

Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities

API RECOMMENDED PRACTICE 14J (RP 14J)
SECOND EDITION, MAY 2001



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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		

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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

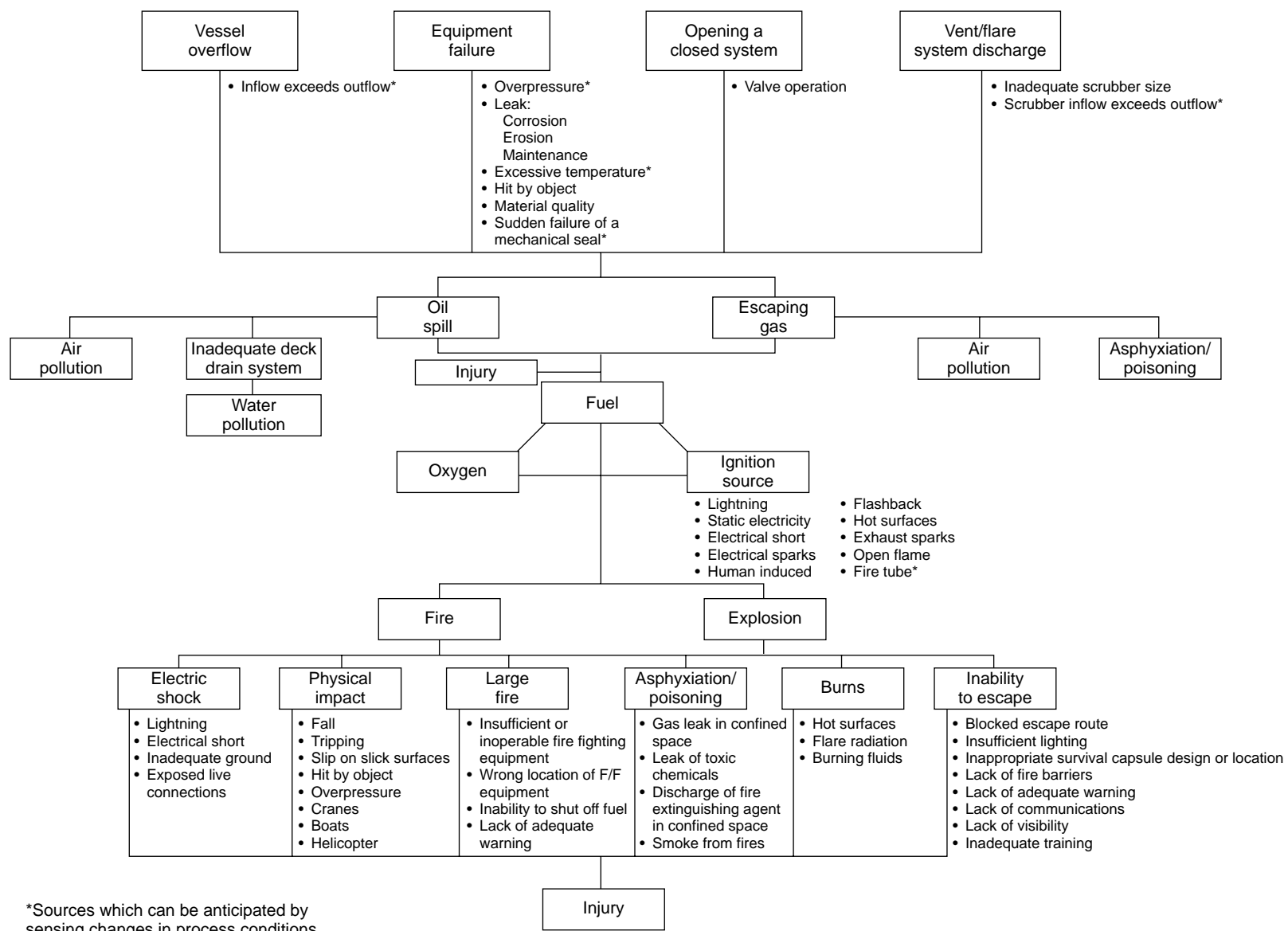
Process equipment should be designed to contain hydrocarbons to the greatest extent possible. The production system should be designed for the appropriate operating conditions with allowances for variations. Additional information on equipment and system mechanical designs with the goal of hydrocarbon 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



*Sources which can be anticipated by sensing changes in process conditions.

Figure 1—Hazard Tree for Production Facility

Figure 2—Matrix of Safe Facilities Design Principles

Facilities Features Practices, System or Equipment	Primary Safety Purposes			
	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 \times $1/2$ 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 $3/4$ inch \times $1/2$ 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 suction 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 suction. 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 arresters 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

should be rated for the setting of the pressure relief valve or maximum pressure of the source if no pressure relief valves are present. Each branch upstream of the first block valve should be pressure rated at this highest pressure at every location, where it can be isolated from any downstream pressure relief valve.

Figure 3 shows an example of spec break locations determined in this manner. Figure 4 shows how the spec breaks change if Valve “5” is added on the inlet to the LP separator. Note this changes the ratings of Valves B, D, and F in the manifold, as well as that of Valves 1 through 4 on the liquid outlet of the HP separator. Figure 5 shows that the pressure rating of Valves 1 through 4 do not need to be changed if the location of Valve 5 is changed. Figure 6 shows an alternative pressure rating scheme brought about by adding a relief valve upstream of Valve 5.

3.3.13 Corrosion and Erosion Prevention

The control of corrosion and erosion is an integral part of failure prevention, pollution control and safety. Most of the control and maintenance techniques developed and utilized onshore apply in offshore operations. However, due to the increased consequences of leaks and failures, design and inspection are more important offshore. In general, the more critical the piping, the more consideration should be given to mitigating corrosion and erosion. Space limitations, the salt air and marine environment and other special requirements inherent to offshore facilities make it important that they be considered in initial planning and design. Corrosion due to heat-exchange media, dehydration media and fuels should be considered as well as corrosion due to produced fluids.

A. Internal Corrosion/Erosion. The prevention of internal erosion/ corrosion in process systems requires that equipment and piping be properly designed and monitored for loss of wall thickness. In some conditions, corrosion resistant materials, coatings, cathodic protection and/or provisions for inhibition of corrosion may be required. A monitoring program may include sand probes, corrosion coupons, radiographic examination or ultrasonic testing. The type fluids being handled should be considered and allowance made for fluids that are particularly corrosive, erosive, or that have a tendency to form scale. The exposure of some metals to hydrogen sulfide can cause stress cracking, accelerate corrosion, or cause hydrogen embrittlement. Therefore, NACE Standard MR-01-75 should be consulted when selecting materials and designing weld procedures for H₂S service. Erosion of piping can be minimized by limiting the number of bends and the length of piping, using flow tees or long radius bends, and by designing for reasonable flow velocities. Particular attention should be given to piping configurations immediately downstream of pressure reductions where velocities are highest. Care should be taken to eliminate dead

spaces in piping systems. Recommendations for the design and installation of piping systems, including corrosion/erosion design, are contained in API RP 14E.

Consideration should be given to providing space, clearance, fittings, etc., for such operations as injection of inhibitors, insertion and removal of internal monitoring and safety devices, collection of samples, internal cathodic protection, and non-destructive methods of inspection. Some type of monitoring program is desirable to locate points of potential internal erosion/corrosion.

B. External Corrosion. The minimizing of external corrosion failure requires selecting proper materials and external coatings. External coatings should be properly applied and failures correctly repaired as soon as practical. In wave splash zone areas, consideration should be given to the use of special coatings and/or extra wall thickness for corrosion allowance. Designs should allow easy access for inspection and maintenance, with priority given to process piping and pipeline risers.

The proper securing and support of piping systems and process equipment is also important in preventing failures due to external corrosion and wear. Pipe supports should be designed to avoid abrasion of external coatings. Surfaces in close proximity or contact that prevent the application of protective coatings may be seal welded if this will not induce overstresses due to reduced flexibility.

Surfaces of piping and equipment on lower platform deck levels that are not exposed to rainwater can accumulate material that can lead to corrosion. Consideration should be given to freshwater wash down systems on platforms to extend their life.

3.3.14 Surface Safety Systems

A properly designed safety system will sense an abnormal operation or equipment condition and react to this condition by shutting in or isolating necessary system components or the entire system. Other actions—such as sounding alarms, starting fire extinguishing systems, and depressurizing equipment—may also be initiated by the safety system. Recommendations for designing, installing and testing basic surface safety systems on offshore platforms are contained in API RP 14C. Systems should be designed to minimize the need, time required, or risk of bypassing safety devices for equipment start-up, maintenance or device testing.

Care should be taken in the material selection and placement of surface safety devices. For example, relief valves should be located upstream of vessel mist eliminators that could plug. Sensors should not be remotely mounted if the sensing lines are susceptible to plugging. Also, materials in safety devices should be suitable for the application and resistant to the fluids being handled and the temperatures expected.

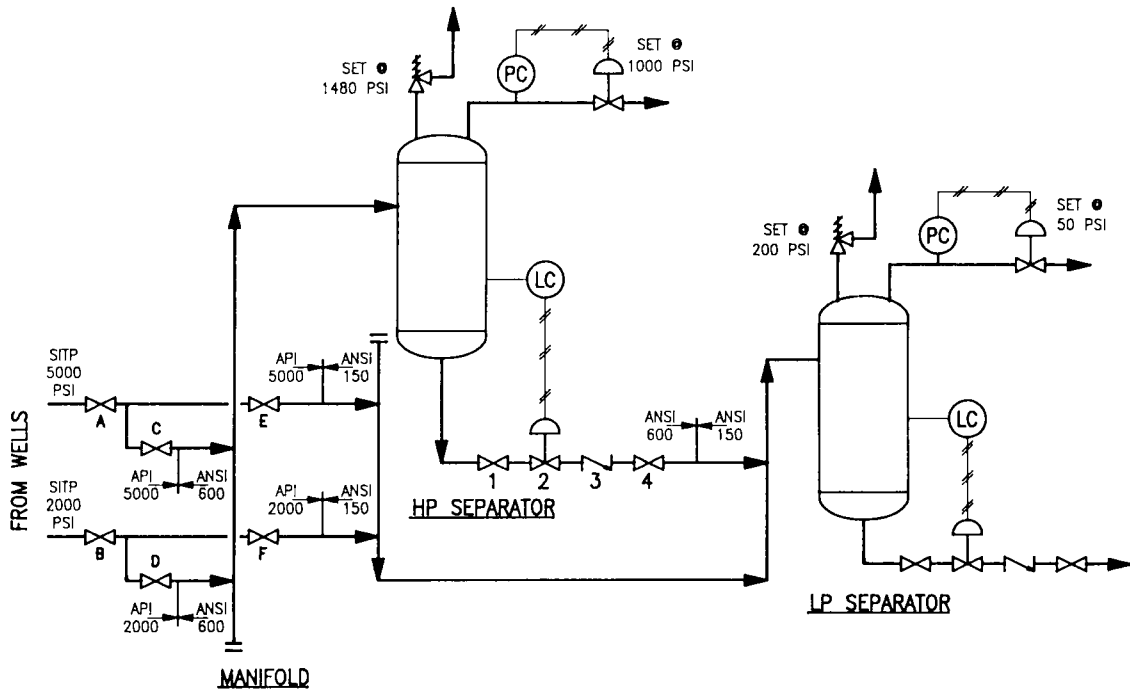


Figure 3—Determining Pressure Breaks

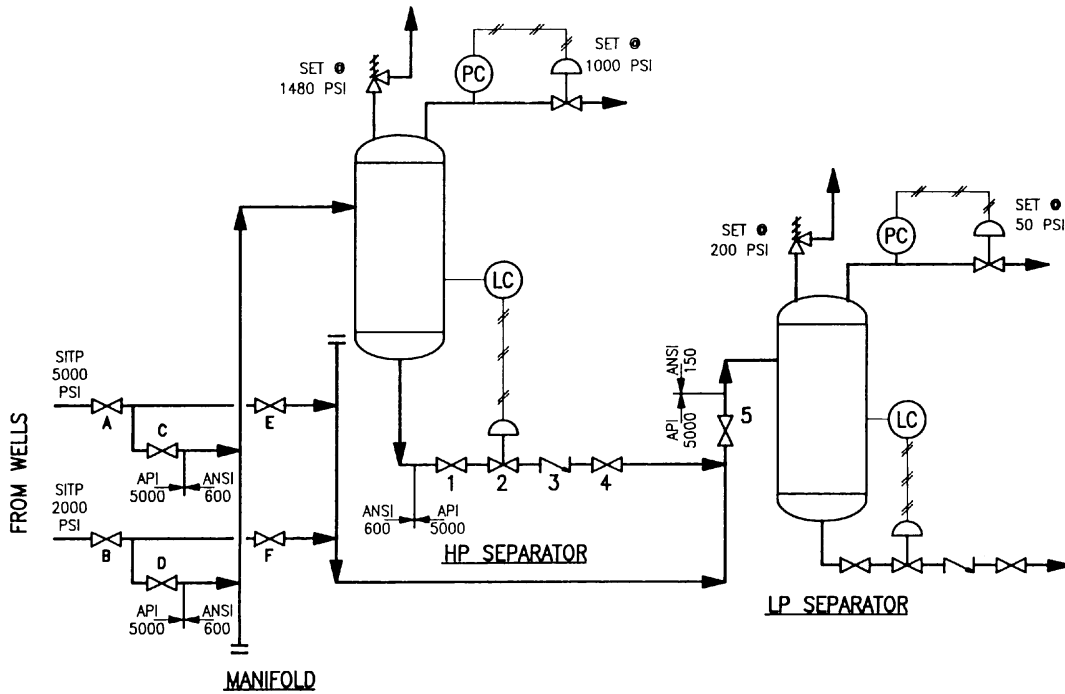


Figure 4—Determining Pressure Breaks

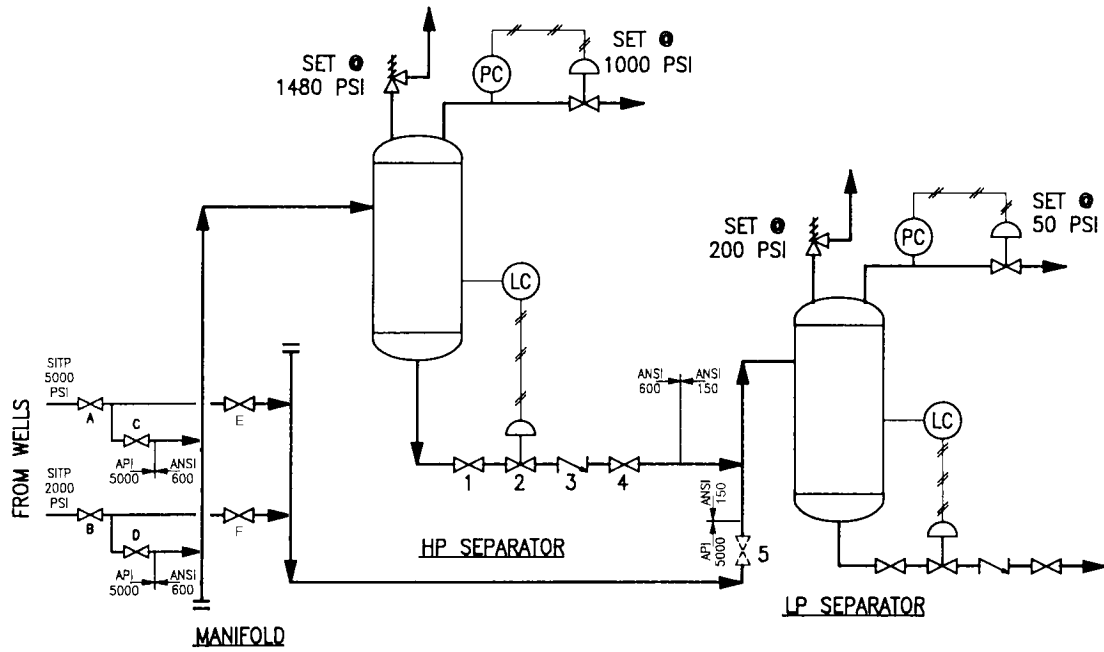


Figure 5—Determining Pressure Breaks

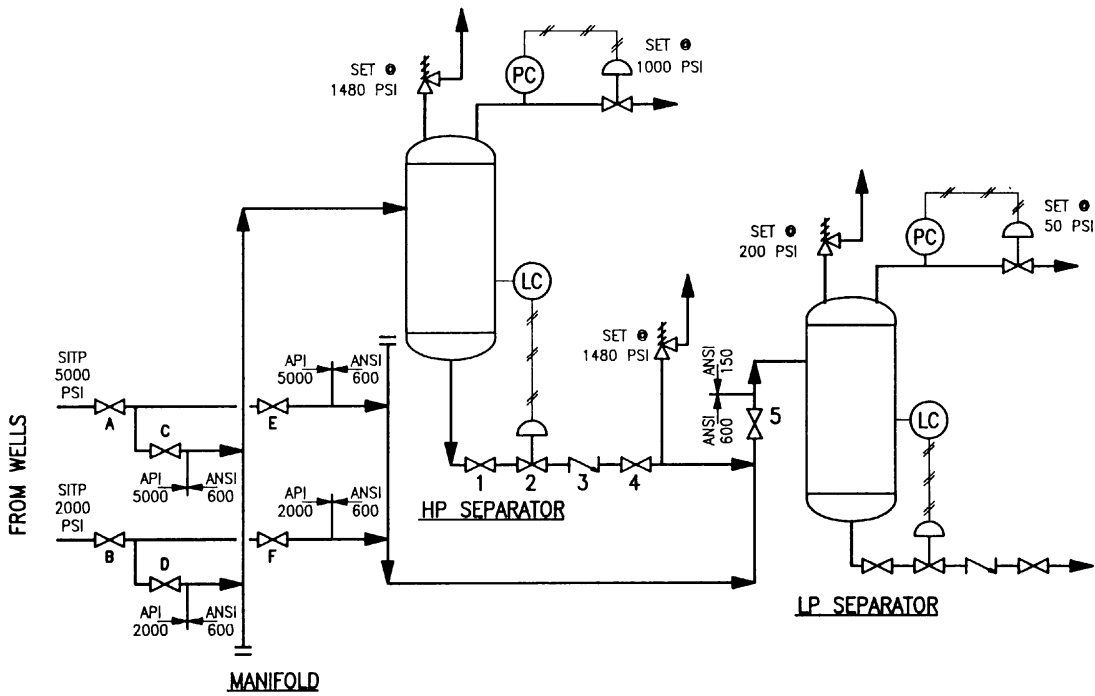


Figure 6—Determining Pressure Breaks

Inspection and testing of safety devices should be considered in planning surface safety systems. Locations and installation details of safety devices for easy access for the required inspection and testing should be included in planning production facilities arrangements.

3.3.15 Programmable Electronic Systems (PES) and Remote Operations

Programmable Electronic Systems (PESs) are commonly used for control systems; safety systems; annunciation systems; and supervisory, control and data acquisition systems (SCADA). The PES may be a distributed control system (DCS), programmable logic controller (PLC), personal computer (PC), main frame computer, customized electronics unit, or a combination thereof communicating with each other over a network.

When designing PESs, consideration should be given to numerous subjects including those detailed below. Additional guidance is given in ISA 584-01.

A. “Availability” of the System to Function upon Demand. In many cases, the use of redundant equipment, “hot standby” units and fault tolerant systems may be utilized to increase the system’s availability and dependability. Required availability of system should be based on acceptable risk factors.

B. Selection of Components. Selection of the proper PES components, as well as their configuration and interconnection, is crucial to the proper operation of the system. This includes proper selection of the PES hardware, end devices, wiring and user interface.

C. Failure Modes of the System’s Components. The system design should consider the safety of personnel and the prevention of pollution in case of a component failure. If possible, all components should fail to a predetermined safe state.

D. Utility Design. Careful consideration should be given to the design of the utility systems for the PES. A primary concern is availability of the power supply for the PES. Other concerns are voltage, frequency tolerance and harmonic wave form. Critical systems are commonly powered from a DC power supply or an uninterruptible power supply (UPS). In either case, adequate battery backup should provide for either continued normal operation for a limited period of time or a predetermined shutdown sequence. Installing noncritical systems that operate on AC power on the same power supply as the PES should not be done without careful consideration. Other utilities to consider include the instrument air (or instrument gas) system and the hydraulic system, if these are being utilized by the PES.

E. Software Design. The programming of any PES should be performed only by personnel trained to work on the particular system. Software changes and additions to the software should be controlled and documented. Access to the internal PES programming should be limited. Common ways to accomplish this include the use of passwords or keyed access. An up-to-date listing (with changes and modifications) of the application program should be available at the site of the PES. The system user should implement a management of change program to evaluate, approve, document and audit system changes.

F. Remote Control. It is not uncommon for processes to be controlled from a remote location by a PES. For these systems, additional consideration should be given to the configuration of both the local and remote system and the points selected to be monitored and controlled.

G. Inspection, Testing, Maintenance, and Documentation. With any PES, inspection, testing and maintenance procedures should be established and personnel adequately trained to perform these tasks. Prior to installation, testing procedures and intervals for testing and maintenance should be developed. Documentation on the system configuration, components and programming should be kept up-to-date.

3.3.16 Electrical Systems

Electrical systems and instrumentation systems that utilize electricity (regardless of voltage and current levels) should be designed and installed in accordance with API RP 14F. This document recommends minimum requirements and guidelines for the design and installation of electrical systems on fixed production platforms, and it is intended to bring together in one document a brief description of basic desirable electrical practices for offshore electrical systems. The recommended practices contained in this document recognize that special electrical considerations exist for offshore production platforms due to the following:

1. The inherent electrical shock possibility presented by the marine environment and steel decks.
2. Space limitations that require equipment to be installed in or near classified areas.
3. The corrosive marine environment.

