Recommended Practice for Diverter Systems Equipment and Operations

API RECOMMENDED PRACTICE 64 (RP 64)
SECOND EDITION, NOVEMBER 2001

REAFFIRMED, JANUARY 2012

AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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FOREWORD

This publication represents a composite of the practices employed by various operating and drilling companies in drilling operations. In some cases, a reconciled composite of the various practices employed by these companies was utilized. This publication is under jurisdiction of the American Petroleum Institute, Upstream Department's Executive Committee on Drilling and Production Operations.

Drilling 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 equipment, and preservation of the environment for land and marine drilling 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 diverter systems in drilling operations. 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 this recommended practice 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.

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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.

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Recommended Practice for Diverter Systems Equipment and Operations

1 Scope

1.1 PURPOSE

This recommended practice (RP) is intended to provide accurate information that can serve as a guide for selection, installation, testing, and operation of diverter equipment systems on land and marine drilling rigs (barge, platform, bottom-supported, and floating). Diverter systems are composed of all subsystems required to operate the diverter under varying rig and well conditions. A general description of operational procedures is presented with suggestions for the training of rig personnel in the proper use, care, and maintenance of diverter systems.

1.2 WELL CONTROL

Opinions differ throughout the drilling industry concerning well control involving shallow gas. Appendix A of this publication is intended to provide some technical understanding of what takes place when shallow gas is drilled and to promote a better understanding of the analysis technique fundamentals. This publication, API RP 64, serves as a companion to RP 59 *Recommended Practice for Well Control Operations* and RP 53 *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells*. RP 59 establishes recommended operations to retain pressure control of the well under pre-kick conditions and recommended practices to be utilized during a kick. RP 53 establishes recommended practices for the installation and testing of equipment for the anticipated well conditions and service.

1.3 DEEPWATER

Operations in deepwater have special requirements with respect to well control and well control systems. This publication discusses some of the special considerations with respect to diverter use in deepwater. The International Association of Drilling Contractors (IADC) has addressed diverter issues in the overall context of deepwater drilling in their publication *IADC Deepwater Well Control Guidelines* published in 1998.

1.4 LOW TEMPERATURE OPERATIONS

Some drilling operations are conducted in areas of extreme low temperatures. Since current general practices usually result in protecting diverter systems equipment from that type environment, an applicable section has not been included for that service.

1.5 GENERAL

Recommended equipment installations, arrangements, and operations as set forth in this publication are deemed adequate to meet specified well conditions and intended uses. Examples presented herein are simplified embodiments and are not intended to be limiting or absolute. These recommended practices were prepared recognizing that alternative installations, arrangements, and/or operations may be equally as effective in meeting well requirements and promoting safety of drilling personnel, public safety, integrity of the drilling equipment, protection of the environment, and efficiency of ongoing operations.

2 References

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 49	*Drilling and Well Servicing Operations Involving Hydrogen Sulfides*
RP 53	*Blowout Prevention Equipment Systems for Drilling Wells*
RP 54	*Occupational Safety for Oil and Gas Well Drilling and Servicing Operations*
RP 59	*Well Control Operations*
RP 500	*Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2*
RP 505	*Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1 and Zone 2*

ANSI[1]

B1.20.1	*General Purpose Pipe Threads*

ASME[2]

	Article II of ASME Boiler and Pressure Vessel Code, Section IX
B31.3	*Process Piping*

NACE[3]

MR 01-75	*Material Requirements*
	Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment

[1]American National Standards Institute, 11 West 42nd Street, New York, New York 10036.
[2]ASME International, 3 Park Avenue, New York, New York 10016-5990.
[3]NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, P.O. Box 218340, Houston, Texas 77218-8340.

3 Definitions and Abbreviations

3.1 DEFINITIONS

The following definitions are provided to help clarify and explain use of certain terms in this publication. Users should recognize that some of these terms can be used in other instances where the application or meaning may vary from the specific information provided in this publication.

3.1.1 accumulator system: A series of pressure vessels used to store hydraulic fluid charged with nitrogen gas under pressure for operation of blowout preventers (BOPs) and/or diverter system.

3.1.2 actuator: A device used to open or close a valve by means of applied manual, hydraulic, pneumatic, or electrical energy.

3.1.3 aerated fluid: Drilling fluid injected with air or gas in varying amounts for the purpose of reducing hydrostatic head.

3.1.4 air/gas drilling: Refer to Aerated Fluid, 6.3 and 6.3.3.

3.1.5 annular packing element: A doughnut shaped, rubber/elastomer element that effects a seal in an annular preventer or diverter. The annular packing element is displaced toward the bore center by the upward movement of an annular piston.

3.1.6 abnormal pressure: Formation 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.

3.1.7 annular sealing device: Generally, a torus-shaped steel housing containing an annular packing element which facilitates closure of the annulus by constricting to seal on the pipe or kelly in the wellbore. Some annular sealing devices also facilitate shutoff of the open hole.

3.1.8 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.

3.1.9 annular preventer: A device that can seal around any object in the wellbore or upon itself. Compression of a reinforced rubber/elastomer packing element by hydraulic pressure effects the seal.

3.1.10 ball valve: A valve that employs a rotating ball to open or close the flow passage.

3.1.11 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.

3.1.12 blooey line: The flow line in air or gas drilling operations.

3.1.13 blowout: An uncontrolled flow of well fluids and/or formation fluids from the wellbore or into lower pressured subsurface zones (underground blowout).

3.1.14 blowout preventer (BOP) stack: The assembly of well control equipment including preventers, spools, valves, and nipples connected to the top of the casing-head that allows the well to be sealed to confine well fluids to the wellbore.

3.1.15 bottom-hole assembly: That part of the drill string located directly above the drill bit. The components primarily include drill collars and other specialty tools such as stabilizers, reamers, drilling jars, bumper subs, heavy weight drill pipe, etc.

3.1.16 bottoms-up gas: Gas that has risen to the surface from previously drilled gas-bearing formations.

3.1.17 bottom-supported drilling vessels: Drilling vessels which float to the desired drilling location and are either ballasted or jacked-up so that the vessel is supported by the soil on the bottom while in the drilling mode. Rigs of this type include platforms, submersibles, swamp barges, and jack-up drilling rigs.

3.1.18 broaching: Flow of fluids to the surface or to the sea bed through channels outside the casing.

3.1.19 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.

3.1.20 cleanout: A point in the flow line piping where access to the internal area of the pipe can be achieved to remove accumulated debris and drill cuttings.

3.1.21 closing unit: The assemblage of pumps, valves, lines, accumulators, and other items necessary to open and close the BOP equipment and diverter system.

3.1.22 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 upflowing drilling fluid from the wellbore to the surface drilling fluid system until the first casing string is set in the well.

3.1.23 conductor casing or conductor pipe (floating installations): The first string of pipe installed below the structural casing on which the wellhead and BOP equipment are installed.

3.1.24 control function: 1) The control system circuit (hydraulic, pneumatic, electrical, mechanical, or a combination thereof) used to operate the position selection of a diverter unit, BOP, valve, or regulator. Examples: diverter "close" function, starboard vent valve "open" function. 2) Each position of a diverter unit, BOP, or valve and each regulator assignment that is operated by the control system.

3.1.25 differential pressure-set valve: A valve that is operated when its actuator senses a change in pressure of a pre-set limit.

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

3.1.27 diverter control system: The assemblage of pumps, accumulators, manifolds, control panels, valves, lines, etc., used to operate the diverter system.

3.1.28 diverter housing: A permanent installation under the rotary table which houses the diverter unit.

3.1.29 diverter packer: Refer to Annular Sealing Device.

3.1.30 diverter piping: Refer to Vent Line.

3.1.31 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.

3.1.32 diverter unit: The device that embodies the annular sealing device and its actuating means.

3.1.33 drill floor substructure: The foundation structure on which the derrick, rotary table, draw-works, and other drilling equipment are supported.

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

3.1.35 drilling fluid return line: Refer to Flow Line.

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

3.1.37 drill ship: A self-propelled, floating, ship-shaped vessel, equipped with drilling equipment.

3.1.38 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.

3.1.39 dynamically positioned drilling vessels: Drill ships and semi-submersibles drilling rigs equipped with computer controlled thrusters, which enable them to maintain a constant position relative to the sea floor without the use of anchors and mooring lines while conducting floating drilling operations.

3.1.40 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 wellbore to effect a kill without completely closing in the well with the surface containment equipment. Refer to Appendix A—Shallow Gas Well Control.

3.1.41 elastomer: Any of various elastic compounds or substances resembling rubber.

3.1.42 fill-up line: A line usually connected into the bell nipple above the BOP to allow adding drilling fluid to the hole while pulling out of the hole to compensate for the metal volume displacement of the drill string being pulled.

3.1.43 fill-up (flood) valve: A differential pressure-set valve installed on marine risers that automatically permits seawater to enter the riser to prevent collapse under hydrostatic pressure after evacuation caused by lost circulation or by gas circulated into the riser.

3.1.44 flex/ball joint: A device installed directly above the subsea BOP stack and at the top of the telescopic riser joint to permit relative angular movement of the riser to reduce stresses due to vessel motions and environmental forces.

3.1.45 flow line: The piping that exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.

3.1.46 flow line valve: A valve that controls the flow of drilling fluid through the flow line.

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

3.1.48 function test: Closing and opening (cycling) equipment to verify operability.

3.1.49 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.

3.1.50 gas drilling: See Aerated Fluid.

3.1.51 gate valve: A valve that employs a sliding gate to open or close the flow passage.

3.1.52 hydrogen sulfide (H_2S): A highly toxic, flammable corrosive gas sometimes encountered in hydrocarbon bearing formations.

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

3.1.54 hydrostatic head: The true vertical length of fluid column, normally in ft.

3.1.55 hydrostatic pressure: The pressure that exists at any point in the wellbore due to the weight of the vertical column of fluid above that point.

3.1.56 inner barrel: The part of a telescopic slip joint on a marine riser that is attached to the flexible joint beneath the diverter.

3.1.57 insert-type packer: A diverter element that uses inserts designed to close and seal on specific ranges of pipe diameter.

3.1.58 inside blowout preventer: 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.

3.1.59 integral valve: A valve embodied in the diverter unit that operates integrally with the annular sealing device.

3.1.60 interlock: An arrangement of control system functions designed to require the actuation of one function as a prerequisite to actuate another.

3.1.61 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.

3.1.62 kick: An influx of gas, oil, or other well fluids, which if not controlled, can result in a blowout.

3.1.63 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.

3.1.64 knife valve: A valve using a portal plate or blade to facilitate open and close operation; different from a gate valve in that the bonnet area is open, i.e., not sealed.

3.1.65 locking mechanism: A support or restraint device.

3.1.66 lost circulation (lost returns): The loss of whole drilling fluid to the wellbore.

3.1.67 marine riser system: The extension of the wellbore 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.

3.1.68 moored vessels: Offshore floating drilling vessels, which rely on anchors, chain, and mooring lines extended to the ocean floor to keep the vessel at a constant location relative to the ocean floor.

3.1.69 mud/gas separator: A device that separates entrained gas from the drilling fluid system.

3.1.70 mud line: The floor of a body of water such as an ocean, lake, bay or swamp.

3.1.71 offshore platforms: Permanently installed bottom-supported/connected, offshore structures equipped with drilling and/or production equipment for drilling and/or development of offshore oil and gas reservoirs.

3.1.72 outer barrel: The part of a telescopic slip joint on a marine riser that is attached to tensioner lines. Tension is transferred through the outer barrel into the riser.

3.1.73 packing element: The annular sealing device in an annular BOP or diverter. Also, the elastomer packing element used in valves or lubricators to effect a seal.

3.1.74 pack-off or stripper: A device with a rubber/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.

3.1.75 pressure equalization valve (dump valve): A device used to control bottom-riser annulus pressure by establishing direct communication with the sea.

3.1.76 pressure regulator: A control system component that permits attenuation of control system supply pressure to a satisfactory pressure level to operate components downstream.

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

3.1.78 remote controlled valve: A valve that is controlled from a remote location.

3.1.79 riser spider: Equipment used to support the marine riser while it is being run or retrieved.

3.1.80 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.

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

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

3.1.83 rotary support beams: The steel beams of a substructure that support the rotary table.

3.1.84 semi-submersible: A floating offshore drilling vessel which is ballasted at the drilling location and conducts drilling operations in a stable, partly submerged position.

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

3.1.86 sour gas: Natural gas containing hydrogen sulfide.

3.1.87 spool: Refer to Drilling Spool.

3.1.88 standard well kill procedure: Any of industry's proven techniques to control a flowing well wherein well control is obtained through pumping drilling fluid of increased density at a predetermined pumping rate with BOP(s) closed and simultaneously controlling casing and drill pipe surface pressures by varying choke manifold choke settings until the well is stable and static with zero surface pressure.

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

3.1.90 substructure: Refer to Drill Floor Substructure.

3.1.91 sweet gas: Natural gas that does not contain hydrogen sulfide gas.

3.1.92 switchable three-way target valve: A device having an erosion resistant target with changeable position to enable selection of flow direction of diverted well fluids.

3.1.93 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.

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

3.1.95 telescopic (slip) joint packer: A torus-shaped, hydraulically or pneumatically actuated, resilient element between the inner and outer barrels of the telescopic (slip) joint which serves to retain drilling fluid inside the marine riser.

3.1.96 torus: A convex profile; shaped like a doughnut.

3.1.97 vent line: The conduit that directs the flow of diverted wellbore fluids away from the drill floor to the atmosphere.

3.1.98 vent line valve: A full-opening valve which facilitates the shut-off of flow or allows passage of diverted wellbore fluids through the vent line.

3.1.99 vent outlet: The point at which fluids exit the wellbore below the annular sealing device via the vent line.

3.1.100 wellhead: The apparatus or structure placed on the top of the casings that support the internal tubulars, seal the well, and permit access to the casing annulus.

3.1.101 working pressure rating: The maximum pressure at which an item is designed for safe operation.

3.2 ACRONYMS AND ABBREVIATIONS

The following acronyms and abbreviations are used in this publication:

ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BOP	Blowout preventer
IADC	International Association of Drilling Contractors
ID	Inside diameter
NACE	National Association of Corrosion Engineers
OD	Outside diameter
psi	Pounds per square in.
psia	Pounds per square in. absolute
psig	Pounds per square in. gauge

4 Diverter Systems

4.1 PURPOSE

A diverter system is often used during top-hole drilling and in conjunction with marine riser systems. The diverter system is not intended to shut-in or halt well flow, rather it provides a low-pressure flow control system to direct controlled or uncontrolled wellbore fluids away from the immediate drilling area for the safety of personnel and equipment. Although there are other uses, the diverter system is primarily used for the potentially hazardous flows that can experienced prior to setting the casing string on which the BOP stack and choke manifold will be installed. Diversion of the flow away from the rig usually results 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 (refer to API RP 59).

4.2 COMPONENTS OF DIVERTER SYSTEMS

The components of a diverter system are an annular sealing device, vent outlet(s), vent line(s), valve(s), and a control system.

4.3 DIVERTER SYSTEM APPLICATIONS

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.

4.3.1 Shallow Gas Flow

Shallow gas sands are usually abnormally pressured and capable of flowing gas at high flow rates and in large volumes. Shallow gas sands may be problematic to drill for several reasons, some of which are addressed below:

1. Fracture gradients are usually very low at the depth where shallow casing strings, such as drive pipe or structural casing, are set. Wells may not be shut-in on a kick at these shallow depths without the danger of possible fluid flow, broaching to the surface up the outside of the casing.
2. Drilling shallow sands too rapidly can gas-cut the drilling fluid with cuttings gas to the extent that expansion during flow to the surface lowers the hydrostatic pressure enough to cause formation flow.
3. Dispersal of drilled cuttings in the drilling fluid may cause the drilling fluid density to increase to a point that circulation may be lost, causing the hydrostatic head to drop to a point that will allow the well to flow.

4.3.2 Drilling with a Rotating-head

A rotating drilling head above the BOP allows operations to continue when circulating gas cut drilling mud out of the wellbore.

4.3.3 Marine Riser

Gas may inadvertently enter the marine riser in a number of situations that occur during routine drilling or well control operations. A diverter system provides an alternate means to safely remove gas from the riser and vent it away from the rig or as described in 7.2.4.

4.4 GUIDELINES FOR USE OF DIVERTER SYSTEMS

Following, in 4.4.1 through 4.4.6, are some 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. Data and information that may be of use for determining applicability of diverter systems include: histories of previously drilled well(s), seismic data, and other information.

4.4.1 Potential Flow below the First Casing String

A diverter system should be considered if there exists 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.

4.4.2 Fracture Gradient Insufficient for Circulating or Kill Weight Fluid

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.

4.4.3 Marine Riser and Subsea BOP Equipment

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.

4.4.4 Subsea Diverter Systems

In some situations, such as drilling in a shallow gas prone area with a floating rig, subsea positioning of the diverter may be beneficial. Subsea diverters are deployed with the vent outlet located just above the mud line. The deeper the water, the less likely a subsea diverter will be deemed necessary. Use of subsea diverters should be evaluated on a case-by-case basis.

4.4.5 Emergency Access/Egress

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.

4.4.6 Drilling with a Rotating-head

A diverter system can be used to advantage with a rotating-head in conjunction with a BOP stack and choke manifold system in certain drilling operations. These operations include, but are not limited to, hydrogen sulfide (H_2S) services, continued drilling operations with gas-cut drilling fluid, and air/gas drilling, etc.

5 Diverter Systems Design and Component Considerations

5.1 GENERAL

The diverter is an annular sealing device used to close and pack-off the annulus around pipe in the wellbore or the open hole when it is desired to divert wellbore fluids away from the rig. Conventional BOPs, insert-type diverters, and rotating-heads can be used as diverters. Some diverter systems are designed to function as diverters and as a BOP. The diverter and all individual components in the diverter system shall have a minimum rated working pressure of 200 psig. The information and recommended practices in this Section 5 are of a general nature and apply to all diverter systems, both onshore and offshore, unless otherwise specified. Further information and recommended practices for onshore and offshore drilling operations are presented in Sections 6 and 7 of this publication.

5.2 ANNULAR PACKING ELEMENT TYPES

The annular packing element serves to effect a seal and stop the upward flow path of well fluids. The diverter housing provides outlets for diverted fluids to flow out the vent lines. Ordinarily, the annular packing element is doughnut shaped and made of natural or synthetic elastomers reinforced with steel or other materials. The packing element moves radially inward when a hydraulic "close" pressure is applied to the diverter. Though some diverters and their annular packing elements are designed for complete pack-off, the device may not do so on open hole. Three types of sealing devices or packer elements commonly used in diverters are:

1. *Annular Packing Element*—An annular packing element seals on any pipe or kelly size in the bore or on open hole if no pipe is present. The annular packing element should be of sufficient internal diameter to pass the various bottom-hole assemblies and casing/liner strings required for subsequent drilling operations (see Figure 5.1).
2. *Insert-type Packing Element*—An insert-type packing diverter element uses inserts designed to close and effect a seal on ranges of pipe diameters. A hydraulic function serves to latch the insert in place. The correct size insert should be in place for the size pipe in use. The insert must be removed to pull or run the bottom-hole assembly (see Figure 5.2).
3. *Rotating-head*—A rotating-head can be used as a diverter to complement a BOP system. Wellbore pressure energizes the stripper element to effect a seal against the drill pipe, kelly, or other pipe to facilitate diverting well fluids. A rotating-head can also permit pipe movement (see Figure 5.3).

5.3 HYDROGEN SULFIDE ENVIRONMENT

Metallic diverter system equipment should comply with NACE MR 01-75 if it may be exposed to a hydrogen sulfide (H_2S) environment. Many resilient, non-metallic components, such as elastomeric seals used in diverter systems, are subject to hydrogen sulfide attack. Manufacturers of those items should be consulted regarding the serviceability of those components in hydrogen sulfide service. For additional information on elastomeric components, refer to API RP 53.

5.4 MOUNTING OF DIVERTER

Diverters attached to the rig's substructure should be designed such that the upward force of the diverted fluids is directed into the substructure. When a diverter is installed, the connection should be in accordance with the applicable provisions of API Spec 6A *Specification for Wellhead and Christmas Tree Equipment.*

5.5 VENT OUTLET(S)

The vent outlet(s) for the diverter system is located below the annular packing element. Vent outlet(s) may be incorporated in the housing of the annular device or an integral part of a separate spool located below the diverter housing. The internal cross sectional area of the vent outlet(s) should be greater than, or equal to, that of the diverter vent line(s). Design considerations for the connection between the vent outlet(s) and vent line(s) should include ease of installation, leak-free construction, and freedom from solids accumulation.

5.6 DIVERTER VALVES

5.6.1 Valve Types

Valves used in the diverter vent line(s) or in the flow line to the shale shaker should:

- be full opening;
- have at least the same opening as the line in which they are installed;
- be capable of manual (onshore operations only) or remote operation; and,
- be capable of opening with maximum anticipated pressure across the valve(s).

Ease of maintenance and reliability are major factors in valve selection. Solids accumulation in the diverter system and related piping can impede efficient operation of the valve. Valves that provide little or no space for solids to accumulate are preferred. Several types of full-opening valves can be used: gate valves (various types), ball valves, switchable three-way target valves, and valves integral to the diverter unit. Knife valves may be used if adequate precautions are taken for any gas leakage during valve operation through the unsealed bonnet. The valve manufacturer can be consulted regarding these capabilities.

5.6.2 Valve Actuators

All non-integral diverter vent valves and flow line valves located below the diverter packing element should be equipped with remote actuators capable of operation from the rig floor. Either hydraulic or pneumatic (air/gas) actuators may be used.

5.6.2.1 Hydraulic actuators may be operated with hydraulic fluid from their own closing unit or with hydraulic fluid from the BOP closing unit.

5.6.2.2 Pneumatic actuators may be operated with compressed air from the rig's air system (rig air) or an independent power and air source. Drilled solids in the valve can cause excessive resistance to full and proper operation of the valve. This may present a problem, especially on pneumatic

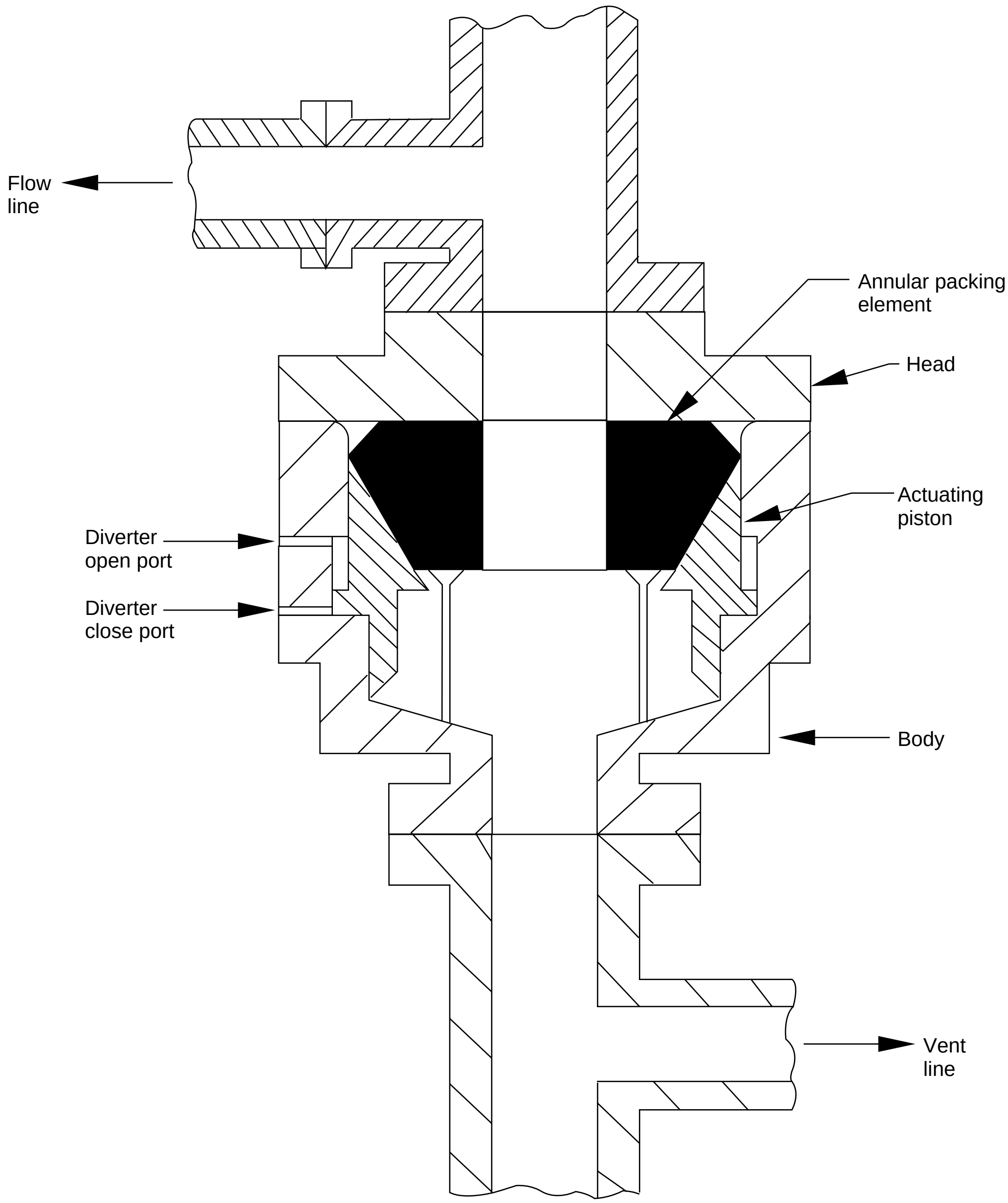


Figure 5.1—Example Diverter with Annular Packing Element

systems where variations in rig air pressure are common. Therefore, in systems utilizing pneumatic operated valves, an independent power source should be provided to supply the necessary air/gas required in the event of reduction or loss of rig air pressure.

5.6.2.3 Actuator Sizing

Actuators fitted to a diverter valve should be sized to open the valve with the minimum rated working pressure of the diverter system applied across the valve. For example, a diverter system rated at 200 psig working pressure should have an actuator designed to open the valve(s) with a differential of 200 psig or more across the valve; a diverter system rated at 500 psig working pressure should have an actuator designed to open the valve(s) with a differential of 500 psig or more across the valve(s).

5.7 DIVERTER PIPING

Erosion and pressure drop are major considerations in the design of diverter system piping. The “ideal” diverter piping would be without bends, as large in diameter as practical, and internally flush. Deviations from the “ideal” tend to increase wellbore backpressure and the possibility of erosion during diverting

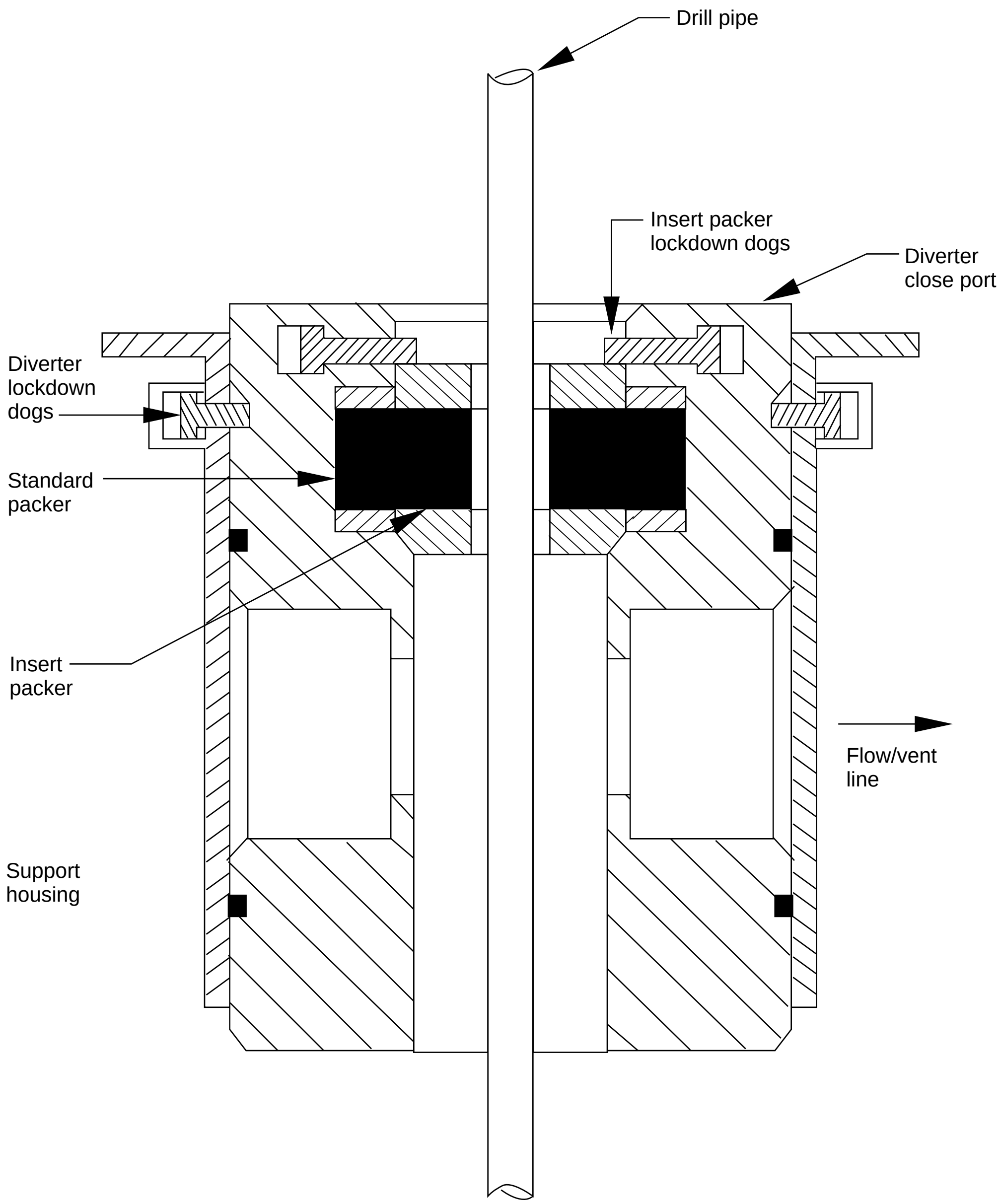


Figure 5.2—Example Diverter with Insert-type Packer

operations. All piping, valves, equipment, and well monitoring devices exposed to diverting fluids, should be able to withstand the anticipated backpressure without leaking or failing.

