Recommended Practices for Diverter Systems Equipment and Operations

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RECOMMENDED PRACTICES FOR DIVERTER SYSTEMS EQUIPMENT AND OPERATIONS

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RECOMMENDED PRACTICES FOR DIVERTER SYSTEMS EQUIPMENT AND OPERATIONS

FOREWORD

a. These recommended practices were prepared by the Subcommittee on Diverter Systems Equipment and Operations. They represent a composite of practices employed by various operating, drilling, and equipment manufacturing companies. In some instances, reconciled composites of these practices are included in this publication. This publication is under jurisdiction of the American Petroleum Institute Production Department's Executive Committee on Drilling and Production Practices.

b. The goal of these voluntary recommended practices is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of the drilling rig and associated equipment, and preservation of the environment for land and marine drilling operations. These recommended practices are published to facilitate the broad availability of proven, sound engineering and operating practices. Recommendations presented herein are based on extensive and wide ranging industry experience. This publication does not purport, however, to present all of the operating practices which 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, however, equivalent alternative installations and practices may be utilized to accomplish the same objectives. The formulation and publication of API recommended practices is not intended to, in any way, inhibit anyone from using other practices. Every effort has been made by API to assure the accuracy and reliability of data contained in this publication. However, the Institute makes no representation, warranty, or guarantee in connection with the publication of these recommended practices and hereby expressly disclaims any liability or responsibility for loss or damage resulting from use or applications hereunder.

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

d. 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)" 1) where a safe comparable alternative practice(s) is available; 2) that may be impractical under certain circumstances; or 3) 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.

e. Suggestions for revisions or additions are invited and should be submitted to: Director, Production Department, American Petroleum Institute, 2535 One Main Place, Dallas, Texas 75202-3904.

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RECOMMENDED PRACTICES FOR DIVERTER SYSTEMS EQUIPMENT AND OPERATIONS

SECTION 1 SCOPE

1.1 The purpose of these recommended practices is to provide accurate information that can serve as a guide for selection, installation, and operation of diverter equipment systems on land and marine rigs (barge, platform, bottom-founded, 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. Refer to Appendix A for discussion of some alternative methods for shallow gas well control.

1.2 Some operations are being 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.

1.3 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 have been 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.

SECTION 2
DIVERTER SYSTEMS — GENERAL

2.1 Function. The function of a diverter system is to provide a low pressure well flow control system to direct controlled or uncontrolled wellbore fluids away from the immediate drilling area *for the safety of personnel and equipment involved in the operation.* The diverter system is not designed to shut in or halt well flow, rather it permits routing of the flow to a safe point away from the rig personnel and equipment.

2.2 General Description. Components of diverter systems include: 1) annular sealing device, 2) vent outlet(s), 3) vent line(s), 4) valve(s), and 5) control system (refer to Par. 8.25).

2.3 Guidelines for Use of Diverter Systems. These are general guidelines for possible use of diverter systems. It should be stressed that there may be other alternatives that are as acceptable or more acceptable. Some possible applications for diverter systems are listed in Pars. 2.3.1 through 2.3.5.

2.3.1 If due to inadequate data or if determined, via a previously drilled well(s), seismic data, or other means, that there exists a reasonable possibility of encountering gas in quantities sufficient to cause well control problems while drilling below the first casing string, i.e., drive pipe, conductor pipe or structural casing, etc., a diverter system, in the absence of positive well control means, should be considered for use in the event the well flows.

2.3.2 A diverter system should also be considered if a situation exists as described in Paragraph 2.3.1 when drilling below the conductor casing on floating installations with or without the use of a blowout preventer stack, when the anticipated formation fracture gradient is insufficient to permit circulating and/or spotting kill weight fluid. If the well is completely shut in with the blowout preventer at this stage of drilling operations, uncontrollable flow around the outside of the casing string may result.

2.3.3 In drilling operations utilizing subsea preventer equipment where gas may have passed the blowout preventers immediately before they are closed on a kick or where gas may surface after being trapped below the blowout preventer in normal kill operations, a diverter system should be considered to divert gas and wellbore fluids when the marine riser unloads.

2.3.4 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 blowout preventers in use, a diverter system should be considered as additional redundancy and safety to divert uncontrolled well flow while evacuating personnel and/or taking corrective action.

2.3.5 A rotating head diverter system can be used to advantage in conjunction with a blowout preventer stack and choke manifold system in certain specialized drilling operations, including but not limited to, hydrogen sulfide service, continued drilling operations with gas-cut drilling fluid, air/gas drilling, etc.

2.3.6 Diverter systems equipment which is exposed to a hydrogen sulfide environment should comply with *NACE Std MR0175: Material Requirements Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment* (check latest revision).*

2.4 Subsea Diverter Systems. In some situations, subsea positioning of the diverter may be beneficial. Subsea diverters have been deployed with the vent outlet located just above the mudline. Use of subsea diverters should be evaluated on a case-by-case basis.

*Available from National Association of Corrosion Engineers, P.O. Box 218840, Houston, Texas 77218.

SECTION 3
DIVERTER SYSTEMS DESIGN AND COMPONENT CONSIDERATIONS

3.1 DIVERTER.

3.1.1 General. The diverter is an annular sealing device used to close and pack off the annulus around the drill string assembly when wellbore fluids are diverted from the rig. The diverter and all individual components in the diverter system shall have a *minimum* rated working pressure of 200 psi.

3.1.2 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 these (diverted) fluids to travel out the vent lines. Ordinarily, the annular packing element is torus shaped and made of steel and rubber (natural or synthetic) and 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:

3.1.2.1 Annular Packing Element (Fig. 3.1). An annular packing element can effect a seal on any pipe or kelly size in the bore or on open hole if no pipe is present and divert well fluids flow. The annular packing element should be of sufficient internal bore to pass the various bottom-hole assemblies required for subsequent drilling operations.

3.1.2.2 Insert-type Packing Element (Fig. 3.2). An insert-type packing diverter element uses inserts which are designed to close and 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 run or pull the bottom-hole assembly.

3.1.2.3 Rotating Head (Fig. 3.3). A rotating head can be used as a diverter to complement a blowout preventer system. The stripper rubber is energized by the wellbore pressure to seal against the drill pipe, kelly, or other pipe to facilitate diverting return well fluids and can be used to permit pipe movement.

3.2 Mounting of Diverter. An important consideration for diverters is to structurally secure the mounting, since the device receives the full force of diverted wellbore fluids. When the diverter is installed, the connection should be made up in accordance with the applicable provisions of Appendix D, *API Spec 6A: Specification for Wellhead and Christmas Tree Equipment* (check latest edition)*. Diverters attached to the rig's substructure should be designed such that the upward force is directed into the substructure.

3.3 Vent Outlet(s). Vent outlet(s) for the diverter system is located below the annular packing element. One or more vent outlet(s) can be used. Vent outlet(s) may either be incorporated in the housing of the annular device or may be an integral part of a separate spool located below the diverter housing. In either case, the vent outlet(s) should have equal or greater internal cross sectional area than 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.

3.4 DIVERTER VALVES.

3.4.1 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, and be capable of opening with maximum anticipated pressure across the valve(s). Several types of full-opening valves which can be used are as follows:

1. gate valves (various types),
2. ball valves,
3. knife valves,
4. switchable three-way target valve, and
5. valves integral to the diverter unit.

Maintenance is a major factor in valve selection. Valves which provide little or no space for solids to accumulate are preferred over valves which allow this to occur, as such accumulation can impede efficient operation.

3.4.2 Actuators. Remote actuators capable of operation from the rig floor should be installed on all non-integral diverter vent valves and flow line valves where these valves are located below the diverter packer. Either hydraulic actuators, operated with hydraulic fluid from their own closing unit or the blowout preventer closing unit, or pneumatic (air) actuators operated from rig air may be used. An actuator 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, for a diverter system rated working pressure equal to 200 psi, the actuator should be designed to open the valve(s) under a differential pressure of 200 psi or more across the valve; for a diverter system rated working pressure equal to 500 psi, the actuator should be designed to open the valve(s) under a differential pressure of 500 psi or

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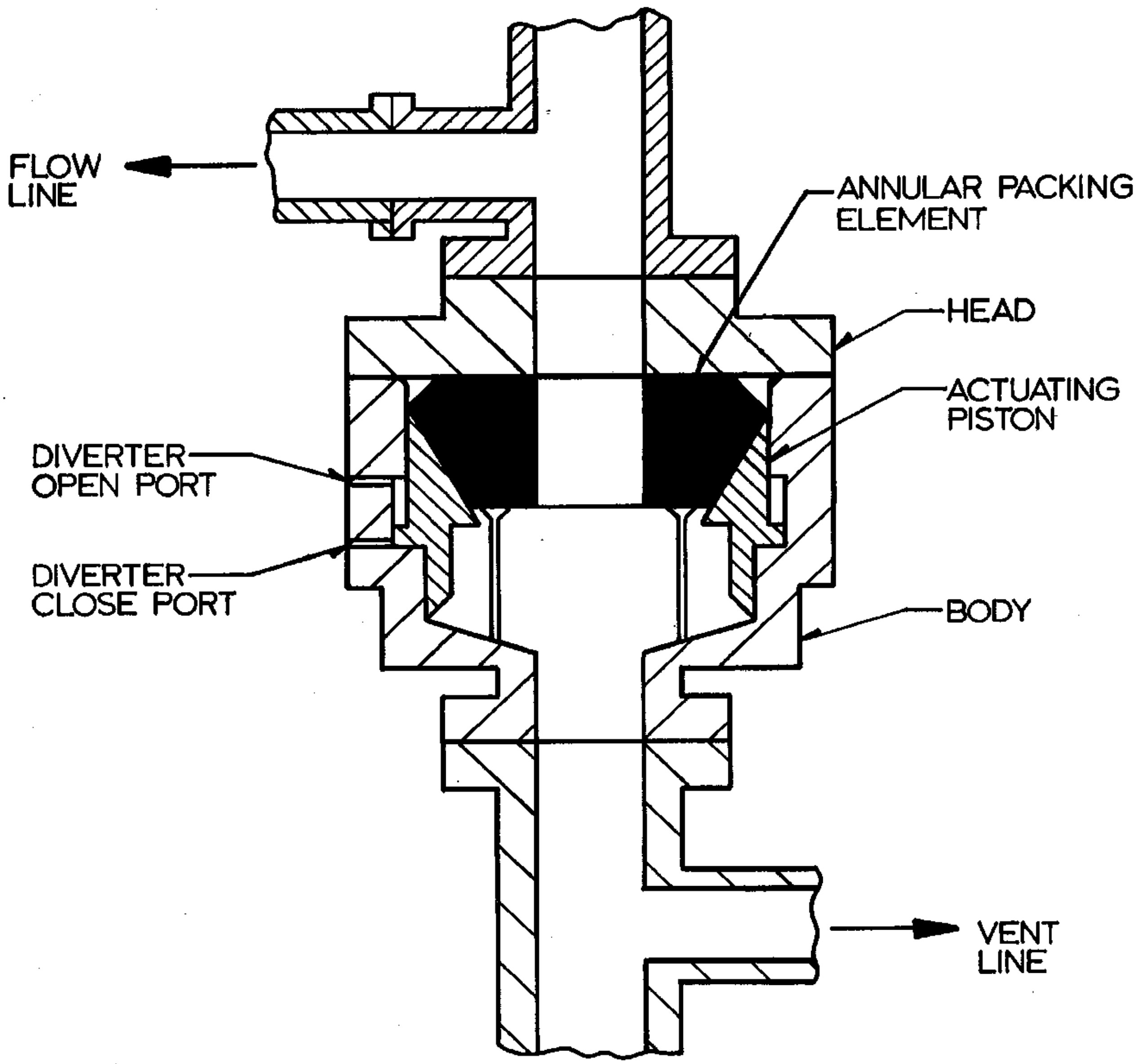


FIGURE 3.1
EXAMPLE DIVERTER WITH ANNULAR PACKING ELEMENT

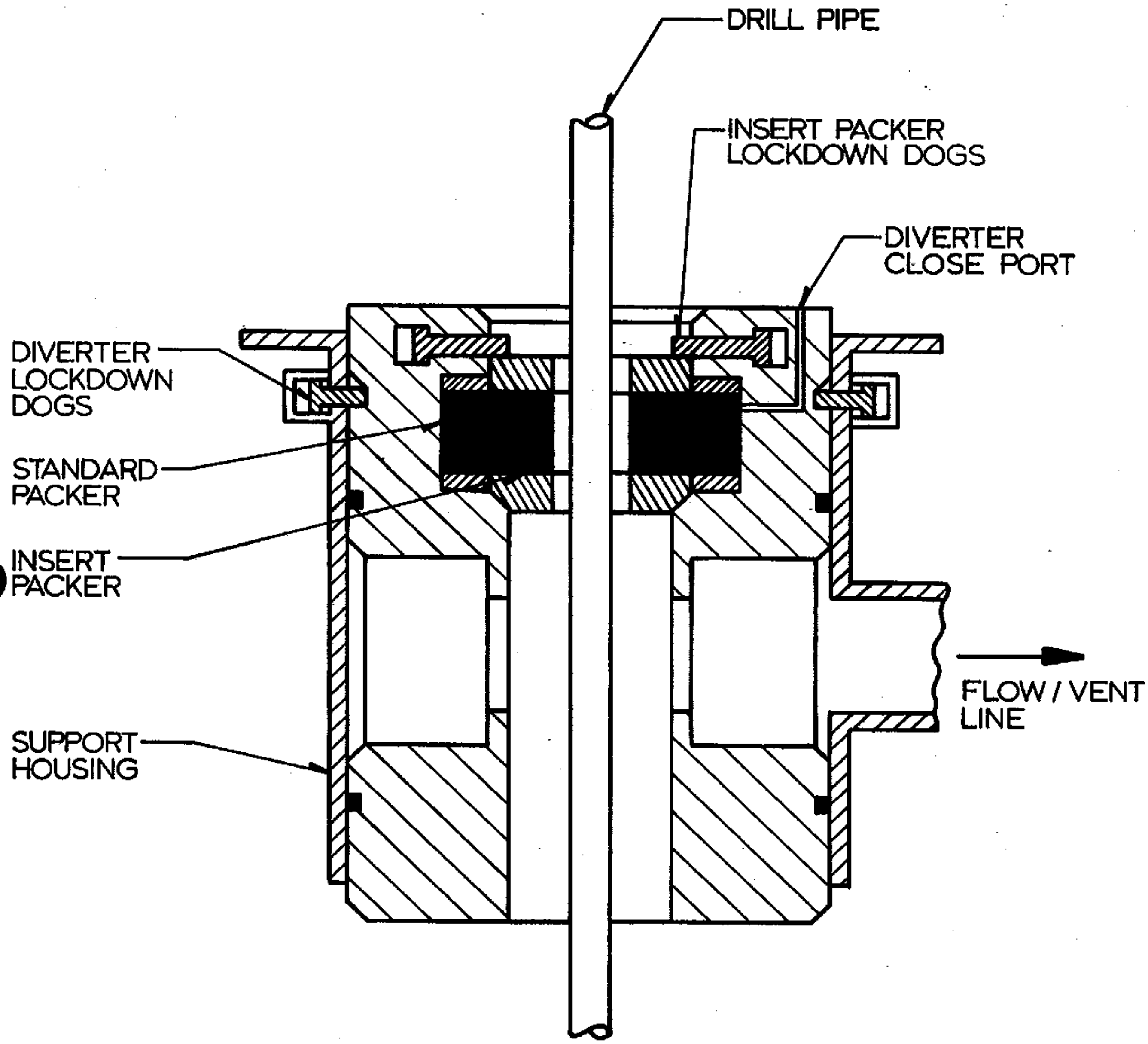


FIGURE 3.2
EXAMPLE DIVERTER WITH INSERT-TYPE PACKER

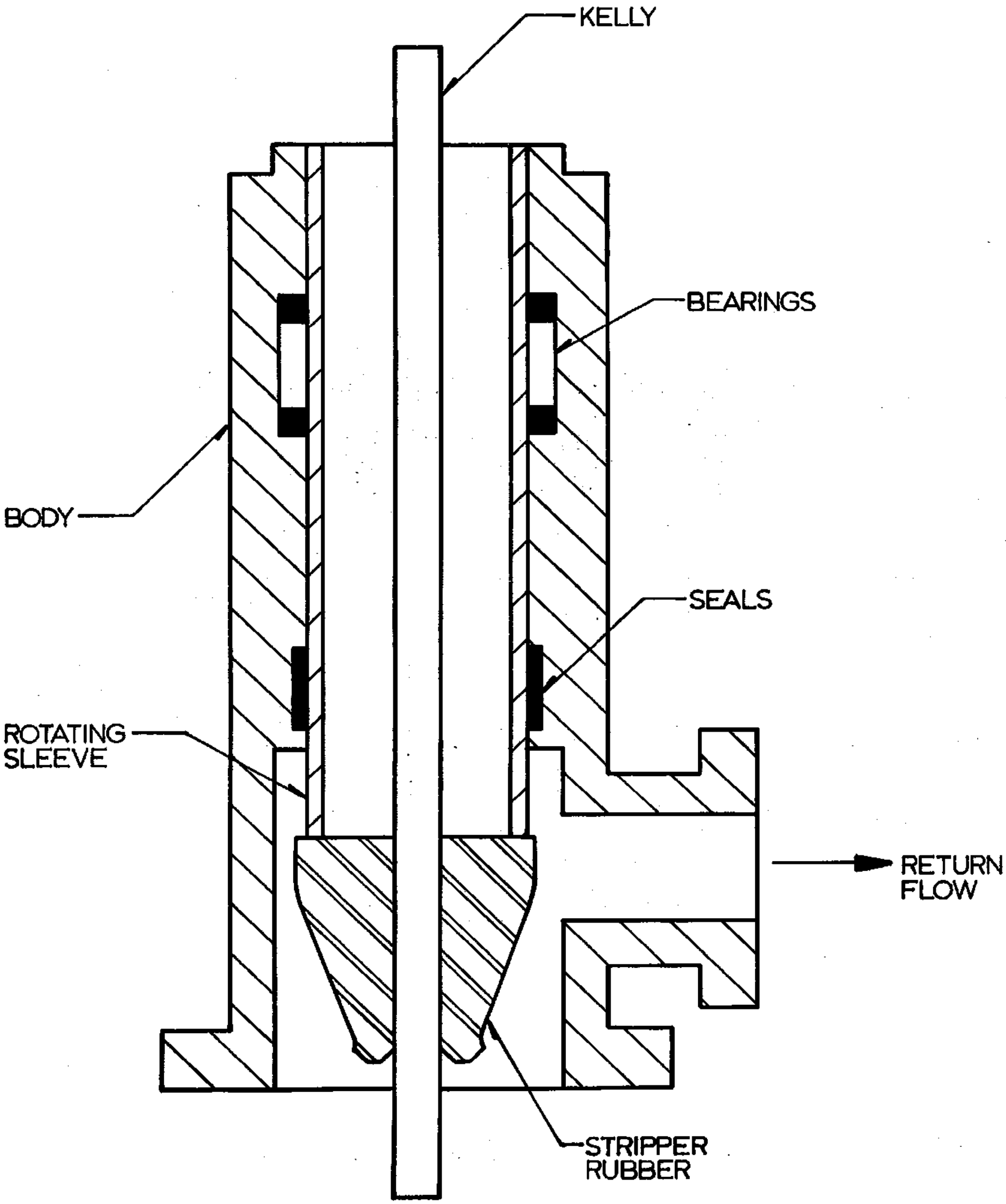


FIGURE 3.3
EXAMPLE DIVERTER WITH ROTATING STRIPPER

more across the valve). Excessive resistance due to drilled solids in the valve should be kept in mind, especially on pneumatic systems where variations in rig air pressure are common. 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.

3.5 Diverter 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 back pressure and create conditions which can increase sand blast and erosion during diverting operations.

3.5.1 Sizing. Diverter piping should be sized to minimize, as much as practical, back pressure on the wellbore while diverting well fluids. Data in Table 3.1 can be useful as a reference to compare vent line sizes for various operating conditions of steady state flow and anticipated back pressure (friction pressure drop) for gas and liquid mixture flow rates in various systems. Back pressure contributed by bends, tees, ells, sonic velocity restrictions, etc., when applicable, should be included in the calculation of total back pressure. The friction loss must not exceed the diverter system rated working pressure, place undue pressure on the wellbore, and/or exceed other equipment's design pressure, etc.; e.g., marine riser. For rigs with two (2) vent lines, each line should be capable of diverting wellbore fluids and still maintain an acceptable back pressure. Changes in diameter of the vent line(s) should be minimized or eliminated. Changes in flow pattern at such diameter changes lead to excessive erosion of the flow line and vent line(s). Where changes in line diameter exist, back pressure calculations should be based on modeling the various diameter lines used in the system.

3.5.1.1 Flexible Lines. Diverter systems may employ flexible lines 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 lines are acceptable provided their resistance to fire and erosion, is compatible with the associated piping and provided they are supported and connected in adequate fashion.

3.5.2 Routing. Diverter vent line(s) should be routed so that at all times one (1) line can vent well fluids downwind of the drilling rig. For certain floating drilling operations where one end of the vessel is always downwind, a single exhaust line may suffice. The 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 back pressure. 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. As a comparison guide, 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 degree bends are used, they should be targeted running tees equipped with a blind flange or plug to minimize effects of erosion. Use of "Y" type branches is preferable to using tees, to reduce the possibility of erosion at the intersection. The vent line(s) should be sloped along their length such that low spots, which may accumulate drilling fluid and debris, are avoided.

3.5.3 Support. The vent line(s) should be firmly secured to withstand the dynamic effects of high volume fluid flow and impact of drilling solids. Supports located at points where piping direction changes 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.

3.5.4 Cleanouts. Provisions for cleaning and flushing any accumulated debris from the vent line(s) should be made. 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. The cleanouts should have the same rated working pressure as the piping in which they are installed. Well monitoring devices (flow indicators, etc.), gumbo busters, etc., which are exposed to diverting fluids should be able to withstand the anticipated back pressure without leaking or failing.

3.5.4.1 Fill Lines. Fill and/or kill lines positioned below the diverter unit should be valved with an independent actuated or check valve near the wellhead and have a rated working pressure equivalent to the system exposed to well fluids.

3.6 CONTROL SYSTEM.

3.6.1 General. 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 blowout preventer control system.

3.6.2 Volumetric Capacity. As a minimum, it is recommended that all diverter control systems should be equipped with sufficient volumetric capacity to provide the usable fluid volume (with pumps inoperative) required to open and close all 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 200 psi above the precharge pressure or the shut off pressure for the

TABLE 3.1*
STEADY STATE PRESSURE DROPS IN PSI FOR VARIOUS GAS AND LIQUID FLOW RATES AND PIPE DIAMETERS

4-IN. NOMINAL (3.25-IN. ID)

MILLION SCF/D	GPM 0	GPM 100	GPM 200	GPM 300	GPM 500	GPM 1000
0	0	1.82	6.13	12.6	31.2	108
5	20.9	108	155	203	297	551
10	49.5	179	251	327	474	860
50	343	1086	1367	1655	2230	3692

6-IN. NOMINAL (5.25-IN. ID)

MILLION SCF/D	GPM 0	GPM 100	GPM 200	GPM 300	GPM 500	GPM 1000
0	0	0.19	0.68	1.28	3.15	10.8
10	9.36	38.3	54.1	67.5	88.9	138
50	74.5	161	194	226	286	419
100	167	377	429	481	583	826

8-IN. NOMINAL (7.25-IN. ID)

MILLION SCF/D	GPM 0	GPM 100	GPM 200	GPM 300	GPM 500	GPM 1000
0	0	0.04	0.14	0.27	0.68	2.31
10	2.36	11.9	17.8	22.8	31.5	48.1
50	27.0	57.9	68.8	78.8	96.9	136
100	62.6	119	133	147	173	232

10-IN. NOMINAL (9.25-IN. ID)

MILLION SCF/D	GPM 0	GPM 100	GPM 200	GPM 300	GPM 500	GPM 1000
0	0	0.01	0.04	0.09	0.21	0.72
10	0.76	4.27	6.69	8.87	12.8	21.0
50	11.2	26.2	31.4	36.1	44.7	62.8
100	29.0	56.0	62.0	67.9	79.0	104

12-IN. NOMINAL (11.25-IN. ID)

MILLION SCF/D	GPM 0	GPM 100	GPM 200	GPM 300	GPM 500	GPM 1000
0	0	0.005	0.02	0.03	0.08	0.28
10	0.30	1.73	2.79	3.80	5.67	9.83
50	5.06	12.9	15.6	18.2	23.0	33.1
100	14.6	30.0	33.2	36.4	42.5	55.9

Refer to Par. 5.6 for diverter systems piping sizing recommen-
dations for offshore installations floating operations.

DATA EMPLOYED IN CALCULATING TABLE 3.1 VALUES:

Line Length = 150 ft. *Mud Density = 9.6 lb/gal*
Outlet Pressure = 0 psig *Plastic Vis. = 8 cp*
Gas Specific Gravity = 0.7 *Temperature = 80 F*
Beggs and Brill correlation; sonic velocity restrictions ignored.

*Reprinted courtesy of Exxon Corp., from *Blowout Prevention and Well Control Manual, Floating Drilling Supplement.* Copyright February 1984.

hydraulic operating system. The minimum recommended accumulator volume should be determined by multiplying the accumulator size factor times the calculated volume to close and open the diverter system and still retain a 50% reserve (refer to *API RP 53: Recommended Practices for Blowout Prevention Equipment Systems,** Second Edition, May 25, 1984). For a closing unit used for both subsea blowout preventer and surface diverter control, the required accumulator volumetric capacity for diverter control should be supplied through a check valve. 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.

