Recommended Practice for Well Control Operations

API RECOMMENDED PRACTICE 59
SECOND EDITION, MAY 2006

REAFFIRMED, JANUARY 2012

AMERICAN PETROLEUM INSTITUTE

Recommended Practice for Well Control Operations

Upstream Segment

API RECOMMENDED PRACTICE 59
SECOND EDITION, MAY 2006

REAFFIRMED, JANUARY 2012

AMERICAN PETROLEUM INSTITUTE

SPECIAL NOTES

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to assure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

FOREWORD

This publicaiton is under jurisdiction of the American Petroleum Institute, Upstream Department's Executive Committee on Drilling and Production Operations.

Drilling and well service unit (production well service, well workover, well completion, and plug and abandonment) operations are being conducted with full regard for personnel safety, public safety, and preservation of the environment in such diverse conditions as metropolitan sites, wilderness areas, ocean platforms, deepwater sites, barren deserts, wildlife refuges, and arctic ice packs. Recommendations presented in this publication are based on extensive and wide-ranging industry experience.

The goal of this voluntary recommended practice is to assist the oil and gas industry in promoting personnel and public safety, integrity of the drilling and well service equipment, and preservation of the environment for land and marine drilling and well service operations. This recommended practice is published to facilitate the broad availability of proven, sound engineering and operating practices. This publication does not present all of the operating practices that can be employed to successfully install and operate well control systems in drilling and well service operations. Nor does this publication imply that all of the practices herein are applicable to all drilling and well service operations. Drilling and well service operations throughout the world vary widely and take place under a wide range of downhole and surface conditions. Practices at one operation will not necessarily be required at a similar operation due to different conditions. Practices set forth herein are considered acceptable for accomplishing the job as described; equivalent alternative installations and practices may be utilized to accomplish the same objectives. Individuals and organizations using these recommended practices are cautioned that operations must comply with requirements of national, state, or local regulations. These requirements should be reviewed to determine whether violations may occur.

Users of recommendations set forth herein are reminded that constantly developing technology and specialized or limited operations do not permit complete coverage of all operations and alternatives. Recommendations presented herein are not intended to inhibit developing technology and equipment improvements or improved operational procedures. These recommended practices are not intended to obviate the need for qualified engineering and operations analyses and sound judgments as to when and where these recommended practices should be utilized to fit a specific drilling application.

This publication includes use of the verbs shall and should, whichever is deemed most applicable for the specific situation. For the purposes of this publication, the following definitions are applicable:

Shall—Indicates that the recommended practice(s) has universal applicability to that specific activity.

Should—Denotes a recommended practice(s) a) where a safe comparable alternative practice(s) is available; b) that may be impractical under certain circumstances; or c) that may be unnecessary under certain circumstances or applications.

Changes in the uses of these verbs are not to be effected without risk of changing the intent of recommendations set forth herein.

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually and updated quarterly by API, 1220 L Street, N.W., Washington, D.C. 20005.

Suggested revisions are invited and should be submitted to the Standards and Publications Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

CONTENTS

CONTENTS

CONTENTS

CONTENTS

Recommended Practice for Well Control Operations

1 Scope

1.1 PURPOSE

The purpose of these recommended practices is to provide information that can serve as a voluntary industry guide for safe well control operations. This publication is designed to serve as a direct field aid in well control and as a technical source for teaching well control principles. This publication establishes recommended operations to retain pressure control of the well under pre-kick conditions and recommended practices to be utilized during a kick. It serves as a companion to API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* and API RP 64 *Recommended Practice for Diverter Systems Equipment and Operations* (reader should check for the latest edition). RP 53 establishes recommended practices for the installation and testing of equipment for the anticipated well conditions and service and RP 64 establishes recommended practices for installation, testing, and operation of diverters systems and discusses the special circumstances of uncontrolled flow from shallow gas formations.

1.2 BOP INSTALLATIONS

The recommended practices are separated into two main systems:

1. Blowout preventers (BOPs) at the surface within reach and sight of the driller or well service unit operator, and
2. BOPs installed on the seafloor with relatively long choke and kill lines.

In this publication, sections have been prepared to establish practices and procedures pertaining to both surface BOP installations and subsea BOP installations. The delineation between surface BOP installations and subsea BOP installations is mainly on an exception basis, and the recommendations made for surface installations apply to subsea installations unless exceptions are stated. The recommended practices can apply to drilling, well service unit, and coiled tubing unit operations. The fundamentals of well flow and well control are the same.

1.3 OPERATIONS

This publication was developed to enhance well control by proper planning and execution and thus avoid a kick. The publication also deals with the eventuality that a well kick may occur and presents details for handling such a kick using basic control methods. Details of these basic control methods are presented for both surface and subsea BOP stack installations. Suggested considerations and modifications to the basic control methods, which may be dictated by special problems or well conditions, are also covered. Recommended well control worksheets for surface and subsea BOP installations are included in Appendix B. Instructions are included for completing and use of the well control worksheets. Recommended practices set forth in this publication are considered adequate to meet specified well conditions. It is recognized that there are alternate procedures that can be utilized in well control that may be equally as effective in meeting the well requirements and promoting safety and efficiency.

1.4 FURTHERING THE UNDERSTANDING OF WELL CONTROL

Details of well control technology and reasons for the recommended procedures are included in Section 4, "Principles of Well Control." Section 4 was prepared so it can be used as a technical base for instructing personnel in well control operations. Appendix A contains several special pressure and pressure gradient calculations and examples to further emphasize the techniques and calculations that can aid a well control supervisor in understanding well control operations.

1.5 DEEPWATER

The International Association of Drilling Contractors (IADC) has published guidelines for planning and drilling deepwater wells, IADC Deepwater Well Control Guidelines, 1998 Edition. The reader is referred to that document for more complete coverage of deepwater well control.

2 References

2.1 STANDARDS

The following standards contain provisions, which through reference in this text, constitute provisions of this standard. All standards are subject to revision and users are encouraged to investigate the possibility of applying the most recent editions of the standards indicated below:

API

Spec 6A	*Wellhead and Christmas Tree Equipment*
RP 5C1	*Recommended Practice for Care and Use of Casing and Tubing*
RP 5C7	*Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services*
RP 7G	*Drill Stem Design and Operating Limits*
RP 10B	*Recommended Practice for Testing Well Cements*
RP 13D	*Rheology and Hydraulics of Oil-Well Drilling Fluids*
RP 13B-1	*Standard Procedure for Field Testing Water-based Drilling Fluids*

RP 13B-2	*Standard Procedure for Field Testing Oil-based Drilling Fluids*
Spec 16A	*Specification for Drill Through Equipment*
RP 16Q	*Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*
RP 49	*Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide*
RP 53	*Blowout Prevention Equipment Systems for Drilling Wells*
RP 64	*Recommended Practice for Diverter Systems* Equipment and Operations
RP 505	*Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities*

ASTM[1]

D-1418	*Practice for Rubber and Rubber Lattices - Nomenclature*

NACE[2]

MR 01-75	*Materials for use in H_2S-containing Environments in Oil and Gas Production*

2.2 OTHER REFERENCES

IADC[3]

IADC Deepwater Well Control Guidelines

3 Glossary for Well Control Operations

3.1 DEFINITIONS

3.1.1 abnormal pressure: Pore pressure in excess of that pressure resulting from the hydrostatic pressure exerted by a vertical column of water with salinity normal for the geographic area.

3.1.2 accumulator: A pressure vessel charged with nitrogen or other inert gas and used to store hydraulic fluid under pressure for operation of BOPs.

3.1.3 annular preventer: A device, which can seal around any object in the well bore or upon itself. Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal.

3.1.4 annulus: The space between the drill string and the inside diameter of the hole being drilled, the last string of casing set in the well, or the marine riser.

[1]ASTM International, 100 Barr Harbor Drive, P.O. Box C700, West Conshohocken, PA, 19428-2959, www.astm.org
[2]NACE International, 1440 South Creek Drive, Houston, Texas 77084-4906, www.nace.org
[3]International Association of Drilling Contractors, P.O. Box 4287, Houston, TX 77210-4287, www.iadc.org

3.1.5 annulus friction pressure: Circulating pressure loss inherent in the annulus between the drill string and casing or open hole.

3.1.6 backpressure (casing pressure, choke pressure): The pressure existing at the surface on the casing side of the drill string/annulus flow system.

3.1.7 barite plug: A settled volume of barite particles from a barite slurry placed in the well bore to seal off a pressured zone.

3.1.8 barite slurry: A mixture of barium sulfate, chemicals, and water of a unit density between 18 and 22 pounds per gallon (lb/gal).

3.1.9 belching: A slang term to denote flowing by heads.

3.1.10 bell nipple: A piece of pipe, with inside diameter equal to or greater than the BOP bore, connected to the top of the BOP or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker or pit. Usually has a second side outlet for the fill-up line connection.

3.1.11 bleeding: Controlled release of fluids from a closed and pressured system in order to reduce the pressure.

3.1.12 blind rams (blank, master): Rams whose ends are not intended to seal against any drill pipe or casing. They seal against each other to effectively close the hole.

3.1.13 blind/shear rams: Blind rams with a built-in cutting edge that will shear tubulars that may be in the hole, thus allowing the blind rams to seal the hole. Used primarily in subsea systems.

3.1.14 blowout: An uncontrolled flow of well fluids and/or formation fluids from the well bore.

3.1.15 blowout preventer (BOP): A device attached to the casinghead that allows the well to be sealed to confine the well fluids to the well bore.

3.1.16 blowout preventer drill: A training procedure to determine that rig crews are completely familiar with correct operating practices to be followed in the use of blowout prevention equipment. A "dry run" of blowout preventive action.

3.1.17 blowout preventer operating and control system (closing unit): The assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the blowout preventer equipment.

3.1.18 blowout preventer stack: The assembly of well control equipment including preventers, spools, valves and nipples connected to the top of the wellhead.

3.1.19 BOPE: An abbreviation for blowout preventer equipment.

3.1.20 BOP: An abbreviation for blowout preventer.

3.1.21 borehole pressure: Total pressure exerted in the well bore by a column of fluid and/or backpressure imposed at the surface.

3.1.22 bottom-hole pressure: Depending upon the context, either a pressure exerted by a column of fluid contained in the well bore or the formation pressure at the depth of interest.

3.1.23 broaching: Venting of fluids to the surface or to the seabed through channels external to the casing.

3.1.24 bullheading: A term to denote pumping into closed-in well without returns.

3.1.25 casing pressure: See Backpressure.

3.1.26 casing seat test: A procedure whereby the formation immediately below the casing shoe is subjected to a pressure equal to the pressure expected to be exerted later by a higher drilling fluid density or by the sum of a higher drilling fluid density and backpressure created by a kick.

3.1.27 casing shoe: A tool joint connected to the bottom of a string of casing designed to guide the casing past irregularities in the open hole; usually rounded at the bottom in shape and composed of drillable materials.

3.1.28 choke: A device with either a fixed or variable aperture used to control the rate of flow of liquid and/or gas.

3.1.29 choke manifold (control manifold): The system of valves, chokes, and piping to control flows from the annulus and regulate pressures in the drill string/annulus flow system.

3.1.30 choke line: The high-pressure piping between BOP outlets or wellhead outlets and the choke manifold.

3.1.31 choke pressure: See Backpressure.

3.1.32 circulating head: A device attached to the top of drill pipe or tubing to allow pumping into the well.

3.1.33 closing unit: The assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the BOP equipment.

3.1.34 conductor casing or conductor pipe (onshore and bottom-supported offshore installations): A relatively short string of large diameter pipe that is set to keep the top of the hole open and provide a means of returning the upward flowing drilling fluid from the well bore to the surface drilling fluid system until the first casing string is set in the well.

3.1.35 control panel, remote: A panel containing a series of controls that will operate the valves on the control manifold from a remote point.

3.1.36 cut drilling fluid: Well control fluid, which has been reduced in density or unit weight because of entrainment of less dense formation fluids or air.

3.1.37 degasser: A vessel, which utilizes pressure reduction and/or inertia to separate entrained gases from the liquid phases.

3.1.38 displacement: The volume of steel in the tubulars and devices inserted and/or withdrawn from the well bore.

3.1.39 diverter: A device attached to the wellhead or marine riser to close the vertical access and direct flow into a line away from the rig.

3.1.40 diverter system: The assemblage of an annular sealing device, flow control means, vent system components, and control system which facilitates closure of the upward flow path of the well fluid and opening of the vent to the atmosphere.

3.1.41 drill pipe safety valve: An essentially full-opening valve located on the rig floor with threads to match the drill pipe in use. This valve is used to close off the drill pipe to prevent flow.

3.1.42 Drill Stem Test (DST): A test conducted to determine production flow rate and/or formation pressure prior to completing the well.

3.1.43 drill string float: A check valve in the drill string that will allow fluid to be pumped into the well but will prevent flow from the well through the drill pipe.

3.1.44 drilling break: A change in the rate of penetration that may or may not be a result of penetrating a pressured reservoir.

3.1.45 drilling spool: A flanged joint placed between the BOP and casing-head or between BOPs that serve as a spacer or crossover.

3.1.46 drive pipe: A relatively short string of large diameter pipe usually set in a drilled hole in onshore operations; it is normally washed, driven, or forced into the ground in bottom-supported offshore operations; sometimes referred to as structural pipe.

3.1.47 dynamic well kill procedure: A planned operation to control a flowing well by injecting fluid of a sufficient density and at a sufficient rate into the well bore to effect a kill without completely closing in the well with the surface containment equipment.

3.1.48 Equivalent Circulating Density (ECD): The sum of pressure exerted by hydrostatic head of fluid, drilled solids, and friction pressure losses in the annulus divided by depth of interest and by 0.052, if ECD is to be expressed in pounds per gallon (lb/gal).

3.1.49 final circulating pressure: Drill string pressure required to circulate at the selected kill-rate adjusted for increase in kill drilling fluid density over the original drilling fluid density; used from the time kill drilling fluid reaches the bottom of the drill string until kill operations are completed or a change in either kill drilling fluid density or kill-rate is effected.

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

3.1.51 formation breakdown: An event occurring when borehole pressure is of magnitude that the exposed formation accepts whole fluid from the borehole.

3.1.52 formation competency (formation integrity): The ability of the formation to withstand applied pressure.

3.1.53 formation competency test (formation integrity test): Application of pressure by superimposing a surface pressure on a fluid column in order to determine ability of a subsurface zone to withstand a certain hydrostatic pressure.

3.1.54 formation fracture gradient: The hydrostatic value expressed in psi/ft. that is required to initiate a fracture in a subsurface formation (geologic strata).

3.1.55 formation integrity: See Formation Competency.

3.1.56 formation integrity test: See Formation Competency Test.

3.1.57 formation pressure (pore pressure): Pressure exerted by fluids within the pores of the formation (see Pore Pressure).

3.1.58 flow line sensor: A device to monitor rate of fluid flow from the annulus.

3.1.59 fracture gradient (frac gradient): The pressure gradient (psi/ft) at which the formation accepts whole fluid from the well bore.

3.1.60 gas buster: A slang term to denote a mud: gas separator.

3.1.61 gas cut drilling fluid: Drilling Fluid that has become entrained with gas from previously drilled gas bearing formation which in turn lowers the drilling fluid density and hydrostatic head of the drilling fluid column.

3.1.62 gunk plug: A volume of gunk slurry placed in the well bore.

3.1.63 gunk slurry: A slang term to denote a mixture of diesel oil and bentonite.

3.1.64 gunk squeeze: Procedure whereby a gunk slurry is pumped into a subsurface zone.

3.1.65 H_2S: An abbreviation for hydrogen sulfide.

3.1.66 hydrogen sulfide: A highly toxic, flammable, corrosive, gas sometimes encountered in hydrocarbon bearing formations.

3.1.67 hydrogen sulfide service: Refers to equipment designed to resist corrosion and hydrogen embrittlement caused by exposure to hydrogen sulfide.

3.1.68 hard close-in: To Close-in a well by closing a BOP with the choke and/or choke line valve closed.

3.1.69 hydrostatic head: The true vertical length of fluid column, normally in feet.

3.1.70 hydrostatic pressure (hydrostatic head): The pressure that exists at any point in the well bore due to the weight of the vertical column of fluid above that point.

3.1.71 influx: The flow of fluids from the formation into the well bore.

3.1.72 initial circulating pressure: Drill pipe pressure required to circulate initially at the selected kill-rate while holding casing pressure at the closed-in value; numerically equal to kill-rate circulating pressure plus closed-in drill pipe pressure.

3.1.73 Inflow Performance (IPR): represents the ability of a well to produce fluids and is typically represented by the curve of a plot of flowing pressure versus flow rate.

3.1.74 inside BOP: A device that can be installed in the drill string that acts as a check valve allowing drilling fluid to be circulated down the string but prevents back flow.

3.1.75 kelly: The uppermost component of the drill string; the kelly is an extra-heavy joint of pipe with flat or fluted sides that is free to move vertically through a “kelly bushing” in the rotary table; the kelly bushing imparts torque to the kelly and thereby the drill string is rotated.

3.1.76 kelly cock: A valve immediately above the kelly that can be closed to confine pressures inside the drill string.

3.1.77 kelly valve, lower: An essentially full-opening valve installed immediately below the kelly, with outside diameter equal to the tool joint outside diameter.

3.1.78 kick: Intrusion of formation fluids into the well bore.

3.1.79 kill drilling fluid density: The unit weight, e.g., pounds per gallon (lb/gal), selected for the fluid to be used to contain a kicking formation.

3.1.80 kill line: The high-pressure piping between the pumps and BOP outlets or wellhead outlets.

3.1.81 kill-rate: A predetermined fluid circulating rate, expressed in fluid volume per unit time, which is to be used to circulate under kick conditions. The kill-rate is usually some selected fraction of the circulating rate used while drilling.

3.1.82 kill-rate circulating pressure: Pump pressure required to circulate kill-rate volume under non-kick conditions.

3.1.83 leak-off test: Application of pressure by superimposing a surface pressure on a fluid column in order to determine the pressure at which the exposed formation accepts whole fluid.

3.1.84 lost circulation (lost returns): The loss of whole drilling fluid to the well bore.

3.1.85 lost returns: See Lost Circulation.

3.1.86 low choke pressure procedure: Consists of circulating and weighting up the drilling fluid, both at the maximum rates, while holding the maximum allowable casing pressure on the choke.

3.1.87 lubrication: Alternately pumping a relatively small volume of fluid into a closed well bore system and waiting for the fluid to fall toward the bottom of the well.

3.1.88 marine riser system: The extension of the well bore from the subsea BOP stack to the floating drilling vessel which provides for fluid returns to the drilling vessel, supports the choke, kill, and control lines, guides tools into the well, and serves as a running string for the BOP stack.

3.1.89 mud-gas separator: A vessel for removing free gas from the drilling fluid returns.

3.1.90 normal pressure: Formation pressure equal to the pressure exerted by a vertical column of water with salinity normal for the geographic area.

3.1.91 overbalance: The amount by which pressure exerted by the hydrostatic head of fluid in the well bore exceeds formation pressure.

3.1.92 pack-off or stripper: A device with an elastomer packing element that depends on pressure below the packing to effect a seal in the annulus. Used primarily to run or pull pipe under low or moderate pressures. This device is not dependable for service under high differential pressures.

3.1.93 pipe rams: Rams whose ends are contoured to seal around pipe to close the annular space. Separate rams are necessary for each size (outside diameter) pipe in use.

3.1.94 pore pressure (formation pressure): Pressure exerted by the fluids within the pore space of a formation.

3.1.95 pressure gradient, normal: The normal pressure divided by true vertical depth.

3.1.96 primary well control: Prevention of formation fluid flow by maintaining a hydrostatic pressure equal to or greater than formation pressure.

3.1.97 Productivity Index (PI): The PI represents one point on an inflow performance curve (IPR) and is defined as the well flow in barrels per day per psi pressure drop.

3.1.98 Remotely Operated Vehicle (ROV): An unmanned vehicle for offshore subsea use.

3.1.99 replacement: The process whereby a volume of fluid equal to the volume of steel in tubulars and tools withdrawn from the well bore is returned to the well bore.

3.1.100 rotating head or rotating drilling head: A rotating, low pressure sealing device used in drilling operations utilizing air, gas, or foam (or any other drilling fluid whose hydrostatic pressure is less than the formation pressure) to seal around the drill stem above the top of the BOP stack.

3.1.101 rotating stripper head: A sealing device installed above the BOPs and used to close the annular space about the drill pipe or kelly when pulling or running pipe under pressure.

3.1.102 rotary table: A device through which passes the bit and drill string and that transmits rotational action to the kelly.

3.1.103 safety factor: In the context of this publication, an incremental increase in drilling fluid density beyond the drilling fluid density indicated by calculations to be needed to contain a kicking formation.

3.1.104 saltwater flow: An influx of formation saltwater into the well bore.

3.1.105 shale shaker: A vibrating screen that removes relatively large size cuttings from the drilling fluid returns.

3.1.106 shear rams: BOP rams with a built-in cutting edge that will shear tubulars that may be in the hole.

3.1.107 soft close-in: To Close-in a well by closing a BOP with the choke and choke line valve open, then closing the choke while monitoring the casing pressure gauge for maximum allowable casing pressure.

3.1.108 sour gas: Natural gas containing hydrogen sulfide.

3.1.109 space-out: Procedure conducted to position a predetermined length of drill pipe above the rotary table so that a tool joint is located above the subsea 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.

3.1.110 space-out joint: The joint of drill pipe used in hang off operations so that no tool joint is opposite a set of preventer rams.

3.1.111 squeezing: Pumping fluid into one side of the drill pipe/annulus flow system with the other side closed to allow no outflow.

3.1.112 stripping: A procedure for running or pulling pipe from the well bore with pressure in the annulus.

3.1.113 structural casing: The outer string of large-diameter, heavy-wall pipe installed in wells drilled from floating installations to resist the bending moments imposed by the marine riser and to help support the wellhead installed on the conductor casing.

3.1.114 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.

3.1.115 swabbing: The lowering of the hydrostatic pressure in the well bore due to upward movement of tubulars and/or tools.

3.1.116 target: A bull plug or blind flange at the end of a tee to prevent erosion at a point where change in flow direction occurs.

3.1.117 targeted: Refers to a fluid piping system in which flow impinges upon a lead-filled end (target) or a piping tee when fluid transits a change in direction.

3.1.118 trip gas: An accumulation of gas, which enters the hole while a trip is made.

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

3.1.120 tubulars: Drill pipe, drill collars, tubing, and casing.

3.1.121 underbalance: The amount by which formation pressure exceeds pressure exerted by the hydrostatic head of fluid in the well bore.

3.1.122 underground blowout: An uncontrolled flow of formation fluids from a subsurface zone into a second subsurface zone.

3.1.123 weight cut: The amount by which drilling fluid density is reduced by entrained formation fluids or air.

3.1.124 wireline preventers: Preventers installed on top of the well or drill string as a precautionary measure while running wirelines. The preventer packing will close around the wireline.

3.2 ACRONYMS AND ABBREVIATIONS

The following acronyms and abbreviations are used in this publication:

API	American Petroleum Institute
BOP	Blowout Preventer
IADC	International Association of Drilling Contractors
ID	Inside Diameter
OD	Outside Diameter
psi	pounds per square inch

4 Principles of Well Control

4.1 GENERAL

Formation flow during drilling and well servicing operations is generally referred to as a "kick." Formation fluid that flows into the well bore is referred to as "well influx." If not controlled, a kick may result in a blowout. Well control procedures are intended to safely prevent or handle kicks and re-establish primary well control. This Section discusses common elements and principles of well control. Appendix A, Kick Pressure and Gradient Calculations, contains additional discussion and calculations for well pressure gradients and well control. Well control procedures and practices are discussed in other Sections. However, each is based on the basic principles referred to in this Section.

4.2 CONVENTIONS

Most of this document and the examples are written from a drilling operations perspective. The principles and procedures in this document cover other operations where well control principles and practices are used such as completion, workover, well service, and plug and abandonment.

4.2.1 Design for Specific Rig, Equipment, and Conditions

The drilling, completion, workover, well service, and plug and abandonment operations are done with a wide range of rigs, equipment, and in a variety of conditions. The procedures contained herein are of a general nature and must be reviewed and modified for the specific rig, equipment, and conditions expected in a particular operation.

4.2.2 Drill Pipe/Tubing/Casing

Unless otherwise noted, the term "drill pipe" can also apply to any string of pipe being run in the hole whether it be drill pipe, drill collars, tubing, casing, a liner, or coiled tubing.

4.2.3 Drilling/Workover Fluid

Unless otherwise noted, the term "drilling fluid" can also apply to "workover" or "completion" fluid. Drilling and workover fluids can be gas, liquid, or foam (refer to 4.5).

4.2.4 Circulation

Unless otherwise noted, the term “circulation” refers to conventional circulation, which is circulating fluids down the interior of a string of pipe in the well and up the annulus. Reverse circulation is the opposite; fluid is circulated down the annulus and up the pipe in the hole.

4.3 PRIMARY WELL CONTROL

Primary well control is the maintenance of hydrostatic pressure in the well bore that is equal to or greater than the formation pressure prevents formation flow. Figure 4.1 illustrates an example. The drilling fluid column pressure is 5,200 psi at the bottom of a 10,000 ft. column of 10.0 lb/gal drilling fluid; the formation fluid pressure is 4,650 psi. The difference, or overbalance pressure, is 550 psi; therefore the formation in the well will not flow.

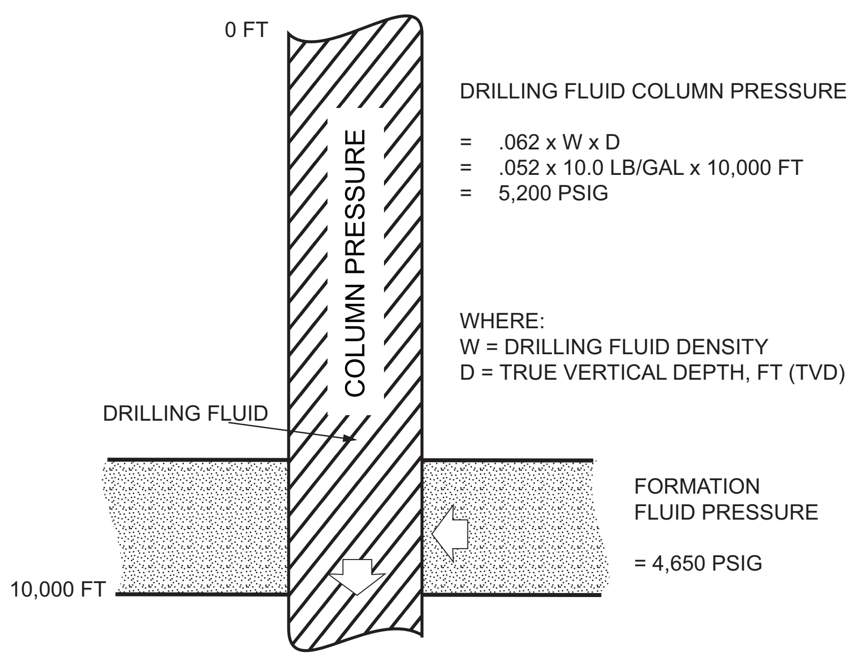
4.4 THE FLOWING WELL

Understanding well control requires some background understanding of well flow. A drilling well experiencing a flow from a formation is acting as a producing well. A producing well is a system of interrelated components. The behavior or performance of any one of the components is related to the performance of each of the other components. These relationships determine the rate and volume at which a particular formation in a well will flow. Two relationships require examination: well performance and equipment performance.

4.4.1 Well Performance

Flow rate versus pressure is calculated through the flow path from the bottom of the well to the top. Well performance is independent of the equipment downstream of the point of analysis. The inflow performance relationship (IPR) is the most common well performance relationship. IPR is the flow rate (q) versus pressure at the formation face (refer to Figure 4.2). The more common term, productivity index (PI), is a special case of IPR that applies only to single phase, incompressible flow.

The type of reservoir and reservoir characteristics influence the production rate. Reservoirs can be one of three basic drive mechanisms: water drive, solution gas drive, or gas cap expansion drive, or combinations of the three. Flow may be water, gas, oil or combinations of all three. The productivity of a well increases as formation permeability and net pay increase; as productivity increases, so does kick intensity. A high-angle or horizontal well bore through a section of formation will have more feet of net pay than a vertical well bore. If permeability is the same in both wells, the one with the most pay has potential for a larger kick. These factors influ-



OVERBALANCE = DRILLING FLUID COLUMN PRESSURE Ð FORMATION FLUID PRESSURE
= 5,200 PSI Ð 4,650 PSI = 550 PSI

Figure 4.1—Example of Primary Well Control Conditions

ence the shape of the IPR curves for particular wells. The same is true for the equipment performance curve. The size of the hole, the size of casings, and the size of the tubular goods influence the shape of a particular equipment performance curve.

4.4.2 Equipment Performance

Flow rate versus pressure is calculated at the point of analysis (refer to Figure 4.3).

Every point on the equipment performance curve is valid. However, the only valid value for the well system is at the intersection of the IPR and equipment performance curve (refer to Figure 4.4).

4.4.3 Conditions for Well Flow

If the equipment performance curve for gas/liquid flows in the well bore does not cross the well performance curve (stays to the right of it in the convention shown in example Figure 4.5), the well will not flow. To kill a well, the equipment performance curve must be designed to exceed the well performance curve. This is called "dynamic kill." This means the backpressure that can be applied by the hydrostatic head plus the hydraulic friction of the fluids in the annulus must exceed the inflow performance relationship (IPR).

4.4.4 Application of Backpressure to Control Well Flow

Backpressure can be affected by the pump rate, drilling fluid density, and flow restriction in the equipment downstream of the formation face. All of these effects should be considered but the choke is used to adjust backpressure during kill operations. Following are three examples:

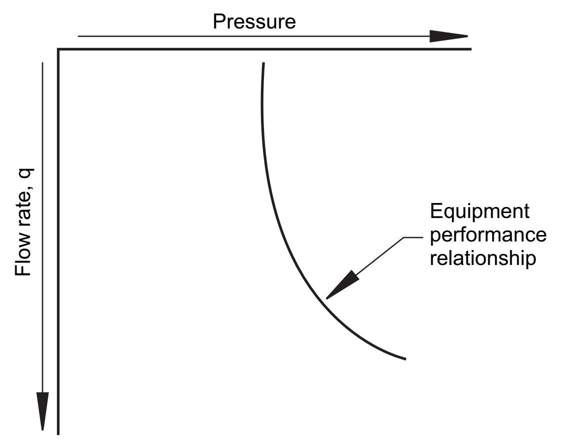


Figure 4.3—Equipment Performance Relationship

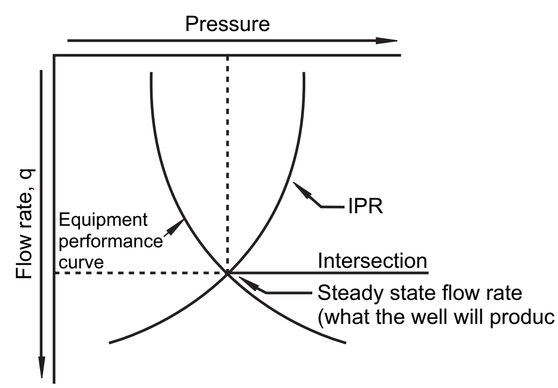


Figure 4.4—Equipment & Well Performance Curves

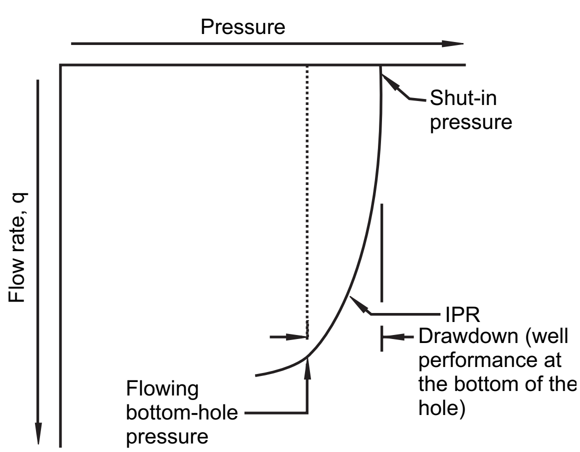


Figure 4.2—Well Performance

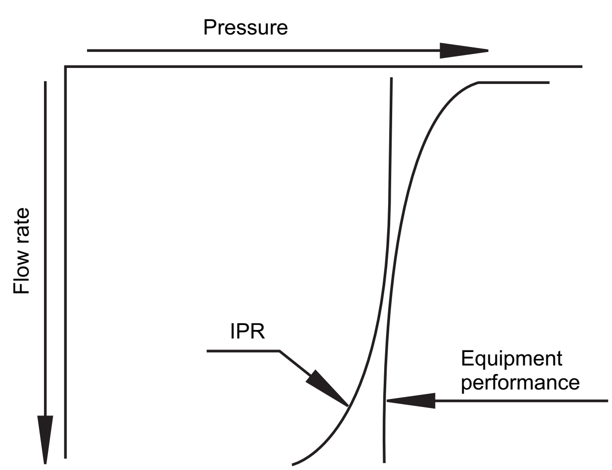


Figure 4.5—Dynamic Kill

1. Pump Rate—Increasing the pump rate results in additional pressure drop, thus more backpressure on the formation.
2. Flow Restriction—When drilling with a BOP, backpressure can be applied by a surface choke.
3. Fluid Density—If drilling without a riser (circulating mud back to the seafloor), backpressure at the formation face is affected by the hydrostatic pressure of the drilling fluid from the bottom of the hole to the sea floor plus the hydrostatic pressure exerted by the sea.

4.4.5 Well Control Design

A well is usually studied at the discharge (surface) or at the formation (bottom), but may be analyzed at any point in the system. The point selected depends on what is being studied. For example, the diverter may be the point of analysis if the effect of vent line size is being evaluated, the riser may be the point of analysis if the effect of riser size is being evaluated, or the choke line if a deepwater subsea stack is being analyzed.

4.5 DRILLING OR WORKOVER FLUID

Drilling fluid properties are of primary significance in well control. The density of the drilling fluid determines the hydrostatic pressure at any point in the static well bore. When a well is circulated, the hydrostatic pressure of the fluid column is combined with the resistance of the fluid to flow, as measured by fluid viscosity, and the pressure drop caused by the friction of the fluids moving through the pipe, equipment, and hole; all must be taken into account to determine pressure at some point in the system. Viscosity is a function of the drilling fluid composition as well as the temperature. Mud system composition varies from the simple to the highly complex. During a kick, the properties of the drilling fluid can be changed due to the influx of formation fluids. For more information on drilling fluids refer to API RP 13D, *Recommended Practice for Rheology and Hydraulics of Oil-Well Drilling Fluids*; API RP 13B-1, *Recommended Practice for Standard Procedure for Field Testing Water- based Drilling Fluids*; and API RP 13B-2, *Recommended Practice for Standard Procedure for Field Testing Oil-based Drilling Fluids*.

4.5.1 Density

Density is the weight of a specific volume of fluid. The density of drilling and workover fluids is commonly referred to "mud weight" and expressed in pounds per gallon (lbs/gal).

4.5.2 Composition

Drilling and workover fluids include air, natural gas, nitrogen, foam, freshwater, saltwater, gelled fresh water, gelled saltwater, seawater, synthetic fluids, and oil-based fluids. The composition of the fluid system design varies with the temperatures, pressures, and composition of the expected formations and the objectives of the well. Fluid composition may be changed several times during the drilling and completion of a well. Environmental and government regulation can affect selection of drilling fluid composition.

4.5.2.1 Air, Natural Gas, and Foam

These highly compressible drilling and workover fluids require special considerations. They are generally used in areas where low-pressure formations are expected when drilling or conducting remedial cleanout operations. Although these operations are not usually associated with well control problems, well control situations can occur. The hydrostatic pressure exerted by a column of these fluids is small and the fluid density cannot be readily increased. It is important to review field and well history, pressure data, and geology to predict potential problems that might occur and have appropriate contingency plans. In many cases, bullheading (refer to 4.11.1 for bullheading operations) water or other fluid will provide the necessary hydrostatic pressure to regain primary well control.

4.5.2.2 Water-Based Fluids

Included in this category are freshwater, seawater, produced saltwater, and specialized brines such as calcium chloride and zinc bromide. The desired fluid properties are achieved with gels, polymers, inhibitors, and/or weighting material. Water-based fluids are, for all practical purposes, incompressible and relatively (compared to oil based fluids) unaffected by expansion due to temperature; the compressibility and temperature expansion factors that exist tend to cancel each other. However, temperature effects should not be ignored when working with water-based fluids. Natural gas solubility in water-based fluids is negligible. These properties provide a relatively stable and predictable fluid density throughout the circulating system and a relatively predictable choke response. Calculated bottom-hole pressures can be predicted with relative certainty. Hydrate formation in cold temperatures can be a concern and is especially so in deepwater. Hydrate formation can be inhibited with glycols and glycerin additives.

4.5.2.3 Oil and Synthetic Based Fluids

Oil-based fluids can be hydrocarbon and mineral oil based. Synthetic fluids include a number of formulations that simulate the properties of oil-based fluids. Oil and synthetic based fluids can be less dense than water-based fluids; a consideration if less hydrostatic pressure is required to avoid fracturing a formation. However, oil and synthetic based fluids are more sensitive to pressure, temperature, and gas solubility than water-based fluids. For example:

1. Oil and synthetic based fluids are more compressible than water-based fluids and as they compress, they gain

density. This effect becomes more pronounced in deep wells and deepwater.

2. Oil and synthetic based fluids are more temperature sensitive than water-based fluids. High temperatures tend to cause thinning and expansion; low temperatures, the opposite. In onshore and shallow water offshore wells, temperature and compressibility tend to balance each other. The temperature effect is most evident in deepwater where the drilling fluid passes from below the mudline to the large diameter riser where the temperatures are in the range of 35° to 50°F. Choke and kill lines are similarly affected.

3. Natural gas is more soluble in oil and synthetic based fluids than in water-based fluids.

4.6 INFLUX BEHAVIOR

Well influx can consist of gas, water, oil, or any combination of these media. Well influx forms a slug in the well bore. The slug is usually less dense than the drilling fluid and must be removed or pumped back into the formation.

4.6.1 Gas

Gas is a highly compressible fluid; the volume occupied depending on temperature and pressure. Consider a barrel of gas at the bottom of a 10,000-ft well. The bottom-hole temperature is 170°F and the well is full of 9.0 lb/gal drilling fluid, which provides a hydrostatic pressure of 4,680 psi on the gas. This same barrel of gas will expand to occupy a volume of 280 barrels under atmospheric conditions (assuming 0.6 specific gravity gas at 80°F and 14.7 psia). If that barrel of gas is not allowed to expand in a controlled manner as it is circulated up the well bore, it will maintain its initial pressure of 4,680 psi as it moves up the annulus, and may create excessive well bore pressures.

Gas is also highly soluble in oil-base and synthetic- or pseudo-oil-base fluids; therefore, special care is required for detecting kicks and handling them with these fluids. Since dissolved gas kicks become an integral part of the liquid phase, these kicks do not behave the same way as free-gas kicks. Specifically, a gas influx which dissolves is more difficult to detect early, and gas breakout can occur rapidly nearer the surface. Solubility depends on factors such as temperature, pressure and fluid composition. For additional information on solubility effects in deepwater operations, refer to the *IADC Deepwater Well Control Guidelines*.

4.6.2 Water

Water is nearly incompressible; it does not expand to any appreciable extent as pressure is reduced. Due to this property, pumping and returns rates are equal as a water kick is circulated from the well bore, provided no further water influx is permitted or fluid is lost. To maintain constant bottom-hole pressure, the casing pressure must be allowed to decline as the lighter water is displaced and heavier drilling fluid replaces it in the annulus. An increase in drilling fluid density during a well kill operation also changes the casing pressure. Nearly all water influxes contain some solution gas, which requires that surface pressures follow a pattern similar to that seen during a gas kick.

4.6.3 Oil

Like gas-charged saltwater, oil behaves essentially like a smaller gas influx.

4.7 FORMATION INTEGRITY TESTS

The pressure at which a formation fractures determines whether the open-hole section can withstand the pressures found in deeper formations. Two tests are designed to yield this information: the leak-off test and the formation competency test. It is important to have accurate drilling fluid density and pressure data for these tests to yield meaningful results. Use representative samples for measuring the fluid density and use a pressure gauge with the appropriate scale and that has been calibrated.

4.7.1 Leak-off Test

A leak-off test is made to determine the pressure at which a formation will fracture. It is usually run after drilling a short distance below the surface casing shoe and may be run as other casing strings are run as well. The test is performed by pumping drilling fluid into the well bore at a slow rate (typically one-half barrel per minute) with the BOP closed and plotting the resulting pressure versus the total volume pumped. The pressure at which the plotted curve begins to flatten, i.e., when the pressure increases a smaller amount for a volume pumped, is the surface leak-off pressure. At that point, the pump should be stopped immediately. This pressure plus the hydrostatic pressure of the drilling fluid is the formation fracture pressure.

$$\text{Formation fracture pressure (psi)} = \text{Leak-off pressure (psi)} + [0.052 \times \text{Drilling fluid density (lb/gal)} \times \text{Casing TVD (ft)}].$$

4.7.1.1 It is useful to calculate the formation fracture gradient as equivalent or fracture drilling fluid density.

$$\text{Fracture drilling fluid density (lb/gal)} = \frac{\text{Leak-off pressure}}{0.52 \times \text{Casing TVD (ft)}} + \text{Drilling fluid density in use during test (lb/gal)}$$

4.7.1.2 Fracture pressure is the maximum surface pressure that can be applied to a casing that is full of drilling fluid without fracturing the formation. Fracture pressure is calculated as follows:

Fracture pressure (psi) =
0.052 x Casing TVD (ft) x
[Fracture drilling fluid density (lb/gal) –
Present drilling fluid density (lb/gal)].

4.7.2 Formation Competency Test

A formation competency test is made to determine if a well bore will support drilling fluid of a higher density at some future time during the well drilling operations. Perform the test by pumping drilling fluid into the well bore at a slow rate, typically one-half barrel per minute, with the BOPs closed. Pump into the well bore until reaching the predetermined test pressure as calculated below:

Test pressure (psi) =
0.052 x Casing TVD (ft) x
[Required test drilling fluid density (lb/gal) –
drilling fluid density currently in use (lb/gal)].

During the test, plot surface pressure against volume pumped. If the plotted curve begins to flatten or the pressure decreases, pumping should be stopped immediately (refer to 4.7.1).

4.8 WELL CONTROL PRESSURES

Well control design and procedures require measurement and calculation of pressure at several points in a well and well control system. A circulating well is more complicated than the static well illustrated in Figure 4.1. This is due to the friction generated by the flow of fluid in the well piping, the open hole, and the inherent resistance of liquids to flow. Pressure must be applied to overcome these forces to circulate a well. Pressure applied at the top of a drilling string alters pressures throughout the pipe and hole. In fact, fluid circulation creates additional overbalance that can help control the well but may also cause excessive pressure that can lead to formation fracture. Several pressure measurements, calculations, and concepts are discussed below with examples to illustrate their significance.

4.8.1 Pressure Measurement

Pressure measurement is a key component of well control. Pressure gauges should be in good working order and calibrated per the recommendations in Section 17 (Surface BOP) and Section 18 (Subsea BOP) of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells*. Select a gauge with a display range appropriate to the pressure information required.

4.8.2 Static Well Pressures

To understand how the various pressures interact, it is necessary to isolate and identify each one. Figure 4.6 illustrates various pressures in a static well bore. The drill pipe gauge pressure plus the hydrostatic pressure of the drilling fluid equals the bottomhole pressure. The same pressure balance can be made for the annulus, i.e., casing gauge pressure plus the hydrostatic pressure of the annulus drilling fluid plus the hydrostatic pressure of the influx equals the bottomhole pressure.

4.8.3 Circulating Pressures

The main pressure losses that occur in a circulation system are:

1. Friction losses inside the drill pipe, casing, or workover string;
2. Pressure drop across the nozzles or water courses in the bit or shoe;
3. Friction loss in the annular space between the well bore and pipe; and,
4. Friction loss in the surface piping and connections.

The total pressure at the bottom of the hole while circulating is the sum of the combined annular fluid column pressure (hydrostatic head) plus the annular friction pressure plus imposed surface backpressure. The drill pipe circulating pressure is the sum of all friction losses plus corrections due to density imbalances between the drill pipe and the annulus plus any imposed surface backpressure.

4.8.4 Equivalent Circulating Density

The density equivalent of friction pressure in the annulus plus the drilling fluid density in the hole is often expressed as equivalent circulating density (ECD). Figure 4.7 illustrates an example. In this case, the circulating pressure applied to the drill pipe is 2,800 psi. It is largely used to overcome friction of flow through the drill string and bit so that only 200 psi remain to increase pressure in the well bore at bottom. The additional pressure at bottom is due to the friction loss in the annulus. The annular friction circulating pressure is equivalent to increasing the drilling fluid density by 0.4 lb/gal. No increase in pressure occurs at the top of the annulus when circulating.

ECDs greater than formation fracture pressure cause loss of mud and well control problems. ECD is relatively high in some operations due to a combination of hole size, drill string OD, measured depth, and mud properties. Some examples are slimhole drilling and some high-angle or horizontal wells. When circulation stops in these operations, there may be a significant bottomhole pressure reduction. Therefore, it is important to flow check the well when circulation stops to ensure the well is stable without the ECD effects. Pressure measurement while drilling can be very useful in monitoring-

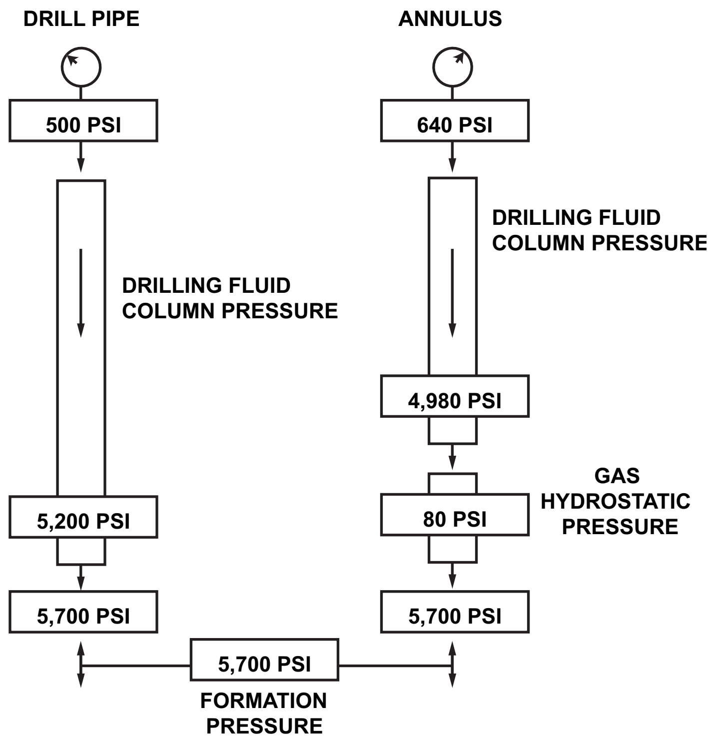


Figure 4.6—Static Well Kick Pressures

ECD. It allows further modeling and calibration of the circulation system.

4.8.5 Reduced Circulating Pressure or Kill-Rate

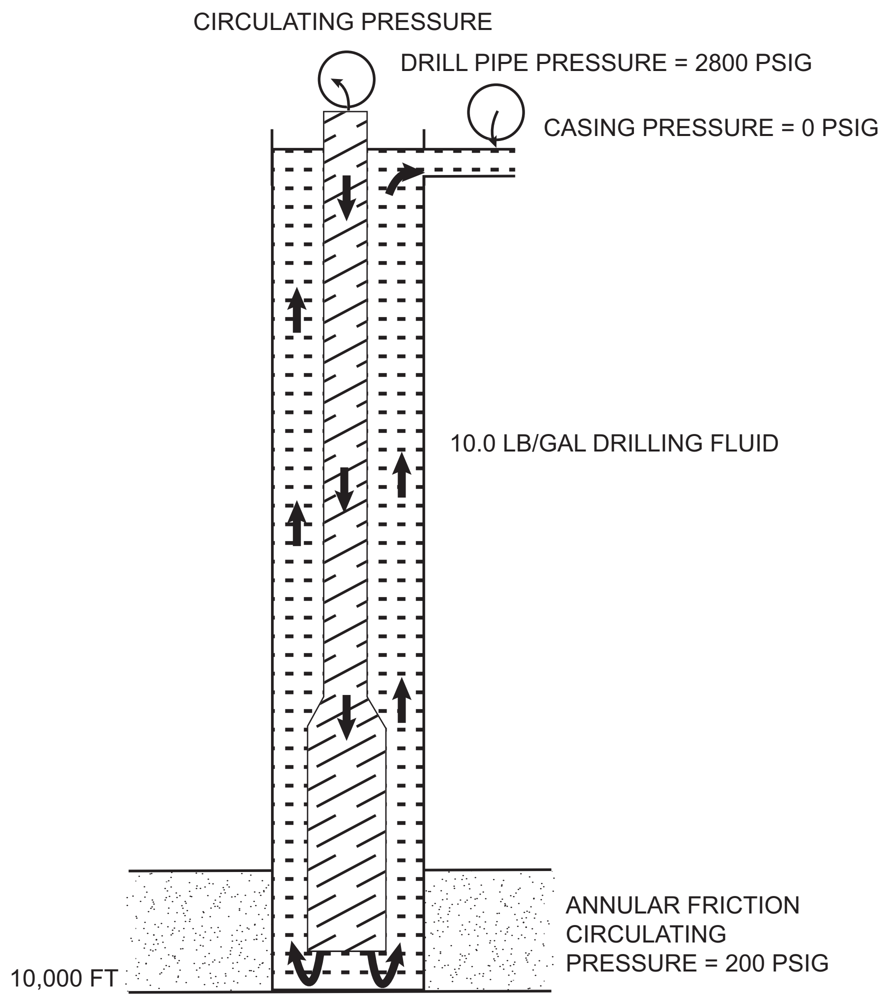
For use in well kill operations, a circulating pressure is generally measured at a convenient reduced circulating (kill) rate. Kill rates are selected based on the ability of the pumps to pump slow, the ability of the mud mixing equipment to weight up mud, maximum circulation pressures, mud gas separator capacity, and choke reaction time, and choke line pressure drop (in the case of subsea wells). The stroke rate and pressure are recorded on the tour sheet for each pump and redone whenever the circulating system pressure is significantly changed, i.e., drilling fluid density, bit nozzles, or over 500 ft of hole is drilled, etc. Reduced circulating pressures are usually required when circulating kicks so that the additional pressure required to prevent formation flow can be added without exceeding the pump discharge pressure rating. The slower circulating rate also simplifies drilling fluid material mixing procedures and handling returns through the choke. In offshore situations, however, it may be desirable to circulate out a kick as rapidly as possible to minimize exposure to adverse weather. The solution to these conflicting objectives is to initiate the well kill at the highest circulating rate that will not cause loss of circulation and reduce the circulation rate preferably before gas reaches the choke line. The example well control worksheet for deepwater operations illustrates a procedure for accomplishing this (refer to Appendix B). Guidance for pre-selecting kill-rates in deepwater is contained in 4.13.4.

