Recommended Practice for Design and Operation of Subsea Production Systems

API RECOMMENDED PRACTICE 17A
SECOND EDITION, SEPTEMBER 1996

EFFECTIVE DATE: DECEMBER 1, 1996

American
Petroleum
Institute

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Exploration and Production Department

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Recommended Practice for Design and Operation of Subsea Production Systems

1 Scope

This recommended practice provides guidelines for the design, installation, operation, repair, and abandonment of subsea production systems. The elements of subsea production systems included (see Figure 1) are wellheads (both subsea and mudline casing suspension systems) and trees; pipelines and end connections; controls, control lines, and control fluids; templates and manifolds; and production risers (both rigid and flexible). Other sections of the recommended practice cover operations, quality assurance, materials, and corrosion. Specialized equipment such as split trees and trees and manifolds in atmospheric chambers are not specifically discussed because of their limited use. However, the information presented is applicable to those types of equipment. This document includes information on a wide range of equipment and operations to emphasize interrelationships and the need to consider subsea production installations as systems.

In planning a subsea production system, a systems approach should be used that considers installation, operation, maintenance, repair, and abandonment requirements. The system may range in complexity from a single satellite well with a flowline, to a fixed platform, to several wells on a template producing, to a floating facility. Produced and injected fluid characteristics, rates, and pressures; number of wells; environmental conditions; and the ultimate field development scheme must be determined before a detailed design can be undertaken.

The development and application of subsea production technology is accelerating at a rapid pace. In those areas where the committee felt that adequate information was available, specific recommendations are given. In other areas, general statements are used to indicate that consideration should be given to particular points. In many cases (particularly with control systems), there are a number of viable options, and operator preference governs the final selection of equipment or an operation. Those involved with subsea production systems are encouraged to utilize all of the new advances available and to suggest revisions or additions to this recommended practice. It is intended that the general statements contained herein will be eventually replaced by firm recommendations.

2 Referenced Standards

The following standards are referenced in part or in whole in this recommended practice. It is recognized that additional standards, specifications, guidance notes and recommended practices have been developed by other bodies. Therefore, this listing is representative and should not be considered as either all inclusive or exclusive of other standards relating to topics covered in this recommended practice.

Unless otherwise specified, the most recent editions or revisions of the following standards, codes, and specifications shall, to the extent specified herein, form a part of this standard.

API

RP 2A	*Planning, Designing, and Constructing Fixed Offshore Platforms*
BULL 2J	*Comparison of Marine Drilling Riser Analyses*
RP 2K	*Care and Use of Marine Drilling Risers*
RP 2Q	*Design and Operation of Marine Drilling Riser Systems*
RP 2R	*Design, Rating, and Testing of Marine Drilling Riser Couplings*
RP 2T	*Planning, Designing, and Constructing Tension Leg Platforms*
SPEC 5L	*Line Pipe*
RP 5L5	*Marine Transport of Line Pipe*
RP 5L6	*Transportation of Line Pipe on Inland Waterways*
SPEC 6A	*Wellhead Equipment*
RP 6G	*Through Flowline (TFL) Pump Down Systems*
SPEC 14D	*Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service*
RP 14H	*Use of Surface Safety Valves and Underwater Safety Valves Offshore*
RP 57	*Offshore Well Completion, Servicing, Workover, and Plug and Abandonment Operations*
RP 500B	*Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms*
STD 1104	*Welding Pipelines and Related Facilities*
RP 1110	*Pressure Testing of Liquid Petroleum Pipelines*
RP 1111	*Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines*
RP T-1	*Orientation Program for Personnel Going Offshore for the First Time.*
RP T-2	*Qualification Programs for Offshore Production Personnel Who Work With Anti-Pollution Safety Devices*
RP T-3	*Training and Qualification of Personnel in Well Control Equipment and Techniques for Drilling on Off-shore Locations*
BULL T-5	*Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations*

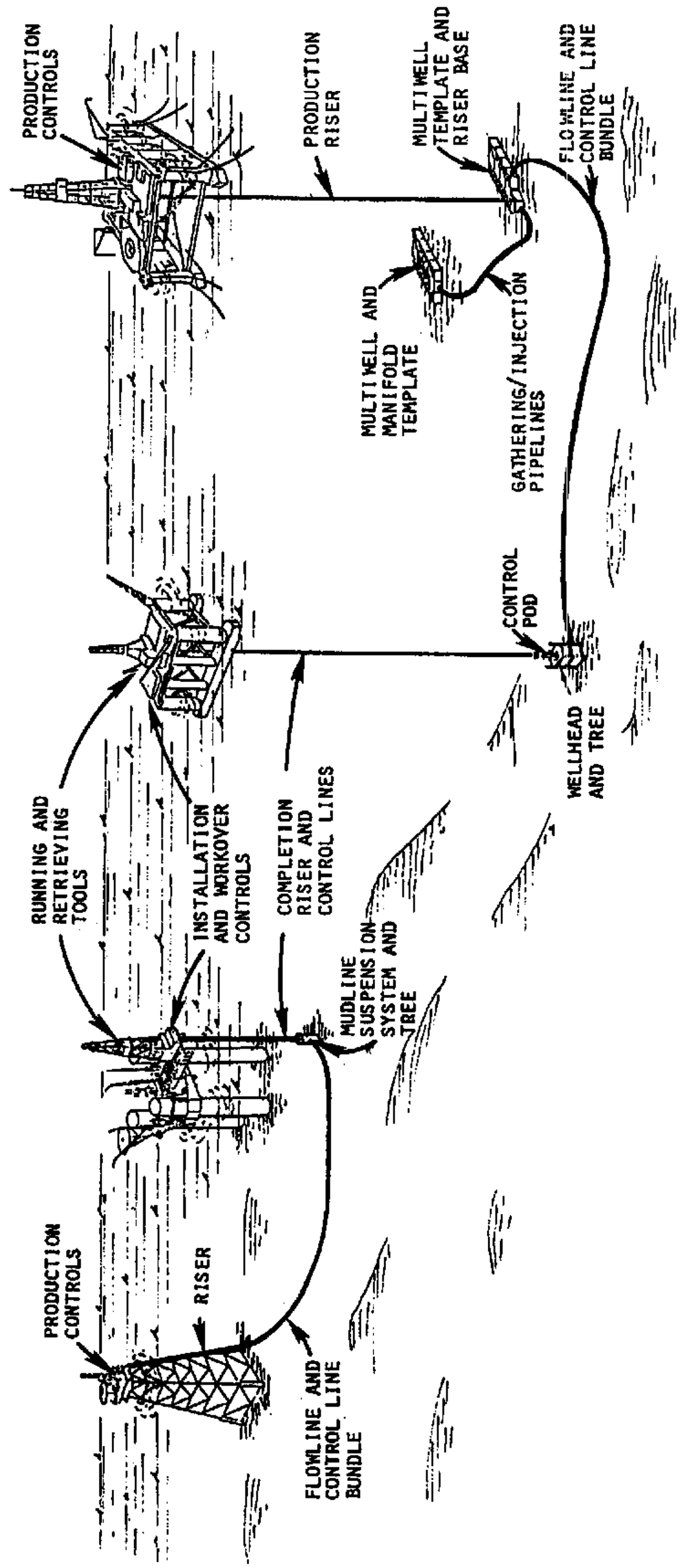


Figure 1—Subsea Production System Elements

ASME[1]

B 16.5	*Pipe Flanges and Flanged Fittings*
B 31.3	*Chemical Plant and Petroleum Refinery Piping*
B 31.4	*Liquid Petroleum Transportation Piping Systems*
B 31.8	*Gas Transmission and Distribution Piping System*

ANSI[2]

S 56-434	*Standard for Polyolifin Insulated Communication Cable for Outdoor Use*
S 66-524	*Cross-Linked Thermosetting Polyethylene Insulated Wire and Cable for Transmission and Distribution of Electrical Energy*

ASTM[3]

D 88	*Saybolt Viscosity, Test Method*
D 92	*Flash and Fire Points by Cleveland Open Cup, Test Method of*
D 341	*Vicosity Temperature Charts for Liquid Petroleum Products*
D 445	*Kinematic Viscosity of Transparent and Opaque Liquids (and the Calculation of Dynamic Vicosity)*
D 665	*Rust-Preventing Characteristics of Inhibited Mineral Oil in Presence of Water*
D 1293	*pH of Water, Test Methods*
D 1384	*Corrosion Test for Engine Coolants in Glassware, Method for*
D 1429	*Specific Gravity of Water and Brine, Test Methods of*
D 2161	*Conversion of Kinematic Vicosity to Saybolt Universal Viscosity or to Saybolt Furol Viscosity*
D 2670	*Measuring Wear Properties of Fluid Lubricants (Falex Pin and Vee Block Methods)*
D 2782	*Measurement of Extreme Pressure Properties of Lubricating Fluids*
D 3233	*Measurement of Extreme Pressure Properties of Fluid Lubricants (Falex Methods)*

NEMA[4]

S 19-81/ WC3	*Rubber Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy*
S 61-402	*Thermoplastic Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy*
S 68-516/ WC8	*Ethylene Propylene Rubber Insulated Wire and Cable for the Distribution of Electrical Energy*

NACE[5]

MR 01-75	*Sulfide Stress Cracking Resistant Metallic Material for Oilfield Equipment*
RP 01-75	*Control of Internal Corrosion in Steel Pipelines and Piping Systems*
RP 06-75	*Control of Corrosion on Offshore Steel Pipelines.*
RP 01-76	*Corrosion Control of Steel Fixed Offshore Platforms Associated With Petroleum Production*

SAE[6]

100R	*Hydraulic Hose and Hose Assemblies*
J343	*Tests and Procedures For SAE 100R Series Hydraulic Hose and Hose Assemblies*
J517	*Hydraulic Hose*

Environmental Protection Agency Federal Test Method No. 150.1

International Standards Organization 4406	*Solid Contaminant Code*
MIL-STD1246A	*Product Cleanliness Levels and Contamination Control Program*
National Aerospace Standard 1638	*Cleanliness Requirements of Parts Used in Hydraulic Systems*
British Standard 5540 Part 4	*Evaluation Particulate Contamination of Hydraulic Fluids*

3 Well Completion Equipment

3.1 SCOPE

This section describes the equipment and reviews the functional and design considerations for subsea well completion equipment. Typical designs and current industry practice are emphasized. Major topics include (a) subsea wellhead systems, (b) subsea tubing hanger/tree systems, and (c) subsea completions on mudline casing suspension equipment.

3.2 SUBSEA WELLHEAD SYSTEM

3.2.1 Subsea Wellhead System Description

The subsea wellhead performs the same general functions as a conventional surface wellhead. It supports and seals casing strings, as well as supporting the blowout preventer (BOP) stack during drilling and the tree after completion. The functional requirements are similar to comparable surface equipment, but the designs are very different because it is necessary to perform casing landing, sealing, and completion operations remotely from the surface.

A typical Subsea Wellhead System (see Figure 2) includes the following: (a) a temporary guide base which

[1]American Society of Mechanical Engineers, 345 East 47th Street, New York, NY, 10017.
[2]American National Standards Institute, 11 West 42nd Street, New York, NY 10036.
[3]American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103-1187.
[4]National Electrical Manufacturers Association, 1300 North 17th Street, Suite 1847, Rosslyn, VA 22209.
[5]National Association of Corrosion Engineers International, P.O. Box 218340, Houston, TX 77218-8340.
[6]Society of Automotive Engineers, (SAE International) 400 Commonwealth Drive, Warrendale, PA 15096-0001.

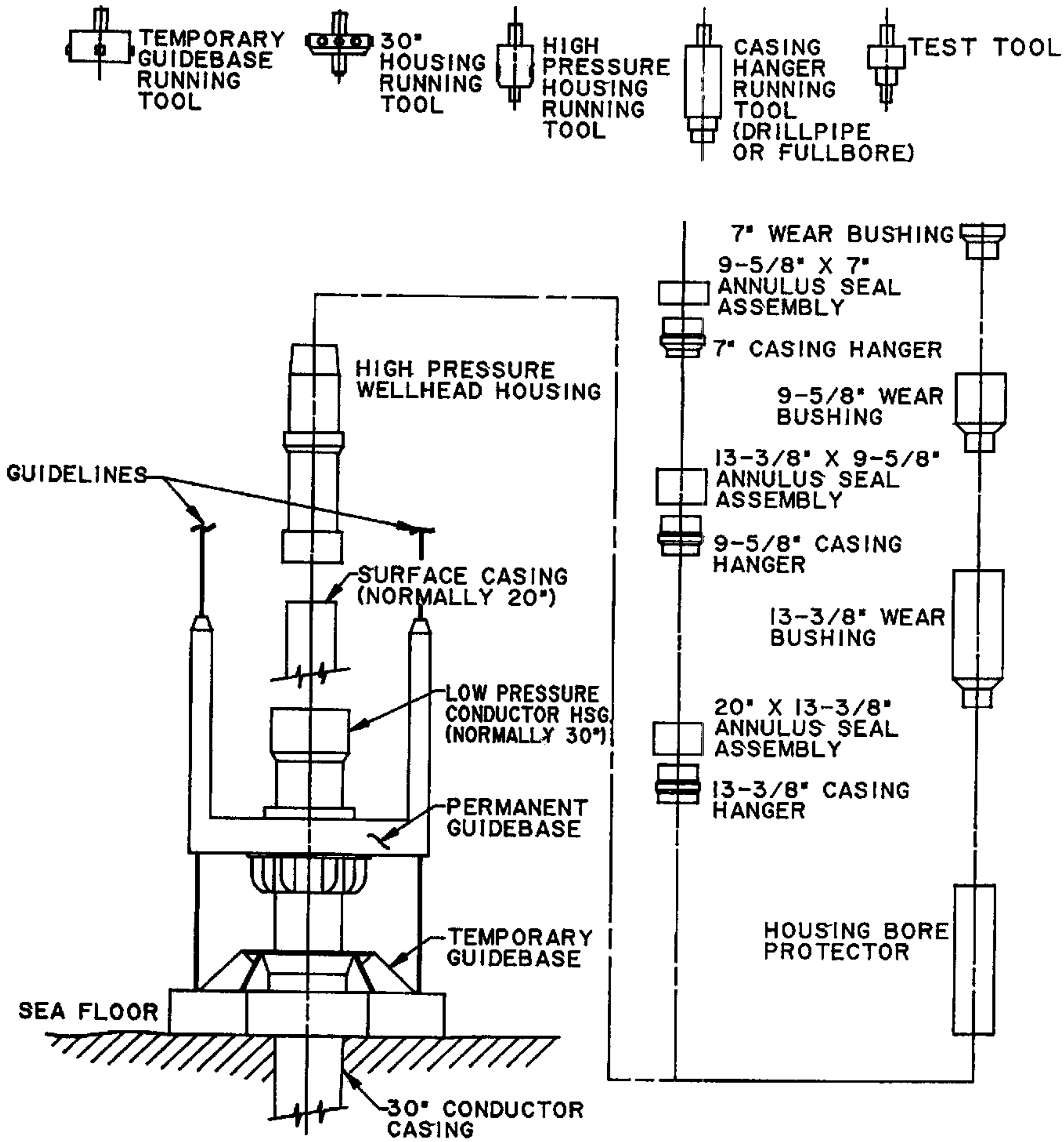


Figure 2—Subsea Wellhead System

attaches wire guidelines to the drilling vessel, allowing subsea re-entry to the well and providing guidance for subsequent components, (b) a conductor housing which is attached to the conductor casing and provides the installation point for the permanent guide base as well as a landing area for the wellhead housing, (c) a permanent guide base which provides positive guidance for the BOP stack during drilling and for the subsea tree during completion, (d) a wellhead housing which provides a landing area for all subsequent casing strings and a profile for attachment of the BOP stack or subsea tree, and (e) the casing hangers and seal assemblies which hang off casing strings and seal the annuli as additional casing strings are run.

3.2.2 Subsea Wellhead System Functional Considerations

3.2.2.1 The guidance of equipment to the ocean bottom from a floating vessel can be accomplished by two methods, the use of wire rope guidelines or guidelineless re-entry techniques. The guideline method uses tensioned wires and equipment-mounted guide sleeves to orient and guide the equipment from the vessel to the seafloor. The guidelineless method typically uses a dynamic position reference system to indicate relative position between the landing point and subsea equipment. The subsea equipment is maneuvered, normally by moving the surface vessel until it is indicated that the equipment is positioned over the landing point. Then the equipment is lowered to the landing point and brought into final position mechanically. Note the following guide bases:

a. Temporary guide base: The temporary guide base provides a guide template for drilling the conductor hole and stabbing the conductor pipe. It compensates for misalignment from irregular ocean bottom conditions and provides a support base for the permanent guide base. For guideline systems, it also establishes the initial anchor point for the guidelines.

b. Permanent guide base: The permanent guide base provides entry into the well prior to BOP installation and also gives guidance for running the subsea BOP stack or tree. It establishes structural support and final alignment for the wellhead system and provides a seat and lock down for the conductor housing. Optionally, it may include provisions for retrieval and to react flowline loads.

Standard permanent guide base dimensions for a guideline system are shown in Figure 3. Permanent guide bases are frequently installed such that the top of the wellhead is 6 to 10 feet above the ocean bottom. This height allows drilling spoil and cement returns to spill onto the ocean floor without interfering with the guidance and installation of subsea equipment.

3.2.2.2 Housings are as follows:

a. Conductor housing: the conductor housing attaches to the top of the conductor casing to form the basic foundation of a subsea well. Extensions of a suitable length and wall section may be used below the conductor housing. The housing typically has a means of attaching to the permanent guide base which prevents rotation of the permanent guide base with respect to the housing.

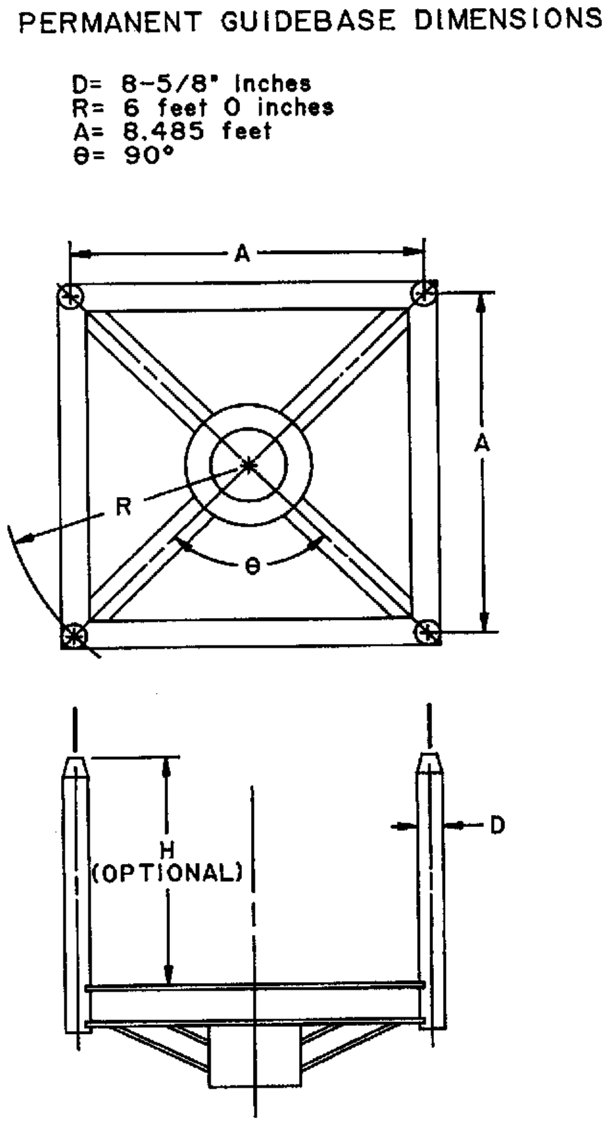


Figure 3—Permanent Guidebase

A typical conductor housing profile is shown in Figure 4. The internal profile of the conductor housing includes a landing shoulder suitable for supporting the wellhead housing and the loads imposed during the drilling operation. Running tool preparations should also be a part of the internal housing profile. Cement return passage ways may be incorporated in the conductor housing/permanent guide base assembly to allow cement and mud returns to be directed below the permanent guide base.

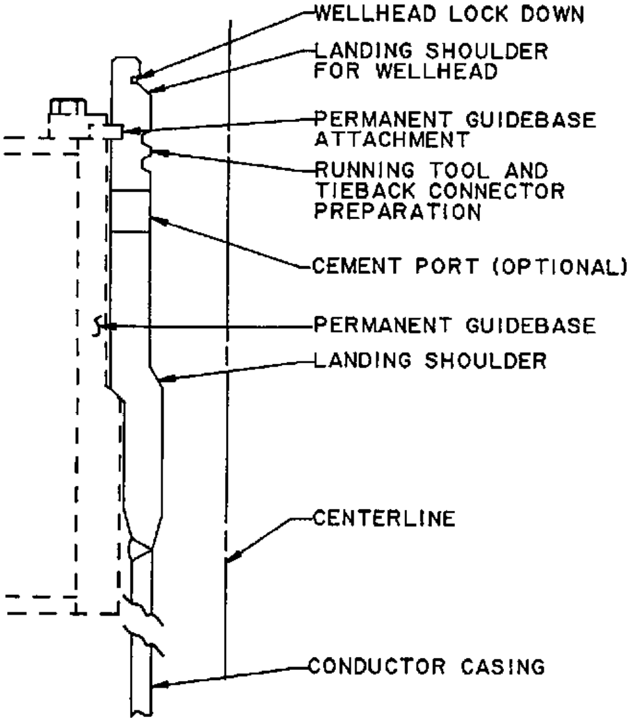


Figure 4—Conductor Housing

b. Wellhead housing: the wellhead housing lands inside the conductor housing. It provides pressure integrity for the well, suspends the surface and subsequent casing strings and reacts external loads. The BOP stack or tree attaches to the top of the wellhead housing using a compatible wellhead connector. The most common system sizes are given in Table 1. Figure 5 shows two profiles of typical wellhead housings.

3.2.2.3 Note the following concerning casing hangers and annulus seal assemblies: As shown in Figure 1, a subsea casing hanger is installed on top of each casing string and supports the string when landed in the wellhead housing. Annulus seal assemblies provide isolation between each casing hanger and the wellhead housing. Note the following:

a. Casing hangers: subsea casing hangers are configured to run through the drilling riser and subsea BOP stack, land in the subsea wellhead, and support the required casing load. They must provide for an annulus seal assembly, support loads generated by BOP test pressures above the hanger, and receive the next casing string. Subsea casing hangers have a profile to accommodate a running tool and will meet or exceed the drift diameter of casing being suspended. A landing shoulder is included to transfer casing load and test pressure load to the wellhead housing.

A lockdown mechanism is recommended to prevent movement of the casing hanger due to thermal expansion or annulus pressure when the well is put on production. An external flowby area allows for returns to flow past the hanger during cementing operations and is designed to minimize pressure drop, while passing as large a particle size as possible. The bottom of the casing hanger is a threaded box-casing connection. A pup joint of casing should be installed on the hanger in the shop. This reduces the risk of damage during handling.

Table 1—Wellhead Systems Common Sizes and Types

Nominal System Designation	BOP Stack Configuration	High Pressure Housing Working Presure (psi)
18 3/4-10m	Single	10,000
18 3/4-15m	Single	15,000
16 3/4-5m	Single	5,000
16 3/4-10m	Single	10,000
21 1/4-2m x 13 5/8-10m	Dual	10,000
21 1/4-5m x 13 5/8-15m	Dual	15,000
18 3/4-5m x 13 5/8-15m	Dual	15,000
16 3/4-10m x 11-15m	Dual	15,000

Notes: Other sizes and pressure ratings are available for special applications.

b. Annulus seal assemblies: these seal working pressure from above and formation pressure from below for the life of the well. They may be run simultaneously with the subsea casing hanger, or separately. Annulus seal assemblies are actuated by various methods, including torque, weight, and hydraulic pressure.

c. Running and retrieving tools: casing hanger and annulus seal assembly running and retrieving tools are used to lower the subsea casing hanger and/or seal assembly into the subsea wellhead housing. For running casing, they provide a sealed conduit to displace cement down the running string and pass returns through the subsea hanger then back up the annulus. When running seals, the tools energize the annulus seal assembly between the casing hanger and the wellhead housing, and allow for testing the seal to full-rated working pressure. All running tools must be compatible with the running string tensile load, cementing practices, and internal pressure rating for the casing string being run.

3.2.2.4 Note the following concerning bore protectors and wear bushings: a bore protector protects all annular sealing surfaces inside the wellhead housing before casing hangers are installed. After a casing hanger is run, a wear bushing of corresponding size is installed to protect the remaining annular sealing surfaces and the previously installed annular seal assemblies and casing hangers (see Figure 2). Bore protectors and wear bushings are capable of being restrained or locked in place. They are generally not pressure-containing devices and do not have a pressure rating. However, wear bushings may be designed to react BOP stack pressure test loading.

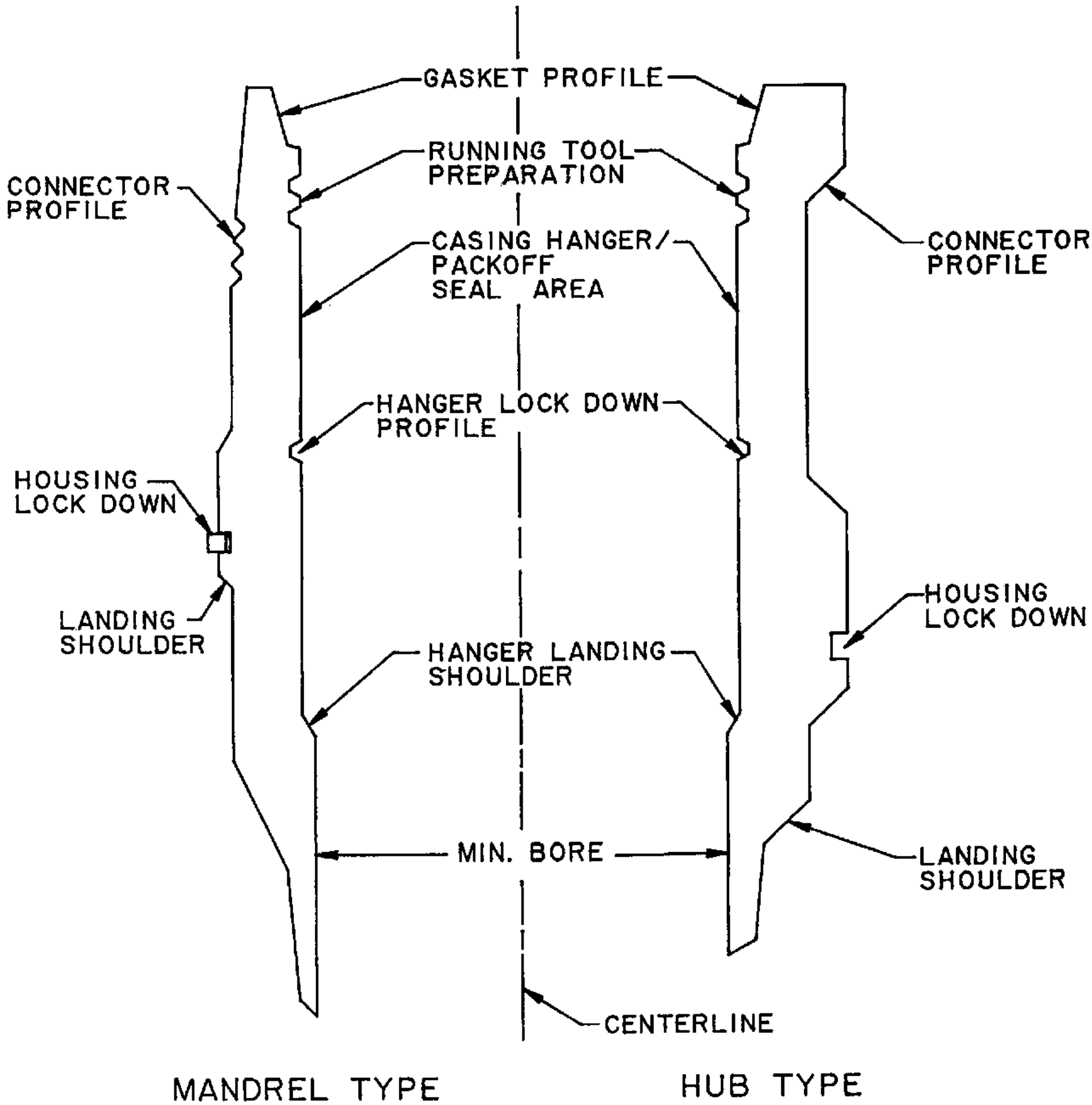


Figure 5—Wellhead Housings

3.2.2.5 A subsea BOP test tool is required to periodically verify pressure integrity of the BOP stack.

3.2.2.6 The function of the protective cap is to protect the subsea wellhead from contamination by debris, marine growth, and corrosion. These caps usually are nonpressure containing and lock into the external profile of the wellhead housing. If a pressure-containing cap is utilized, provision should be made for sensing and relieving pressure. The cap is installed just prior to temporary abandonment of a well.

3.2.3 Subsea Wellhead System Design Considerations

3.2.3.1 Structural integrity: the wellhead system is the structural foundation for a subsea completion. It must transfer applied loads to the casing strings and into the surrounding soil. Depending on the configuration of the production system, the environmental conditions and soil conditions, the loads applied to the wellhead system may vary significantly. Structural integrity should be evaluated for maximum load conditions considering all drilling and production operations, as follows:

a. Geotechnical investigation: the starting point for an investigation of structural integrity is a geotechnical investigation of the intended location. If data is not available, a shallow hazard survey and/or soil borings will provide soil data near the seabed. If a planned well-site is in an area that is subject to massive soil movements, special soil borings will be required to assess the extent of the geohazard. API Recommended Practice 2A provides more information on soil sampling techniques.

b. External loading: loads on a subsea wellhead system may include component dead loads, riser tension, flowline pull-in loads, thermal growth, and direct environmental action. Typical loading conditions are shown in Figure 6.

Applied riser loads are generally the largest loads considered. Bottom riser tension acting through an angle induces tension, bending moment, and shear. Increasing the height of the subsea equipment increases this bending moment. These loads should be determined by performing a riser analysis. This type of analysis is especially important for floating drilling vessels. Further guidance may be obtained from API Recommended Practice 2Q. Fatigue analysis may also be required when variable loading conditions exist (such as riser vibration due to high current).

Flowline pull-in loads can induce significant shear and bending moments on the wellhead. Consideration must also be given to the effects of thermal growth in the well tubulars and attached flowlines.

Although a subsea completion is usually removed from surface storm effects, it may be subject to some direct environmental loads. These may include current, wave action, earthquakes, ice, and soil movements. Dropped objects and snag loads from anchors or trawls may also be a concern for some specific applications.

c. Structural analysis: the soils data, external loads and reactions are used as input for a structural analysis of the subsea wellhead system. This structural evaluation assures that all components, as well as the foundation, will retain structural integrity under all load situations (drilling, completion, operation, and workover). API Recommended Practice 2A (Section 3.6) contains a discussion of methods available for this type of soil-structure analysis.

3.2.3.2 Pressure rating: subsea wellhead systems are designed to a specific maximum working pressure. The design of the subsea wellhead housing is such that the BOP stack or tree is usually attached directly to the housing. Therefore, the housing must be designed to the maximum pressures anticipated for the life of the well, including shut-in pressure and pressure during well kill, stimulation, or injection operations.

The environment of the equipment should be considered when determining pressure ratings. In deep water situations, the hydrostatic head of water outside the equipment may be such that the differential pressure the equipment must withstand is substantially less than might exist at surface conditions. Subsea wellhead systems commonly being manufactured are rated to working pressures of 5,000, 10,000 and 15,000 psi (see Table 1).

3.2.3.3 Size and compatibility: subsea wellhead systems are not presently standardized, and components generally are not interchangeable among manufacturers. The size of a subsea wellhead housing must be compatible with the size of BOP and the number and size of subsequent casing strings, including production casing and the tubing hanger. The top profile of the wellhead housing must match the BOP hydraulic connector. All assemblies that are run into or out of the wellbore should be configured to allow smooth passage through the riser and BOP.

3.2.3.4 Service: subsea wellhead systems should be compatible with the type of service anticipated after completion as a subsea well. Consideration must be given to produced fluid temperature and the presence of carbon dioxide, hydrogen sulfide, or chlorides, all of which may contribute to weight loss corrosion or stress-cracking failures.

Metallic gasket material should conform to the material and hardness requirements given in API Specification 6A. The gasket grooves or profiles should be inlaid with corrosion resistant alloy as specified in API Specification 6A. Special consideration should be given to elastomeric or other seals used in the wellhead system.

The selection of materials and manufacturing processes to provide proper corrosion protection should be made prior to drilling the well to insure that appropriate components are utilized. Additional information for design of components to be used in an H_2S environment can be found in NACE MR 01-75.

3.2.3.5 In addition to specific requirements for its job, each running tool design should meet these basic guidelines: (a) adequate flowby area around or through the tool, (b) sufficient length on the OD to prevent a hang up in a BOP ram cavity, (c) resistance to drilling mud and cuttings, (d) shouldered connections for tools required to rotate, (e) running protection for seals located on the OD, and 6) be able to be stripped down and redressed on the rig.

3.2.3.6 Completing exploratory wells: in some cases, subsea completions are made on wells originally drilled as expendable evaluation wells. The considerations in this document should be applied to such wells, and potential problem areas identified. The wellhead system should be inspected to insure that damage has not occurred since the well was suspended. Some particular areas to be investigated prior to making a decision to complete exploratory wells are (a) height of the wellhead above mudline, (b) setting of casing hangers at proper locations within the well-

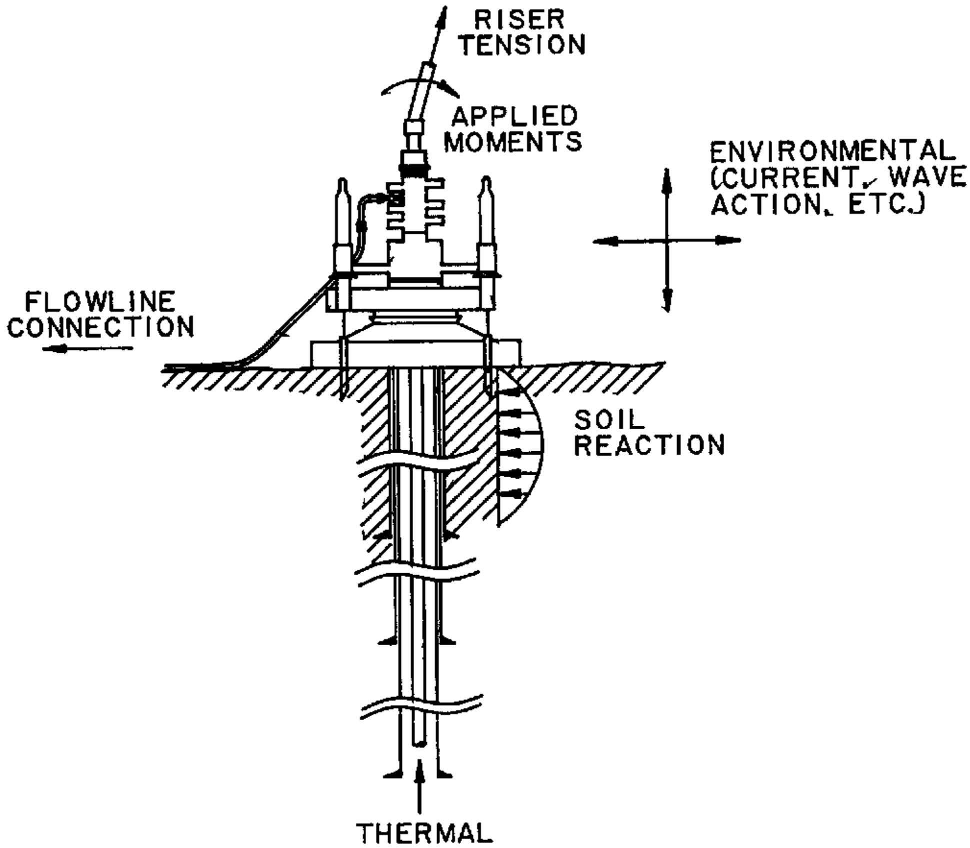


Figure 6—Loads and Reactions for a Subsea Completion

head housing, (c) insuring that casing hanger seal assemblies have been properly set and tested, (d) condition of the permanent guide base, (e) condition of the latching profile and seal area of the wellhead housing, and (f) a detailed review of the well history to determine other possible problem areas.

3.3 SUBSEA TUBING HANGER/TREE SYSTEM

3.3.1 Subsea Tubing Hanger/Tree System Description

The equipment required to complete a subsea well for production or injection includes a tubing hanger system and a tree. The subsea tubing hanger system supports the tubing inside the wellhead and seals off the tubing/production casing annulus. The tree consists of an arrangement of remotely controlled valves to interrupt or direct flow when necessary for operational or safety reasons. It performs much the same as a surface tree but must be designed for remote control and underwater service. There are two categories of subsea trees, through flowline (TFL) trees designed for the use of pump down tools in well bore maintenance and non-through flowline (Non-TFL) trees which require wire line operations for well bore maintenance. Either TFL or non-TFL trees may be configured for maintenance by divers or, alternatively, for diverless intervention.

3.3.2 Tubing Hanger/Tree System Functional Considerations

3.3.2.1 The tubing hanger must provide structural support for the tubing and assure pressure integrity between the tubing and the tree. Ports for control lines to downhole safety valves and other wellbore sensors must be included. If vertical access to the annulus is needed, or the completion has multiple tubing strings, the tubing hanger will have multiple pipe bores, and it must be properly oriented to match the tree. For single completions, where vertical annulus access is not required, a concentric tubing hanger can be used without orientation. A typical installation is shown in Figure 7.