3.6.3 Primary Response Time. A primary diverter closing system should be capable of operating the vent line and flow line valves, as necessary, and closing the annular packing element on pipe in use within thirty (30) seconds of actuation if the packing element has a nominal bore of twenty (20) inches or less. For elements of more than twenty (20) inches nominal bore, the diverter control system should be capable of operating the vent line and flow line valves, as necessary, and closing on pipe in use within forty-five (45) seconds. Well conditions may require faster closing times than those recommended. This possibility should be considered and appropriate action taken during the design or selection of new diverter closing systems.

3.6.4 Diverter Closing Unit Backup System. An alternate means (backup system) should be employed to permit sequencing the diverter system should the primary closing system become inoperative. This can be accomplished by alternative pump system capacity, separate isolated accumulator capacity, nitrogen backup capacity, or other means. The backup system should be capable of meeting the recommendations of Par. 3.6.3 (refer also to *API RP 16E: Recommended Practice for Design of Control Systems for Drilling Well Control Equipment,** (check latest edition). The backup system should be automatically or selectively available on demand.

3.6.5 Diverter System 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.

3.6.6 Closing Unit Pressure Rating Recommendations. Each closing unit should be equipped with a pump(s) that will provide a discharge pressure equivalent to the rated working pressure of the closing unit.

3.6.7 Pump Power Recommendations. Power for the closing unit pump(s) should be available to the accumulator unit at all times, such that the pump(s) will automatically start when the closing unit manifold pressure has decreased to less than 90 percent of the accumulator operating pressure. Similarly, the pump(s) should automatically stop when the full design accumulator charging pressure is reached. The automatic pressure control system should additionally include a secondary overpressure protection device such as a relief valve. The relief valve should be set to function at not more than 110 percent of the design accumulator charging pressure. Relief valves should be designed to automatically reseat and shut off within 25 percent below the pressure setting.

3.6.8 Closing Unit Valves, Fittings, Lines, and Manifolds. Recommendations for closing units are shown in Sections 5A and 5B of *API RP 53: Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells,** Second Edition, May 25, 1984. Each installation should be equipped as follows:

3.6.8.1 Each diverter control system should be equipped with a full-opening valve into which a separate operating fluid pump can be easily connected (refer to Figure 5.A.1, *API RP 53**).

3.6.8.2 The diverter annular sealing device regulators should be isolated from the primary closing unit. The diverter closing unit should be equipped with sufficient check or shut-off valves to separate the primary closing unit pumps and accumulators from the primary closing unit manifold.

3.6.8.3 The closing unit should be equipped with accurate pressure gauges to indicate the operating pressure of the closing unit both upstream and downstream of the annular sealing device pressure regulating valve.

3.6.8.4 The closing unit should be equipped with necessary pressure regulators to permit manual control of the system components within their rated operating pressure.

3.6.9 Recommendations for Closing Unit Fluids and Capacity. A suitable hydraulic fluid (nonflammable petroleum or water base) should be used as the closing unit control operating fluid. Sufficient volume of glycol must be added to any closing unit fluid containing water if ambient temperatures below 32 F (0 C) are anticipated. Use of diesel oil, motor oil, chain oil, or any other similar fluid is not recommended due to the possibility of an 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 diverter system.

*Available from American Petroleum Institute, Publications and Distribution Section, 1220 L St., N.W., Washington, D.C. 20005.

**NOTE: The diverter system recharging interval of five minutes or less is considered acceptable because of the recommended performance of the closing unit backup system as stipulated in Par. 3.6.4.

3.6.10 Recommended Locations for Closing Unit and Control Units.

3.6.10.1 Closing Unit. The main pump accumulator unit should be located in a safe place which is easily accessible to rig personnel in an emergency. It 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 preventer stack, additional accumulator volume should be added to compensate for flow back in the closing lines.

3.6.10.2 Control Units. Each installation should be equipped with at least one control unit 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.

3.6.10.3 Each control unit should be located to comply with the area classifications in *API RP 500B: Recommended Practice for Classification of Locations for Electrical Installations at Drilling Rigs and Production Facilities on Land and Marine Fixed and Mobile Platforms*, check latest edition.*

3.7 CONTROL SYSTEM OPERATIONS

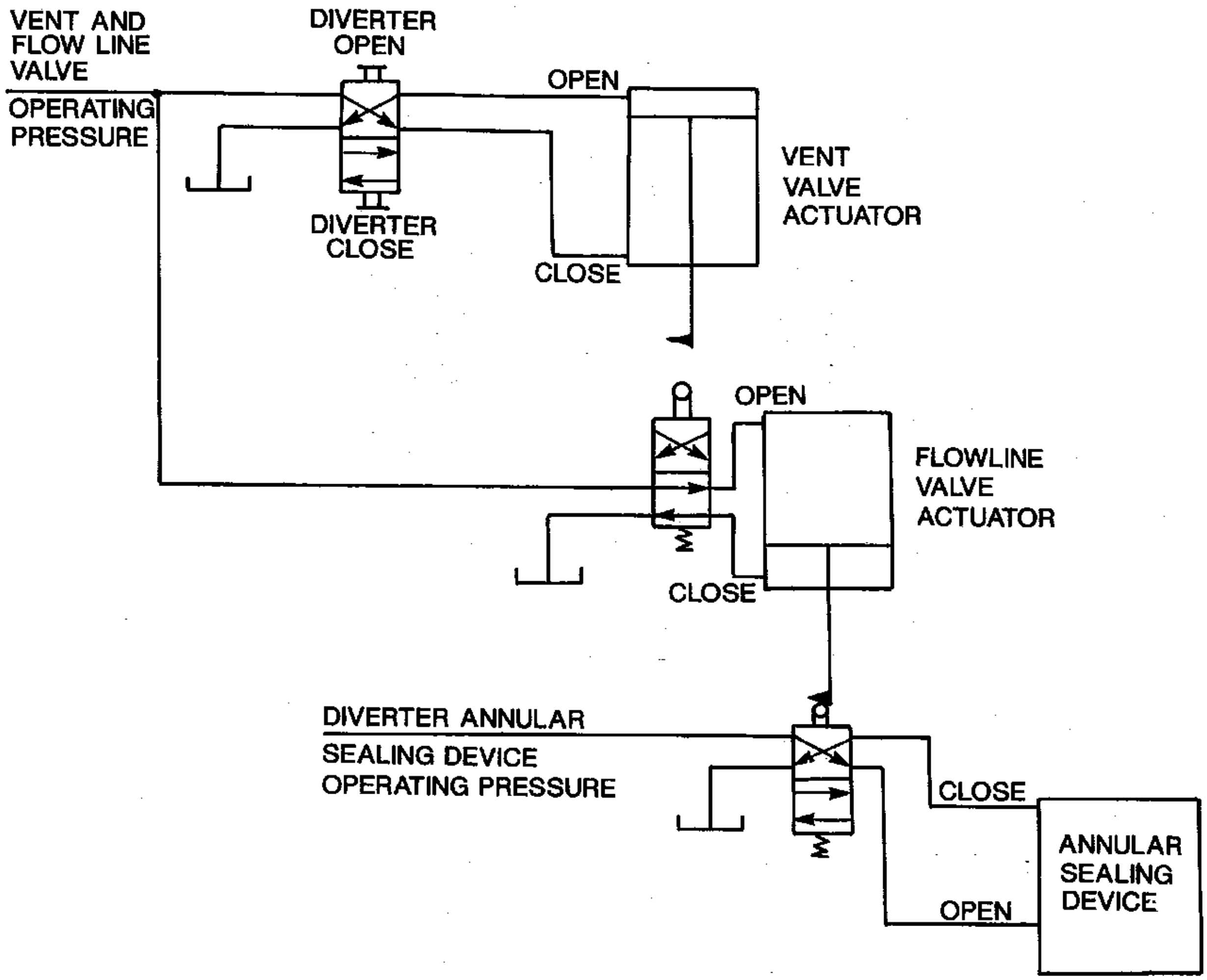
3.7.1 General. The diverter control system shall be operated such that the well will not be shut in with the diverter system. For installations with the annular sealing device below the flow line, equipment should be set up such that the desired vent valve(s) is opened before the annulus is closed. On 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, at least one vent valve should 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. Regardless of the sequencing method used, competent, trained, and experienced personnel should be used for design, installation, operation, and maintenance of the system. The diverter control system manufacturer should be consulted for recommended proper installation of any sequencing devices, as improper installation can negate any benefits of such safety devices.

*Available from American Petroleum Institute, Publications and Distribution Section, 1220 L St., N.W., Washington, D.C. 20005.

3.7.2 Types of Control Sequencing.

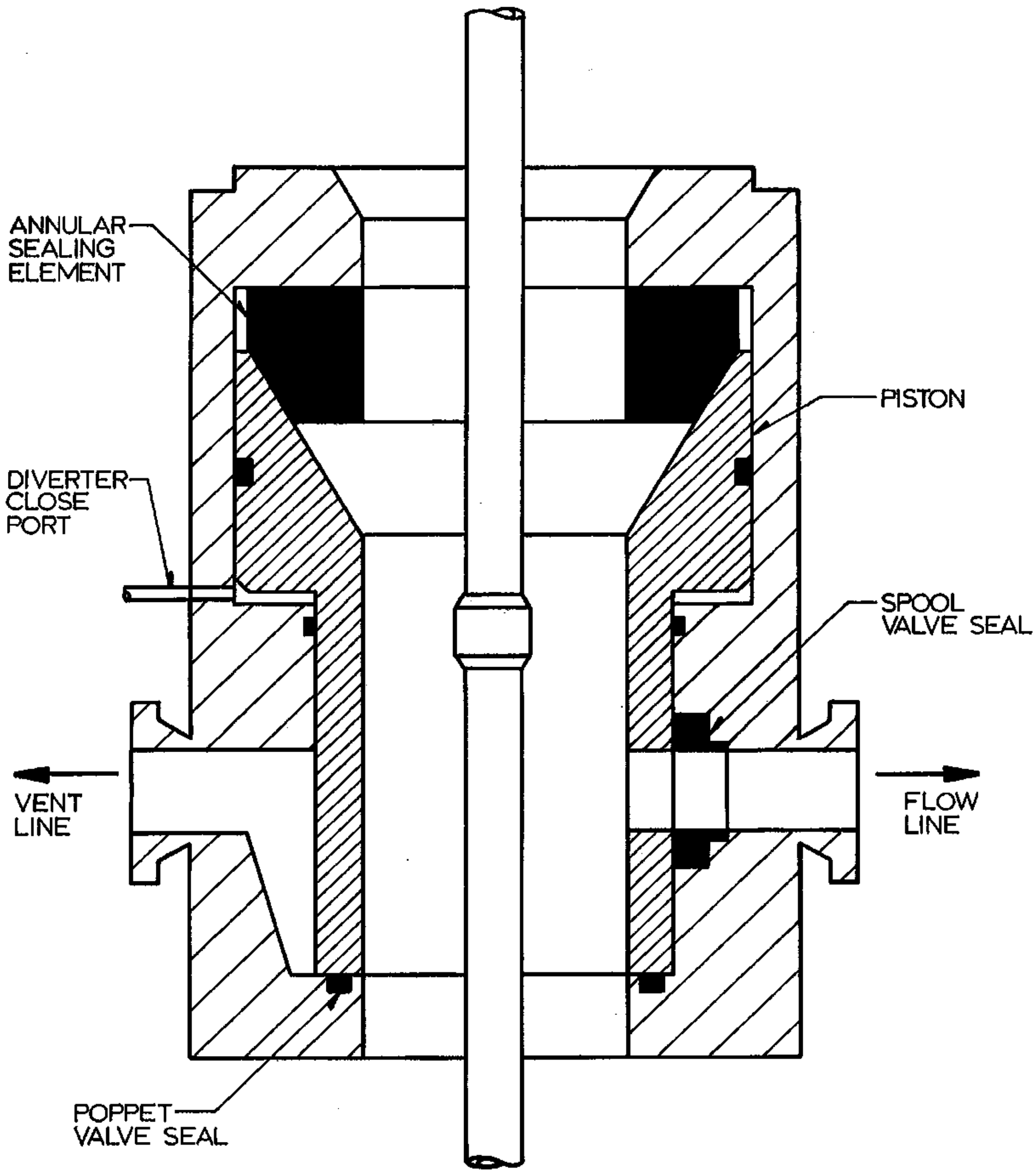
3.7.2.1 Automatic Sequencing. Typically, hydraulic sequence valves, mechanical linkage, and/or limit switches are used in an automatically sequenced diverter system. Actuation of a single pushbutton or lever automatically initiates the entire sequence. One automatic method using control valves that are tripped by the physical cycling of the vent and flow line valve gates is shown in a very simplified sketch in Fig. 3.4. 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 Fig. 3.5). Some automatically sequenced diverter systems require interlocks in the controls to prevent continuation of the sequence if one function should fail to operate.

3.7.2.2 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 judgement 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 has been opened and the insert (if needed) is latched down.



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 3.4
EXAMPLE SIMPLIFIED DIVERTER CONTROL SYSTEM SCHEMATIC (AUTOMATIC SEQUENCING) SHOWN IN OPEN POSITION



NOTE: WHEN THE DIVERTER CLOSES, THE PISTON MOVES UPWARD OPENING THE FLOW PATH TO THE VENT LINE WHILE CLOSING THE FLOW PATH TO THE FLOW LINE.

FIGURE 3.5
EXAMPLE DIVERTER SYSTEMS — INTEGRAL SEQUENCING

SECTION 4
DIVERTER SYSTEMS — ONSHORE AND/OR BOTTOM-SUPPORTED OFFSHORE INSTALLATIONS

4.1 Onshore and/or Bottom-supported Offshore Drilling Operations. When diverter systems are deemed necessary (refer to Paragraph 2.3), they should be installed on the drive or conductor pipe.

4.1.1 Annular Packing Element Types. Refer to Par. 3.1.2.

4.1.2 Diverter Systems Piping. Refer to Paragraph 3.5 for recommendations on diverter systems piping. The vent line outlet(s) and vent line(s) should be installed below the diverter and extended a sufficient distance from the rig to permit safe venting of flow from a diverted well. For onshore drilling operations, a single vent line oriented downwind from the rig and facilities is typically used and discharged to the pit. However, it may be desirable to provide a second vent line which discharges into a second pit and is oriented in a different direction as a precaution against changes in prevailing wind(s). For most bottom-supported drilling operations, two (2) vent lines oriented in different directions are normally used. In the case of some offshore platforms, one vent line is used due to prevailing wind.

4.1.3 Diverter Systems Valves. If a valve(s) is used in the diverter system, it should be full opening and can be operated either manually (onshore operations only) or remotely. The valve(s) should be installed close to the annular sealing device to minimize the 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 close to 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).

4.1.4 Diverter System Sequencing. Sequencing of the diverter system (refer to Par. 3.7) should be such that the vent line valve(s), if used, would be fully open prior to closure of the annular sealing device. This is important to ensure the well is never shut in. If multiple vent lines are used it is then possible to select the proper downwind vent line to divert the flow.

4.1.5 Example Diverter Systems for Onshore and/or Bottom-supported Offshore Locations. Figures 4.1 through 4.8 illustrate example diverter systems for onshore and/or bottom-supported offshore drilling locations.

4.2 Specailized Onshore and/or Bottom-supported Offshore Drilling Operations. A diverter system when used in conjunction with a blowout preventer stack can also provide an added degree of protection during specialized onshore and/or bottom-supported offshore drilling operations, which include but are not limited to, sour gas drilling, handling sweet gas-cut drilling fluid, and air, aerated fluid, or gas drilling operations.

4.2.1 Sour Gas Drilling Operations. When drilling in an area where sour gas is present, the addition of a rotating drilling head to the blowout preventer stack should be considered. This diverter system will minimize the amount of personnel exposure to hydrogen sulfide gas on the rig floor or under the substructure when circulating out drilling breaks or bottoms-up gas. The diverter system uses the drilling fluid return flowline as a vent line constructed such that the fluid flow can be directed, by valves located in the flowline, to a mud/gas separator and then vented to a safe distance from the rig (refer to Fig. 4.5).

4.2.2 Gas-cut Drilling Fluid. A rotating drilling head can also be used to advantage where high-pressure, low-volume sweet 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 Par. 4.2.1 and illustrated in Fig. 4.5.

4.2.3 Air, Aerated Fluid, or Gas Drilling Operations. A diverter system is required in all air/gas drilling service and consists of at least a rotating drilling head and a blooey line (vent line). This diverter system could also be used with the blowout preventer stack as illustrated in Fig. 4.6. In areas where gas is used as the circulating fluid or where hydrocarbon bearing formations will be drilled, the use of a full opening valve installed on the rotating drilling head should be considered. This valve will allow repairs to be made to the blooey line while diverting any flow through the choke line(s).