4.8.6 Initial and Final Circulating Pressures

An initial and final circulating pressure are used when circulating out kicks. These pressures are a necessity when using the Wait and Weight or Concurrent Weight-up Methods described in 4.10.

4.8.6.1 Initial Circulating Pressure

The initial circulating pressure is the drill pipe pressure after bringing the pump up to the kill-rate while holding casing pressure constant at the closed-in value. It is also equal to the closed-in drill pipe pressure plus the measured circulating pressure at the selected kill-rate (refer to Figure 4.11).



$$\text{EQUIVALENT CIRCULATING DENSITY} = 10\ \text{LB/GAL} + \frac{\text{ANNULAR FRICTION CIRCULATING PRESSURE}}{.052 \times \text{TVD}} = 10.4\ \text{LB/GAL}$$

Figure 4.7—Equivalent Circulating Density

4.8.6.2 Final Circulating Pressure

The final circulating pressure is the measured circulating pressure at the selected kill-rate corrected for drilling fluid density increase.

$$\text{Final Circulating Pressure (psi)} = \text{Kill-rate Pressure (psi)} \times \frac{\text{New Drilling Fluid Density (lb/gal)}}{\text{Old Drilling Fluid Density (lb/gal)}}$$

4.8.6.3 Example: Figure 4.11 shows that, before the kick, the driller measured 750 psi at a kill-rate of 30 strokes per minute, or 4.5 barrels per minute, using a 10.0 lb/gal drilling fluid. The shut-in drill pipe pressure of 520 psi indicates a required drilling fluid density of 11.0 lb/gal at 10,000 feet.

$$\text{Final Circulating Pressure (psi)} = 750\ \text{psi} \times \frac{11.0\ \text{lb/gal}}{10.0\ \text{lb/gal}} = 825\ \text{psi}$$

4.8.7 Closed-in Drill Pipe and Annulus Pressure

Formation pressure near the well bore is reduced during flow. When a well is closed-in, the borehole pressure rises until equal to formation pressure. As the drill pipe and annulus are in communication with the borehole, the drill pipe pressure will also rise and stabilize. The stabilized drill pipe pressure indicates the amount to increase the drilling fluid density to balance the formation pressure. If the well is not circulated, the gas influx will slowly migrate up the hole and increase the well bore and drill pipe pressures. Therefore, drill pipe pressures after the initial stabilized reading indicate excessive drilling fluid density increase. The initial stabilized pressures are very important; they are the basis for determining the fluid density required to regain primary well control. To avoid excess well bore pressure due to the gas influx migrating up the hole, use a choke to bleed drilling fluid from the casing and maintain the initial shut-in drill pipe pressure. These conditions are illustrated in Figure 4.9.

4.8.7.1 Example: Stabilized Pressures of a Well Closed-In on a Kick–Figure 4.8, is a schematic diagram of a well shut-in on a kick. A 20-barrel gas influx occurs while drilling at 10,000 ft with a 10.0 lb/gal drilling fluid. The stabilized closed-in pressures are 500 psi on the drill pipe and 640 psi on the casing or annulus gauge.

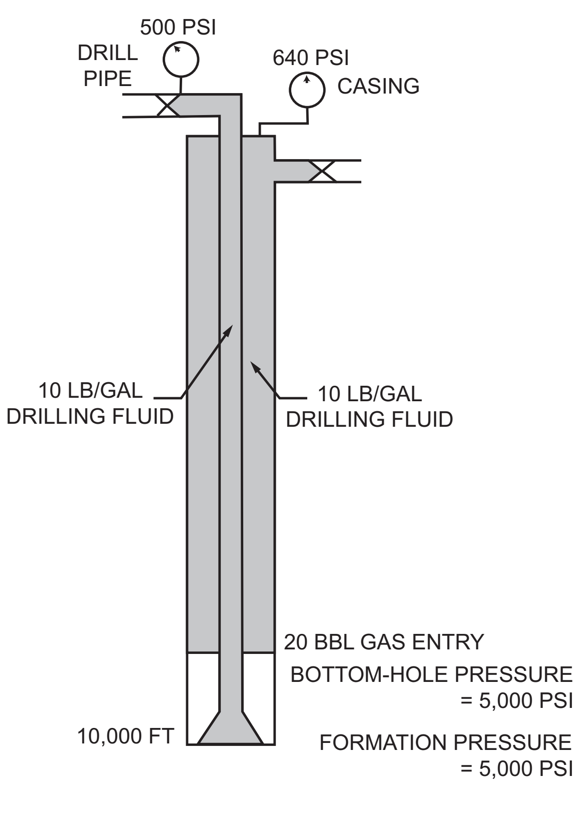


Figure 4.8—Well Closed-In on a Kick

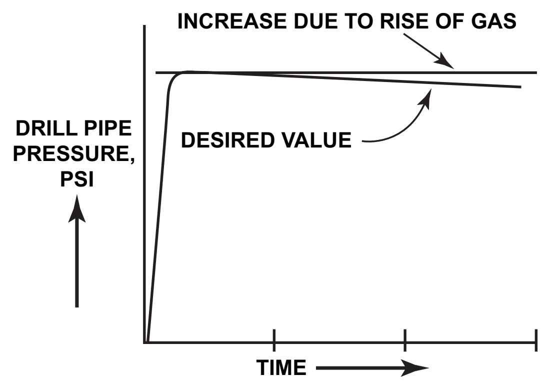


Figure 4.9—Closed-In Drill Pipe Pressure

4.8.7.2 Example: Closed-In Drill Pipe Pressure with a Backpressure Valve, Figure 4.9, to determine the closed-in drill pipe pressure when a backpressure valve is in the drill string, pressure should be increased slowly using the smallest pump available to open the backpressure valve. That pressure is the closed-in drill pipe pressure. If casing pressure rises while pumping on the drill pipe, pumping should be stopped and the increase in casing pressure subtracted from drill pipe pressure.

4.8.7.3 Example: Gas Influx Migrating Up The Hole–Figure 4.10, illustrates an example of a 10,000 ft closed-in well with 10.0 lb/gal drilling fluid and a small volume of gas at bottom. When the gas rises to 5,000 ft without expansion or temperature change, the bottom-hole pressure rises to 7,800 psi, which is equivalent to a 15.0 lb/gal drilling fluid column. When the gas reaches the surface, bottom-hole pressure is 10,400 psi, which is equivalent to a 20.0 lb/gal drilling fluid column. At 5,000 ft the borehole pressure is equivalent to a 30.0 lb/gal drilling fluid column to that depth. Such excessive pressure should be avoided whether gas rises through a static drilling fluid column or circulated out by allowing the gas to expand as it rises. This situation requires that the pits be allowed to gain volume. If a gas bubble is permitted to rise in a well bore without expanding, the gas pressure will remain constant. The reduced hydrostatic head above the gas column must be overcome by increased surface pressure on the casing; in turn, this increased pressure results in a higher bottom-hole pressure.

4.9 WELL CLOSE-IN PROCEDURES

When a kick is detected, the well should be closed-in as quickly as possible to minimize influx volume. There are two close-in procedure options, the soft close-in and the hard close-in. The hard close-in minimizes kick influx volume is less complicated, can be performed by one person working on the rig floor, and is usually performed faster than the soft close-in procedure.

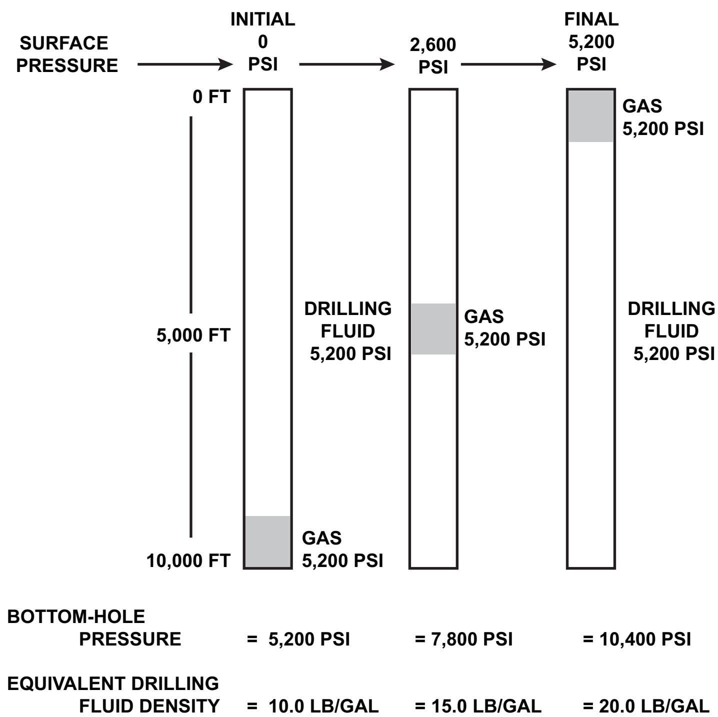


Figure 4.10—Gas Influx Migrating Up The Hole

4.9.1 Soft Close-in Procedure

A choke is left open at all times other than during a well control operation. This permits control and monitoring of casing pressure buildup during closure, an important feature if formation fracturing and broaching to the surface is likely or if the initial closed-in casing pressure is likely to exceed the maximum allowable casing pressure. The soft close-in procedure permits initiation of pre-identified alternate procedures, such as the low choke procedure (see 12.3.5) before maximum allowable casing pressure is reached. The major disadvantage of the soft close-in procedure is that the additional time involved in opening the choke line valve and closing the choke allows additional influx into the well bore. This results in a larger kick volume and potentially higher casing pressure while circulating out the kick thus complicating well control. If the soft close-in procedure is contemplated, it should be given consideration in the well pre-planning phase where other steps may be identified to alleviate its need (higher strength casing, additional casing strings, etc), it can be well planned, and training and drills can be considered.

With the exception of one choke line valve located near the BOP, the choke line valves are aligned such that a flow path is open through the choke system. The soft close-in procedure is:

1. Open the choke line valve.
2. Close the BOP.
3. Close the choke.

4.9.2 Hard Close-in Procedure

The BOP is closed and the chokes remain closed at all times other than during a well control operation. The procedure is simple, allows well closure in the shortest possible time, and minimizes additional influx into the well bore. It is limited to well conditions where the maximum allowable casing pressure is greater than the anticipated initial close-in pressure and a well fracture would not be expected to broach to the surface on initial closure. With the exception of the choke(s) itself and one choke line valve located near the BOP stack, the choke line valves are aligned such that a flow path is open through the choke system. If the casing pressure cannot be measured at the wellhead, the choke line valve is opened with the choke, or adjacent high-pressure valve, remaining closed so that pressure can be measured at the choke manifold.

4.10 METHODS FOR CIRCULATING KICKS AT CONSTANT BOTTOM-HOLE PRESSURE

After a kick is stopped by well closure, circulation should be established, the kick circulated to the surface at constant bottom-hole pressure to avoid further influx, and drilling fluid density increased to establish primary well control (refer to Section A-1 in Appendix A). When circulation can be established, there are three methods of circulating out kicks:

1. Driller's Method—The well is closed-in; then the kick is circulated out without increasing the drilling fluid den-

sity; after the kick is circulated out, drilling fluid of required density circulated.

2. Wait and Weight Method—The well is closed-in; the drilling fluid density is increased in the pits as required; then the kick is circulated out with the required density fluid.

3. Concurrent or "Circulate and Weight" Method—The well is closed-in; then circulation is resumed as soon as pressures stabilize; addition of weight material to the drilling fluid is begun as soon as circulation is started.

4.10.1 Establishing Circulation

The recommended procedure to establish a steady circulating rate while keeping a constant bottom-hole pressure is as follows:

1. Concurrently open the annulus choke and slowly bring the pump up to the selected kill-rate speed.
2. While bringing the pump up to speed, adjust the choke to hold the casing pressure constant at the closed-in value. Holding the casing pressure constant at the closed-in value for the short time required to bring the pump up to speed holds the bottom-hole pressure essentially constant.
3. With the pump running at the desired speed and the casing pressure stabilized at the desired value, read the drill pipe pressure. The drill pipe pressure read at this point is that pressure necessary to maintain a constant bottom-hole pressure as long as the mud weight and pump rate are held constant. The difference between the closed-in and pumping drill pipe pressure is the pressure required to cause the drilling fluid to circulate at the desired rate.
4. Determine the sum of the closed-in drill pipe pressure and the pre-recorded kill-rate circulating pressure. If the drill pipe pressure is appreciably different, investigate the cause.

Note: Changes in pressure due to choke manipulation require approximately two seconds per 1,000 feet of drill string to register on the standpipe gauge; however, this lag in response time can be longer if a large gas kick is present.

5. Keep the drill pipe pumping pressure constant by manipulating the annulus choke, while holding a constant pump rate. If the drilling fluid density in the drill string is increased, reduce the drill pipe pressure to maintain a constant bottom-hole pressure.

4.10.1.1 Annular friction pressure can be viewed as a safety factor to prevent formation fluid flow. This is because, in a circulating well, bottom-hole pressure exceeds formation pressure by the amount of the annular circulating pressure. Annular friction pressure is usually in the range of 50 – 200 psi at 10,000 ft, which is the equivalent of a 0.1 – 0.4 lb/gal increase in the density of a static drilling fluid column.

Note: Additional casing pressure may be applied to provide more safety factor. This additional safety factor should be chosen carefully based on ability to manipulate choke pressure to desired values and fracture pressure of the last casing seat. Extra care should be taken with only surface pipe set because shallow formations may breakdown easily. In general, it is recommended the well be killed first then raise the drilling fluid weight to provide the desired overbalance.

4.10.1.2 Establishing circulation is not always possible, practical or desirable. In those cases, refer to 4.11 for bullheading and top-kill kill methods and to Section 13 for addressing lost circulation and underground blowouts.

4.10.1.3 Example: Stabilized Pumping of a Kick—Figure 4.11 illustrates a well just after circulation is initiated. The well was initially closed-in with 520 psi on the drill pipe and 875 psi on the annulus. Circulation was initiated and the choke adjusted to keep 875 psi on the casing while the pump is brought up to the kill-rate of 4.5 barrels per minute (30 strokes per minute). When the kill-rate is reached, a pumping pressure of 1,270 psi on the drill pipe is indicated. The pumping pressure is composed of the kick pressure of 520 psi plus the pressure necessary to overcome the friction losses in the various parts of the circulating system as shown. The friction loss (750 psi) at 30 strokes per minute should have been measured and recorded previously. Since the drill pipe pressure is the same as the sum of the closed-in drill pipe pressure and the kill-rate pressure (520 psi + 750 psi), no adjustment in drill pipe pressure is necessary (refer to 9.6.4). The annular circulating pressure is assumed to be about 50 psi. The bottom-hole pressure is equal to the sum of the casing pressure plus the hydrostatic pressure of the annular fluids plus the annular circulating friction pressure. The bottom-hole pressure is also equal to the drill pipe pressure plus the hydrostatic pressure of the fluid in the drill string less the friction pressure loss in the drill string and bit. The bottom-hole pressure is also equal to the closed-in drill pipe pressure plus the hydrostatic pressure of the fluid in the drill string plus the annular circulating friction pressure loss.

4.10.2 Driller's Method

The casing pressure required to maintain a constant bottom-hole pressure is dependent on the type of formation fluid and a changing vertical length of formation fluid in the annulus. Under actual conditions, neither the type nor height of formation fluid is known. Therefore, drill pipe pressure control should always be used to keep constant bottom-hole pressure when circulating kicks out of the annulus. In the drill pipe, drilling fluid density is known and the drill pipe pressure can be read on the gauge. These factors, properly used, determine bottom-hole pressure with relative certainty.

4.10.2.1 The procedure described for establishing circulation (refer to 4.10.1) results in a desired drill pipe pressure at a constant kill-rate. To circulate a kick at constant bottom-hole pressure without increasing drilling fluid density, circulating rate and drill pipe pressure should be constant. Drill

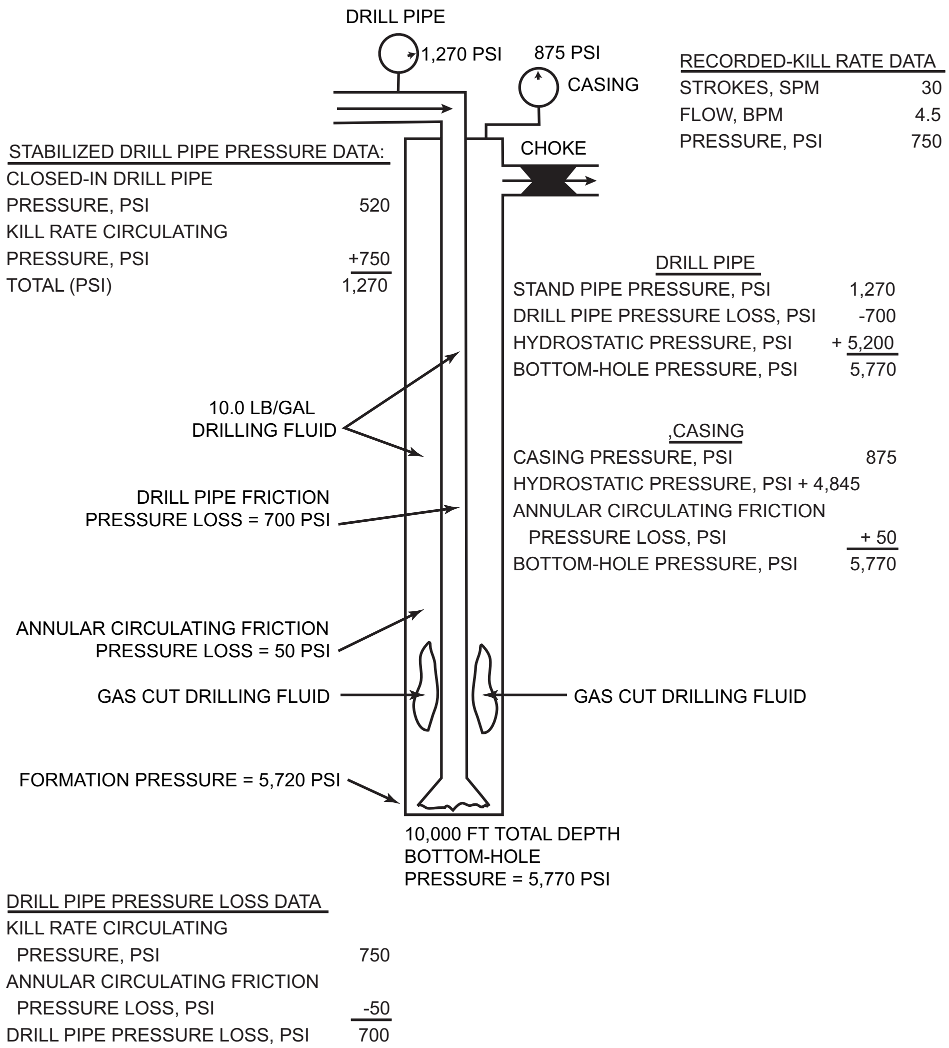


Figure 4.11—Stabilized Pumping Of A Kick

pipe pressure should be held constant by choke manipulation. Circulation can be stopped at any time and the choke closed by keeping casing pressure constant while stopping the pump. Closed-in drill pipe pressure should be the same as when the well was originally closed.

4.10.2.2 During circulation of the kick, gas expansion and pit volume gain should be allowed. As drilling fluid volume in the annulus decreases due to gas expansion, higher casing pressures will result to maintain constant bottom-hole pressure; but the correct bottom-hole pressure will result at all times from proper control of drill pipe pressure.

4.10.2.3 After the kick is circulated out without increasing drilling fluid density, the annulus should be full of drilling fluid. When the well is closed-in, the pressure on the drill pipe and casing should be the same as the original closed-in drill pipe pressure. However, the well is not dead at this point. The well should be closed-in and the drilling fluid density increased in the pits to the required value.

4.10.2.4 Circulation of heavier fluid down the drill pipe at a constant rate will change the circulating drill pipe pressure and eliminate the closed-in drill pipe pressure. The drilling fluid density in the annulus will not change while the heavier fluid is pumped to the bit, therefore a simple way to control bottom-hole pressure is to use constant casing pressure. After the heavier drilling fluid passes the bit, the casing pressure will change; but drill pipe pressure need not change and can be used for control. The steps are as follows:

1. Establish circulation at the selected kill-rate as described in 4.10.1. Hold casing pressure constant at the closed-in value by choke manipulation while bringing the

pump to speed and thereafter until heavy drilling fluid reaches the bit.

2. When the heavy drilling fluid reaches the bit, read the drill pipe pressure gauge and hold the drill pipe pressure constant at the kill-rate by manipulating the choke until the heavy drilling fluid reaches the surface.

3. Shutdown the pump and check for flow.

4.10.2.5 Example: Driller's Method of Circulating Out a Kick—Figure 4.12 illustrates an example of casing pressure and pit volume increase based on the well conditions shown in Figure 4.11. Initial closed-in drill pipe and casing pressures are 520 psi and 875 psi respectively. When circulation is started, a 50-barrel gas influx is alongside the drill collars and the lower part of the drill pipe. The initial closed-in casing pressure is 875 psi and kick volume is 50 barrels as shown at point A. When 25 barrels of drilling fluid is pumped, the gas bubble is alongside the drill pipe and its total length is shortened in the larger annulus. This produces a longer column of drilling fluid and less casing pressure is required at point B to balance bottom-hole pressure. Gas expansion is slow at first, increasing as it rises in the hole. Maximum casing pressure, gas volume in the hole, and pit gain occur when the gas reaches the surface at point C. Between points C and D, the casing pressure decreases rapidly as gas is being replaced in the well by drilling fluid. Pit volume decreases accordingly. At point D all gas is removed and casing pressure is the same as the original closed-in drill pipe pressure. Casing pressure and drill pipe pressure are the same because 10.0 lb/gal drilling fluid fills both the drill pipe and annulus. During a kick while drilling, gas flows into the circulating drilling fluid and a mixture occurs. When the well is shut-in, gas migrates up the hole. While circulating the kick, the gas generally rises faster than the drilling fluid. Because the drilling fluid flow rate outside the drill string is not the same at all points across the hole, some gas will be pushed ahead during the circulation and some will lag. As a result, casing pressures are not exactly as discussed for a single bubble nor are they precisely calculable. Fortunately, the peak casing pressure can be expected to be somewhat less and will occur sooner than displacement volume would indicate as shown at point C in Figure 4.13. Due to lag of gas, some additional volume of drilling fluid will be pumped before the well is free of gas as shown in Figure 4.13.

4.10.3 Wait and Weight Method

When the Wait and Weight Method is used, the well is closed-in on the kick, drilling fluid density is increased as required, and the kick is circulated out using the weighted fluid. Circulation is established at the kill-rate as described in 4.10.1. Drill pipe pressure is used to control bottom-hole pressure because of gas expansion in the annulus, but the required drill pipe pressure changes as the pipe fills with the heavy drilling fluid. Drill pipe pressure is maintained by manipulation of the choke.

4.10.3.1 A schedule of drill pipe pressure change should be prepared and followed. Figure 4.14 shows such a schedule based on the conditions of the 50-barrel kick illustrated in Figures 4.11 and 4.12. Initial circulating pressure is plotted above zero pumpstrokes, and final circulating pressure is plotted above pumpstrokes to the bit. A line is drawn between the two points. If a pumpstroke counter is not available, the drill pipe pressure reduction schedule can be constructed using either minutes or barrels instead of pumpstrokes in Figure 4.14. These values are the drill pipe pressures to hold at the strokes, minutes or barrels shown.

4.10.3.2 The final circulating pressure is held until the heavy drilling fluid circulates around, reaches the surface and the well is dead. Casing pressures and pit volume increases shown in Figure 4.15 are entirely the result of controlling drill pipe pressure. The original closed-in casing pressure is at point A. At point B the gas bubble has been displaced to alongside the drill pipe and has shortened in the larger annulus, thus requiring less casing pressure. At point C, the balancing density drilling fluid enters the annulus and begins to reduce the casing pressure.

At point D, the gas begins to expand rapidly, forcing drilling fluid from the hole and increasing casing pressure. At point E, gas reaches the surface. From points E to F, gas escapes and is replaced by drilling fluid, reducing casing pressure. At point F, light drilling fluid in the drill pipe at the time of well closure reaches the surface and the casing pressure continues to drop until the balancing drilling fluid density reaches the surface and casing pressure is zero. Not shown is pit volume increase due to addition of barite. Note: Due to resistance to flow in the choke line and open choke, a small casing pressure may remain when balancing drilling fluid density reaches the surface. The pressure should be less than 100 psi and will bleed off when the pump is stopped.

4.10.4 Concurrent Method

When the Concurrent Method (also called "Circulate and Weight Method" and "Slow Weight-up Method") is used, the well is closed-in on the kick and circulation resumed as soon as pressures stabilize. Addition of weight material begins as soon as circulation is started.

4.10.4.1 Circulation should be established as described in 4.10.1. Due to gas expansion in the annulus, drill pipe pressure must be controlled to maintain balanced bottom-hole pressure. Changing drilling fluid density alters the circulating pressure required to maintain the balanced bottom-hole pressures so a schedule of drill pipe pressure should be prepared and followed by manipulating the choke. As the drilling fluid density increases continuously until the suction pit reaches

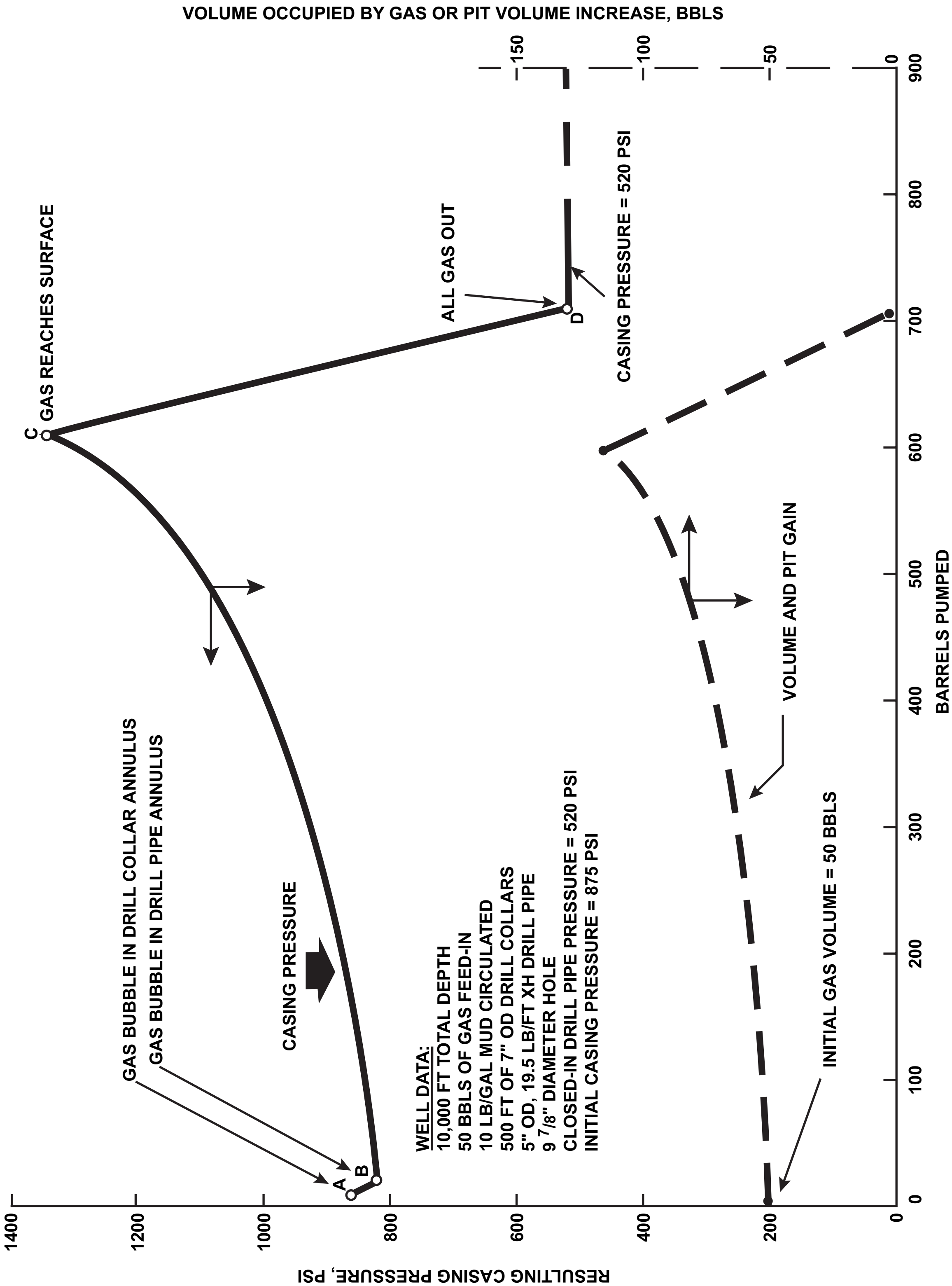


Figure 4.12—Casing Pressure And Gas Volume Resulting From Using The Driller's Method

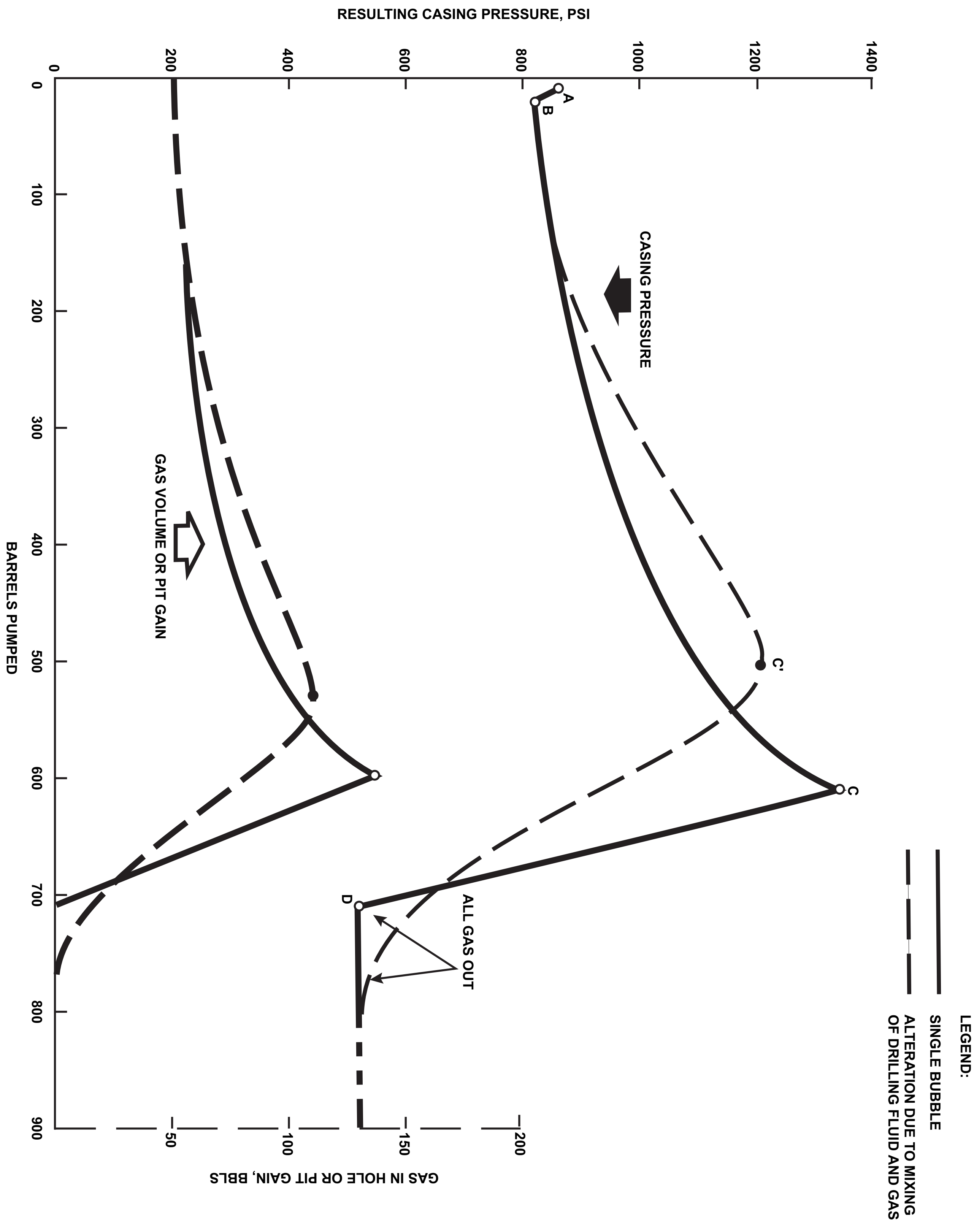


Figure 4.13—Casing Pressure and Gas Volume Using the Driller's Method

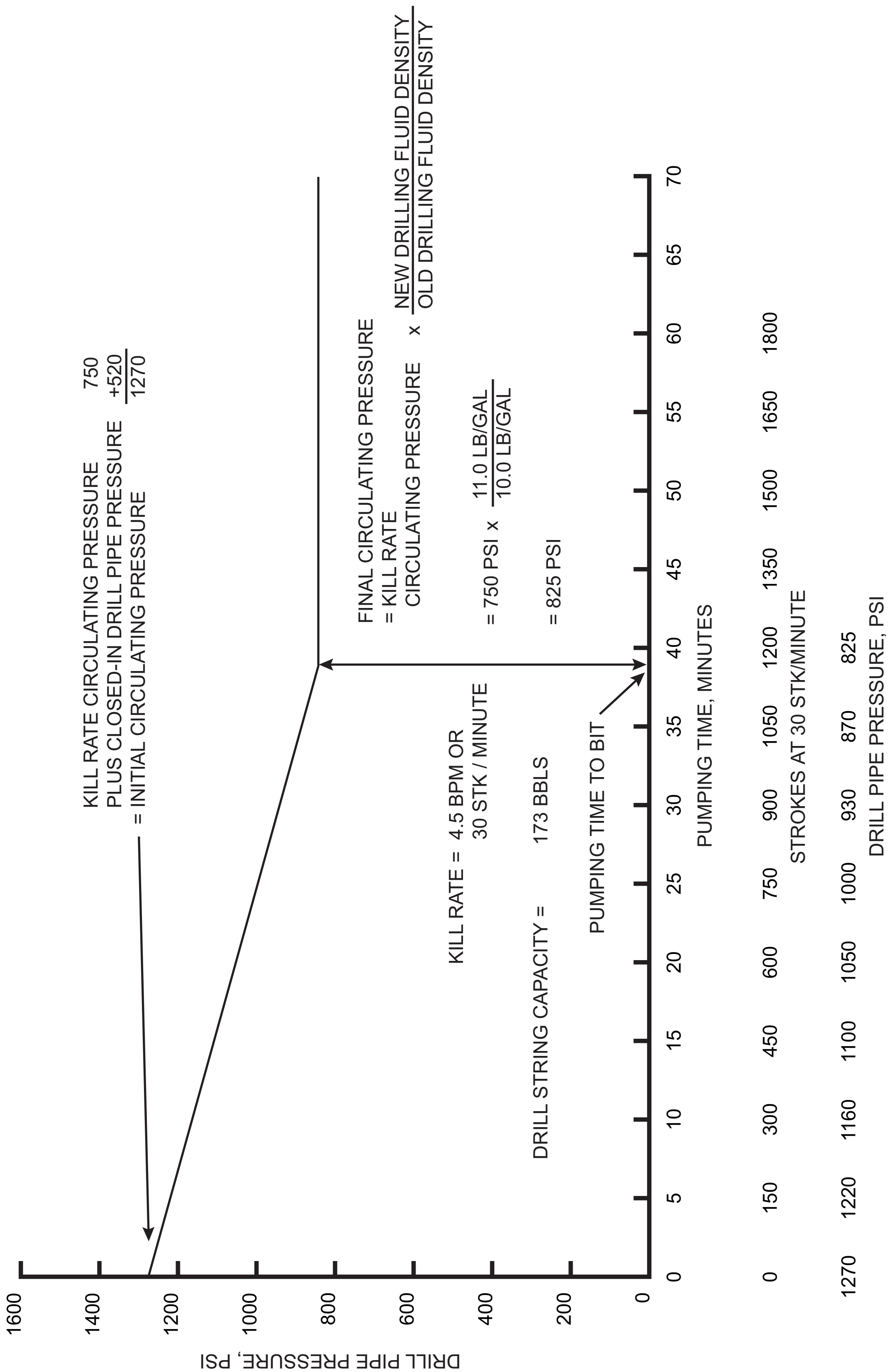


Figure 4.14—Drill Pipe Pressure Schedule for the Wait and Weight Method

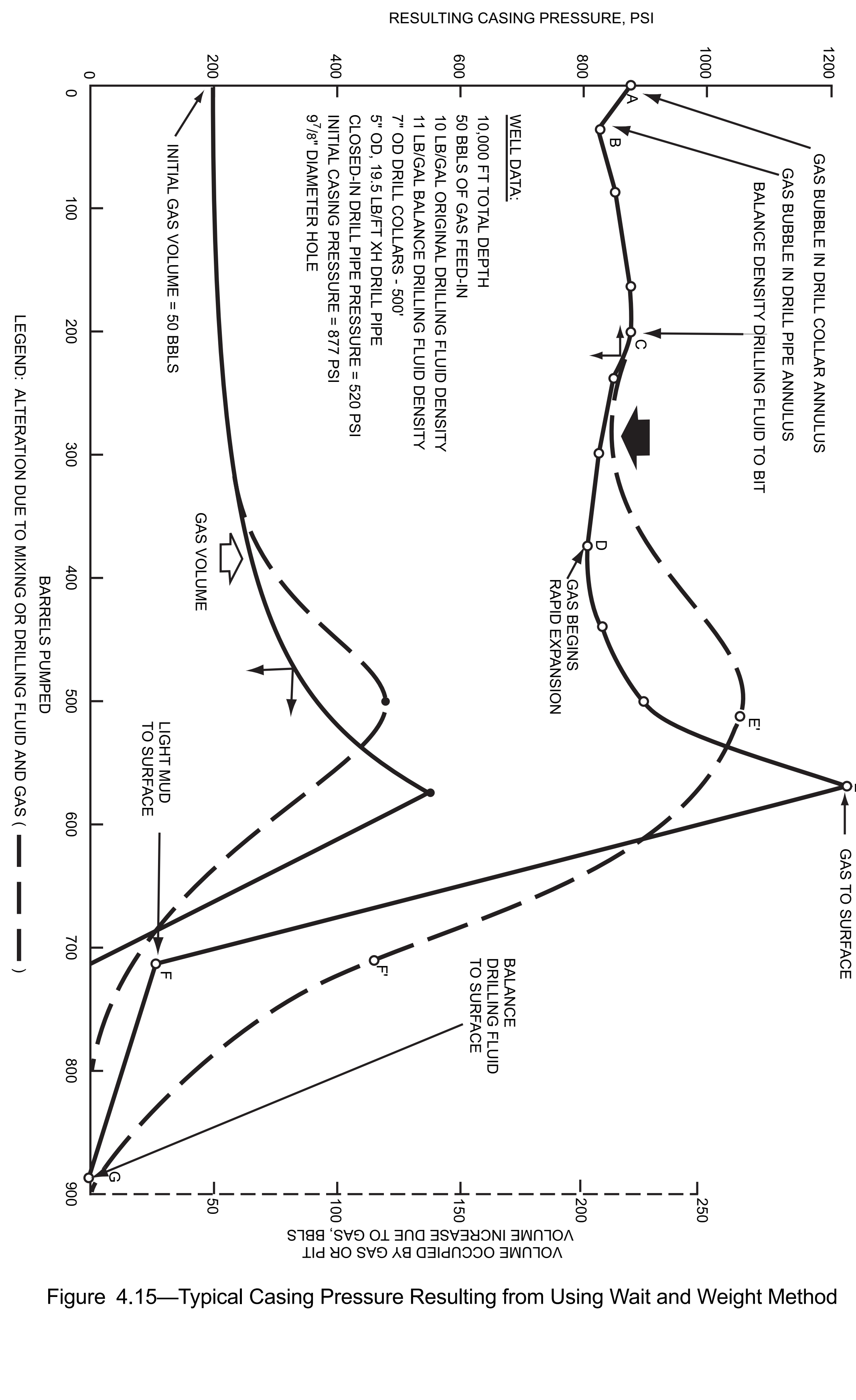


Figure 4.15—Typical Casing Pressure Resulting from Using Wait and Weight Method

required density, prime requirements are continuous monitoring of the fluid in the suction pit and recording the time each 0.1 lb/gal increase in drilling fluid density occurs. These times are used with circulating times to the bit to make the drill pipe pressure schedule. Weighting is done best if reverse circulation is established between the suction pit and an adjacent pit through auxiliary pumps so fluid density in the suction pit increases at a slow, even rate. The rate the fluid density increases depends on the rate at which weight material can be added and the circulating rate. In some instances, the addition rate may be insufficient to bring the circulating drilling fluid to desired density during the first circulation of weighted drilling fluid. If so, the fluid going in the hole will stay at the same stabilized density until weighted fluid reaches the surface, then the density in the suction pit will again increase. This circumstance is automatically handled, as the prepared drill pipe pressure schedule is based on the density of drilling fluid being pumped.

4.10.4.2 Example of Drill Pipe Pressure Schedule (Concurrent Method)—Figure 4.16 illustrates a typical drill pipe pressure schedule prepared for the 50-barrel kick and conditions illustrated in Figure 4.12. Drilling fluid density increases of 0.1 or 0.2 lb/gal are plotted along the bottom of the graph from initial to final drilling fluid densities. The initial circulating pressure is plotted above the initial drilling fluid density and the final circulating pressure is plotted above the final drilling fluid density. A line drawn between the two points indicates the drill pipe pressures to hold when the drill string is one-half full of the corresponding drilling fluid densities shown. These should be read from the graph recorded. The time to hold each pressure read is obtained by adding one-half circulating time to the bit to the time at which the suction pit reaches incremental drilling fluid density. Once the balancing drilling fluid density reaches the bit, the corresponding final drill pipe pressure should be held until the same drilling fluid density reaches the surface. During the period when drilling fluid density is increasing in the suction pit, the drill pipe has higher drilling fluid density at the top than at the bottom. If the time to hold a pressure for an increment of drilling fluid density is based on total circulating time to the bit, a small amount of excess bottom-hole pressure results from the shallower higher density fluid. The excess pressure is approximately eliminated by basing the drill pipe pressure schedule on one-half the circulating time to the bit.

4.10.4.3 Example: Casing Pressure (Concurrent Method)—Figure 4.17 shows typical casing pressures resulting from use of the Concurrent Method. The original closed-in casing pressure at point A reduces to point B due to the gas bubble shortening and more drilling fluid column in the annulus. At point C, drilling fluid of slightly increased density reaches the bit and slows the casing pressure rise as it flows into the annulus. At point D, gas volume begins to increase, overriding the increasing annular drilling fluid density, and requiring increased casing pressure. At point E, gas has reached the surface and casing pressure is at its maximum. As gas is freed and replaced in the hole by drilling fluid, the casing pressure drops until point F is reached and light fluid that was in the drill pipe at the time of close-in reaches the surface. Casing pressure continues to decrease until balancing drilling fluid density reaches the surface at point G. Note: Due to resistance to flow in the choke manifold and open choke, a small casing pressure may remain when the balancing drilling fluid density reaches the surface. The pressure should be less than 100 psi and will bleed off when the pump is stopped.

4.11 NON-CIRCULATION KILL METHODS

4.11.1 Bullheading Operations

Bullheading is continuous pumping of sufficiently dense fluid to kill the well. Bullheading operations are usually employed when anticipated surface pressures exceed the maximum that can safely be handled, or when the influx, contains hydrogen sulfide for example, cannot safely be handled at the surface. Bullheading is often used in well service operations where circulating is difficult due to a depleted formation. Often in drilling operations, bullheading requires surface pressures that will exceed formation fracture pressure. In these instances, well bore fluids are often pumped into the weakest zone exposed in the open hole, which may not be the formation that originally kicked. For these reasons, bullheading is more successful if a long string of protective pipe has been set and the open-hole section is relatively short. Bullheading operations can be used with pipe in or out of the hole and to force lost circulation material into a formation.

4.11.2 Top Kill (Lubricator Technique Operations)

Top kill operations provide a method of reducing surface pressures in a well when gas is at the surface and circulation cannot be established or the pipe is out of the hole. The procedure is as follows:

1. Mix kill fluid of sufficient density to ensure that a minimum volume of kill fluid will be necessary to reduce the pressures to kill the well.
2. Pump a measured volume of kill fluid into the hole until the injection pressure reaches the predetermined maximum limit.
3. Allow drilling fluid to settle, then bleed gas (Note: Bleed dry gas only, do not bleed drilling fluid.) until the pressure is reduced an amount equivalent to the hydrostatic pressure of the injected kill fluid.

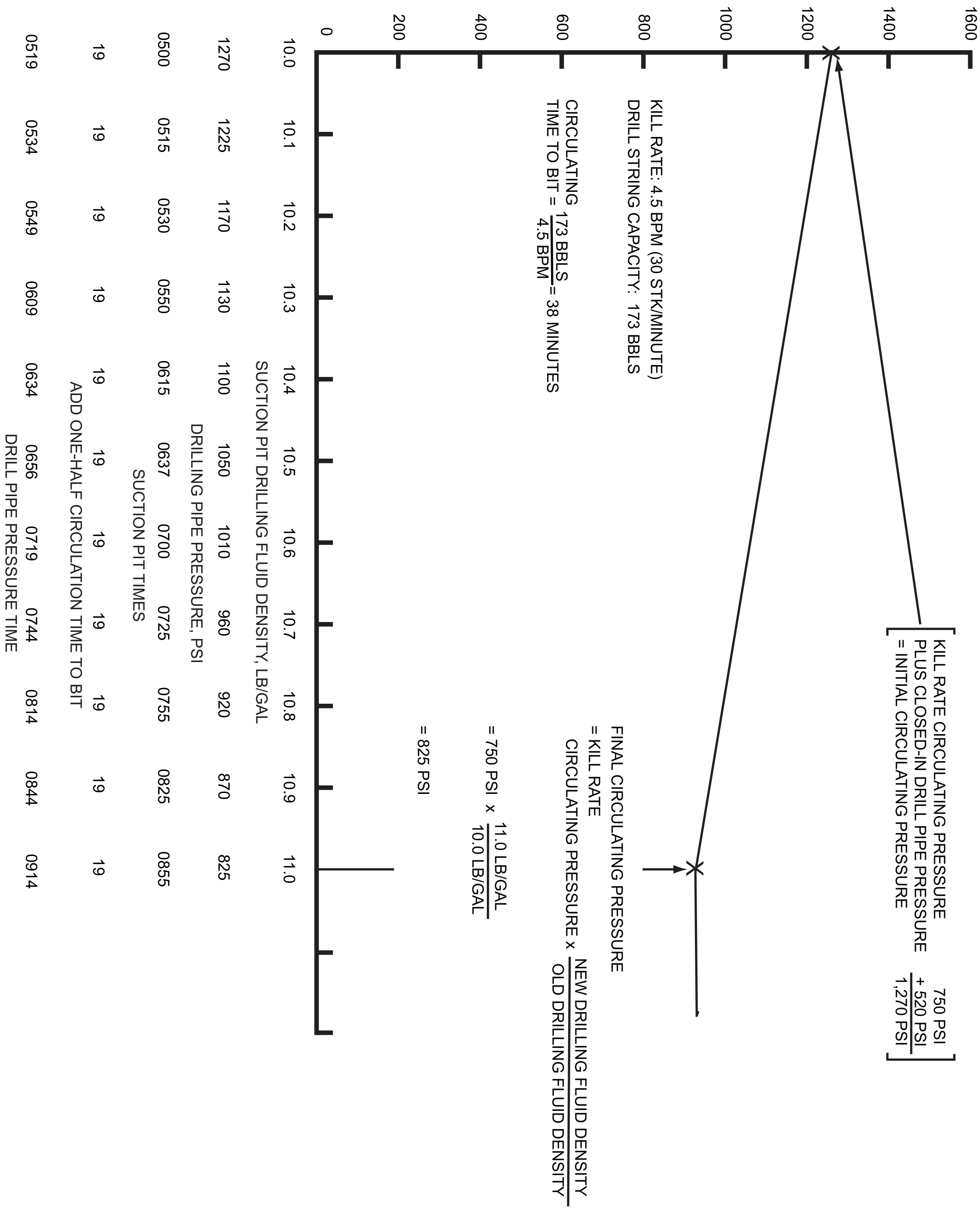


Figure 4.16—Drill Pipe Pressure Schedule-Concurrent Method

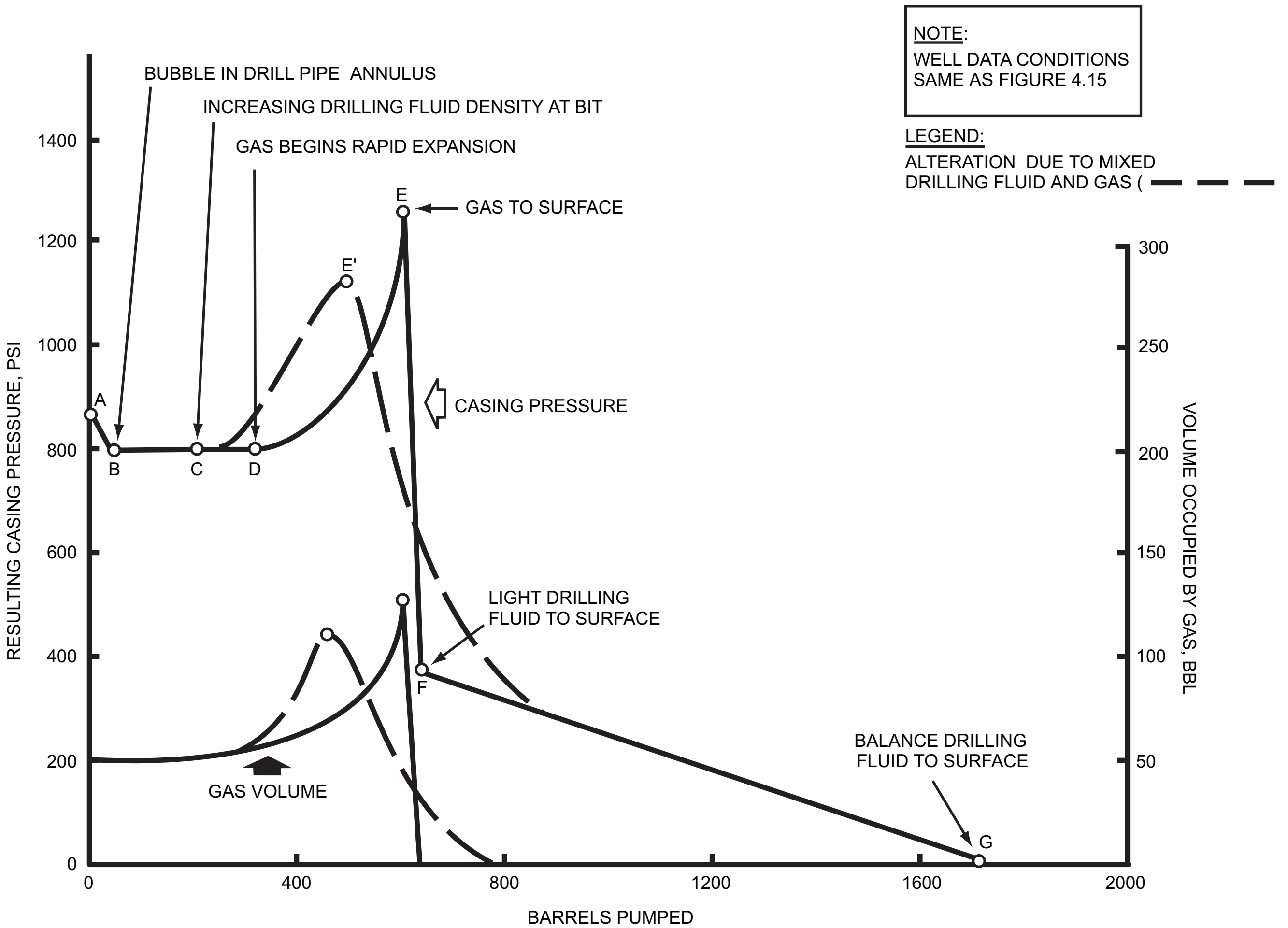


Figure 4.17—Typical Casing Pressure Resulting From Using Concurrent Method

The following is a method for calculating hydrostatic pressure reduction.

$$\text{Hydrostatic pressure reduction (psi)} = \frac{53.0 \times \text{kill fluid density (lb/gal)} \times \text{vol. injected (bbls)}}{(\text{casing ID, in.})^2 - (\text{drill pipe OD, in.*})^2}$$

*Note: If pipe is out the hole, use 0.

