

Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities

API RECOMMENDED PRACTICE 14J
SECOND EDITION, MAY 2001

REAFFIRMED, SEPTEMBER 2019



AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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Abbreviations

AGA	American Gas Association	NEMA	National Equipment Manufacturers Association
ANSI	American National Standards Institute	MPMS	Manual of Petroleum Measurement Standards
API	American Petroleum Institute	NFPA	National Fire Protection Association
ASME	American Society of Mechanical Engineers	OSHA	Occupational Safety and Health Administration
AWWA	American Water Works Association	PES	Programmable Electronic Systems
CAA	Clean Air Act	PLC	Programmable Logic Controller
Chapt	Chapter	P&ID	Process and Instrument Diagram
CFR	Code of Federal Regulations	PFD	Process Flow Diagram
DOT	Department of Transportation	PSV	Pressure Safety Valve
EPA	Environmental Protection Agency	PTC	Power Test Code (ASME)
ESD	Emergency Shutdown	Publ	Publication
FAR	Federal Aviation Regulation	RP	Recommended Practice
FCC	Federal Communications Commission	SAFE Chart	Safety Analysis Function Evaluation Chart
HA	Hazards Analysis	SCADA	Supervisory Control and Data Acquisition Systems
IEEE	Institute of Electrical and Electronics Engineers	SEMP	Safety and Environmental Management Plan
ISA	Instrument Society of America	SOLAS	International Convention of the Safety of Life at Sea
MAWP	Maximum Allowable Working Pressure	Std, S	Standard
MMS	Minerals Management Service	TEMA	Tubular Exchanger Manufacturers' Association
MSDS	Material Safety Data Sheet	USCG	United States Coast Guard
NEC	National Electric Code		
NFC	National Fire Code		

Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities

1 General

1.1 PURPOSE

The purpose of this recommended practice is to assemble into one document useful procedures and guidelines for planning, designing and arranging offshore production facilities, and performing a hazards analysis on open-type offshore production facilities. This will promote safe, pollution free and efficient production of oil and gas. This publication is only a guide and requires the application of sound engineering judgment. Furthermore, it is not intended to override or otherwise supersede any existing code or governmental rule or regulation, nor is it intended as a comprehensive document containing all useful and appropriate information.

1.2 SCOPE

This document recommends minimum requirements and guidelines for the design and layout of production facilities on open-type offshore platforms, and it is intended to bring together in one place a brief description of basic hazards analysis procedures for offshore production facilities. This recommended practice discusses several procedures that could be used to perform a hazards analysis, and it presents minimum requirements for process safety information and hazards analysis that can be used for satisfying the requirements of API RP 75.

The concepts contained herein recognize that special hazard considerations exist for offshore production facilities. As a minimum, these include:

1. Spatial limitations that may cause potential ignition sources being installed in or near production equipment.
2. Spatial limitations that may result in quarters being installed near production equipment, pipeline/flow line risers, fuel storage tanks, or other major fuel sources.
3. The inherent fire hazard presented by the release of flammable liquids or vapors, whether during normal operations or as a result of any unusual or abnormal condition.
4. The severe marine environment, including corrosion, remoteness/isolation, and weather (i.e., wind, wave and current, ice).
5. High-temperature and high-pressure fluids, hot surfaces, and rotating equipment located in or near operating areas.
6. The handling of hydrocarbons over water.
7. Large inventories of hydrocarbons from wells/reservoirs and pipelines connected to or crossing a producing platform.
8. Storage and handling of hazardous chemicals.
9. Potential H₂S releases.

This recommended practice is directed to those permanent and temporary installations associated with routine production operations. The guidelines presented herein should provide an acceptable level of safety when used in conjunction with referenced industry codes, practices and standards.

1.3 INDUSTRY CODES, PRACTICES, AND STANDARDS

Various organizations have developed numerous codes, practices and standards that have substantial acceptance by industry and governmental bodies. Codes, practices, and standards useful in the design, fabrication, installation, layout, and operation of offshore production facilities are listed in Appendix C. These references are not to be considered a part of this recommended practice except for those specific sections of documents referenced elsewhere in this recommended practice.

1.4 GOVERNMENT CODES, RULES, AND REGULATIONS

Government regulatory agencies have established certain requirements for the design, fabrication, installation, layout and operation of facilities on offshore production platforms. These requirements may supersede the recommendations of this document. Refer to Appendix D for applicable government codes, rules and regulations related to the outer continental shelf of the United States.

1.5 ORGANIZATION OF TECHNICAL CONTENT

The technical content of this recommended practice is arranged as follows:

Section 2—Introduction. Presents an overview of the general principles of safe facilities design. It addresses the importance of containing flammable hydrocarbons, minimizing the chances of hydrocarbon ignition, preventing fire escalation, and providing personnel escape routes.

Section 3—Basic Facilities Design Concepts. Presents a detailed discussion on basic facilities design. It addresses both general and special safety considerations as well as operational and maintenance considerations.

Section 4—Hazard Mitigation and Personnel Evacuation. Presents a detailed discussion on mitigation and evacuation. It addresses the importance of inventory reduction, fire and gas detection, escape paths, alarm and communication systems, passive and active fire mitigation, and fire-fighting and evacuation procedures.

Section 5—Platform Equipment Arrangements. Presents a detailed discussion on the importance of proper arrangement of production equipment. It emphasizes the importance of safety aspects in arranging production equipment.

Section 6—Documentation. Presents a summary of the minimum process safety information required to satisfy API RP 75 as well as descriptions of documentation that may be reviewed for hazards analysis and for new facility design. A discussion of operating procedures is also included.

Section 7—Hazards Analysis. Describes the principal elements of hazards analysis, methods available for performing hazards analysis, and guidelines for selecting an appropriate method. A basic hazards analysis method based on a checklist procedure is provided.

Appendix A—Hazards Analysis Checklists.

Appendix B—Analysis of Example Layouts.

Appendix C—Industry Codes, Guides and Standards.

Appendix D—Government Codes, Rules and Regulations.

2 Introduction

2.1 GENERAL

The possible consequences of hazardous situations that may occur on all offshore facilities are the same: air and water pollution, fire or explosion, and injury to personnel. Figure 1 is a generic hazard tree that illustrates the interrelationship of events, conditions and sources required to lead to these three consequences. If, through good design, it were possible to break each of the chains leading to a hazardous situation, then that hazard could be eliminated. Unfortunately, even the best design can only reduce the probability of a chain occurring and cannot ensure that the chain will always be broken.

The goal of a safe facility design is to reduce the risk of each of the identified hazards to a reasonable level. This is done by reducing the probability of occurrence of those events, conditions and sources, and minimizing their consequences. It can be seen that the likelihood of occurrence of some of the paths can be minimized by providing sensors to detect measurable changes in process parameters (i.e., pressure, level, temperature). However, other chains exist that cannot be broken by sensing process upsets; thus, human

intervention, equipment layout and other factors must be addressed in the design.

Design safety is comprised of three approaches: Inherent design features, engineering controls, and administrative controls. Inherent design features include designing inherently safer facilities by reducing or eliminating hazardous materials or processes. The first step should be the elimination of potential hazards by improving the inherent safety of the design and then relying next on engineering controls and finally on administrative controls where inherent design is not technically or economically feasible.

The main principles for safe facilities design and operation are: (1) Minimizing the likelihood of uncontrollable releases of hydrocarbons and other hazardous materials, (2) Minimizing the chances of ignition, (3) Preventing fire escalation and equipment damage, (4) Providing for personnel protection and escape. Formal identification and assessment of hazards are necessary for proper application of these four principles. Proper application of these principles, along with sound engineering judgment and proper maintenance and operation of the entire production facility, should result in a safe facility. Figure 2 is a matrix which shows the applicability of these principles to various practices, systems and equipment.

2.2 CONTAINING HYDROCARBONS

Process equipment should be designed to contain hydrocarbons to the greatest extent possible. The production system should be designed for the appropriate operating conditions with allowances for variations. Additional information on equipment and system mechanical designs with the goal of hydrocarbon containment is included in Section 3. Also, see API RP 75, Section 8, concerning quality control and mechanical integrity of critical equipment.