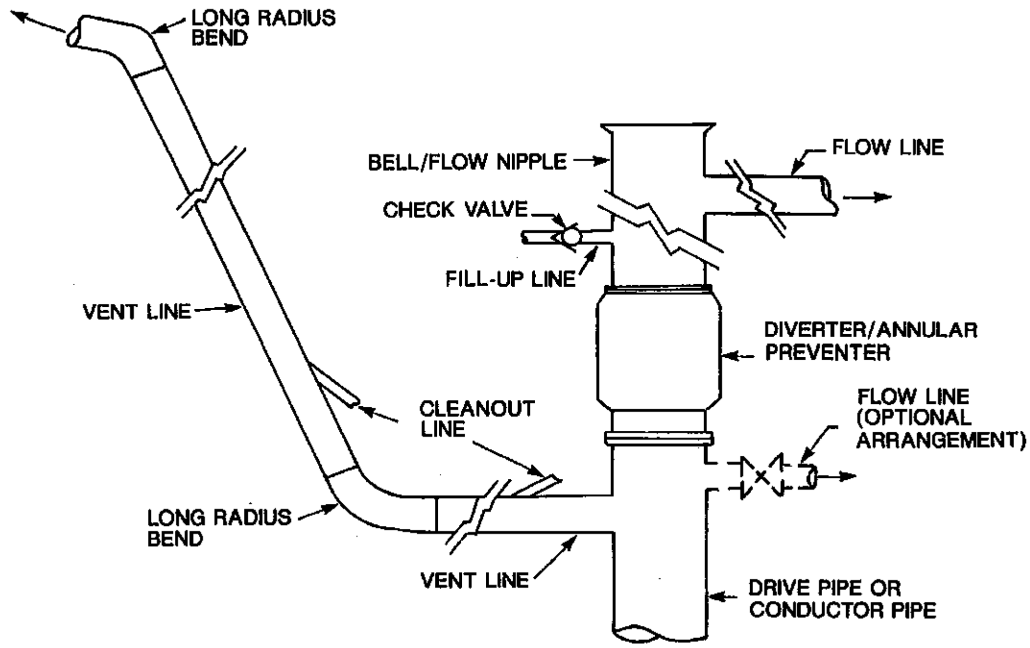


FIGURE 4.1
EXAMPLE DIVERTER SYSTEM — OPEN FLOW SYSTEM

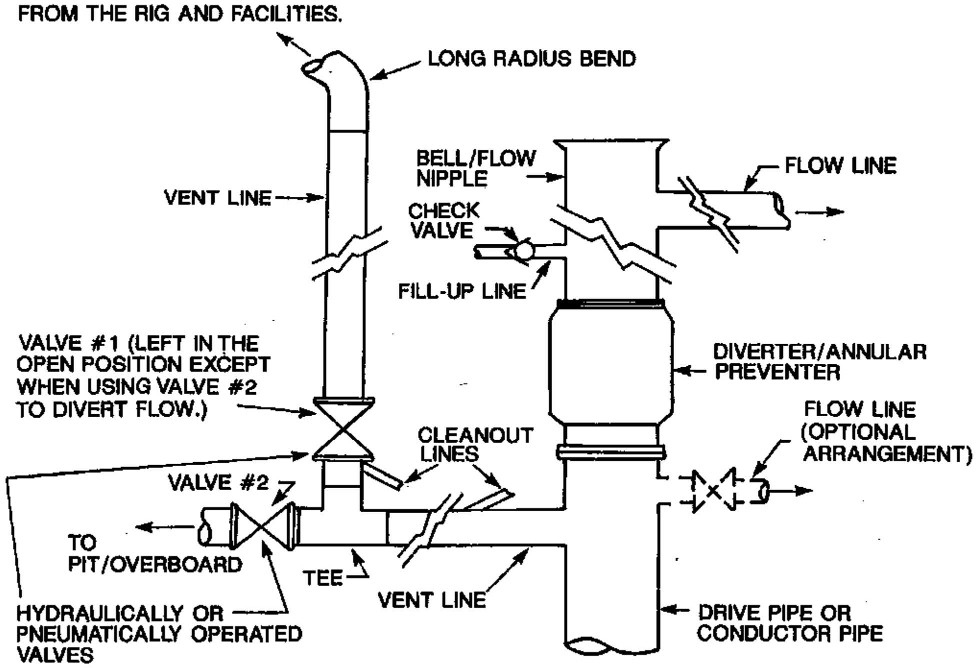


FIGURE 4.2
EXAMPLE DIVERTER SYSTEM — MANUAL SELECTIVE FLOW SYSTEM

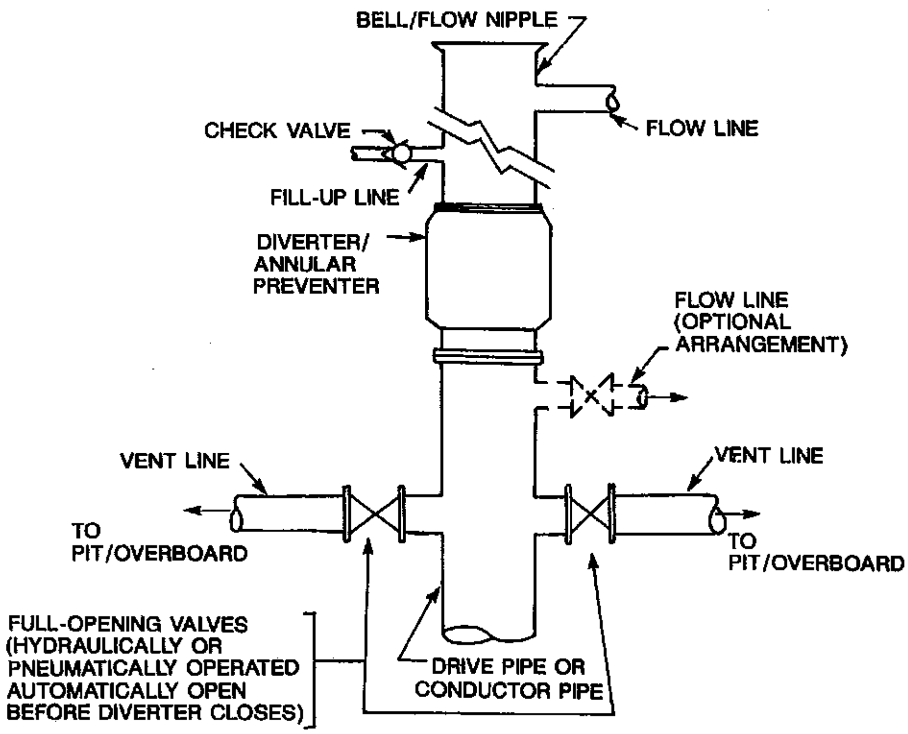


FIGURE 4.3
EXAMPLE DIVERTER SYSTEM —
CONTROL SEQUENCED FLOW SYSTEM

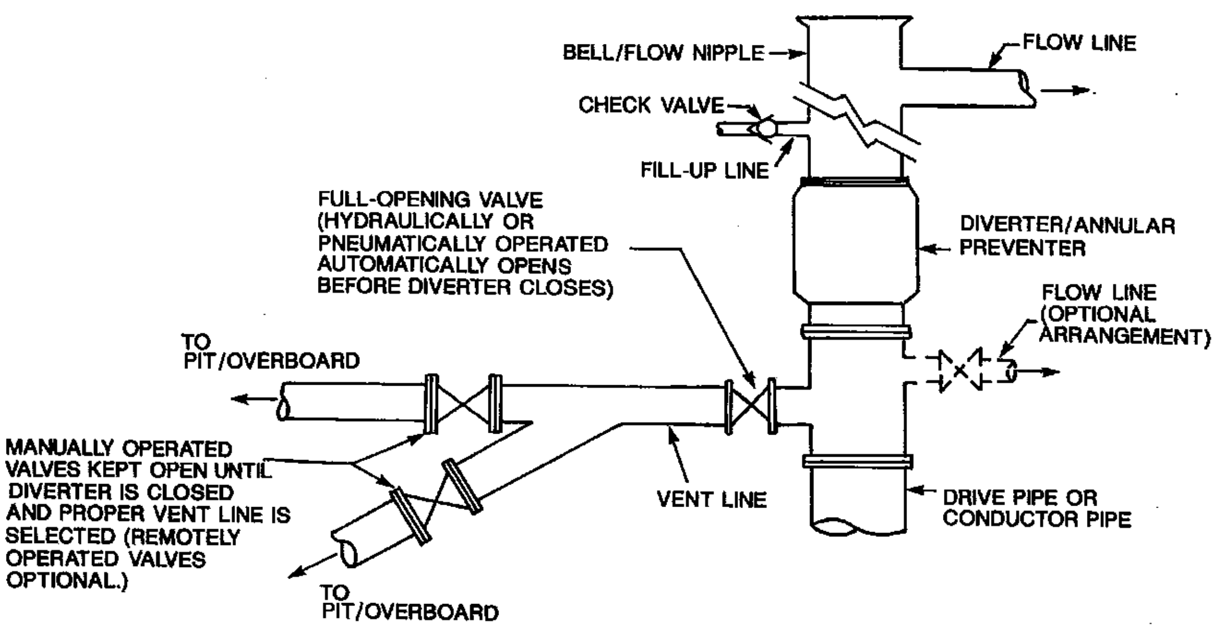


FIGURE 4.4
EXAMPLE DIVERTER SYSTEM —
CONTROL SEQUENCED FLOW SYSTEM WITH
AUXILIARY VENT LINE

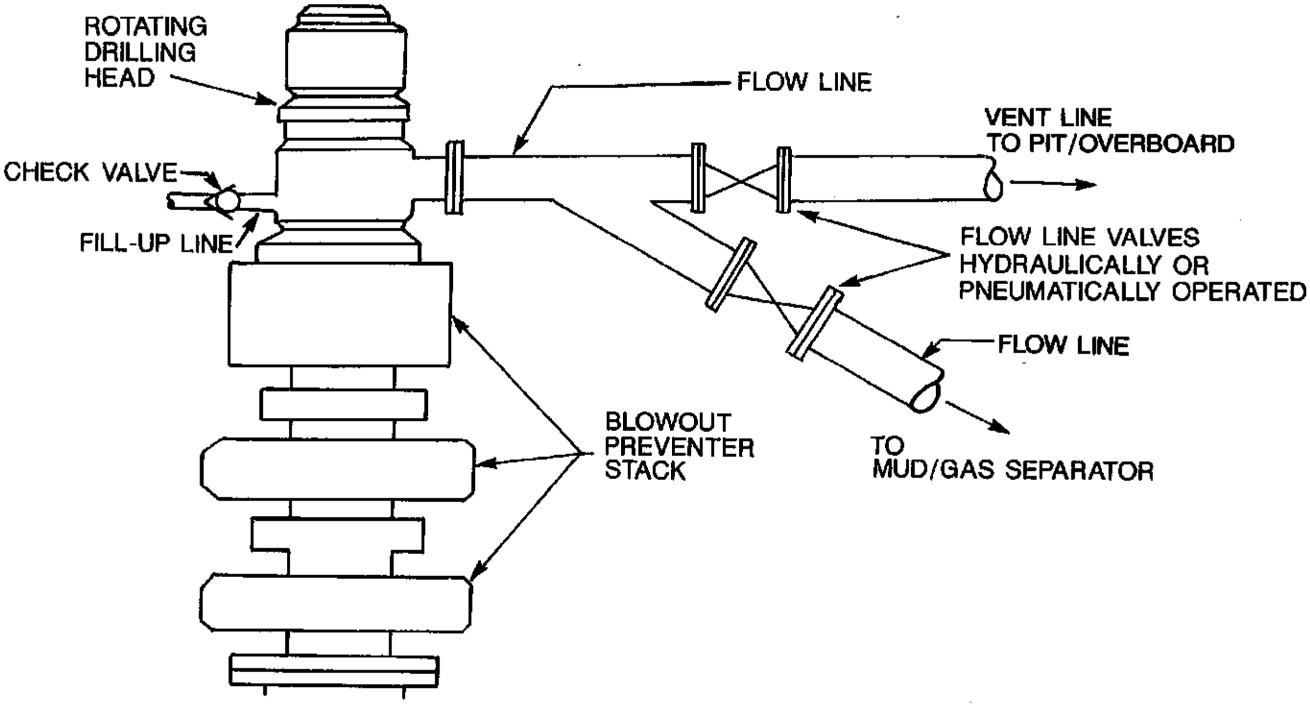


FIGURE 4.5
EXAMPLE DIVERTER SYSTEM —
SOUR GAS/GAS-CUT DRILLING FLUID
DRILLING OPERATIONS

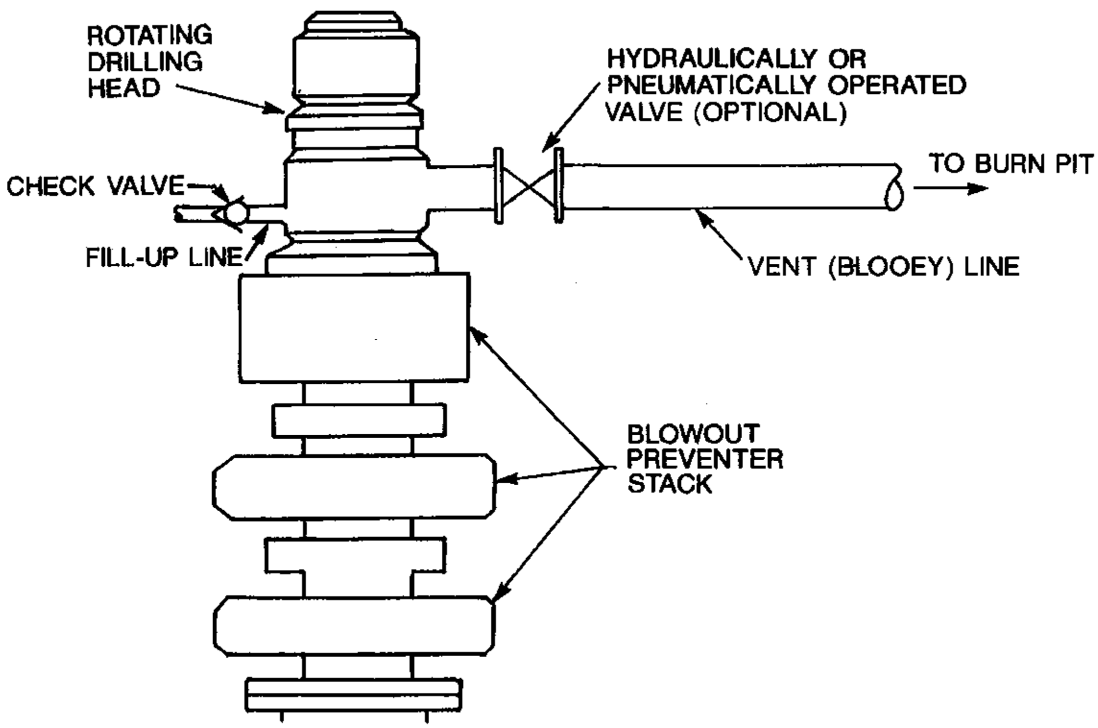


FIGURE 4.6
EXAMPLE DIVERTER SYSTEM —
AIR/GAS DRILLING OPERATIONS

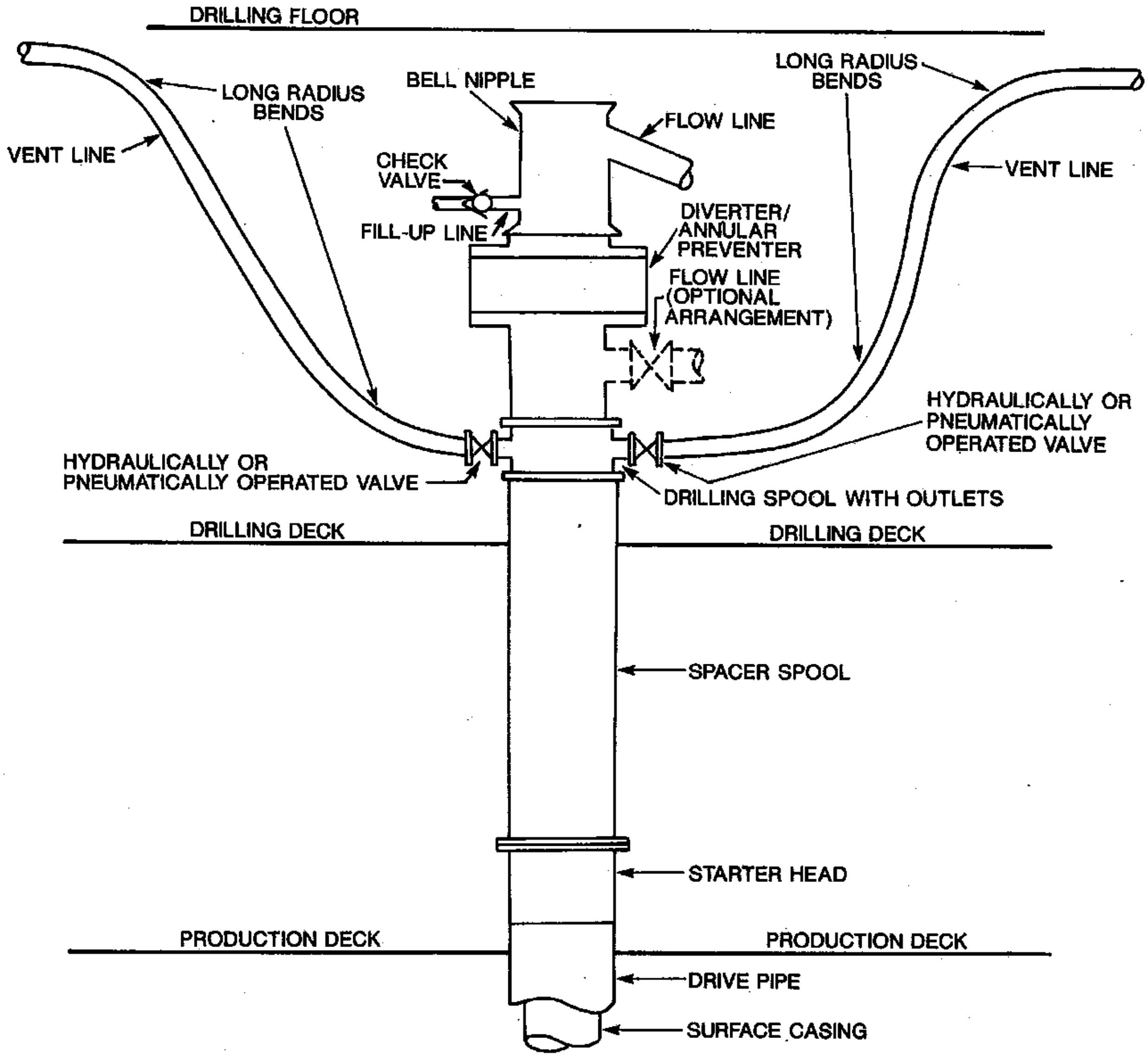


FIGURE 4.7
EXAMPLE DIVERTER SYSTEM FOR BOTTOM-SUPPORTED OFFSHORE OPERATIONS

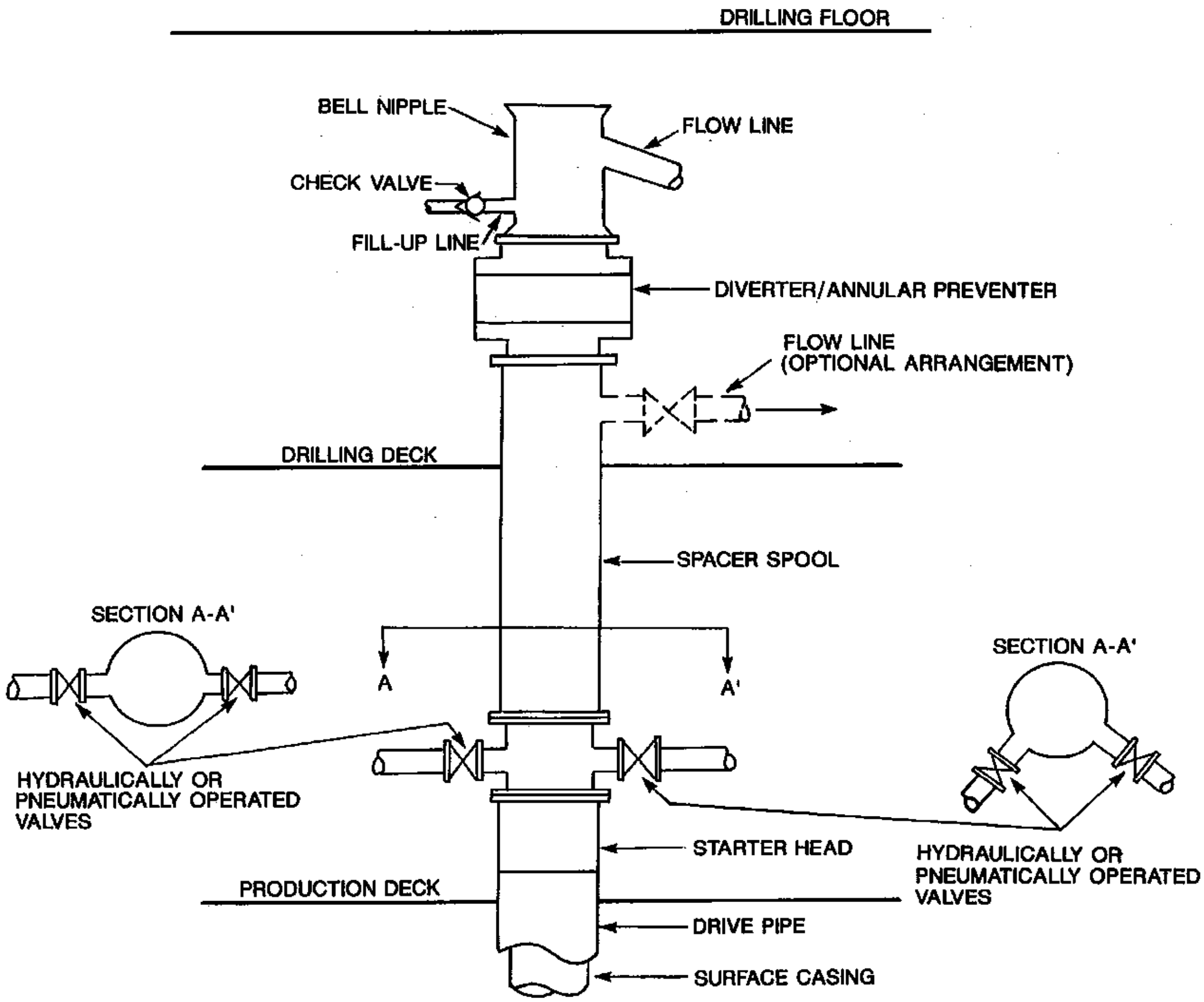


FIGURE 4.8
EXAMPLE DIVERTER SYSTEM FOR BOTTOM-SUPPORTED OFFSHORE OPERATIONS
(Illustrating valves in vent lines.)

SECTION 5
DIVERTER SYSTEMS — FLOATING INSTALLATIONS

5.1 General. Floating drilling operations include operations from drillships and semisubmersibles that drill in the floating mode. These vessels are distinguished from other types of drilling units by the use of subsea blowout preventer stacks. The subsea blowout preventer stack and associated equipment are connected to the drilling vessel via the marine riser system.

5.2 Installation. Diverter systems on floating drilling rigs are typically mounted to the drill floor substructure and are at the upper end of the marine riser system (refer to Figs. 5.1 and 5.2). 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 Pars. 3.5.1 and 3.5.2) Features of the auxiliary equipment such as the sealing pressure limit of the telescopic (slip) joint packer, the burst and collapse rating of the marine riser tube, etc., are important links in the overall design of diverter systems (refer to Section 3, "Diverter Systems Design and Component Considerations") and should receive particular attention to prevent leaking or failure.

5.3 Criteria for Use of Diverter Systems. The diverter system is installed when the marine riser is run. However, the decision to run the marine riser on a particular casing string must take into account certain factors, including assessment of the formation fracture gradient at the shoe of the casing string and the pullout resistance of that casing. The formation fracture gradient and casing string pullout resistance is sometimes inadequate, which could rule out the use of the marine riser/diverter system. When the hole is drilled below the structural casing, a pilot hole can be drilled to the next casing seat depth. The decision to drill a pilot hole is generally based on anticipated geological conditions and the drilling practices best suited for these conditions. A secondary consideration would be whether a pilot hole would permit use of a dynamic kill procedure should a well control problem occur (refer to Appendix A, "Shallow Gas Well Control").

5.3.1 Use of a Diverter System Without a Blowout Preventer Installed. 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 sea water head plus the soil overburden pressure below the sea floor is less than the total soil overburden pressure at the same depth for a land location. Similarly, the overburden pressure of the water head plus the soil overburden pressure to casing shoe depth can be less than the hydrostatic pressure of the drilling fluid in the marine riser system. In addition, the marine 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 from the marine riser tube. In turn, since hydrostatic pressure via the marine riser has been reduced, the well may kick. A pressure equalizer valve (dump valve or drilling fluid discharge valve) is sometimes used to allow discharge of heavy returns 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 sea water should it become evacuated due to gas expanding.

Water depth is a primary factor in the decision to install a marine riser and diverter system on the structural casing, since the weight of the blowout preventer stack is not available to help counteract marine riser overpull and the structural casing string is short and may not be cemented. Assessment of pullout resistance is usually critical. Generally, the deeper the water depth the more impractical use of a diverter system on the structural casing string becomes. In conjunction with Par. 2.1, use of a marine riser and diverter system is not recommended on the structural casing when using a dynamically positioned drilling vessel, since the vessel can readily evacuate the drilling location and, thus, ensure the safety of equipment and personnel in the event of an uncontrolled kick.

5.3.2 Use of a Diverter System With a Blowout Preventer Installed. Subsequent to running the second casing string (typically 20 inch OD and referred to as the conductor casing), a blowout preventer stack is installed (refer to Fig. 5.2). Use of a diverter system in conjunction with a blowout preventer stack should be considered because on closing the blowout preventer the marine riser may unload gas if the bubble is above the closed blowout preventer. Also, gas may surface after being trapped below a blowout preventer in normal well kill operations. The deeper the water depth (the longer the marine riser) the more likely the occurence of the riser unloading (refer to Par. 2.3.3).

In drilling below conductor casing and before setting surface casing, the formation fracture gradient may not permit use of standard well control techniques. In which case, priorities in well control techniques are: 1) close the blowout preventer recognizing that the formation may break down, 2) attempt dynamic well control procedure (refer to Appendix A, "Shallow Gas Well Control" for dynamic kill analysis), and 3) use of the diverter system.

5.4 Auxiliary Equipment Applicable Only to Floating Drilling. Floating drilling requires equipment that allows for relative motion between the subsea blowout preventer stack and drilling vessel. One flex/ball joint is usually located above the blowout preventer stack. Additional flex/ball joints may be located at the bottom and the top of the telescopic joint. Flex/ball joints permit relative angular movement of the riser elements to reduce bending stresses caused by vessel offset, vessel surge and sway motions, and environmental forces.

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.

5.5 Example Vent Line(s) and Flow Line(s) Arrangements. Figures 5.1 and 5.2 illustrate example arrangements for vent line(s) and flow line(s). 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.

5.5.1 Figures 5.3 and 5.4 illustrate other example vent line(s) arrangements where the flow line is above or in line with the vent line(s). In these arrangements, the vent line valve(s) remains closed during normal drilling operations. For this type system, valves in the vent line(s) must 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 (refer to Par. 3.7.1).

5.5.2 The example arrangement in Figure 5.5 shows the flow line outlet above the vent line(s), but the vent line(s) subsequently extended above the flow line. 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.

5.6 Diverter Piping Sizing. In conjunction with Par. 3.5, for rigs engaged in exploratory drilling where anticipated well flows are unknown or unpredictable, normal 10″ ID is the recommended minimum vent line(s) size, with 12″ ID or larger lines preferred. Table 3.1 can be useful as a reference to compare vent line(s) sizes for various operating conditions of steady state flow and anticipated back pressure (friction back pressure) for gas and liquid mixture flow rates in various systems.

5.7 Installation of Vent Lines. Vent line(s) in the system should be arranged so as to extend past the extremity of the drilling vessel (refer to Par. 3.5.2).

5.7.1 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. Figures 5.6 and 5.7 show schematic illustrations of example vent line arrangements for vent lines on drill ships and semisubmersibles. 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. Figure 5.7 illustrates example optional arrangements of vent lines on semi-submersible drilling vessels.

5.7.2 Dynamically Positioned Drilling Vessels. These vessels have the capability to maintain headings into changing prevailing winds, thus, the diverter line(s) may extend to the vessel's stern. Figure 5.8 illustrates example vent line(s) layout for dynamically positioned drilling vessels. It may be desirable to have other vent lines (refer to Par. 5.7.1).