API RP 14F emphasizes safe practices for classified areas on offshore production platforms but does not include guidelines for classifying of location. For guidance on the classification of areas, refer to API RP 500.

3.3.17 Living Quarters

Living quarters should be protected from external fires, explosions and noise. Where living quarters are located on a

drilling or production platform, a firewall or adequate space should be considered to separate the quarters from areas containing hydrocarbon sources. For a new facility, the firewall should have a rating of at least 60 minutes in a hydrocarbon fire. The firewall may be an integral part of the quarters building. Windows and other openings facing the hydrocarbon sources should be minimized, and those that are installed should have the same ratings as the firewall. The interior of the quarters building should have an adequate exhaust system to preclude accumulation of smoke and odors. Smoke detectors should be provided. For guidance on smoke detector location, refer to API RP 14C, Appendix C, and RP 14G.

Passageways should have stand-by lighting and illuminated exit signs. To provide safe egress, walkways should be constructed on the exterior sides of the quarters' building opposite the operational areas.

3.4 SPECIAL SAFETY CONSIDERATIONS

The design and equipment layout of production systems are usually complex. Design personnel should be knowledgeable of special safety considerations concerning simultaneous operations, toxic gas and gas processing when these are part of the production operations.

3.4.1 Simultaneous Operations and Multiple Use

Design personnel should take into consideration that the facility could be used to support drilling, production, remedial well work and occasional construction activities. Activities that make up the simultaneous operations are covered in Section 5.1.6 and the reader is referred to that section for information on layout consideration.

It is important in the early stages of design to consider protection of the components of the facility from falling objects or collision, and to develop procedures, if necessary, to maintain this mitigation effort. It is equally important to shelter components and work areas from corrosive fluids, solids and other deleterious materials (such as abrasive grit) that may be used in drilling, remedial, production or construction operations.

During simultaneous operations, crew staffing is normally expanded and significant demands are imposed on the facilities. Systems should be designed to be flexible and expandable for interfacing with any temporary buildings or added support equipment.

3.4.2 Toxic Gas Considerations

Production of liquid and gaseous hydrocarbons containing hydrogen sulfide in significant amounts can be hazardous to personnel and can cause failure of equipment. Hydrogen sulfide gas detectors should be installed on offshore production platforms where concentrations of hydrogen sulfide gas may reach hazardous levels. The presence of hydrogen sulfide also

presents the possibility of exposure to sulphur dioxide, which is produced from the combustion of hydrogen sulfide. Sulfur dioxide monitoring equipment should be utilized when flaring operations could result in personnel exposure to hazardous levels. It should be recognized that H₂S gas has an ignition temperature about half that of methane gas. When evaluating the risk from H₂S, consideration should be given to potential sources within the process and utility systems where H₂S can be concentrated above 50 ppm (such as low pressure or utility systems, water treating units or produced water tanks where H₂S is present, etc.). See API RP 14C, RP 55, 30 *CFR* 250 and NACE Standard MR-01-75 for further discussions on toxic gas considerations.

Accumulations of gases or vapors are more likely to occur in poorly ventilated areas, particularly enclosed areas. Methods for increasing safety include providing breathing (respiratory protection) equipment, improving ventilation, installing toxic gas detector (OSH) systems and providing personnel monitors. Toxic gas detector systems should alert personnel by unique audible or visual (as most appropriate for the area) alarms to the presence of low level concentrations of toxic gases. Also, since many toxic gases are flammable, sources of ignition should be removed if concentrations approach the lower flammable limit (LFL) of the gas present. All detectors should be designed, installed and maintained in accordance with API RP 14F and RP 14C. For additional guidance, refer to ISA RP 12.15 Part II.

3.4.3 Gas Processing

When planning an offshore process facility, special consideration should be given to the increased hazards that are associated with "gas processing" equipment installed to lower the hydrocarbon dew point of gas. These processes produce low boiling point liquids that are handled and stored at pressures above atmospheric. Released vapors are heavier-than-air and are difficult to disperse, thus increasing the potential of a fire or an explosion. Should a fire occur around a vessel, it could lead to a so-called "boiling liquid expanding vapor explosion" (BLEVE). This phenomenon is usually catastrophic in nature. Consequently, the type, amount and complexity of the equipment should be evaluated for process safety. Dispersion and fire/explosion modeling may be useful to help understand the potential consequences of a release.

Special metallurgy may be required due to the low temperature processes employed. Attention should be given to the increased potential for extremely low temperatures in the pressure relief system caused by autorefrigeration.

3.4.4 Human Engineering

It should be recognized that adherence to this Recommended Practice, referenced codes and standards does not guarantee that equipment or software will be designed so as to match the workers' physical and mental capabilities and

limitations. For years, human error has been cited as a cause of industrial accidents and incidents. Human error can be induced by deficiencies in design that require mental or physical behaviors from the worker that contravene well established culturally or genetically based human behavioral patterns or that are beyond the normal human being's physical or mental capabilities.

A specialized engineering discipline called Human Engineering (Ergonomics), which combines traditional engineering training with special knowledge of human and mental capabilities and limitations, can assist in eliminating man/equipment mismatches. For guidance on general human engineering design criteria that incorporate human capabilities into a design, refer to ASTM F1166, *Standard Practice for Human Engineering Design for Marine Systems, Equipment and Facilities*.

4 Hazard Mitigation and Personnel Evacuation

4.1 GENERAL

A primary objective in the design, maintenance and operation of offshore production facilities is to minimize the risks associated with hazards. This risk minimization is referred to as hazard mitigation. Two major goals of a safe design are prevention of fire escalation and providing for personnel evacuation of the platform when required. This section reviews some of the key aspects of accomplishing these two goals.

It is recommended that an overall philosophy of hazard mitigation and personnel evacuation be developed for an offshore production facility in the early phases of equipment selection, arrangement and design. This philosophy should consider whether the platform is continuously attended, the number of personnel generally in attendance, the platform's distance from nearby platforms and the coast, environmental conditions, the types of operations to be performed, the availability of boat and air transportation, and the size and type of the platform. Once this philosophy is developed, it will impact equipment selection and spacing, location of walkways, positioning of escape paths, and the designs of many emergency related systems.

The hazard mitigation and evacuation philosophy should, at a minimum, consider the subjects of fire and gas detection, alarm and communication systems, personnel escape paths, fire-fighting and evacuation procedures, passive and active fire mitigation schemes, and the reduction of hydrocarbon inventory. Examples of passive fire mitigation schemes are fire walls and insulation. Examples of active fire mitigation schemes are water deluge, spray and foam systems, dry chemical extinguishing agents, and gaseous extinguishing systems.

4.2 FIRE AND GAS DETECTION, ALARM/ COMMUNICATION SYSTEMS

On manned platforms, or on platforms where personnel are frequently in attendance, personnel should quickly be made aware of a potential emergency situation by a hazard detection and alarm system. Alarms should warn personnel of fires, gas releases and other events. It also is essential that personnel be able to communicate with others as an emergency develops, so that plans can be made to cope with the situation or to evacuate. The detection, alarm and communications systems should be continuously powered and protected to reduce the likelihood that they will be rendered inoperable by the event.

Platforms can be equipped with both manual and automatic fire detection and alarm systems. Automatic fire detection and alarm systems are best used in areas where a quick response significantly reduces the extent of damage and increases the safety of personnel. One widely used method of automatically detecting fires is a pneumatic fire loop system containing strategically located fusible elements. In addition to pneumatic fire loop systems, electrical systems that detect heat or flame (i.e., UV/IR or thermal) and smoke are commonly used on offshore production platforms. These devices activate alarms, initiate shut-in actions, and/or activate fire suppression systems (e.g., CO₂, dry chemical agents and water system). Equipment required to control the fire should not be shut down. Manual fire detection and alarm systems should be incorporated to complement automatic systems when operating personnel are available on a routine basis. For more discussion on the types of fire detection and alarm systems, locations and suggested design features, refer to API RP 14C, RP 14F, RP 14G and applicable regulatory requirements.

Gas detection systems should be provided in areas where adequate ventilation cannot be achieved or in areas where personnel are frequently in attendance, such as quarters, offices, and switchgear rooms. The gas detector system should alert personnel by audible and/or visual alarms to the presence of low level concentrations of flammable and/or toxic gases or vapors and should activate valves that shut off gas sources. Also, consideration should be given to eliminating all sources of ignition if the concentration approaches the lower flammable limit (LFL) of the gas. Recommended practices for sensor locations and operation of combustible and toxic gas detectors are presented in API RP 14C. For additional information concerning the selection and installation of gas detection systems, refer to API RP 500, RP 14F, RP 14G, RP 55, ISA RP 12.13 (Part II), and ISA RP 12.15 (Part II) and applicable regulatory requirements.

Pneumatic or electrical alarms should alert personnel to a potential emergency situation. Where practical, defined alarm tones (i.e., to indicate gas, fire, and abandon platform) should be consistent within an operating company from platform to platform.

Systems for communication between locations on a platform should be included if the size, complexity, number of personnel or type of operations warrant. Generally, continuously attended platforms should have a paging and local communication system with stations at important operating locations on the platform. Communications equipment should be provided to allow coordination of activities between the platform, boats, helicopters, other nearby platforms and onshore bases. Communication systems utilizing microwave or cellular transmission methods may also be considered. All communications systems should have a source of backup power in case of the loss of primary power.

For platforms which do not have a permanently installed communications system, portable equipment can be used when personnel are onboard.

4.3 ESCAPE PATHS

It is essential that personnel on multi-leg structures have at least two paths by which they can escape. The escape paths should be located so that it would be very unlikely for a single event to block both paths. Primary escape paths should be situated along the outboard edge of the platform, if practical, to reduce the problems caused by smoke. Primary escape paths should be designed to minimize the exposure of personnel to potential heat and flame sources. Escape paths should have adequate headroom, ample width and be free of obstructions to quick departure. Also, consideration should be given to marking escape paths with emergency lighting and/or markings on the floor.

On large platforms, high risk facilities or where environmental conditions make escape to the sea difficult, the evacuation philosophy may include a temporary mustering area. A temporary mustering area is a location where personnel can gather and develop plans to either contend with the emergency or evacuate. Commonly designated temporary mustering areas are the living quarters, control room, or lifeboat station areas. The mustering area should provide protection for personnel for an amount of time consistent with the platform evacuation philosophy. At the designated temporary mustering area, there should be offshore survival gear and lifeboats, rafts or capsules available for all personnel to utilize in the event of an evacuation. From the temporary mustering area, there should be at least two independent paths to the sea (e.g., davited life boats and stairs to the boat landing). Facilities with H₂S should have an escape route to the helipad since H₂S is heavier than air.

All living quarters should be provided with two independent paths of escape, with at least one path of escape to the sea. If there is a nearby mustering area, there should be two independent paths from the quarters to the mustering area. For existing facilities, where it may not be practical to provide two independent paths, the quarters egress provisions

should be sufficiently secure and protected to allow for personnel evacuation in the event of an emergency. Consideration should be given to constructing walkways on the exterior sides of the quarters building opposite the operational areas. Locating walkways here will facilitate safe egress from the quarters building.

4.4 FIRE-FIGHTING AND EVACUATING 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/or evacuation becomes necessary. Drills should be conducted on a regular basis, and training should be provided for new personnel to acquaint them with the emergency equipment and fire-fighting procedures they are expected to perform. Personnel should be familiar with various emergency alarms and know their specific duties during an emergency. Manned production platforms should have a communication and public address system to assist and direct personnel in emergencies. All personnel should be familiar with the various escape devices and know their specific duties during the evacuation of the platform. Personnel not normally assigned to a facility should be instructed to recognize alarms, be told of the action required of them from each alarm, and should be made familiar with evacuation routes immediately after arrival on the platform. For additional guidance refer to API RP 14C and RP 14G.

4.5 PASSIVE FIRE MITIGATION

Passive fire mitigation techniques are defined as any fire protection system that does not have to be activated to play a role in the protection of personnel or property from fire, or in the prevention or delay of fire escalation. Passive fire protection could also include the physical separation of equipment according to service insofar as practical. Generally, passive fire protection is not the only means of fire protection, but it is used in concert with active fire protection systems. This rationale is necessary because passive fire 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 passive fire protection systems are fire walls, spray-on insulating materials, and insulating blankets of fireproof materials. Examples of where passive fire protection is commonly used are: critical structural steel, living quarters, mustering areas, critical equipment, structural supports, etc. For more guidance refer to API RP 14G.

4.6 ACTIVE FIRE MITIGATION

Active fire mitigation systems can be water only, water with a foaming agent, chemical only, or a combination of

water, foams and chemical. Active fire mitigation systems are recommended on all platforms with process equipment whether continuously attended or not. Active fire mitigation systems can also include an inert gas for enclosed spaces and can be manually or automatically activated. For more details refer to API RP 14G.

Active fire protection systems are installed on offshore platforms to cool, control and/or extinguish fires on platform equipment (i.e., wellheads, pumps, separators, tanks and fired vessels) and on main structural members. The basic components of a fire water system are the fire water pump, the distribution piping, hoses with nozzles, fixed nozzles and monitors. Fire water hoses with nozzles allow one or two people to fight a fire from up to 100 feet away. Fixed water spray systems and fixed monitors can be useful to protect areas that cannot be adequately reached by hand-held hose streams. The fixed spray and monitor systems can be used in combination or separately. Portable pressurized water extinguishers are used to extinguish cellulose fires that could occur in quarters buildings.

Foam-forming additives can increase the effectiveness of water in controlling liquid-hydrocarbon fires. Foams may be employed using hose stations, fixed systems, or portable extinguishers. The foaming agent may be applied by directly introducing foam concentrates into the fire water system, or it may be applied as a premixed solution of concentrate and water. Foaming agents are especially useful on liquid hydrocarbon pool fires but are not effective on grated areas or for gas pressure fires.

Dry chemical fire-fighting systems effectively extinguish fires; however, the dry chemical agent must be matched to the type or class of fire. Dry chemical agents may be applied by portable extinguishers, hand-held hose lines or fixed nozzles. A major advantage of dry chemical systems is their self-contained feature, which does not rely upon an external energy source. Dry chemical agents are suitable for use indoors or outdoors and can generally be applied on most platform equipment.

Gaseous extinguishing agent systems are especially suitable for enclosed locations such as control or switchgear rooms and engine drivers. Gaseous extinguishing agents are electrically nonconductive, leave no residue, and may be applied using portable extinguishers or fixed systems.

4.7 HYDROCARBON INVENTORY REDUCTION

The inventory of hydrocarbons produced, processed, transported and stored on an offshore production facility represents a potential major hazard. The primary hydrocarbon inventories on an offshore production facility are connected wellbores, pipelines, pressure vessels and associated process piping, produced fluid storage tanks, fuels and flammable chemicals. It is important to minimize the available hydrocarbon inventory in the event of emergency.

Treated liquid storage tanks represent a large volume of hydrocarbons. These tanks should be sized to store and process the minimum volume consistent with operational and measurement considerations and pipeline pumping equipment designs. Where pipeline transport systems are not available for continuous pumping, trade-offs on inventory storage and location will have to be made.

The hydrocarbon inventory can be reduced in an emergency through isolation of hydrocarbon sources, gaseous depressuring, and liquid dumping. One or more of these schemes can be used on a platform.

Isolating hydrocarbon sources is commonly done to reduce hydrocarbon inventories. Wellbores are required to be isolated in a emergency. Also, consideration should be given during an emergency to isolating other major hydrocarbon sources such as pipelines.

Another method of minimizing gaseous hydrocarbon inventory is process system depressuring. This is a procedure to minimize or eliminate the quantity of pressured gaseous sources present in the production facility during emergency situations. Also, depressuring results in the reduction or elimination of pressure-induced stresses at a time when a pressure vessel is weakened by elevated temperature. An example would be to depressure hydrocarbon processing equipment and/or vessels to a vent system when a shutdown occurs. This is a common practice on large gas compressors. However, these benefits should be weighed against discharging large volumes of gas in a short period during an emergency situation. For additional information concerning depressuring system philosophy and design considerations, refer to API RP 14G.

Finally, in some special situations, dumping hydrocarbon liquids from a tank or vessel to a safer location may be warranted. This method of hydrocarbon inventory reduction should be carefully designed to limit the impact to the environment and to assure that greater hazards are not introduced through the use of this method.

5 Platform Equipment Arrangements

5.1 GENERAL

A general rule for equipment layout planning is to keep potential fuel sources (any combustible material) as far from ignition sources as practical. The primary goals of this separation of equipment are to prevent hydrocarbon ignition and fire escalation. Vertical as well as horizontal spacing between fuel and ignition sources should be considered in equipment layouts. Examples of fuel and ignition sources are listed in Table 3.

It is not always possible to separate fuel and ignition sources completely. For example, engine driven pumps and gas compressors are both a fuel and an ignition source. In

the final analysis, any equipment layout must be a compromise, taking into account the associated risks and possible consequences.

Platform equipment can be arranged in groups according to nine specific categories, as described in Table 4. Comments pertaining to the location of each category are discussed below.

Adequate space between equipment categories is an important factor in promoting a safe operation. Factors such as platform design, water depth, size and extent of the hydrocarbon reservoir, method of operation, governmental regulations, etc., will influence the number of equipment categories and the location of equipment on a particular structure.

5.1.1 Wind Direction

Equipment arrangement should take advantage of the prevailing winds to minimize the chance that escaping or vented hydrocarbon vapors will be carried toward potential ignition sources on the platform. Such sources would include fired process equipment, combustion engines, living quarters and helidecks. In general, atmospheric vents, flare systems and emergency gas release vents should be placed so that prevailing winds will carry heat and/or unburned gases away from the platform. Air intakes of fired process equipment, combustion engines, air compressors and HVAC systems should be located so as to provide the greatest amount of isolation from sources of flammable gas.

5.1.2 Firewalls and Barrier Walls

Separation of ignition sources from fuel sources is an essential safety consideration. If the necessary physical space to satisfy this need is unavailable, fire walls or barrier walls may be considered. Barrier walls can impede escaping gas or liquid leaks from entering an area with a potential ignition source. Fire walls can provide a heat shield to protect equipment and allow personnel to escape without being subjected to radiant heat from a fire.

Fire walls or barrier walls are often used to separate well-head areas from process areas, to separate process areas from storage tanks and to separate living quarters from any potential external fire.

Fire walls and barrier walls have the disadvantage of restricting natural ventilation and hampering escape. For these reasons, they should be used only where it is impractical to adequately separate fuel from sources of ignition. While fire walls and barrier walls can decrease the consequences of fires and explosions, they may increase the overpressure created by an explosion, thereby increasing damage to piping and equipment in other areas of the platform. If spaces are confined, blast protection should be considered. Great care should be taken to minimize the impact of explo-

sions on escape routes. Due consideration should be given to the placement of shutdown or isolation valves on lines that penetrate fire or barrier walls. These could help to isolate sources of fuel in the event of a fire.

5.1.3 Process Flow

Equipment areas are sometimes initially located so as to streamline the process flow and to simplify piping systems. Simplifying piping contributes to safety by minimizing the potential for operator error. Reducing the length of piping reduces the potential for leaks. However, the other safety aspects of equipment separation discussed in this section should also be considered.

5.1.4 Maintenance of Equipment

Sufficient space should be considered for easy access to each piece of equipment to provide room for operating personnel, for inspection and maintenance and for painting. For example, space should be allowed for:

1. Pulling fire tubes from fired heaters.
2. Pulling tube bundles or plates from heat exchangers.
3. Removing compressor cylinders.
4. Replacing generators, engines, air compressors and pumps.
5. Pulling vertical turbine or can-type pumps.
6. Removing plate packs from plate coalesces.
7. Pig insertion and removal (including more lengthy "smart" pigs).
8. Changing filter elements and filter media.
9. Removing and installing bulk storage containers.
10. Opening and removing inspection plates and manways.

It may be necessary to provide supplementary overhead cranes or lifting frames for heavy equipment that cannot be reached by the platform crane.

5.1.5 Safe Welding Areas

On platforms, safe welding areas may be designated where minor construction or routine maintenance can be performed. These could be simply an open area with solid floor and adequate access from the platform crane, or a fully equipped maintenance shop with overhead crane, lathes, welding machines, etc. Safe welding areas should be separated from fuel sources and adequately ventilated. On small platforms, barrier walls are often used to separate safe welding areas from potential fuel sources. Drains from welding areas should be isolated from other drains that could contain hydrocarbon vapors.