2.2.1 Mechanical Design and Quality Control

The design of production equipment should be in accordance with applicable codes and standards. Materials used should be appropriate for the liquid or gas, temperature and pressure service. Quality control, inspection and testing should be part of the design, fabrication, and installation process. Additionally, for packaged production equipment (e.g., pumps, compressors, generators, control systems, and engines) the manufacturers' recommendations regarding proper installation of the equipment should be observed.

2.2.2 Surface Safety Systems

All production systems, no matter how well designed, are subject to upset conditions, malfunctions and even occasional uncontrolled flow due to accidents. Therefore, all production systems should include safety devices and have an automatic surface safety system designed to shut down part or all of the production system upon the detection of process upsets or

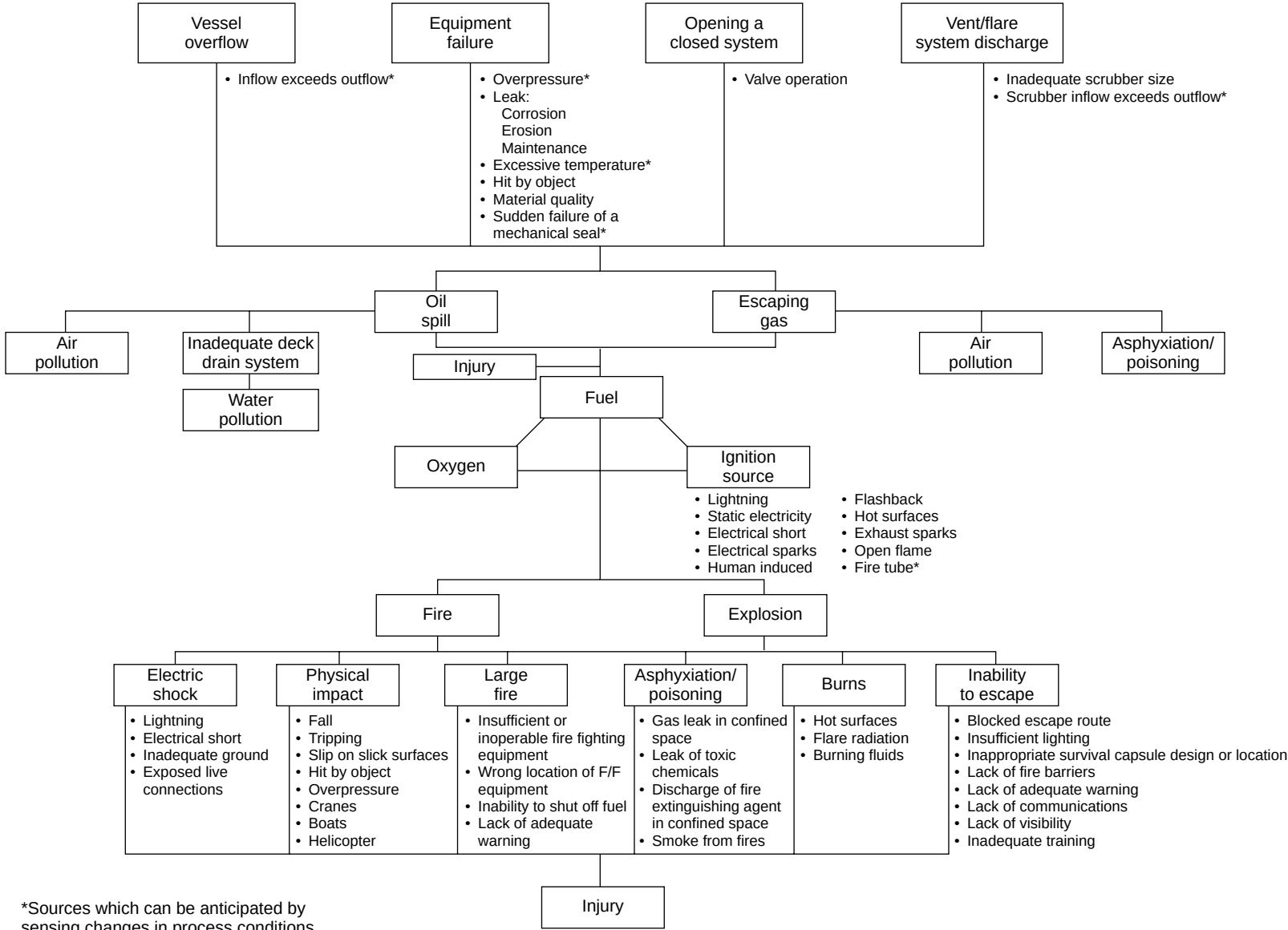


Figure 1—Hazard Tree for Production Facility

Figure 2—Matrix of Safe Facilities Design Principles

Facilities Features	Primary Safety Purposes			
Practices, System or Equipment	Prevent Fluid Release	Prevent Ignition	Prevent Fire Escalation	Provide for Personnel Escape
Hazards Analysis and Risk Assessment	√	√	√	√
Equipment Designs per Codes, Stds, and RP's	√	√	√	
Fabrication QA/QC	√	√		
Equipment Protection	√			
Equipment Maintenance	√	√		√
Surface Safety System	√	√	√	√
Drain Systems	√	√	√	
Operating Procedures	√	√		
ESD System	√	√	√	
Relief System		√		
Ventilation		√		
Hot Surface Insulation		√		
Gas Detection System		√		√
Separation of Fuel and Ignition Sources	√	√		
Equipment Blowdown		√	√	
Fire Detection System			√	√
Fireproofing			√	√
Water Deluge			√	√
Blastwalls			√	√
Fire Fighting			√	√
Firewalls			√	√
Personnel Protection Devices			√	√
Emergency Procedures			√	√
Escape Routes				√
Escape Mechanisms				√
Communication System			√	√
Muster Areas				√

component failure. Production systems also should be protected by a manual shutdown system (e.g., manually actuated ESD system) serving as a backup to the automatic system. Safety systems should be tested, inspected and calibrated on a regular basis to provide confidence that they will function as designed.

2.2.3 Production Equipment Maintenance

Production systems require maintenance for reliable operation. Systems that are not properly maintained risk potential failure and possible hydrocarbon escape. It is recommended that a program for equipment maintenance be implemented. This program may establish maintenance schedules, taking into account the equipment manufacturer's recommendations as well as periods of reduced or increased operational activity. Preventive maintenance techniques should be considered for rotating and other critical equipment. Maintenance checks should include investigation for internal and external corrosion and erosion. Production systems should be designed to provide appropriate working space to service and maintain equipment, and allow for such other operations as cleaning sand or paraffin from vessels. Equipment and procedures should be designed with lock-out, tag-out features to prevent accidental release of fluids and to prevent injury to personnel.

2.2.4 Equipment Operation

Proper operation of production equipment is essential to safety. Facilities should be designed to control normal operations and automate those that require quick response. Operating controls, and the sequence and logistics of operating steps, should be arranged for ease of operation. The operator should maintain standard procedures for the safe operation of common devices and pieces of equipment. Operating procedures should address concerns relating to facility start-ups, normal operations and shutdowns, and should cover the operations of critical equipment, such as compressor purging, loading, unloading and blowdown. ("Critical equipment" is defined in RP 75.)

2.2.5 Special Precautions

Exposure to potential damage from hydrocarbon containing equipment and piping of routinely manned spaces, egress routes, and emergency response equipment should, as much as practical, be located away from equipment containing hydrocarbon and other hazardous materials. Exposure of equipment and piping to potential physical damage from collisions and dropped objects due to simultaneous drilling, workover and logistical operations should be minimized. Special care should be taken in the design of equipment and systems handling toxic gases and corrosive fluids. Precautions should be taken against the freezing and plugging of process and instrumentation systems due to cold processes, cold weather, and hydrate, paraffin or asphaltene deposition.

2.2.6 Control of Normal Hydrocarbon Releases

Process vessels, tanks, pumps and control elements may release small amounts of hydrocarbons to maintain production operations or to maintain safety (e.g., prevent vessel rupture). The controlled release of small quantities of hydrocarbons is normal; however, it is recommended that facilities be designed and operated to minimize these controlled releases as much as possible and to control their location. Some normal practices that allow hydrocarbon releases include venting of tanks, blowdown of pressure from vessels, bleeding of control devices, and disposing of produced water that contains trace amounts of hydrocarbons.