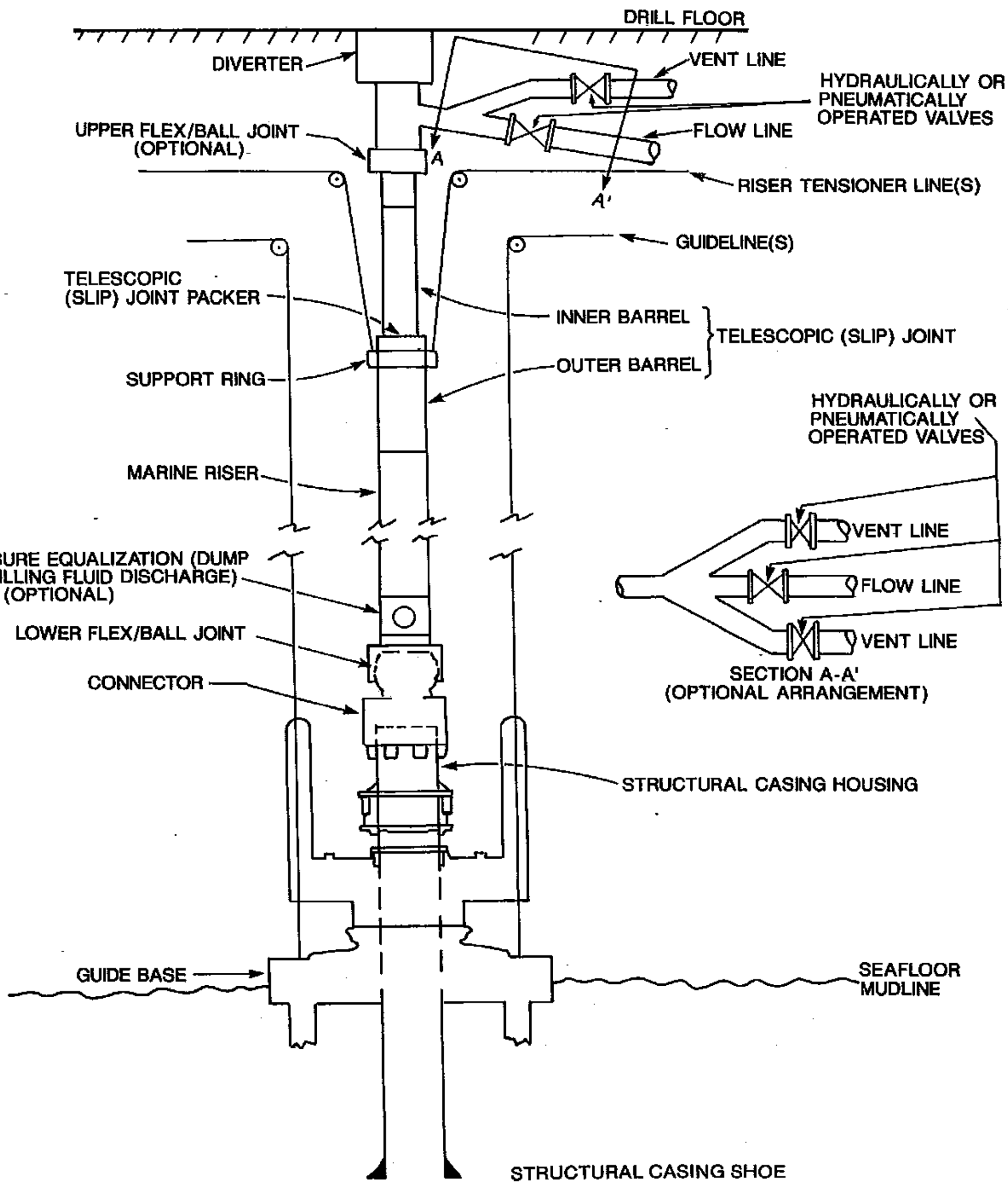


FIGURE 5.1
EXAMPLE FLOATING DRILLING VESSEL DIVERTER AND RISER SYSTEM INSTALLED ON STRUCTURAL CASING HOUSING

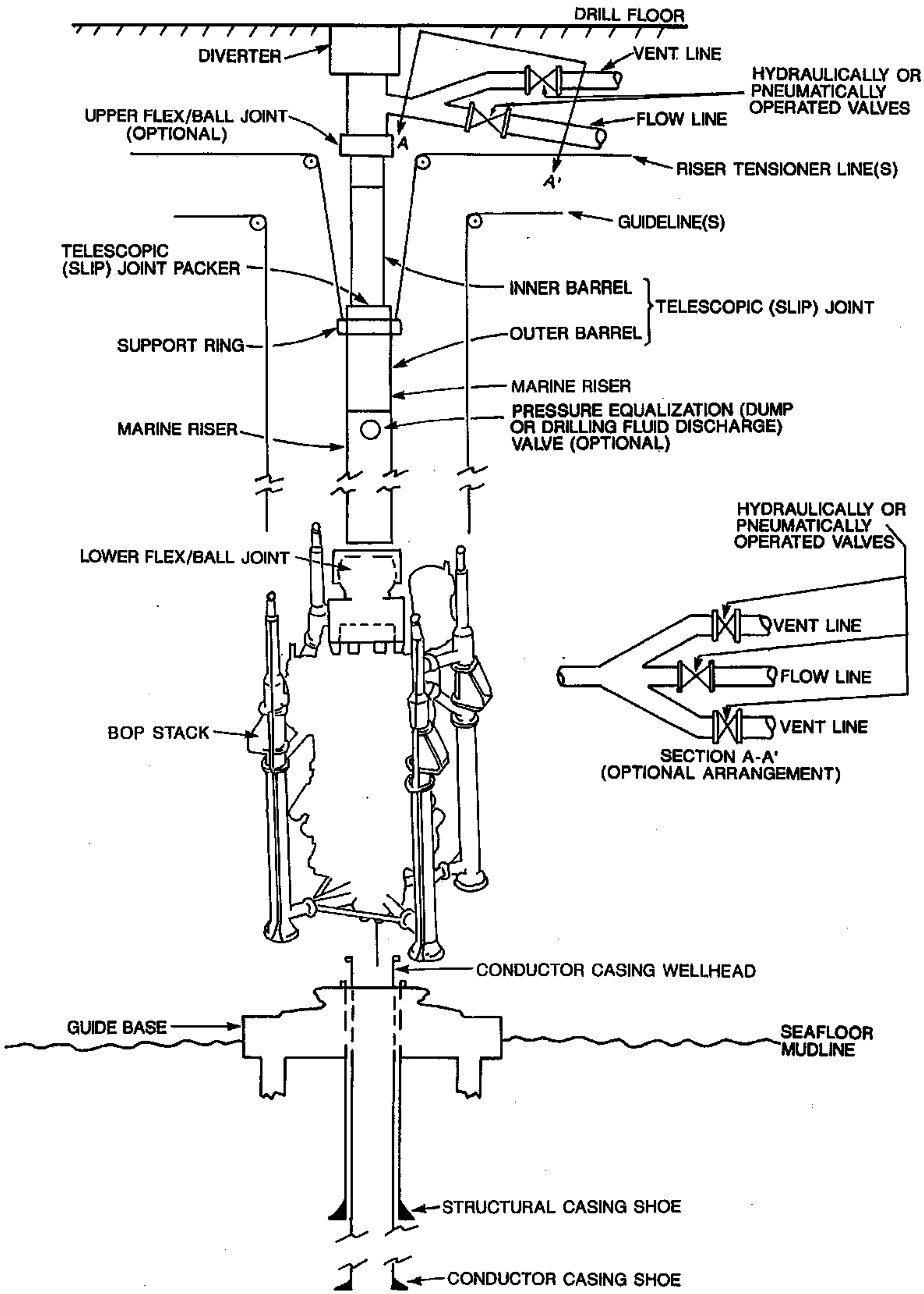


FIGURE 5.2
EXAMPLE FLOATING DRILLING VESSEL DIVERTER WITH RISER AND BLOWOUT PREVENTER SYSTEM BEING LOWERED

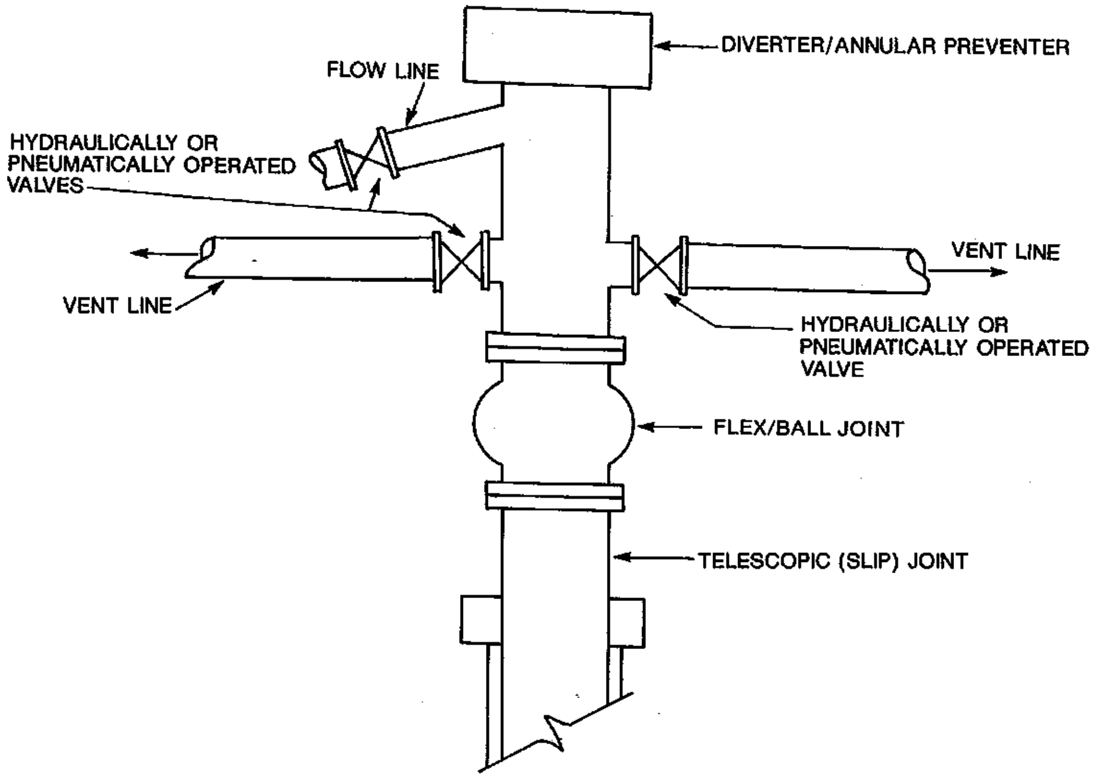


FIGURE 5.3
EXAMPLE DIVERTER SYSTEM SCHEMATIC
(FLOW LINE ABOVE VENT LINES)

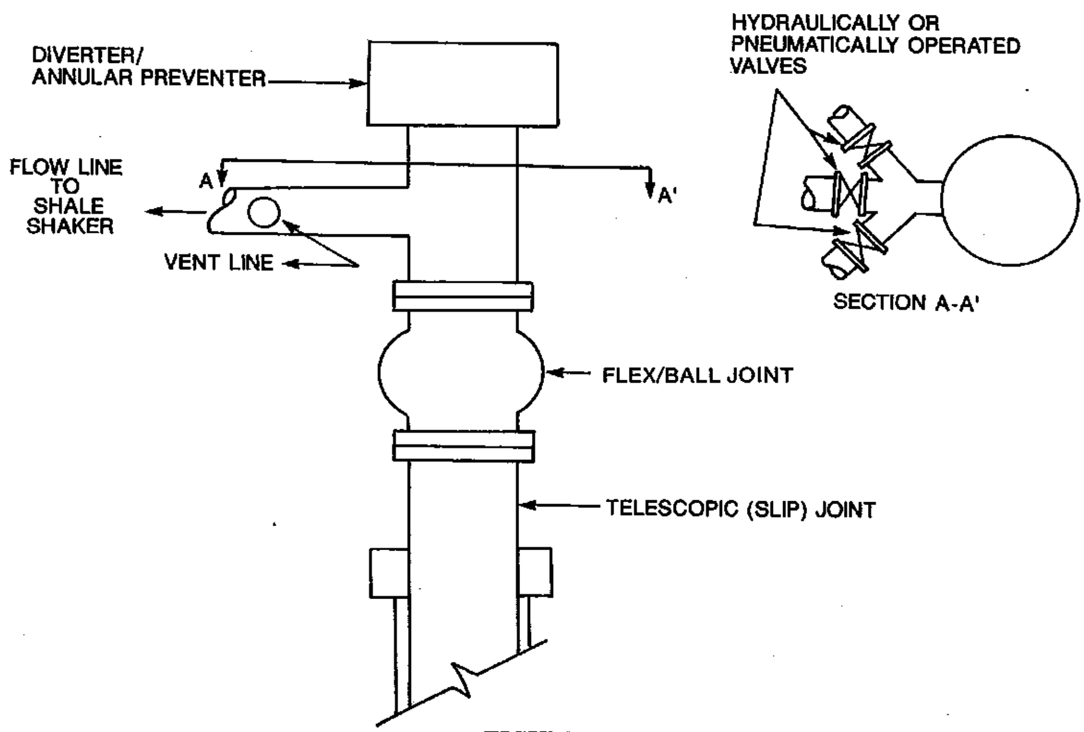


FIGURE 5.4
EXAMPLE DIVERTER SYSTEM SCHEMATIC
(FLOW LINE IN LINE WITH VENT LINES)

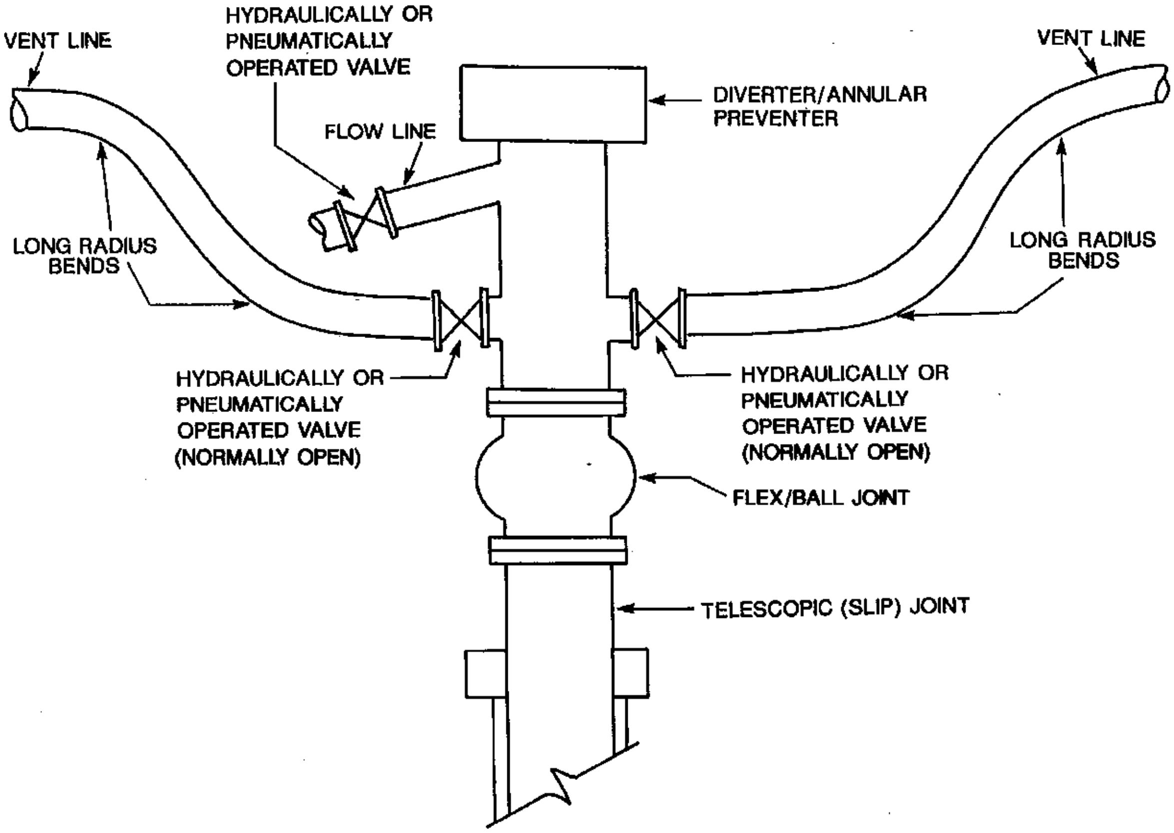


FIGURE 5.5
EXAMPLE DIVERTER SYSTEM SCHEMATIC (FLOW LINE DISCHARGE ABOVE VENT DISCHARGE LINE(S) BUT VENT LINE(S) EXTENDED ABOVE FLOW LINE)

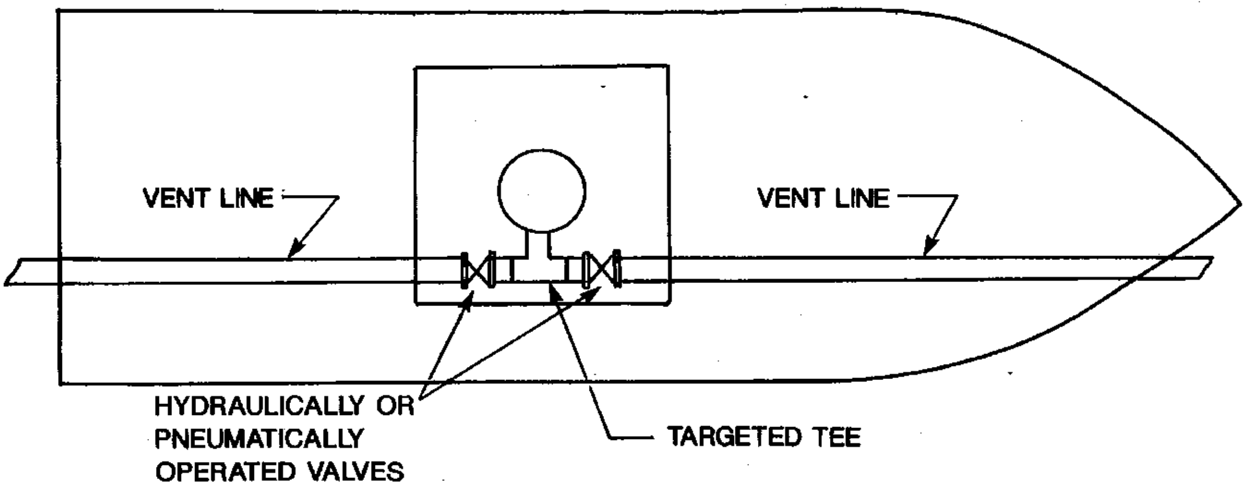


FIGURE 5.6.A
DIVERTER LINES EXTEND FORE AND AFT

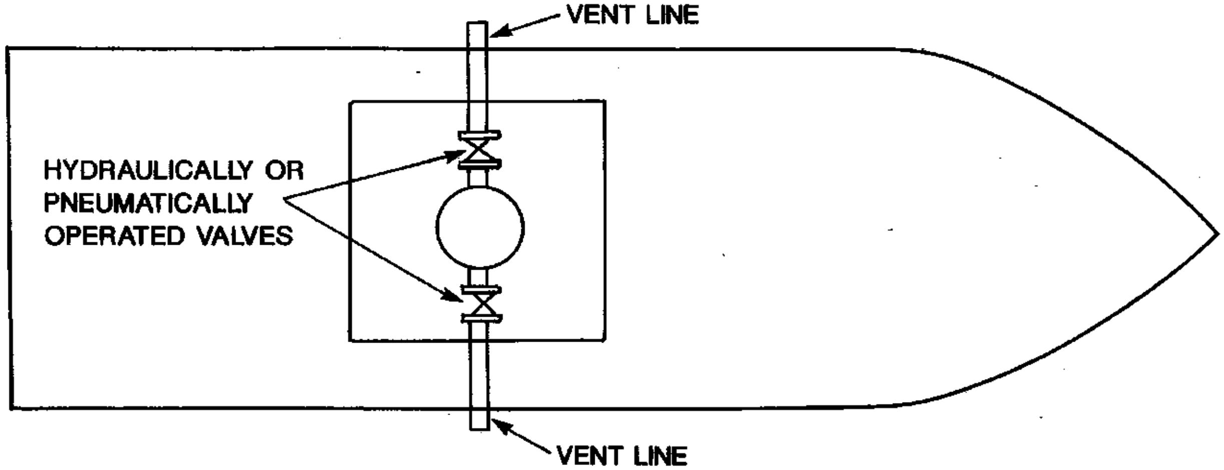


FIGURE 5.6.B
DIVERTER LINES EXTEND TO PORT AND STARBOARD

FIGURE 5.6
EXAMPLE DIVERTER LINE SCHEMATICS
FOR CONVENTIONALLY MOORED DRILLSHIPS

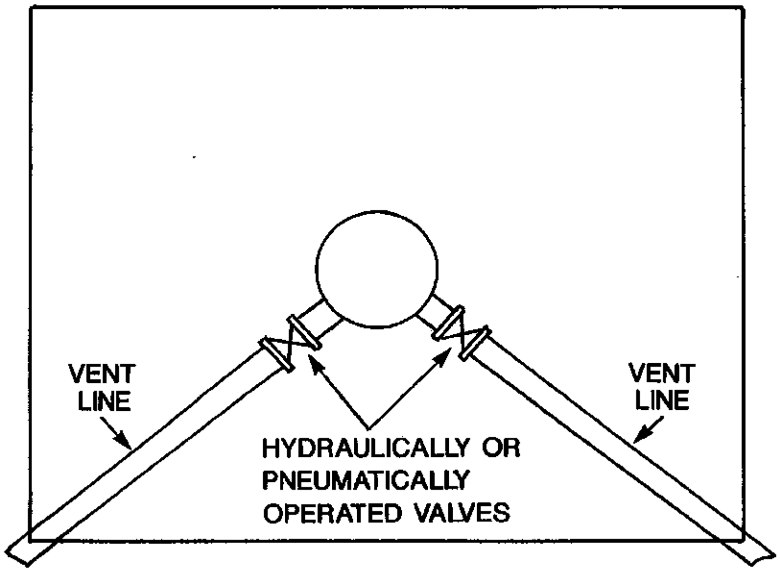


FIGURE 5.7.A

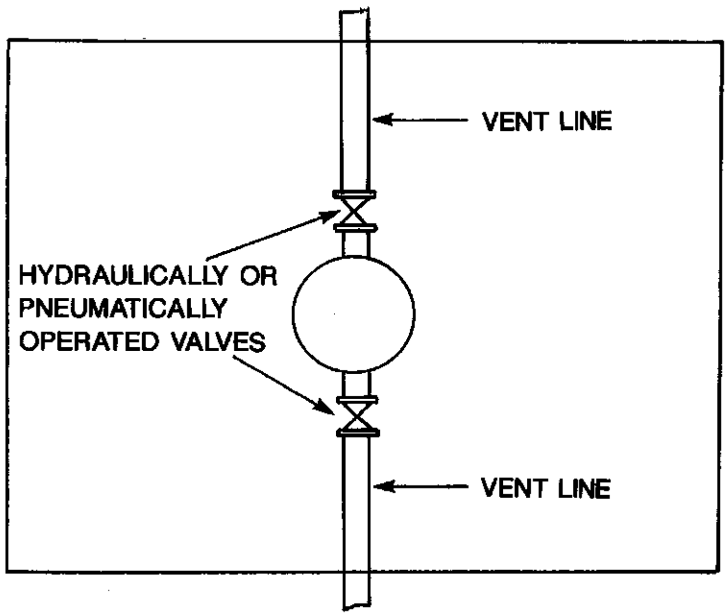


FIGURE 5.7.B
DIVERTER LINES EXTEND TO PORT AND STARBOARD

FIGURE 5.7
EXAMPLE DIVERTER LINE SCHEMATICS
FOR CONVENTIONALLY MOORED SEMISUBMERSIBLES

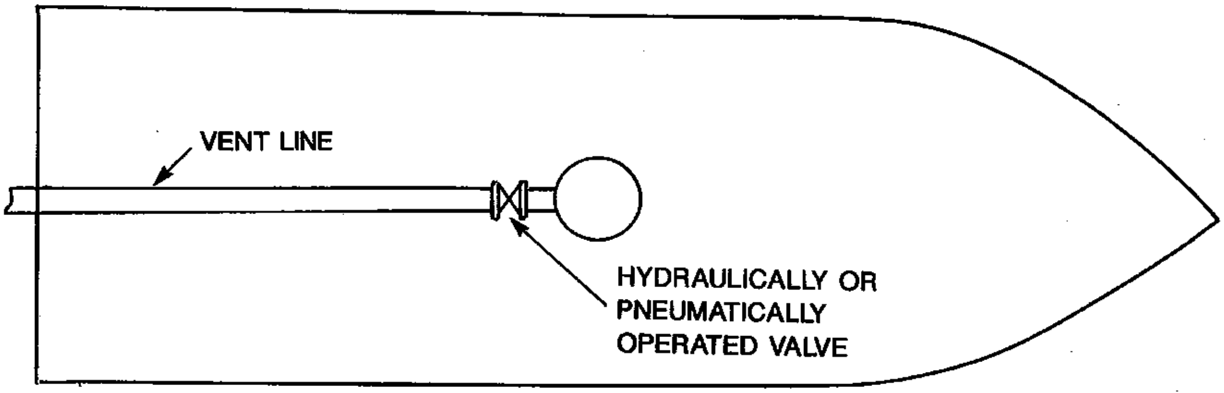


FIGURE 5.8.A
DRILLSHIPS

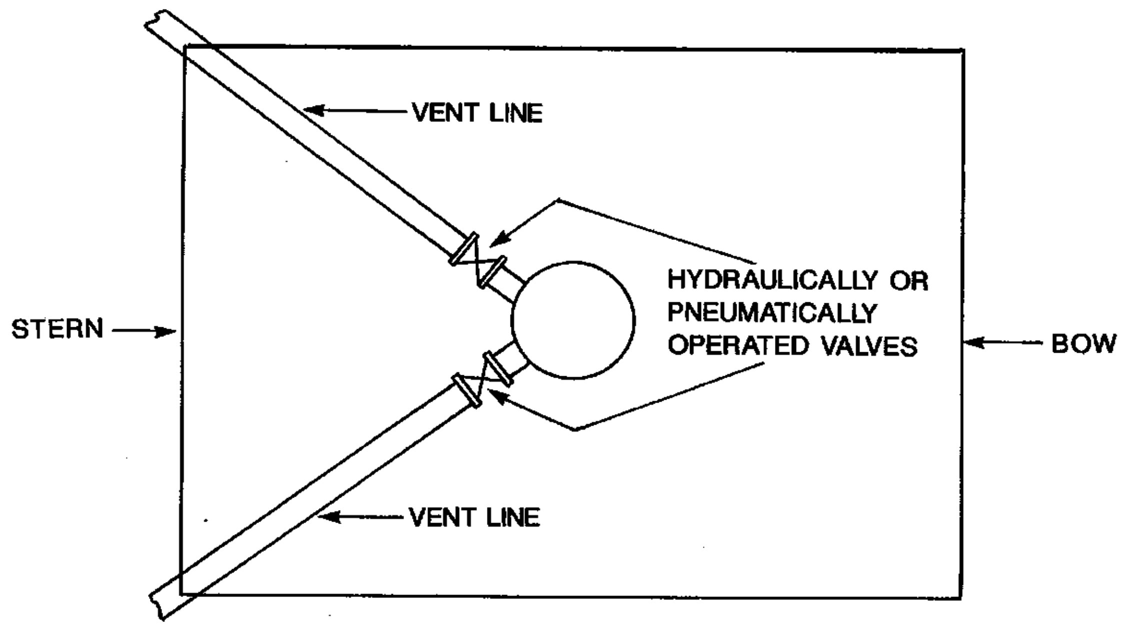


FIGURE 5.8.B
SEMISUBMERSIBLES

FIGURE 5.8
EXAMPLE DIVERTER LINE SCHEMATICS
FOR DYNAMICALLY POSITIONED VESSELS

SECTION 6
RECOMMENDED DIVERTER OPERATING PROCEDURES

6.1 Onshore and Bottom-supported Offshore Drilling Operations. The preplanning and operating procedures necessary to successfully and properly operate diverter systems in onshore and bottom-supported offshore installations are quite similar. The following recommended contingency and operating plans are pertinent to these operations.

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

6.1.2 Training and Instruction. All concerned personnel should be familiar with the diverter system components and installation and should be capable of reacting to potential situations requiring use of the diverter. The following general guidelines are offered for personnel training and instruction:

1. Drills should be conducted at appropriate intervals to ascertain that personnel are competent and capable of reacting to situations requiring use of the diverter.
2. Because of the limited response time required where diverter systems are employed, written procedures should be developed that detail specific emergency action plans. These emergency action procedures should be prepared prior to spudding the well.

6.1.2.1 Operating Guidelines During a Kick. 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 flowline and fillup line valves, if used, are closed.
3. Advise drill floor and service (vessel) 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.
5. Consider leaving all vent line(s) open, if conditions permit, to reduce back pressure.

6.1.3 Installation Test. All diverter system components shall be inspected and tested to ascertain proper installation and functioning. Simulate loss of rig air supply to the control system (accumulator unit and actuated valves) and determine effects, if any, on the diverter unit and vent line valves. These inspections and tests should include, but not be limited to:

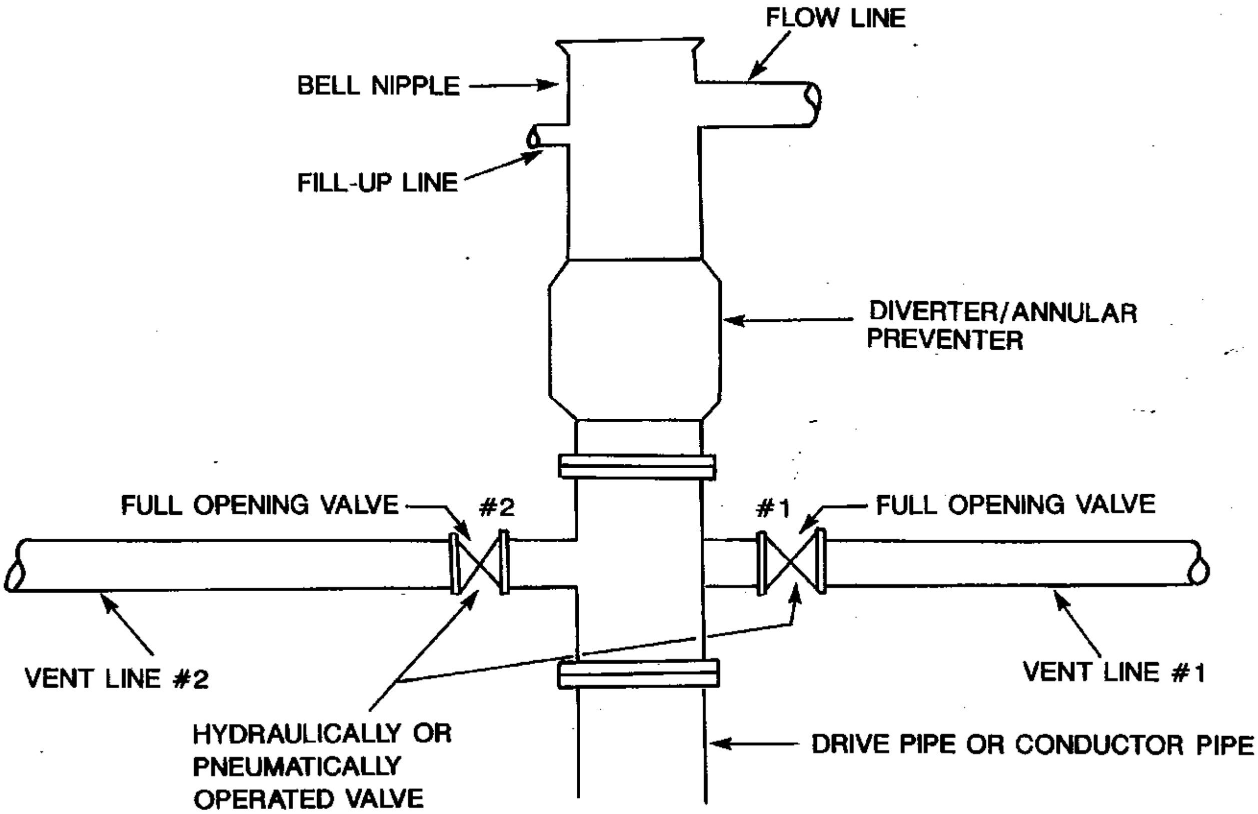
1. Check and verify the proper structural mounting of the annular sealing device assembly, and, if applicable, that the insert packing element is secured in place.
2. For installations using remote operators, record hydraulic pressure and air supply pressure with the accumulator fully charged and the controls in the normal drilling position.
3. Actuate the diverter close and open sequence with drill pipe or test mandrel in the diverter to verify control functions, proper equipment operating sequence and interlock, if applicable, and record response time(s). An example diverter installation test schedule is shown in Figure 6.1.
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.
6. Pump water or drilling fluid through the diverter system at low pressure and high rates and check vent line(s) for returns. Examine the entire system for leaks, excessive vibrations, and proper tie down while pumping fluid at high rates.