5.7.1 Pipe Size

Diverter piping should be sized to minimize, as much as practical, backpressure on the wellbore while diverting well fluids. Vent line piping is generally 6-in. inside diameter (ID) or larger for onshore diverter systems and 10-in. ID or larger for offshore. Backpressure contributed by the vent line pipe, bends, tees, ells, sonic velocity restrictions, etc., when applicable, should be included in the calculation of total pressure. The friction loss must not exceed the diverter system rated working pressure, place undue pressure on the wellbore, or exceed other equipment's design pressure, etc.; e.g., marine riser and its telescoping slip joint. For rigs with two vent lines, each line should be capable of diverting wellbore fluids and still maintain an acceptable backpressure. Changes in diameter of the vent line(s) should be eliminated or minimized. Changes in flow pattern at such diameter changes may lead to excessive erosion of the flow line and vent line(s) or excessive deposition of fluids/solids. Where changes in line diameter exist, backpressure calculations should be based on

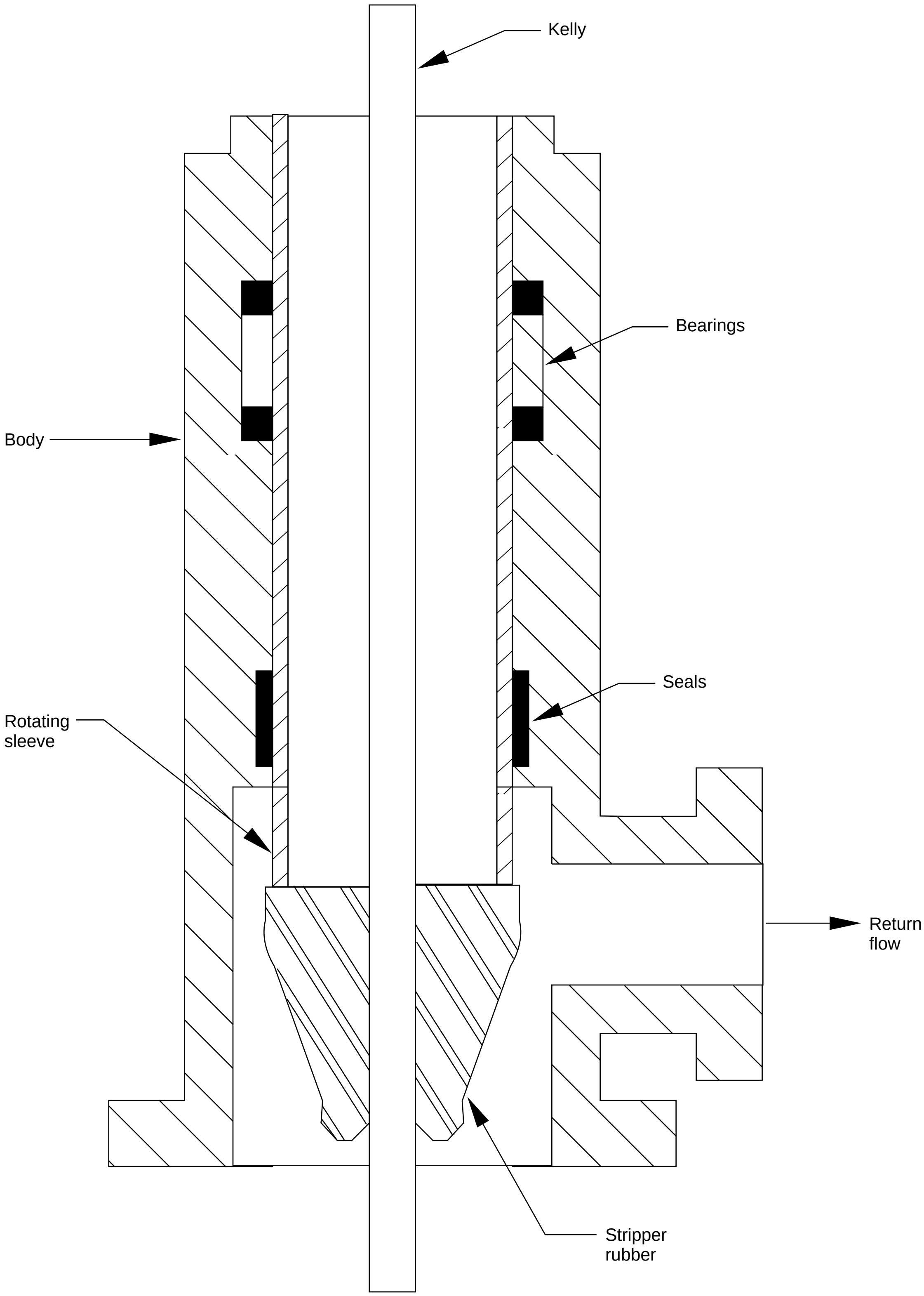


Figure 5.3—Example Diverter with Rotating Stripper

modeling the various diameter lines used in the system. Table 5.1 can be useful as a reference to compare vent line(s) sizes for various operating conditions of steady-state flow and anticipated backpressure (friction backpressure) for gas and liquid mixture flow rates in various systems.

5.7.1.1 Diverter systems may utilize flexible piping with integral end couplings to connect the vent line(s) outlet(s) on the drive or conductor pipe, diverter spool, or diverter housing to the vent line(s). Such flexible piping is acceptable provided its resistance to fire and erosion is compatible with the associated piping and provided it is adequately supported and connected.

Table 5.1—Pressure Drops for Various Combinations of Gas and Liquid Flow Rates and Pipe Internal Diameters

6-in. ID Pipe

Gas Rate, MMSCF/D	Liquid Pump Rate, GPM					
	0	100	200	300	500	1000
0	0	0.125	0.412	0.83	2.16	7.28
10	4.1	27	38.5	49	65.2	101
50	43	118	139	165	210	302
100	125	270	301	340	410	585

8-in. ID Pipe

Gas Rate, MMSCF/D	Liquid Pump Rate, GPM					
	0	100	200	300	500	1000
0	0	0.028	0.08	0.15	0.362	1.16
10	1.51	7.28	11.5	15.4	21.3	32.6
50	20	40.1	48	54.6	66.4	91.3
100	44.2	82.6	90.2	98.5	114	148

10-in. ID Pipe

Gas Rate, MMSCF/D	Liquid Pump Rate, GPM					
	0	100	200	300	500	1000
0	0	0.0076	0.025	0.059	0.138	0.49
10	0.5	3.19	4.8	6.3	9.36	15.7
50	9	20.3	23.9	28	32.9	49.9
100	22	45.3	49	54.3	62.1	79

12-in. ID Pipe

Gas Rate, MMSCF/D	Liquid Pump Rate, GPM					
	0	100	200	300	500	1000
0	0	0.0039	0.017	0.02	0.062	0.21
10	0.15	1.14	1.95	2.45	4.25	6.19
50	3.02	9.7	13.1	14.1	19.1	24.8
100	11.1	22.8	26.1	26.7	32.3	47.5

Data in table were calculated using the following conditions:

Line Length = 150 ft	Mud Weight = 9.6 ppg
Outlet Pressure = 0 psig	Plastic Viscosity = 8 cp
Gas Specific Gravity = 0.7	Temperature = 80°F

5.7.2 Pipe Routing

Diverter vent line(s) should be routed so that at all times one line can vent well fluids in a direction where the wind will not carry the diverted fluids back to the drilling rig, populated areas, or access/egress roads, etc. Vent lines should be routed as straight as possible with a minimum of bends and branches to minimize erosion, flow resistance, fluid/solid settling points, and associated backpressure. Routing changes should be as gradual as practical. Due to lack of space on some rigs, it may not always be possible to utilize large bend radii. For example, for pipe to be considered "straight," the bend radius should be 20 times the inside diameter of the pipe. Long radius bends are preferred over short radius bends; however, when 90° short radius bends are used, they should be tees equipped with a targeted blind flange or a targeted plug to minimize erosion or its impact. The vent line(s) should be sloped along its length to avoid low spots that may accumulate drilling fluid and debris.

5.7.3 Pipe Support

Vent line(s) should be firmly secured to withstand the dynamic effect of high volume fluid flow and the impact of drilling solids. Supports and fasteners located at points where piping changes direction must be capable of restraining pipe deflection. Special attention should be paid to the end sections of the vent line(s) because the diverter piping will tend to whip and vibrate at this location.

5.7.4 Cleanouts

Provisions should be made for cleaning and flushing accumulated debris from the vent line(s). Cleanouts should be placed upstream of all valves and sharp direction changes, with flushing jets located to aid removal of debris and drilling solids. Cleanouts and flushing ports should be adequately sealed to prevent the escape of any gas or well fluids when the diverter is in use.

5.7.5 Fill Lines

Fill and/or kill lines positioned below the diverter unit should be equipped with valves with an independent actuated valve or check valve near the wellhead.

5.8 CONTROL SYSTEM

The diverter control system shall be operated such that the well will not be shut-in with the diverter system. The diverter control system is usually hydraulic or pneumatic, or a combination of both types, which may be electrically controlled and capable of operating the diverter system from two or more control units. Control units should be available for ready access to operating personnel. The diverter control system may be self-contained or may be an integral part of the BOP control system. Refer to API RP 53 for additional information. Elements of the control system include:

1. Storage equipment for supplying control fluid to the pumping system.
2. Pumping systems for pressurizing the control fluid.
3. Accumulator bottles for storing pressurized control fluid.
4. Hydraulic control manifold for regulating and directing control fluid to operate the system functions.
5. Remote control panels for operating the system from remote locations.
6. Hydraulic control fluid.

5.8.1 Fluid Capacity

As a minimum, all diverter control systems should be equipped with sufficient volumetric capacity to provide the usable fluid volume (with pumps inoperative) required to operate all divert mode functions in the diverter system and still retain a 50% reserve. Usable fluid volume is defined as that fluid recoverable from an accumulator between the limits of the accumulator operating pressure and the pre-charge pressure, or the shut-off pressure, for the hydraulic operating system.

5.8.1.1 The minimum recommended accumulator volume should be determined as described in API RP 53 for the applicable diverter system, either surface or subsea.

5.8.1.2 For a closing unit used for both subsea BOP and surface diverter control, the required accumulator volumetric capacity for diverter control should be supplied through a check valve.

5.8.1.3 On systems utilizing pneumatic-operated valves, an independent power source should be provided to supply the necessary air/gas required in the event of reduction or loss of rig air pressure.

5.8.2 Primary Response Time

Well conditions may require faster closing times than those recommended below. That possibility should be considered and appropriate action taken during the design or selection of diverter closing systems.

5.8.2.1 Packing Element ID 20 in. or Less

The primary diverter closing system should be capable of operating the vent line and flow line valves and closing the annular packing element on the pipe within thirty seconds of actuation.

5.8.2.2 Packing Element ID Greater Than 20 in.

The diverter control system should be capable of operating the vent line and flow line valves and closing on the pipe within forty-five seconds.

5.8.3 Closing Unit Backup System

A secondary means (backup system) should be employed to permit sequencing the diverter system should the primary closing system become inoperative. This may be accomplished by alternative pump system capacity, separate isolated accumulator capacity, nitrogen backup capacity, or other means. The backup system should be automatically or selectively available on demand. The backup system should be included in diverter system testing and maintenance procedures.

5.8.4 Accumulator Recharging Capability

The pump system(s) should be capable of recharging the primary diverter control system accumulators to full system design pressure within five minutes or less after one complete divert mode operation of the diverter control system. This should be verified by fully charging the accumulators, isolating the pumps from service, and sequencing the divert functions using only the accumulators.

5.8.5 Pump Systems

A pump system consists of one or more pumps. Each pump system (primary and secondary) should have independent power sources, such as electricity or air. The same pump system may be used to provide power fluid to the BOP stack and the diverter system. Power for the closing unit pump(s) should be available to the accumulator unit at all times, such that the pump(s) automatically start when the closing unit manifold pressure has decreased to less than 90% of the accumulator operating pressure. Similarly, the pump(s) should automatically stop when the full design accumulator charging pressure is reached.

5.8.5.1 Pump Pressure

Each closing unit should be equipped with a pump(s) that provides a discharge pressure at least equivalent to the working pressure rating of the closing unit.

5.8.5.2 Pressure Protection

Each pump system should be protected from over pressurization by a minimum of two devices to limit the pump discharge pressure. One device, normally a pressure limit switch, should limit the pump discharge pressure so that it will not exceed the working pressure rating of the diverter control system. The second device, normally a relief valve, should be sized to relieve at a flow rate at least equal to the designed flow rate of the pump systems and should be set to relieve at not more than 10% over the control unit working pressure. These pressure limiting devices should be installed directly in the control system supply line to the accumulators and should not have isolation valves or any other means that could defeat their intended purpose. If isolation valves are desired to permit service or testing of the pressure-limiting device, those valves should be car-sealed open. Rupture disc(s) or relief valve(s) that do not automatically reset are not recommended.

5.8.6 Control System Valves, Fittings, Lines, and Manifolds

Additional information and recommendations for closing units are found in API RP 53. That document describes recommended practices for surface and subsea installations.

5.8.6.1 Valves, Fittings, and Other Components

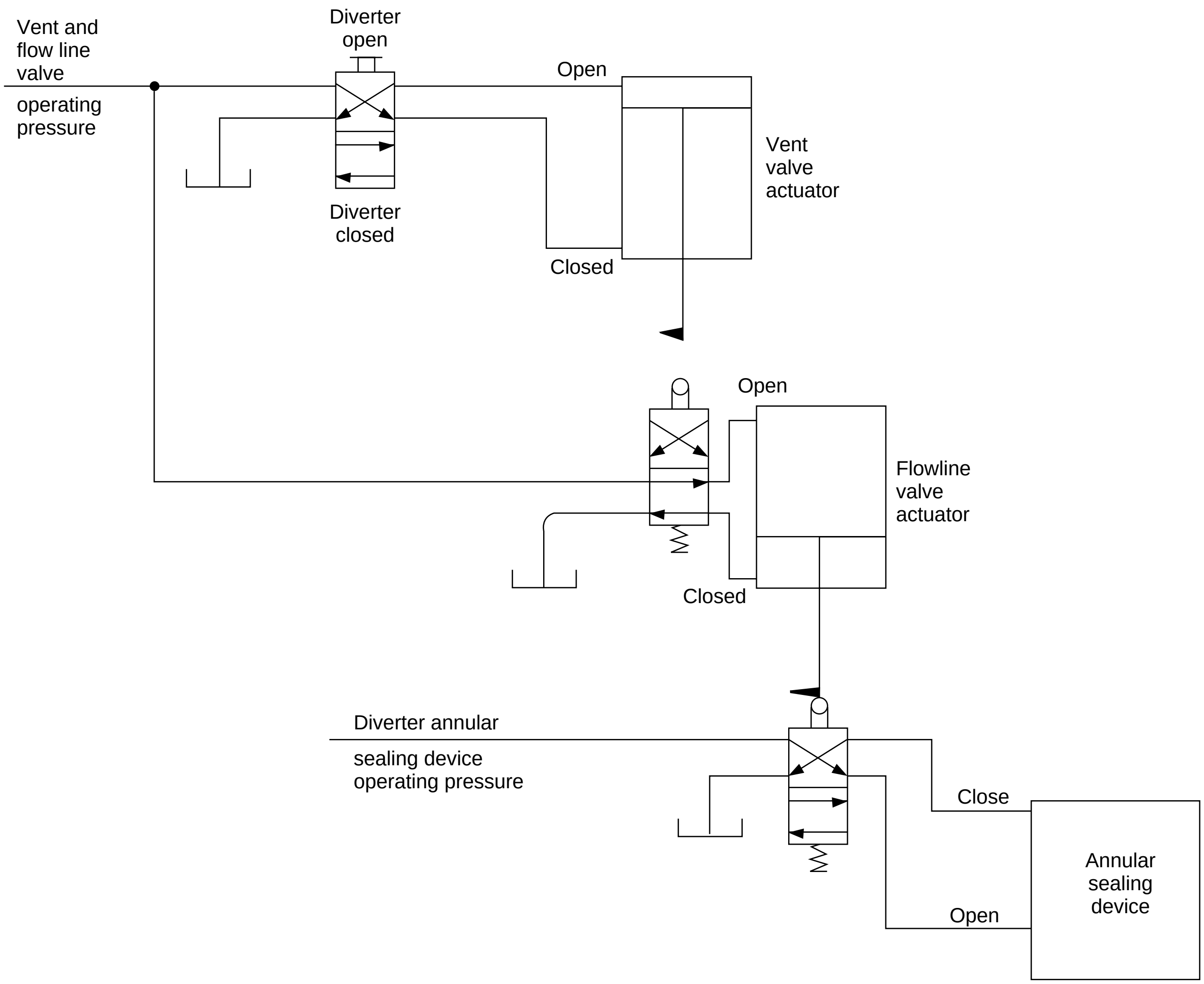
The diverter control system should be equipped:

1. With a full-opening valve into which a separate fluids pump can be easily connected.
2. To allow isolation of the pumps and accumulators from the manifold and annular control circuits, for maintenance and repairs.
3. With pressure gauges to indicate: a) accumulator pressure, b) regulator manifold pressure, c) annular pressure, and d) air pressure. Control system pressure gauges should be calibrated at least once every year.
4. With necessary pressure regulators to permit manual control of system components within their rated working pressure.
5. With clearly marked controls to indicate which valve is operated and the position of the valve (i.e., open, closed, neutral).

5.8.6.2 Conformity of Piping Systems

All piping components and all threaded connections installed on the diverter control system should conform to the design and tolerance specifications for American National Standards Taper Pipe Threads as specified in ANSI B1.20.1. Pipe and pipe fittings should conform to specifications of ASME B31.3. If weld fittings are used, the welder shall be certified for the applicable procedure required. Welding should be performed in accordance with a written weld procedure specification (WPS), written and qualified in accordance with Article II of ASME Boiler and Pressure Vessel Code, Section IX.

5.8.6.3 All rigid or flexible lines between the control system and diverter or BOP stack should be flame retardant, including end connections, and should have a working pressure equal to the working pressure of the BOP control system if a BOP is in use with the diverter system.



Note: If an annular sealing device which requires lockdown of an insert packer is in use, the lockdown function should be included in the automatic sequence.

Figure 5.4—Example Simplified Diverter Control System Schematic (Automatic Sequencing) Shown in Open Position

5.8.6.4 All control system interconnect piping, tubing, hose, linkages, etc., should be protected from damage during drilling operations, or day-to-day equipment movement.

5.8.7 Control System Fluid and Capacity

A suitable hydraulic fluid (hydraulic oil or fresh water containing a lubricant) should be used as the closing unit control operating fluid. Sufficient volume of glycol should be added to any closing unit fluid containing water if ambient temperatures below 32°F (0°C) are anticipated. Use of diesel oil, kerosene, motor oil, chain oil, or other similar fluid is not recommended due to the possibility of explosion or resilient seal damage. Each closing unit should have a fluid reservoir with a capacity equal to at least twice the usable fluid capacity of the accumulator system.

5.8.8 Hydraulic Control Unit Location

5.8.8.1 The main pump accumulator unit should be located in a safe place, easily accessible to rig personnel in an emergency, and should comply with the area classifications in the latest edition of API RP 500 *Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2* or RP 505 *Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1 and Zone 2.*

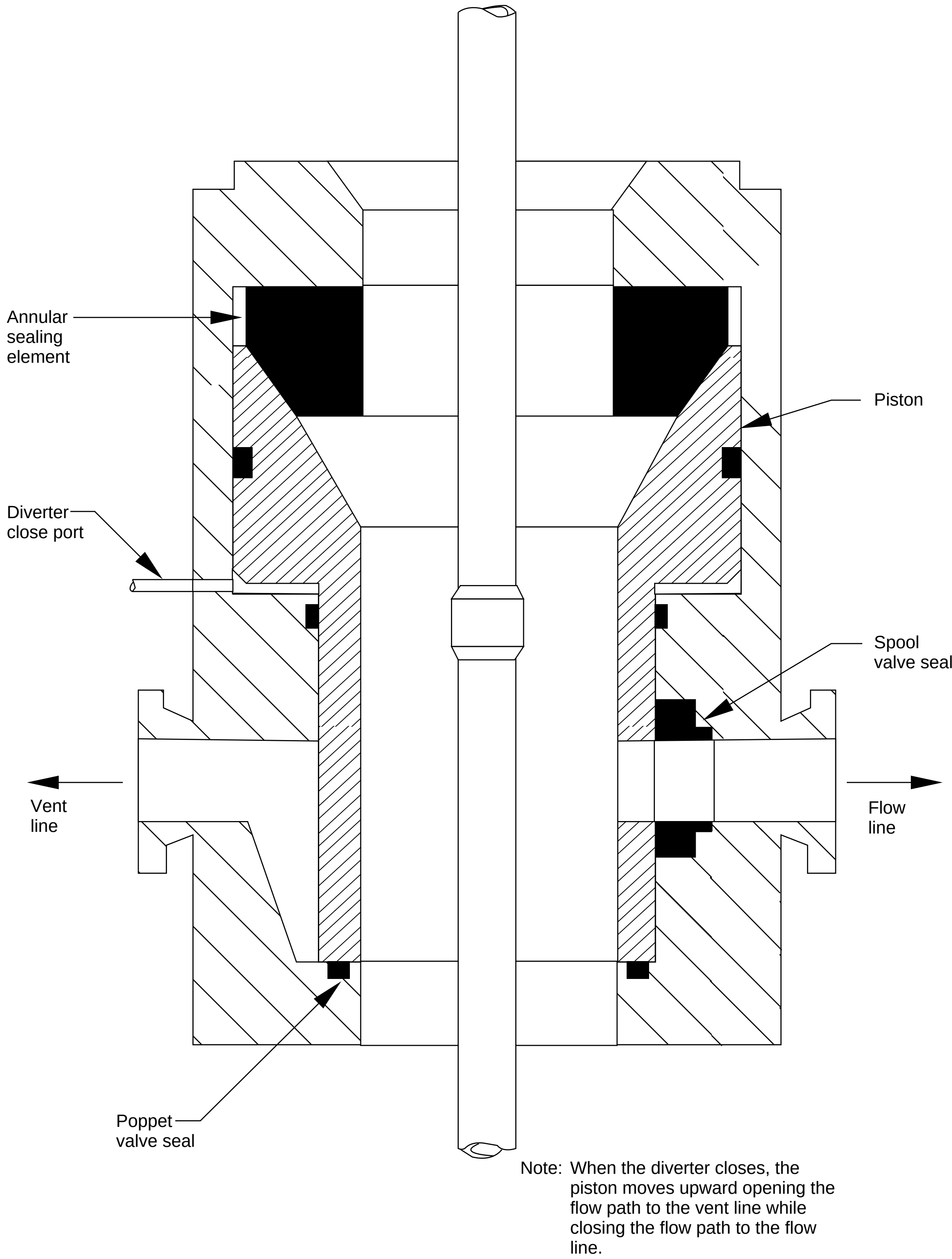


Figure 5.5—Example Diverter Systems—Integral Sequencing

5.8.8.2 The main pump accumulator unit should also be located to prevent excessive drainage or flow back from the operating lines to the reservoir. Should the main pump accumulator be located a substantial distance below the BOP stack, additional accumulator volume or alternative means should be added to compensate for flow back in the closing lines.

5.8.8.3 At least one control unit should be located such that the operation of the diverter system can be controlled from a position readily accessible to rig personnel in an emergency. In some cases, it may be desirable to have more than one control unit with the additional unit(s) located at an accessible point a safe distance away from the rig floor. The function of each control valve or regulator on the control unit shall be clearly identified at the control unit(s).

5.9 CONTROL SYSTEM OPERATIONS

The diverter control system shall be operated such that the well will not be shut-in with the diverter system. For installations with the annular sealing device below the flow line, equipment should be designed and installed such that the desired vent valve(s) is opened before the annulus is closed. On installations with more than one vent valve, both valves should remain open during this operation with the upwind valve being subsequently closed, if so desired. For non-integral valve installations where the flow line is below the annular sealing device, the desired vent valve(s) should be opened (if not already open) while simultaneously closing the shale shaker (flow line) valve and the diverter. Regardless of the vent valve sequencing, to maintain the fail-safe objective, at least one vent valve shall remain open at all times to prevent a complete shut-in of the well if there is a partial failure of the control system and/or vent controls system pressure.

5.9.1 Types of Control Sequencing

5.9.1.1 Automatic Sequencing

Typically, hydraulic or pneumatic valves, mechanical linkage, and/or limit switches are used in an automatically sequenced diverter system. Actuation of a single pushbutton or lever automatically initiates the entire sequence. One automatic method using control valves that are tripped by the physical cycling of the vent and flow line valve gates is shown in a very simplified sketch in Figure 5.4. As shown, the sequencing action is executed by the vent line valve opening, thereby tripping the control valve that enables the flow line valve to close, which in turn trips the control valve governing the annular sealing device, allowing it to close. This is only one example. Many other automatic sequencing methods for diverters and associated valves are in use. For instance, there are diverter systems that do not require associated vent line valves (refer to Figure 5.5). Some automatically sequenced diverter systems require interlocks in the controls to prevent continuation of the sequence should one function fail to operate.

5.9.1.2 Manual Sequencing

Another way to execute the divert sequence depends on trained personnel to properly execute manual operation of the functions, in correct order, by means of pushbuttons or levers. This method permits the observation and judgment of the operating personnel to guide the timing between component actuation. A manual interlock system is sometimes utilized such that operation of one function is used to enable another to operate. A typical arrangement would prevent fluid from being supplied to the diverter unless at least one vent line valve is open and the insert (if needed) is latched down.

6 Onshore and/or Bottom-supported Marine Drilling Operations

6.1 GENERAL

These operations include drilling from any land or marine structure supported by a mat type base, legs, or a barge that rests on the bottom. In the marine environment, these operations include jack-up drilling rigs, barge rigs, and production platforms. Shut-in of the BOP on a shallow fluid flow may cause the formation to fracture and allow wellbore fluids to flow up the outside of the casing to the surface. In addition to the other hazards associated with uncontrolled flows to the surface, these flows may cause damage to, or failure of, the rig foundation. Bottom-founded drilling units in a marine environment are vulnerable to foundation failure under these conditions and may overturn or collapse. Production platforms have additional exposure due to the presence of oil and gas processing facilities, pipeline connections, and producing wells as well as production and service personnel on board.

6.2 DIVERTER SYSTEMS

When diverter systems are deemed necessary (refer to 4.1 and 4.4), they should be installed on the first casing string, i.e., drive pipe, conductor pipe or structural casing.

6.2.1 Diverter Systems Valves

Refer to 5.6 and its sub-paragraphs for more information. The valve(s) should be installed close to the annular sealing device to minimize space for cuttings to collect and plug the vent line(s). If a valve(s) is not used in the diverter system or if the valve cannot be installed near the annular sealing device, the diverter system vent line(s) or riser pipe should be equipped to allow for flushing drill cuttings from the vent line(s).

6.2.2 Diverter Systems Piping

Refer to 5.7 and its sub-paragraphs. The vent line outlet(s) and vent line(s) should be installed below the diverter and extended a sufficient distance and direction from the rig to permit safe venting of diverted well fluids. For onshore drilling operations, a single vent line oriented downwind or crosswind from the rig and facilities is typically used and discharged to the pit. However, it may be desirable to provide a second vent line that discharges into a second pit and is oriented in a different direction as a precaution against changes in prevailing winds. For most bottom-supported marine drilling operations, two vent lines, oriented in different directions, are normally used. Some offshore drilling/production platforms use only one vent line due to prevailing winds.

6.2.3 Example Diverter Systems for Onshore and/or Bottom-supported Drilling Operations

Figures 6.1 through 6.8 illustrate some, but not all, examples of diverter systems for onshore and/or bottom-supported marine drilling locations.

6.3 SPECIALIZED ONSHORE AND/OR BOTTOM-SUPPORTED MARINE DRILLING OPERATIONS

A diverter system used in conjunction with a BOP stack can provide additional protection during some drilling operations. These include, but are not limited to: sour gas drilling; handling sweet gas-cut drilling fluid; and, air, aerated fluid, or gas drilling operations.

6.3.1 Sour Gas Drilling Operations

A rotating drilling head on the BOP stack should be considered when drilling where sour gas is present. This diverter system will minimize personnel exposure to hydrogen sulfide gas on the rig floor or under the substructure when circulating out drilling breaks or bottoms-up gas. The drilling fluid return flow line is used as a vent line. The drilling fluid flow line is constructed such that fluid flow can be directed, by valves located in the flow line, to a mud/gas separator and then vented a safe distance and direction from the rig (refer to Figure 6.5). For more information on sour gas drilling, refer to API RP 49 *Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfides* and RP 54 *Occupational Safety for Oil and Gas Well Drilling and Servicing Operations.*

6.3.2 Gas-cut Drilling Fluid

A rotating drilling head is useful where high-pressure, low-volume sweet or inert gas shows are frequent and it is desirable to continue drilling while handling gas cut drilling fluid. This diverter system is similar to that described in 6.3.1 and illustrated in Figure 6.5.