3.3.2.2 A tubing hanger spool may be used to provide a wellhead profile and tubing hanger receptacle if no space exists in the wellhead housing for landing a tubing hanger or if the bore is damaged. This assembly connects to the wellhead housing and restores or converts an existing system to one suitable for subsea completion. The tubing

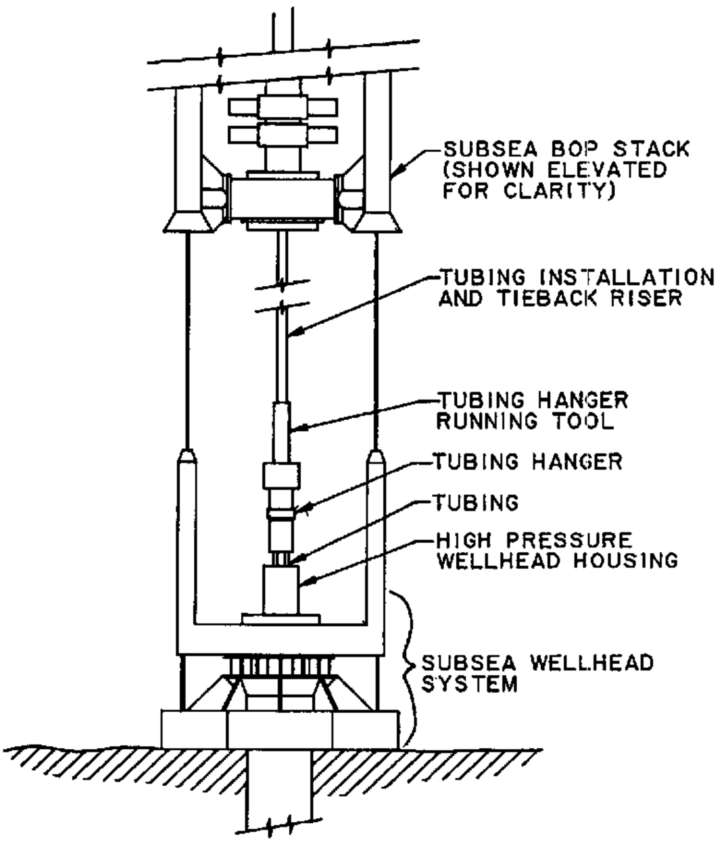


Figure 7—Tubing Hangar Installation

hanger spool may also be utilized to convert from one wellhead size and/or type to another.

3.3.2.3 A typical non-TFL subsea tree is illustrated in Figure 8. A tree designed for TFL service is shown in Figure 9. The following is a list of tree components:

a. Tree connector: the tree connector must provide a mechanical and pressure connection between the tree assembly and the wellhead. The connector must be compatible with the mating profile and seal preparation on the wellhead. There are basically two connector configurations, hydraulic and manual. They can be used for either diverless or diver-assist installations.

b. Tree bore extension subs: extension subs make a connection between the tubing hanger and the tree. They provide communication for the tubing and annulus bores, downhole safety valve control lines, and downhole monitoring devices.

c. Tree valves: reference may be made to API Specification 6A for general background and terminology. The tree consists of master valves, wing valves, swab valves, and crossover valves for both the tubing and annulus bores. The arrangement of these valves, the type of valves, and the use of wing valves, crossover valves and swab valves depends on the intended application. The valves may have flanged, clamp hub, or welded end connections, or they may be built in a single valve block. Additional information on valves and actuators may be found in API Specification 14D and API Recommended Practice 14H.

d. Wye spool: Used on TFL trees, it provides a transitional path between the flowlines and the tree bores for through-flowline tools. It is located between the master valves and the swab and wing valves. Diverters within the wye spool may be manually installed while the installation/workover riser is in place, hydraulically or electrically operated, or detented to the last position used to enter the wellbore. Additional information can be found in API Recommended Practice 6G.

e. Seal subs: these are used to isolate individual bores within tree assembly connections.

f. Tree loops: these loops provide fluid paths between the bores of the tree and the flowline connection point. When used for TFL applications, they must be built with a large radius (per API Recommended Practice 6G) to accommodate pumpdown tools.

g. Upper tree termination: the top of the tree should be provided with a connection to allow vertical access through the

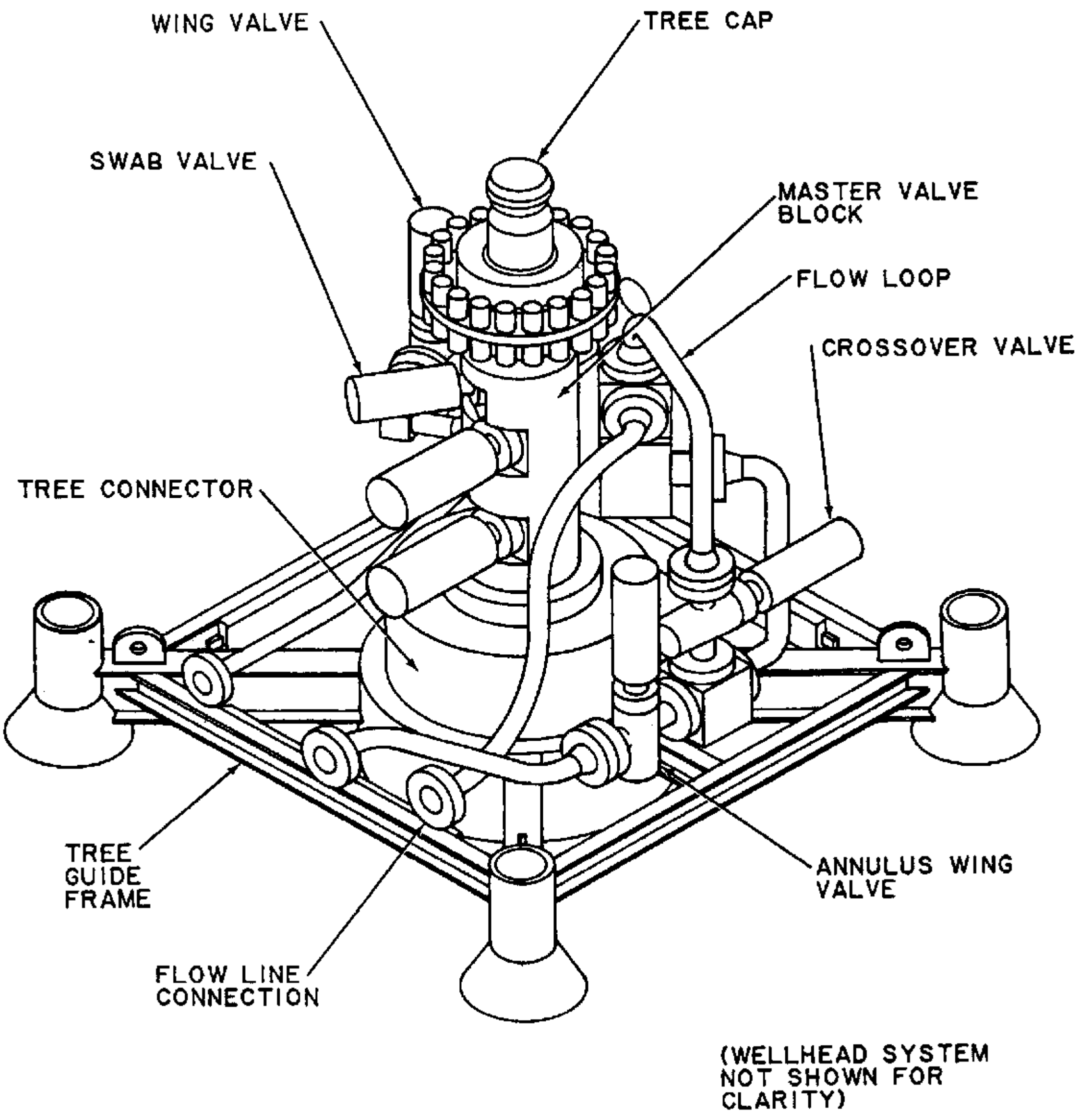


Figure 8—Non-TFL Tree

tree and handling during running operations. Individual seal areas should be provided for isolation of the bores. The upper tree connection must withstand installation, well service, or workover loads from a workover riser and wireline BOP. This component may contain an area for pressure-retaining devices, such as plugs, and interface connections for hydraulic control lines.

h. Tree caps: they prevent marine growth on the upper tree connection area and sealing bores and may be either pressure containing or non-pressure containing. Pressure containing caps provide an additional environmental seal above the swab valves and/or wireline plugs, and should contain a provision for monitoring and for relieving trapped pressure before removal. The tree cap may be combined with the control components to form an integral part of the tree control system.

i. Flowline connection: it joins the integral piping of the tree with the subsea flowline. The various alternatives for this type of connection are discussed in Section 4.

j. Control system: this typically consists of hydraulic or electro-hydraulic links to the tree. These are used to operate valves or connectors and monitor the condition of the well. Section 5 describes the commonly used control systems.

k. Guidance equipment: guideline or guidelineless methods may be used for subsea trees as described in Section 3.2.2.1. Some systems may require more precise alignment than that given by guidelines. Secondary mechanical means may be used in these cases.

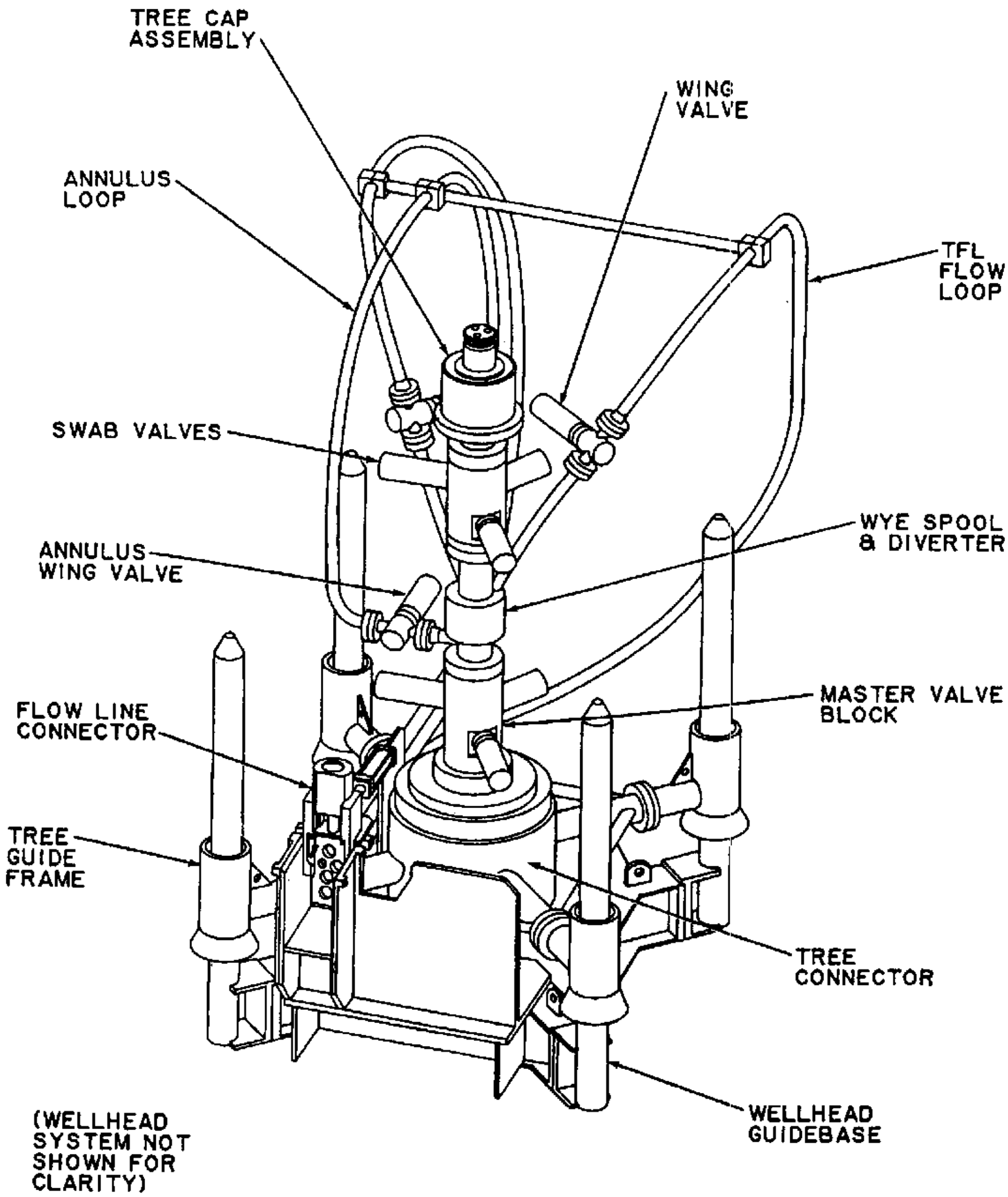


Figure 9—TFL Tree

l. Tree running tool: it must withstand all installation loads. The tool is a hydraulic or mechanical device that is attached to the top of the tree. It forms the lower part of the completion or workover riser or drill pipe which acts as the handling string for the tree. Usually the running tool includes a means of hydraulic communication with the control functions of the tree wellhead connector, valves, and flowline connector.

3.3.2.4 Completion or workover riser system: a completion riser is generally used to run the tubing hanger and tubing through the drilling riser and BOP into the well bore. The completion riser may also be designed to run the tree. A workover riser is typically used in place of a drilling riser to reenter the well through the tree, and may also be used to install the tree.

Either type of riser provides communication between the wellbore and surface equipment. Both must resist pressure loads and accommodate wireline tools for necessary operations. The workover riser must also resist external loading.

A completion riser system typically includes the following major components and features: (a) tubing hanger running tool, (b) means of sealing off against the riser inside the BOP stack for pressure testing (for both subsea and surface stacks), (c) intermediate riser joints, (d) means of tensioning, and (e) a surface tree.

A workover riser system may include the following major components: (a) tree running tool, (b) subsea wireline BOP or cutting valve sized and configured as required for vertical reentry, (c) stress-joint or other stress-relieving bottom component, (d) intermediate riser joints, (e) tensioner ring and tensioning system, and (f) surface tree.

Each type of riser should have as many conduits as there are tubing strings, plus additional paths for annulus access, downhole safety valve control, and control lines for running tool and tree operation. Control functions are sometimes supplied via an umbilical strapped to the riser.

Either type of riser may be configured as integral or non-integral. Non-integral risers include the required conduits as individual strings (for example, drill pipe, tubing, control hose, etc.). Integral risers provide all the conduits in a single assembly or joint. The joints are then made up end-to-end for the required depth.

The surface tree or terminal head on the upper end of either riser type will include valves (typically master, swab, and wing) and manifold connections for flow testing, circulation, or injection. Connections are provided at the top for wireline assemblies. Necessary work platform and handling provisions are also incorporated in the termination.

3.3.2.5 Auxiliary tools: In addition to the tools listed in the preceding, several auxiliary tools may be required depending on the design configuration of the tree. The following list briefly describes the function of the more common tools:

a. The recall buoy is used to reestablish physical contact with the subsea tree for workover or maintenance operations. The system provides a buoy that can bring a messenger line to the surface after receiving a signal via the subsea control system.
b. The remote guideline installation/retrieving tool is used to attach guidelines to any of the guide posts of a permanent guide base. The tool may be run on drillpipe with a jet sub and TV camera to establish a guideline to the post. A universal guide arm may also be used, indexing off of existing guidelines to establish guidelines on vacant posts. The remote guideline releasing tool allows removal of the guidelines without the aid of divers.
c. Universal or utility guide frames are used to orient various tools and equipment using at least two of the primary guidelines/posts for orientation and alignment.
d. A test stump should be provided to properly test the integrity of the subsea tree prior to installation. The stump simulates the wellhead, (complete with the tubing hanger) and allows the tree to be landed and locked for the purpose of pressure testing. The configuration of the test stump is such that the fit and orientation of the subsea tree may also be verified. The stump also provides a convenient means of storage for the tree prior to installation.
e. Suitable lifting means (for example, padeyes, shackles, and slings) should be provided to allow proper handling of the subsea tree prior to installation. Usually, the transportation of the tree to the field requires several transfers. Having adequate lifting systems at each point of transfer, further ensures that no damage will occur prior to installation. Special consideration should also be given to larger trees that may require partial disassembly or shipment in a horizontal position.

Various other tools may be required to run or retrieve auxiliary items such as tree caps or control pods.

3.3.3 Tubing Hanger/Tree Design Considerations

3.3.3.1 The general considerations given earlier for subsea wellhead systems (see Section 2.2.3) are also applicable to the tubing hanger and tree systems.

3.3.3.2 Specific design considerations with regard to the tubing hanger system include the following:

a. Number and size of tubing strings to be supported.
b. Type of threaded connection for the tubing.
c. Number and size of control ports and pressure rating for downhole safety valve(s).
d. Installation to be in the wellhead or a tubing hanger spool.
e. Electrical connector for downhole monitoring (if necessary).
f. Manufacturer and type of wireline or TFL plug profiles (if any) to be machined in the major bores.
g. Feasibility of vertical access to the tubing hanger annulus port. This determines if a wireline plug, stab-to-open check valve, hydraulically actuated sleeve, or other means will be used to secure the annulus when the tree or BOP is removed.
h. Orientation (if required) relative to a given datum for corresponding interface with the tree.
i. Feasibility of using an integral riser or individual tubing tieback strings for installation and wireline work.
j. Protection of control ports from debris/fluid contamination.

3.3.3.3 There are a number of areas that need special consideration in the design of a subsea tree. They include:

a. Pressure rating: A complete profile of the expected maximum and minimum pressures for the wellbore, annulus, service bore (if used), and hydraulic lines should be outlined. Flow pressure, shut-in pressure, injection, and/or kill pressure of the well should be considered. In addition, the maximum service pressure for a TFL tree and the maximum control pressure for the SCSSV should also be considered.

The pressure information should be evaluated in conjunction with the external loads that are acting on the system for the particular operation that is taking place.

All components and connections should have a minimum pressure rating consistent with that of the system. Wye spools should be rated to the same pressure as other tree components. Tree loops located outboard of the wing valve should conform to the same pressure rating as the flowline; inboard tree loops should conform to the rating of the tree components. The tree running tool(s) should have a pressure rating equal to or greater than the lesser of the tree or the installation riser. Proof testing of the components, pressure testing across valves and plugs, and gas testing (required for trees used in gas service) should be performed. API Specification 6A and the guidelines in Section 8 of this document should be followed for determining test criteria.

b. Service: Tree components should be evaluated based on fluid compatibility. A careful examination of the potential fluid types and constituents should be performed considering amounts, states, total and partial pressures, and temperature ranges. Constituents such as hydrogen sulfide and carbon dioxide should be dealt with using standard industry practices and guidelines, such as API Specification 6A and NACE MR-01-75 for H2S service. The tree bore extension subs and seals should receive particular attention in this regard.

c. Water depth: The installation water depth should be considered so that hydraulic and pressure compensation devices can be adequately specified and designed. These devices include, but are not limited to, the control system, running tools, and hydraulic valve operators. Differential pressure effects on the pressure rating of components should also be considered.

d. Rig type: Overall tree and running tool size and shape should be compatible with vessel handling space and opening constraints. This should be evaluated early in the design. The use of a bottom-supported or floating vessel will determine the tension and bending capabilities required of the tree during workovers through the tree.

e. External loads: There are two primary external load cases other than environmental loads to which a subsea tree and its upper and lower connectors may be subjected. The first is installation, which includes, but is not limited to riser loads and flowline connection loads. The second external load case is a workover situation in which a wireline BOP and workover riser may be used. The loads for each case should be stated as maximum tension, bending, and torsion with points of reaction.

Snag loads imposed on the tree and/or the flow lines may also be a concern. If the loads are such that damage is unavoidable, then the failure point and the reaction of the tree functions after the damage should be considered (see following Item j).

When flow loops are connected to pressure-containing members such as valve bodies, the external loads (in addition to maximum pressure loads) should be considered to act on the valves.

f. Tree valve configuration: Arrangements of tree valves depend on the intended service. Fluid paths should be studied to assure the necessary operational flexibility including compatibility with downhole tools, plugs, wireline operations, and TFL equipment (See API Recommended Practice 6G). In addition, the fluid paths should be examined for potential fluid collection and erosion.

A composite valve block should be considered when installation and workover will be performed from a floating vessel. This approach has greater external load carrying capacity, fewer connections, and more compactness. At least one master valve per bore should be a fail-closed valve. A diver or remotely operated vehicle ROV override should be considered for hydraulic valves that are critical to well kill operations.

In normal operations, a minimum of two pressure-containing barriers are recommended between the well tubing bore and the tree outlets. These can be plugs, manual valves, or hydraulic valves; downhole safety valves are not included. If the tree is manifolded on a template, there should be a pressure-containing barrier on the manifold piping to isolate the tree. This barrier can serve as one of the two barriers noted above, provided the tree is sufficiently close to the manifold to be considered an integral assembly.

g. Bore size: The production or injection bore should be compatible with the tubing program. The bore should also be vertically accessible for installation and removal of plugs, and for workover operations. Flow direction, fluid type, suspended particle type and size, and flow rates should also be considered.

In the case of TFL trees, the wye spool should be designed to pass TFL tools in accordance with API Recommended Practice 6G.

The annulus bore may be either vertically accessible from the upper tree connection to the tubing hanger bore, or accessible only for pressure monitoring and injection. If injection of a fluid (into the annulus) will be performed, the path configuration should be designed to avoid potential erosion.

h. Flowline connection: Flowline connections are discussed in more detail in Section 4. The method and type of flowline connection influences the transmission and reaction of loads that may be imparted to the tree.

When mounted outboard of the wing valve, the flowline connector should be designed for the same pressure rating as the flowline. If used with a TFL tree, the bores of the flowline connection should be designed in accordance with API Recommended Practice 6G.

i. Subsea intervention: The type of installation, whether diver-assisted or diverless, and the handling of back-up operations if the primary method fails, are important concerns. These topics are addressed in more detail in Section 8. If an ROV is used, its capabilities and type should be considered. Special ROV concerns include access, docking/reaction points, required mechanical or hydraulic power, load carrying capacity, and the design of special service tools.

j. Tree control: A number of control systems and associated configurations are covered in detail in Section 5. The external loading, layout, and space constraints for the interface with the tree must be considered in the design of both components.

All hydraulic functions necessary for tree operation should be controlled from the remote control station. A tree control pod can be mounted at any location on the tree that provides access and protection. Hydraulic plumbing and electrical cables should be routed to minimize potential damage. The weight and location of the production control system pod should be considered in order to attain a vertical tree attitude during running.

Hydraulic tree connector control functions should not be accessible from the production or injection control system. The system should be designed to tolerate a hydraulic control pressure loss; fail-closed valves should be used to isolate the well.

k. Piping, connections, ring grooves, and gaskets: the vertical tree bores should be compatible with any downhole tools, plugs, wireline retrievable valves, or other downhole operations. Piping runs should be examined for potential fluid collection points and erosion, and appropriate allowances made for expected corrosion/erosion.

Proprietary or special connections are commonly used in subsea applications. Inlays for corrosion protection of seal surfaces, gaskets, and all bolting should be in compliance with API Specification 6A. Connections that are to be made subsea should be examined for possible hydraulic lock during stabbing or make up. In particular, BX and RX gaskets are susceptible to this problem.

3.3.3.4 Specific design considerations for completion and workover risers include: (a) connection strength, (b) water depth, (c) tubing pressure/rating, (d) inside diameter, (e) tubing configuration/spacing, (f) wireline restrictions, (g) other dimensional constraints, (h) control line or umbilical requirements, (i) operating weather conditions, and (j) operating life.

The completion riser design is analogous to downhole tubing design if it is to be used only inside the marine riser and BOP stack or jackup conductor pipe. Workover risers, and completion risers (used in the open sea) must also be designed with due consideration for environmental loading factors. These may include surface vessel motion (if floating), wave action, and current (see API Recommended Practice 2Q for a discussion of drilling riser analysis).

3.4 SUBSEA COMPLETION ON MUDLINE CASING SUSPENSION SYSTEM

3.4.1 Description

Mudline casing suspension systems are designed to be used with bottom supported drilling rigs. The systems provide a suspension point near the mudline to support the weight of casing strings within the wellbore. Each of the individual conductor and casing strings with their respective annuli are tied back to the surface where they are terminated in conventional wellhead equipment with a surface BOP.

Wells drilled with mudline casing suspension systems can be completed with a subsea tree, if proper adaptation for subsea completion is made. The conventional tieback and wellhead at surface must be removed from the mudline casing suspension system. Isolation of the annuli is accomplished, and mechanisms for load transfer are incorporated to transfer loads to the conductor or surface casing. An adaptor is provided to give a profile for the tubing hanger and an attachment point for the subsequent tree installation (See Figure 10).

This section outlines the equipment design considerations and component functions to be considered for subsea completions on mudline casing suspension systems. Many considerations associated with the tree hardware are similar to that already discussed in Section 3.3.

3.4.2 Functional Considerations for Subsea Completion on Mudline Casing Suspension System

3.4.2.1 The key components that must be considered for the system include the following:

a. The conductor pipe provides primary guidance and centralization for casing strings and provides structural support for BOP loads and external forces. The conductor landing ring provides the primary load shoulder for all subsequent suspended casing hangers, and establishes a reference location point for the mudline system. It centralizes the first mudline casing hanger and provides a mud and cement bypass area. The conductor connections provide a means to connect or disconnect risers during drilling and completion operations.

b. Mudline casing hangers support the casing weight for the string of which they are a part as well as all subsequent hangers that are run. They must provide bit access for the drilling of the wellbore for the next casing string. Typically, an internal profile (either flush bore or upset) is provided for landing the next casing hanger. The outside profile of the hanger should provide annulus access. The hanger profile should include a method for attachment of running and tieback tools, corrosion caps, and adapters for completion. The hanger may have flush ports (see following Item c) that permit washing cement from the casing hanger back to the surface, thus allowing later riser string disconnection.

c. The running tools suspend the weight of each casing string while running the string into the wellbore. They provide a pressure seal between the riser string and the casing hanger for subsequent cementing and drilling operations. The running tool may have flush ports (see preceding Item

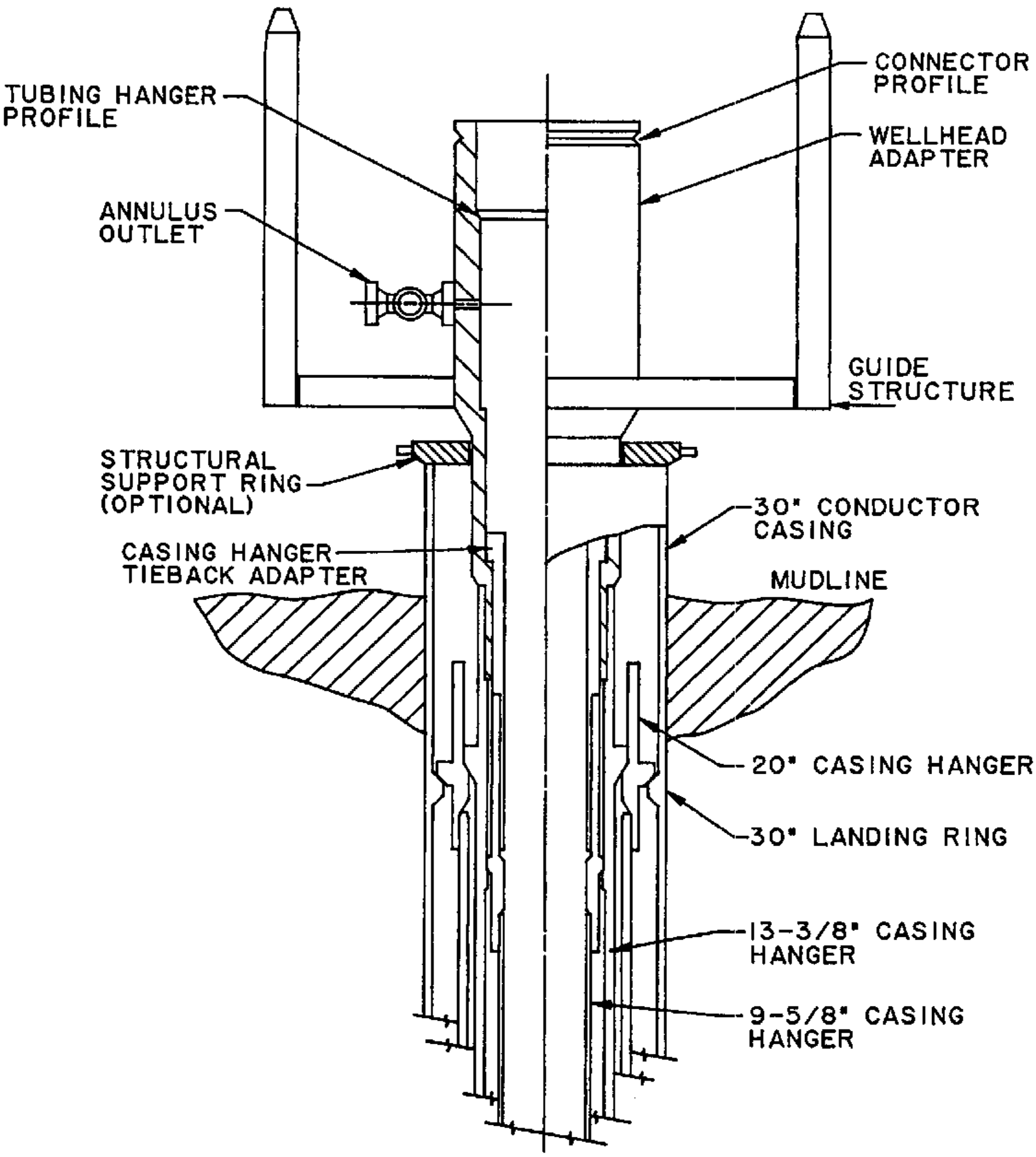


Figure 10—Mudline System With Wellhead Adapter and Casing Adapters Installed

b) that permit washing cement from the running tool/hanger interface, thus allowing later riser string disconnection. Tieback tools provide a method for reconnection of the riser string to a previously installed casing hanger for wellbore pressure containment. Running tools and tieback tools may be one and the same.

d. Protective caps may be installed at temporary abandonment of the well, or during interruption in a completion program. They protect the mudline casing hanger system from contamination by debris, marine growth, and corrosion. Protective caps are normally not pressure-containing. Temporary abandonment caps are pressure-containing caps that may be used to seal individual casing strings at the mudline suspension hanger.

e. A mudline system drilling riser consists of concentric casing strings that tie into the mudline casing hangers via running or tieback tools, and provide a connection point at the surface for the BOP stack.

3.4.2.2 The key components that must be considered for adapters include the following:

a. The subsea guidance system: provides alignment and orientation for installing the subsea tieback components, wellhead adapter, subsea tree, running tools, and re-entry equipment.

b. The wellhead adapter: provides a receptacle for the subsea tubing hanger and a lockdown profile for the subsea tree. The tubing hanger spool, when used, is attached to the wellhead adapter. The adapter may also provide the guidance system attachment point. It supplies annulus sealing surfaces for the tieback adapters, and provides structural support for the completion.
c. The casing hanger tieback adapter: provides structural and sealing interfaces between adjacent mudline casing hangers and the wellhead adapter. This component may be integral with the wellhead adapter.
d. An annulus seal assembly: isolates the casing annulus when installed during a subsea completion.
e. A casing hanger lockdown assembly. prevents casing movement due to annulus pressure or thermal expansion during production.

3.4.2.3 After the well head adapter is installed on the mudline drilling system, well bore re-entry should be established with a high-pressure riser to a surface BOP system. Casing hanger tieback adapters are installed, and annulus seal assemblies are run and tested. The tubing hanger can then be installed in the subsea wellhead adapter or tubing hanger spool. Plugs are set in the tubing hanger, the BOP and riser are removed, and the subsea tree is installed on the wellhead adapter or tubing hanger spool. Important components involved in this process are as follows:

a. The high pressure riser establishes a connection between the wellhead adapter at the mudline, and the surface wellhead/BOP stack. The riser provides pressure integrity for completion operations at the mudline and for the surface BOP stack. It also gives structural support, establishes a guide for re-entering the well, and provides orientation for the tubing hanger.
b. The surface tree establishes vertical entry into the tubing bores, terminates the tubing riser and provides flow control during well testing. It may also provide control access to operate and functionally test the tubing hanger.
c. A tubing hanger spool may be included to house the tubing hanger. The spool may also be used to provide annulus access.
d. The tubing hanger tree fulfills the same functional requirements it would have for a subsea wellhead system (see Section 3.3).

3.4.2.4 Certain mudline systems allow for a hybrid completion where the production casing is run with a subsea-type hanger. The main advantage is to avoid the use of casing hanger tieback adapters during completion.

3.4.3 Design Considerations for Subsea Completion on Mudline Casing Suspension System

3.4.3.1 The general considerations to be reviewed for completing a mud line casing suspension well subsea are essentially the same as for a subsea wellhead (see Section 2.2.3).

3.4.3.2 The following special considerations apply to subsea completion on mudline casing suspension systems:

a. The system should be compatible with jack-up or other bottom-supported rigs.
b. Casing loads should be suspended near the ocean floor to reduce loads on the rig and provide a disconnect/reconnect point.
c. The hanging capacity, pressure rating, and drift requirements should be selected to meet the requirements of a particular well. Care should be exercised when selecting reduced bore hangers to ensure that they are compatible with the drill bit program.
d. Adequate annulus flowby areas should be incorporated in mudline components both in the running and landed condition. The combined total area and quality of the flowpaths should be examined.
e. The casing annuli should be accessible at the surface wellhead during drilling operations, but may be isolated when a subsea tree is installed.
f. Applied external loads which affect the mudline drilling system must be considered (for example, wave and current forces, riser/BOP weight, etc.).
g. Direction of rotation and required downhole torque of mudline components must be compatible with the rest of the drilling system for installation and retrieval.
h. Accessibility and adaptability should be incorporated for abandonment, conventional platform tieback/completion, and subsea tieback/completion.
i. Maximum allowable misalignment and lateral offset between the running/tieback strings and hangers must be defined.
j. Upon temporary abandonment, individual casing risers should be removed to meet elevation requirements at the ocean floor. Protective cap(s) should be installed on the well, as required for the well program.
k. An annulus seal assembly should be installed between the production casing and intermediate casing strings at the adaptation point.
l. Seal selection for component interfaces should be carefully considered.

4 Pipelines and End Connections

4.1 SCOPE

This section presents guidelines intended for the design, construction, testing, and installation of subsea pipelines and end connectors used in a subsea production system. The guidelines cover the unique factors of subsea systems that are high pressure, multiphase flow, multiple lines, subsea connections, and TFL systems. Engineering considerations commonly encountered in subsea pipelines and end connectors are discussed.

This document does not replace API Recommended Practice 1111, which should be referenced for details on design, construction, and testing. API Recommended Practice 1111 should also be used for subsea pipelines intended for the transportation of hydrocarbons to other destinations.

This section does not apply to piping located on a platform.

4.2 SYSTEM DESCRIPTION

A pipeline system as covered by this Recommended Practice (Figure 11) begins with both halves of the connector used at the subsea facility and ends with one of the following: (a) both halves of a connector used at another subsea facility, (b) the pipeline side of a surface connection or weld at the top of a platform riser, or (c) the point at which riser design begins (in the case of a flexible production riser that does not have a riser base).

4.3 FUNCTIONAL CONSIDERATIONS

4.3.1 Pipeline Types

Pipelines may be dedicated to a number of special purposes. These purposes include, but are not limited to, the following:

a. Flowlines are used for producing and, in some cases, servicing wells. The term is generally applied to pipelines upstream of processing facilities.
b. Gathering lines are used for transporting produced fluids from two or more subsea facilities to a central point.
c. Injection lines are used for the injection of water, gas, methanol, or other chemicals to a subsea facility.
d. Service lines include test and hydraulic lines used for the control of a subsea facility, annulus access/monitoring lines, and kill lines. Some of these lines are often incorporated into an umbilical. (See Section 5 for further information on control lines.)

4.3.2 Platform Risers

The portion of a pipeline extending from the seafloor to the surface is a platform riser. Examples include (a) conventional riser consisting of rigid piping attached to the platform structure and serving as the pipeline; (b) a J-tube riser for rigid pipe, and J-tube or I-tube riser for flexible pipe, which permits installation of the pipeline without connections on the seafloor and consists of rigid conduit attached to the platform through which the pipelines are pulled; or (c) a flexible pipe riser consisting of flexible pipe attached to a platform (in a manner similar to a conventional riser) or suspended from a floating facility.

4.3.3 Pipeline Components

Components used in a pipeline system may include, but are not limited to, the following:

a. A connector provides a leak-free structural connection between two segments of pipe. Connectors include bolted flanges, clamped hubs, and proprietary connectors. They may be designed for diver assisted makeup or for diverless operation using either mechanical or hydraulic apparatus.
b. A spool is a short piping segment commonly used in connecting pipelines. A spool typically includes a connector at each end.
c. A safety joint is a device designed to fail at a predetermined structural load. Safety joints may be used to a subsea facility, platform, or other installation could result from an overload applied through the pipelines.

4.3.4 Special Tools

Purpose-built tools are often used for making pipeline connections, particularly in water depths requiring diverless operations. Such tools may include the following:

a. A pull-in tool is used to pull in and align the end of a pipeline or bundle of lines at a subsea facility, the base of a platform, or another point in preparation for the connection operation.
b. A connector tool is used to complete the connection of two piping segments by actuating a clamp, proprietary connector, or other device.
c. A combination pull-in/connector tool performs the function of both a pull-in tool and a connector tool.

4.3.5 Installation

Installation of the pipeline should involve a detailed plan. Pipelines may be installed using a variety of methods. Established methods include the following:

a. "S" curve (conventional): the pipeline is made up in horizontal or near horizontal position on the lay vessel and lowered to the seafloor in an elongated "S" shape as the vessel moves forward (Figure 12).
b. Reel: the pipeline is made up on shore and spooled onto a reel for installation. The axis of the reel may be horizontal (Figure 13) or vertical.
c. Tow. The pipeline is made up onshore or in a mild offshore environment, and towed to its final location. There are several versions of the tow method (Figure 14), including near-surface tow, controlled-depth tow, near-bottom tow, and bottom tow. The tow methods differ primarily in requirements for buoyancy control and in sensitivity to environmental loading.
d. J-Lay: the pipeline is made up in a vertical or near vertical position on the lay vessel and lowered to the seafloor in a near vertical orientation (Figure 15). This approach eliminates the overbend region of the suspended pipe catenary. It has seen very limited use, but has potential for certain applications.