6.1.4 Routine Equipment Function Test. When in primary diverter service (no blowout preventer 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.

6.1.5 Materials, Equipment, and Supplies. Sufficient materials, equipment, and supplies should be available on location prior to spud. These include, but are not limited to:

1. Drilling fluid treating chemicals and weight material to increase density of the kill fluid. Consideration should be given to having available premixed kill fluid.
2. Adequate reserve fluid (water volumes).
3. 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).

6.2 Floating Drilling Operations. The preplanning and operating procedures necessary to successfully operate a diverter system in floating drilling operations is heavily dependent on the type of vessel and the anticipated well problems. In the case of moored drilling vessels, it is more difficult to move off the location than a dynamically positioned vessel, thus the planning and procedures should be tailored accordingly. The installation of a subsea blowout preventer stack may have an impact on the procedures to be followed compared to operations where a subsea stack is not in service. The basic components to successful operations are appropriate *preplanning and execution of drilling crew drills,*



NOTE:
THE DIVERTER SYSTEM ILLUSTRATED HERE IS A GENERIC EXAMPLE ONLY. INSTALLATION TEST REQUIREMENTS WILL VARY DEPENDING ON THE SYSTEM CONFIGURATION.

FIGURE 6.1
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. 6.1.3.5.
9. Restore the diverter system to the operational mode.

so that if use of the diverter system is required employees will be knowledgeable of the procedure to be followed and their specific duties in the procedure.

6.2.1 Advance Planning and Preparation. Advance planning should include an equipment and operations procedure check list depending on the drilling depth, company policies, government regulations, anticipated use of the diverter equipment, and other items discussed in Paragraph 6.2. Advance well planning should include assessment of the well control equipment performance curve as discussed in Appendix A, "Shallow Gas Well Control." Drilling crew members should be familiar with the equipment and its proper operation. The diverter line should be clear of obstructions at all times. In the event a blowout preventer 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 preplanned. Depending on the type power plant(s) on the rig, engine and generator assignments should be preplanned for use during divert operations. If a decision is made to leave the location, windlasses/winches should be set up 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. If a marine riser is in use, sufficient riser tension should be available to lift the lower marine riser package clear of the structural pipe or blowout preventer stack in the event of an emergency disconnect. The marine riser spider and proper diverter and riser handling tools should be available near the drill floor. The subsea television should be at stack level if the blowout preventer stack is in use. Engine spark arrestors should be in good working order. 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 to achieve full utilization.

6.2.2 Diverter System Equipment Installation. Refer to Paragraph 6.1.1.

6.2.3 Training and Instruction. Refer to Paragraph 6.1.2. The following example divert procedures may be considered at the first signs of confirmed well flow or if flow is suspected.

A. *Example Diverter Procedures Without Blowout Preventer Stack Installed.*

1. Pick up the kelly lower connection about 2-3 feet above the rotary table.
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. 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 sea water when drilling fluid is in short supply.
8. Radar observers and control room operators should watch for appearance of gas bubbles in the vicinity of the drilling vessel.

B. *Example Shut In Procedure With Diverter and Subsea Blowout Preventer Installed.* If drilling out of conductor casing, the following is an example of a well shut-in procedure when the diverter is complemented with blowout preventers installed:

1. Pick up the kelly lower connection about 2-3 feet above the rotary table.
2. Stop the pump, shut in the well with the blowout preventer(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: Recommended Practices for Well Control Operations**, First Edition, August 1987) 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 gas bubbles appear, notify the person in charge.

6.2.4 Installation Test. Refer to Paragraph 6.1.3. Vessel motion and pressure limitation(s) of riser system components, such as flex/ball joint and telescopic (slip) joint packer, should not be overlooked during equipment installation tests.

6.2.5 Routine Equipment Function Test. Refer to Paragraph 6.1.4.

6.2.6 Materials, Equipment, and Supplies. Refer to Paragraph 6.1.5.

6.3 Maintenace Manuals. Maintenance manuals furnished by manufacturers of the various components of the diverter system should be readily available for reference and use by maintenance personnel.

*Available from American Petroleum Institute, Publications and Distribution Section, 1220 L St., N.W., Washington, D.C. 20005.

SECTION 7
DIVERTER SYSTEMS MAINTENANCE

7.1 General. A schedule for routine checkout and maintenance of diverter systems equipment should be implemented and kept by the rig operating personnel. Specific guidelines for each diverter component or subsystem should be based on maintenance manuals and recommendations provided by the equipment manufacturer. Some general guidelines for diverter systems maintenance are:

1. Visually inspect the rubber 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. Precharge 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 shall be calibrated and tagged at intervals not to exceed twelve (12) months.

SECTION 8
GLOSSARY

NOTE: 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 hereunder.

8.1 Accumulator System. A series of pressure vessels used to store hydraulic fluid charged with nitrogen gas under pressure for operation of blowout preventers and/or diverter system.

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

8.3 Aerated Fluid. Drilling fluid injected with air or gas in varying amounts for the purpose of reducing hydrostatic head.

8.4 Air/Gas Drilling. Refer to *Aerated Fluid,* Par. 8.3.

8.5 Annular Packing Element. A rubber/steel torus 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.

8.6 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.

8.7 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.

8.8 Ball Valve. A valve which employs a rotating ball to open or close the flow passage.

8.9 Bell Nipple. A cylindrical conduit with inside diameter equal to or greater than the blowout preventer bore; connected to the top of the blowout preventer or marine riser with a flow line 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.

8.10 Blooey Line. The flow line in air or gas drilling operations.

8.11 Blowout Preventer Stack. The assembly of well control equipment including preventers, spools, valves, and nipples connected to the top of the casinghead.

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

8.13 Bottoms-up Gas. Gas that has risen to the surface from previously drilled gas bearing formations.

8.14 Bottom-supported Drilling Vessels. Offshore drilling vessels which float to the desired drilling location and are either ballasted or jacked up so that the vessel is supported by the ocean floor while in the drilling mode. Rigs of this type include platforms, submersibles, swamp barges, and jack-up drilling rigs.

8.15 Casing Shoe. The rounded concrete bottom end of a string of casing.

8.16 Cleanout. A point in the flowline piping where access to the internal area of the pipe can be achieved for the purpose of removing accumulated debris and drill cuttings.

8.17 Closing Unit. The assemblage of pumps, valves, lines, accumulators, and other items necessary to open and close the blowout preventer equipment and diverter system.

8.18 Conductor Casing — Onshore and Bottom-supported Offshore Installations. A relatively short string of large diameter pipe which 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 on onshore and bottom-supported offshore installations.

8.19 Conductor Casing — Floating Installations. The first string of pipe installed below the structural casing on which the wellhead and blowout preventer equipment are installed.

8.20 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, blowout preventer, valve, or regulator. Examples: diverter "close" function, starboard vent valve "open" function. 2) Each position of a diverter unit, blowout preventer, or valve and each regulator assignment that is operated by the control system.

8.21 Diverter Control System. The assemblage of pumps, accumulators, manifolds, control panels, valves, lines, etc., used to operate the diverter system.

8.22 Diverter Housing. A permanent installation under the rotary table which houses the diverter unit.

8.23 Diverter Packer. Refer to *Annular Sealing Device,* Par. 8.6.

8.24 Diverter Piping. Refer to *Vent Line,* Par. 8.34.

8.25 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 atmosphere.

8.26 Diverter Unit. The device that embodies the annular sealing device and its actuating means.

8.27 Drill Floor Substructure. The foundation structure on which the derrick, rotary table, drawworks, and other drilling equipment are supported.

8.28 Drilling Break. A change in the rate of penetration which may or may not be a result of penetrating a pressured reservoir.

8.29 Drilling Fluid Return Line. Refer to *Flow Line*, Par. 8.38.

8.30 Drilling Spool. A flanged joint placed between the blowout preventer and casinghead that serves as a spacer or crossover.

8.31 Drill Ship. A self-propelled, ocean-going, floating, ship-shaped vessel, equipped with drilling equipment.

8.32 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. (Refer to Par. 8.18.)

8.33 Dynamically Positioned Drilling Vessels. Drillships and semisubmersible drilling rigs equipped with computer controlled thrusters which enable them to maintain a constant position relative to the seafloor without the use of anchors and mooring lines while conducting floating drilling operations.

8.34 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."

8.35 Fill-up Line. A line usually connected into the bell nipple above the blowout preventers 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.

8.36 Fill-up (Flood) Valve. A differentially set valve installed on marine risers that automatically permits sea water to enter the riser to prevent collapse under hydrostatic pressure after evacuation caused by lost circulation or by gas circulated into the riser.

8.37 Flex/Ball Joint. A device installed directly above the subsea blowout preventer 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.

8.38 Flow Line. The piping which exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.

8.39 Flow Line Valve. A valve which controls the flow of drilling fluid through the flow line.

8.40 Formation Fracture Gradient. The hydrostatic value expressed in psi/ft that is required to initiate a fracture in subsurface formation.

8.41 Function Test. Closing and opening (cycling) equipment to verify operability.

8.42 Gas Cut Drilling Fluid. Drilling Fluid that has become entrained with gas from previously drilled gas bearing formations which in turn lowers the drilling fluid density and hydrostatic head of the drilling fluid column in the wellbore.

8.43 Gas Drilling. See *Aerated Fluid*, Par. 8.3.

8.44 Gate Valve. A valve which employs a sliding gate to open or close the flow passage.

8.45 Hydrogen Sulfide (H_2S). A highly toxic, flammable, corrosive, gas sometimes encountered in hydrocarbon bearing formations.

8.46 Hydrogen Sulfide Service. Refers to equipment designed to resist corrosion and hydrogen embrittlement caused by exposure to hydrogen sulfide.

8.47 Inner Barrel. The part of a telescopic slip joint on a marine riser which is attached to the flexible joint beneath the diverter.

8.48 Insert Type Packer. A diverter element which uses inserts designed to close and seal on specific ranges of pipe diameter.

8.49 Integral Valve. A valve embodied in the diverter unit which operates integrally with the annular sealing device.

8.50 Interlock. An arrangement of control system functions designed to require the actuation of one function as a prerequisite to actuate another.

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

8.52 Knife Valve. A valve using a portal plate or blade to facilitate open and close operation.

8.53 Locking Mechanism. A support or restraint device.

8.54 Lower Ball Joint. A device located above a subsea blowout preventer stack that permits relative angular movements of marine riser elements to reduce bending stresses caused by vessel offset, vessel surge and sway, and environmental forces (refer to *Flex/Ball Joint*, Par. 8.37).

8.55 Marine Riser System. The extension of the wellbore from the subsea blowout preventer 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 blowout preventer stack.

8.56 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.

8.57 **Mud/Gas Separator.** A device which separates entrained gas from the drilling fluid system.

8.58 **Mud Line.** The ocean floor.

8.59 **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.

8.60 **Outer Barrel.** The part of a telescopic slip joint on a marine riser which is attached to tensioner lines. Tension is transferred through the outer barrel into the riser.

8.61 **Overboard (Diverter) Line.** Refer to *Vent Line*, Par. 8.84.

8.62 **Packing Element.** The annular sealing device in an annular blowout preventer or diverter.

8.63 **Pressure-differentially-set Valve.** A valve that is operated when its actuator senses a change in pressure of a preset limit.

8.64 **Pressure Equalization Valve (Dump Valve).** A device used to control bottom riser annulus pressure by establishing direct communication with the sea.

8.65 **Pressure Regulator.** A control system component which permits attenuation of control system supply pressure to a satisfactory pressure level to operate components downstream.

8.66 **Rated Working Pressure.** The maximum safe operating pressure for which an item is designed.

8.67 **Remote Controlled Valve.** A valve which is controlled from a remote location.

8.68 **Riser Spider.** Equipment used to support the marine riser while it is being run or retrieved.

8.69 **Rotating Drilling Head.** A sealing device installed above the blowout preventers and used to close the annular space about the kelly when drilling with pressure at the surface.

8.70 **Rotating Stripper Head.** A sealing device installed above the blowout preventers and used to close the annular space about the drill pipe or kelly when pulling or running pipe under pressure.

8.71 **Rotary Table.** A device through which passes the bit and drill string and that transmits rotational action to the kelly.

8.72 **Rotary Support Beams.** The steel beams of a substructure which support the rotary table.

8.73 **Semisubmersible.** A floating offshore drilling vessel which is ballasted at the drilling location and conducts drilling operations in a stable, partly-submerged position.

8.74 **Shale Shaker.** A vibrating screen that removes relatively large size cuttings from the drilling fluid returns.

8.75 **Sour Gas.** Natural gas containing hydrogen sulfide.

8.76 **Spool.** Refer to *Drilling Spool*, Par. 8.30.

8.77 **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 blowout preventer(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.

8.78 **Stripping.** A procedure for running or pulling drill string with pressure in the annulus.

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

8.80 **Substructure.** Refer to *Drill Floor Substructure*, Par. 8.27.

8.81 **Sweet Gas.** Natural gas that does not contain hydrogen sulfide gas.

8.82 **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.

8.83 **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.

8.84 **Vent Line.** The conduit which directs the flow of diverted wellbore fluids away from the drill floor to the atmosphere.

8.85 **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.

8.86 **Vent Outlet.** The point at which fluids exit the wellbore below the annular sealing device via the vent line.

8.87 **Working Pressure Rating.** The maximum pressure at which an item is designed for safe operation.

APPENDIX A
SHALLOW GAS WELL CONTROL

Principles of Appendix A can be applied equally to analysis of onshore and offshore floating and bottom-supported drilling operations. Appendix A is not purported as an all-inclusive analysis of dynamic kill calculations for control of shallow gas. It is intended to promote a better understanding of the analysis technique fundamentals. 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 has been 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 back pressure at the sea bed will be the greater of the hydrostatic pressure due to water depth or the back pressure 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 Appendix A.

INTRODUCTION

A.1 Opinions differ throughout the drilling industry concerning well control involving shallow gas. Some experts advocate using risers and diverters, while others support drilling without using a riser and circulating seawater back to the seafloor. 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 few situations where any of these techniques work when applied without precise planning, there appears to be a real need for better understanding about the way a shallow gas kick produces and is controlled.

A.2 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. This discussion is not intended to advocate drilling with or without a riser, but does present fundamentals for study by those who make such decisions. Industry personnel should develop and use numerical values in design and procedures and avoid recommending techniques which do not have a chance of success except under very limited circumstances. Each specific situation should be individually designed. Some situations will favor the use of a drilling riser; others will best be drilled without use of a riser. The title and coverage of this publication implies that diverters are used in some operations, hence risers are also used in some operations. An understanding of the fundamentals will influence selection of the well control technique(s) to be used and will emphasize the realization that a particular technique cannot be indiscriminately applied.

FUNDAMENTALS

A.3 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 nearly always abnormally pressured.
2. Shallow gas zones can be very prolific with extremely high deliverability.
3. Any permeable formation that becomes underbalanced will flow. In the case of drilling underbalanced 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) and the wellbore cross section (including fracture gradients and casing depths). If a shallow gas zone is penetrated offshore, while utilizing only sea water and circulation back to the sea bed elevation, the gas zone will likely flow. Some shallow gas zones offshore may also 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 Par. 2.1, Par. A.6, and Fig. 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 to be penetrated 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 deep water

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.

10. In an offshore shallow gas uncontrolled flow situation, the gas flow rate may be decreased if the full seawater hydrostatic pressure is applied at the seabed 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.4 Shallow gas is nearly abnormally pressured. It is usually underlaid by water which is normally pressured.

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 Fig. A.1). (Other shallow gas accumulations may have higher pressures due to faulting, formation dip, etc.)

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

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 .006 at 1000 ft, .03 at 2000 ft, and .06 at 5000 ft).

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

H_G = height of gas column, ft.

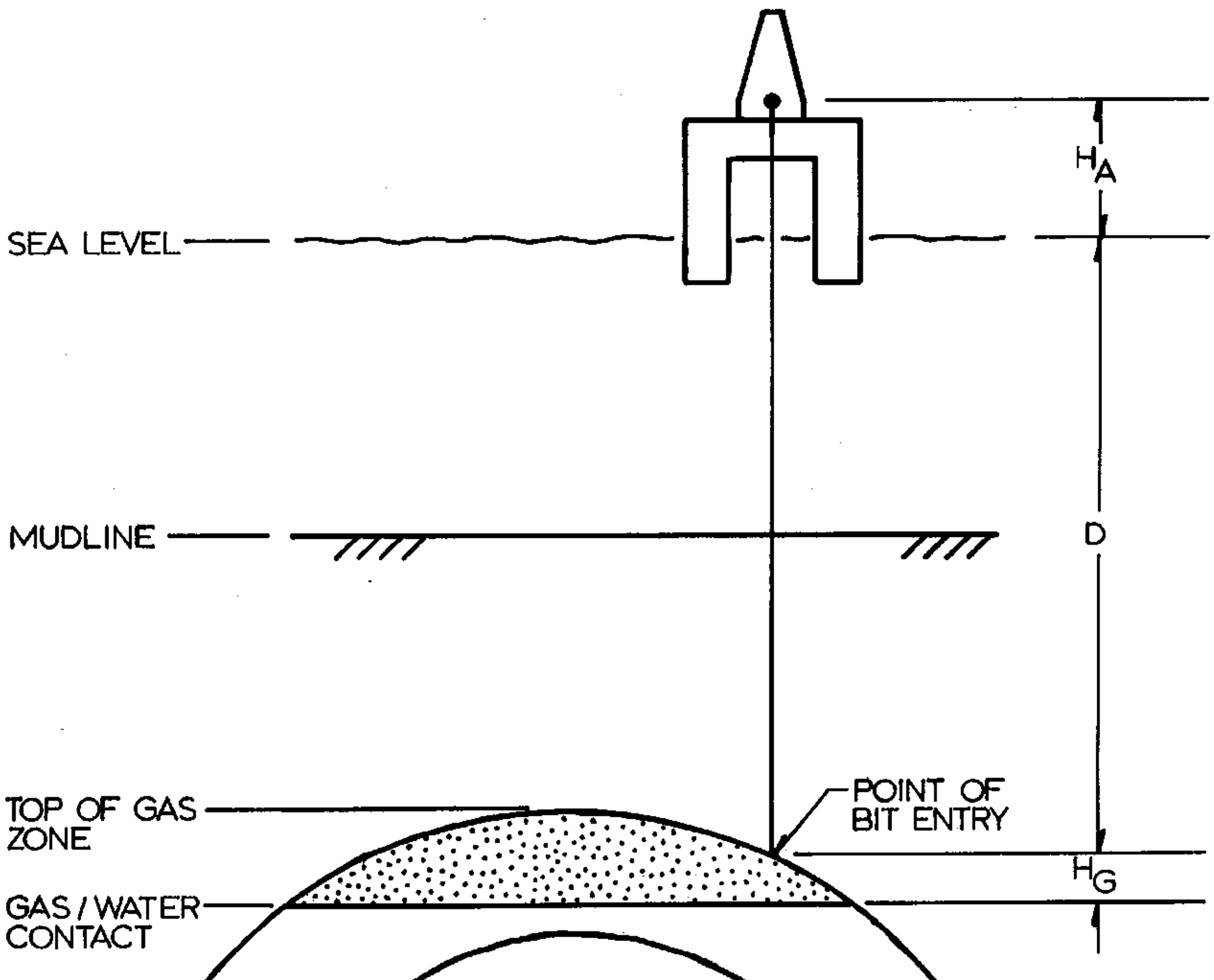


FIGURE A.1
ABNORMAL PRESSURE FROM DENSITY DIFFERENCES

A.5 If drilling a shallow gas zone while circulating seawater back to the seafloor without a riser (refer to Par. A.6 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 underbalanced (refer to Fig. A.2). Neglecting the gas gradient, the overpressure at the top of the gas sand can be estimated by Equation (A-2). A reduction in head due to drilled gas can also contribute to an underbalanced condition.

$$\Delta P = 0.44 \times h \quad \text{(A-2)}$$

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 feet thick will be overpressured by approximately 44 psi. If the shallow gas zone is steeply inclined, the abnormal pressure can be even greater.

A.6 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 Fig. 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:

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

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 elevation above mean sea level, ft. Refer to Figs. 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:

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

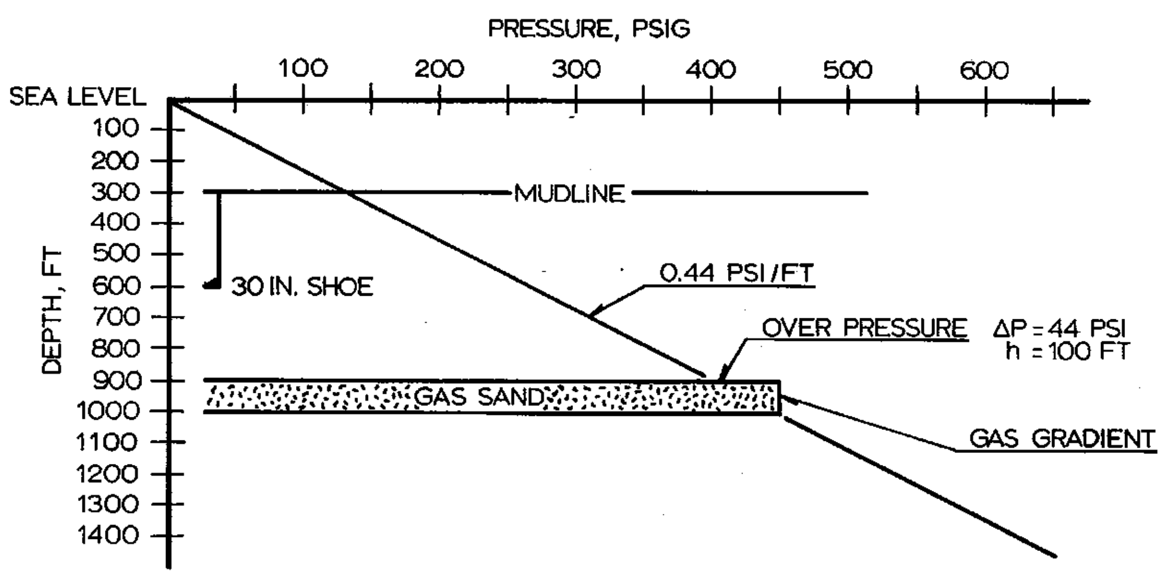


FIGURE A.2
SHALLOW GAS IS ABNORMALLY PRESSURED

where:

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

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:

$$MW = \frac{APG \times D}{.052\,(D+H_A)} \quad \text{(A-5)}$$

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.

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.7 A drilling well experiencing a 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.8 There are two types of performance relationships to be analyzed: a) well performance, and b) equipment performance.