2.3 PREVENTING HYDROCARBON IGNITION

In the event of abnormal release of hydrocarbons from production equipment, the goal of safe facilities design is to prevent ignition. Abnormal hydrocarbon releases can be caused by erosion/corrosion leaks; failures of piping systems caused by vibration and mechanical damages; fugitive emission from flanges, fittings, valves, etc.; emergency relieving of pressure; and operator error. Hydrocarbons released from equipment can be ignited if exposed to high temperatures, flame, static electricity, or arcing electrical or instrumentation equipment. The intensity and size of a fire is determined by the volume and rate of liquid or gas that could be released.

The speed and direction of a gas release as well as the flow rate of the release can substantially influence the ignitable concentration. Wind speed and direction should also be taken into account. Low wind speed reduces the dispersion of gas and extends the aerial limits over which combustion concentration is likely to occur. Gases should be analyzed to determine whether they are heavier- or lighter-than-air under all operating conditions. Mixtures often contain both lighter-than-air and heavier-than-air components. For heavier-than-air gas releases, potentially ignitable concentrations are most likely found below the point of release. For lighter-than-air gases, there is greater potential for ignitable concentrations above the point of release. Gas releases can result in deflagration and explosive situations which could damage other equipment due to overpressure and lead to the ignition of other flammable/combustible materials.

Liquid leaks and spills will fall until they contact surfaces. Liquid can then spread very quickly to pose a threat to personnel and facilities. Liquids should be channeled away to safe locations to avoid contacting ignition sources.

2.3.1 Flare, Vent, and Drain Systems

Certain normal and abnormal releases of process vapors and liquids are collected and directed to safe locations by way of a facility's gas disposal and drain systems. Both routine and emergency relief releases from a pressurized component or tank are potential fuel sources that should be removed from

areas where ignition sources may exist. This is usually done by collecting these releases in a flare or vent system and routing these releases to a safe location away from the production facility to allow for safe disposal of vapors by burning or dispersion. If liquids are expected in these releases, the flare or vent system should include provisions for liquid removal prior to final discharge of the vapors.

Similarly, drain systems collect and direct spills or leaks to a safe location. The liquids must be collected in order to avoid pollution, and then must be directed to a safe location to avoid ignition prior to being injected back into the processing equipment. See Section 3 for further details.

2.3.2 Separation of Fuel and Ignition Sources

Protection against hydrocarbon ignition can be provided by locating potential ignition sources away from equipment containing hydrocarbons. Additionally, potential ignition sources, such as fired process components and certain rotating machinery, should be designed to minimize the possibility of igniting released hydrocarbons. Suitable protective measures such as insulation, barrier walls and cooling water should be utilized to isolate high-temperature surfaces. The layout of equipment with the goal of preventing ignition is discussed in Section 5.

Other potential ignition sources include appliances associated with quartering personnel (e.g., water heaters, stoves, air conditioners, deep fat fryers, and clothes dryers). General purpose appliances should be located in unclassified locations as defined by API RP 500 whenever possible. If appliances are gas-fueled and are installed in inadequately ventilated buildings, combustible gas detector systems should be installed to shut off the fuel supply in the event of gas accumulation. The use of gas-fueled appliances inside quarters buildings is not recommended.

Much electrical and instrumentation equipment can be a source of ignition. Equipment placement and selection are therefore important considerations. With careful planning, arcing, sparking, and high temperature equipment often can be located in unclassified locations. If that is not possible, such equipment must be suitable for use in the specific classified location. For guidance in area classification criteria, refer to NEC Article 500, API RP 500 and ISA S12.1. For guidance in selecting and installing electrical equipment and instrumentation systems, refer to API RP 14F, the NEC (NFPA 70), and ISA S12.6.

API RP 500, et al, provides a level of protection against ignition from nominal leaks and releases. Large abnormal releases could result in a hydrocarbon cloud being ignited by devices located in a “safe area” outside of the “classified areas.” Physical effects modeling may be required to assess the potential for such releases to impact these “safe areas” and should be considered in a hazards analysis.

2.3.3 Adequate Ventilation

The accumulation of combustible gases in the atmosphere on offshore platforms could create a threat to safety. Accumulations are more likely to occur in enclosed areas. Methods for increasing safety include providing adequate ventilation, installing a combustible gas detector system for early warning and shutdown, and providing pressurization.

Adequate ventilation is defined by API RP 500 as ventilation (natural or artificial) that is sufficient to prevent the accumulation of significant quantities of vapor-air mixtures in concentrations above 25 percent of their lower flammable limit. See Section 4 of API RP 500 for additional details, including recommended methods of achieving adequate ventilation.

2.3.4 Combustible Gas Detection

For those areas with inadequate ventilation, combustible gas detectors may be desirable to enhance safety. Refer to Section 4.2 for more details.

2.4 PREVENTING FIRE ESCALATION

In the event of a fire, the goal of safe facilities design is to prevent fire escalation. Even though events of a catastrophic nature are unlikely, all production facility designs should consider the worst-case scenario. Usually, catastrophic events occur as a result of escalations. Often, one event can trigger another event and, if proper precautions are not designed and planned into production operations, these escalating events can result in a catastrophe. A fire on an offshore platform is a threat to personnel safety and to the environment and may cause property damage. Prevention of fire escalation, or consequence mitigation, is discussed in Section 4.

2.4.1 Fire Detection

Fire detectors should be provided on offshore platforms to sense fires immediately. These fire detectors should be integrated into a system providing signals to shut down all hydrocarbon sources (i.e., wells, pipelines, etc.), activate alarms and initiate fire suppression equipment. Fire detection devices should be installed in all areas classified (Division 1 or 2) by API RP 500 and in all buildings where personnel regularly or occasionally sleep. Equipment required to control the fire (e.g., electric generators powering fire pumps) should not be automatically shut down by the fire detection systems.

2.4.2 Hydrocarbon Inventory Reduction

One method of reducing the risk of fire escalation is to reduce hydrocarbon inventory on a platform by providing for minimum storage of treated production liquids and fuels, and conduct transportation and resupply operations accordingly. Another method of minimizing or preventing fire escalation is

through process system depressuring. This is a procedure that may be used to complement other fire protection systems by minimizing or eliminating the quantity of pressured fuel sources present in the production facility during emergency situations.

2.4.3 Passive Fire Protection

Passive fire protection is defined as any fire protection system that, by its nature, plays an inactive role in protecting personnel and property from damage by fire. Passive fire protection is generically referred to as structural fire protection, particularly in governmental regulations, and includes firewalls. Passive protection does not, in and of itself, provide inherent protection and is normally effective only for a limited time period. Once passive fire protection is exhausted, the protected structure is vulnerable to damage by fire. Examples of where passive fire protection is commonly used are: critical structural steel, living quarters, muster areas, critical pressure vessels, etc.

2.4.4 Active Fire Protection

Active fire protection systems are often installed on offshore structures to cool, control and/or extinguish fires. Examples of active fire protection systems are firewater, foam, gaseous and dry chemical systems. Firewater system coverage may include platform equipment such as major vessels, glycol regenerators, storage facilities, gas compressors, shipping and process pumps, wellheads, etc. Fixed water spray systems and fixed monitor nozzles can be useful to protect areas that cannot be safely reached by hand-held hose streams. In determining the size of fire mains and fire pumps, consideration should be given to simultaneous operation of two or more firewater system components.

2.5 PERSONNEL PROTECTION AND ESCAPE

Another important goal of safe facilities design is to provide for personnel protection and escape, since the possibility of a fire escalation cannot be totally eliminated. The placement of fire-fighting equipment and its proper use and maintenance are important for personnel protection. A fire-fighting and escape diagram should be developed for each platform, showing clearly all escape routes and the location of fire-fighting equipment in the immediate area. The diagram should be prominently placed near the exit of each cabin, mess room, lounge and work space normally occupied by personnel. A station bill should be posted in a highly visible location. Escape mechanisms should be in place to allow the orderly escape of personnel to the sea. Provisions for personnel escape are discussed in Section 4.

2.5.1 Personnel Escape Routes

The layout of production equipment should allow space for personnel escape routes, as well as space for fighting fires. Living quarters should be positioned to provide a quick and easy escape for personnel to the boat landing or escape devices. Production equipment should be positioned to facilitate access by personnel to escape routes from various locations anywhere on the production facility.