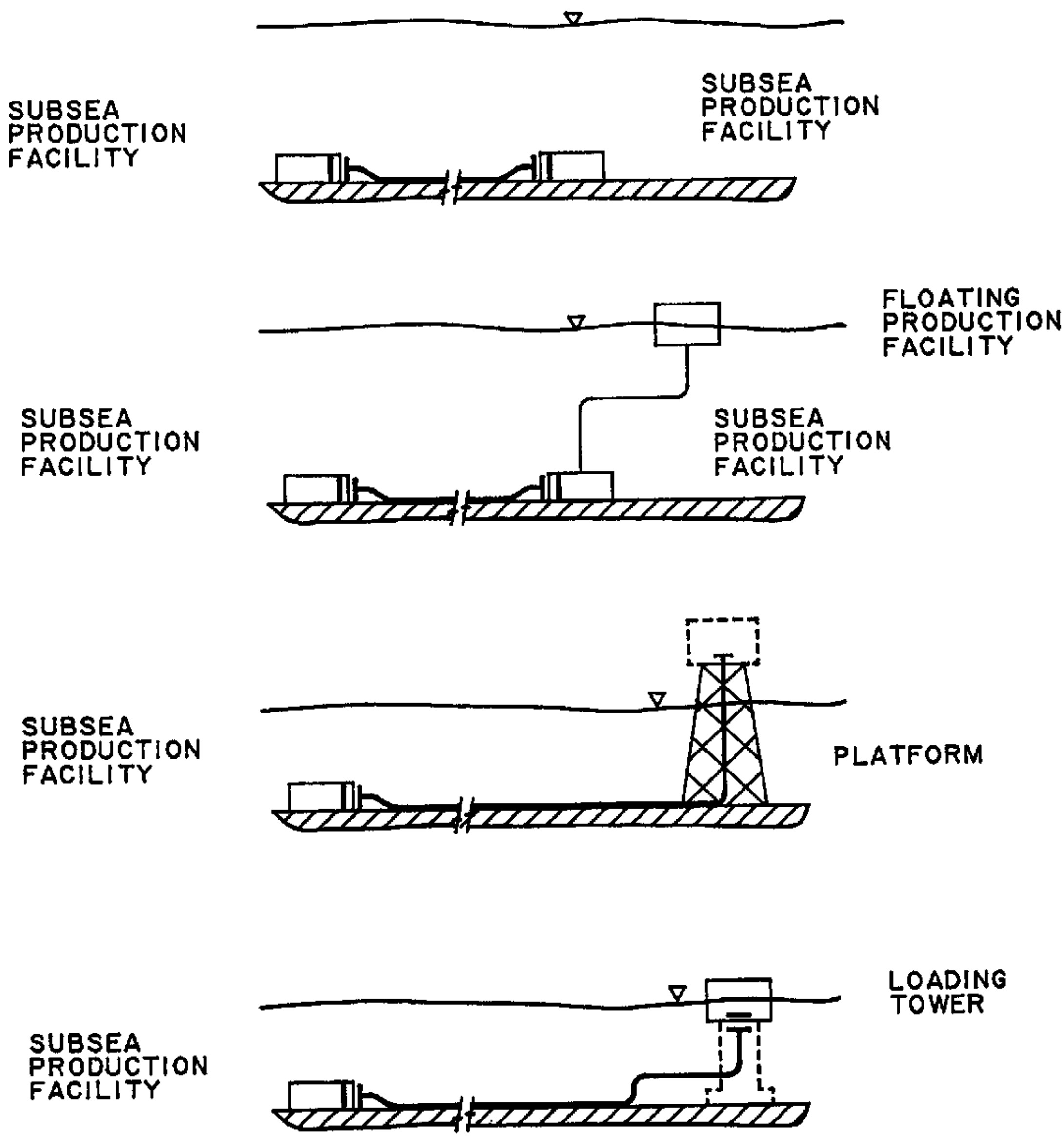


Figure 11—Subsea Pipeline Boundaries

4.4 DESIGN CONSIDERATIONS

4.4.1 Pipeline Design

4.4.1.1 Basic considerations: The following pipeline design considerations should be addressed:

a. The installed configuration of the pipeline should be considered. Pipeline systems may be configured in a number of ways including individual lines (Figure 16, View A), bundled lines (Figure 16, View B), and cased bundle (Figure 16, View C).

b. The loads imposed on the pipeline during installation may be larger than any subsequent load. Selection of a method for a particular application depends on number of lines to be laid together, pipeline diameter and submerged weight, water depths, burial requirements, pipeline length, distance from a shore base, availability of suitable equipment, end connection method, and economics.

c. Many operating factors should be considered in pipeline design. These include the following:

1. Pipeline fluid: The line may convey produced oil and natural gas, water, solids, injection chemicals, carbon dioxide, hydrogen sulfide, etc.
2. Multiphase flow.
3. Fluid flow rate.
4. Fluid properties: Pressure, temperature, viscosity, density, and corrosion potential are important.

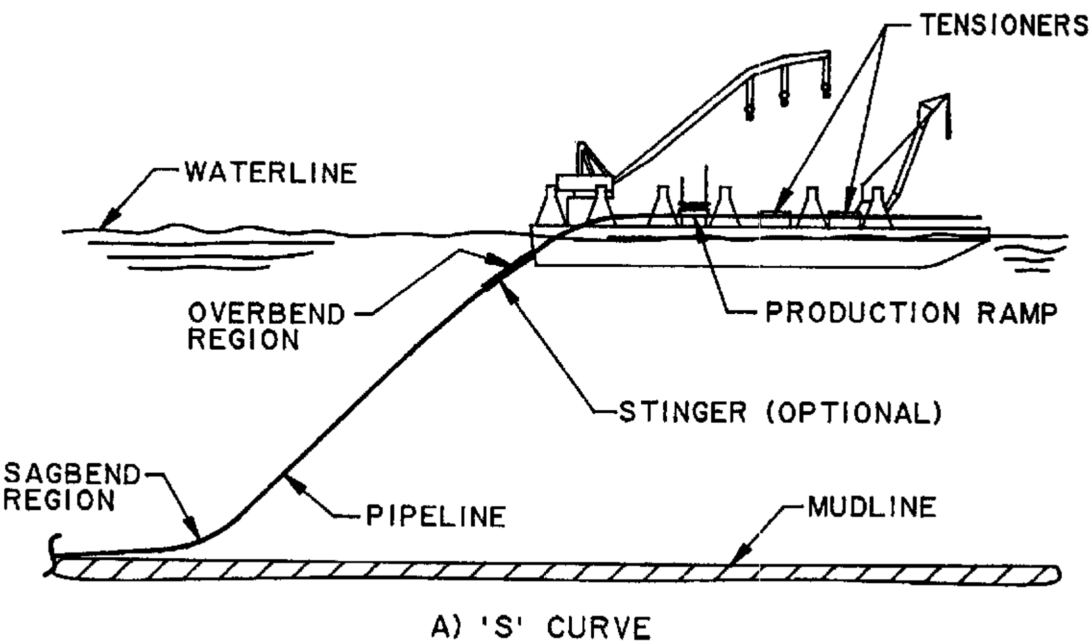


Figure 12—"S" Curve Lay Techniques

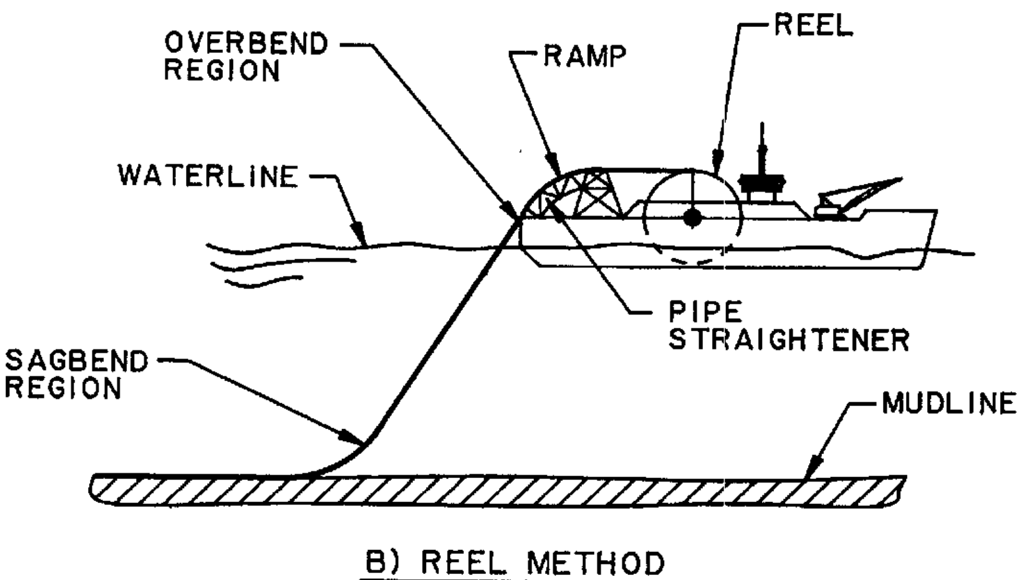


Figure 13—Reel Method Lay Techniques

5. TFL applications: TFL pipelines should be designed for free passage of TFL tools. API Recommended Practice 6G should be referenced regarding pipeline diameters, minimum radius of curvature, and other requirements for TFL pipelines.

6. Pigging procedures: As with TFL tools, the use of pigs may restrict the permissible valves, fittings, connections, pipe inside diameters, and pipe bending radii.

7. Location of pipeline ends.

8. Location of nearby pipelines: Adjacent or crossing lines may interfere with one another during operations as well as installation.

9. Seafloor topography: Hills and valleys can induce slug fluid flow in the line; boulders and mud slides can induce stresses in the pipe.

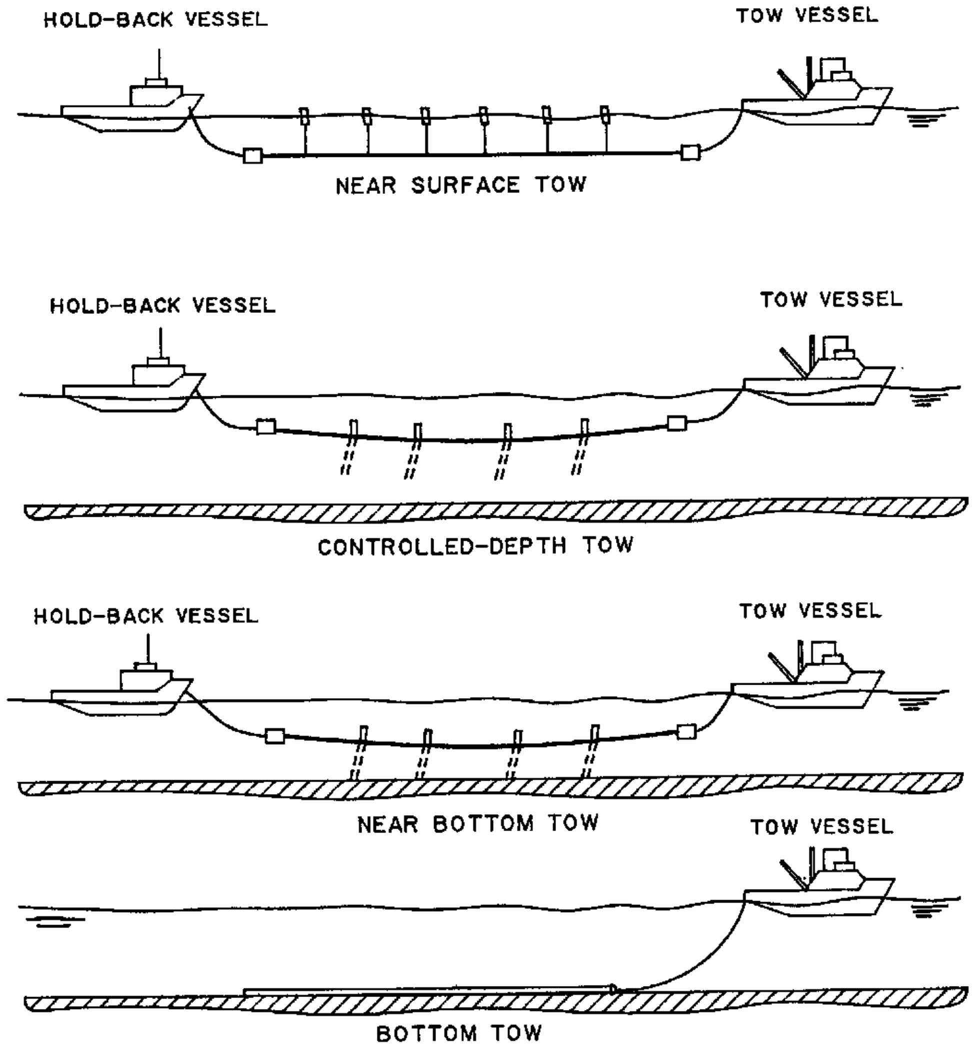


Figure 14—Tow Method Lay Techniques

10. Seafloor environment: Currents and hydrostatic pressure apply forces to the pipeline. Seafloor sediment supports the pipe, while sea water temperature and oxygen content affect the pipe's external corrosion. Other uses of the seafloor such as fishing and ship anchoring can affect the safety of the pipeline.

11. Anticipated line life: The corrosion protection requirements are a function of the design life of the pipeline.

d. The design of a pipeline and its end connections should consider intervention requirements throughout the life of the pipeline. Intervention will be required for:

1. Initial end-connection procedures.
2. Routine in-service inspections.
3. Maintenance.
4. Repairs.

The intervention method chosen (for example, divers, manned submersibles, ROVs, or remotely operated tools) will affect the design of various components, the overall installation technique, and the operational procedures for the pipeline system.

4.4.1.2 Route selection: Although the location of the pipeline ends may be specified, a straight line between them may not be best. The pipeline should, if possible, avoid mudslide areas, seafloor canyons, boulders, rock outcroppings, and established anchor patterns. The route should avoid restricting future field developments and operations. The approach to a connection point is important for correctly aligning the connectors and accommodating other equipment or structures. Possible expansion or contraction of the pipeline due to temperature changes can be accom-

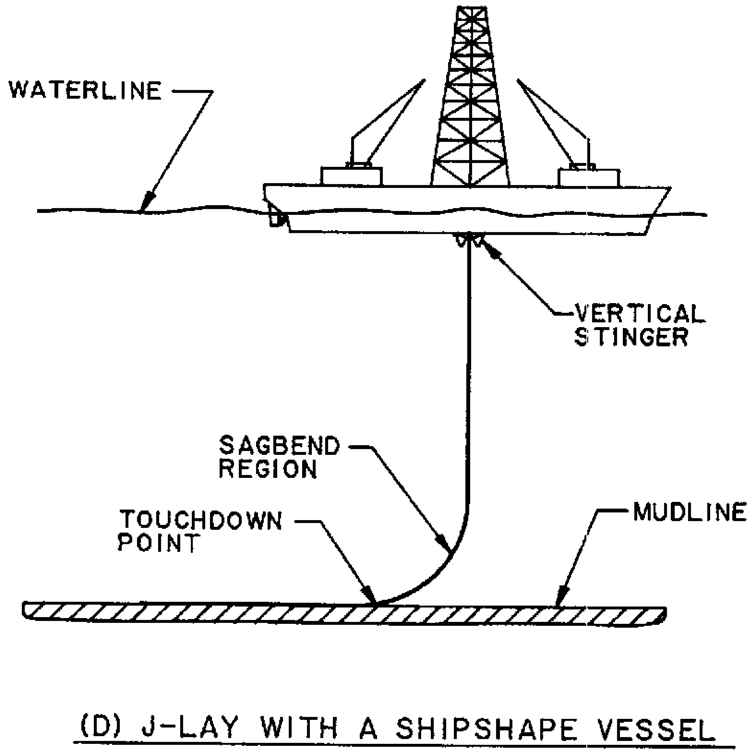


Figure 15—J-Lay Techniques

modated by loops or bends in the line. In addition, legal or regulatory restrictions may require the pipeline to stay within or to avoid certain areas.

The route should be thoroughly analyzed utilizing all available information. A pre-installation survey to avoid underwater objects (for example, pilings, pipelines, and so on) is recommended. An as-laid (post-installation) survey, whether a contractual or regulatory requirement, may prove beneficial in verifying actual position of the pipeline. This survey may also prove very useful for future equipment requirements particularly around subsea facilities or platforms.

4.4.1.3 Weather: anticipated weather conditions during the installation phase of the project should be thoroughly evaluated. Seasonal directions and magnitude of waves/winds combined with the average frequency of excessive sea states should be considered to determine the optimum timing for the project.

4.4.1.4 Pipe design: the following factors should be considered in pipe design:

a. Selection of pipe diameter and wall thickness is determined by the following factors:

1. Applicable codes such as ASME/ANSI B31.4 for liquid pipelines and ASME/ANSI B31.8 for gas and multiphase pipelines should be consulted along with regulatory codes.
2. Flow rates.
3. Maximum working pressure.
4. External pressure.
5. Pressure drop.
6. Pipeline elevation variations.
7. Fluid density and viscosity.
8. Line length.
9. Use of TFL tools.
10. Installation and intervention equipment requirements.
11. Parallel lines for pigging or redundancy.
12. Availability of suitable pipe.
13. Corrosion/erosion allowance.

b. Pipe specifications, such as API Specification 5L, should be referenced for various grades of steel for use in line pipe. Another choice is flexible pipe made from several layers of different materials, which may meet the design requirements.

c. API Recommended Practice 1111 should be used to determine allowable stresses in steel pipe. No comparable recommended practice exists for flexible pipe.

d. Pipe design should consider the affect of overbend and sagbend strains, tension, hydrostatic pressure, vessel motions, current, seafloor topography and soil conditions, pipe yield and ovality, methods of joining, and cost.

e. The following in-service factors should be considered:

1. Tension, bending, and torsion imparted to the pipe-

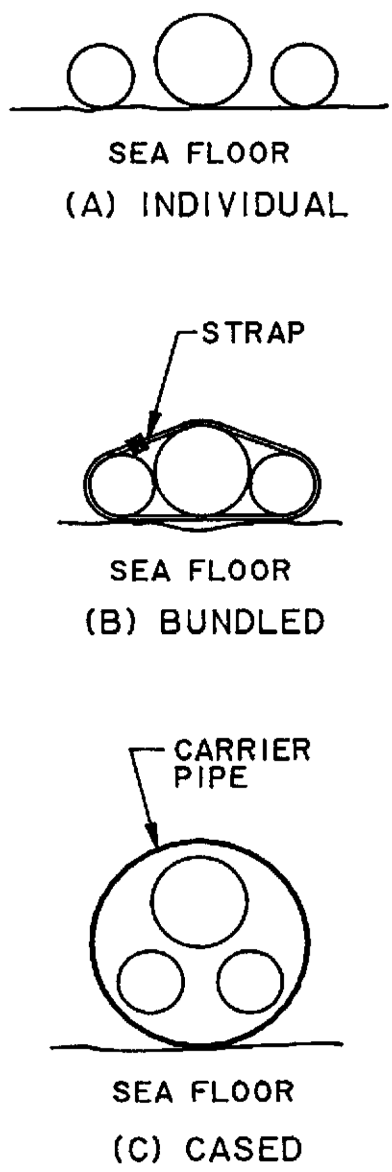


Figure 16—Pipeline Configurations

line during installation or fabrication may result in residual pipe stresses.

2. Environmental forces on an offshore pipeline are composed of gravity loads, hydrostatic loads, hydrodynamic loads, and pipe-soil interactions. Figure 17 identifies these loads in more detail.

3. The pipeline will expand or contract (or attempt to do so if restrained) as a result of a temperature change in the internal or external fluids.

4. Events that may cause large loads include earthquakes, mudslides, anchor lines snagging the pipeline, and input from anchors or other heavy objects. Subsidence or scour of the supporting seafloor soil also may impart unexpected loads. Safety joints, breakaway couplings or other protective devices may be used near the pipeline ends to protect the subsea facilities from overloads.

f. Spans are the result of not having continuous support underneath the pipe. This may be caused by laying over rock, coral, or a hard uneven profile. Some spans may be caused by subsidence or by scour underneath the pipeline. The effect of spans should be considered with regard to the effect of combined stresses when pressured, and fatigue through vibration as a result of possible vortex shedding from transverse current flow.

g. A pipe buckles when it bends in too small a radius of curvature, or is severely compressed. For subsea pipelines, a buckle occurs most often when the pipe is bent under external pressure with insufficient tension, such as in the sagbend of the pipeline as it is installed, or when hot fluids cause thermal expansion inside a restrained or buried pipe. Once a buckle initiates locally subsea, it will proceed at a lower external pressure than the initiation pressure. The buckle will propagate until the pipe moment of inertia increases and/or the external pressure decreases sufficiently to arrest the buckle.

Buckles should be avoided or minimized by the following:

1. Designing the pipeline to have sufficient wall thickness to prevent local buckle initiation.
2. Allowing for the pipe ovality, which results from the manufacturing and handling processes.
3. Considering temperature and pressure effects.
4. Using buckle arrestors, when needed, to limit the distance a buckle can propagate.
5. Maintaining sufficient tension on the pipeline during installation.
6. Ensuring that any spans along the installed pipeline are not too long.

h. Fluid temperatures greater than 190°F may be a concern for flexible pipe, most corrosion coatings, and cathodic protection systems. Subsea heat exchangers been successfully used to reduce fluid temperature prior to entering flowlines. The effect of high production temperatures should be carefully evaluated prior to selecting pipeline materials.

i. Pipelines may be insulated to help maintain fluid temperature high enough to minimize undesirable increases in fluid viscosity, formation of hydrates, deposition of paraffin, or solidification of liquids with a high pour point under steady state flowing conditions.

4.4.1.5 Pipeline Protection: subsea pipelines should be protected from damage caused by the following effects.

a. Mechanical effects: pipelines should be protected in regions of heavy wave action, extremely high seafloor currents, boat traffic, bottom fishing activities, and where required by government regulations. Wave forces are greatest in the surf zones and in shallow water. Currents high

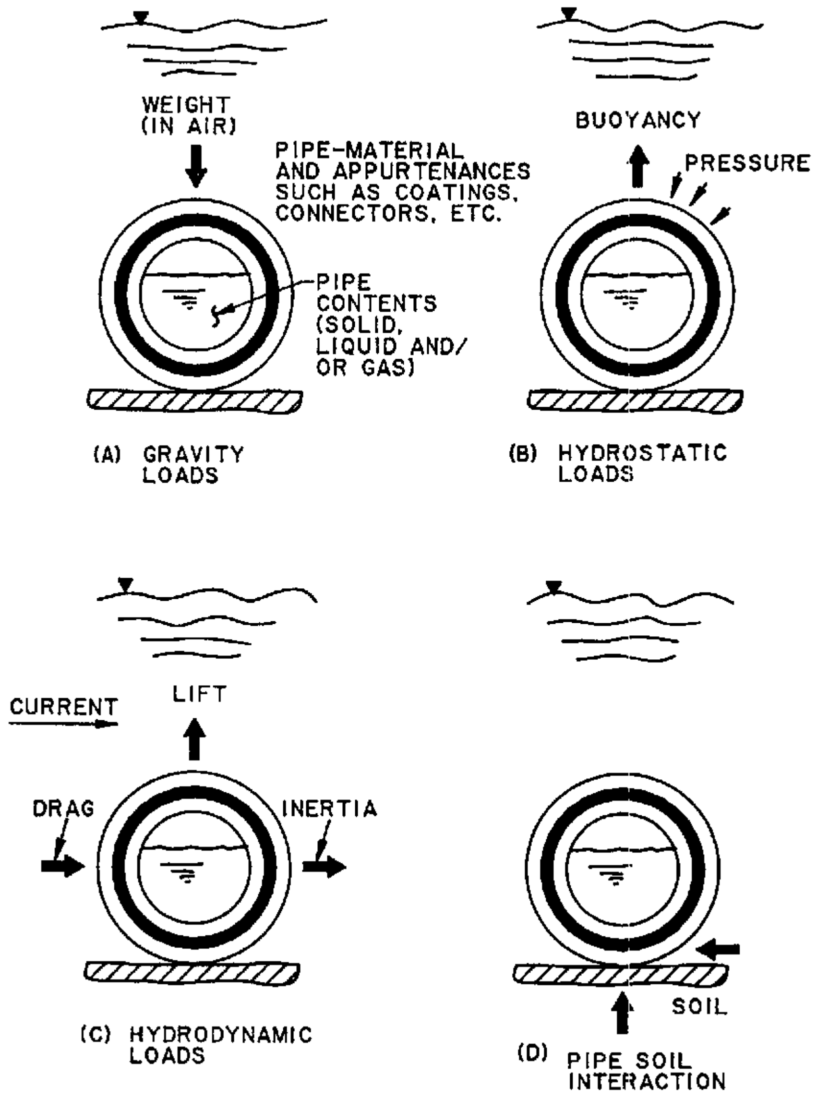


Figure 17—Forces Acting on Subsea Pipeline

enough to cause pipeline stability problems can justify some form of protection. Extensive boat traffic with the attendant anchors and fishing gear may require the pipelines to be lowered below the seafloor.

Various methods of mechanical pipe line protection are as follows:

1. Trenching/Burial is accomplished by bottom-towed trenching plows, trenching machines, or a barge-towed bury sled. The soil characteristics determine the best method or combination of methods to use.

2. Overburden can reduce vulnerability by placement of gravel, iron ore, or other similar material on the top of the pipeline.

3. Anchoring protects against pipe movement caused by high bottom currents or mudslides. Methods used include: weight blocks, concrete coating on outside of pipe, anchors which auger into the seabed, and stabilization matts.

4. Several lines which are bundled together can be encased in a larger diameter (carrier) pipe, thereby protecting the bundle from mechanical and corrosion damage. A carrier pipe is typically found where a tow method is used to install flowlines.

5. Crossing pipelines should be separated to prevent one pipeline from damaging the other. Sand bags or grout-filled bags may be used to support one pipeline above the other. Crossings should comply with design specification, notification, installation, inspection, and as-built records requirements of the owners/operators of the pipelines involved.

b. Corrosion effects: Protection is recommended to limit corrosion from both the external effects of the seawater environment and the internal effects of the product being transported. The pipeline should be protected in accordance with API Recommended Practice 1111, NACE Standard MR-01-75, and NACE Standard RP-06-75. Care should be taken to select a corrosion protection system that can be readily repaired under field installation conditions and maintained throughout the design life of the pipeline. A corrosion protection strategy should consider the following:

1. Corrosion can be controlled by the use of coatings, cathodic protection systems, and careful selection of the pipeline material.
2. Proprietary coating systems are available that provide protection from internal and external corrosion. Examples include coal tar, mastics, and various organic/inorganic compounds. Procedures to repair the coatings in the field may be required.
3. Passive (cathodic) protection is gained by sacrificial anodes attached to the pipeline, which protect against galvanic corrosion caused by voids (holidays) in the coating. Zinc and aluminum alloys are commonly used anode materials. It is sometimes desirable to electrically isolate the pipeline from its surface connections: special electrical insulating flanges are available. Active protection relies on impressed currents established between the anode and the pipeline. Design of the cathodic protection system is based on current density of exposed areas.
4. Increased wall thickness will compensate for material lost due to corrosion. The selected pipe material could be one that has self-protecting characteristics.

4.4.2 End Connection Design

4.4.2.1 Pipeline end alignment: after placing a pipeline on the ocean floor, it may be necessary to re-position or modify the pipeline ends, so that a connection can be made without further gross adjustment. Both methods may be necessary as well. If TFL is specified, then the bends, welds, and other parts of the pipe line configuration should comply with API Recommended Practice 6G.

Methods of pipeline end alignment include the following:

a. The spool piece method (Figure 18) uses a spool piece assembly to bridge the distance (gap) between the end of the pipeline and its connection point. Spool pieces can consist of any of the following:

1. A rigid pipe fabricated into a specific configuration at the work site or on shore.
2. An articulated spool piece made up of rigid pipe connected to ball joints, telescoping joints, etc., which allow the spool piece to conform to the gap configuration.
3. A flexible pipe jumper where its inherent pliancy makes it adjustable over a range of gap lengths.

b. The pull-in method (Figure 19) aligns the pipeline by pulling it towards its connection point using a wire rope(s) fastened to the pipeline end (pull-in head). Final alignment and positioning may require special tools or alignment frames. Temporary buoyancy or flexible pipe jumpers may be used to reduce pull-in forces and moments. In diverless situations, the pull-in is conducted through the use of remotely controlled special tools. These tools are designed with enough power to pull, lift, bend, and rotate the pipeline into its final position at the connection point. The tool may also assist in the locking of the pipeline to the connection point.

c. The lay-away method (Figure 20) involves lowering the pipeline end to the ocean floor and locking it to a subsea structure. The pipelay vessel then moves off location, laying the pipeline to its installed configuration. If installing rigid pipe, the pipelay vessel may need to be equipped with motion compensation devices to reduce the chances for buckling or over tensioning the pipeline once it is locked to the subsea structure.

4.4.2.2 Alignment design: the choice of a pipeline alignment method and its subsequent design is influenced by several considerations, including the following:

a. The location of the target area and accuracy in which the pipeline end is placed affect the lateral angular alignment and related stresses.

b. The water depth influences the decision to use diver-assisted or diverless intervention, the station keeping requirements of surface vessels, and complexity of offshore operation and/or tools.

c. The chosen alignment method's procedures and equipment should be compatible with those selected to install the rest of the pipeline. Alignment equipment should also be designed for any residual pipeline reaction loads caused by the pipeline installation method.

d. Certain alignment methods, such as the lay-away method, are limited to first end connections; other methods are suited for either end. The order of end connection can also influence the choice of alignment method.

e. The type and amount of alignment forces required of the chosen alignment method can be influenced by the pipeline being a single, bundle, or case-bundled pipe design; pipe size, weight, strength and stiffness; and TFL requirements.

f. Soil friction forces and bearing capacity, local obstructions, and ocean floor topography may affect the alignment procedure.

g. Alignment design is influenced by the connection point being either another subsea facility or an offshore platform. An offshore platform can offer additional pipeline alignment methods, such as conventional riser installation or J-tube installation. Connection points may also require expansion loops, breakaway features, or valving to complement the overall pipe design. Spool pieces may be designed to incorporate these added features.

h. It is essential to the integrity of the end connection that the alignment method positions the end of the pipe within the appropriate axial, lateral, and angular makeup tolerances

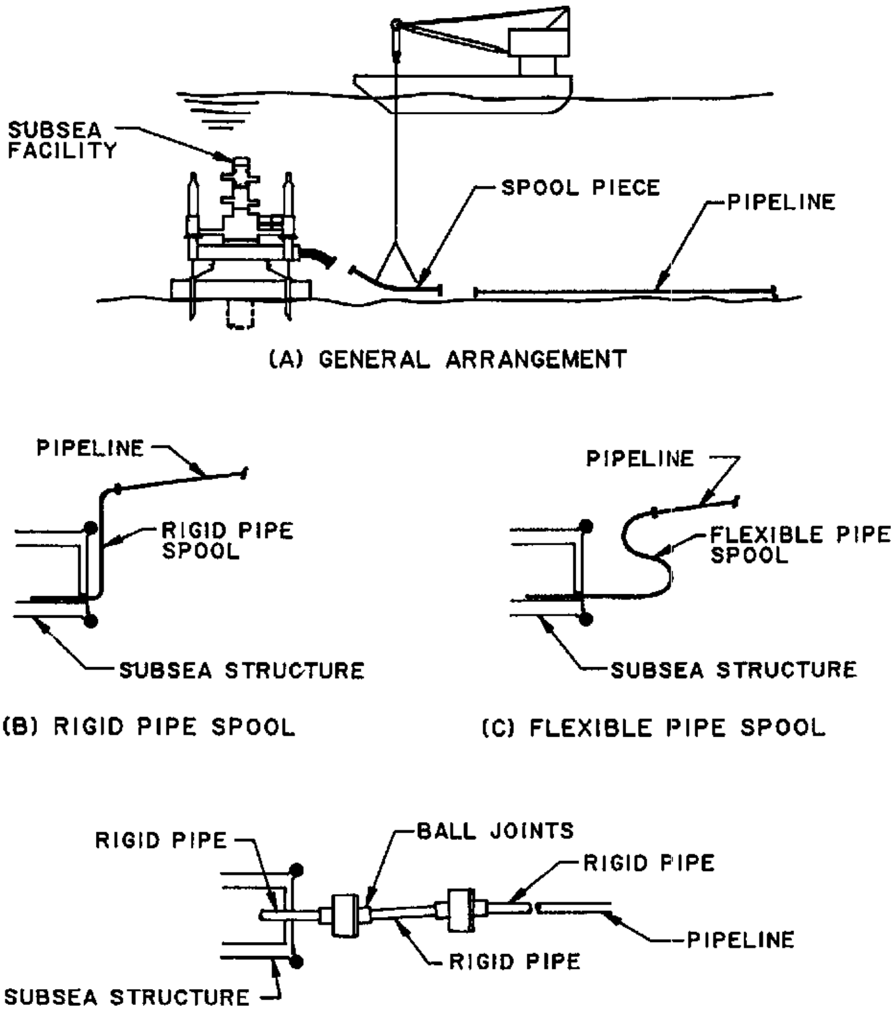


Figure 18—Spool Piece Alignment Method

of the pipeline connector. Rotational alignment should also be accommodated for bundled pipelines to guarantee proper port orientation.

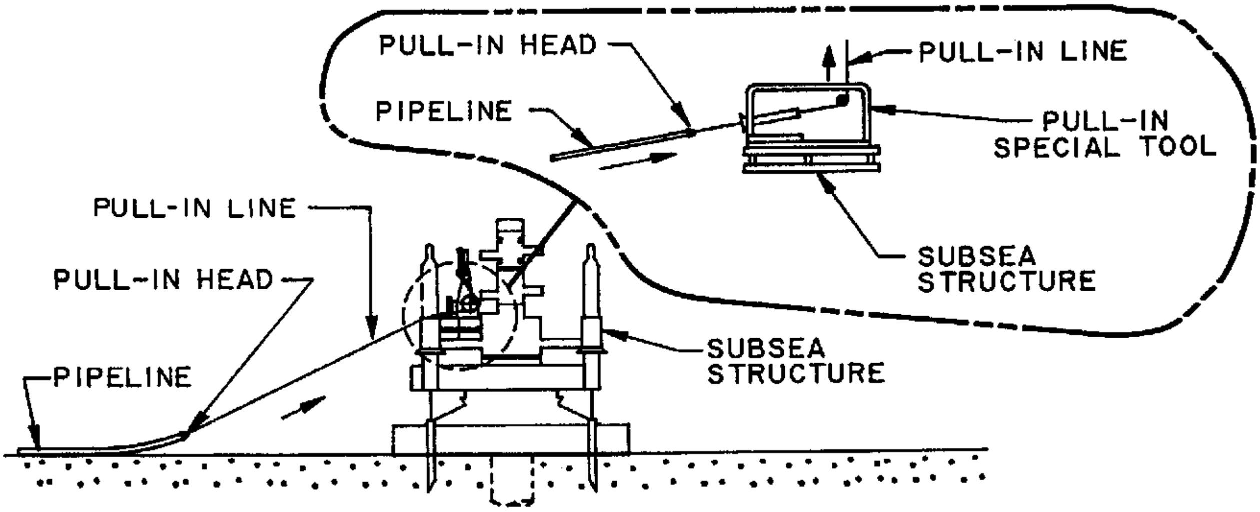
i. The design of the pipeline near the end connection and its alignment hardware are influenced by the strength and stiffness of the pipeline, and the amount of movement required to align the pipeline end with its connection point. Pull-in and lay-away methods require re-positioning the pipeline, which imparts axial loads and bending moments that should be accounted for in the pipeline and alignment equipment design. Spool piece methods leave the pipe in its as-laid configuration.

Factors that influence the design loads and resultant pipeline stresses during alignment operations (Figure 21) include the following:

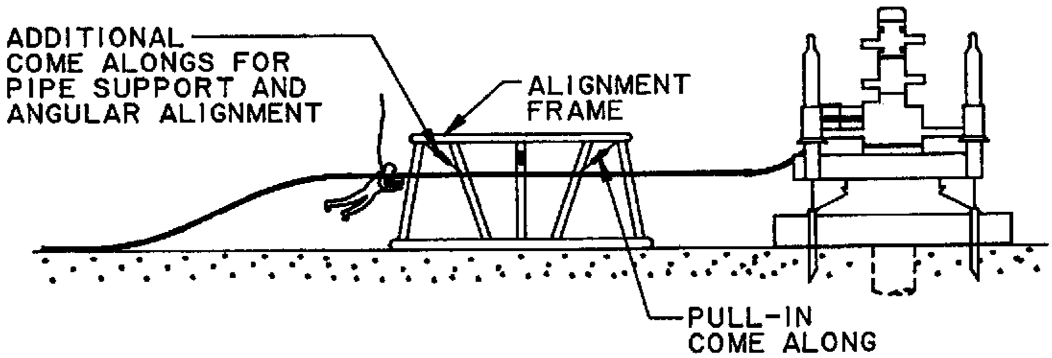
1. Connection point height and relative angle off bottom.
2. Pipeline weight (and buoyancy).
3. Unsupported span length.
4. Lateral angular movement to align the pipeline.
5. Pull-in forces versus residual pipeline installation forces and soil friction.
6. Torque required (to orient ports).

4.4.2.3 Pipeline Connector: the connection between the pipeline and the connection point is generally made after pipeline end alignment is complete. The primary purpose of the connection methods described below is to create a pressure-tight seal that resists the abuses associated with subsea environments. If TFL is specified, the connectors in the pipeline configuration should comply with API Recommended Practice 6G.