1. *Well performance* is flow rate versus pressure calculated from the bottom up and is independent of

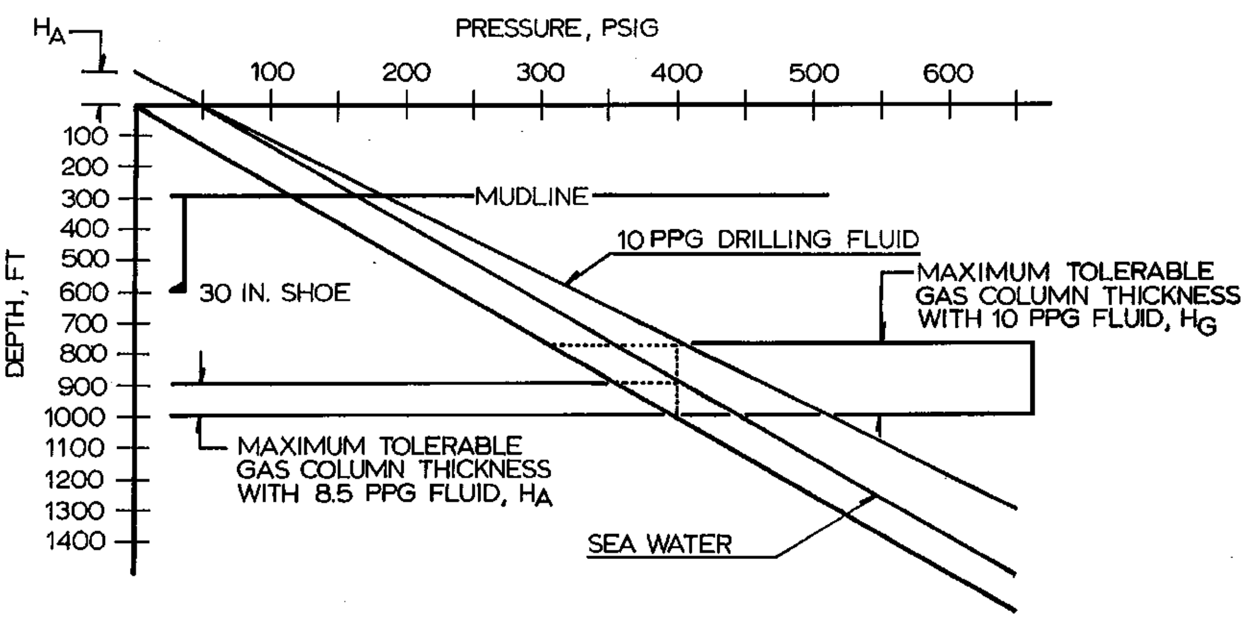
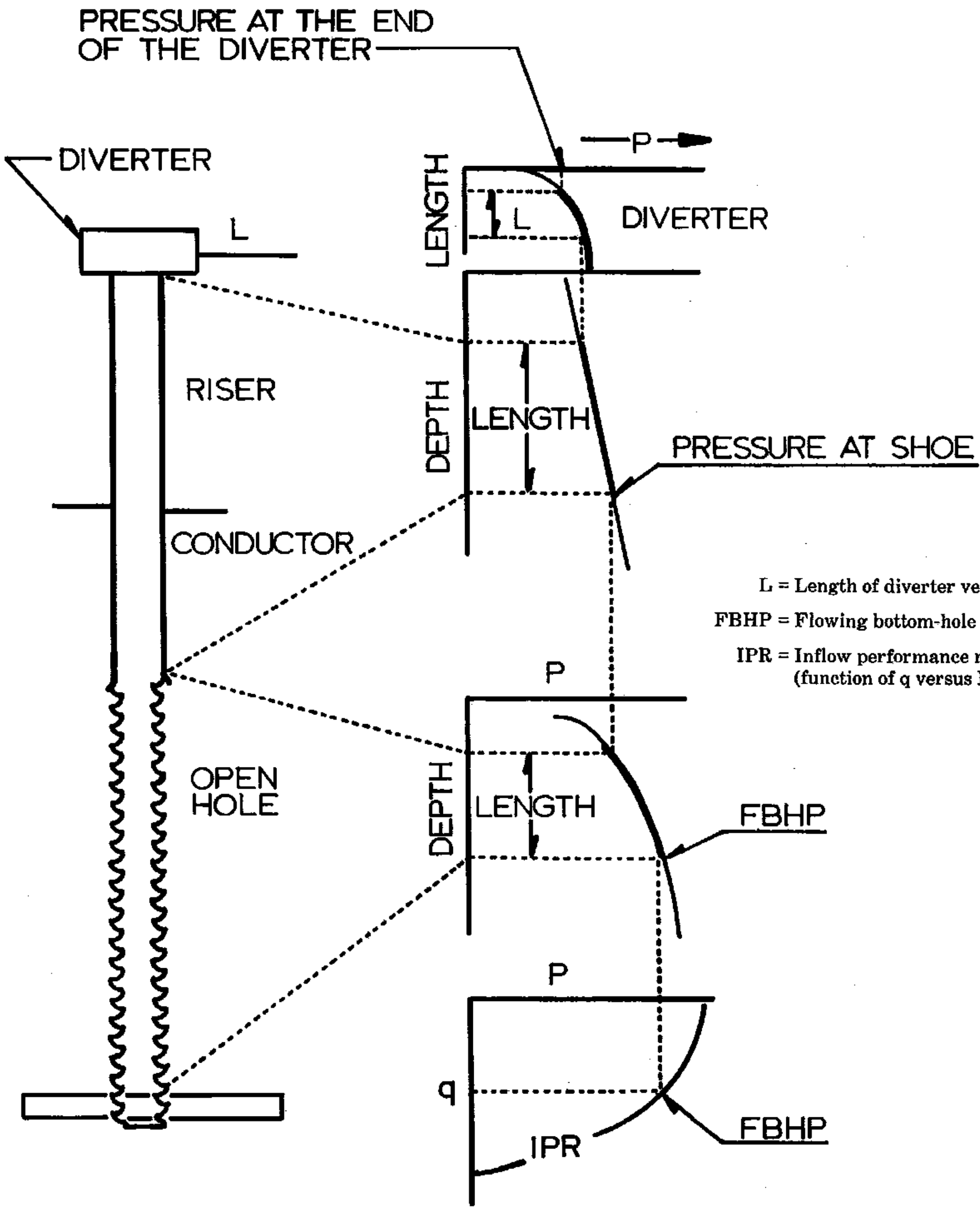


FIGURE A.3
EFFECT OF WEIGHTED MUD



L = Length of diverter vent line.

FBHP = Flowing bottom-hole pressure.

IPR = Inflow performance relationship (function of q versus P).

FIGURE A.4
A DRILLING WELL EXPERIENCING
A GAS KICK IS A PRODUCING WELL SYSTEM.

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 better known term, productivity index (PI), is a special case of IPR that applies only to single phase, incompressible flow.

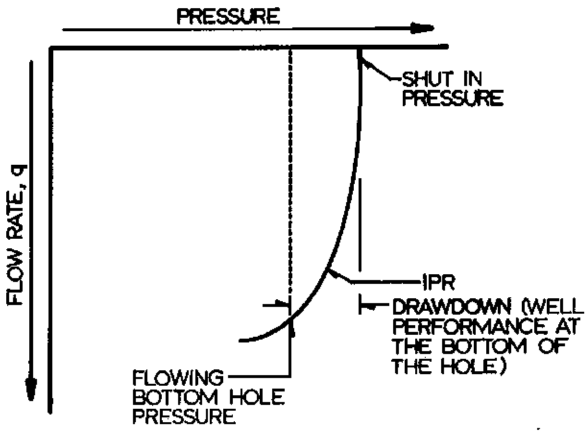


FIGURE A.5
WELL PERFORMANCE

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).

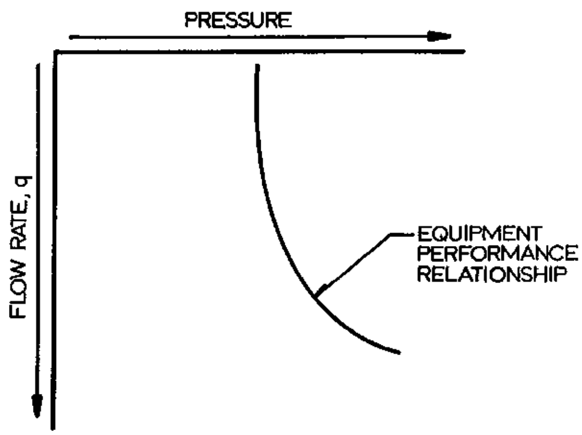


FIGURE A.6
EQUIPMENT PERFORMANCE RELATIONSHIP

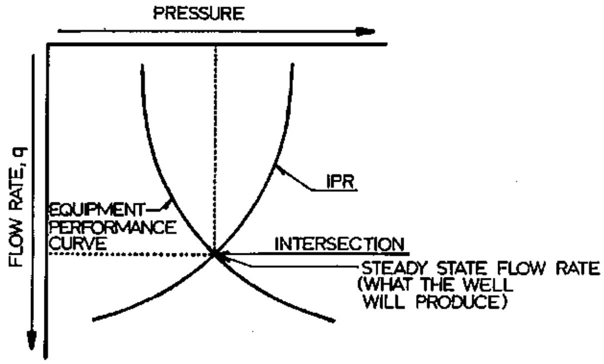


FIGURE A.7

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.

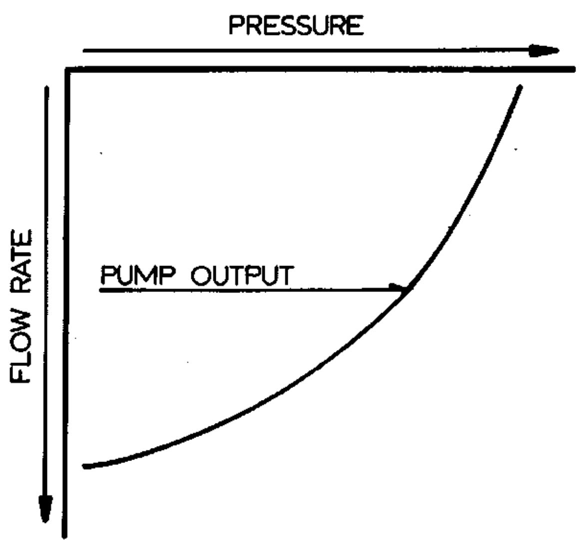


FIGURE A.8

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

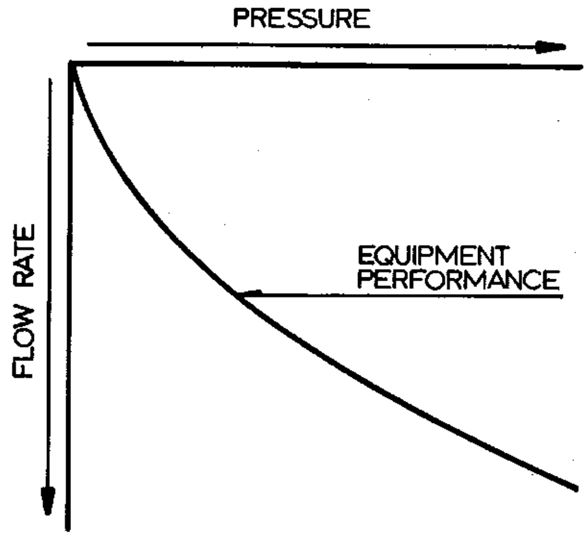


FIGURE A.9

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

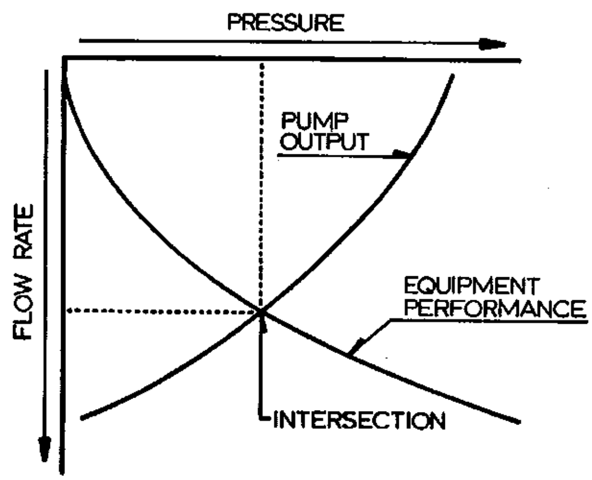


FIGURE A.10

A.9 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 blowout, the equipment performance curve must exceed the well performance curve. This is called "dynamic kill." To be able to dynamically kill a blowout, the well should be designed so the equipment performance curve can be developed to exceed the well performance curve. This means the back pressure 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).

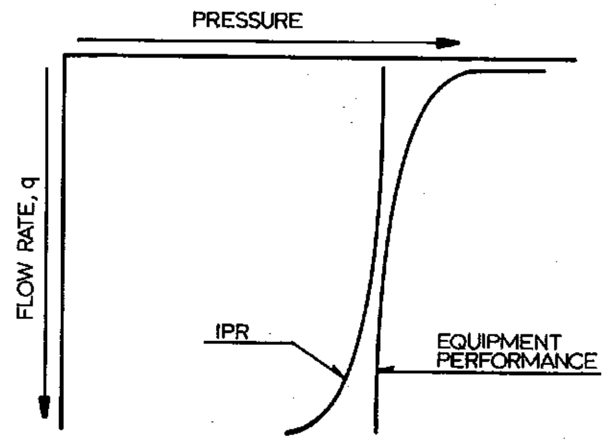


FIGURE A.11

The back pressure can be adjusted by the pump rate, drilling fluid density, and flow restriction in the equipment downstream of the formation face. However, 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 1000 gallons per minute 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_f) equal to a water gradient times the depth of the bottom of the sand (refer to Fig. A.12).

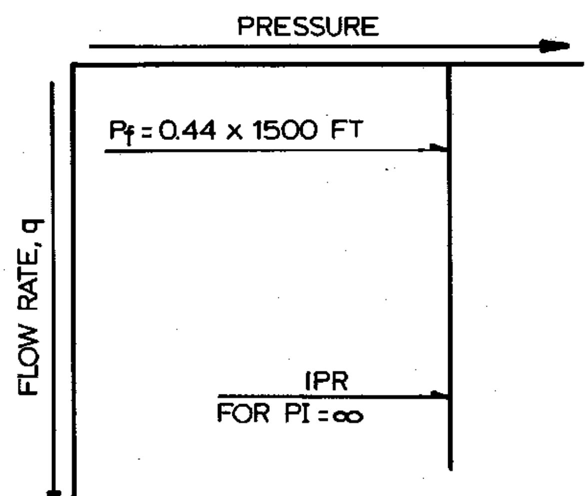


FIGURE A.12

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 8½ inch, 17½ inch, and 19½ inch diameter pipe or boreholes. In order to allow flexibility in depth and back pressure, traverses for hypothetical boreholes thousands of feet deep are used. Gilbert's[1] method of adjusting the pressure traverses for pressure and length can be used.

Horizontal two-phase pressure traverses were also estimated[2]. 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 back pressure for critical flow must be considered and is used as the initiation point for the vent line pressure traverses. The method introduced by Gilbert[1] is used to predict the two-phase critical flow back pressure. This empirical technique has stood the test of time (since 1954) and reasonably approximates the laboratory values developed by Beck, Langlinais, and Bourgoyne[3].

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

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

1. Develop the well performance relation from the bottom up.
2. Develop the equipment performance relation from the top down.
3. 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).

A.10 There are four primary relationships that must be determined to initiate steady state analysis of a diverter system. Models must be used to approximate behavior of these relationships.

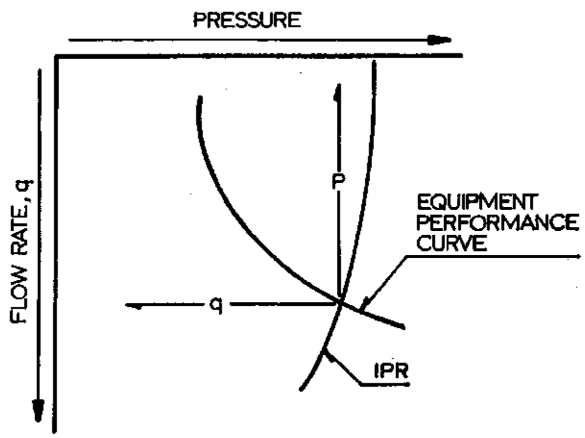


FIGURE A.13

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.

EXAMPLE EQUIPMENT PERFORMANCE

A.11 Determining Back Pressure on the Diverter.

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

$$P_{tf} = \frac{q\ 435R^{0.546}}{S^{1.89}} \quad \text{(A-6)}$$

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. Back pressure at the diverter. Notice the traverses are developed (refer to Fig. A.14) for a hypothetical vent line length of 1000 feet with a fixed liquid flow rate at 1000 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 1000 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.

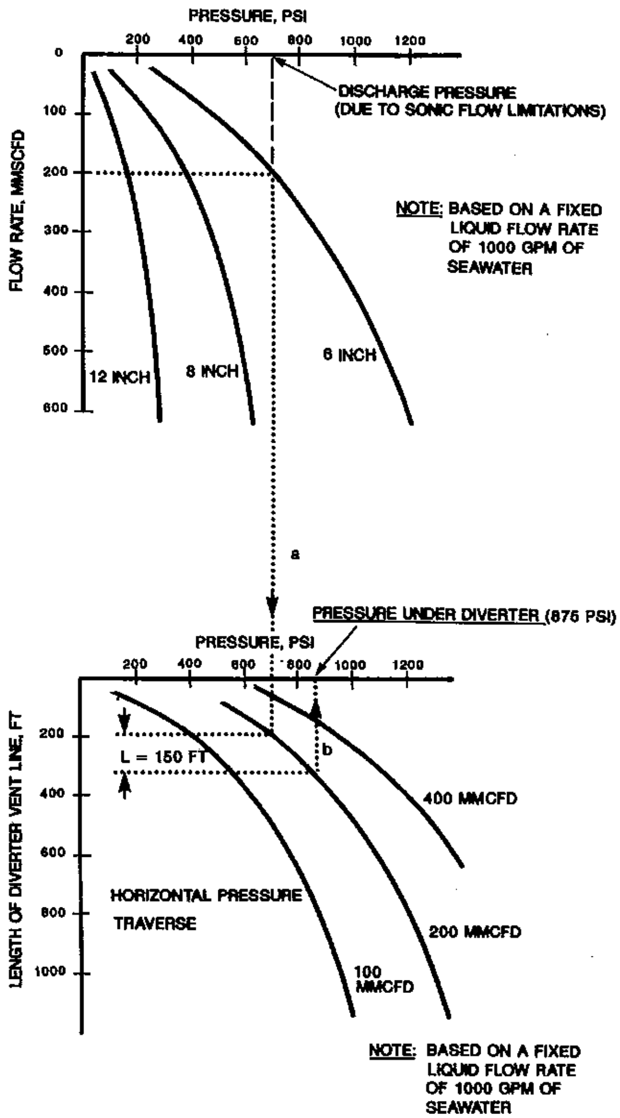


FIGURE A.14

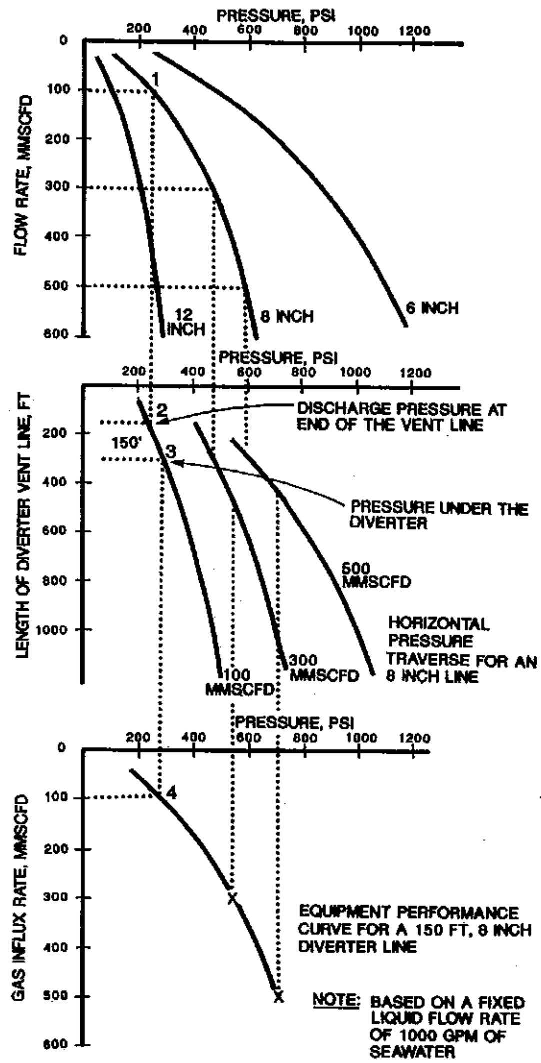


FIGURE A.15

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

   a. Enter the sonic back pressure curve for an 8 inch 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 inch diverter line.

   d. Select another flow rate (300 MMSCFD).

   e. 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 inch 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 inch diverter line.

f. 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 inch diverter line. These points should be connected to form the equipment performance curve.

A cursory examination of the data and equipment performance curve seems to indicate that back pressure on the diverter is primarily a function of the diverter line diameter. In fact, this is where available literature treatise stops. 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 1500 ft. or 3000 ft. deep, will exert the *same* back pressure on the diverter. In order to get a truer performance picture, we must consider equipment performance *plus* well performance.

EXAMPLE WELL PERFORMANCE

A.12 Effect of Pilot Hole Depth on Diverter Back Pressure. An example well will be used for illustrative purposes:

Total Depth = 1600 ft. subsea
Water Depth = 300 ft.
Conductor Pipe (30″) Depth = 300 ft. below mudline
Pilot Hole Depth = 1000 ft. below 30″ conductor pipe
Formation Pressure, $P_s = 0.44 \times 1600 = 704$ psig
Diverter Location = 100 ft above sea level

The permeability of shallow formations is usually, 2-8 Darcies. At a penetration rate of 50 ft. per hour, significant formation can be penetrated before the influx is recognized at the surface. For practical purposes the formation productivity index, 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[1] to adjust for pressure and length variations. Figs. A.24, A.25, A.26, and A.27 are for pressure drop through diverter lines. Figs. A.28, A.29, A.30, A.31, and A.32 are for pressure drop in the wellbore. Note that 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:

a. 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).

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

c. From the intersection of the FBHP and the 100 million SCFD rate pressure traverse curve, add the 1000 ft. vertical length of the 12¼ inch x 8½ inch 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).

d. 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 1000 ft. of 12¼ inch x 8½ inch pilot hole.

e. Repeat Steps a, b, c, and d for different well flow rates and construct a well performance curve 1000 ft. above the gas zone at the top of the pilot hole (or bottom of the 30 inch conductor pipe).

f. 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 1000 ft. deep 12¼ inch 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 1000 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 inch diameter diverter line when pumping 1000 gpm of seawater. The back pressure under these conditions is 550 psi. The back pressure will reduce to 150 psi for a 12 inch diameter diverter line, but the well will produce 270 million SCFD.

Figure A.19 shows that when the pilot hole is 17½ inches or greater, there is little effect of diverter line size on the pressure at the diverter. However, the gas influx rate is drastically affected by diverter line diameter. For a 6 inch diameter diverter line, the gas influx rate is 120 million SCFD. For an 8 inch diameter diverter line, the gas influx rate is 450 million SCFD. The pressure at the diverter is approximately 650 psi for either the 6 inch or the 8 inch diameter line. *NOTE:* The well performance curve for 17½ x 8½ inch pilot hole was developed using Items a through f in Par. A.12 plus pressure traverse curves shown in Figure A.31.

Figure A.20 illustrates that there is little difference between a 17½ inch pilot hole and no pilot hole. *NOTE:* The well performance curve was developed using Items a through f in Par. A.12 plus pressure traverse curves shown in Figure A.32.