2.5.2 Fire-fighting and Other Emergency Equipment

Fire-fighting equipment should be strategically located on the platform to provide for both fire-fighting and escape capabilities. The safety system should shut down all hydrocarbon sources so that personnel who are trained in fire fighting can begin fire-fighting operations immediately. Should the fire escalate, the fire-fighting equipment could be utilized to assist in the evacuation of personnel. Fire-fighting equipment should be inspected and tested functionally on a regular basis to provide confidence that it remains in proper operating condition.

Appropriate personnel, including contractor's personnel, should be trained in the proper use of fire-fighting and other emergency equipment provided on the platform. Breathing apparatus should be provided on the platform, especially when production operations involve toxic gas. Stand-by lighting systems may be desirable for certain offshore locations to illuminate escape routes during times of power failure.

2.5.3 Fire-fighting and Evacuation Procedures

All personnel normally assigned to a facility should be familiar with its fire-fighting and evacuation procedures. All personnel should be trained to perform their specific duties in the event that fire-fighting and evacuation become necessary. Scenario drills should be conducted on a regular basis, and training should be provided for new personnel to acquaint them with the alarms, emergency equipment and fire-fighting and evacuation procedures. Manned production platforms should have a communication system to assist and direct personnel in emergencies. The communication system should be designed to operate during an emergency. Immediately after arrival on the platform, personnel not normally assigned to a facility should be instructed to recognize alarms, told of the action required of them from each alarm, and made familiar with evacuation routes.

2.6 HAZARDS ANALYSIS

A hazards analysis should be performed for all production facilities designated in API RP 75. The purpose of the analysis is to minimize the likelihood of the occurrence and the consequences of a hydrocarbon release by identifying, evaluating and controlling the events that could lead to releases.

The likelihood and consequences of the failure scenarios should be assessed using qualitative or quantitative techniques judged to be appropriate. Once the hazards identifications and the risk assessment have been made, design or operational improvements should be made to mitigate any unacceptable risks.

The hazards analysis should use systematic approaches to identify failure scenarios. Several widely known approaches are presented in Section 7.

3 Basic Facilities Design Concepts

3.1 GENERAL

There are many different types of facilities in offshore producing operations. These vary from single well structures to multi-well, self-contained, drilling and production facilities and their utilities and living quarters vary accordingly. To plan and design production facilities for offshore structures that will provide personnel safety and protection of the environment, many factors must be considered. Some of the more important factors are presented in this section.

In planning and designing facilities, consideration should be given to number and type of wells, oil and gas processing requirements, anticipated production rates, number of people to be housed on the structure, mitigation and evacuation philosophy, type of control system, and electric power source. Consideration should be given to other operations on the structure, such as drilling and well workovers. The distance between the platform and shore-side terminals or existing transportation infrastructure is a consideration when planning pipelines, storage of spare parts and expendables and required on-site maintenance capabilities. Facilities installed in remote locations require considerably more preplanning than those located near existing transportation facilities and supply points.

Utilities on offshore structures may include potable water, non-potable water, diesel and helicopter fuel, electricity, fuel and power gas, treating chemicals, instrument and utility air, sewage treatment and garbage disposal. A single well structure may not require the installation of any utility system; a self-contained manned structure may require multiple utilities.

Concepts which may be justified for new designs are not always the appropriate choice when considering the modification of existing facilities. Marginal increases in safety are often more than offset by incremental safety risks associated with performing the construction required for a modification. Thus, while a specific design feature may be preferable to an operator in a new design, it may be perfectly appropriate for an operator to decide that retrofitting an existing facility to incorporate the feature is not warranted.

The concepts discussed in this section are meant to apply to new facilities. These concepts should also be considered

when reviewing existing facilities. However, before any recommendations for modifying the existing facilities are adopted, the operator should balance the risks associated with the modification against the expected risk reduction due to the modification. This analysis should take into consideration the operator's safety experience with the existing design.

3.2 APPLICABLE CODES, REGULATIONS, STANDARDS, AND RECOMMENDED PRACTICES

Facilities and equipment should be designed, fabricated and installed in accordance with the latest applicable industry standards and recommended practices, and in compliance with current regulations of the authorities having jurisdiction. Process systems and design aids are listed in Table 1. Some design codes, standards and recommended practices for process system components are listed in Table 2. These design aids should be considered where appropriate and supplemented by prudent engineering judgment.

Requirements for means of escape, personnel landings, guard rails, and lifesaving appliances normally are specified by the authority having jurisdiction. For example, United States, U.S. Coast Guard Rules and Regulations contained in 33 *CFR* subchapter N—Outer Continental Shelf Activities, Parts 140 through 147 set requirements in offshore waters of the U.S. Likewise, in OCS waters of the United States, requirements are specified by Minerals Management Service, 30 *CFR* Parts 250 and 256, Oil and Gas and Sulphur Operations on the Outer Continental Shelf.

Discharges to the air and offshore waters must meet the requirements of the authorities having jurisdiction. Specific limitations may also exist on engine exhaust emissions, produced water discharges, rainwater for sumps, sanitary discharges, and solid wastes such as paper, sand blasting media, wood or plastic products.

3.3 MECHANICAL DESIGN CONSIDERATIONS

Some features of offshore production facilities require special consideration due to the limited space on offshore structures and the physical offshore environment. The goals here are to contain hydrocarbons within the process components and piping systems; to prevent accumulation of combustible hydrocarbons in the facilities areas, minimizing the chances of ignition of flammable mixtures; and to prevent escalation of fire. Living quarters, offices, and control rooms require special consideration.

Construction materials in all components and piping systems should be compatible with the fluid being processed or handled and the offshore saltwater environment. In general, carbon and low-alloy steels should be used for pressure-containing parts in hydrocarbon service. High-alloy and stainless steels should be used for corrosive and/or low-temperature services; however, these materials should

Table 1—Design Aids for Process Facilities Systems

System	Design Aids
Wellhead Accessories, Flowlines and Manifolds	API 14E; 30 <i>CFR</i> 250.87, .123, .124 (MMS)
Production Separation	API 14E; API-MPMS; 30 <i>CFR</i> 250.123.b.1 (MMS)
Oil Handling	
Treating	—
Metering	30 <i>CFR</i> 250.180; API-MPMS
Pumping	API 14E
Pigtraps and Risers	49 <i>CFR</i> 195 (DOT)
Gas Handling	
Compression, including Vapor Recovery	API 11P; 30 <i>CFR</i> 250.123.b.7 (MMS)
Dehydration	API 12GDU, 14E
Sweetening	42 USCA 7401-7671 (EPA—Clean Air Act)
Metering	API-MPMS; AGA Report 3; API 2530; 30 <i>CFR</i> 250.181 (MMS)
Pigtraps and Risers	49 <i>CFR</i> 192, 195 (DOT); 30 <i>CFR</i> 250 Subpart J (MMS)
Water Handling	
Treating and Disposal	API Publ. 421
Injection	—
Secondary Recovery	
Water Flooding	—
Gas Injection	—
Chemical Injection	
Fluid Treating	—
Corrosion Inhibition	—
Hydrate Inhibition	—
Heating and Cooling	API 14E
Surface Safety Systems	API 14C; 30 <i>CFR</i> 250.122, 124
Personnel Safety System	46 <i>CFR</i> 108.151-.167 (USCG); 46 <i>CFR</i> 108.501-.527 (USCG); SOLAS Chapt. II-2
Fire Prevention & Control	API 14C, 14G, 14E, Publ. 2021, Publ. 2218, Publ. 2030; 46 <i>CFR</i> 108.401-.499 (USCG); 30 <i>CFR</i> 250.123.6.8, b.9 (MMS); 30 <i>CFR</i> 250.124 (MMS); SOLAS Chapt. II-2.
Emergency Relief Systems	API 520, 521, 14E; 30 <i>CFR</i> 250.123.6.1 (MMS)
Flare and Vent Systems	API 14E
Drain Systems	API 14E; 30 <i>CFR</i> 250.40.b.4-.5 (MMS)
Utilities and Supports	
Quarters, Sewage and Waste	API 14E; 46 <i>CFR</i> 108.193-.215 (USCG); SOLAS; 29 CRF 1910, 1926 (OSHA)
Water, Diesel and Helicopter Fuel Storage	API 14E; 46 <i>CFR</i> 108.237 (USCG)
Utility/Instrument Air or Gas	API 14E
Communications	FCC, FAA for Towers
Electrical Power and Lighting	API 14F; NFPA 70 (NEC); API RP 500, IEEE 446
Nav-aids	33 <i>CFR</i> 67.01-.30 (USCG); SOLAS Chapt. 5
Fire and Gas Detection	Federal Register Volume 37, No. 132, Part II; API 14C, 2031; NFPA Codes; 30 <i>CFR</i> 250.123-.124 (MMS); SOLAS Chapt. II-2.
Safe Welding Areas	30 <i>CFR</i> 250.52 (MMS); ISA S12.13; ISA RP 12.13, ISA S12.15, ISA RP 12.15, API RP 14F; API RP 55
Electrical Systems	
Intrinsically Safe	ISA RP 12.6; NFPA 70 (NEC), Article 504