6.3.3 Air, Aerated Fluid, or Gas Drilling Operations

A diverter system is required in all air/gas drilling service. It consists of at least a rotating drilling head and a blooey line (vent line). This system may also be used with a BOP stack as illustrated in Figure 6.6. When natural gas is used as the circulating fluid or hydrocarbon-bearing formations will be drilled, a full-opening valve installed on the rotating drilling head should be considered. This valve allows repair of the blooey line while diverting flow through the choke line(s).

7 Diverter Systems on Floating Drilling Operations

7.1 GENERAL

Floating drilling operations include those from drill ships and semi-submersibles that drill in the floating mode. They may be moored or dynamically positioned. These vessels are distinguished from other types of drilling units in that they use subsea BOP stacks. Drilling operations from these vessels may be conducted with or without a marine riser system (riserless drilling). In riserless drilling, drilling mud is returned from the wellbore directly to the sea floor. When in use, the marine riser system connects the subsea BOP stack and associated equipment to the drilling vessel and is the conduit for all operations conducted on the well.

7.1.1 Drilling with a Marine Riser

7.1.1.1 Floating vessels drilling with a marine riser have certain advantages with regard to shallow gas flows: drilling mud returns are available to monitor for, and circulate out, gas kicks; kill weight mud can be used for well control; and, the additional mud column in the riser due to the air gap between the rig floor and the water surface provides additional hydrostatic head for well control. The marine riser may be disconnected in an emergency well control situation and the vessel moved away from the location.

7.1.1.2 There are disadvantages to drilling with a marine riser with regard to shallow gas flows. The riser provides a direct conduit for uncontrolled wellbore fluid flow to reach the drilling rig. If evacuated, the large internal diameter of the riser results in lower backpressure on the formation, thus higher flow rates. As water depth increases, the risk of riser collapse increases as gas displaces the mud inside the riser. Well kill operations are more difficult due to the large diameter of risers. Furthermore, disconnecting the marine riser in an emergency is not always without incident and becomes more complicated in deeper water. Riser disconnects can sometimes result in damage to the casing, riser, or other components.

7.1.2 Riserless Drilling

Some advantages for floating vessels drilling without a marine riser include: no direct path for wellbore fluid flows to reach the rig; the riser disconnect procedure and risk is eliminated; and, the drilling vessel may be more readily moved off location in an emergency.

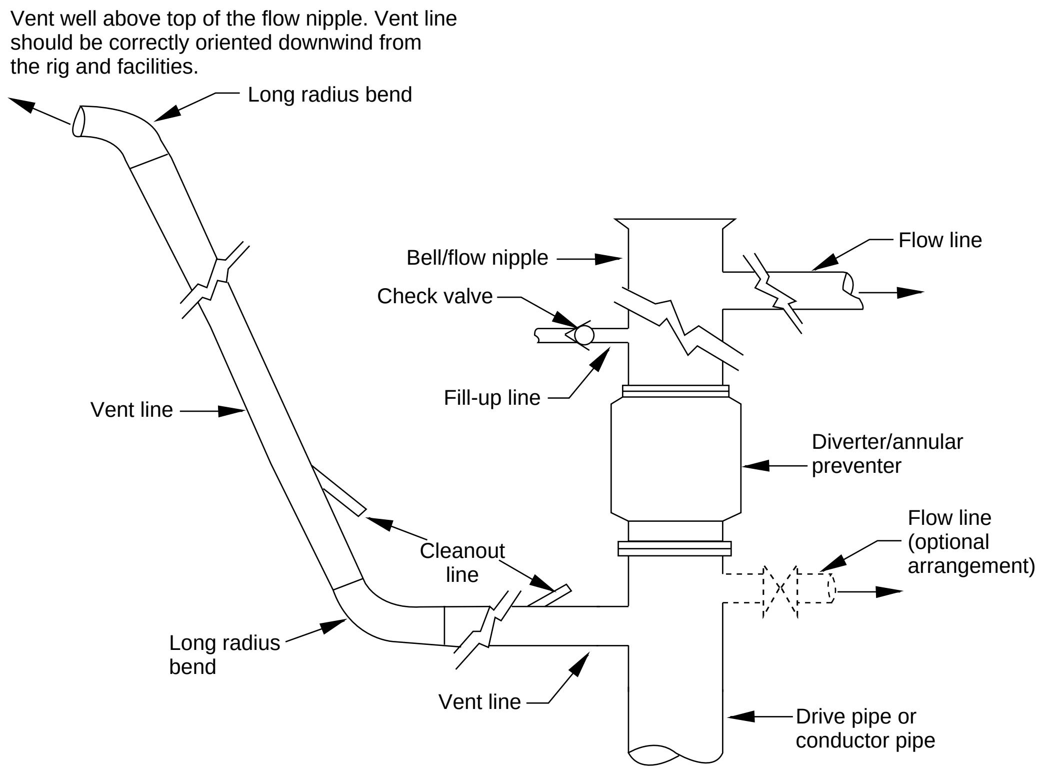


Figure 6.1—Example Diverter System—Open Flow System

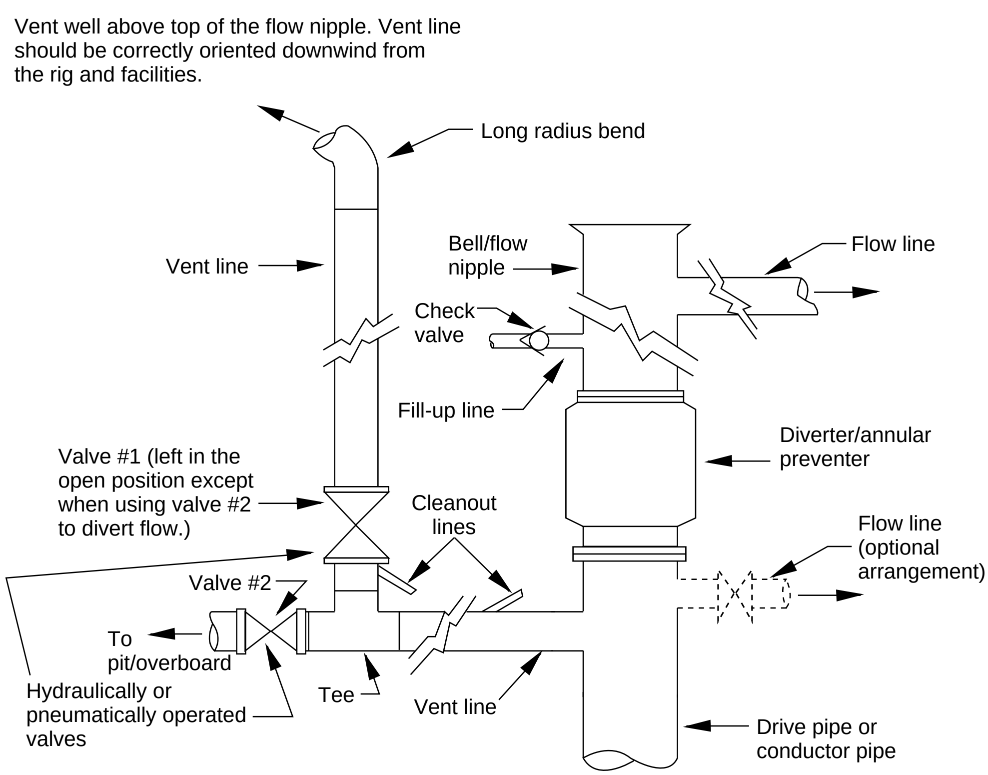


Figure 6.2—Example Diverter System—Manual Selective Flow System

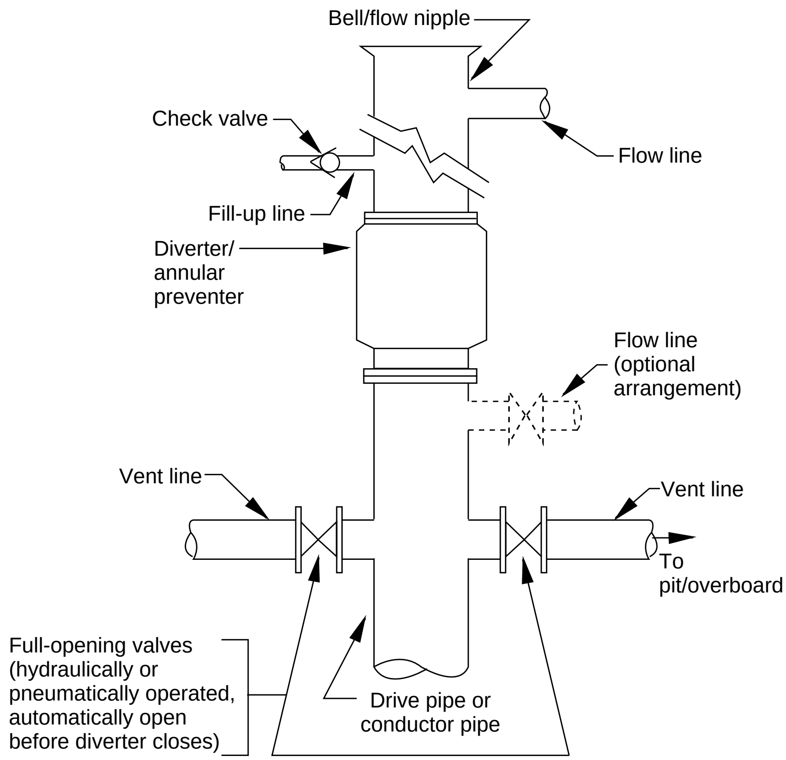


Figure 6.3—Example Diverter System—Control Sequenced Flow System

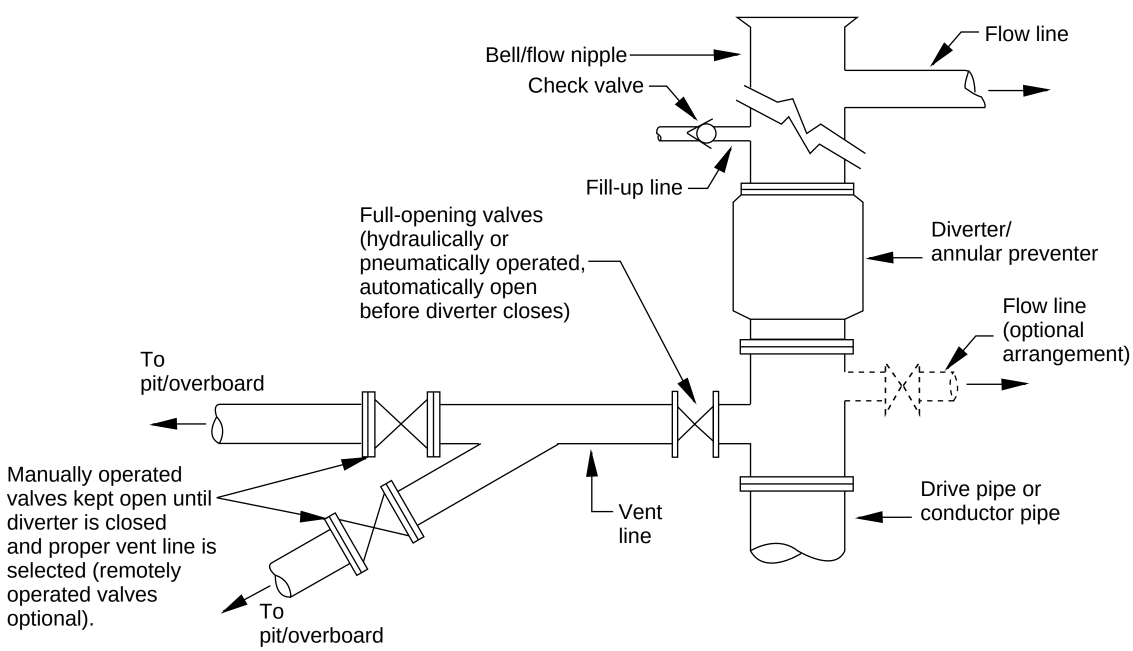


Figure 6.4—Example Diverter System—Control Sequenced Flow System with Auxiliary Vent Line

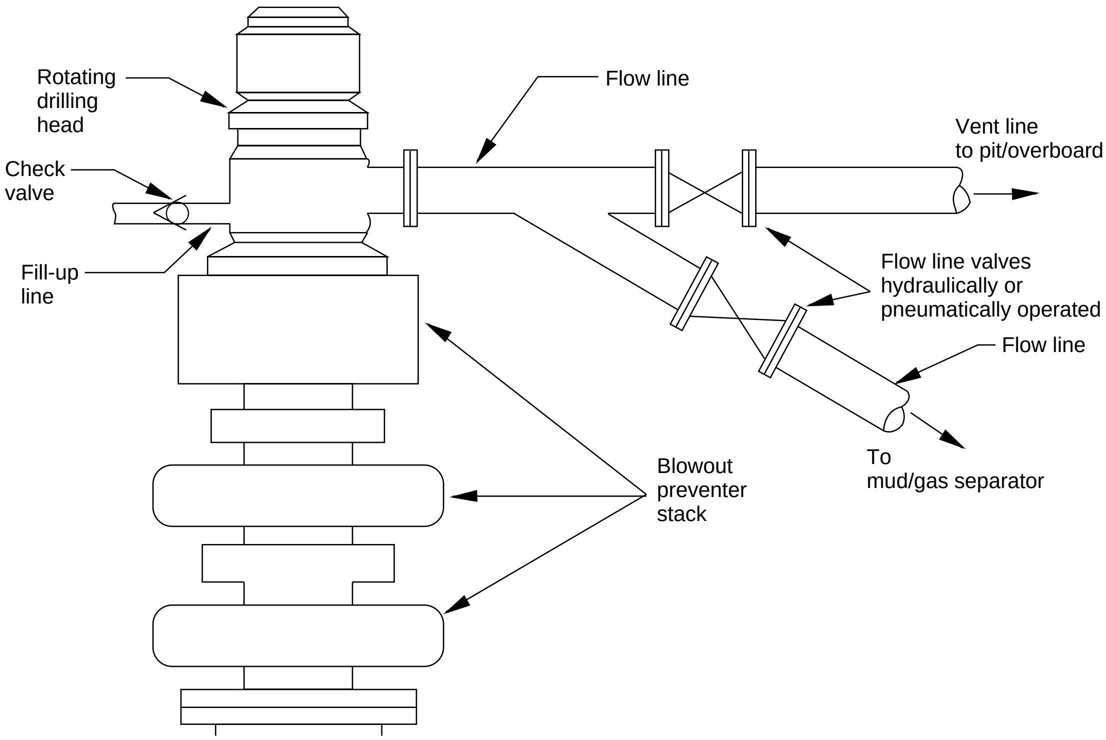


Figure 6.5—Example Diverter System—Sour Gas/Gas-cut Drilling Fluid Drilling Operations

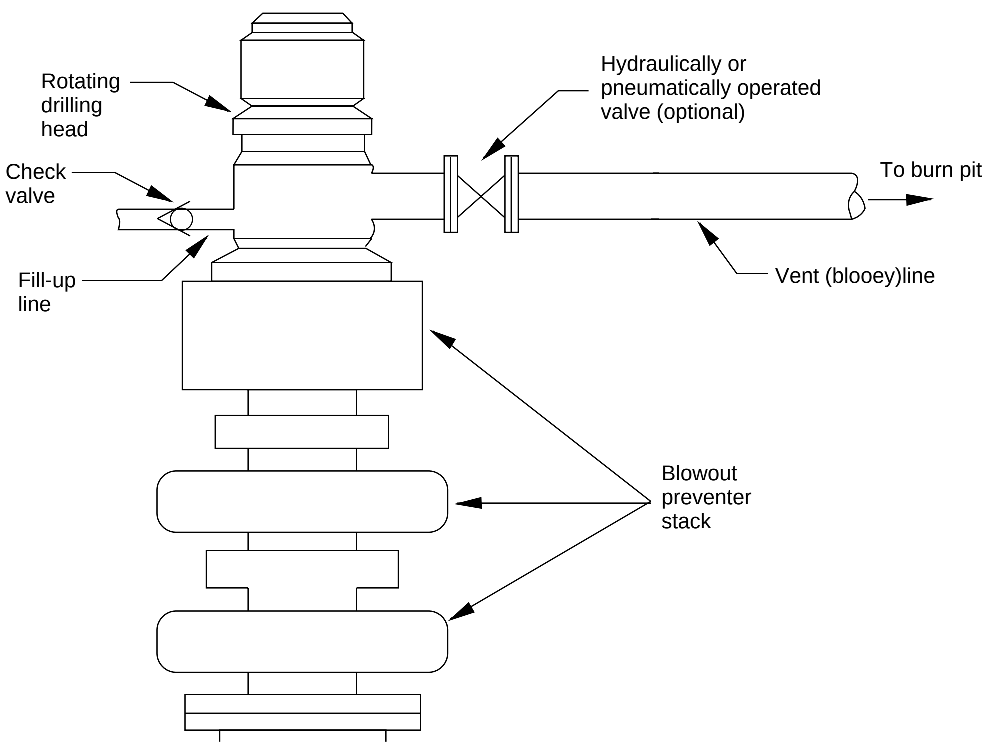


Figure 6.6—Example Diverter System—Air/Gas Drilling Operations

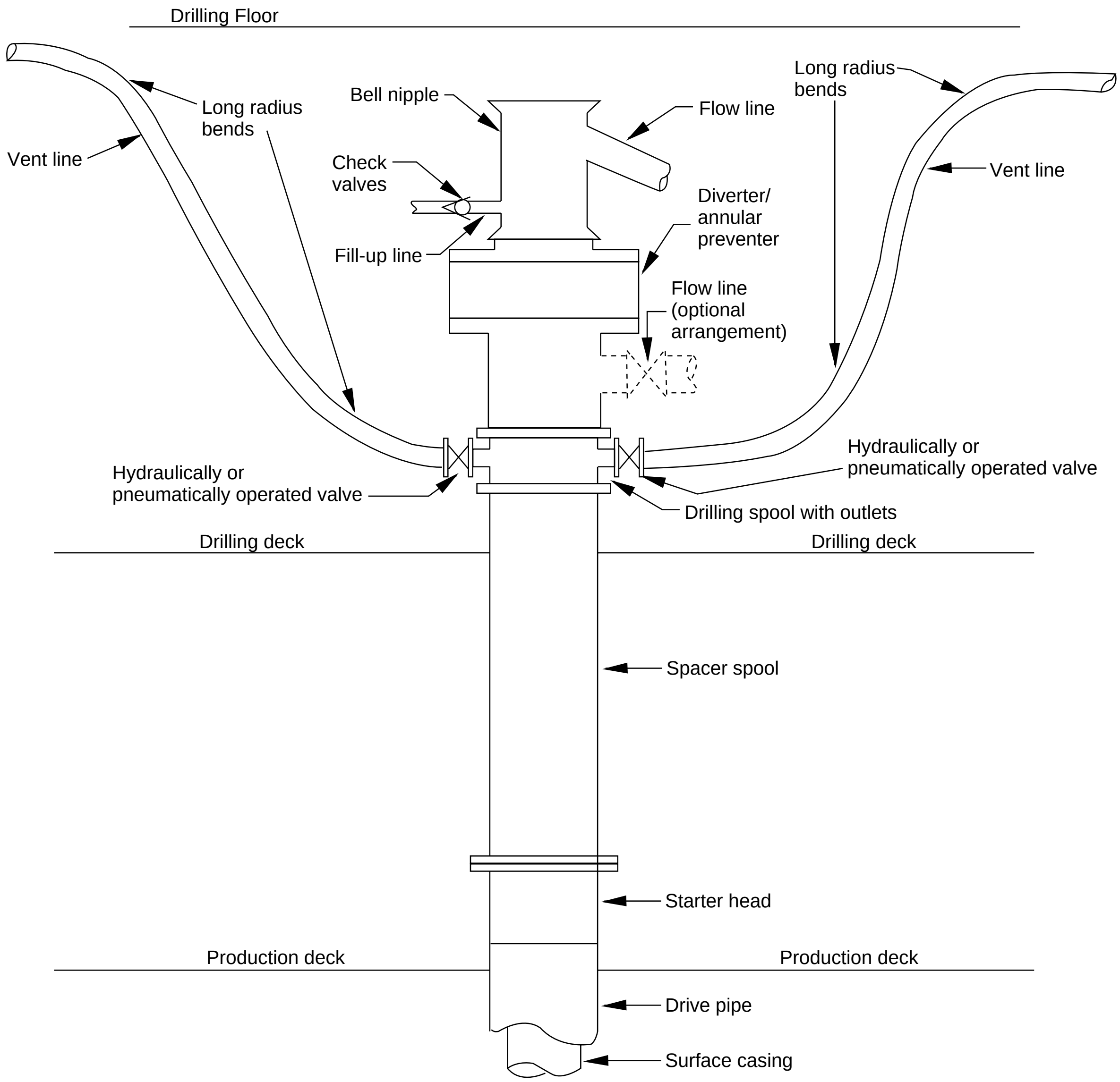


Figure 6.7—Example Diverter System for Bottom-supported Marine Operations

7.2 CRITERIA FOR DIVERTER SYSTEMS IN FLOATING DRILLING OPERATIONS

Diverter systems may be beneficial in a number of situations on floating drilling operations. The decision to use a diverter system should take several factors into account. These include the type of drilling vessel, the capabilities and layout of a particular drilling vessel, water depth, etc. Some, but not all, of the factors to be considered are presented in 7.2.1 through 7.2.5.

7.2.1 Type of Drilling Vessel Used

Drill ships and semi-submersibles have different characteristics. The following examples illustrate some of the differences.

7.2.1.1 The air gap between the water and rig on a semi-submersible vessel exposes any gas reaching the sea surface from the mud line to air currents, which can dissipate the gas or blow it away from the rig. A drill ship does not have that advantage.

7.2.1.2 A drill ship moored in relatively shallow water may not have the same stability as a semi-submersible in a situation where shallow gas is flowing from the mud line. This is due to the pontoons on the semi-submersible being deeper underwater than the hull of a drill ship thus further out of the aeration (boil) zone of a gas flow rising from the mud line.

7.2.1.3 A marine riser and diverter system is not recommended on the first casing string when using dynamically

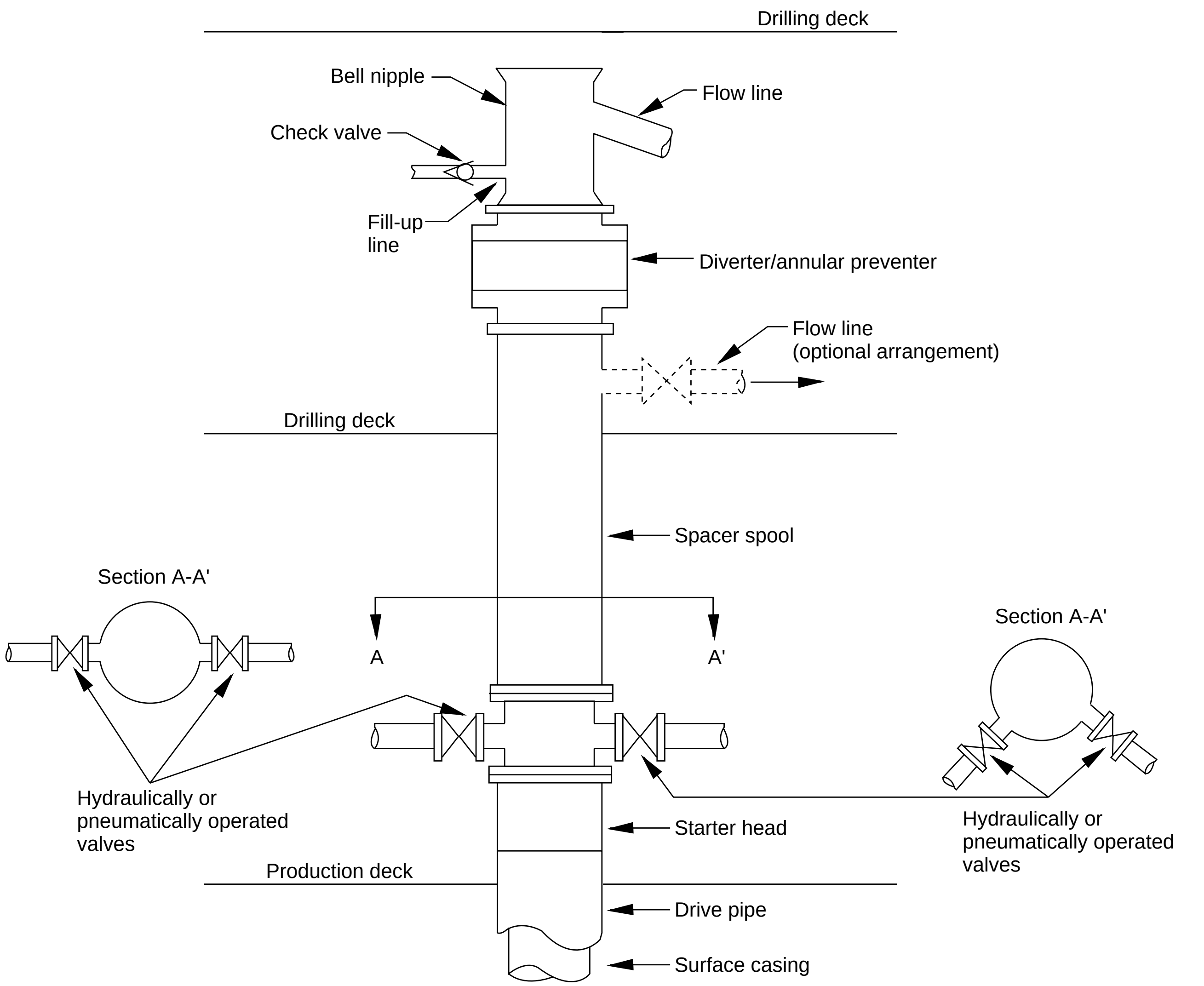


Figure 6.8—Example Diverter System for Bottom-supported Offshore Operations (Illustrating Valves in Vent Lines)

positioned drilling vessels operating without a BOP. The vessel can readily evacuate the drilling location and, thus ensure the safety of equipment and personnel in the event of an uncontrolled kick (refer to 4.1).

7.2.2 Water Depth

The deeper the water, the more likely that any shallow gas flows at the mud line will be carried away from the drilling vessel and dissipated by currents, a factor that might lend credence to a case for drilling riserless.

7.2.3 Formation Fracture Gradient

If the formation fracture gradient is inadequate, it could rule out the use of the marine riser/diverter system. The overburden pressure from sea level to the casing shoe is less than the overburden pressure at comparable land drilling depths. This is because 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 location (water density is less than rock density). Similarly, the overburden pressure of the seawater head plus the soil overburden pressure to casing shoe depth can be less than the hydrostatic pressure of the drilling fluid in the riser system. In addition, the riser system extends above mean sea level and the hydrostatic pressure of the fluid column in that part of the riser results in added pressure at the casing shoe. Thus, circulation of fluid to the drilling vessel without sufficient fracture gradient at the shoe of the last casing string can cause the formation to fracture. This may result in partial evacuation of drilling fluid in the riser, which reduces the hydrostatic head on the formation, and may cause the well to kick. Alternatives in this case may be riserless drilling or a subsea diverter.

7.2.4 Inadvertent Gas Entry into the Riser

Shallow gas flows are not the only application for a diverter system when using a marine riser. Gas may inadvertently enter the riser while drilling at any depth when the BOP is shut-in on a kick. Gas may also enter the riser if the rams leak after the BOP is closed. Gas in the riser may be safely removed by diverting the flow overboard. In some designs, a mud/gas separator is utilized in the diverter system to separate the gas from the mud and return the mud to the system. Again, the design should not allow the diverter to completely shut-in the well. For additional information on mud/gas separators operations, controls, and piping, refer to API RP 53.

7.2.5 Trapped Gas after Kick Circulation

After a kick circulation is completed, some compressed gas may remain between the closed BOP and the choke line connection (called "trapped gas"). This gas will tend to migrate into the riser when the BOP is re-opened. BOP design (e.g., a choke line connection below the annular BOP) and/or well control procedures can minimize this trapped gas volume.

7.3 DIVERTER INSTALLATION ON A FLOATING RIG WITH A MARINE RISER SYSTEM

Diverter systems on floating drilling rigs are typically mounted to the drill floor substructure below the rotary table, at the upper end of the marine riser system (refer to Figures 7.1 and 7.2). There are instances where the diverter unit is installed subsea[4]. Vent line piping length, configuration (i.e., fittings, ells, etc.), and size are critical factors in determining fluid head loss of the system (refer to 5.7.1 and 5.7.2). Features of auxiliary equipment are important links in the overall design of diverter systems. These features include the sealing pressure limit of the telescopic (slip) joint packer, the burst and collapse rating of the marine riser tube, etc. (refer to Section 5—Diverter Systems Design and Component Considerations). This equipment should receive particular attention to prevent leaking or failure.

7.3.1 Use of a Diverter System without a BOP Installed

If the formation fracture gradient is suspected of being inadequate, a pressure equalizer valve (dump valve or drilling fluid discharge valve) is sometimes used at the bottom of the riser to allow discharge of heavy drilling fluid at or near the sea floor to reduce hydrostatic head on the formation. The same valve could be used to flood the riser with seawater should it become evacuated due to gas expanding.

7.3.2 Use of Diverter System with a BOP Installed

Subsequent to running the second casing string (typically referred to as the conductor casing in an offshore operation), a BOP stack is installed (refer to Figure 7.2). Use of a diverter system in conjunction with a BOP stack should be considered as a means of removing gas from the marine riser. The deeper the water depth (the longer the marine riser), the more likely the occurrence of gas entering the riser (refer to 4.4.3 and 7.2.5).