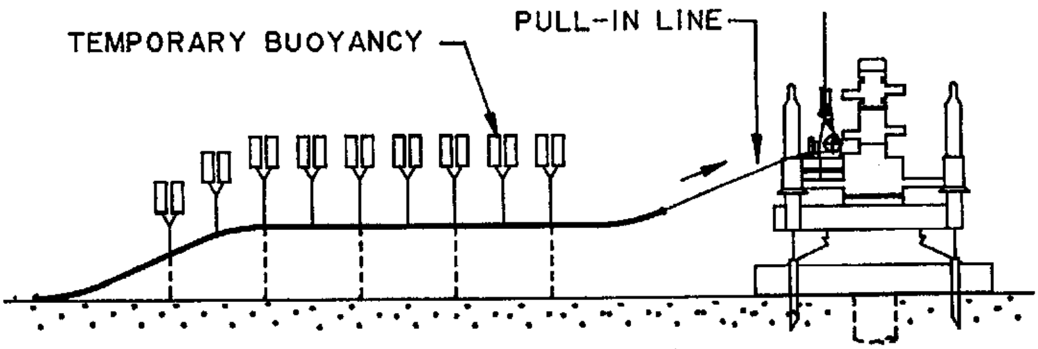
The following are several types of pipeline connectors that typify the many available options:



(A) GENERAL ARRANGEMENT



(B) ALIGNMENT FRAME ASSIST



(C) BUOYANCY ASSIST

Figure 19—Pull-in Methods

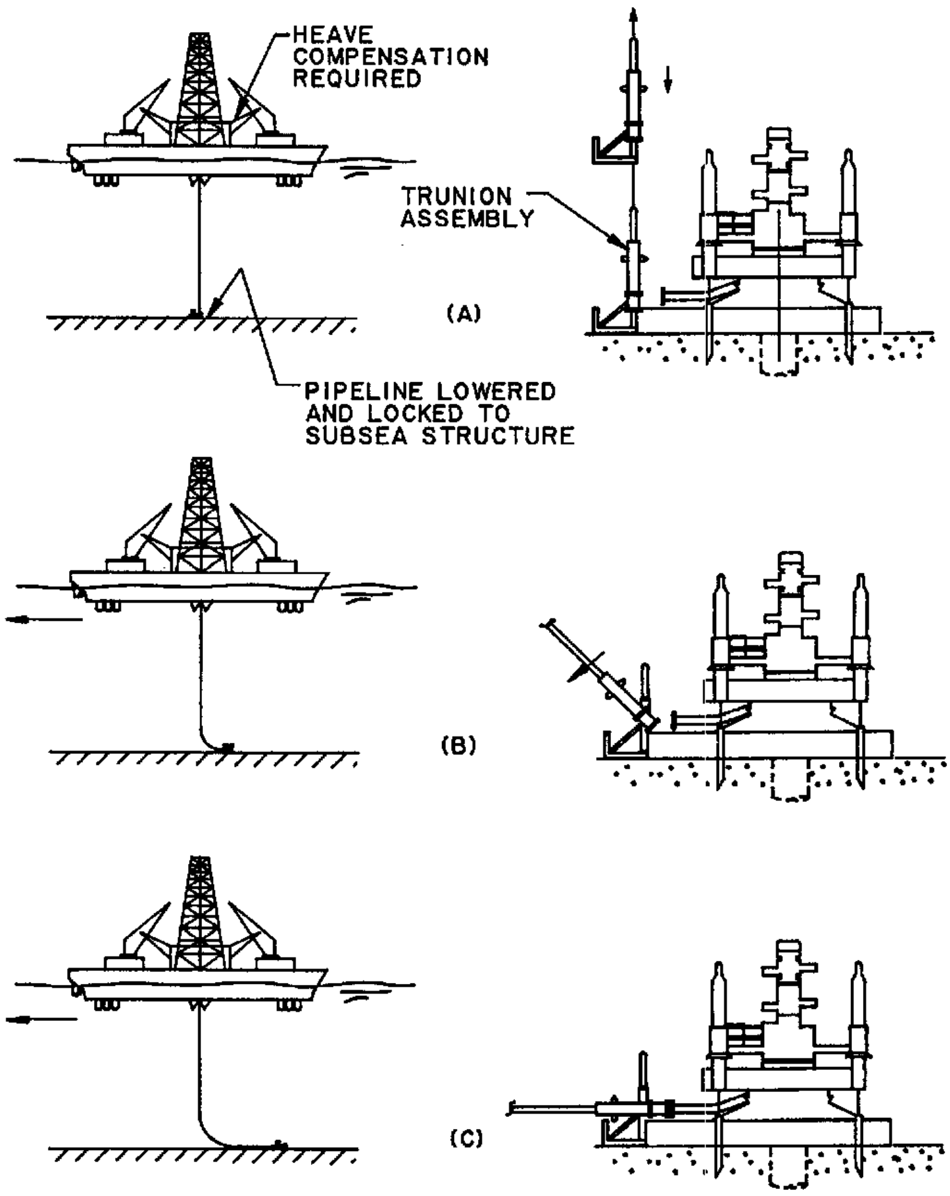


Figure 20—Lay-Away Methods

a. Bolted flange designs are covered in ANSI 16.5 and API Specification 6A. These designs make use of metal ring joint gaskets that compress when the bolts are tightened. Special consideration should be given to these gaskets for underwater applications. Some gaskets (for example, API BX gaskets) tend to trap water behind the gasket when made up underwater, resulting in improper sealing of the gasket and flange connection. The gasket ring grooves should be specified with stainless steel welded in-lays to reduce the effects of corrosion on the seal surface.

Bolted flange connections may permit a limited degree of initial misalignment. However, rotational alignment is restricted because of bolt hole orientation. Swivel flanges may be used to facilitate bolt hole alignment.

b. A clamped hub connector is similar in principle to a bolted flange connector. Clamped hub connectors may use the same metal ring gaskets as bolted flange connectors; they may also use proprietary gasket designs. The clamping device forces the mating hubs together as the clamping device is tightened.

Clamped hub connections are generally faster to make up than bolted flange connections because fewer bolts are required. Rotational alignment is unnecessary as the mating hubs do not have bolt holes. On the other hand, most

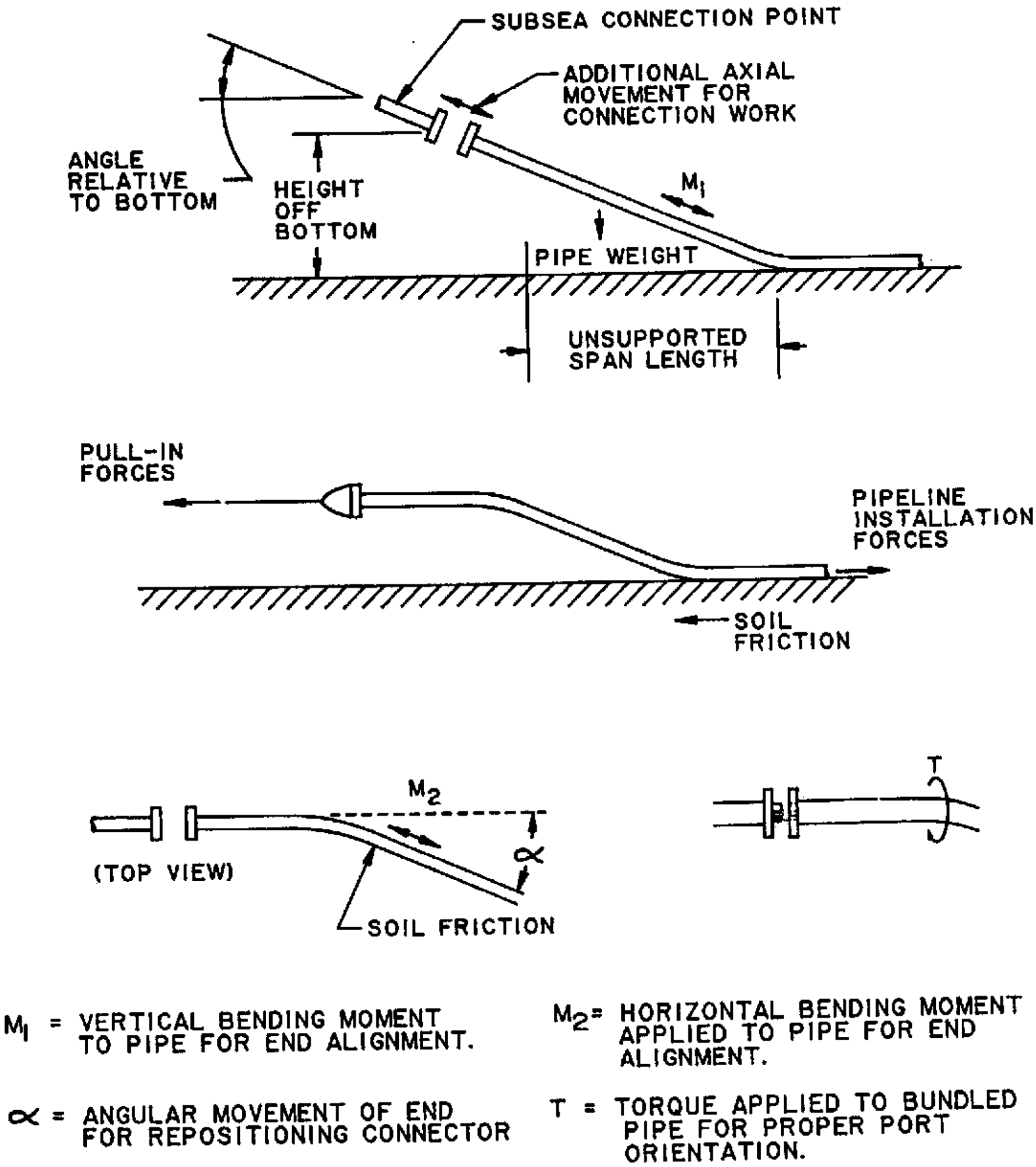


Figure 21—Factors That Influence Alignment Loads and Stresses

clamped hubs do not permit the amount of initial misalignment that bolted flange connections may provide.

c. Welding pipe under water is usually performed by one of two dry welding methods which involve either a one-atmosphere chamber or a chamber filled with an inert gas at ambient water pressure (hyperbaric). Both methods use manual welding techniques that are subject to the API Standard 1104 welding code. The higher pressures and gas mixtures involved with hyperbaric welding may affect the quality of the weld unless special qualified procedures are used.

d. Proprietary connectors are specially designed underwater connectors to perform final alignment, locking, and seal energizing tasks. Proprietary connectors latch the pipeline to the connection point by various means such as expanding collets, locking dogs, or other mechanical devices. The latching procedure generally includes a few inches of axial travel for one or both pipe ends being connected.

Proprietary connectors can be classified as either mechanical or hydraulic. *Mechanical connectors* are activated by divers or remotely through special tools. These tools are retrieved after connection leaving only passive mechanical hardware subsea. *Hydraulic connectors* are mechanical connectors with hydraulic actuation devices. Hydraulic connectors are generally operated via multi-hose hydraulic control lines, and may leave the hydraulic actuation devices subsea after connection.

Proprietary connectors typically use specially designed metal gaskets that are deformed when the connector is locked.

4.4.2.4 Connector design: pipeline connector choice and its subsequent design should consider factors such as water depth (and diver intervention), type of connection point, pipeline installation method, and misalignment tolerance compatibility with the alignment method. In addition, the choice and design of the connector can be influenced, by the following:

a. Residual stresses in the pipe and pipeline connector resulting from a particular alignment method and the additional axial movement required for end connection (Figure 21) should be analyzed in conjunction with operating stresses to determine if the combined stress is within allowable limits.
b. Materials used in the connector design should be chosen based on design loads and their compatibility with fluids, service conditions, temperature, weldability, corrosion/erosion resistance, and isolation of dissimilar metal galvanic cells.
c. Make-up requirements for connectors should be reviewed to ensure that:
   1. The connector will deform (or deflect) the gasket to effect a seal.
   2. There is enough preload in the connector to offset the installation and operating loads that could otherwise break the gasket seal.
   3. There is enough axial clearance and access for seal replacement.
d. Pipeline connectors should be in-plant tested to the hydrostatic test pressure stipulated for the pipeline as recommended in API Recommended Practice 1111. In some cases, the connector may be part of and tested with the subsea facility. In such cases, the connector should be tested to the hydrostatic test pressure stipulated for the subsea facility. If TFL is specified, each made-up connector should be drifted in accordance with API Recommended Practice 6G. Additional in-plant testing may be required to verify make-up preloads, fit, and functional performance of locking devices and hydraulic actuation devices.

End connector equipment should be designed to provide some testing means to verify that the gasket has formed an adequate seal, and that the connector has been fully actuated or clamped together after it has been installed subsea.

4.4.3 Fabrication/Installation Design

4.4.3.1 The pipeline will normally contain components that should be fabricated, assembled, drifted, or packaged on land and offshore in a shelter with limited exposure to the environment. As such, consideration should be given to some of the following factors:

a. Should welding be chosen, it is necessary to ensure that proper welding specifications/techniques are both available and utilized during the design and fabrication process. Mechanical joining techniques, if chosen, should be evaluated with regard to metal compatibility as varying electrochemical nobility among dissimilar metals could cause adverse corrosion effects.
b. Sizing of fabricated components should be thoroughly evaluated both to permit ease of fabrication by personnel within a shelter and to hamper neither the transportation nor the installation of the components.
c. In the case of bundled lines, which may or may not be encased, particular attention should be paid to the location of all connections to ensure ease of fabrication. For cased bundles, sufficient access should be allowed to enable joining the individual lines prior to the joining of the casing.
d. Selected coating systems should be investigated for their adhesion properties with the pipeline surface (to avoid slipping), mechanical strength, and damage resistance during pipeline fabrication, handling, and installation. Coating layers should be terminated a sufficient distance from the end of the pipe joint for easy access to the ends for joining. Should welding be chosen, the coating system should be terminated a sufficient distance away from the heat zone.

4.4.3.2 Joining of the pipeline sections is normally achieved through welding. The weld joints should meet the minimum requirements of API Standard 1104 and/or ANSI B31.3, B31.4, B31.8. Should a mechanical technique be selected for joining, the connection should be investigated for its capability to withstand the combined stresses in the pipeline.

In either case, should the pipeline be used as a TFL service line, joining techniques should be used in accordance with API Recommended Practice 6G Section 3. Particular attention should be given to joint design tolerance stackup from the tolerances allowed for piping under API Specification 5L and joint tolerances under API Recommended Practice 6G.

If a coating system is used, a protective sleeve or coating splice may be required to protect the ends of the coating, or to fill in the gap. Joining procedures should incorporate proper field dressing of the joint to ensure the integrity of the coating system. Examples of joint field dressing include painting, tape wrapping, heat shrink sleeves, pouring quick setting materials in a temporary mold, and fastening sectional bracelets. Similar field dressing procedures should be established in the event the coating system, joint, or pipeline are damaged during installation.

5 Control Systems, Lines and Fluids

5.1 SCOPE

This section provides functional and design guidelines based on current industry practices in the use of control systems, control lines, and control fluids. An overview of commonly used control system types is presented to familiarize the reader with the important operating features of each, and to aid in selecting or specifying a control system for a particular application.

5.2 SYSTEM DESCRIPTION

Subsea control systems consist of two major subsystems (a) installation and workover (I/WO) (Figure 22), and (b) production control, (Figure 23). ROV and diver intervention is used in many instances in place of, or as a back-up to, hardware and control components. Subsea data monitoring/acquisition is used as necessary to provide information relating to well or production system status.

5.3 FUNCTIONAL CONSIDERATIONS

5.3.1 Installation/Workover Control System

An I/WO system provides the means to control subsea equipment functions associated with the following:

a. Initial installation and testing of production facilities and ancillary support equipment.
b. Operation of production facilities during vertical reentry for well servicing.
c. Retrieval and subsequent reinstallation of portions or all of a production system to facilitate a major well workover.

Installation and workover controls are generally designed to actuate all of the normal production functions, as well as functions that are restricted to installation and workover phases. Examples of restricted functions are connector latch/unlatch, vertical well bore access, and SCSSV control line isolation valve open/close.

5.3.2 Production Control System

A production control system provides the means to control operation of a subsea production facility. Depending on the nature of the system, production control functions typically include:

a. Open/close downhole, tree, manifold, and flowline valves during normal operation.
b. Shift position of TFL tool diverters.
c. Control subsea chokes.
d. Shut-in production due to abnormal flow conditions (for example, high-low pressures).
e. Operate miscellaneous utility functions.

Production control systems are seldom provided with a means of controlling installation functions such as latching subsea hydraulic connectors or operating vertical access valves and pressure test ports.

A subsea control pod, if used, is normally mounted directly on the facility to be controlled (for example, a subsea tree). Locating the pod either on a tree cap or on a special base depends upon the design of the subsea facility.

5.3.3 Control System Types

Several control system types are used for installation/workover and production operations. General characteristics of the most common systems are shown in Table 2.

Because of the large number of variables and the high degree of operator preference in choosing control systems, only relative comparisons of systems are possible. Important features of each system are described in the following sections. Common to each is the requirement to provide high pressure hydraulic fluid to subsea controlled functions. This is accomplished by a hydraulic power unit (HPU) that is generally located on the surface, but may also be located subsea. Types of control systems include the following:

a. Open control system: a system in which spent control fluid is exhausted subsea (Figures 25, 27, and 28).
b. Closed control system: a system in which spent control fluid is returned to a reservoir subsea or surface, and is subsequently repumped (Figures 24, 26, 29, and 30).

5.3.3.1 A closed direct hydraulic control system (Figure 24) utilizes a single line between a surface control valve and a subsea function or group of ganged functions. This system can provide individual control over each subsea function or group of functions. It can also provide inferred feedback concerning subsea operations from pressure switches on the control line, and by metering fluid supply and return.

An open direct hydraulic system (Figure 25) utilizes a dump valve subsea. This system improves valve operating time by eliminating the need to flow control fluid back to the surface facility and renews control fluid with each operation.

5.3.3.2 Discrete piloted hydraulic control (Figure 26) utilizes a signal line between a surface control valve and a subsea pilot control valve for each subsea function or group of ganged functions. A common high pressure hydraulic supply is used between the surface and the subsea facility. This system provides discrete control over each subsea function.

5.3.3.3 Sequential piloted hydraulic control (Figure 27). utilizes subsea pilot valves that switch position at signal pressures applied from the surface. Subsea pilot valves are interconnected so that high-pressure hydraulic fluid supply is applied to subsea actuators in a predetermined sequence in response to preset changes in signal pressure. Independent, discrete function control is not possible with this system, and there is no ready means of confirming device operations other than by observing fluid flow or pressure build-up. Operating sequences must be determined in advance.

5.3.3.4 Direct electrohydraulic control (Figure 28) utilizes a single separate electric circuit in a subsea electrical cable to control a solenoid pilot valve for each function or group of ganged functions. A high pressure hydraulic line normally supplies control fluid subsea.

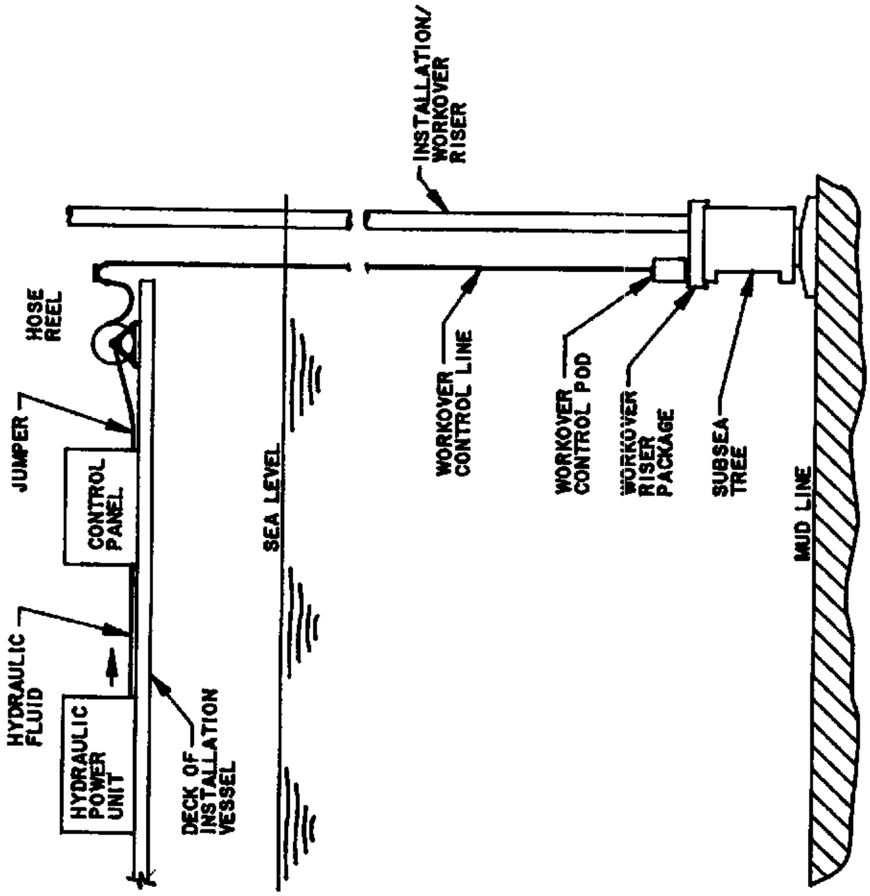


Figure 22—Schematic Design Installation/Workover Control System

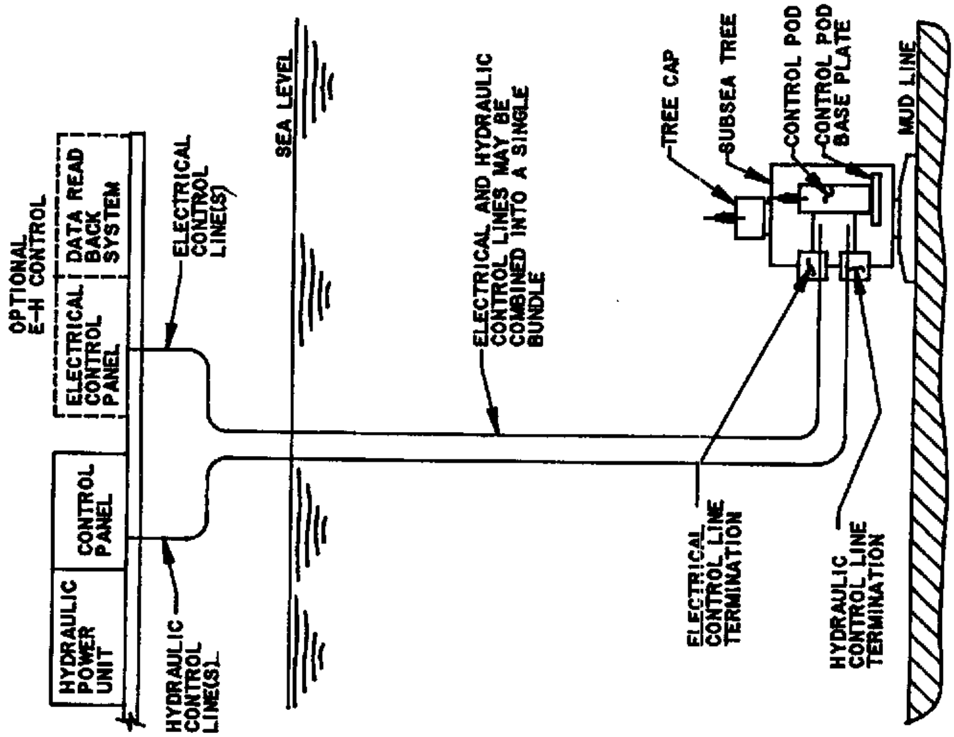


Figure 23—Schematic Design Satellite Well Production Control System

Table 2—Characteristics of Different Types of Control Systems

Features Systems	Complexity	Response Rate		Discrete Control Subsea Functions	Data Readback	Umblical(s)		
		Signal	Actuation			Type	Size	Length
Direct hydraulic	Low	Slow	Slow	Yes	Separate if desired	Hydraulic	Large	Short
Discrete piloted hydraulic	Moderately low	Slow	Fast	Yes	Separate if desired	Hydraulic	Moderately large	Moderate
Sequential piloted hydraulic	Moderate	Slow	Fast	No	Separate if desired	Hydraulic	Small	Moderate
Direct electro-hydraulic	Moderate	Very fast	Fast	Yes	Separate if desired	hydraulic and electric or composite	Moderate	Long
Multiplexed	High	Very fast	Fast	Yes	Integral	Hydraulic and electric or composite	Small	Long

5.3.3.5 The electrohydraulic multiplex system (Figure 29) is the most commonly used form of electrohydraulic control. It utilizes dedicated or common conductors to supply control signals (usually multiplexed digital data) and power for the operation of all subsea functions. Electronic encoding and decoding logic is required at the surface and subsea. This approach reduces electrical cable and subsea electrical connection complexity and lends itself to the use of inductive couplers in underwater make-and-break circuits. Figure 30 shows a schematic of an E-H multiplex control system that uses a subsea hydraulic power unit (see Section 5.4.3.2).

5.3.3.6 Many completion systems use ROVs and/or divers as primary or back-up systems during installation and operation of subsea production systems. Typical functions of the ROV/diver include:

a. Observation.
b. Operation of connectors.
c. Operation of valves.
d. Operation of manual overrides on valves and connectors.
e. Guidance during equipment placement and retrieval

5.3.4 Control System Monitoring/Data Acquisition

The need for data acquisition is normally dictated by the complexity of subsea operations and/or operator preference. The need/benefits of having data readback should be evaluated when designing or specifying a control system. Examples of functions that may be monitored include the following:

a. Valve, choke, or diverter position.
b. Well/production stream temperatures and pressures.
c. Differential pressures across chokes.
d. Control system variables, such as pressures and hydraulic fluid usage.
e. Pig or TFL tool location.
f. Hydrocarbon leaks.
g. Downhole temperature and pressure monitoring.

Subsea monitoring is easily implemented as an integral part of a multiplexed electrohydraulic control system (see Section 5.3.3), or it can be an independent feature of an all-hydraulic control system. Common data acquisition system transmission modes are hardwire, multiplexed, and acoustic.

5.3.5 Test Stands and Test Equipment

Test stands and equipment ensure that the control system equipment is functioning in accordance with all operational specifications prior to installation.

5.3.6 Subsea Systems

5.3.6.1 When used, a control pod (or control module) is the interface between the control lines, which supply hydraulic and/or electric power and signals from a surface facility, and the subsea facility to be controlled. It is generally mounted on a base from which it can be removed for maintenance or replacement. The control pod contains pilot valves powered by hydraulic fluid or electric power (or both) which is supplied from a surface facility. If specified, the pod can also contain electric or electronic components that are used for control, communications or data gathering.

5.3.6.2 The types of control lines and their functions include the following:

a. Hydraulic control lines: conduct hydraulic fluid supply and return, and hydraulic signals between a surface facility and subsea control systems. Individual hoses or tubes making up the control line may be manufactured from carbon steel, corrosion resistant steels, thermoplastic materials or flexible pipe.

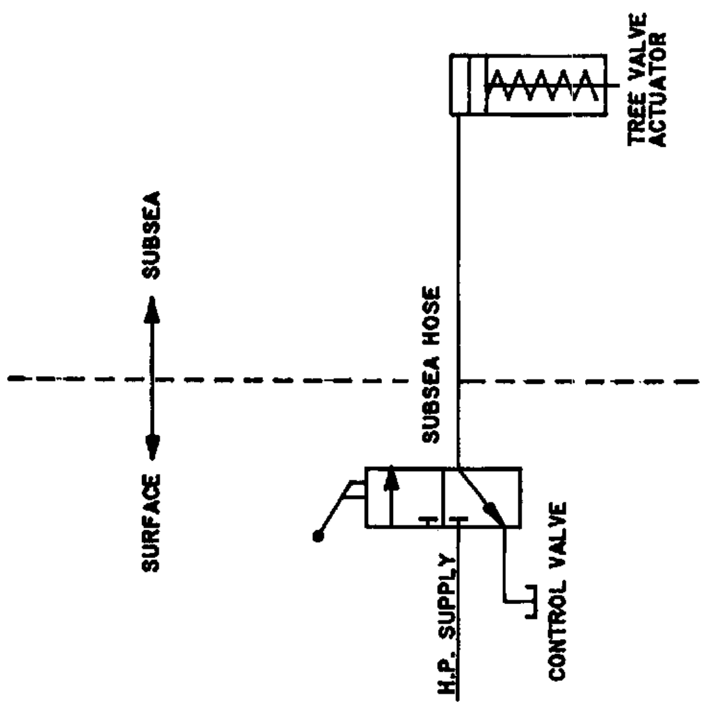


Figure 24—Closed Direct Hydraulic Control

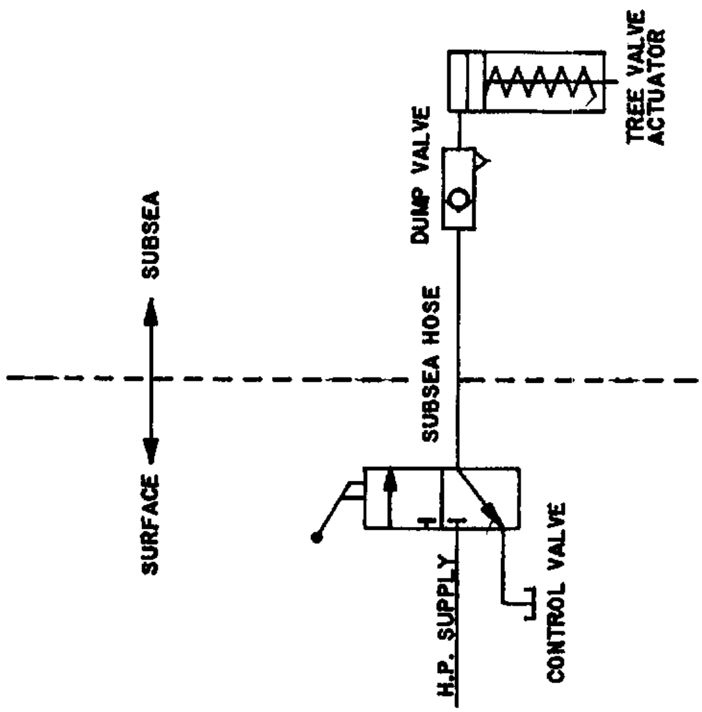
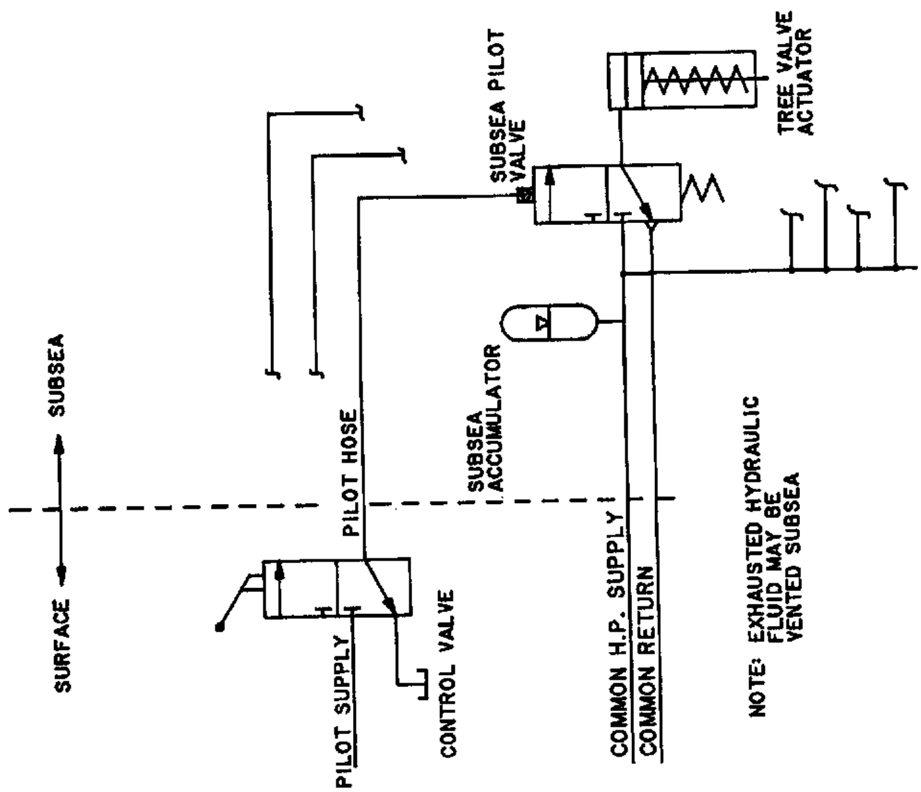
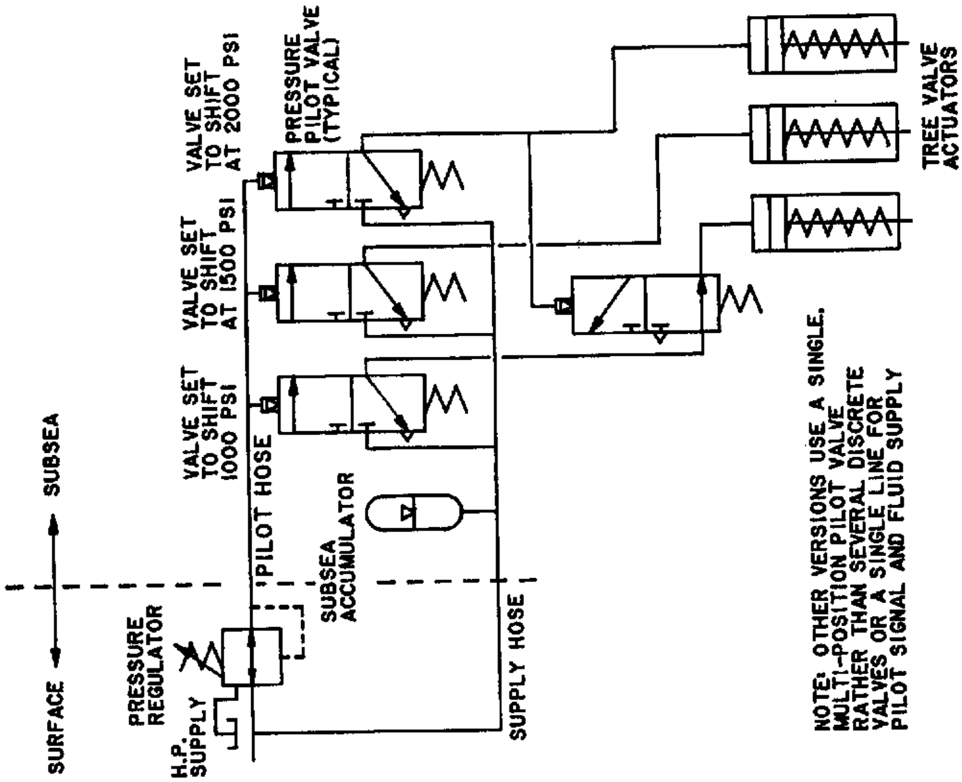


Figure 25—Open Direct Hydraulic Control With Subsea Dump Valve



NOTE: EXHAUSTED HYDRAULIC FLUID MAY BE VENTED SUBSEA

Figure 26—Discrete Piloted Hydraulic Control



NOTE: OTHER VERSIONS USE A SINGLE, MULTI-POSITION PILOT VALVE RATHER THAN SEVERAL DISCRETE VALVES OR A SINGLE LINE FOR PILOT SIGNAL AND FLUID SUPPLY

Figure 27—Sequential Piloted Hydraulic Control

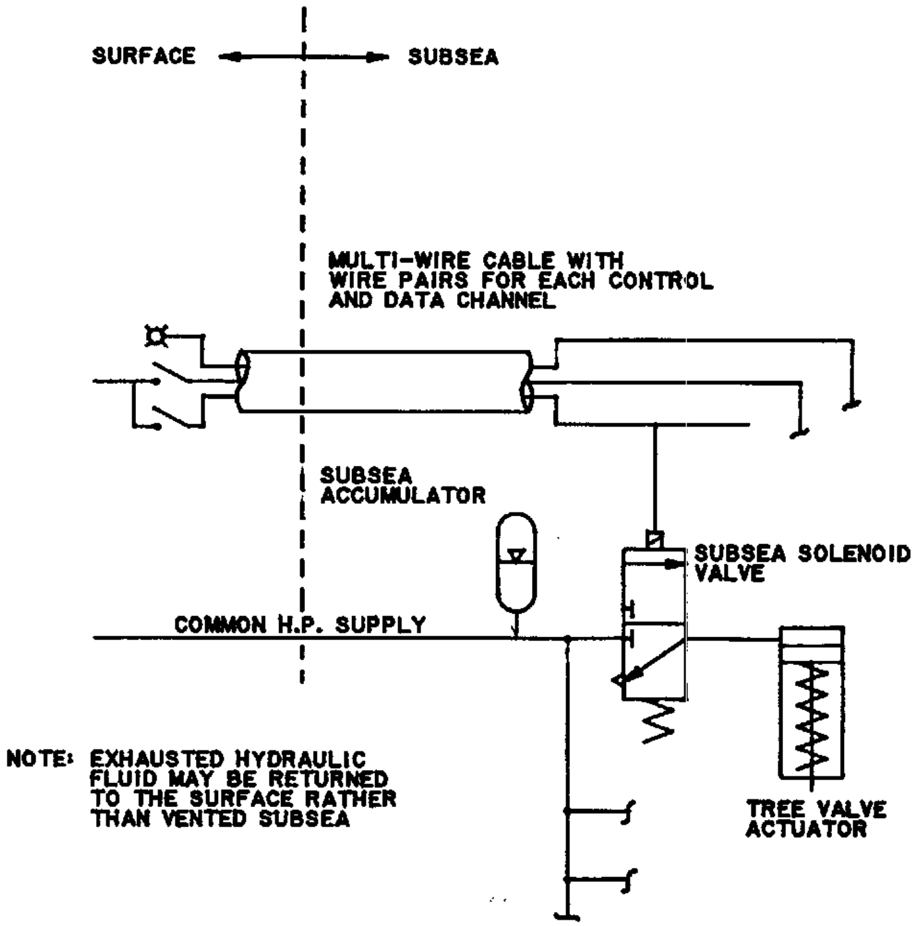


Figure 28—Direct Electrohydraulic Control

b. Electrical control lines or cables: generally contain both power and signal conductors, and can either be deployed as a separate control line or combined in a common bundle with hydraulic control lines.

5.3.6.3 Pressurized control fluids are used to actuate subsea functions: these fluids are designed to lubricate and to provide corrosion protection to wetted parts. Both biodegradable water-based and petroleum-based fluids are used. Water-based fluids should be used in open systems in which spent fluid is exhausted subsea. Petroleum-based fluids should only be used in closed systems in which exhausted fluid is returned to a reservoir for repumping.

5.3.7 Control Functions

Table 3 lists typical remotely controlled functions of I/WO and production control systems. Any of the listed functions, except SCSSV, may be operated manually using divers or ROVs. However, API Recommended Practice 14H should be followed for installation and operation of underwater safety valves. Use and control of SCSSV isolation valves varies. However, possible leakage of well bore fluids into SCSSV control lines should be considered during control system design.

5.4 DESIGN CONSIDERATIONS

5.4.1 General Design Factors

The following general factors should be considered during control system design.

5.4.1.1 Control systems should withstand environmental effects such as water depth, currents and turbidity, marine life, seafloor conditions, and operating temperatures.

5.4.1.2 Control system operability may be maximized by the following procedures:

a. Selecting high reliability assemblies and components.
b. Selecting components that have a high resistance to wear and corrosion.
c. Providing component redundancy.
d. Providing back-up or secondary systems.