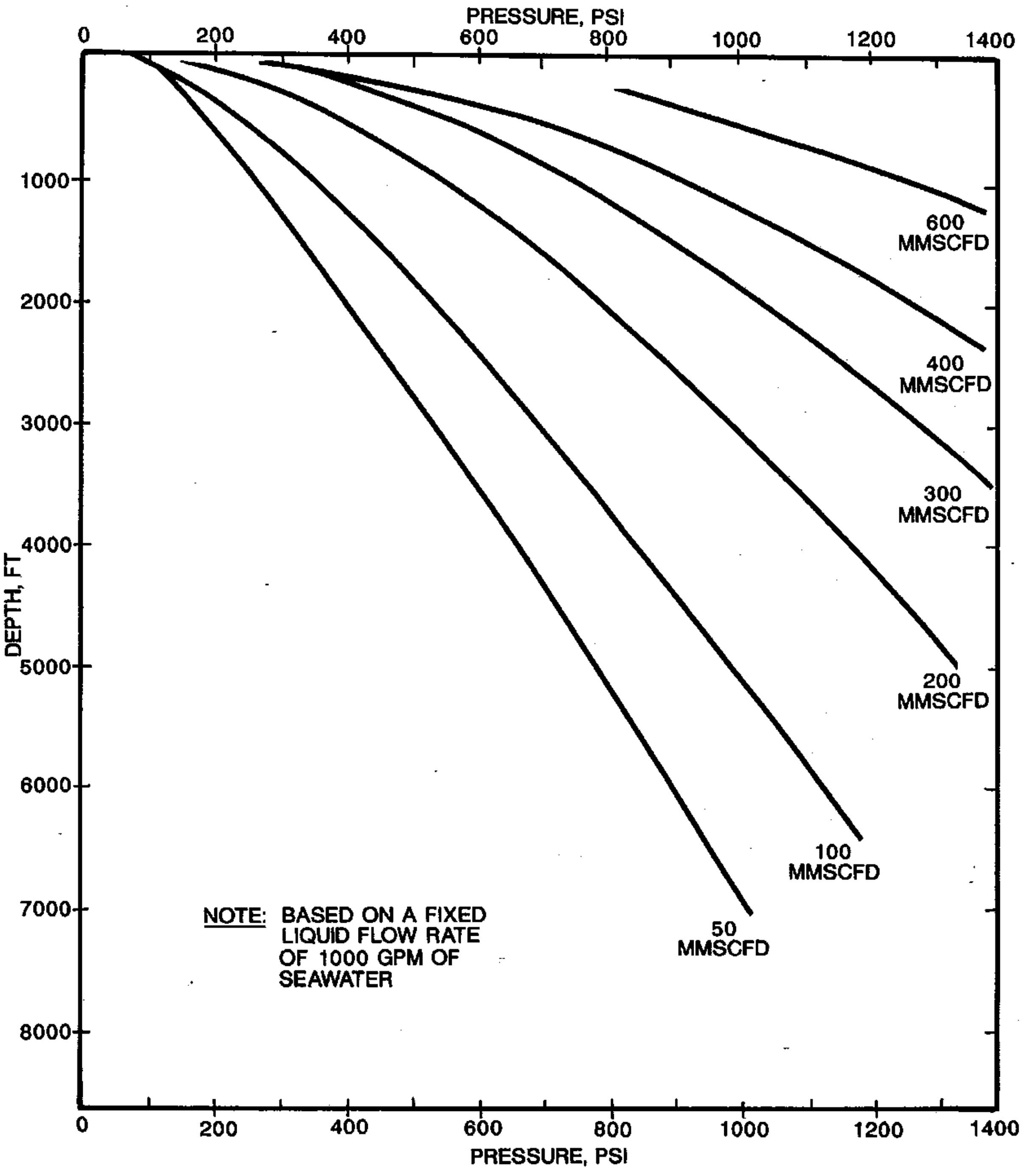
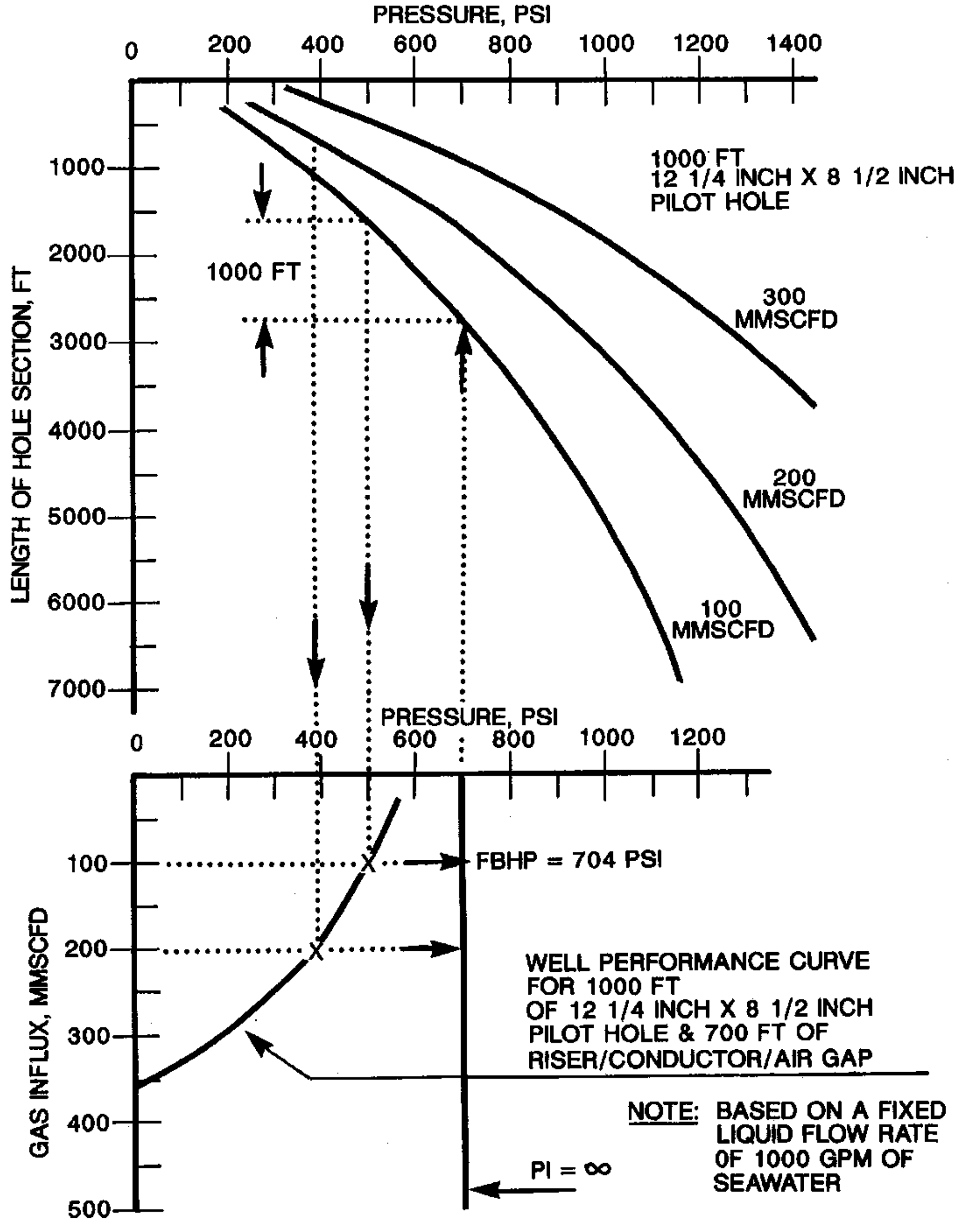


FIGURE A.16
VERTICAL TWO-PHASE PRESSURE TRAVERSE
(12¼ INCH BOREHOLE x 8½ INCH DRILL COLLARS)

(Refer to Gilbert, W. E.[1], "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
12 1/4 INCH X 8 1/2 INCH
PILOT HOLE
1000 FT
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 12 1/4 INCH X 8 1/2 INCH
PILOT HOLE & 700 FT OF
RISER/CONDUCTOR/AIR GAP
NOTE: BASED ON A FIXED
LIQUID FLOW RATE
OF 1000 GPM OF
SEAWATER
PI = ∞

FIGURE A.17

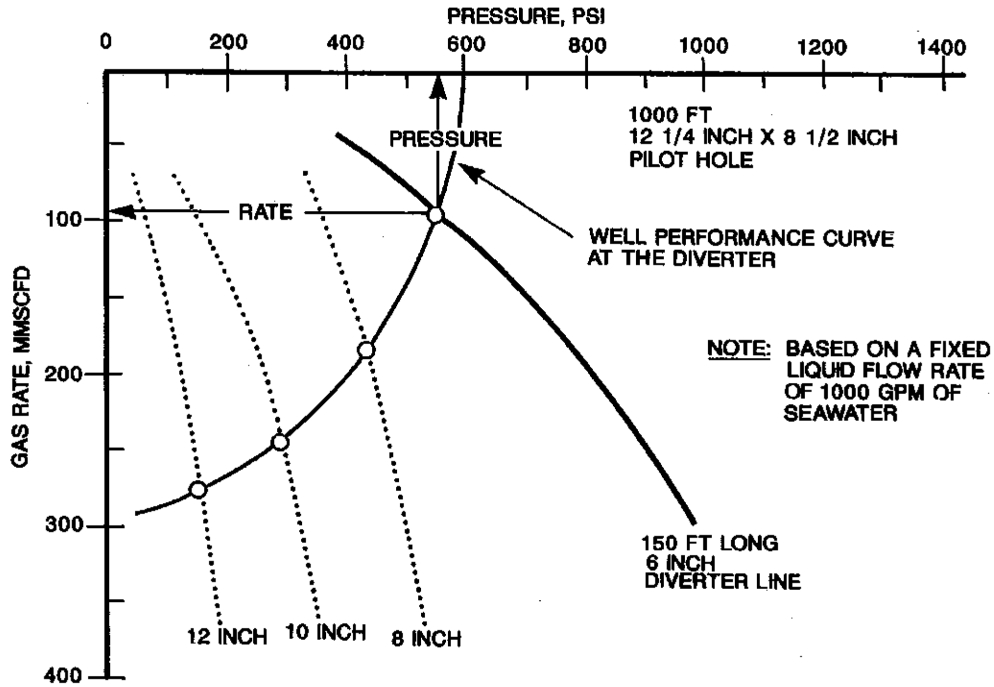


FIGURE A.18
EFFECT OF DIVERTER SIZE ON DIVERTER PRESSURE
(With a 12¼ inch x 8½ inch pilot hole.)

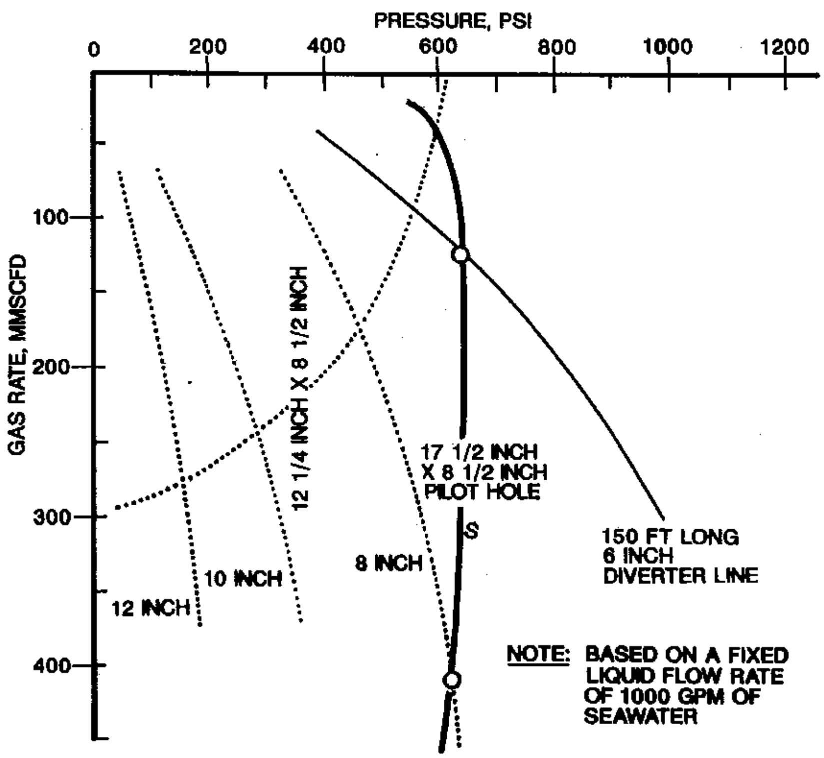


FIGURE A.19
EFFECT OF DIVERTER SIZE ON DIVERTER PRESSURE
(With a 17½ inch x 8½ inch pilot hole.)

A.13 Effect of Pilot Hole Diameter on the Ability to Kill a Well.

a. Calculate and plot the equipment performance curve at the 30 inch shoe. (Refer to Figure A.21).

b. From the point of the 30 inch 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 8½ inch diameter pilot hole. The well cannot be killed with a 12¼ inch diameter or larger pilot hole. *NOTE:* The well performance curve was developed using Items a through f in Par. A.12 plus pressure traverse curves shown in Fig. A.22.

A.14 Summary. As previously stated, Appendix A presents some fundamental concepts to be considered 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.

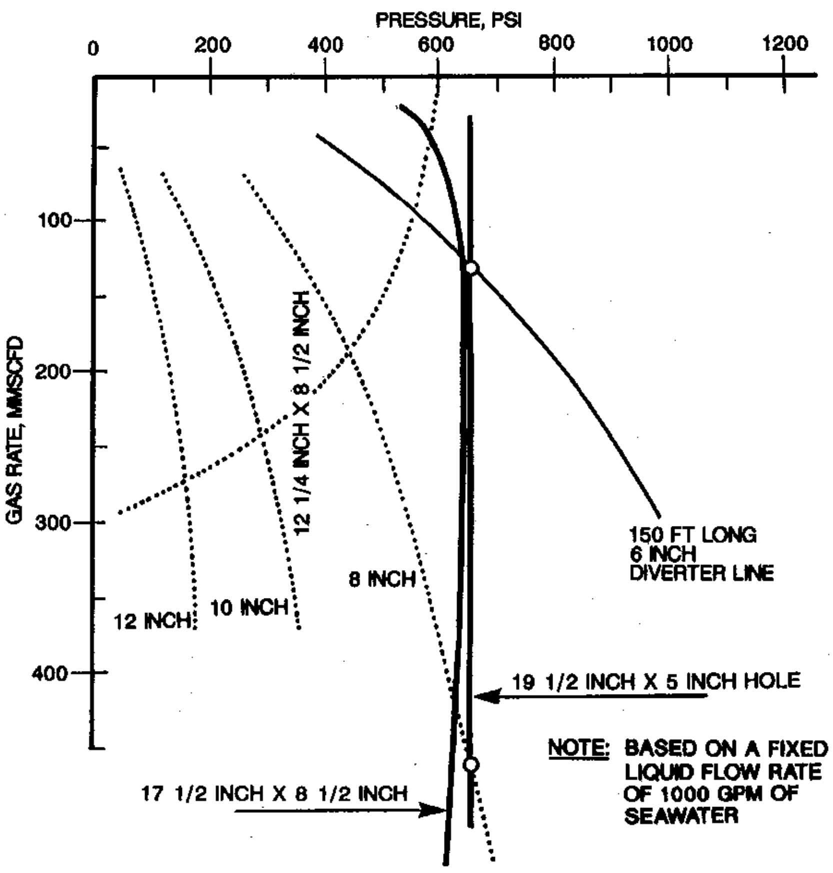
REFERENCES FOR APPENDIX A

1. Gilbert, W. E.; "Flowing and Gas-lift Well Performance"; *Drilling and Production Practice — 1954*, American Petroleum Institute, Dallas, TX, 126.

2. 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, TX.

3. 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, TX.

4. Nind, T. E. W.; *Principles of Oil Well Production*, McGraw Hill, Inc., 1964, 133.



There is little difference between 17½ inch and larger holes.

FIGURE A.20

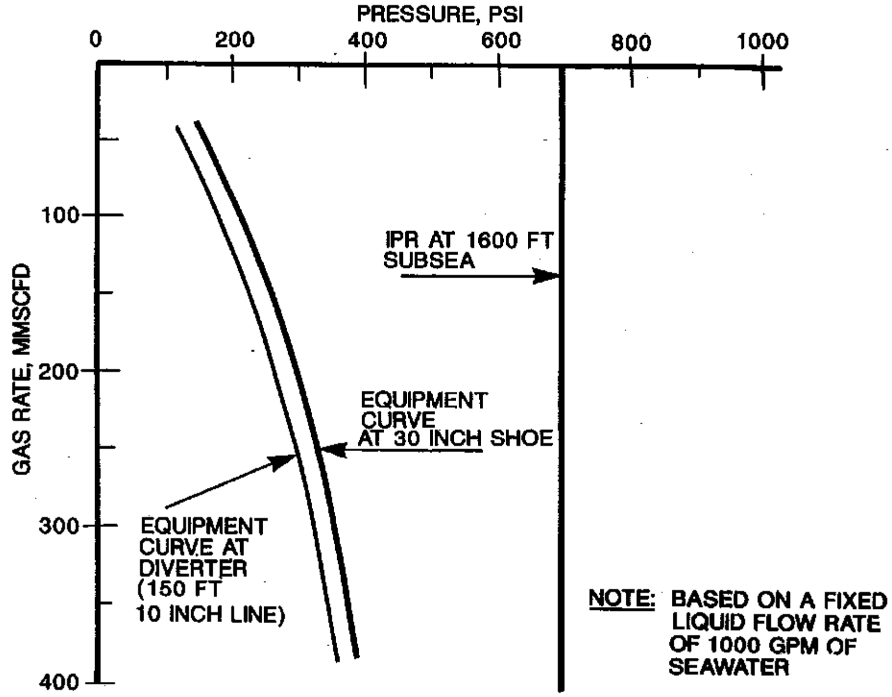


FIGURE A.21

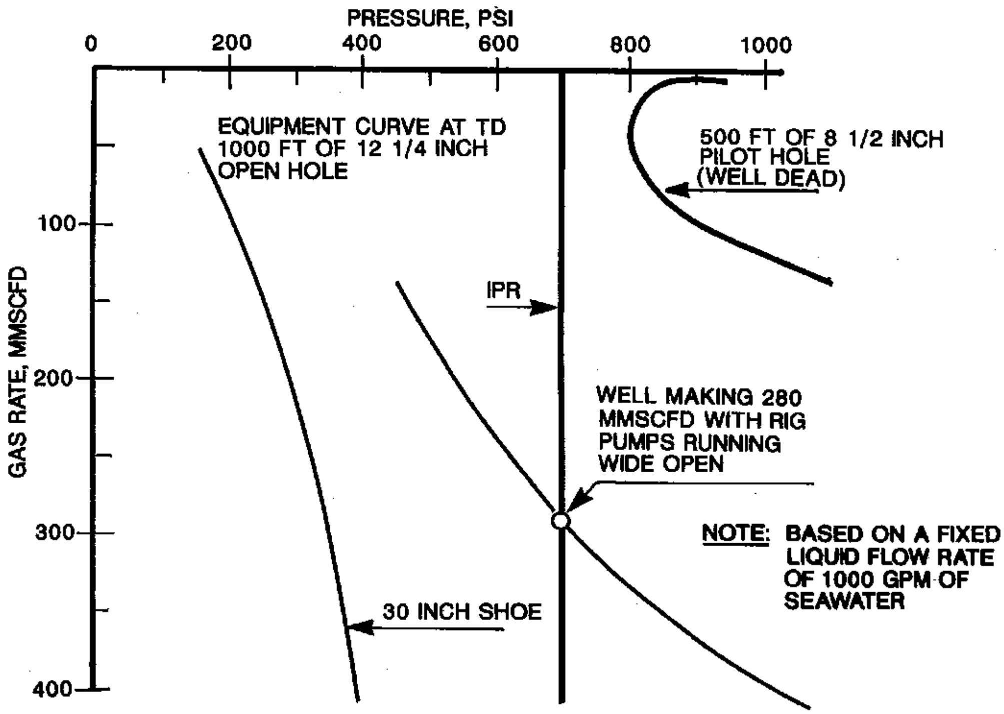


FIGURE A.22

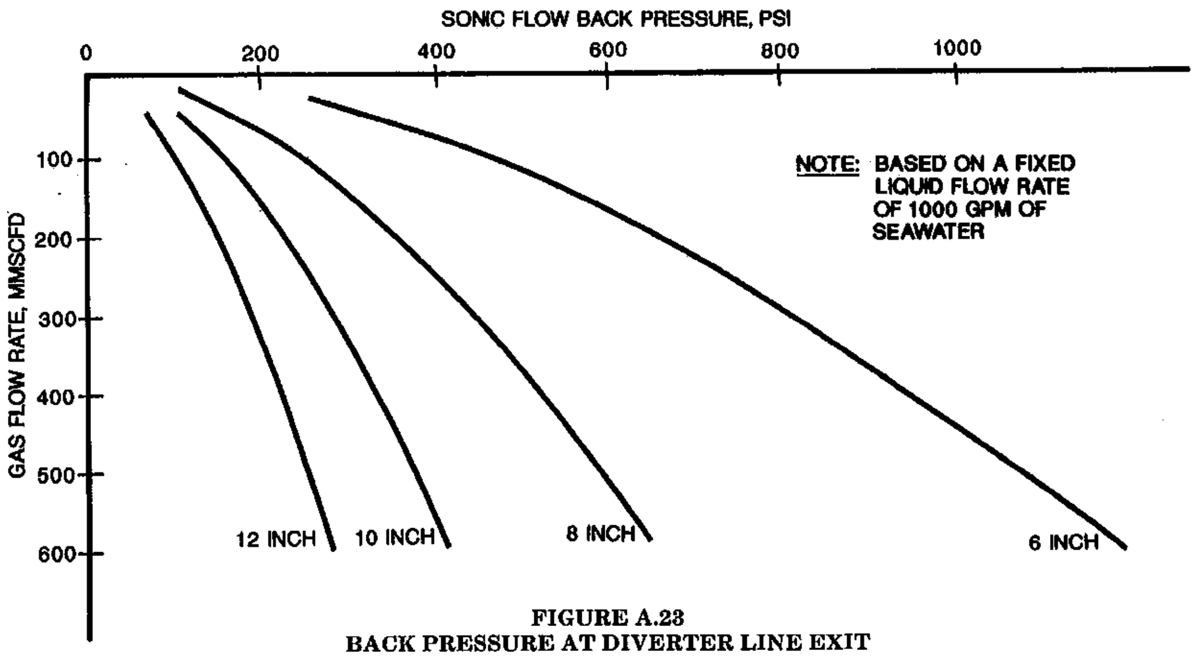


FIGURE A.23
BACK PRESSURE AT DIVERTER LINE EXIT DUE TO SONIC FLOW

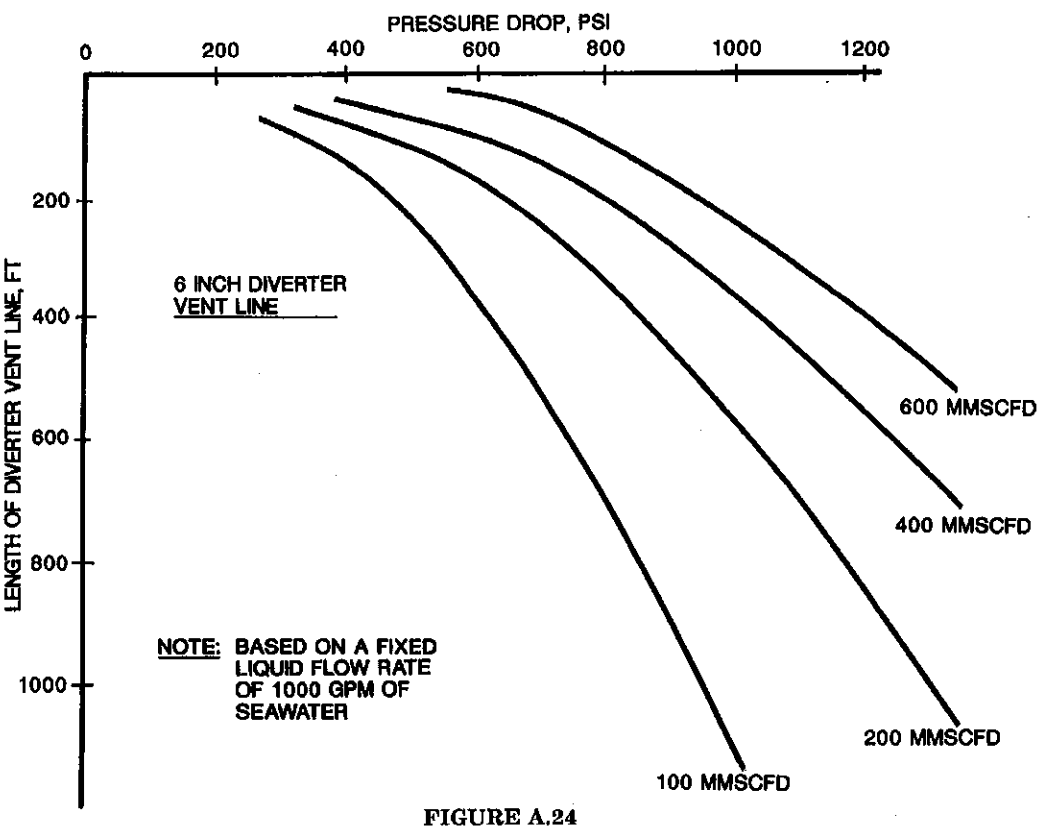


FIGURE A.24
FRICTIONAL PRESSURE DROP FOR 6 INCH OD DIVERTER LINE

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical length developed in accordance with discussion in Par. A.12.)

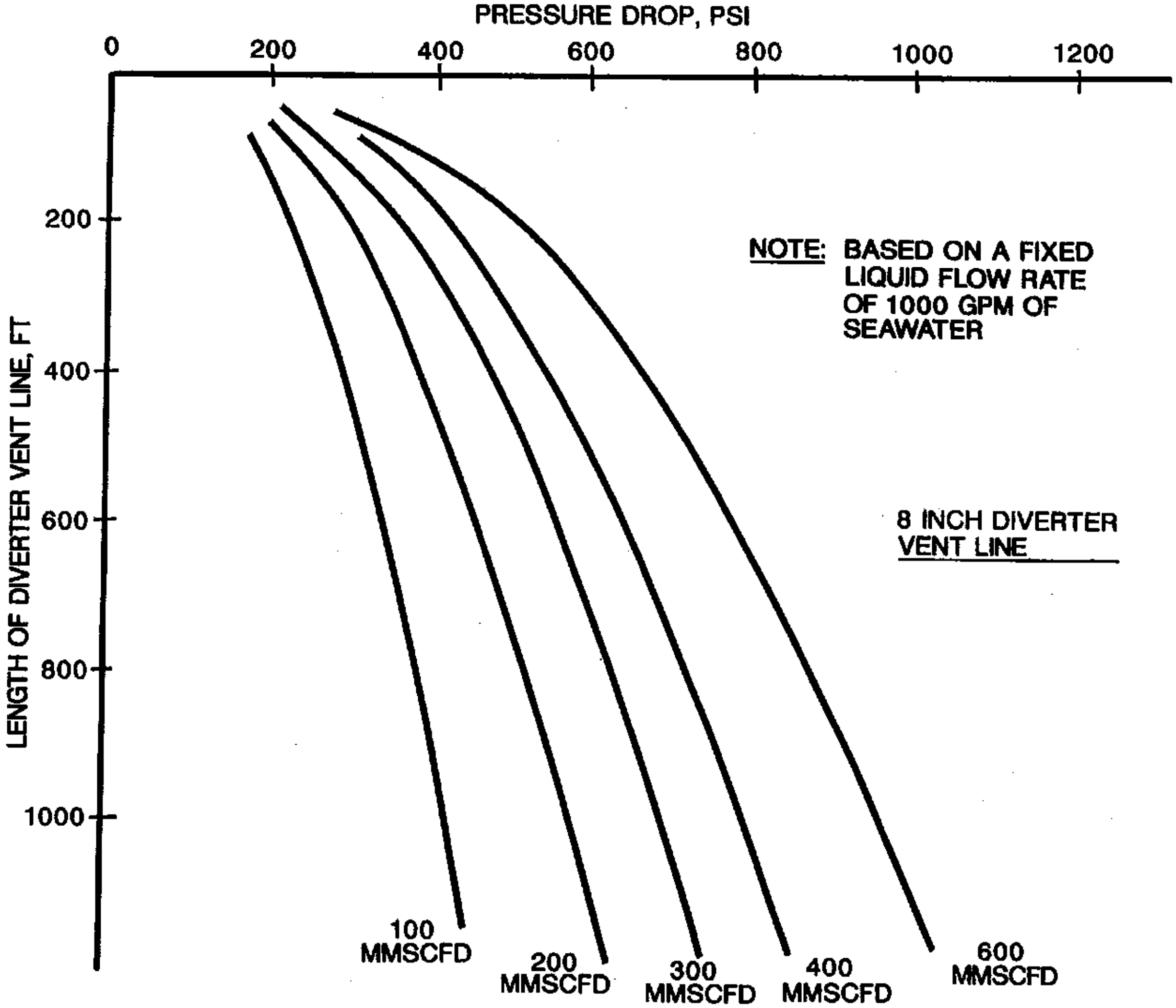


FIGURE A.25
FRICTIONAL PRESSURE DROP FOR
8 INCH OD DIVERTER LINE

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical length developed in accordance with discussion in Par. A.12.)