7.4 DIVERTER PIPING SIZE

In conjunction with 5.7, for rigs engaged in exploratory drilling where anticipated well flows are unknown or unpredictable, 10-in. ID is the recommended minimum vent line(s) size, with 12-in. ID or larger lines preferred. Table 5.1 can be useful as a reference to compare vent line(s) sizes for various operating conditions of steady-state flow and anticipated backpressure (friction backpressure) for gas and liquid mixture flow rates in various systems.

7.5 INSTALLATION OF VENT LINES

Vent line(s) in the system should be arranged to extend past the extremity of the drilling vessel (refer to 5.7.2 through 5.7.5).

7.5.1 Moored Drilling Vessels

Many moored drilling vessels have limited capability to change the vessel heading during routine operations and thus should be equipped with more than one vent line. Normally, the vessel will be anchored in the direction of the prevailing wind; however, a dominant current may dictate a different heading to preserve station keeping. Figures 7.6 and 7.7 show schematic illustrations of example arrangements for vent lines on drill ships and semi-submersibles. Figure 7.7 illustrates example optional arrangements of vent lines on semi-submersible drilling vessels.

7.5.2 Dynamically Positioned Drilling Vessels

These vessels have the capability to maintain headings into changing winds, thus, the diverter line(s) may extend to the vessel's stern. Figure 7.8 illustrates example vent line(s) layout for dynamically positioned drilling vessels. It may be desirable to have other vent lines in the case of a dominant current (refer to 7.5.1).

[4] For example: See Society of Petroleum Engineers (SPE) Paper No. 22541, "Improved Subsea Drilling System for Deep Development Wells in Deep Water: Auger Prospect," dated 1991.

7.5.3 Example Vent Line(s) and Flow Line(s) Arrangements

Regardless of the arrangement used, the diverter control system shall be operated such that the well will not be shut-in with the diverter system. Following are some example arrangements.

7.5.3.1 Vent Line(s) above Flow Line

Illustrated by Figures 7.1 and 7.2. The vent line(s) is illustrated at an elevation above the flow line. The diverter line valves allow venting to one side of the drilling vessel and closing of the upwind diverter line, if desired. These systems allow drilling operations to be conducted with all vent lines and valves open.

7.5.3.2 Vent Line(s) below or In-line with Flow Line

Illustrated by Figures 7.3 and 7.4. In these arrangements, the vent line valve(s) remains closed during normal drilling operations. For this type system, valves in the vent line(s) should be open prior to closing the flow line valve to prevent pressure build-up in the marine riser. The diverter control system shall be operated such that the well will not be shut-in with the diverter system.

7.5.3.3 Flow Line Outlet above the Vent Line(s) with Vent Line(s) Subsequently Extended above the Flow Line

Illustrated by Figure 7.5. This type arrangement permits the valves in the vent line(s) to remain open, which is preferable, during routine operations. Vent line valves provide a means to selectively close an upwind vent line so the fluid discharged can be directed downwind. In subfreezing operations, routing of vent and flow lines to eliminate freezing of standing drilling fluid should be considered.

7.6 AUXILIARY EQUIPMENT APPLICABLE ONLY TO FLOATING DRILLING

Floating drilling requires equipment that allows for relative motion between the subsea BOP stack and drilling vessel.

7.6.1 Flex/Ball Joint

Flex/ball joints permit relative angular movement of the riser elements to reduce bending stresses caused by vessel offset, vessel surge and away motions, and environmental forces. One flex/ball joint is usually located above the BOP stack. Additional flex/ball joints may be located at the bottom and the top of the telescopic joint.

7.6.2 Telescopic Slip Joint

The telescopic (slip) joint packer is an important consideration of the diverter system operation. It seals the inner barrel (attached to the vessel) and outer barrel (attached to the marine riser) and must have sealing capacity if diverting is required. Only the minimum operating pressure required to effect a seal should be used as excessive pressure may cause damage to the telescopic joint inner barrel or telescopic joint packer.

8 Recommended Diverter Operating Procedures

8.1 GENERAL

Advance planning should include an equipment and operations procedure checklist. The items on the checklist depend on the drilling depth, company policies, government regulations, anticipated use of the diverter equipment, and other items discussed in 7.2 and its sub-paragraphs. Operating procedures should be prepared and posted. Basic to successful operations are appropriate planning, installation, testing, maintenance, training, and execution of emergency drills by the crew.

8.2 ADVANCE PLANNING AND PREPARATION

Advance well planning should include:

1. An assessment of the well control equipment performance curve as discussed in Appendix A—Shallow Gas Well Control.
2. Ensuring crew members are familiar with the equipment and its proper testing, maintenance, and operation. Installation, operation, and maintenance manuals provided by the manufacturer should be available on the rig.
3. Procedures to ensure diverter line is clear of obstructions at all times.
4. If a BOP stack is in use, the position (open or closed) of the kill and choke fail-safe valves in relation to the choke manifold should be pre-planned.
5. Depending on the type power plant(s) on the rig, engine and generator assignments should be pre-planned for use during divert operations.
6. Engine spark arrestors should be in good working order and electrical equipment locations should conform to API RP 500, RP 505 or applicable mobile operating drilling unit classification standards.
7. In case a decision is made to leave the location, emergency meeting points for employees should be planned. For marine operations, windlasses/winches should be setup to pay out leeward mooring lines without power either by release of chain stoppers/locking pawl or release of the band/motor brakes. Consideration may be given to moving crosswind if a strong wind prevails.

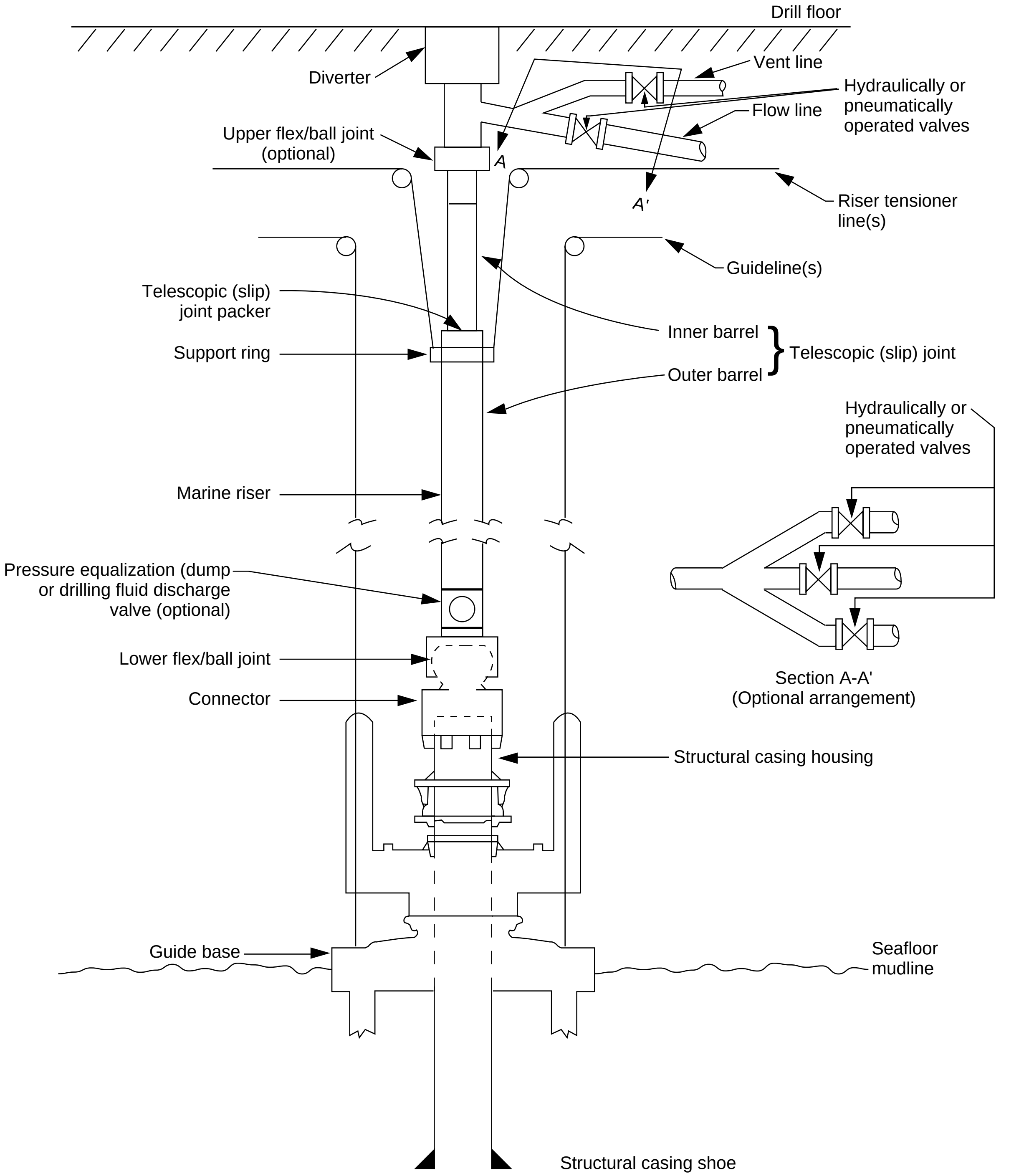


Figure 7.1—Example Floating Drilling Vessel Diverter and Riser System Installed on Structural Casing Housing

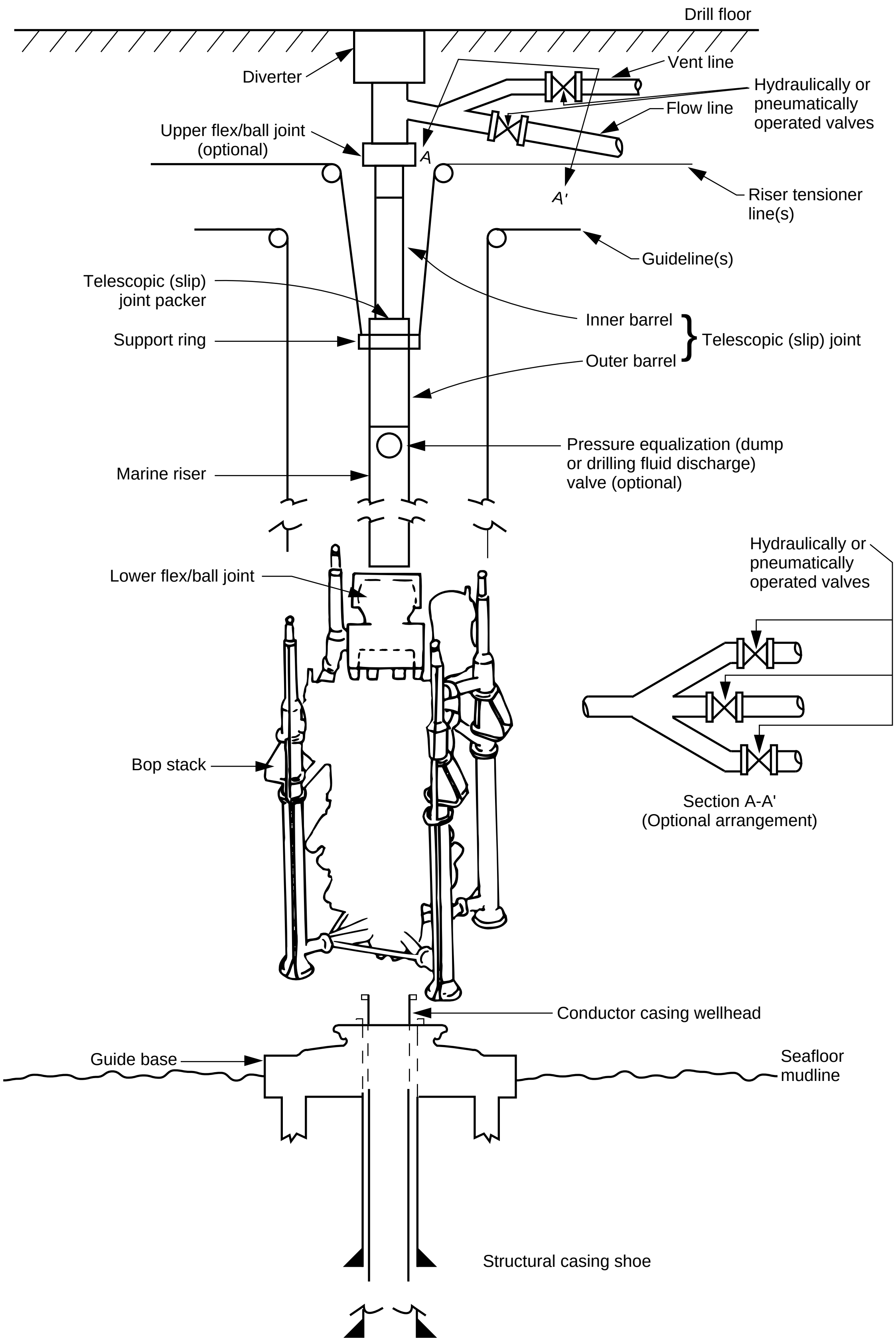


Figure 7.2—Example Floating Drilling Vessel Diverter with Riser and BOP System Being Lowered

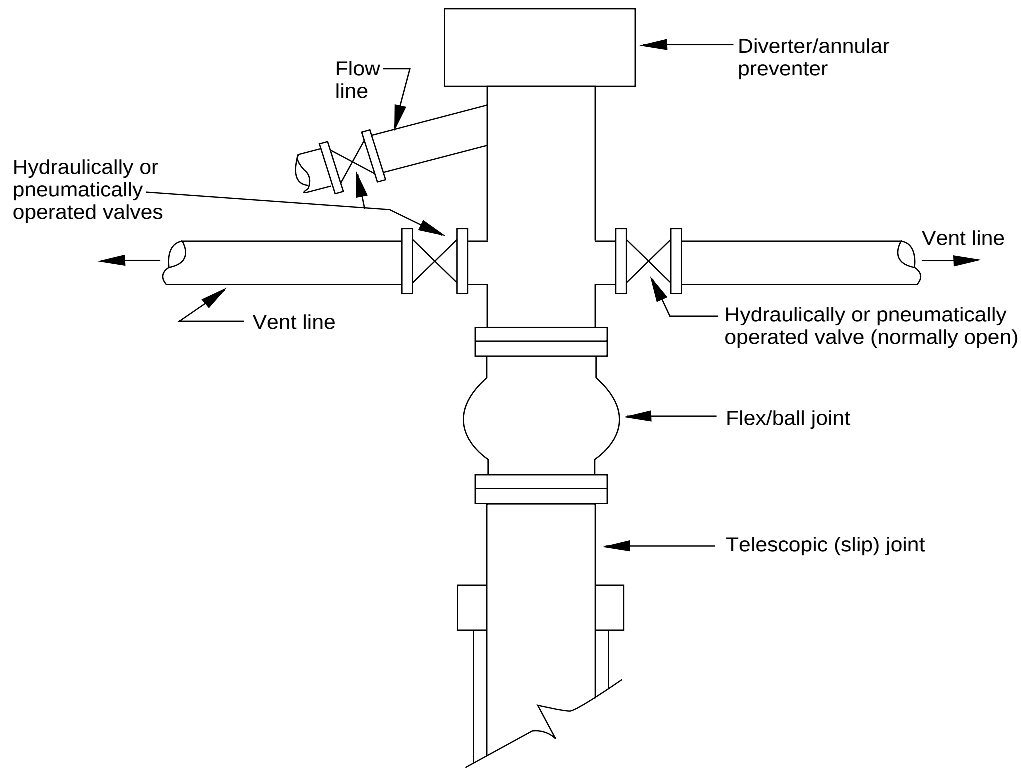


Figure 7.3—Example Diverter System Schematic (Flow Line above Vent Lines)

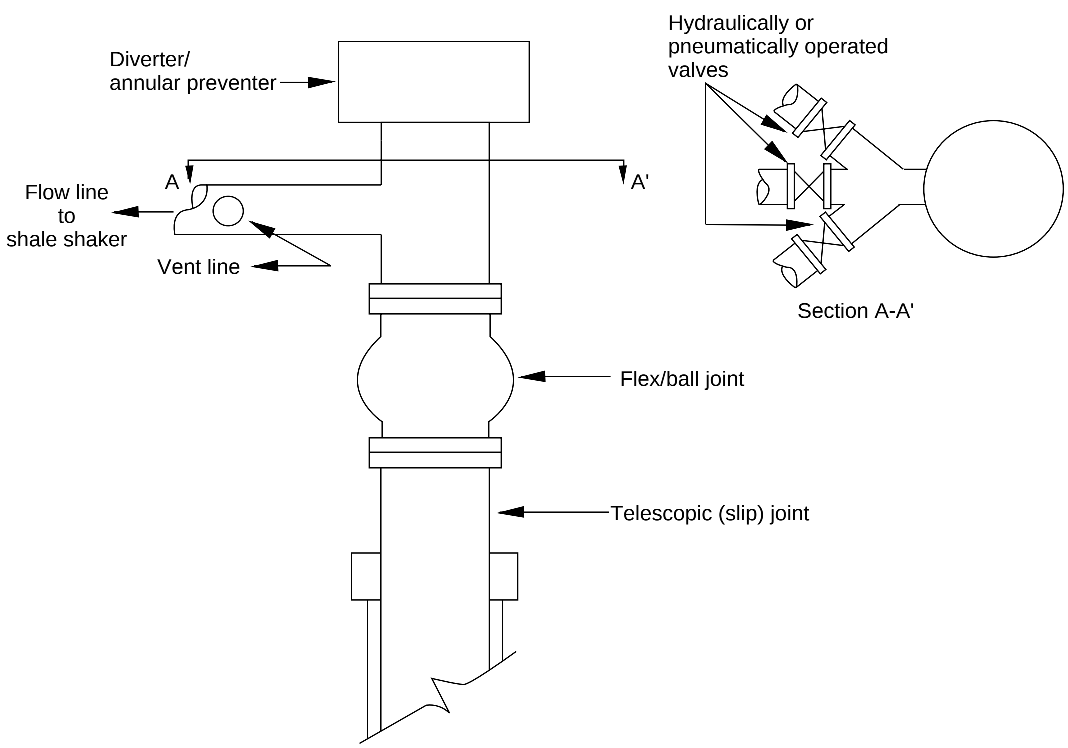


Figure 7.4—Example Diverter System Schematic (Flow Line In-line with Vent Lines)

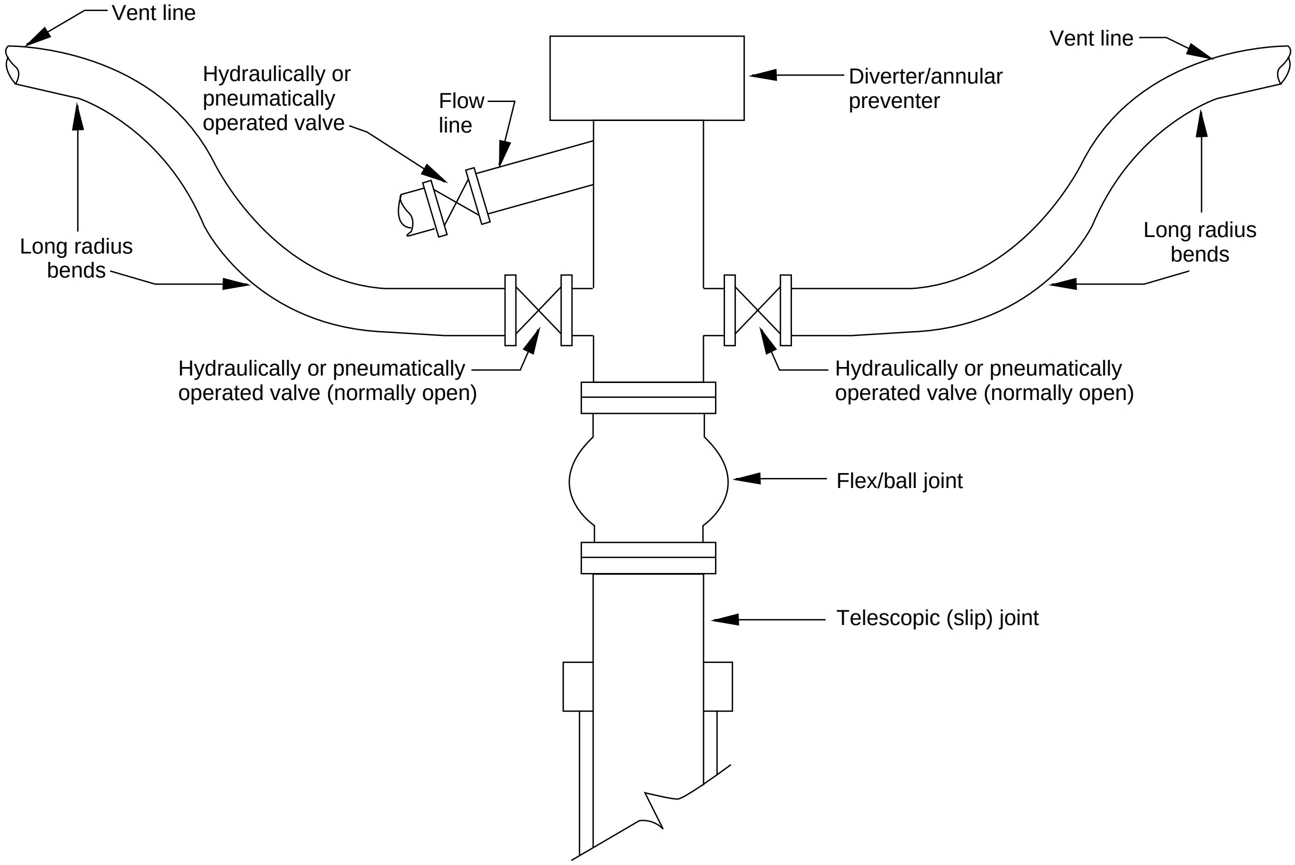
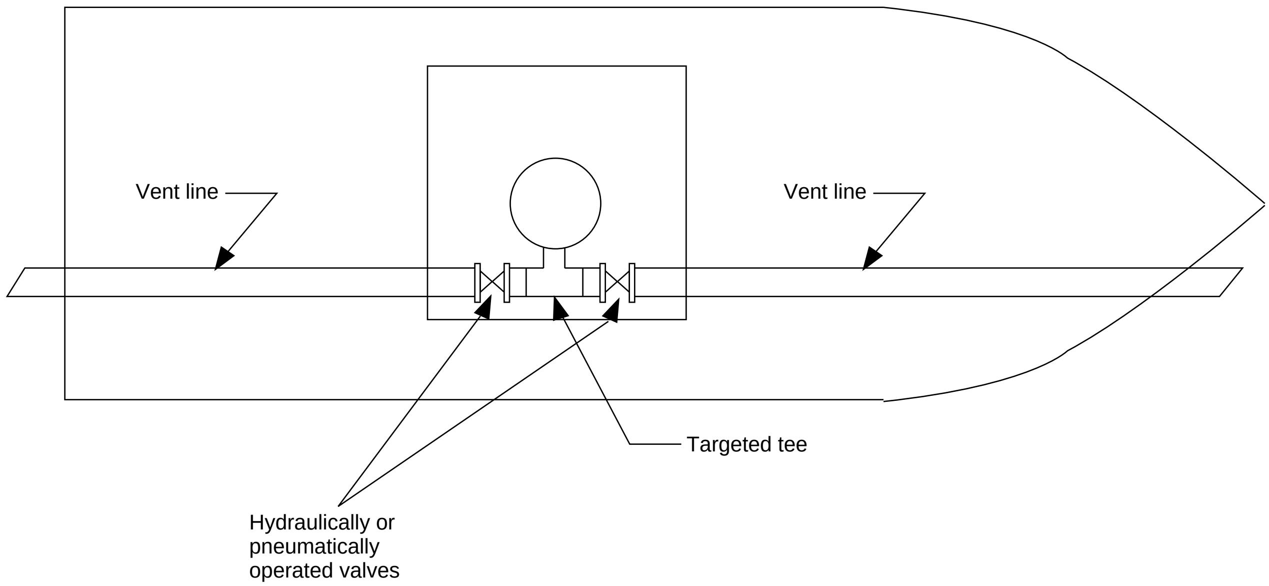
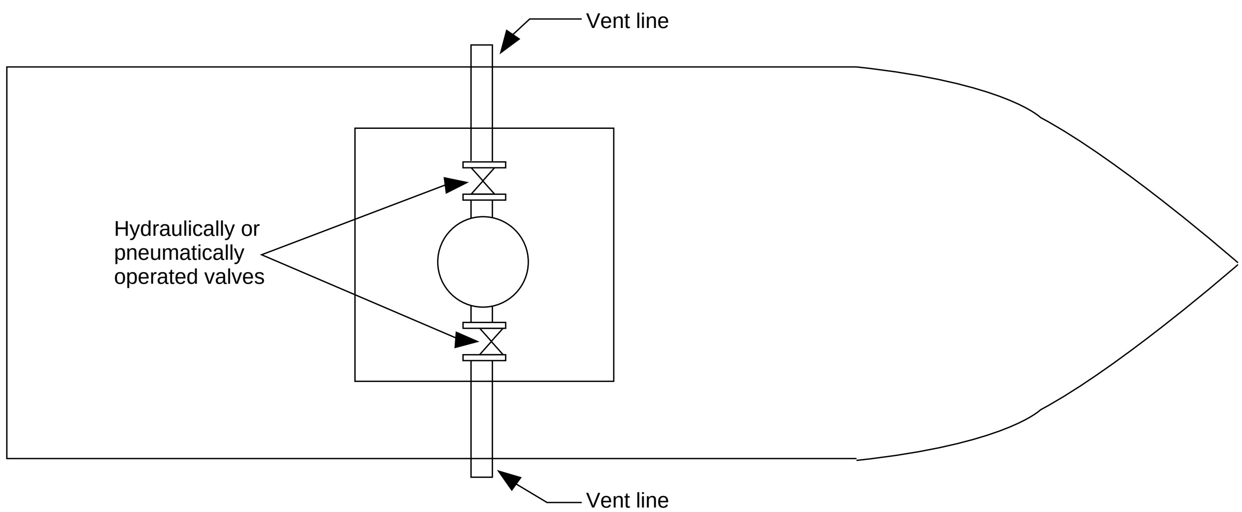


Figure 7.5—Example Diverter System Schematic (Flow Line Discharge above Vent Discharge Line(s) but Vent Line(s) Extended above Flow Line)

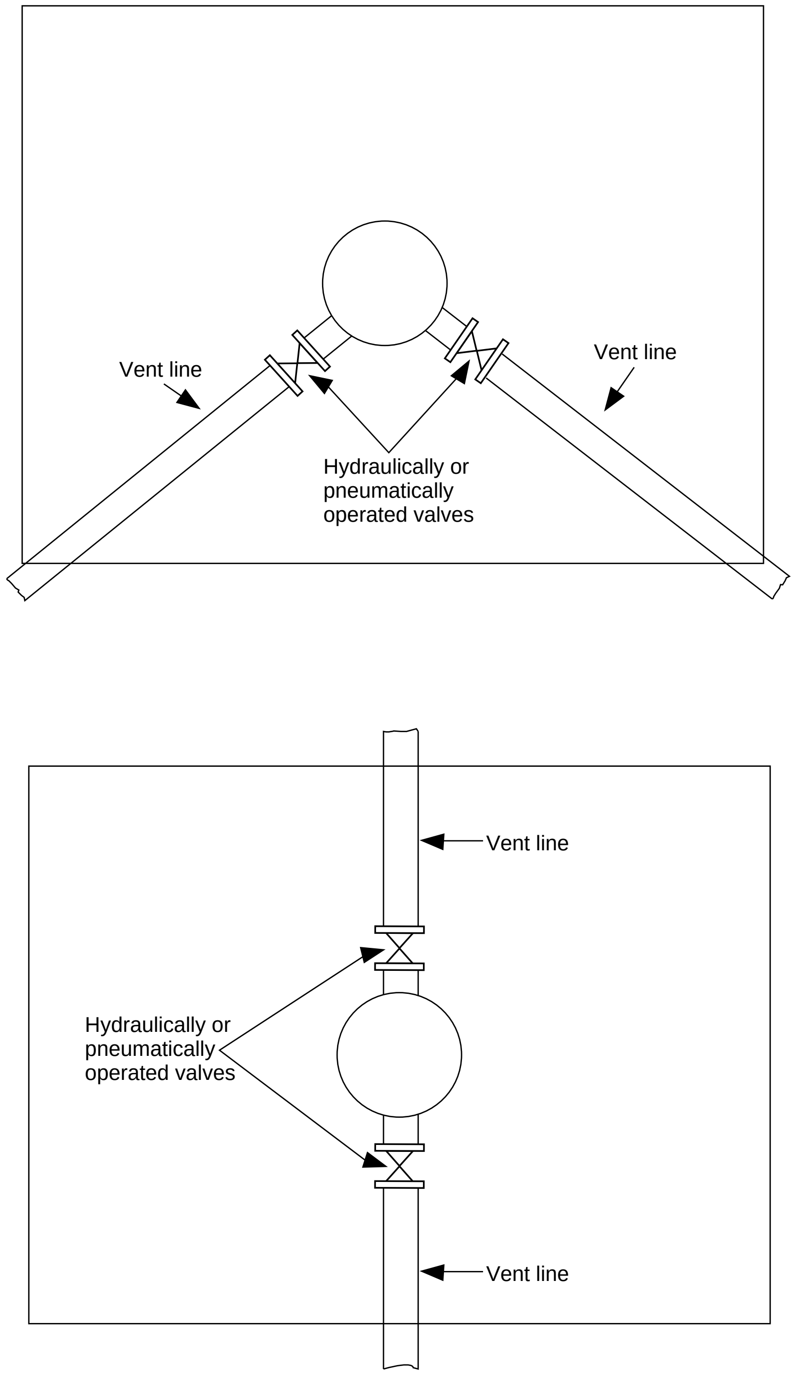


Diverter Lines Extend Fore and Aft



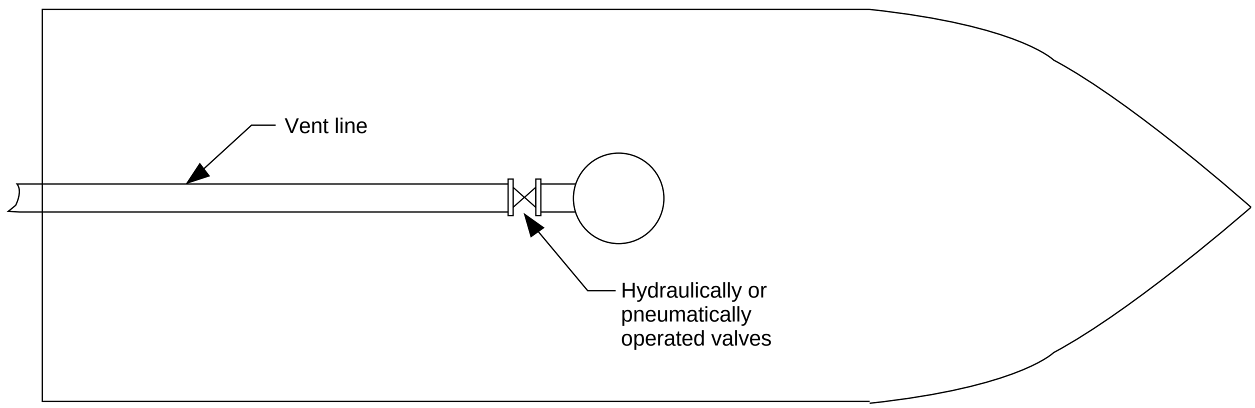
Diverter Lines Extend to Port and Starboard