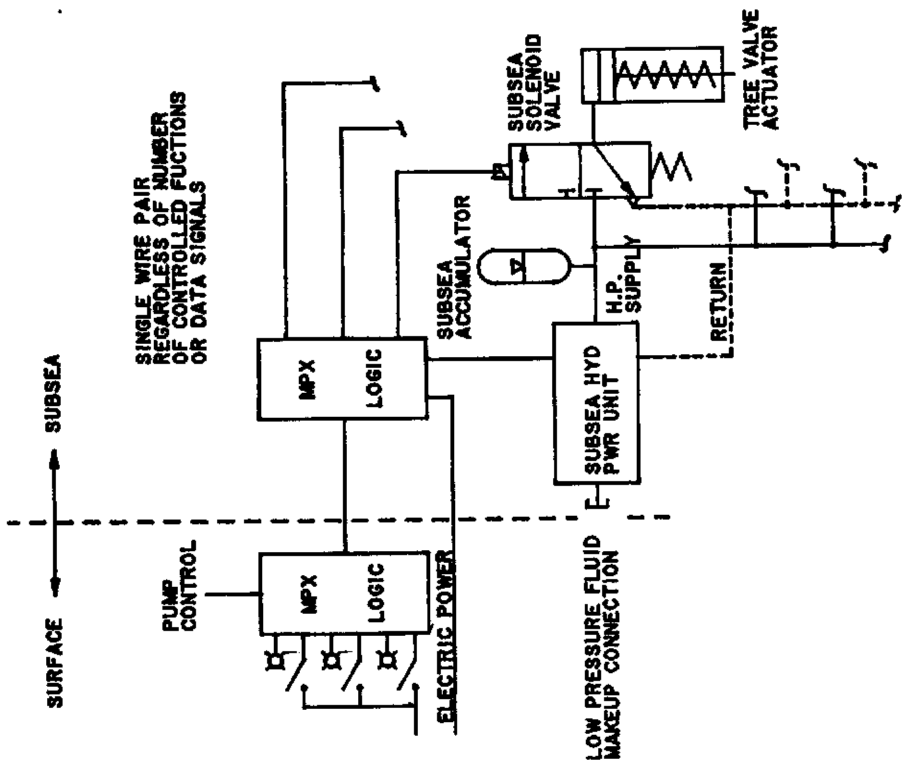


Figure 30—Electrohydraulic Multiplex Control With Subsea Hydraulic Power Unit

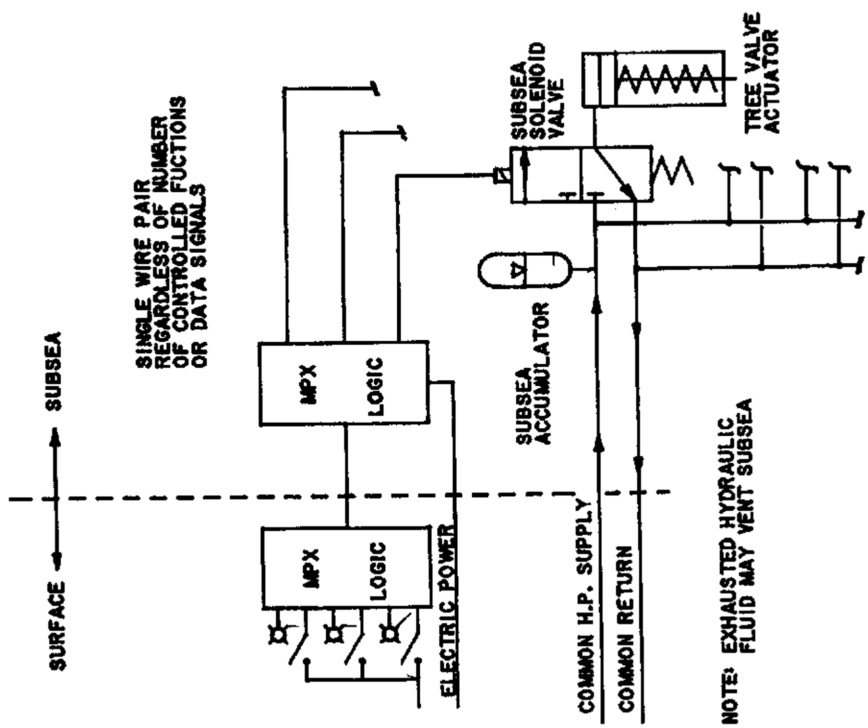


Figure 29—Electrohydraulic Multiplex Control

Table 3—Typical Subsea Production System Control Functions

Component	I/WO Control System	Production Control System
I. Christmas tree		
1. Master valves	Open/close	Open/close
2. Wing valves	Open/close	Open/close
3. Swab valves	Open/close	—
4. Crossover valve	Open/close	Open/close
5. SCSSV Isolation valve	Optional	Optional
6. SCSSV	Open/close	Open/close
7. Flowline valves	Open/close	Open/close
II. Running tools		
1. Tree connectors	Latch/unlatch	—
2. Flowline connectors	Latch/unlatch	—
3..Riser connectors	Latch/unlatch	—
4. Manifold connectors	Latch/unlatch	—
5. Miscellaneous functions	Lock/unlock Extend/retract	—
III. Manifold		
1. Block Valves	—	Open/close
2. Chokes	—	Open/close
3. Diverters	Chg. position	Chg. position

Notes: Not an all inclusive list of functions. Not all functions are required. Any function shown may be operated manually subsea, except SCSSV. Use of a SCSSV isolation valve is optional.

e. Providing diver/ROV intervention capability.
f. Providing system bypasses.
g. Providing spare units (modules) for replacement.
h. Establishing control fluid properties and cleanliness standards.
i. Establishing QA procedures.

5.4.1.3 Maintenance should be considered early in system design. Maintainability of surface and subsea equipment can be enhanced by the following procedures:

a. Designing equipment for accessibility and easy maintenance.
b. Designing control system assemblies to be retrieved independently from subsea completion hardware.

5.4.1.4 Generally, "immediate" actuation of subsea devices is not required. Control system design should consider both the time for control signals to reach the subsea control pod (signal time) and the time for the controlled device (such as a tree valve,) to shift position (actuation time).

5.4.1.5 Produced fluids may affect pressure/temperature rating and material selection of control system components (primarily monitoring devices) that are in contact with the produced fluid. Produced fluids pressure may also affect hydraulic fluid pressure required to actuate SCSSV and tree valves.

5.4.1.6 If subsea intervention is envisioned, sufficient access plus reaction/anchor points should be provided in the vicinity of potential work areas to ensure that divers or ROVs can do the required work.

5.4.2 Surface Control Systems

5.4.2.1 The hydraulic power unit (HPU) provides fluid storage, fluid conditioning, high pressure generation, and high pressure fluid storage. A typical HPU schematic is shown in Figure 31. Design requirements include the following:

a. The HPU should be equipped with sufficient number and sizes of hydraulic pumps to satisfactorily keep up with minor internal leakage and normal system operation. Additional pump capacity may be warranted to facilitate testing of subsea valves and controls. Two independent sources of power (electrical and pneumatic) are often used. Each should be capable of operating the pumps at a rate that will allow normal system operation.

The pressure required to operate SCSSVs may be greater than that required to operate tree valves; therefore, a high pressure SCSSV circuit may be required.

b. Each HPU should be equipped with the following components:

1. Sufficient check valves or shut-off valves to isolate pumps and accumulator banks from the low- and high-pressure manifolds.
2. Pressure gauges to indicate manifold pressure and pressure upstream and downstream of any pressure regulating valve.
3. Isolation valves for each tree, if the installation is multi-well.
4. Clearly labeled control valves that indicate the function that each control valve operates and the position (open/close) of the valves.
5. Relief valves on pump discharge.

c. The low pressure fluid storage reservoir should be capable of storing sufficient fluid to provide efficient operation. The reservoir should also be capable of handling return fluid requirements. A reservoir fluid level indicator should be employed. A low fluid level alarm and shutdown is recommended to prevent running the pumps dry.

d. High-pressure storage accumulators with sufficient usable fluid volume to satisfy the subsea production system requirements are recommended for efficient operation.

Usable fluid volume is defined as the volume of fluid recoverable from an accumulator between the operating pressure and the minimum system working pressure. Minimum operating system volume requirements normally include the sum of all tree valve and SCSSV operators, and the volume of system internal leakage for some specified time period. Additionally, direct hydraulic systems should consider the effects of fluid compression and hose expansion. Careful consideration should be given to system cycle rate and recharging capacity of hydraulic pumps.

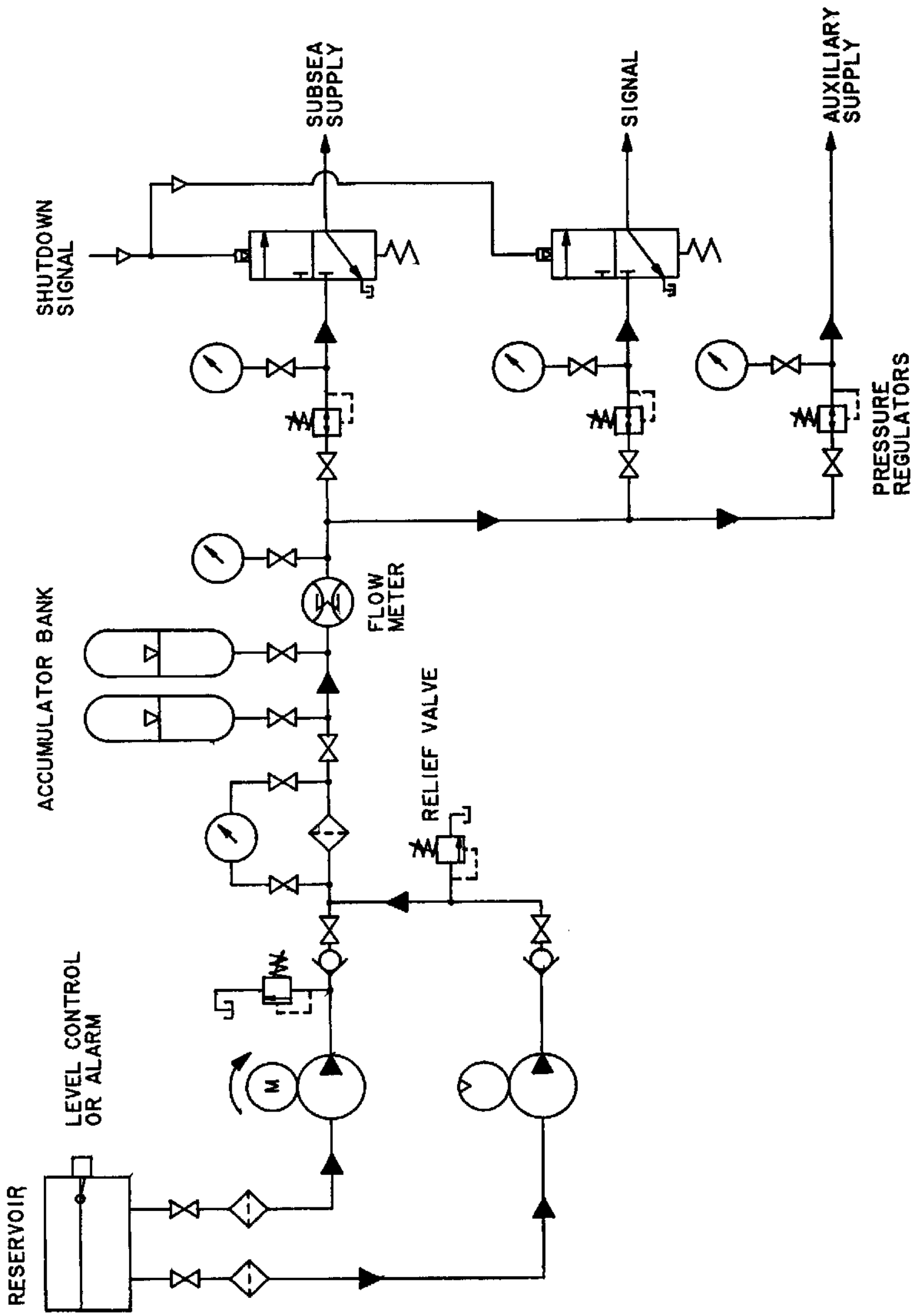


Figure 31—Schematic of Hydraulic Power Unit

e. Fluid filters should be provided to achieve required fluid cleanliness. They should be easily replaced with minimum contamination risk to the system. A clogged-filter indicator is recommended. In case of an oil-based system, water removal is also a consideration.

5.4.2.2 The control panel can either be a stand-alone unit or be integrated with the HPU. If possible, panel face layout should mimic the controlled facility. All controls and indicators should be properly labeled, and all components should be suitable for the operating environment. For production control units, the control panel should be connected to a shutdown system that shuts in subsea production upon command from the surface process facility.

An uninterruptible power supply (UPS) capable of operating the control system for a specified length of time in case of an electrical power failure should be considered for electrical control systems.

5.4.2.3 Electrical equipment design should meet hazardous area location requirements. API Recommended Practice 500B should be followed as a guideline for establishing hazardous area classification.

5.4.3 Subsea Systems

5.4.3.1 The components of control pods and their design considerations include the following:

a. Components should be protected from the environment and from the mechanical damage that can occur during transportation, handling, and installation. An outer housing usually provides this protection.

When used, electronics should be contained in a one-atmosphere, dry-nitrogen-filled pressure vessel or in a pressure-compensated, dielectric-fluid-filled chamber. Other electrical components (such as pressure switches, pressure transducers, flow meters, and so forth.,) are normally designed to operate at ambient subsea hydrostatic pressure.

b. Footers affecting specific control pod connections include the following:.

1. Control pod to tree, manifold or riser base connections are generally made so that the control pod can be retrieved for maintenance. Hydraulic and electrical connections should be mateable under water. Parting forces, if any, between the pod and base plate, exerted by hydraulic fluid pressure, should be analyzed to determine whether the pod must be locked down during operation. If the pod is locked down, two release methods should be considered (for example, hydraulic and mechanical).

2. Control lines may be connected directly to the control pod, as shown in Figure 32, View A, or to intermediate components, as shown in Figures 32, View B and 31, View C. Other configurations are possible. Make-up of the control line connection may be done on the surface or subsea using diver-assisted or diverless methods.

3. Control components or circuits which are isolated from produced or injected fluids by a single seal, should have the same pressure rating as the tree. Components affected include SCSSV hydraulic circuits and tree mounted sensors.

c. When control lines are not installed or if the control pod is removed, consideration should be given to protecting hydraulic and electrical connections from physical damage and from collection of foreign material or marine life.

d. Running tools used to run and retrieve control pods should be designed to provide suitable guidance and orientation. Guide structures should be sized to support expected horizontal and vertical contact forces and designed to accept equipment entry within a specified misalignment.

5.4.3.2 Key considerations for providing subsea hydraulic power include the following:

a. Subsea pumps and motors should be sized to closely match operating requirements, which minimizes electric cable size. However, consideration should be given to testing requirements when sizing subsea pumps. Although subsea pumping systems are closed systems, provision for replenishing "lost" fluid should be made.

b. Maintaining the cleanliness of the hydraulic fluid is important for system reliability. Use of filters in the subsea control module is recommended. Flushing and cleaning of all portions of the control system prior to installation is an important factor in achieving high system reliability (operability).

c. Subsea accumulators are used to improve valve actuator response times and to minimize hydraulic pressure transients subsea. The effect of hydrostatic pressure should be considered in addition to those factors mentioned in Section 5.4.2.1, Item d when using accumulators subsea.

5.4.4 Control Lines

5.4.4.1 Hydraulic control lines are generally comprised of reinforced thermoplastic hoses, steel tubing, or pipe, which are bundled together with a protective jacket and/or armor. A number of factors should be considered in the design and fabrication of a hydraulic control line. They include the following:

a. Two factors that enter into selection of control line size are response time and fluid flow rate. A third factor, handling considerations, is important especially for long control lines (that is, use of smaller diameter lines may reduce or eliminate the need for control line splices).

b. Factors affecting the selection of thermoplastic hoses include:

1. Hose liner materials must be compatible with wetting fluids (that is, control, produced, or injection fluids) and temperatures as dictated by the application.

2. Volumetric expansion of long pilot/signal lines may

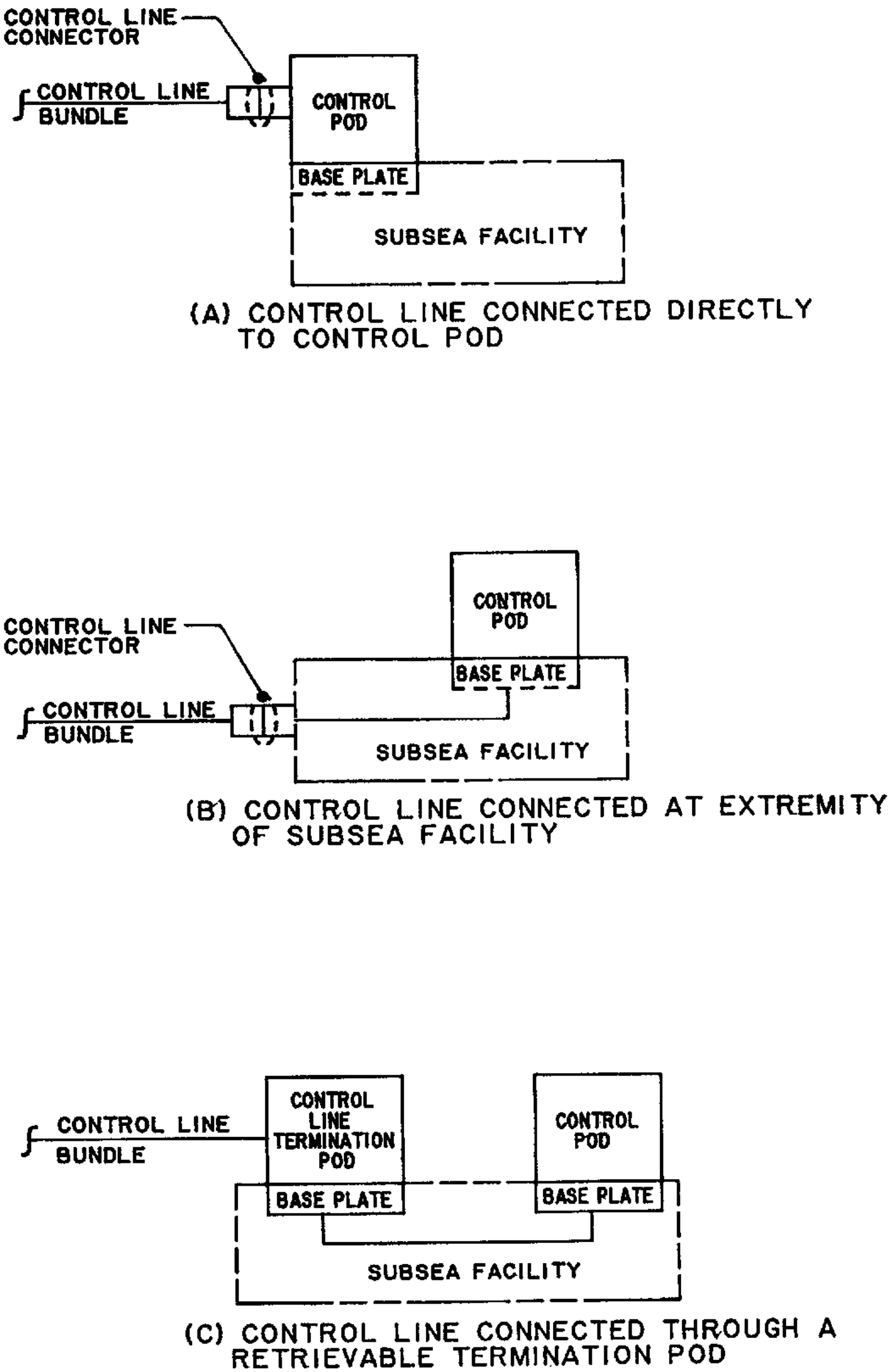


Figure 32—Control Line to Control Pod Connection Methods

be an important design consideration because of its effect on response time and reservoir/accumulator sizing.

3. The hose jacket material should offer abrasion resistance and provide proper bedding for mechanical attachment of hose end fittings. The material should have good mechanical strength, sufficient hardness to resist cold flow, and be non-abrasive to fiber strength members.

c. Selection of tubing/pipe material should be based on the application, design life, and environment. A primary concern is the effect of long-term corrosion and work hardening during installation on tubing pressure rating. Use of corrosion resistant alloys is recommended.

d. Hose termination fittings normally are a corrosion resistant swivel nut type fitting with a metal-to-metal seal surface. Hose end fittings should be permanently attached to the hose. Reusable fittings are not recommended for subsea use, but may be used on the surface if they are accessible. Subsea connectors, the anchor mechanism, and surrounding metals should be compatible with corrosion-resistant hose termination materials to minimize galvanic corrosion.

e. Individual thermoplastic hoses should be cabled (bundled) to form a tight bundle with allowance for expansion and change in length of hoses (Figure 33). An overall thermoplastic jacket is normally extruded over the bundled hoses. The jacket provides nominal protection against abrasion and cuts, and holds the hose bundle together.

Contra-helically wound, torque balanced, or nonrotating construction armor may be used on production control line bundles to facilitate control line installation, and to provide stability and minor mechanical protection on the seafloor.

f. When steel tubing is used in a bundle, the individual tubes may be laid out in a parallel array and encased in an extruded thermoplastic jacket. Steel cables are incorporated in the jacket on either side of the tubing for ballast, and to provide tensile load carrying capability. Steel tubing may also be bundled similarly to thermoplastic hoses.

g. Individual hoses within a thermoplastic umbilical should not be spliced. If splices are required (usually because of long length), they should be contained in splice boxes, which provide protection and strength, and facilitate field service of the splice.

Steel tubing lengths should be joined together by approved welding procedures.

h. The hose bundle should be constructed (using armor as appropriate) such that installation loads do not result in a damaging strain on individual hoses. If the hose bundle is operated in a dynamic configuration, fatigue of components should be considered.

i. Recognized hose manufacturing standards (such as SAE 517D, 100R series) and testing standards (such as SAE J343) should be specified. It is recommended that all hose or tubing lengths be "proof pressure" tested.

5.4.4.2 Electrical control lines are generally comprised of power and signal conductors cabled together with an appropriate jacket and armor. Key design considerations include the following:

a. Electrical parameters: size of conductors, conductor resistance, voltage rating, cross talk between power and signal pairs, end-to-end attenuation, and characteristic impedance should be considered.

b. Redundancy: requirements for spare power and signal conductors should be considered.

c. Materials: factors affecting the control line components include the following:

1. Stranded copper wires are generally used for cable conductors.
2. Thermoplastics or elastomers are generally used as insulation material for conductors. Factors affecting material selection are expected service life, insulation quality, salt water resistance, and thickness.
3. Thermoplastics are common jacket materials. In water subject to Toredo worm infestation, protective measures should be taken in the jacket design. A copper sheath is a commonly used worm barrier.
4. Galvanized improved plow steel, galvanized mild steel, stainless steel, and thermoplastic sheathed steel wires are generally acceptable armor wire materials.

d. Armor design: production control cables should be armored to provide:

1. Strength to support cable weight and dynamic loads during installation and recovery. Recovery loads may be significantly greater than installation loads.
2. Mechanical protection before and during laying.
3. Torque balancing at varying tensile loads if the cable is laid from a cable reel or subject to dynamic loads.
4. Minor mechanical protection and stability on the seabed.

Design working strength of an armored electrical cable is normally defined as the maximum tensile load at which a resultant strain will not cause mechanical or electrical damage to conductors within the cable. Design breaking strength of the cable armor is generally four times the design working strength. If electrical cables are operated under dynamic conditions, the maximum working load should be limited to 10 percent to 20 percent of cable design breaking load.

e. Water sealing: the cable jacket and cable terminations should be designed such that cable interstices are normally dry. However, individual conductor jackets and conductor terminations should be designed such that the cable will be able to operate with interstices flooded.

f. Cable terminations and bend restrictors: cable terminations should be designed to interface with the cable armor, providing mechanical strength to facilitate the laying, stab-in, or pull-in of the cable.

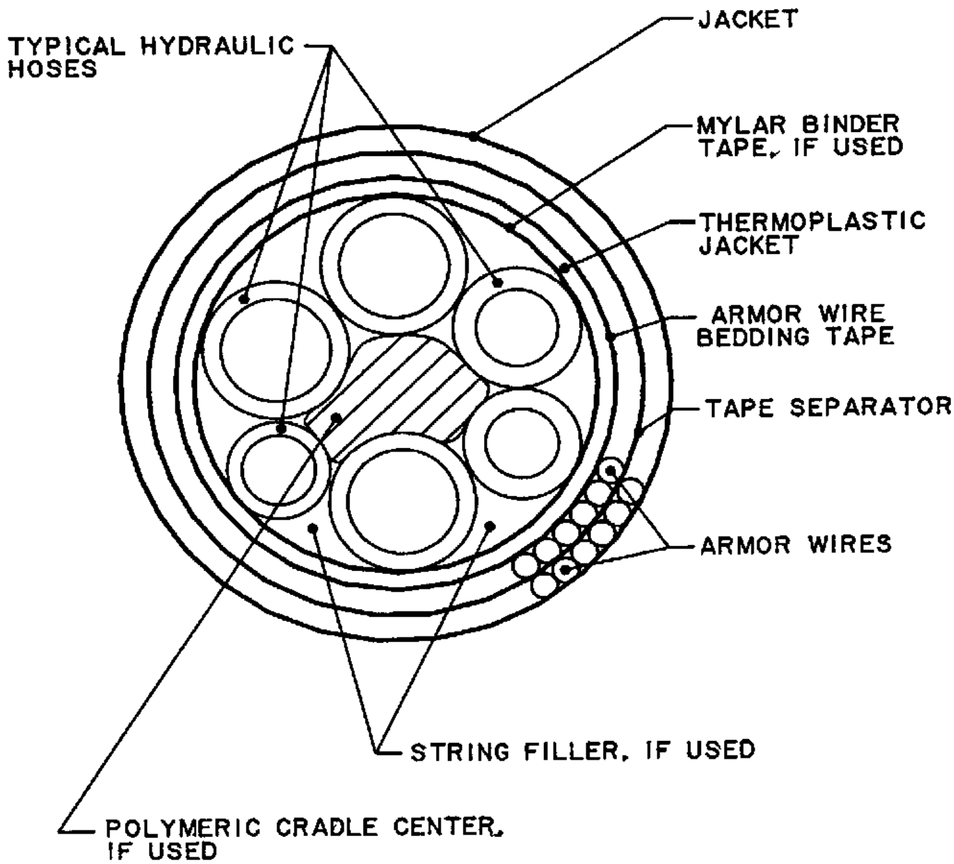


Figure 33—Typical Cross Section of Double Wire Armored Hydraulic Control Line

Bend restrictors at terminations should be provided to protect the cable from bending at a radius smaller than its design minimum bending radius.

g. Cable connectors: electrical cable connectors at the subsea end of the electrical cable consist of the following general types:

1. Inductive couplers: electrical energy is transmitted through magnetic coupling of the two connector halves. Inductive couplers work only with AC electrical circuits. Some loss of energy is typical with these devices.

2. Conductive connectors: electrical energy, either AC or DC, is transmitted with little power loss through conductive, pin and socket, connectors.

Choice of a cable connector should be based on the type of electrical power or signal (AC or DC), frequency range, power level, and acceptable power loss across the connector.

h. Conductor and cable splicing: individual conductors should be fabricated in one piece without splices. Cable splicing, if required, should be designed with appropriate connectors that will transmit armor strength from one section of the cable to the next.

i. Repair and retrieval: the cable, terminations, armor joints, and installation methods should be designed to facilitate the possible need to retrieve and repair.

j. Construction (Figure 34): generally accepted construction practices for subsea production control cable are as follows:

1. Conductors are generally arranged to provide a circular cross-section and are cabled in a helical twist. Conductor insulation thickness, space between conductors, and pitch of twist can be adjusted to provide the optimum mechanical and electrical characteristics.

2. A thermoplastic jacket is normally extruded over the cabled conductors. This jacket is also used as bedding for the armor wires if the cable is armored.

3. Armoring of the cable is generally fabricated with two layers of contra-helically wound, torque-balanced, or non-rotating construction steel wires.

4. An overall thermoplastic jacket is sometimes extruded over the armor wires to preclude birdcaging, and for protection during handling.

k. Manufacture and test standards: conductor and cable construction and testing should be referenced to industry standards such as those of the Insulated Cable Engineers Association (ICEA). The ICEA Standards are prepared for industrial power applications. They should be used as a reference or modified as needed to suit the specific cable appli-

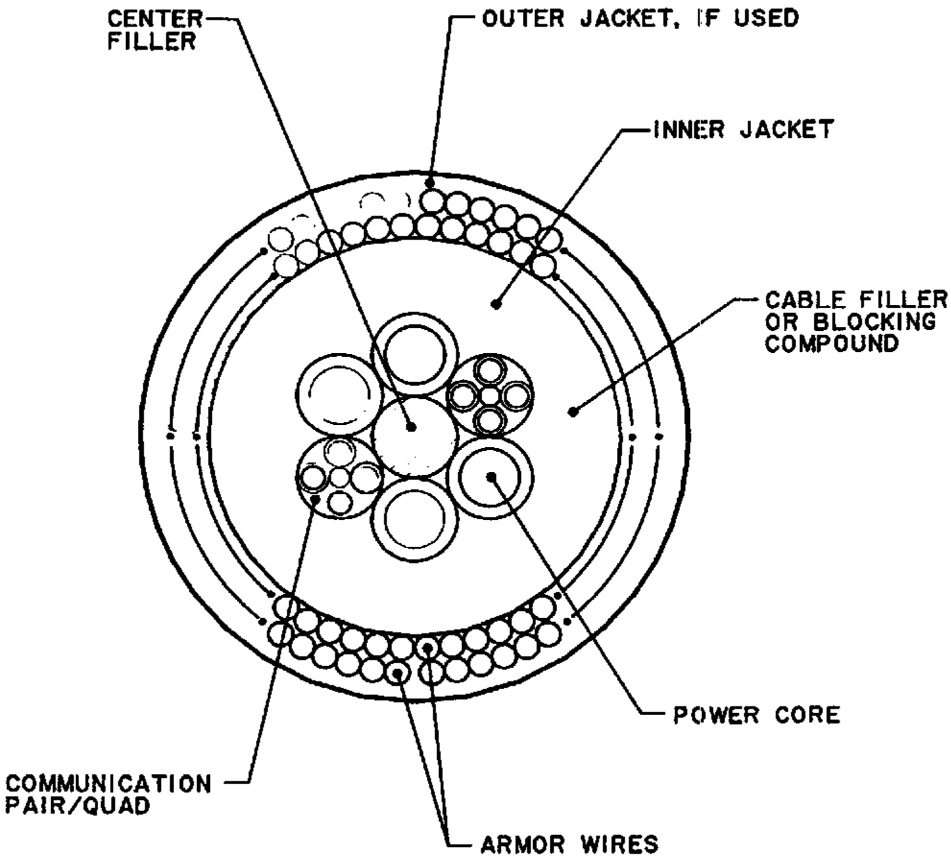


Figure 34—Typical Cross Section of Double Wire Armored Electrical Control Line

cation. Commonly used ICEA Standards are S-19-81, S-56-434, S-61-402, S-66-524, and S-68-516.

5.4.4.3 A composite control line contains both hydraulic hoses and electrical conductors in one single bundle. Provisions should be made in the lay-up configuration of the hoses and conductors to allow movement, expansion, and elongation/contraction of hydraulic hoses without damaging the electrical conductors.

5.4.5 Control Fluids

5.4.5.1 The following factors should be considered when using water-based fluids:

a. Important properties of water-based control fluids are given in Table 4. Control fluids should be formulated with these properties to provide long-term service, minimize corrosion and wear, and to remain non-toxic to handle as well as safe for discharge. Table 4 also provides information on test procedures that are used to evaluate control fluid properties. Care should be taken in system design and operation that these fluid properties are not destroyed by excessive filtering or heat.

b. Fluids should be clean prior to being placed in the control system. All hydraulic system components should be cleaned to the same cleanliness level during system factory acceptance tests. These tests should be conducted with the same fluid as will be used in service. Control fluids supplied by different manufacturers or different types of fluids should not be mixed because of the danger of forming precipitates.

Fluid cleanliness can be maintained during system start-up and operation by means of mechanical filtration. Provisions for circulation and/or intermittent renewal of the control fluid should be considered during the design of the control system in order to maintain the prescribed level of cleanliness.

Reference levels of contamination are contained in ISO 4406, BS5540: Part 4, NAS 1638, and MIL-STD 1246A. The level selected should be a function of control system component contamination tolerance. An appropriate means of determining particle size and distribution should be employed to evaluate contamination levels.

Fluids should have sufficient biocidal additives to resist growth of micro-organisms, which, if unchecked, can clog

Table 4—Control Fluid Properties

Property	Significance	Evaluation Test Procedure
Bacterial resistance	Provides resistance to the growth of micro-organisms, such as bacteria and fungus	No standardized test procedure is utilized; however, plate count bacteria cultures are often used to express levels of fluid contamination
Stability	Characterizes, the miscibility of the fluid, that is, the stability of the solid components to remain in solution, as well as the resistance of the fluid to seawater contamination	No standardized test procedure is utilized; however, numerous solutions of varying concentrations are typically subjected to long-term visual examination to determine stability
Compatibility	Characterizes the effect a fluid may have on the materials with which it will come into contact (that is, other fluids, seals, metals, metallic surfaces, paints, etc).	No standardized test procedure utilized
Corrosion inhibition	Provides protection against corrosion of any metal parts in contact with the fluid, as well as those in air spaces above the fluid	ASTM tests D-665 and D-1384 are often used to evaluate corrosion protection
Lubricity	Characterizes the ability of a fluid to form and maintain a film between rubbing surfaces of metal parts	Commonly used test procedures include ASTM tests, D-2670, D-2782, and D-3233
Toxicity	Characterizes the effect of a fluid in various concentrations on marine life	No standardized test procedure is utilized; however, toxicity is commonly evaluated by LC_{50} values that represent the fluid concentration level that is lethal to one-half a fish population during a 96-hour test period
Viscosity	Essential in determining the control system response time Particularly important at low-temperature and sub-zero operating conditions. Antifreeze additives may be required to maintain viscosity	ASTM tests D-88, D-341, D-445, and D-2161
Specific gravity	Will be essentially equal to 1.0 for water-based fluids	ASTM test D-1429
pH	High pH values between 8 and 10.5 may be sufficient to combat microbiological growth and corrosion; values above 10.5 should be avoided unless its compatibility with system components, etc., is evaluated	Environmental Protection Agency Federal test method No. 150.1; ASTM test D-1293

filters and accelerate corrosion. In addition, clean potable water should be used to dilute the control fluid concentrate to the desired water/concentrate ratio. Pre-mixed fluids are available and should be considered in areas where water quality is questionable.

c. The suitability of a fluid for discharge should be evaluated on the basis of toxicity (see Table 4).

d. The optimum control fluid concentration (water/concentrate ratio) to be utilized in a particular system should be determined by laboratory testing unless a satisfactory performance record has been established.

5.4.5.2 Two types of oil-based fluids are available for subsea control applications: (a) water-soluble oil, and (b) petroleum-based oil. The following factors should be considered in the use of oil-based fluids:

a. It is generally recognized that both water-soluble oil and petroleum-based oil control fluids exhibit, to varying degrees, those properties listed in Table 4 for water-based control fluids, with the exception that petroleum-based fluids should also be evaluated on the basis of bulk modulus of elasticity and flash point.

The significance of these additional properties is briefly discussed in Table 5, along with the most generally accepted evaluation test procedures.

b. Cleanliness considerations for oil-based fluids are essentially the same as those listed above for water-based fluids. However, provisions to remove free water should be made.

c. Oil-based fluids are not intended for discharge to the ocean.

5.4.5.3 Other control fluids (for example, synthetic hydrocarbons, hybrids, etc.), can be evaluated for use on the basis of the requirements presented above.

6 Template and Manifold Systems

6.1 SCOPE

These guidelines are intended for all template and manifold systems founded on the seabed that may incorporate and physically support wellheads, drilling and production risers, pipeline connections, trees, manifolds, control system components, and protective framing. Production from the templates may flow to floating production systems, platforms, or other remote facilities.

These guidelines are applicable for both wet and dry template systems. Although the wet system is principally addressed, the same criteria should be followed for dry systems in regard to functional requirements and design considerations. Special design principles associated with dry production systems, such as life support systems and dry

Table 5—Oil Base Control Fluid

Property	Significance	Evaluation Test Procedure
Bulk modulus	Used to express fluid compressibility High compressibility affects the pressure response characteristics; low volume transfer may result in increased valve response time	No standardized test; values are typically estimated from available test data and/or manufacturer's information
Flash point	Essential in evaluating auto-ignition or dieseling characteristics; low flash points may be indicative of unsafe operating conditions	ASTM test D-92

docking and transfer system, are not covered here and are beyond the scope of this document.

6.2 SYSTEM DESCRIPTIONS

6.2.1 Template

A *template* is a seabed-founded structure that provides a guide for drilling and/or support for other equipment, and provisions for establishing a foundation (piled or gravity-based). A template is typically used to group several subsea wells at a single seabed location. Templates may be of a unitized or modular design. Several types of templates are discussed below. Actual templates may combine features of more than one of these types.

6.2.1.1 A *well spacer/tieback template* is a multi-well template used as a drilling guide to pre-drill wells prior to installing a surface facility (see Figure 35). The wells are typically tied back to the surface facility during completion. The wells could also be completed subsea, with individual risers back to the surface.

6.2.1.2 A *multi-well/manifold template*: has multiple wells drilled through it, and supporting a manifold system. This type of template is illustrated in Figure 36.

6.2.1.3 A *manifold template*: supports a manifold for produced or injected fluids. Wells would not be drilled through such a template. The design is similar to the one depicted in Figure 36 with the well drilling guides omitted.

6.2.1.4 A *riser support template*: supports a marine production riser or loading terminal, and which serves to react loads on the riser throughout its service life (see Figure 37). This type of template may also include a pipeline connection capability. Figure 38 shows a combination template with wells, manifold, and production riser support.

6.2.1.5 *A modular template:* is assembled in modules around a base structure (often the first well). These modules may or may not be of a cantilevered design.

6.2.2 Manifold

A *manifold* is a system of piping and associated equipment used to gather produced fluids or to distribute injected fluids. A manifold system may also provide for well testing and well servicing if TFL capability is included along with annulus monitoring and bleed capability. The associated equipment may include valves, connectors for pipeline and tree interfaces, chokes for flow control, and TFL diverters. The manifold system may also include control system equipment such as a distribution system for hydraulic and electrical functions, as well as interface connections to control modules. All or part of the manifold may be integral with the template or may be installed separately at a later date if desired. Figure 39 illustrates a typical manifold schematic. Other headers could include chemical injection, gas lift, and well control lines.

6.3 FUNCTIONAL CONSIDERATIONS

This section provides a listing of functional requirements. Further discussion concerning design to achieve these requirements is contained in Section 6.4.

6.3.1 Template Functional Requirements

6.3.1.1 Installation: the template should provide sufficient capability to allow for all installation requirements. Tradeoffs of the types of installation vessels, such as drilling rigs or crane barges, should be considered. The requirements may include some or all of the following items:

a. Loadout.
b. Transportation to site.
c. Launch capability.
d. Buoyancy capability.
e. Ballast/flooding system.
f. System for lowering to seabed.
g. Positioning capability.
h. Leveling system.
i. Foundation interface.

6.3.1.2 *Load-bearing capability:* the template is the framework that supports other equipment such as manifolds, risers, drilling and completion equipment, and pipeline pull-in and connection equipment. The template should provide a sufficiently strong foundation to be able to transfer design loads into the seabed.