Table 3—Fuel and Ignition Sources

Fuel Sources Include:	Ignition Sources Include:
Wellheads	Fired Vessels
Manifolds	Combustion Engines
Separators and scrubbers	(including gas turbines)
Coalesces	Living Quarters
Oil Treaters	Electrical Equipment
Gas Compressors	Flares
Liquid Hydrocarbon Pumps	Welding Machines
Heat Exchangers	Grinding Machinery
Hydrocarbon Storage Tanks	Cutting Machinery or Torches
Process Piping	Waste Heat Recovery Equipment
Gas-Metering Equipment	Static Electricity
Risers and Pipelines	Lightning
Vents	Spark Producing Hand Tools
Pig Launchers and Receivers	Portable Computers
Drains	Cameras
Portable Engine-Driven Equipment	Cellular Phones
Portable Fuel Tanks	Non-intrinsically Safe Flashlights
Chemical Storage	
Laboratory Gas Bottles	
Sample Pots	

Table 4—Equipment Categories

Area	Location Objective	Example Equipment Types
Wellhead	Minimize sources of ignition and fuel supply Protect from mechanical damage and exposure to fire	Wellheads, Chokes, Manifolds, Headers (all F)
Unfired Process	Minimize sources of ignition	Manifolds and Headers, Separators, Gas Sales Station, Pig Traps, Heat Exchangers, Water Treatment Equipment, Pumps, Compressors, LACT units (all F)
Hydrocarbon	Minimize sources of ignition	Storage Tanks, Gunbarrel Tanks, Tanks Sump Tanks, Produced Water Treating Tanks, (all F)
Fired Process	Minimize fuel supply	Fired Treaters, Line Heaters Glycol Reboilers (all I)
Machinery	Minimize fuel supply	Generators, Electric Hoisting Equipment Type A or B, Air Compressor A or B, Engines, Turbines (all I)
Quarters	Personnel safety Minimize sources of fuel	Living Quarters, Maintenance Areas/Building, Sewage Disposal, Water Maker (all I)
Risers	Minimize sources of ignition	Risers, Pig Launchers, Pig Traps (all F) Protect from mechanical damage and exposure to fire.
Vents	Minimize ignition sources	Discharge Point
Flares	Minimize fuel Sources	Discharge Point

(F)—Fuel Source

(I)—Ignition Source

Equipment (Type A)—Manual, fluid powered, or explosion proof electric motor powered

Equipment (Type B)—Internal combustion engine or electric motor powered

5.1.6 Simultaneous Operations

Offshore structures often are used for multiple operations to support drilling, production, remedial well work and occasional construction activities for modifications, additions or upgrades. During a platform's active life, all these activities may exist either in conjunction with others or as a specific phase. While the specific placement and arrangement of drilling, workover or other remedial well equipment is beyond the scope of this RP, full consideration should be given to this use when planning the arrangement of production, compression and support equipment such as generators, cranes, quarters, heliport, etc. Simultaneous operations pose additional complexities to the use of the facilities whenever two or more of the following operations occur:

1. Production.
2. Drilling.
3. Completion.
4. Wireline.
5. Pumpdown.
6. Snubbing unit work.
7. Construction activities.
8. Surface preparation and painting.
9. Removal or installation of well head equipment.
10. Installation of conductor pipe.

Workover and drilling rigs, wireline and snubbing units, and construction equipment require considerable space. Layout arrangements for simultaneous operations should be considered during the planning stages to ensure that adequate space for these operations are incorporated in the original design. Once an acceptable process equipment arrangement is determined, various combinations of simultaneous operations can be overlaid to check that adequate space is available.

In conjunction with the major components of the drilling rigs, construction and remedial equipment, adequate space for consumables and support items, such as drilling crew's living quarters, welding machines, air compressors, generators, and mixing pits should be anticipated. Adequate crane aprons and "stacking areas" should be identified and noted on drawings.

5.2 WELLHEAD AREAS

The location of the wellhead area(s) on a structure is influenced by several factors. Wellheads should be located where they will be accessible to the drilling rig and remedial equipment, and where adequate structural support can be provided. Wellheads should be separated or protected from sources of ignition, other large inventories of fuel, machinery and dropped objects. Equipment and piping in, and adjacent to,

the wellhead area should be protected from the adverse effects of drilling and completion fluids.

The highest pressures encountered on an offshore platform will normally be associated with the wellheads. Uncontrolled flow from the wellheads can be very difficult to contain. Therefore, protection of the wellhead areas should receive high priority.

Wellhead areas should have adequate ventilation and should be separated from large inventories of fuel such as hydrocarbon or methanol storage tanks or pipeline risers. Long-term exposure to fire could seriously reduce the ability of the wellhead to contain pressure.

To provide for either fire fighting or personnel escape, wellhead areas should permit access to and egress from the wellheads on at least two sides of the wellhead area. Wellheads should be separated from living quarters by the maximum distance practicable.

5.3 UNFIRED PROCESS AREAS

Equipment located in this area may be a potential source of fuel and should be protected from ignition sources. Equipment should be located so as to provide adequate horizontal and vertical separation from other sources of fuel and ignition. Unfired process equipment should not be placed directly above or below ignition sources without special protection. Liquid leaks could fall on ignition sources located below the unfired process area, and gas leaks could be ignited by ignition sources above the area.

Unfired process equipment may be located adjacent to wellhead areas since equipment in both areas are potential sources of fuel and should contain no sources of ignition. The normal flow pattern is from the wellheads to the headers and manifolds, and then to the unfired process vessels. Placing these areas near one another should simplify interconnecting piping. Care should be taken in locating this equipment to protect against objects dropped in drilling and servicing operations.

5.4 HYDROCARBON STORAGE TANKS

Hydrocarbon storage tanks are potentially hazardous due to the inventory they contain. Hydrocarbon storage tanks should be separated from wellheads, pipeline risers and potential ignition sources, and should not be located directly under the control room or living quarters.

Precautions should be taken to prevent spilled hydrocarbon liquids from flowing into other production equipment and personnel areas.

Hydrocarbon storage tanks should be protected from crane loads and separated from machinery areas where movement of equipment or material could lead to accidental puncturing of the tanks.

5.5 FIRED PROCESS AREA

Equipment located in the fired process area can be considered a potential source of ignition, as some sources of fuel will be present. Fired process vessels should be remote or protected from any area that is a source of fuel, whether liquid, gas or vapor.

If fired vessels are located on the same structure with other process equipment, the potential ignition hazard should be lessened by installing the safety devices discussed in API RP 14C. In addition, the use of barrier walls to separate the fired equipment from sources of fuel should be considered.

5.6 MACHINERY AREAS

Machinery may be classified as potential ignition sources although some source of fuel may also be present. The machinery area should be remotely located or otherwise protected from other sources of fuel like wellheads, unfired process equipment, risers and hydrocarbon storage tanks.

Machinery, equipment that does not contain hydrocarbons and living quarters are similar in type and degree of hazard; all may be regarded as sources of ignition and, therefore, may be located in proximity to each other.

Machinery areas containing gas- or oil-fired engines will have sources of fuel and ignition in close proximity to one another - and therefore represent a higher risk of fire than unfired hydrocarbon processing equipment. Combustion engine driven hydrocarbon pumps or natural gas compressors represent an even higher risk of fire.

All combustion engine driven equipment should be adequately separated from wellheads, risers, hydrocarbon storage tanks and living quarters. If spatial limitations do not allow adequate separation, further isolation can be achieved by utilizing individual enclosures, enclosed rooms or buildings to house such machinery. Enclosing machinery reduces ventilation and allows combustible gases to accumulate. These enclosures should therefore be provided with fire and gas detection systems and should be adequately ventilated to dilute and remove hazardous vapors from enclosed spaces. Consideration should be given to the use of suitable fire suppression systems within these enclosures.

Consideration should also be given to providing enclosed machinery areas with positive differential air pressure to help prevent the migration of combustible gases into such areas where sources of ignition exist. Accordingly, ventilation systems should derive their intake air from uncontaminated sources to minimize the probability of ingesting contaminated air during either normal or abnormal operating conditions. Consult API RP 500 for ventilation recommendations.

In addition to the above precautions, further steps may be deemed necessary to provide adequate protection. These could include the use of gas detectors near the intake to the ventilation system and within the enclosure to be protected. Such enclosures may also be equipped with fire detectors and

systems to automatically shut down the engines and the ventilating system if a fire or high concentrations of combustible gases are detected. Also, automatically controlled dampers and shutters on the ventilating system supply and exhaust ports could further isolate this enclosed space by reducing the amount of air available to support combustion, or by preventing the ingestion of air contaminated by combustible gases.

Electric motor-driven hydrocarbon pumps and compressors may be installed in the process area if the electrical equipment components are suitable for the area classification per API RP 500.

5.7 LIVING QUARTERS AREA

The location of living quarters should take into account the direction of the prevailing winds so as to protect personnel from hydrocarbon vapors, external fires, explosions and noise. Consideration should be given to the possibility of external fires and explosions and noise from adjacent equipment.

Living quarters should be isolated from fuel sources to the greatest extent practicable, because they contain multiple sources of ignition. The potential for the entry of gas or smoke into the quarters should be minimized. In addition to smoke detection, the same general considerations for ventilation, gas detection and fire detection mentioned above for machinery areas also apply to living quarters.

Utilities such as electrical switching equipment, sewage treatment facilities, and air conditioning equipment may be located in the same area as the quarters, if the electrical equipment is suitable for the area classification as per API RP 500. Precautions should be taken to control noise and unpleasant odors so they do not cause unpleasant living conditions in the quarters.

5.8 PIPELINES AND RISERS

Riser areas may be potentially hazardous due to possible uncontrolled flows of hydrocarbons from incoming or departing pipelines in an emergency. Risers should be protected or separated from ignition sources, boats and falling objects. Risers should not be placed adjacent to or under living quarters unless appropriate mitigation methods have been implemented.

Pipelines, risers and related systems such as pig launchers, receivers and their valving components pose special design problems. These transportation system components are normally associated with large volumes of hydrocarbons at relatively high pressures. Their isolation from the various other platform components and protection from damage should be carefully considered early in the planning stages of the facility.

Once transportation agreements are confirmed and tie-in arrangements are decided between an operator and the transporter or buyer, plans should be made to review the pipeline

route and determine the impact of this route on the orientation and operation of the facilities in general. Pipeline routing should not interfere with access to the facilities by marine support equipment and mobile drilling equipment. The route chosen should minimize proximity of both the submerged portion of the pipeline and its riser system to logistical operations and unloading operations.

Once a route is agreed upon and a riser location determined, care should be taken to position the riser to protect it from environmental loading and marine vessels. Adequate horizontal and vertical support, as well as access at the splash zone, is important for inspection and operational needs. As a further precaution, riser guards may be installed to protect against mechanical damage.

Because of the large volumes normally associated with these systems, evaluations should be made to determine if shutdown valves are appropriate to provide protection to the facilities should damage occur to the pipelines, or to isolate these large hydrocarbon inventories should damage occur to the facilities. Both departing and boarding field gathering and transportation lines need to be evaluated to determine if conventional flow safety valves (i.e., check valves, or shutdown valves) are appropriate.

Pig launcher and receiver devices require significant space for access and maintenance. For large diameter lines, handling equipment for pigs may be required. Launchers normally require less physical space than receivers and may be placed in the vertical position to conserve platform space and allow for gravity assistance in inserting pigs. Adequate lateral and vertical space for maintenance and use is necessary as lines may require frequent pigging to prevent slug flow, remove paraffinic deposits, etc.

Launcher and receiver areas should be located away from potential ignition sources, highly traveled personnel routes, and material handling areas such as crane aprons or overhead storage racks to the extent practicable. Launcher or receiver doors should face outboard of the platform to minimize the possibility of any projectiles hitting personnel or other equipment.

Automatic shutdown valves on incoming risers should be located close to the point where the risers come on to the platform. Consideration should be given to protecting the shutdown valve and upstream valves and piping from the effects of long-term exposure to fire. Similarly, check valves or shutdown valves on departing risers should be located as close as possible to the point where the riser departs the platform, and the piping downstream of the check valve should also be protected from long-term exposure to fire.

Shutdown valves should be accessible for service or testing, yet isolated from potential hazards. The area of the platform between the splash zone elevation and the lower process deck elevation has proven effective for the location of shut-

down valves. The area should be chosen carefully to both isolate the piping and provide access for inspection and maintenance of isolation valves, instrumentation and shutdown valves, as applicable.

Protection of riser valves from explosive blast pressures or falling debris generated in a fire should be considered. Care should be taken to eliminate features such as drip pans or access platforms where liquid hydrocarbons can accumulate near or under riser valves. These hazards could jeopardize the integrity of the riser system.

5.9 FLARES AND VENTS

The normal and abnormal releases of process vapors are collected and directed to safe locations by way of a facility's gas disposal systems. Both emergency relief and routine releases from a pressurized component or tank vent 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 directing the release 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 will usually allow liquid removal prior to final discharge of the vapors.

Flares are a source of ignition and are generally cantilevered off the main platform or located on a separate structure. In some cases a vertical flare tower on the main platform is used.

The permissible distance from the flare tip to various locations on the platform is determined from radiant heat calculations, or, if the flare has been extinguished, from gas dispersion calculations.

Procedures for performing these calculations are contained in API RP 521. All wind velocities and directions should be considered in the design.

Flares should be designed to minimize the possibility that liquid carryover will fall on the platform or on boats or barges. Liquid knock-out drums should be installed if liquid carryover can be expected.

Hydrocarbon vents are a source of fuel. They may be located either on the main platform or on a separate structure. The minimum distance from the vent tip to potential sources of ignition is determined by dispersion calculations. It is also necessary to check radiant heat for flares, in case the vent is accidentally ignited. This latter calculation may control the location of the vent tip.

In most cases, the final discharge of a gas disposal system (gas outlet) should be an upward vertical or cantilevered pipe. The final discharge point should be located where the gas can be burned safely, or where it can be diluted with air to below the lower flammable limit (LFL) before reaching sources of

ignition. The following should be considered in selecting a safe discharge point:

1. Personnel safety.
2. The discharge volume and toxicity.
3. The location in relation to other equipment, particularly fired vessels or other ignition sources, personnel quarters, fresh-air intake systems, helicopter and boat approaches, drilling derricks, other elevated structures and down wind platforms.
4. Prevailing wind direction.

Vents should be designed so that accidental liquid carry-over will not fall on hot surfaces or personnel areas.

Local venting of non-process and low-volume sources (e.g., storage tank vents, surge tank vents, etc.) is acceptable provided that items 1 through 4 above are considered in the location of the discharge point.

5.10 PRACTICAL LIMITATIONS

Appendix B gives examples of equipment arrangement. These arrangements shown possible variations in accordance with this RP and indicate the trade-offs which must be made when these concepts are applied to practical problems. Other arrangements which satisfy this RP are also acceptable.

6 Documentation

6.1 GENERAL

The amount of documentation required for the safe design and operation of an offshore production facility depends upon the type of facility and the purpose for the information. Different levels of documentation may be required for developing operating procedures and for training personnel than for design or hazards analysis. Information necessary for one purpose (e.g., design) may be helpful for another purpose (e.g., hazards analysis)—but may not be *necessary* to develop and maintain if such information is not readily available.

The purpose of this section is fourfold: to outline the minimum documentation which should be maintained in accordance with the safety and environmental information requirements of API RP 75, to outline what additional information may be considered for performing a hazards analysis; to provide guidelines for design documentation that should be considered for new designs; and to provide guidelines for developing operating procedures.

6.2 SAFETY AND ENVIRONMENTAL INFORMATION

API RP 75 requires that certain safety and environmental information be developed and maintained for all facilities. The purpose of this information is to provide the basis for

hazards analysis, for developing operating procedures, for training personnel and for implementing the other program elements in a safety and environmental management program.

The following minimum safety and environmental information should be maintained: a simplified process and instrument diagram (P&ID), process design information, relief valve sizing information, process safety information, layout drawings, fire protection and safety equipment information, hazards analysis information, and material safety data, as discussed below. The operator may elect to develop and maintain additional documentation. However, to meet the recommendations of API RP 75, it is not necessary that this additional documentation be maintained to reflect the condition of the facility or that it be readily available.

6.2.1 Simplified (P&ID) Process and Instrument Drawing

The simplified P&ID should show equipment and interconnecting lines including relief, vent and drain systems. It should include all control valves and controllers, manual valves, check valves, relief valves and safety shutdown sensors. Set points of relief valves, maximum allowable pressure ratings of equipment and pressure ratings of piping systems should also be shown.

It is not necessary to show utility systems, details of instrument hookup, line numbers, valve types, individual instrument tag numbers or other such information.

6.2.2 Process Design Information

Process design information should include design flow rates, fluid properties, pressures and temperatures used to size the different subsystems or individual pieces of equipment. This can be done in a separate process flow diagram, as notes on the simplified P&ID, or in a separate narrative.

Because of the widely varying flow conditions to which production facilities could be subjected, it is not necessary to have a detailed material balance. The intent of the design flow data is to document the information required to adequately size relief valves and other critical components for the most critical service from a safety standpoint.

Often, detailed information on the composition of the fluid is not available. The fluid properties can be approximated with sufficient accuracy from an estimate of the specific gravity. However, acid gas concentrations which could affect material selection or endanger personnel should be indicated.

6.2.3 Relief Valve Sizing Information

Relief valve information should include valve characteristics and the basis for sizing. This could be included in a separate form, as notes on the simplified P&ID, as part of hazards analysis report, or in any other manner deemed appropriate by the operator. Refer to Section 3.3.10.

6.2.4 Process Safety Information

Process safety information should include an API RP 14C SAFE Chart. All safety devices listed in the SAFE Chart should be shown on the simplified P&ID.

6.2.5 Layout Information

Layout drawing or drawings should show the location of all major process, utility and life support equipment, quarters, risers, escape paths, evacuation equipment, and fire and blast walls. Areas of electrical classification should be shown.

6.2.6 Fire Protection and Safety Equipment Information

Drawing(s) should show the locations of the fire-fighting equipment and other safety equipment, such as ESD (Emergency Shutdown) stations and fire and gas detectors. The locations of equipment such as fire extinguishers, firewater pumps, deluge areas, hose reels, monitors, life jacket boxes, ring buoys, life rafts, and escape devices should be shown if they are provided on the facility.

6.2.7 Hazards Analysis

A summary of any hazards analysis performed on the facility should be maintained, describing the method employed, potential problems identified and the final resolution of these problems. It is not necessary to maintain all working documents, back-up calculations, etc., used in the hazards analysis.

6.2.8 Material Safety Data

Safety data should be maintained for chemicals used in the facility. This data should include: toxicity information, permissible exposure limits, reactivity and corrosivity information, thermal and chemical stability, and measures to be taken if physical contact or airborne exposure occurs. Material Safety Data Sheets (MSDS) forms provide the necessary information.

6.3 DOCUMENTATION FOR HAZARDS ANALYSIS

The minimum safety and environmental information of Section 6.2 forms the basis of any hazards analysis. Additional information may have to be developed to perform the analysis, to answer specific questions raised by the analysis, or to evaluate potential mitigation scenarios indicated by the analysis. The type of documentation required depends on the specific analysis technique employed and on the specific risk assessments and mitigations that are to be evaluated.

Appendix A contains two example checklists which require different minimum documentation. Additional documentation may be required to perform risk assessment and mitigation analyses. The documentation required for analysis

is useful information which could minimize future work under the management of change and audit requirements of API RP 75. The operator may wish to keep this information readily available, and update it periodically.

6.4 DESIGN DOCUMENTATION FOR NEW FACILITIES

In addition to the recommendations in Sections 6.2 and 6.3 above, the design of a new facility should be clearly documented to provide a record of the design parameters, calculation methods, codes and standards used. The documentation should include the basis for the facility design, as well as the corresponding component sizing calculations and drawings. Vendor information for equipment and components should be included. The record of any hazards analysis done on the facility should also be included in this documentation.

There is no requirement that this information be kept up-to-date and readily available (other than as discussed in Section 6.2); however, this information will save considerable time and effort if it is later necessary to perform a hazards analysis, in order to manage change, or to perform an audit of the safety and environmental management system. This documentation may not be available for existing facilities, and it may not be necessary to recreate it to perform a hazards analysis.

6.4.1 Design Basis

In developing the design basis for new facilities the following should be considered:

1. Design flow rates of oil, water and gas form the basis of the design requirements for a facility. Nominal rates of anticipated production are normally estimates based on reservoir study and comparison to similar fields.
2. The physical characteristics and properties of the oil, water and gas may have to be obtained from records of prior production of similar reservoirs. These physical characteristics and properties may be as critical as the nominal rates and in some cases influence design parameters more than the rates themselves. This is especially true for high-pour point crudes, viscous crudes and acid gases.
3. Expected flowing and shut-in pressures and temperatures from the wellhead will have to be estimated, based on well test information and/or prior operating experience.
4. The platform control philosophy (human intervention in a manual facility or remote electronic/pneumatic intervention for an unmanned facility) needs to be established and will form the basis of the control system that will be used. Questions concerning electronic versus pneumatic and local versus remote operation need to be addressed and fit into the operating philosophy chosen by the production personnel.

5. The platform shut down and hazard mitigation philosophy (shut-down hierarchy, depressurization, passive fire protection and active fire mitigation) needs to be established.
6. Proposed sales agreement requirements need to be reviewed, such as maximum water content and vapor pressure of the hydrocarbon liquids and, for gas, acceptable heating value, dew point, maximum temperature and minimum pressure. Regulatory requirements for water disposal should also be reviewed.
7. Environmental design conditions need to be identified and documented, as dictated by the geographic area or regulatory restrictions imposed by either internal company policy or government agencies having jurisdiction. Severe weather design requirements (such as extreme heat or cold and hurricanes) may impose facility constraints that affect areas of design.
8. Utility system requirements for electricity, communications, fuel, chemicals, instrument air and water should be established.
9. Accommodations requirements should be established. These will depend not only on the number of operating personnel, but also on the number and type of support personnel required. Existing infrastructure, vessel support and frequency of re-supply should be considered.
10. The storage and operating space necessary for consumables used in the operation of the facility should be established. This requirement will be determined by the supply frequency for consumables such as food, fuel and lube oil, which will normally be dictated by the remoteness of the location, available infrastructure, weather and other demands on the existing transportation network. These conditions will determine the storage and operating space necessary for the consumables used in the operations of the facility.
11. Plans should consider providing adequate space or capacity for future expansion. As an example, the production of "oil rims" in initial phases of a gas reservoir could lead to the "blow down" of the gas caps of an oil reservoir later in the production life of the facility.
12. The need for future drilling and remedial well work capability should be considered.