Example: For 8 bbl of 12 lb/gal drilling fluid pumped into 9 5/8-in. 36-lb/ft casing with 4 1/2-in. drill pipe.

$$\text{Hydrostatic pressure reduction (psi)} = \frac{53.5 \times 12 \times 8}{(8.921)^2 - (4.5)^2} = \frac{53.5 \times 12 \times 8}{59.334} = 87 \text{ psi}$$

4. Repeat this procedure until the pressure is reduced to zero or the hole is full of drilling fluid. The injected volume increments will reduce with time. This may be a very lengthy procedure consuming hours or days. If the pressure cannot be reduced to zero, a snubbing operation may be required.

4.12 COMPARISON OF KILL METHODS

Each of the methods has relative advantages and disadvantages. The Driller's Method is the simplest to handle and to teach; but it requires two circulations and may result in the highest casing pressure as shown in Figure 4.18. This also means that a higher casing seat pressure and lost circulation are more likely. The Wait and Weight Method generally produces the lowest casing pressure (often less than initial closed-in pressure) due to assistance of increased drilling fluid density in the annulus while the gas bubble is circulated to the surface. However, this is true only if the drill pipe volume is less than the annulus volume and kill weight mud enters the annulus before the gas bubble reaches the surface. Due to the effect of pressure at the casing seat and associated danger of lost circulation, consideration should be given to use of the Wait and Weight Method, especially if only surface casing is set. The Wait and Weight Method is more complicated than the Driller's Method and stuck pipe may occur while the drilling fluid pits are weighted and the kick not circulated. Other considerations of the Driller's versus Wait and Weight Methods are time on the BOPs, availability of weighting material, ability to mix mud and circulate, hydrates, gas migration rate (function of hole angle, influx type, drilling fluid type), and hole type (straight or directional). The Concurrent Method has the least danger of stuck pipe, as there is less time with pressure on the well and less time with an uncirculated kick. For the Concurrent Method, casing pressures are intermediate to other methods; however, it is the most complicated to run. Bullheading and the Top-Kill Methods are for special situations where circulation is impractical or high surface pressure needs to be handled as described in 4.11.1 and 4.11.2.

4.13 CHOKE LINE PRESSURE—SUBSEA STACKS

When handling kicks in deepwater, flow resistance in the choke line from the BOP stack to the surface plus the manifold and open choke may be significant. Unless kill-rates are low and the choke line pressure properly taken into account during well kill operations, excess pressures may be unnecessarily applied in the hole. Figure 4.19 shows the pressure losses for pipe of various inside diameters at varied flow rates. However, restrictions in joints, manifold, and choke can add additional pressures, so it is best to make actual measurements on the rig.

4.13.1 Measurement of Subsea Choke Line Pressures

The choke line pressure at any one rate is the drill pipe circulating pressure with BOPs closed and the choke line and choke fully open, minus the drill pipe circulating pressure with BOPs open. Unless the choke line pressure is less than the closed-in casing pressure, a balanced bottom-hole pressure cannot be established when circulation is started. Drill pipe pressure will be higher than desired and the choke will be wide open. Also, even if the initial drill pipe circulating pressure can be established at correct value, there will be some period in the well killing operation where the choke is wide open but the drill pipe circulating pressure is greater than desired by the amount of the choke line pressure. Therefore, a graph should be prepared showing choke line pressure at various flow rates so that a kill-rate can be selected that has a choke line pressure less than anticipated closed-in casing pressure and so that the excess pressure in the well due to choke flow line resistance can be evaluated. The procedure is as follows:

1. Before drilling out surface casing, determine the drill pipe circulating pressure through the drill string, choke line, and open choke using a closed BOP and at least three circulating rates. Plot on log-log paper and draw a line through these points.
2. Determine kill-rate circulating pressure for at least three circulating rates with BOPs open. Plot on a graph and draw a line through these points.
3. At three or more flow rates, subtract values obtained in Step 2 from those obtained in Step 1 and plot values at the same flow rates. Draw a line through these points. This shows choke and choke line pressures for water depth and drilling fluid density. Corrected choke line pressures are obtained for a new drilling fluid density by using the following formula at two or more points and drawing a corrected line.

$$\text{Corrected Choke Line Pressure (psi)} = \text{Choke Line Pressure Determined (psi)} \times \frac{\text{Present Drilling Fluid Density (lb/gal)}}{\text{Drilling Fluid Density when Choke Line Pressure Determined (lb/gal)}}$$

Using two flow lines, i.e., choke and kill lines, reduces the choke flow line pressure by a factor of approximately four (4). Therefore, if the rig is capable of using both lines to the choke, the procedure should be repeated using both lines in step 1 and determining a kill and choke line pressure. At low flow rates, laminar flow may result causing some plotted results to flatten. The procedure provides data for the water depth at the time of measurement. If pressures on the manifold gauge are also read, plotted, and subtracted, the pressure for 100 feet of choke line can be calculated and a graph prepared. The manifold open choke readings should be added back for each depth. Figure 4.20 illustrates the results of these measurements and calculations for a particular rig. Each rig will have a unique graph depending on the inside diameter of the choke line and the arrangement of the choke and manifold.

4.13.2 Direct Measurement of Choke Line Pressure Losses

Choke line pressure losses can be measured directly by pumping into the choke manifold, down the choke line or choke and kill lines into the open BOP stack, and up the riser. The pressure shown on the choke manifold gauge is the choke line pressure loss. Any errors caused by small circulatory pressure losses in the riser are negligible. Choke line pressure losses at several rates can be plotted on log-log paper and extrapolated to provide estimated pressure losses at various pump rates. Choke line pressure loss measurements should be repeated whenever drilling fluid properties are significantly changed.

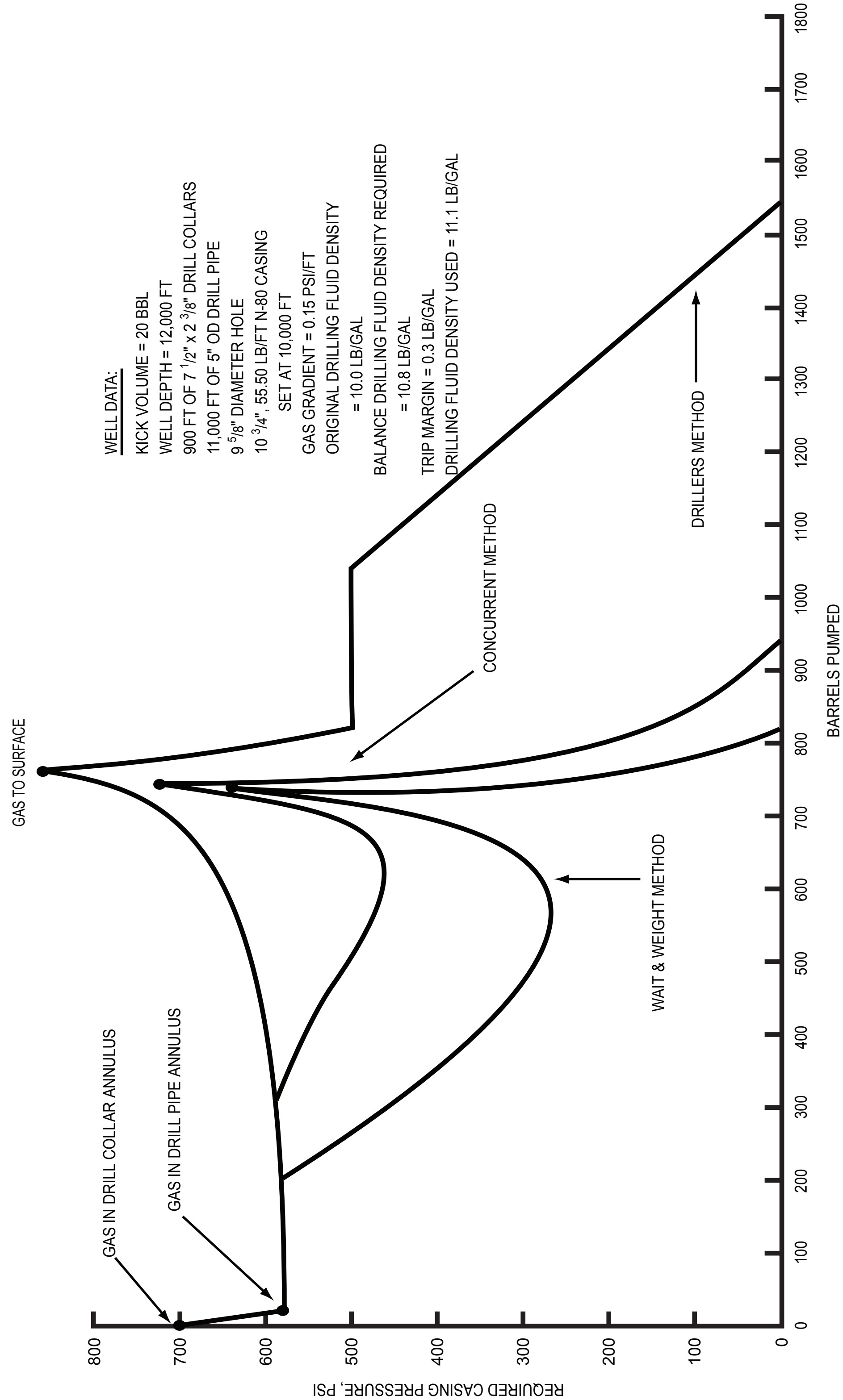


Figure 4.18—Example Of Approximate Casing Pressures With Different Kill Methods

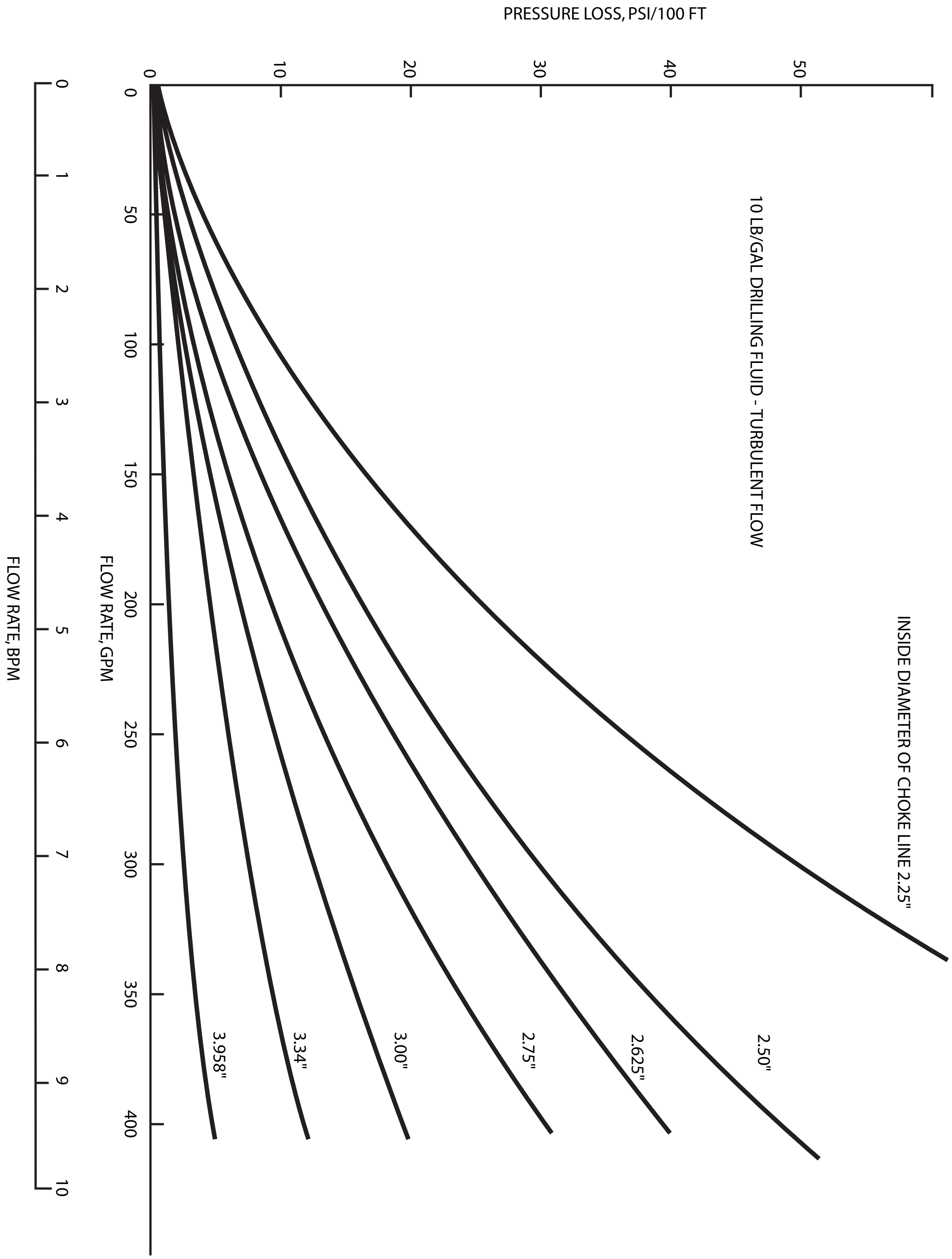


Figure 4.19—Pressure Loss versus Flow Rate

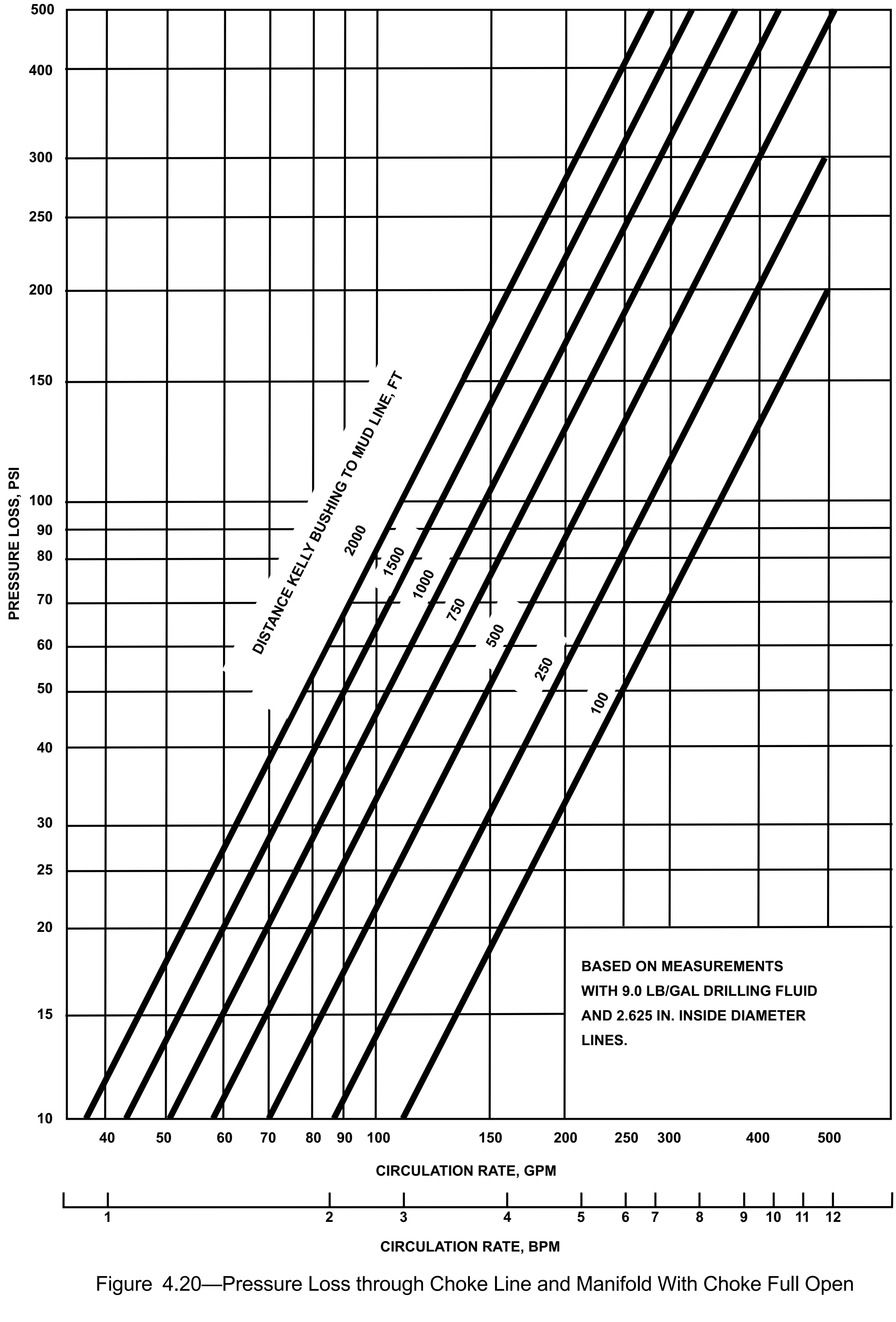


Figure 4.20—Pressure Loss through Choke Line and Manifold With Choke Full Open

4.13.3 Handling Subsea Choke Line Pressures During Kicks

The kill line can be used to monitor casing pressure when circulation is begun after a kick. The kill line should be opened to the surface manifold and the kill line pressure held constant by adjustment of the choke line choke while bringing the pump up to speed. The kill line should also be opened to monitor pressure during any changes in circulation rate. If it is not possible to utilize the kill line pressure, the choke pressure should be allowed to drop an amount equal to the calculated or measured choke line pressure losses while bringing the pump(s) up to speed. Otherwise, the drill pipe pressure will be too high as will bottom-hole pressure and pressure at the casing seat. Even when correct drill pipe pressure is established there will be a time near the end of the kick kill operation when the choke will be wide open and the drill pipe pressure will build to a value higher than desired by the amount of the choke line pressure loss. The recommended well control worksheets for subsea stacks present proper steps for handling choke line pressure during kicks (refer to Appendix B).

4.13.4 Kill-rate Selection with Subsea Stacks in Deepwater

Experience has shown that low formation breakdown pressures are expected in deepwater. For a given depth the seawater head plus the soil overburden pressure is less than the total soil overburden pressure at the same depth for a land or shallow water location (water density is less than rock density). Due to the high friction loss in the relatively long choke line used with subsea stacks in deepwater, it may be necessary to circulate out a kick at a very slow rate (less than one-half normal circulating rate) to avoid formation breakdown. This fact should be considered in selecting kill-rates. A reasonable premise would be to circulate any kick that can be closed-in at a rate that will not cause formation fracture. After a string of casing has been set and formation breakdown pressure is determined, the maximum choke manifold pressure that can be shut-in without causing formation breakdown can be determined as follows:

$$P_k = P_f - G_o D_s \qquad \text{(Equation 4.1)}$$

where

P_k = choke manifold pressure, psi

P_f = formation fracture pressure, psi

D_s = casing shoe *TVD*, ft (*RKB*)

G_o = drilling fluid gradient, psi/ft

4.13.4.1 The maximum initial circulating rate that will not cause formation breakdown can then be determined as follows:

$$R = 0.917\,(P_k / LG_o)^{0.5376} \times (D_i)^{2.613} \qquad \text{(Equation 4.2)}$$

where

R = circulating rate, gpm

L = choke line length, Mft

P_k = choke manifold pressure, psi

G_o = drilling fluid gradient, psi/ft

D_i = inside diameter of choke line, in.

This is the maximum rate at which the kick can be circulated out using the Driller's Method or, in the case of the Wait and Weight Method, the maximum initial circulation of a multi-rate kill. The calculation neglects pressure losses.

4.13.4.2 The gradient of a kill fluid that will balance the maximum kick that can be shut-in without causing formation fracture can be calculated as follows:

$$G_k = \frac{G_o + P_f - G_o D_s}{D} \qquad \text{(Equation 4.3)}$$

where

G_k = drilling fluid kill gradient at depth D, psi/ft

G_o = drilling fluid gradient, psi/ft

P_f = formation fracture pressure, psi

D_s = casing shoe *TVD*, ft

D = depth of hole, ft

4.13.4.3 The maximum pressure loss in the cased hole and choke system can be calculated as follows:

$$P_c = P_f - D_s G_k \qquad \text{(Equation 4.4)}$$

where

P_c = pressure loss in cased hole and choke system with drilling fluid gradient, G_k, psi

P_f = formation fracture pressure, psi

D_s = casing shoe *TVD*, ft (*RKB*)

G_k = drilling fluid kill gradient at depth D, psi/ft

4.13.4.4 The circulating rate in gpm (gallons per minute) corresponding to P_c can be calculated from Equation 4.2, substituting G_k for G_o and P_c for P_k. This is the maximum circulating rate for a depth when drilling fluid of the density required (to kill the largest kick that can be shut-in without causing formation breakdown) reaches the choke line.

4.13.4.5 Following are examples of calculations for the following hole conditions:

Water TVD = 3,000 ft

Casing Shoe TVD = 6,000 ft (RKB)

Casing Shoe Breakdown Pressure = 3,432 psi

Drilling Depth (TVD) = 12,000 ft

Drilling Fluid Gradient in Hole = 0.468 psi/ft (9 lb/gal)

Inside Diameter of Choke Line = 2.5 in.

1. $P_k = P_f - G_o D_s$

   $P_k = 3{,}432 - 0.468\,(6000) = 624 \text{ psi}$

2. $R = 0.917\,(P_k / LG_o)^{0.5376} \times (D_i)^{2.613}$

   $R = 0.917\,[624 / (3 \times 0.468)]^{0.5376} \times (2.5)^{2.613}$
   $= 266 \text{ gpm}$

3. $G_k = G_o + \dfrac{(P_f - G_o D_s)}{D}$

   $G_k = 0.468 + \dfrac{3432 - (0.468 \times 6{,}000)}{12{,}000} = 0.520 \text{ psi/ft}$

4. $P_c = P_f - D_s G_k$

   $P_c = 3{,}432 - (0.520 \times 6{,}000) = 312 \text{ psi}$

5. $R = 0.917\,(P_k / LG_k)^{0.5376} \times (D_i)^{2.613}$

   $R = 0.917\,[(312 / (3 \times 0.520)]^{0.5376} \times (2.5)^{2.613}$
   $= 174 \text{ gpm}$

In these example calculations, the maximum initial circulating rate that will not result in formation breakdown would be 266 gpm. Prior to the kill drilling fluid reaching the choke line, the circulating rate should be reduced to 174 gpm.

4.13.5 Example: Raising Density—A part of planning and preparedness is knowing how fast the drilling fluid density can be raised or cut in the circulating system. For example, to raise drilling fluid density $^1/_2$ lb/gal at a pump rate of 200 gpm, the rig must be capable of adding 90 to 120 sacks (1 sack = 100 lbs) of weighting material per hour, depending on fluid density. For each 1 lb/gal increase in drilling fluid density, 60 to 90 sacks (1 sack = 100 lbs) of weight material are required per 100 barrels of total system capacity. Two equations that can be used to calculate weight material requirements are as follows:

$$\text{Sacks per 100 bbl} = 1{,}470 \times \frac{[\text{Required Drilling Fluid Density (lb/gal)} - \text{Present Fluid Drilling Density (lb/gal)}]}{[35 - \text{Required Drilling Fluid Density(lb/gal)}]}$$

$$\text{Sacks of Barite Required} = \frac{\text{Drilling Fluid Volume} \times \text{Sacks/100 bbl}}{100}$$

Note: One sack = 100 lbs.

4.14 DIVERTER SYSTEMS APPLICATIONS

At shallow depths where drive pipe, conductor pipe, and structural casing are set, fracture gradients are very low and wells sometimes cannot be closed-in on a kick without danger of lost circulation and possible broaching to the surface. Controlling these shallow gas flows can be difficult as these formations can be abnormally pressured and gas expands rapidly as it rises to the surface. Furthermore, drilling these shallow gas sands can rapidly gas-cut the drilling fluid to the extent that expansion during flow to the surface lowers the hydrostatic pressure enough to cause formation flow. In addition, dispersal of drilled cuttings in the drilling fluid may cause the drilling fluid density to increase to a point where circulation may be lost, causing the hydrostatic head to drop thereby allowing the well to flow. In these situations, a diverter may be used to direct well flow away from the rig during kicks. The diverter should be arranged so that a diverter line automatically opens or is open when the diverter is closed to divert the fluids and prevent backpressure on the hole. Diversion is usually away from the rig, resulting in loss of drilling fluid from the system. Under these conditions, formation fluid flow continues during the well control operation until the hole bridges or hydrostatic pressure can be built enough to regain primary control and stop formation fluid flow. Pumping at a fast rate with heavy fluids is the best method for controlling a shallow gas kick. Refer to 8.3 for more information on diverter operations and Section 13 for mixing of heavy fluids.

4.15 WELL CONTROL WORKSHEETS

Recommended well control worksheets are shown in Appendix B for the Driller's Method, Wait and Weight Method, and Concurrent Method for surface BOP assemblies and subsea BOP assemblies. A recommended well control worksheet for the Wait and Weight Method for a subsea BOP assembly in deepwater is also included in Appendix B. Use of these worksheets is recommended as all steps for each method are listed in order with appropriate

5 Causes of Kicks

5.1 CONDITIONS NECESSARY FOR A KICK

Two conditions in the well bore are required for a kick to occur:

1. The pressure at the face of the kicking formation must be greater than the pressure in the well bore; and
2. The kicking formation must have sufficient permeability to allow flow into the well bore.

Loss of primary well control is usually due to:

1. Failure to keep the hole full;
2. Swabbing;
3. Insufficient drilling fluid density; and/or
4. Lost circulation.

These problems can occur during any operation conducted on a well.

5.2 INSUFFICIENT HYDROSTATIC PRESSURE

Two primary causes of well kicks are insufficient fluid density and insufficient fluid level in the well bore, especially while tripping.

5.2.1 Insufficient Density

This can be caused by:

1. Higher than anticipated pore pressures or,
2. The drilling or workover fluid becoming contaminated by less dense fluids or formation gas.

5.2.2 Hole Not Full of Adequate Density Fluid

When the fluid level in the well bore is allowed to drop the resulting reduced hydrostatic pressure can become less than the formation pressure and allow formation fluid entry into the well bore.

5.2.3 Tripping Out of the Hole

When pipe is pulled from a well, a reduction of bottom-hole hydrostatic pressure may occur. Two causes of lower hydrostatic pressure are:

1. failure to fill the hole to correct for the volume displacement of the pipe and,
2. swabbing.

5.2.3.1 Drilling and Completion Operations

In operations where circulation is desirable, such as most drilling or completion operations, the displacement volume of the pipe being pulled from the hole should be replaced to keep the hole full and maintain constant hydrostatic pressure. If the hole fails to take the proper amount of drilling fluid, hoisting operations should be suspended and an immediate safe course of action determined while observing the well. This usually requires returning to bottom and circulating the hole. The frequency of filling the hole during tripping operations is critical; the hole should be completely filled at intervals that prevent an influx of formation fluid. Continuous filling or filling after each stand of drill pipe may be advisable. The hole should be filled after each stand of drill collars. When the hole is filled continuously, an isolated drilling fluid volume measurement facility (such as a trip tank) must be used.

5.2.3.2 Well Service Operations

In operations where circulation is not normally maintained, such as many well service operations where wells with depleted formations are being worked over, consideration should be given to keeping a volume of fluid in reserve to add or bullhead into the well as needed to maintain control.

5.2.3.3 Swabbing

Bottom-hole pressure reduction of several hundred pounds per square inch (psi) can occur when swabbing takes place and is one of the major reasons for losing primary well control. When pipe is pulled from a well, swabbing can be difficult to detect. The well may take some fluid as the pipe is withdrawn but less than the complete pipe displacement. Detection of swabbing can only be done by accurately measuring the drilling fluid added to the hole as pipe is pulled. Three prime factors in controlling swabbing are:

1. Drilling fluid properties;
2. Rate of pulling pipe; and
3. Drill string and hole configurations.

5.2.4 Tripping In the Hole

When running pipe in the hole, the drilling fluid volume increase at the surface should be no greater than the predicted pipe volume displacement. Some holes take significant volumes of drilling fluid during trips due to seepage loss. Highly permeable and weak formations may be susceptible to fluid loss or fracture if pipe or tools are run in the hole too fast, causing pressure surges.

5.2.5 Lost Circulation

Lost circulation may quickly result in loss of the hydrostatic overbalance that constitutes primary control. The loss can result from natural or induced causes. Natural causes include fractured, vugular, cavernous, subnormal-pressured, or pressure-depleted formations. Induced loss can result from mechanical formation fracturing resulting from:

1. Excessive drilling fluid density,
2. Excessive annular circulating pressure,
3. Pressure surges related to running pipe or tools,
4. Breaking circulation, or
5. Packing-off in the annulus.

Casing leaks or downhole plug failures can also cause lost circulation (refer to 13.2 and its sub paragraphs).

5.2.6 Excessive Drilling Rate Through a Gas Sand

Even if the drilling fluid density in the hole is sufficient to control formation pressure, gas from the drilled cuttings will mix with drilling fluid. The composition of the drilling fluid can influence the amount of mixing (refer to 4.5 and its subparagraphs). A high drilling penetration rate through a shallow gas zone or coal bed can supply enough gas from the cuttings to reduce the hydrostatic pressure of the drilling fluid column. This occurs through a progressive combination of density reduction and "belching" drilling fluid out of the hole. The hydrostatic pressure loss can reach the point where the formation begins flowing into the well bore.

5.2.7 Drill Stem Testing

A drill stem test (DST) is performed by setting a packer above the formation to be tested and allowing the formation to flow. During the course of testing, the borehole or casing below the packer and at least a portion of the drill pipe or tubing is filled with formation fluid. At the conclusion of the test, the fluid in the test string above the circulating valve must be removed by proper well control techniques, such as reverse circulation, to return the well to a safe condition. Depending on the length of hole below the packer, type of fluid entry, and formation pressure, the normal drilling hydrostatic overbalance can be reduced or lost. Exercise caution to avoid swabbing when pulling the test string because of the large diameter packers.

5.3 DRILLING INTO AN ADJACENT WELL

A large number of directional wells may be drilled from the same offshore platform or onshore drilling pad. If a drilling well penetrates the production string of an existing well, the formation fluid from the existing well may enter the well bore of the drilling well or the drilling fluid of the well being drilled may be lost to the penetrated well bore; either of which can lead to a kick.

6 Well Control Warning Signals

6.1 GENERAL

Well control warning signals can be classified in three major general categories as follows:

6.1.1 Previous Field History and Drilling Experiences

- Depth of zones capable of flowing.
- Formation gradients.
- Fracture gradients.
- Formation content.
- Formation permeability.
- Intervals of lost circulation.

6.1.2 Physical Response From the Well

- Pit gain or loss.
- Increase in drilling fluid return rate.
- Changes in flow line temperature.
- Drilling breaks.
- Variations in pump speed and/or standpipe pressure.
- Flow after the pumps are stopped.
- Swabbing.
- Drilling fluid density reduction.
- Effects of connections, short trip, and trip on shows and gains.
- Hole problems indicating underbalance (i.e., tight hole, packing-off, sloughing).
- Excessive pressure or pressure changes between casing strings.
- Cuttings size, shape, and quantity.

6.1.3 Chemical and Other Technical Responses From the Well

- Chloride changes in the drilling fluid.
- Oil show.
- Gas show (chromatograph).
- Formation water.
- Shale density.
- Electric logs.
- Drilling equation exponents.

6.2 GAIN IN PIT VOLUME

An unaccounted volume gain in the drilling fluid pit(s) is an indication that a kick may be occurring. As the formation fluid feeds into the well bore, it causes more drilling fluid to flow from the annulus than is pumped down the drill string, thus the volume of fluid in the pit(s) increases.

6.3 INCREASED FLOW FROM ANNULUS

If the pumping rate is held constant, the flow from the annulus should be constant. If the annulus flow increases without a corresponding change in the pump rate, the additional flow is caused by formation fluid(s) feeding into the well bore or gas expansion.

6.4 VOLUME OF DRILLING FLUID TO KEEP THE HOLE FULL ON A TRIP IS LESS THAN CALCULATED OR LESS THAN TRIP BOOK RECORD

This condition is usually caused by formation fluid entering the well bore due to the swabbing action of the drill string. As soon as swabbing is detected, the drill string should be run back to bottom. Circulate and condition the drilling fluid to minimize further swabbing. It may be necessary to increase the drilling fluid density, but this should not be the first step considered because of the inherent potential problems of causing lost returns or differential sticking.

6.5 SUDDEN INCREASE IN BIT PENETRATION RATE

A sudden increase in penetration rate (drilling break) is usually caused by a change in the type of formation being drilled; however, it may also signal an increase in formation pore pressure. Increased penetration rates due to higher pore pressures are usually not as abrupt as formation drilling breaks, but they can be. To be certain that gradual increases in pore pressure are recognized, a penetration rate versus depth curve plot is recommended to highlight the trend of increasing pore pressure.

6.6 CHANGE IN PUMP SPEED OR PRESSURE

The initial surface indication that a well kick has occurred could be a momentary increase in pump pressure. The pump pressure increase is seldom recognized because of its short duration, but it has been noted on some pump pressure recording charts after a kick was detected. The pressure increase is followed by a gradual decrease in pump pressure, and may be accompanied by an increase in pump speed. As the lighter formation fluid flows into the well bore, the hydrostatic pressure exerted by the annular column of fluid decreases, and the drilling fluid in the drill pipe tends to U-tube into the annulus. When this occurs, the pump pressure will drop and the pump speed will increase. The lower pump pressure and increase in pump speed are also indicative of a hole in the drill string. Until a confirmation can be made as to whether the cause is a hole or a well kick, a kick should be assumed.

6.7 FLOW AFTER PUMPS STOPPED

This can be due to several causes including an underbalanced formation kick, thermal expansion of the drilling fluid, rig heave, or an overbalanced formation ballooning (opening and closing of a fracture). This should be systematically measured and recorded in the trip book to ensure proper response.

6.8 GAS-CUT DRILLING FLUID

Gas-cut drilling fluid often occurs during drilling operations and can be considered one of the early warning signs of a potential well kick; however, it is not a definite indication that a kick has occurred or is impending. An essential part of analyzing this signal is being able to determine the downhole conditions causing the drilling fluid to be gas-cut. Gas-cut fluid occurs due to one or more of the following downhole conditions:

1. Drilled Gas—drilling a gas-bearing formation with the correct drilling fluid density in the hole;
2. Trip or Connection Gas—swabbing while making connections or making a trip; and
3. Gas Flow—influx of gas from a formation having a pore pressure greater than the pressure exerted by the drilling fluid.

6.8.1 Drilled Gas

When the hydrostatic pressure exerted by the drilling fluid is greater than the pore pressure of a gas-bearing formation being drilled, there is no influx of gas from the formation. Nevertheless, gas from the drilled cuttings will usually mix with the drilling fluid causing the returns to be gas cut. As gas is circulated up the annulus, it expands slowly until just before reaching the surface. The gas then undergoes a rapid expansion, resulting in the drilling fluid density being reduced considerably upon leaving the annulus. In some cases, this reduction in density can be extreme but it may not mean that a kick is about to occur. Usually, only a small loss in hydrostatic pressure results because the majority of gas expansion occurs in the top of the hole. Drilling fluid of proper density is still maintained in most of the hole. Quite often, when the drilled gas reaches the surface, the annular preventer must be closed and the drilling fluid circulated through the open choke manifold. This prevents the expanding gas from "belching" fluid through the bell nipple. If "belching" continues, the hydrostatic head is reduced due to loss of drilling fluid from the hole.

6.8.2 Trip or Connection Gas

After circulating "bottoms-up" following a trip or connection, a higher level of gas entrained in the drilling fluid returns may cause a short duration density reduction or gas unit increase. If the well did not flow when the pumps were stopped during the trip or connection, it can be reasonably assumed that the gas was swabbed into the well bore by the pipe movement. These symptoms can indicate increasing formation pressure when compared with previous trips and connections.

6.8.3 Gas Flow

Influx from a gas zone while drilling is a serious situation. While drilling, the formation pore pressure must exceed the hydrostatic pressure of the drilling fluid plus the circulating friction losses in the annulus for gas from the formation to flow into the well bore. Once influx begins, continued circulation without the proper control of surface pressures will induce additional flow, since the density of the hydrostatic column (annulus) is continually lessened by the flow of formation fluid and expansion of gas. An exception is a very low permeability formation that can be drilled while allowing a continuous small influx to occur. This type of underbalanced drilling is only practical in well-known drilling areas where the geology and pressures are sufficiently known to pre-plan the rig equipment and operations practices necessary.

6.9 LIQUID-CUT DRILLING FLUID

When a permeable liquid-bearing formation having pore pressure greater than the drilling fluid hydrostatic pressure is encountered, fluid will feed into the well bore. Depending upon the pressure differential between the formation and the drilling fluid, the influx may be detected by:

1. A gain in pit volume,
2. Lower density returns,
3. A change in drilling fluid chlorides, and/or
4. An increase in rotary torque.

The volume of liquid contained in the cuttings is usually so small that unless accompanied by gas, it will not significantly affect the drilling fluid density.

7 Well Planning

7.1 INTRODUCTION

Well control starts with the planning of a drilling and completion of a new well, workover, or remediation of an existing well. A well control plan is a program worked out beforehand that will accomplish the objective of keeping a well under control during the phase of operation being considered. To be successful, subsurface conditions must be predicted, detected, and controlled. Consideration must be given to the conditions to be encountered, the equipment to be used, the procedures to be followed and training of the crew. Advance planning should include an equipment and operations procedure checklist. The items on the checklist depend on the drilling depth, company policies, government regulations, and anticipated use of the well control equipment. Operating procedures should be prepared and posted. The first step is to assemble the available data, then evaluate and predict what could happen, and prepare contingency plans.

7.2 DATA AVAILABILITY AND GATHERING

The following types of data are useful and, if available, should be obtained:

- Lithology,
- Seismic,
- Downhole surveys,
- Drill stem tests,
- Drilling logs (bit records and penetration rates),
- Mud logs,
- Temperature and pressure gradients,
- Drilling fluid programs,
- Cementing programs and techniques,
- Hazards,
- Environmental conditions,
- Logistics,
- Communications,
- Safety practices,
- Well control indications and problems,
- Remedial operations,
- Plug and abandonment, and
- Government regulatory requirements.

7.2.1 Geologic and Geophysical Data

Seismic data should be tied to data from wells in the area where the well is proposed. Regional and area geological studies and maps, high-resolution 3D seismic data, and sequence stratigraphy are among the information and methods that can aid in predicting the presence of permeable formations and pressures. Based on the information and predictions, well locations, well path, drilling fluids, well logging, and casing programs may be designed or modified. On deviated and closely spaced wells, care should be taken not to drill into other wells or in proximity close enough to communicate hydraulically between wells.

7.2.2 Formation Pressure

All available engineering, geophysical and geological information should be analyzed to predict formation fracture gradients, pore pressure, and shallow hazards. Investigate the area for the possibility of charged or depleted formations from previous drilling or production. Pressure profiles should be made and plans prepared for handling under- and over-pressured formations, both shallow and deep. Pressure data and formation strength are fundamental to the design of the drilling program, drilling fluids required, casing strings, and selection of best operating practices. Prediction of formation pressure can be difficult in exploratory wells; seismic data and field analogs may be the only data available. As more experience is gained in a field, the problem is minimized as correlation with nearby wells improves predictability.

7.2.3 Casing Programs

Casing programs in offset wells, offset fields, and regional wells, combined with geologic and formation pressure data, can be of tremendous value in planning a well.

7.2.4 Drilling Data Utilization

A number of methods or indicators that can be used to detect abnormal pressure while drilling, include:

1. Drilling rate or “d” exponent;
2. Sloughing shale;
3. Shale density;
4. Gas units in drilling fluid;
5. Chloride increases in drilling fluid;
6. Drilling fluid properties;
7. Temperature measurements;

8. Bentonite content in shale;
9. Paleontology information;
10. Wireline logs; and
11. Torque and drag.

Data can be obtained from previously drilled wells and also obtained and interpreted while drilling. Real time logging while drilling (LWD) can provide instant feedback on a number of parameters: gamma ray, resistivity, formation density, temperature, and pressure. This data can be correlated to geologic and geophysical data to provide warning of potential well control problems such as over pressured shallow water or shallow gas zones and pressure transition zones. However, LWD tools are located above the bit and this must be accounted for as the bit may have already penetrated a formation containing abnormal pressures before the logging tool detects the formation.

7.2.5 Plug and Abandonment

Plug and abandonment rules and regulations, as well as actual plug and abandonment data on area wells, can provide insight into problems that may have occurred with offset wells and lead to useful contingency planning for future operations.

7.3 SHALLOW FLOWS

Shallow gas and liquid flows are problematic wherever they occur. Drilling and workover operations involving any land or marine structure supported by a mat type base, legs, or a barge are particularly susceptible to shallow flows. These operations include all onshore drilling and workover operations; in the marine environment, they include jack-up drilling rigs, barge rigs, and production platforms. Shut-in of a BOP on a shallow gas flow may cause the formation to fracture and allow well bore fluids to flow up the outside of the casing then to the surface. In addition to the other hazards associated with uncontrolled flow to the surface, gas flows (and to some degree, liquid flow) may cause damage to, or failure of, the rig foundation. Onshore and offshore bottom-founded drilling units and production platforms are vulnerable to foundation failure under these conditions and may overturn or collapse. Diverter systems are designed not to shut-in the well but to divert gas or liquid flows away from the rig to a safe place. Shallow water flows are generally only a problem in the deepwater offshore environment.

7.3.1 Guidelines for Use of Diverter Systems

Following are general guidelines for possible use of diverter systems. There may be other alternatives that are as, or more, acceptable for site-specific conditions or environments. For more information, refer to API RP 64, *Recommended Practice for Diverter Systems Equipment and Operations* (reader should check for the latest edition).

1. A diverter system should be considered if there is a reasonable possibility of encountering gas or fluid flows in quantities sufficient to cause well control or operational problems while drilling below the first casing string, i.e., drive pipe, conductor pipe or structural casing.
2. A diverter system should be considered when drilling below the first casing string and the anticipated formation fracture gradient is insufficient to permit circulation and/or spotting of kill weight fluid. If the well is shut-in with the blowout preventer (BOP) at this stage of drilling operations, uncontrollable flow up the outside of the casing string may result.
3. A diverter system should be considered in drilling operations utilizing a marine riser and subsea BOP equipment. Gas may pass the BOPs immediately before they are closed on a kick or gas may be trapped below the BOPs in normal kill operations. A diverter can provide additional flexibility and safety when removing gas in the marine riser.
4. In some situations, such as drilling in a shallow gas prone area with a floating rig, subsea positioning of the diverter may be beneficial.
5. On drilling locations where personnel and/or equipment cannot readily evacuate the immediate location in the event of a complete loss of well control, with or without BOPs in use, a diverter system should be considered as additional redundancy and safety to divert uncontrolled well flow while taking corrective action and/or evacuating personnel.

7.3.2 Shallow Water Flows in Deepwater

Shallow water flows may result in loss of well support, buckling and collapse of the casing, and poor well bore integrity that can result in loss of well control at a later stage in the operation. By predicting the occurrence, pore pressure and fracture gradients of potential shallow water flows, the problems may be avoided. If a shallow water flow must be drilled, consideration should be given to maintaining control during drilling, running casing, and casing cementing operations. Casing should be set above the shallow flow zone, if possible. The real time information provided by LWD can be of benefit; allowing timely correlation of the formations with available geological and geophysical data. Mechanical shut-off devices for shallow water flow should be considered.

7.3.3 Other References

The International Association of Drilling Contractors (IADC) has devoted considerable attention to guidelines for predicting, drilling, cementing, and controlling shallow water flows, including several descriptions and illustrations of mechanical shallow water flow shut-off devices. This information is available in the 1998 edition of *IADC Deepwater Well Control Guidelines*.

7.4 CASING

When considering well control, the most important casing requirements are tube strength, setting depth, and size. Misalignment, hydrogen sulfide exposure, deviated holes, doglegs, long drilling times, coarse hardbanding, and corrosion are some of the factors affecting design and performance. Inspection and/or test schedules should consider all of these factors. Each new string should be set at a depth so that formation fracture gradients will exceed anticipated gradients of the drilling fluid. The internal pressure and external collapse ratings of casing should be designed to handle the anticipated pressures.

7.4.1 Casing Wear

Wear bushings should be considered. If the surface pipe becomes worn or holed, closure on a kick can allow formation fluids to broach to the surface or allow an underground blowout. Consideration should be given to casing thickness measurements should any casing string be exposed to longer than anticipated drilling operations.

7.4.2 Setting Depths

These will vary according to well conditions. Surface casing is usually the first well control string and should be set into formations competent to hold drilling fluid densities anticipated at least until the intermediate casing string is set. Prior to drilling out the casing shoe, the casing should be pressure tested. A pressure test of the cement job and a formation competency test should be considered after drilling out below each casing string. These tests will dictate the drilling fluid densities and surface pressure that will be allowed before the next string is set.

7.4.3 Existing Wells

The setting depth and condition of the casing should be considered before drilling, workover, or well service operations. Depending on the operation, testing of the casing may be warranted.

7.4.4 Casing and Liner Landing and Handling Practices

These should be designed and planned to avoid buckling and joint failure with subsequent higher drilling fluid density, temperature, and pressure. Consideration should be given to casing and liner running and handling procedures in order to be prepared should a kick occur.

7.4.5 Contingency Plans

Consideration should be given to actions to be taken if the maximum allowable casing pressure is reached, considering each of the following possibilities:

1. Casing failure,
2. Broaching,
3. Underground blowout, and
4. Capabilities of surface equipment.

7.5 CEMENTING

Casings should be adequately cemented to confine well bore fluids; this is especially important in surface and conductor cementing. Lightweight cements are sometimes necessary to keep from breaking down the formation(s) encountered. A good cement job is essential so any pressure encountered later will not break out around the casing and broach to the surface. Drilling fluid returns should be monitored while cementing to determine if there is a gain or loss. When cementing in deepwater, consideration should be given to using a remotely operated vehicle (ROV) to ensure cement returns have reached the mudline.

7.6 BLOWOUT PREVENTION EQUIPMENT SELECTION

Blowout prevention equipment systems are composed of all equipment components required for well control. These systems include BOPs, choke and kill lines, choke manifold, closing unit, marine riser, and auxiliary equipment. Their primary function is to confine well fluids to the well bore, provide means to add fluid to the well bore, and allow controlled volumes to be withdrawn while allowing controlled pipe movement. The selection of equipment for a particular well is dictated by many factors including, but not necessarily limited to, casing program, anticipated pressures, environment, space, governmental regulations, and availability. Following are some general guidelines:

1. The working pressure of ram-type BOPs should exceed the maximum anticipated surface pressure. Provisions should be made for closing BOPs on all sizes of drill pipe, drill collars and casing that may be used.
2. The well plan should contain drawings showing equipment and arrangement of the wellhead, BOP stack, valves, lines, manifold, and accessory equipment required for each casing string. These drawings should clearly indicate the location, size, and type of rams with instructions to outline any changes desired during specific operations.
3. If hydrogen sulfide is predicted or suspected, materials used in the equipment must be resistant to hydrogen embrittlement (sulfide stress cracking). The following references are recommended:

- API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits*;
- API RP 49, *Recommended Practice for Safe Drilling of Wells Containing Hydrogen Sulfide*;
- API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells*;

- API Spec 16A, *Specification for Drill Through Equipment*; and
- NACE Standard MR-01-75, *Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment*.

4. Additional considerations for blowout prevention equipment selection are: 1) distance between rams so pipe can be stripped; 2) sizing of lines and valves to minimize friction losses and backpressure during well killing operations; and 3) marine applications as discussed in Sections 7.3 and 10 of this publication.
5. Additional information on BOP equipment systems is available in API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* (reader should check for the latest edition). Information on marine riser systems is available in API RP 16Q, *Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems* (reader should check for the latest edition).

7.7 DRILLING FLUID

A variety of fluids are available to satisfy well objectives: air, nitrogen, natural gas, foam, water-based, synthetic-based, oil-based, and specialized heavy weight brines. Following are some considerations for well planning (refer to 4.5).