6.3.1.3 *Drilling and completion interface:* if wells are to be drilled through the template, it should provide a guide for drilling, landing/latch capability for the first casing string, and sufficient space for running and landing a BOP stack. If subsea trees are to be installed, the template should provide

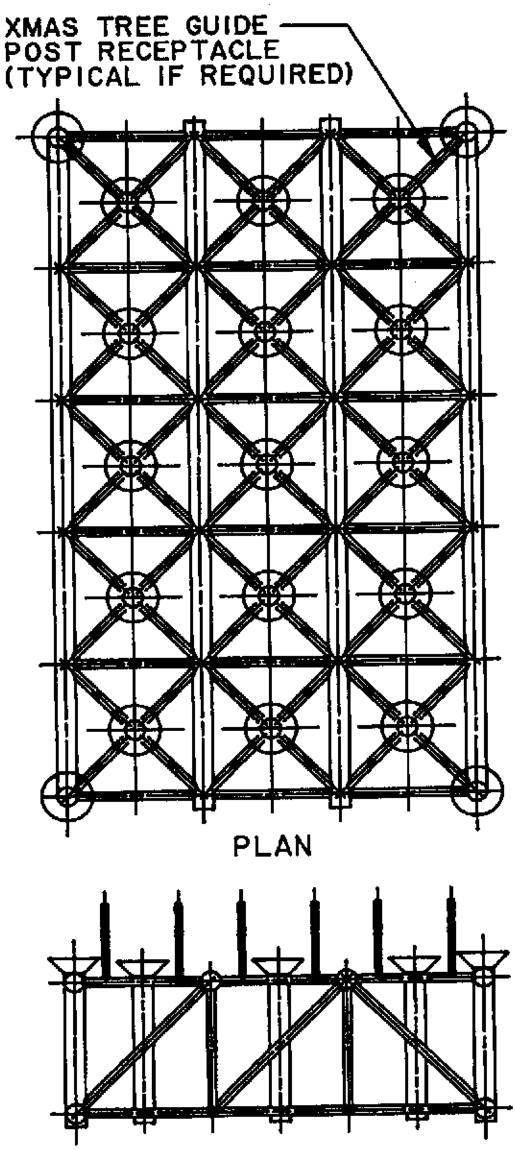


Figure 35—Well Spacer/Support Template

proper mechanical positioning and alignment for the trees, and sufficient clearance for running operations.

6.3.1.4 *Alignment:* the template should provide alignment capability for proper physical interfaces among sub systems, such as wellhead/tree, tree/manifold, and manifold/flowlines and umbilicals.

6.3.1.5 *Guidance:* the template should provide for a guidance system to support operations through the life of the installation. If guidelines are used, the template should provide proper spacing and installation/maintenance capability for the guide posts. If guidelineless methods are used, the template should provide sufficient space and passive guidance capability to successfully install key equipment items.

6.3.1.6 *Abandoned provisions:* if the template is to be recovered at the end of the project, its design should include provisions for the requirement.

6.3.2 Manifold Functional Requirements

Manifold systems may provide some of the following functional requirements. Not all of these capabilities are required for every manifold system.

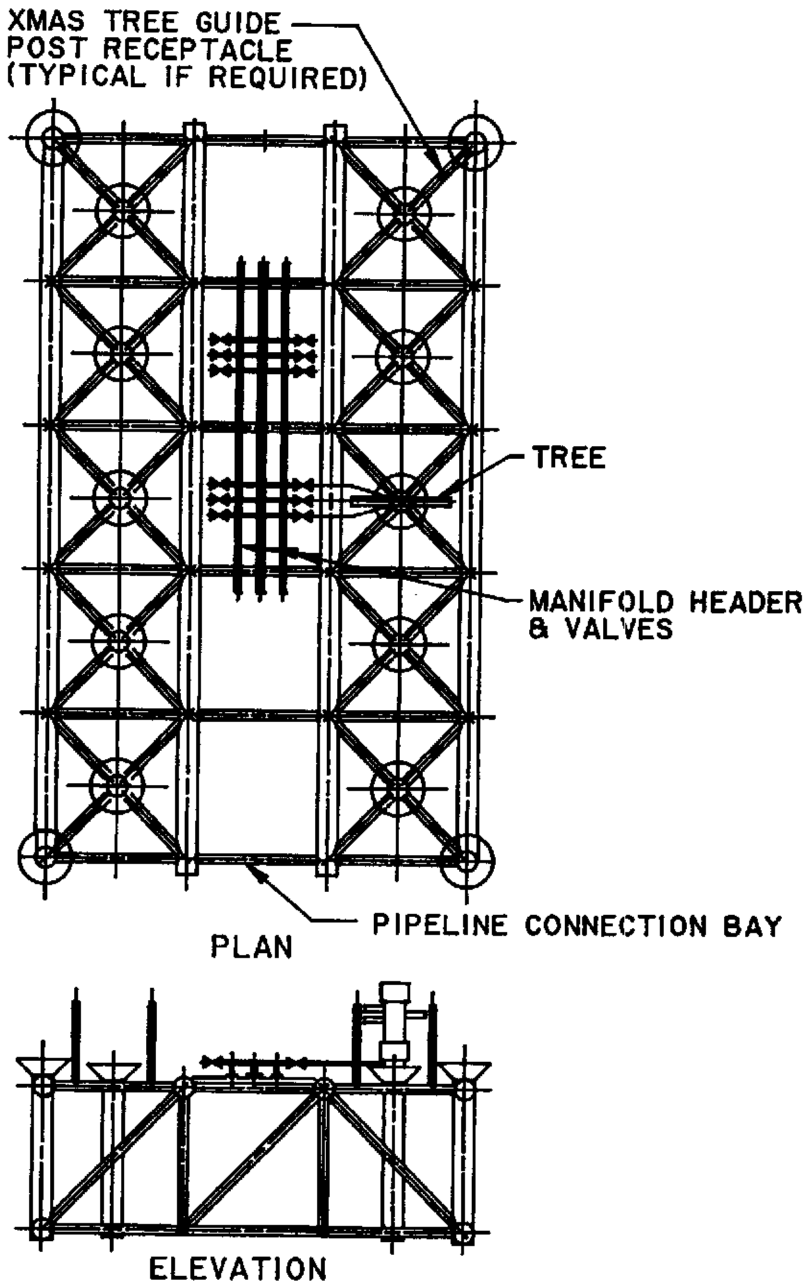


Figure 36—Manifold/Multi-Well Template

6.3.2.1 The manifold should provide sufficient piping, valves, and flow controls to safely gather produced fluids or distribute injected fluids, such as gas, water, or chemicals.

6.3.2.2 The manifold may provide for testing of individual wells.

6.3.2.3 The manifold should provide appropriate valving and line bore size considerations to allow pigging of pipelines and appropriate manifold headers.

6.3.2.4 If wells are to be completed on the template, the manifold provides for connection to the Christmas tree.

6.3.2.5 The manifold provides for mounting and protecting equipment needed to control and monitor production/injection operations. The manifold system may include a distribution system for hydraulic and/or electrical supplies for the control system.

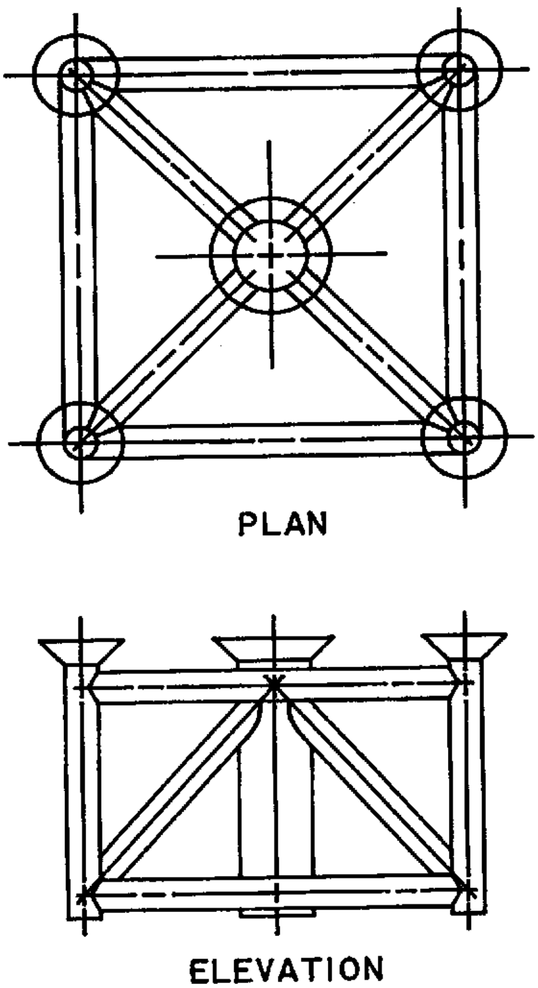


Figure 37—Riser Support Template

6.3.2.6 The manifold should provide for connection of pipelines and control umbilicals. The manifold will typically provide sufficient flexibility to make and break these connections.

6.3.2.7 If the system is designed for TFL capability, the manifold provides piping and well diverters to support that capability.

6.4 DESIGN CONSIDERATIONS

This section contains information to aid the design of template and manifold systems. It provides information on factors that should be considered, but does not attempt to provide solutions for all the design problems involved with these considerations.

6.4.1 Overall System Design Considerations

The items in this section affect both template and manifold design.

6.4.1.1 Maintenance is a key factor in system design; the maintenance approach should be considered early in the design of a template/manifold system. Factors to be considered include the following:

a. Diver-assisted or remote maintenance methods.
b. Components that will be made retrievable.
c. Clear access space for divers, ROVs, or other maintenance equipment.
d. Clear markings to allow similar components to be distinguished.
e. Height above seabed for adequate visibility.
f. System safety with components removed.
g. Fault analysis capability to identify the failed component.

6.4.1.2 Where wells are incorporated into the template and manifold, the number will vary depending on the site-specific application and greatly influence template size and manifold design. The addition of spare well slots should be considered for contingencies such as dry holes, drilling problems, and other unforeseen production requirements.

6.4.1.3 Well spacing may be governed by the type and size of drilling and production equipment used, the functional requirements of the manifold, and subsequent maintenance and inspection requirements.

Consideration should be given to providing space for such items as pipeline and wellhead connections and their running tools, and adjacent BOP and production tree clearances. Access should also be provided for inspection and maintenance tools.

6.4.1.4 If satellite wells are to be tied in, the template and manifold designs should provide this capability. Pipeline and control umbilical connections should be considered, and the template structure should be designed for anticipated pull-in loads. Adequate valving for distribution of injected or produced fluids and pigging of the satellite lines should be considered in the design.

6.4.1.5 The protection requirements for the system should be considered. The types of accidental damage events that the system can withstand should be part of initial design considerations. The two major types of protection to consider are lateral (for example, fishing trawlors and, anchor snags) and dropped object (for example, drill pipes and collars). The design does not necessarily have to provide protection from every conceivable event, but a decision should be made as to what level of protection will be included in the system design.

6.4.1.6 Special prototype testing for critical components should be considered during the design process. Special testing may be needed to achieve an appropriate level of design confidence for components that are essential for proper system operation or are new items with little field usage.

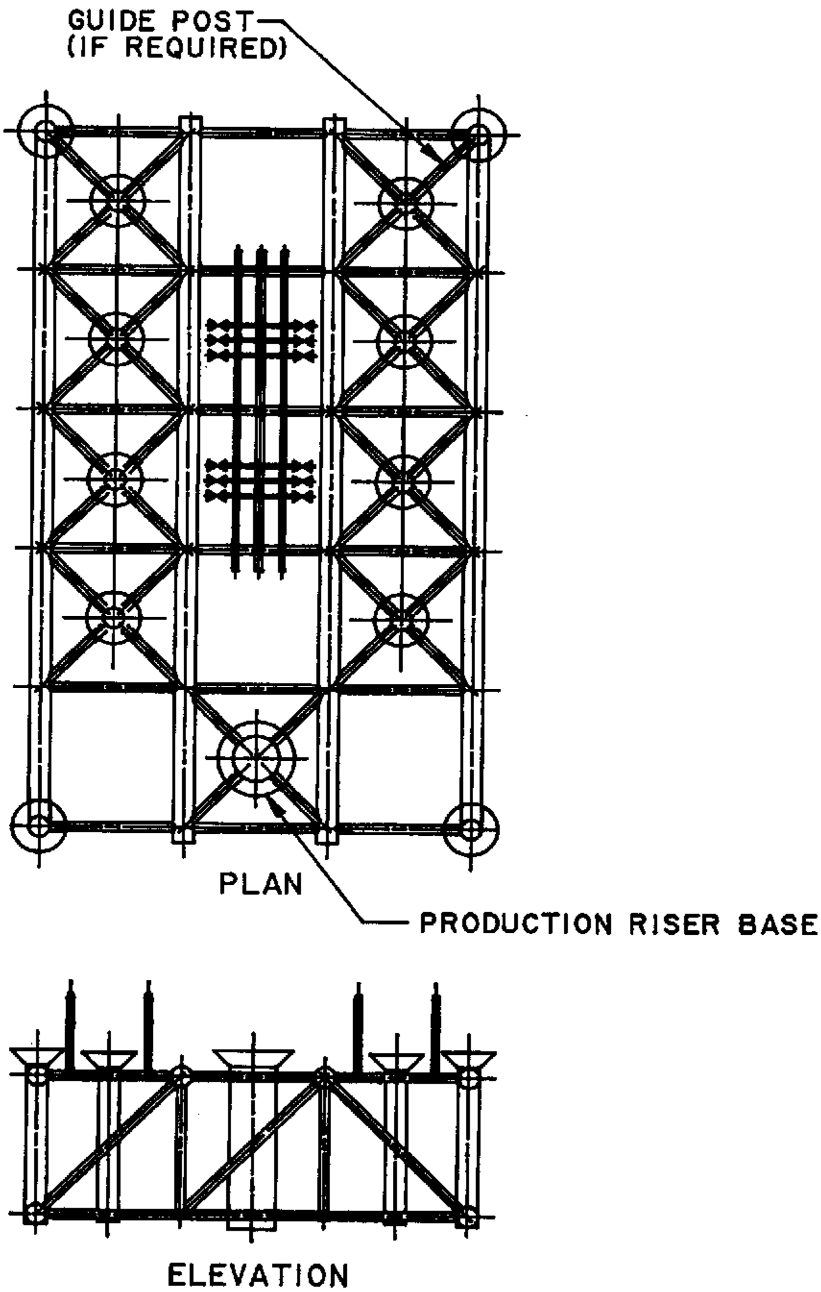


Figure 38—Manifold/Multi-Well Template with Productive Riser

6.4.2 Template Design Considerations

Items in this section are primarily concerned with templates, but in some cases may apply partially to manifolds as well. Refer to API Recommended Practice 2A for structural and foundation design information.

6.4.2.1 The design loading criteria will be established by the operator after an engineering assessment of site-specific environments and operational conditions. The designer should consider all applicable external loads that may affect the template system. Figure 40 is a diagrammatic illustration of typical loads on a template, together with load application points. Factors to be considered include the following:

a. Subsea templates designed to provide underwater wellhead support should incorporate well bay and associated structure sufficient to withstand drilling loads. The design

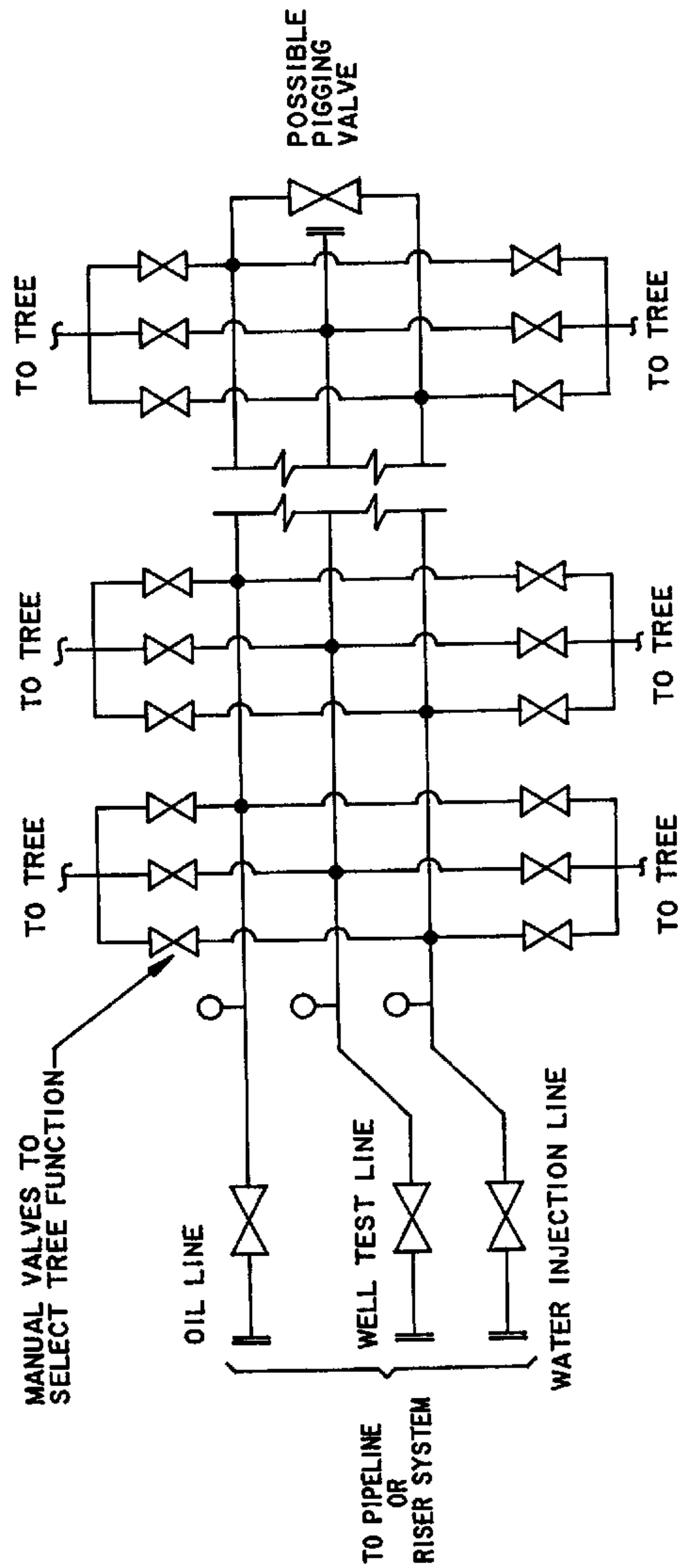


Figure 39—Typical Manifold Schematic

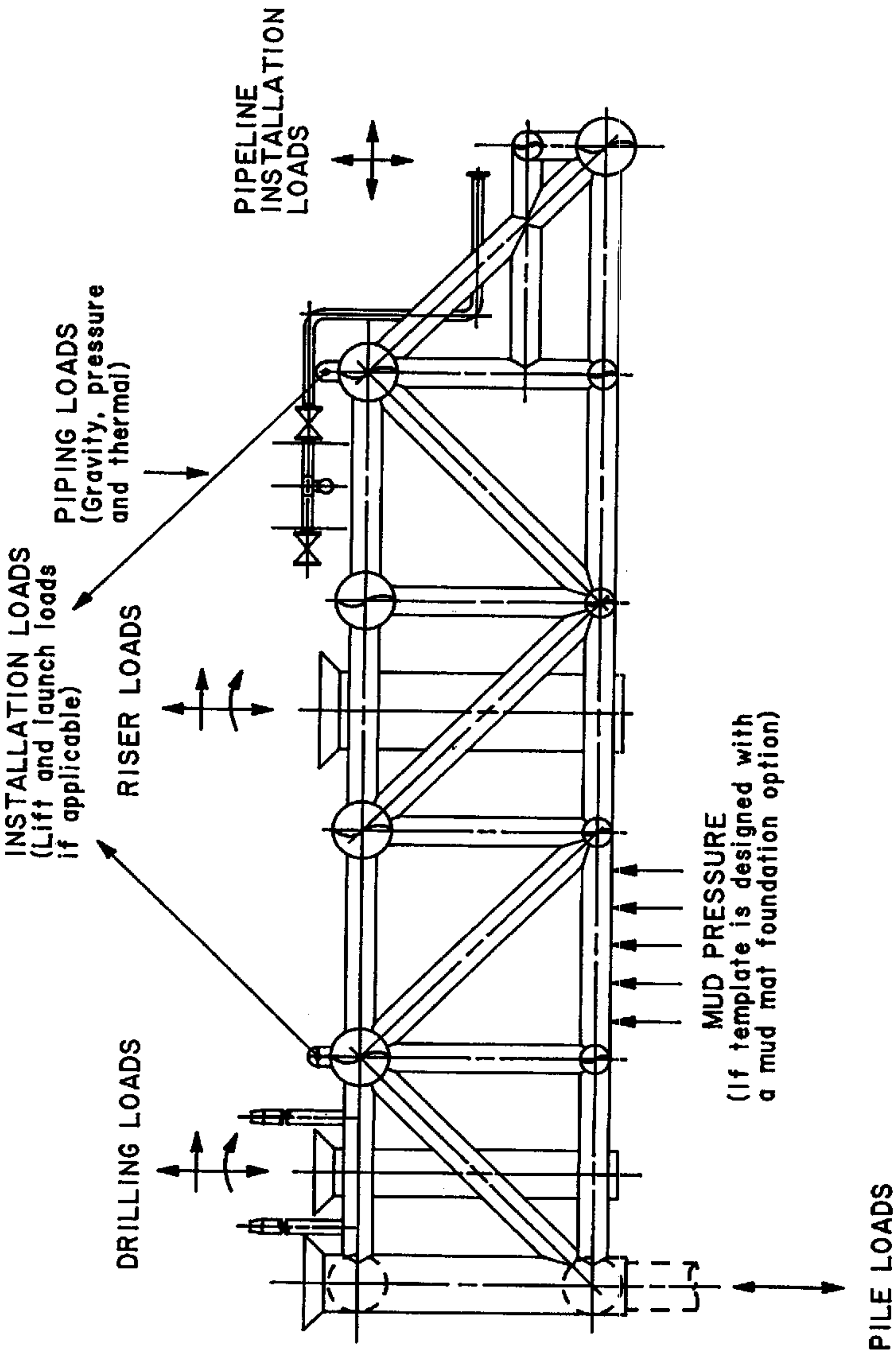


Figure 40—Template Loading Diagram

should provide sufficient rigidity to maintain known design spatial tolerances among various components when load deflected. Loads may include weight of the structural or conductor casing, and the weight of the surface casing if cementing of the first casing string is inadequate. Some operators may also choose to design for a portion of the BOP weight, which can be installed before the surface casing cement bond has achieved full strength. Drilling riser loads caused by drilling vessel offset should also be considered.

b. The template should withstand pipeline installation forces and any loads induced by thermal expansion. Pipeline snag loads will likely be the highest pipeline-induced load on the template. If the template cannot be practically designed for pipeline snag loads, a protective breakaway device should be considered.

c. Subsea templates should be designed for all loads during the installation phase. Particular attention should be given to the following:

1. Loadout forces.
2. Transportation-induced loads.
3. Lifting forces.
4. Launching forces.
5. Lowering forces/current-induced loads.
6. Maximum hydrostatic load.
7. Forces transferred to template during piling operation.
8. Leveling loads; areas of high stress may result from reactions at the leveling points.

d. The riser support structure should accommodate loads resulting from riser buoyancy, installation, and specified environmental loads. These loads should consider the extreme design events for strength purposes. Accumulative fatigue damage appraisal may be required depending upon site-specific conditions. Refer to API Recommended Practice 2A for details.

e. When trees and pipelines are connected to the manifold, flexibility is needed in piping on one side of the connection to allow sufficient movement to secure the connection. Loads caused by this flexure of piping should be accounted for in the design.

f. The template and the support structure should be capable of withstanding the applicable loads due to the use of maintenance equipment.

g. The effects of earthquakes, where applicable, should be considered for templates installed in seismically active regions.

h. The effects of temperature induced loads should be considered. The design should also allow for thermal expansion loads of elements heated by the produced fluid stream .

i. Hydrostatic loads should be computed and designed for in accordance with API Recommended Practice 2A.

j. In regions where mud slides may occur, the piles/structure should be designed to withstand the forces resulting from mud flows.

k. Loads resulting from accidental snagging of the structure by trawling equipment, anchors, or other foreign objects should be considered. The structural shape and strength should be designed for the maximum snag load to be accommodated without damaging critical equipment such as valves and piping.

l. If the template is to be recovered at the end of the project, the recovery method and resulting loads on the template should be considered.

6.4.2.2 For a given set of loading conditions, soil characteristics at the site should be used to design the gravity foundation or determine the number of piles, pile diameter, length and locations, and the degree to which mudmats and other footings are required. Both static and cyclic behavior should be considered, as well as possible scouring by currents near the bottom. Other items that can affect foundation design include: damage due to pile and conductor installation, group pile effect, and soil heating and hydrates in shallow sediments. Refer to API Recommended Practice 2A for details.

6.4.2.3 A means of handling drill cuttings and cement returns should be considered in the design of the template and drilling systems. Typical methods to alleviate this problem include:

a. Elevate the system components that may be affected sufficiently to provide enough space for accumulated cuttings and cement returns.

b. Provide for diverting cuttings/cement away from the template.

6.4.2.4 A ballast/deballast system, either remotely controlled or diver-operated, may be designed to selectively control flooding of the template to:

a. Provide flotation during template positioning.
b. Maintain template stability during lowering.
c. Provide buoyant forces necessary for retrieval.

During template installation and retrieval, the vertical center of buoyancy should be maintained well above the center of gravity. This condition provides sufficient righting movement to maintain stability under all anticipated launch operations.

Ballast water should be carefully distributed to various parts of the template during the lowering operation to maintain template attitude control. Large horizontal tubular members should be segmented into buoyancy cells by bulkheads to provide for trim control and damage stability.

6.4.2.5 Generally, subsea systems require the template to be reasonably level in its final position for proper interface and mating of the various components and subsystems. Typical leveling methods include one- and two-way slips between piles and pile guides, and jacking systems at the template corners. A means for level indication should also be included.

6.4.2.6 Tie-back systems require special consideration during the template design. The spacing between well bays will be established by the space requirements for the subsea BOP or jackup rig derrick skidding pattern.

The design loads for the template should also account for the tie-back system. The initial tension imparted to the template by the tie-back strings as well as the current wave loading on the tie-back system should be included in the design loads on the template.

6.4.2.7 Templates incorporating production risers should be equipped with a riser support structure designed to accept the riser base and to facilitate its installation. A lead-in structure can provide a large target area for installing the riser base, assist in its proper orientation and engagement, and reduce the potential for inducing casualty loads in adjacent template system components during the riser installation operation.

6.4.2.8 The template should be designed to provide for alignment among components installed on it. For example, the well bays should be designed to provide lateral, vertical, and angular alignment for the wellhead system. This alignment is critical for mating subsea trees to the wellhead and manifold. The design should consider whether guidelines or a guidelineless system will be used for guidance. If guidelines are used, the template should include guideposts in its design, and a decision should be made regarding whether the guideposts will be retrievable. A temporary means of guidance may be achieved by guidelines attached to padeyes on the template. If a guidelineless approach is adopted, sufficient clearance and guiding tapers and funnels should be included to facilitate equipment installation.

6.4.2.9 Corrosion protection of the template is an important design consideration, and is discussed in Section 8.4. Special additional considerations for the template include placement of sacrificial anodes and possible replacement capability. The effect of accumulated drill cuttings accumulation on anode placement should be considered, as any anodes covered by cuttings will not be effective. If a possible need for anode replacement is anticipated, that capability should be considered in the original design.

6.4.2.10 If the template is to be recovered, the removal system (that is, the deballasting, heavy lift, etc.) should be considered as part of the original design. Abandonment in place may be a desirable alternative.

6.4.3 Manifold Design Considerations

The design considerations included in this section are primarily concerned with manifold systems, but may partially apply to templates as well.

6.4.3.1 Some knowledge of the fluid characteristics should be available prior to the design of the manifold. These fluids include produced hydrocarbons (liquids and gases), injected water and gases, and injected chemicals. The general design characteristics for these fluids include the following:

a. Pour point.
b. Pressure.
c. Temperature.
d. Chemical composition.
e. Viscosity.
f. Gas/oil/water ratio.
g. Sand/paraffins/hydrates.
h. Corrosivity.

6.4.3.2 The size (that is, diameter, wall thickness, and so forth,) of production piping will be determined from anticipated well flowrates and well pressures for individual lines and/or combined streams. Consideration should be given to plans for water/gas injection, gas lift, and TFL operation (see API Recommended Practice 6G). Fluid velocities should be considered in sizing pipes to reduce pressure drops and control-flow-induced erosion. An internal corrosion allowance should be considered in determining required wall thickness. External hydrostatic pressure can be taken into account when determining pressure ratings.

6.4.3.3 Piping connections in the manifold system should provide pressure integrity for the internal fluids, ease of installation, and enable any required maintenance. Seal characteristics are determined by the physical and chemical characteristics of the internal fluids, as well as their ability to withstand the internal and external environment.

6.4.3.4 The design of the manifold system should accommodate the selected control system. The hydraulic and/or electrical distribution system may be an integral part of the manifold design.

6.4.3.5 Pipeline connections should be positioned in line with respect to the anticipated pipeline entry corridors.

Initial planning should consider the following:

a. Type of pipelines.
b. Number of lines.
c. Space requirements.
d. Installation method.
e. Height of connection above seabed.
f. Pipeline flexibility for connection operations.

6.4.3.6 The designer should consider loads induced in the piping system as a result of thermal expansion. If these movements are constrained, very large loads can be developed in the pipeline support, resulting in large stresses in the manifold piping. These stresses can be incorporated into the design. Another option is to design the piping supports to allow movement of the pipe when thermal expansion occurs.

6.4.3.7 Pigging systems may be required for the removal of liquid, sediment, or paraffin removal from the pipeline and manifold system. Design for pigging should consider the following:

a. Piping size.
b. Bend radius.
c. Internal protrusions.
d. Valve type.
e. Pig launcher/receiver.
f. Pig location determination.
g. Pigging procedures.

7 Production Risers

7.1 SCOPE

This section addresses the structural analysis procedures, design guidelines, component selection criteria, and typical designs for production risers operated in conjunction with subsea production systems and floating production platforms (FPP). Fluid lines supported along their length at intermediate points by structural elements of a vessel mooring system are not addressed in this Recommended Practice. Risers operated in conjunction with fixed platforms are covered in Section 4.

7.2 SYSTEM DESCRIPTION

7.2.1 Functions

The function of a subsea production riser is to provide conduit(s) for conveying hydrocarbons or injection fluids between the seafloor equipment and the FPP. The risers and support structures may also provide support for auxiliary lines and control umbilicals.

7.2.2 Production Riser Design Types

Production risers fall into three broad design types: (a) rigid-pipe riser, (b) flexible-pipe riser, and (c) combinations of rigid and flexible pipe.

7.2.2.1 A rigid-pipe riser is made of individual pipe sections assembled to obtain the desired number of lines and length of riser. Rigid pipe risers require tension to prevent buckling and resist lateral loads. They may also be integral or nonintegral in construction with the lines arranged internal or external to the primary structural member (See Figure 41). Types of rigid pipe risers include the following:

a. Rigid-pipe integral riser: the lines of an integral riser cannot be retrieved separately. An integral riser with external lines includes a central structural member which may carry fluids or perform other functions in addition to providing structural support to the flowlines by means of external brackets. An integral riser with internal lines may support these lines at intermediate points along the joint to prevent line buckling.

On either integral-riser type, the ends of the structural member are fitted with couplings. A section of the production riser consisting of the structural member, lines and coupling, is collectively called a "riser joint." When two joints of integral-riser are connected, the coupling causes the simultaneous connection of the flowlines with full design pressure capacity. Integral risers are compact and simple to run; however, they require system shut-in and retrieval for repair.

b. Rigid-pipe nonintegral riser: a nonintegral riser's flowlines may be run and retrieved separately from each other and from the main structural member. A nonintegral riser includes a tensioned central structural member, which may carry fluids or perform other functions besides providing structural support and guidance to lines. The structural member is fitted with support/guidance devices to locate and laterally guide individual lines.

The two ends of the structural member are fitted with the two halves of a coupling. A section of the structural member including the coupling and guidance devices is called a *joint*; the associated sections of lines are also called *joints*. The two ends of each line joint are fitted with mechanical/pressure couplings, typically threaded box and pin, independent of the central pipe coupling. Other lines are installed individually after the structural member is installed and tensioned. They are retrieved individually before the structural member is retrieved.

The design has the advantages of simplicity and of permitting the retrieval of a single line (as, for repair) without requiring the shut-in and retrieval of the whole system. It has the disadvantage of being slow to run or retrieve.

7.2.2.2 A flexible-pipe riser: is characterized by a composite construction with layers of different materials that allows large amplitude deflections without adverse effects on the pipe. This product may be delivered in one continuous length or joined together with connectors.

Flexible risers accommodate differential motion by an added length of pipe between the two points to be linked. The added length can be utilized in different patterns according to the environmental conditions, loads to which it is subjected, and the relative motion and position of the FPP with respect to the seabed connection point.

The major flexible riser configurations currently in use are shown in Figure 42. The *free hanging* riser runs in a catenary from the floating production unit to the seabed. The *lazy S* riser runs in a double catenary configuration from the floating production unit to the seabed over a mid-water pipe tray supported by a subsurface buoy. The subsurface buoy is kept in position by a chain or cable attached to a dead weight anchor positioned on the seabed. The *steep S* riser is similar to the *lazy S*, except that the lower section of the flexible pipe between the buoy and the riser base is used as a tension member. The riser base replaces the dead weight anchor. The *lazy wave* and *steep wave* designs use an appro–

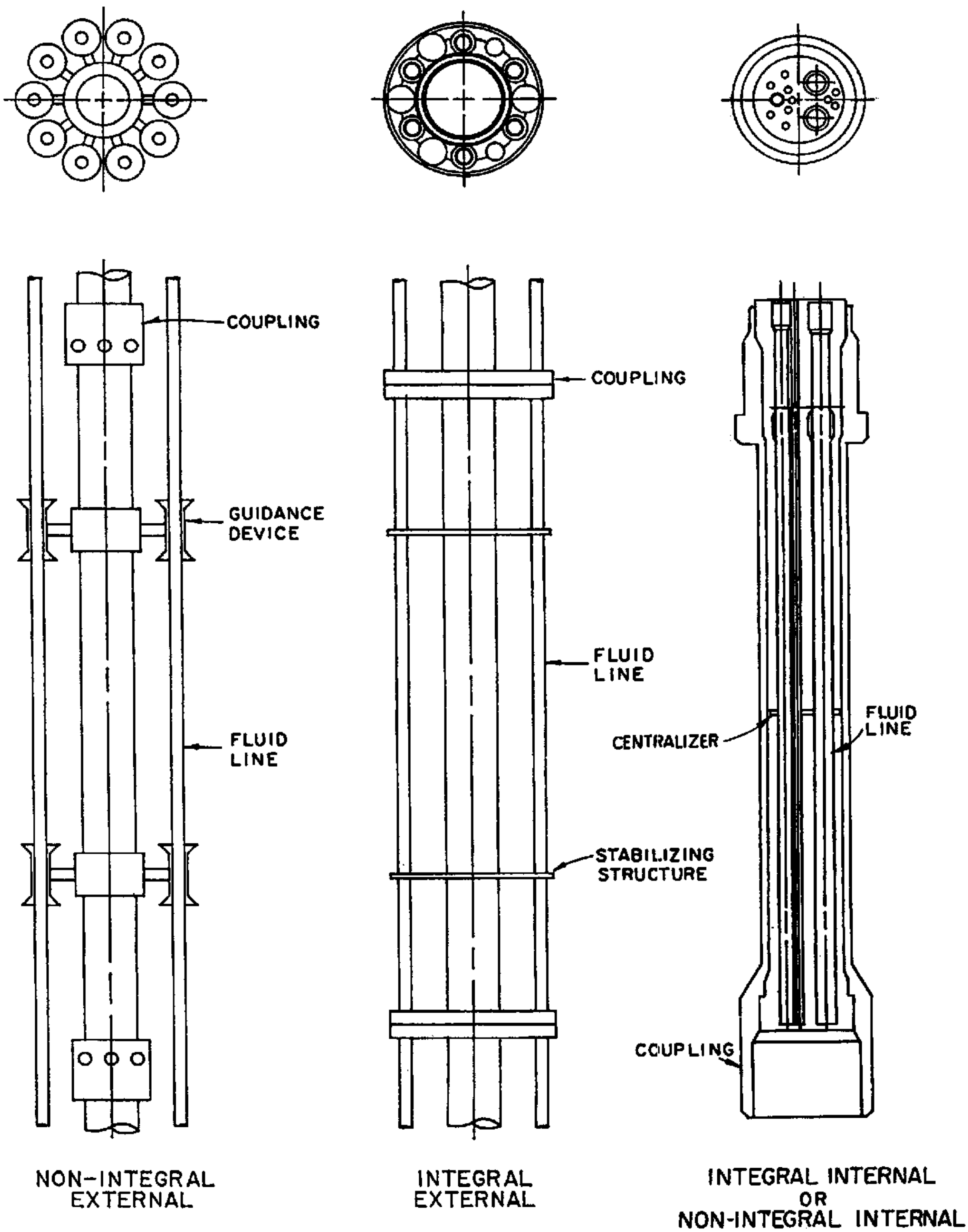


Figure 41—Rigid Pipe Risers

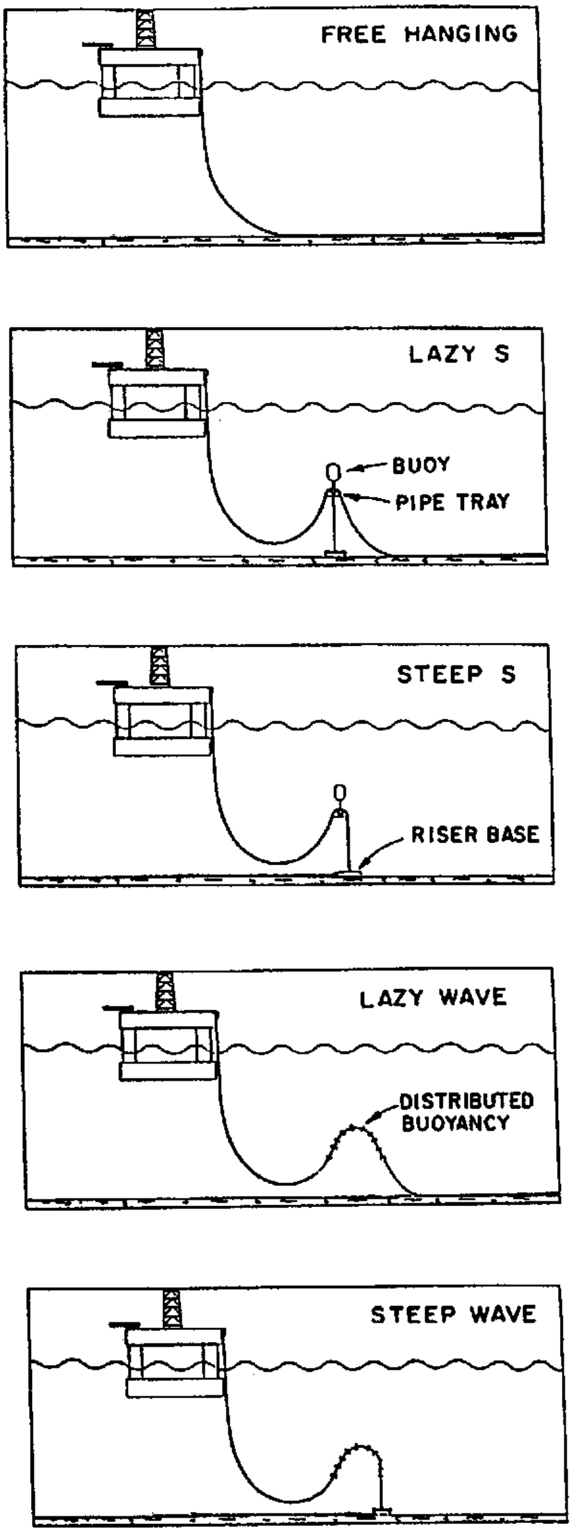


Figure 42—Flexible Pipe Risers

priate distribution of small buoyancy modules along a section of the riser to replace the pipe tray and subsurface buoy.

