeping the hole full, swabbing/surging, insufficient drilling fluid density, and/or lost circulation.

8.1.6 When an influx is detected, the well should be shut-in as quickly as possible to minimize influx volume. Well control procedures should be used to manage the influx prior to resuming tripping operations.

NOTE See API 59 for more information when conducting drilling operations using a surface diverter.

8.1.7 The ballooning effect will affect the static fluid volumes during tripping operations. When ballooning is suspected, it should be confirmed by conducting an investigation, and if present, should be monitored throughout the tripping operation.

8.1.8 The Driller has the ultimate authority and responsibility to shut in the well without asking permission and without any repercussion(s) when a kick is indicated or detected.

8.1.9 A schematic drawing(s) should be available on the rig showing the following:

a) BOP stack arrangement, including ram designations, pressure ratings, and drift diameter;

c) BOP and choke manifold valve alignment;

d) wellhead and BOP space-out from rotary height;

8.2 Well Barrier Elements

8.2.1 Well barrier elements can be mechanical or non-mechanical and may include but are not limited to the following: fluid column, BOPs, FOSVs, packers, plugs, casing, cement, and the wellhead.

8.2.2 The operator's well plan should define well barriers and testing requirements for the different sections of the well construction design.

The operator's well plan should include a process to monitor and maintain the integrity of well barriers as they degrade over time and through service parameters such as, but not limited to,

a) temperature

b) pressure

c) solids or particulates

d) operating time

e) flow rate

8.2.3 For hydrostatically overbalanced wells the hydrostatic column is the primary well barrier and can be affected by tripping operations.

8.2.4 If the primary well barrier (the drilling fluid hydrostatic column) falls below the design tolerance, the operator shall ensure that no other activities take place, other than those intended to restore the primary well barrier. If the primary well barrier cannot be re-established, an MOC shall be conducted prior to continuing tripping operations according to company policies and procedures.

8.3 Kick Indicators

8.3.1 Warning signs of a kick during tripping operations shall be investigated. These warning signs can include, but are not limited to the following:

a) pit gain;

b) increased flow;

c) flow after the pumps is stopped;

d) changes in fluid returns, e.g. temperature and density;

e) variations in pump speed and/or standpipe pressure;

f) changes in cutting (e.g. size, shape, quantity, etc.).

8.3.2 Kick indication and detection can be complicated by the following:

a) high-angle or horizontal wellbores;

b) slowly occurring gas migration;

c) simultaneous fluid loss and influx in different parts of the wellbore;

d) a net fluid loss on a trip sheet concealing an influx.

8.3.3 If there is an indication of simultaneous fluid loss and influx taking place, appropriate well control actions should be taken.

8.3.4 Flow checks may not show a flow increase when simultaneous fluid loss and influx is occurring.

8.3.5 Simultaneous fluid loss and influx is particularly a concern when oil-based drilling fluid is being used, as entrained gas will typically not “boil-out” before the gas gets closer to the surface.

8.4 Trip Margins

8.4.1 A trip margin that offsets the effects of swabbing should be determined and considered for use because the additional hydrostatic pressure allows some degree of swabbing without losing the primary well barrier.

8.4.2 The maximum tripping speed should be determined at the planning stage for bottom-hole assemblies and casing for the different hole sections.

8.5 Flow Checks

8.5.1 A flow check shall be performed to determine if the well is static and no fluid is being lost to or gained from the formation. Flow checks for tripping out of a hole shall be performed, at a minimum:

a) prior to starting tripping operations,

b) at the lowest casing shoe, and

c) before pulling BHA into the BOP.

8.5.2 Additional flow checks may be necessary to confirm that the primary well barrier is still effective. These include but are not limited to the following:

a) between 3 and 5 stands after starting tripping operations,

b) when circulation stops;

c) halfway through the open-hole section;

d) before pulling into the curve from a horizontal section;

e) at the kickoff point for the curve in a horizontal section;

f) after pulling out of a weighted pill;

g) before removing the RCD bearing/sealing element;

h) at tour change;

i) before resuming operations after opening the well;

j) at the lowest casing shoe when tripping into the hole;

k) when the discrepancy between the calculated and measured volumes in the trip sheet is above a predetermined threshold.