6.4.2 Supporting Calculations

The various components and piping systems that may be found on offshore facilities can be sized using many different methods and philosophies. It may be beneficial to maintain the design criteria and sizing calculations for the processing and safety components of new facilities. This information is often useful for future modifications and for performing hazards analysis.

Supporting calculations for the emergency relief systems should be retained. Supporting calculations which were developed for any other equipment such as wellhead flowlines, headers, pressure vessels, atmospheric vessels or tanks, heat exchangers, pumps, compressors, pipeline, process piping, control valves, fire-fighting system, instrumentation and control system, and electrical system may also be useful.

6.4.3 Drawings

The documentation should include process flow diagrams (PFDs), process and instrument diagrams (P&IDs), SAFE Chart, equipment layouts, and electrical area classification drawings. The design documentation should be cross referenced with the drawings so that the various process, safety and fire-fighting components can be identified.

A process flow diagram should show, at a minimum, major process equipment, their interconnecting lines and how major process variables (e.g., pressure, level, and temperature) are controlled. The basis for sizing the equipment should be indicated. It is not necessary to show utility systems and instrument details.

Detailed P&IDs should show equipment and interconnecting lines, including relief, vent and drain systems. These drawings should include all control valves and controllers, manual valves, check valves, pressure relief valves and safety shutdown sensors. Set points of pressure relief valves and maximum allowable pressure ratings of piping systems should also be shown. Utility systems, line numbers, valve types and individual instrument tag numbers should be indicated. Details of instrument hook-up are often shown on other drawings.

A SAFE Chart, as recommended by API RP 14C, should be prepared and should reflect current information. Shut-in sensors and shutdown valves listed in the SAFE Chart should be shown on the P&ID. Cause and effect charts, logic diagrams, and other drawings are sometimes helpful.

Equipment arrangement drawings should show the location of all major equipment, escape paths, evacuation equipment, and any fire and barrier walls. These drawings should also indicate the area classification of all areas of the platform. On more complex platforms, it may be desirable to have several layout drawings and to identify area classification on a separate set of drawings. The location of quarters, heliports, boat landings, cranes, risers, wellheads, and flare and vent discharge points should be shown.

A drawing showing the location of the fire fighting equipment should be developed, and it can be expanded to include other safety equipment such as ESD stations, fusible plug loops, smoke detectors, and fire and gas detection systems. The fire-fighting equipment drawings should show the location of firewater systems, including deluge areas, hose reels, monitors, and foam stations. The location of fire extinguishers and automatic chemical units should be indicated.

6.4.4 Vendor Supplied Information

Operating procedures written for each facility should be supplemented with the operating and maintenance instructions furnished by equipment vendors or manufacturers. These should include maintenance procedures and materials and spare parts lists, especially for equipment critical to safety. In order to give operators a complete understanding of the facility and aid in overall maintenance and troubleshooting, the vendor information should include final drawings (including internals) and material lists for fabricated equipment (pressure vessels, tanks, heat exchangers, etc.).

6.5 PRE-START-UP REVIEW

Prior to the initial start-up of a new facility, or after a modification of an existing facility as defined under "Management of Change" in API RP 75, certain items should be completed to prepare the facility for safe operation. The following is a list of general areas that should be reviewed:

1. Necessary hazards analysis recommendations have been included in the facilities.
2. Construction has been completed according to design specification. Equipment commissioned in accordance with the manufacturer's recommendations.
3. Piping is routed and valved according to the P&IDs.
4. Nondestructive testing requirements have been completed.
5. All protective shipping brackets and packing have been removed from controllers, instruments and other equipment.
6. Pre-service recommended by vendors has been performed.
7. All safety and control devices are set and operate properly (API 14C Appendix D outlines the proper testing of safety devices).
8. Actual device function tests are performed, and control and safety system logic match the design requirements.
9. Utility, fire-fighting and personnel safety equipment are functional.
10. Maintenance procedures are in place.
11. Written start-up, operating and shutdown procedures are in place, and personnel are trained.
12. Emergency response and evacuation procedures are in place, and personnel are trained.

6.6 OPERATING PROCEDURES

Operating procedures should be written, addressing activities for safe start-up, normal operations, and shutdown. Procedures should include administrative controls to assure the safe and environmentally sound operation of the facility.

6.6.1 Start-up Procedures

The procedures for start-up should include the sequence of events required to bring the various components up to their intended operating conditions in a safe and orderly manner. Vendor information concerning start-up of components should be included in the procedure. As a minimum, the following items should be covered in start-up procedures:

1. To the extent possible, both safety and control systems and relief and vent systems should be in service before hydrocarbons are brought into the facility.
2. Systems should be flushed to remove debris in piping, as needed, and purged to avoid explosive mixtures. Flushing is normally done using water; it is required to remove welding slag and other trash particles that can clog filters, prevent control valves from properly seating, or severely damage rotating equipment. Some special components such as high speed turbine compressors or critical fuel systems may require a gas or diesel flush. Purging can be accomplished by continual gas purge or by displacement of the system with an inert medium such as nitrogen or water. The object is to remove oxygen from the system prior to pressurization and start-up.
3. Vessels should be internally inspected for debris and loose internals, then closed and filled, where possible, with the proper amounts of water or process fluids to enable initial level controller settings. Some three-phase components (such as separators or skimmers) require a water "prime" to avoid being inadvertently filled with oil and causing problems downstream.
4. Pressurization of components should be done in stages, and the system should be checked for leaks at incremental pressures. Gas and oil leaks can develop even after hydrotesting due to vibration, viscosity and temperature differences.
5. Lighting of fired components should be done only after the unit is purged (to avoid backfire) and in strict adherence to the manufacturers instructions. All safety devices should be functional, and the fluid level should cover the fire tube.
6. Starting of rotating equipment should be done only after the pre-service recommended by the vendor has been completed. This may include checking for proper rotation and alignment, flushing and filling with fluids and checking the lubrication system. Manufacturer's literature should be reviewed to avoid equipment damage or personnel injury.
7. Loading sequence for compressors is often automated and controlled by the unit's panel board. This sequence would normally consist of opening the loading valve, possibly through a smaller restricted flow orifice, opening the discharge valve, and closing the blowdown valve. The

start-up and loading procedure, including pre-lube, should be posted on the unit's panel board.

8. Proper warm-up of heated items should be done according to the vendors recommendations and under the close watch of operators. Gradual warm-ups minimize differential thermal stresses in the component and piping. Monitoring will allow for early detection of leaks caused by thermal expansion.

9. The proper sequence of start-up of the various components on a facility should be predetermined and communicated to all personnel involved. A final check should be made that all valves are in their proper open or closed position. The flow path will govern this sequence to an extent, but the communication of the planned flow and disposition of the initial hydrocarbons through the facility is essential to a safe and orderly start-up.

6.6.2 Normal Operating Procedures

The procedures for normal operations should include the proper process parameters and their tolerances. The design conditions and safety device set points should be listed for the various process components so that operations personnel will have a clear understanding of the normal operating conditions and their maximum safe range.

Procedures for adjustments, testing, inspection, and routine maintenance should be included, including those recommended by vendors. Each component should have the important operating parameters (such as pressure, temperature, flowrate, level, speed, or other parameters) clearly defined so that the operators are aware of what should be monitored.

The expected causes and results of each process parameter going out of range may also be identified in order to assist operators in determining and solving process upsets. Correct response procedures to out of range alarms or shutdowns should be included.

6.6.3 Shutdown Procedures

The written shutdown procedures should include both emergency and routine procedures to stop operations safely. The emergency shutdown procedures should outline the sequence of events that will happen if the facility's automatic system is activated. This should identify the closing of automatic valves, stopping of rotating equipment, and whether vessels are depressurized. The failure mode of control valves as well as any equipment left in operation should be identified.

The normal shutdown procedures should outline the sequence of events to perform the same items as listed above manually or under the control of operators. These procedures should cover the draining, flushing and depressuring of the various process components. Any required cooling, lubrication or post-operational procedures recommended by vendors of specific components should be included.

7 Hazards Analysis

7.1 GENERAL

Hazards analysis is a systematic procedure for identifying, evaluating and controlling potential hazards in a facility. A hazards analysis program should be applied to all phases of the life of a facility from project inception through abandonment to assess potential hazards during design, construction and operation. A thorough and accurate assessment of the potential hazards in a facility will minimize the risk of personnel injuries, loss of equipment, and damage to the environment.

A hazards analysis alone does not ensure that an adequate level of safety is provided for a facility. It is only a part of an overall safety management system. Other areas that must be addressed include operating procedures, safe work practices, training and emergency response. Refer to API RP 75 for a description of how hazards analysis fits in the safety management system.

The following sections describe the principal elements of hazards analysis and the various methods available, discuss review procedures to be followed, and outline the guidelines for selection of an appropriate method.

The minimum acceptable hazards analysis for offshore production facilities should provide a check for compliance with standard practice. The use of checklists is the normal method for reviewing for compliance with standard practice. Example checklists for hazards analysis of offshore production facilities are provided in Appendix A. Drilling, well servicing and construction equipment and activities are not covered.

7.2 INTRODUCTION

Most of the literature on hazards analysis has been developed for use by the chemical and petrochemical industries because of their potential for catastrophic events. In most cases, these plants house complex processes that frequently involve new configurations, new feed stocks and products, and untried operating conditions. Also, the plants frequently deal with toxic, reactive, unstable and explosive materials that could present an extreme hazard to plant personnel, the environment and the public.

The general direction of hazards analysis has been towards procedures identifying unforeseen hazards associated with the process (i.e., reactions, corrosion, decomposition and failure of controls) and procedures for detailed evaluation and assessment of the risk associated with the hazard. Most of these techniques are complex, time consuming and expensive, but they are justified by the degree of hazard and the consequences of accidents.

In determining appropriate hazards analysis methods, it is important to consider the differences between these complex industrial plants and a typical production facility. Compared

to other industrial plants, production facilities are generally simple, standard processes with a vast amount of operating experience and a relatively low inherent risk. This risk is dependent, to some extent, on location and environment. All hazards analysis procedures apply to production facilities; however, the direction and level of effort devoted to hazards analysis should be relative to the inherent risk. In general, the more sophisticated techniques for hazards analysis will be the exception rather than the rule for production facilities.

Hazards analysis alone does not ensure a safe operation. For most accidents on offshore production facilities, unsafe work practices, poor operating procedures, poor management of change and poor maintenance and testing have been contributing factors. These areas must be addressed through safety management systems before a hazards analysis will be of much benefit.

7.3 APPLICATION

Hazards analysis is applicable to all phases in the life cycle of a facility: from project inception through design, construction, operation and abandonment. It is important to identify hazards as early as possible; time is needed for adequate study and evaluation before determining the most appropriate solutions to identified hazards. It is relatively easy and inexpensive to make modifications early in the design stage of a project, when changes can be incorporated with minimal effect on cost or schedule.

Hazards analysis can also be applied to existing facilities; however, modifications are more difficult and expensive than during design. In some cases, changes that are justified during design may not be practical for an existing facility. As an example, improvements in layout concepts are not practical for existing facilities. In fact, the act of making a modification to an existing facility introduces an additional risk of an accident.

The following is a list of hazards analysis activities associated with phases in the life cycle of a facility:

1. Project Inception

- Develop hazard criteria.
- Examine for inherent hazards.
- Identify additional study or research.
- Risk comparison of alternative development concepts.
- Identify major safety requirements.
- Identify and schedule future safety activities.

2. Preliminary Design

- Safety considerations in trade-off studies.
- Design requirements and standards.
- Define safety systems (e.g., fire and gas).
- Preliminary hazards analysis.

3. Detailed Design

- Formal hazards analysis.
- Address future change orders.
- Develop start-up and commissioning procedure.
- Develop hand over procedure.
- Develop safety information package.

4. Pre-Start-up

- Audit for compliance with codes and standards.
- Confirm facility built as designed.
- Verify all hazard review recommendations are resolved.
- Audit for adequacy of:
 - Start-up and commissioning procedures.
 - Operating, maintenance and testing procedures.
 - Operator training.
 - Pre-start-up checks and equipment testing.

5. Operation

- Periodic hazards analysis.
- Management of change.
- Periodic audit and update of policy and procedures.
- Incident investigations and statistics.

7.4 HAZARDS ANALYSIS CONCEPTS

There are two fundamental steps associated with a hazards analysis of any process. The first step is *hazard control* through compliance with standard practice. The second step is *predictive hazard evaluation*, which is required for processes without sufficient previous experience or that present an unusually high risk. The guidelines for selection of one of the methods for hazards analysis are presented in Section 7.7 based on this concept.

7.4.1 Compliance with Standard Practice

The experience gained by industry in the design and operation of process plants, including offshore structures, has been compiled in a series of standard procedures, recommended practices, company standards, and regulatory requirements that represent good practice. These documents incorporate the lessons learned from previous designs and hazards analyses, and accident and incident investigations.

These standard practices have a “built-in” hazards analysis since the inherent hazards have already been identified and the standard methods for control of the hazards have been defined. A high level of safety can be achieved by checking for compliance with these standard practices in design, construction, operation and maintenance.

Once a process has been thoroughly evaluated, the hazards are identified, and the controls are defined. Then subsequent

similar processes can be analyzed by checking that the standard controls are installed.

A good example of safety through standard practice is given by API RP 14C, *Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms*. This document was prepared by first analyzing the basic hazards inherent in production facilities and defining the standard measures to control the hazards.

For example, the hazards associated with production headers have been identified from previous analysis as over pressure and leak. API RP 14C presents guidelines for protective devices for these hazards including pressure pilots and pressure relief valves to protect against these hazards. Thus, checking for compliance with these guidelines indirectly provides a hazards analysis and eliminates the need for a separate analysis to identify and evaluate hazards.

The normal method for hazards analysis by compliance with standard practice is using checklists. The checklists help determine that design standards and practices are met and that previously recognized hazards are properly addressed. They are quick and easy to use and are very effective for control of common hazards. However, checklists do not provide a creative format for identifying or evaluating new hazards where previous experience is lacking.

7.4.2 Predictive Hazards Analysis

Predictive hazards analysis is an additional step designed to analyze new or significantly different materials, equipment, processes or procedures where compliance with standard practice may not be sufficient. Predictive hazards analysis is used to identify and evaluate previously unforeseen hazards and unintended events that could lead to an accident.

Predictive hazards analysis can be viewed as a series of steps to minimize the inherent risk of a facility by reducing the probability and consequences of accidents. The natural order of steps are:

1. Identification of potential hazards.
2. Consideration of risk acceptability.
3. Elimination or mitigation of the hazards.

The results of each step of the process will assist in determining whether the risk is acceptable or whether the hazards analysis should continue.

The first step, and by far the most important, is to identify the types of hazards that are likely to exist based upon the physical and chemical properties of the fluids being handled, equipment arrangement, operating and maintenance procedures and the processing conditions.

The second step is to evaluate the risk that an identified hazard presents to personnel, the facility and the environment. This normally includes identifying initiating events,

identifying the accident sequence, estimating the probability of the accident event sequence and the magnitude of the consequences, and judging the acceptability of the risk.

The final step is to eliminate or mitigate hazards where the risk is determined to be unacceptable. This consists of identifying opportunities to reduce the probability and/or consequence of the accident. Examples of methods of risk reduction include:

- a. Changing the process or mechanical design.
- b. Additional hazard detection and protection systems.
- c. Improvements in equipment layout.
- d. Depressuring systems.
- e. Improved impoundment systems.
- f. Decreased population counts.
- g. Increased inspection and testing frequencies.
- h. Increased audit frequency.

7.4.3 Application to Offshore Operations

Standard design practices evolve with time, based on prior hazard analysis and review of incidents and near misses. Therefore, the basic approach to hazards analysis for offshore facilities should be compliance with standard practice. The hazards inherent in these facilities are well known, and the consequences of accidents are generally much less severe than other industries.

The potential hazards that are associated with an offshore oil and gas facility arise from the fluids being produced, processing systems (particularly systems such as LPG recovery or gas treating), limited space, and procedures used for operating and maintaining the facilities.

For production facilities:

- a. The basic hazards are flammable and toxic materials, such as H₂S.
- b. The initiating event is loss of containment.
- c. The consequences are fires, explosions, personnel injury and pollution.
- d. The mitigation steps are relief and drain systems, fire and gas detection and protection systems, emergency shutdown systems, and emergency response procedures.

The recommended approach to hazards analysis on offshore facilities is to concentrate on the areas that present the greatest risk. For low risk facilities, such as unmanned well-head platforms with minimal processing equipment, the review should concentrate on checking that the facility will shut-in upon detection of unsafe conditions. For moderate risk facilities, such as unmanned production and processing platforms, the review should additionally concentrate on mitigation of an accidental release. This should include fire and gas detection/protection and ignition prevention.

For facilities that present the highest risk, such as production or processing platforms with living quarters, the review should additionally concentrate on the effects of an uncontrolled release on personnel. This should include layout, fire or explosion effects, escape and rescue, and emergency response.

Guidelines for selecting a hazards analysis method for offshore production facilities are provided in Section 7.7.

7.5 HAZARDS ANALYSIS METHODS

7.5.1 Checklist

A checklist is commonly used to verify compliance with minimal standards and to identify areas that require further evaluation. A checklist is easy to use and can be used during any stage of a project life cycle (design, construction, start-up, operation, and shutdown). A checklist is a convenient means of communicating the minimal acceptable level of hazard evaluation that is required for any job.

The checklist is prepared by experienced personnel familiar with the design and operation of the facilities and with company and industry standards and procedures. Once the checklist has been prepared, it can then be applied by less experienced personnel. Checklists are limited by the experience of the authors and diligence of the users. Checklists should be audited and updated regularly to incorporate new experience by the company and industry, including the results of accident and incident investigations.

A checklist can be as detailed as necessary to satisfy the specific situation, and it should be applied conscientiously in order to evaluate whether standard procedures are being followed and to identify problems that require further attention. A checklist is generally the quickest and easiest method of hazards analysis and is very effective for control of standard hazards.

Checklists provide a guide to the evaluator of items to be considered in performing the hazards evaluation. The actual procedure by which these items are considered and the manner in which it is documented that they have been considered can vary widely and are at the discretion of the operator. Appendix A contains two example checklists. These checklists should be modified to reflect the operator's standards, philosophy and experience.

7.5.2 "What If" Analysis

The "what if" procedure is an unstructured method for considering the results of unexpected events that could lead to an undesirable result. This method uses questions that begin with "what if..." For example, consider a condensate barge loading operation:

1. What if the loading pump fails to shut down?
2. What if the shutdown valve fails to close?

3. What if the high-level alarm on the barge fails?
4. What if barge personnel ignore the high-level alarm?
5. What if the barge drifts off location while loading?

This method is not overly concerned with how the "what if" situation develops. For example, above it is postulated that the barge high-level alarm can fail, but its exact mode of failure is not important to this analysis. The analysis team should be careful not to become unrealistic and begin postulating unlikely scenarios. Questions should be realistic and be seriously investigated. The questions should be based on the previous experience of the analysis team and will vary for each process system. The analysis is only as good as the analysis team is experienced.

The "what if" analysis can be applied to the design, modification or operation phase of an offshore facility. Data utilized may include process flow diagrams, P&IDs, layout drawing and operating procedures. The result is a list of problem areas that potentially lead to accidents and suggested methods/changes for preventing or mitigating the accidents.

Frequently the "what if" analysis is combined with the checklist technique. This is referred to as the "what if—checklist" method.

7.5.3 Hazard and Operability (HAZOP) Study

The HAZOP technique was developed to identify hazards in all types of process/plants/ facilities, including offshore platform facilities, and to identify problem areas regarding the operability of the facility.

A HAZOP study uses a multi-disciplinary team that works together to identify hazards and operability problems using a formal, structured form of the "what if" analysis. The team leader should be experienced in the HAZOP technique in order to guide the team through the analysis with "guide words" and "process parameters." The team normally consists of five to seven engineering, operations, and health, safety, and environmental staff depending on the size and complexity of the facility. The team members should be very knowledgeable about the process, equipment and operations.

The guide words and process parameters are applied at "study nodes" (i.e., specific lines or locations) in the facility to identify potential problems at those nodes. For example, the guide word "high" combined with the process parameter "level" results in questions concerning possible "high level" deviations from design intent. The team analyzes the effects of any deviations at the point in question (study node) and determines possible causes for the deviation (e.g., operator inadvertently opens valve and barge overflows into the water). If the causes, probabilities and consequences are realistic and significant, they are recorded so that further actions can be taken outside the HAZOP study.

This method can be used during design, modification or operation of a facility. It is particularly useful during the

detailed design phase, after P&IDs are complete. It produces a list of problem areas that could lead to potential hazards or operability problems, and a list of recommended changes, suggestions or actions to improve safety or operability. Requirements include a complete set of process flow diagrams, P&IDs, plot plans, equipment layouts and operating procedures.

Time requirements and effectiveness are directly related to the size and complexity of the facility and the experience of the team. Generally, HAZOP is a time consuming method.

7.5.4 Failure Modes and Effects Analysis (FMEA)

FMEA is a tabulation of facility equipment items, their potential failure modes, and the effects of these failures on the equipment or facility. The *failure mode* is simply a description of what caused the equipment to fail. The *effect* is the accident, consequence or system response to the failure.

The FMEA identifies single failure modes that can cause or contribute to the cause of an accident. The FMEA is not useful for identifying combinations of failures that can lead to accidents. The FMEA may be used in conjunction with other hazard identification techniques such as HAZOP for special investigations such as critical or complex instrumentation systems.