As with the rigid-riser assemblies, flexible-pipe risers installed in any of the above described configurations may be individual or multiple in similar or different sizes and arrangements and may be integral (also called multibore) or nonintegral (bundled). Types of flexible-pipe risers include the following:

a. An individual flexible-pipe is not connected to any other line though it may have common attachment points with other risers at the floating facility and at the seabed. It may be retrieved individually.
b. An integral flexible-pipe riser is an assembly of individual flexible-pipe lines and may include other components such as electric or hydraulic control lines. The outer jacket may contain the lines in either a compact helically wound arrangement or a flat ribbon-type assembly. Individual lines may not be retrieved separately.
c. A nonintegral flexible-pipe riser is an assembly of individual flexible lines constrained together at one or more intermediate points along the riser's length. These constraints can be a pipe tray, a common flotation device, or spacer bars. Depending on the design of the common attachment points, individual lines may or may not be retrieved separately.

7.2.2.3 A rigid-flexible combination riser. A third type of production riser utilizes rigid pipe technology for part of the riser and flexible pipe for the remainder. The design usually has a lower section made of rigid pipe and an upper section made of flexible pipe. The lower rigid-pipe section is tensioned by a subsurface buoy and the flexible-pipe sections run in a catenary from the subsurface buoy to the FPP. Design variations discussed under the two types above are applicable for this type of riser.

7.2.3 Production Riser Interfaces

7.2.3.1 The primary factors affecting the riser top interface include riser type, tensioning requirements, riser handling equipment, type of FPP, and FPP motions relative to the riser. Equipment arrangement at the top interface should receive careful attention to enable access for inspection, maintenance, and repair.

The FPP moonpool space requirements are greatest for the nonintegral rigid riser configuration, followed by the integral rigid riser configuration, and the flexible riser configuration. Flexible risers may not require access to a moonpool because tensioning equipment is not normally needed, and riser deployment and retrieval may not require the FPP drawworks and derrick.

Typically, multiple flexible jumpers are used to bridge between the riser and the deck of the FPP. Other equipment at the riser-top interface (such as valves, chokes, and gauges) will require routine inspection and service. Personnel access to the top of the riser is essential.

The handling system for a rigid-pipe riser is used for installation, recovery, and to assist with riser hang-off if necessary. Typically, rigid riser handling equipment is similar to pipe-handling equipment for a drilling rig. Riser storage and handling methods must be properly integrated with the FPP.

The location of the riser system should minimize risks from collision with service/supply vessels, mooring equipment, or dropped objects. Provisions for emergency disconnect of the riser system and access for inspection, maintenance, or repair should be considered.

7.2.3.2 The interface design of the riser bottom connector and the seafloor equipment will depend on several factors such as type of seafloor equipment, water depth, riser size, and whether the riser pipe is rigid or flexible. Operator's decision about seafloor manifolding or active components, such as valves, may influence the bottom interface. Subsea valves may be integrated into the riser bottom connector, allowing recovery of the active components for maintenance and repair. The loads imparted to the seafloor equipment by a rigid riser are a major interfacing factor.

The type of seafloor equipment that the riser may be connected to can range from simple, single-purpose riser base structures to very large, multi-well subsea well template structures. For the single-purpose riser base structure, the interface consists of straightforward landing, orienting, locking, and sealing between the riser system and the seafloor structure. Generally, this operation will be quite similar to landing the lower marine riser package onto a subsea BOP stack assembly.

7.2.3.3 Rigid pipe risers and rigid-flexible combination risers can be designed to disconnect at an intermediate point between the top and bottom interfaces. Additional interface design considerations include: (a) disconnect and reconnect means for fluid lines, (b) structural members and auxiliary lines, (c) self tensioning for the seabed connected portion of the riser, (d) relative motion between upper and lower sections during reconnect, and (e) fluid isolation valves for lines.

7.3 FUNCTIONAL AND OPERATIONAL CONSIDERATIONS

Each riser line is designed to satisfy requirements for throughput rate, pressure, corrosion, erosion, and temperature while maintaining structural integrity. Operational considerations include provision for riser system handling during extreme storm conditions, mooring failures, marine fouling, interface loads between lines, and riser protection against external loading. Long-term plans for inspection, maintenance, and repair can influence the riser system design. Operational activities such as pigging through the various flowlines and provisions for displacing hydrocarbons prior to riser disconnect also influence production riser design.

7.3.1 Applications

The selection of the most appropriate riser system should be performed on the basis of comparisons of various alternative riser configurations. Factors to be considered include:

a. Type, number, and size of flow paths.
b. Performance characteristics.
c. Simplicity of design.
d. Ease of handling.
e. Environment.
f. Design life.
g. Risk assessment.
h. Interfaces.
i. Reliability and redundancy.
j. Maintenance and inspection.
k. Required deck space.
l. Required total top tension.
m. Static and fatigue strength.
n. Code requirements.
o. Operator's preferences.
p. Cost and delivery schedules.
q. Subsea facility type.
r. FPP type, motions, mooring, and offsets.
s. Installation methods and constraints.
t. Retrieval and deployment time.
u. Field layout.
v. Corrosion properties.
w. Fluid properties

To achieve satisfactory operating performance, the riser design must be coordinated with the design of the equipment to which it is connected, both at the riser top (FPP) and bottom (subsea equipment). Operating choices must also be made about whether the riser is to be designed to remain connected at extreme FPP offsets, disconnected and hung off, or disconnected and fully recovered. The riser size and complexity can be reduced by commingling production at the seabed, but this may result in added subsea equipment complexity.

7.3.2 Production Aspects

Design of the production riser requires not only definition of the loads that may occur on the system, but a clear definition of the number, size, and service for each of the lines that will be needed to meet the initial and projected system production requirements. Service requirements may include produced fluids, product export, injection fluids (for example, water, gas, and chemicals), well test, annulus monitor/control functions, and TFL tools. Expected requirements for workover may be a major factor in design selection. Each riser design will also be influenced by the various upstream and downstream choices. For example, the riser flow path may be designed for full shut-in pressure of the wells. Alternatively, an isolation valve may be placed subsea, with the riser flow path protected against over-pressure with a relief valve at the surface. The functional life of the production riser is an important consideration, not only from the standpoint of assessing wear and fatigue, but also from the standpoints of corrosion (both internal and external) and the probability of extreme load occurrences. Early decisions about these matters can simplify the interactive process required to arrive at a satisfactory production riser design.

7.3.3 Inspection and Maintenance

The level of inspection and maintenance required in the operation of a production riser must be addressed at the preliminary design specification stage of the design process. The types of inspection and the inspection method(s) may significantly impact the size and configuration of the riser. Inspection philosophy should be coordinated with service life projection and regulatory requirements. Maintenance requirements may influence the riser spacing/configuration and fastening assemblies, thereby influencing the riser system design.

7.3.4 Sealing

Almost all riser components have some provision for sealing to maintain pressure and segregate internal fluid from the environment, isolate hydraulic or electric actuation systems, and/or protect against contamination. The sealing devices are most critical when the pressure differentials are high, and when moving surfaces are present. The specifications should clearly call out required pressure differentials, the kinds of fluids that may come in contact with the seals, fluid temperature, and the cyclic life required if there are moving surfaces. Prototype testing under design conditions is recommended.

7.3.5 Structural Integrity

The design load for each component should be based in part on the riser response analysis described in Section 7.5. Loadings such as tension, bending, torsion, pressure, and thermal gradients should be included in the component specifications. Consideration should be given as to how the component is to be qualified for these loadings. Where appropriate, the resistance of the component to yielding, collapse, and fatigue should be demonstrated by analysis and tests. Techniques such as finite element analysis and strain gauge testing may be specified.

7.3.6 Handling and Storage

For many components, handling and storage may impose the most severe loadings. API Recommended Practice 2K, which is specifically for drilling risers, can also give general guidance for other riser systems.

7.3.7 Contingency Planning

The production riser is applied in a service environment that is vulnerable to both the vagaries of weather and the possibility of failure of other equipment that may cause production riser hazards. For example, the mooring system must maintain the FPP within certain limits relative to the sea floor connection. If these limits are exceeded, unplanned riser forces can result in overstress conditions. Other incidents that may require contingency planning include tensioner failure and interface equipment malfunction. It may also be prudent to plan for emergency disconnect and/or recovery of the production riser.

The importance of allowing for possible unplanned conditions depends on the results of risk assessments that can be done on a site-specific basis. Early assessment of these matters can influence the production riser design and, perhaps, the selection of the type of production riser that is best suited to the application. Design philosophy should minimize the possibility of single component failure leading to overall riser failure.

7.4 PRODUCTION RISER COMPONENTS

7.4.1 Introduction

This section briefly describes the various components that make up the riser system. Individual components are discussed according to the following:

a. Function: the basic function that the component performs within the riser system is described.
b. Selection/acceptance criteria: general performance and qualification requirements are outlined.
c. Typical designs: typical existing designs are described.

The design engineer should have two primary objectives in developing requirements and specifications for riser components. The specifications should be sufficiently comprehensive to assure the required performance of the component and the riser system of which it is a part. The specifications should also be accompanied by qualification criteria to demonstrate the component design complies with the specifications.

7.4.2 Rigid-Pipe Riser Components

7.4.2.1 Tensioning and motion compensating systems provide near constant axial tension to support and stabilize the riser while the FPP moves vertically and/or laterally with wind, waves, and current. Typically, pneumatic and hydro-pneumatic tensioner units utilize multiple piston and cylinder arrangements operated in conjunction with controlled gas pressure accumulators. Other aspects to be considered in selecting the tensioning and motion compensation equipment are related to the capacity and placement of the equipment, friction losses, and system dynamics.

7.4.2.2 Riser couplings connect fluid lines and structural elements at the interface between riser joints. Typical coupling mechanisms include threads and bolted flanges. Riser joint couplings should have a strength equal to or greater than that of the elements they connect. Particular attention should be given to fatigue, hang-off loads, and running and retrieval requirements.

7.4.2.3 A moment controlling device is used to minimize bending stress or to control curvature. Devices such as ball joints and elastomeric flexjoints reduce bending stresses induced by relative angular movements along the riser. When curvature control is necessary, tapered joints are typically used.

Key considerations in the design and specification of moment controlling devices include: (a) deflection stiffness, (b) angular limits, (c) axial load capacity, (d) temperature, (e) internal pressure, (f) external pressure, (g) fatigue, (h) elastomeric degradation, and (i) fluid compatibility.

A single centrally located moment controlling device may be satisfactory for multi-line, widely spaced (especially nonintegral) systems, where the fluid lines are much more flexible than the main structural member. In closely spaced multi-bore systems, especially in integral risers, provision of moment control in all lines may be necessary.

7.4.2.4 Connectors are used to latch the riser to a subsea termination and provide structural continuity and pressure integrity.

Connectors consist of a passive half (generally, a male hub or mandrel) and an active half (generally, a female connector mechanism). The active element is generally attached to the riser so that it can be retrieved. Connectors can be actuated hydraulically or mechanically.

The connector must withstand internal pressure, riser tension, and bending moment. Fatigue resistance is also important. The connector's ability to engage, latch, and disengage in the presence of angular rotational and translational misalignment should be considered in the design.

7.4.2.5 Stabilizing structures laterally restrain individual flowlines and should be designed to accommodate static and dynamic loads. Their effect should be included in the riser response analysis.

Guidance equipment is used to direct and orient risers to the seafloor equipment. Design considerations include: (a) maximum environment for deployment and retrieval operations; (b) size, weight and drag characteristics of equipment to be run; and (c) proximity of other equipment and structure.

7.4.2.6 Buoyancy, in the form of foam modules or air cans, may be added to risers to reduce externally applied top tension. It can also act as an insulator to reduce the heat loss from production lines.

Important design considerations for buoyancy devices include: (a) compressive strength, (b) compressibility, (c) water absorption and service life of foam, (d) the density of compressed air in the air cans, and (e) the hydrodynamic drag on the buoyancy devices.

7.4.2.7 Riser instrumentation may be desirable as an operations aid or in gathering data for confirmation of design analysis methods. The instrumentation may include measurement of top and bottom angles, stresses, motions, and internal and external pressures. These instruments may be packaged in a specially prepared "pup" joint called an *Instrumented Riser Joint* (IRJ), or may be clamped to a riser joint. Other information, including environmental and vessel motion data, may be desirable to complement the riser measurements.

Instrument considerations include accuracy, reliability, long-term drift, measurement range, maintainability, and ability to resist service loading. The IRJ should be qualified to function under extended exposure to the ocean environment for the required service life. Particular attention should be given to electrical insulation, instrumentation attachments, and signal transmission to the surface (usually hardwire). An IRJ should be qualified to the same strength and fatigue requirements as the rest of the riser.

7.4.2.8 Services provided by auxiliary lines include the following:

a. Control and monitor (pilot/electrical) signals for subsea equipment and instrumentation including riser functions (for example, connector release) and all other subsea functions (for example, tree valve control).
b. Power (hydraulic/electrical) supply for subsea equipment.
c. Air supply for riser buoyancy devices.

7.4.2.9 This riser equipment suppresses hydrodynamic vibrations and in some cases may also reduce fluid drag.

Susceptibility of the riser to such vibrations depends on the coincidence of structural natural frequencies and a vortex shedding frequency acting over a substantial extent of the riser. Analyses should be performed to assess the likelihood of the occurrence of these phenomena.

Helical strakes and perforated shrouds have been successfully employed to suppress vortex induced vibrations. Vanes or fairings have been used in drilling applications to suppress vibrations and to reduce drag.

7.4.2.10 The lower end of the production riser includes means to port the flow paths through or around the riser structural connector and into piping on the template. The riser base, connectors, and flow paths must accommodate extreme loads and angles predicted by the riser analysis.

The upper end connections are generally flexible *jumper lines* linking the riser to deck mounted facilities. These flexible pipes must incorporate sufficient motion range to accommodate extreme vessel motions (unless a disconnect is required at a less severe storm level). Flexible pipes are generally attached to a rigid "gooseneck" piece that turns the upper end of the lines downward at the top of the riser.

7.4.3 Flexible-Pipe Riser Components

7.4.3.1 Each end of a flexible pipe segment is terminated with end fittings. The pressure integrity and load bearing capacity of the fittings should be greater than that of the pipe. The end fitting is itself terminated by a flange, hub, mandrel, or other coupling system.

Design criteria include the abilities to resist internal and external pressure and support the predicted tensions and bending moments.

7.4.3.2 Bend stiffeners are tapered elements installed over the flexible pipe to maintain its curvature within the recommended limits.

7.4.3.3 A bend limiter is usually intended to protect the riser from installation and/or static loads rather than the continuous motions imposed by the FPP. It consists of external devices that limit the radius of curvature of the flexible pipe. Two systems currently in use are a bell-mouth and a vertebrae-type device made of a series of interacting annular elements.

7.4.3.4 Buoyancy is added to the flexible riser system in order to reduce topside loads and allow greater excursions of the FPP. Buoyancy force is either transmitted to the riser through a pipe tray, or by a distribution of discrete buoyancy modules clamped directly to the riser.

7.4.3.5 The pipe tray provides intermediate support for the flexible pipe between the seabed and the FPP, and may also restrict pipe curvature. The riser is clamped to the pipe tray to prevent slippage.

7.4.3.6 The riser base anchors the flexible pipe or its supporting buoy at the seabed to control movement. The riser base may be either a deadweight or a piled structure. The flexible pipe riser may connect to a subsea facility at the riser base or continue to another location.

7.4.3.7 Emergency disconnect systems can be used to link the riser system to the FPP. Both halves of the disconnect system may be equipped with spill prevention devices that should be activated before disconnecting. Such disconnects are usually hydraulically operated.

7.5 DESIGN CONSIDERATIONS

Design of the production riser system requires definition of the production functions (flow paths), properties of fluids in the lines, the environmental loadings that will be imposed on the riser, and the motions of the equipment to which the riser will be connected. Resulting loads, forces, moments, and displacements can then be investigated and analyzed as appropriate for a given production riser system design and its components. Local overstressing or rapid accumulation of fatigue damage must be avoided. Installation procedures and accompanying loads must be considered in the design.

Similarities exist between the analysis methods for drilling risers and rigid-pipe production risers. However, unique functional differences do exist and must be accounted for in the design and analysis of production risers. These differences include service life, fluid types, high pressure, and opportunity for frequent inspection.

7.5.1 Riser Design Data

Typical data requirements for the design and specification of a production riser are listed in Table 6 and discussed below.

7.5.1.1 Environmental design data: design of the production riser is dependent on the following information representative of the risers location.

a. Oceanographic: Wind, wave, and current information is essential for riser design. In environmentally active areas, good statistical data regarding direction, frequency, magnitude, and seasonal variations are necessary to allow determination of satisfactory riser design and operating loads. Currents can vary greatly in magnitude and direction over the water column. Tidal changes and storm surge alter the apparent water depth for loading determination. Marine growth on riser systems can influence both their design and maintenance.
b. Meteorological: Reasonably accurate air and sea temperature data are important for determining design temperatures, thermal displacements, and thermal stresses. Low temperatures may affect material ductility and impact resistance against brittle fracture. The upper portion of the riser may be exposed to icing loads.
c. Geotechnical: The geotechnical matters are primarily related to the support of seafloor equipment and seismicity. The riser imposes loads on the seafloor equipment, and the way in which this equipment and the riser base react to the riser loads can be an important boundary condition in riser design. Seismicity of the area can result in additional loadings on the production riser and should be appropriately accounted for. Mud slides may also pose additional loading hazards. Flexible pipe risers in motion at the seabed may be subject to abrasion, wear and burial.
d. Other: Various other factors unique to a given location may influence the design of a production riser. They include sea surface ice, internal waves, current eddies, and fishing activities.

Note: See Figure 42.

7.5.1.2 FPP data: Vessel response to environmental loading is required to determine vessel station keeping requirements ,and to evaluate riser loading. Placement of the production riser top-end equipment not only influences riser design, but may also influence vessel loading, especially for large production riser systems that require high top tensions. Vertical motions of the FPP at the top interface

Table 6—Typical Data for Specification and Analysis of Production Risers

Functional and operational requirements
- Riser contents
  - Fluid composition (gas, vapor, liquid, solid)
  - Fluid properties
  - Flow rates
  - Pressure, temperature
- Allowable alternating stress, top and bottom angles, flexible joint angles
- Safety factor for allowable angles, stresses and buckling
- Allowable bending radii and tension (flexible pipe)

Environment
- Water depth
- Wave height, period, direction and spectral description
- Wind data
- Current profile and directions
- Tidal data
- Seawater properties
  - Salinity
  - Oxygen content
- Marine growth
- Ice and icing conditions
- Air and water temperature data
- Geotechnical and seismic data

FPP motion data
- Wave and low frequency response characteristics
- Mooring system performance characteristics

Preliminary riser design specification
- Arrangement of risers
  - Spacing and end connection description
  - Auxiliary lines description
- Riser interface at FPP
- Riser interface at seabed

Riser configuration
- Length of joints
- Stroke length of tensioning equipment
- Termination and flexible joint elevation
- Lateral constraints and vertical support elevations

Riser joint properties
- Cross-sectional dimensions
- Material properties
- Component stress analysis data
- Design, burst and collapse pressure and temperature (flexible pipe)
- Weights of joint components (including marine growth, cathodic protection appliances, coatings, ice, corrosion allowance, etc.)
- Stiffness of flexible joints (axial, flexural and torsional)
- Weight of appurtenances (space frame, etc.)
- Gas permeability (flexible pipes)

Buoyancy devices
- Dimensions and attachments
- Weight in air and water
- Lift in water at installed depth
- Weight and mass of fill air for air cans at installed depth

Hydrodynamic coefficients
- Drag
- Mass

Note: List is not inclusive

may induce larger tension variations in flexible pipe risers than in rigid-pipe risers supported by tensioners. If the system configuration includes simultaneous drilling or workover activities while the production riser is connected, the space, load, and interference between equipment and adjacent risers can become important design considerations. The availability of specific information about the surface equipment at an early date in the design process can help to minimize the number of riser analysis/design iterations. The technical limitations and economics of the production riser system may be so demanding that they strongly influence the selection of the FPP and its associated station keeping system.

7.5.2 Riser Design Criteria

7.5.2.1 The operator's plan of operation for the field, the production system, and the field location affect many of the design and operating limits for the production riser. Environmental limits must be set for each mode of operation that may occur including normal operation, riser connection or disconnection, system shut in, inspections, maintenance, and repair activities. These limits are also a function of the particular surface equipment, its stationkeeping system, and the modes of operation required of the production riser. Riser functions, stress levels and cycles, offset angles, clearances, and equipment handling methods must each be appropriately considered when setting design and operating limits.

7.5.2.2 Sizing of the lines in a production riser should be done at an early stage of the production riser investigation to avoid excessive riser design iterations. Factors to be considered include the following:

a. Single-phase conditions: flow velocity criteria can have a sizable influence on the design and cost trade-offs for a vertically suspended riser system. Higher velocity criteria can reduce flow path sizes. This reduction is also reflected throughout the production riser/top tension/surface support equipment. This relationship is different from the "normal" pipe sizing guidelines. API Recommended Practice 14E provides useful guidance in pipe sizing.

b. Multi-phase conditions: flow-path sizing for multi-phase flow in smaller sizes (4-5 inches) can be handled with a relatively high degree of confidence because the contained fluid volumes are small and analysis techniques are the same as those used for typical wellbore tubular sizing activities. For larger-size riser tubulars in deeper water, the contained fluid volumes increase, steady state flow analysis methods become less reliable, and transient/slug flow conditions can occur. These matters are important design considerations for the riser lines.

7.5.2.3 Structural considerations: there are presently no codes, specifications, or recommended practices that pertain specifically to the structural design criteria that should be used for production riser systems for floating production systems. The ANSI Code documents such as B31.3, B31.4, and B31.8 (which have been incorporated in other API documents) can provide useful guidance to the rigid-pipe riser designer. In general, the design should be directed to: (a) metallurgical compatibility with the product and environment, (b) prevention of overstress during the installation, producing, and shut-in modes; (c) prevention of buckling; (d) corrosion allowance; (e) temperature effects, and (f) high yield strength. Other factors may be considered as well. Allowable stress limit criteria for conceptual design with low alloy steels are as follows:

For flexible pipe risers, the designer will have to exercise considerable engineering judgment and rely on the specific product manufacturer's advice. Analysis and testing of flexible pipe and its end fittings may also be necessary to qualify the pipe for a specific application. Some guidance is provided in DNV's "Technical Note TNA 503 Flexible Pipes and Hoses for Submarine Pipeline Systems."

7.5.3 Riser Analysis Methodology

7.5.3.1 Typical production riser analysis and design activities are outlined in flow chart form in Figure 43. Environmental and FPP motions data of the type summarized in Table 6 provide a data base from which specific riser analysis load cases can be determined. These cases should include survival and operating storm conditions in addition to any short duration loading condition or damage conditions that as may occur during installation/retrieval or operation of the riser or related auxiliary equipment.

The load conditions specified should be used during all steps of the design process. They are used in the preliminary response analysis in association with the preliminary riser design specifications, where emphasis is focused on riser stability and overall suitability of the design for the application. Static and frequency domain analyses are typically employed. During this phase, the riser preliminary design and specifications may have to be modified to ensure compliance with all riser functional, operational and structural requirements.

When a satisfactory preliminary design has been identified, more rigorous response analyses should be performed. This would typically include both frequency and time domain analyses, and constitutes a higher level analytic check on the riser design configuration. Model test programs may be appropriate following this level of response analyses. Model test results check analytically predicted motion and stress ranges, and may provide insight to anomalous responses not identified in the analytical investigation. The analyses and tests provide data required to specify design loads on individual components, and to perform a preliminary fatigue analysis. When component designs and stress analyses have been completed, a final fatigue analysis on the overall system should be performed.

A failure analysis may be useful to identify possible component malfunctions or failures that can propagate, causing the failure or overstressing of other system components. These analyses should identify risks to equipment or personnel. If unacceptable risks are identified, the design process should be repeated after appropriate adjustments to the load cases and preliminary design specifications. Frequently, component specifications can be developed which will reduce or preclude major system failures resulting from individual component failure. The failure analysis can identify where a redundancy or fail-safe design philosophy is appropriate.

At the completion of the design phase, all riser system loads and operating limitations should be clearly understood.

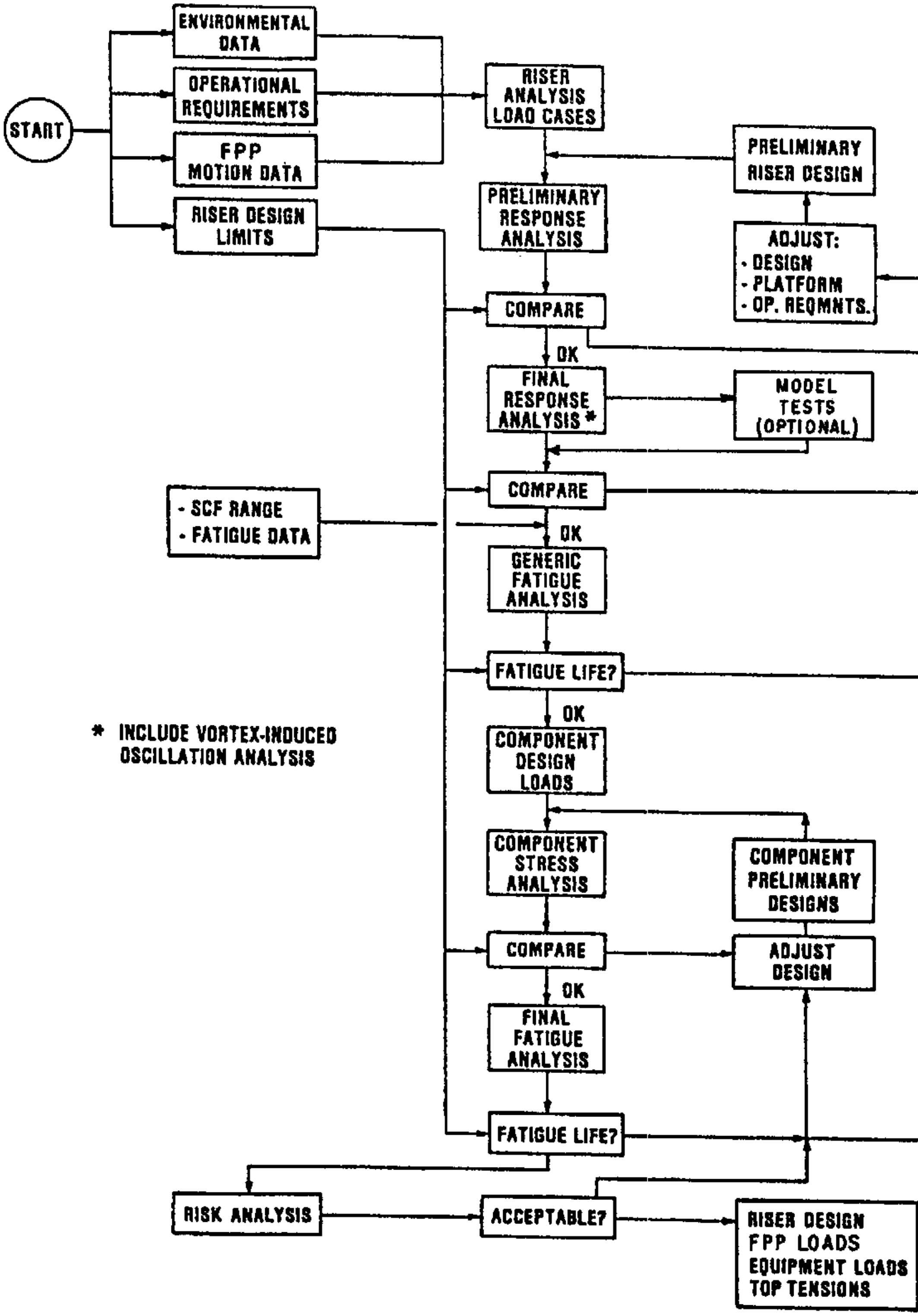


Figure 43—Riser Analysis and Design Activities

These loads and limitations should be coordinated with the development of techniques for riser installation, inspection, service, recovery and replacement, operating procedures, and personnel training.

7.5.3.2 The types of riser analysis models include the following:

a. The structural model used for the analysis of riser response must be consistent with the type of riser employed; (that is, rigid or flexible). Integral and nonintegral rigid risers are usually assumed to be near-vertical tensioned beams, which allows analysis using Bernoulli Euler beam theory. However, interaction loads between the various lines and structural members must be considered. API Recommended Practice 2Q and 2T provide introductory treatments of the applicable governing equations. Production risers constructed from flexible materials and rigid-pipe catenary risers cannot be analyzed using rigid riser analysis tools because flexible riser sections generally contain nonvertical catenary segments. The flexible riser structural model must also be capable of accurately describing large displacements and rotations. The analysis should employ either nonlinear catenary theory or large deflection beam theory, including the ability to model nonlinear cross-sectional properties.

b. Use of the hydrodynamic model should include consideration of the following:

1. Seasurface Hydrodynamics: although the ocean surface is random and multi-directional, a unidirectional random-wave model is recommended for design purposes. Unidirectional waves are easier to model and are generally believed to predict more conservative loading on the riser than multidirectional models. The influence of the surface vessel on the waves (scattering/sheltering) that act on the riser should also be considered in developing this model.

2. Wave Kinematics: various wave kinematics models have been employed for predicting fluid velocities and accelerations beneath the wave surface. Recent data indicate that the Airy linear wave function accurately models a random wave surface condition, especially when the "stretched kinematics" feature is incorporated. Nonlinear models have been developed, but they are complicated and are generally used only with the regular wave sea surface model.

3. Hydrodynamic forces: the hydrodynamic force algorithm most commonly employed is the Morison equation. Based on experimental data, this empirical equation assumes that the kinematics of the flow near the structure do not change in the flow direction. The force is broken down into two components: (a) drag and (b) inertia. The selection of appropriate drag and inertia coefficients for Morison's equation is an area of continuing research and the relevant literature should be reviewed.

Force calculation techniques based on wave diffraction analysis are not usually included in production riser analysis. These techniques assume that the body significantly scatters or diffracts the incident waves. To be significant, the ratio of the riser's horizontal dimension to the incident wavelength would have to be greater than 0.2. This requirement is not met by most production riser designs.

Factors that may be important in the determination of hydrodynamic coefficients for Morison-equation-based methods include: (a) relative motion between the riser and fluid; (b) drag variation due to surface roughness, marine growth, and variation in Reynolds Number and Keulegan-Carpenter Number; (c) flow disturbances due to nearby bodies; (d) wake encounter in oscillating flow; (e) fluctuating in-line and transverse forces due to vortex shedding; and (f) drag amplification due to vortex-induced vibrations. Model tests may be helpful in addressing some of these topics. However, care must be exercised in the interpretation and use of these results due to scaling and other limitations of hydrodynamic modeling.

7.5.3.3 Solution of the governing equation for production riser behavior requires the selection of a technique for reducing the equation into a simplified set of parametric equations and a technique for numerical solution of those equations. These considerations include the following:

a. Lumped parameter models: due to the complexity of the equation, and the requirement that several parameters vary over the length of the riser, the partial differential equation describing riser behavior is not directly solvable. Finite element or finite difference methods may be used to approximate the governing equations. Both techniques require that the riser be described by a system of continuous elements. Each element has uniform properties; the nonuniform nature of the riser's design can be modeled by appropriate selection of each element's length and parameters. Solution of the parametric equations are computed at the element interfaces.

Both methods are appropriate for production riser analysis. In either case, the choices of element properties and node locations are critical in solution accuracy. Short element lengths should be used in areas of high motion or stress gradients, such as the wave zone, near significant changes in riser properties, and areas where large deflections are anticipated.

The upper and lower boundary conditions of the riser model should reflect realistic tensioner properties, flex joint stiffness, or FPP motion.

Preliminary analysis of multi-line risers can be performed using a single element configuration in the lumped parameter model that has equivalent properties to the multi-line riser. However, the detailed design of multi-line risers may require the use of more accurate modeling to determine structural loads and response.

b. Numerical solution techniques: once the lumped parameter model has been specified, the equations are numerically solved to determine the riser's response characteristics. Tables 7 and 8 summarize the numerical solution techniques and their appropriate application.

Table 7—Static Analysis

Item	Explanation
Goal	"Snapshot Type Evaluation" of extreme response
Application	Preliminary design phase, prior to dynamic analysis, to eliminate riser configurations which do not meet global functional and operational requirements
Assumptions	Inertia effects neglected Relative velocity effects neglected
Technique invoked	Time series response simulated by variation of time dependent parameters in a sequence of static solutions to the lumped parameter equations
Benefits/Liabilities	Economic Not ensured to be conservative

Table 8—Dynamic Analysis

Item	Frequency Domain	Time Domain
Goal	Statistical evaluation of riser response as a function of frequency	Generate response time series to evaluate response statistics and extreme values
Application	Preliminary and final design phases for evaluation/ detailed specification of riser design. Provides stress transfer functions for fatigue life assessments of rigid-pipe risers	Final design phase for confirmation of response and load predictions from frequency domain analysis and to study probabilistic distribution of loads on individual components. Also provides stress transfer function and cumulative wear factor for service life assessment of flexible-pipe risers
Assumptions	Drag linearized Dynamics, relative velocities included	All dynamics, relative velocities, and nonlinearities included
Techniques invoked	Riser transfer function and design wave spectrum used to generate spectral response characteristics of riser	Direct numerical integration of lumped parameter equations; input time series simulated from design wave spectrum
Benefits/Liabilities	Economic Nonlinearities simplified Linearized drag increases error compared to time domain solution	Modeling of input requirements nearly unlimited Costly

Static analysis is rapid and economic to perform. Static analysis should only be used for initial design.

Two different techniques are employed for dynamic analysis of production risers, frequency domain, and time domain. Each approach has three unique benefits for riser design. The frequency domain technique provides a statistical response summary on the riser's performance, and is economic to perform. It is also useful during the preliminary and final design phases. However, frequency domain solutions include nonlinearity simplifications and a linearization of the drag term.

The time domain solution technique is the most general and the most accurate. It should be employed during the final design phase for confirmation of response predictions from static and frequency analyses.

Most time and frequency domain techniques in use today assume that the environmental forces and riser responses occur in a single plane. These environments are referred to as colinear. The analysis techniques are referred to as planar or two-dimensional. However, wind, waves, and current forces generally act on the riser from different directions. Vessel motions also provide forcing in the out-of-plane direction.

The limitation of planar analysis has led to the development of biplanar (sometimes called *3D*) analysis tools. These codes are particularly useful for the analysis of flexible risers.

7.5.4 Service Life Considerations

Production risers should ideally be designed for the same useful life as the FPP. To achieve this functional requirement, the fatigue life of the production riser system must be properly considered. It is important that all components of the riser system (including those at the top and bottom interfaces) be included in the fatigue analysis for both rigid and flexible risers. In addition to conventional fatigue considerations related to a rigid type riser, the flexible type riser design should consider the consequences of internal wear and abrasion. These considerations include the following.

a. The most commonly used method to estimate the expected fatigue life of the riser components is the

Palmgren-Miner rule. It is based on a comparison of cyclic stresses that may occur over the life of the system to a predicted fatigue failure level of cyclic stresses. This method is well documented in the literature for offshore applications. Both time domain and frequency domain analysis methods can be used to compute the production riser response as described previously. The time domain method is generally required for flexible-pipe risers, whereas the frequency domain technique is more commonly used for rigid-pipe users. When the frequency domain method is used, proper consideration of the linearization of the drag term and the possibility of non-Gaussian behavior is essential to obtaining proper results.

Cumulative fatigue damage over the life of the production riser can be assessed at each riser point of interest by comparing the long-term stress range distributions to the applicable S-N curve. For metals, these S-N curves are generally described in terms of hot spot stresses. For other materials or special components (such as flex joints, interface connectors, and jumper hoses), S-N curves must be either derived from prototype tests or engineering judgment.

A minimum fatigue life of three times the service life should be used for each component of a production riser. The applicable service life for the component can be less than the life of the field where appropriate inspection measures or replacement intervals are instituted.

b. Abrasion and wear are important considerations in the evaluation of flexible-pipe for the design of riser systems. Wear is a function of cyclic friction over time, and can be quantified using a cumulative damage model.

8 Operations

8.1 INTRODUCTION

8.1.1 Scope

The purpose of this section is to provide general guidelines and recommendations for operation of subsea production systems. It is assumed that proper design practices have been followed and the equipment is ready for delivery to the operator. The following operations are discussed:

a. Equipment Integration Tests.
b. Installation.
c. Production/Injection.
d. Maintenance.
e. Abandonment.

Not included in this section are recommendations on the selection of marine vessels and equipment or guidelines for downhole operations. These areas, being complex and involving many alternatives and economic considerations, are left to the judgment and preference of the operator.

8.1.2 General

Subsea production systems operations are often complicated by their remote nature. Planning and adherence to sound engineering practices are the keys to safe, successful operations. Specifications, tests and procedures that rely on proven technology and the experience of offshore operators, contractors, and manufacturers will help assure success. Documentation of the results of each phase of operations is essential to succeeding phases. Examples of such documentation are reports, records, drawings, photographs, and video tapes.

An especially critical aspect of subsea systems is the project team interface between design and operation. A good way of minimizing this interface problem is to have operations personnel participate in the design phase, and design personnel participate in the operations phase. This project team continuity principle improves planning and communication, and facilitates troubleshooting of problems.