7.7.1 Maintenance of Overbalance

Depending on pressures in the well, overbalance can be maintained with gas, foam, water-based or oil-based drilling fluids. Significant changes in drilling fluid density can be caused by drilled solids and/or influx of fluids. Controlled drilling rates are advisable in certain cases where fast drilling is possible or overbalance is critical. Unrestrained penetration of gas-filled formation(s) can cause severe fluid density cuts, particularly if the formation pressure is high. The equivalent circulating density must be considered. Density control and fluid loss are primary considerations.

7.7.2 Underbalanced Drilling

This is a specialized application used where conditions are well known and predictable.

7.7.3 Drilling Fluid Monitoring Equipment

It is essential to monitor the quality and quantity of fluid in the system. Fluid measuring devices that will monitor the active drilling fluid volume should be provided. Several methods of combining different types of equipment can be used, depending upon the well requirements. These may include:

1. Pumpstroke counters;
2. Flow line sensors with alarms;
3. Pit level recorders with alarms;
4. Trip gain-and-loss meters; and
5. Trip tanks.

Pit level monitoring devices may not be adequate for operations involving large drilling fluid surface volumes, such as floating rigs. Quality of drilling fluid is extremely important. Provisions should be made to measure the density, viscosity, and other fluid properties as required (refer to the references in 4.5).

7.7.4 Fluid Storage Capacity

Adequate supplies of fluids are necessary for well control operations. Logistics and storage should be thoroughly reviewed and planned, especially offshore where space on a drilling rig or platform is limited. Priority should be considered for storage of adequate supplies of base fluids, weighting material, and loss circulation materials. Procedures and fluid recipes should be pre-planned and readily available. It may be desirable to have kill weight or LCM fluids pre-mixed and available during certain operations such as drilling into a suspected shallow gas formation or a transition zone. In floating drilling operations, plans should be made to recover and store riser fluids during planned and emergency disconnects, especially when using oil or synthetic based drilling fluids and certain heavy brines.

7.7.5 Mud-Gas Separator

Selection and sizing of the mud-gas separator should be done in the pre-planning stage before rig selection. Sizing of the mud-gas separator should consider vent line diameter and length and maximum gas rates. A bypass line to a flare or a vent line must be provided in case of a malfunction or the capacity of the separator is exceeded. Precautions should be taken to prevent or minimize erosion at the point of impingement of flow on the vessel and provisions should be made for ease of cleanout of the vessel and lines. Examples of mud-gas separator sizing guidelines can be found in SPE Paper No. 20430: *Mud Gas Separator Sizing and Evaluation*, G. R. MacDougall, December 1991.

7.7.6 Hydrates

Hydrates are potential problems in cold weather and deepwater operations. An analysis of hydrate formation potential and the associated risks should be made, appropriate contingency plans and well control procedures developed, and hydrate prevention programs implemented. For more information, refer to the 1998 edition of *IADC Deepwater Well Control Guidelines*.

7.8 SERVICE OPERATIONS

Well planning should include service operations. These include, but are not limited to: logging, coring, fishing, drillstem testing, slick-line, and coiled tubing operations (refer to API RP 5C7, *Recommended Practice for Coiled Tubing*

Operations in Oil and Gas Well Services). Considerations for all these operations include:

- Keeping the hole full
- Avoiding surge and swabbing
- Well bore monitoring when out of the hole
- Consideration of lubricator design and best operating practice for high-pressure wireline work
- Procedures for stuck pipe and tools
- Procedures for plugged tubulars and bits when fishing or coring
- Stripping procedures and equipment arrangement
- The hazards and material requirements associated with sour gas

7.9 KICK RESPONSE PLANS

Once all the well data are gathered and a general well plan is complete, attention should focus on response to potential kicks during drilling and workover operations. Following are some of the items that should be considered.

1. Pre-kick data requirements and collection for each stage of operations
2. Divert procedures
3. BOP close-in procedure selection at each stage
4. Kicks while tripping pipe in and out of the hole
5. Kicks while tripping in the hole with casing and liner
6. Underground blowout
7. Stuck pipe procedures
8. Plugged or packed-off pipe or bit
9. Defoaming agent to eliminate foam in the pits
10. Gas bubble migration
11. Lost circulation–recipes and procedures
12. Riser disconnect procedures–planned and emergency

7.10 RISER DISCONNECT

Situations that can cause the need to release the marine riser should be reviewed: well or equipment problems, severe weather, eddy currents, etc. When an incident occurs the well needs to be secured and the riser disconnected before damage occurs to the wellhead or any of the drilling rig or well control equipment. If the loss of station keeping ability occurs while drilling or tripping pipe it is necessary to be able to:

1. Hang-off the drill pipe on pipe rams;
2. Shear the pipe;
3. Effect a seal on the wellbore;
4. Disconnect the lower marine riser package;
5. Clear the BOP with the BOP with the lower marine riser package;
6. Dissipate any energy in the riser/riser tensioning system; and,
7. Capture the riser.

Those situations and conditions where a riser disconnect procedure are to be initiated must be clearly defined. Disconnect procedures should be prepared. Crew training and drill exercises should also be prepared. For additional information and recommendations, refer to the 1998 edition *IADC Deepwater Well Control Guidelines*.

7.11 SIMULTANEOUS OPERATIONS

Plans for simultaneous operations should be considered when drilling and workover operations are conducted in close proximity with other operations. Examples include: a drilling and production pad, an offshore drilling and production platform, or drilling/workover operations in a gas storage field or a natural gas plant. These facilities all have additional exposure due to the presence of oil and gas processing facilities, pipelines and pipeline connections, and producing wells as well as the potential for production and service personnel nearby or on-board. Consideration should be given to shut-in of producing wells and oil and gas processing facilities during certain simultaneous operations such as moving the rig or hoisting loads near or above producing wellheads, piping, or process vessels. Be certain that operations on one well do not cause loss of control on another. Government regulations and local safe operating practices should be reviewed.

7.12 LOGISTICS

Access to the well, transportation, material and equipment acquisition, competent and adequately trained service personnel, and communications are extremely important during a well control situation. Consideration should be given to pre-arranging contractor services. These services include equipment and material specifications, contracts, methods and terms of payment, personnel, and personnel qualifications. Some logistics considerations are discussed below:

7.12.1 Access/Egress

Consider the ability for equipment to access the location in a well control incident. For example: an arid, flat drilling location provides adequate access from all directions whereas a location in a swamp area may have only one road. Careful consideration should be given to the design and construction of that road and controlling traffic in an emergency. A helicopter landing area should be considered. Consideration should be given to prevailing winds, especially if hydrogen sulfide gas is expected.

7.12.2 Equipment

Bulldozers, front-end loaders, cranes, heavy-lift trucks, pump trucks, and tank trucks should be located before spudding the well and appropriate arrangements made for their possible use should a well control incident occur. The same consideration and planning should be done for spare BOPs, chokes, choke manifolds, tool joints, and general oilfield supplies. Offshore operations require additional marine equipment: supply and work boats, anchor handling boats, and remotely operated vehicles (ROV).

7.12.3 Services

A wide variety of service personnel could be required, depending on the circumstances of the well control incident. Finding the most qualified personnel requires investigation and planning before spudding. Some service personnel that may be needed include: well head technicians, BOP technicians, pneumatic and hydraulic controls specialists, well capping professionals, well control technical and operations advisors, welding and fabrication personnel, machine shop services, pumping and cementing, water-well driller, pumps, pit liner, snubbing, hot tap services, and communications technicians.

7.13 SAFETY AND MEDICAL

Contingency plans should be prepared in advance. Among the considerations are:

1. Personal protection equipment considerations are: hard-toe shoes, head protection, eye protection, hearing protection, and gloves. Eye wash stations and showers should be considered.
2. If hydrogen sulfide is a possibility, consider H2S detection and monitoring equipment and services as well as emergency breathing air and equipment.
3. First-aid training of all personnel should be reviewed and updated as necessary.
4. Medical evacuation services, such as ambulance or helicopters, should be identified and reviewed.
5. Local hospitals and clinics should be identified.

7.14 COMMUNICATION

A large number of personnel and disciplines may be involved with a drilling or workover operation. These include geophysicists, geologists, landmen, engineers, safety and environmental personnel, government agencies, landowners, and a host of contractors, vendors, and service companies. When devising the well plan all possible sources of information should be contacted. Prior to commencing operations, it is advisable that all involved parties understand the objectives, procedures, and hazards. All personnel should be encouraged to report abnormal conditions. Alertness and speed of communication are critical factors in well control. Some elements for consideration in a communication plan are presented below.

7.14.1 Emergency Notification Plan

The plan should identify who should be notified, when, and how. The plan should consider company management, government agencies, landowners, neighbors, and news organizations. Also, consider having a thorough plan for managing communications during the well control operations. Updated contact information should be maintained for:

1. Well owners or management.
2. Emergency medical evacuation services and medical personnel.
3. Emergency management personnel, whether government, volunteer, or private organizations.
4. Government agencies responsible for the particular operation.
5. Nearby personnel, residents, or operations personnel that may be affected by the emergency.
6. Vendor and service personnel identified in 7.11.2 through 7.12.3.

7.14.2 Communications System

Whether a communication infrastructure is in place depends on the type of operation, location, and proximity to operations bases. Communications systems, equipment, and personnel have a wide variety of sophistication around the world as well as from operation to operation. For example, an onshore communications system for well service operations is not likely as sophisticated as those systems on an offshore platform where computer and satellite communications may be utilized. However, due to distance and other factors, the well service unit communications may be as or more reliable. Consideration should be given to updating or expanding communications systems prior to commencing operations. Other considerations for communications are:

1. Equipment should be explosion proof.
2. Uninterruptible power system (UPS) for communications equipment and computers.
3. Backup communications systems, i.e., a short wave radio to backup a microwave system.
4. Handheld radios for site communications as well as hard-hat headsets.
5. Satellite, FM, or short-wave radios for longer distance communications.
6. Fax capability for drawings.

7.15 TRAINING AND INSTRUCTION

Well control situations, especially those involving shallow gas flows, can develop quickly and be difficult to detect early. All concerned personnel should be familiar with the well control system components and installation and capable of reacting quickly and efficiently to potential situations requiring its use. The following general guidelines are offered for personnel training and instruction:

1. Formal training and instruction in well control procedures should be reviewed and updated as necessary prior to spudding.
2. Written emergency procedures should be developed prior to spudding that detail specific emergency action plans.

3. Drills should be prepared in advance with consideration given to testing response to various scenarios.
4. Drills should be conducted at appropriate intervals to ensure personnel are capable of quickly and competently reacting to various scenarios.
5. Drills should be documented and analyzed to identify areas where improvement is required.
6. Follow-up on problem areas identified in the drills should be completed and documented.
7. Emergency plans, training, and drills should be kept up-to-date and change as conditions change.

7.15.1 Industry Association Training

The International Association of Drilling Contractors (IADC) has implemented two training programs for industry.

1. RIG PASS Accreditation System—The program identifies core elements of training programs for new rig employees and recognizes programs that adhere to those elements. Completion of a RIG PASS accredited program confirms that personnel have met basic requirements defined by safety and training professionals in the drilling industry, irrespective of the rigs location.
2. WellCAP Program—The program emphasizes the knowledge and practical skills critical to successful well control. It uses quality benchmarks developed together with operators, drilling contractors, professional trainers and well control specialists. WellCAP ensures that well control training schools adhere to a core curriculum developed by industry. Accreditation is achieved only after an extensive review of a provider's curriculum, testing practices, faculty, facilities, and administrative procedures.

8 Well Control Procedures for Surface Diverter Installations

8.1 PURPOSE

The diverter is an annular sealing device used to close and pack-off the annulus around pipe in the well bore or the open hole when it is desired to divert well bore fluids away from the drilling rig and personnel. Conventional BOPs, insert-type diverters, and rotating-heads can be used as diverters. Some diverters are designed to function as diverters and as a BOP. A diverter system is not designed to shut-in or halt flow; rather it permits routing of the flow to a safe distance away from the rig. It packs-off around the kelly, drill string, or casing and directs flow to a safe location. Diverters are primarily used to divert flow from the rig in three situations:

1. Shallow fluid and gas flows,
2. Drilling with a rotating head, and,
3. Drilling with a marine riser.

8.2 INSTALLATION OF EQUIPMENT

Diverter system equipment, operations, and maintenance are covered in API RP 64 and RP 53. It is beyond the scope of this publication to cover those topics. API RP 64, *Recommended Practice for Diverter Systems Equipment and Operations* (reader should check for the latest edition) sets forth recommended equipment installations and equipment requirements for diverters. Section 4 of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* (reader should check for the latest edition) addresses diverters used with surface BOP stack installations while Section 5 addresses diverters used with subsea BOP stack installations. For diverter systems used on marine drilling riser systems, more information can be found in API RP 16Q, *Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems* (reader should check for the latest editions).

8.3 DIVERTER OPERATION

Following are recommendations for diverter operation and controlling diverted flow. Under no circumstances should diverter lines be closed on a possible kick.

8.3.1 Kick or Suspected Kick

When drilling through a diverter at shallow depth and a kick is indicated or suspected, stop drilling, pick up to clear the kelly or tool joints, close the diverter, sound the alarm, stop the pump, and check for flow through the open diverter line. Allow the well to flow through the open diverter line; pump water or drilling fluid as necessary to moderate the flow.

8.3.2 Divert Pressure Trapped Under a Subsea BOP

If a subsea stack has been used to control a kick in normal well control operations, the diverter should be used to divert gas that accumulates under the BOPs.

8.3.3 Controlling Flow

Pumping at a fast rate tends to improve the drilling fluid/gas ratio and creates a small increase in bottom-hole pressure due to annular friction pressure. Increasing the drilling fluid density at a fast rate increases hydrostatic pressure and can eventually stop flow. Thus, when a shallow gas flow occurs, the following actions should be taken immediately:

1. Pump as fast as possible.
2. Increase drilling fluid density as rapidly as possible while pumping.
3. If drilling fluid supply should be exhausted, continue by pumping water.

8.3.4 Slurry Volume and Slurry

If room on the rig permits, in areas with possible shallow gas, a reserve supply of drilling fluid weighted 1 to 2 lb/gal above the expected need is often carried in reserve, and is immediately pumped in the well if a shallow gas kick occurs. This may be effective in maintaining well control. If the drilling fluid supply is exhausted and conditions are such that the attempt can be made safely, a barite-water slurry of 18-20 lb/gal density may be pumped using chemicals to increase settling rate as described for barite plugs (refer to 13.4). This procedure serves to increase the hydrostatic pressure and settles the barite to form a plug. For more information on diverters and shallow gas flows, refer to 4.14, 7.3 and 7.3.1 as well as the references to API RP 64 and API RP 53 listed in 8.2.

8.4 DIVERTER STRIPPING OPERATIONS

Diverters should permit stripping pipe into the hole while diverting well flow. Inflation type diverters permit such stripping. Stripping life of this type diverter is maximized by use of minimum inflation pressure and by having a suitable accumulator of at least five-gallon capacity in the closing line near the diverter. This accumulator will reduce pressure surges when tool joints pass through the closing element. Closing time of such diverters is decreased with increasing closing pressure but, if stripping pipe through the diverter is required, closing pressure should be reduced to the minimum required to effect a seal.

For more information on stripping, see 12.8 entitled Stripping Operations.

9 Control Procedures—Surface Bops

9.1 PRE-KICK PLANNING

Prior to taking a kick, consider what action to take should a kick occur. A plan should be designed and implemented by the rig supervisor, utilizing the equipment and personnel available. This varies from rig to rig and for various operations, i.e., drilling, workover, tripping, etc. Some preliminary tasks must be performed to assure that all equipment is functional and the crew is aware of its duties in the program. The following outline details the recommended minimum pre-kick planning.

9.1.1 Supervision

1. Plan—Prepare detailed plan noting equipment limitations, casing setting depths, fracture gradients, expected hazards, maximum fluid density, and pressure that may be encountered. The plan should contain duty stations and functions for each member of the crew involved in the well control program.
2. Communications—Post the plan and discuss each function with personnel concerned.
3. Practice—Drills enhance crew response and assure that necessary safety devices are available and functioning.
4. Pre-recorded Information—Prior to drilling out the casing shoe, and daily while drilling or after a significant change in the circulating system pressure, the operator's representative should fill-in the pre-recorded information as shown on the applicable well control worksheets (refer to Appendix B):

   a. Record pertinent casing data-For combination casing strings, define the weight, grade, and internal yield strength of the uppermost section.
   b. Mechanical pressure limit-This is the safe working pressure of the surface BOP equipment, wellhead, and casing string.
   c. Casing pressure to cause fracture based on present drilling fluid density-This pressure may be calculated using either estimated or measured fracture drilling fluid density (refer to Notes 1A and 1B on the well control worksheets, Appendix B). If formation leak-off pressure is measured, use this pressure to determine the fracture drilling fluid density (refer to Note 1A on the well control worksheets, Appendix B) and to calculate the fracture pressure (refer to Note 1B on the well control worksheets, Appendix B).
   d. Approved maximum allowable casing pressures-The operator's representative should define the maximum allowable casing pressures for initial closure and the entire well control operation, select the contingency plan (refer to Paragraph 7.4.5) in the event maximum allowable casing pressure will be exceeded, and sign the well control worksheet.
   e. Normal circulating pressure and kill pressure data-The driller should record the normal circulating pressure and pump rate data; and, measure and record the kill pressure and pump rate data on the daily drilling report form.
   f. Calculate the pump rate (barrels per minute); enter it on the kill pressure and rate table; and obtain the drill pipe capacity in barrels per ft .
   g. The operator's representative should pre-select the shut-in method to be used by checking the appropriate box in the immediate action section of the suggested well control worksheet (refer to Appendix B).
   h. The operator's representative should also pre-select the trip margin for use in calculating the required drilling fluid density by completing the appropriate portion of the equation for calculating "Required Drilling Fluid Density" on the well control worksheets (refer to Appendix B).

9.1.2 Equipment Inspection and Test Schedule

1. BOPs and well control equipment should be inspected and tested in accordance with Section 17 (Surface BOPs) and Section 18 (Subsea BOPs) of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* (reader should check for the latest edition).
2. Warning Devices—Inspect hourly and maintain operational (pit level recorders, flow indicators, gas detectors, lights, horns, etc.).
3. Drilling Fluid System—The primary well control system must be maintained continuously, with sufficient inventory of materials to handle, within reason, any unexpected well flow or lost circulation condition.

9.2 WELL CONTROL PROCEDURES

The following procedures assume that pre-kick planning is complete and a kick is suspected with the bit on, or near, bottom. This is generally the most desirable position for well control operations.

9.2.1 Suspected Kick

1. Stop drilling (or other operation) and position the pipe for the BOPs while sounding the alarm. (Note: Be aware of where tool joints are positioned in the BOPs.)
2. Shutdown the drilling fluid pump(s).
3. Check the well for flow.

9.2.2 Immediate Action When a Kick Occurs

1. When a kick occurs, stop drilling (or other operation), position the pipe for the BOPs while sounding the alarm, and stop the pump(s).
2. Chose 2(a) or 2(b) below:
   2(a) If the "soft shut-in procedure" has been selected: open the choke line; close the BOP, and close the choke (refer to 4.9.1).
   2(b) If the "hard shut-in procedure" has been selected: close the BOP and open the choke line with the choke or adjacent high-pressure valve closed (refer to 4.9.2).
3. Observe the casing pressure. If the casing pressure will exceed maximum allowed, follow the pre-selected contingency plan (refer to 7.4.5).
4. After closure, check for trapped pressure (refer to 9.5.1).
5. Allow closed-in pressures to stabilize and record the drill pipe and casing pressures.
6. If part of the approved well control plan, initiate pipe movement. Note: This action should be viewed with caution. Stuck pipe may be a minor problem compared with worn or leaking sealing elements during a well kick.
7. Determine the kick volume.
8. Calculate the drilling fluid density required to kill the kick (refer to 9.5.2).
9. Initiate the approved well kill method.
10. Check rig crew duties and stations.
11. Review and update pump output and hole volume data and complete the suggested well control worksheet (refer to Appendix B).
12. Adjust pit volume to allow for kick fluids volume and/or barite addition.
13. Check pressures on all annuli of the well.

9.2.3 Circulating Out Using the Driller's Method

This procedure dictates that the invading fluid (flow) be circulated out before increasing the drilling fluid density. Constant drill pipe pressure control is required throughout the initial circulation (refer to 4.10.2 and its subparagraphs).

1. Open the choke while bringing the pump to the kill-rate (refer to 9.5.3). Increase the pump rate slowly while holding the casing pressure at its initial closed-in value by adjusting choke.
2. When the kill-rate is reached, the observed drill pipe pressure should be equal to the calculated initial circulating pressure. If not, investigate cause (refer to 9.5.4). If no cause is evident, use the observed drill pipe pressure.
3. Continue to pump drilling fluid of the original density at the kill-rate, maintaining the drill pipe pressure constant by adjusting the choke. Continue to pump until the well is free of invading fluids.
4. Stop the pump while holding the casing pressure constant. The closed-in drill pipe and casing pressures should be equal and approximately the same as the initial closed-in drill pipe pressure. If not, circulate additional drilling fluid as in step 3 until the well is free of invading fluids.
5. Increase the drilling fluid density in the suction pit to the density required to kill the well. Monitor drill pipe and casing pressures. Percolation of gas causes shut-in drill pipe and casing pressures to increase. If this occurs repeat steps 4 and 5.
6. Circulate heavy drilling fluid, establishing circulation by bringing the pumps up to speed while holding the casing pressure constant at the value observed in the step 3 procedure plus any desired safety factor. Hold the pump rate constant at the kill-rate. Maintain casing pressure constant by adjusting the choke until the drill pipe is displaced.
7. When the drill string has been displaced with heavy drilling fluid, observe the drill pipe pressure.
8. Continue to circulate at a constant rate holding the drill pipe pressure constant at the pressure observed in step 7 by adjusting the choke. When the heavy drilling fluid reaches the surface, the casing pressure should approach zero.

9. Simultaneously close the choke and stop the pump. The closed-in drill pipe and casing pressure should be zero.
10. If the closed-in pressures are not zero, check the well for flow. If the well will flow, repeat the aforesaid operations beginning with step 5 and recalculate the drilling fluid density required to kill the well on the basis of the observed shut-in pressure.
11. If shut-in pressures in step 9 are zero and well will not flow, prepare to open the preventers. Caution: If, for some reason, more than one preventer is closed, pressure may be trapped between the closed preventers.
12. Open preventers and resume operations.

9.2.4 Wait and Weight Method

The well is closed-in on the kick; the drilling fluid density is increased in the pits as required; then the kick is circulated out with the weighted fluid (refer to 4.10.3 and its subparagraphs).

1. Mix kill fluid while maintaining constant drill pipe pressure by bleeding the annulus. Note how long it takes to mix and at what rate the equipment can continue to mix to the proper drilling fluid density. This gives a guide to selection of proper kill or displacement rate. To avoid shutdown, do not displace at a rate exceeding mixing rate (refer to Appendix B).
2. While mixing kill fluid, review and update pump output volume data and complete the suggested well control worksheet (refer to Appendix B).
3. Open and adjust the choke to hold casing pressure constant at its present closed-in value while bringing the pump up (slowly, if possible) to the kill-rate. Hold the kill-rate. At this time, the observed drill pipe pressure should be equal to the calculated value for initial circulating pressure. If they are approximately equal, then add or subtract the difference to/from the drill pipe schedule. If they widely differ, then use the observed drill pipe pressure as the initial circulating pressure and re-calculate the drill pipe schedule.
4. If the circulating pressure is correct, displace drill pipe at a constant pump rate in accordance with the pumping schedule on the well control worksheet. Maintain drill pipe pressure as per schedule by adjusting the choke.
5. Maintain constant pump rate and drilling fluid density. After the kill fluid reaches the bit, vary the backpressure on the annulus with the choke to maintain the drill pipe pressure constant at the final circulating pressure. Continue this operation until kill fluid is circulated. The variation in backpressure and pit volume during this circulation is a function of the amount and type (gas, water, or oil) of kick.
6. Continue pumping until kill fluid is circulated to the surface. Then stop the pump and shut-in the well. If sufficient kill fluid density was used during this circulation, the pressure should be zero.
7. If pressures are not zero, repeat operations in steps 1 through 6, with drilling fluid density adjustments.
8. If shut-in pressures in step 6 are zero, check well for flow before opening preventers. Caution: If, for some reason, more than one preventer is closed, pressure may be trapped between the closed preventers.
9. Open preventers and resume operations.

9.2.5 Concurrent Method

This procedure permits resuming well circulation and beginning weight-up operations immediately after well closure and pressure stabilization (refer to 4.10.4 and Figure 4.16).

1. Review and update pump output and hole volume data and complete the suggested well control worksheet (refer to Appendix B).
2. Open choke while bringing the pump up to kill-rate—Increase pump rate slowly, if possible. Adjust the choke to hold casing pressure constant at the initial closed-in casing pressure while bringing the pump up to kill-rate. Hold the kill-rate. At this time, the observed drill pipe pressure should be equal to the calculated value for initial circulating pressure. If they are approximately equal, use the choke to adjust the observed drill pipe pressure to the calculated pressure. If the two pressures are widely divergent, close-in the well and consider alternatives (refer to 9.6.4).
3. Start increasing the drilling fluid density—Record time and strokes when each drilling fluid density change occurs in the suction pit. A more even drilling fluid density is produced if auxiliary circulation is maintained between two pits.
4. Prepare a drill pipe pressure schedule so that the drill pipe pressure may be reduced (refer to 4.10.4) as the hydrostatic pressure inside the drill string increases due to heavier drilling fluid being pumped to the bit. More than one circulation may be necessary before the required drilling fluid density is attained.
5. Hold drill pipe pressure per prepared schedule—When the required drilling fluid density reaches the bit, drill pipe pressure should be held constant until the required drilling fluid density reaches the surface.

9.3 DRILL STRING OFF-BOTTOM

If the bit is off-bottom any significant distance, a drill pipe safety valve and inside BOP should be installed and the pipe stripped back to bottom (refer to 12.8). Well control operations with the bit off-bottom a significant distance offer less chance of achieving hydrostatic control of formation pressure. If it is impractical to strip back to the bottom, refer to procedures covered in Sections 12 and 13.

9.4 HIGH-ANGLE AND HORIZONTAL WELL BORES

The techniques used in conventional well control can apply to high-angle or horizontal wells. The high angles and small hole sizes require some additional considerations and precautions.

9.4.1 Kicks and Kick Detection

Compared to a vertical well bore, the characteristics of a kick in a high-angle or horizontal well include:

- Potential kick intensity can be high due to the long, high-angle section that may be through the kicking formation.
- ECD is relatively high due to small hole size and high measured depth.
- Kick detection can be complicated in a high-angle or horizontal well bore; pit gain and monitoring for drilling fluid flow are extremely important.
- Gas migration will occur relatively slowly in the high-angle well bore and may not occur at all in the horizontal portion of the well bore.

9.4.2 Well Control

Once a kick is detected, conventional close-in and well kill methods are effective. The hard close-in procedure is recommended to minimize kick influx due to the potential high productivity of the horizontal or high-angle formation. Some factors to consider after shut-in include:

9.4.2.1 Zero shut-in pressures do not mean a kick has not occurred. A positive pit gain may indicate a kick that is still in the high-angle or horizontal hole section.

9.4.2.2 Shut-in casing and shut-in drill pipe pressures will be very close due to little or no reduction in the annular hydrostatic pressure in high-angle or horizontal well bores.

9.4.2.3 Determining influx fluid type based on shut-in pressures and pit gain are not valid with high-angle/horizontal sections. However, increasing casing pressure indicates a gas kick expanding above the horizontal section.

9.4.2.4 The pump schedule for displacing the drill string with kill weight fluid is more complex due to the horizontal section.

9.5 REFERENCE NOTES FOR SECTION 9

9.5.1 Trapped Pressure

Trapped pressure in the case where a well with a kick is shut-in and the bottomhole pressure is above the reservoir pressure. For example, when the choke is closed before the pump is shut down, or gas migration occurs in a shut-in well (refer to 10.2.2 for trapped gas below subsea BOPs). It is good practice to check for trapped pressure after each well shut-in. The recommended check consists of bleeding the annulus slowly through a manual adjustable choke to detect any decrease in drill pipe pressure. The maximum volume bled should be limited to one barrel or less (much less in cases where the annular volume is relatively small). If drill pipe pressure does not decrease, pressure was not trapped.

9.5.2 Required Drilling Fluid Density Calculations

Required drilling fluid density is calculated using the initial static, shut-in drill pipe pressure. The equation is:

$$\text{Required drilling fluid density (lb/gal)} = \frac{\text{Closed-in drill pipe pressure (psi)}}{\text{Depth } (TVD)\text{, ft} \times 0.052} + \text{Present drilling fluid density (lb/ gal) in the drill pipe (and trip margin where appropriate)}$$

Prior to mixing kill fluid, the pit volume should be adjusted to allow for gas expansion and barite addition anticipated during the kill circulation.

9.5.3 Kill-rate

Rig equipment may be the primary factor in selecting a kill rate for the well (refer to 4.8.5 for a description of kill-rate and 4.13 for information on subsea choke lines, another factor affecting kill-rate selection). A rate should be selected which will eliminate interruptions. Some of the considerations are:

a. Drilling fluid mixing capabilities, i.e., displacement rate should not exceed the mixing rate;

b. Surface fluid handling equipment, e.g., the mud-gas separator;

c. Minimum pump speeds (pump crippling may be required);

d. Pump pressure limitations;

e. Choke line friction; and

f. Choke-manipulation delays (human factors). Lower kill-rates should be selected to minimize interruptions.

9.5.4 Initial Circulating Pressure

In the event the observed initial drill pipe circulating pressure does not equal or approximate the calculated value, the well should be closed-in and the reasons for the wide divergence determined. This divergence may be caused by any of several factors including, but not limited to:

1. Calculation mistake,
2. Washout,
3. Pump failure,
4. Plugged bit nozzle or hole pack-off,
5. Gas cut drilling fluid in the pump suction,

6. Erroneous gauges, and
7. Changes in mud properties.

Recommendations for remedial actions for several of the factors listed above are covered in Section 12.

10 Well Control Procedures for Subsea BOPs

10.1 GENERAL

The procedures used to control wells equipped with subsea blowout prevention equipment are essentially the same as for those with surface control. There are, however, several additional factors, which must be taken into consideration. The purpose of this Section is to discuss these factors and show how they can be taken into consideration in applying the procedures recommended in Section 9, "Well Control Procedures—Surface BOPs."

10.2 ADDITIONAL CAUSES OF KICKS UNIQUE TO SUBSEA OPERATIONS

10.2.1 Loss of Integrity in the Marine Riser

Well bore hydrostatic pressure is a function of the height and density of the drilling fluid column from the flow line to the depth of interest. If a riser fails, leaks, or becomes disconnected, the drilling fluid gradient in the riser is lost and replaced by a seawater gradient (approximately 0.445 psi/ft-8.56 lb/gal) from the point of failure to sea level. The loss of well bore hydrostatic pressure associated with this situation can sometimes be sufficient to allow a well to flow. The first response should be to close the BOPs. In some situations, the drilling fluid density may be sufficient to compensate for the loss of hydrostatic pressure. If not, the loss of hydrostatic pressure should be restored prior to opening the BOP.

10.2.2 Trapped Gas Below BOPs

Subsequent to control operations during which gas is circulated out the choke line, free gas will remain trapped below the closed preventer; the gas volume can be quite significant with an annular preventer. To prevent rapid unloading of the riser due to trapped gas when the closed preventer is opened or the introduction of a secondary kick due to light density drilling fluid in the riser, close the uppermost rams below the choke line and close the diverter. Open the preventer above the trapped gas and allow this gas to rise toward the surface. Displace the riser with kill fluid and reopen the rams. It may be necessary in extreme cases to close the bottom rams to isolate the hole and fill the riser by circulating through the kill line. This problem becomes more severe with increased water depth and/or BOP size. The basic steps are as follows:

1. Isolate the wellbore by closing a lower set of preventers;
2. Lower the gas pressure by exposing it to a lower hydrostatic pressure;
3. Circulate the BOPs choke and kill lines and riser with kill mud; and,
4. Open the well.

10.2.3 Vessel Motion

Although it may not be a direct cause of a kick, vessel motion complicates kick recognition and can cause wear in the annular BOP or diverter sealing elements.

10.2.3.1 Vessel heave alternately lengthens and shortens the drilling riser and can make the well appear to flow. In extreme cases, it can cause an apparent loss of returns by exceeding the surge capacity of the shale shaker. In severe weather, vessel pitch and roll can conceal changes in pit level.

10.2.3.2 Wear on BOP or Diverter Sealing Elements—Pipe movement through a closed annular BOP or diverter can cause rapid wear of the sealing elements. Pipe movement results from vessel heave or pipe stripping operations or a combination of both. Wear on sealing elements can be minimized by:

1. Adjusting the system closing pressure to the lowest pressure that results in an acceptable closing time,
2. Hanging off the drill pipe as soon as practical after a kick has been identified,
3. Reducing the closing pressure to the lowest practical value during sustained periods of pipe motion, and
4. Adjusting the motion compensator.

Many floating drilling rigs with subsea BOP stacks have ram locks that lock automatically upon closure. Hence, reducing closing pressure will do little to relieve the stress on the rubber packers after the BOP is closed and locked. Consideration should be given to installing rams that do not automatically lock upon closure. Specific recommendations as to closing pressures should be obtained from equipment manufacturers.

10.3 SUBSEA EXCEPTIONS TO CONTROL PROCEDURES

The control techniques discussed under Section 9, "Well Control Procedures—Surface BOPs," apply to subsea operations with the following special considerations:

1. Choke line pressure loss.
2. Establishing circulation.
3. Low fracture gradients in deepwater.
4. Close-in and hang-off operations.

10.3.1 Choke Line Pressure Loss

The choke manifold on a surface BOP installation is located close enough to the BOP stack that the pressure loss in the choke line can be neglected for most installations. The pressure at the choke manifold can be considered the wellhead pressure. In the case of a subsea stack, this is not the case. The pressure loss in the choke line can impose a significant backpressure on the well bore (refer to 4.13.1). This pressure loss can be reduced by taking returns through both choke and kill lines or reducing the circulating rate. Whichever method is used, it is imperative that correct drill pipe pressure is maintained to hold the correct bottom-hole pressure. If the circulating rate is reduced, it is necessary to have pre-determined the circulating system pressure loss for the reduced rate. In the case of wells in deepwater, at least two, and preferably three, reduced circulating rates and pressures and the corresponding choke line pressure losses should be determined. The pressure loss in the choke and kill lines can be determined by circulating down the line (refer to 4.13.1 and 4.13.2 for more detail).

10.3.2 Establishing Circulation

To establish circulation with a subsea BOP stack while maintaining a constant bottom-hole pressure, it is necessary to reduce the surface choke line pressure by an amount equal to the choke line friction loss while bringing the circulating pump up to speed. If the kill line can be used to monitor casing pressure, the choke in the choke line should be used to keep the closed-in kill line pressure constant while bringing the pump up to speed. If the kill line pressure cannot be monitored, the choke line pressure should be reduced by the previously measured choke line pressure loss while bringing the pump up to speed.

10.3.3 Fracture Gradients

Experience in deepwater has shown that low formation breakdown pressures can be expected. The basic cause is that a substantial part of the overburden is water. To avoid formation breakdown, it may be necessary to circulate out a kick at a very slow rate.

10.4 SPECIAL SUBSEA PROCEDURES

10.4.1 Marine Riser Emergency Release

If time and weather conditions permit, the following is an example outline of a procedure to release the drill string before the well is killed. Specifics of each rig and operation will vary and should be planned well before operations begin.

1. Displace the drill string with a kill weight fluid and install a backpressure valve in the drill string.
2. Bleed-off the drill pipe pressure.
3. Pick up the weight of the drill string from the closed pipe ram supporting it.
4. Close the annular preventer and adjust the closing pressure so the tool joints may be stripped into and out of the annular preventer. Open the pipe rams.
5. Strip out enough drill pipe to reach the joint that was hung in the ram preventer (refer to 10.4.3).
6. Install the rig's subsea preventer hang-off tool or loosen the tool joint of the landing joint if a hang-off tool is not available.
7. Strip the drill string back into the hole to place the hang-off tool or loosened tool joint immediately above the closed annular preventer.
8. Close the hang-off ram, bleed the pressure between the preventers, and open the annular preventer.
9. Lower the drill string, landing the hang-off tool or loosened tool joint on the hang-off ram.
10. Release the hang-off tool or back-out the loosened tool joint above the hang-off ram.
11. Close and lock the blind shear rams above the hang-off tool or broken-out tool joint.
12. Close the choke lines; close and lock the applicable pipe rams.
13. Pull the remaining drill string, recover the drilling fluid in the riser, and release the riser.

10.4.1.1 If weather conditions or other well problems prevent the above procedure, an emergency release may be performed per the following general outline:

1. Hang-off as described in 10.4.3.
2. Displace the drill string with a kill weight fluid and pump downinstall a backpressure valve to the receiving sub in the drill string.
3. Bleed off the drill pipe pressure.
4. Shear off the drill pipe using the blind shear rams and leave the shear rams closed.
5. Release the marine riser.

10.4.2 Kick With Drill Pipe Out of Hole

Should a well begin to flow when the drill pipe is out of the hole, following is an outline of a procedure that can be used to regain control:

1. At the first indication of the well flowing, close the blind rams, open the gate valve on the subsea BOP stack to open the choke line, close the choke line at the surface, and record the shut-in pressure. A 0-500 psi gauge is recommended to detect small pressure changes (refer to 4.8.1). If the choke line is filled with water this must be taken into consideration when using the shut-in casing pressure in calculations. Record the kick volume.
2. Run the drill string in the hole to the top of the BOPs. Insert a backpressure valve.

3. Add the hydrostatic pressure of the fluid in the choke line to the surface pressure to determine the pressure below the blind rams.
4. Determine if the pressure below the blind rams can be overbalanced by hydrostatic pressure of the drilling fluid that can be safely contained by the riser. If so, adjust the riser tensioners to support the additional drilling fluid weight and displace the drilling fluid in the riser with drilling fluid of the required density.
5. Close the diverter. Open the BOPs and watch for flow. If the well does not flow, open the diverter and go in the hole.
6. If the well starts to flow, close the blind ram preventer, displace the choke and kill lines with heavy drilling fluid, and circulate until the riser contains drilling fluid of the desired density.
7. Continue going in the hole. Stop periodically, close the pipe rams, and circulate the riser by pumping down the kill line to maintain the required drilling fluid density in the riser.

10.4.3 Close-in and Hang-off Operations

To minimize wear on the annular BOP sealing element, to be prepared for an emergency disconnect, or to minimize trapped stack gas, the drill string can be hung-off in the BOP stack after a kick is shut-in.

1. Stop drilling (if applicable) and position the pipe for the BOPs while sounding the alarm.

Note: Be aware of where tool joints are positioned in BOPs.

2. Shutdown the drilling fluid pumps.
3. Check the well for flow-If it is flowing, perform the shut-in in accordance with step 4 below.
4. If the “soft shut-in procedure” has been selected: open the choke line, close BOP, and close the choke (refer to 4.9.1). If the “hard shut-in procedure” has been selected: close the BOP and open the choke line with the choke closed (refer to 4.9.2).
5. Observe the casing pressure. If the casing pressure will exceed the allowable level, follow the pre-selected contingency plan (refer to 7.4.5).
6. Adjust the closing pressure on the annular preventer to permit stripping of tool joints. (Refer to 12.8 for stripping operations).
7. Check for trapped pressure (refer to 9.6.1 and 10.2.2).
8. Hang-off the drill pipe as follows:
   A. With a motion compensator:
      i. Position a tool joint above the hang-off rams leaving the lower kelly cock (refer to 9.5.5) high enough above the floor to be accessible during the maximum expected heave and tide when the selected tool joint rests on the hang-off rams.
      ii. Close the hang-off rams.
      iii. Carefully lower the drill string until the tool joint rests on the hang-off rams.
      iv. Reduce support pressure on the motion compensator so it will support about half the weight of the drill string above the BOPs plus some overpull to provide drill string tension to aid shearing. Continue with step 9 below.
   B. Without a motion compensator.
      i. Set the slips on the top joint of drill pipe.
      ii. Close the lower kelly cock (refer to 9.5.5).
      iii. Break the kelly/top drive connection above the lower kelly cock and stand it back in the rat hole.
      iv. Pick up the assembled space-out joint, safety valve, and circulating head with the safety valve closed. Make up the space-out joint on the closed lower kelly cock.
      v. Open the lower kelly cock, remove the slips, and position a tool joint above the hang-off rams leaving the safety valve high enough above the floor to be accessible during the maximum expected heave and tide when the selected joint rests on the hang-off rams.
      vi. Close the hang-off rams.
      vii. Carefully lower the drill string until the tool joint has landed on the closed hang-off rams. Slack off the entire weight of the drill string while holding tension on the circulating head with the air tugger or other tension device.
      viii. Connect the circulating head to the standpipe, open the supper safety valve. Continue with step 9 below.
9. Allow the shut-in pressure to stabilize and record pressures.
10. Determine the volume of the kick.
11. Calculate the drilling fluid density required to kill the kick (refer to 9.6.2).
12. Select a kill method.
13. Check rig crew duties and stations.
14. Review and update output and hole volume data and complete the well control worksheet (refer to Appendix B).
15. Inspect the BOP stack with television, if feasible.

11 Well Control Procedures—Recommended Rig Practices

11.1 WELL CONTROL SYSTEM EQUIPMENT INSTALLATION

On drilling rigs, a schematic drawing should be available on the rig showing all system components, equipment sizes, and equipment locations, including the location of the main control panel and remote panel(s). Well completion and well service operations should consider schematic drawings if the operations are expected to be complicated; i.e., high pressure, hydrogen sulfide gas, low pressure thief formations, etc.

11.2 WELL CONTROL EQUIPMENT INSTALLATION TEST

All well control system components shall be inspected and tested to ascertain proper installation and function. Simulate loss of rig air supply to the control system and determine effects, if any, on the primary well and backup systems. Refer to Sections 17 (Surface BOP) and 18 (Subsea BOPS) of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* and API RP 64, *Recommended Practice for Diverter Systems Equipment and Operations* (reader should check for the latest edition) for general testing considerations.

11.3 CREW DRILLS

Shallow gas flows generally develop quickly; can be difficult to detect early; and, will flow high volumes of gas from abnormally pressured, highly permeable formations. Likewise, inadvertent gas entry in a marine riser or a gas bubble migrating up the annulus can be difficult to detect. All concerned personnel should be familiar with the well control system components and installation and capable of reacting quickly and efficiently to potential situations requiring their use. Drills should be documented, executed, repetitive, and followed-up to correct identified problems. Drills should be clearly announced so all concerned know that a drill, not an actual event, is taking place. Drills generally enhance the crew proficiency in well control situations. When the desired proficiency is attained, periodic drills should be continued to maintain performance. The following drills, frequency, and proficiency levels are considered desirable for drilling operations.

11.3.1 Pit Drill

During a routine operation, the rig supervisor should simulate a gain in pit drilling fluid volume by raising a float sufficiently to cause an alarm to be activated. If automatic equipment is not available, the drills may be signaled by word of mouth. The drilling crew should immediately initiate one of the four procedures discussed in 11.3.2.1 through 11.3.2.4 below, depending on the operation at the time of the drill. A pit drill is terminated when the crew has completed the steps up to, but not including, closing the BOPs. The supervisor initiating the drill should record response time, which should be one minute or less.

11.3.2 BOP Drill

This drill includes all steps of the pit drill in 11.3.1 but is continued through all the steps of closing-in the well. The drill should be repeated on a daily basis until each crew closes-in the well within a span of two minutes. Thereafter, the drill should be repeated weekly to maintain proficiency. Following are simplified drill outlines that should be modified for the specifics of the particular rig, equipment, and operation.

11.3.2.1 On-Bottom Drill

This drill should be carried only to the point of driller recognition, signaled by raising the kelly/top drive and pump shutdown. This is to avoid the danger of stuck pipe.

1. Signal given.
2. Stop drilling or other operation.
3. Position the drill pipe for the BOPs while sounding the alarm.
4. Stop pump.
5. Check for well flow.

11.3.2.2 Tripping Pipe Drill

Drills while tripping drill pipe should be performed after the bit is up in the casing. A full-opening safety valve for each size and type connection in the string must be open and on the floor ready for use. Safety valves must be clearly identified as to size and connection to avoid confusion and lost time when stabbing.

1. Signal given.
2. Position the upper tool joint above the floor and set slips.
3. Stab the full open safety valve on drill pipe.
4. Close the drill pipe safety valve.
5. Close the BOP.

11.3.2.3 Drill Collars or Tool Joints in the BOP Drill

Preparation for this operation must be made in advance. Prior to reaching the drill collars or bottom-hole assembly when pulling out of the hole, the appropriate crossover sub must be placed on a single joint of pipe. A full open safety valve is then made-up on the top of the joint of pipe. Flows that occur with drill collars or the bottom-hole assembly in the BOPs are generally quite rapid since they are usually the result of expansion of a gas bubble close to the surface. A joint of pipe picked up with the elevators is usually easier to stab and make-up than a safety valve alone. Under actual kick conditions (other than drill) if only one stand of drill collars or the bottom-hole assembly remained in the hole it is probably faster to simply pull that last stand and close the blind rams.

1. Signal given.
2. Position the upper drill collar or tool joint and set the slips.
3. Stab the full open safety valve made up on one joint of pipe with the appropriate crossover sub onto the drill collars or tool joint.

4. Lower the collars with joint of pipe into the hole.
5. Close the drill pipe safety valve.
6. Close the pipe rams above the pipe tool joint.

11.3.2.4 Out of the Hole Drill

1. Signal given.
2. Close the blind rams.

11.3.3 Stripping Drill

A stripping drill by at least one crew on each well should be considered. This drill can be conveniently performed after casing is set and before drilling out cement. With drill pipe in the hole, the BOP is closed and the desired pressure trapped. Each member of the crew should be assigned a specific position. Strip sufficient pipe into the hole to establish the workability of the equipment and allow the crew an opportunity to perform their assignments. In addition to establishing equipment reliability, at least one crew on each well is trained. All crews should become proficient in stripping operations. Stripping drills are not recommended for operations involving subsea BOP stacks. For more information on stripping operations, refer to 12.8.

11.3.4 Choke Drill

Choke drills should be performed before drilling out surface casing and each subsequent casing string. With pressure trapped below a closed preventer, use the choke to control casing pressure while pumping down the drill pipe at a prescribed rate. This drill establishes equipment performance and allows the crew to gain proficiency in choke operation. Discharge into a trip tank to accurately monitor flow rates for correlation with choke opening, pump rates, and pressure drops in the circulating system and across the choke. This is particularly important for subsea BOP stacks in deepwater, which may have significant circulating pressure losses in the choke lines.

11.3.5 Hang-off Drill (Subsea BOPs Only)

Following prescribed procedures, the crew should place the drill string in position for hang-off. One hang-off should be made before drilling out of surface pipe to ensure that all necessary equipment is on hand and in working condition. Actual hang-off is not normally performed on subsequent drills. This drill can be conveniently performed in conjunction with the pit drill.

11.4 TRIP TANKS

A trip tank is a low-volume, calibrated tank, which can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the volume of fluid going into or coming from the well. The primary use is to measure the amount of drilling fluid required to fill the hole while pulling pipe to determine if drilling fluid volume matches pipe displacement. Other uses include measuring drilling fluid or water volume into the annulus when returns are lost, monitoring the hole while logging or following cement job, and calibrating drilling fluid pumps. A trip tank may be any shape if it is calibrated accurately and a means is provided for reading the volume contained in the tank at any liquid level. The readout may be direct or remote, preferably both. The size of the tank and readout arrangement should be such that volume changes in the order of one-half barrel can be easily detected. Tanks containing two compartments with monitoring arrangements in each compartment are preferred as this facilitates removing or adding drilling fluid without interrupting rig operations. Measurement of drilling fluid volume and flow rate is critical in all operations but most critical in floating operations. In floating operations, pit level monitoring devices (floats) should be located in the center of the pits or multi-floats with sequential integration utilized. A trip tank and pit watcher should be considered if vessel movement creates any problem in measuring drilling fluid requirements on trips.

11.5 GAS-CUT DRILLING FLUID

Gas-cut drilling fluid may occur during well control operations. Gas cutting of the drilling fluid column causes relatively small reduction in hydrostatic pressure. The reduction in hydrostatic pressure can be estimated using the chart shown in Figure 11.1. This reduction in hydrostatic pressure is normally not a severe problem except where the casing seat is shallow. However, gas-cut drilling fluid reduces the efficiency of drilling fluid pumps. Foam on the drilling fluid pits may create some misinterpretation and gas cutting can cause an indication of pit volume increase even when there is no flow into the well bore. For proper well control, drilling systems should be equipped with mud-gas separators and degassers to minimize recirculation of gas-cut drilling fluid. Use of a pressurized drilling fluid balance and defoaming agents are also recommended. Refer to 15.9 and 15.10 of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* for more information on mud/gas separators and degassers.