Table 2—Design Aids for Facilities Components

Component	Design Aids
Pressure Vessels	
General	ASME Code, Section VIII; ANSI B16.5
Separator	API 12J, Publ. 421
Indirect-type Oil Field Heaters	API 12K, 12N
Emulsion Treaters	API 12L
Storage Tanks	ANSI/AWWA D103; API 12B, 12D, 12F, 12P, 12R1, Std. 2000, Publ. 2210
Engines	ANSI 7B-11C, 1B; ASME PTC 17-73
Aerial Coolers	API 11K, 631M, 661, 632
Wellhead SSV's	API 14D, 14H; 30 <i>CFR</i> 250.122 (MMS)
Pipe, Valves Fittings	ANSI B31.3, B31.4, B16.5, B31.8; API 6D, 14E, Publ. 2028, Std. 590
Instrumentation	ISA RP7.1, RP12.1, 12.2, S7.4, S12.4
Cranes	API 2C
Heliports	API 2L; Louisiana DOT, Offshore Heliport Design Guide Information Publ.; 46 <i>CFR</i> Part 108.233, .235, .235 (USCG)
Relief Valves/Vent Systems	API 520, 521
Vent Tank	API 2000
Centrifugal Pumps	API 610; Hydraulic Institute Stds.; ANSI B73.1, B73.2
Gas Turbines	API 616; ASME PTC 1-86, PTC 16-58
Centrifugal Compressors	API 617; ASME B19.3D-90, PTC 10-65
Reciprocating Compressors	API 618; ASME B19.3D-90, PTC 9-70
Shell-and-Tube Heat Exchangers	API 660; TEMA Std.
Reciprocating Pumps	API 674; ASME PTC 7-49, PTC 7.1-62
Rotary Pumps	API Publ. 676
General-Purpose Gear Units	API 677
Packaged, Centrifugal Air Compressors	API 672; ASME B19.1-90
Packaged, Reciprocating Air Compressors	API 680; ASME B19.1-90
Glycol Dehydration	API 12GDU
Rotary Type Positive Displ. Compr.	API 619
Generators and Motors	NEMA and UL standards
Generators, Emergency	IEEE 446
Transformers	IEEE C57

be selected and specified with care as some can pit from proximity to the offshore saltwater environment. Since cast iron may crack if suddenly cooled by water when fighting a fire, and may burst if water in the produced fluids freezes, it is only used for certain compressor and pump parts where other materials are unavailable. The use of low melting point materials such as brass; copper and aluminum should be limited for hydrocarbon service since they can fail quickly when exposed to fire. The use of fiberglass pipe and tanks is becoming more popular because of its resistance to both external and internal corrosion. However, its use for fluids containing hydrocarbons should be restricted because unless properly installed, it can weaken rapidly in a fire.

With the exception of corrosion resistant materials, material thicknesses should include a corrosion allowance based on the corrosivity of the fluids, the inhibition program and the design life of the facility. Lacking this information, consideration should be given to providing a higher corrosion allowance than the minimum required by code for the full well stream piping systems. Protective coatings (external and/or internal, where appropriate) should be applied to all surfaces except corrosion resistant material surfaces. Protective coatings should be compatible with the offshore environment and the fluids being handled. Anodes and/or internal coatings should be considered for use in the water handling compartments of vessels and tanks.

Capacity, pressure and temperature ratings should allow for anticipated conditions over the life of the facility, including start-up, shutdown and upset conditions. In capacity sizing calculations, an appropriate surge factor should be added to the anticipated steady flowing conditions, particularly for components and piping systems receiving satellite production. Pressure and temperature ratings should be suitably above and below the anticipated operating range to allow for variations from the anticipated conditions, and to allow for adequate range between alarms and primary and secondary safety devices.

Environmental factors (wind loads, icing, earthquakes, etc.) and support conditions should also be considered when selecting the design criteria for components and piping systems. In general, equipment items should be solidly supported by structural members, not placed on deck plate or grating. External attachments to equipment should be seal-welded where practical to prevent corrosion.

All exposed rotating parts (couplings, shafts, gears, belts, sheaves, etc. on pumps, compressors, coolers, engines, etc.) should be provided with guards for personnel protection. Exposure to equipment sound pressure levels should comply with local regulations. Acceptable practices include sound proofing equipment or providing personnel hearing protection devices.

3.3.1 Wellheads, Flowlines, and Headers

The wellhead area on a platform should receive special consideration. The wellhead valve assemblies, flowlines and headers are subjected to large liquid and gas (and, in some instances, sand) flows. The corrosive/erosive action of produced oil, gas, condensate, salt brines, sand and various other trace compounds such as CO₂, along with the usually high pressures associated with the well stream, make these high risk components. Once the general physical characteristics of the drilling equipment and its support needs are known and the number and capacity of wells projected are determined, the design, spacing and layout of the components can begin.

The design, materials of construction, fabrication, inspection and testing of wellhead assemblies should be in accordance with API Specifications 6A, 6D, and RP 14H. Flowlines and headers should be designed in accordance with API RP 14E.

3.3.2 Pressure Vessels

The design, materials, fabrication, inspection and testing of pressure vessels not subjected to the addition of heat should be in accordance with the *ASME Boiler and Pressure Vessel Code (ASME Code) for Unfired Pressure Vessels*, and vessels should be ASME Code stamped. The minimum thickness of any pressure containing part of a pressure vessel should be established—plus specified corrosional allowance. Pressure vessels subject to vacuum should be designed for full vacuum.

In addition to the required surface safety system instruments and controls, connections for level, temperature and pressure indicators should be installed to provide for monitoring of operating conditions, as necessary. Where possible, instrument connections should be sized to minimize the use of 3/4 inch x 1/2 inch bushings. Temperature indicators should be located in the liquid sections, and pressure indicators should be located in the vapor sections. Appropriate nozzles and openings should be provided for the process, inspection and maintenance operations. Flanges should be considered for all connections that are two inches and larger. Vessels in dirty or sandy service may require connections to flush or remove contaminants. Skirts and saddles should allow for protective coating inspection and maintenance.

The installation of level control and monitoring devices on external control columns or bridles should be considered so as to facilitate testing, inspection and maintenance. Steel encased gauge glasses with safety check gauge valves should be provided. Pump suction shutdown valves should be installed as close as practical to vessel nozzle connections. Vortex breaker baffles should be considered on all flowing liquid outlet nozzles. With regard to vessels having devices such as mist eliminators in which fouling or plugging can restrict flow, a relief valve should be installed in the vapor space upstream of the device.

3.3.3 Atmospheric Tanks

The design, materials, fabrication, inspection and testing of tanks should be in accordance with established engineering standards or practices such as API Standard 650 or 620 or Specifications 12B, 12D, 12F, 12P, or 12R1, where applicable.

Adequate vacuum prevention due to pump or gravity draining rates, as well as pressure build-up during filling operations, gas blow-by from pressurized equipment, and heating of contents from fire or other causes should be analyzed (see Section 3.3.10). Consideration should be given to installing internal downcomers in tanks containing flammable or combustible liquids with top fill connections to minimize the potential for fire or explosion due to static electricity discharge.

Air exclusion methods, such as blanket gas systems, should be utilized on tanks storing high vapor pressure liquids or liquids subject to degradation in a moist air environment. Gas blanketing also provides a good means of controlling corrosion in the vapor space of atmospheric tanks. Where blanket gas or make-up gas regulators are installed, the failure of the regulator should be considered in vent system design.