Figure 7.6—Example Diverter Line Schematics for Conventionally Moored Drillships

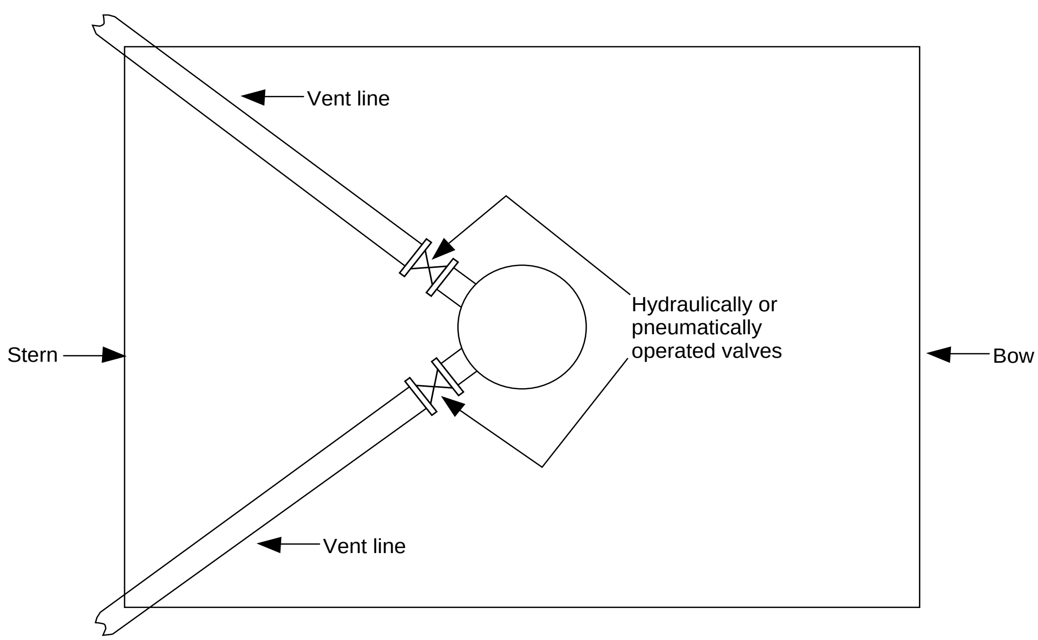


Diverter Lines Extend to Port and Starboard

Figure 7.7—Example Diverter Line Schematics for Conventionally Moored Semisubmersibles



Drillships



Semisubmersibles

Figure 7.8—Example Diverter Line Schematics for Dynamically Positioned Vessels

8. If the vessel propulsion system is to be used to move the rig off location, the system should be in an operational mode and require no start-up or warm-up time.
9. If a marine riser is in use, sufficient riser tension should be available to lift the lower marine riser package clear of the BOP stack in the event of an emergency disconnect.
10. The marine riser spider and proper diverter and riser handling tools should be available near the drill floor.
11. Procedures for welding or operations involving open flames.

8.3 TRAINING AND INSTRUCTION

Shallow gas flows generally develop quickly; can be difficult to detect early; and, can flow high volumes of gas from highly permeable formations or due simply to large near-surface gas expansion. Likewise, inadvertent gas entry in a marine riser can be difficult to detect. All concerned personnel should be familiar with the diverter system components and installation and should be capable of reacting quickly and efficiently to potential situations requiring use of the diverter.

8.3.1 General Guidelines

The following are offered for personnel training and instruction:

1. Written emergency procedures should be developed prior to spudding the well that detail specific emergency action plans.
2. Drills should be prepared in advance with consideration given to testing response to various scenarios.
3. Drills should be conducted at appropriate intervals to ensure personnel are capable of quickly and competently reacting to situations requiring use of the diverter.
4. Drills should be documented and analyzed to identify areas where improvement is required.
5. Follow-up on problem areas identified in the drills should be completed and documented.
6. Emergency plans, training, and drills should be kept up-to-date and change as conditions change.

8.3.2 Industry Association Training

The International Association of Drilling Contractors (IADC) has instituted 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 rig's 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.

8.3.3 Operating Guidelines during a Kick

For training purposes, following are general guidelines for use of the diverter system in controlling a kick:

1. Initiate action as per posted procedures.
2. Carry out diverter close sequence. Visually verify that vent line valve(s) are open and that flow line and fill-up line valves, if used, are closed. Consider leaving all vent line(s) open, if conditions permit, to reduce backpressure.
3. Advise the drill floor and service (rig, vessel, platform, and supply boat) personnel of potential for drilling fluid discharge from diverter vent line(s) and annular sealing device leakage.
4. Adjust annular sealing device regulator pressure, if necessary, to minimize leakage.

8.3.4 Example Divert Procedures

For training purposes, following are example procedures that may be considered at the first signs of confirmed well flow or if flow is suspected in offshore drilling operations.

a. Example Diverter Procedures for an Offshore Drilling Rig without BOP Stack Installed.

1. Pick up the lower kelly connection about 2 – 3 ft above the floor.
2. Select and open the proper overboard vent line depending on the volume of discharge from the well and wind direction.
3. Close the diverter and the shale shaker valve.

Note: This action will depend on the sequencing logic of the shut-in control system.

4. If a floating rig is being used, check the slip joint packer pressure and adjust as required.
5. Change the pump suction(s) to the kill drilling fluid pit and pump at a rate determined in the equipment performance evaluation.
6. Alert the person in charge and all personnel aboard the rig.
7. Continue to pump kill drilling fluid at a rate determined in the equipment performance evaluation. Plan for routine change to seawater when drilling fluid is in short supply.
8. Post personnel to watch for appearance of gas bubbles in the vicinity of the drilling vessel.
9. Notify the person in charge.

b. Example Shut-in Procedure for a Floating Drilling Rig with a Diverter and Subsea BOP Installed. If drilling out of conductor casing, the following is an example of a well shut-in procedure when the diverter is functioned with BOPs installed:

1. Pick up the lower kelly connection about 2 – 3 ft above the floor.
2. Stop the pump, shut-in the well with the BOP(s).
3. Close the diverter and the shale shaker valve with vent valve(s) open.
4. Determine the appropriate well control method (refer to API RP 59) for the conditions and continue well control procedures.
5. In conjunction with steps b.2 and b.3, alert the person in charge and all personnel on the rig. Check the slip joint packer pressure and adjust as required.
6. Extinguish all open flames and shut down unnecessary electrical systems.
7. Immediately place a personnel watch to watch for gas bubbles in the vicinity of the drilling vessel.
8. If diverter flow or gas bubbles appear, notify the person in charge.

8.4 DRILLING OPERATIONS

The pre-planning and operating procedures necessary to successfully operate diverter systems in onshore and offshore installations are similar. The following contingency and operating plans are pertinent to these operations.

8.4.1 Diverter System Equipment Installation

A schematic drawing should be available on the rig showing all diverter system components, equipment sizes, and equipment locations, including the location of the main control panel and remote panel(s).

8.4.2 Installation Test

All diverter system components shall be inspected and tested to ascertain proper installation and function. Simulate loss of rig air supply to the diverter control system and determine effects, if any, on the diverter system, vent line valves, and backup systems. In offshore floating drilling operations, vessel motion and pressure limitations of riser components, such as flex/ball joint and telescopic (slip) joint packer, should be considered during equipment installation tests. For general testing considerations, refer to API RP 53. An example diverter installation test schedule is shown in Figure 8.1. Inspections and tests should include, but not be limited to:

1. Check and verify the proper structural mounting of the annular sealing device assembly, and, if applicable, that the insert packing element is secured in place.
2. For installations using remote operators, record hydraulic pressure and air supply pressure with the accumulator fully charged and the controls in the normal drilling position.
3. Actuate the diverter close and open sequence with drill pipe or a test mandrel in the diverter to verify control functions, proper equipment operating sequence and interlock, if applicable, and record response time(s).

Note: The rig's available well control equipment may have a higher rated working pressure than required. Site-specific test requirements should be considered in these situations.

4. For diverter installations equipped with manual valve(s), ascertain that hand wheels are installed and that the valve(s) operate easily.
5. A pressure integrity test (200 psig minimum) should be made on the diverter system after each installation. The tests may be made on parts of the system or on individual components of the system should certain components of the casing string or riser components not support a complete system test. The test should be stable for at least five minutes.
6. Pump water or drilling fluid through the diverter system at low pressure and high rates. While pumping, check the vent line(s) for returns and examine the entire system for leaks, excessive vibrations, and proper tie-down.

8.4.3 Routine Equipment Function Test

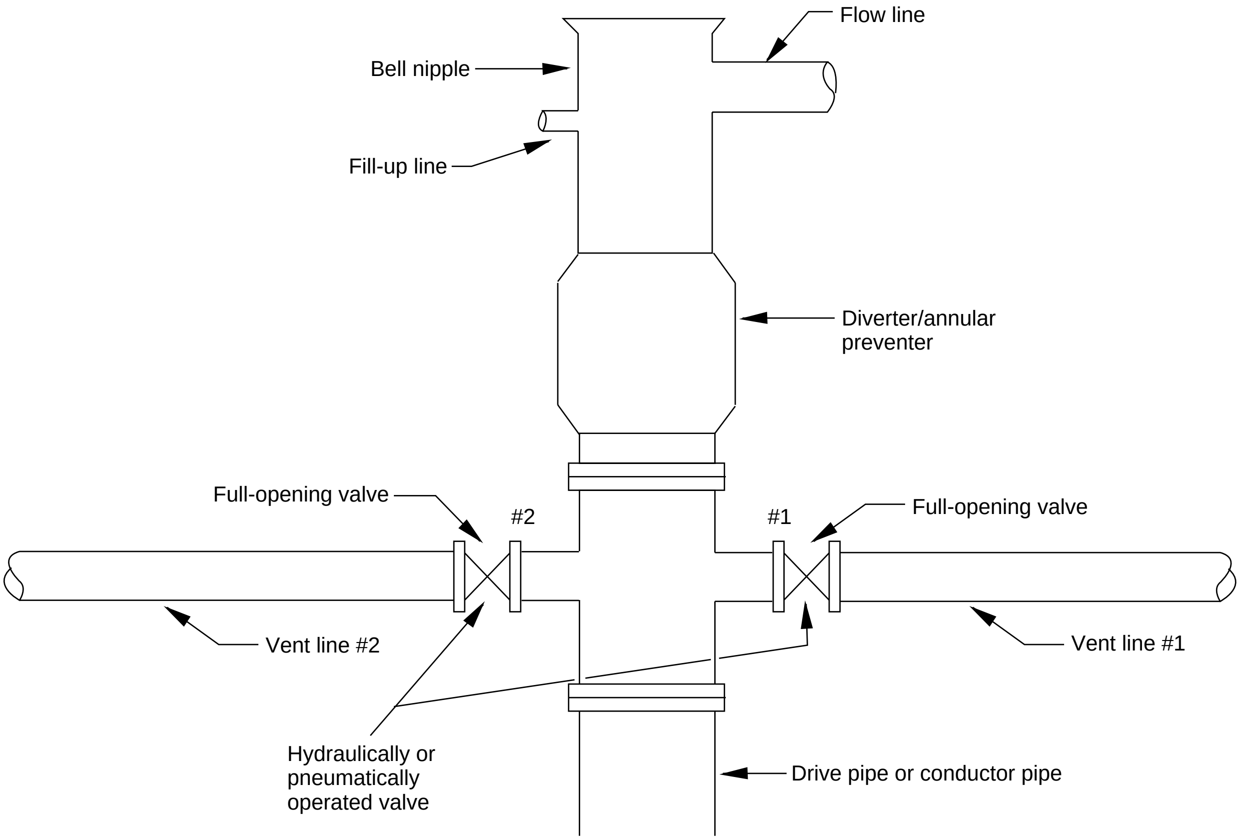
When in primary diverter service (no BOP installed), function tests should be performed daily using the driller's panel to verify that functions are operable; i.e., valve(s) fully open or closed. Fluid should be pumped through each diverter line at appropriate times during operations to ensure that line(s) are not plugged.

8.4.4 Diverter Operation

When drilling through a diverter at shallow depth and a kick is indicated or suspected, stop drilling, pick up the pipe, 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. If flowing, pump water or drilling fluid as necessary to moderate the flow. Under no circumstances should the valve, if any, on the diverter line be closed when the diverter is closed on a possible kick. If the well cannot be brought under control by pumping drilling fluid or water, consider pumping a barite slurry if conditions are safe enough for continued personnel presence at the rig (if not, evacuate rig). For more information, refer to API RP 59.

8.4.5 Cold Weather Operation

In cold climates, the diverter vent lines should be protected from freezing. Possible methods include flushing with antifreeze solution, draining, insulation, and heat tracing.



NOTE: The diverter system illustrated here is a generic example only.
Installation test requirements will vary depending on the system configuration.

Figure 8.1—Example Diverter System Installation Test

1. Actuate "diverter close" with drill pipe or test mandrel in the diverter. Observe and record response time for: a) #2 valve opening, b) #1 valve opening, and c) diverter element closing.
2. Actuate "#1 valve close." Observe that #1 valve closes.
3. Actuate "#1 valve open." Observe that #1 valve opens.
4. Actuate "#2 valve close." Observe that #2 valve closes.
5. Actuate "#1 valve close." Observe that #1 valve remains open—control system designed to prevent closing in the well.
6. Actuate "diverter open." Observe that diverter sealing element opens.
7. Actuate "#1 and #2 valve close." Observe that both valves close.
8. Close the diverter system and pressure test according to Par. 8.4.2.5.
9. Restore the diverter system to the operational mode.

9 Diverter Systems Maintenance

9.1 GENERAL

A schedule for routine inspection and maintenance of diverter systems equipment should be implemented and kept by the rig operating personnel. Specific guidelines for each diverter component or sub-system should be based on installation, operation and maintenance manuals provided by the equipment manufacturer. Some general guidelines for diverter systems maintenance are:

1. Visually inspect the elastomer components of the system after each test to verify that they are in good working condition. Packer components should be replaced when their proper functioning is questionable due to damage, wear, and/or age.
2. During diverter function tests, observe all components of the diverter system including the diverter, valves, valve actuators, piping, and control panel to verify that there are no leaks in the system. In the event a leak is discovered, it should be repaired immediately.
3. The control panel requires weekly maintenance including such items as checking various fluid levels, cleaning air strainers, cleaning pump strainers, and cleaning filter elements. Tightening of packing and lubrication of power actuating cylinders should be performed on a weekly basis. Pre-charge pressure in the accumulator bottles should be checked at this time.
4. Control hoses, tubing, vent line piping support brackets, targets, valves, fittings, etc., should be visually checked on a routine basis and any necessary repairs should be made immediately.
5. Control system pressure gauges should be calibrated and tagged at intervals not to exceed one year.

9.2 DIVERTER SYSTEM PIPING

The wall thickness on all turns and bends in the diverter system should be checked at least annually and after each use of the system to divert a well kick. Erosion of metal from the turns and bends can be severe if sustained flows of gas-associated sand are diverted through the system.

9.3 MANUFACTURER'S DOCUMENTATION

Installation, operation, and maintenance manuals, furnished by manufacturers of the various components of the diverter system, should be readily available for training, reference, and use by maintenance personnel.

9.4 MATERIALS, EQUIPMENT, AND SUPPLIES

The original equipment manufacturer is a good source of information for spare parts for the equipment. Sufficient materials, equipment, and supplies should be available on location prior to spud. These include, but are not limited to:

1. A spare packing element and complete set of seals.
2. One complete valve for each non-integral valve size in the system.
3. Drilling fluid treating chemicals and weight material to increase density of the kill fluid. Consider having premixed kill fluid available.
4. Adequate reserve fluid volumes.
5. Verify that other emergency equipment is readily available. These could include but are not limited to: safety valve(s), inside blowout preventer, drill string float(s).

APPENDIX A—SHALLOW GAS WELL CONTROL

A.1 Introduction

Opinions differ throughout the drilling industry concerning well control involving shallow gas. In marine operations, some experts advocate using risers and diverters, while others support drilling without using a riser and circulating seawater back to the sea floor. Recognized techniques for handling well kicks are at least as diverse. “Pump as fast as you can,” “drill a pilot hole and dynamically kill,” or “shut-in” are some, but not all, of the techniques offered for general application regardless of the circumstances. Since there are a few situations where any of these techniques work when applied without precise planning, it is useful to have an understanding about the way a shallow gas kick produces and is controlled.

This Appendix discussion presents fundamentals based upon analysis of steady-state conditions without advocating use of any particular technique(s). The intent is to provide some technical understanding of what takes place when shallow gas is drilled and to promote an understanding of the analysis technique fundamentals. The principles herein can be applied equally to analysis of onshore and offshore floating and bottom-supported drilling operations but are not purported as an all-inclusive analysis of dynamic kill calculations for control of shallow gas.

This discussion is not intended to advocate drilling with or without a riser in marine operations, but does present fundamentals for study by those who make such decisions. Each specific situation should be individually designed. Some situations will favor the use of a riser; others will best be drilled without use of a riser. An understanding of the fundamentals will influence selection of the well control technique(s) to be used and will emphasize that a particular technique cannot be indiscriminately applied.

The numbers used in this discussion must be treated with caution, as stated, and are not intended for use in detailed planning of shallow gas well control operations. Emphasis is given to using a riser in offshore operations to bring flow back to a surface diverter only to cover the most involved case. The case of using no riser is a sub-case requiring only part of the analysis technique. The backpressure at the sea bed will be the greater of the hydrostatic pressure due to water depth or the backpressure for sonic flow for the given hole/drill collar annulus size. Certain limitations, such as transient well response as the well unloads, are not addressed in the steady-state model used in this Appendix A.

A.2 Fundamentals

As a prelude, the following fundamentals are presented.

Note: Formation characteristics for a particular land or offshore area should be used in analyzing performance of a particular well.

1. A shallow gas zone is usually abnormally pressured.
2. Shallow gas zones can have very high deliverabilities.
3. Any permeable formation that becomes under-balanced will flow. In the case of drilling under-balanced into shallow gas zones in offshore wells, flow will occur regardless of whether or not a riser is in use.
4. A shallow gas zone should not be knowingly penetrated without in-depth, pre-spud planning of equipment and operations requirements.
5. The probability for well flow depends on both the individual zone’s characteristics (including pressure, permeability, and gas thickness) the wellbore cross section (including fracture gradients and casing depths), the density of drilling fluid, and drilling procedures. If a shallow gas zone is penetrated offshore, while utilizing only seawater and circulation back to the sea bed elevation, the gas zone will likely flow. Some shallow gas zones offshore may have a high potential for well flow even when drilled with a riser.
6. A riser provides a direct flow conduit to the rig, which increases the personnel safety risk should surface equipment fail. When surface diverting a shallow gas flow, entrained formation particles can lead to erosion and rapid failure of surface equipment.
7. A diverter is not a well blowout prevention device; the riser, however, when penetrating some shallow gas zones, can serve to prevent blowouts by extending the column of drilling fluid above sea level. (Refer to 4.1, A.5, and Figure A.3.)
8. A shallow gas zone can be drilled with a riser using seawater, provided the resultant gas column between the point of bit entry and top of the gas-water contact is equal to or less than the flow line elevation above mean sea level. A heavier drilling fluid is required if the expected gas column is larger than the flow line elevation above mean sea level.
9. The extended drilling fluid column associated with a riser increases the hydrostatic pressure on the shallow casing shoe. Lost circulation may be a primary consideration, especially in deepwater operations where low fracture gradients will not support a riser column of fluid. If lost circulation occurs, the resulting conditions, depending on fracture pressure and drilling fluid density, may be similar to those incurred when drilling without a riser. A shallow gas zone can be drilled without a riser, using a weighted drilling fluid with returns directly to the sea floor. This approach involves a higher drilling fluid loss and cost and special procedures to detect flow.
10. In an offshore, uncontrolled flow situation involving shallow gas, the gas flow rate may be decreased if the full seawater hydrostatic pressure is applied at the sea bed

rather than routing flow through a riser to a surface diverter at the rig.

11. The pressure or thickness of a shallow gas zone is not always predictable by the operator. In this case the formation pressure can exceed the maximum practical drilling fluid hydrostatic pressure and once the zone is penetrated the inflow cannot be prevented.

A.3 Shallow Gas—Abnormal Pressure

Shallow gas is usually abnormally pressured and it is usually under-laid by normally pressured water.

Estimated pressure at the top of the shallow gas zone is equal to the aquifer pressure at the gas-water contact minus the hydrostatic pressure of the gas column (refer to Figure A.1). Other shallow gas accumulations may have higher pressures due to the faulting, formation dip, etc.

$$(P/D)_{TS} = \frac{(P/D)_N(D+H_G)-(P/D)_G \times (H_G)}{D} \qquad \text{A-1}$$

where

$(P/D)_{TS}$ = estimated pressure gradient at the top of the shallow gas sand, psi/ft,

$(P/D)_N$ = normal pressure gradient for the area, psi/ft (normal pressure gradients observed range from 0.416 psi/ft to 0.52 psi/ft, depending on formation fluid salinity and temperature),

$(P/D)_G$ = gas gradient for methane, psi/ft (approximately 0.006 at 1,000 ft, 0.03 at 2,000 ft, and 0.06 at 5,000 ft),

D = depth to the point of bit entry, ft,

H_G = height of gas column, ft.

A.4 Riserless Drilling

If drilling a shallow gas zone while circulating seawater back to the sea floor without a riser (refer to A.5 for cases with a riser), the seawater gradient will only balance the pressure at the bottom of the gas sand and the overpressured top of the sand will be under-balanced (refer to Figure A.2). Neglecting the gas gradient, the overpressure at the top of the gas can be estimated by Equation A-2. A reduction in head due to drilled gas can also contribute to an under-balanced condition.

Note: This overpressure can be offset by using a weighted drilling fluid (with returns to the sea floor). The density is selected to provide the desired overbalance from Equation A-2 with the weighted fluid only from the mud line down to the depth of interest.

$$\Delta P = 0.44 \times h \qquad \text{A-2}$$

where

ΔP = overpressure, psi,

h = vertical thickness of the gas sand, ft.

In the simplified example shown in Figure A.2, the top of a gas zone 100 ft thick will be overpressured by approximately 44 psi. If the shallow gas zone is steeply inclined, the abnormal pressure can be even greater.

A.5 Drilling with a Riser

A riser extending above sea level and full of seawater can provide a means for controlling a shallow gas zone that has a thickness equal to or less than the air gap. Heavier drilling fluid in the riser will allow for controlling of a thicker shallow gas zone (refer to Figure A.3). The approximate thickness of the shallow gas zone that can be controlled by the heavier drilling fluid may be calculated using the following relationship:

$$H_G = (H_A + D)\,\frac{MW}{SW} - D \qquad \text{A-3}$$

where

H_G = height of gas column between the gas-water contact and point of bit entry into the zone, ft,

H_A = flow line evaluation above mean sea level, ft Refer to Figures A.1 and A.3,

D = depth of bit entry into the zone below sea level, ft,

MW = drilling fluid density required to control the gas zone pressure, lb/gal.,

SW = seawater density, lb/gal.

Drilled gas reduces the thickness of sand that can be drilled with a given air gap. The penetration rate (ROP) influences the reduction in gradient.

The drilling fluid density required to balance the gas zone is illustrated in the following relationship:

$$MW = \frac{0.44(D+H_G)-0.06H_G}{0.052(D+H_A)} \qquad \text{A-4}$$

where

MW = drilling fluid density required to balance the gas zone pressure, lb/gal.,

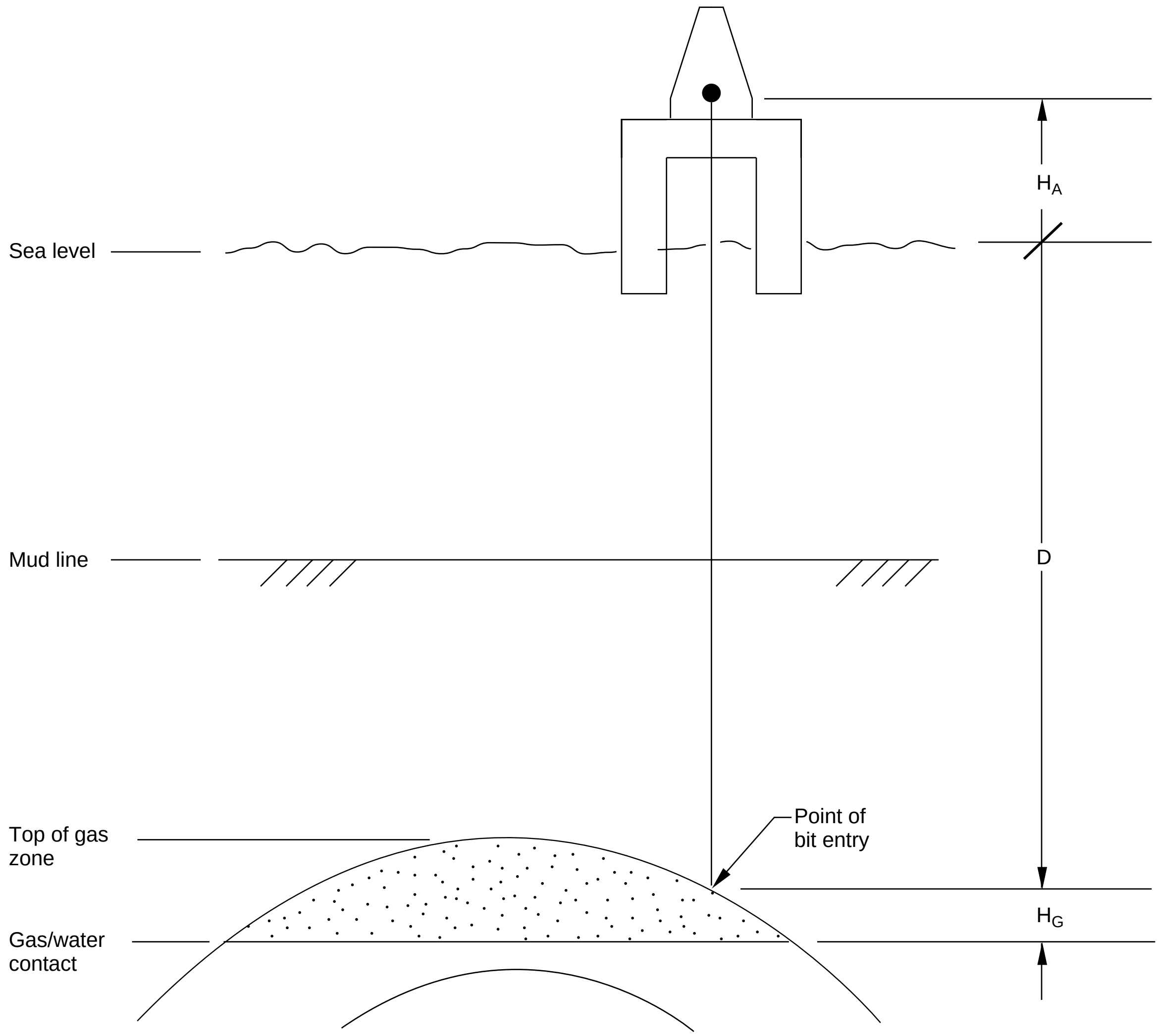


Figure A.1—Abnormal Pressure from Density Differences

D = depth of bit entry into the gas zone below sea level, ft,

H_G = height of the gas column above gas-water contact and the point of bit entry into zone, ft,

H_A = height of the air gap (distance from the flow line to sea level),

0.44 = hydrostatic pressure gradient, psi/ft,

0.06 = gas gradient, psi/ft.

Note: These values are not applicable for all geographic locations. Applicable values should be determined and used for specific applications.

For shallow gas zones in which the abnormal pressures are the result of compaction disequilibrium (sealed lens), drilling fluid density required to control the gas zone is a function of the abnormal pressure gradient as follows:

$$MW = \frac{APG \times D}{0.052(D + H_A)} \qquad \text{A-5}$$

where

MW = drilling fluid density required to balance the gas zone pressure, lb/gal.,

D = true vertical depth of bit entry into the gas zone below sea level, ft,

H_A = height of the air gap (distance from the flow line to sea level), ft,

APG = abnormal pressure gradient, psi/ft.