The purpose of a FMEA is to identify equipment failure modes and the effect of each failure mode on the process system. In the design phase, FMEA can be used to identify the need for additional protective systems or redundancy. During facility modifications, FMEA can be used to identify the effects of field modifications to existing equipment. The FMEA is also useful during operation to identify single failures that could result in significant accidents. Because FMEAs are subjective, the technique requires at least two analysts who are familiar with the process and the equipment. The analysts may change from one section of a facility to another.

A “failure modes, effects, and criticality analysis” (FMECA) is the same as an FMEA except that the relative ranking (criticality) of each failure mode is included in the analysis.

7.5.5 Fault Tree Analysis (FTA)

FTA is a deductive technique that focuses on one particular accident event, often called a top event, and then constructs a logic diagram of all conceivable event sequences (both mechanical and human) which could lead to that accident event. The fault tree is a graphic illustration of various combinations of equipment faults, failures and human errors that could result in an accident.

As a qualitative tool, FTA is useful because it breaks an accident down into the basic failures and errors that could cause an accident. It also allows the analyst to determine the effect of changing or adding components to a system; e.g.,

supplying redundant, independent high-level alarms or shut-downs.

The FTA can be used during design, modification or operation of a facility. It can be especially useful in analyzing new or novel processes for which there is no operating history. The procedure results in a set of logic diagrams that illustrates how certain combinations of failures and/or errors can result in specific accidents. The results of a FTA are qualitative, but can be made quantitative if failure rate data are available for the failure events. Data requirements for FTA include P&IDs, equipment drawings and specifications, operating procedures, knowledge of failure modes, and, where applicable, failure rate data. Normally, one person is assigned to prepare a single fault tree for a given accident. This person should have a thorough knowledge of the facility processes. The preparation of fault trees can be very time consuming for large or complex facilities.

7.5.6 Other Methods

There are many other hazards analysis methods available and in use by industry. They include methods such as Event Tree Analysis, Cause Consequence Analysis, and Human Error Analysis. They vary in purpose, nature of results, manpower requirements, and time and cost requirements. For more in-depth study of other hazard evaluation procedures refer to “Guidelines for Hazard Evaluation Procedures” by the Center for Chemical Process Safety (CCPS).

7.6 REVIEW PROCEDURES

7.6.1 Organization

A hazards analysis is normally performed by a team, but it can be performed by an individual for simple facilities. The team or individual should be person(s) knowledgeable in engineering, operations, design, process and other specialties deemed appropriate. The effectiveness of a hazards analysis depends on the skills, knowledge and efforts of the analysis personnel. At least one person on the team should be intimately familiar with the hazard evaluation procedure being employed. The size and the complexity of the facility should dictate the experience base and number of team members. For example, a large multi-well processing facility will require more team experience and members than a single-well facility. If only one person is employed in the evaluation, that person should not have participated in the original design of the facility and should be qualified per API RP 75.

7.6.2 Hazards Analysis

Once the hazards analysis team has identified the hazards, it should evaluate them in terms of the risk they present to personnel, environment and the facility. It is important to consider a wide range of possible solutions to identified hazards

and not to expect that every hazard must be controlled by an alteration in physical design.

The hazards analysis team should make recommendations to management for mitigating hazards. In most cases, mitigation of the hazards is simple or obvious and involve modifications to comply with standard practice. Recommendations are based on the team's own qualitative risk assessment. For more significant items, the team may recommend further investigation or quantitative risk assessment by some other group. Risk assessment considers both probability and consequence.

7.6.3 Documentation

A written hazards analysis report should be prepared. The report should identify the hazards procedure utilized; identify the potential hazards; describe any risk assessments; and include recommendations for application of appropriate safeguards, alternatives or corrective actions as may be necessary for risk mitigation. Management should establish a system to address the report's findings and recommendations, document the actions taken, and communicate the findings and recommendations to appropriate personnel.

7.6.4 Corrective Action

Implementing recommendations and preparing follow-up documentation are normally not the responsibility of the hazards analysis team. However, it is not unusual for members of the evaluation team to be consulted and even to participate in this step.

7.7 GUIDELINES FOR SELECTING AN ANALYSIS METHOD

There are numerous methods available for conducting hazards analysis on operating facilities or new projects. The different methods have various applications and benefits, and they require different levels of effort and resources. Selecting an appropriate method depends on the level of risk inherent in the facility. Examples of factors that influence the risk include size and complexity of the facility, types of hazards, personnel exposure and proximity to environmentally sensitive areas.

A hazards analysis that checks for compliance with standard practice is the minimum requirement for review of offshore facilities. In general, the checklist method provides this minimum level of review for most offshore facilities. In addition, past incidents and near misses at existing facilities should be reviewed.

The following guidelines should be used for selecting the minimum appropriate hazards analysis method:

1. The checklist method for hazards analysis should be performed regardless of any additional technique that will be applied. Additional techniques should be used only to supplement the checklist analysis. (An alternative technique can be used in lieu of the checklist method if the technique checks for the same level of compliance with standard practice).
2. Low risk facilities such as single well caissons and most unmanned wellhead platforms with minimal process equipment can be analyzed using a simplified checklist such as the one shown in Appendix A.1.
3. Higher risk facilities, including all manned facilities, can be analyzed using a more detailed checklist such as the one shown in Appendix A.2.
4. When the checklist analysis identifies areas that cannot be resolved and require further evaluation, other methods such as What-If, HAZOP, or Fault Tree can be used. These methods should be utilized to analyze specific areas or events and not as a complete analysis in themselves. They should generally be limited to analyzing the following areas:
 - New processes.
 - Complex control systems.
 - Toxic material processes.
 - Unusually high risk to personnel or environment.
5. When a facility contains new equipment or processes without previous experience, a HAZOP or FMEA should be considered to identify hazards associated with these areas.
6. If a specific undesirable event is to be studied more closely, a Fault Tree Analysis or other methods should be considered.

APPENDIX A.1—EXAMPLE SIMPLIFIED CHECKLIST

This example simplified checklist is intended for hazards analysis of low risk facilities such as single well caissons and most unmanned wellhead platforms with minimum process facilities. The primary concern in these types of facilities is that production is shut-in on detection of an abnormal condition.

This checklist should be modified to incorporate the operator's design standards, philosophy, and experience. The modified checklist should be updated to incorporate changes in standard practices and results of accident and incident investigations.

The checklist may be used by an individual if the individual is experienced in the applicable codes, standards and regulations and is familiar with the operator's facilities. The analysis should be documented to show who conducted the analysis, when it was conducted, what information was covered and any recommendations.

The safety information normally required for this review includes an up-to-date P&ID, SAFE chart, MAWP of any process equipment, details of any relief or vent system, and a platform layout.

Checklist Questions

1. Is the safety system designed in accordance with API RP 14C? The first step in the review should normally involve a review of the SAFE chart for compliance.
2. Is piping designed for the maximum shut-in pressure of any input source or adequately protected per API RP 14C?
3. Do all SDVs fail in the safe position?
4. Are pipeline riser SDVs or FSVs located below the lowest process level if practical?
5. Have relief and vent systems (if any) been determined to be adequately sized and properly located?
6. Are there adequate start-up, operations, shutdown, maintenance, inspection, and testing programs and procedures in place?
7. Are there any unusual materials, equipment or circumstance that may require additional review?

Note: It is not the intention of API to present this as an approved checklist. This checklist is included to illustrate the types of things the operator might wish to consider but is neither all inclusive nor mandatory.

Each operator should develop its own checklist which may or may not reflect the specific questions included in this appendix. The checklist should represent the operator's judgement of what is necessary to establish compliance with good engineering practice. It is anticipated each operator will develop its own checklist system which could contain questions not included in this appendix, not include questions contained in this checklist, or be organized in a form that the operator finds easier to complete and audit.

APPENDIX A.2—EXAMPLE DETAILED CHECKLIST

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Note: It is not the intention of API to present this as an approved checklist. This checklist is included to illustrate the types of things the operator might wish to consider but is neither all inclusive nor mandatory.

Each operator should develop its own checklist which may or may not reflect the specific questions included in this appendix. The checklist should represent the operator's judgement of what is necessary to establish compliance with good engineering practice. It is anticipated each operator will develop its own checklist system which could contain questions not included in this appendix, not include questions contained in this checklist, or be organized in a form that the operator finds easier to complete and audit.

INTRODUCTION

This appendix provides an example detailed checklist for hazards analysis of medium to high risk offshore production facilities. The checklist and methodology presented below attempt to identify design errors and potential safety hazards through the use of a list of questions intended to stimulate thought and discussion.

This example checklist should be modified to incorporate the operator's design standards, philosophy, and experience. The modified checklist should be updated to incorporate changes in standard practices and the results of accident and incident investigations.

The example checklist questions provided in this appendix cover areas where errors have occurred. Many of the questions are a result of problems identified in previous reviews or incidents. This checklist does not cover areas where errors are seldom made by design personnel. **Consequently, a checklist should be used only for reviewing a thorough and complete design, and not as a method for designing a facility.**

REQUIRED INFORMATION/SCOPE

The following information may be required by this checklist procedure:

Basis of Design	Piping and Valve Specifications
Material Safety Data Sheets*	Flare and Vent System Data
Electrical One Line Diagram*	Logic Diagrams*
Electrical Area Classifications	Process Flow Diagram and P&IDs
Equipment Arrangements	SAFE Charts
Fire Protection and Safety System Layout	Cause and Effect Charts*
Building Plans*	Equipment Data Sheets
Operating Procedures*	PSV and Control Valve Data Sheets

* These documents may not be required to perform the minimum hazards analysis for a facility. These documents should be reviewed if they exist, but developing these documents may not be justified for facilities where they do not already exist. Some of this information, if not available, may have to be developed if identified as a concern during the review.

It is recommended that this package be maintained throughout the life of a facility to provide the basis for future modifications and hazards analyses.

PROCEDURE

The hazards analysis should begin at the earliest opportunity to minimize the effects of any changes in the design. For new projects, the hazards analysis team should be organized at the beginning of the detailed design phase of the project. The documents in the Safety Information Package can be reviewed individually or in groups as soon as they are in final form.

The team should consist of project personnel, operations personnel and at least one experienced person not involved directly in the design or operation of the facility. The bulk of the analysis may be performed by individuals or small groups organized by discipline. The analysis should be conducted or chaired by an individual other than the originating engineer. The example checklist is organized into the following areas to facilitate discipline reviews:

Review	Content	Useful Documentation
General	General Layout Emergency Response Escape and Rescue	Basis of Design Material Safety Data Sheets Process Flow Diagrams (PFDs) Equipment Arrangement
Process	SAFE Chart Piping and Valves Equipment Flare and Vent Systems Drain Systems	PFDs and P&IDs SAFE Chart Cause and Effect Equipment Data Sheets PSV and Control Valve Data Flare and Vent System Design Piping and Valve Specifications
System	Surface Safety Systems	SAFE Chart Cause and Effect Chart P&IDs Logic Diagrams Electrical One Line Diagrams Area Classification Drawings Equipment Arrangement
Fire and Gas	Process Area Buildings and Enclosures Quarters	Equipment Arrangement Fire Protection and Safety System Layout Building Plans
Mechanical	Construction Materials Piping Quarters Helidecks Structural	Equipment Data Sheets Equipment Arrangement Piping and Valve Specifications

Each question in the checklist should be studied closely to stimulate thought and to identify potential problems. There is no requirement to document that each question has been answered “yes” or “no.” The evaluators should use the checklist questions as guides.

The checklist questions are *not* necessarily meant to be “requirements for safe design.” In many cases they are provided to encourage evaluators to consider options. It should be expected that a review of an existing facility will result in more undesirable answers than a review of a new design because of the additional safety risk associated with field modifications. The operator should carefully review the need to modify existing facilities to meet current design in light of manning levels, complexity of operations, adequacy of operating practices and procedures, level of opera-

tor training, and additional safety risk associated with field modifications.

REPORTING

The analysis should be documented to show who conducted the analysis, when it was conducted, what information was covered, and any recommendations. Identified hazards and recommendations resulting from the checklist questions could be summarized on a form similar to the example presented at the end of the example checklist. Each entry refers to the corresponding checklist question number where the problem was identified. These entries are based on the hazards analysis team’s assessment and the discussions with the project team or operations and engineering staff involved. Entries should only be made for areas of concern.

1. GENERAL FACILITY CHECKLIST

1.A General.

- 1.A.1** Have the following hazards been adequately addressed? Have methods of eliminating or controlling these hazards been considered?

Blowout.

Wellhead and process fires and explosions.

Pipeline riser failure.

Weather.

Impacts and collisions.

Falling objects.

Human error.

Site specific conditions.

- 1.A.2** Is there anything unusual about the facility, such as new equipment or processes, complex control, etc., that may require a more thorough safety review (e.g., HAZOP)?

- 1.A.3** Has the operability of the process been considered in the design? (Systems that are complex, difficult to operate, maintain, or could result in excessive shutdowns will likely be operated incorrectly or disconnected.)

- 1.A.4** Have safety system testing requirements been defined? Does the design allow these requirements to be met?

- 1.A.5** Have all materials in the process been identified and classified as “hazardous” and “non-hazardous?” For each hazardous material:

- Has the material safety data sheet been reviewed?
- Have the hazards associated with transfer and storage of the material been addressed?
- Has a handling procedure been developed to protect personnel?

1.B Layout.

General

- 1.B.1** Are living quarters, control room, radio room, etc., located to reduce exposure to potentially hazardous process equipment, the wellhead area, and from high noise sources and hot exhausts?

- 1.B.2** Are there any fired equipment, compressors, generators, or engine exhaust equipment located where the exhaust could affect helicopters? Is the helideck located on the prevailing upwind side of the platform?

- 1.B.3** Do any pipeline risers come up the structure below the living quarters area? If so, what protection against riser failure has been provided?

- 1.B.4** Has the installation of future equipment, platforms or pipelines been considered? (Past experience has shown that laying pipelines or maneuvering marine equipment near an existing facility can be very difficult if pipeline laying equipment or anchor lines have to cross existing pipelines.)

- 1.B.5** Has the separation of fuel and ignition sources been considered in the layout of platform equipment?

- 1.B.6** Have the sources of ignition been minimized in the process and wellbay areas?

- 1.B.7** Have means of “natural ventilation” been considered for wellhead areas, pig launchers and receivers, and equipment exhausts?

- 1.B.8** Have the effects of prevailing winds been considered on escaping hydrocarbons or gases from the flares, vents, wells or other equipment?

- 1.B.9** Has routing of hydrocarbon piping through utility and life support areas been minimized?

- 1.B.10** Are the cranes located so the supply boats and laydown areas are reached with a minimum of lifting over process and wellhead areas, or over any equipment or piping which contain hydrocarbons? If this is not possible, has dropped-object protection been considered for critical equipment?

- 1.B.11** Have the following requirements been met:

- Crane cabin(s) located so the crane operator has free view of all areas?
- Adequate lighting provided for crane operations?
- Hatches or deck extensions provided for cargo handling?
- Adequate reach and capacity for process and utility equipment maintenance?

Egress

1.B.12 Are there two paths of escape?

1.B.13 Have the following requirements been met:

- All doors open in the direction of the escape routes?
- All stairways, passageways and boat landings are illuminated?
- Do major passageways and stairs allow for means for the evacuation of personnel on stretchers?

1.B.14 Are all escape paths from the quarters adequately protected from fire to allow for safe evacuation of personnel?

1.B.15 Have firewater hose stations been positioned outside the quarters to provide maximum coverage and to provide for safe evacuations?

1.C Emergency Response/Medical.

1.C.1 Have provisions been made to accommodate personnel in the event of an emergency (bad weather, delayed transportation, required overnight surveillance of an operation/test, etc.)?

1.C.2 Have the following requirements been met:

- Medical cabinets/kits for each location?
- Stretchers?
- Eyewash stands and showers near batteries and near chemical storage and pumping areas?
- Capability to communicate with the central facility/complex from an unmanned platform?

- Capability to communicate with vessels or shore?

1.C.3 Have provisions have been made for emergency care during installation, hook-up and commissioning?

1.D Escape and Rescue.

Survival Crafts/Lifeboats/Liferafts

1.D.1 Is the capacity of survival crafts and lifeboats or liferafts sufficient for 100% of the maximum number of personnel on the facility at one time, including visitors?

1.D.2 Are the survival crafts/lifeboats/liferafts located in positions to maximize the escape routes provided?

1.D.3 Has consideration been given to using knotted ropes as a last-resort form of escape in situations where other means of escape may not be accessible?

Survival Equipment

1.D.4 Have the following requirements been met:

- Life jackets for maximum number of persons on the platform?
- Storage bins for the life jackets?

1.D.5 If survival kits are being provided for the personnel, has adequate space been provided in the quarters or mustering areas to store these kits? (A survival kit could be any combination of a life jacket, smoke hood, emergency breathing apparatus, flashlight, survival suit, etc.)

2. PROCESS CHECKLIST

2.A SAFE Chart.

- 2.A.1** Has a review of the SAFE chart been performed to check for compliance with API RP 14C?
- 2.A.2** Do major process headers such as production, gas lift, and injection headers comply with API RP 14C, Section A3.2, and are they covered in the SAFE charts?
- 2.A.3** Has the double PSH/SDV concept for pressure protection of pipelines and manifolds been carefully considered? (This may not be as reliable as pressure relief valves. Pressure switch settings are frequently changed over the life of a field.)
- 2.A.4** Has an evaluation been made to determine if SDVs, FSVs, or a combination should be installed on departing pipelines?

2.B Piping, Valves and Instruments.

Piping

- 2.B.1** Have production headers been designed for the maximum pressure of any incoming production well/riser or process stream up to the separator inlet? If not, are there any valves that could isolate the header from the pressure protection?
- 2.B.2** Where spec breaks are found downstream of control valves, is overpressure protection provided before the next downstream block valve or restriction?
- 2.B.3** Are bleed valves installed on segments of piping that can be isolated between block valves?
- 2.B.4** Are there situations where piping may be exposed to temperatures well below or above design due to:
 - Auto-refrigeration of light ends? (This can be a problem with large pressure drops across control valves in high pressure gas and condensate service.)
 - Failure of a temperature control loop?
- 2.B.5** Is heat tracing specified for piping where water freezing is possible due to accumulation or intermittent service in cold weather?
- 2.B.6** Will the inadvertent operation of a manual or automatic valve or combination of valves

(including valve leaks) result in overpressure of piping or equipment?

- 2.B.7** Have connections between the process and service water been avoided? (For example, inadvertent operation of block valves in a jet water system could allow crude to get into the service water system and subsequently contaminate the toilets or firewater system.)
- 2.B.8** Are all vents and drains specified?
 - Are their ratings consistent with the vessel design pressure and temperature?
 - Are all drains valved and, where required, plugged, capped or blinded?
 - Are double valves provided on regularly used pressure drain connections for vessels with quick-opening valves nearest the vessels?
 - Are vents that are not normally or frequently opened plugged, capped or blinded?
 - Is there an adequate vent (or vent capability) on all vessels that are planned for manual entry?

Check Valves

- 2.B.9** For each check valve, will failure of the check valve to seal result in overpressure or other hazard? (Check valves are used to minimize backflow and should never be depended upon to completely isolate a part of the system from another part that remains under pressure. A check valve should be assumed to leak.)
- 2.B.10** Are check valves installed and properly located, such as:
 - Downstream of control valves?
 - In pump discharge lines?
 - Where lines tie into common headers?
- 2.B.11** Are the check valves designed to work in the installed position (e.g. vertical/horizontal)?

Control Valves

- 2.B.12** On failure of control medium or signal, does the control valve fail in the least hazardous position?
- 2.B.13** Have provisions been made in the design for failure of a single control valve in which the

valve sticks in the opposite position from the design failure position?

2.B.14 Will any mode of control valve failure result in overpressuring or other risk to equipment or piping, downstream or upstream? For example:

- Are upstream vessels between a source of pressure and the control valve designed for the maximum pressure when the valve closes?
- Can the design temperature be exceeded?

2.B.15 Can the pressure rating of the downstream side of self-contained regulators be exceeded?

Locked Valves

2.B.16 For locked-open or locked-closed valves:

- What is the justification for having the valve locked?
- Has a system for communicating the reasons for locking each valve been provided?
- Are the procedures for unlocking the valve clear?

2.B.17 Have any temporary valves been installed to facilitate future tie-ins? Have they been capped, plugged or blinded?

Pressure Relief Valves (PSVs)

2.B.18 Are PSV set points staggered in multiple valve installations? (Staggering will reduce chattering and minimize relief losses and upsets for relief situations lower than the design capacity. ASME allows a set pressure of 105% of MAWP and an accumulation pressure of 116% of MAWP for multiple valves. One PSV must be set at or below the MAWP.)

2.B.19 Are provisions made for testing and maintenance of PSVs?

2.B.20 Are PSVs sized for the worst case failure scenario, including:

- Isolation of both liquid and gas outlets?
- Gas blow-by from upstream separators?
- Failure of upstream control valves?
- Thermal relief for fire exposure?

- Utility failure?
- Failure of blanket gas regulators?

(Designs which depend on a check valve to provide isolation should be carefully scrutinized, especially if failure of the check valve could significantly increase the total flow to the relief device.)

2.B.21 In situations where flow restrictions due to piping, an orifice, or a control valve limit the required capacity of a PSV, have the effects of future modifications been considered? (API Standards allow consideration of flow limitations due to upstream equipment when determining the required capacity of a PSV. However, future operating parameters may require changing valve trims, orifice sizes, etc.)

2.B.22 Is PSV installed upstream of the mist eliminator on vessel?

2.B.23 Are thermal PSVs installed for fire exposure or liquid expansion on sections of process piping that:

- Are isolated from other PSVs by automatic valves on an ESD and,
- Contain large volumes of hydrocarbons or,
- Are liquid packed?