NOTE When circulation stops, there can be a significant bottom hole pressure reduction. Therefore, it is important to perform a flow check to ensure the well is static without the equivalent circulating density (ECD) effects.

8.5.3 Contractors and operators should determine and agree on which additional flow checks are necessary for their operations and what thresholds trigger additional flow checks and well control responses.

8.5.4 Prior to performing a flow check it is recommended that one or more bottoms-up circulation is completed prior to beginning tripping operations. This can help to remove gas from the wellbore and condition the drilling fluid.

8.5.5 Flow checks should be documented and readily accessible for the duration of the well operations.

8.5.6 Details regarding the flow check should be recorded and include, but are not limited to time, depth, duration, outcome, and driller's initials.

8.5.7 The well shall be shut in upon a positive flow check.

8.5.8 Flow checks should be conducted for a length time to confirm the well is static. Conditions that impact the length of time the well is static can include, but is not limited to drilling fluid medium, wellbore design, formation type, and wellbore depth.

NOTE 1 Typical flow check times can vary between 3 minutes to 30 minutes or longer.

NOTE 2 Flow check times start when pumping or any other type of operation that can induce flow has ceased.

8.5.9 When conducting flow checks in instances where loss circulation is occurring, it may be advisable to continue circulating over the top of the wellbore to keep the hole full and measure the amount or rate of circulation loss.

8.5.10 The drill string should be stationary when conducting flow checks while circulating over the top of the wellbore.

9 Tripping Operational Guidelines

9.1 General

9.1.1 Safety meetings should be conducted with appropriate personnel prior to starting tripping operations and repeated as needed throughout the operation (see Section 5).

9.1.2 Safety meetings should cover risk assessment, equipment procedures and parameters, equipment alignment and verification, job steps, flow checks, drill string, BHA, and type of fill methods to be employed etc.

9.1.3 Prior to tripping out of the hole, the well control worksheet should be verified or updated, including, but not limited to drill string information, drilling fluid density, slow circulating rate, and hole depth. See API 59 for examples of well control worksheets.

9.1.4 Current BOP and choke manifold drawings, detailing space-out, pressure ratings, and ram closing pressures for different tubulars utilized shall be maintained and available in the driller's cabin (see API 53 for more information). .

9.1.5 Contractor's should have a documented and accessible procedure to verify the presence of trapped pressure in the wellbore prior to opening the BOP.

9.2 Training

9.2.1 Personnel should be educated and trained on, but not limited to, the following:

a) well control system components, including installation, maintenance, and operation.

b) response capability to potential well control situations;

c) tripping procedures, including the equipment used for tripping operations;

d) trip sheets and hole fill methods and monitoring;

e) ERPs, including emergency action procedures;

f) well control training for wellsite leaders as required (assistant driller, driller, rig manager, company representative, etc.)

9.2.2 Training can be a combination of both formal and informal methods, which should include a mentorship and on-the-job training.

9.2.3 A method of competency assurance should be in place to measure the effectiveness of training.

9.2.4 Training should be modified or updated as needed to address unique or rig-specific conditions or operations.

9.2.5 Training should be provided when introducing new technologies, systems, or methods.

9.3 Conventional Tripping Operations

9.3.1 Operational parameters and alarms should be pre-determined, set prior to, and adjusted as needed (e.g. hook load, overpull, bridge protection, torque, block height, flow and gain, etc.).

9.3.2 Personnel should verify that drilling fluid returns and hole-fill surface lines are correctly routed and aligned prior to starting tripping operations to enable accurate trip sheet monitoring.

9.3.3 Flow checks shall be conducted in accordance with 8.5.

9.3.4 Prior to performing tripping operations, personnel working in the mast shall tie-off (fall arrest and restraint) and have a designated method to provide confirmation of such tie-off to the driller or rig floor personnel. Whenever personnel are required to disconnect from the fall restraint during tripping operations there shall be a tie-off reconfirmation.