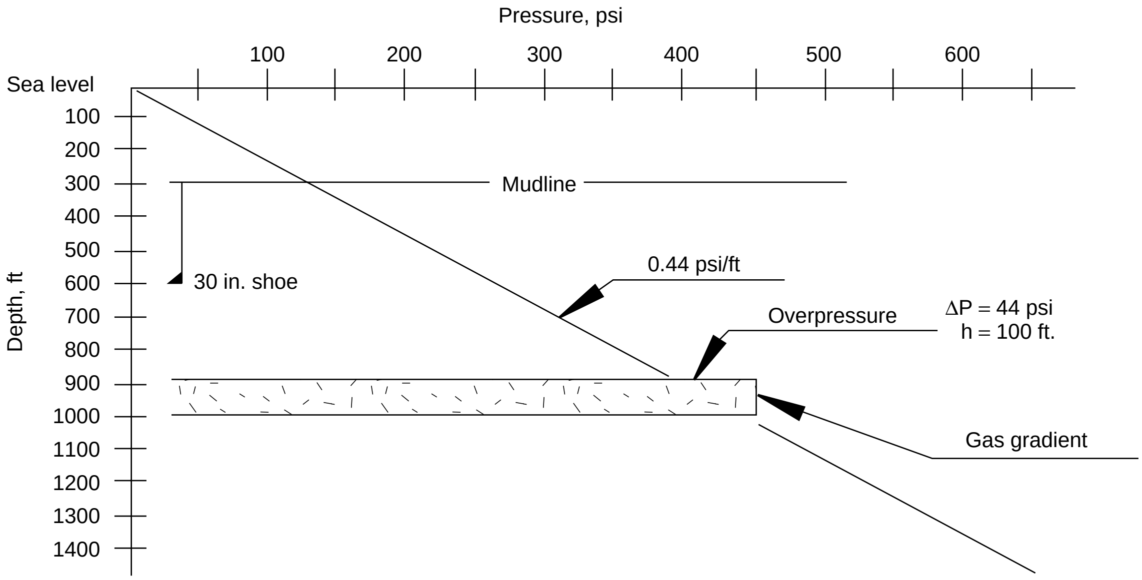


Figure A.2—Shallow Gas is Usually Abnormally Pressured

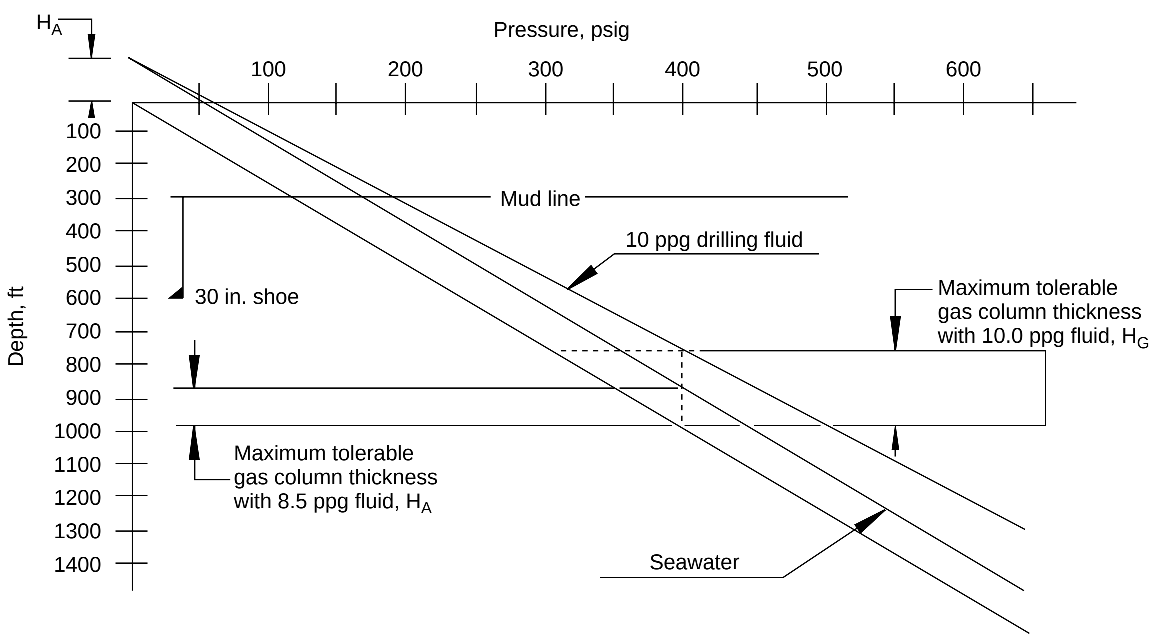


Figure A.3—Effect of Weighted Mud

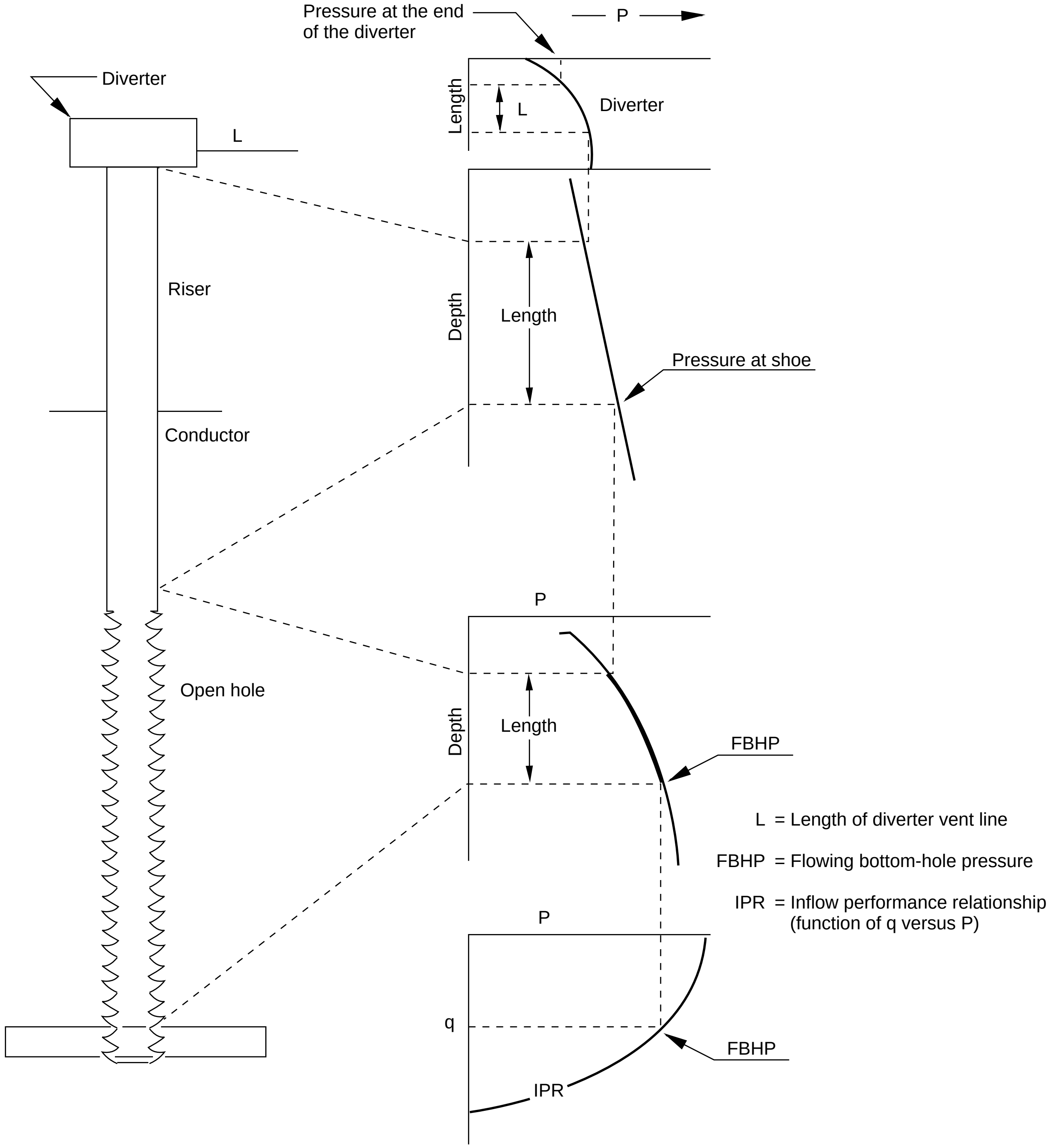


Figure A.4—A Drilling Well Experiencing a Gas Kick is a Producing Well System

Note: The abnormal pressure gradient (APG) can vary from 0.44 to 0.8 psi/ft in the near-surface formations. These values are not absolute worldwide. The use of Equation (A-5) for designing a system requires assumption of a maximum pressure gradient. APG's are seldom very high due to hydrostatic effects. Shallow gas zones rarely have structural relief. The exceptions occur in the vicinity of shallow piercement structures where a significant vertical gas column can be created. Sealed lenses in shale masses can have an APG that approaches overburden pressure, which can be as high as 0.8 psi/ft in the near-surface formations. These sealed lenses are usually relatively thin and may not be predictable by geophysical techniques.

A.6 A Drilling Well Experiencing Shallow Gas Influx is a "Producing Well"

A producing well is a system of interrelated components (refer to Figure A.4). The behavior or performance of any one of the components is related to the performance of each of the other components. An understanding of flowing well performance can be utilized to control a shallow gas influx.

A.7 Well Performance and Equipment Performance

There are two types of performance relationships to be analyzed: 1) well performance, and 2) equipment performance.

1. *Well performance* is flow rate versus pressure calculated from the bottom up and is independent of the equipment downstream of the point of analysis. All values on a well performance curve are valid. 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 A.5). A more familiar term, productivity index (PI), is a special case of IPR that applies only to single phase, incompressible flow.

2. *Equipment performance* is flow rate versus pressure at the point of analysis (refer to Figure A.6). 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 A.7).

A familiar analogy is the performance of a centrifugal pump. The pump curve supplied by the manufacturer describes the flow rate versus discharge pressure of the pump (refer to Figure A.8). The flow rate decreases as the discharge pressure increases. This relationship is analogous to the inflow performance relationship.

If this pump or any pump is discharging into a pipeline, the backpressure (due to hydraulic friction) will increase as the rate increases. This relationship is analogous to the equipment performance relationship (refer to Figure A.9).

The intersection of the two curves denotes the volumetric output of the pump (refer to Figure A.10).

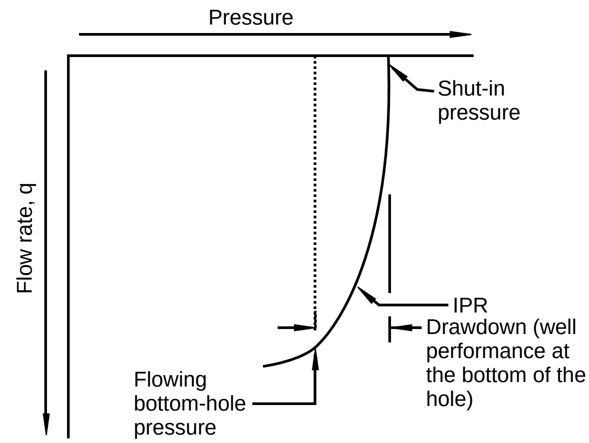


Figure A.5—Well Performance

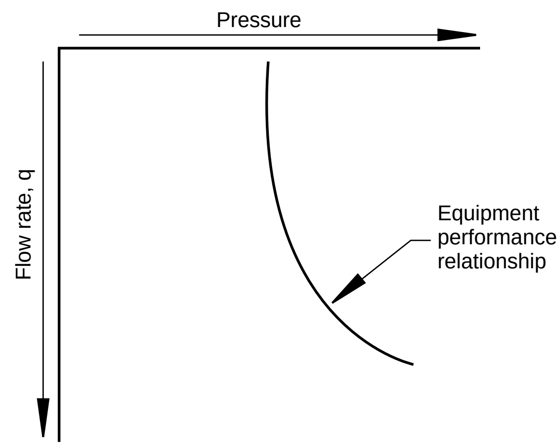


Figure A.6—Equipment Performance Relationship

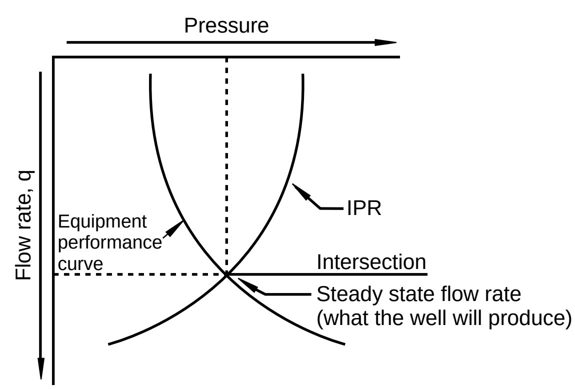


Figure A.7

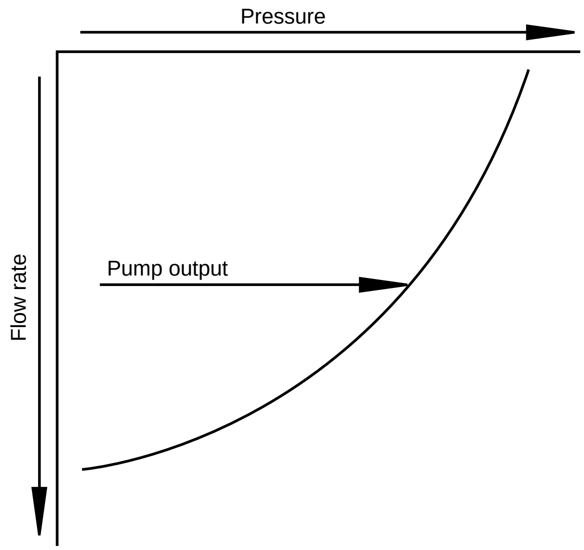


Figure A.8

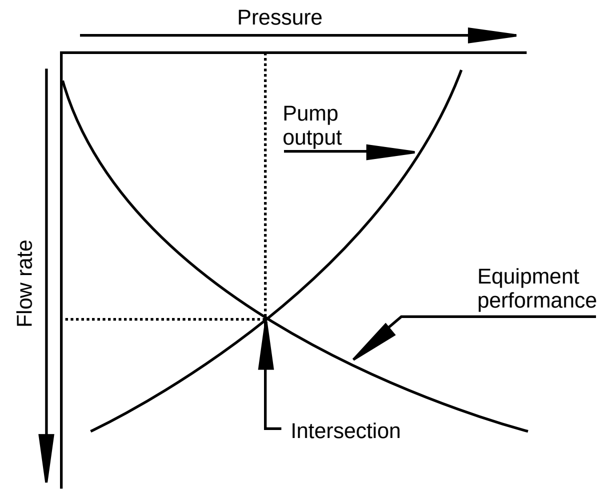


Figure A.10

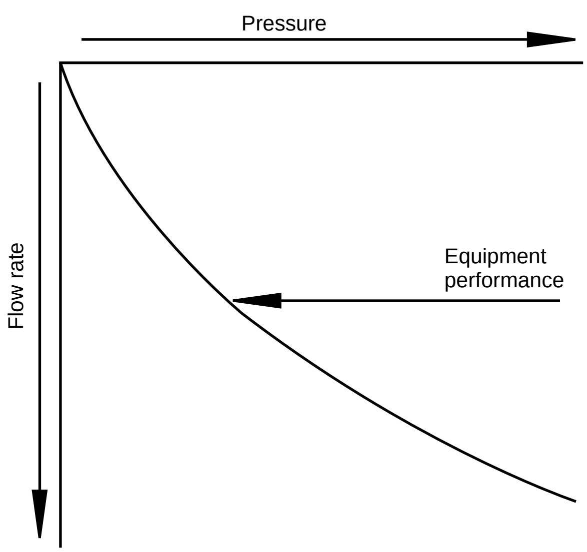


Figure A.9

A.8 Dynamic Kill

How does a well die? If the equipment performance for gas/liquid flow in the wellbore does not cross the well performance (stays to the right of it in the convention shown in Figure A.11) 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).

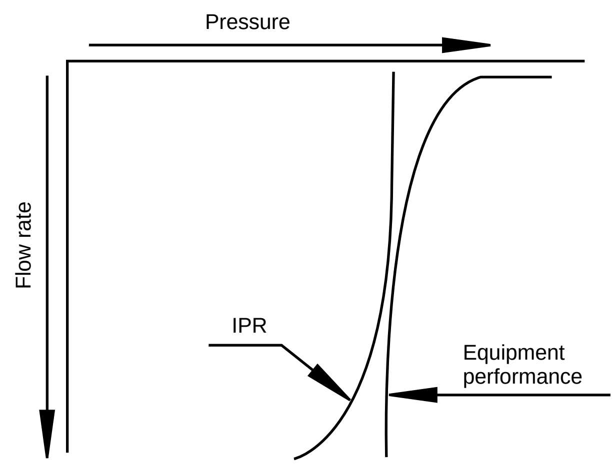


Figure A.11

The backpressure can be adjusted by the pump rate, drilling fluid density, and flow restriction in the equipment downstream of the formation face. The maximum pump rate is limited by the capacity of the rig pumps and the flow friction resistance of the drill string. A representative volumetric rate of 1,000 gallons per minute (gpm) will be used for illustration purposes in this discussion.

The permeability of shallow formations is very high and by the time a kick is evident, enough formation will be exposed to allow a very high deliverability. An estimate of the IPR can be made by assuming a formation pressure (P_t) equal to a water gradient times the depth of the bottom of the sand (refer to Figure A.12).

Vertical two-phase pressure traverse models have been developed for water-air or gas-oil from experimental data for small diameter tubes. Extrapolating to the diameters of riser pipe is probably not justified but has been done to illustrate the technique involved. Two-phase pressure traverses are estimated for 8 $^1/_2$-in., 17 $^1/_2$-in., and 19 $^1/_2$-in. diameter pipe or bore holes. In order to allow flexibility in depth and backpressure, traverses for hypothetical bore holes thousands of ft deep are used. Gilbert's[5] method of adjusting the pressure traverses for pressure and length can be used.

Horizontal two-phase pressure traverses were also estimated[6]. Unwarranted liberty is again taken by extrapolating the small diameter tube data to large diameter vent lines. The same technique is used to account for pressure and length with the horizontal traverses as is used with the vertical traverses. This procedure is not reported in literature, but should be as valid for horizontal flow as for vertical flow.

The backpressure for critical flow is considered and is used as the initiation point for the vent line pressure traverses. The method introduced by Gilbert[5] is used to predict the two-phase critical flow backpressure. This empirical technique has stood the test of time (since 1954) and reasonably approximates the laboratory values developed by Beck, Langlinais, and Bourgoyne[7].

In the case of a drilling well with a competent BOP, the backpressure can be supplemented by the surface choke. If a diverter system is used without a BOP, backpressure can be exerted by increasing the pump rate. If drilling progresses without a riser (by circulating seawater back to the sea floor) the backpressure at the formation face will be the result of the hydrostatic pressure at the sea floor.

A well is usually studied at either the discharge (surface) or at the formation (bottom), but can be analyzed at any point in the system. Selection of the point of interest 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 well may be analyzed at the 30-in. casing shoe if the effect of pilot hole diameter is being studied. The rules are the same for analysis at any point:

a. Develop the well performance relation from the bottom up.

b. Develop the equipment performance relation from the top down.

c. The intersection of the well performance and equipment performance curves at any point in the well system indicates the rate (q) the well will flow (refer to Figure A.13).

[5]Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126.

[6]Beggs, D. and Brill, J. P.; "A Study of Two-phase Flow in Inclined Pipes"; Journal of Petroleum Technology, May 1973, 607 – 617, Society of Petroleum Engineers, Richardson, Texas.

[7]Beck, F. E., Langlinais, J. P., and Bourgoyne, A. T.; "Experimental and Theoretical Considerations for Diverter Evaluation and Design," SPE 15111, Society of Petroleum Engineers, Richardson, Texas.

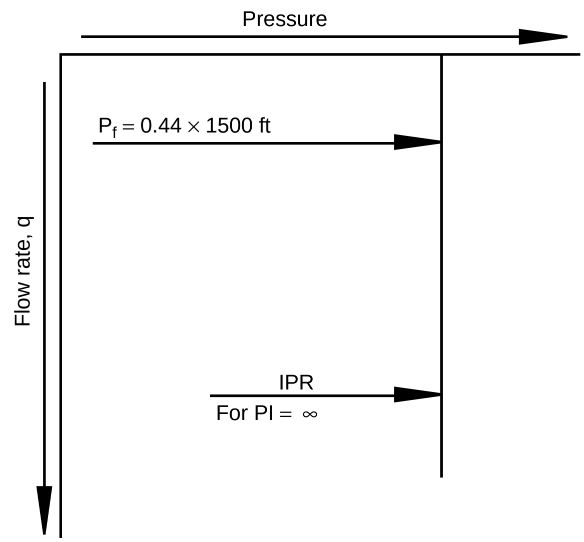


Figure A.12

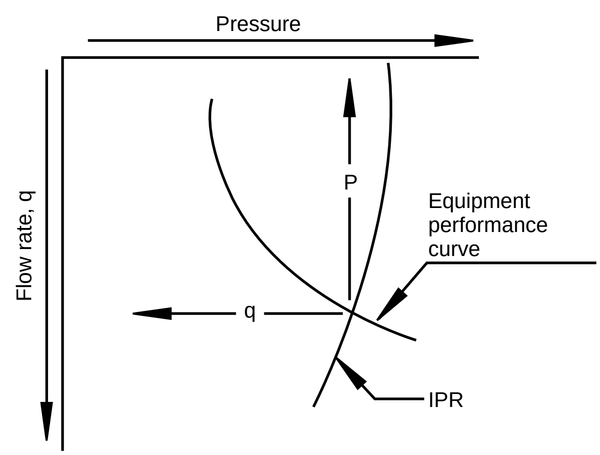


Figure A.13

A.9 Developing a Steady-state Analysis

Four primary relationships can be used to develop a steady-state analysis of a diverter system. Models are used to approximate behavior of these relationships.

1. The inflow performance relationship—IPR of the formation.
2. The vertical two-phase flow pressure traverses.
3. The horizontal two-phase flow pressure traverses.
4. The critical flow relationships.

A.10 Equipment Performance Example

The following is an example for determining the backpressure on the diverter.

1. Backpressure at the exit of the diverter line due to sonic flow.

$$P_{tf} = \frac{q435R^{0.546}}{S^{1.89}} \qquad \text{A-6}$$

where

P_{tf} = upstream pressure, psia,

R = gas-liquid ratio, thousand CF/bbl,

q = liquid flow rate, bbl/day,

S = diverter line exit diameter, 64th in.

2. Determine backpressure at the diverter. Notice the traverses are developed (refer to Figure A.14) for a hypothetical vent line length of 1,000 ft with a fixed liquid flow rate at 1,000 gpm. The curves are for different gas flow rates as illustrated. To calculate flowing pressure, P_f, for a 150-ft diverter line in the illustrated 1,000-ft hypothetical line:

a. Enter at the discharge pressure due to sonic flow at an arbitrarily chosen gas flow rate, which in the example is 200 million SCFD.

b. Add the 150 ft length of vent line (L). Read off the pressure at the upstream end of the 150 ft-line (diverter end).

c. Pressure at the diverter, P_d, for 200 million SCFD is 875 psi.

3. Develop an equipment performance curve for the diverter. For purposes of illustration use 150 ft of 8-in. vent line and a flow rate of 100 million SCFD (refer to Figure A.15):

a. Enter the sonic backpressure curve for an 8-in. diameter line and drop a vertical line to the 100 million SCFD curve.

b. Add 150 ft of vent line to get the diverter discharge pressure (275 psi) at 100 million SCFD.

c. Drop a vertical from this point and plot the flow rate (100 million SCFD) versus diverter discharge pressure (275 psig) to obtain a point on the equipment performance line for the 8-in. diverter line.

4. Select another flow rate (300 MMSCFD).

a. Using the same procedures outlined in Steps 3.a, 3.b and 3.c, determine the diverter discharge pressure for 300 million SCFD flow rate in the 8-in. line. Drop a vertical from this point and plot the flow rate (300 million SCFD) versus diverter discharge pressure (525 psig) to obtain another point on the equipment performance curve for the 8-in. diverter line.

b. Repeat Steps 3.a, 3.b, and 3.c for another flow rate (500 million SCFD) and obtain another point on the equipment performance curve for the 8-in. diverter line. These points should be connected to form the equipment performance curve.

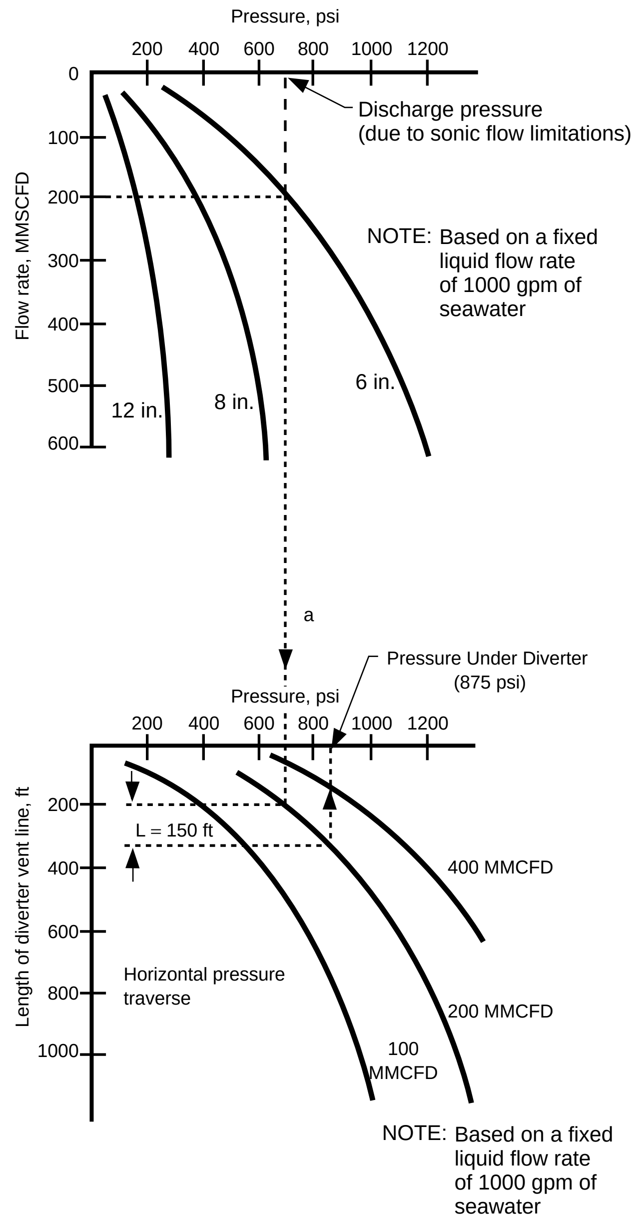


Figure A.14

A cursory examination of the data and equipment performance curve seems to indicate that backpressure on the diverter is primarily a function of the diverter line diameter. This is not the complete picture. This information reflects the equipment performance only and does not take into account performance of the well. If equipment performance reflects the total picture, any shallow gas zone, whether 1,500 ft or 3,000 ft deep, will exert the same backpressure on the diverter.

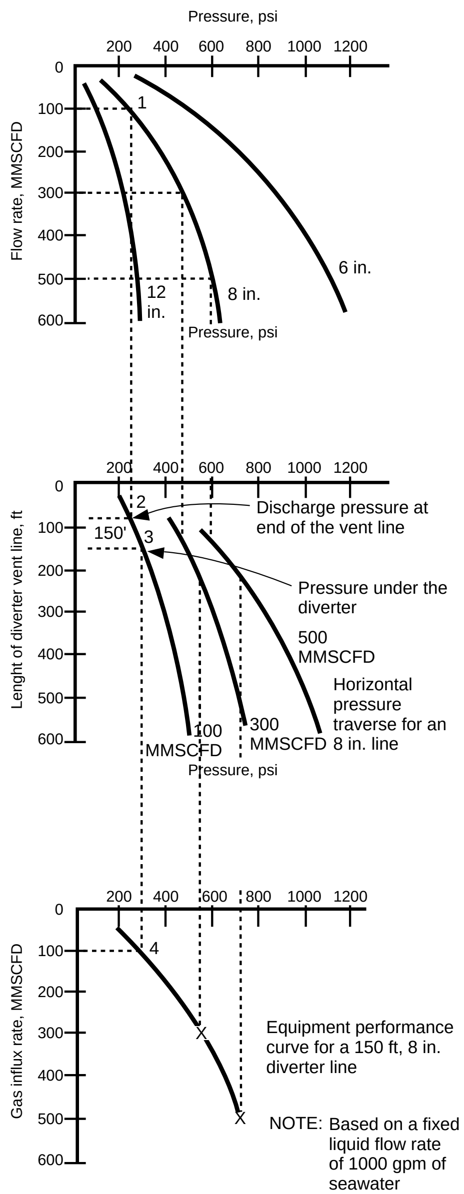


Figure A.15

In order to get a truer performance picture, one should consider equipment performance plus well performance.

A.11 Well Performance Example

The following example demonstrates the effect of pilot hole depth on diverter backpressure. The example well has the following characteristics.

Total Depth = 1,600 ft subsea

Water Depth = 300 ft

Conductor Pipe (30 in.) Depth = 300 ft below mud line

Pilot Hole Depth = 1,000 ft below 30-in. conductor pipe

Formation Pressure, Ps = 0.44 ×1,600 = 704 psig

Diverter Location = 100 ft above sea level

The permeability of shallow formation is usually, 2 – 8 Darcies. At a penetration rate of 50 ft per hour, significant formation may be penetrated before the influx is recognized at the surface. For practical purposes, the PI can be very high.