In addition to the required surface safety system instruments and controls, connections for level, temperature and pressure indicators should be installed to provide for monitoring of operating conditions, as necessary. Where possible, instrument connections should be sized to minimize the use of $\frac{3}{4}$ inch $\times$ $\frac{1}{2}$ inch bushings. Temperature indicators should be located in the liquid sections, and pressure indicators should be located in the vapor sections.

Tank overflows should be routed to a containment area and should be designed to prevent siphoning. Shutdown valves installed on pump suctions should be connected directly, or as close as practical, to the tank nozzle. Vortex breaker baffles should be considered on all flowing liquid outlet nozzles.

3.3.4 Direct-Fired and Exhaust-Heated Components

There are no specific codes covering design, materials, fabrication, inspection and testing of direct-fired and exhaust-heated components containing process fluids. Applicable portions of the *ASME Code for Unfired Pressure Vessels* and the *ASME Code for Power Boilers* can be used for guidance. Other applicable documents, such as the Tubular Exchanger Manufacturers Association (TEMA) Standards should be referenced when specifying the heat exchangers. All pressure containing components of exhaust heating units should be ASME Code stamped. Refer to Sections 3.3.2, 3.3.8, 3.3.12, and 3.3.16, herein, for guidance to applicable pressure vessel, heat exchanger, piping and electrical design considerations.

3.3.5 Pumps

Although many types of pumps are found in offshore facilities, centrifugal and reciprocating units are routinely utilized. The following may be considered in the design, materials selection, fabrication, inspection, and testing of these pumps: API Standard 610 or ANSI B73.1 or B73.2 for centrifugal pumps and API Standard 674 for reciprocating pumps. Many reciprocating pumps used on production facilities do not conform to all of the requirements of this latter standard. Operator experience and preference as well as manufacturer standards and warranty should be considered in the selection of such units.

Centrifugal pumps are the most commonly used pump for almost all services other than those characterized by extremely low flow rates combined with very high differential pressures. Reciprocating pumps are usually used for those applications requiring a combination of high differential pressure and relatively low fluid capacities. Typically, critical service pumps are spared, such as installing two 100 percent capacity pumps or three 50 percent capacity pumps.

Produced liquids normally contain dissolved gases which will flash at some reduced pressure. It is critical to the performance and life of pumps to maintain a vapor-free suction to the pump. This is accomplished by making the piping self-venting and maintaining adequate net positive suction head (NPSH). The use of large suction piping with minimum length, size changes and number of fittings; elevated pump suction tanks or vessels; suction stabilizers; and/or charge pumps should be evaluated to maintain adequate pump suction pressure and minimize vapors from flashing. Pump suction piping should never be smaller than the pump inlet. If a reducer is required in the suction piping, an eccentric fitting should be used with the flat side on top to prevent the accumulation of vapors.

Pumps and drivers should be mounted on a common rigid base plate or structural steel skid with drain lip or drain pan and drain connections. Base plate or skid design should provide sufficient rigidity to maintain pump and driver alignment for the worst combination of pressure, torque or allowable piping loads. Pump suction and discharge piping should be adequately supported so as to minimize forces and moments on pump casings. Piping should be securely anchored and braced to prevent piping damage from fatigue due to vibrations. To reduce pulsating forces and piping vibrations, pulsation suppression devices should be considered for both the suction and discharge connections of all reciprocating pumps.

When pumps are driven by engines or turbines, exhaust silencers should be provided. Also, exhaust silencers and piping should be insulated to reduce the probability that these hot surfaces will be a source of ignition for hydrocarbons that may contact them. Electric motors should be installed at an elevation to prevent motor damage from a flooded deck.

In addition to the recommended surface safety system instruments and controls, pressure indicators should be installed in the discharge piping of all pumps to monitor performance. In some applications, pressure indicators in pump suction piping should also be considered. Vibration sensors should be considered to shut down the driver on high vibration on reciprocating pumps and large high speed centrifugal pumps. Pump suction piping should have the same pressure rating as the discharge piping or be protected by a relief valve. Pump suction piping may be equipped with temporary in-line strainers to prevent contaminants from entering the pump during start up.

Single mechanical seals should be considered on centrifugal pumps in low-pressure hydrocarbon service. Consideration should be given to the use of tandem mechanical seals in high pressure hydrocarbon applications. Seal arrangements should be compatible with API Standard 610, and external cooling systems should be provided for hot service applications.

Where a minimum flow is recommended by the pump manufacturer or where there is a possibility of a control valve blocking the discharge of the pump without shutting down the pump, a minimum flow by-pass back to the pump suction source or other appropriate location should be incorporated into the design for each pump to protect the pumped fluid from overheating and vaporizing.

3.3.6 Compressors

Some of the types of gas compressors that are utilized in offshore production facilities include integral engine-driven reciprocating units; low, medium and high-speed separable reciprocating units; and centrifugal units. Compressor drivers include reciprocating engines, gas turbines and electrical motors (single speed or variable speed). The following may be considered in the design, materials selection, fabrication, inspection and testing of compressors: API Standard 618 for reciprocating compressors, API Standard 617 for centrifugal compressors, and API Specification 11P for packaged high-speed separable engine driven reciprocating gas compressors. However, since there are so many different designs and manufacturers, many requirements of the standards may not be applicable. Operator experience and preferences should be applied to the design as appropriate.

For separable units, the compressor, gear unit (if applicable) and driver should be mounted on a rigid structural steel skid. The skid design should provide sufficient rigidity to maintain compressor, gear and driver alignment and prevent local resonance. Compressor skids, integral units or compressor packages should be adequately connected to the supporting platform's structure in a manner that will provide continuity of structural action. Compressor suction and discharge piping should be adequately supported while compensating for mechanical and thermal loads so as to not impose

undue forces and moments on the piping, compressor cylinders and frames. Piping should be securely anchored and braced to prevent piping damage from fatigue due to vibrations or pressure pulsations. Consideration should be given to providing overhead access for maintenance of compressors, drivers and all ancillary equipment.

Mechanical and acoustical pulsation studies which include all piping, vessels and coolers should be considered for reciprocating compressors. Pulsation suppression devices may be installed on suction and discharge of the compressor cylinders where appropriate. Pulsation suppression devices should be accessible for inspection and fitted with connections for routine checking of liquid build up.

Inlet piping and equipment to each stage should consider designs to prevent liquids from entering the compressor suctions. If possible, suction scrubbers should be located close to the compressor to minimize overhead piping and supports. Compressor suction piping should have the same pressure rating as the discharge piping or be protected by a relief valve.

Compressor stations or each stage of compression should be supplied with recycle valves (surge valves on centrifugal compressors) to protect the compressors from mechanical damage.

In addition to the recommended surface safety system instruments and controls, vibration sensors should be considered to shut down the driver on high vibration. Pressure and temperature indicators should also be considered in the suction and discharge of each cylinder as a way to monitor performance. External pressure connections on suction and discharge may be provided by the manufacturer for both the head and crank ends of each cylinder for compression test equipment. Compressor inlet connections should be provided with temporary screens or strainers to prevent contaminants from entering the compressor during start-up. All compressor instruments and controls should be mounted and supported in a manner so as to provide for proper operation of the devices without damage due to vibration.

When compressors are driven by engines or turbines, exhaust silencers should be provided. Also, exhaust silencers and piping should be insulated to reduce the probability that these hot surfaces will be a source of ignition for hydrocarbons that may contact them. Electric motors should be installed at an elevation to prevent motor damage from a flooded deck.

3.3.7 Pipelines and Pipeline Risers

Pipelines, pipeline risers, and related systems such as pig launchers, receivers and their valving components require special attention for safety. These components are normally associated with large volumes of hydrocarbons at relatively high pressures, and their isolation from the various other platform components and protection from damage should be carefully considered early in the planning stages of a

facility. Guidance in locating these components can be found in Section 5.8.

The design and safety regulations regarding these components are normally specified by the regulatory agency or agencies having jurisdiction, and these should be consulted early to avoid conflicts. In OCS, Gulf of Mexico waters, 49 *CFR* parts 190 through 193 and part 195, as well as 30 *CFR* part 250 Subparts H&J should be consulted.

Evaluations should be made to determine if shutdown valves or flow safety valves, or a combination, are appropriate to provide protection to the facilities, in the event of damage to the pipelines. Both incoming and departing field gathering and transportation lines should be evaluated.