9.3.5 The derrick board escape device and route should be verified prior to starting the trip.

9.3.6 Abnormal flow after the process of shutting down the pumps is completed can be caused by several factors including, but not limited to:

a) an influx of formation fluid;

b) thermal expansion of the drilling fluid;

c) an overbalanced formation ballooning (opening and closing of a fracture);

d) return lines draining.

These causal factors should be investigated, documented, and managed prior to starting tripping operations.

9.3.7 The hole should be filled continuously to prevent an influx of formation fluid. While the continuous-fill method is preferred, if operational or equipment limitations exist, the hole may be filled at pre-determined intervals. When the continuous-fill method is not used, the drilling contractor and operator should agree on hole-fill method and predetermined hole-fill intervals.

9.3.8 The continuous-fill method is preferred for various reasons. These may include, but are not limited to

a) ensuring the hole is always full;

b) providing early identification when an influx is occurring; and

c) serving as an early indication when the formation is taking fluid (i.e. losing returns), which, if not recognized in enough time, could lead to a drop in hydrostatic pressure that may result in an influx.

9.3.9 If the circulating rate is held constant, the flow from the annulus (or over the top of the annulus if using the continuous fill method) should be constant. If the annulus flow increases without a corresponding change in the pump rate, the additional flow could be caused by the influx of formation fluid(s) into the wellbore or entrained gas expansion.

9.3.10 Monitoring fluid volumes and tripping speeds are essential to identify and mitigate the risk associated with surging and swabbing.

9.3.11 When running tubulars into the wellbore, mitigation actions should be taken when drilling fluid volume measured at surface is abnormally less than or greater than the calculated pipe volume displacement.

9.3.12 Dynamic variation in flow rates and volumes can occur when running or pulling tubulars in and out of the wellbore. Volume and flow variations during tripping operations should be fingerprinted, and the appropriate boundaries should be established for the alarms.

9.3.13 Contributing factors to drilling fluid losses include, but are not limited to the following:

a) excessive drilling fluid density;

b) excessive annular circulating pressure;

c) packing-off in the annulus;

d) pressure surges related to running pipe or tools;

e) breaking circulation;

f) faults or naturally fractured formations;

g) weak formation or highly permeable formations.

9.3.14 When retrieving tubulars from the wellbore, mitigation actions should be taken when drilling fluid volume measured at surface is abnormally less than or greater than the calculated hole fill volume.

9.3.15 Swabbing the well beyond the trip margin/safety factor can result in an influx of formation fluid into the wellbore. Hole fill volumes that are less than calculated on the trip sheet can be an indication of swabbing.

NOTE See API 59 for response actions when swabbing is detected.

9.3.16 The initial tank volume shall be recorded prior to starting tripping operations to enable accurate trip sheet monitoring. Trip sheets shall be completed and monitored in accordance with 7.4.

9.3.17 If the primary well barrier (the drilling fluid hydrostatic column) falls below the design tolerance, the operator shall ensure that no other activities take place, other than those intended to restore the primary well barrier. If the primary well barrier cannot be re-established, the well shall be secured and an MOC shall be conducted prior to continuing tripping operations according to company policies and procedures.

Bibliography

[1] API Specification 16A, *Specification for Drill-Through Equipment*

[2] API Standard 16AR, *Standard for Repair and Remanufacture of Drill-Through Equipment*

[3] API Specification 16C, *Choke and Kill Equipment*

[4] API Specification 16D, *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

[5] API Recommended Practice 54, *Occupational Safety and Health for Oil and Gas Well Drilling and Servicing Operation*

[6] API Recommended Practice 59, *Recommended Practice for Well Control Operations*

[7] API Standard 64, *Diverter Equipment Systems*

[8] API Recommended Practice 92M, *Managed Pressure Drilling Operations with Surface Back-Pressure*

[9] API Recommended Practice 92U, *Underbalanced Drilling Operations*

[10] API Recommended Practice 97L, *Onshore Well Construction Interface Document*

[11] IADC *Drilling Control System Alarm Management Guidelines*