2.B.24 Are thermal PSVs installed for liquid expansion on equipment where an increase in temperature might exist or develop, after shutdown, between the trapped process liquid and its environment? (A component containing a cold liquid that is isolated on a shutdown could easily result in overpressure as the liquid warms to ambient temperature. The failure of a check valve to hold a tight seat should not be counted as a means of limiting pressure increase from thermal expansion.)

2.B.25 In cases where a single PSV protects multiple lines and vessels, are there any scenarios where one component could be isolated from the PSV due to:

- Maintenance isolation?
- Plugging from hydrates or sand?
- Inadvertent closing of a manual valve?

2.B.26 Does the PSV setting allow for static head and frictional losses upstream and downstream of the PSV?

2.B.27 Application. Have the following general concerns been addressed:

- Is PSV materials selection consistent with corrosiveness, auto-refrigeration, etc.?
- Is heat tracing required to avoid inlet plugging by congealing/freezing?
- If balanced bellows or pilot-operated PSVs are considered for congealing or viscous liquids services, are they adequately adapted for these severe conditions?
- In toxic service, are vents from balanced bellows or pilots routed to a safe location?

2.B.28 For PSVs with an upstream rupture disk (PSE):

- Is the piping between the PSE and PSV continuously vented to atmosphere to prevent pressure build up?
- If vent contains excess-flow check valve, is a pressure gauge provided?
- If a burst disk (PSE) is installed in the PSV inlet, is the capacity of the PSV and burst disk, in combination, derated to 90% of the rated PSV capacity?

2.B.29 Piping

- Are inlet and outlet line diameters the same or larger than PSV inlets and outlets?
- Are inlet and outlet line ratings consistent with the PSV nozzle ratings?
- Are all maintenance isolation valves on PSV inlets or outlets locked open and covered by a locked valve procedure?
- Is the PSV inlet line pressure drop less than 3 percent of set pressure or is the PSV a remote sensing or a modulating pilot operated relief valve designed to prevent chatter?
- Is the maximum built-up back pressure at the PSV outlet less than 10 percent of set pressure? (Less than 50 percent for balanced bellows or pilot operated?)

- Do PSV outlet lines enter the sides or top of the relief header?
- Are inlet lines off process lines located in active flow portions of the lines, and do they come off the sides or tops of the lines?

2.B.30 Where PSV outlet line velocities are greater than 75 percent of sonic, has the superimposed back pressure been adequately evaluated?

2.B.31 Have back pressures been calculated for the actual PSV sizes and associated flow rates for the piping configuration installed?

2.B.32 For PSVs with atmospheric discharge:

- Is there adequate liquid capacity above the high level shutdown on vessels to allow time to shut off inflow before liquid is carried over?
- Are PSV discharges piped to a safe area?
- Has ignition of the discharge been considered?

2.C Flare and Vent System.

2.C.1 Have scrubbers been provided where needed to prevent liquid carryover? Are lines self-draining towards the scrubber?

2.C.2 Have multiple high and low pressure components been tied into the same flare or vent system, without taking worst case back pressure into account?

2.C.3 In flare/vent system design, has provision been made for:

- Low temperature effects?
- Line and scrubber supports to withstand acceleration forces created by high velocity liquid slugs?

2.C.4 Are flame arresters installed on atmospheric vents? Are they located at the discharge of vents or designed for self-draining of downstream condensation?

2.C.5 Are flame arresters accessible for routine inspection and maintenance?

2.C.6 Would ignition of the vent not expose personnel to excessive thermal radiation rates?

2.C.7 Are flame arresters tested and approved for the specific application?

2.C.8 Is purge gas provided for vent and flare headers?

2.C.9 Have extinguishing systems been provided for the vent tip?

2.D Drain System.

2.D.1 Are open and closed drain systems completely segregated?

2.D.2 Are open drains from classified and unclassified areas segregated?

2.D.3 Are there any block valves in the drain system located downstream of pressure components that could result in over pressure? Has hydrate plugging been considered?

2.D.4 In closed drain systems, have the downstream sump and vent systems been designed to adequately handle the maximum rates from drain valves that are inadvertently left open? Is the header rated for the maximum built-up back pressure due to open drain valves on high pressure components?

2.D.5 Are any drains from pressurized process lines and vessels piped directly into atmospheric (open) hydrocarbon drains or sewer systems?

2.D.6 On closed drain headers:

- Is the header material suitable for the maximum and minimum temperatures expected from discharging into it (including auto-refrigeration)?
- Is heat tracing required because the system may receive heavy crude or water (or moisture) which may solidify?

2.D.7 Are all vents and drains specified?

- Are their ratings consistent with the vessel design pressure and temperature?
- Are all drains valved and, where required, plugged, capped or blinded?
- Are double valves provided on regularly used pressure drain connections for vessels with quick-opening valves nearest the vessels?
- Are vents that are not normally or frequently opened plugged, capped or blinded?

- Is there an adequate vent (or vent capability) on all vessels that are planned for manual entry?

2.E Equipment.

Pipelines and Risers

2.E.1 Are SDVs and FSVs on pipeline risers installed below the lowest process level, or otherwise protected against thermal and/or mechanical damage?

2.E.2 Are all connections (i.e., pressure taps) installed on the inboard side of an incoming or departing pipeline SDV? (Depressurization of the pipeline cannot be controlled if an outboard connection fails.)

2.E.3 Are suitable provisions made for pressurizing and blowing down of pipelines?

2.E.4 Are risers suitably protected from collision from boats?

Pressure Vessels

2.E.5 If installed, are shutdown valves located as close to the vessel outlet nozzles as possible?

2.E.6 Has automatic or remote manual vapor depressurization been installed for pressure vessels? (If depressurization is utilized, see Section 4.7 of this RP.)

2.E.7 Are vessels designed for full vacuum where:

- Failure of downstream equipment, such as a recycle valve failure on a compressor, could impose a vacuum?
- Improper pump out or draining could impose a vacuum?

2.E.8 Are safety devices (pressure, temperature, level, flow, etc.) installed in locations and with set points that will effectively prevent an unsafe situation before it occurs? For example:

- Are high (or low) level shutdowns located below (or above) the elevation of the outlet it is trying to protect?
- Are pressure sensing devices and PSVs located upstream of mesh pads or other restrictions?
- Are shutdown devices located to allow sufficient time to isolate the source of the problem (e.g., close an SDV) before carryover or blow-by occurs?

- Are instrument bridle connections located to avoid plugging?

Atmospheric Vessels

- 2.E.9** Is adequate vacuum protection provided on atmospheric vessels? (Failure scenarios which could cause abnormal liquid draw-down or vapor evacuation should be investigated. Many atmospheric tanks have been collapsed due to improper manual draining procedures.)
- 2.E.10** Have liquid overflow lines been adequately designed to prevent siphoning?
- 2.E.11** Are liquid inlets located to prevent static electricity build up during filling?

Centrifugal Pumps

- 2.E.12** Is the pressure rating of pump discharge piping suitable for the greater of:
- Normal pump suction pressure plus maximum differential pressure developed by the pump (e.g., blocked discharge)?
 - Maximum pump suction pressure (e.g., suction vessel relieving pressure) plus normal differential pressure developed by the pump?
 - Maximum specific gravity of pumped fluid combined with either of the above?
- 2.E.13** Are suction piping and valves rated for full discharge pressure or are other means of suction over pressure provided (e.g., relief valves):
- Where one pump in a set of parallel pumps is shut down?
 - Where there is an alternate source of pressure at least equal to pump discharge pressure in the discharge line of a single pump?
 - Where the discharge line volume is sufficient to overpressure the suction piping if the pump is shut down and a suction valve is closed?
- 2.E.14** Is a discharge check valve installed to prevent backflow?
- 2.E.15** Is a minimum flow recycle provided to prevent pump damage due to low flow and overheating?

- 2.E.16** Are multiple seals and inner seal failure sensors installed on high pressure liquid hydrocarbon pumps to minimize leaks?

- 2.E.17** Are start-up suction screens provided?

Positive Displacement Pumps

- 2.E.18** Is the pump discharge piping protected by a relief valve upstream of the first block valve?
- 2.E.19** Are suction piping and valves rated for full discharge pressure or are other means of suction overpressure provided (e.g., relief valves)?
- 2.E.20** Is there a discharge check valve to prevent backflow?
- 2.E.21** Are start-up suction screens provided?
- 2.E.22** Do all pumps handling combustible or toxic fluids have cast or forged steel fluid ends?
- 2.E.23** If pump is V-belt or chain driven, is there a completely enclosed guard?
- 2.E.24** Are drain and vent connections on pumps handling toxic or combustible fluids tied to the closed drain system?
- 2.E.25** Are pump motors and controls designed properly for the area classification where they are installed?
- 2.E.26** Are both the pump and driver adequately protected from pressure fluctuations by pulsation devices on the suction and discharge of the pump if required?
- 2.E.27** Is the fluid velocity in the suction and discharge piping within the guidelines of API RP 14E?
- 2.E.28** Are both the pump and driver protected by vibration sensors?
- 2.E.29** Are screwed connections adequately braced for vibration?
- ### Centrifugal Compressors
- 2.E.30** Is suction over pressure protection provided for:
- Maximum settle-out pressure after a shut-down?
 - Backflow via recycle loop?
 - Surge valve failure?
- 2.E.31** Is discharge over pressure protection provided for:

- Anticipated changes in molecular weight?
- Overspeed?
- Blocked discharge at maximum suction pressure?

2.E.32 Is high temperature protection provided for:

- Loss of process cooling?
- Changes in molecular weight?

2.E.33 Is there chance of mechanical damage from:

- Liquid carryover?
- Surge?
- Reverse rotation? (Are check valves installed on each stage discharge?)
- Air entry into machine?
- Excessive Speed? (Is overspeed cutout provided?)

2.E.34 Is the potential for a leak and fire limited by providing:

- Remote shutdown?
- Isolation valves?

2.E.35 Are shutdown valves located outside of any enclosure?

2.E.36 For centrifugal compressor seal oil systems with overhead seal oil and run down lube oil tanks:

- Is overflow protection provided for the seal oil overhead tanks?

(The compressor can lose its seal if the overhead tank overflows. This can result in oil flowing to the compressor case and consequent damage to the compressor, possibly leading to the release of hydrocarbon gas.)

- Are all overhead seal oil tanks designed for maximum seal oil pump discharge pressure for compressor trains with multiple stages on a common shaft?

(Overhead seal oil tanks are typically supplied from one seal oil pump. As such, the pump must be capable of delivering oil to the overhead tanks with the highest operating pressure, which would be the tank for the highest stage. The lower stage overhead tanks must be suitably protected against overpressure from the seal oil pump.)

- Has the effect of seal oil dilution on the seal oil overhead tank level control scheme been considered when processing a gas stream containing heavy gas components?

(Level control malfunction [due to seal oil dilution with condensation from heavy hydrocarbons in the reference gas line] may occur if the seal oil overhead tank temperature is below the hydrocarbon's dew point. Loss of level may result in loss of seal in the compressor with subsequent damage and possibly a gas release.)

2.E.37 For centrifugal compressor seal oil systems with backup seal oil pumps:

- Is the power supply independent so that the pump will function regardless of the cause of compressor shut-in?

2.E.38 For all compressor seal oil systems:

- Is seal oil degassing tank vent line capacity adequate to handle blow-by from a seal oil trap?

(The pressure rating of the seal oil reservoir is typically given in inches of water. Blow-by gas from a seal oil trap can be driven by several thousand psi. The reservoir vent must be sized to handle corresponding flow rates without overpressuring the reservoir.)

- Is the seal oil reservoir designed to prevent static charge accumulation?

Positive Displacement Compressors

2.E.39 Is overpressure protection provided for:

- Backflow through recycle loop?
 - PSVs for low pressure stages sized for maximum recycle.
 - Consideration of parallel machines.
 - Restriction to limit recycle flow - high pressure machines
- Blocked discharge (PSV required)?

2.E.40 Is protection provided to reduce the possibility that the design temperature is exceeded from:

- Loss of cooling?
 - Feed or recycle gas.
 - Cylinder jacket cooling water.

- Running on total recycle?
- Low suction pressure?

2.E.41 Is protection provided to reduce the possibility of mechanical damage from:

- Liquid carryover?
- Air entry into machine?

2.E.42 Are shutdown valves located outside of any enclosure?

Heat Exchangers

2.E.43 Is adequate overpressure protection provided for:

- Shutoff against maximum pressure source?

– Upstream, downstream, thermal expansion (trapped cold side).

- External fire contingency?
- Tube leak or rupture?

2.E.44 Can design temperatures be exceeded from:

- Maximum upstream temperature at source?
- Bypassing of upstream heat removal equipment?
- Loss of flow on cold side?

2.E.45 Are shell and/or tubes rated for vacuum, where required?

3. SYSTEMS CHECKLIST

3.A Surface Safety System.

Shutdown Valves

- 3.A.1** Have valve testing requirements been accounted for in the valve actuator and pilot valve configuration? In the access to the valve?
- 3.A.2** Are external environmental conditions considered in the shutdown valve design? For example,
- Salt air corrosion of actuator spring return.
 - Mechanical damage to pilot valve or solenoid valve.
 - Damage or corrosion to air accumulator tank, if used.
 - Damage or corrosion to pneumatic or hydraulic tubing and connections.

Motor Control

- 3.A.3** Have Hand/Off/Auto control switches been specified? If so, can the safety system override a motor left in the Hand position?

Input Sensors (Transmitters, Transducers, Switches)

- 3.A.4** Does the installation of sensors put priority on minimizing process lags, eliminating plugging and freeze-up problems, etc.?
- 3.A.5** Are isolation valves in plain sight and accessible for operation?
- 3.A.6** On critical sensors, can the process signal to the sensor be independently checked (by a pressure gauge, for example)? Can sensors be easily and accurately calibrated?
- 3.A.7** Are low flow detection devices located downstream of points where leakage is the greatest concern?
- 3.A.8** Are temperature sensing devices located in continuously active flowstreams?

System Hardware

- 3.A.9** Are process control and safety systems separated? This includes:
- Sensing devices.
 - Power supplies.

- Branch air regulators (beyond main distribution header).
- Process sensing lines (valved level bridles, pressure taps).

- 3.A.10** Have components that could hinder or defeat the shutdown function through improper adjustment been identified and minimized and a system implemented to prevent unauthorized or undocumented changes? Such as:

- Timing relays?
- Restriction orifices, needle valves?
- Trip function requiring multiple pressure switches set at the same value?

- 3.A.11** Is the system designed to clearly indicate its status? Examples:

- Normal/bypass.
- Running/tripped.
- System fault/system OK.

- 3.A.12** Can the system give clear (first out) indication of the cause of shutdown?

- 3.A.13** Where maintenance bypasses are used, do they bypass the minimum number of functions to allow on-line maintenance? Have timed bypasses been considered?

Logic Philosophy

- 3.A.14** Has the system logic considered offsite conditions? Examples:

- Shutdown on adjacent platforms.
- Bridge landing ESD stations.
- Import/export pipeline upset.
- Utilities failures (partial and total).

- 3.A.15** Where the operator is required to manually respond to emergency conditions, has consideration been given to the following:

- Does he/she have sufficient information to correctly interpret the condition?
- Is the information presented in a simple, direct format allowing for stressful conditions which may be present?
- Do alarm settings, location of controls, etc., allow enough time to respond?

Logic Development

- 3.A.16** Do all elements of the shutdown system, including controls on packaged units, follow the same philosophy?
- 3.A.17** Has the control logic provided positive lock-out after shutdown? Does the tripped indication inform the operator that a reset step is required?
- 3.A.18** Is the reset procedure clear and simple, reducing the need for resetting several different pieces of equipment?
- 3.A.19** Is “first out” annunciation indicated?

3.B Electrical System.

Area Classification

- 3.B.1** Are extents of Class 1, Division 1 and Division 2 areas clearly shown on area classification plans and elevations?
- 3.B.2** Are flammable liquids, gases, and vapors handled, processed, and stored away from areas in which unclassified equipment is located?
- 3.B.3** Has vapor tight design/construction of walls and barriers that form division boundaries been confirmed?
- 3.B.4** Have drilling and recompletion-remedial work been considered in the electrical equipment layout? (During drilling/well workover operations, all available deck space is often used for extra tanks, piping, trailers, logging equipment, etc. This equipment could compromise the “normal operating” conditions on which Area Classifications are based.)
- 3.B.5** Has normal maintenance been considered in determining area classification?
- 3.B.6** Is process gas being used as supply for instruments? If so, was this considered in determining area classification?
- 3.B.7** Have decisions been made involving whether or not any areas should be classified

as “enclosed” and whether all enclosed areas are adequately ventilated in determining area classifications?

- 3.B.8** If adequate ventilation and/or pressurization is the technique used to reduce area classification or de-classify an area, is the source of fresh air outside the classified area? If so, has automatic shut-off of electrical power to potential arcing devices been provided on detection of loss of ventilation pressurization resulting in an accumulation of gas or vapors?
- 3.B.9** Are combustible gas detection devices used to reduce the classification of enclosed areas? If so, do they shut-off electrical power to all devices which would not be suitable for the classified area if gas detectors had not been installed?

Equipment

- 3.B.10** Have equipment certification/labeling/listing requirements (e.g., NRTL listing) been checked?
- 3.B.11** Is all electrical equipment installed in classified locations suitable for the location?
- 3.B.12** Are Class 1 gases and vapors grouped and identified per Table 3.5 of API RP 500 (e.g., Group A, B, C or D)? If so, are thermal ratings of electrical devices in accordance with NEC Table 500-3(d)?
- 3.B.13** Have Hand/Off/Auto control switches been specified? If so, can the safety system override a motor left in the Hand position?
- 3.B.14** Has access to emergency shutoff devices been considered in design?
- 3.B.15** Do all disconnect switches and breakers have lockout provisions?
- 3.B.16** Are all non-current carrying metallic parts of the electrical system properly grounded? (This can be achieved through proper grounding of connected cable and conduit systems.)

4. FIRE AND GAS SYSTEM CHECKLIST

4.A Process Area.

Fire and Gas Detection

- 4.A.1** Does the detection system provide the following:
- Isolation of the hydrocarbon sources?
 - Indication of the location of undesirable event?
 - Activation of an adequate audible/visual alarm system?
- 4.A.2** If fusible loop heat detection is used, have zone layout and panel construction allowed for periodic testing and inspection?
- 4.A.3** Is fusible loop tubing well protected from mechanical damage, especially in well bays?
- 4.A.4** If optical flame detection is used, does the installation avoid false alarms due to lightning, flares, etc.? (False alarms undermine operator confidence and encourage system bypassing/ignoring.)
- 4.A.5** Is the bypass status of the fusible loop panel indicated to the operator at all times?

Fire and Gas Protection

- 4.A.6** Has deluge been considered for any vessel, header, equipment or wellhead areas that contain high inventories of hydrocarbons?
- 4.A.7** If a deluge system is installed:
- Are deluge valves installed to permit testing?
 - If deluge valves are isolated or bypassed, is this properly indicated to the operator?
 - Have provisions been made to prevent plugging of deluge lines and valves due to sediment or corrosion products?
- 4.A.8** Has the use of firewalls been considered to separate the higher risk areas, such as fired equipment, from the unfired process equipment and storage tanks? (Has the use of firewalls between decks been considered as well?)
- 4.A.9** Can the effectiveness of firewalls be compromised in any way, such as by a door remaining open?

4.A.10 Can all areas of the platform be protected from two different directions? (Protection methods could include fire hoses, fire monitors, wheeled extinguishers, etc.)

4.A.11 If provided, are fire monitors located in the most effective locations? Will the stream path be blocked by any other equipment such as a wellhead, a manifold or a structural member? Can a person easily get to and away from the monitor?

4.A.12 Are fire hoses located near all stairways and exits?

4.A.13 Are the dry chemicals on the structure compatible with their intended use?

4.A.14 Is there an ABC dry chemical extinguisher or equivalent located on at least one stairway exit from the helideck? (There must be one at all fueling stations.)

4.A.15 If the platform is manned, is there a fire pump(s) capable of maintaining the water discharge at the required rate and pressure? (The system could include the deluge, fire monitors and fire hoses.)

4.A.16 Is the fire pump caisson(s) protected from collision?

4.A.17 Do the AFFF reels have the capability to switch between a water stream only and a water-foam stream?

4.A.18 If fire-fighting clothing is provided, are the responsible personnel trained in its use? (Past experience indicates that fire-fighting clothing and equipment are burdensome and awkward to those who are not properly trained in their use.)

4.B Buildings and Enclosures.

Fire and Gas Detection

- 4.B.1** Do zone layouts of building fire detection systems provide for clear identification of alarm source?
- 4.B.2** Are normally unattended areas covered?
- 4.B.3** Is the system compatible with platform alarms for other facilities within the same area of operation?
- Alarm tones?
 - Manual stations?
 - Alarms transmitted to central points?

- 4.B.4** Does a detector fault initiate an alarm?
- 4.B.5** Are air intakes located to minimize ingestion of smoke or flammable gases and located in unclassified locations? Have combustible gas detectors been considered for air intake areas?
- 4.B.6** Is there sufficient back-up power (e.g., a battery) to the electrical source supplying the detection system?
- 4.B.7** Are manual fire alarm stations located at each exit?
- 4.B.8** Have provisions been made to maintain and test the detection system?