Contractor and service company personnel employed by the operating company should also be totally aware of the operations work plan. This should happen well before actual execution of the work and can be accomplished through meetings, discussions and written correspondence.

8.1.3 Training of Personnel

Personnel should be highly trained and knowledgeable in the performance of their jobs. Classroom and work training for each particular operation is recommended so that tasks can be done safely and efficiently. The following references (see Section 2 for titles) provide training guidelines and courses that should be considered for personnel involved with subsea operations.

a. API Recommended Practice T-1.
b. API Recommended Practice T-2.
c. API Bulletin T-5.
d. International Association of Drilling Contractors-sponsored training courses.
e. Association of Diving Contractors-sponsored training courses.

8.1.4 Safety

The intent of this section is to promote safety and protect the environment through the use of industry-proven practices and equipment. All subsea production system operations should be conducted in accordance with applicable rules and regulations.

8.2 EQUIPMENT INTEGRATION TESTS

8.2.1 Purpose

Subsea production system integration testing is an important part of subsea projects. Following factory acceptance of individual components and assemblies, it allows the equipment and tools to be tested as a unit. Such tests typically include assembly, functional checks, interface checks, and comprehensive operational simulations for individual components, subsystems and integrated systems. This allows debugging and the refinement of equipment designs and operating scenarios prior to actual installation. Integration testing also provides an opportunity for key project participants to be trained in equipment operation and become familiar with equipment.

8.2.2 Pretest Requirements

All equipment test procedures should be prepared well in advance of the scheduled test dates. Such procedures should be submitted to and thoroughly reviewed by concerned/affected parties. Procedures should have a clear purpose/objective, use a test method that will produce the desired output data, and have clearly stated acceptance criteria.

The test site should have adequate room, facilities, calibrated equipment, and safety arrangements.

Testing should be conducted in an orderly, well-planned manner. Such planning might include a management system wherein the responsibilities and working relationships of all test participants are well defined. Designated witnesses should receive adequate notice when their presence is required at times other than indicated by the master schedule.

8.2.3 Test Procedure Format

A typical format for subsea equipment integration testing procedure could include the following:

a. Purpose/objective.
b. Scope.
c. Requirements for fixtures/setups, facilities, equipment, environment, and personnel.
d. Performance.
e. Data.
f. Changes.
g. Acceptance criteria.
h. Certification.
i. Reference information.

8.2.4 Test Types

Depending on the production system, there are many types of checks that can be performed. If possible, it is best to perform the test utilizing the actual subsea equipment and tools.

8.2.4.1 All components, including spares, should be tested for ease of assembly, handling, and interchangeability. Interface checks should be made under static and dynamic conditions.

Misalignment checks should consider stack-up elevation, horizontal plane, orientation, and angular aspects. Equipment with self-alignment features should intentionally be misaligned to verify its alignment capability.

Functional checks should include make-up, normal and emergency release, reversibility, repeatability, and pressure integrity. The sequence and items to be tested would normally be individual components, component/running tool, subsystems, and total system assembly.

8.2.4.2 Tests should consider (and simulate when required) field and environmental conditions for all phases or operations from installation through maintenance. Special tests might be needed for handling and transport, dynamic loading, and backup systems. Performance tests may be appropriate and can supply data on response time measurements, operating pressures, fluid volumes, and fault finding of shutdown systems.

8.2.5 Subsea Production System Interfaces

Correct fit-up of the subsea components to each other is vital. Possible interfaces are described in the following subsections.

8.2.5.1 Satellite completion interfaces include the following:

a. Tree to tubing hanger, wellhead, flowline, control pod, tree cap, umbilical, workover riser, and protective structure.
b. Tubing hanger to wellhead.
c. Workover riser to surface termination.
d. ROV or divers to all components.
e. Running tools to all components.
f. TFL/wireline tools to all components.

8.2.5.2 Template/Manifold interfaces include the following:

a. Template to wellhead, drilling system, workover system, leveling system piling, controls, tree, manifold, flowlines, and protective structures.
b. Manifolds to tree, flowline, production riser, and controls.
c. Trees to controls, and flowline.
d. ROV or divers to all components.
e. Running tools to all components.
f. TFL tools to manifold and trees.

8.2.5.3 Production riser interfaces include riser to surface termination, subsea termination, controls and ROV or diver.

8.2.5.4 Controls Interfaces include the following:

a. Surface controls to surface power unit, and control umbilical.
b. Umbilical to workover riser, control pod, tree, and running tools.

8.2.6 Equipment Rework

All changes, discrepancies, and rework should be reviewed, approved and documented in accordance with an established quality plan. Care should be taken to ensure that changes and rework do not compromise equipment performance standards.

8.2.7 Post-Test Documentation

Integration test data/results and general learning experiences should be used to revise and create equipment drawings, operating procedures, maintenance/storage procedures, assembly/handling/installation procedures, and training manuals.

8.2.8 Additional Considerations

8.2.8.1 Training: integration testing provides an opportunity for key project participants to observe and participate in critical equipment tests, which familiarizes them with the details of equipment operation relating to their project function. Participants who might benefit from inclusion in integration testing include equipment operators, service personnel, key rig personnel, key company personnel, installation contractors, divers, and ROV operators.

8.2.8.2 Photographic documentation: integration testing provides an excellent opportunity for all equipment to be photographed (including movies and videos) in a relatively controlled environment. This documentation can serve as an excellent source of training and troubleshooting information, both during and after the installation.

8.2.8.3 Actual Weights: each component and each assembly/system that will be handled as a unit should be weighed and the center of gravity determined: this information should be recorded during integration testing. Knowledge of these data may be important during the installation phase and for subsequent maintenance operations.

8.3 INSTALLATION

8.3.1 Scope

The *installation* of a subsea production system is defined as the operations of transporting the various components of the system to the installation site, positioning the system on the site, and assembling the components in accordance with the design.

8.3.2 General

8.3.2.1 Site-specific, step-by-step installation procedures (including backup procedures and contingency measures) should be prepared. Installation procedures should be designed to minimize the time required to install the subsea production system. The weather limitations for initiating critical operations should be defined. All procedures should be reversible or capable of suspension in a safe position in the event that bad weather occurs during installation. Copies of the installation and operating manuals should be maintained onshore and offshore.

8.3.2.2 Onshore integration tests should be used to provide training for installation personnel whenever possible. In some cases, procedures and steps should be practiced in a full-scale test of simulated conditions, particularly those that involve divers or ROVs. Special tools should be thoroughly tested and evaluated during onshore testing.

8.3.2.3 An adequate supply of spare parts and necessary equipment (that is, tools, rigging, etc.) should be provided and included with the onshore mobilization.

8.3.2.4 When loading out equipment for offshore transport, care should be exercised to provide seafastenings that are adequate to resist the overturning moments from vessel roll, pitch, and heave acceleration forces. Some items may require welding to the vessel or barge deck (in addition to the slings, lines, and turnbuckles) to prevent shifting while in transit. Environmental data will determine the size and redundancy of the transporter seafastenings.

8.3.2.5 For transport, an adequate number of seagoing barges, tugs, and support vessels should be provided. Due consideration should be given to the stability and motion response of the transporting vessel(s). These vessels should be of sufficient size to accomplish the work and to operate safely under the environmental and oceanographic conditions that may be encountered during the voyage and at the job site. Weather conditions should be within prescribed limits during installation to prevent damage to the subsea production system and/or installation equipment. The installation operation should not be initiated unless the projected weather window is sufficient to enable a complete operation.

8.3.2.6 All slings, shackles, spreader bars, pins, and hooks should be checked, approved, and properly stored or preserved prior to commencing installation operations. Shackle-to-shackle connections generally should not be used. Appropriate factors of safety for rigging should be used on load-out, seafastening, and offloading at sea.

8.3.2.7 Installation coordinates for the subsea system and the installation vessel(s) anchoring system should be established prior to beginning operations; both should account for seafloor obstructions and irregularities. If necessary, subsea transponders may be installed to assist in orientation and positioning of the installation vessel(s) and the subsea production system.

8.3.2.8 Strict attention should be given to correct procedures for handling equipment on the installation vessel to reduce the risk of damage from dropped objects. The method of orienting the equipment on the sea floor should be predetermined.

8.3.3 Templates/Bases

8.3.3.1 Normally, the following methods of template transportation should be used: (a) carrying under a semisubmersible; (b) wet tow, where the template is placed in the water and towed behind a vessel; or (c) barge tow, where the template is fastened onto an oceangoing barge or crane vessel that the template taken to site.

For carrying the template under a semisubmersible, a detailed tie-down and transport analysis should be conducted. The template should be positioned in a manner to prevent wave slamming, which could damage components and/or cause the template to break away from the semisubmersible during transit.

For a wet tow, model tests or detailed calculations should be performed to determine towing characteristics. Special attention should be given to avoid having any protruding members that may break or become damaged.

For a barge tow, particular attention should be given to the barge stability, especially if the template has a high center of gravity or a large sail area that may cause overturning moments due to wind.

8.3.3.2 After arrival at the installation site, the template should be inspected for transport damage; necessary repairs should be made and documented. Following removal of seafastenings, all damaged paint areas should be repaired.

8.3.3.3 The template should be lifted, launched, or otherwise placed in the water; care should be taken to avoid any anchor lines or other obstructions in the water. The submergence through the air/water interface should be accomplished in the minimum of time to reduce the effects of wave action. Lowering through the interface should be at a rate to avoid snap loads on the slings.

8.3.3.4 Normally, the following methods for setting the template should be used: (a) Lifting and lowering with a derrick barge; (b) launching from a barge and lowering with a derrick barge or other suitable vessel; (c) lowering from a drilling vessel's moon pool; or (d) keelhauling and lowering from a drilling vessel.

When lifting or launching a template, the guidelines described in API Recommended Practice 2A should be followed. The slings normally should be attached above the center of gravity to avoid possible damage to the template and/or barge during the lifting operation.

When keelhauling and lowering a template, one or more side handling lines should be attached to the template and properly attended.

8.3.3.5 Prior to lowering, the maximum acceptable heave acceleration of the lifting/lowering rigging should be determined. The template/base should be lowered slowly to the seabed and oriented to the proper position in accordance with the design. The correct position, orientation, and levelness should be checked before releasing any slings or tag lines. Care should be exercised when disconnecting shackles subsea to avoid damage to the template by the slings.

8.3.3.6 The template/base should be fixed to the seafloor through well casings, piles, or gravity loads. If piling operations are required, the guidelines described in API Recommended Practice 2A should be followed. The template/base should be leveled to the acceptable tolerances in accordance with the design. Care must be taken to maintain the level of the template/base if it is to be grouted to piles, using pre- or post-installed leveling devices or visual inspection. Leveling devices should be located on points of the template structure that are not subject to deformation during installation.

8.3.4 Tree/Manifold Components

8.3.4.1 The tree/manifold should be properly protected during shipment to avoid damage to critical interfaces and vulnerable subcomponents, and to avoid contamination of hydraulic control circuits. Subsequent to completion of the shore-based stack-up test, the tree/manifold should be shipped completely assembled to the extent practical. This ensures the integrity of the integration test and minimizes the risks of further handling. If possible, the tree/manifold should be flushed internally, locked to the test stump, or shipping base; all valves closed or returned to their normal position; and all hydraulic connectors fully locked. The test stump should have external support to avoid overturning. The control umbilical connector half should be covered with waterproof material if applicable, the control module should be locked down to its base. Lifting slings should be attached to the main supporting members, usually the tree/manifold frame.

8.3.4.2 Arrival of the tree/manifold components at the installation site should be timed to permit a thorough checkout of all equipment prior to running subsea. If damage did occur, sufficient time would then be available to make minor repairs.

8.3.4.3 The installation vessel should have ample crane capacity and deck space to offload the components safely. It is recommended that the crane on the lee side of the vessel be used when offloading, and that an area of the installation vessel be reserved for checking and training. If possible, heavy components should be handled down-current of the subsea installation to minimize dropped object risk.

8.3.4.4 The tree/manifold should be function-tested on a test stump prior to running. All seals should be inspected and pressure-tested where possible to ensure that no damage has occurred. Running tool connectors and hydraulic umbilical connections should be tested before running any component.

8.3.4.5 If guidelines are used, they should run through the component guide frames, taking care to ensure proper orientation before the component is run. The guideline tension should be sufficient to prevent excessive deflection of the equipment due to current forces as it is run and landed.

8.3.4.6 When running a component using hydraulic tools, the hydraulic umbilical should be checked to ensure that it is properly attached to the component and running tool. Provisions should be made to maintain hydraulic pressure on both the lock port of the running tool connector and the unlock port of the component's vertical connector while lowering to the seafloor.

8.3.4.7 As a component is being landed, the operation should be visually monitored to ensure that guide funnels engage guideposts properly and (when possible) simultaneously. Installation procedures should be designed to avoid a hydraulic block when landing equipment on a wellhead or other connections with sealing interfaces. This is usually done by ensuring that appropriate valves are open. The component should be visually inspected to ensure that it is level and at the proper elevation in accordance with the design.

After landing and lockdown, an over-pull should be taken on the running string to ensure that the component is properly installed. The component then should be function- and pressure-tested from the installation rig. When appropriate, protective covers or caps should be installed over connection interfaces to prevent damage from dropped objects or corrosion/debris accumulation on critical sealing surfaces and latching profiles.

8.3.5 Pipelines/Umbilicals

8.3.5.1 Guidelines described in API Recommended Practice's 5L5, 5L6, 6G, 1110, and 1111 for transportation, installation, testing, and operation of pipelines should be followed where applicable. For umbilicals, any load-out and installation procedures should be established in agreement with control system and umbilical manufacturers.

8.3.5.2 The pipeline/umbilical route should be surveyed and marked prior to installation. Suitable markings may include physical identification or instrumented identification of the designated route. Pre-installation dredging, jetting, matting, and other subsea site preparation should be completed prior to commencing installation.

8.3.5.3 All pipeline/umbilical components should be carefully inspected prior to placing them in the water, with special attention paid to end connections. To the extent practical, one umbilical end should be connected and tested on the surface (for example, to junction box, tree or manifold) before installation to reduce the number of connections made subsea. The continuity of electrical conductors and hydraulic hoses should be monitored during installation.

8.3.5.4 If a drawdown technique or other method of installation requiring buoyancy devices is used, care should be taken to avoid interference between anchor lines and the buoyancy devices.

8.3.5.5 Prior to lowering to the seabed, any pull-in sleds, bullnoses, or other guidance assemblies should be securely attached to the end connections.

8.3.5.6 The pipeline should be properly positioned on the seabed using a proven method which prevents ovalling, flattening, or otherwise overstressing the pipe. The line ends should be located within prescribed target zones.

After laying, the line should be inspected, cleaned, and, if necessary, gauge-checked. If the line is to be trenched, it should be tested and surveyed after trenching. As necessary, anti-scour mats and/or pipe end stabilization mats should be installed to avoid spanning problems.

8.3.5.7 For the spool piece end connection method, the spool pieces should be accurately sized and measured, inspected, gauge-checked, and pressure-tested before lowering them to the seabed for installation.

8.3.5.8 The pulling operation should be continuous to prevent sticking or creeping of the lines. Forces should be monitored during the pull-in operation to prevent overstressing of cables, rigging, or other equipment. The pull-in operation should be visually monitored using tool-mounted, diver-held, or ROV-carried TV cameras.

8.3.5.9 The pipeline should be pressure-tested to applicable levels after it has been laid and/or connected. After installation and connection of umbilicals, hydraulic lines should be pressure-tested, electrical insulation should be tested, and the control umbilicals should be function-tested from the surface control station.

8.3.5.10 When laying umbilicals separately, sufficient overlengths should be left at either end to facilitate connection. If practical, the overlength should be sufficient to enable the end to be retrieved to the surface from directly overhead. Care should be taken to avoid unsupported lengths of cables and hoses at both ends.

8.3.5.11 After final testing, all running tools, guidelines, cables, and other installation equipment should be retrieved to prevent future interference. A final inspection and as-built survey should be conducted. As-built video and still photographic surveys should be performed on the pipe line/umbilical tie-ins. Installation reports should be prepared, including brief work descriptions, daily reports, test results, damage reports and remedial measures, and post-installation survey information.

8.3.6 Risers

8.3.6.1 Rigid production risers can be considered equivalent to marine drilling risers from an installation viewpoint. The guidelines described in API Recommended Practices 2K and 2Q should be followed.

8.3.6.2 Installation of flexible risers should include the following procedures:

a. The area should be marked with a suitable array of transponders to assist in location of the riser base and locating the riser in the proper catenary trajectory.

During the unspooling phase, the riser should be visually checked for twist, abrasions and other surface damage. Any buoyancy devices connected to the riser should not chafe. During the lowering phase the riser's radius of curvature should be visually monitored and controlled to keep it within design limits.

b. The installed riser should be surveyed from vessel connection to riser base connection using divers or ROV. The correct orientation of the riser should be verified. The correct position of the riser in buoy support cradles, if used, should be checked. The path of the catenary section on the seafloor should be monitored and checked for interference between individual riser lines. Bend limiters, if used, should be checked for proper position. If flexible pipe construction incorporates a venting system for diffused gas, the vented gas should be disposed of safely.

8.4 PRODUCTION/INJECTION OPERATIONS

8.4.1 Introduction

This section presents general guidelines for safe operation of subsea oil and gas production or injection installations. These guidelines address considerations applicable to subsea installations ranging from simple satellite wells to sophisticated installations, which may consist of multiple wells, templates, manifolds, pipelines, risers, and self-contained production handling facilities. The guidelines are not intended to cover specific installations, particular operating situations or local regulatory requirements.

8.4.2 General

If possible, the operating organization should be established at an early stage of the subsea project so that key operating personnel can participate in design, testing, and installation of subsea equipment. This early involvement of operating staff should help incorporate operating considerations into designs, as well as facilitate handover from the design and installation project team to the operating organization.

Field activities (that is, drilling, construction and maintenance) that involve the subsea installations should be coordinated with the subsea operating organization. This provides a single point of responsibility to ensure that all work is carried out in a coordinated and safe manner.

8.4.3 Operating Guidelines

8.4.3.1 Commissioning of subsea installations occurs when well completion and/or installation activities are complete and responsibility is handed over to the operating organization. Commissioning usually involves tests and inspections to ensure that installations have been made in accordance with specifications. It may involve certain preparations (that is, purging, displacing, charging hydraulic systems, etc.) that are required to ready the facilities for operation. The operating organization should actively be involved in planning and executing commission tests. The tests should be completed prior to exposure to well fluids, and planned and executed in a manner that verifies the integrated performance of the subsea systems.

All valves should be tested wherever possible for performance and pressure integrity. It may be difficult to achieve meaningful pressure-test results due to the large bulk volume of the pressured system and/or the location of the valves. Where required, drifting (that is, TFL drifts or scrapers of surface piping, risers, pipelines, manifolds, trees, etc.) should be demonstrated. Surface and subsea controls should be thoroughly checked, including pressure integrity tests of hydraulic control circuits, function tests of command, alarm and shutdown systems, response time tests, and calibration tests.

All surface support systems (that is, power supplies, panels, pumps, manifolds, etc.) should be tested to demonstrate performance and proper systems integration.

8.4.3.2 Special care should be exercised when initiating flow through a subsea system after commissioning or after shutdowns. Start-up should be carried out in a defined and controlled manner to ensure proper system performance and minimize wear and risk of damage. Detailed start-up procedures should be prepared and followed. General considerations regarding start-up include:

a. Initial start-up: a checklist approach is recommended for initial start-up to ensure that controls and valves are energized in a correct sequence and are operating normally.

Displace auxiliary flow systems with appropriate fluids (for example, lift gas inhibitors, and the like).

Override the emergency shutdown (ESD) controls.

Position valving to start flow. Pressure across valves, especially SCSSVs, should be equalized whenever possible prior to opening. Downstream valves on producing flow runs should be opened last. Flow from producing wells may be initiated by:

1. Opening up an underbalanced well.
2. Circulating out kill fluid to an underbalanced or flowing condition.
3. Activating an artificial lifting system (that is, gas lift).

As flow commences, carefully monitor pressures and temperatures and, if necessary, introduce hydrate, paraffin or corrosion inhibition chemicals. Well annulus pressures should be monitored as flow commences. In certain cases, it may be necessary to bleed or vent annulus pressure build-up resulting from expansion of annulus liquids as the wellbore temperature increases.

After flow stabilizes, pressure-sensing shutdown devices should be adjusted to proper setpoints and the control system returned to ESD control.

b. Routine start-up: start-up after routine shut-downs may not require repeat of all the steps for initial start-up. However, the status of the system should be checked before start-up and rigorous start-up procedures should be followed.

8.4.3.3 After normal production and/or injection has been established, continued monitoring of pressures, temperatures, and flow rates of fluids (that is production, injection, lift gas, chemicals, etc.) is advised. Changes in status should be noted that may indicate conditions requiring further attention. Records of system parameters under routine conditions will be very important to any diagnostic work required later.

8.4.3.4 Total or partial shut down of a subsea installation may be required for routine or emergency reasons. Emergency shut downs may result from alarms in the subsea system or by interruptions in downstream fluid processing facilities. Recommended guidelines for the shut down of subsea installations are as follows:

a. Unnecessary closure of subsea valves should be avoided because it accelerates wear of flow control devices; damages equipment through pressure and temperature stress cycles; and reduces productivity through accumulation of hydrates, paraffin and sand.
b. Downstream valves (preferably at the surface) should be closed first in all shutdown sequences to minimize wear on the most inaccessible subsea valves. For routine temporary shutdowns, only the furthest downstream valve should be closed. The SCSSV should be closed only in predetermined well emergency scenario for extended shutdowns or for regulatory testing.
c. Chemical inhibitors should be injected for certain production applications to minimize potential hydrate problems upon start-up.
d. Sensors, if provided, should be monitored after each shutdown to assess the status of the subsea system.
e. The cause of any emergency shutdown should be identified as soon as possible in order to determine if follow-up actions (that is, displace flowlines, disconnect riser, kill wells, etc.) are required. Predeveloped emergency shutdown plans and clearly defined procedures should be available for use by operating personnel.
f. Weather-related shutdown procedures should be provided in order to secure the installation (that is, wells, pipelines, risers and production facilities) in a safe and timely manner.

8.4.3.5 A program to evaluate the status of a subsea production or injection system should be adopted to ensure safe, efficient, and long-term performance. The program should provide for monitoring of critical operating parameters and for subsystem tests as necessary. Monitoring and testing programs may include well flow tests, flow conduit pressure tests, performance/pressure tests of flow control devices, and control system and sensor tests. Complete records of all test and monitoring information should be maintained by operating crews.

8.4.3.6 Periodic pigging and scraping of flow conduits may be required. This activity could include clearing liquids from gas lines, and/or removing accumulations of paraffin from oil lines. The operating crews should determine an optimum frequency for scraping and pigging based on rates of build-up, lost production, and costs. The pig and/or scraper should pass through the flow system in a controlled manner to avoid damage.

8.4.3.7 Well stimulation and treatment operations should be carefully planned if chemicals are involved which may damage or plug the subsea flowsystem. Particular attention must be given to selection of chemicals that will not alter or otherwise affect the performance of sensitive materials (that is, coatings, elastomer seals, etc.) in the flow system.

8.4.3.8 Procedures should be developed (and equipment and supplies kept available) to carry out well killing operations if required on short notice. This operation may be accomplished either by pumping kill fluid into the well through a flowline, or vertically through a workover riser from a workover vessel.

8.4.3.9 Subsea installations are vulnerable to damage by mooring systems and fishing gear. To minimize these risks, the operating organization should develop means to carefully control mooring and fishing activities in the area of the subsea installations. Ways of accomplishing this protection include: (a) establishment of a safety zone around the subsea installation; (b) use of visual and/or radar surveillance, monitoring vessels, marker buoys and signs; and (c) indicating the safety zone on marine maps.

Careful planning and control of anchoring required for in-field construction or drilling/workover operations is also recommended.

8.5 MAINTENANCE OPERATIONS

8.5.1 Introduction

Maintenance is an important aspect of subsea oil and gas production installations. Subsea installations should have equipment designed and manufactured to facilitate maintenance, a systematic approach to maintenance should be adopted by operating organizations. Maintenance of subsea wells and associated facilities may range from inspections and minor adjustments to major repairs involving expensive and sophisticated equipment and services. In some cases, maintenance operations may equal or exceed the difficulty, risk, and cost of making original installations.

Many maintenance tasks may be required for subsea systems, and there are many approaches that can be taken to carry out these tasks. This section covers General Maintenance

Considerations and Maintenance Approaches/Guidelines. No attempt is made to address specific maintenance tasks or to consider requirements for particular subsea hardware.

8.5.2 General Maintenance Considerations

Planning for maintenance should begin during the subsea hardware design. Potential maintenance tasks should be identified, optional approaches evaluated, and selections made as to provisions for maintenance to be incorporated into subsea hardware. In some cases, simple and basic maintenance methods (that is, wet divers with hand tools) may be warranted; in other applications, sophisticated approaches (that is, remote diverless tools) may be necessary.

Special maintenance tools and procedures should be thoroughly tested and evaluated during onshore testing programs. Outline procedures should be developed and full-scale tests performed if practical. Detailed photo and/or video documentation of subsea hardware and maintenance tools is recommended.

Detailed procedures should be prepared prior to initiating any subsea maintenance operation. The procedure should indicate planned work and define how the maintenance operation is to be coordinated with other ongoing field activities. The procedure should list materials, equipment, and services required for the particular maintenance operation.

The organization responsible for operating the subsea installation should coordinate maintenance work. This will help ensure that all maintenance work and other field activities are carried out in a safe and efficient manner.

Completed maintenance work should be thoroughly documented.

8.5.3 Maintenance Approaches/Guidelines

There are three general categories of maintenance for subsea wells and associated facilities: (a) downhole well maintenance, (b) seafloor equipment maintenance, and (c) surface equipment maintenance.

8.5.3.1 Downhole well maintenance involves typical remedial operations that are common to all wells. Downhole maintenance may be conducted by the following methods:

a. Vertical well entry. Vertical access may be gained through the subsea tree or a BOP installed after the tree has been removed. A riser system with pressure-containing flow conduits and control circuits is required to link the subsea tree or BOP to the surface vessel. Appropriate subsea or surface BOP equipment should be employed that satisfies the required service conditions and conforms with accepted industry practices and applicable regulations.

If possible, subsea wells should be safely secured prior to commencing any well maintenance operation involving potential exposure to live well fluids. A minimum of two upstream pressure containing barriers (pressure-tested, if practical) should be established before breaking any pressure connection. The barriers could be effected by closing a tree valve or SCSSV, installing tubing plugs, permitting an annulus check valve to close, or displacing the well with kill fluid. The best procedure is situation-dependent and should be left to the operator's discretion.

Extreme care should be taken when lowering and landing tools that connect to the subsea tree and/or wellhead to minimize potential damage to installed components. If possible, the rig or surface vessel should be displaced to a position offset from the center of the well when handling and running packages in order to reduce the risk of dropping objects or debris onto the well or adjacent components.

Pipelines should also be purged of all hydrocarbons prior to disconnection from the tree.

After well repairs are completed, downhole and tree components should be reinstalled and tested in accordance with original installation procedures.

b. Through-Flowline TFL pumpdown well maintenance: TFL methods are an effective means to carry out many downhole remedial operations from a remote production station by pumping TFL tools into the well through the flowlines. Typical TFL maintenance tasks include:

1. Placement and removal of tubing flow control devices, plugs, standing valves, gas lift valves, insert safety valves, etc.
2. Deployment of tools for pressure, temperature and corrosion surveys.
3. Paraffin scraping.
4. Sand washing.

Detailed plans and qualified operators should be utilized in performing TFL operations. General guidelines for conducting TFL operations include the following:

1. Prepare a detailed work plan.
2. Assemble and check out TFL equipment and tools in accordance with established procedures.
3. Complete planned TFL operations, making certain that the flow system is clear of debris and will freely pass a sizing drift prior to displacing tools.
4. Document all TFL work.

8.5.3.2 Maintenance of equipment located on or near the seafloor (that is., wellheads, trees, control modules, valves, pipeline connectors, manifold, templates, pipelines, riser bases, and risers) can be carried out by modular replacement or in situ repairs. Modular or component replacement involves packaging repair/maintenance-prone items into composite units that may be removed to the surface for replacement or repair. Modules may be removed and replaced using tools deployed on pipe work strings, wirelines, and ROVs, or by manned intervention methods involving wet divers, one-atmosphere habitats, and manned vehicles.

In situ repairs are those made without recovery of the equipment to the surface and may be accomplished by remotely operated tools or by wet and one-atmosphere divers.

An effort should be made to diagnose and define a problem prior to initiating a maintenance operation. The affected well(s) should be shut-in; the subsea system should be put into a safe condition for removal/repair of the component requiring maintenance. For manifolded systems, it may be possible to isolate the affected well(s) and continue normal operations. Steps then should be taken to preclude the possibility of operations personnel inadvertently operating the subject or related equipment after it has been put into a safe condition.

Live wells should be isolated by a minimum of two pressure-containing barriers, as described in Section 8.5.3.1, Item a, if maintenance involves possible exposure to well fluids.

Pressure-containing conduits should be bled down to ambient pressure. If possible, hydrocarbons and other potentially contaminating fluids should be displaced from flow circuits.

Electrical circuits should be de-energized if they pose a hazard for divers and other maintenance systems.

Lowering and recovering of tools and modules on drill-strings or cables should be executed with care to minimize risks of damage to sea floor equipment by dropped objects, or by impact during positioning or landing.

After maintenance operations on subsea equipment are completed, the subsea system should be thoroughly tested before being put back into service. Comprehensive records of all maintenance work should be maintained.

8.5.3.3 Maintenance of surface equipment (that is, upper riser equipment, production control and handling facilities, utilities, TFL equipment, etc.) would be similar to that required for typical surface facilities, although special requirements may be necessary to meet unique subsea system needs (for example, adhering to strict hydraulic fluid cleanliness specifications). Preventive maintenance as well as necessary repairs should be performed.

8.6 ABANDONMENT

8.6.1 General

Subsea production systems abandonment operations include safely plugging wells, removal of equipment and structures, and clearance of the seabed. Abandonment in place is also an option that may be possible in some locations. Marine vessels, equipment, running tools, etc., similar to or the same as that used on the original installation will be required. Other requirements and considerations are governmental approvals/permits, well-thought-out and documented plans and procedures, pre- and post-abandonment surveys, and transport or disposal of the salvaged hardware.

8.6.2 Well Plug and Abandonment

Various aspects and options for plugging and abandoning platform wells are discussed in API Recommended Practice 57. The discussion of the downhole operations is applicable to subsea wells and referenced for detailed consideration. Additional considerations are present in the permanent abandonment of subsea template wells as compared to satellite wells. As with other operations on multi-well templates, the hazards and effects of well abandonment on adjacent wells and equipment should be analyzed.

8.6.3 Manifolds/Template

When the decision has been made to abandon a subsea template, the design method should be reviewed in light of changes to the template and salvage technology. In certain situations, the manifold/template may be left in place. If it is to be removed, a subsea survey should be conducted to ascertain the manifold/template physical condition.

The integrity of the lifting points and ballasting system are critical. After collecting the desired information, a detailed plan of removal should be developed.

8.6.3.1 Manifolds that are integrated into the template would be abandoned with the template. Packaged manifolds designed to be installed and removed by a drilling rig could be abandoned in conjunction with well abandonment. A separate manifold system, such as part of a riser base, would require its own abandonment analysis.

Before abandonment of manifolds, hydrocarbons should be purged from the piping systems and risers by flushing with seawater. The flushed fluid should be recovered at the surface to avoid pollution.

8.6.3.2 General guidelines for template removal are as follows:

a. Disconnect all risers, pipelines, flowlines, control and power lines.
b. Piles, like well casing, should be cut off at the required distance below mudline. The cut-off pile sections may require pulling to reduce suction effects and lift loads when the template is removed. If so, the template/pile connection should be broken so as not to damage the template's structural integrity.
c. Removing the template will require a well-thought out plan. Among the things that may need to be considered are a lifting analysis, removal of cuttings and cement, jetting to reduce bottom suction, addition of flotation devices, and lifting in pieces. The crane barge or lifting vessel should have adequate capacity to handle higher than expected loads.
d. Visual surface monitoring of the rigging up and lifting should be carried out using diver-held or ROV-mounted subsea TV.

e. After the template is lifted and secured to a cargo barge, it can be transported to the chosen disposal site.

8.6.4 Pipelines

Abandonment of subsea pipelines is accomplished by either abandonment in place or complete removal. Each line abandoned in place should be flushed of hydrocarbons and filled with seawater or other inert material. The ends of the line should be disconnected and sealed from all hydrocarbon sources. The ends should not extend above mudline in a snagging position. Abandonment of control umbilicals either attached to or separate from the flowline should follow the same general procedure.

9 Quality Assurance, Materials and Corrosion

9.1 SCOPE

This section provides guidelines for the establishment of quality procedures for subsea production systems components consistent with functional, environmental, and safety requirements. Not all components should require identical procedures as the consequences of failure may vary. For example, failure of pressure-containing elements could jeopardize personnel safety and/or damage the environment, whereas failure of other elements may inhibit the system from performing its function and possibly be difficult, time consuming, or costly to repair without causing harm to personnel or the environment. Likewise, failed elements may be easy to repair or may not even inhibit the system functions. There also may be complete redundancy with some piping or control systems.

As use becomes more critical, additional requirements should be imposed. These may include improved metallurgical properties, traceability, documentation, third-party inspection, environmental testing, use of simulators, integration testing, etc.

Specific procedures should be written to cover required criteria which are beyond what would be expected from a properly installed quality assurance program.

9.2 QUALITY ASSURANCE ELEMENTS

9.2.1 Quality Assurance Program

A documented Quality Assurance Program covering activities, items, and services should be planned, implemented, and maintained in accordance with requirements of applicable specifications.

The program should provide for a staff trained to assure compliance with the applicable specifications. The staff must be independent of the manufacturing organization. Management should periodically assess the program and take corrective action, as needed.

9.2.2 Quality Assurance Manual

The quality assurance program should be described in a quality assurance manual.

9.2.3 Design Control

Designs should be defined, controlled, and verified to ensure conformance to design criteria, requirements, and standards. The design should be verified by persons other than those who designed the item or process. Changes should be governed by the same control measures applied to the original design.

9.2.4 Process Control

Processes affecting quality should be controlled in accordance with specified requirements and documented procedures. Working level instructions should be prescribed in job sheets, route sheets, plant procedures, drawings, operating manuals, test procedures, or any other type of written and/or graphic form. Controls should prevent the use of obsolete or inappropriate instructions, procedures, or drawings. As-built drawings should be available as requested.

9.2.5 Procurement Control

Requirements necessary to assure compliance with the applicable specifications should be included or referenced in documents for procurement of materials, items, and services.

9.2.6 Material/Product Identification

Material and product identification should include provisions for maintenance or replacement of identification marks and identification control records as required.

9.2.7 Traceability

Traceability of design, material processes, inspection, and testing should be maintained in accordance with documented instructions and procedures.

9.2.8 Special Processes

Special processes affecting quality such as welding and nondestructive examination should be performed by qualified personnel using qualified procedures given in the applicable specifications.

9.2.9 Inspection and Testing

Inspection and testing should be planned and controlled for the verification of conformance to documented instructions, procedures, and drawings describing acceptance criteria. Testing should include but not be limited to components, subassemblies, factory acceptance, and systems integration. Results should be documented.

9.2.10 Control of Measuring and Test Equipment

Measuring and testing equipment used for activities affecting quality should be controlled, calibrated, and adjusted at specified periods to maintain required accuracy. Specifications, calibration, and control of measuring and testing equipment used for acceptance should be described in written instructions or procedures.

9.2.11 Documentation

Records should be specified, compiled, and maintained to furnish documentary evidence that services and items meet applicable specifications. Records should be legible, identifiable, and retrievable. Requirements and responsibilities for record transmittal, distribution, retention, maintenance, and disposition should be established and documented.

9.2.12 Handling, Storage, and Shipping

Handling, storage, cleaning, packaging, shipping, and preservation of items should be controlled to prevent damage or loss and to minimize deterioration. All should be in accordance with applicable specifications.

9.3 MATERIALS

Where H_2S, CO_2, and/or chlorides are present, chemical composition and manufacturing processes are of particular importance. Materials exhibiting specialized resistance should be used in accordance with applicable specifications.

9.3.1 Metals

Metallic components may vary depending upon the service but should comply with the manufacturer's written specifications. Manufacturer specifications should define the following:

a. Chemical composition limit.
b. Heat treatment conditions.
c. Mechanical property limits:
   1. Tensile strength.
   2. Yield strength.
   3. Elongation.
   4. Hardness.
   5. Impact strength.
d. Melting practice.
e. Forming practice.

9.3.2 Dissimilar Metals

The use of dissimilar metals in an assembly should be avoided in order to prevent galvanic corrosion. If dissimilar metals must be used, care should be used in selecting metals with nearly equal electrical potentials in the environments to which they are exposed. Generally the least critical or more massive component should possess the higher electrode potential (anodic), thus corroding sacrificially and is protecting the more critical or smaller component.

9.3.3 Non-Metals

Non-metallic materials should be capable of withstanding the operating pressures and temperatures specified by the operator and should be compatible with the intended service.

9.4 CORROSION

9.4.1 Internal

The type of fluids being handled should be considered and allowance made for fluids that are particularly corrosive. Corrosion due to treating fluids must be considered as well as corrosion due to produced fluids. Careful selection of locations for taps, tees, flow restrictions, and short-radius bends can also limit corrosion due to dead spaces.

Where necessary, internal corrosion may be mitigated by one or more of the following: (a) pipeline scraping or pigging at regular intervals, (b) dehydration, (c) inhibition, (d) bactericides, oxygen scavengers, and (e) internal coating. The variables and severity of each case will determine the preventive methods that should be used. A monitoring program should be established to evaluate the corrosiveness of the fluid and the results of the internal corrosion mitigation systems.

9.4.2 External

External protection may be provided by material selection, coatings, or cathodic protection.

9.4.2.1 External contact with fluids should be considered in the design. Splash zone areas require additional protection due to sunlight, wave action, and possible mechanical damage. Where required, external coating systems should include, but not be limited to the following considerations:

a. Loading characteristics.
b. Resistance to underfilm water migration.
c. Electrical resistance and degradation of resistance in service.
d. Capability to withstand storage conditions.
e. Resistance to debonding, cold flow, embrittlement, and cracking.
f. Installation stresses.

Welds should be inspected for irregularities that could protrude through a coating.

9.4.2.2 Cathodic protection should be provided by a galvanic anode system, an impressed current system, or both, capable of delivering sufficient current to adequately protect the equipment. Key considerations including the following:

a. Galvanic anode systems should employ only alloys which have been successfully tested for offshore applications.
b. Galvanic anode systems should be designed for the life of the equipment if practical.

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