Figure A.16 illustrates a vertical two-phase flow pressure traverse diagram to a hypothetical depth. These data are used in the manner devised by Gilbert[5] to adjust for pressure and length variations. Figures A.24, A.25, A.26, and A.27 are for pressure drop through diverter lines. Figures A.28, A.29, A.30, A.31, and A.32 are for pressure drop in the wellbore.

Note: The length and depth scales are for reference purposes and a fraction of the scale (length or depth) is used for calculating purposes.

Following the step-by-step procedure, develop a well performance curve for assumed flow rate(s) and selected well configuration parameters:

The flowing bottom-hole pressure (FBHP) from the IPR is 704 psia. Use a flow rate of 100 million SCFD (refer to Figure A.17).

a. Enter the lower vertical two-phase flow pressure traverse at FBHP ($\simeq$ 700 psi) and project vertically to the flow rate curve (100 million SCFD) on the pressure traverse diagram.

b. From the intersection of the FBHP and the 100 million SCFD rate pressure traverse curve, add the 1,000 ft vertical length of the 12 $^{1}/_{4}$-in. × 8 $^{1}/_{2}$-in. pilot hole. This point on the 100 million SCFD rate pressure traverse curve gives the pressure at the top of the pilot hole (500 psi).

c. Project vertically down from the pressure at the top of the pilot hole (500 psi) to the flow rate (100 million SCFD) to obtain a point on the well performance curve for 1,000 ft of 12 $^{1}/_{4}$-in. × 8 $^{1}/_{2}$-in. pilot hole.

d. Repeat Steps *a*, *b*, *c*, and *d* for different well flow rates and construct a well performance curve 1,000 ft above the gas zone at the top of the pilot hole (or bottom of the 30-in. conductor pipe).

Use the same procedure for 700 ft of riser and conductor and construct a well performance curve at the diverter. In this case, the influence of 700 ft of large diameter riser/conductor/hole is insignificant and will be neglected for the balance of this example study.

Superimposing the well performance curve at the diverter on the equipment performance curve for various sizes of diverter lines, illustrates that for a 1,000 ft deep 12 $^{1}/_{4}$-in. pilot hole the diverter pressure is significantly influenced by diameter of the diverter line (refer to Figure A.18).

In this example, the well would not be killed by pumping 1,000 gpm of seawater. The gas flow rate is influenced by the diverter line diameter. The well will flow 100 million SCFD gas through a 6-in. diameter diverter line when pumping 1,000 gpm of seawater. The backpressure under these conditions is 550 psi. The backpressure will reduce to 150 psi for a

12-in. diameter diverter line, but the well will produce 270 million SCFD.

Figure A.19 shows that when the pilot hole is 17 $^1/_2$ in. or greater, the diverter line size has little effect on the pressure at the diverter; however, the gas influx rate is drastically affected by diverter line diameter. For a 6-in. diameter diverter line, the gas influx rate is 120 million SCFD. For an 8-in. diameter diverter line, the gas influx rate is 450 million SCFD. The pressure at the diverter is approximately 650 psi for either the 6-in. or the 8-in. diameter line.

Note: The well performance curve for 17 $^1/_2$-in. × 8 $^1/_2$-in. pilot hole was developed using Items a through f in A.12 plus pressure traverse curves shown in Figure A.31.

Figure A.20 illustrates that there is little difference between a 17 $^1/_2$-in. pilot hole and no pilot hole.

Note: The well performance curve was developed using Items a through f in A.12 plus pressure traverse curves shown in Figure A.32.

A.12 Effect of Pilot Hole Diameter on the Ability to Kill a Well

a. Calculate and plot the equipment performance curve at the 30-in. shoe (refer to Figure A.21).

b. From the point of the 30-in. shoe, calculate and plot the equipment performance curve at total depth for different size pilot holes.

c. The rate the well will produce can be determined from the intersection of the equipment performance curve with the well performance curve.

d. If the equipment performance exceeds the well performance and the curves do not intersect, the well can be killed. In the example shown in Figure A.22, the well can be killed with an 8 $^1/_2$-in. diameter pilot hole; the well cannot be killed with a 12 $^1/_4$-in. diameter or larger pilot hole.

Note: The well performance curve was developed using Items *a* through *f* in A.12 plus pressure traverse curves shown in Figure A.22.

A.13 Summary

As previously stated, Appendix A presents some fundamental concepts for consideration when planning shallow gas handling procedures. This Appendix does not recommend particular procedures, rather it illustrates a method that may be used in designing specific handling procedures for given situations. Only by performing such an analysis can optimized handling procedures for a specific well be determined. Figures A.23 through A.32 present information to aid analyses of various situations.

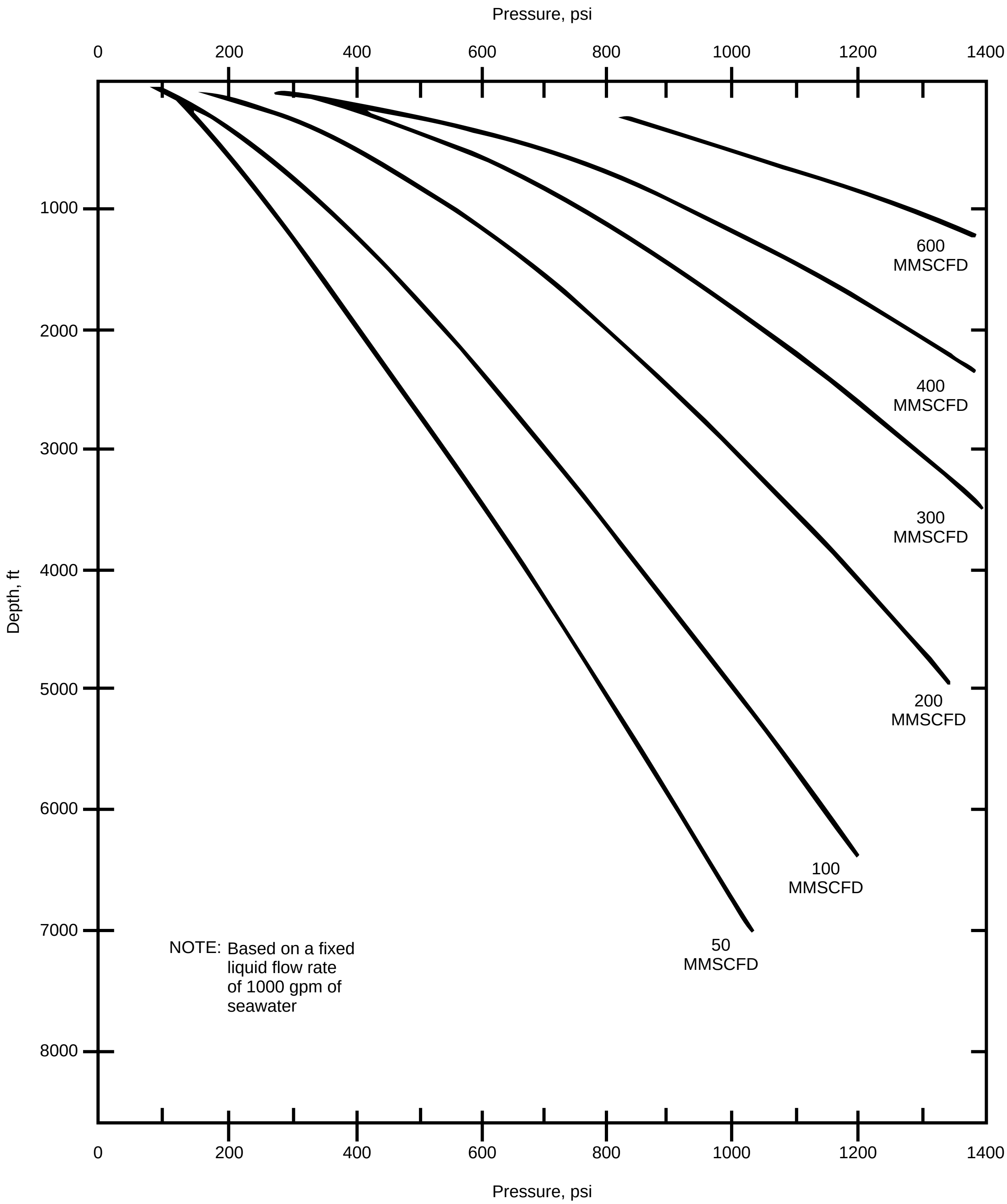


Figure A.16—Vertical Two-phase Pressure Traverse
(12 1/4-in. Borehole × 8 1/2-in. Drill Collars)

(Gilbert, W. E., “Flowing and Gas-lift Well Performance,” *Drilling and Production Practice—1954,* American Petroleum Institute, Dallas, Texas, 126.)

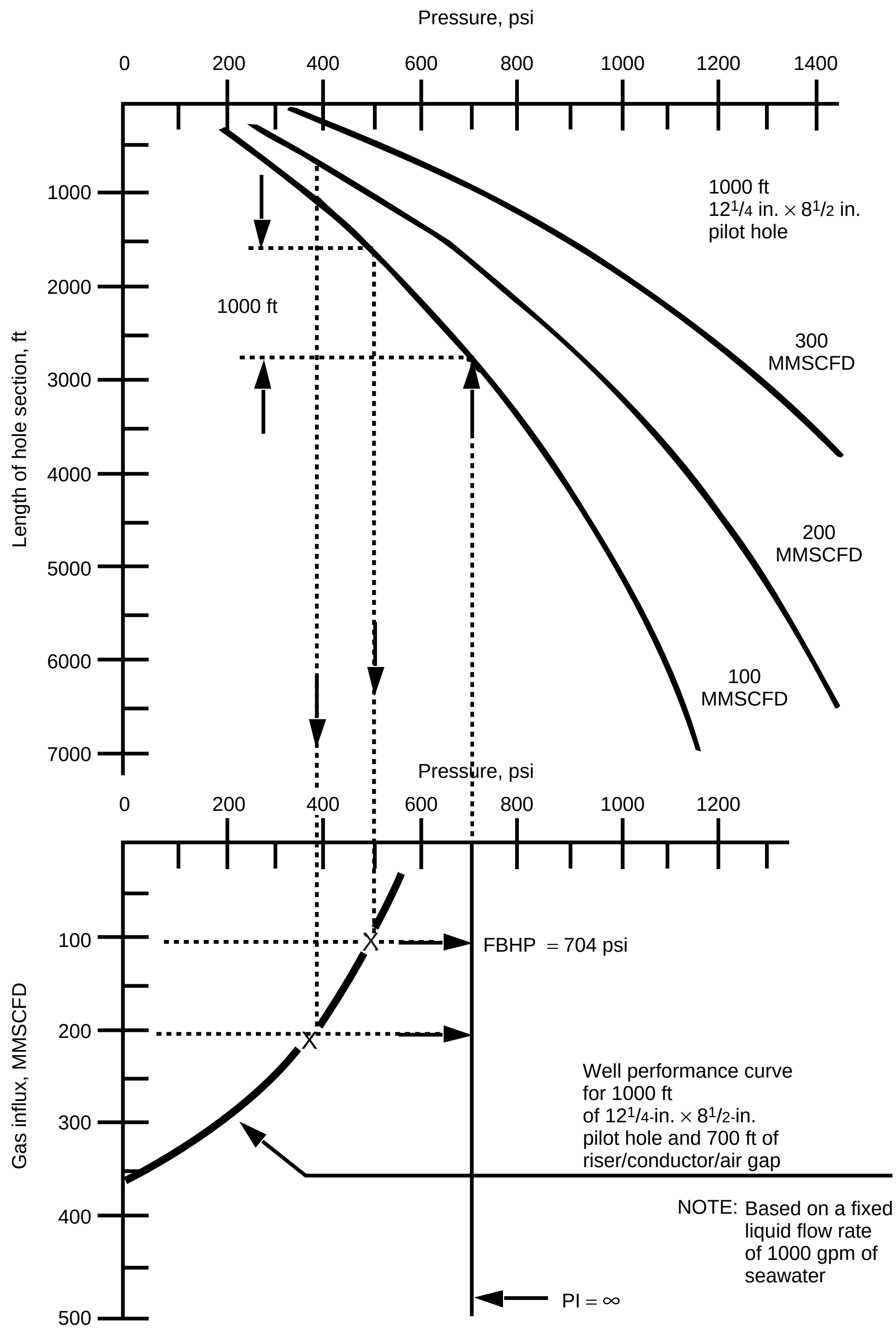

Pressure, psi
0
200
400
600
800
1000
1200
1400
Length of hole section, ft
1000
2000
3000
4000
5000
6000
7000
1000 ft
1000 ft
12¼ in. × 8½ in.
pilot hole
300
MMSCFD
200
MMSCFD
100
MMSCFD
Pressure, psi
0
200
400
600
800
1000
1200
Gas influx, MMSCFD
100
200
300
400
500
FBHP = 704 psi
Well performance curve
for 1000 ft
of 12¼-in. × 8½-in.
pilot hole and 700 ft of
riser/conductor/air gap
NOTE: Based on a fixed
liquid flow rate
of 1000 gpm of
seawater
PI = ∞

Figure A.17

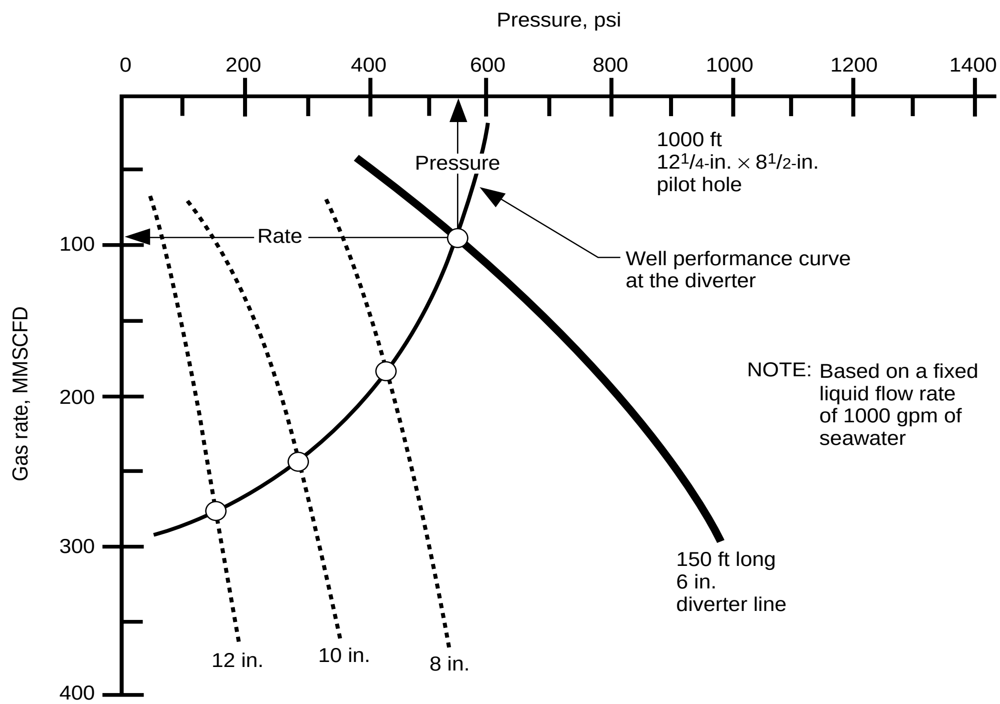


Figure A.18—Effect of Diverter Size on Diverter Pressure
(With a 12 $^1/_4$-in. × 8 $^1/_2$-in. Pilot Hole)

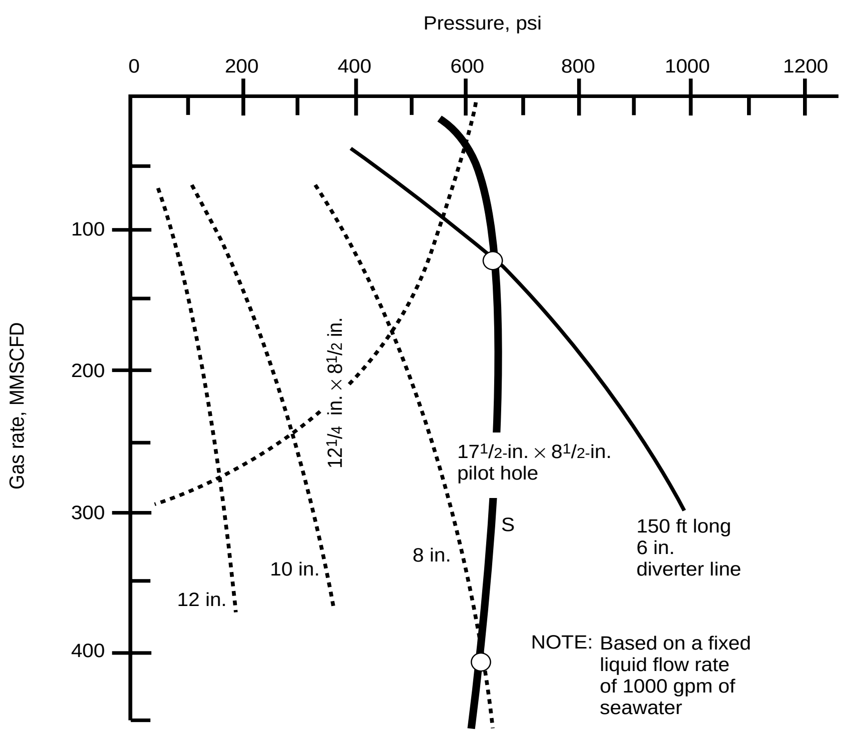


Figure A.19—Effect of Diverter Size on Diverter Pressure
(With a 17 $^1/_2$-in. × 8 $^1/_2$-in. Pilot Hole)

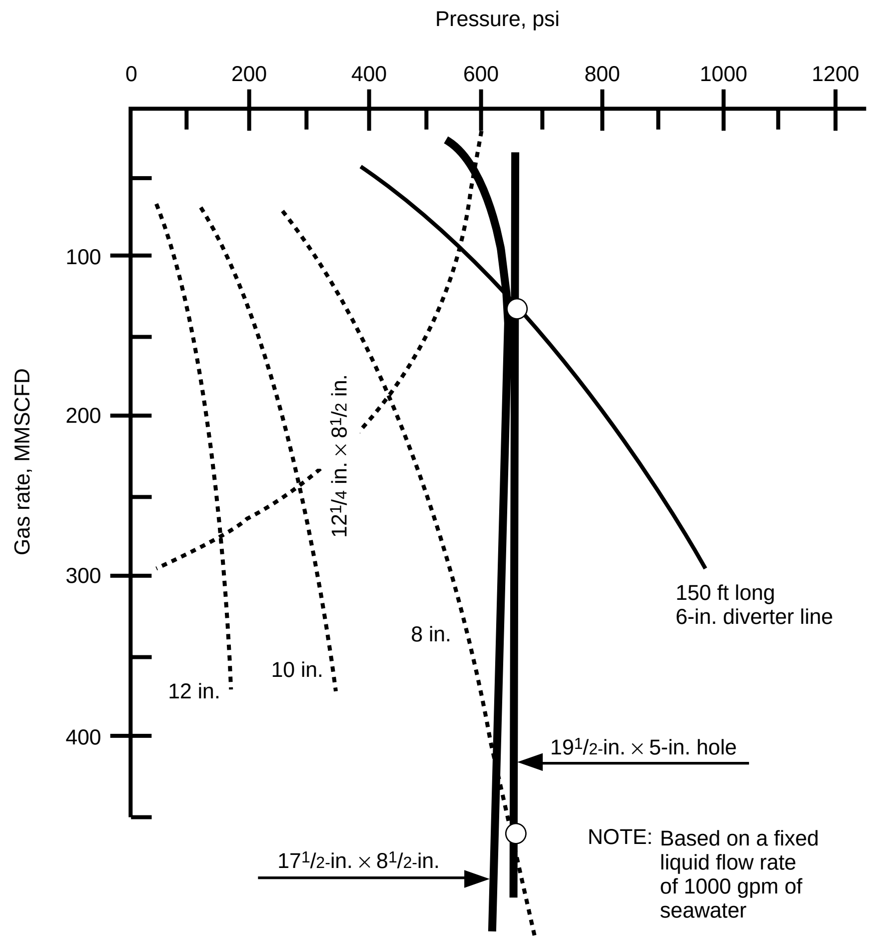


Figure A.20—Depicting Little Difference between 17½-in. and Larger Holes

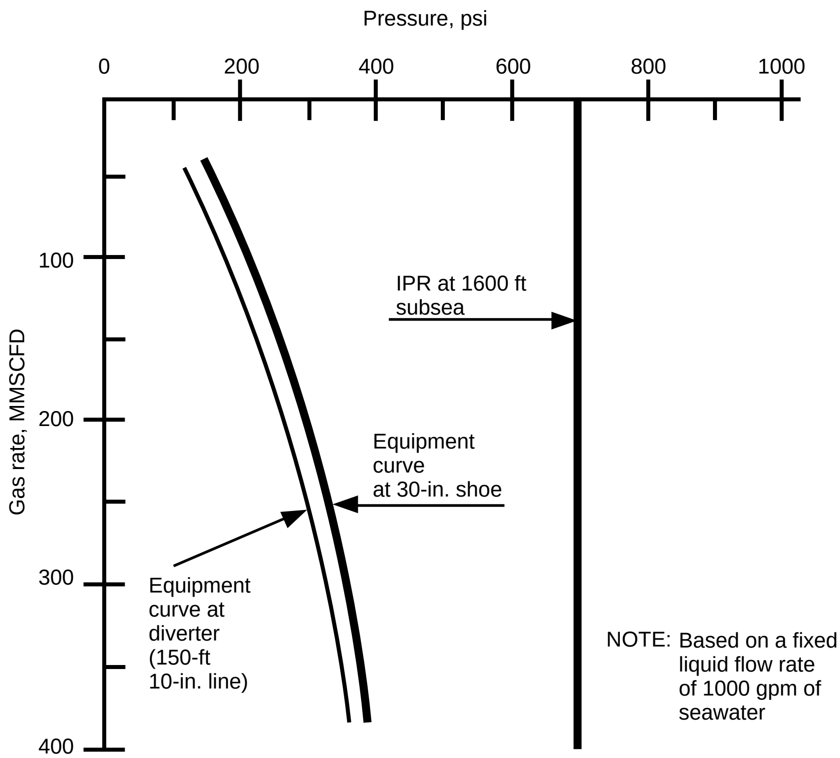

Pressure, psi
0
200
400
600
800
1000
100
200
300
400
Gas rate, MMSCFD
IPR at 1600 ft subsea
Equipment curve at 30-in. shoe
Equipment curve at diverter (150-ft 10-in. line)
NOTE: Based on a fixed liquid flow rate of 1000 gpm of seawater