3.3.8 Heat Exchangers

There are many different types of unfired heat exchangers used in the production of hydrocarbons on offshore facilities. Some of these types include: shell-and-tube, air-cooled and plate heat exchangers. The design, materials, fabrication, inspection, and testing of heat exchangers should be in accordance with Section VIII, Division 1, of the *ASME Code for Unfired Pressure Vessels*, where applicable. Other documents, such as Tubular Exchanger Manufacturers Association (TEMA) Standards and API Standards 660 and 661, should be referenced when specifying heat exchangers.

Tubes and tube side components should be designed to withstand the maximum internal or external pressure that may exist when the shell or other side is reduced to atmospheric pressure—or to its design pressure if lower—while the tube side remains at its maximum allowable working pressure. Maximum allowable working temperature of parts subjected to both shell and tube fluids should be the greater of shell or tube design temperature. Requirements for expansion joints should be determined by using the most adverse combination of shell and tube side allowable working temperatures. Packed joints should not be used.

Tube leakage and rupture should be considered when selecting the operating pressures of heat exchanger sections. If leakage or rupture occurs, the higher pressure fluid will naturally be commingled with the lower pressure fluid and the lower pressure side will be exposed to the higher pressure source. These failure modes should be considered in the design of heat exchangers, piping and relief systems.

Air-cooled heat exchangers should be located on the facility in locations that provide for maximum available fresh, dry, clean, non-recirculated air. Measures should be considered to provide protection from dropped objects.

In addition to the recommended surface safety system instruments and controls, temperature and pressure connections should be installed in all inlets and outlets, where applicable, to check heat exchanger performance. Vibration switches for each fan drive should be considered for air-

cooled heat exchangers to shut down the drive on high vibration.

Appropriate nozzles and openings should be provided for process, inspection and maintenance operations. Flanges should be considered for all process connections that are two inches and larger. Valves should be installed on vent and drain connections at high and low points on both fluid sides of heat exchangers. Heat exchanger supports should allow protective coatings inspection and maintenance. Insulation for process and energy conservation should be considered. Insulation supports should be considered where insulation is required on vertical units. External surfaces 160°F and hotter should be insulated or otherwise protected against direct contact by personnel. Piping should be designed to allow for thermal expansion and contraction without imposing excessive forces and moments on the heat exchanger (see NEMA SM-23, “Allowable Forces on Moments and Nozzles”). Plate heat exchangers in hydrocarbon service should be provided with a metal shroud covering the sides and top of the heat exchanger to confine leakage from a gasket failure.

3.3.9 Vent, Flare, and Emergency Relief Systems

Systems for discharging gas to the atmosphere provide a means for conducting gas from process components under normal operations and abnormal conditions (emergency relief) to safe locations for final release. In vent systems, the gas exiting the system is dispersed in the atmosphere. Consideration should be given to a means of visually warning helicopter pilots and marine vessel crews of vent stacks. Flare systems generally have a pilot or ignition device that ignites the gas exiting the system. Flare and vent systems require attention to flashback protection (the possibility that the flame will travel upstream into the system).

Gas disposal systems and devices should be designed in accordance with API RP 520 and 521, Specification 2000 and the *ASME Boiler and Pressure Vessel Code*—Section VIII.

A. Purposes. A flare or vent system is a system for collecting and discharging gas from atmospheric or pressurized process components to the atmosphere during *normal operations*. This discharge may be either continuous or intermittent. Gas disposal systems for tanks operating essentially at atmospheric pressure are often called “atmospheric” vents or flares; those from pressure vessels, “pressure” vents or flares. A flare or vent system from a pressurized source may include a control valve, collection piping, flash-back protection and a gas outlet. A scrubbing vessel should be provided to remove liquid hydrocarbons. A flare or vent system from an atmospheric source may include a pressure-vacuum valve, collection piping, flash-back protection and a gas outlet. The actual configuration of the flare or vent system will depend upon the assessment of hazards for the specific installation.

A relief system is an emergency system for discharging gas during *abnormal conditions*, by manual or controlled means or by an automatic pressure relief valve, from a pressurized vessel or piping system to the atmosphere for the purpose of relieving pressures in excess of maximum allowable working pressure. The relief system may include the relief device, the collection piping, flashback protection and a gas outlet. A scrubbing vessel should be provided for liquid separation if liquid hydrocarbons are anticipated. The relief system outlet may be either vented or flared. If designed properly, vent or flare and emergency relief systems from pressure vessels may be combined.

Some facilities include systems for de-pressuring pressure vessels in the event of an emergency shutdown. The de-pressuring system control valves may be arranged to discharge into the vent, flare or relief systems.

Consideration should be given to the possibility of freezing and hydrate formation during high pressure releases to atmosphere.

B. System Design. The pressure developed in the collection piping as a result of a disposal event is a critical design parameter that must be checked for any flare or vent system. For any reasonable scenario of gas disposal, the pressure at the outlet of every relief device should be less than the maximum allowable working pressure of the disposal system components when calculated, assuming maximum instantaneous flow and including inertial forces. In addition, the back pressure at the outlet of every relief device should be such that the device can handle its design capacity with the calculated back pressure using design relief conditions.

Atmospheric and pressure gas disposal systems should be separate. Atmospheric tanks are susceptible to damage from even very low back-pressures. Even when calculations indicate they can be combined, separate systems are desirable because atmospheric tanks can be affected if there are small inaccuracies in the calculations.

Back pressures in the system connecting high pressure vessels can be higher than those in the system connecting low pressure vessels. Often when there is a large design flow rate of high pressure gas, it is desirable to separate the piping to the scrubbing vessel into “high pressure” and “low pressure” systems.

To avoid valve chatter, inlet pressure drop to a pressure relief valve should not exceed three percent of set pressure.

The temperature rating of materials should be suitable for the flowing conditions, particularly if gas is to be relieved from incoming subsea flow lines or if low temperature effects (significant expansion cooling) are

expected. The choice of material should also take into account the process fluid properties.

Gas disposal piping should not contain any low point where liquids could accumulate and block the relief passages. If a scrubbing vessel is installed, the piping should be designed to be self-draining toward the vessel from both sides. Pressure relief valves should be located above relief headers where practical. If low points can not be avoided or if a scrubbing vessel is not installed, traps drains should be installed to keep the pockets free of liquids. See Section 5.9 for location of final discharge point.

C. Flare and Vent Scrubbers. Scrubbing vessels (scrubbers) should be adequately sized for all continuous or intermittent releases from the gas disposal systems. A scrubber should be a pressure vessel designed to handle maximum anticipated pressure. The scrubber should be sized for at least 400–500 micron droplet removal from the gas stream. The scrubber should be sized for retention of liquids during upset conditions and should have a high level sensor which shuts in the total facility. The retention capacity of the scrubber should allow sufficient time for shutdowns to be effected or operators to intervene without liquid carryover. If the scrubber has an internal component, such as a mist extractor, or an external component, such as a back pressure control valve or flame arrestor, then a relief device should be installed in order to bypass these components, should they become plugged.

D. Flashback Protection. Flashback protection should be considered for all gas disposal systems, since flashback can result in pressure build up in piping and vessels. Flashback is more critical where there are tanks or pressure vessels with MAWP less than 125 psig and in flare systems. Flashback protection is discussed in API RP 520 for pressure vents and flares, and in API RP 2000 for atmospheric vents and flares. API RP 14C recommends that vents from atmospheric vessels contain a flame arrestor. Because the flame arrestor can plug, a secondary pressure-vacuum valve without a flame arrestor should be considered for redundancy. The secondary system should be set at a high enough pressure and low enough vacuum so that it will not operate unless the flame arrestor on the primary system is plugged.

Pressure vents with vessels rated 125 psig and above do not normally need flashback protection. In natural gas streams, the possibility of vent ignition followed by flashback pressures above 125 psig is considered minimal. When low pressure vessels are connected to pressure vents, molecular or fluidic seals and purge gas are often used to prevent flashback. If pressure relief valves are tied into the vent, the surge of flow when a relief valve opens could destroy a flame arrestor and lead to a hazardous condition. Also, there is potential for flame arrestors to

become plugged. A means of flame snuffing should be considered for vent systems.