11.6 TRIP BOOK

A tally should be maintained showing the volume of drilling fluid required to fill the hole after a specified number of stands along with the cumulative volume. Keep this data in a "Trip Book" or on a computer to compare with previous trips. In addition to comparison with theoretical displacement volume this data can be used to spot anomalous well behavior. A similar record should be made of drilling fluid returns while running pipe in the hole. Table 11.1 illustrates an example trip

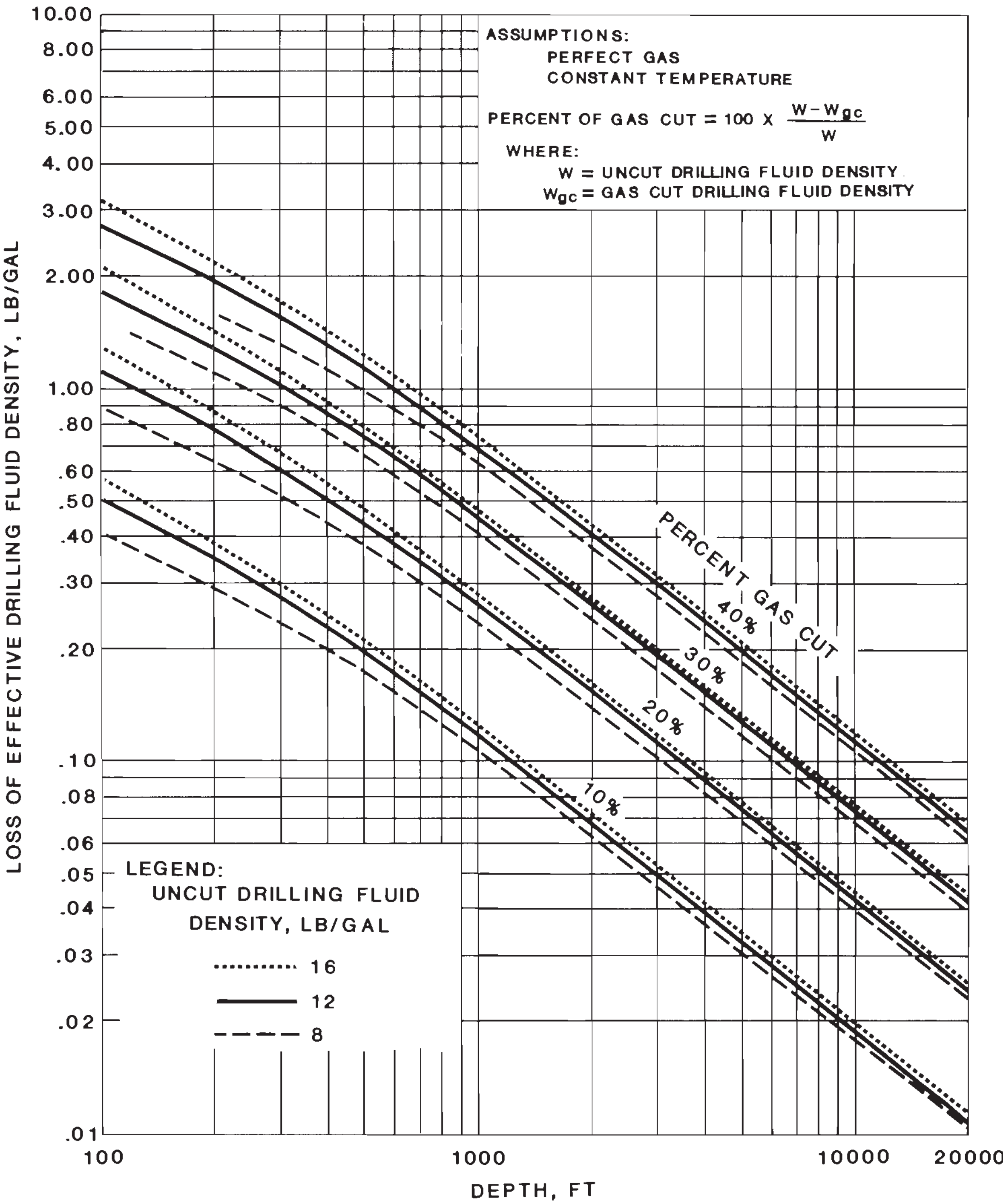


Figure 11.1—Loss of Effective Drilling Fluid Density Due to Gas Cut

book form that could also be used in a spreadsheet format in a computer. Trip books are normally printed and bound in a pocketbook-size driller's log for convenience.

11.7 PRE-KICK INFORMATION

Prevention, control, and circulation of kicks is enhanced by collection of selected information and performing certain calculations prior to a kick. The following outlines some desirable information.

11.7.1 Formation Integrity

Following the cementing of each casing string and drilling out the shoe, a formation competency test or a leak-off test may be conducted to assure that the formation will support the maximum required hydrostatic pressure. Either test may be repeated as the well is being drilled to maintain reliable information. Note: Formation competency tests and leak-off tests are not synonymous (refer to 4.7, 4.7.1, and 4.7.2).

11.7.2 System Pressure Losses

Daily, while drilling or after a significant change in the circulating system pressure, the pressure drop (circulating pressure) throughout the circulation system should be obtained and recorded on the recommended well control worksheet (refer to Appendix B) and the tour report. The pump rate used to obtain this pressure drop should be the reduced rate that would be used to circulate a kick from the well.

11.7.3 Capacities—Displacement

Drilling fluid tank capacities should be calculated in barrels per inch for both the entire surface drilling fluid system and individual tanks. The capacities of tubing or drill pipe, tool joints, drill collars, marine riser, casings, well bore, and choke and kill lines should be tabulated. The annular volume between any possible combination of pipe/pipe, pipe/hole, and service tool/hole/pipe should be calculated. Displacement of the pipe string (tubing, casing, drill pipe, drill collars, regular stabilizers, service tools, etc.) should be calculated and tabulated at intervals and maintained at the rig for ready reference in the event of a kick.

11.7.4 Pressure Limitations of Installed Equipment, Tubulars, Etc.

The maximum allowable pressure that may be applied against each component within the well control system should be determined and used in evaluating component pressure protection and the advisability of circulating a gas kick to the surface.

11.7.5 Drilling Fluid Pump(s)

The volume per stroke output for each pump should be obtained and entered on the tour report at periodic intervals while drilling the well.

11.7.6 Drilling Fluid Mixing Capability

The rig's actual maximum efficient rate of mixing drilling fluid should be determined. This mixing rate and its effect on drilling fluid properties should be used in planning well control operations.

11.7.7 Post-kick Information

Following control of a kick, a safe trip margin and drilling fluid density should be determined. The drilling fluid density should be sufficient to permit safe withdrawal of the drill pipe from the hole based on swab and fracture considerations.

11.8 MINIMIZE TIME OUT OF THE HOLE

Time with pipe out of the hole should be minimized. Particular care should be taken to have all necessary crossover connection(s) readily available when running service tools that may interfere with closure of the rams in the BOP. An example is long core barrel: It is probably too long to clear the ram closure zone and its outside diameter too large to fit the pipe rams. Having the proper connections readily available ensures that pipe movement can be accomplished in order to close more than the annular BOP. In case of equipment repair on drilling rigs, the pipe should be run at least back to the last casing shoe, if possible, before repairs are undertaken. In well servicing operations, when making equipment repairs, effecting routine maintenance, or shutting down overnight, the pipe should be run to a sufficient depth to ensure that the well can be controlled.

11.9 TRIP MARGIN

The use of a trip margin is encouraged to offset the effects of swabbing. The additional hydrostatic pressure permits some degree of swabbing without losing primary well control.

11.10 SHORT TRIP

After tripping and circulating "bottoms-up," the amount of gas, saltwater, or oil contamination will enable the evaluation of operating practices affecting swabbing. Adjustments in pulling speed, drilling fluid flow properties, and/or drilling fluid density may be warranted. A short trip and circulating

Table 11.1—Example Form from a Trip Book

Well Name ______________________________

Date __________ Drilling Fluid Density ____________

Depth __________________ DP Size ____________

Time Trip Started _________ DC Size ____________

Trip No. ____________________________

Fluid Loss ____________________________

DP Displacement ______________________

DC Displacement ______________________

No. of Stands	DISPLACEMENT						Comments
	Theoretical		Last Trip		This Trip		
	Per ___ Std	Total	Per ___ Std	Total	Per ___ Std	Total	

"bottoms-up" before pulling out of the hole can also be used to determine the system's swabbing characteristics.

11.11 RIG PRACTICES FOR HANDLING PRESSURE

The well planning process should consider whether a well will flow or whether the well might flow as a result of the operations (refer to Section 7, Well Planning). This process should include all well operations from well drilling to well servicing to plug and abandonment. Depending on the well control deemed necessary, if any, consideration should be given to barriers to flow and certain rig practices should be considered.

11.11.1 Barriers to Flow

If a well is considered to have potential to flow, maintenance of a two barriers to flow system should be considered. Barriers to flow include:

1. Drilling or workover fluid overbalance;
2. Blowout preventers or safety valves;
3. Mechanical plugs such as bridge plugs or wireline set plugs in tubing; and
4. Cement or barite plugs.

11.11.2 Other Practices

Some rig practices for handling pressure in certain situations are listed below:

- A spare surface safety valve should be on the rig floor at all times.
- An inside BOP, drill pipe float valve, or drop-in valve should be available on the rig floor when stripping in or out of the hole. Crossovers of the proper size and thread design for any pipe in use should be available.
- If possible, avoid setting retainers, bridge plugs, packers, etc., high in the hole. Under certain conditions, pressure can accumulate below that might be difficult to control without snubbing equipment.
- Consider the possibility of higher pressures below a bridge or fish in the well bore when washing over or drilling through it.
- Never back-off high in a stuck string during a well control problem without first setting a plug or backpressure valve in the bottom of the stuck string.
- Some blowouts have occurred during coring operations. If the core barrel plugs and it is not possible to circulate, take special care not to swab the well in when pulling out of the hole. If there is a kick, do not attempt to pull out of the hole.

11.12 RIG PRACTICES FOR PIPE HANDLING

In addition to testing and maintenance of BOP equipment and controls, the pipe run in the hole should be properly designed, inspected, and maintained. The stress of bending and rotating through doglegs in the hole, torsional stress, collapse and internal stress, joint integrity, wear, hydrogen sulfide exposure, and corrosion/erosion are factors affecting drill pipe, drill collars, tubing, casing, and liners that may be run in the hole. Pipe should be designed, maintained and inspected per the following:

- Drill Stem Pipe and Components—API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits* (reader should check for the latest edition) covers all aspects of drill stems: kelly, tool joints, drill pipe, and drill collars.
- Casing and Tubing—API RP 5C1, *Recommended Practice for Care and Use of Casing and Tubing* which covers storage, transportation, handling, and reconditioning of casing and tubing.

11.13 DRILL STEM TESTS

Take precautions to prevent leaks during a drill stem test. Recognize the hazards associated with drill stem testing and pulling of tools. Special precautions should be taken for drill stem tests under high pressure or sour gas conditions. Refer to API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits* and API RP 49, *Recommended Practice for Safe Drilling of Wells Containing Hydrogen Sulfide* (reader should check for the latest editions) for special precautions if a possibility of hydrogen sulfide exists for drill stem testing under critical high pressure.

12 Procedures for Dealing with Special Problems

12.1 INTRODUCTION

Most well control problems are caused by equipment failure, formation breakdown, or improper operating procedures. This section outlines procedures that can be used to minimize or solve many well control problems. The following problems are included in this discussion.

1. Pump failure.
2. Excessive casing pressure.
3. Low choke pressure method.
4. Well kick while running liner or casing.
5. Parted or washed-out drill stem.
6. Stuck drill stem.
7. Plugged or packed-off bit.
8. Gas-cut drilling fluid.
9. Gas influx in cemented annulus.
10. Procedures for gas bubble migration.
11. Drill Stem Testing.
12. Stripping procedures.

12.2 PUMP FAILURE IN A KICK SITUATION

Pump failures can cause erratic drill pipe pressure surges, pounding noises, or erratic movement of the rotary hose. The following paragraphs outline pump problems and some recovery methods if the problems occur during a kick.

12.2.1 Partial Pump Failure

A partial pump failure can reduce fluid delivery. It is indicated by a decrease in pump pressure, an increase in pump-stroke rate, and erratic rotary hose movements. Some of the symptoms of partial pump failure might also be caused by a drill stem washout, bit jet washout, washed out choke, or gas-cut drilling fluid. If partial pump failure is found to be the problem, and no standby pump is available, circulating operations may continue with the partially effective pump. A new reduced circulating pressure should be determined. Shut-in the well; read the drill pipe and casing pressure; and bring the pump up to speed while holding the casing pressure constant until the circulating drill pipe pressure can be determined.

12.2.2 Severe or Total Pump Failure

If the pump failure is severe or total, the well might be controllable by bleeding drilling fluid from the annulus through the casing choke to maintain constant closed-in drill pipe pressure using casing control as the influx fluid migrates up the annulus. If the influx is gas, small quantities of drilling fluid must be released from the annulus in order to maintain constant bottom-hole pressure as the gas rises and expands (refer to 12.6).

12.2.3 Well Kill

The well cannot be completely killed and adequate well control established until the pump is repaired, replaced, or supplemented so that drilling fluid can be circulated.

12.3 EXCESSIVE CASING PRESSURE

Mechanical failure or formation breakdown can result from excessive casing pressure during initial closure or while circulating out a kick. Mechanical failure of the casing at the surface or of the BOP and related well control equipment could result in loss of well control. Formation breakdown can lead to loss of circulation, an underground blowout, and/or possible broaching to the surface. To prevent these failures a maximum allowable casing pressure must be determined as indicated on the well control worksheets (refer to Appendix B).

12.3.1 Design Considerations

In most cases, with proper casing string design, equipment selection, and testing of surface equipment, the risk of mechanical failure is small. In fact, the system should be designed to ensure formation fracture in preference to mechanical failure at the surface. The consequences of formation fracture while closing-in or circulating out a kick can also be catastrophic, especially if the casing seat is shallow and broaching to the surface is a possibility (refer to 4.14 and 7.3). If intermediate casing is set, broaching to the surface is unlikely. Formation breakdown precludes pressure control using the choke and makes an underground blowout possible. Either of these problems must be alleviated before the well can be killed.

12.3.2 Alternatives If Maximum Pressure Is Reached at Close-In

If the casing pressure increases to the maximum allowed during initial closure, a decision must be made as to whether the well should be killed by conventional circulation methods, or whether alternative methods should be implemented. The well control contingency plan (refer to 7.4.5) should be consulted and one of the following alternatives considered:

1. Low choke pressure procedure;
2. Flowing the well under controlled conditions; or
3. Consider bullheading.

12.3.3 Alternatives If Maximum Pressure Is Reached While Circulating a Kick

The alternatives are:

1. Continue circulation of the kick with drill pipe pressure control while allowing the casing pressure to increase; or
2. Follow the low choke pressure procedure until the well can be closed-in when appropriate; or
3. Close-in the well and bullhead (refer to 4.11.1) the kick back down the annulus to reduce casing pressure or spot a heavy pill of drilling fluid, barite, or cement (refer to Section 13 and its subparagraphs).

12.3.4 Possible Consequences

The alternatives listed above have the following possible consequences:

1. Allowing the casing pressure to increase can lead to mechanical failure or formation fracture.
2. Control of high volume gas flow using the low choke pressure is extremely difficult.
3. Closing-in the well, bullheading, or spotting a heavy fluid pill can cause formation breakdown.
4. If formation fracture occurs and only a small amount of casing has been set, the possibility of broaching to the surface exists.

12.3.5 Handling Excessive Casing Pressure

If the casing pressure exceeds the rating of the surface equipment, the possibilities of surface equipment failure, or broaching to the surface should the formation or casing cement job break down, exist. Alternatives include using the low choke pressure procedure (refer to 12.3.5), pumping a barite plug (refer to 13.4), pumping cement slurry (refer to 13.5.3), or allowing the well to flow until the pressure is reduced. If the surface equipment rating will not be exceeded and casing is set to a depth where broaching to the surface is not likely, consideration can be given to closing the well and allowing an exposed formation to fracture, or to create conditions which cause formation fracture by bullheading fluid down the annulus (refer to 4.11.1). This operation can cause an underground blowout, as is discussed in 13.3.

12.3.6 Low Choke Pressure Procedure

The low choke pressure procedure consists of circulating and weighting up the drilling fluid, both at the maximum rates, while holding the maximum allowable casing pressure on the choke. With the low choke pressure procedure, the influx will continue to invade the well until the drilling fluid is properly weighted. This usually takes a number of circulations. The required drilling fluid density is not known because the drill pipe pressure is not allowed to stabilize upon initial closure; however, an estimate must be made. After heavier drilling fluid has been circulated, the well can be shut-in and the drilling fluid density required for control can be determined. Effective degassers and mud/gas separators are essential (refer to 15.9 and 15.10 of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* for more information on mud/gas separators and degassers).

12.3.6.1 Once the decision is made to use the low choke pressure procedure, weighting material should be added to the circulating drilling fluid as rapidly as possible while applying maximum allowable casing pressure. A pre-mixed, weighted fluid in reserve will increase chances for success. Because annular pressure-drop aids in the low choke pressure procedure, the highest possible circulation rate should be used except with subsea BOP stacks where the choke line pressure may become excessive. In these cases, returns should be taken through both the choke and kill lines and the hole circulated at the maximum rate that will not cause shoe breakdown due to pressure losses in the choke and kill system. Preparations should be made to run a barite plug or cement slurry if the well cannot be killed.

12.3.6.2 Following is a recommended outline for low choke pressure control:

1. Circulate using the maximum practical pump rate, except observe the limitations and practices shown in 12.3.6.1 when operating with subsea BOP stacks where the choke line pressure may become excessive. In this case, circulation should be continued at the pre-selected kill-rate.
2. Start weighting-up to the estimated required drilling fluid density at the maximum rate as soon as possible.
3. Begin circulating while holding maximum allowable casing pressure or maximum allowable initial closed-in casing pressure, if defined, by adjusting the choke. The casing pressure can be increased above the maximum allowable initial closed-in casing pressure after the kick fluid has entered the casing, but must not be allowed to increase above the maximum allowable casing pressure. Drilling fluid pits should be closely observed, as a drop in pit level before the kick reaches the surface indicates loss of circulation.
4. Circulate out the mixture of kick fluids and drilling fluid until a reduction in choke size is necessary to maintain the maximum allowable casing pressure.
5. Shut-in the well and read the drill pipe and casing pressures. The Wait and Weight Method or Concurrent Method can then be used. To obtain the initial circulating pressure, multiply the pre-recorded kill-rate pressure by the ratio of present drilling fluid density to the drilling fluid density used to obtain the kill-rate and add to the closed-in drill pipe pressure.
6. If unable to kill the well or reduce the casing pressure so the well can be safely closed-in, prepare a barite plug or cement slurry for plugging (refer to 13.4 and its subparagraphs for barite plug operations and 13.5 and its subparagraphs for cement slurry operations).

12.4 PIPE PROBLEMS WITH A WELL KICK

Pipe problems can complicate dealing with a kick. This section addresses several potential problems: running casing, running a liner, parted drill pipe or tubing, drill pipe or tubing that has developed a hole, and stuck pipe.

12.4.1 Running Liner

Well kicks that occur while running a liner can generally be handled in the same manner as a kick that occurs while drilling. If the liner is near bottom, an attempt should be made to strip it into the hole to the desired point before it becomes stuck (refer to 12.8 and its subparagraphs for recommended stripping procedures). The influx can then be circulated out, the drilling fluid conditioned, and the liner cemented in place. In some cases, consideration should be given to stripping the liner up into the casing to prevent becoming stuck in an unstable open hole. The annulus pressure may often be reduced by bullheading heavy drilling fluid to overbalance the pressure (refer to 4.11.1 for the recommended procedure). This may permit opening the BOPs temporarily. It must be noted that running pipe into the well under these conditions displaces part of the heavy drilling fluid and may start the well flowing again. Pumping high density drilling fluid into the annulus can cause or aggravate lost circulation below the casing shoe, and these effects must be considered as a penalty for being able to conduct stripping operations with less or no pressure on the annulus. After the influx zone is killed, the liner can be tripped out of the hole and the hole reconditioned prior to re-running the liner. If the well kick occurs while running the liner inside the casing and the bottom of the liner is not as deep as the casing shoe, an attempt should be made to strip the liner to the casing shoe but not into open hole below the shoe.

Table 12.1—Indicators of Possible Problems while Circulating Out a Kick

Major Indication Larger Arrow ⬇

Other Indication Smaller Arrow ↓

	Drill Pipe Pressure	Casing Pressure	Drill String Weight	Pit Level	Pump SPM
Choke Washes Out	⬇	⬇		⬆	↑
Gas Reaches Surface	⬇	⬇	↓	⬇	
Loss of Circulation	⬇	↓	⬆	⬇	↑
Hole in Drill String	⬇				↑
Pipe Parted	⬇		⬇		↑
Bit Nozzle Out	⬇				↑
Pump Volume Drops (Pump Damage Ñ Gas Cut Mud)	↓	↓			↑
Gas Feeding In		↑	↑	⬆	
Choke Plugs	⬆	⬆			↓
Bit Nozzle Plugs	⬆				↓
Hole Caved In	⬆		Stuck	↓	↓

12.4.2 Running Casing

A kick while running casing can produce extreme complications. Stripping the casing to bottom should only be attempted if the casing shoe is within a few joints of bottom (refer to 12.8 and its subparagraphs). If only a short section of casing is in the hole, annulus pressure will tend to force the casing upward, in which case it must be tied down and filled with drilling fluid immediately. If a long section of casing is in the hole, the combination of tension forces, external annulus pressure, and the force of the BOPs could collapse the casing; therefore, annular BOPs should be closed with extreme care and with the choke fully open. As the choke is closed or manipulated, casing should be carefully observed. When long casing sections are exposed to annulus pressure, significant hook load reductions will be observed as annulus pressure increases. Because of the relatively large diameter casing and the small annulus area, pumping rates to displace the well fluids must be slower, and it takes much longer to completely fill the casing with weighted drilling fluid. Gas entering the casing can continue upward in spite of pumping and may complicate pumping pressure calculations, but this problem can wait until the annulus is completely displaced with higher density drilling fluid to control the influx. Dangers of lost circulation and an underground blowout are much greater while running casing due to the small annulus area. As a last resort to gain well control, a barite plug may be pumped through the casing or casing may be cemented in place.

12.4.3 Parted or Washed-Out Pipe in the Hole

Refer to Table 12.1 for indicators of problems while circulating out a well kick. Traditional indicators of a washout are:

1. An increase in pumpstroke rate, and
2. A decrease in pump pressure.

A loss of string weight is also an indication that the drill stem has parted. Pump rate may increase and pump pressure may decrease due to loss or washout of a bit nozzle, pump parts failure, or gas-cut drilling fluid. Pipe should not be tripped out of the hole if there is any indication of a well kick.

12.4.4 Procedures for Parted or Washed-Out Pipe While Circulating Out a Kick

If the drill stem has developed a hole (washout), every consideration should be given to preventing hole enlargement and overstressing the weakened section. Drilling fluid circulation, pipe movement, and string rotation should be done carefully to minimize chances of the drill stem parting. With the aforementioned exceptions, procedures for removing the influx fluid and killing the well are the same for a parted drill stem, drill stem washout, or when the bit is off-bottom and cannot be successfully stripped back to bottom. The following procedures are recommended.

1. If the drill stem has parted, location of the break should be estimated by using current drill stem weight versus weight prior to parting. If the drill stem has a washout, its location can be estimated by circulating a marker.
2. Observe the closed-in drill pipe pressure and casing pressure. If the closed-in drill pipe pressure is not significantly lower than the casing pressure, the influx gas is still below the washout or the bottom of the drill bit (if off-bottom).
3. If the influx is below the washout or bit (if off-bottom), allow it to migrate upward, resulting in increases in drill pipe pressure and casing pressure as the bubble rises. Circulation before the influx moves above the washout serves no useful purpose in removal of influx fluid and may increase danger of further complications in drill stem recovery. As the gas percolates up the well bore, it carries trapped pressure and must expand. Excess pressure must be bled off carefully to prevent further influx. Refer to 12.5 for suggested procedures for gas bubble migration.
4. When the influx rises above the washout in the drill stem, the shut-in casing pressure will be higher than the shut-in drill pipe pressure. The influx may then be circulated out using conventional well choking procedures. Higher density drilling fluid may be placed in the upper portion of the hole to decrease chances of well flow while the drill stem is repaired or replaced. The increase in drilling fluid density may be estimated by using the following parameters:

$$\frac{\text{Closed-in drill pipe pressure (psi)}}{\text{TVD to washout or lower end of drill stem (feet)} \times 0.052}$$

Note: The well is not killed until the pipe is run to bottom and all well fluids displaced with drilling fluid of the proper density and other fluid physical parameters required to maintain well control.

12.4.5 Stuck Pipe in the Hole

An influx of formation fluids and/or increase in annulus pressure may increase the chances of sticking the pipe. Stopping pipe movement to close the BOPs may allow the drill stem to become stuck. The only preventive measure that can be undertaken at this point is to carefully move the pipe. In the event of a well kick, the first consideration should be to control and kill the well. If the pipe becomes stuck, well killing operations should continue. After the well is brought under control, pipe recovery operations can be initiated. Refer to 12.2 through 12.6 of API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits* for recommendations on pulling on stuck drill pipe, jarring, washover, and hook load considerations.

12.4.6 Plugged or Packed-Off Pipe

If the pipe or bit becomes plugged, the drill pipe pressure will suddenly increase while constant pumping rate is maintained. Do not open the choke to maintain constant drill pipe pressure, as the resulting decrease in casing pressure will allow more influx fluid to enter the well bore and make well control more difficult. Stop the pump and shut-in the well. Re-determine the shut-in casing pressure and maintain this casing pressure while bringing the pump back up to a new reduced circulating rate, without encountering excessive drill pipe pressure. This new pumping rate and drill pipe circulating pressure should be used to continue well killing operations. If the bit becomes entirely plugged, drill pipe pressure cannot be used to maintain constant bottom-hole pressure. The casing pressure will slowly increase as the gas influx percolates upward through the drilling fluid to the surface. Allow the casing pressure to increase 100 psi above the initial shut-in casing pressure. Then start bleeding small quantities of fluid from the choke into a tank that can measure the fluid volume, following the procedures for gas bubble migration (refer to 12.5). Consideration may be given to running a string shot, junk shot, or perforating to reestablish circulation. If there is a restriction in the annulus, circulating drill pipe pressure is likely to be erratic. When this happens, casing pressure should be closely monitored and maintained (for brief periods only) at its then current value when the drill pipe pressure fluctuates. Additionally, circulation should be interrupted occasionally and the well closed-in so that the proper shut-in casing pressure can be ascertained.

12.5 PROCEDURES FOR GAS BUBBLE MIGRATION

Normal circulation operations for well drilling are not always possible during well control procedures. A technique known as volumetric control can be used when:

1. Drill stem is a long way off the bottom,
2. There is a washout or parted drill stem near the surface,
3. The bit is plugged, or
4. The pumps are down.

Volumetric control operations maintain a constant bottom-hole pressure by allowing a measured amount of drilling fluid to flow as the kick moves up the hole. Accurate pit volume measurement and monitoring is essential. As any gas percolates up the well bore, it carries trapped pressure and must expand. This will cause the casing pressure to increase, thereby increasing the danger of equipment failure or formation breakdown and lost circulation. Excessive pressure must be prevented. This can be accomplished by controlled bleeding off small amounts of drilling fluid without allowing the bottom-hole pressure to drop low enough to permit additional influx. The following procedures can be used to estimate the maintenance pressure required to prevent further influx while avoiding excessive casing pressure:

1. Observe the casing pressure gauge while gas is percolating to assure that excessive pressures do not build up unnoticed.
2. Arrange a choke line so that it can discharge into a device that can be used to measure discharged fluids.
3. Allow the casing pressure to increase at least 100 psi above the initial shut-in casing pressure.

CAUTION: The initial pressure increase may occur very gradually, but the pressure increase will occur faster as gas percolates upward.

4. Calculate the minimum pressure increase which must be maintained for each barrel of drilling fluid vented using the following equation:

$$\frac{\textit{Pressure increase (psi)}}{\textit{per barrel vented}} = \frac{MW \times 53.5}{HD^2 - PD^2}$$

where

MW = drilling fluid density, lb/gal.

HD = inside diameter of the well bore at the top of the gas, in.

PD = the outside diameter in inches of the pipe, tubing, or collars at the top of the gas (use 0 if gas is below bit)

Normally after the initial 100 psi increase in pressure the gas can be assumed to be inside the casing or in open hole at nearly the casing inside diameter, therefore HD^2 is the square of the casing inside diameter and PD^2 is the square of the drill pipe outside diameter.

5. As the pressure increases, vent small quantities of drilling fluid, but do not allow the pressure to drop below the minimum casing pressure to assure no further influx as calculated below:

Current minimum casing pressure (psi) =
Initial shut-in casing pressure (psi) + 100 psi + pressure increase per barrel vented (psi/bbl per calculation in step 4) x total volume vented (bbls)

6. When gas reaches the surface, vent only as required to maintain constant surface pressure or maintain such pressure as required to replace the hydrostatic pressure of any additional drilling fluid vented.

12.6 GAS INFLUX IN CEMENTED ANNULUS

Gas influx can occur during and after cementing operations. The primary cause of gas influx is loss of hydrostatic head due to:

1. Water separation,
2. Cement dehydration,
3. Poor cement retarder design or performance,
4. Insufficient annulus fill-up,
5. Lost returns during cementing,
6. Cementing with gas-cut drilling fluid, and
7. Swabbing the hole while reciprocating pipe in cementing operations.

Loss of hydrostatic pressure when cement begins to set can allow formation gas to migrate through the setting cement, creating channels and further reducing hydrostatic pressure. The BOP stack should not be removed before the cement has taken a final set and the likelihood of annular gas flow has passed. Refer to API RP 10B, *Recommended Practice for Testing Well Cements*. Following are practices that can help minimize gas influx in the cemented annulus:

- Properly designed cement retarders can achieve a uniform set from the bottom of the hole to the top of the cemented section.
- Proper conditioning of the drilling fluid and well bore prior to running casing can help minimize lost returns during cementing operations.
- Proper conditioning of drilling fluids can help minimize gas cutting, bridging, and viscosity problems.
- Proper design of casing fill-up and float equipment, along with controlled running and reciprocating speeds, can minimize lost returns and swabbing problems in the hole.

12.7 DRILL STEM TESTING

Drill stem tests are performed by setting a packer above the formation to be tested and allowing the formation to flow. During the course of testing, the borehole or casing below the packer and at least a portion of the drill pipe or tubing is filled with formation fluid. At the conclusion of the test, the fluid in the test string above the circulating valve must be removed by proper well control techniques, such as reversing, to return the well to a safe condition. Depending on the length of hole below the packer, type of fluid entry, and formation pressure, the normal drilling hydrostatic overbalance can be reduced or lost. Caution should be exercised to avoid swabbing when pulling the test string because of the large diameter packers.

12.8 STRIPPING PROCEDURES

During operations on a drilling well, producing well, injection well, or sometimes when plugging and abandoning a well, a sequence of events may require tubing, casing, or drill pipe to be run or pulled while annulus pressure is contained by the BOPs. Such practice is called stripping. Stripping is normally considered an emergency procedure to maintain well control; however, plans for some drilling, completion, or well work operations may include stripping to eliminate the necessity of loading the well with fluid. Stripping techniques vary, and the equipment required depends on the technique employed. Each stripping operation tends to be unique, requiring adaptation to the particular circumstances. For the equipment considerations of stripping operations, refer to Section 21 of API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells* (reader should check for the latest edition).

12.8.1 Preparation

Preparation for stripping operations should begin in well planning. When rigging up the BOP stack and trip tank, the following should be considered:

1. Proper spacing of the spool between preventers; this should be posted on the driller's control panel.
2. An adjustable choke arrangement on the BOP stack to bleed drilling fluid into the trip tank.
3. A kill line so that drilling fluid can be pumped between the preventers.
4. The annular regulator for the annular BOP pressure should be responsive to less than 100 psi differential. If an accumulator bottle is used, the bottle should be installed as close to the annular preventer as possible in the closing line and an additional bottle may be installed in the opening line. The pre-charge pressure of these accumulators should be determined and set for the specific rig and well conditions upon nippling up the BOPs.
5. Safety valves, an inside BOP, drill pipe float valve, and/or a drop-in safety valve should be on the rig floor and tested.
6. Tool joint length and outside diameter, distance from the rotary table to the preventers, distance between ram preventers, and other details that might be needed should be recorded.
7. Spare preventer elements should be available.
8. The annular preventer four-way valve should not contain a check valve.
9. It is essential that the crew understand job assignments for the operation.

12.8.2 Stripping Operations

Before beginning to strip, some type of backpressure valve must be installed in the drill string. Pipe should be run slowly and an amount of drilling fluid equal to the capacity and displacement of the pipe must be bled as the stand is lowered to avoid excessive pressure build-up. Well pressure should be monitored continuously throughout the stripping operation.

12.8.3 Annular Preventer Stripping

Stripping through the annular preventer is preferred over other techniques due to its speed and relative simplicity. It requires that the effective string weight be greater than the upward force of the well pressure acting on the cross-sectional area of the tool joint. In some cases, the pipe body may move through the preventer but the tool joint will not because of the greater upward force exerted on the larger cross section. In these cases, it is necessary to strip with a combination of preventers where the tool joint is moved past the preventers by alternatively closing and opening them (ram-to-ram or annular-to-ram).

12.8.4 Preventer Combination Stripping

When the surface pressure is high or the effective string weight is insufficient to pull a tool joint through the annular preventer, it may be necessary to use two preventers to pass the tool joints through the stack. The combination of preventers can be either annular-to-ram or ram-to-ram. The preventer above the drilling spool is used as the primary stripping preventer and the lower preventer is used only to strip far enough to move the tool joint through the upper preventer. Distances from the rotary table to the preventers must be known so that the tool joint position can be determined at all times. A means of applying pressure between the preventers to equalize the pressure across the lower ram must be provided. This is necessary to avoid damaging the ram seal when it is opened and to avoid allowing additional influx to enter the well. One of the closing unit pumps or a cementing unit can provide this capability.

12.8.5 Sealing Elements

Life of the preventer sealing elements can be maximized by regulating the closing line pressure to the minimum required to maintain a seal and by lubricating the pipe as it passes through the preventer elements. After stripping for a short time (10 or 20 tool joints), the regulator setting can be adjusted for the optimum closing pressure. One method to attain optimum pressure would be to reduce the pressure 50 psi while continuing to strip. If no leakage is detected during additional stripping (5 minutes, 1 or 2 tool joints), reduce the pressure another 50 psi. Continue the process until a leak is detected. Thereafter, increase pressure as needed to keep leakage minimal but adequate to keep the sealing element lubricated. The pipe should be lubricated with a mixture of bentonite and water or some other lubricating fluid as it runs through the preventer to reduce packing element wear. It is necessary to know the spacing from the rotary table to the top of the annular preventer so that the tool joint can be eased into the packing element. The operator should be prepared to transfer control to another BOP when the sealing element is near the end of its useful life.

12.9 BULLHEADING AND TOP KILL METHODS

Refer to 4.11.1 and 4.11.2.

13 Slurries and Plugs to Deal with Lost Circulation and Underground Blowouts

13.1 INTRODUCTION

Lost circulation, underground blowouts, shallow gas flows, or the simple need to maintain a hole full of fluid are situations that lend themselves to slurries of various compositions and weights that plug formations or create barriers to flow in the hole. This section deals with testing, mixing, and placement of barite slurries, diesel oil/bentonite slurries, and cement slurries. These slurries will likely have a detrimental effect on any drilling fluid they come in contact with. Special handling procedures and equipment may be required. The drilling fluid manufacturer should be consulted as to slurry composition and special handling recommendations to avoid problems. Environmental rules and regulations should also be reviewed. Use of slurries and plugs for these purposes should be a part of the well planning process.

13.2 LOST CIRCULATION

Loss of workover fluid or loss of drilling fluid returns can lower the hydrostatic head of drilling fluid in the well bore, thereby creating a kick. When this occurs, fluid inflow such as gas, oil, or water can reach the surface or flow into the loss zone of less pressure. The loss can result from natural or induced causes. Causes include fractured, vugular, cavernous, sub-normal pressure or pressure-depleted formations. Pressure surges related to running pipe or tools (plunger effect) or breaking circulation can cause formation fracturing. Annular friction during circulation, sloughing shale, or casing pressures imposed in controlling a kick can also lead to lost circulation.

13.2.1 Development into an Underground Blowout

Loss of returns while attempting to control a kick can develop into an underground blowout. If sufficient drilling fluid volume is lost, the reduced hydrostatic pressure may result in a blowout at the surface. An attempt should be made to keep the hole full. If the hole will not support drilling fluid, the hole should be filled with a lighter drilling fluid or water down the annulus. The amount of fluid used should be recorded.

13.2.2 Controlling the Situation with Slurries

The risks of blowout (surface or underground) should be evaluated any time drilling fluid loss occurs; i.e., are permeable zones exposed which might produce into the well bore upon loss of hydrostatic head. If a kick is impending or an underground blowout has already started, a barite plug (refer to 13.4 and its subparagraphs) can sometimes be used to isolate the loss zone from the kick. If partial loss of returns is occurring while circulating out a kick, a fine sealing material might be added to the drilling fluid in an attempt to slow the loss. Note: Do not add coarse sealing materials if there is a possibility of plugging the bit, choke, or choke line. However, in some cases a coarse sealing material might be bullheaded into the annulus without plugging the bit (refer to 4.11.1). Normally, the lost circulation zone should be sealed either before a kick occurs or after the loss zone has been isolated from the influx zone by a barite plug or other procedure.

13.3 UNDERGROUND BLOWOUTS

An underground blowout is uncontrolled flow of formation fluids from a high-pressure zone into a lower pressure zone. Characteristics of underground blowouts include: closed-in drill pipe pressure greater than closed-in casing pressure, erratic drill pipe pressure response, or loss of large volumes of drilling fluid. Underground blowouts can occur when the formation just below the casing seat fractures due to excessive annulus pressure or while drilling or working over a high-pressure formation in the presence of a depleted formation. It may be possible to heal the fracture or plug the depleted zone by pumping lost circulation materials in a lightweight drilling fluid or a gunk squeeze (refer to 13.5.1 and 13.5.2) down the annulus while killing the high-pressure zone through the drill pipe with heavy drilling fluid. A gunk plug may also be pumped down the drill stem ahead of the barite slurry or heavy drilling fluid. Another remedial approach for underground blowouts is to pump a barite plug down the drill pipe while bullheading as heavy as practical drilling fluid down the annulus. In some cases, underground blowouts have been killed by gradually increasing the kill fluid density over the span of several circulations. High fluid density, high viscosity, and high pump rates will minimize contamination by influx fluid.

13.4 BARITE PLUGS

In case of underground blowout, lost circulation, or in limiting pressure situations requiring low choke pressure control, it may become necessary to attempt control using a barite plug. A barite plug is simply a slurry of barite in water, weighing about 18 to 22 pounds per gallon, that will bridge-off the hole due to high water loss and rapid settling when pumping is stopped. The use of a barite plug has several potential advantages over the use of cement; barite has a higher density, it is more likely to set up without any inherent channels, and it does not contaminate the drilling fluid system.

13.4.1 Running a Barite Plug

In drilling or workover operations, a barite plug must be run under backpressure when the kick has occurred but not yet controlled. Well influx must be stopped by hydrostatic or casing pressure to allow the barite to settle. The plug volume used depends upon hole size, depth, and kick severity. Due to the variations in quality of both barite and mixing water (freshwater should be used, if available), pilot tests must be made to determine the actual necessary chemical treatment and barite concentration that can be used. Sufficient volume of barite should be used to provide adequate hydrostatic pressure control.

13.4.2 Pilot Testing of Barite Slurry

Table 13.1 illustrates three formulations of slurries that can be used to produce barite plugs. These formulations are given in units for mixing laboratory pilot tests, field pilot testing in the absence of laboratory precision equipment, and a field formulation (39 bbl total volume). Generally, the highest density barite slurry that settles into a solid plug is desired.

13.4.3 Preparation and Testing of Pilot Samples

The pilot testing procedure listed below will produce qualitative or quantitative indications of which mixtures have the better chance of forming successful barite plugs. The greatest volume of non-pourable settled plug material is preferred.

1. Use a high-speed mixer for blending the slurry.
2. Add phosphate, Tetra Sodium Pyrophosphate (TSPP) or Sodium Acid Pyrophosphate (SAPP) or a suitable lignosulfonate thinner, and caustic soda to the fresh water prior to adding barite. TSPP and SAPP are used to accelerate barite settling so that a hard plug is formed. Addition of caustic soda to raise the pH to 9.5 – 11.0 range creates better barite settling tendencies.
3. Add barite rapidly (within 5 seconds) then stir sample on high speed for 15 seconds.
4. Pour 200 ml of the sample into a 250 ml container (preferably a graduated beaker). The sample should settle rapidly into a high-density cake. Pour off the liquid phase after a settling time of 15 minutes. The container should have at least 100 ml of settled material that will not pour; i.e., the settled material volume should be at least one-half of the initial total volume placed in the container.

Table 13.1—Barite Slurry Formulations

Laboratory Pilot Test Formula		Field Pilot Test Formula	Field Preparation Formula (39 bbl total volume)
18 lb/gal. slurry			
Water	480cc	2 cups*	225 bbl
Phosphate	**1.25g±	$^{1}/_{4}$ teaspoon	25 lbs (approx. 10 qts.)
Caustic Soda	**0.5g±	$^{1}/_{10}$ teaspoon	10 lbs (approx. 4 qts.)
Barite	1150g	$2^{1}/_{4}$	210 sacks (100 lb. ea.)
		*8 fluid oz. coffee cups	(Note: A mud cup is about 1 qt.)
20 lb./gal. slurry			
Water	425cc	$1^{3}/_{4}$ cups*	22 bbl
Phosphate	**1.25g±	$^{1}/_{4}$ teaspoon	25 lbs. (approx. 10 qts.)

Table 13.1—Barite Slurry Formulations (Continued)

Laboratory Pilot Test Formula		Field Pilot Test Formula	Field Preparation Formula (39 bbl total volume)
Caustic Soda	**0.5g±	1/10 teaspoon	10 lbs. (approx. 4 qts.)
Barite	1380g	3 cups*	250 sacks (100 lb. ea.)
		*8 fluid oz. coffee cups	
22 lb/gal. slurry			
Water	370cc	1 1/2 cups*	19 bbl
Phosphate	**1.25g±	1/4 teaspoon	25 lbs (approx. 10 qts.)
Caustic Soda	**0.5g±	1/10 teaspoon	10 lbs. (approx. 4 qts.)
Barite	1635g	3 1/2 cups*	295 sacks (100 lb. ea.)
		*8 fluid oz. coffee cups	

**For some barites and under high well temperature conditions, other thinners, notably lignosulfonates (up to 8 lb/bbl or more), may be used

Table 13.2—Slurry Volumes

Hole Diameter, in.	Feet of Hole Filled per Barrel of Slurry	Volume of Barite Slurry Required for 450 Feet of Open Hole, bbls
6 1/4	26.3	20
7 7/8	16.6	30
8 3/4	13.4	35
9 1/2	11.4	40
11	8.5	53
12 1/4	6.85	65
14 3/4	4.73	95
17 1/2	3.36	135

Table 13.3—Barite Required (API Barite Specific Gravity = 4.20)

Slurry Density, lb/gal	Pressure Gradient, psi/ft	Water Vol., gal/sacks	Slurry Yield, bbls/sacks			
			100 sx	200 sx	300 sx	400 sx
18.0	.935	5.00	18.6	37.1	55.6	74.3
20.0	1.039	3.70	15.6	31.1	46.6	62.5
22.0	1.142	2.71	13.2	26.4	39.6	52.8

Table 13.4—Diesel Oil-Bentonite Drilling Fluid Reactive Slurries

Materials required for *10 barrels* of slurry

Type	"Gunk" Diesel Oil-Bentonite	DOBC	DOB2C	DOBB2C
Diesel Oil, bbls	7.3	7	7	6.75
Bentonite, sacks*	23	14	10	4
Cement, sacks**		14	20	8
Barite sacks*				31
Density, lb/gal***	10.5	11.4	11.8	14.7

*100 lbs. net per sack.
**94 pounds net per sack (finest grind available).
***Density and final volume will vary depending on quality of materials used.

13.4.4 Barite Plug Procedure

A barite plug is mixed at the surface using cementing equipment with jet mixer, pumped through the drill pipe, and spotted as near to the influx zone as possible. The barite must settle rapidly to be effective or gas or saltwater percolating through the plug may not allow the plug to settle thereby reducing its effectiveness. On the other hand, the drill pipe may become plugged or stuck if the operation is not performed rapidly and efficiently. Drilling fluid contamination of the barite plug must be avoided. Table 13.2 presents volume information for placing barite slurry in various hole sizes. Slurry density-volume relationships are shown in Table 13.3. A high capacity cementing unit should be used to mix and displace the slurry. Barite should be mixed into fresh water containing the required amounts of phosphate or other thinner and caustic soda, as determined by pilot testing. A barite slurry may be mixed in the slugging pit if continuous and violent agitation action can be attained. Lines from the cementing unit may be connected directly to the drill pipe through a plug valve.

13.4.5 Checklist for Balanced Barite Plug Operations

The following checklist of recommended operations should be considered in planning barite plug operations:

1. Determine how many feet of unsettled barite plug in the open hole is desired (450 ft is usually considered a minimum).
2. Choose a slurry weight that will produce the desired results (higher weights are preferable if slurry will settle to produce a hard plug).
3. Calculate barrels of slurry required.
4. Calculate amounts of fresh water, phosphate, or lignosulfonate, caustic soda, and barite required to produce desired barite slurry.
5. Calculate the length of unsettled barite plug with drill collars and drill pipe in the hole. Calculate the drill pipe capacity above the top of plug (this will be the drilling fluid quantity needed to displace the barite slurry for balance plug).
6. Displace the barite slurry out of the drill stem utilizing a slug of high-density drilling fluid to minimize the chance of backflow and bit plugging.
7. Pull one stand of drill pipe from the hole as rapidly as possible. Continue pulling out of the hole until the lower end of the drill stem is above the top of the barite plug. The top of the plug will move downward as drill pipe is removed from the hole, if the annulus is kept properly pressurized by pumping into the kill line as pipe is stripped out of the hole. No more pipe should be removed than necessary to prevent becoming stuck in the barite plug. Circulate to clear the drill stem of plug residual material while maintaining backpressure.
8. Wait for barite to bridge and plug (4 to 12 hours), holding backpressure to prevent further fluid influx. Bleed the annulus pressure slowly to see if the plug is holding.
9. Consider running a temperature or noise log to determine if the underground flow has been stopped.
10. Circulate and condition the drilling fluid to remove any gas-cut fluid.
11. Run back in the hole slowly and tag the top of the barite plug.
12. Proceed with the next operation(s) to strengthen or isolate the upper loss zone.

13.4.6 Pumping Large Volumes of Barite Slurry

Barite plugs of limited volume and height will not generate enough hydrostatic pressure to stop the influx of formation fluids in some underground blowouts and kicks on diverter. The necessary hydrostatic pressure can be obtained in some cases by pumping a large volume of barite slurry (1,000 to 6,000 sacks) at 10 to 30 barrels per minute in an uninterrupted placement. The large volume barite slurry should be tested in the same manner as the barite plug (refer to 13.4.2 and 13.4.3). Provisions should be made to treat the mix water so the slurry can be pumped rapidly and continuously. Consideration should be given to spearheading the barite slurry with a "gunk" plug. A "gunk" plug of 30 to 100 barrels will often provide sufficient flow resistance to slow the influx enough to place the barite more efficiently. The "gunk" plug may be formulated as shown in Table 13.4. The drill string should be cleared after each barite slurry placement until it is determined that the formation influx has stopped.

13.5 SQUEEZE SLURRIES

Lost circulation can often be remedied most quickly utilizing a squeeze slurry. Diesel oil-bentonite cement slurries (DOBC) thicken by mixing of the slurry with drilling fluid and can tolerate 50 – 100% dilution by the drilling fluid. High-water-loss, high-solids cement slurries thicken by partial dehydration. Both mixtures gain the strength of the cement.

13.5.1 DOBC Test Procedure

The following test procedure should be used to predict the applicability of particular oils in diesel oil-bentonite cement (DOBC) slurries. To a sand content tube add a representative sample of the diesel oil to the 20% line; then add water to the "mud-to-here" line. Shake vigorously for 10 seconds and allow it to stand for 10 minutes. If the oil and water separate into two distinct layers, the oil is satisfactory to use. However, if the oil and water separate into three layers, i.e., oil on top, a white emulsion in the center, and water on the bottom, the oil will not form satisfactory DOBC squeeze slurries. If a stable emulsion is formed, the oil should not be used. A pilot test using varying mixtures of drilling fluid and DOBC should be run to assure downhole thickening of the slurry. DOBC slurries have failed due to surfactants present in the diesel oil, which will prevent the bentonite and cement from being wet by the water and "gunking up" to form a satisfactory seal.

13.5.2 DOBC Slurry Procedure

The following procedure is recommended for applying DOBC slurries to well lost circulation zones:

1. Locate the top of the lost circulation zone by use of a temperature survey or other means.
2. DOBC slurries can be pumped through a bit or open-ended, however, mixing can be improved by using a special drill pipe sub prepared by plugging one end of one-half of a joint of drill pipe and drilling 15 to 20 holes (half inch diameter), spaced randomly around the joint.
3. Run the drill pipe, with a backpressure or check valve, to a point just above the casing shoe or 20 to 30 feet above the lost circulation zone.
4. Test the surface equipment and piping to the maximum anticipated working pressure.
5. Wash out all equipment with the diesel oil to be used. Caution: All pumping and mixing equipment must be free of water prior to preparing the slurry.
6. Pump five barrels or more of diesel oil into the drill pipe using a pump truck. This prevents contact between the drilling fluid and slurry during displacement.
7. Mix the required amounts of cement and bentonite into the diesel oil using a jet mixer. The slurry weight should be approximately 11.5 pounds per gallon. Guidelines for mixtures preparations are shown in Table 13.4.
8. Displace the slurry down the drill pipe and follow with a diesel oil pad.
9. When the cushion of diesel oil which precedes the reactive slurry reaches the bit or mixing sub, close the BOP and begin pumping drilling fluid down the annulus, using a second pump, while the reactive slurry is being displaced from the drill string. The speed of the pump on the annulus should be held at a low constant rate. The initial pumping rate on the drill pipe should be greater than that on the annulus. The drill pipe pumping rate should be varied based on response of the casing pressure, so that the thickness of the drilling fluid plus reactive slurry being blended at the bit or mixing sub is thinner at the beginning and finally is thick enough to produce the desired squeeze pressure. A pilot test of mixture ratios of the reactive slurry with the drilling fluid in the annulus will help the supervisor select changes in the ratio as the two fluids are being mixed downhole. Estimates of the range of ratios required to yield a thin or thick mixture are shown in Table 13.5.
10. If the annulus will not stand full prior to starting treatment, fill it with water. It should begin filling soon after the slurry starts clearing the drill stem.
11. A surface pressure should be obtained on the annulus during displacement. If pressure is not obtained, attempt a "hesitation squeeze" while displacing the last one-fourth of the slurry volume. A "hesitation squeeze" is used to attempt to build up some squeeze pressure. Approximately one barrel of slurry should be left in the drill pipe at the completion of the squeeze. Do not attempt to reverse circulate. Release the pressure on the annulus, pull the drill pipe slowly, replace the bit, and drill out in not less than 8 hours.
12. Repeat treatment if circulation is lost while drilling out.

13.5.3 High-Water-Loss, High-Solids Cement Slurry (HWL-HS)

This is a low strength mixture of water, cement, barite for correct density, 10 – 20 pounds per barrel of a mixture of fibrous, flake, granular sealing materials, and HWL-HS additive. Table 13.6 presents a guide of suggested material quantities for preparing a one-barrel mixture of HWL-HS cement slurry.

Table 13.5—Trial Mixing Ratios for Reactive Slurry Mixtures

	DOB: "Gunk" Drig. Fluid: DOB	Drig Fluid: DOBC	Drig Fluid: DOB2C	Drig. Fluid: DOBB2C
Thin Mixture	8:1 to 4:1	4:1 to 6:1	4:1 to 6:1	4:1 to 6:1
Thick Mixture	2:1 to 1:1	2:5:1 to 1:1	2:5:1 to 1:1	2:1 to 1:1

* These suggested ratios should be refined by pilot testing before use on a specific job.