Fire and Gas Protection

- 4.B.9** Has consideration been given to the isolation of air intakes if fire or gas is detected?
- 4.B.10** Does gas detection isolate electrical power to eliminate ignition sources?
- 4.B.11** Is an automatic inverting or extinguishing agent system installed? Is a time delay provided to allow personnel to escape before the system is discharged?
- 4.B.12** Are all pathways to exits free of obstructions?
- 4.B.13** Are windows, doors and the material in firewalls of the same fire or blast rating as the firewalls?

- 4.B.14** If an enclosure contains a potentially explosive substance, has a means of venting the explosion been provided?

4.C Quarters.

Fire and Gas Detection

- 4.C.1** Are heat detectors located in hallways adequately spaced? Are smoke detectors located in each sleeping room? Do equipment and other rooms contain potential ignition sources?
- 4.C.2** Can the audible fire/smoke alarm(s) be prominently heard from all locations within the quarters?

Fire and Gas Protection

- 4.C.3** Are fire and smoke barriers fitted in appropriate positions in the void spaces of the quarters ceilings to prevent migration?
- 4.C.4** Are all escape paths from the quarters adequately protected from fire to allow for safe evacuation of personnel?
- 4.C.5** Have the appropriate number and type of portable or semi-portable fire extinguishers been provided within the quarters?
- 4.C.6** Have firewater hose stations been positioned outside the quarters to provide maximum coverage and to provide for safe evacuations?

5. MECHANICAL CHECKLIST

5.A Construction Materials.

- 5.A.1 Have steel materials been used in hydrocarbon service, where feasible (no aluminum, brass, cast iron, etc.)?
- 5.A.2 Are materials in sour service in accordance with NACE requirements?
- 5.A.3 Are material specifications in accordance with ANSI B31.3 and *ASME Boiler and Pressure Code*, Section VIII?
- 5.A.4 Are there other special requirements for materials which should be addressed?

5.B Piping.

- 5.B.1 Have stresses and movements due to thermal expansion or contraction been considered in piping systems?
- 5.B.2 On piping that operates above 160°F, has adequate thermal protection for personnel been provided?
- 5.B.3 Are all vent, flare and relief lines self-draining?
- 5.B.4 Have all packing vents, vents from pilot-operated PSVs, etc., been routed to a safe location outside of any enclosure?
- 5.B.5 Have dead legs been avoided to prevent corrosion?
- 5.B.6 Are all walkways free of obstructions?
- 5.B.7 Have the number and length of high pressure pipelines that cross the working areas been minimized?
- 5.B.8 Are supports on PSV discharge piping designed for the fluid reaction force when the PSV operates?
- 5.B.9 Is there access to critical valves for operation and maintenance?
- 5.B.10 Is all piping in vibrating service adequately supported? Has screwed piping been avoided?

5.C Quarters.

General Layout and Design

- 5.C.1 Is a suitable fire wall provided on the side facing the process area?

- 5.C.2 Are there at least two primary means of escape from each floor?

- 5.C.3 Do exits give ready access to life-saving equipment?

- 5.C.4 Have adequate medical treatment facilities been provided? Is the entrance to the treatment facility situated to allow the easy transport of a person on a stretcher?

- 5.C.5 Are the following designed to meet building requirements for width, height, incline, etc.:

- Stairways?
- Aisles and passageways?
- Hatches?
- Railings?
- Elevators, if applicable?

- 5.C.6 Has adequate space been made available to store personnel protective gear, such as life vests, emergency breathing apparatus, etc.?

- 5.C.7 Have walkways on the exterior sides of the quarters building opposite the operational areas been considered to provide safe avenues of egress?

- 5.C.8 Has the use of windows, especially on the process side of the quarters, been minimized as much as possible?

Construction and Materials

- 5.C.9 Have fireproof materials been used for construction of the quarters?

- 5.C.10 Have non-skid materials been used on stairs and in entry ways? Shower and washing areas?

Emergency Exits

- 5.C.11 Are exits on the same floor located as far opposite each other as practical? Are the exit paths laid out in such a way as to avoid dead ends?

- 5.C.12 Do common areas exceeding 300 ft², or having an occupancy capacity of 50 persons or more, have a minimum of two doors, located at opposite sides of the room?

- 5.C.13 Do the doors used for emergency exits open outward in the direction of escape? Are they equipped with safe opening mechanisms?

- 5.C.14 Are all exits properly marked and lighted?

Lighting

- 5.C.15** Has adequate lighting been provided at all entry ways, passageways and stairs?
- 5.C.16** Is emergency lighting along exitways located such that evacuation of the quarters can be executed safely?
- 5.C.17** Is emergency lighting provided in key areas (such as the medical treatment room, offices and galley) to allow for continued operation or proper execution of emergency procedures?
- 5.C.18** In the event of total power failure, including main and emergency, have provisions been made for lighting in the quarters to facilitate an orderly exit?

Utilities

- 5.C.19** Have the hazards associated with any fuel gas to the quarters been addressed?
- 5.C.20** Is there an alarm installed on the incoming fuel gas system to detect pressure loss/increase?
- 5.C.21** Do hot water heaters have a combination thermal/pressure valve that is set to relieve at the water tank design working pressure or 126 psig and 210°F, whichever is the lesser? Does the relief vent terminate at a safe location outside the building?
- 5.C.22** Are gas-fired heaters equipped with an automatic shutoff and manual reset for fuel gas and pilot gas upon loss of the pilotflame?
- 5.C.23** If storage spaces are provided within the quarters, have provisions been made to eliminate the storage of flammable or toxic materials there?

5.D Helidecks.

General Design

- 5.D.1** Is the helideck designed to accommodate the largest sized helicopter expected to land on

it? Has consideration been given to handling two helicopters if the need arises?

- 5.D.2** Is the approach path obstruction free? Have any obstructions been adequately marked? Have precautions been taken so that a crane that can reach the approach path will not be operating during landings and takeoffs?
- 5.D.3** Has a non-skid type surface that adheres to the deck been used?

Accessories

- 5.D.4** Have the following requirements been met:
- Safety fence or solid safety shelf around the perimeter of the helideck?
 - Tie-down rings for the applicable number of helicopters?
 - Wind indicator?
 - Lighting (for night operations)?
- 5.D.5** If a fueling system is being provided, is it located on a separate level from the helideck? Is it located so as to minimize the risk of damage in the event of a helicopter crash?

5.E Structural.

- 5.E.1** Have the following requirements been met:
- Non-skid surfaces on all steps and landings for stairs and ladders?
 - Railings around permanent openings in the decks, walkways, platforms and stairways?
- 5.E.2** Have railings with toeboards been provided for any area on the outside perimeter of all decks or passageways (with the exception of the helideck) which are located over frequented areas and/or are over open sea?

APPENDIX B—ANALYSIS OF EXAMPLE LAYOUTS

In designing a platform, the need to separate fuel from ignition sources by the greatest distance practical, and to separate a concentration of personnel (as in the living quarters) from fuel sources and machinery areas, is inherently incompatible with the limited space available. Equipment that would be separated by large distances (i.e., tens, hundreds or even thousands of feet) onshore because of availability of space or for convenience, must be accommodated within a limited amount of space offshore. Safe offshore platform design requires considerable thought and application of guidelines that, no matter how carefully applied, will inevitably result in trade-offs or compromises.

Three representative deck layouts follow. Each illustrates the trade-offs involved in developing a design based on the recommendations of this RP. The advantages and disadvantages of each design are listed—but are not exhaustive. The main purpose of the analyses is to demonstrate that no design can be free of disadvantages; the best that can be hoped for is an acceptable compromise with a relatively few number of disadvantages.

B.1 Figure B-1

B.1.1 NEGATIVE POINTS

B.1.1.1 Main Deck

1. The gas compressor is located on the main deck relatively close to the living quarters. An alternate location that would overcome this disadvantage would be at the other end of the platform, with the compressor cantilevered outboard of the well bay area. However, in this location, a compressor package would block access to the wells when using a jack-up unit.

Methods of mitigation for the compressor in the location shown would include fire detection and automatic water deluge. The firewall shown provides additional isolation between the living quarters and the compressor.

2. The fired oil treaters and the fired glycol reboiler represent additional instances where sources of fuel and ignition cannot be separated. To reduce the consequences of a fire or explosion, it may be advisable to install a firewall to isolate these vessels from the living quarters and the compressor, and to provide additional fire detection and automatic fire water deluge.

B.1.1.2 Cellar Deck

1. Electric motor-driven hydrocarbon handling equipment (oil shipping pumps, LACT units, vapor recovery units,

etc.) may be a major source of fuel and ignition. When seals and bearings become worn, leaks occur and heat is generated. Fuel may come into contact with hot surfaces, causing hydrocarbon fires to occur even though the motor is properly rated for the environment in which it is placed. This hazard can never be eliminated and can only be mitigated through inspection, proper preventive maintenance and by having a fire detection and suppression system installed in appropriate proximity to this equipment.

2. The air compressor is located in relatively close proximity to unfired process equipment, which through malfunction could become a source of hydrocarbon vapor that could be ingested into the cylinders of the air compressor, resulting in combustion. To reduce the chance of this occurring, it may be advisable to install gas detectors on the suction inlet to the air compressor. This gas detection system could then be used to shut down the air compressor. Alternatively, a remote source of inlet air could be considered. A fire detection and automatic fire water deluge system may also be used as a further precaution.
3. Oil and gas pipeline risers are located in the middle of the platform in close proximity to other sources of fuel such as separators and LACT unit. A rupture of a riser and subsequent fire might eventually involve these fuel sources. Moving the pipeline risers closer to the wellhead area would mean that the wells could be endangered, and moving them closer to the other end of the platform would place the risers closer to the living quarters. Placing the risers at the opposite end of the platforms from the quarters may be an acceptable compromise except in the case where the subsea lines may be endangered by a jack-up rig.

B.1.2 POSITIVE POINTS

B.1.2.1 Main Deck

1. The well bay area is located at opposite end of the platform from the living quarters, providing the maximum separation practical.
2. The area around the well bay area is adequate for access by a jack up drilling or workover rig.
3. All fired vessels are on main deck. In the event of a fire, flame would not impinge on overhead equipment.
4. The living quarters are cantilevered to provide maximum separation both horizontally and vertically from hydrocarbon sources and machinery.

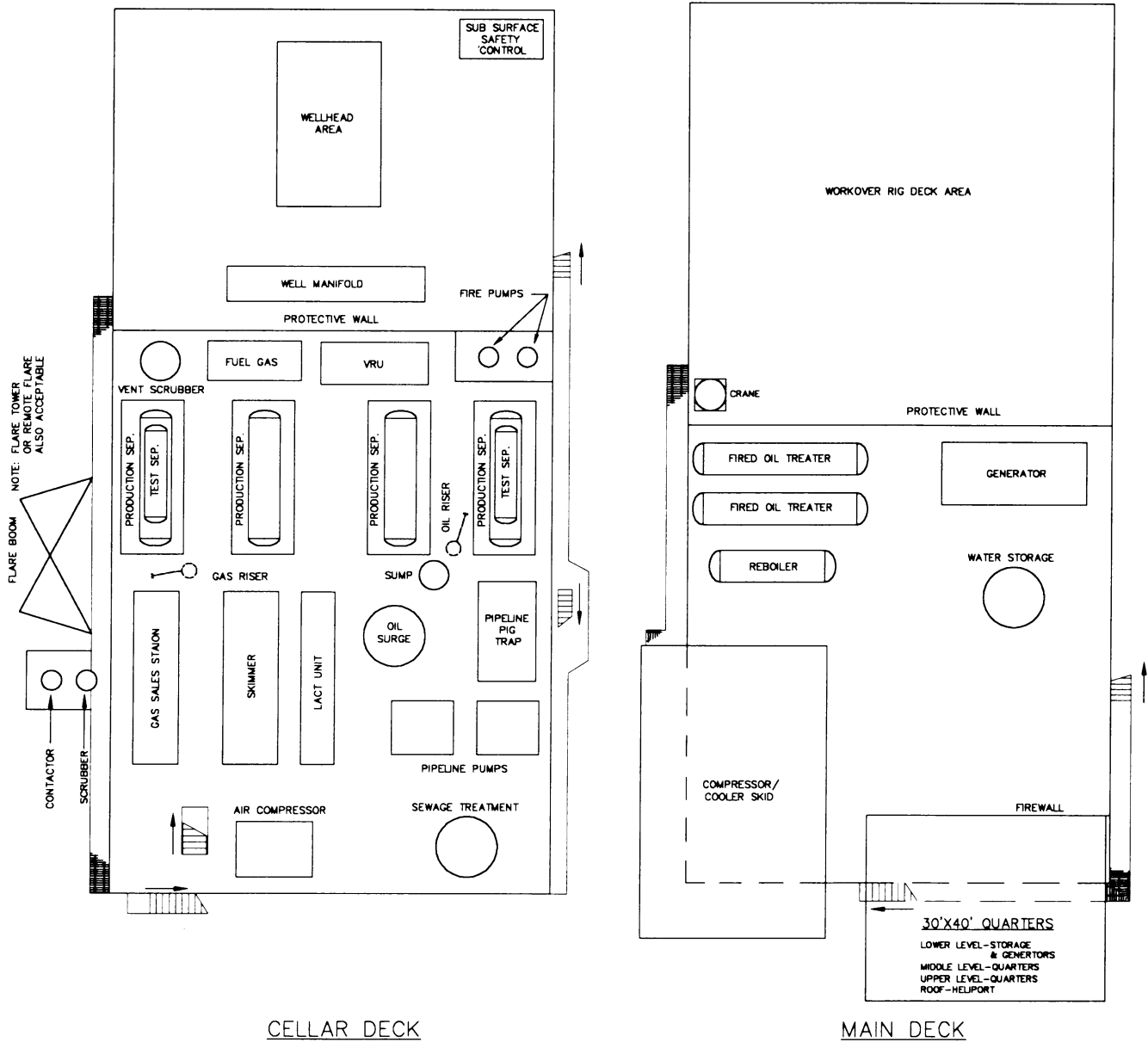


Figure B-1—Oil Production Facility, 2-Level Platform

B.2 Figure B-2

B.2.1 MAIN DECK

B.2.1.1 Negative Points

1. The generator, a source of noise, ignition, and fuel, is part of the living quarters package. Mitigation methods would include gas and fire detection and fire suppression.
2. The flare scrubber and tower at the wellhead end of the platform impede access to the wells by jack up or on-board drilling rig.
3. The gas compressor, a source of noise, fuel, and ignition, is relatively close to the living quarters. A firewall would provide greater isolation.
4. Unfired process vessels (high and low pressure separators) are close to machinery areas and living quarters.

B.2.1.2 Positive Points

1. Heat recovery on the compressor can be used to eliminate direct fired process vessels.
2. A generous amount of space has been provided for lay down area for crane loads.
3. The living quarters are located in corner of the deck as far as practical from machinery and process equipment. The

quarters building is equipped with firewalls on the two sides facing machinery and process equipment.

4. Escape routes from the quarters are not blocked by machinery or equipment.

B.2.2 CELLAR DECK

B.2.2.1 Negative Points

1. The well bay area is almost enclosed on its three outboard sides by well manifolds and other equipment that would impede egress or access in case of a blowout or well fire.
2. Test separators are located in the well bay area and could be relocated to the unfired process area on the cellar deck.
3. The large oil storage tank represents a significant source of fuel located in the center of the platform. Possible mitigation measures may include fire detection and suppression (e.g., aqueous film-forming foam).
4. The fire pump is located in close proximity to hydrocarbon handling equipment. It should be better isolated from source of fuel and ignition.
5. The work shop area is in relatively close proximity to the hydrocarbon processing area, placing sources of ignition close to sources of fuel.

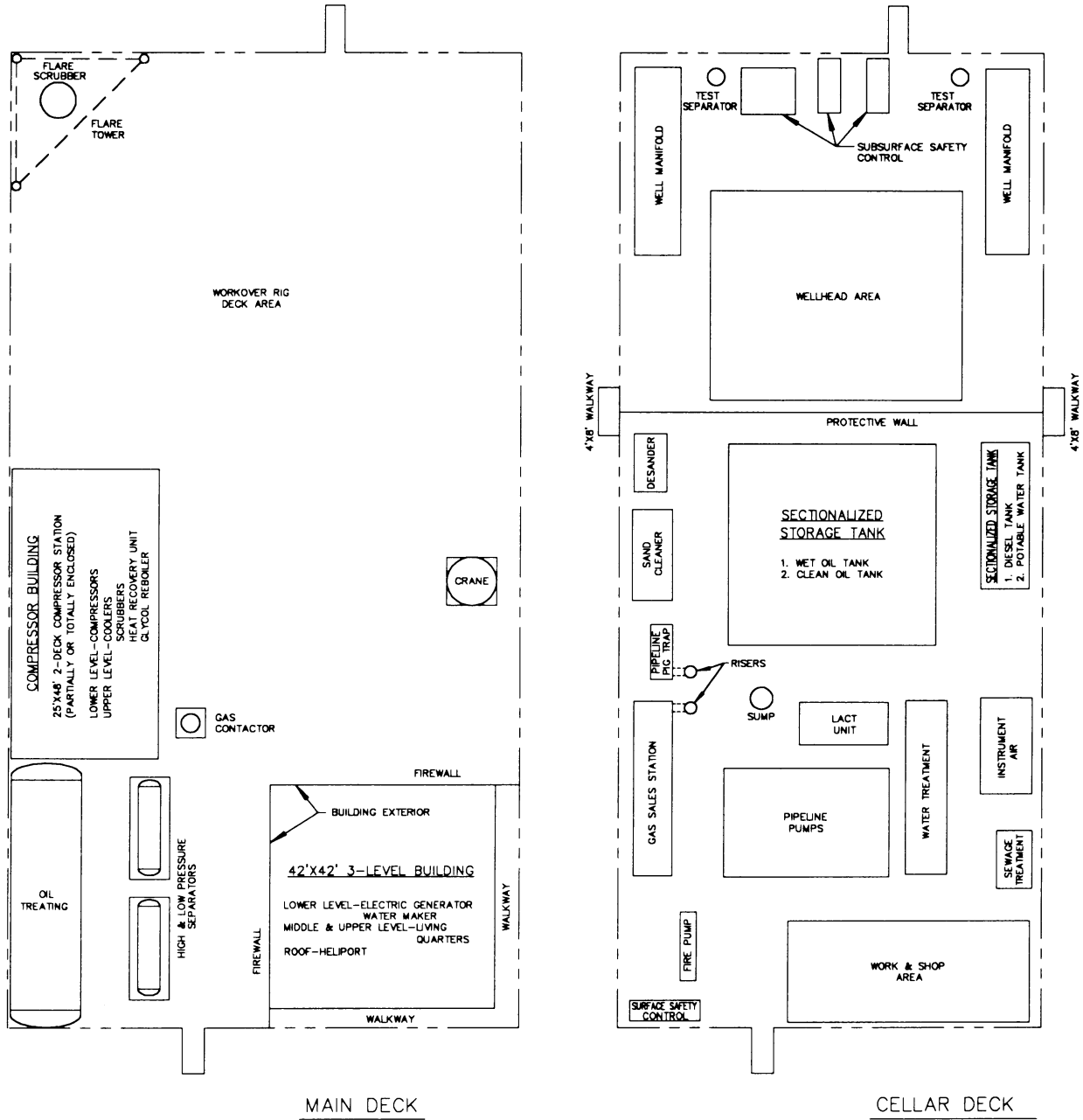


Figure B-2—Oil Production Facility, 2-Level Platform

B.3 Figure B-3

B.3.1 NEGATIVE POINTS

1. The well bay area is immediately adjacent to the living quarters building—a detriment in case of well blowout and fire. A firewall offers some protection.
2. The wellhead area is largely enclosed by the living quarters, machinery and process vessels and piping, thereby restricting egress and access in case of a well fire or blowouts.
3. The oil processing area is in close proximity to the gas compressor. A firewall separating the two may offer some protection.

Fire detection and suppression are options which may mitigate some or all of the above.

4. The electric generator (a source of both fuel and ignition) is located in the base of the living quarters building. Mitigation could include fire detection and suppression.

5. Center bay layout of wells impedes access by jackup-rig, onboard drilling rig or workover rig.
6. The gas compressor is located directly beneath oil treaters and gas scrubbers. A solid deck could separate the compressor from the equipment above it, and fire detection and automatic fire water deluge may be installed to mitigate the effects of fire above and below this separating deck.

B.3.2 POSITIVE POINTS

1. The pipeline riser and flare tower are at the opposite end of the platform from the living quarters.
2. Process machinery and process vessels are relatively far away from the living quarters.
3. Located in the base of the living quarters, the fire pump is isolated from the process area.
4. Heat recovery units for the glycol reboiler and oil treating eliminate the need for fired process vessels.