Flares have the added consideration of a flame always being present, even when there is a very low flow rate. They are typically equipped with molecular or fluidic seals and a small amount of purge gas to protect against flashback.

3.3.10 Relief Valve Sizing

Sizing equations for pressure relief valves are included in API RP 520. Single or multiple pressure relief valves may be utilized to protect each component. The size of the pressure relief valve(s) in the system should be checked for the following conditions:

A. Blocked Discharge. It is possible to isolate a component or piping segment for maintenance by blocking all inlets and outlets. On start-up, all the outlet valves could inadvertently be left closed. If the inlet source can be at a higher pressure than the maximum allowable working pressure of the component, only a properly sized pressure relief valve could keep the component from rupturing due to overpressure. Thus, one design condition for the pressure relief valve is to assume that it must handle the total design flow rate (gas plus liquid) into the component. This is called “blocked discharge.”

B. Gas Blow-by from Upstream Vessel. On tanks and low pressure vessels normally receiving liquids from higher pressure upstream vessels, often the maximum flow rate through the relief valve is determined by “gas blow-by.” This situation occurs when the level controller or level control valve of the upstream vessel fails in the open position, or a drain valve from an upstream vessel is inadvertently left open, allowing liquid and/or gas to flow into the component being evaluated. Under blow-by conditions, it can be assumed that both the normal liquid and gas outlets on the component being evaluated are functioning properly. However, the flow of gas into the component could greatly exceed the capacity of the normal gas outlet. This excess gas flow must be handled by the relief valve to keep from exceeding the MAWP of the component.

Gas blow-by conditions can also occur when a pressure regulator feeding a component fails in the open position, creating a higher than design inlet flow rate of gas.

Gas blow-by rate is the maximum that can flow given the pressure drop between the upstream component and the component being evaluated. In computing the maximum rate that can flow due to pressure drop, consideration should be given to the effects of control valves, chokes and other restricted orifices in the line. A more conservative approach would be to assume that these

devices have been removed or have the maximum size orifice which could be installed in the device.

C. Fire/Thermal Expansion. The pressure in process components exposed to the heat from a fire will rise as the fluid expands and the process liquid vaporizes. For tanks and large low pressure vessels, the need to vent the liberated gas may govern the size of the vent or pressure relief valve. Fire sizing a pressure relief valve only keeps pressure build up to less than 120 percent of the MAWP. If the component is subjected to a fire for a long time, it may fail at a pressure less than MAWP because a metal’s strength decreases as temperature increases. See Section 4 regarding blowdown considerations.

On components that can be isolated from the process, it is possible for the process fluid contained in the component to be heated. This is especially true for cold (relative to ambient) service, or when the component is heated (such as a fired vessel or heat exchanger)—and it is also true for compressor cylinders and cooling jackets. The pressure relief valves on such components should be sized for thermal expansion of the trapped fluids. This will not normally govern the final size selected unless no pressure relief valve is needed for the other conditions.

3.3.11 Drain Systems

Planning and construction of offshore production facilities should include methods to collect and direct escaped liquid hydrocarbons to a safe location in an “open drain” (deck or drip-pan drainage) system. All components subject to leaks or overflow should be protected by curbs, gutters or drip pans that drain to a sump. Solid deck areas are often drained to a gutter and routed through a system of gutters or piping to a central point. This may also be done by providing a number of drain openings in the decks which are then piped to a central point. Deck areas that have a source of oil leakage, spills or drips should be liquid tight, with the periphery surrounded by curbing or a continuous gutter. Alternatively, drip pans may be installed under equipment, provided liquids are routed to a central point. Structures that do not have process vessels or other equipment subject to leak or overflow (e.g., structures with only wells, headers, pipelines, cranes and/or instrument gas scrubbers) often do not have open drain systems.

The collected liquids from an open drain system should be discharged into a sump tank, where separation occurs according to specific gravity differences. The sump tank should be equipped with an automatic discharge system. Liquid hydrocarbons can then be skimmed off and routed back into the production system. Thus, the highly corrosive, oxygenated rainwater is separated from the fluids pumped back into the process system.

Since liquid drained to the sump may contain hydrocarbon gases that could flash, the sump should have an adequately sized gas disposal system (refer to Section 3.3.9).

The design of the overall open drain system should include at least one liquid seal to prevent gas from the sump from migrating into the drain system. Care should be taken not to locate buildings and other enclosures on top of drain openings as gas may migrate through the drain piping from other areas into these spaces. Likewise, drain systems from enclosures should not be tied in directly to deck drain systems. Instead, there should be a break in the piping with a liquid seal on one side, and a method should be devised for operators to verify that the liquid seal is maintained. Liquid seals are also desirable to isolate open areas of the platform from each other to prevent gas migration via the drain system. Refer to API RP 14C and RP 500 for additional guidance.

Drain piping should be adequately sized and sloped to prevent plugging and, under design conditions, to minimize the back-up of liquids on decks or in drip pans. Turns in drain headers can be constructed with tees, with one outlet blind flanged to facilitate cleaning. Similarly, laterals can be tied into headers with crosses to facilitate cleaning.

Separate closed (pressurized) hydrocarbon drain systems and sump tanks are sometimes used to drain pressure vessels. Since this liquid can contain hydrocarbons which flash in the drain system, closed drains should be separate from open drains. In closed drain systems, there should be no block valves between vessel drain valves and the sump tank, unless the entire system upstream of the block valve is pressure rated for the highest working pressure connected to it (See Section 3.3.12). Also, consideration should be given to the possibility of freezing or plugging of the drain system and the generation of steam and pressure due to the draining of hot liquids.

3.3.12 Piping Design

All platform piping should be designed and installed in accordance with API RP 14E. It is essential that piping be designed to withstand the maximum pressure to which it could be exposed. Section 1.6 of API RP 14E provides guidance for pressure rating of piping systems and defines the demarcation between systems with different pressure ratings (“spec break” locations). Facility piping systems should be rated to the maximum pressure capable of being developed by a source (e.g., a well, pump, compressor), or should be equipped with pressure relief valves that can handle the total throughput in the event that the flow is blocked. Either the source pressure or the pressure setting on the pressure relief valves will determine the piping pressure rating required. Process pressure reductions and increases can occur throughout a facility. Pressure reductions normally take place at chokes, control valves and dump valves, while pressure increases can occur at pumps or compressors. Both reductions and increases can be a reason to change the pressure rating of a

piping system. These “spec break” locations should be chosen to accomplish the facility’s objective prudently while protecting each piping section and component from overpressure. Pipe, fittings and valves should be designed to withstand the maximum pressure possible due either to leaks of control valves and check valves or to the inadvertent opening or closing of manual valves. Care should be taken in the placement of block valves, since they may isolate portions of piping systems from critical relief devices which may be a factor in determining the pressure rating of that section of pipe.

In determining the proper maximum allowable pressure to use in designing a segment of a piping system and the location of spec breaks, the following assumptions should be made:

1. Check valves may leak or fail open and allow communication of pressure from the high side to the low side. (Check valves should still be used as required by API RP 14C to minimize back flow in case of a leak, but cannot be relied upon to prevent over pressure.)
2. Control valves, including self-contained regulators, can be in either the open or closed position, whichever allows the piping segment to be exposed to the maximum pressure.
3. Block valves can be positioned in either the open or closed position, whichever position creates the highest pressure. Locked open (or closed) valves can be considered always open (or closed), if the lock and key are maintained in accordance with a proper lockout and tagout procedure. A hazards analysis should be performed to determine if the risk associated with relying on the lockout/tagout procedure is justified.
4. High-pressure sensors alone do not provide sufficient protection from over pressure. The one exception is that API RP 14C allows the use of two independent sensors that operate independent isolation valves on production flowline segments. This should be approached with caution after thorough consideration of other alternatives.
5. Pressure relief valves and rupture discs will always work due to the high reliability of their design. (In critical service, some operators require a back-up [relief valve or rupture disc] to the primary relief device to increase reliability or to provide a spare).

In checking for spec break locations, it is easiest to start at a primary pressure relief valve (one designed for blocked discharge) and trace the upstream piping (including all branches) to the first block valve or control valve. It is then assumed the valve is closed, and the line is followed further upstream (including all branches) to the next pressure relief valve or the source of pressure. The piping from the first block valve to the upstream pressure relief valve or source of pressure