Table 13.6—Materials Quantities for Mixing One Barrel of HWL-HS Cement Slurry

Density, lb/gal	HWL-HS Additive, lbs	Cement, sacks (Min.)	Cement, sacks (Max.)	Barite sacks (avg.)	Water, barrell
9.5	15	1.0	1.4	0	.84
10.0	20	1.0	1.4	0	.83
11.0	20	1.0	1.4	1.0	.78
12.0	20	1.0	1.4	1.4	.75
13.0	20	1.0	1.4	1.8	.72
14.0	20	1.0	1.4	2.5	.68
15.0	15	1.0	1.3	2.7	.65
16.0	15	1.0	1.2	3.2	.61
17.0	12	1.0	1.2	3.8	.57
18.0	10	1.0	1.0	4.4	.54

NOTE: Add to the above mixture 5 – 10 lb/bbl of mixed fibrous, flake, and granular sealing material and a 20 lb/bbl addition of mixed sizes of granular materials. If the mixutre must be pumped through a bit, careful selection of the sealing materials must be made to prevent plugging of bit jets.

13.5.4 Cement Retarders

Common cement additives may be necessary for successful slurry mixing and placement. Cement retarders should be added as required for pumping time. Turbulence inducers may be added for mixing and pumpability. In the lower range of slurry densities, calcium carbonate may be used as weight material for a better filler.

13.5.5 Mixing Procedure

Use of a blender truck and the following mixing procedure are recommended:

1. Measure water volume into the truck.
2. Add HWL-HS additive while running the blender.
3. Add barite and lost circulation materials.
4. Add cement (bulk may be quickest).

13.5.6 HWL-HS Cement Slurry Squeeze Operations

Take care to prevent pumping a slurry containing coarse lost circulation material through a bit or mud-motor with small diameter nozzles. It is more desirable and safe to pump the HWL-HS cement pill through a squeeze tool. In performing the squeeze, it is desirable to perform a "hesitation squeeze" once the bit or squeeze tool is clear of slurry. The "hesitation squeeze" is used to attempt to build up some squeeze pressure. The slurry should be spotted just as in any normal squeeze operation; however, pumping time should be considered critical and adequate precautions observed. Waiting-on-cement time between the squeeze and circulated drill-out should be at least 8 hours and preferably, 12 hours or longer to allow sufficient setting time for the cement.

13.5.7 Recommended Procedures for High-Water-Loss, High-Solids Cement Squeeze

The following steps should be used in effecting HWL-HS cement squeeze operations:

1. Pull up far enough into casing so that volume of casing below the bit equals approximately one-third the total volume of the squeeze slurry.
2. Pump HWL-HS cement slurry down the drill stem to just above the bit or squeeze tool. Some drilling fluid may be needed to reach this stage if slurry volume is less than drill stem capacity.
3. Shut-in the well to assure slurry goes down the casing. Compensate for lack of returns on the annular side by filling the annulus with a fluid lighter than the drilling fluid. Pull drill string far enough into the casing to prevent sticking.
4. Follow slurry with enough drilling fluid to clear the drill string but leave enough slurry in the casing to permit three squeeze stages. Gas expansion may require periodic bleed-off of excess pressure through a choke line. This condition will be indicated by a buildup of pressure on both the casing and the drill stem. Some of this pressure can be used to help expel slurry water and to speed setting. Additional benefits will be continuous, slow void filling and additional control of intruding fluids.
5. Wait 3–4 hours, depending on hole temperature and conditions, and pump enough to get pressure communication from surface drill pipe to casing gauges. If the hole takes fluid, stop after one-third of slurry is squeezed from the casing.
6. Wait 4–6 hours and repeat step 4 and stop when casing pressure goes up to 500 psi or when another one-third of slurry is squeezed out, whichever occurs first.
7. Either repeat step 5 or circulate until annulus is clean. Utilize choke if needed.
8. Trip for new bit or to change bottom-hole assembly if squeeze pressure is 500 psi above formation pressure, or wait remainder of 24 hours and start washing down.

APPENDIX A—KICK PRESSURE AND GRADIENT CALCULATIONS

A.1 Pressure Calculations

Several special pressure and pressure gradient calculations can aid a well control supervisor in understanding well control operations. These calculations are based on the following assumptions:

1. The well bore is vertical,
2. The kick fluid is initially on bottom,
3. The kick fluid is 0.6 specific gravity hydrocarbon gas,
4. The influx is one discrete bubble occupying 100% of its annular space in a gauge hole, and
5. The influx gas is completely insoluble in the drilling fluid.

The four calculations discussed in this section are:

1. Kick gradient,
2. Maximum expected surface pressure,
3. Initial closed-in pressure gradient at the casing shoe, and
4. Maximum expected pressure gradient at the casing shoe.

While an accurate knowledge of these four items would be of benefit to the well control supervisor, the general lack of precision in defining the well kick parameters, gas mixing and migration, and uncertainties in field measurements, significantly affect the ability to precisely calculate these values. For these reasons, the well control worksheets (refer to Appendix B) do not include steps requiring these calculations.

A.2 Kick Gradient Calculations

The apparent density of the kick fluids is given by the following relation:

$$\rho_k = \rho_o - \frac{(P_{csg} - P_{dp})}{0.052 H_k} \quad \text{(Equation A.1)}$$

The kick density can be calculated from the kick volume, closed-in pressure, and hole dimensions after determining if the top of the kick extends above the top of the drill collars. The first step is to compute the annular volume in the annulus surrounding the drill collars, which is given as follows:

$$V_{dca} = \frac{(D_h^2 - D_{dc}^2) l_{dc}}{1029} \quad \text{(Equation A.2)}$$

If the kick volume is less than the volume of the annulus surrounding the drill collars, the density of the kick fluids is given by:

$$\rho_k = \rho_o - \frac{(P_{csg} - P_{dp})(D_h^2 - D_{dc}^2)}{53.5 V_b} \quad \text{(Equation A.3)}$$

If the volume of the kick fluids exceeds the volume of the drill collar annulus, the density of the kick fluids is given by the following relation:

$$\rho_k = \rho_o - \frac{(P_{csg} - P_{dp})}{0.052 L_{dc} + \dfrac{53.5(V_b - V_{dca})}{(D_h^2 - D_{dc}^2)}} \quad \text{(Equation A.4)}$$

The density of a gas kick should be in the range of 11/2 to 2 lb/gal. An oil kick should have a density of about 6 lb/gal, and a saltwater kick should have a density of about 9 lb/gal. The calculations assume that the kick fluid is on bottom and not mixed with the drilling fluid. This is seldom true. If the kick fluid extends above the drill collars when the calculations assume the fluid to be alongside the collars, the calculated kick fluid density, (k will be too low.

A.3 Closed-in Bottom-hole Pressure

The closed-in bottom-hole pressure is given by the following relation:

$$P_b = 0.052\ \rho_o\ TVD = P_{dp} \quad \text{(Equation A.5)}$$

A.4 Hydrostatic Pressure of the Kick Fluids in the Casing/Drill Pipe Annulus

The hydrostatic pressure of the gas after circulating the kick into the casing/drill pipe annulus is given by:

$$\frac{(W)}{A_c} = \frac{1.27 W}{D_{csg}^2 - D_p^2} \quad \text{(Equation A.6)}$$

The total weight of the gas (W) in the kick can be determined from Figure A.1 using the calculated closed-in, bottom-hole pressure and the kick volume. In Equation A.6, the constant 1.27, = 4/1/4.

A.5 Maximum Surface Pressure for Gas Kick Using Driller's Method

When using the Driller's Method, the maximum surface pressure from a gas kick occurs when the gas reaches the surface. The maximum expected surface pressure for the Driller's Method can be determined from Figures A.2 and A.3 using the following relation:

$$P_{surf} = P_g = (P_{dp} \times f) \qquad \text{(Equation A.7)}$$

where

P_g is determined from Figure A.2, using (ρ_o and $\frac{(W)}{A_c}$

And, f is determined from Figure A.3, using $P_{add} = P_{dp}$.

The maximum expected surface pressure is determined from Figure A.2 using the original drilling fluid density and the hydrostatic pressure of the gas in the drill pipe/casing annulus as determined from Equation A.6. The factor (f) is determined from Figure A.3 and the gas column pressure (P_g) is determined from Figure A.2.

A.6 Maximum Surface Pressure for Gas Kick Using Wait and Weight Method

When using the Wait and Weight Method, the maximum surface pressure normally occurs either during the initial closed-in condition or when the gas has been circulated to the surface. The maximum surface pressure that occurs as gas reaches the surface when using the Wait and Weight Method can be determined from Figures A.2 and A.3 using the following relation:

$$P_{surf} = P_g + \left(P_{dp} \times \frac{ID^2}{D_n^2 - D_p^2} \times f\right) \qquad \text{(Equation A.8)}$$

where:

P_g is determined from Figure A.2, using (ρ_o and $\frac{(W)}{A_c}$

And, f is determined from Figure A.3, using

$$P_{add} = \frac{P_{dp} \times ID^2}{D_n^2 - D_p^1}$$

In this case, the pressure from Figure A.2 is determined using the required drilling fluid density rather than the original drilling fluid density and with the hydrostatic pressure of the gas in the annulus as determined using Equation A.6. The factor (f) is determined from Figure A.2 using a ratio of the inside area of the drill string to the annular area times the initial closed-in drill pipe pressure for the P_{add} term and P_g as obtained from Figure A.2. Migration and mixing of the kick fluids in the drilling fluid reduce the actual maximum surface pressure below the calculated value. The accuracy of the calculation decreases as the kick volume and mixing of the kick fluids in the drilling fluid increase.

A.7 Initial Closed-in Pressure Gradient at the Casing Shoe

A knowledge of the maximum expected well control pressures at the casing shoe and the formation fracture pressure at the casing shoe can aid the well control supervisor in judging the likelihood of an underground blowout or a partial loss of returns while killing the well. The two highest pressures occur during the initial closed-in conditions and after the gas has been circulated to the casing shoe. The maximum gradient for the initial closed-in conditions is based on the assumption that the casing/drill string annulus is full of drilling fluid. For this assumption, the maximum initial closed-in pressure gradient at the casing shoe is given by:

$$g_o = \rho_o + \frac{P_{esg}}{0.052\,TVD_{esg}} \qquad \text{(Equation A.9)}$$

A.8 Hydrostatic Pressure of the Gas Influx in the Open Hole/Drilling String Annulus

The maximum pressure that occurs after circulating the gas kick up to the casing shoe can be determined from the hydrostatic pressure of the gas in the open hole/drill string annulus immediately below the casing shoe and the relationships defined in Figures A.2 and A.3. The hydrostatic pressure of the gas kick in the open hole/drill string annulus is given by the following relation:

$$\frac{(W)}{A_h} = \frac{1.27W}{D_n^2 - D_p^2} \qquad \text{(Equation A.10)}$$

A.9 Maximum Pressure at the Casing Shoe After Circulating Gas to the Casing Shoe Using the Driller's Method

The maximum pressure at the casing shoe while controlling a kick with the Driller's Method can be determined from Figures A.2 and A.3 and the following equation:

$$P_{shoe} = P_g + (P_{dp} + 0.052\ \rho_o\ TCD_{csg}) \times f \qquad \text{(Equation A.11)}$$

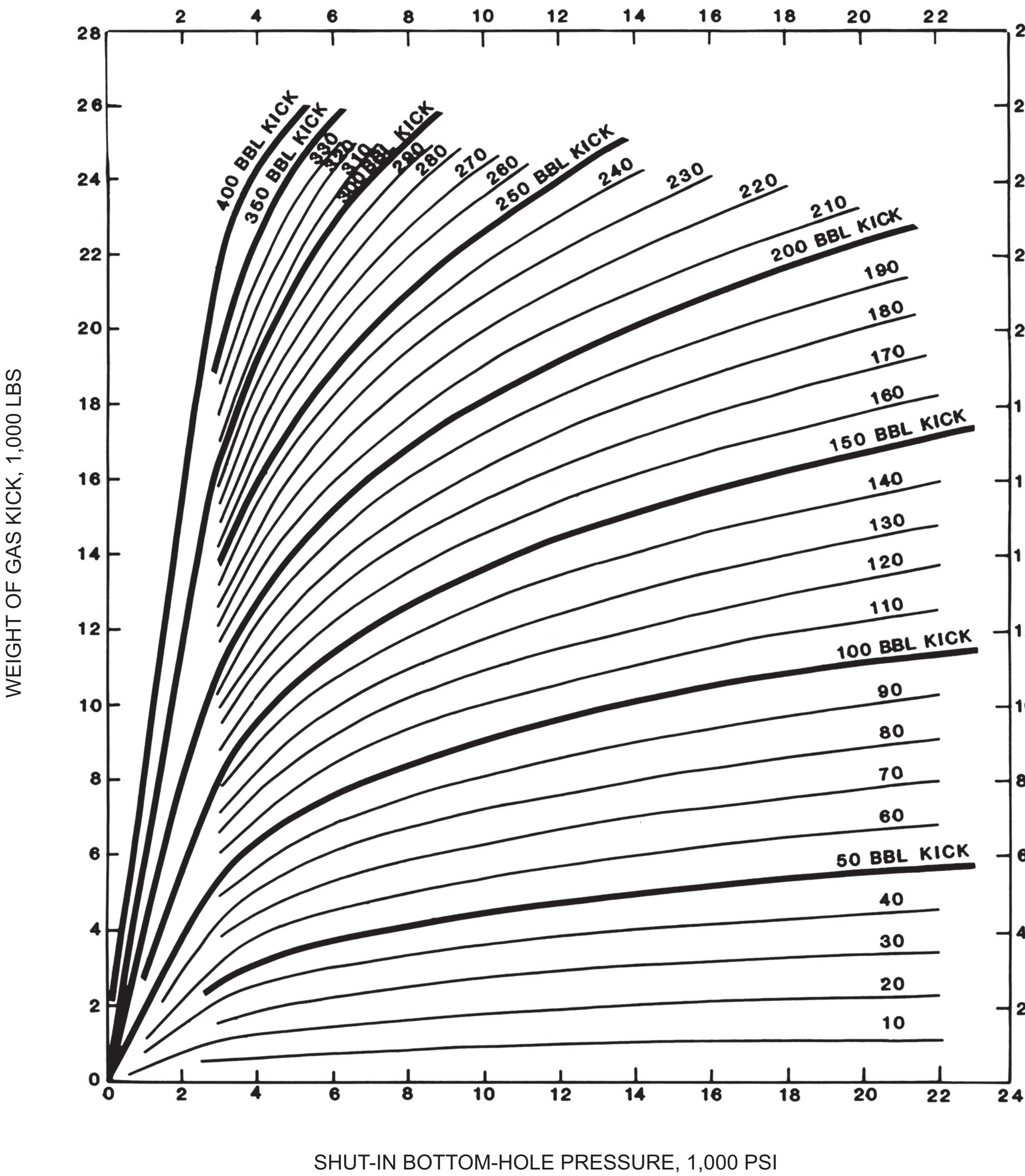
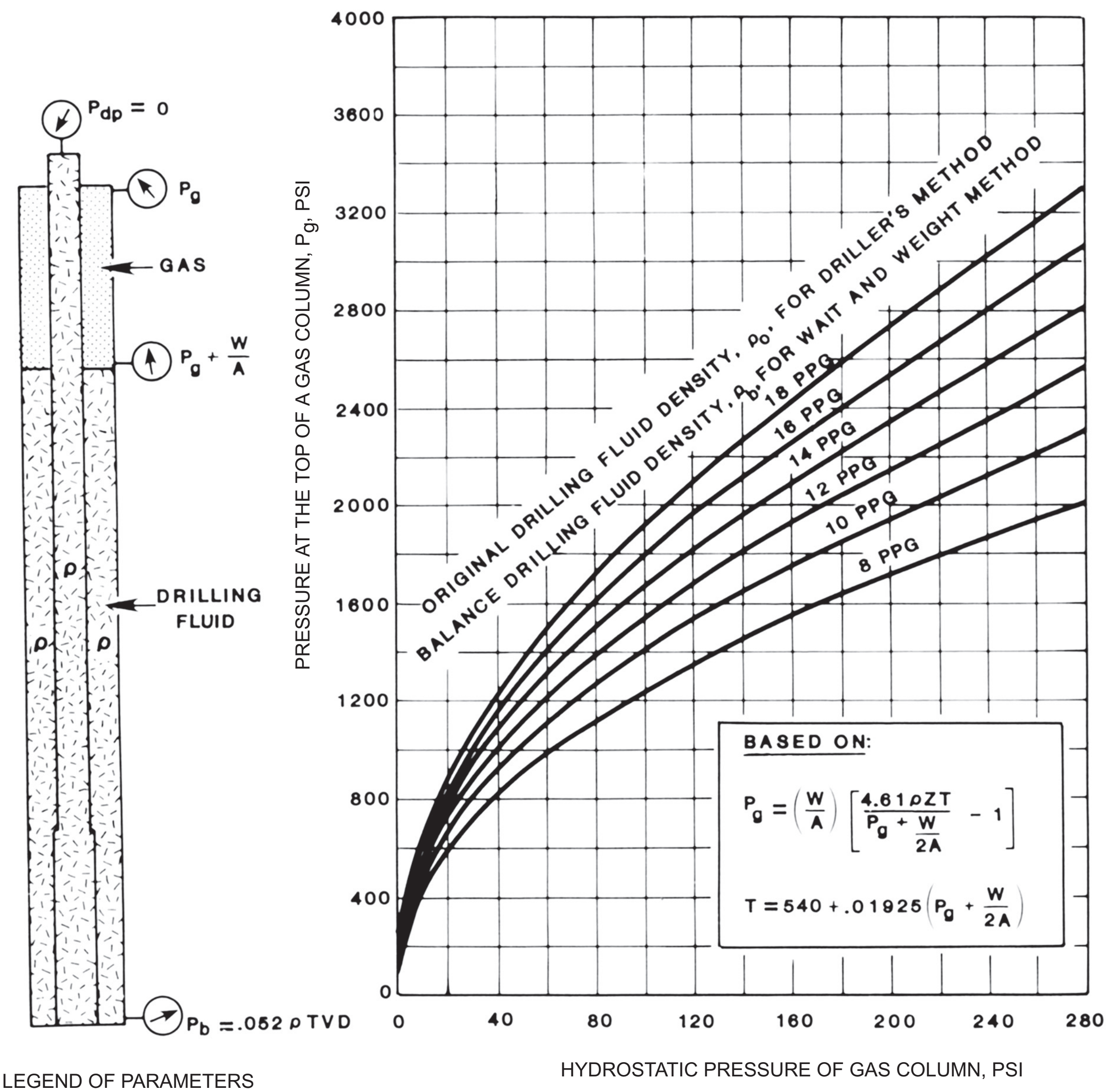


Figure A.1—Weight of a Gas Kick, 0.6 Gravity Gas



LEGEND OF PARAMETERS
USED IN DEVELOPING
FIGURE A.2

Figure A.2—Maximum Surface Pressure of a Zero Intensity Gas Kick (P_{dp} = 0)

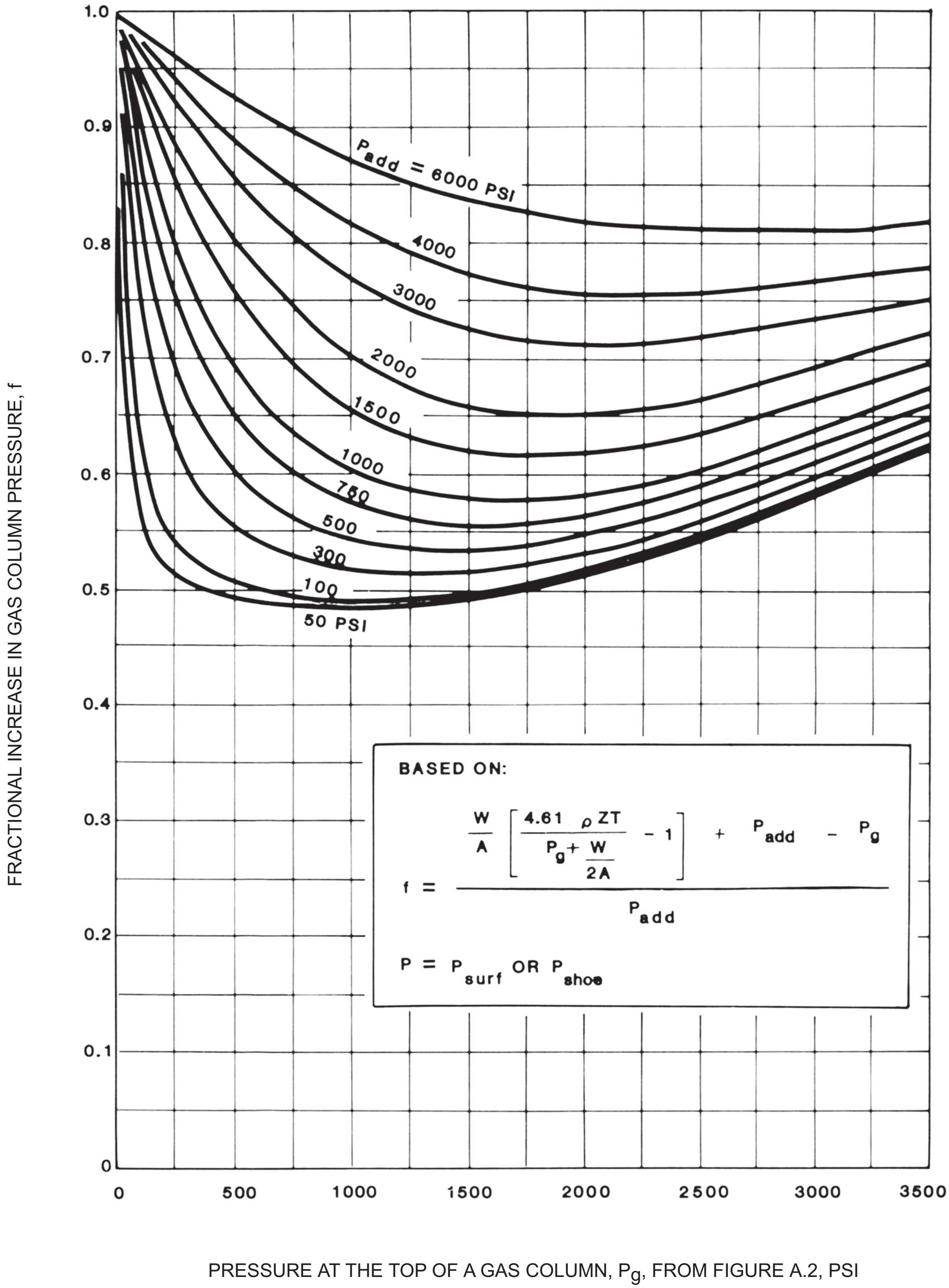


Figure A.3—Factor for Determining the Maximum Surface or Casing Shoe Pressure while Killing a Gas Kick with a Constant Bottom-Hole Pressure Method where

P_g is determined from Figure A.2, using (ρ_o and $\frac{(W)}{A_c}$

And f is determined from Figure A.3 using

$P_{add} = (P_{dp} + 0.052\ \rho_o\ TCD_{csg})$ and P_g from Figure A.2.

P_g is determined from Figure A.2 using the initial drilling fluid density and the hydrostatic pressure of the gas in the open hole/drill string annulus below the casing shoe.

Factor (f) from Figure A.3 is determined using the sum of the initial closed-in drill pipe pressure and the hydrostatic head of the initial drilling fluid at the casing shoe for the P_{add} term.

A.10 Maximum Pressure at the Casing Shoe After Circulating Gas to the Casing Shoe Using the Weight and Weight Method

The maximum pressure at the casing shoe that occurs after circulating a gas kick to the casing shoe using the Wait and Weight Method can also be determined from Figures A.2 and A.3 using the following relation:

$$P_{shoe} = P_g + \left(P_{dp} \times \frac{ID^2}{D_n^2 - D_p^2} + 0.052\rho_o TVD_{csg}\right)$$

(Equation A.12)

where

P_g is determined from Figure A.2, using (ρ_o and $\frac{(W)}{A_c}$

And f is determined from Figure A.3 using

$P_{add} = P_{dp} \times \frac{ID^2}{D_n^2 - D_p^2} + 0.052\rho_o TVD_{csg}$ and P_g from Figure A.2.

The pressure (P_g) is determined from Figure A.2 using the required drilling fluid density and the hydrostatic pressure of the gas in the hole/drill string annulus immediately below the casing shoe. The factor (f), determined from Figure A.3, is based on the Padd term that includes the sum of the ratio of the inside area of the drill string to the annular area times the initial closed-in drill pipe pressure plus the hydrostatic pressure of the column of the required drilling fluid density to the casing shoe.

A.11 Gradient at the Casing Shoe After Circulating Gas to the Casing Shoe

For either control method the equivalent pressure gradient at the casing shoe after circulating the top of the gas to the casing shoe is given by the following:

$$g_f = \frac{P_{shoe}}{0.052 TVD_{csg}} \qquad \text{(Equation A.13)}$$

A.12 Example Calculations

The pressure and pressure gradient equations can be used to calculate the four desired parameters as shown by the following example:

Initial closed-in drill pipe pressure: P_{dp} = 500 psi.

Initial closed-in casing pressure: P_{esg} = 700 psi.

Initial closed-in kick volume: V_b = 50 bbls.

Total depth of well: *TVD* = 10,400 feet.

Original drilling fluid density: ρ_o = 9.5 lb/gal.

Diameter of the hole: $D_h = 12\ ^1/_4$ inches.

Depth of the casing shoe: TVD_{csg} = 4,000 feet.

Casing: 13 $^3/_8$ in., 72 lb/ft., N80.

Drill pipe: 5 in., 19.5 lb/ft., *XH*.

Drill collars: 600 ft of 8 in. *OD* x 3 in. *ID*.

For this well, the volume of the drill collar/hole annulus from Equation A.2 is given as follows:

$$V_{dca} = \frac{(D_h^2 - D_{dc}^2)L_{dc}}{1029} = \frac{(12.25^2 - 8^2) \times 600}{1029} = 50.2\text{bbls.}$$

Since the kick volume is less than the drill collar/hole annulus volume, the kick gradient is determined from Equation A.3 as follows:

$$\rho_k = \rho_o - \frac{(P_{esg} - P_{dp})(D_h^2 - D_{dc}^2)}{53.5 V_b}$$

$$= 9.5 - \frac{(700 - 500)(12.25^2 - 8^2)}{53.5 \times 50}$$

$$= 9.5 - 6.43$$

$$= 3.1 \text{ lb/gal}$$

The closed-in gradient of the kick fluids is 3.1 lb/gal. This suggests that the kick contains gas. Since the indicated density is greater than the density of gas, it is possible that the kick also contains some more dense fluid, or that the hole size near the bottom of the well is larger than 12 1/4 in., or that a portion of the gas is above the top of the collars. The maximum surface pressure if the well is killed with the Driller's Method is calculated from Equations A.6 and A.7 and Figures A.1, A.2, and A.3. Assuming that the kick is 100% gas, the weight of the gas in the kick is determined from Figure A.1 using the kick volume of 50 bbls, and the closed-in bottom-hole pressure determined from Equation A.5 as follows:

$$P_b = 0.052 \times \rho_o TVD + P_{dp}$$

$$= (0.052 \times 9.5 \times 10{,}400) + 500 = 5{,}638 \text{ psi.}$$

From Figure A.1, using 50 bbls and 5,638 psi, the weight of the gas kick is determined to be 3,700 lbs.

The hydrostatic pressure of the gas in the casing/drill pipe annulus is given using Equation A.6 as follows:

$$\frac{(W)}{A_c} = \frac{1.27W}{D_{csg}^2 - D_p^2} = \frac{1.27 \times 3700}{12.347^2 - 5^2} = 37\text{psi}$$

The maximum surface pressure for a well killed with the Driller's Method is given by Equation A.7:

$P_{surf} = P_g$ (from Figure A.2) + $P_{dp} \times f$ (from Figure A.3).

P_g is determined from Figure A.2 using 9.5 lb/gal drilling fluid in $\frac{(W)}{A_c}$ of 37 psi. Figure A.2 shows P_g is 860 psi.

The term (f) is determined from Figure A.3 using P_g obtained from Figure A.2 and P_{dp} for the P_{add} term. For P_g equal to 860 psi and P_{add} equal to 500 psi, f is found to be 0.55. Therefore, P_{surf} for the Driller's Method is equal to:

$$P_{surf} = 860 + (500 \times 0.55) = 1{,}135 \text{ psi.}$$

If the well were to be killed with the Wait and Weight Method, the maximum surface pressure would be determined from Equation (A.8):

$$P_{surf} = P_g \text{ (from Figure A.2)} + \left(\frac{ID^2}{D_n^2 - D_p^2}\right) P_{dp} \times f$$

(from Figure A.3).

In this case, P_g is determined from Figure A.2 using the required drilling fluid density. The required drilling fluid density, (ρ_b, is calculated as follows (using a 0.9 lb/gal trip margin):

$$\rho_b = \rho_o + \frac{P_{dp}}{0.052 \times TVD} \quad \text{(Equation A.14)}$$

$$= 9.5 + \frac{500}{0.052 \times 10400} = 10.4 \text{ lb/gal}$$

For 10.4 lb/gal required drilling fluid density and 37 psi hydrostatic pressure of the gas column, Figure A.2 shows the P_g term to be 900 psi. The P_{add} term for Figure A.3 is computed as follows:

$$P_{add} = \frac{(ID^2)}{D_{csg}^2 - D_p^2} P_{dp} = \frac{(4.276)^2}{(12.347)^2 - (5)^2} \times 500 = 72 \text{ psi}$$

Using P_g equal to 900 psi and P_{add} equal to 72 psi, f is found to be equal to 0.49. The maximum surface pressure for the Wait and Weight Method is:

$$P_{surf} = 900 + (72 \times 0.49) = 935 \text{ psi.}$$

For this example, the maximum surface pressure using the Wait and Weight Method would be 200 psi less than the maximum surface pressure for the Driller's Method. The initial closed-in pressure gradient at the casing shoe is determined from Equation (A.9) as follows:

$$g_o = \rho_o + \frac{P_{esg}}{0.052 \times TVD_{esg}}$$

$$= 9.5 + \frac{700}{0.052 \times 4000}$$

$$= 9.5 + 3.4 = 12.9 \text{ lb/gal}$$

This maximum pressure gradient at the casing shoe depends on the well control method. The maximum pressure when the gas reaches the casing shoe for the Driller's Method is determined from Equations A.10 and A.11, Figures A.2 and A.3, and the previous data. The hydrostatic pressure of the gas kick in the annulus below the casing shoe is calculated from Equation A.10 as follows:

$$\frac{(W)}{A_c} = \frac{1.27W}{D_h^2 - D_p^2} = \frac{1.27 \times 3700}{12.25^2 - 5^2} = 38 \text{ psi}$$

The pressure at the casing shoe is given by Equation A.11 as follows:

$P_{shoe} = P_g$ (from Figure A.2) + (P_{dp} + 0.052 ρ_o TVD_{esg}) x f (from Figure A.3).

Using a hydrostatic pressure of the gas column of 38 psi and an initial drilling fluid density of 9.5 lb/gal, Figure A.2 shows P_g to be 870 psi. The P_{add} term for determining f in Figure A.3 is equal to:

$$P_{add} = (P_{dp} + 0.052\ \rho_o\ TVD_{esg}) \quad \text{(Equation A.16)}$$

$$= 500 + 0.052 \text{ x } 9.5 \text{ x } 4{,}000 = 2{,}476 \text{ psi}$$

Using a P_g of 870 psi and a P_{add} of 2,476 psi, Figure A.3 shows that the f term is equal to 0.75; therefore, the maximum pressure at the casing shoe when gas has been circulated to the casing shoe using the Driller's Method is equal to:

$$P_{shoe} = 870 + (2{,}476 \text{ x } 0.75) = 2{,}727 \text{ psi}$$

If the well is killed using the Wait and Weight Method, the maximum pressure after circulating gas up to the casing shoe is given by Equation (A.12), as follows:

$$P_{shoe} = P_g \text{ (from Figure A.2)} + \left(\frac{ID^2}{D_n^2 - D_p^2}\right) P_{dp} +$$
$$0.052\ \rho_o\ TVD_{csg} \text{ x } f \text{ (from Figure A.3)}$$

The term P_g is determined from Figure A.2 using the hydrostatic pressure of the gas column and the required drilling fluid density. Using 38 psi as the hydrostatic pressure of the gas column and 10.4 lb/gal required drilling fluid density, P_g is found to be 910 psi from Figure A.2. The P_{add} term for Figure A.3 is equal to:

$$P_{add} = \frac{ID^2}{D_n^2 - D_p^2} \times P_{dp} + (0.052\rho_o TVD_{csg})$$

(Equation A.17)

$$= \frac{4.276^2 \times 500}{12.25^2 - 5^2} + (0.52 \times 10.4 \times 4000)$$

= 2,234 psi

Using P_g = 910 psi and P_{add} = 2,234 psi, Figure A.3 shows the f term to be 0.73. Therefore, the pressure after circulating gas to the casing shoe using the Wait and Weight Method is given by:

$$P_{shoe} = 910 + (2234 \text{ x } 0.73) = 2{,}540 \text{ psi}$$

The pressure gradient at the casing shoe for these conditions is calculated from Equation (A.13).

$$g_t = \frac{P_{shoe}}{0.052 TVD_{csg}}$$

For the Driller's Method the gradient is:

$$g_t = \frac{2727}{0.052 \times 4000} = 13.1 \text{ lb/gal}$$

For the Wait and Weight Method the gradient at the casing shoe is:

$$g_t = \frac{2540}{0.052 \times 4000} = 12.2 \text{ lb/gal}$$

In the Driller's Method, the maximum gradient at the casing shoe occurs after circulating gas to the casing shoe. For this example, the maximum gradient would be 13.1 lb/gal which is 0.2 lb/gal greater than the gradient at the initial closed-in conditions. With the Wait and Weight Method the maximum gradient may occur either under the initial conditions or after circulating the gas to the casing shoe, depending on the kick volume and required drilling fluid density increase. For this example, the gradient at the casing shoe would be 0.7 lb/gal lower than the initial closed-in conditions after circulating gas to the casing shoe.

A.13 Nomenclature Of Terms Used In Appendix A

A_c = area of drill /pipe casing annulus, in.^{2} .

A_h = area of drill pipe/hole annulus, in.^{2}.

D_h = diameter of hole containing gas, in.

D_p = drill pipe OD, in.

D_{dc} = drill collar OD, in.

D_{csg} = casing inside diameter, in.

f = factor defined by Figure A.3, psi/psi.

G = specific gravity of gas, dimensionless.

g_o = maximum initial closed-in pressure gradient at the casing shoe, lb/gal.

g_f = pressure gradient at casing shoe after circulating gas kick to the casing shoe, lb/gal.

H_k = height of the kick fluids, ft.

h = length (height) of gas column, ft.

ID = inside diameter of drill pipe, in.

L_{dc} = length of drill collars, ft.

P_b = closed-in bottom-hole pressure, psi.

P_{dp} = initial closed-in drill pipe pressure, psi.

P_{csg} = initial closed-in casing pressure, psi.

P_g = pressure term determined from Figure A.2, psi.

P_{add} = pressure term used to determine f on Figure A.3, psi.

P_{surf} = maximum expected surface pressure while circulating a kick utilizing the constant bottom-hole pressure method, psi.

P_{shoe} = maximum pressure at the casing shoe after circulating gas up to the casing shoe, psi.

T = gas temperature, degrees Rankin, R.

TVD = true vertical depth of kick zone and drill string, ft.

TVD_{csg} = total vertical depth of casing shoe (casing presumed vertical), ft.

V_b = initial closed-in kick volume (assumed at TVD), bbls.

V_{dca} = volume of the hole/drill collar annulus, bbls.

W = weight of the gas kick, lbs.

Z = gas compressibility factor, dimensionless.

ρ_o = density of drilling fluid in the hole at the time of the kick, lb/gal.

ρ_k = apparent density of kick fluids, lb/gal.

ρ_b = required drilling fluid density, lb/gal

Notes:

Derivation Information Related to Figure A.1.

In Figure A.1, the factor, 0.01935, is empirical. This factor is based on an observation by Louis R. Records and was published as follows: LeBlanc, J. L. and Lewis, R. L., "A Mathematical Model of a Gas Kick," Journal of Petroleum Technology, August 1968, p. 888, Society of Petroleum Engineers, Richardson, Texas. Records' observation in the Gulf Coast states that formation temperature and formation pressure are correlated reasonably well regardless of whether pressures are normal or abnormal. The factor, 0.01935, is derived as follows:

Formation temperature in the Gulf Coast area is estimated to be 80 F + 0.9 (F/100 feet of depth, in degrees F. In degrees R, this temperature would be 460 + 80 + 0.9 (F/100 feet). In a normal pressured interval, the formation pressure is 0.465 psi per foot of depth or 46.5 psi per 100 foot. Substituting this in the temperature relationship yields 540 + 0.01935 (pressure). The plot shown in Figure A.1 is exact excepting the empirical correlation between reservoir temperature and pressure.

APPENDIX B—WELL CONTROL WORKSHEETS

WELL NAME
DATE

API RECOMMENDED
WELL CONTROL WORKSHEET
DRILLERS METHOD

CONTRACTOR
RIG

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size ____________ in., Weight _____________ lb/ft, Grade _____________, Internal Yield ___________ psi, Depth (TVD) ___________ ft
Mechanical Pressure Limit __________ psi
Casing Pressure to Cause Fracture __________ psi *(1)*, based on present drilling fluid density of _________ lb/gal.
Maximum Allowable Casing Pressure: Initial Closure ________ psi
Entire Well Kill _______ psi } Approved by: ____________________________________ (Name)
Contingency Procedure *(2)* if casing pressure reaches maximum approved: ____________________________________

____

Normal Circulating Pressure and Rate: ___________ psi at ___________ stks/min. and ___________ bpm* at __________ lb/gal and __________ ft
Kill Pressure and Rate: Pump No. 1, ____________ psi at ___________ stks/min. and ___________ bpm* at __________ lb/gal and ________ ft *(3)*
Pump No. 2, ____________ psi at ___________ stks/min. and ___________ bpm* at __________ lb/gal and ________ ft *(3)*
Drill Pipe Capacity: _________bbl/ft

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump. [□ open choke line and choke, close blowout preventer, close choke], or [□ close blowout preventer, open choke line with choke closed, and observe casing pressure]. Do not exceed Maximum Allowable Casing Pressure *(2)*. Check for trapped pressure and record the following:
Closed-in Drill Pipe Pressure__________ psi, Casing Pressure __________ psi, Drilling Fluid Density __________ lb/gal,
Depth (TVD) __________ ft, Kick Volume __________ bbl.

III. ESTABLISH CIRCULATION

Open choke while bringing pump up to Kill Rate. Increase pump rate slowly, if possible.
Adjust choke to hold Casing Pressure constant at closed-in value while bringing pump to Kill Rate. Hold Kill Rate constant.
The observed Drill Pipe Pressure should be equal to the Calculated Initial Circulating Pressure *(4)*. When approximately equal, use the choke to adjust the observed drill pipe pressure to the calculated pressure. If widely divergent, close in the well and consider alternatives.
Record time when circulation started __________ hrs __________min.

IV. CIRCULATE OUT THE KICK

While holding Kill Rate constant, keep Drill Pipe Pressure constant by adjusting choke. If Drill Pipe Pressure increases, open choke. If Drill Pipe Pressure decreases, close choke. Casing Pressure must be allowed to vary to maintain constant bottom-hole pressure. When well is free of gas, salt water, and oil, stop pump and close choke. Record New Closed-in Casing Pressure __________ psi.

V. INCREASE DRILLING FLUID DENSITY

Calculate the Required Drilling Fluid Density *(5)* and increase fluid density in the suction pit *(6)*.

VI. CIRCULATE HEAVY DRILLING FLUID

Establish circulation as per item III, using New Closed-in casing Pressure plus 100 psi. †
Hold Kill Rate constant and hold New Casing Pressure constant by adjusting the choke.
Maintain required drilling fluid density in pits while circulating.
Circulate heavy drilling fluid to bit as determined by time or strokes *(7) (8)*.
When heavy drilling fluid reaches bit, read and record Final Drill Pipe Circulating Pressure __________ psi.
Hold Final Drill Pipe Pressure constant by varying choke while holding Kill Rate constant.
After uncut heavy drilling fluid reaches the surface, shut down pump and check for flow.

CALCULATIONS AND NOTES

(1) A. Fracture Drilling Fluid Density $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}}$ + Leak-off Test Drilling Fluid Density

$= \dfrac{\_\_\_\_\_\_\ \text{psi}}{.052 \times \_\_\_\_\_\_\ \text{ft}}$ + ______ lb/gal = _______ lb/gal.

B. Fracture Pressure = .052 x Casing Depth x (Fracture Drilling Fluid Density – Present Drilling Fluid Density)

= .052 x _______ ft x (______ lb/gal – _______ lb/gal) = ______ psi.

(2) If casing pressure reaches maximum allowed, follow the Contingency Procedure.

(3) Measure daily while drilling or after a significant change in circulating system pressure.

(4) Calculated Initial Circulating Pressure = Kill Rate Pressure plus Closed-in Drill Pipe Pressure.

= _______ psi + ______ psi = ______ psi.

(5) Required Drilling Fluid Density $= \dfrac{\text{Closed-in Drill Pipe Pressure}}{.052 \times \text{Bit Depth (TVD)}}$ + Present Drilling Fluid Density + Trip Margin †

$= \dfrac{\_\_\_\_\_\_\ \text{psi}}{.052 \times \_\_\_\_\_\_\ \text{ft}}$ + _______ lb/gal + _______ lb/gal † = ______ lb/gal.

(6) If two sections or two pits are weighted and reverse circulation established between, drilling fluid density is more evenly controlled while circulating the hole.

(7) Circulating Time To Bit $= \dfrac{\text{Drill Pipe Capacity} \times \text{Drill String Length}}{\text{Kill Rate}}$

$= \dfrac{\_\_\_\_\_\_\ \text{bbl/ft} \times \_\_\_\_\_\_\ \text{ft}}{\_\_\_\_\_\_\ \text{bpm}}$ = __________ min.

(8) Strokes To Bit = Kill Rate x Time = _________ stks/min. x __________ min. =__________ stks.

*Notes: *Considering pump efficiency.*

† *Trip Margin and Safety Factor may be omitted, but these give little risk of loss and circulation as the open hole and casing seal are subjected to higher pressures when circulating out the kick. If Trip Margin is used, when heavy drilling fluid nears the surface the choke will be wide open and the Final Drill Pipe Circulation Pressure can no longer be controlled. The Drill Pipe Pressure will slowly increase to compensate for the Trip Margin. Trip Margins range from 0.0 to 0.3 lb/gal for hole sizes greater than 7-in. diameter and from 0.0 to 0.5 lb/gal for smaller holes.*

(over)

API RECOMMENDED
WELL CONTROL WORKSHEET
DRILLERS METHOD

COMPANY	WELL
DATE	DEPTH

PREPARED BY: ______________________________ **COMPANY** ______________________________

CAPACITY AND DISPLACEMENT OF DRILL PIPE

Drill Pipe *(1)*				Tool Joint			Average	Capacity			Displacement	
		Weight					Overall					
O.D., in.	Upset	Nominal (lb/ft)	Approx. (lb/ft) *(2)*	Name	NC No.	O.D. in.	Joint Length, ft. *(4)*	Barrels Per Foot	Barrels Per 3-Joint Stand	Feet Per Barrel	Barrels Per Foot *(5)*	Barrels Per 3-Joint Stand
$2\frac{7}{8}$	I.U.	10.40	10.28	Slim Hole	26	$3\frac{3}{8}$	30.64	0.00440	0.404	227.5	0.00374	0.344
$2\frac{7}{8}$	E.U.	10.40	10.76	I.F.	31	$4\frac{1}{8}$	30.74	0.00449	0.414	222.7	0.00392	0.361
$3\frac{1}{2}$	I.U.	13.30	13.40	Slim Hole	31	$4\frac{1}{8}$	30.86	0.00723	0.669	138.4	0.00488	0.452
$3\frac{1}{2}$	E.U.	13.30	14.77	I.F.	38	$4\frac{3}{4}$	30.94	0.00739	0.686	135.4	0.00501	0.465
$3\frac{1}{2}$	E.U.	15.50	16.39	I.F.	38	5	30.99	0.00657	0.611	152.3	0.00596	0.554
4	E.U.	14.00	15.85	I.F.	46	6	31.10	0.01081	1.008	92.6	0.00577	0.538
$4\frac{1}{2}$	E.U.	16.60	18.98	I.F.	50	$6\frac{3}{8}$	31.07	0.01419	1.323	70.5	0.00691	0.644
$4\frac{1}{2}$	I.E.U.	16.60	17.81	H-90		6	31.06	0.01394	1.292	71.7	0.00648	0.604
$4\frac{1}{2}$	I.E.U.	16.60	18.37	X.H.	46	$6\frac{1}{4}$	31.11	0.01394	1.301	71.8	0.00668	0.624
$4\frac{1}{2}$	E.U.	20.00	21.62	I.F.	50	$6\frac{3}{8}$	31.07	0.01287	1.200	77.3	0.00786	0.733
$4\frac{1}{2}$	I.E.U.	20.00	22.09	X.H.	46	$6\frac{1}{4}$	31.11	0.01257	1.173	79.5	0.00804	0.750
5	I.E.U.	19.50	20.89	X.H.	50	$6\frac{3}{8}$	31.05	0.01746	1.626	57.3	0.00760	0.708
5	I.E.U.	25.60	26.89	X.H.	50	$6\frac{3}{8}$	31.05	0.01528	1.423	65.5	0.00979	0.912
$5\frac{1}{2}$	I.E.U.	21.90	23.77	F.H.	*(3)*	7	31.17	0.02169	2.028	46.1	0.00865	0.809
$5\frac{1}{2}$	I.E.U.	24.70	26.33	F.H.	*(3)*	7	31.17	0.02077	1.942	48.2	0.00958	0.896

(1) Grade E drill pipe.
(2) Table 2.10, API RP 7G: Recommended Practice for Drill Stem Design and Operating Limits, Twelfth Edition, May 1987.
(3) Obsolete tool joint.
(4) Based on an average pipe length of 29.4 feet before adding tool joints.
(5) The approximate weight per foot is converted to barrels using steel density of 489.54 lb/ft^3 and volume of one barrel equal to 5.61458 ft^3.

* * * * * *

BARITE REQUIREMENTS

Sacks/100 bbl = $\dfrac{\text{1470 x (Required Drilling Fluid Density – Present Drilling Fluid Density)}}{\text{(35 – Required Drilling Fluid Density)}}$

= $\dfrac{\text{1470 x (\_\_\_\_\_ lb/gal – \_\_\_\_\_\_ lb/gal)}}{\text{(35 – \_\_\_\_\_\_ lb/gal)}}$ = __________ sx/100 bbl.

Barite Required = $\dfrac{\text{Drilling Fluid Volume x Sacks/100 bbl}}{100}$ = $\dfrac{\text{\_\_\_\_\_\_ bbl x \_\_\_\_\_ sx/100 bbl.}}{100}$ = ____ sx.

Required Mixing Rate = $\dfrac{\text{Sacks/100 bbl x Kill Rate}}{100}$ = $\dfrac{\text{\_\_\_\_\_ sx/100 bbl x \_\_\_\_\_ bpm}}{100}$ = ______ sx/min.

DILUTION OF RESERVE DRILLING FLUID WITH WATER

Barrels Water = $\dfrac{\text{(Present Drilling Fluid Density – Desired Drilling Fluid Density) x Present Drilling Fluid Volume}}{\text{(Desired Drilling Fluid Density – 8.34)}}$

= $\dfrac{\text{(\_\_\_\_ lb/gal – \_\_\_\_\_\_\_ lb/gal) x \_\_\_\_\_\_ bbl.}}{\text{(\_\_\_\_\_ lb/gal – 8.34)}}$ = _____ bbl.

Displacement of Duplex, Double-acting Pumps

(90 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = $.0001619\ L\ [2D^2 - d^2]$ (Eff.)

Where: L = Stroke length, in.
D = Liner diameter, in.
d = Rod diameter, in.
Eff. = Volumetric efficiency, decimal fraction.

Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.
16	5	$2\frac{1}{2}$	.102	18	5	$2\frac{1}{2}$	.115
16	$5\frac{1}{2}$	$2\frac{1}{2}$	.126	18	$5\frac{1}{2}$	$2\frac{1}{2}$	.142
16	6	$2\frac{1}{2}$	.153	18	6	$2\frac{1}{2}$	.172
16	$6\frac{1}{2}$	$2\frac{1}{2}$	.182	18	$6\frac{1}{2}$	$2\frac{1}{2}$	.205
16	7	$2\frac{1}{2}$	.214	18	7	$2\frac{1}{2}$	.241
16	$7\frac{1}{2}$	$2\frac{1}{2}$	.248	18	$7\frac{1}{2}$	$2\frac{1}{2}$	.279
16	8	$2\frac{1}{2}$	.284	18	8	$2\frac{1}{2}$	.319
16	6	3	.147	18	6	3	.165
16	$6\frac{1}{2}$	3	.176	18	$6\frac{1}{2}$	3	.198
16	7	3	.207	18	7	3	.233
16	$7\frac{1}{2}$	3	.241	18	$7\frac{1}{2}$	3	.271
16	8	3	.277	18	8	3	.312
16	$8\frac{1}{2}$	3	.316	18	6	$3\frac{1}{2}$	.157
16	6	$3\frac{1}{2}$	.139	18	$6\frac{1}{2}$	$3\frac{1}{2}$	.190
16	$6\frac{1}{2}$	$3\frac{1}{2}$	.168	18	7	$3\frac{1}{2}$	.225
16	7	$3\frac{1}{2}$	.200	18	$7\frac{1}{2}$	$3\frac{1}{2}$	.263
16	$7\frac{1}{2}$	$3\frac{1}{2}$	.234	18	8	$3\frac{1}{2}$	.304
16	8	$3\frac{1}{2}$	.270				

Displacement of Triplex, Single-acting Pumps

(100 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = $.000243 \times L \times D^2$

Where: L = Stroke length, in.
D = Liner diameter, in.

Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.
7	3	.0153	9	$3\frac{1}{2}$	.0268
7	$3\frac{1}{2}$	.0208	9	4	.0350
7	4	.0272	9	$4\frac{1}{2}$	.0443
7	$4\frac{1}{2}$	.0344	9	5	.0546
7	5	.0425	9	$5\frac{1}{2}$	.0661
7	$5\frac{1}{2}$	.0514	9	6	.0787
7	6	.0612	10	$4\frac{1}{2}$	.0492
7	$6\frac{1}{2}$	.0718	10	5	.0607
7	7	.0833	10	$5\frac{1}{2}$	.0735
8	$4\frac{1}{2}$	.0393	10	6	.0874
8	5	.0486	10	$6\frac{1}{2}$	.1026
8	$5\frac{1}{2}$	.0588	12	5	.0729
8	6	.0699	12	$5\frac{1}{2}$	.0882
8	$6\frac{1}{2}$	.0821	12	6	.1049
			12	$6\frac{1}{2}$	.1231
			12	7	.1428

WELL NAME	CONTRACTOR
DATE	RIG

API RECOMMENDED WELL CONTROL WORKSHEET WAIT AND WEIGHT METHOD

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size __________ in., Weight __________lb/ft, Grade __________, Internal Yield __________ psi, Depth (TVD) __________ ft
Mechanical Pressure Limit __________ psi
Casing Pressure to Cause Fracture__________psi *(1)*, based on present drilling fluid density of __________ lb/gal.
Maximum Allowable Casing Pressure: Initial Closure______ psi
Entire Well Kill_____ psi } Approved by: ______________________________
(Name)
Contingency Procedure *(2)* if casing pressure reaches maximum approved: ______________________________

Normal Circulating Pressure and Rate: __________ psi at __________ stks/min. and __________ bpm* at __________ lb/gal and __________ ft
Kill Pressure and Rate: Pump No. 1, __________ psi at __________ stks/min. and __________ bpm* at __________ lb/gal and ________ ft *(3)*
Pump No. 2, __________ psi at __________ stks/min. and __________ bpm* at __________ lb/gal and ________ ft *(3)*
Drill Pipe Capacity:__________ bbl/ft

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump. [□ open choke line and choke, close blowout preventer, close choke], or [□ close blowout preventer, open choke line with choke closed, and observe casing pressure]. Do not exceed Maximum Allowable Casing Pressure *(2)*. Check for trapped pressure and record the following:
Closed-in Drill Pipe Pressure__________ psi, Casing Pressure__________ psi, Drilling Fluid Density__________ lb/gal,
Depth (TVD)__________ ft, Kick Volume__________ bbl.

III. INCREASE DRILLING FLUID DENSITY

Calculate the Required Drilling Fluid Density *(4)* and increase fluid density in the suction pit *(5)*, *(6)*.

IV. PREPARE DRILL PIPE PRESSURE SCHEDULE

Determine Initial Circulation Pressure and plot above zero time *(7)*.
Determine Final Circulating Pressure *(8)* and plot above Circulating Time To Bit *(9)*.
Draw a line between the points.
Read Drill Pipe Pressure at 5-minute intervals and record in blank spaces.
Calculate Strokes To Bit *(10)* and fill in the blanks below the drill pipe pressure schedule chart.

V. ESTABLISH CIRCULATION

Open choke while bringing pump up to Kill Rate. Increase pump rate slowly, if possible.
Adjust choke to hold Casing Pressure constant at closed-in value while bringing pump to Kill Rate. Hold Kill Rate constant.
The observed Drill Pipe Pressure should be equal to the Calculated Initial Circulating Pressure *(7)*. When approximately equal, use the choke to adjust the observed drill pipe pressure to the calculated pressure. If widely divergent, close in the well and consider alternatives.
Record the drill Pipe Pressure at __________ psi at__________ stks/min. and__________ bpm.
Record time when circulation started __________ hrs __________ min.

VI. CIRCULATE HEAVY DRILLING FLUID

Maintain drilling fluid density in suction pits while circulating at Kill Rate.
Use choke to adjust Drill Pipe Pressure to values recorded at times or strokes shown on drill pipe pressure schedule.
If Drill Pipe Pressure increases, open the choke; if Drill Pipe Pressure decreases, close the choke.
After heavy drilling fluid reaches bit *(9)* *(10)*, hold Drill Pipe Pressure constant until uncut drilling fluid of required density reaches the surface. Stop circulation and check for flow.

CALCULATIONS AND NOTES

(1) A. Fracture Drilling Fluid Density $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}}$ + Leak-off Test Drilling Fluid Density

$= \dfrac{\_\_\_\_\_\_ \text{ psi}}{.052 \times \_\_\_\_\_\_ \text{ ft}}$ + ______ lb/gal = ______ lb/gal.

B. Fracture Pressure = .052 x Casing Depth x (Fracture Drilling Fluid Density – Present Drilling Fluid Density)

= .052 x ________ ft x (______ lb/gal – ______ lb/gal) =_____ psi.

(2) If casing pressure reaches maximum allowed, follow the Contingency Procedure.

(3) Measure daily while drilling or after a significant change in circulating system pressure.

(4) Required Drilling Fluid Density $= \dfrac{\text{Closed-in Drill Pipe Pressure}}{.052 \times \text{Bit Depth (TVD)}}$ + Present Drilling Fluid Density + Trip Margin †

$= \dfrac{\_\_\_\_\_\_ \text{ psi}}{.052 \times \_\_\_\_\_\_ \text{ ft}}$ + ________ lb/gal + ________ lb/gal † = _______ lb/gal.

(5) If two sections or two pits are weighted and reverse circulation established between, drilling fluid density is more evenly controlled while circulating the hole.

(6) If drill pipe pressure increases during weighting, reduce to initial stabilized value by bleeding through the choke.

(7) Calculated Initial Circulating Pressure = Kill Rate Pressure plus Closed-in Drill Pipe Pressure.

= ______ psi + ______ psi = ______ psi.

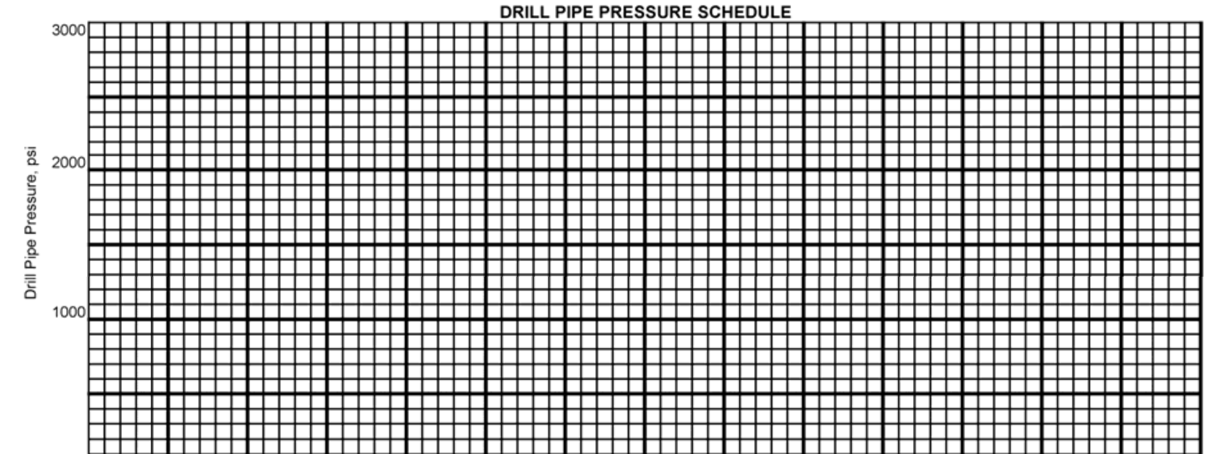
(8) Final Circulating Pressure = Kill Rate Pressure x $\dfrac{\text{Required Drilling Fluid Density}}{\text{Original Drilling Fluid Density}}$ = _____ psi x $\dfrac{\_\_\_\_\_\_ \text{ lb/gal}}{\_\_\_\_\_\_ \text{ lb/gal}}$ =_______ psi.

(9) Circulating Time To Bit $= \dfrac{\text{Drill Pipe Capacity} \times \text{Drill String Length}}{\text{Kill Rate}} = \dfrac{\_\_\_\_\_\_ \text{ bbl/ft} \times \_\_\_\_\_\_ \text{ ft}}{\_\_\_\_\_\_ \text{ bpm}}$ = ______ min.

(10) Strokes To Bit = Kill Rate x Time =__________stks/min. x __________ min. =__________ stks.

Notes: **Considering pump efficiency.*
† Trip Margins range from 0.0 to 0.3 lb/gal for hole sizes greater than 7-in. diameter and from 0.0 to 0.5 lb/gal for smaller holes.

DRILL PIPE PRESSURE SCHEDULE



Time, min.	0	5	10	15	20	25	30	35	40	45	50	55	60	65	70
Drill Pipe Pressure, psi															
Strokes															

API RECOMMENDED
WELL CONTROL WORKSHEET

WAIT AND WEIGHT METHOD

COMPANY	WELL
DATE	DEPTH

PREPARED BY: ______________________ **COMPANY** ________________________________

CAPACITY AND DISPLACEMENT OF DRILL PIPE

Drill Pipe (1)				Tool Joint				Capacity			Displacement	
		Weight										
O.D., in.	Upset	Nominal (lb/ft)	Approx. (lb/ft) *(2)*	Name	NC No.	O.D., in.	Average Overall Joint Length, ft. *(4)*	Barrels Per Foot	Barrels Per 3-Joint Stand	Feet Per Barrel	Barrels Per Foot *(5)*	Barrels Per 3-Joint Stand
2 7/8	I.U.	10.40	10.28	Slim Hole	26	3 3/8	30.64	0.00440	0.404	227.5	0.00374	0.344
2 7/8	E.U.	10.40	10.76	I.F.	31	4 1/8	30.74	0.00449	0.414	222.7	0.00392	0.361
3 1/2	I.U.	13.30	13.40	Slim Hole	31	4 1/8	30.86	0.00723	0.669	138.4	0.00488	0.452
3 1/2	E.U.	13.30	14.77	I.F.	38	4 3/4	30.94	0.00739	0.686	135.4	0.00501	0.465
3 1/2	E.U.	15.50	16.39	I.F.	38	5	30.99	0.00657	0.611	152.3	0.00596	0.554
4	E.U.	14.00	15.85	I.F.	46	6	31.10	0.01081	1.008	92.6	0.00577	0.538
4 1/2	E.U.	16.60	18.98	I.F.	50	6 3/8	31.07	0.01419	1.323	70.5	0.00691	0.644
4 1/2	I.E.U.	16.60	17.81	H-90		6	31.06	0.01394	1.292	71.7	0.00648	0.604
4 1/2	I.E.U.	16.60	18.37	X.H.	46	6 1/4	31.11	0.01394	1.301	71.8	0.00668	0.624
4 1/2	E.U.	20.00	21.62	I.F.	50	6 3/8	31.07	0.01287	1.200	77.3	0.00786	0.733
4 1/2	I.E.U.	20.00	22.09	X.H.	46	6 1/4	31.11	0.01257	1.173	79.5	0.00804	0.750
5	I.E.U.	19.50	20.89	X.H.	50	6 3/8	31.05	0.01746	1.626	57.3	0.00760	0.708
5	I.E.U.	25.60	26.89	X.H.	50	6 3/8	31.05	0.01528	1.423	65.5	0.00979	0.912
5 1/2	I.E.U.	21.90	23.77	F.H.	*(3)*	7	31.17	0.02169	2.028	46.1	0.00865	0.809
5 1/2	I.E.U.	24.70	26.33	F.H.	*(3)*	7	31.17	0.02077	1.942	48.2	0.00958	0.896

(1) Grade E drill pipe.
(2) Table 2.10, API RP 7G: Recommended Practice for Drill Stem Design and Operating Limits, Twelfth Edition, May 1987.
(3) Obsolete tool joint.
(4) Based on an average pipe length of 29.4 feet before adding tool joints.
(5) The approximate weight per foot is converted to barrels using steel density of 489.54 lb/ft^3 and volume of one barrel equal to 5.61458 ft^3.

****

BARITE REQUIREMENTS

Sacks/100 bbl = $\dfrac{\text{1470 x (Required Drilling Fluid Density – Present Drilling Fluid Density)}}{\text{(35 – Required Drilling Fluid Density)}}$

= $\dfrac{\text{1470 x (\_\_\_\_\_\_ lb/gal – \_\_\_\_\_\_ lb/gal)}}{\text{(35 – \_\_\_\_\_\_ lb/gal)}}$ = ________ sx/100 bbl.

Barite Required = $\dfrac{\text{Drilling Fluid Volume x Sacks/100 bbl}}{100}$ = $\dfrac{\text{\_\_\_\_\_\_ bbl x \_\_\_\_\_\_ sx/100 bbl}}{100}$ = ________ sx.

Required Mixing Rate = $\dfrac{\text{Sacks/100 bbl x Kill Rate}}{100}$ = $\dfrac{\text{\_\_\_\_\_\_ sx/100 bbl x \_\_\_\_\_\_ bpm}}{100}$ = ____ sx/min.

DILUTION OF RESERVE DRILLING FLUID WITH WATER

Barrels Water = $\dfrac{\text{(Present Drilling Fluid Density – Desired Drilling Fluid Density) x Present Drilling Fluid Volume}}{\text{(Desired Drilling Fluid Density – 8.34)}}$

= $\dfrac{\text{(\_\_\_\_\_\_ lb/gal – \_\_\_\_\_\_ lb/gal) x \_\_\_\_\_\_ bbl}}{\text{(\_\_\_\_\_\_ lb/gal – 8.34)}}$ = _______ bbl.

Displacement of Duplex, Double-acting Pumps

(90 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = 0001619 L [2D^2 – d^2] (Eff.)
Where: L = Stroke length, in.
D = Liner diameter, in.
d = Rod diameter, in.
Eff. = Volumetric efficiency, decimal fraction.

Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.
16	5	2 1/2	.102	18	5	2 1/2	.115
16	5 1/2	2 1/2	.126	18	5 1/2	2 1/2	.142
16	6	2 1/2	.153	18	6	2 1/2	.172
16	6 1/2	2 1/2	.182	18	6 1/2	2 1/2	.205
16	7	2 1/2	.214	18	7	2 1/2	.241
16	7 1/2	2 1/2	.248	18	7 1/2	2 1/2	.279
16	8	2 1/2	.284	18	8	2 1/2	.319
16	6	3	.147	18	6	3	.165
16	6 1/2	3	.176	18	6 1/2	3	.198
16	7	3	.207	18	7	3	.233
16	7 1/2	3	.241	18	7 1/2	3	.271
16	8	3	.277	18	8	3	.312
16	8 1/2	3	.316	18	6	3 1/2	.157
16	6	3 1/2	.139	18	6 1/2	3 1/2	.190
16	6 1/2	3 1/2	.168	18	7	3 1/2	.225
16	7	3 1/2	.200	18	7 1/2	3 1/2	.263
16	7 1/2	3 1/2	.234	18	8	3 1/2	.304
16	8	3 1/2	.270				

Displacement of Triplex, Single-acting Pumps

(100 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = 000243 x L x D^2
Where: L = Stroke length, in.
D = Liner diameter, in.

Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.
7	3	.0153	9	3 1/2	.0268
7	3 1/2	.0208	9	4	.0350
7	4	.0272	9	4 1/2	.0443
7	4 1/2	.0344	9	5	0546
7	5	.0425	9	5 1/2	.0661
7	5 1/2	.0514	9	6	.0787
7	6	.0612	10	4 1/2	.0492
7	6 1/2	.0718	10	5	.0607
7	7	.0833	10	5 1/2	.0735
8	4 1/2	.0393	10	6	.0874
8	5	.0486	10	6 1/2	.1026
8	5 1/2	.0588	12	5	.0729
8	6	.0699	12	5 1/2	.0882
8	6 1/2	.0821	12	6	.1049
			12	6 1/2	.1231
			12	7	.1428

WELL NAME
DATE

API RECOMMENDED
WELL CONTROL WORKSHEET
CONCURRENT METHOD

CONTRACTOR
RIG

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size ___________ in., Weight ___________ lb/ft, Grade ___________, Internal Yield ___________ psi, Depth (TVD) __________ ft
Mechanical Pressure Limit__________psi
Casing Pressure to Cause Fracture__________psi *(1)*, based on present drilling fluid density of __________ lb/gal.
Maximum Allowable Casing Pressure: Initial Closure __________ psi
Entire Well Kill _________ psi } Approved by:______________________________
(Name)

Contingency Procedure *(2)* if casing pressure reaches maximum approved: ____
____

____

Normal Circulating Pressure and Rate: __________ psi at _________ stks/min. and __________ bpm* at ________ lb/gal and __________ ft
Kill Pressure and Rate: Pump No. 1, ___________ psi at _________ stks/min. and __________ bpm* at ________ lb/gal and ________ ft *(3)*
Pump No. 2, ___________ psi at _________ stks/min. and __________ bpm* at ________ lb/gal and ________ ft *(3)*
Drill Pipe Capacity:____________ bbl/ft

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump. [□ open choke line and choke, close blowout preventer, close choke], or [□ close blowout preventer, open choke line with choke closed, and observe casing pressure]. Do not exceed Maximum Allowable Casing Pressure *(2)*. Check for trapped pressure and record the following:
Closed-in Drill Pipe Pressure__________ psi, Casing Pressure__________ psi, Drilling Fluid Density__________ lb/gal,
Depth (TVD)__________ ft, Kick Volume__________ bbl.

III. ESTABLISH CIRCULATION

Open choke while bringing pump up to Kill Rate. Increase pump rate slowly, if possible.
Adjust choke to hold Casing Pressure constant at closed-in value while bringing pump to Kill Rate. Hold Kill Rate constant.
The observed Drill Pipe Pressure should be equal to the Calculated Initial Circulating Pressure *(4)*. When approximately equal, use the choke to adjust the observed Drill Pipe Pressure to the calculated pressure. If widely divergent, close the well and consider alternatives.
Record time when circulation started __________ hrs __________min.

IV. INCREASE DRILLING FLUID DENSITY

Record time or strokes at which fluid in the suction pit is increased each 0.1 or 0.2 lb/gal on graph *(5)*.
Calculate Required Drilling Fluid Density *(6)*.

V. PREPARE DRILL PIPE PRESSURE SCHEDULE

Fill in bottom of graph with even increments of drilling fluid density from Initial to Required Drilling Fluid Density.
Plot Initial Circulating Pressure *(4)* above Initial Drilling Fluid Density.
Determine Final Circulating Pressure *(7)* and plot above Required Drilling Fluid Density *(6)*.
Draw a line between the points.
Read Drill Pipe Pressure at each increment of drilling fluid density and record in blank spaces.
Calculate Circulating Time *(8)* (or strokes) *(9)* to Bit.
Fill blank spaces with 1/2 Circulating Time (or strokes) to Bit.
Add 1/2 Circulating Time (or strokes) to Bit to time (or strokes) for each drilling fluid density increment.

VI. KILLING THE WELL

Hold Drill Pipe Pressures shown for each drilling fluid density increment at times (or strokes) shown by adjusting choke, while holding Kill Rate constant.
After Required Drilling Fluid Density *(6)* reaches the bit, hold Final Circulating Pressure *(7)* constant until uncut drilling fluid of required drilling density reaches surface, stop circulating and check for flow.

CALCULATIONS AND NOTES

(1) A. Fracture Drilling Fluid Density $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}} +$ Leak-off Test Drilling Fluid Density $= \dfrac{\_\_\_\_\text{ psi}}{.052 \times \_\_\_\text{ ft}} + \_\_\text{lb/gal} = \_\_\text{lb/gal.}$

B. Fracture Pressure = .052 x Casing Depth x (Fracture Drilling Fluid Density – Present Drilling Fluid Density)

= .052 x __________ ft x (__________ lb/gal – __________ lb/gal) =__________ psi.

(2) If casing pressure reaches maximum allowed, follow the Contingency Procedure.

(3) Measure daily while drilling or after a significant change in circulating system pressure.

(4) Calculated Initial Circulating Pressure = Kill Rate Pressure plus Closed-in Drill Pipe Pressure

= _______ psi + ______ psi =______ psi.

(5) If two sections or two pits are weighted and reverse circulation established between, drilling fluid density is more evenly controlled while circulating the hole.

(6) Required Drilling Fluid Density $= \dfrac{\text{Closed-in Drill Pipe Pressure}}{.052 \times \text{Bit Depth (TVD)}} +$ Present Drilling Fluid Density + Trip Margin †

$= \dfrac{\_\_\_\_\_\_\text{ psi}}{.052 \times \_\_\_\_\_\_\text{ ft}} + \_\_\_\_\_\_\_\text{ lb/gal} + 0.3\text{ lb/gal †} = \text{lb/gal.}$

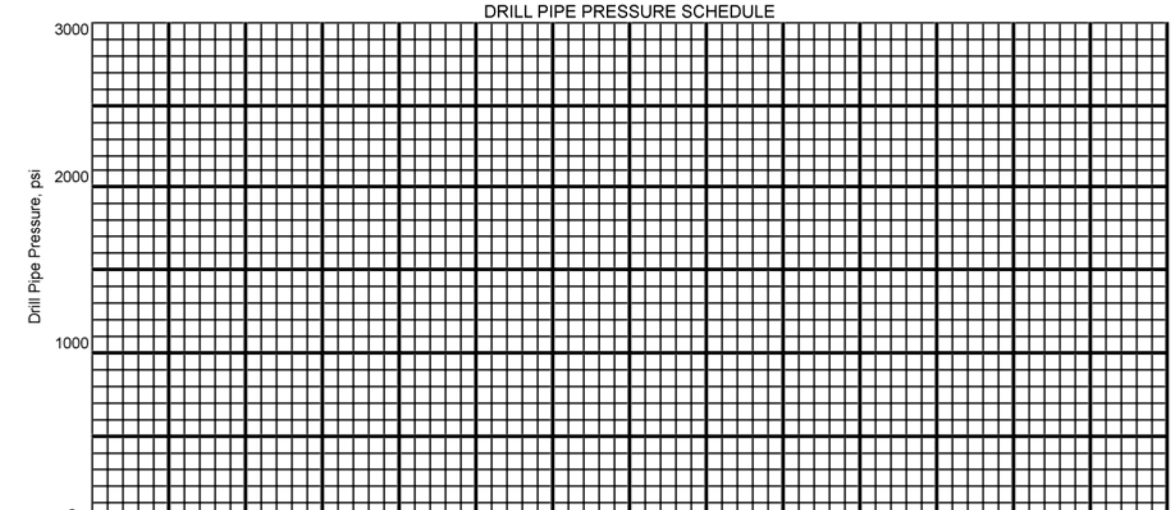
(7) Final Circulating Pressure = Kill Rate Pressure $\times \dfrac{\text{Required Drilling Fluid Density}}{\text{Original Drilling Fluid Density}} = \_\_\_\text{ psi} \times \dfrac{\_\_\_\_\_\text{ lb/gal}}{\_\_\_\_\_\text{ lb/gal}} = \_\_\_\_\_\_\text{ psi.}$

(8) Circulating Time To Bit $= \dfrac{\text{Drill Pipe Capacity} \times \text{Drill String Length}}{\text{Kill Rate}} = \dfrac{\_\_\_\_\_\_\text{ bbl/ft} \times \_\_\_\_\_\_\text{ ft.}}{\_\_\_\_\_\_\_\_\text{ bpm}} = \_\_\_\_\_\_\_\_\text{ min.}$

(9) Strokes To Bit = Kill Rate x Time = ________ stks/min. x __________ min. =__________ stks.

*Notes:*Considering pump efficiency.*
† Trip Margins range from 0.0 to 0.3 lb/gal for hole sizes greater than 7-in. diameter and from 0.0 to 0.5 lb/gal for smaller holes.

DRILL PIPE PRESSURE SCHEDULE



Drilling Fluid Density, lb/gal															
Drill Pipe Pressure, psi															
Time, min. or Strokes															
1/2 Time or 1/2 Strokes to Bit															
Total Time or Strokes															

(over)

API RECOMMENDED
WELL CONTROL WORKSHEET

CONCURRENT METHOD

COMPANY	WELL
DATE	DEPTH

PREPARED BY: ______________________________COMPANY ______________________________

CAPACITY AND DISPLACEMENT OF DRILL PIPE

Drill Pipe *(1)*				Tool Joint				Capacity			Displacement	
		Weight										
O.D., in.	Upset	Nominal (lb/ft)	Approx. (lb/ft) *(2)*	Name	NC No.	O.D., in.	Average Overall Joint Length, ft. *(4)*	Barrels Per Foot	Barrels Per 3-Joint Stand	Feet Per Barrel	Barrels Per Foot *(5)*	Barrels Per 3-Joint Stand
$2\frac{7}{8}$	I.U.	10.40	10.28	Slim Hole	26	$3\frac{3}{8}$	30.64	0.00440	0.404	227.5	0.00374	0.344
$2\frac{7}{8}$	E.U.	10.40	10.76	I.F.	31	$4\frac{1}{8}$	30.74	0.00449	0.414	222.7	0.00392	0.361
$3\frac{1}{2}$	I.U.	13.30	13.40	Slim Hole	31	$4\frac{1}{8}$	30.86	0.00723	0.669	138.4	0.00488	0.452
$3\frac{1}{2}$	E.U.	13.30	14.77	I.F.	38	$4\frac{3}{4}$	30.94	0.00739	0.686	135.4	0.00501	0.465
$3\frac{1}{2}$	E.U.	15.50	16.39	I.F.	38	5	30.99	0.00657	0.611	152.3	0.00596	0.554
4	E.U.	14.00	15.85	I.F.	46	6	31.10	0.01081	1.008	92.6	0.00577	0.538
$4\frac{1}{2}$	E.U.	16.60	18.98	I.F.	50	$6\frac{3}{8}$	31.07	0.01419	1.323	70.5	0.00691	0.644
$4\frac{1}{2}$	I.E.U.	16.60	17.81	H-90		6	31.06	0.01394	1.292	71.7	0.00648	0.604
$4\frac{1}{2}$	I.E.U.	16.60	18.37	X.H.	46	$6\frac{1}{4}$	31.11	0.01394	1.301	71.8	0.00668	0.624
$4\frac{1}{2}$	E.U.	20.00	21.62	I.F.	50	$6\frac{3}{8}$	31.07	0.01287	1.200	77.3	0.00786	0.733
$4\frac{1}{2}$	I.E.U.	20.00	22.09	X.H.	46	$6\frac{1}{4}$	31.11	0.01257	1.173	79.5	0.00804	0.750
5	I.E.U.	19.50	20.89	X.H.	50	$6\frac{3}{8}$	31.05	0.01746	1.626	57.3	0.00760	0.708
5	I.E.U.	25.60	26.89	X.H.	50	$6\frac{3}{8}$	31.05	0.01528	1.423	65.5	0.00979	0.912
$5\frac{1}{2}$	I.E.U.	21.90	23.77	F.H.	*(3)*	7	31.17	0.02169	2.028	46.1	0.00865	0.809
$5\frac{1}{2}$	I.E.U.	24.70	26.33	F.H.	*(3)*	7	31.17	0.02077	1.942	48.2	0.00958	0.896

(1) Grade E drill pipe.
(2) Table 2.10, API RP 7G: Recommended Practice for Drill Stem Design and Operating Limits, Twelfth Edition, May 1987.
(3) Obsolete tool joint.
(4) Based on an average pipe length of 29.4 feet before adding tool joints.
(5) The approximate weight per foot is converted to barrels using steel density of 489.54 lb/ft^3 and volume of one barrel equal to 5.61458 ft^3.

****

BARITE REQUIREMENTS

Sacks/100 bbl = $\dfrac{\text{1470 x (Required Drilling Fluid Density – Present Drilling Fluid Density)}}{\text{(35 – Required Drilling Fluid Density)}}$

= $\dfrac{\text{1470 x (\_\_\_\_\_\_ lb/gal – \_\_\_\_\_\_ lb/gal)}}{\text{(35 – \_\_\_\_\_\_ lb/gal)}}$ = ______________ sx/100 bbl.

Barite Required = $\dfrac{\text{Drilling Fluid Volume x Sacks/100 bbl}}{100}$ = $\dfrac{\text{\_\_\_\_\_\_ bbl x \_\_\_\_\_\_ sx/100 bbl}}{100}$ = ______ sx.

Required Mixing Rate = $\dfrac{\text{Sacks/100 bbl x Kill Rate}}{100}$ = $\dfrac{\text{\_\_\_\_\_\_ sx/100 bbl x \_\_\_\_\_\_ bpm}}{100}$ = ______ sx/min.

DILUTION OF RESERVE DRILLING FLUID WITH WATER

Barrels Water = $\dfrac{\text{(Present Drilling Fluid Density – Desired Drilling Fluid Density) x Present Drilling Fluid Volume}}{\text{(Desired Drilling Fluid Density – 8.34)}}$

= $\dfrac{\text{(\_\_\_\_\_\_ lb/gal – \_\_\_\_\_\_ lb/gal) x \_\_\_\_\_\_ bbl}}{\text{(\_\_\_\_\_\_ lb/gal – 8.34)}}$ = ______ bbl.

Displacement of Duplex, Double-acting Pumps

(90 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = $.0001619\ L\ [2D^2 - d^2]\ (\text{Eff.})$
Where: L = Stroke length, in.
D = Liner diameter, in.
d = Rod diameter, in.
Eff. = Volumetric efficiency, decimal fraction.

Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.
16	5	$2\frac{1}{2}$	.102	18	5	$2\frac{1}{2}$	.115
16	$5\frac{1}{2}$	$2\frac{1}{2}$	.126	18	$5\frac{1}{2}$	$2\frac{1}{2}$	.142
16	6	$2\frac{1}{2}$	.153	18	6	$2\frac{1}{2}$	.172
16	$6\frac{1}{2}$	$2\frac{1}{2}$	.182	18	$6\frac{1}{2}$	$2\frac{1}{2}$	.205
16	7	$2\frac{1}{2}$	.214	18	7	$2\frac{1}{2}$	.241
16	$7\frac{1}{2}$	$2\frac{1}{2}$	.248	18	$7\frac{1}{2}$	$2\frac{1}{2}$	.279
16	8	$2\frac{1}{2}$	.284	18	8	$2\frac{1}{2}$	.319
16	6	3	.147	18	6	3	.165
16	$6\frac{1}{2}$	3	.176	18	$6\frac{1}{2}$	3	.198
16	7	3	.207	18	7	3	.233
16	$7\frac{1}{2}$	3	.241	18	$7\frac{1}{2}$	3	.271
16	8	3	.277	18	8	3	.312
16	$8\frac{1}{2}$	3	.316	18	6	$3\frac{1}{2}$	.157
16	6	$3\frac{1}{2}$	.139	18	$6\frac{1}{2}$	$3\frac{1}{2}$	.190
16	$6\frac{1}{2}$	$3\frac{1}{2}$	.168	18	7	$3\frac{1}{2}$	.225
16	7	$3\frac{1}{2}$	.200	18	$7\frac{1}{2}$	$3\frac{1}{2}$	.263
16	$7\frac{1}{2}$	$3\frac{1}{2}$	.234	18	8	$3\frac{1}{2}$	.304
16	8	$3\frac{1}{2}$	.270				

Displacement of Triplex, Single-acting Pumps

(100 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = $.000243 \times L \times D^2$
Where: L = Stroke length, in.
D = Liner diameter, in.

Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.
7	3	.0153	9	$3\frac{1}{2}$	.0268
7	$3\frac{1}{2}$	.0208	9	4	.0350
7	4	.0272	9	$4\frac{1}{2}$	.0443
7	$4\frac{1}{2}$	.0344	9	5	.0546
7	5	.0425	9	$5\frac{1}{2}$	.0661
7	$5\frac{1}{2}$	.0514	9	6	.0787
7	6	.0612	10	$4\frac{1}{2}$	.0492
7	$6\frac{1}{2}$	0718	10	5	.0607
7	7	.0833	10	$5\frac{1}{2}$	.0735
8	$4\frac{1}{2}$	.0393	10	6	.0874
8	5	.0486	10	$6\frac{1}{2}$	.1026
8	$5\frac{1}{2}$	.0588	12	5	.0729
8	6	.0699	12	$5\frac{1}{2}$	.0882
8	$6\frac{1}{2}$	.0821	12	6	.1049
			12	$6\frac{1}{2}$	.1231
			12	7	.1428

WELL NAME	
DATE	

API RECOMMENDED
WELL CONTROL WORKSHEET
WAIT AND WEIGHT METHOD
(SUBSEA STACK)

CONTRACTOR	
RIG	

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size __________ in., Weight __________lb/ft, Grade __________, Internal Yield__________ psi, Depth (TVD) __________ ft
Mechanical Pressure Limit__________psi
Casing Pressure to Cause Fracture__________psi *(1)*, based on present drilling fluid density of__________lb/gal.
Maximum Allowable Casing Pressure: Initial Closure _________ psi
Entire Well Kill ________ psi } Approved by: ______________________________
(Name)

Contingency Procedure *(2)* if casing pressure reaches maximum approved:______________________________

Normal Circulating Pressure and Rate: _________ psi at _________ stks/min. and _________ bpm* at __________ lb/gal and _____________ ft
Kill Pressure and Rate: Pump No. 1, _________ psi at _________ stks/min. and _________ bpm* at __________ lb/gal and __________ ft *(3)*
Pump No. 2, _________ psi at _________ stks/min. and _________ bpm* at __________ lb/gal and __________ ft *(3)*
Drill Pipe Capacity: ____________ bbl/ft, Choke Line Pressure at Kill Rate _____________ psi at ______________ bpm and ____________ lb/gal *(4)*

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump. [□ open choke line and choke, close blowout preventer, close choke], or [□ close blowout preventer, open choke line with choke closed, and observe casing pressure]. Do not exceed Maximum Allowable Casing Pressure *(2)*. Hang off drill pipe, check for trapped pressure and record the following:
Closed-in Drill Pipe Pressure__________ psi, Casing Pressure__________ psi, Drilling Fluid Density__________ lb/gal,
Depth (TVD)__________ ft, Kick Volume__________ bbl.

III. INCREASE DRILLING FLUID DENSITY

Calculate the Required Drilling Fluid Density *(5)* and increase fluid density in the suction pit *(6), (7)*.

IV. PREPARE DRILL PIPE PRESSURE SCHEDULE

Determine Calculated Initial Circulation Pressure and plot above zero time *(8)*.
Determine Final Circulating Pressure *(9)* and plot above Circulating Time to Bit *(10)*.
Draw a line between the points.
Read Drill Pipe Pressure at 5-min. intervals and record in blank spaces.
Calculate Strokes To Bit *(11)* and fill in the blanks below the drill pipe pressure schedule.

V. ESTABLISH CIRCULATION

Open the kill line to a pressure gauge. Slowly open the choke controlling the choke line and make adjustments as necessary to hold the kill line pressure constant while the pump is brought up to kill rate. If kill line pressure monitoring cannot be done, allow the choke manifold pressure to drop by an amount equal to the corrected choke line pressure *(12)*. Hold Kill Rate constant.
The observed Drill Pipe Pressure should be equal to the Calculated Initial Circulating Pressure *(8)*. When approximately equal, use the choke to adjust the observed Drill Pipe Pressure to the calculated pressure. If widely divergent, close in the well and consider alternatives.

VI. CIRCULATE HEAVY DRILLING FLUID

Maintain Drilling Fluid Density in pits while circulating at Kill Rate.
Use choke to adjust Drill Pipe Pressure to values recorded at times or strokes shown.
If Drill Pipe Pressure increases, open the choke; if Drill Pipe Pressure decreases, close the choke.
After heavy drilling fluid reaches bit *(10), (11)*, hold Final Circulating Pressure constant at Kill Rate.
When gas reaches the choke line, sudden loss of hydrostatic pressure may result in rapid drop in Drill Pipe Pressure requiring quick choke adjustment.
At some time, the choke may be wide open and Drill Pipe Pressure higher than scheduled.
Open kill line to choke for an additional choke line, if not already open.
If Drill Pipe Pressure cannot be reduced using wide open choke, hold Drill Pipe Pressure constant by reducing the pump rate.
After uncut drilling fluid of required density reaches the surface, shut down pump and check for flow.
If well is dead, circulate heavy drilling fluid into riser. Take steps to circulate out possible gas trapped in blowout preventers using a closed diverter. If possible, continue circulating slowly through choke line while displacing riser.

CALCULATIONS AND NOTES

(1) A. Fracture Drilling Fluid Density $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}}$ + Leak-off Test Drilling Fluid Density

$= \dfrac{\_\_\_\_\_\_\text{ psi}}{.052 \times \_\_\_\_\text{ ft}}$ + _______ lb/gal = _______ lb/gal.

B. Fracture Pressure = .052 x Casing Depth x (Fracture Drilling Fluid Density – Present Drilling Fluid Density)
= .052 x __________ ft x (__________ lb/gal – ___________ lb/gal) =__________ psi.

(2) If casing pressure reaches maximum allowed, follow the Contingency Procedure.

(3) Measure daily while drilling or after a significant change in circulating system pressure.

(4) Choke Line Pressure (measure by circulating at the Kill Rate through the choke manifold down the choke line and up the riser).

(5) Required Drilling Fluid Density $= \dfrac{\text{Closed-in Drill Pipe Pressure}}{.052 \times \text{Depth (TVD)}}$ + Present Drilling Fluid Density + Trip Margin †

$= \dfrac{\_\_\_\_\_\_\text{ psi}}{.052 \times \_\_\_\_\_\_\text{ ft}}$ +_______ lb/gal + 0.3 lb/gal † =______ lb/gal.

(6) If two sections or two pits are weighted and reverse circulation established between, drilling fluid density is more evenly controlled while circulating the hole.

(7) If drill pipe pressure increases during weighting, reduce to initial stabilized value by bleeding casing pressure through the choke.

(8) Calculated Initial Circulating Pressure = Kill Rate Pressure plus Closed-in Drill Pipe Pressure
= _______ psi +_______ psi =_______ psi.

(9) Final Circulating Pressure = Kill Rate Pressure x $\dfrac{\text{Required Drilling Fluid Density}}{\text{Original Drilling Fluid Density}}$ = _____ psi x $\dfrac{\_\_\_\_\text{ lb/gal}}{\_\_\_\_\text{ lb/gal}}$ = ____ psi.

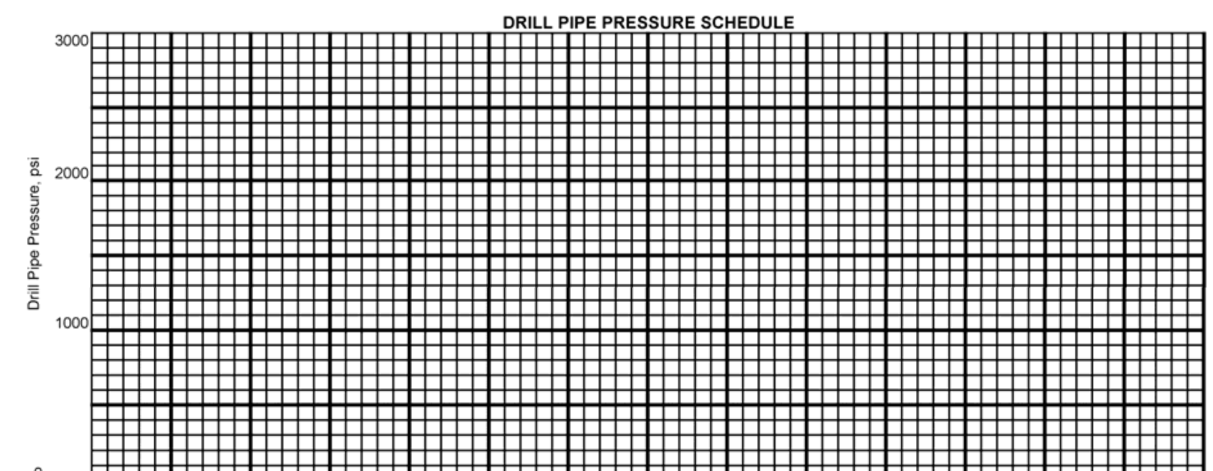
(10) Circulating Time To Bit $= \dfrac{\text{Drill Pipe Capacity x Drill String Length}}{\text{Kill Rate}} = \dfrac{\_\_\_\_\text{ bbl/ft} \times \_\_\_\_\text{ ft}}{\_\_\_\_\_\_\text{ bpm}}$ = ________ min.

(11) Strokes To Bit = Kill Rate x Time =__________stks/min. x __________ min. =__________ stks.

(12) Corrected Choke Line Pressure $= \dfrac{\text{Measured Choke Line Pressure x Present Drilling Fluid Density}}{\text{Drilling Fluid Density When Choke Line Pressure Measured}} = \dfrac{\_\_\_\_\text{ psi} \times \_\_\_\_\text{ lb/gal}}{\_\_\_\_\_\_\text{lb/gal}}$ =___ psi.

Notes: Considering pump efficiency.*
† Trip Margins range from 0.0 to 0.3 lb/gal for hole sizes greater than 7-in diameter and from 0.0 to 0.5 lb/gal for smaller holes.
Omit Trip Margin if only surface casing set or drilling fluid is near fracture gradient

DRILL PIPE PRESSURE SCHEDULE



Time, min.	0	5	10	15	20	25	30	35	40	45	50	55	60	65	70
Drill Pipe Pressure, psi															
Strokes															

(over)

API RECOMMENDED
WELL CONTROL WORKSHEET

WAIT AND WEIGHT METHOD
(SUBSEA STACK)

COMPANY	WELL
DATE	**DEPTH**

PREPARED BY: ________________________________ **COMPANY** ________________________

CAPACITY AND DISPLACEMENT OF DRILL PIPE

Drill Pipe *(1)*				Tool Joint				Capacity			Displacement	
		Weight										
O.D., in.	Upset	Nominal (lb/ft)	Approx. (lb/ft) *(2)*	Name	NC No.	O.D., in.	Average Overall Joint Length, ft. *(4)*	Barrels Per Foot	Barrels Per 3-Joint Stand	Feet Per Barrel	Barrels Per Foot *(5)*	Barrels Per 3-Joint Stand
$2^7/_8$	I.U.	10.40	10.28	Slim Hole	26	$3^3/_8$	30.64	0.00440	0.404	227.5	0.00374	0.344
$2^7/_8$	E.U.	10.40	10.76	I.F.	31	$4^1/_8$	30.74	0.00449	0.414	222.7	0.00392	0.361
$3^1/_2$	I.U.	13.30	13.40	Slim Hole	31	$4^1/_8$	30.86	0.00723	0.669	138.4	0.00488	0.452
$3^1/_2$	E.U.	13.30	14.77	I.F.	38	$4^3/_4$	30.94	0.00739	0.686	135.4	0.00501	0.465
$3^1/_2$	E.U.	15.50	16.39	I.F.	38	5	30.99	0.00657	0.611	152.3	0.00596	0.554
4	E.U.	14.00	15.85	I.F.	46	6	31.10	0.01081	1.008	92.6	0.00577	0.538
$4^1/_2$	E.U.	16.60	18.98	I.F.	50	$6^3/_8$	31.07	0.01419	1.323	70.5	0.00691	0.644
$4^1/_2$	I.E.U.	16.60	17.81	H-90		6	31.06	0.01394	1.292	71.7	0.00648	0.604
$4^1/_2$	I.E.U.	16.60	18.37	X.H.	46	$6^1/_4$	31.11	0.01394	1.301	71.8	0.00668	0.624
$4^1/_2$	E.U.	20.00	21.62	I.F.	50	$6^3/_8$	31.07	0.01287	1.200	77.3	0.00786	0.733
$4^1/_2$	I.E.U.	20.00	22.09	X.H.	46	$6^1/_4$	31.11	0.01257	1.173	79.5	0.00804	0.750
5	I.E.U.	19.50	20.89	X.H.	50	$6^3/_8$	31.05	0.01746	1.626	57.3	0.00760	0.708
5	I.E.U.	25.60	26.89	X.H.	50	$6^3/_8$	31.05	0.01528	1.423	65.5	0.00979	0.912
$5^1/_2$	I.E.U.	21.90	23.77	F.H.	*(3)*	7	31.17	0.02169	2.028	46.1	0.00865	0.809
$5^1/_2$	I.E.U.	24.70	26.33	F.H.	*(3)*	7	31.17	0.02077	1.942	48.2	0.00958	0.896

(1) Grade E drill pipe.
(2) Table 2.10, API RP 7G: Recommended Practice for Drill Stem Design and Operating Limits, Twelfth Edition, May 1987.
(3 Obsolete tool joint.
(4) Based on an average pipe length of 29.4 feet before adding tool joints.
(5) The approximate weight per foot is converted to barrels using steel density of 489.54 lb/ft^3 and volume of one barrel equal to 5.61458 ft^3.

****

BARITE REQUIREMENTS

Sacks/100 bbl $= \dfrac{\text{1470 x (Required Drilling Fluid Density – Present Drilling Fluid Density)}}{\text{(35 – Required Drilling Fluid Density)}}$

$= \dfrac{\text{1470 x (\_\_\_\_\_\_ lb/gal – \_\_\_\_\_\_ lb/gal)}}{\text{(35 – \_\_\_\_\_\_\_\_\_\_ lb/gal)}}$ = ________ sx/100 bbl.

Barite Required $= \dfrac{\text{Drilling Fluid Volume x Sacks/100 bbl}}{100} = \dfrac{\text{\_\_\_\_\_\_\_\_ bbl x \_\_\_\_\_\_\_\_ sx/100 bbl}}{100}$ = _____ sx.

Required Mixing Rate $= \dfrac{\text{Sacks/100 bbl x Kill Rate}}{100} = \dfrac{\text{\_\_\_\_\_\_\_\_ sx/100 bbl x \_\_\_\_\_\_\_\_ bpm}}{100}$ = _____ sx/min.

DILUTION OF RESERVE DRILLING FLUID WITH WATER

Barrels Water $= \dfrac{\text{(Present Drilling Fluid Density – Desired Drilling Fluid Density) x Present Drilling Fluid Volume}}{\text{(Desired Drilling Fluid Density – 8.34)}}$

$= \dfrac{\text{(\_\_\_\_\_ lb/gal – \_\_\_\_\_\_\_ lb/gal) x \_\_\_\_\_\_ bbl}}{\text{(\_\_\_\_\_ lb/gal – 8.34)}}$ = _______ bbl.

Displacement of Duplex, Double-acting Pumps

(90 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = .0001619 L [2D^2 – d^2] (Eff.)
Where: L = Stroke length, in.
D = Liner diameter, in.
d = Rod diameter, in.
Eff. = Volumetric efficiency, decimal fraction.

Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.
16	5	$2^1/_2$	.102	18	5	$2^1/_2$	.115
16	$5^1/_2$	$2^1/_2$	.126	18	$5^1/_2$	$2^1/_2$	.142
16	6	$2^1/_2$	.153	18	6	$2^1/_2$	.172
16	$6^1/_2$	$2^1/_2$	.182	18	$6^1/_2$	$2^1/_2$	.205
16	7	$2^1/_2$	.214	18	7	$2^1/_2$	.241
16	$7^1/_2$	$2^1/_2$	.248	18	$7^1/_2$	$2^1/_2$	.279
16	8	$2^1/_2$	.284	18	8	$2^1/_2$	.319
16	6	3	.147	18	6	3	.165
16	$6^1/_2$	3	.176	18	$6^1/_2$	3	.198
16	7	3	.207	18	7	3	.233
16	$7^1/_2$	3	.241	18	$7^1/_2$	3	.271
16	8	3	.277	18	8	3	.312
16	$8^1/_2$	3	.316	18	6	$3^1/_2$	.157
16	6	$3^1/_2$	.139	18	$6^1/_2$	$3^1/_2$	.190
16	$6^1/_2$	$3^1/_2$	.168	18	7	$3^1/_2$	.225
16	7	$3^1/_2$	.200	18	$7^1/_2$	$3^1/_2$	.263
16	$7^1/_2$	$3^1/_2$	.234	18	8	$3^1/_2$	.304
16	8	$3^1/_2$	.270				

Displacement of Triplex, Single-acting Pumps

(100 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = .000243 x L x D^2
Where: L = Stroke length, in.
D = Liner diameter, in.

Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.
7	3	.0153	9	$3^1/_2$	.0268
7	$3^1/_2$	.0208	9	4	.0350
7	4	.0272	9	$4^1/_2$	.0443
7	$4^1/_2$	.0344	9	5	.0546
7	5	.0425	9	$5^1/_2$	.0661
7	$5^1/_2$	.0514	9	6	.0787
7	6	.0612	10	$4^1/_2$	.0492
7	$6^1/_2$	.0718	10	5	.0607
7	7	.0833	10	$5^1/_2$	.0735
8	$4^1/_2$	.0393	10	6	.0874
8	5	.0486	10	$6^1/_2$	.1026
8	$5^1/_2$	.0588	12	5	.0729
8	6	.0699	12	$5^1/_2$	.0882
8	$6^1/_2$	.0821	12	6	.1049
			12	$6^1/_2$	.1231
			12	7	.1428

WELL NAME	
DATE	

API RECOMMENDED
WELL CONTROL WORKSHEET
CONCURRENT METHOD
(SUBSEA ATTACK)

CONTRACTOR	
RIG	

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size __________ in., Weight __________lb/ft, Grade __________, Internal Yield__________ psi, Depth (TVD) __________ ft
Mechanical Pressure Limit __________ psi
Casing Pressure to Cause Fracture __________ psi *(1)*, based on present drilling fluid density of __________ lb/gal.
Maximum Allowable Casing Pressure: Initial Closure______________ psi
Entire Well Kill______________ psi } Approved by: ______________________________________ (Name)
Contingency Procedure *(2)* if casing pressure reaches maximum approved: ______________________________________

____

Normal Circulating Pressure and Rate: _________ psi at __________ stks/min. and ___________ bpm* at ___________ lb/gal and ____________ ft
Kill Pressure and Rate: Pump No. 1, __________ psi at __________ stks/min. and ___________ bpm* at ___________ lb/gal and ____________ ft *(3)*
Pump No. 2, __________ psi at __________ stks/min. and ___________ bpm* at ___________ lb/gal and ____________ ft *(3)*
Drill Pipe Capacity:____________bbl/ft, Choke Line Pressure at Kill Rate ______________ psi at ______________ bpm and _____________ lb/gal *(4)*
Choke Line Pressure at Kill Rate ______________ psi at ______________ bpm and _____________ lb/gal *(4)*
Choke Line Pressure at Kill Rate ______________ psi at ______________ bpm and _____________ lb/gal *(4)*

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump. [□ open choke line and choke, close blowout preventer, close choke], or [□ close blowout preventer, open choke line with choke closed, and observe casing pressure]. Do not exceed Maximum Allowable Casing Pressure *(2)*. Hang off drill pipe, check for trapped pressure, and record the following:
Closed-in Drill Pipe Pressure__________ psi, Casing Pressure__________ psi, Drilling Fluid Density__________ lb/gal,
Depth (TVD)__________ ft, Kick Volume__________ bbl.