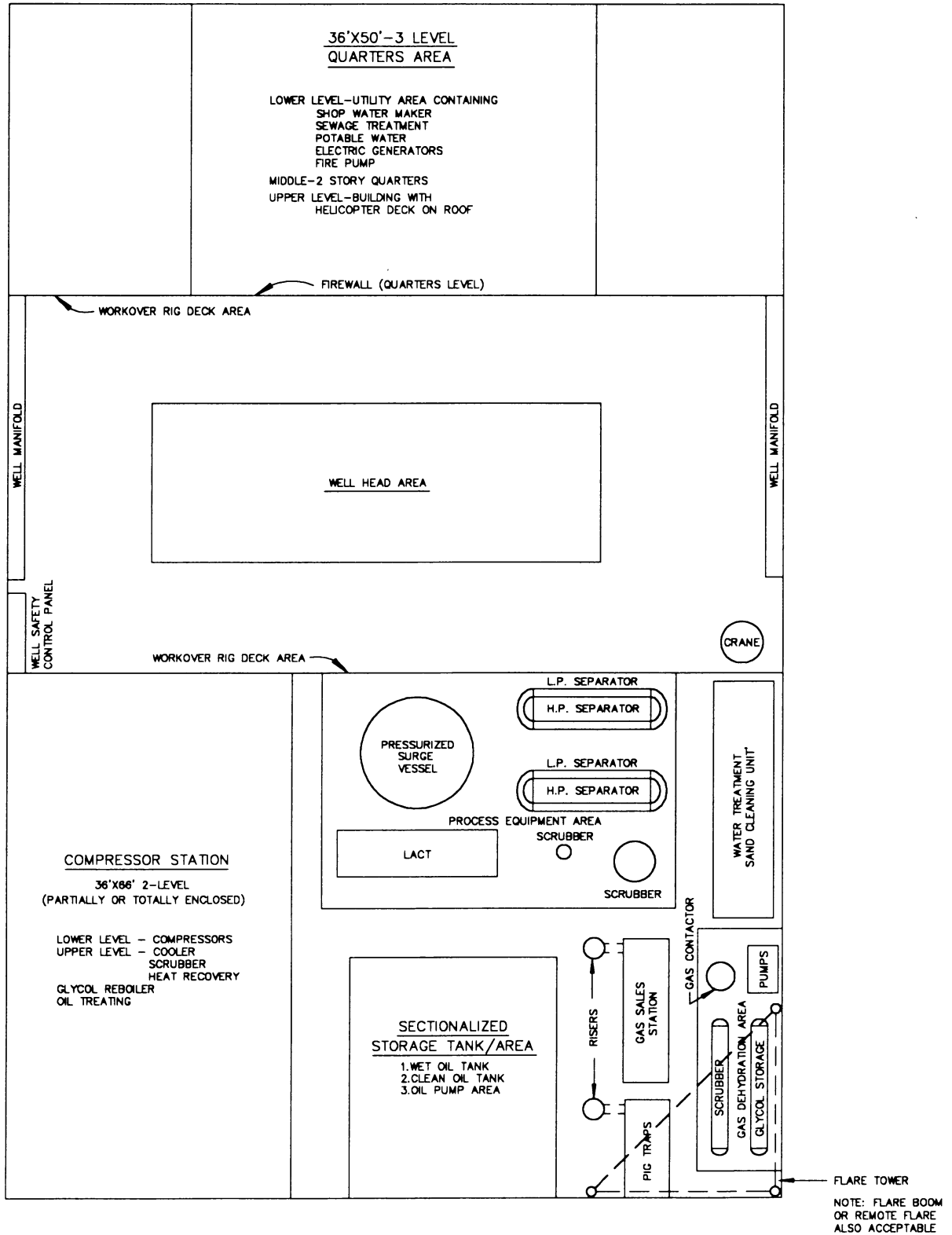


Figure B-3—Oil Production Facility, 2-Level Platform

APPENDIX C—INDUSTRY CODES, GUIDES, AND STANDARDS*

A. American Bureau of Shipping (ABS)

1. *Rules for Building and Classing Mobile Offshore Drilling Units*
2. *Rules for Building and Classing Steel Vessels*

B. American Iron and Steel Institute (AISI)

AISI Steel Products Manual, *Stainless and Heat Resisting Steels*

C. American National Standards Institute (ANSI)

1. ANSI/IEEE Std. 100-1984. *IEEE Standard Dictionary of Electrical and Electronics Terms*
2. ANSI B2.1, *Pipe Threads*
3. ANSI B16.5, *Steel Pipe Flanges, Flanged Valves, and Fittings*
4. ANSI B16.9, *Factory-Made Wrought Steel Butt-welding Fittings*
5. ANSI B16.10, *Face-to-Face and End-to-End Dimensions of Ferrous Valves*
6. ANSI B16.11, *Forged Steel Fittings, Socket-Welding and Threaded*
7. ANSI B16.28, *Wrought Steel Butt-welding Short Radius Elbows and Returns*
8. ANSI B31.3, *Petroleum Refinery Piping*
9. ANSI B31.4, *Oil Transportation Piping*
10. ANSI B31.8, *Gas Transmission Piping and Distribution Piping Systems*
11. ANSI B36.10, *Wrought-Steel and Wrought-Iron Pipe*
12. ANSI C2, *National Electrical Safety Code (NEC)*
13. ANSI C84.1, *Voltage Ratings for Electric Power Systems and Equipment (60 Hz)*
14. ANSI C57.12.70, *Terminal Markings and Connections for Distribution and Power Transformers*
15. ANSI Y14.15, *Electrical and Electronics Diagrams*
16. ANSI Y32.9, *Graphic Symbols for Electrical Wiring and Layout Diagrams used in Architecture and Building Construction*

17. ANSI Y32.11, *Graphical Symbols for Process Flow Diagrams*
18. ANSI Z21.52, *Standards for Gas Fired Single Fire Box Boilers*
19. ANSI Z32.2.3, *Graphical Symbols for Pipe Fittings, Valves, and Piping*

D. American Petroleum Institute (API)

1. API Spec Q1, *Specification for Quality Programs*
2. API RP 2A-LRFD, *Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms*
3. API RP 2D, *Recommended Practice for Operation and Maintenance of Offshore Cranes*
4. API RP 2L, *Recommended Practice for Planning, Designing, and Constructing Heliports for Fixed Offshore Platforms*
5. API RP T-2, *Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work with Anti-Pollution Safety Devices*
6. API Bul 5A2, *Bulletin on Thread Compounds for Casing, Tubing, and Line Pipe*
7. API Spec 5B, *Specification for Threading, Gaging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads*
8. API Spec 5L, *Specification for Line Pipe*
9. API Spec 6A, *Specification for Wellhead Equipment*
10. API Spec 6D, *Specification for Pipeline Valves*
11. API Spec 11P, *Specification for Packaged High Speed Separable Engine-Driven Reciprocating Gas Compressors*
12. API RP 11R, *Recommended Practice for Electric Submersible Pump Installations*
13. API Spec 12B, *Specification for Bolted Tanks for Storage of Production Liquids*
14. API Spec 12D, *Specification for Field Welded Tanks for Storage of Production Liquids*
15. API Spec 12F, *Specification for Shop Welded Tanks for Storage of Production Liquids*
16. API Spec 12P, *Specification for Fiberglass Reinforced Plastic Tanks*

*The user should use the latest edition of these codes, guidelines and standards.

17. API RP 12R1, *Recommended Practice for Setting, Maintenance, Inspection, Operation and Repair of Tanks in Production Service*
18. API Spec 14A, *Specification for Subsurface Safety Valve Equipment*
19. API RP 14B, *Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems*
20. API RP 14C, *Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms*
21. API RP 14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems*
22. API RP 14F, *Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms*
23. API RP 14G, *Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms*
24. API RP 14H, *Recommended Practice for Use of Surface Safety Valves and Underwater Safety Valves Offshore*
25. API RP 55, *Recommended Practice for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*
26. API RP 75, *Development of a Safety and Environmental Management Program for Outer Continental Shelf Operations and Facilities*
27. API RP 500, *Recommended Practice for Classification of Locations for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms*
28. API RP 505, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1 and Zone 2*
29. API RP 510, *Pressure Vessel Inspection Code*
30. API RP 520, *Recommended Practice for Design and Installation of Pressure-Relieving Systems in Refineries, Parts I and II*
31. API RP 521, *Guide for Pressure Relief and Depressuring Systems*
32. API Std 526, *Flanged Steel Safety Relief Valves*
33. API RP 540, *Recommended Practice for Electrical Installations in Petroleum Processing Plants*
34. API RP 550, *Manual on Installation of Refinery Instruments and Control Systems, Parts I and II*
35. API Std 600, *Steel Gate Valves (Flanged or Butt-welding Ends)*
36. API Std. 602, *Carbon Steel Gate Valves for Refinery Use (Compact Design)*
37. API Std 617, *Centrifugal Compressors for General Refinery Service*
38. API Std 618, *Reciprocating Compressors for General Refinery Service*
39. API Std 620, *Design and Construction of Large, Welded, Low-Pressure Storage Tanks*
40. API Std 650, *Welded Steel Tanks for Oil Storage*
41. API Std 660, *Shell-and-Tube Heat Exchangers for General Refinery Service*
42. API Std 661, *Air-Cooled Heat Exchangers for General Refinery Service*
43. API Std 1104, *Standard for Welding Pipelines and Related Facilities*
44. API RP 1111, *Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines*
45. API Std 2000, *Venting Atmospheric and Low-Pressure Storage Tanks*
46. API RP 2003, *Protection Against Ignitions Arising Out of Static, Lightning, and Stray Currents*
47. *API Guide for Inspection of Refinery Equipment, Chapter VI, Pressure Vessels (Towers, Drums, and Reactors)*
48. *API Guide for Inspection of Refinery Equipment, Chapter IX, Fired Heaters and Stacks*
49. *API Guide for Inspection of Refinery Equipment, Chapter XIII, Atmospheric and Low-Pressure Storage Tanks*
50. *API Guide for Inspection of Refinery Equipment, Chapter XV, Instruments and Control Equipment*
51. *API Guide for Inspection of Refinery Equipment, Chapter XVI, Pressure-Relieving Devices*
52. API PSD 2216, *Ignition Risk of Hot Surfaces in Open Air*
53. API Medical Research Report EA 7301, *Guidelines on Noise*
54. *Fugitive Hydrocarbon Emissions from Petroleum Production Operations, Volume I and Volume II*

E. American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE)

1. ASHRAE Handbook and Product Directory, Systems Volume
2. ASHRAE Handbook—Fundamentals

F. American Society of Mechanical Engineers (ASME)

1. ASME Boiler and Pressure Vessel Code—Section I, *Power Boilers*
2. ASME Boiler and Pressure Vessel Code—Section II, *Material Specifications*
3. ASME Boiler and Pressure Vessel Code—Section IV, *Heating Boilers*
4. ASME Boiler and Pressure Vessel Code—Section V, *Nondestructive Examinations*
5. ASME Boiler and Pressure Vessel Code—Section VIII, *Pressure Vessels, Divisions I and II*
6. ASME Boiler and Pressure Vessel Code, Section IX, *Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators*

G. American Society of Testing and Materials (ASTM)

1. ASTM A53, *Specification for Welded and Seamless Steel Pipe*
2. ASTM A105, *Specification for Forgings, Carbon Steel, for Piping Components*
3. ASTM A106, *Specification for Seamless Carbon Steel Pipe for High-Temperature Service*
4. ASTM A153, *Specification for Zinc Coating (Hot-Dip) on Iron and Steel Hardware*
5. ASTM A193, *Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service*
6. ASTM A194, *Specification for Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service*
7. ASTM A234, *Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and Elevated Temperatures*
8. ASTM A333, *Specification for Seamless and Welded Steel Pipe for Low-Temperature Service*
9. ASTM A354, *Specification for Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners*

10. ASTM D-323, *Standard Test Method for Vapor Pressure of Petroleum Products—The Reid Method*

11. ASTM F1166, *Standard Practice for Human Engineering Design for Marine Systems, Equipment and Facilities*

H. Canadian Standards Association (CSA)

1. CSA Standard C22.1 Canadian Electrical Code, Part 1
2. CSA Standard C22.2 No. 30, *Explosion-Proof Enclosures for Use in Class I, Hazardous Locations*
3. CSA Standard C22.2 No. 157, *Intrinsically Safe and Non-Incendive Equipment for Use in Hazardous Locations*
4. *Hazardous Locations, a Guide for the Design, Construction, and Installation of Electrical Equipment*, John Bossert and Randolph Hurst

I. Factory Mutual Research Corporation (FM)

1. Approval Standard 3600, *Electrical Equipment for Use in Hazardous (Classified) Locations, General Requirements*
2. Approval Standard 3610, *Intrinsically Safe Apparatus and Associated Apparatus for Use in Class I, II, and III, Division I, Hazardous (Classified) Locations*
3. Approval Standard 3611, *Electrical Equipment for Use of Class I, Division 2, Class II, Division 2, and Class III, Divisions 1 and 2, Hazardous (Classified) Locations*
4. Approval Standard 3615, *Explosion-Proof Electrical Equipment General Requirements*
5. Approval Standard 3620, See NFPA No. 496
6. Approval Standard 3810, *Electrical and Electronic Test, Measuring, and Process Control Equipment*
7. Approval Standard 6310-6330, *Combustible Gas Detectors*

J. Gas Processors Suppliers Association (formerly Natural Gas Processors Suppliers Association)

Engineering Data Books

K. Hydraulics Institute

1. *Standards for Centrifugal, Rotary, and Reciprocating Pumps*
2. *Pipe Friction Manual*

L. Illuminating Engineering Society (IES)

1. IES RP-1, *American National Standard Practice for Office Lighting*
2. IES RP-7, *American National Standard Practice for Industrial Lighting*
3. *IES Lighting Handbook*

M. Institute of Electrical and Electronics Engineers (IEEE)

1. IEEE Std. 45, *Recommended Practice for Electric Installations on Shipboard*
2. IEEE Std. 141, *Recommended Practice for Electric Power Distribution for Industrial Plants*
3. IEEE Std. 142, *Recommended Practice for Grounding of Industrial and Commercial Power Systems*
4. IEEE Std. 242, *Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems*
5. IEEE Std. 303, *Recommended Practice for Auxiliary Devices for Motors in Class I, Groups A, B, C, and D, Division 2 Locations*
6. IEEE Std. 315, *Graphic Symbols for Electrical and Electronics Diagrams*
7. IEEE Std. 383, *Standard for Type of Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations*
8. IEEE RP 446, *Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications*
9. IEEE Std. 450, *Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations*
10. IEEE Std. 484, *Recommended Practice for Installation, Design, and Installation of Large Lead Storage Batteries for Generating Stations and Substations*
11. IEEE Std. 485, *Recommended Practice for Sizing Large Lead Storage Batteries for Generating Stations and Substations*
12. IEEE Std. 515, *Recommended Practice for the Testing, Design, Installation, and Maintenance of Electrical Resistance Heat Tracing for Industrial Applications*

N. Instrument Society of America (ISA)

1. ISA RP 7.1, *Pneumatic Control Circuit Pressure Test*
2. ISA RP 12.1, *Recommended Practice for Electrical Instruments in Hazardous Atmospheres*
3. ISA S 12.4, *Instrument Purging for Reduction of Hazardous Area Classification*
4. ISA RP 12.6, *Recommended Practice for Installation of Intrinsically Safe Systems for Hazardous (Classified) Locations*
5. ISA S 5.1, *Instrumentation Symbols and Identification*
6. ISA S 12.12, *Electrical Equipment for Use in Class I, Division 2 Hazardous (Classified) Locations*
7. ISA S 12.13, Part I, *Performance Requirements for Combustible Gas Detectors*
8. ISA RP 12.13, Part II, *Installation Operation and Maintenance of Combustible Gas Detection Instruments*
9. ISA S 12.15, Part I, *Performance Requirements for Hydrogen Sulfide Detection Instruments (10–100 ppm)*
10. ISA RP 12.15, Part II, *Installation, Operation and Maintenance of Hydrogen Sulfide Detection Instruments*
11. ISA RP 42.1, *Nomenclature for Instrument Tubing Fittings*
12. ISA RP 60.9, *Piping Guide for Control Centers*
13. ISA S 20, *Specification Forms for Process Measurement and Control Instruments, Primary Elements and Control Valves*
14. ISA S 51.1, *Process Instrumentation Terminology*
15. *Electrical Instruments in Hazardous Locations*, Ernest C. Magison. ISBN: 87664-376-4
16. *Electrical Systems for Oil and Gas Production Facilities*. ISBN:1-55617-127-7

O. National Electrical Manufacturers Association (NEMA)

1. NEMA MG 1, *Motors and Generators*
2. NEMA MG 2, *Safety Standard for Construction and Guide for Selection, Installation, and Use of Electric Motors and Generators*
3. NEMA MG 10, *Energy Guide for Selection and Use of Polyphase Motors*
4. NEMA VE 1, *Cable Tray Systems*

5. NEMA ICS 2, *Standards for Industrial Control Devices, Controllers and Assemblies*
6. NEMA ICS 2.1, *Seismic Testing of Motor Control Centers*
7. NEMA ICS 6, *Enclosures for Industrial Controls and Systems*

P. National Association of Corrosion Engineers (NACE)

1. NACE Std. MR-01-75, *Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment*
2. NACE Std. RP-01-76, *Corrosion Control on Steel, Fixed Offshore Platforms Associated with Petroleum Production*

Q. National Fire Protection Association (NFPA)

1. NFPA No. 30, *Flammable and Combustible Liquids Code*
2. NFPA No. 37, *Standard for the Installation and Use of Stationary Combustion Engines and Turbines*
3. NFPA No. 69, *Explosion Prevention Systems*
4. NFPA No. 70, *National Electrical Code*
5. NFPA No. 77, *Recommended Practice on Static Electricity*
6. NFPA No. 78, *Lightning Protection Code*
7. NFPA No. 90A, *Standard for the Installation of Air Conditioning and Ventilating Systems*
8. NFPA No. 91, *Standard for the Installation of Blower and Exhaust Systems for Dust, Stock and Vapor Removal or Conveying*
9. NFPA No. 101, *Life Safety Code--Code for Safety to Life from Fire in Buildings and Structures*
10. NFPA No. 321, *Standard on Basic Classification of Flammable and Combustible Liquids*
11. NFPA No. 325M, *Fire Hazard Properties of Flammable Liquids, Gases, and Volatile Solids*
12. NFPA No. 493, *Standard for Intrinsically Safe Apparatus and Associated Apparatus for Use in Class I, II, and III, Division 1 Hazardous Locations*
13. NFPA No. 496, *Standard for Purged and Pressurized Enclosures for Electrical Equipment in Hazardous (Classified) Locations*
14. NFPA No. 497A, *Recommended Practice for Classification of Class I Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas*

15. NFPA No. 497M, *Manual for Classification of Gases, Vapors, and Dusts for Electrical Equipment in Hazardous (Classified) Locations*
16. NFPA SPP-11A, *Industrial Heating and Pressure Equipment*
17. *Electrical Installations in Hazardous Locations*, Schram & Earley, First Printing, December 1988. ISBN:0-87765-356-9
18. *Electrical Installations in Hazardous Locations*, P. J. Schram and M. W. Earley
19. National Fire Code Volume 6, *Sprinklers, Fire Pumps and Water Tanks*
20. National Fire Code Volume 8, *Portable and Manual Fire Control Equipment*

R. Underwriters Laboratories, Inc. (UL)

1. UL 595, *Standard for Marine-Type Electric Lighting Fixtures*
2. UL 674B, *Safety Standard for Electric Motors and Generators for Use in Hazardous Locations, Class I, Groups C and D*
3. UL 698, *Safety Standard for Electric Industrial Control Equipment for Use in Hazardous Locations, Class I, Groups A, B, C, and D, and Class II, Groups E, F, and G*
4. UL 783, *Electrical Flashlights and Lanterns for Use in Hazardous Locations, Class I, Groups C and D*
5. UL 844, *Standard for Electric Lighting Fixtures for Use in Hazardous Locations*
6. UL 1604, *Electrical Equipment for Use in Hazardous Locations, Class I and II, Division 2, and Class III, Divisions 1 and 2*
7. UL 913, *Standard for Intrinsically Safe Apparatus and Associated Apparatus for Use in Class I, II, and III, Division 1, Hazardous (Classified) Locations*
8. UL Product Directories (Red and Green Books)
9. Bulletin of Research No. 58, *An Investigation of Fifteen Flammable Gases or Vapors with Respect to Explosion-Proof Electrical Equipment*
10. Bulletin of Research No. 58A, *An Investigation of Additional Flammable Gases or Vapors with Respect to Explosion-Proof Electrical Equipment*
11. Bulletin of Research No. 58B, *An Investigation of Additional Flammable Gases or Vapors with Respect to Explosion-Proof Electrical Equipment*

APPENDIX D—GOVERNMENT CODES, RULES AND REGULATIONS

A. Code of Federal Regulations (CFR)

1. Title 29, Part 1910, *Occupational Safety and Health Standards*
2. Title 30, Part 250, *Oil and Gas and Sulphur Operations on the Outer Continental Shelf*
3. Title 33, Subchapter C, *Aids to Navigation*, Part 67, *Aids to Navigation on Artificial Islands and Fixed Structures*
4. Title 33, Subchapter N, *Outer Continental Shelf Activities*, Parts 140 through 147
5. Title 33, Part 153, *Control of Pollution by Oil and Hazardous Substances, Discharge Removal*
6. Title 40, Part 110, *Discharge of Oil*
7. Title 40, Part 112, *Oil Pollution Prevention*
8. Title 46, Shipping Subchapter I-A, Parts 107-108, *Mobile Offshore Drilling Units (United States Coast Guard)*
9. Title 46, Shipping Subchapter J, *Electrical Engineering*, Parts 110 through 113 (United States Coast Guard, CG259)
10. Title 49, Part 192, *Transportation of Natural and Other Gas in Pipeline: Minimum Federal Safety Standards*
11. Title 49, Part 195, *Transportation of Liquids by Pipeline*

B. United States Department of the Interior

Bureau of Mines, *Flammability Characteristics of Combustible Gases and Vapors*, Bulletin 627. Note: No longer available from Bureau of Mines, but included as an Appendix in ISA RP 12.13 Part II.

C. U.S. National OCS Orders

MMS Federal and Regional Notices to Lessees and Operators of all Federal Oil, Gas, and Sulphur Leases on the Outer Continental Shelf.

D. Environmental Protection Agency (EPA)

Document AP-26, *Workbook of Atmospheric Dispersion Estimates*

E. State, municipal, and other local regulatory agencies, as applicable

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