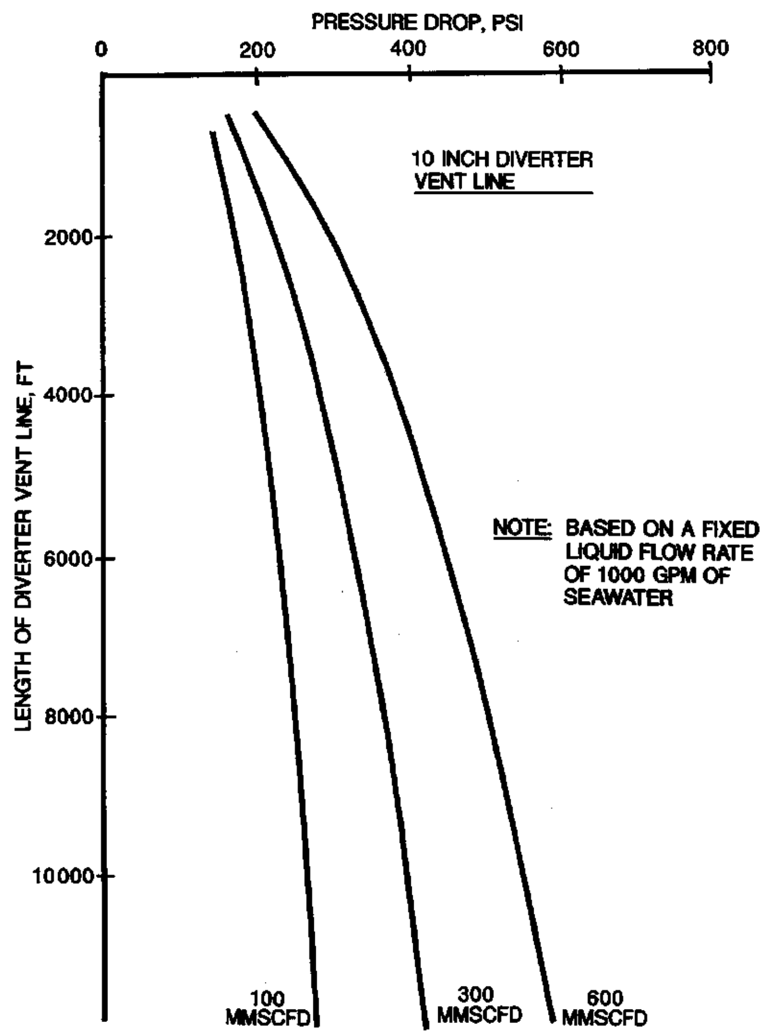


FIGURE A.26
FRICTIONAL PRESSURE DROP FOR
10 INCH OD DIVERTER LINE

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical length developed in accordance with discussion in Par. A.12.)

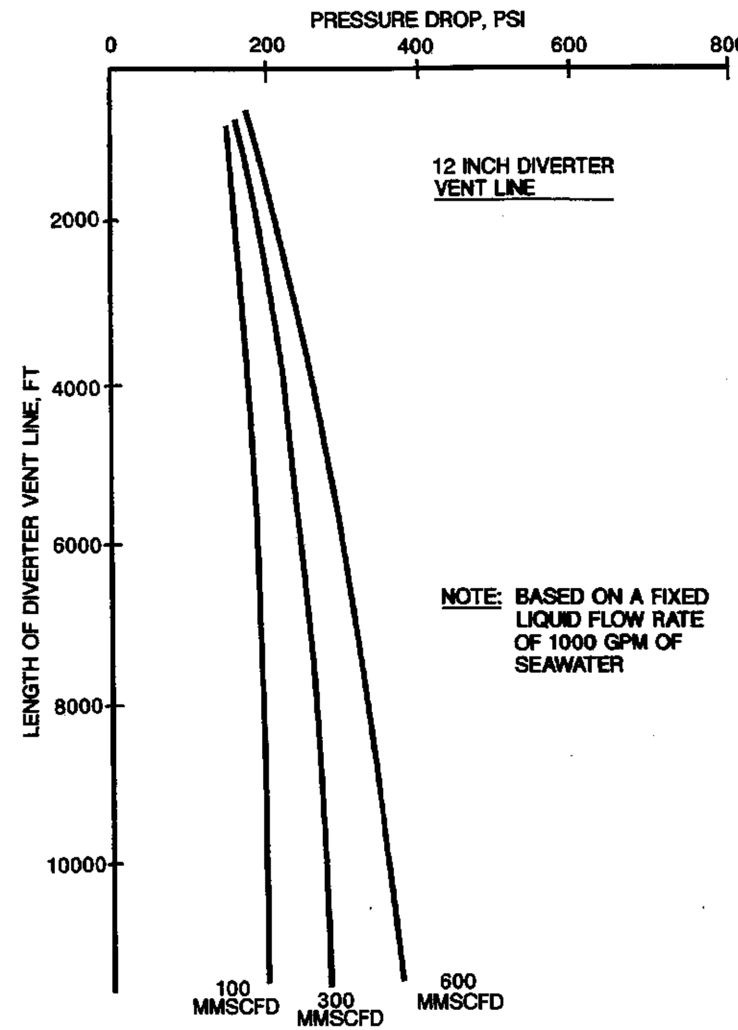


FIGURE A.27
FRICTIONAL PRESSURE DROP FOR
12 INCH OD DIVERTER LINE

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical length developed in accordance with discussion in Par. A.12.)

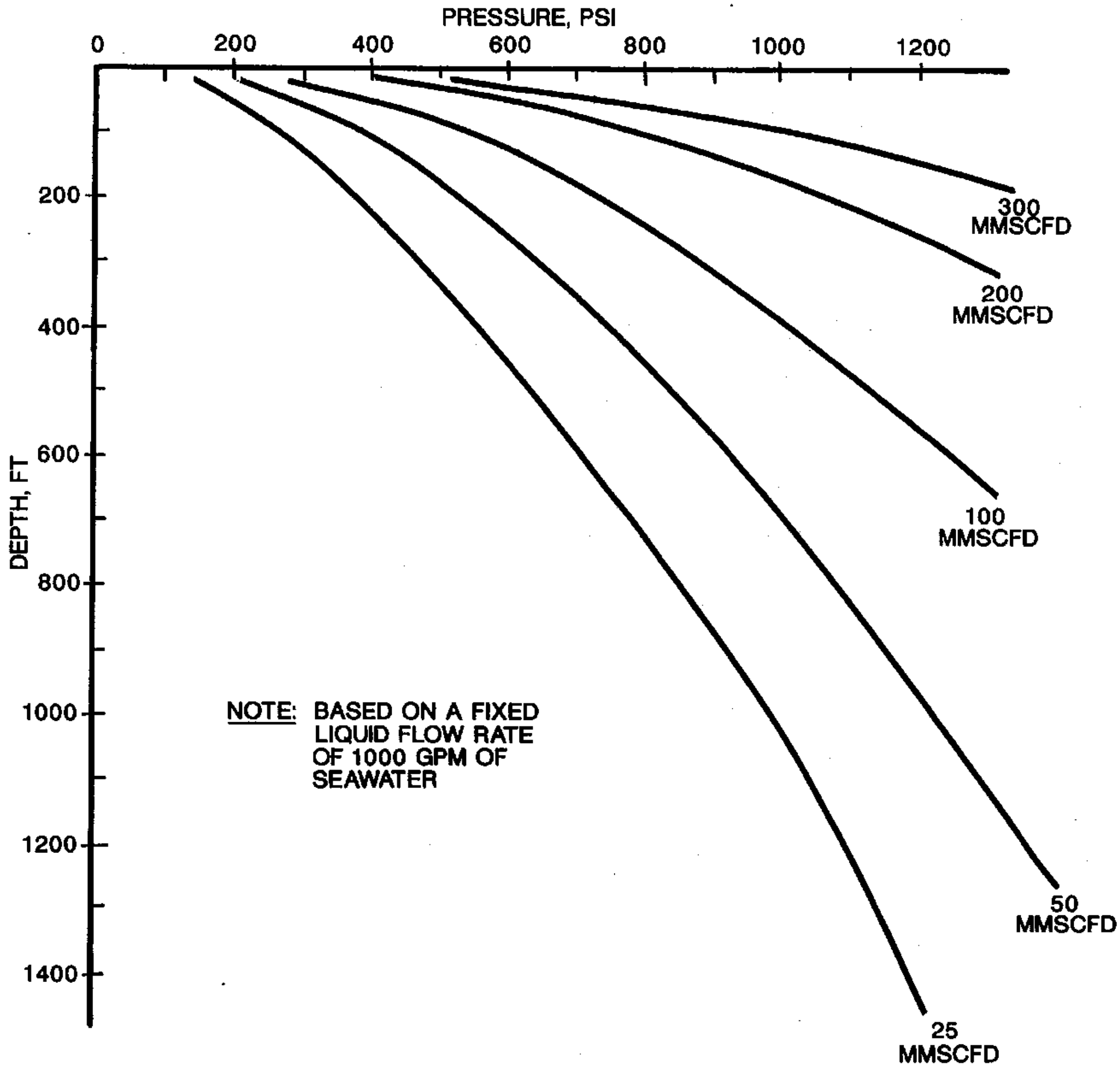


FIGURE A.28
TWO-PHASE VERTICAL PRESSURE TRAVERSE
(8½ INCH BOREHOLE x 6¾ INCH DRILL COLLARS)

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical depth developed in accordance with discussion in Par. A.12.)

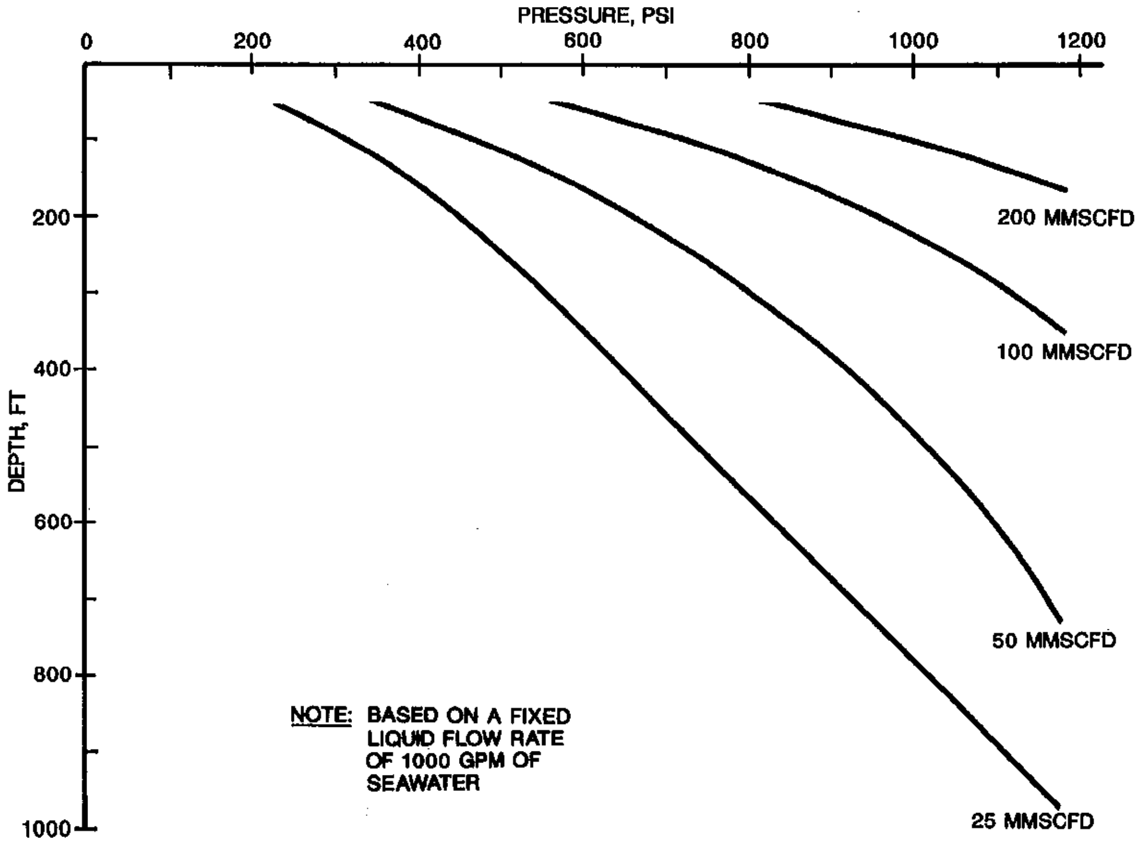


FIGURE A.29
VERTICAL TWO-PHASE FLOW PRESSURE TRAVERSE
(9⅞ INCH BOREHOLE x 8 INCH COLLARS)

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical depth developed in accordance with discussion in Par. A.12.)

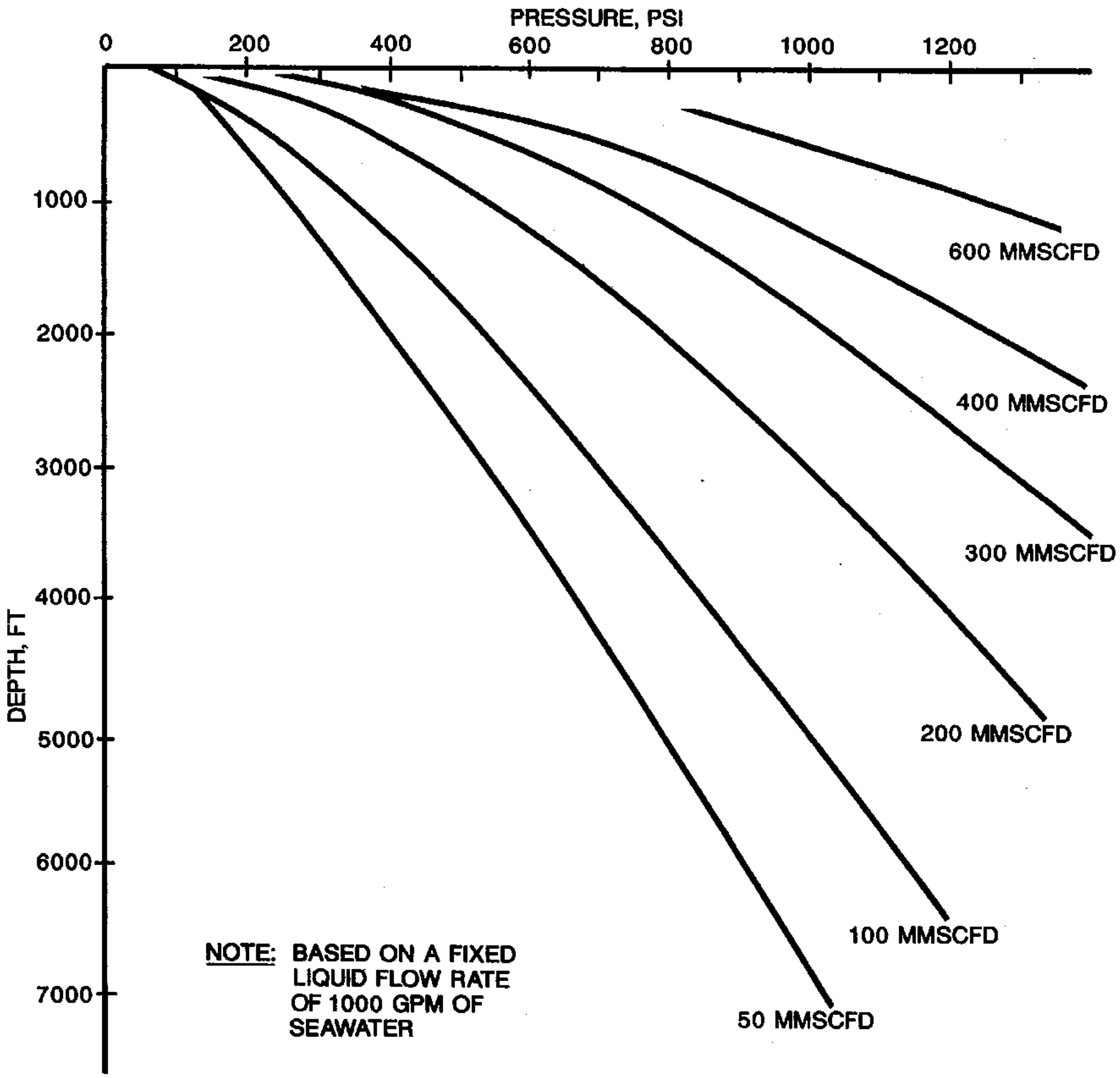


FIGURE A.30
VERTICAL TWO-PHASE PRESSURE TRAVERSE
(12¼ INCH BOREHOLE x 8½ INCH DRILL COLLARS)

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical depth developed in accordance with discussion in Par. A.12.)

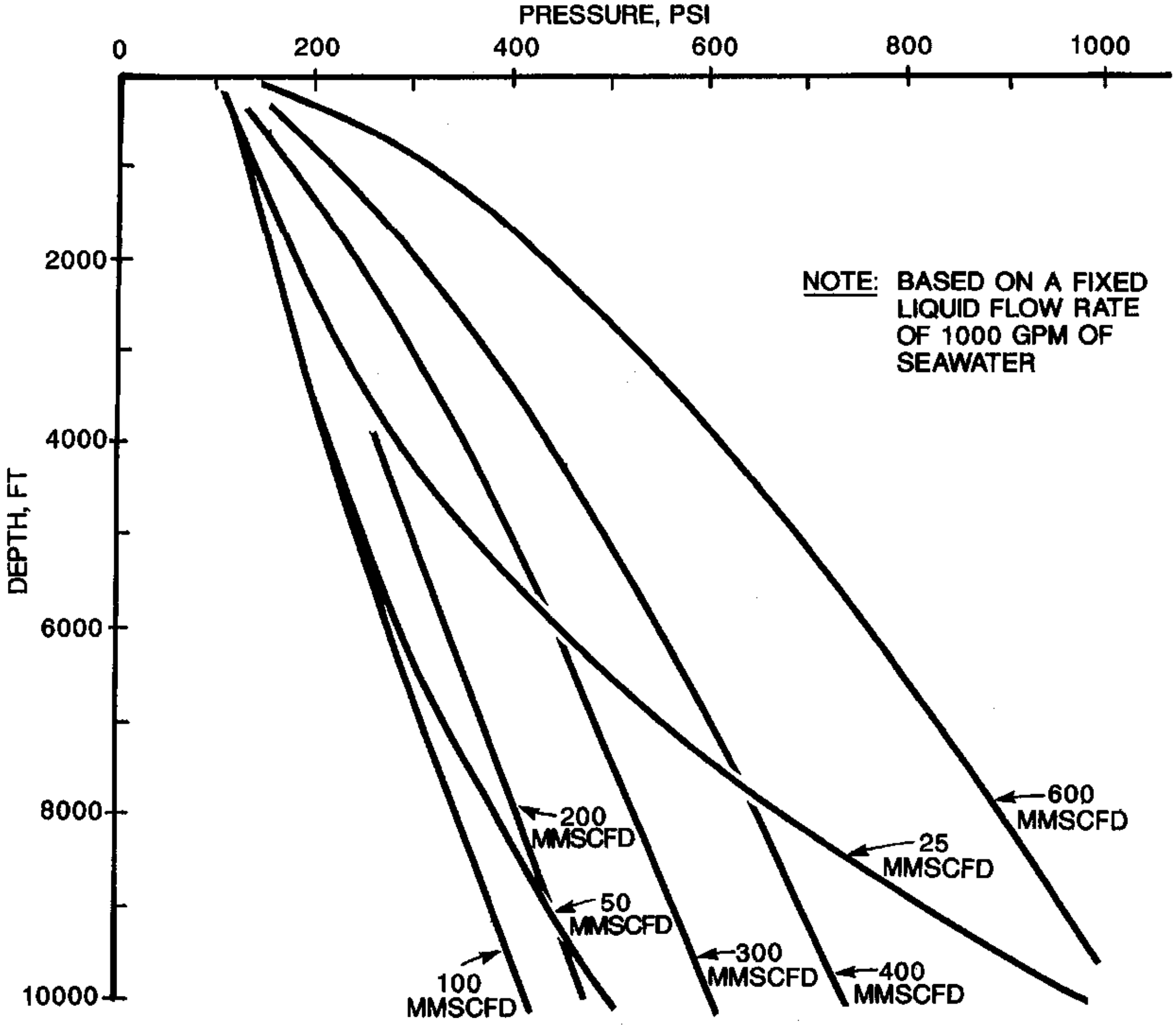


FIGURE A.31
TWO-PHASE VERTICAL PRESSURE TRAVERSES
(17½ INCH BOREHOLE x 8½ INCH DRILL COLLARS)

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical depth developed in accordance with discussion in Par. A.12.)

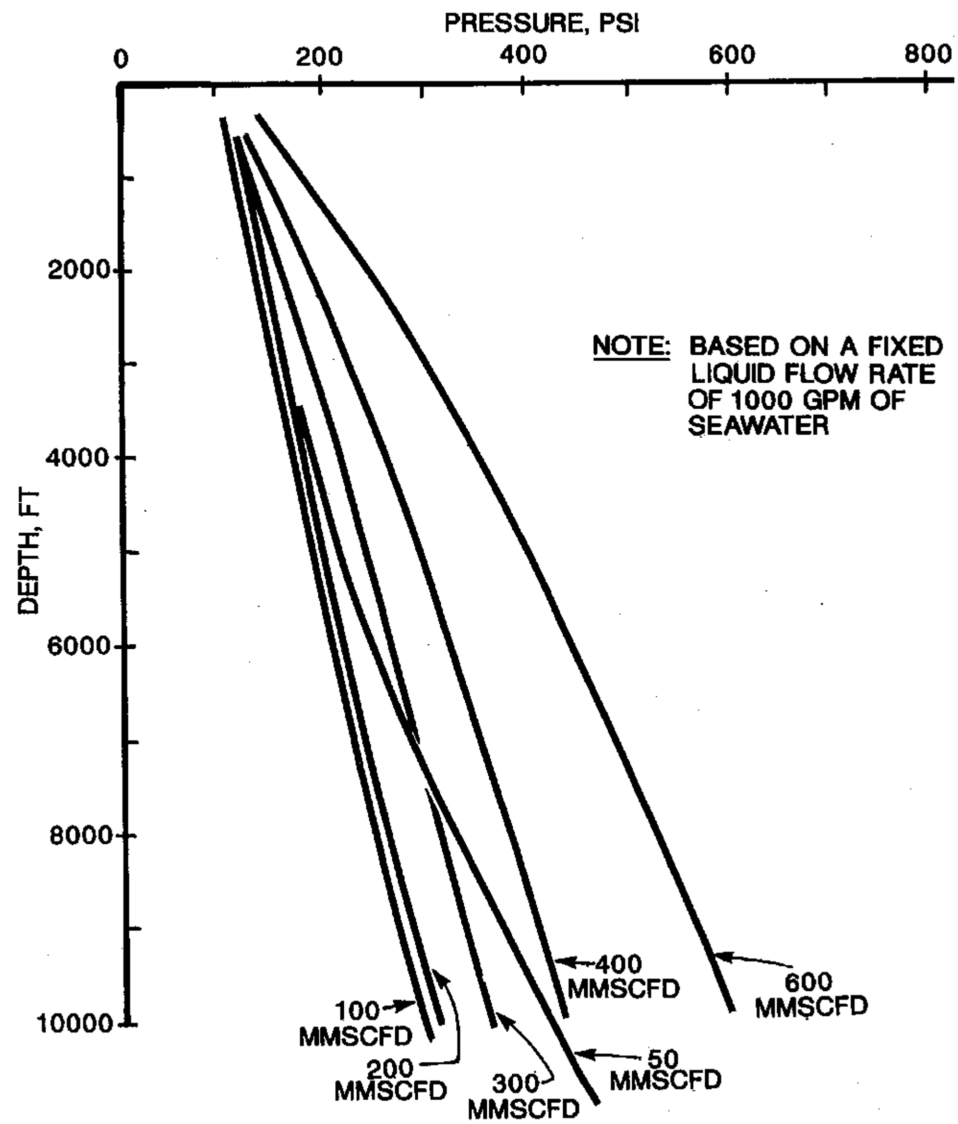


FIGURE A.32
TWO-PHASE VERTICAL PRESSURE TRAVERSES
(19½ INCH BOREHOLE x 5 INCH DRILL COLLARS)

(Refer to Gilbert[1] for detailed discussion on the development of this methodology. This is a theoretical depth developed in accordance with discussion in Par. A.12.)

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