Figure A.21

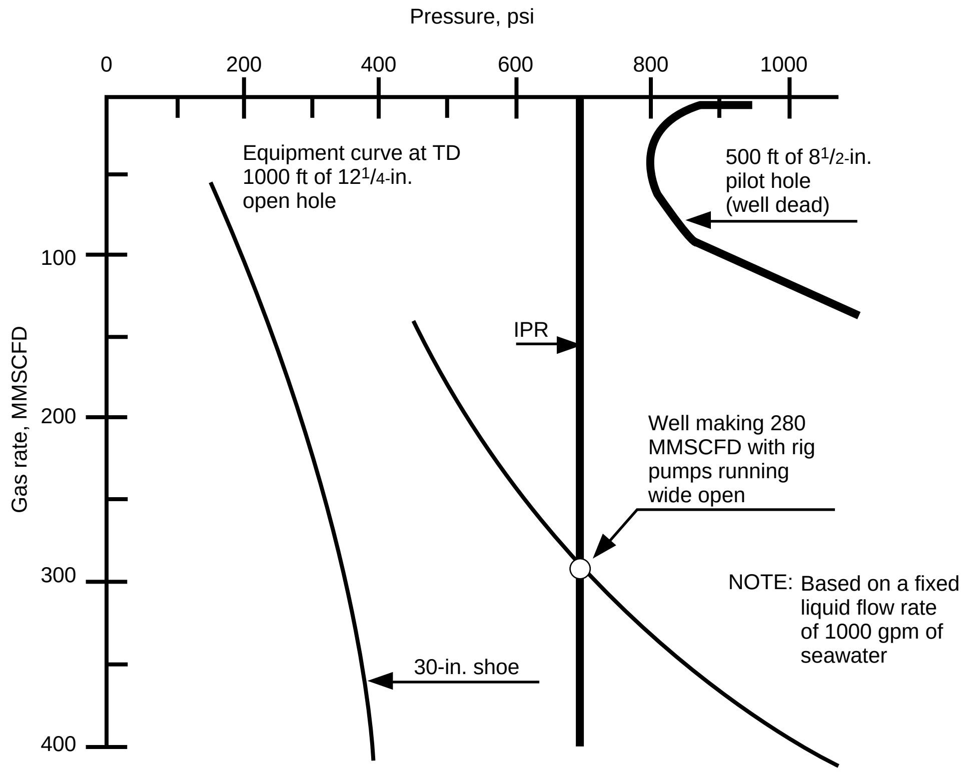


Figure A.22

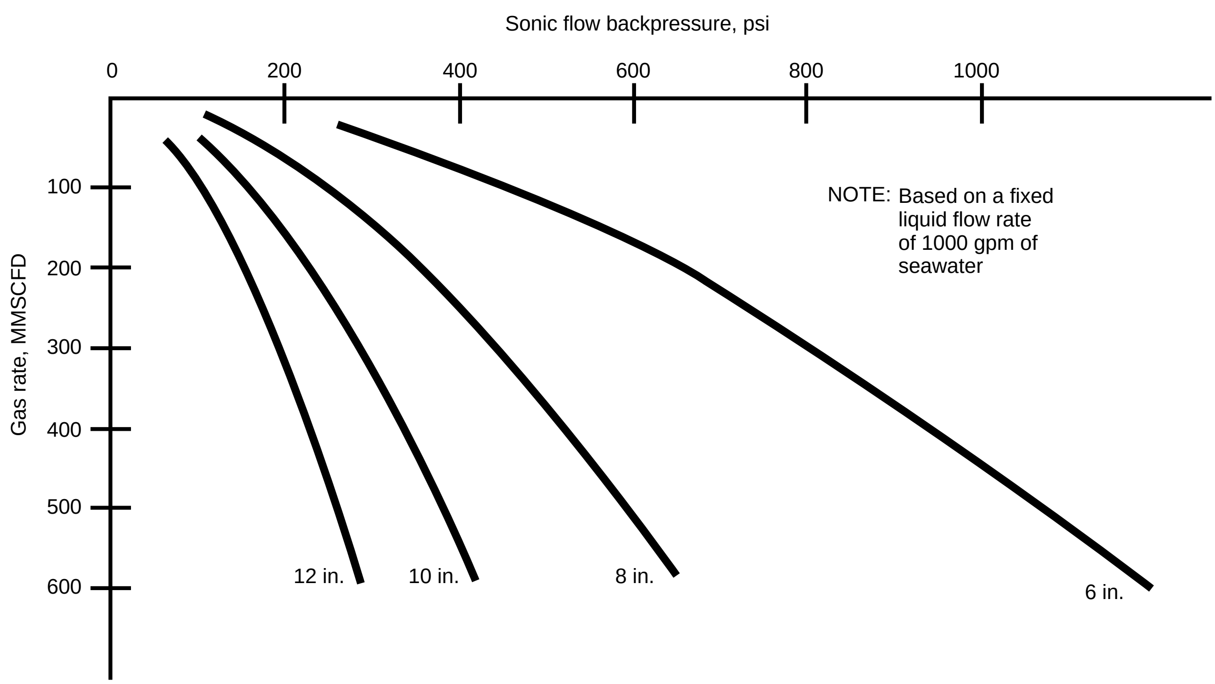


Figure A.23—Backpressure at Diverter Line Exit Due to Sonic Flow

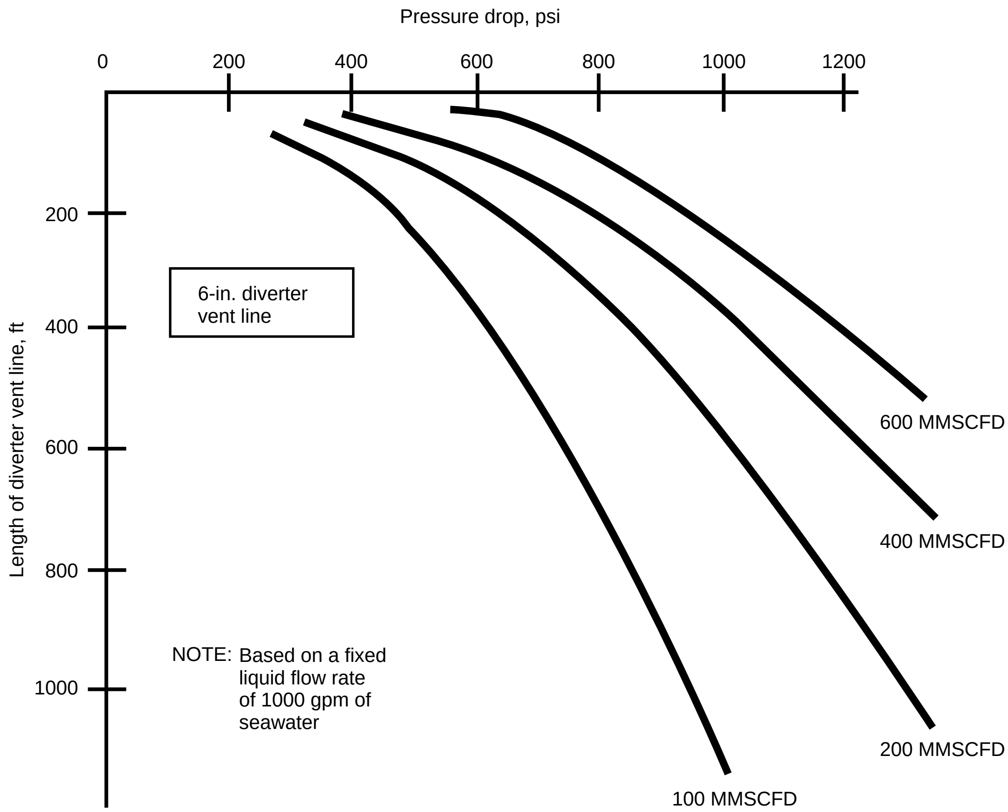


Figure A.24—Frictional Pressure Drop for 6-in. OD Diverter Line

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

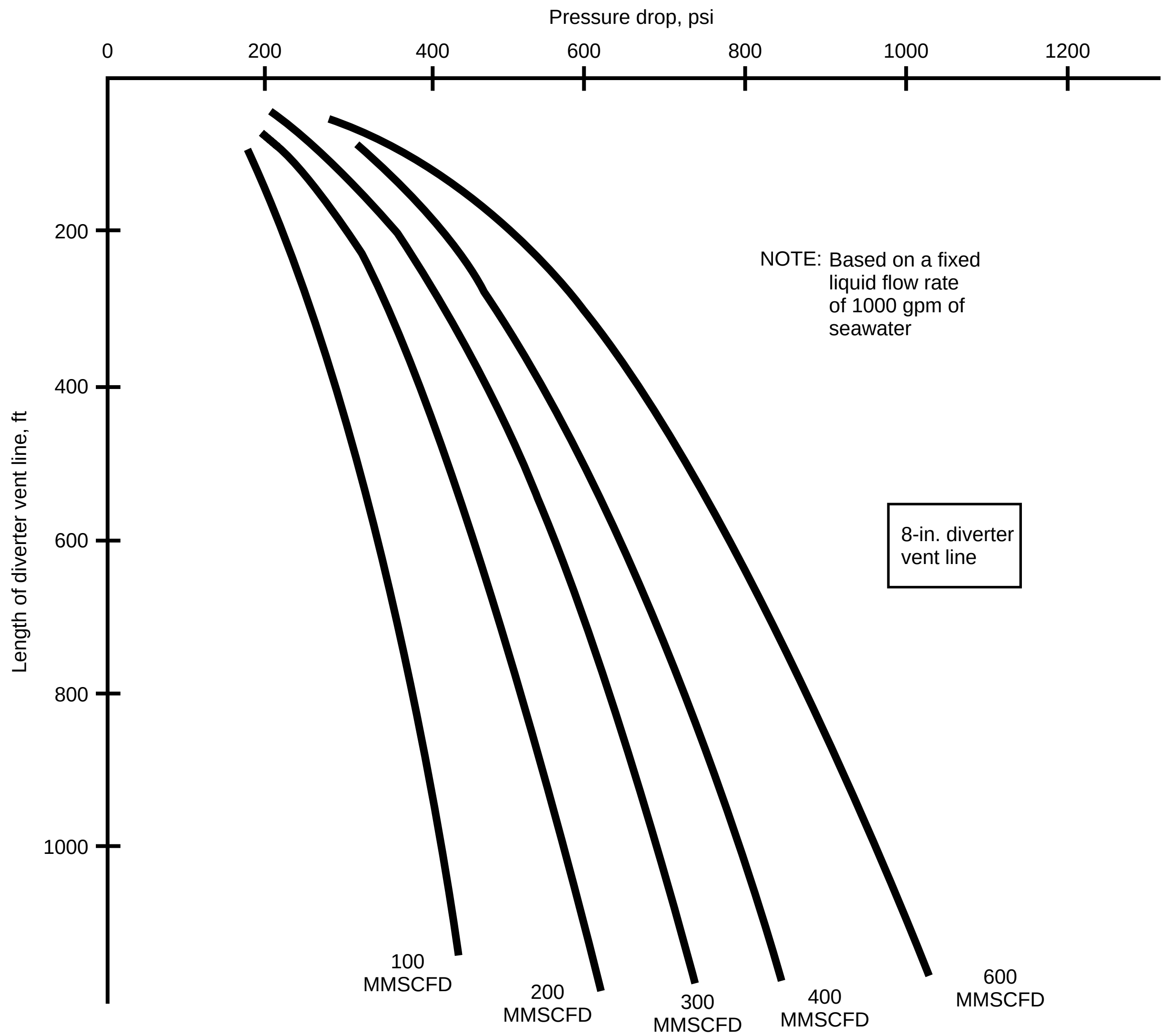


Figure A.25—Frictional Pressure Drop for 8-in. OD Diverter Line

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

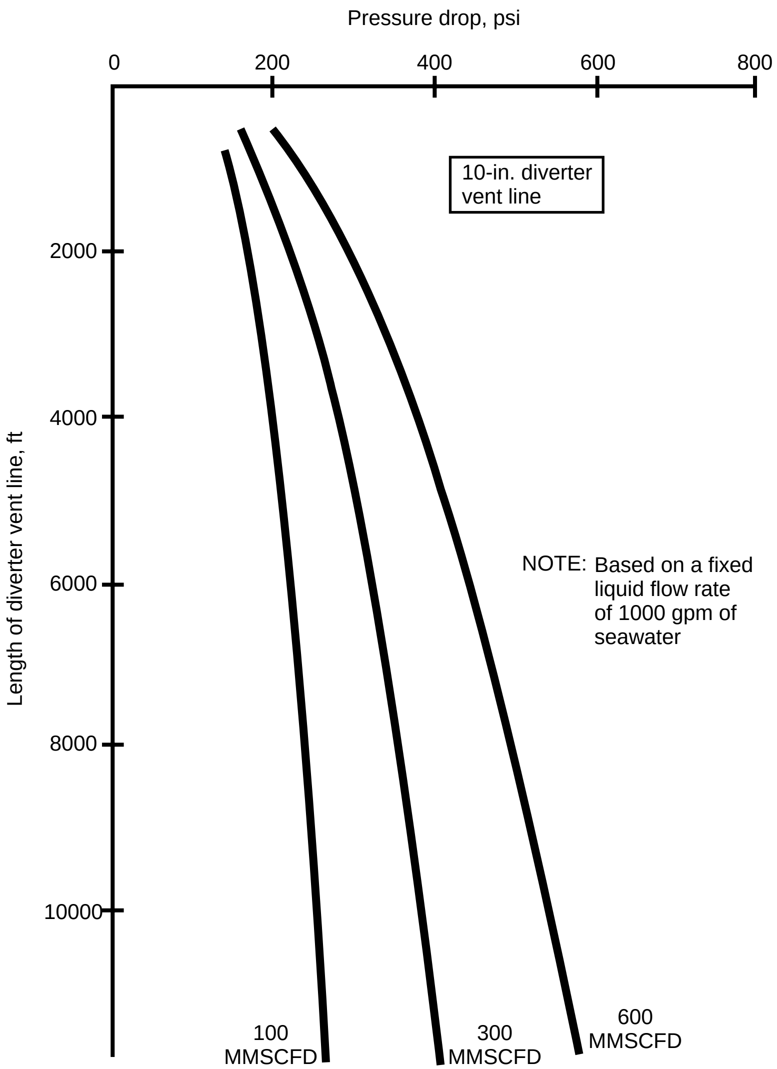


Figure A.26—Frictional Pressure Drop for 10-in. OD Diverter Line

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

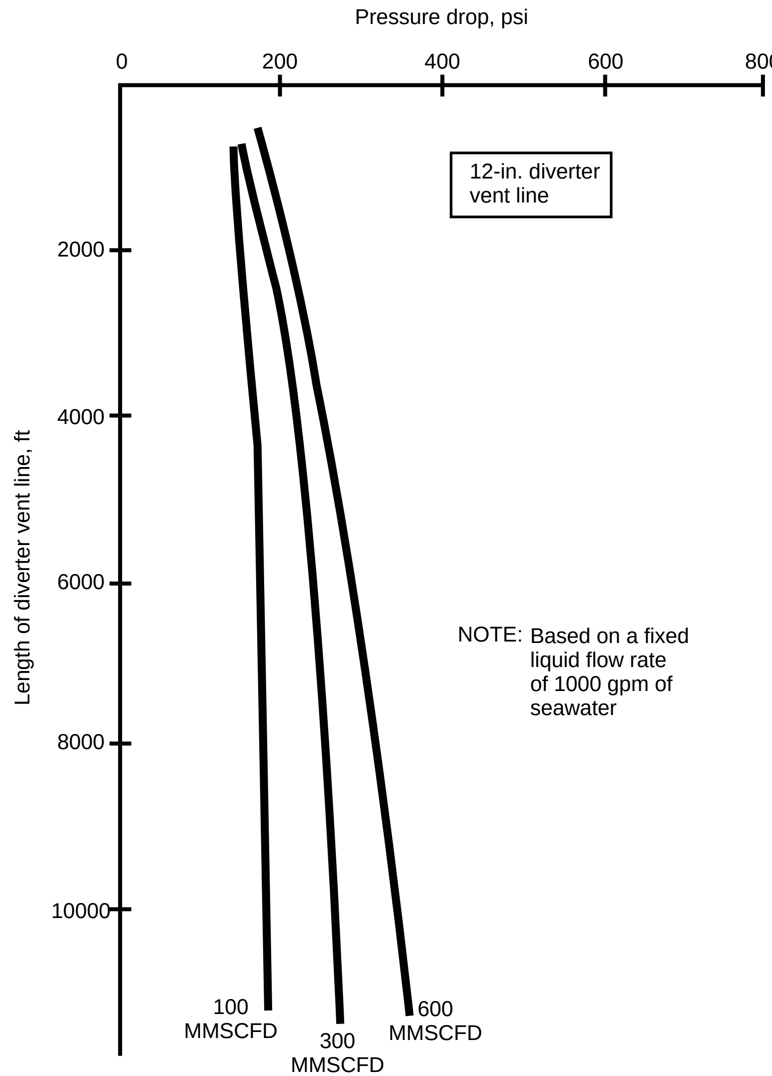


Figure A.27—Frictional Pressure Drop for 12-in. OD Diverter Line

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

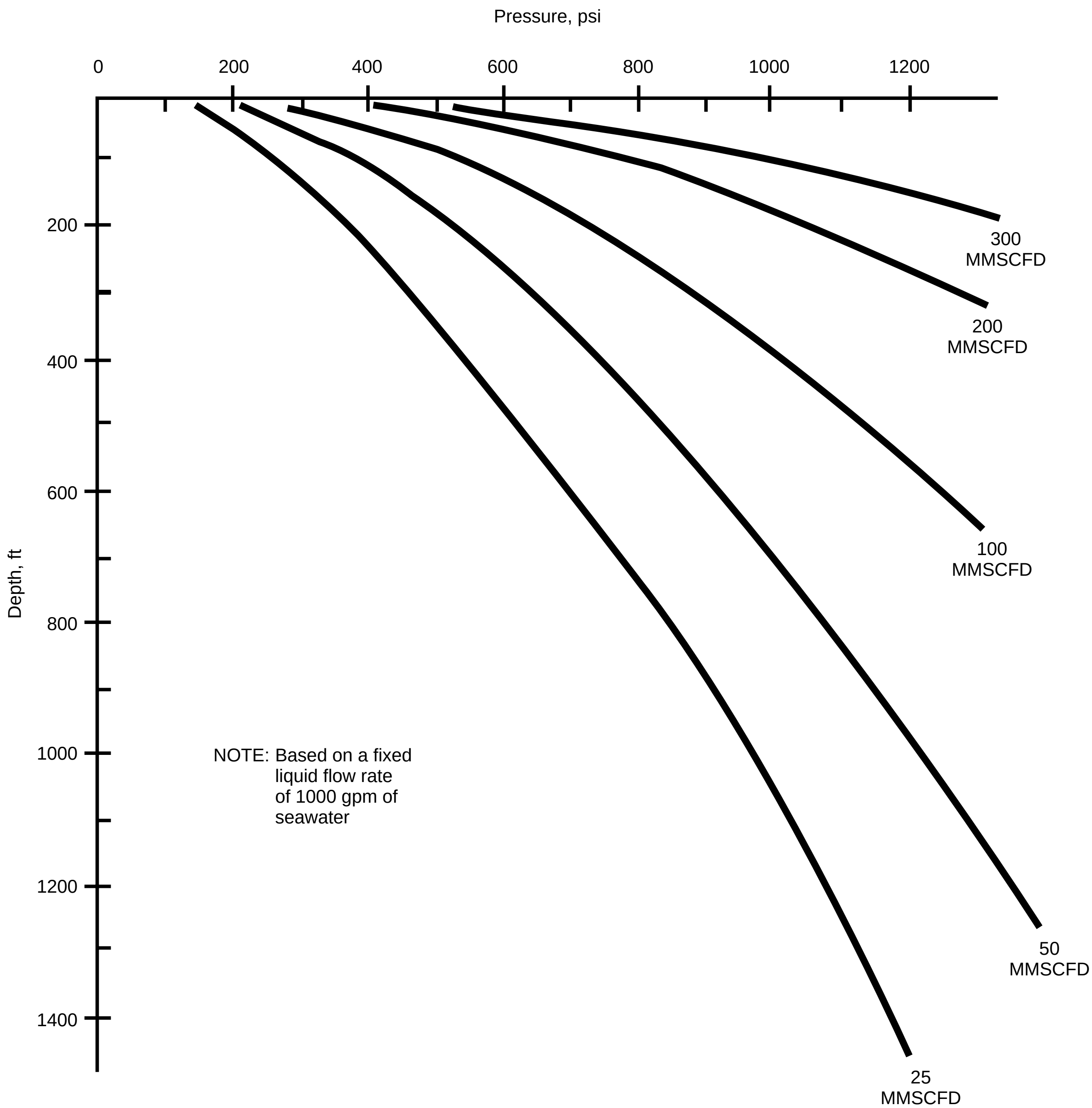


Figure A.28—Two-phase Vertical Pressure Traverse
(8 1/2-in. Borehole × 6 3/4-in. Drill Collars)

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

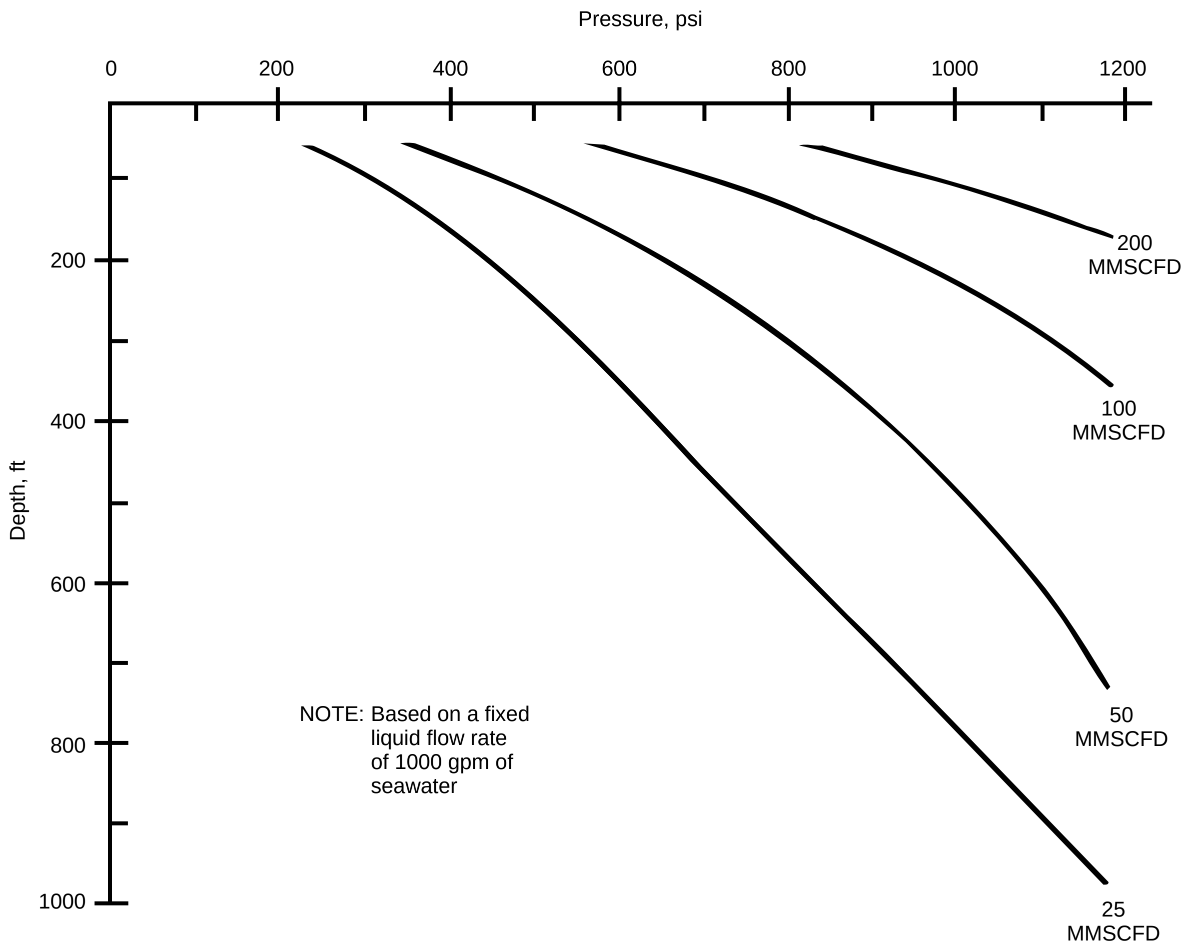


Figure A.29—Vertical Two-phase Flow Pressure Traverse
(9 $^{7}/_{8}$-in. Borehole × 8-in. Collars)

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

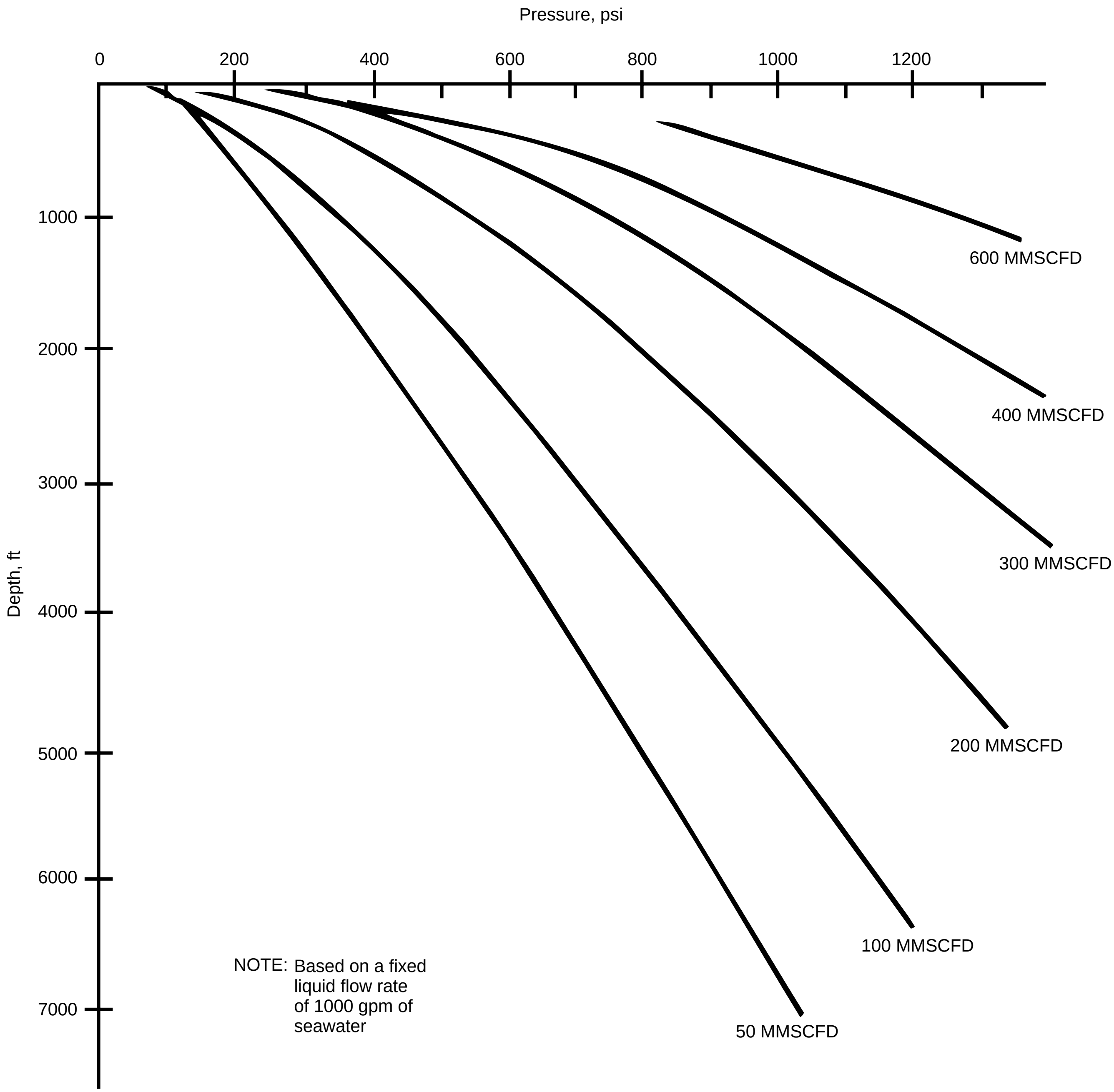


Figure A.30—Vertical Two-phase Pressure Traverse
(12 1/4-in. Borehole × 8 1/2-in. Drill Collars)

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

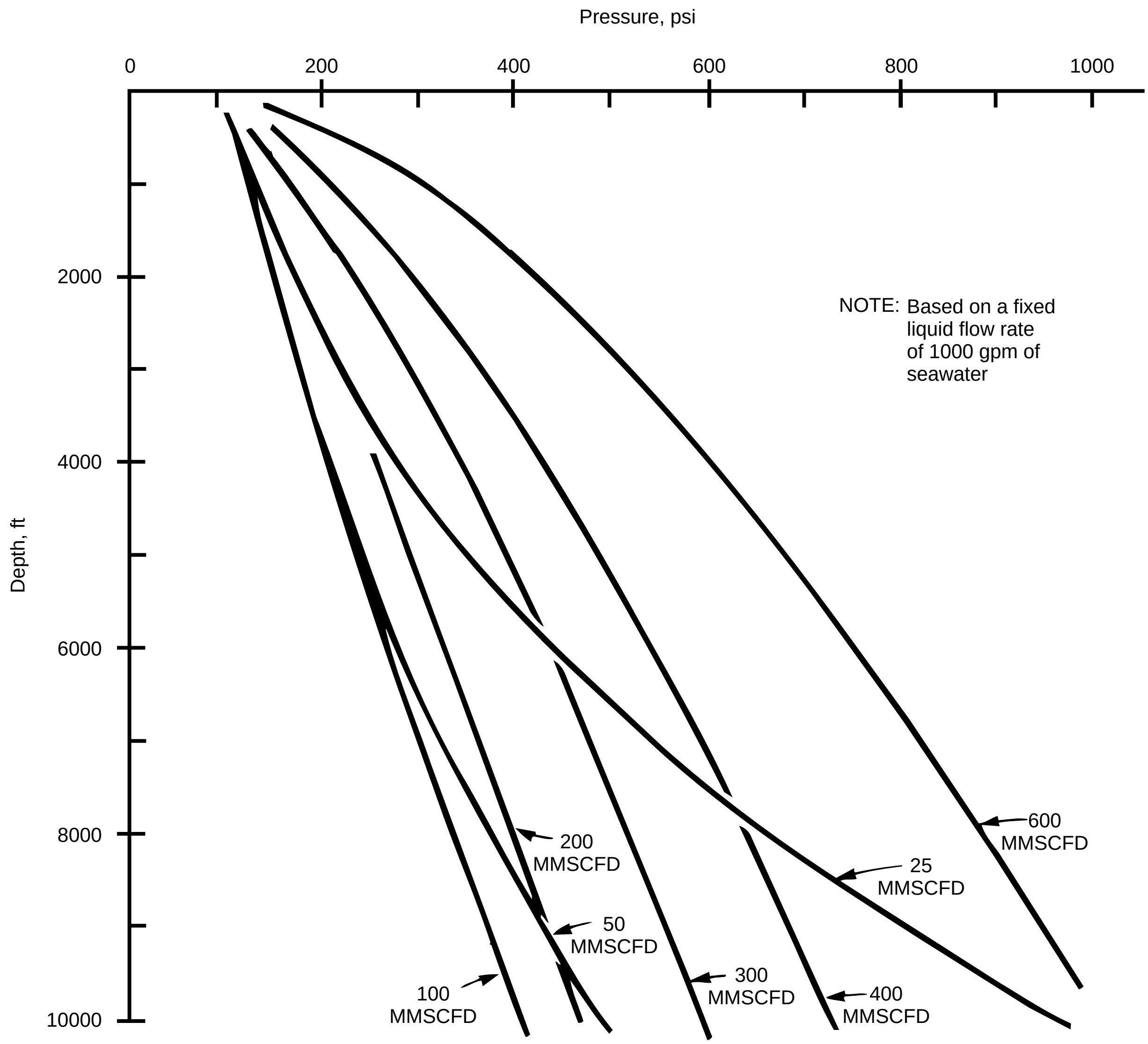


Figure A.31—Two-phase Vertical Pressure Traverses
(17 1/2-in. Borehole × 8 1/2-in. Drill Collars)

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

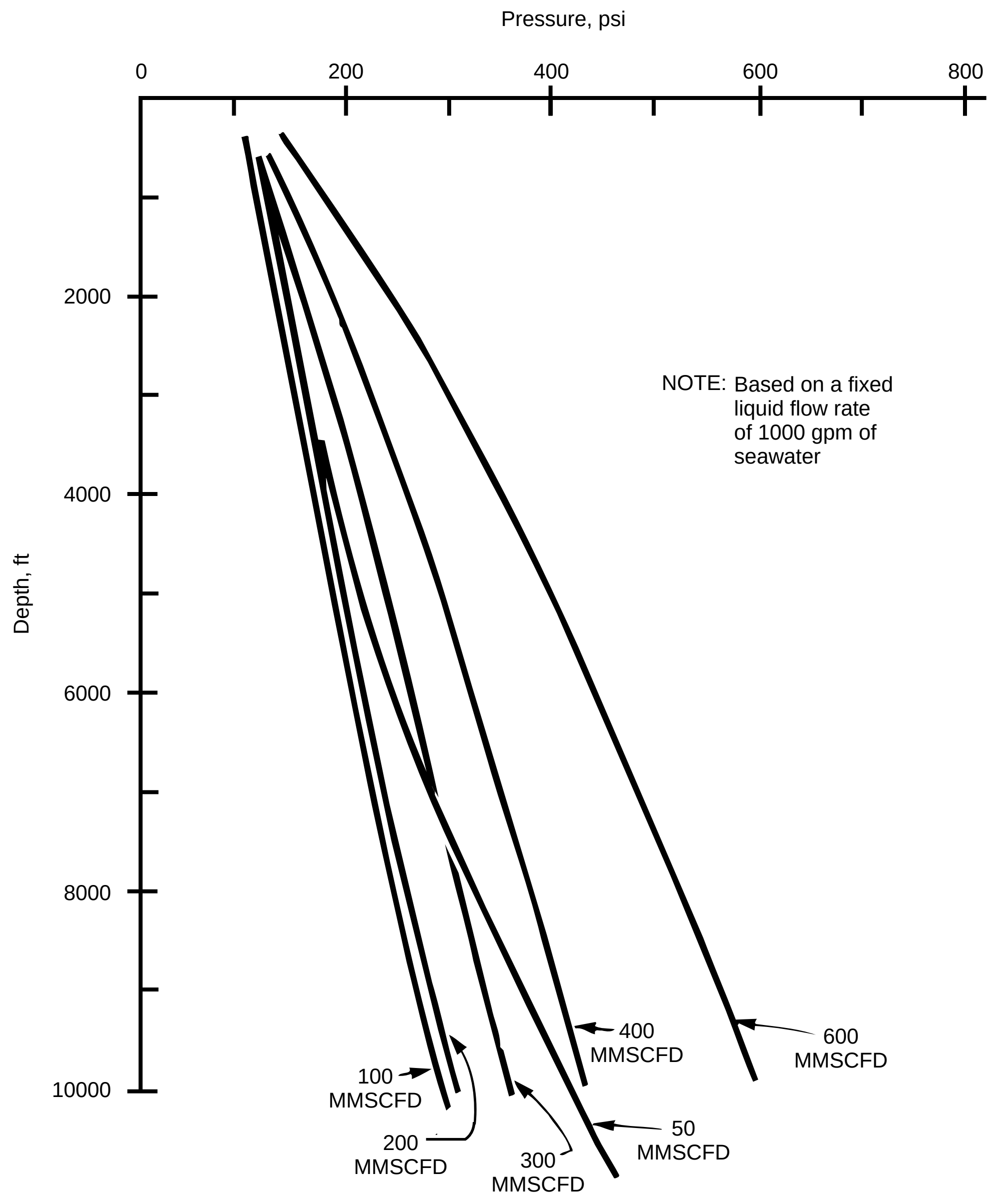


Figure A.32—Two-phase Vertical Pressure Traverses
(19 1/2-in. Borehole × 5-in. Drill Collars)

(Gilbert, W. E.; "Flowing and Gas-life Well Performance," Drilling and Production Practice—1954, American Petroleum Institute, Dallas, Texas, 126. This is a theoretical length developed in accordance with discussion in Par. A.11.)

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