III. ESTABLISH CIRCULATION

Open the kill line to a pressure gauge. Slowly open the choke controlling the choke line and make adjustments as necessary to hold the kill line pressure constant while the pump is brought up to kill rate. If kill line pressure monitoring cannot be done, allow the choke manifold pressure to drop by an amount equal to the corrected choke line pressure *(5)*. Hold Kill Rate constant.
The observed Drill Pipe Pressure should be equal to the Calculated Initial Circulating Pressure *(6)*. When approximately equal, use the choke to adjust the observed Drill Pipe Pressure to the calculated pressure. If widely divergent, close in the well and consider alternatives.
Record time when circulation started __________ hrs __________min.

IV. START INCREASING DRILLING FLUID DENSITY

Record time or strokes at which fluid in suction pit is increased each 0.1 or 0.2 lb/gal on graph *(7)*.
Calculate Required Drilling Fluid Density *(8)*.

V. PREPARE DRILL PIPE PRESSURE SCHEDULE

Fill in bottom of graph with even increments of drilling fluid density from Initial to Required Drilling Fluid Density.
Plot Initial Circulating Pressure *(6)* above Initial Drilling Fluid Density.
Determine Final Circulating Pressure *(9)* and plot above Required Drilling Fluid Density *(8)*.
Draw a line between the points.
Read from graph Drill Pipe Pressure at each increment of drilling fluid density and record in blank spaces.
Record time (or strokes) at which suction pit has each increment of drilling fluid density.
Calculate Circulating Time *(10)* (or strokes) *(11)* to Bit.
Fill blank spaces with $^{1}/_{2}$ Circulating Time (or strokes) to Bit.
Add $^{1}/_{2}$ Circulating Time (or strokes) to Bit to time for each drilling fluid density increment.

VI. KILLING THE WELL

Hold Drill Pipe Pressures shown for each drilling fluid density increment at times (or strokes) shown by adjusting choke, while holding Kill Rate constant.
If Drill Pipe Pressure increases, open the choke; if Drill Pipe Pressure decreases, close the choke.
When Required Drilling Fluid Density *(8)* reaches bit, hold Final Circulating Pressure *(9)* constant.
After gas reaches the choke line, sudden loss of hydrostatic pressure may result in rapid drop in Drill Pipe Pressure requiring quick choke adjustment.
At some time the choke may be wide open and Drill Pipe Pressure higher than scheduled.
Open kill line to choke for an additional choke line, if not already open.
If Drill Pipe Pressure cannot be reduced using wide open choke, hold Drill Pipe Pressure constant by reducing the pump rate.
After uncut drilling fluid of required density reaches the surface, shut down pump and check for flow.
If well is dead, circulate heavy drilling fluid into riser. Take steps to circulate out possible gas trapped in blowout preventers using a closed diverter. If possible, continue circulating slowly through choke line while displacing riser.

CALCULATIONS AND NOTES

(1) A. Fracture Drilling Fluid Density $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}} + \text{Leak-off Test Drilling Fluid Density}$

$= \dfrac{\_\_\_\_\_\_ \text{ psi}}{.052 \times \_\_\_\_\_ \text{ ft}} \times \_\_\_\_\_\_ \text{ lb/gal} = \_\_\_\_\_\_ = \text{lb/gal.}$

B. Fracture Pressure = .052 x Casing Depth x (Fracture Drilling Fluid Density – Present Drilling Fluid Density)
= .052 x ________ ft x (_______ lb/gal – _______ lb/gal) =______ psi.

(2) If casing pressure reaches maximum allowed, follow the Contingency Procedure.

(3) Measure daily while drilling or after a significant change in circulating system pressure.

(4) Choke Line Pressure (measure by circulating at the Kill Rate through the choke manifold down the choke line and up the riser).

(5) Corrected Choke Line Pressure $= \dfrac{\text{Measured Choke Line Pressure} \times \text{Present Drilling Fluid Density}}{\text{Drilling Fluid Density When Choke Line Pressure Measured}} = \dfrac{\_\_\_ \text{ psi} \times \_\_\_ \text{ lb/gal}}{\_\_\_\_\_\_ \text{ lb/gal}} = \_\_\_\_ \text{ psi.}$

(6) Calculated Initial Circulating Pressure = Kill Rate Pressure plus Closed-in Drill Pipe Pressure =____psi + _____ psi = _____ psi.

(7) If two sections or two pits are weighted and reverse circulation established between, drilling fluid density is more evenly controlled while circulating the hole.

(8) Required Drilling Fluid Density $= \dfrac{\text{Closed-in Drill Pipe Pressure}}{.052 \times \text{Depth (TVD)}} + \text{Present Drilling Fluid Density} + \text{Trip Margin} \dagger$

$= \dfrac{\_\_\_\_\_\_ \text{ psi}}{.052 \times \_\_\_\_\_\_ \text{ ft}} + \text{ lb/gal} + 0.3 \text{ lb/gal} \dagger = \_\_\_\_\_\_\_\_ \text{ lb/gal.}$

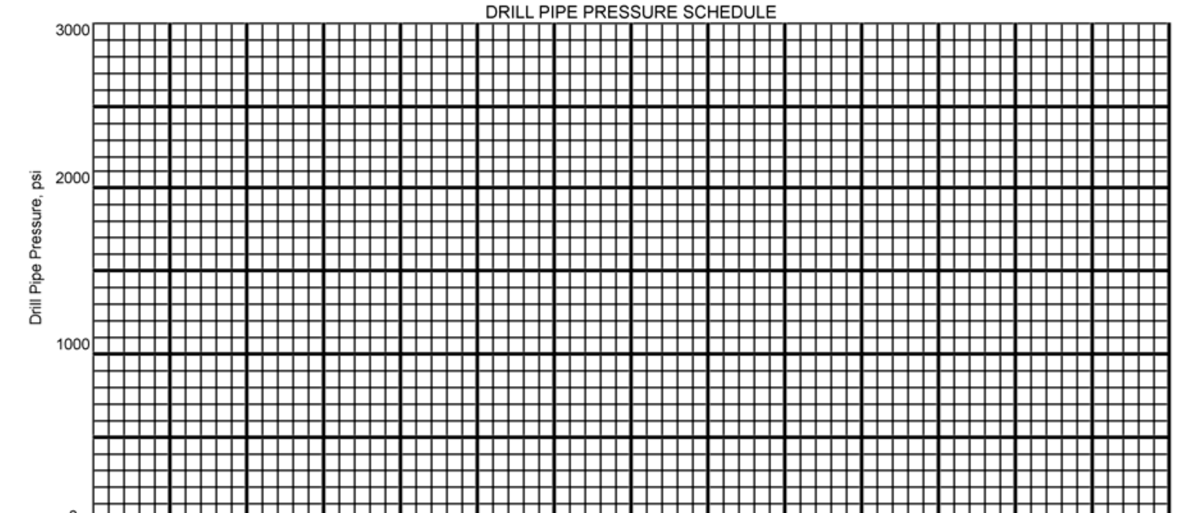
(9) Final Circulating Pressure $= \text{Kill Rate Pressure} \times \dfrac{\text{Required Drilling Fluid Density}}{\text{Original Drilling Fluid Density}} = \_\_\_\_ \text{ psi} \times \dfrac{\_\_\_ \text{ lb/gal}}{\_\_\_ \text{ lb/gal}} = \_\_\_\_\_ \text{ psi.}$

(10) Circulating Time To Bit $= \dfrac{\text{Drill Pipe Capacity} \times \text{Drill String Length}}{\text{Kill Rate}} = \dfrac{\_\_\_\_\_\_ \text{ bbl/ft} \times \_\_\_\_\_\_ \text{ ft}}{\_\_\_\_\_\_ \text{ bpm}} = \_\_\_\_\_ \text{ min.}$

(11) Strokes To Bit = Kill Rate x Time = _______ stks/min. x _______ min. = ______ stks.

Notes: **Considering pump efficiency.*
† Trip Margins range from 0.0 to 0.3 lb/gal for hole sizes greater than 7-in. diameter and from 0.0 to 0.5 lb/gal for smaller holes. Omit Trip Margin if only surface casing set or drilling fluid is near fracture gradient.

DRILL PIPE PRESSURE SCHEDULE



Drilling Fluid Density, lb/gal															
Drill Pipe Pressure, psi															
Time, min. or Strokes															
1/2 Time or 1/2 Strokes to Bit															
Total Time or Strokes															

(over)

API RECOMMENDED
WELL CONTROL WORKSHEET

CONCURRENT METHOD
(SUBSEA STACK)

COMPANY	**WELL**
DATE	**DEPTH**

PREPARED BY: ______________________________ **COMPANY** ______________________

CAPACITY AND DISPLACEMENT OF DRILL PIPE

Drill Pipe *(1)*				Tool Joint				Capacity			Displacement	
		Weight										
O.D., in.	Upset	Nominal (lb/ft)	Approx. (lb/ft) *(2)*	Name	NC No.	O.D., in.	Average Overall Joint Length, ft. *(4)*	Barrels Per Foot	Barrels Per 3-Joint Stand	Feet Per Barrel	Barrels Per Foot *(5)*	Barrels Per 3-Joint Stand
2 7/8	I.U.	10.40	10.28	Slim Hole	26	3 3/8	30.64	0.00440	0.404	227.5	0.00374	0.344
2 7/8	E.U.	10.40	10.76	I.F.	31	4 1/8	30.74	0.00449	0.414	222.7	0.00392	0.361
3 1/2	I.U.	13.30	13.40	Slim Hole	31	4 1/8	30.86	0.00723	0.669	138.4	0.00488	0.452
3 1/2	E.U.	13.30	14.77	I.F.	38	4 3/4	30.94	0.00739	0.686	135.4	0.00501	0.465
3 1/2	E.U.	15.50	16.39	I.F.	38	5	30.99	0.00657	0.611	152.3	0.00596	0.554
4	E.U.	14.00	15.85	I.F.	46	6	31.10	0.01081	1.008	92.6	0.00577	0.538
4 1/2	E.U.	16.60	18.98	I.F.	50	6 3/8	31.07	0.01419	1.323	70.5	0.00691	0.644
4 1/2	I.E.U.	16.60	17.81	H-90		6	31.06	0.01394	1.292	71.7	0.00648	0.604
4 1/2	I.E.U.	16.60	18.37	X.H.	46	6 1/4	31.11	0.01394	1.301	71.8	0.00668	0.624
4 1/2	E.U.	20.00	21.62	I.F.	50	6 3/8	31.07	0.01287	1.200	77.3	0.00786	0.733
4 1/2	I.E.U.	20.00	22.09	X.H.	46	6 1/4	31.11	0.01257	1.173	79.5	0.00804	0.750
5	I.E.U.	19.50	20.89	X.H.	50	6 3/8	31.05	0.01746	1.626	57.3	0.00760	0.708
5	I.E.U.	25.60	26.89	X.H.	50	6 3/8	31.05	0.01528	1.423	65.5	0.00979	0.912
5 1/2	I.E.U.	21.90	23.77	F.H.	*(3)*	7	31.17	0.02169	2.028	46.1	0.00865	0.809
5 1/2	I.E.U.	24.70	26.33	F.H.	*(3)*	7	31.17	0.02077	1.942	48.2	0.00958	0.896

(1) Grade E drill pipe.
(2) Table 2.10, API RP 7G: Recommended Practice for Drill Stem Design and Operating Limits, Twelfth Edition, May 1987.
(3) Obsolete tool joint.
(4) Based on an average pipe length of 29.4 feet before adding tool joints.
(5) The approximate weight per foot is converted to barrels using steel density of 489.54 lb/ft^3 and volume of one barrel equal to 5.61458 ft^3.

****

BARITE REQUIREMENTS

Sacks/100 bbl $= \dfrac{\text{1470 x (Required Drilling Fluid Density – Present Drilling Fluid Density)}}{\text{(35 – Required Drilling Fluid Density)}}$

$= \dfrac{\text{1470 x (\_\_\_\_\_ lb/gal – \_\_\_\_\_ lb/gal)}}{\text{(35 – \_\_\_\_\_ lb/gal)}} = \text{\_\_\_\_\_ sx/100 bbl.}$

Barite Required $= \dfrac{\text{Drilling Fluid Volume x Sacks/100 bbl}}{100} = \dfrac{\text{\_\_\_\_\_ bbl x \_\_\_\_\_ sx/100 bbl.}}{100} = \text{\_\_\_\_\_ sx.}$

Required Mixing Rate $= \dfrac{\text{Sacks/100 bbl x Kill Rate}}{100} = \dfrac{\text{\_\_\_\_\_ sx/100 bbl x \_\_\_\_\_ bpm}}{100} = \text{\_\_\_\_\_ sx/min.}$

DILUTION OF RESERVE DRILLING FLUID WITH WATER

Barrels Water $= \dfrac{\text{(Present Drilling Fluid Density – Desired Drilling Fluid Density) x Present Drilling Fluid Volume}}{\text{(Desired Drilling Fluid Density – 8.34)}}$

$= \dfrac{\text{(\_\_\_\_\_ lb/gal – \_\_\_\_\_ lb/gal) x \_\_\_\_\_ bbl}}{\text{(\_\_\_\_\_ lb/gal – 8.34)}} = \text{\_\_\_\_\_ bbl.}$

Displacement of Duplex, Double-acting Pumps

(90 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = .0001619 L [2D^2 – d^2] (Eff.)

Where: L = Stroke length, in.
D = Liner diameter, in.
d = Rod diameter, in.
Eff. = Volumetric efficiency, decimal fraction.

Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.
16	5	2 1/2	.102	18	5	2 1/2	.115
16	5 1/2	2 1/2	.126	18	5 1/2	2 1/2	.142
16	6	2 1/2	.153	18	6	2 1/2	.172
16	6 1/2	2 1/2	.182	18	6 1/2	2 1/2	.205
16	7	2 1/2	.214	18	7	2 1/2	.241
16	7 1/2	2 1/2	.248	18	7 1/2	2 1/2	.279
16	8	2 1/2	.284	18	8	2 1/2	.319
16	6	3	.147	18	6	3	.165
16	6 1/2	3	.176	18	6 1/2	3	.198
16	7	3	.207	18	7	3	.233
16	7 1/2	3	.241	18	7 1/2	3	.271
16	8	3	.277	18	8	3	.312
16	8 1/2	3	.316	18	6	3 1/2	.157
16	6	3 1/2	.139	18	6 1/2	3 1/2	.190
16	6 1/2	3 1/2	.168	18	7	3 1/2	.225
16	7	3 1/2	.200	18	7 1/2	3 1/2	.263
16	7 1/2	3 1/2	.234	18	8	3 1/2	.304
16	8	3 1/2	.270				

Displacement of Triplex, Single-acting Pumps

(100 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = .000243 x L x D^2

Where: L = Stroke length, in.
D = Liner diameter, in.

Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.
7	3	.0153	9	3 1/2	.0268
7	3 1/2	.0208	9	4	.0350
7	4	.0272	9	4 1/2	.0443
7	4 1/2	.0344	9	5	.0546
7	5	.0425	9	5 1/2	.0661
7	5 1/2	.0514	9	6	.0787
7	6	.0612	10	4 1/2	.0492
7	6 1/2	.0718	10	5	.0607
7	7	.0833	10	5 1/2	.0735
8	4 1/2	.0393	10	6	.0874
8	5	.0486	10	6 1/2	.1026
8	5 1/2	.0588	12	5	.0729
8	6	.0699	12	5 1/2	.0882
8	6 1/2	.0821	12	6	.1049
			12	6 1/2	.1231
			12	7	.1428

WELL NAME
DATE

API RECOMMENDED WELL CONTROL WORKSHEET DRILLERS METHOD

(SUBSEA STACK)

CONTRACTOR
RIG

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size ____________ in., Weight ____________ lb/ft, Grade ______________, Internal Yield _____________ psi, Depth (TVD) ____________ ft
Mechanical Pressure Limit ____________ psi.
Casing Pressure to Cause Fracture__________ psi *(1)*, based on present drilling fluid density of__________ lb/gal.
Maximum Allowable Casing Pressure: Internal Closure ___________ psi
Entire Well Kill ___________ psi } Approved by: ____ (Name)
Contingency Procedure *(2)* if casing pressure reaches maximum approved: ____

Normal Circulating Pressure and Rate: ___________ psi at ___________ stks/min. and ___________ bpm* at ____________ lb/gal and ____________ ft
Kill Pressure and Rate:Pump No. 1, ____________ psi at ___________ stks/min. and ___________ bpm* at___________ lb/gal and ___________ ft *(3)*
Pump No. 2, ____________ psi at ___________ stks/min. and ___________ bpm* at___________ lb/gal and ___________ ft *(3)*
Drill Pipe Capacity: _______________ bbl/ft Choke Line Pressure at Kill Rate __________psi at__________ bpm and__________ lb/gal *(4)*

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump. [☐ open choke line and choke, close blowout preventer, close choke], or [☐ close blowout preventer, open choke line with choke closed, and observe casing pressure]. Do not exceed Maximum Allowable Casing Pressure *(2)*. Hang off drill pipe, check for trapped pressure and record the following:
Closed-in Drill Pipe Pressure__________ psi, Casing Pressure__________ psi, Drilling Fluid Density__________ lb/gal,
Depth (TVD)__________ ft, Kick Volume__________ bbl.

III. ESTABLISH CIRCULATION

Open the kill line to a pressure gauge. Slowly open the choke controlling the choke line and make adjustments as necessary to hold the kill line pressure constant while the pump is brought up to kill rate. If kill line pressure monitoring cannot be done, allow the choke manifold pressure to drop by an amount equal to the corrected choke line pressure *(5)*.
The observed Drill Pipe Pressure should be equal to the Calculated Initial Circulating Pressure *(6)*. If not, investigate the cause.
Record the Drill Pipe Pressure__________ psi at__________ stks/min. and__________ bpm.
Record time when circulation started__________ hrs __________ min.

IV. CIRCULATE OUT THE KICK

While holding Kill Rate constant, keep Drill Pipe Pressure constant by adjusting choke. If Drill Pipe Pressure increases, open choke. If Drill Pipe Pressure decreases, close choke. Casing Pressure must be allowed to vary to maintain constant bottom-hole pressure. When gas reaches the choke line, sudden loss of hydrostatic pressure may result in a rapid drop in Drill Pipe Pressure requiring quick choke adjustment. When well is free of gas, salt water, and oil, stop pump and close choke. Record New Closed-in Choke Manifold Pressure__________ psi.

V. INCREASE DRILLING FLUID DENSITY

Calculate the Required Drilling Fluid Density *(7)* and increase fluid density in the suction pit *(8)*.

VI. CIRCULATE HEAVY DRILLING FLUID

Establish circulation as per item III, adding a 100 psi safety factor. Let the New Closed-in Choke Manifold Pressure drop by the amount of the Corrected Choke Line Pressure *(5)*.
Hold Kill Rate constant and hold New Reduced Choke Manifold Pressure constant by varying the choke.
Maintain required drilling fluid density in pit while circulating.
Circulate heavy drilling fluid to bit using time *(9)* or strokes *(10)*.
When heavy drilling fluid reaches bit, read and record Final Drill Pipe Circulating Pressure__________ psi.
Hold Final Drill Pipe Pressure constant by varying choke while holding Kill Rate constant.
At some time, the choke may be wide open and Drill Pipe Pressure higher than recorded Final Drill Pipe Circulating Pressure.
Open Kill Line to choke for an additional choke line, if not already open.
If Drill Pipe Pressure cannot be reduced using wide open choke, hold recorded Final Drill Pipe Pressure constant by reducing pump rate.
After uncut drilling fluid of required density reaches surface, shut down pump and check for flow.
If well is dead, circulate heavy drilling fluid into riser. Take steps to circulate out possible gas trapped in blowout preventers using a closed diverter. If possible, continue circulating slowly through choke line while displacing riser.

CALCULATIONS AND NOTES

(1) A. Fracture Drilling Fluid Density $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}}$ + Leak-off Test Drilling Fluid Density

$= \dfrac{\_\_\_\_\_\_ \text{ psi}}{.052 \times \_\_\_\_\_ \text{ ft}} + \_\_\_\_\_\_ \text{ lb/gal} = \_\_\_\_\_\_ \text{ lb/gal.}$

B. Fracture Pressure = .052 x Casing Depth + (Fracture Drilling Fluid Density – Present Drilling Fluid Density)

= .052 x _______ ft x (_______ lb/gal – _____ lb/gal) = ______ psi.

(2) If casing pressure reaches maximum allowed, follow the Contingency Procedure.

(3) Measure daily while drilling or after a significant change in circulating system pressure.

(4) Choke Line Pressure (measure by circulating at the Kill Rate through the choke manifold down the choke line and up the riser.)

(5) Corrected Choke Line Pressure $= \dfrac{\text{Measured Choke Line Pressure} \times \text{Present Drilling Fluid Density}}{\text{Drilling Fluid Density When Choke Line Pressure Measured}} = \dfrac{\_\_\_\_ \text{ psi} \times \_\_\_ \text{lb/gal}}{\_\_\_\_\_\_ \text{ lb/gal}} = \_\_\_\_\_ \text{ psi.}$

(6) Calculated Initial Circulating Pressure = Kill Rate Pressure plus Closed-in Drill Pipe Pressure.

= _______ psi + _______ psi = _______ psi.

(7) Required Drilling Fluid Density $= \dfrac{\text{Closed-in Drill Pipe Pressure}}{.052 \times \text{Bit Depth (TVD)}}$ + Present Drilling Fluid Density + Trip Margin †

$= \dfrac{\_\_\_\_\_\_ \text{ psi}}{.052 \times \_\_\_\_\_ \text{ ft}} + \_\_\_\_\_\_ \text{ lb/gal} + 0.3 \text{ lb/gal.} \dagger = \_\_\_\_\_\_\_ \text{ lb/gal.}$

(8) If two sections or two pits are weighted and reverse circulation established between, drilling fluid density is more evenly controlled while circulating the hole.

(9) Circulating Time To Bit $= \dfrac{\text{Drill Pipe Capacity} \times \text{Drill String Length}}{\text{Kill Rate}} = \dfrac{\_\_\_\_\_\_ \text{ bbl/ft} \times \_\_\_\_\_ \text{ ft}}{\_\_\_\_\_\_ \text{ bpm}} = \_\_\_\_\_\_ \text{ min.}$

(10) Strokes To Bit = Kill Rate x Time = _______ stks/min. x ______min. = _____ stks.

*Notes: *Considering pump efficiency.*

† *Trip Margin and Safety Factor may be omitted, but these give little risk of loss and circulation as the open hole and casing seat are subjected to higher pressures when circulating out the kick. If Trip Margin is used, when heavy drilling fluid nears the surface the choke will be wide open and the Final Drill Pipe Circulation Pressure can no longer be controlled. The Drill Pipe Pressure will slowly increase to compensate for the Trip Margin. Trip Margins range from 0.0 to 0.3 lb/gal for hole sizes greater than 7-in. diameter and from 0.0 to 0.5 lb/gal for smaller holes.*

(over)

API RECOMMENDED

WELL CONTROL WORKSHEET

DRILLERS METHOD
(SUBSEA STACK)

COMPANY	WELL
DATE	DEPTH

PREPARED BY: ______________________ **COMPANY** ______________________

CAPACITY AND DISPLACEMENT OF DRILL PIPE

Drill Pipe *(1)*				Tool Joint			Average Overall Joint Length, ft. *(4)*	Capacity			Displacement	
		Weight										
O.D., in.	Upset	Nominal (lb/ft)	Approx. (lb/ft) *(2)*	Name	NC No.	O.D., in.		Barrels Per Foot	Barrels Per 3-Joint Stand	Feet Per Barrel	Barrels Per Foot *(5)*	Barrels Per 3-Joint Stand
2 7/8	I.U.	10.40	10.28	Slim Hole	26	3 3/8	30.64	0.00440	0.404	227.5	0.00374	0.344
2 7/8	E.U.	10.40	10.76	I.F.	31	4 1/8	30.74	0.00449	0.414	222.7	0.00392	0.361
3 1/2	I.U.	13.30	13.40	Slim Hole	31	4 1/8	30.86	0.00723	0.669	138.4	0.00488	0.452
3 1/2	E.U.	13.30	14.77	I.F.	38	4 3/4	30.94	0.00739	0.686	135.4	0.00501	0.465
3 1/2	E.U.	15.50	16.39	I.F.	38	5	30.99	0.00657	0.611	152.3	0.00596	0.554
4	E.U.	14.00	15.85	I.F.	46	6	31.10	0.01081	1.008	92.6	0.00577	0.538
4 1/2	E.U.	16.60	18.98	I.F.	50	6 3/8	31.07	0.01419	1.323	70.5	0.00691	0.644
4 1/2	I.E.U.	16.60	17.81	H-90		6	31.06	0.01394	1.292	71.7	0.00648	0.604
4 1/2	I.E.U.	16.60	18.37	X.H.	46	6 1/4	31.11	0.01394	1.301	71.8	0.00668	0.624
4 1/2	E.U.	20.00	21.62	I.F.	50	6 3/8	31.07	0.01287	1.200	77.3	0.00786	0.733
4 1/2	I.E.U.	20.00	22.09	X.H.	46	6 1/4	31.11	0.01257	1.173	79.5	0.00804	0.750
5	I.E.U.	19.50	20.89	X.H.	50	6 3/8	31.05	0.01746	1.626	57.3	0.00760	0.708
5	I.E.U.	25.60	26.89	X.H.	50	6 3/8	31.05	0.01528	1.423	65.5	0.00979	0.912
5 1/2	I.E.U.	21.90	23.77	F.H.	*(3)*	7	31.17	0.02169	2.028	46.1	0.00865	0.809
5 1/2	I.E.U.	24.70	26.33	F.H.	*(3)*	7	31.17	0.02077	1.942	48.2	0.00958	0.896

(1) Grade E drill pipe.
(2) Table 2.10, API RP 7G: Recommended Practice for Drill Stem Design and Operating Limits, Twelfth Edition, May 1987.
(3) Obsolete tool joint.
(4) Based on an average pipe length of 29.4 feet before adding tool joints.
(5) The approximate weight per foot is converted to barrels using steel density of 489.54 lb/ft^3 and volume of one barrel equal to 5.61458 ft^3.

****

BARITE REQUIREMENTS

Sacks/100 bbl $= \dfrac{1470 \times (\text{Required Drilling Fluid Density} - \text{Present Drilling Fluid Density})}{(35 - \text{Required Drilling Fluid Density})}$

$= \dfrac{1470 \times (\_\_\_\_\ \text{lb/gal} - \_\_\_\_\ \text{lb/gal})}{(35 - \_\_\_\_\ \text{lb/gal})} = \_\_\_\_\ \text{sx/100 bbl.}$

Barite Required $= \dfrac{\text{Drilling Fluid Volume} \times \text{Sacks/100 bbl}}{100} = \dfrac{\_\_\_\_\ \text{bbl} \times \_\_\_\_\ \text{sx/100 bbl}}{100} = \_\_\_\_\ \text{sx.}$

Required Mixing Rate $= \dfrac{\text{Sacks/100 bbl} \times \text{Kill Rate}}{100} = \dfrac{\_\_\_\_\ \text{sx/100 bbl} \times \_\_\_\_\ \text{bpm}}{100} = \_\_\_\_\ \text{sx/min.}$

DILUTION OF RESERVE DRILLING FLUID WITH WATER

Barrels Water $= \dfrac{(\text{Present Drilling Fluid Density} - \text{Desired Drilling Fluid Density}) \times \text{Present Drilling Fluid Volume}}{(\text{Desired Drilling Fluid Density} - 8.34)}$

$= \dfrac{(\_\_\_\_\ \text{lb/gal} - \_\_\_\_\ \text{lb/gal}) \times \_\_\_\_\ \text{bbl}}{(\_\_\_\_\ \text{lb/gal} - 8.34)} = \_\_\_\_\ \text{bbl.}$

Displacement of Duplex, Double-acting Pumps

(90 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = $.0001619\ L\ [2D^2 - d^2]$ (Eff.)

Where: L = Stroke length, in.
D = Liner diameter, in.
d = Rod diameter, in.
Eff. = Volumetric efficiency, decimal fraction.

Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.
16	5	2 1/2	.102	18	5	2 1/2	.115
16	5 1/2	2 1/2	.126	18	5 1/2	2 1/2	.142
16	6	2 1/2	.153	18	6	2 1/2	.172
16	6 1/2	2 1/2	.182	18	6 1/2	2 1/2	.205
16	7	2 1/2	.214	18	7	2 1/2	.241
16	7 1/2	2 1/2	.248	18	7 1/2	2 1/2	.279
16	8	2 1/2	.284	18	8	2 1/2	.319
16	6	3	.147	18	6	3	.165
16	6 1/2	3	.176	18	6 1/2	3	.198
16	7	3	.207	18	7	3	.233
16	7 1/2	3	.241	18	7 1/2	3	.271
16	8	3	.277	18	8	3	.312
16	8 1/2	3	.316	18	6	3 1/2	.157
16	6	3 1/2	.139	18	6 1/2	3 1/2	.190
16	6 1/2	3 1/2	.168	18	7	3 1/2	.225
16	7	3 1/2	.200	18	7 1/2	3 1/2	.263
16	7 1/2	3 1/2	.234	18	8	3 1/2	.304
16	8	3 1/2	.270				

Displacement of Triplex, Single-acting Pumps

(100 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = $.000243 \times L \times D^2$

Where: L = Stroke length, in.
D = Liner diameter, in.

Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.
7	3	.0153	9	3 1/2	.0268
7	3 1/2	.0208	9	4	.0350
7	4	.0272	9	4 1/2	.0443
7	4 1/2	.0344	9	5	.0546
7	5	.0425	9	5 1/2	.0661
7	5 1/2	.0514	9	6	.0787
7	6	.0612	10	4 1/2	.0492
7	6 1/2	.0718	10	5	.0607
7	7	.0833	10	5 1/2	.0735
8	4 1/2	.0393	10	6	.0874
8	5	.0486	10	6 1/2	.1026
8	5 1/2	.0588	12	5	.0729
8	6	.0699	12	5 1/2	.0882
8	6 1/2	.0821	12	6	.1049
			12	6 1/2	.1231
			12	7	.1428

WELL NAME
DATE

API RECOMMENDED
WELL CONTROL WORKSHEET
WAIT AND WEIGHT METHOD
(SUBSEA STACK IN DEEP WATER)

CONTRACTOR
RIG

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size __________ in., Weight __________ lb/ft, Grade _____________, Internal Yield __________ psi, Depth (TVD) ____________ ft
Mechanical Pressure Limit _______________ psi
Static Choke Manifold Pressure To Cause Fracture ____________ psi *(1)*, based on present drilling fluid density of ___________ lb/gal
Maximum Allowable Choke Manifold Pressure: Initial Closure _____________ psi; Entire Well Kill ____________ psi } Approved by: ______________________________ (Name)

Contingency Procedure *(2)* if casing pressure reaches maximum approved: ____
____
____

Normal Circulating Pressure and Rate: __________ psi at ___________ stks/min. and ___________ bpm* at __________ lb/gal ___________ ft

Kill Pressure (KP) and Rate *(3)* at ____________ lb/gal.

	psi	spm	bpm*	Depth, ft
PUMP No. 1				
PUMP No. 2				

Choke Line Pressure Loss at Kill Rate *(4)*

Choke Line	Kill Line	Choke and Kill

Drill Pipe Capacity:___________ bbl/ft

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump. [☐ open choke line and choke, close blowout preventer, close choke], or [☐ close blowout preventer, open choke line with choke closed, and observe choke manifold pressure]. Do not allow choke manifold pressure to exceed maximum allowed *(2)*. Hang off drill pipe, Check for trapped pressure, and record the following:
Closed-in Drill Pipe Pressure__________ psi, Closed-in Choke Manifold Pressure__________ psi,
Drilling Fluid Density__________ lb/gal, Depth (TVD)__________ ft, Kick Volume__________ bbl.

III. INCREASE DRILLING FLUID DENSITY

Calculate the Required Drilling Fluid Density *(5)* and increase fluid density in the suction pit *(6)*, *(7)*.

IV. PREPARE DRILL PIPE PRESSURE SCHEDULE

Determine Initial Circulating Pressures *(8)* and record in spaces provided *(12)*.
Determine Final Circulating Pressures *(9)* and record in space provided *(13)*.
Select a Kill Rate whose corresponding Choke Line Pressure is less than the Closed-in Choke Manifold Pressure.
Calculate Circulating Time to Bit *(10)* and Strokes to Bit *(11)* for the selected Kill Rate and record in the space provided *(14)*.
Plot Initial Circulating Pressure for the selected Kill Rate above zero time on the Drill Pipe Pressure schedule.
Plot Final Circulating Pressure for the selected Kill Rate above the corresponding Circulating Time to Bit.
Join the Initial and Final Circulating Pressures with a straight line.
Draw a line between the points.
Read Drill Pipe Pressure at five-minute intervals and record in space provided.
Select a second, lower Kill Rate and calculate the corresponding Final Circulating Pressure and record in space provided *(13)*.

V. ESTABLISH CIRCULATION

Open the kill line to a pressure gauge. Slowly open the choke controlling the choke line and make adjustments as necessary to hold the kill line pressure constant while the pump is brought up to the higher of the two preselected kill rates. If kill line pressure monitoring cannot be done, allow the choke pressure to drop an amount equal to the corresponding choke line pressure loss *(4)*.
Hold Kill Rate constant.
The observed Drill Pipe Pressure should be equal to the Calculated Initial Circulating Pressure. If not, investigate cause.

VI. CIRCULATE HEAVY DRILLING FLUID

Maintain Required Drilling Fluid Density in pits while circulating at Kill Rate.
Use choke to adjust Drill Pipe Pressure to values recorded at times or strokes shown.
If Drill Pipe Pressure increases, open the choke; if Drill Pipe Pressure decreases, close the choke.
When heavy drilling fluid reaches bit *(10)*, *(11)*, hold Final Circulating Pressure constant at Kill Rate.
When gas reaches the choke line, sudden loss of hydrostatic pressure may result in rapid drop in Drill Pipe Pressure requiring quick choke closure.
At some time, the choke may be wide open and Drill Pipe Pressure higher than scheduled. The kill line can be used as an additional choke line, if desired, or the pumping rate can be reduced to the lower preselected rate and the Drill Pipe Pressure lowered to the corresponding Final Circulating Pressure using the choke.
After uncut drilling fluid of the required density reaches the surface, shut down the pump and check for flow. If the well is dead, circulate the riser with drilling fluid of the required density before opening the blowout preventer.

CALCULATIONS AND NOTES

(1) A. Fracture Drilling Fluid Density $= \dfrac{\text{Leak-off Pressure}}{.052 \times \text{Casing Depth}}$ + Leak-off Test Drilling Fluid Density

$= \dfrac{\_\_\_\_\_\_ \text{ psi}}{.052 \times \_\_\_\_\_\_ \text{ ft}}$ + _______ lb/gal = _______ lb/gal.

B. Fracture Pressure = .052 x Casing Depth x (Fracture Drilling Fluid Density – Present Drilling Fluid Density)
= .052 x ________ ft x (________ lb/gal – _______ lb/gal) = _______ psi.

(2) If choke manifold pressure reaches maximum allowed, follow the Contingency Procedure.
(3) Measure daily while drilling or after a significant change in circulating system pressure.
(4) Determine by circulating through choke manifold, down choke and/or kill lines, and up riser.
(5) Required Drilling Fluid Density $= \dfrac{\text{Closed-in Drill Pipe Pressure}}{.052 \times \text{Bit Depth (TVD)}}$ + Present Drilling Fluid Density + Trip Margin †

$= \dfrac{\_\_\_\_\_\_ \text{ psi}}{.052 \times \_\_\_\_\_\_ \text{ ft.}}$ + _____ lb/gal + _____ lb/gal.

(6) If two sections or two pits are weighted and reverse circulation established between, drilling fluid density is more evenly controlled while circulating the hole.
(7) If drill pipe pressure increases during weighting, reduce to initial stabilized value by bleeding through the choke.
(8) Initial Circulating Pressure (ICP) = Kill Rate Pressure plus Closed-in Drill Pipe Pressure = ________ psi + _______ psi = _______ psi.

(9) Final Circulating Pressure (FCP) = Kill Rate Pressure x $\dfrac{\text{Required Drilling Fluid Density }(MW_R)}{\text{Original Drilling Fluid Density }(MW_O)}$ = _____ psi x $\dfrac{\_\_\_\_\_\_ \text{ lb/gal}}{\_\_\_\_\_\_ \text{ lb/gal}}$ = _______ psi.

(10) Circulating Time To Bit $= \dfrac{\text{Drill Pipe Capacity x Drill String Length}}{\text{Kill Rate}} = \dfrac{\_\_\_\_\_ \text{ bbl/ft} \times \_\_\_\_\_ \text{ ft.}}{\_\_\_\_\_\_ \text{ bpm}}$ = _______ min.

(11) Strokes To Bit = Kill Rate x Time = ________ stks/min. x ________ min. =_______ stks.

(12) Initial Circulating Pressure (ICP)

	spm	KP	CIDPP	ICP
PUMP No. 1				
PUMP No. 2				

(13) Final Circulating Pressure (FCP)

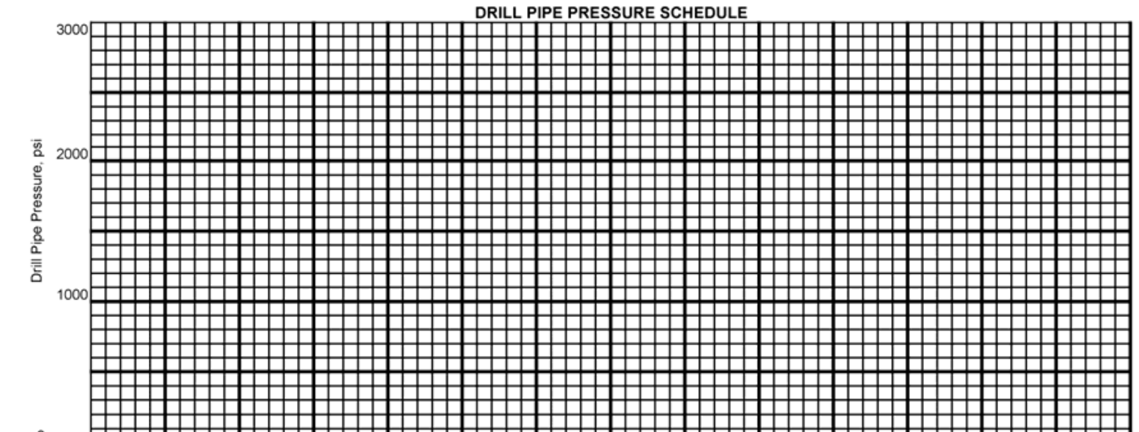
KP	MW_R/MW_O	FCP

(14) Circulating Time To Bit

min.	stks

Notes: **Considering pump efficiency.*
† Trip Margins range from 0.0 to 0.3 lb/gal for hole sizes greater than 7-in diameter and from 0.0 to 0.5 lb/gal for smaller holes.

DRILL PIPE PRESSURE SCHEDULE



Time, min.	0	5	10	15	20	25	30	35	40	45	50	55	60	65	70
Drill Pipe Pressure, psi															
Strokes															

(over)

API RECOMMENDED
WELL CONTROL WORKSHEET

WAIT AND WEIGHT METHOD
(SUBSEA STACK IN DEEP WATER)

COMPANY	WELL
DATE	DEPTH

PREPARED BY: ______________________________ **COMPANY** ______________________________

CAPACITY AND DISPLACEMENT OF DRILL PIPE

Drill Pipe *(1)*				Tool Joint			Average	Capacity			Displacement	
		Weight					Overall		Barrels			Barrels
							Joint	Barrels	Per	Feet	Barrels	Per
O.D.,		Nominal	Approx.		NC	O.D.,	Length, ft.	Per	3-Joint	Per	Per	3-Joint
in.	Upset	(lb/ft)	(lb/ft) *(2)*	Name	No.	in.	*(4)*	Foot	Stand	Barrel	Foot *(5)*	Stand
2 7/8	I.U.	10.40	10.28	Slim Hole	26	3 3/8	30.64	0.00440	0.404	227.5	0.00374	0.344
2 7/8	E.U.	10.40	10.76	I.F.	31	4 1/8	30.74	0.00449	0.414	222.7	0.00392	0.361
3 1/2	I.U.	13.30	13.40	Slim Hole	31	4 1/8	30.86	0.00723	0.669	138.4	0.00488	0.452
3 1/2	E.U.	13.30	14.77	I.F.	38	4 3/4	30.94	0.00739	0.686	135.4	0.00501	0.465
3 1/2	E.U.	15.50	16.39	I.F.	38	5	30.99	0.00657	0.611	152.3	0.00596	0.554
4	E.U.	14.00	15.85	I.F.	46	6	31.10	0.01081	1.008	92.6	0.00577	0.538
4 1/2	E.U.	16.60	18.98	I.F.	50	6 3/8	31.07	0.01419	1.323	70.5	0.00691	0.644
4 1/2	I.E.U.	16.60	17.81	H-90		6	31.06	0.01394	1.292	71.7	0.00648	0.604
4 1/2	I.E.U.	16.60	18.37	X.H.	46	6 1/4	31.11	0.01394	1.301	71.8	0.00668	0.624
4 1/2	E.U.	20.00	21.62	I.F.	50	6 3/8	31.07	0.01287	1.200	77.3	0.00786	0.733
4 1/2	I.E.U.	20.00	22.09	X.H.	46	6 1/4	31.11	0.01257	1.173	79.5	0.00804	0.750
5	I.E.U.	19.50	20.89	X.H.	50	6 3/8	31.05	0.01746	1.626	57.3	0.00760	0.708
5	I.E.U.	25.60	26.89	X.H.	50	6 3/8	31.05	0.01528	1.423	65.5	0.00979	0.912
5 1/2	I.E.U.	21.90	23.77	F.H.	*(3)*	7	31.17	0.02169	2.028	46.1	0.00865	0.809
5 1/2	I.E.U.	24.70	26.33	F.H.	*(3)*	7	31.17	0.02077	1.942	48.2	0.00958	0.896

(1) Grade E drill pipe.
(2) Table 2.10, API RP 7G: Recommended Practice for Drill Stem Design and Operating Limits, Twelfth Edition, May 1987.
(3) Obsolete tool joint.
(4) Based on an average pipe length of 29.4 feet before adding tool joints.
(5) The approximate weight per foot is converted to barrels using steel density of 489.54 lb/ft^3 and volume of one barrel equal to 5.61458 ft^3.

****

BARITE REQUIREMENTS

Sacks/100 bbl $= \dfrac{1470 \times (\text{Required Drilling Fluid Density} - \text{Present Drilling Fluid Density})}{(35 - \text{Required Drilling Fluid Density})}$

$= \dfrac{1470 \times (\_\_\_\_ \text{ lb/gal} - \_\_\_\_ \text{ lb/gal})}{(35 - \_\_\_\_ \text{ lb/gal})} = \_\_\_\_ \text{ sx/100 bbl.}$

Barite Required $= \dfrac{\text{Drilling Fluid Volume} \times \text{Sacks/100 bbl}}{100} = \dfrac{\_\_\_\_ \text{ bbl} \times \_\_\_\_ \text{ sx/100 bbl}}{100} = \_\_\_\_ \text{ sx.}$

Required Mixing Rate $= \dfrac{\text{Sacks/100 bbl} \times \text{Kill Rate}}{100} = \dfrac{\_\_\_\_ \text{ sx/100 bbl} \times \_\_\_\_ \text{ bpm}}{100} = \_\_\_\_ \text{ sx/min.}$

DILUTION OF RESERVE DRILLING FLUID WITH WATER

Barrels Water $= \dfrac{(\text{Present Drilling Fluid Density} - \text{Desired Drilling Fluid Density}) \times \text{Present Drilling Fluid Volume}}{(\text{Desired Drilling Fluid Density} - 8.34)}$

$= \dfrac{(\_\_\_\_ \text{ lb/gal} - \_\_\_\_ \text{ lb/gal}) \times \text{ bbl}}{(\_\_\_\_ \text{ lb/gal} - 8.34)} = \_\_\_\_ \text{ bbl.}$

Displacement of Duplex, Double-acting Pumps

(90 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = $.0001619\ L\ [2D^2 - d^2]\ (\text{Eff.})$
Where: L = Stroke length, in.
D = Liner diameter, in.
d = Rod diameter, in.
Eff. = Volumetric efficiency, decimal fraction.

Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Diameter, in.	Rod Diameter, in.	Displacement, bbl/stk.
16	5	2 1/2	.102	18	5	2 1/2	.115
16	5 1/2	2 1/2	.126	18	5 1/2	2 1/2	.142
16	6	2 1/2	.153	18	6	2 1/2	.172
16	6 1/2	2 1/2	.182	18	6 1/2	2 1/2	.205
16	7	2 1/2	.214	18	7	2 1/2	.241
16	7 1/2	2 1/2	.248	18	7 1/2	2 1/2	.279
16	8	2 1/2	.284	18	8	2 1/2	.319
16	6	3	.147	18	6	3	.165
16	6 1/2	3	.176	18	6 1/2	3	.198
16	7	3	.207	18	7	3	.233
16	7 1/2	3	.241	18	7 1/2	3	.271
16	8	3	.277	18	8	3	.312
16	8 1/2	3	.316	18	6	3 1/2	.157
16	6	3 1/2	.139	18	6 1/2	3 1/2	.190
16	6 1/2	3 1/2	.168	18	7	3 1/2	.225
16	7	3 1/2	.200	18	7 1/2	3 1/2	.263
16	7 1/2	3 1/2	.234	18	8	3 1/2	.304
16	8	3 1/2	.270				

Displacement of Triplex, Single-acting Pumps

(100 Percent Volumetric Efficiency)

Displacement (bbl/stk.) = $.000243 \times L \times D^2$
Where: L = Stroke length, in.
D = Liner diameter, in.

Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.	Stroke Length, in.	Liner Size, in.	Displacement, bbl/stk.
7	3	.0153	9	3 1/2	.0268
7	3 1/2	.0208	9	4	.0350
7	4	.0272	9	4 1/2	.0443
7	4 1/2	.0344	9	5	.0546
7	5	.0425	9	5 1/2	.0661
7	5 1/2	.0514	9	6	.0787
7	6	.0612	10	4 1/2	.0492
7	6 1/2	.0718	10	5	.0607
7	7	.0833	10	5 1/2	.0735
8	4 1/2	.0393	10	6	.0874
8	5	.0486	10	6 1/2	.1026
8	5 1/2	.0588	12	5	.0729
8	6	.0699	12	5 1/2	.0882
8	6 1/2	.0821	12	6	.1049
			12	6 1/2	.1231
			12	7	.1428

API

American Petroleum Institute

2006 Publications Order Form

Effective January 1, 2006.
API Members receive a 30% discount where applicable.
The member discount does not apply to purchases made for the purpose of resale or for incorporation into commercial products, training courses, workshops, or other commercial enterprises.

Available through Global Engineering Documents:
Phone Orders: **1-800-854-7179** (Toll-free in the U.S. and Canada)
303-397-7956 (Local and International)
Fax Orders: **303-397-2740**
Online Orders: **www.global.ihs.com**

Date: ____________________

❑ **API Member** (Check if Yes)

Invoice To (❑ Check here if same as "Ship To")
Name:
Title:
Company:
Department:
Address:

City: State/Province:
Zip/Postal Code: Country:
Telephone:
Fax:
E-Mail:

Ship To (UPS will not deliver to a P.O. Box)
Name:
Title:
Company:
Department:
Address:

City: State/Province:
Zip/Postal Code: Country:
Telephone:
Fax:
E-Mail:

Quantity	Product Number	Title	SO★	Unit Price	Total
	GX16A03	Spec 16A/ISO 13533, Drill-through Equipment, Petroleum and natural gas industries--Drilling and production equipment: Drill through equipment (Modified)		$137.00	
	G07242	Spec 16C, Choke and Kill Systems		$110.00	
	G16D02	Spec 16D, Control Systems for Drilling Well Control Equipment		$147.00	
	G64002	RP 64, Diverter Systems Equipment and Operations		$86.00	
	G53003	RP 53, Blowout Prevention Equipment Systems for Drilling Operations		$110.00	

❑ **Payment Enclosed** ❑ **P.O. No.** (Enclose Copy) ____________

❑ **Charge My Global Account No.** ____________

❑ **VISA** ❑ **MasterCard** ❑ **American Express** ❑ **Diners Club** ❑ **Discover**

Credit Card No.:
Print Name (As It Appears on Card):
Expiration Date:
Signature:

Subtotal	
Applicable Sales Tax *(see below)*	
Rush Shipping Fee *(see below)*	
Shipping and Handling *(see below)*	
Total *(in U.S. Dollars)*	

★ ***To be placed on Standing Order for future editions of this publication, place a check mark in the SO column and sign here:***

Pricing and availability subject to change without notice.

Mail Orders – Payment by check or money order in U.S. dollars is required except for established accounts. State and local taxes, $10 processing fee*, and 5% shipping must be added. Send mail orders to: **API Publications, Global Engineering Documents, 15 Inverness Way East, M/S C303B, Englewood, CO 80112-5776, USA.**
Purchase Orders – Purchase orders are accepted from established accounts. Invoice will include actual freight cost, a $10 processing fee*, plus state and local taxes.
Telephone Orders – If ordering by telephone, a $10 processing fee* and actual freight costs will be added to the order.
Sales Tax – All U.S. purchases must include applicable state and local sales tax. Customers claiming tax-exempt status must provide Global with a copy of their exemption certificate.
Shipping (U.S. Orders) – Orders shipped within the U.S. are sent via traceable means. Most orders are shipped the same day. Subscription updates are sent by First-Class Mail. Other options, including next-day service, air service, and fax transmission are available at additional cost. Call 1-800-854-7179 for more information.
Shipping (International Orders) – Standard international shipping is by air express courier service. Subscription updates are sent by World Mail. Normal delivery is 3-4 days from shipping date.
Rush Shipping Fee – Next Day Delivery orders charge is $20 in addition to the carrier charges. Next Day Delivery orders must be placed by 2:00 p.m. MST to ensure overnight delivery.
Returns – All returns must be pre-approved by calling Global's Customer Service Department at 1-800-624-3974 for information and assistance. There may be a 15% restocking fee. Special order items, electronic documents, and age-dated materials are non-returnable.
***Minimum Order –** There is a $50 minimum for all orders containing hardcopy documents. The $50 minimum applies to the order subtotal including the $10 processing fee, excluding any applicable taxes and freight charges. If the total cost of the documents on the order plus the $10 processing fee is less than $50, the processing fee will be increased to bring the order amount up to the $50 minimum. This processing fee will be applied before any applicable deposit account, quantity or member discounts have been applied. There is no minimum for orders containing only electronically delivered documents.

Additional copies are available through IHS
Phone Orders: 1-800-854-7179 (Toll-free in the U.S. and Canada)
303-397-7956 (Local and International)
Fax Orders: 303-397-2740
Online Orders: global.ihs.com

Information about API Publications, Programs and Services
is available on the web at **www.api.org**

1220 L Street, NW
Washington, DC 20005-4070
USA

202.682.8000

Product No. G59002